Rosebery Substation T1 & T2 and 44 kV switchgear replacement

RIT-T Project Specification
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Public

TasNetworks | Powering a Bright Future

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TasNetworks acknowledges the palawa (Tasmanian Aboriginal community) as the original owners and custodians of lutruwita (Tasmania). TasNetworks, acknowledges the palawa have maintained their spiritual and cultural connection to the land and water. We pay respect to Elders past and present and all Aboriginal and Torres Strait Islander peoples.

Contents

Glossary

AACE	Association for the Advancement of Cost Engineering
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CNAIM	Common Network Asset Indices Methodology
GPMBOK	Guide to the Project Management Body of Knowledge
GWP	Global Warming Potential
IASR	Input Assumptions and Scenarios Report
ISP	Integrated System Plan
kV	Kilovolt
MVA	Megavolt Ampere
NER	National Electricity Rules
NPV	Net Present Value
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PoE	Probability of Exceedance
PoF	Probability of Failure
PSCR	Project Specification Consultation Report
R24	Regulatory control period 2024-2029
R29	Regulatory control period 2029-2034
RIT-T	Regulatory Investment Test for Transmission
SF6	Sulphur Hexafluoride
T1	Transformer 1
T2	Transformer 2
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
VNR	Value of Network Resilience
WACC	Weighted Average Cost of Capital

Disclaimer

This document has been prepared and published solely for the purpose of meeting TasNetworks' Regulatory Investment Test for Transmission obligations as required under the National Electricity Rules. TasNetworks has used its best endeavours to ensure the accuracy of the information in this document is fit for purpose, and makes no other representation or warranty about the accuracy or completeness of the document or its suitability for any other purpose.

Executive summary

This Project Specification Consultation Report (PSCR) represents the first step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for addressing environmental, safety and reliability risks caused by age-related condition issues of two transformers and the 44 kilovolt (kV) switchgear at Rosebery Substation.

Rosebery Substation currently operates with three transformers, two of which are 36 megavolt ampere (MVA) transformers (T1 and T2). T1 and T2 are 110/44-22 kV transformers that were manufactured in 1968 and commissioned later in that year. Consistent with assets nearing the end of their technical lives, the health-based assessment utilising the industry accepted Common Network Asset Indices Methodology (CNAIM) rates the assets as poor with increasing asset risk. These asset conditions pose a risk to the reliability of supply to customers served by Rosebery Substation because transformers are used to change higher voltage electricity to a lower voltage for transportation through the distribution network.

The 44 kV switchgear at Rosebery Substation is also nearing its end of life. Switching constraints are emerging as the ageing switchgear is often out of service, leading to a risk of unserved energy. The circuit breakers are subject to increased risk of leaks and failure, leading to increased unplanned corrective maintenance accompanied by environmental and worker safety risks. These assets are also time-consuming and expensive to repair and replace because the 44 kV network in North-West Tasmania is unique in Australia.

Rosebery Substation supplies electricity to the local Rosebery community and to Trial Harbour Zone Substation (which feeds Zeehan). It also supplies mining customers (MMG mine and Bluestone) and is the only 44 kV injection point in the network, with MMG mine being supplied via a dedicated 44 kV feeder. It supplies approximately 40 megawatt (MW) of load in total. In the event of failure of two transformers, the substation would be able to supply a maximum of 36 MW from one remaining transformer. Such a scenario would lead to involuntary load shedding until a system spare is commissioned, which is likely to take up to 18 months given that there is no spare 44 kV transformer at present.

Identified need: managing risks at Rosebery Substation

TasNetworks has identified an opportunity to increase market benefits by addressing reliability, financial, environmental and safety risks associated with ageing transformers and switchgear at Rosebery Substation.

If action is not taken, the condition of the T1 and T2 transformers and 44 kV switchgear at Rosebery Substation will expose us and our customers to increasing levels of risk going forward, as deterioration increases the likelihood of failure.

Under the 'do nothing' base case, there is an increasing risk of transformer and switchgear failure. Such incidents pose significant reliability risks due to unserved energy and environmental risks through oil leaks. There may also be serious safety consequences for nearby residents and members of the public, as well as our field crew who may be working on or near the assets. Additionally, these incidents carry financial risk associated with the increased cost of emergency reactive maintenance or replacement.

Addressing the condition issues of the transformers will enable us to manage reliability, financial, safety and environmental risks at Rosebery Substation. TasNetworks expects that addressing these issues will result in significant market benefits and, as such, we consider the identified need for this investment to be market benefits under the RIT-T.

Three credible options have been considered

We consider that there are three credible options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need. Each credible option involves replacement of the ageing T1 and T2 transformers and 44 kV switchgear. The options vary based on the location of the replacement transformers and the timing of investment. Specifically:

- Option 1 involves the replacement of T1 and T2 transformers and the 44 kV switchgear in the 2024-2029 regulatory control period (**R24**);
- Option 2 involves installing two new transformers at Farrell substation in R24; and
- Option 3 involves the replacement of T1 and T2 transformers and the 44 kV switchgear in the 2029-2034 regulatory control period (**R29**).

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

We do not consider non-network options to be commercially or technically feasible to assist with meeting the identified need for this RIT-T, as non-network options will not mitigate the reliability, environmental, safety and financial risks posed as a result of asset deterioration.

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 these risks at a lower cost than network options. We consider that non-network options are unable to sufficiently reduce risk costs and provide greater net economic benefits than the network options because:

- non-network options are unable to address the risk of transformer or switchgear failure, so will not substantially reduce environmental, safety, and financial risk related costs; and
- non-network options are unlikely to completely eliminate load shedding risks due to the extended duration required.

The options have been assessed against three reasonable scenarios

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the most likely scenario from the 2024 Integrated System Plan (**ISP**) (i.e., the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of the Australian Energy Market Operator's (**AEMO**) ISP assumptions, and have been based on TasNetworks' analysis.

Table 1 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate[1]	7.00%	7.00%	7.00%

[1] The discount rate of 7 per cent aligns with the discount rate used by AEMO in the ISP as mandated by the RIT-T guidelines.

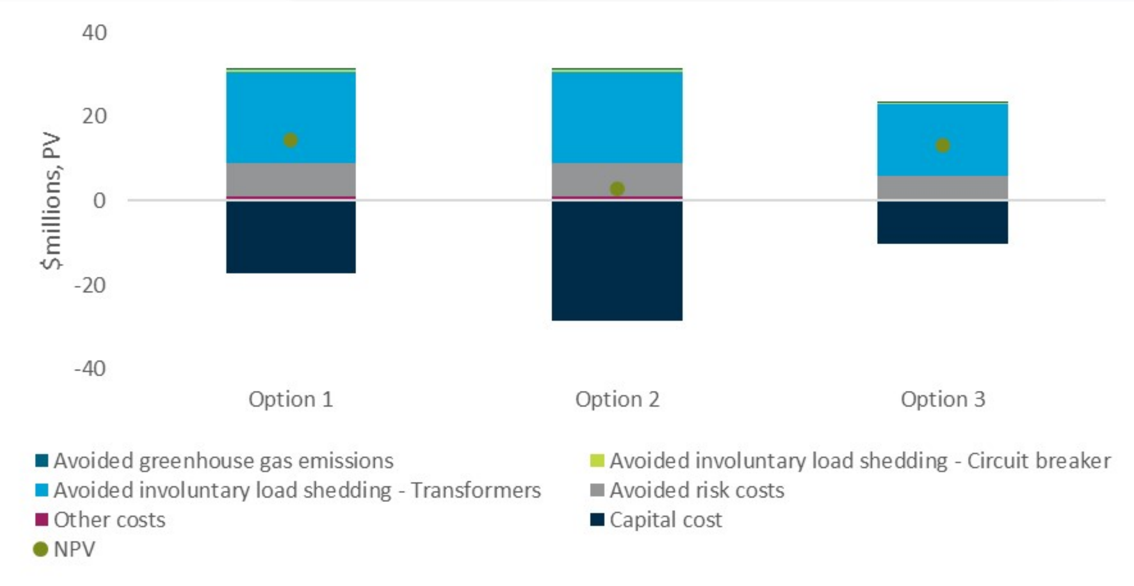
Network capital costs	Base estimate	Base estimate	Base estimate
Operating and maintenance costs	Base estimate	Base estimate	Base estimate
Environmental, safety and financial risk benefit	Base estimate	Base estimate – 25%	Base estimate +25%

We have weighted the three scenarios equally as nothing has been identified to suggest an alternate weighting would be more appropriate.

Option 1 delivers the greatest estimated net benefits

All three credible options are found to have positive benefits for all scenarios investigated. Option 1 is expected to deliver the greatest net economic benefits across all scenarios investigated.[2] On a weighted basis, the net economic benefits of Option 1 are approximately $14.4 million, which is 7.8 per cent greater than the net economic benefits of the second-ranked option, Option 3 (with net benefits of approximately $13.2 million). Figure 1 below shows a breakdown of the weighted net economic benefits for each option.

Figure 1: Weighted net economic benefits ($m, PV)



Option 1 is the preferred option because it is expected to maximise net economic benefits on a weighted basis. In addition to having the highest net market benefits (based on weighting the scenarios considered), Option 1 is preferred over Option 3 for the following reasons:

- Option 1 is already ranked above Option 3 even though we have not applied real cost escalation to the costs of Option 3 despite construction commencing later – some degree of cost escalation is likely and would increase the extent to which Option 1 results in higher net economic benefits relative to Option 3; and
- TasNetworks is expecting additional mining load in the area in the near-to-short term, meaning earlier investment will support accommodating that increased load in the network without risk of even greater unserved energy in the future.

[2] Option 1 is the top-ranked option in the central and high scenarios – Option 1 is expected to deliver net benefits 7.8 and 10.8 per cent greater than the second ranked option in those scenarios respectively. Option 1 and Option 3 are effectively ranked equally in the low scenario given that there is only a 3.9 per cent difference between the two options in that scenario.

Draft conclusion

This PSCR has found that Option 1 is the preferred option at this draft stage of the RIT-T. Option 1 involves the replacement of both T1 and T2 transformers and 44 kV switchgear in R24, commissioning the assets at the end of this regulatory control period, R24. The estimated capital expenditure associated with Option 1 is $24.1 million (in 2024/25 dollars).

Exemption from preparing a PADR

NER 5.16.4(z1) provides for a TNSP to be exempt from producing a Project Assessment Draft Report (PADR) for a particular RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $54 million;[3]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

We consider that the investment in relation to Option 1 and the analysis in this PSCR meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR will no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period.

Accordingly, if we consider that any such additional credible options are identified, we will produce a PADR which includes an NPV assessment of the net market benefit of each additional credible option.

[3] NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $54m based on the AER Final Determination: 2024 RIT and APR cost threshold review – final determination, November 2024, available at: https://www.aer.gov.au/documents/2024-rit-and-apr-cost-threshold-review-final-determination-12-november-2024, accessed 3 June 2024.

Introduction

This Project Specification Consultation Report (PSCR) represents the first step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for addressing environmental, safety and reliability risks caused by age-related condition issues of two transformers and the 44 kV switchgear at Rosebery Substation.

Rosebery Substation currently operates with three transformers, two of which are 36 Megavolt ampere (MVA) transformers (T1 and T2). T1 and T2 are 110/44-22 kilovolt (kV) transformers that were manufactured in 1968 and commissioned later that year. Consistent with assets nearing the end of their technical lives, the health-based assessment utilising the industry accepted Common Network Asset Indices Methodology (CNAIM) rates the assets as poor with increasing asset risk. These asset conditions pose a risk to the reliability of supply to customers served by Rosebery Substation because transformers are used to change higher voltage electricity to a lower voltage for transportation through the distribution network.

The 44 kV switchgear at Rosebery Substation is also nearing its end of life. Switching constraints are emerging as the ageing switchgear is often out of service, leading to a risk of unserved energy. The circuit breakers are subject to increased risk of leaks and failure, leading to increased unplanned corrective maintenance accompanied by environmental and worker safety risks. These assets are also time-consuming and expensive to repair and replace because the 44 kV network in North-West Tasmania is unique in Australia.

Rosebery Substation supplies electricity to the local Rosebery community and to Trial Harbour Zone Substation (which feeds Zeehan). It also supplies mining customers (MMG mine and Bluestone) and is the only 44 kV injection point in the network, with MMG mine being supplied via a dedicated 44 kV feeder. It supplies approximately 40 MW of load in total. In the event of failure of two transformers, the substation would be able to supply a maximum of 36 MW from one remaining transformer. Such a scenario would lead to involuntary load shedding until a system spare is commissioned, which is likely to take up to 18 months given that there is no spare 44 kV transformer at present.

More broadly, the transformers at Rosebery Substation do not align with current standard fire mitigation requirements and a fire incident could lead to the simultaneous loss of multiple transformer assets. The bushings of T1/ T2 are also original and, in the case of catastrophic failure, the porcelain may shatter and send sharp projectiles across the switchyard – representing a safety concern to both operators and adjacent in-service equipment. Finally, both the transformer's aged oil containment systems have deficiencies, which pose environmental risks in the event of oil leakages.

TasNetworks is therefore examining options for addressing the age-related condition issues of the transformers and switchgear so that Rosebery Substation continues to operate in a safe and reliable manner. We expect that addressing these issues will significantly reduce reliability, safety and environmental risks and, by consequence, result in significant market benefits. Consequently, we consider the identified need for this investment to be market benefits under the RIT-T.

Purpose of this report

The purpose of this PSCR[4] is to:

- set out the reasons why we propose that action be undertaken (the 'identified need');
- present the options that we currently consider address the identified need;
- outline the technical characteristics that non-network options would need to provide (although we consider that non-network options are unlikely to be able to contribute to meeting the identified need for this RIT-T);
- present the economic assessment of all credible options, as well as the assumptions feeding into the analysis, and identify a preferred option at this draft stage of the RIT-T; and
- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

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

Exemption from preparing a PADR

The National Electricity Rules (**NER**) 5.16.4(z1) provides for a Transmission Network Service Provider (**TNSP**) to be exempt from producing a Project Assessment Draft Report (**PADR**) for a particular RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $54 million;[5]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary load curtailment and involuntary load shedding.

We consider the investment in relation to all of the options considered and the analysis presented in this PSCR meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR will no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period.

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4 See *Appendix 1 Compliance checklist* for the National Electricity Rules requirements. Note that that National Electricity Rules Version 230 was referenced during the preparation of this document.

5 NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $54m based on the AER's most recent cost threshold determination: AER, 2024 RIT and APR cost thresholds review – Final determination, November 2024, available at: https://www.aer.gov.au/documents/2024-rit-and-apr-cost-threshold-review-final-determination-12-november-2024, accessed 3 June 2025.

Accordingly, if we consider that any such additional credible options are identified, we will produce a PADR which includes a Net Present Value (**NPV**) assessment of the net market benefit of each additional credible option.

Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 30 October 2025.

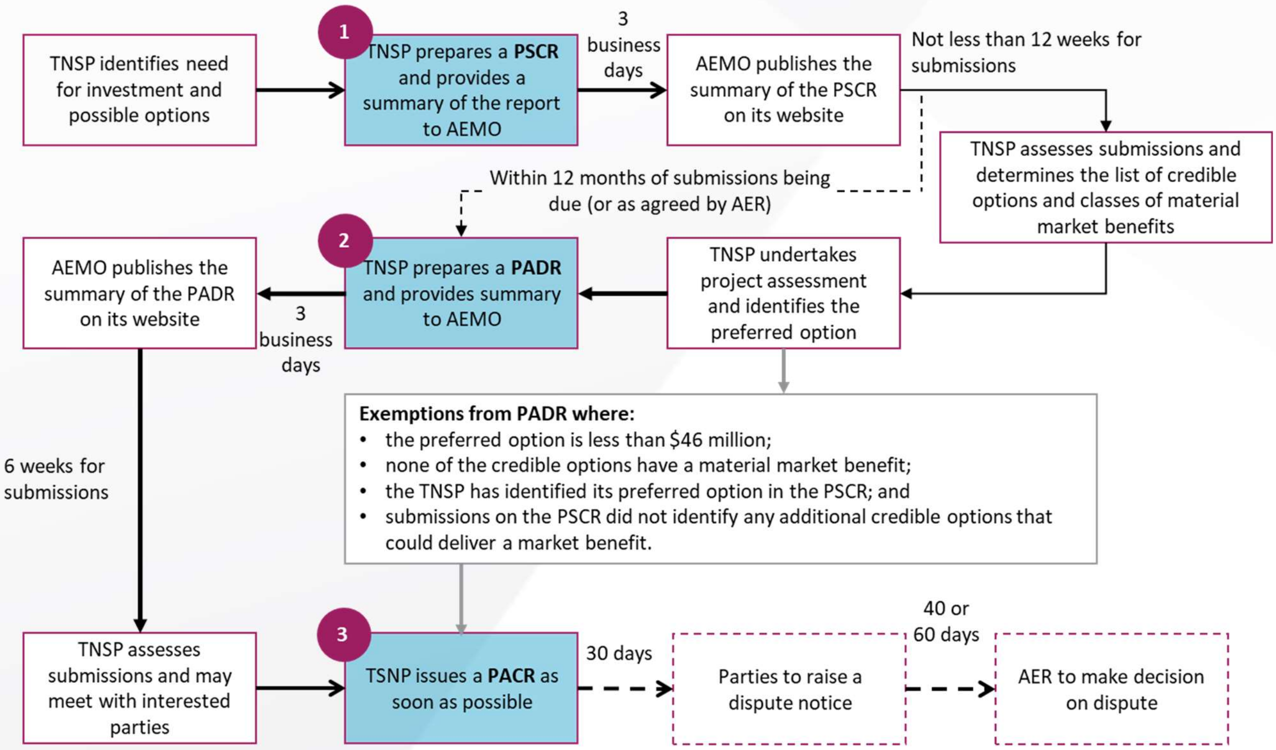
Submissions should be emailed to the Regulation Team via regulation@tasnetworks.com.au.[6] In the subject field, please reference 'Rosebery PSCR'.

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

Should we consider that no additional credible options were identified during the consultation period that could provide material market benefits, we intend to produce a Project Assessment Conclusions Report (**PACR**) that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.[7] Subject to no additional credible options being identified, we anticipate publication of a PACR in November 2025.

Figure 2 summarises the RIT-T process.

Figure 2: Overview of the RIT-T process



[6] We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

[7] In accordance with NER 5.16.4(z2).

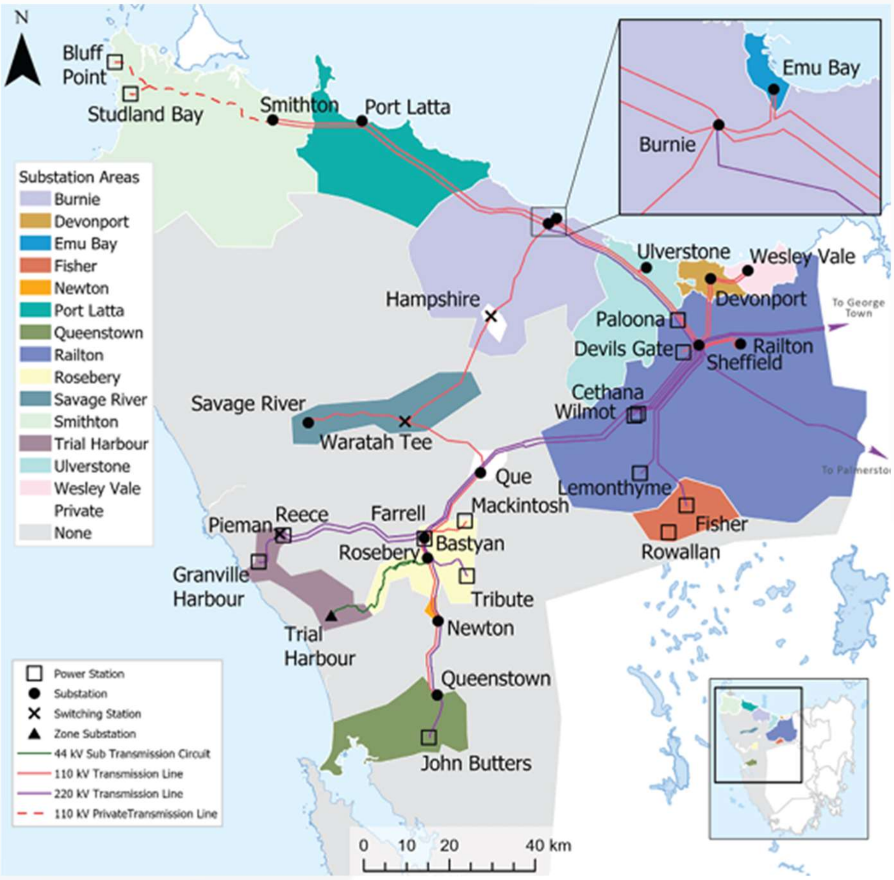
The identified need

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 Rosebery Substation and the relevant transformers.

Background to the identified need

Figure 3 provides an overview of TasNetworks' transmission network. It illustrates that Rosebery Substation is located on the west coast of Tasmania in the township of Rosebery in the North West and West Coast planning area. The substation supplies the local Rosebery community, the MMG and Bluestone mines and the Zeehan community via Trial Harbour Zone Substation.

Figure 3: North West and West Coast planning area

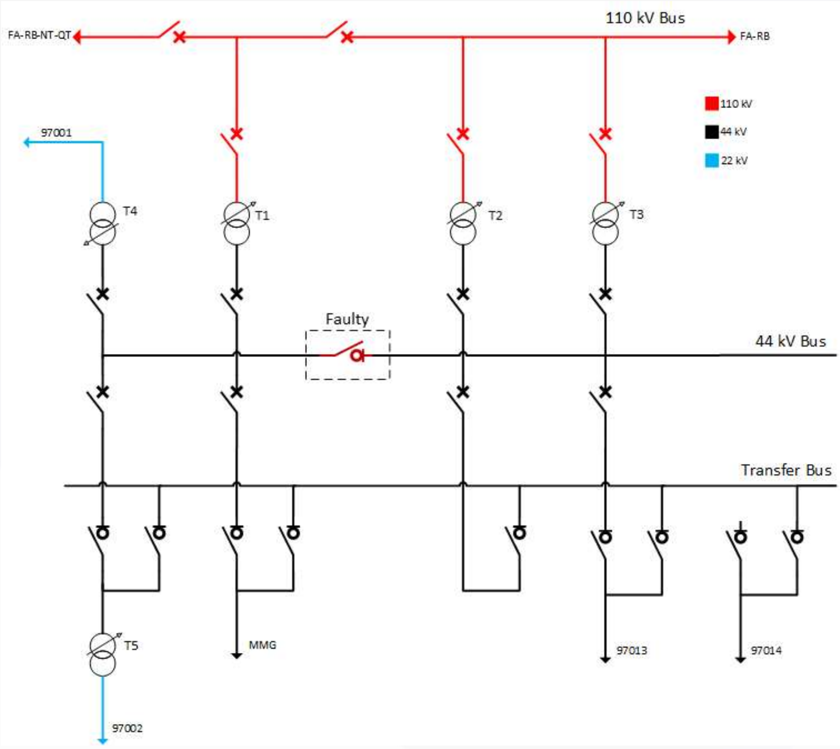


Source: TasNetworks, Annual Planning Report 2024, p 65.

Network configuration

Supply to Rosebery is from two transmission circuits. The area is supplied from the main transmission network at 110 kV from Farrell Substation (near Tullah), with a 110 kV transmission circuit via Burnie Substation available as an alternate supply. Parts of the site were redeveloped in 2012 through replacement of the 110 kV switchgear and associated protection equipment. This included reconfiguring the incoming 110 kV landing spans. A simplified one-line diagram of the current Rosebery Substation layout is shown in Figure 4.

Figure 4: Current configuration of the Rosebery Substation one-line diagram



Transformer asset condition issues

At Rosebery there are three operational transformers, T1, T2 and T3. T1 and T2 are rated at 36 MVA each and T3 is rated at 30 MVA, giving Rosebery a firm rating of 66 MVA at 44 kV. Both T1 and T2 are 110/44-22 kV transformers that were manufactured in 1968 by Tyree and commissioned towards the end of that year. T1 and T2 have both previously received refurbishments, with T1 having received midlife refurbishments in 2000 and T2 having received a full refurbishment in 1994. The refurbishment of T1 included the replacement of transformer oil and the installation of new bushings, radiators and LV conductor terminations. The refurbishment of T2 included a redesign of the core and coil assembly, winding replacement, oil replacement and the replacement of cooling radiators. Leak repairs have been conducted on both T1 and T2 transformers in previous years. However, minor oil leaks persist on the lower flanges (main tank and radiator), Buchholz, main tank sight glass, 44 kV bushing turrets, pumps and around the pressure relief valves. The T1 and T2 transformers will be 60 years old by the end of FY29, while the T3 transformer will only be 46 years old. The age of the T1 and T2 transformers places them at a significantly higher risk of failure when compared to more recently commissioned transformers.

The transformers also have inherent design deficiencies that reflect practices at the time of their manufacture, such as bolted lids/flanges on the transformer tank, free breathing tanks, oil level indication, lack of HV neutral bushing, oil filled porcelain bushings and excessive extra unused flanges. These deficiencies increase the likelihood and consequence of asset failures. Further, both transformers contain flammable oil, of which these transformers' current fire mitigation techniques do not meet the standards outlined in the Australian Standard for Substations and high voltage installations exceeding 1 kV a.c. (AS2067), posing increased risks of oil fires spreading between adjacent assets.

TasNetworks has identified through our regular asset inspections that the T1 and T2 transformers at Rosebery Substation are approaching their end of life with health-based assessments rating the assets as poor with increasing asset risk utilising the Common Network Asset Indices Methodology (CNAIM). The condition of both assets, which will continue to deteriorate over time, will affect the reliability of their performance now and into the future. These condition issues are consistent with the age of these assets and their usage since commissioning.

Figure 5 illustrates the oil leaks that are present on each of the transformers.

Figure 5: Oil leaks on T1 (left) and T2 (right)

The higher risk of failure associated with T1 and T2 transformers has led to an increased risk of unplanned maintenance of these assets. The risk of reactive replacement of transformers and circuit breakers has also increased. This is exacerbated by the fact that there currently does not exist a readily available spare 44 kV transformer nor can one be obtained on the secondary market since this voltage is unique in Australia to the North-West of Tasmania. In the event of a combined failure of T1 and T2 transformers, Rosebery Substation will not be capable of servicing the current demand and as a result lead to involuntary load shedding.

There is significant financial risk associated with increased unplanned maintenance and reactive replacement for TasNetworks. Due to the unique nature of the 44 kV transformers, current estimates place an 18 month procurement period to obtain a new suitable transformer. Additionally, TasNetworks would be required to conduct emergency works which would incur substantial resource and labour costs.

44 kV switchgear asset condition issues

The 44 kV switchgear at Rosebery has been identified as requiring replacement due to the assets reaching end-of-life. The switchgear has not undergone any major refurbishment work since its original commissioning and the overhead gantries to which the switchgear is mounted are currently experiencing corrosion related issues and restrict access to the transformers for maintenance and replacement.

As part of the switchgear at Rosebery, there are a total of nine circuit breakers, which are comprised of five Siemens SPS72 SF6 circuit breakers and four Sprecher & Schuh AR45 oil circuit breakers. The frequency of unplanned corrective maintenance to refill the Siemens SPS72 circuit breakers with SF6 is increasing due to the age of these assets. One specific SF6 circuit breaker (C252) has a persistent leak on the mechanism and interrupter housing connection, and due to the location of this leak, any local repair is not feasible. Currently the Sprecher & Schuh AR45 circuit breakers are in acceptable condition. However, they are reaching end-of-life and maintenance requirements have increased such that they are now higher than maintenance requirements for circuit breakers as defined in the current TasNetworks' standard.

Both types of circuit breakers have known design deficiencies. Specifically, the 44 kV Sprecher and Schuh circuit breakers are oil filled units which require significantly more maintenance compared to SF6 CBs. The bushings are porcelain which presents a safety risk if the CB fails catastrophically as sharp shards of porcelain are projected outward. The sight glasses for indicating the internal oil level are prone to leaking and moisture ingress. The Siemens SPS-72.5 circuit breakers are filled with SF6 and leaks are consistently discovered on these units requiring the unit to be taken out of service to refill. Similar to the Sprecher and Schuh circuit breakers, the Siemens SPS-72.5 circuit breakers also use porcelain insulation on the bushings, presenting a safety risk from circuit breaker failures.

Figure 6 demonstrates one of the persistent SF6 leaks on the switchgear.

Figure 6: Persistent SF6 leak on switchgear

The higher risk of failure associated with the circuit breakers has led to an increased risk of unplanned maintenance of these assets. The risk of reactive replacement of circuit breakers has also increased. This is exacerbated by the fact that there currently do not exist any dedicated spares for the 44 kV circuit breakers. While there is a spare circuit breaker in the Devonport store, substantial modifications to both the circuit breaker and the support structure at Rosebery Substation would need to be incurred. There is significant financial risk associated with increased unplanned maintenance and reactive replacement for TasNetworks. Furthermore, as the MMG mine has a dedicated 44 kV feeder, if the respective circuit breaker fails we estimate that it will take approximately four hours to manually switch the network such that a by-pass setup feeder can supply the MMG mine. As a result, there would be approximately four hours of unserved energy.

Rosebery Substation customers

Rosebery Substation supplies approximately 40 MW of load, including:

- a majority of the load (approximately 36 MW) is attributable to the two mines in the local area, ie:
  - the MMG mine, which is supplied by a dedicated 44 kV feeder from Rosebery Substation; and
  - the Bluestone mine; and

- the remainder is residential load including the Rosebery and Zeehan communities.[8]

Residential load is expected to continue at a consistent level into the future. However, there is potential additional load in the near-to-short term due to underground mining expansion in the region which could exacerbate load curtailment in the event that both transformers fail simultaneously.

There are also two hydro power stations that rely on their station supply from Rosebery Substation to connect to the transmission network.

Description of identified need

If action is not taken, the condition of the T1 and T2 transformers and 44 kV switchgear at Rosebery Substation will expose us and our customers to increasing levels of risk going forward, as deterioration increases the likelihood of failure.

Under the 'do nothing' base case, there is an increasing risk of transformer and switchgear failure. Such incidents pose significant reliability risks due to unserved energy, environmental risks through oil leaks and could have serious safety consequences for nearby residents and members of the public, as well as our field crew who may be working on or near the assets. These incidents also carry additional financial risk associated with the increased cost of emergency reactive maintenance or replacement.

Addressing the condition issues of the transformers will enable us to manage reliability, financial, safety and environmental risks at Rosebery Substation. TasNetworks expects that addressing these issues will result in significant market benefits and, as such, we consider the identified need for this investment to be market benefits under the RIT-T.

Assumptions underpinning the identified need

TasNetworks has applied an asset 'risk cost' evaluation framework to quantify the risks caused by the deteriorating condition of the transformers and switchgear and the risk cost reductions resulting from addressing the condition issues. Risks are assessed against TasNetworks' risk framework using the AER's risk-cost assessment methodology outlined in its Industry practice Application Note: Asset Replacement Planning 2019.[9]

The risk costs have been calculated by reference to the following formula:

$$TQR = \sum_{n=0}^{n} (PoF \times No) \times (LoC \times CoC)$$

where:

- TQR is the total quantified risk/risk cost per year of the event happening;
- PoF is the annual asset probability of failure, which is obtained from our asset performance records, as well as being benchmarked against national and international standards where applicable;
- No is the number of assets;

[8] Zeehan community is supplied from a single 22 kV distribution line from Trial Harbour Zone Substation, with Trial Harbour being supplied via a single 35 km, 44 kV sub-transmission line from Rosebery Substation.

[9] See: https://www.aer.gov.au/system/files/D19-2978%20-%20AER%20-Industry%20practice%20application%20note%20Asset%20replacement%20planning%20-%2025%20January%202019.pdf .

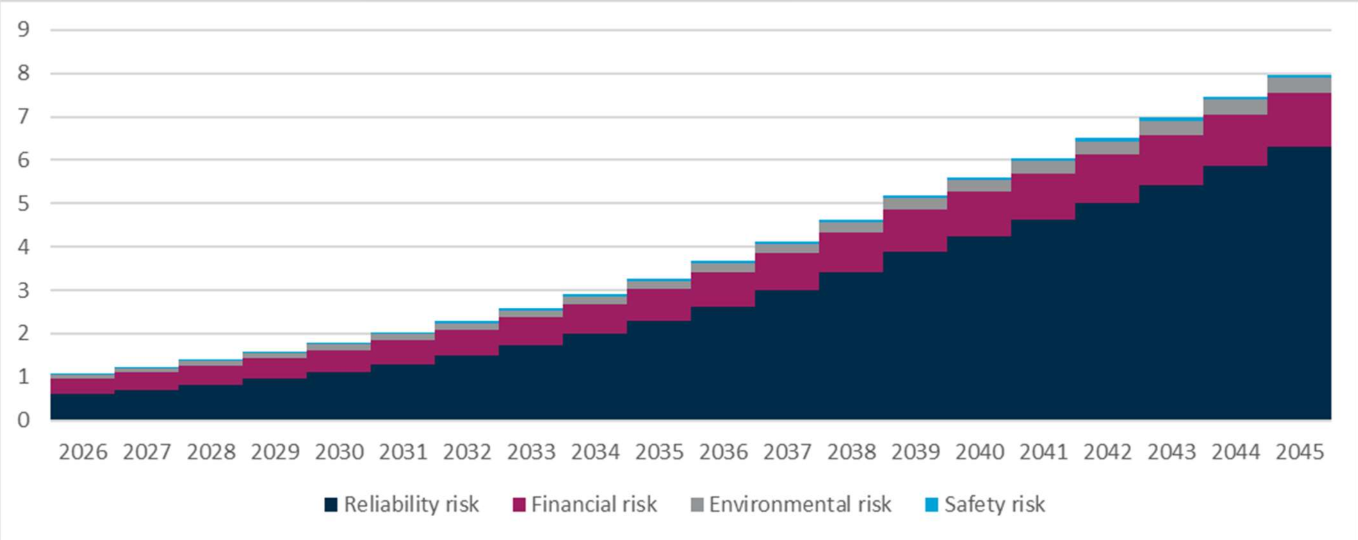
- CoC is the cost of consequence of the failure event, which is evaluated by an external consultant to align with contemporary methodologies of risk-based asset management; and
- LoC is the likelihood of consequence of failure event, which is determined using both actual (as observed by both TasNetworks and its peers) and estimated data.

The key risks considered as part of this RIT-T are:

- network performance risk, i.e. involuntary load shedding;
- direct financial costs risk, e.g. reactive maintenance upon failure of the asset; and
- environmental and safety risks, e.g. oil spills from the containment system.

The remainder of 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. Figure 7 summarises the increasing risk costs over the assessment period under the base case.

Figure 7: Estimated risk costs ($m real)



Asset health and the probability of failure

Our asset health modelling aligns with Chapter 3.2 and 5.2 of the Australian Energy Regulator's (AER) Asset replacement planning guideline.[10] Condition information for each asset is assessed to generate an asset health index and assets approaching their end of life, as identified through the asset health index, are candidates for a replacement or refurbishment intervention. Specifically, asset health is rated on a scale of one to ten using CNAIM.[11] The asset health ratings determine a health based PoF in line with industry standard.

The asset health issues identified at Rosebery Substation are summarised in Table 2.

[10] AER, *Industry practice application note – Asset replacement planning*, January 2019 – available at https://www.aer.gov.au/system/files/D19-2978%20-%20AER%20-Industry%20practice%20application%20note%20Asset%20replacement%20planning%20-%2025%20January%202019.pdf

[11] For more information on CNAIM see, The Office of Gas and Electricity Markets (UK), *DNO common network asset indices methodology*, 1 April 2021, available at https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/dno_common_network_asset_indices_methodology_v2.1_final_01-04-2021.pdf.

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Table 2 Asset health issues at Rosebery Substation and their consequences

Issue	Consequences if not remediated
Increasing risk of transformer failure	Increasing risk over time of the below consequences
Increasing risk of switchgear failure	Increasing risk over time of the below consequences
Non-firm supply following failure	Involuntary load shedding and increased risk of simultaneous transformer failure
Oil containment system does not meet standard	Oil lost to environment

Reliability risk

This risk refers to the consequence arising from a reduction in reliability of electricity supply for customers through involuntary load shedding and is valued using the AER's 2024 estimated Value of Customer Reliability (VCR) for Tasmania, weighted by load connected to the Rosebery Substation.[12] Table 3 summarises our calculation of the load-weighted VCR used in our analysis.[13]

We have multiplied the load-weighted VCR amount by 0.5 in accordance with the AER's Value of Network Resilience (VNR) for long-duration outages.[14]

Table 3: Calculated of load-weighted VCR

Load type	VCR ($/kWh)	Weighting (%)
Residential – Tasmania	35.69	10
Very large business customers – Mines	10.63	90
Weighted VCR	13.14	-
VNR adjustment	6.57	-

As discussed above, if both transformers were to fail at Rosebery Substation, involuntary load shedding will occur as there is not currently a suitable replacement for the 44 kV transformer at the substation. For the purposes of this RIT-T we have calculated the load at risk by reference to historical load at the substation and the level of load that would be curtailed in the event that one 36 MW transformer and one 30 MW transformer fail simultaneously. This results in a load at risk of 4 MW. We consider that this is a conservative assumption because if both 36 MW transformers failed it is likely there would be greater levels of energy at risk and therefore unserved energy.

The reliability risk has been captured as avoided involuntary load shedding benefits in the NPV analysis – see the assessment of credible options below.

Reliability risk is the largest of all risks quantified under the base case for this RIT-T, making up approximately 71 per cent of the total estimated risk cost in present value terms.

Financial risk

This risk refers to the direct financial consequence arising from the failure of an asset including the cost of replacement, which may need to be under emergency conditions. Our estimation of financial risk for this RIT-T does not include the expected escalating cost of reactive maintenance associated with aging

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[12] AER, *Values of customer reliability: Final report on VCR values*, December 2024, Table 1 and Table 3.

[13] We use the weighted VCR when calculating the reliability risk if both T1 and T2 transformers fail and we use the very large business customers – Mines VCR when calculating the reliability risk if the circuit breaker that is a part of the dedicated 44 kV feeder for the MMG mine fails.

[14] AER, *Value of Network Resilience 2024*, Final decision, September 2024, p 24.

transformers and switchgear. Instead, we assume a flat cost overtime for regular maintenance of the aging assets and include this under the general maintenance category for this RIT-T.

Financial risk is the second largest of all risks quantified under the base case for this RIT-T, making up approximately 22 per cent of the total estimated risk cost in present value terms.

Environmental risk

This risk refers to the consequence arising from fire risk, loss of oil due to the degraded transformers and switchgear and the leakage of SF6 from circuit breakers at Rosebery Substation.

While oil spills may have broader environmental impacts, for the purposes of this RIT-T we have only included the financial costs imposed on TasNetworks as a result of an oil spill, e.g. clean-up costs. Further, since the T1 and T2 transformers at Rosebery do not align with current standard fire mitigation requirements, a fire incident could lead to the simultaneous loss of multiple transformer assets and broader switchgear. Specifically, the current firewall is inadequate to prevent any fire spreading across the equipment.[15]

For the environmental risks associated with SF6 leakage, we calculate this following the AER's example in the 2024 RIT-T application guidelines.[16] The environmental risk associated with the SF6 circuit breakers has been captured as avoided greenhouse gas emissions benefits in the NPV analysis – see the assessment of credible options below.

Under the TQR framework detailed above, the likelihood of an environmental 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 and other events. Further, the cost of an environmental consequence considers the cost associated with damage to the environment including compensation, clean-up costs, litigation fees, fines and any other related costs.

Environmental risk is the third largest of all risks quantified under the base case for this RIT-T, making up approximately five per cent of the total estimated risk cost in present value terms.

Safety risk

This risk refers to the safety consequence to our workforce, contractors and/or members of the public of an asset failure whose failure modes can create harm. The main safety risk associated with the transformers at Rosebery Substation is that workers in the area may be impacted by the catastrophic failure causing oil fires. The main safety risk associated with the switchgear at Rosebery Substation is that workers in the area may be impacted by the catastrophic failure of porcelain bushings.

Under the TQR framework detailed above, the likelihood of a safety 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. Further, the cost of a safety consequence accounts for the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs.

Safety risk is the smallest of all risks quantified under the base case for this RIT-T and represents less than two per cent of the total estimated risk cost in present value terms.

[15] See Australian Standard 2067 2026.

[16] AER, *Regulatory investment test for transmission: Application guidelines*, November 2024, p 96-97.

Credible options

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

We consider that there are three credible options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need. Other options were considered but not progressed for various reasons that are outlined in Table 10.

Each credible option involves replacement of the ageing T1 and T2 transformers and 44 kV switchgear. The options vary based on the location of the replacement transformers and the timing of investment.

The scope of each option is set out in further detail below.

All costs and benefits presented in this PSCR are in real 2024/2025 dollars, unless otherwise stated.

Base case

The costs and benefits of each option in this PSCR are compared against those of a base case. Under this base case, no proactive capital investment is made to remediate the deterioration of the T1 and T2 transformers and the 44 kV switchgear. Under this 'do nothing' base case, there is an increasing risk of transformer and switchgear failure and the associated reliability, financial, safety and environmental risks.

Further, TasNetworks would then be forced to replace the failed assets under emergency conditions. Several of the safety and environmental issues would therefore remain.

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

Option 1 – Replace T1 and T2 transformers and 44 kV switchgear in R24

Option 1 involves the replacement of both T1 and T2 transformers and 44 kV switchgear in the 2024-2029 regulatory control period (R24). The works are estimated to be completed by the end of R24. The new transformers and switchgear will align with TasNetworks' current standards and, as such, will address all the identified condition issues. Specifically, this option includes the:

- replacement of T1 and T2 with new 60 MVA 110-44 kV transformers;
- reconfiguration of 110 kV switchgear;
- replacement and reconfiguration of 44 kV circuit breakers, busbar and disconnectors;
- relocation of T3 as a cold spare on the western side of the substation;
- installation of a new firewall between T1 and T2, T2 and T3 (cold spare) and T1 and T4;
- installation of new oil bunds and storage for transformer;
- reconfiguration of substation boundary fence on the northwestern side; and
- associated civil works for the transformer plinths, switchgear footings and other relevant items.

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The estimated capital cost of this option is approximately $24.1 million. Table 4 provides a breakdown of these capital costs by category of expenditure.

Table 4: Breakdown of Option 1's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
Rosebery	10.1	11.8	1.2	1.0	24.1

The expenditure for Option 1 is expected to occur between FY26 and FY29, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 5 shows the expected expenditure profile of Option 1 across the construction period.

Table 5: Annual breakdown of Option 1's expected capital cost, $m real

Year	Capital cost
FY26	0.5
FY27	4.8
FY28	13.8
FY29	5.0

Note: The sum of the numbers does not equal the total due to rounding.

Option 2 – Install two new transformers at Farrell substation in R24

Option 2 involves supplying the connected customers' load from Farrell substation by installing two new transformers at Farrell in R24. The works are estimated to be completed by the end of R24. The new transformers and switchgear will align with TasNetworks' current standards and, as such, will address all the identified condition issues. Specifically, this option includes the:

- installation of two new 110/44-22 kV 60 MVA supply transformers at Farrell substation;
- development of two 110 kV transformer bays with double disconnector bus selectivity;
- installation of two 110 kV transformer control and protection panels;
- extension of the 110 kV bus zone protection;
- installation of a 44 kV side double bus with disconnector selectivity;
- installation of two 44 kV transformer bays with disconnector selectivity;
- installation of three 44 kV transmission line bays with disconnector selectivity;
- installation of one set of 44 kV bus coupler bays;
- installation of a 44 kV transformer, line and bus coupler protection and control panels;
- installation of a 44 kV bus zone protection;
- civil works for new transformer plinths, oil bunds, fire walls and the approach road;
- civil works for 44 kV line bays, bus coupler bay, two 110 kV and two 44 kV transformer bays;
- installation of a 110 kV bus extension of both busses on the eastern side including relocation of the fence line;
- installation of three circuits of 44 kV (insulated at 66 kV) sub-transmission 5.5 km each from Farrell to Rosebery Substations through TL451 Easement;

- upgrade of Rosebery Substation 44 kV side bays by replacement of 44 switchgear bays for existing A252, B252 (with new B852), C452, D452, C252 and D252;
- installation of three new 44 kV transmission line bays to connect new transmission line bays into the Rosebery Substation; and
- civil works at Rosebery.

The estimated capital cost of this option is approximately $41.0 million. Table 6 provides a breakdown of these capital costs by category of expenditure.

Table 6: Breakdown of Option 2's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
Rosebery	15.0	22.0	2.5	1.5	41.0

The expenditure for this option is expected to occur between FY26 and FY29, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 7 shows the expected expenditure profile of Option 2 across the construction period.

Table 7: Expected expenditure profile of Option 2

Year	Capital cost
FY26	0.5
FY27	9.3
FY28	21.3
FY29	9.8

Note: The sum of the numbers does not equal the total due to rounding.

Option 3 – Replace T1 and T2 transformers and 44 kV switchgear in R29

Option 3 involves all works outlined under Option 1 with works occurring in the 2029-2034 regulatory control period (R29). The works are estimated to be completed by the end of R29.

Compared to Option 1, Option 3 delays replacement of T1, T2 and 44 kV switchgear by 5 years, i.e. until the next regulatory control period. The estimated capital cost of this option is approximately $24.1 million. Table 8 provides a breakdown of these capital costs by category of expenditure. TasNetworks has not applied any real cost escalation to these costs relative to Option 1. However, we are currently developing our approach to real cost escalation as part of our upcoming regulatory proposal.

Table 8: Breakdown of Option 3's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
Rosebery	10.1	11.8	1.2	1.0	24.1

The expenditure for this option is expected to occur between FY31 and FY34, reflecting the procurement of long lead time equipment and the ultimate commissioning works during two regulatory control periods. Table 9 shows the expected expenditure profile of Option 3 across the construction period.

Table 9: Expected expenditure profile of Option 3

Year	Capital cost
FY31	0.5
FY32	4.8
FY33	13.8
FY34	5.0

Note: The sum of the numbers does not equal the total due to rounding.

Options considered but not progressed

TasNetworks has considered several additional options to meet the identified need in this RIT-T. Table 10 summarises the reasons the following options were not progressed further.

Table 10 Options considered but not progressed

Description	Reason(s) for not progressing
Increased inspections	The condition issues have already been identified and cannot be rectified through increased inspections. While more frequent inspections may assist in identifying when an asset is approaching failure, possibly enabling postponed replacement, increased inspections are not prudent in this situation. Further, inspections may not identify failures in enough time to obtain replacements and avoid unserved energy, given the uniqueness of the 44 kV network.
Non-network solutions	We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need, as non-network options will not mitigate the environmental, safety, reliability and financial risks posed as a result of asset deterioration. This is outlined in more detail below.

No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[17] A "material inter-network impact" is defined by the NER in the following terms:[18]

> "A material impact on another Transmission Network Service Provider's network, which 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."

In determining whether a proposed transmission augmentation can be expected to have a material inter-network impact, the Australian Energy Market Operator (AEMO) screening test can be applied which describes the following considerations:[19]

- an increase in fault level of more than 10 MVA at any substation in another TNSPs network;
- a change in power transfer capability between transmission networks or in another TNSPs network of more than the minimum of 3% of maximum transfer capability and 50 MW;
- there is a significant change to voltage or any power quality metrics at the network boundary; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

Each credible option satisfies these conditions. By reference to AEMO's screening criteria, there is therefore no material inter-network impacts associated with any of the credible options considered.

[17] As per NER 5.16.4(b)(6)(ii).

[18] Refer NER Chapter 10.

[19] Inter-Regional Planning Committee. "Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations." Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 10 June 2025. https://www.aemo.com.au/-/media/Files/PDF/170-0035-pdf

Non-Network options

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T, since non-network options will not mitigate the environmental, safety, reliability and financial risks posed as a result of asset deterioration.

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 environmental, safety, financial and reliability risk related costs (which in practice are not expected to be affected by non-network solutions).

Required technical characteristics of non-network options

The extent of reliability risk may reduce if load is reduced through a non-network option such as a battery unit. However, the identified environmental, safety and financial risk related costs are, for the most part, not load dependent, and so would not be reduced by a non-network option.

The 2024 recorded maximum demand of Rosebery Substation was 40 MVA, while our maximum demand 50% probability of exceedance (PoE) forecast for 2050 is 50 MW. In the event of switchgear failure, our assumption is that it would take approximately four hours to reconfigure the operation of the substation to supply the mining load (see Network configuration). In the event of double transformer failure, our assumption is that it would take 18 months to deploy a system spare transformer to the site. In the event of a switchgear or double transformer failure, the non-network option would therefore be required to provide short term supply of this maximum demand until load resupply via the network is achieved. Following this, the non-network option would be required to supply the remaining unserved energy until normal operating conditions are restored.

Notwithstanding, while non-network options may reduce the reliability risk related costs, they are unlikely to substantially reduce the environmental, safety, and financial risk related costs. It is therefore not likely that the risk costs will be sufficiently reduced to make the non-network option more cost effective overall, irrespective of their type, size, operating profile and location.

In summary, we consider that non-network options are unable to sufficiently reduce risk costs and provide greater net economic benefits than the network options.

This is based on:

- non-network options being unable to address the risk of transformer or switchgear failure, so will not substantially reduce environmental, safety, and financial risk related costs; and
- non-network options being unlikely to completely eliminate load shedding risks due to the extended duration required.

Materiality of market benefits

The NER requires that RIT-T proponents consider a number of different classes of market benefits that could be delivered by a credible option.[20] Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why:[21]

- a particular class of market benefit is likely not to materially affect the outcome of the assessment of the credible options under the RIT-T; or
- the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate to the scale, size and potential benefits of each credible option being considered.

There has recently been a law change to introduce an emissions reduction objective into the national energy objectives[22] and the NER have been updated to add a new category of market benefit to the RIT-T reflecting changes in Australia's greenhouse gas emissions.[23] There is a risk of SF6 leakages from the ageing 44 kV circuit breakers, which has been captured in the analysis.

Market benefits considered material

Changes in involuntary load shedding

Currently, Rosebery Substation is not fit to fulfill the future state of forecast maximum demand described in the TasNetworks annual planning report. The current configuration of the T1, T2 and T3 transformers suffers from a common mode of failure when a line fault on the 110 kV side occurs. If a fault occurs, T2 and T3 are disconnected to isolate the rest of the substation. This reduces the firm capacity of the site, until switching can be conducted to put T2, T3 or both back into service. While Rosebery would be able to meet current demand if one transformer was no longer operational, it would not be able to meet current demand if two transformers were no longer operational.

The oil present within each transformer (used for insulation and cooling) is flammable and both T1 and T2 transformers currently do not meet the mitigation standards outlined in the Australian Standard for substations and high voltage installations exceeding 1 kV a.c., increasing the risks of oil fires spreading between adjacent assets and subsequently increasing the risk of joint failure. During peak demand periods this situation would force load shedding until a system spare is commissioned. Given the uniqueness of the 44 kV transformers current procurement estimates to obtain and install a replacement transformer are 18 months.

The MMG mine is currently supplied through a dedicated 44 kV feeder. In the event of a failure pertaining to the specific circuit breaker which services the MMG mine's dedicated feeder, TasNetworks would have to manually adjust other circuit breakers at Rosebery to re-route electricity to the MMG

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[20] Refer NER 5.15A.2(b)(4)

[21] NER clause 5.15A.2(b)(6).

[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] NER clause 5.15A.2(b)(4)(viii).

mine. We estimate that the required manual adjustment would take approximately four hours, forcing load shedding until the circuit breakers have been manually adjusted.

Replacing both T1 and T2 transformers and the circuit breakers at Rosebery reduces the risk of failure and reduces the likelihood of involuntary load shedding. Reductions in expected involuntary load shedding are included as a market benefit for this RIT-T. Our approach to calculating this category of market benefit is outlined in our description of the identified need above, i.e. using the probability of failure, a load-weighted VCR and the load reduction from a combined failure of T1 and T2 transformers.

Avoided greenhouse gas emissions (SF6)

The Rosebery Substation currently uses five circuit breakers which contain SF6. Due to the age of these assets the probability of catastrophic failure has increased substantially above that of a reasonably new circuit breaker containing SF6. In the event of catastrophic failure, the entire weight of SF6 contained within the circuit breaker would be emitted into the atmosphere. SF6 has a Global Warming Potential (**GWP**) value of 23,500 compared to CO2.[24] Replacing the existing end of life SF6 circuit breakers with new SF6-free circuit breakers at Rosebery reduces the likelihood of large greenhouse gas emissions and removes the existing leakage of SF6 due to the age of the assets. Reductions in expected greenhouse gas emissions are included as a market benefit for this RIT-T. Our approach to calculating this category of market benefit is outlined in our description of the identified need above, i.e. using the probability of failure, current leakage, SF6's GWP and the relevant VER values.

Market benefits not considered material

Wholesale market benefits

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[25]

The credible 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;
- changes in network losses; and
- competition benefits.

[24] National Greenhouse and Energy Reporting Regulations 2008, Regulation Section 2.02, Federal Register of Legislation – National Greenhouse and Energy Reporting Regulations 2008.

[25] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, October 2023, Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

Differences in the timing of expenditure

None of the credible options are expected to affect the timing of expenditure to address other identified needs in the network.

Option value

Option value is the value gained or foregone from implementing a credible option with respect to the likely future investment needs of the market.

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[26]

Further, the AER's view is 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.

We note that no credible option is sufficiently flexible to respond to change or uncertainty for this RIT-T. Specifically, each option is focused on proactively replacing deteriorating assets ahead of when they fail.

[26] Australian Energy Regulator, *Regulatory investment test for transmission, Application guidelines*, October 2023, Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

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.

Description of the base case

The costs and benefits of each option are compared against the base case. Under this base case, no proactive investment is undertaken, we incur routine and reactive maintenance costs, and the transformers will continue to operate with an increasing level of risk.

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]

The assumed base case for this RIT-T is described further in the previous section.

Assessment period and discount rate

A 20-year assessment period from 2025/26 to 2044/45 has been adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of the options.

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 functional 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 serviceable asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period.

A real, pre-tax discount rate of 7.0 per cent has been adopted as the central assumption for the NPV analysis presented in this PSCR, consistent with AEMO's latest Input Assumptions and Scenarios Report (IASR).[28] 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 4.18 per cent.[29] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest final IASR).[30]

[27] 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. Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, October 2023, Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

[28] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.

[29] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Directlink) as of the date of this analysis. See: https://www.aer.gov.au/industry/registers/determinations/directlink-determination-2025-30

[30] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.

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.

Specifically, we apply a bottom-up approach whereby the cost of each component within an option is individually estimated, and the cost of each of these components is then aggregated to provide a total central capital cost estimate for the option. This tool draws upon the latest quotes that we have received from our suppliers for the relevant equipment and the associated unit costs. For example, TasNetworks has recently completed two similar transformer replacements at Kermandie Substation and Port Latta Substation which provide increased accuracy cost estimates for the Rosebery transformer replacements. TasNetworks has escalated these costs to reflect the changes in costs since the commissioning of those assets.

TasNetworks considers the cost estimate for the Rosebery Substation options to have a cost accuracy of 15 per cent, which reflects a level three estimate.[31] TasNetworks utilises three levels of project estimating. As the level of project definition improves the level of uncertainty may reduce and the cost accuracy may improve. As such, selection of the estimate level is primarily driven by the stage of the project. The three levels of estimate and their respective normal application are:

- level one, which is used for the project concept stage, to perform feasibility and options analysis – considering scope and time risks;
- level two, which is used for the project development stage and to evaluate the preferred option – considering scope, time and contingent risk; and
- level three, which is used for the project implementation stage and to support business case approval – considering all management elements.

TasNetworks' estimating process was developed with consideration of the Association for Advancement of Cost Engineering International (AACE) guidelines and Guide to the Project Management Body of Knowledge (GPMBOK).

No specific contingency allowance has been included in the cost estimates for the options evaluated in this RIT-T.

All cost estimates are prepared in real, 2024/25 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials from the point at which they have been estimated.

Given that the replacement of existing assets does not require new easements, the credible options are not expected to impose social license costs. The exception is that the need to build new 44 kV lines as part of option 2 could carry some social license risk, due to some uncertainty over easements. However, this is not expected to materialise given that Option 2 is the lowest ranked option without the inclusion of social license costs.

[31] TasNetworks notes that the cost estimate for Option 2 is a level one estimate with a cost accuracy of 30 per cent, while the cost estimate for Options 1 and 3 are level three estimates (15 per cent accuracy). This is not expected to affect the ranking of the options, given that Option 2 is substantially higher cost than Option 1 (>40 per cent) and that the similarity in the components of the options means that any cost changes are likely to affect the options in a similar way. Given that Options 1 and 3 are the two highest ranked options, the sensitivity analysis in the assessment of credible options below is based on the 15 per cent accuracy associated with the level three estimates.

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 determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the most likely scenario from the 2024 Integrated System Plan (**ISP**) (i.e., the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, 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 TasNetworks' analysis, as discussed in the description of the identified need above.

The effect of changes to other variables (including the discount rate and capital costs) on the NPV analysis has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (i.e. where wholesale market benefits are not expected to be material).[32,33]

Table 11 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate[34]	7.00%	7.00%	7.00%
Network capital costs	Base estimate	Base estimate	Base estimate
Operating and maintenance costs	Base estimate	Base estimate	Base estimate
Environmental, safety and financial risk benefit	Base estimate	Base estimate – 25%	Base estimate +25%

We have weighted the three scenarios equally as nothing has been identified to suggest an alternate weighting would be more appropriate.

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:

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32 AER, *Regulatory investment test for transmission Application guidelines*, October 2023, pp. 44-46.

33 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.

34 The discount rate of 7 per cent aligns with the discount rate used by AEMO in the ISP as mandated by the RIT-T guidelines.

- lower and higher assumed capital costs;
- lower and higher weighted VCR;
- lower and higher estimated environmental, safety, reliability and financial risk benefits; 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 as part of the following section.

In addition, we have also sought to identify the 'boundary value' for key variables beyond which the outcome of the analysis would change, including the amount by which capital costs would need to increase for the preferred option to no longer be preferred.

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 the credible option to the base case. Benefits of the credible option are represented by reduction in costs or risks compared to the base case.

Estimated gross benefits

Table 12 below summarises the present value of the gross benefit estimates for each credible option relative to the base case under the three scenarios. The benefits included in this assessment consist of avoided risk, i.e. a reduction in reliability, financial, environmental and safety risks. It shows that Option 1 and Option 2 have the same gross market benefits. This reflects the fact that these options, although comprising different scopes, are commissioned at the same time and therefore address the identified need in a similar manner. Option 3 has lower gross market benefits because it is commissioned later, meaning there is a longer period of reliability, financial, safety and environmental risk costs.

Table 12 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	*1/3*	*1/3*	*1/3*	
Option 1	30.6	28.6	32.6	30.6
Option 2	30.6	28.6	32.6	30.6
Option 3	23.0	21.6	24.4	23.0

Estimated gross costs

Table 13 below summarises the costs of the options, relative to the base case, in present value terms.

The costs consist of the direct capital costs for each option, relative to the base case. It shows that Option 2 is the highest cost option, which reflects the additional works that are required to establish supply from the Farrell substation. It also shows that, although Option 1 and Option 3 have the same real cost, Option 3 is lower cost in present value terms because it occurs further into the future and so its costs are more heavily discounted. However, the lower cost of Option 3 also reflects the fact that we have not applied any real cost escalation to our cost estimate for this scope of works. We are currently developing our approach to real cost escalation as part of our upcoming revenue proposal.

Table 13 Costs of credible options relative to the base case ($m, PV)

Option/scenario	Central
Option 1	16.3
Option 2	27.7
Option 3	9.8

Estimated net market benefits

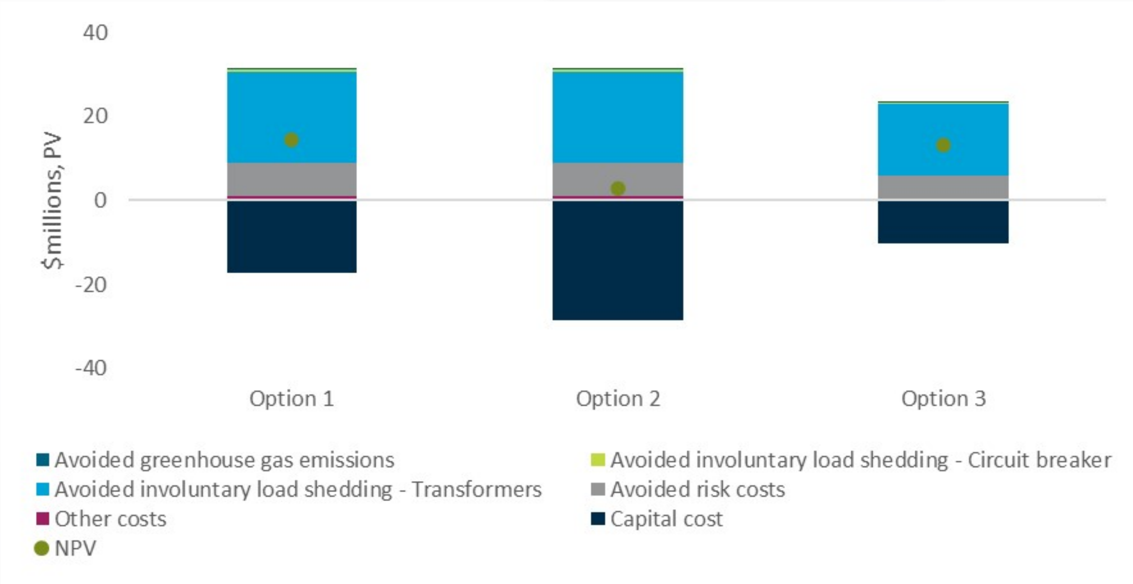
The net economic benefits are the differences between the estimated gross benefits less the estimated costs. Table 14 below summarises the present value of the net economic benefits for each credible option across the three scenarios and the weighted net economic benefits.

Table 14: Weighted net economic benefits for credible options relative to the base case ($m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1	14.4	12.4	16.4	14.4
Option 2	3.0	1.0	5.0	3.0
Option 3	13.2	12.0	14.6	13.2

All three credible options are found to have positive benefits for all scenarios investigated. Option 1 is expected to deliver the greatest net economic benefits across all scenarios investigated.[35] On a weighted basis, the net economic benefits of Option 1 are approximately $14.4 million, which is 7.8 per cent greater than the net economic benefits of the second-ranked option, Option 3 (with net benefits of approximately $13.2 million). Figure 8 below shows a breakdown of the weighted net economic benefits for each option.

Figure 8 Weighted net economic benefits ($m, PV)



Option 1 is the preferred option because it is expected to maximise net economic benefits on a weighted basis. In addition to having the highest net market benefits (based on weighting the scenarios considered), Option 1 is preferred over Option 3 for the following reasons:

- Option 1 is already ranked above Option 3 even though we have not applied real cost escalation to the costs of Option 3 despite construction commencing later – some degree of cost escalation is likely and would increase the extent to which Option 1 results in higher net economic benefits relative to Option 3; and

[35] Option 1 is the top-ranked option in the central and high scenarios – Option 1 is expected to deliver net benefits 7.8 and 10.8 per cent greater than the second ranked option in those scenarios respectively. Option 1 and Option 3 are effectively ranked equally in the low scenario given that there is only a 3.9 per cent difference between the two options in that scenario.

- TasNetworks is expecting additional mining load in the area in the near-to-short term, meaning earlier investment will support accommodating that increased load in the network without risk of even greater unserved energy in the future.

Sensitivity testing

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

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

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

Step 1 – sensitivity testing of the optimal timing

This section outlines the sensitivity of the identification of the commissioning year to changes in the underlying assumptions. Each timing sensitivity has been undertaken on the central scenario.

The optimal timing of Option 1 is found to be at the beginning of FY30, consistent with the proposed commissioning year. In determining the optimal timing of an option, the annualised cost is compared to the net operating benefits.

When conducting sensitivity testing, the optimal timing of Option 1 varies between FY30 and FY32. The optimal timing of Option 1 is found to be equal to the proposed commissioning year, FY30, in the central scenario and under the majority of sensitivities investigated, ie:

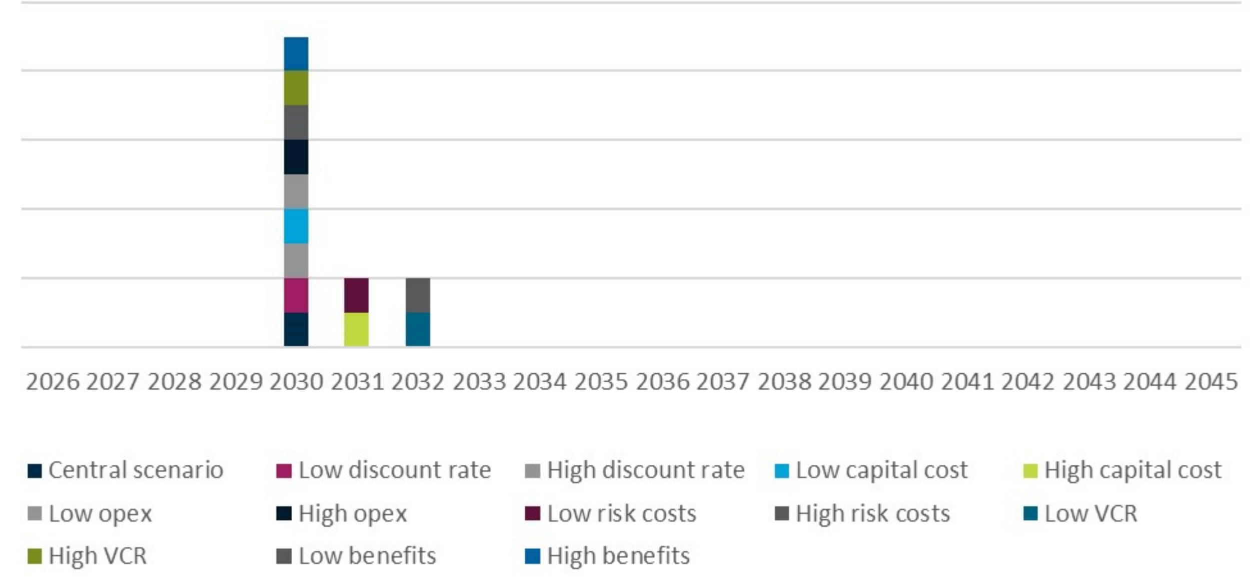
- the main central scenario;
- high and low discount rate sensitivities;
- 15 per cent higher and 15 per cent lower maintenance costs;
- 15 per cent lower assumed network capital costs;
- higher assumed reliability, financial, environmental and safety risks; and
- higher weighted average VCR.

The optimal timing of Option 1 is found to be beyond FY30 under the assumptions of:

- a 15 per cent increase in the assumed network capital costs;
- lower weighted average VCR; and
- lower assumed reliability, financial, environmental and safety risks.

Specifically, Figure 9 below outlines the impact on the optimal commissioning year for each line, under a range of alternate assumptions.

Figure 9: Optimal timing for Option 1



Step 2 – sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit, based on undertaking the project in FY26 with completion of construction in FY29 (commissioning at the beginning of FY30). Specifically, we have investigated the following same sensitivities under this step as in the first step:

- a 15 per cent increase/decrease in the assumed network capital costs;
- lower (or higher) weighted average VCR;
- lower (or higher) assumed financial, environmental and safety risks; and
- lower discount rate of 4.18 per cent as well as a higher rate of 10.50 per cent.

All these sensitivities investigate the consequences of 'getting it wrong' having committed to a certain investment decision. Figures below illustrate the estimated net economic benefits for each option if separate key assumptions in the central scenario are varied individually.

Figure 10 shows that Option 1 delivers higher expected benefits than Option 2 and Option 3 for all sensitivities of capital costs within TasNetworks' 15 per cent cost accuracy for this RIT-T (i.e. 85 per cent to 115 per cent of estimated capital costs).

Figure 10: Capital costs sensitivity testing

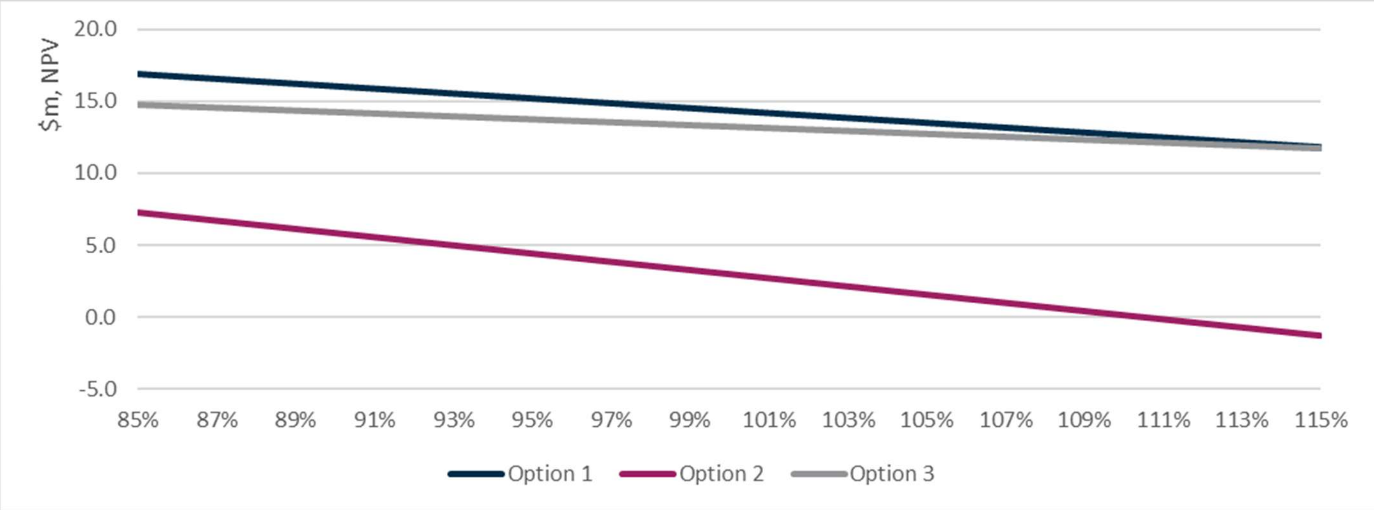


Figure 11 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the VCR (i.e. plus and minus 30 per cent, or $4.60/kWh to $8.54/kWh), while Option 3 delivers higher expected benefits for a VCR below $5.03/kWh (noting that the VCR values reported here include the VNR adjustment as explained in the 'Reliability risk' section under 'Assumptions underpinning the identified need' above).

Figure 11: VCR sensitivity testing

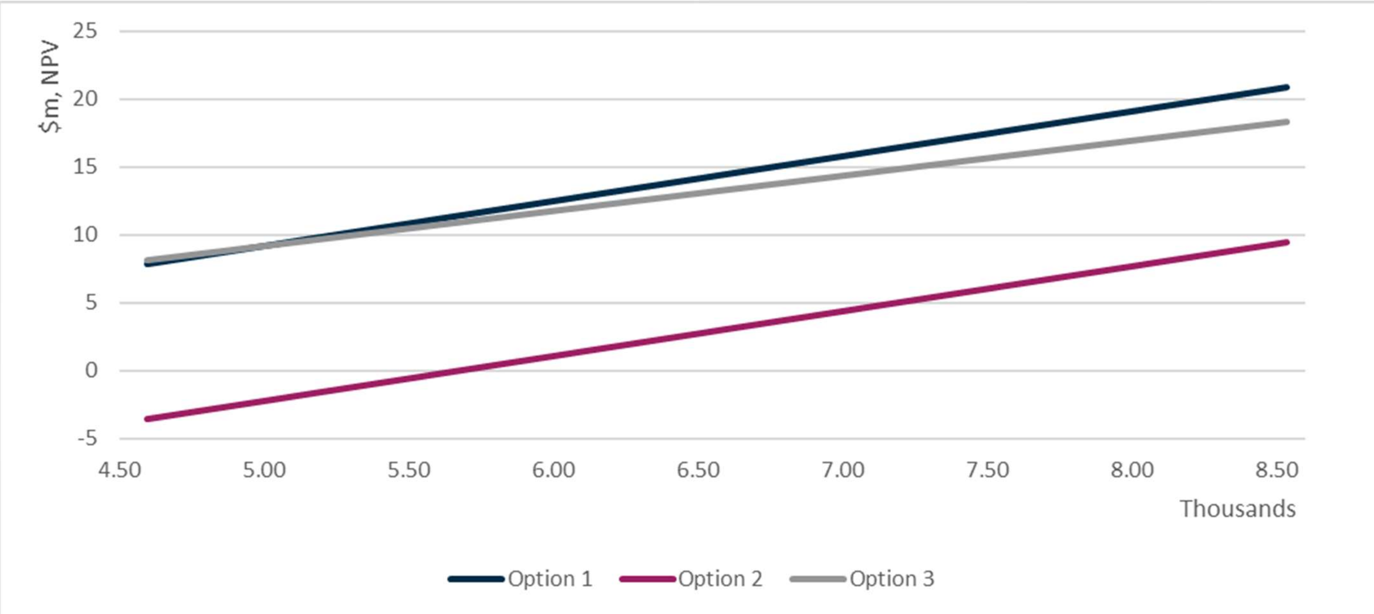


Figure 12 shows that Option 1 delivers higher expected benefits than Option 2 and Option 3 for all sensitivities of the environmental, safety and financial risk costs (i.e. plus and minus 30 per cent).

Figure 12: Risk costs sensitivity testing

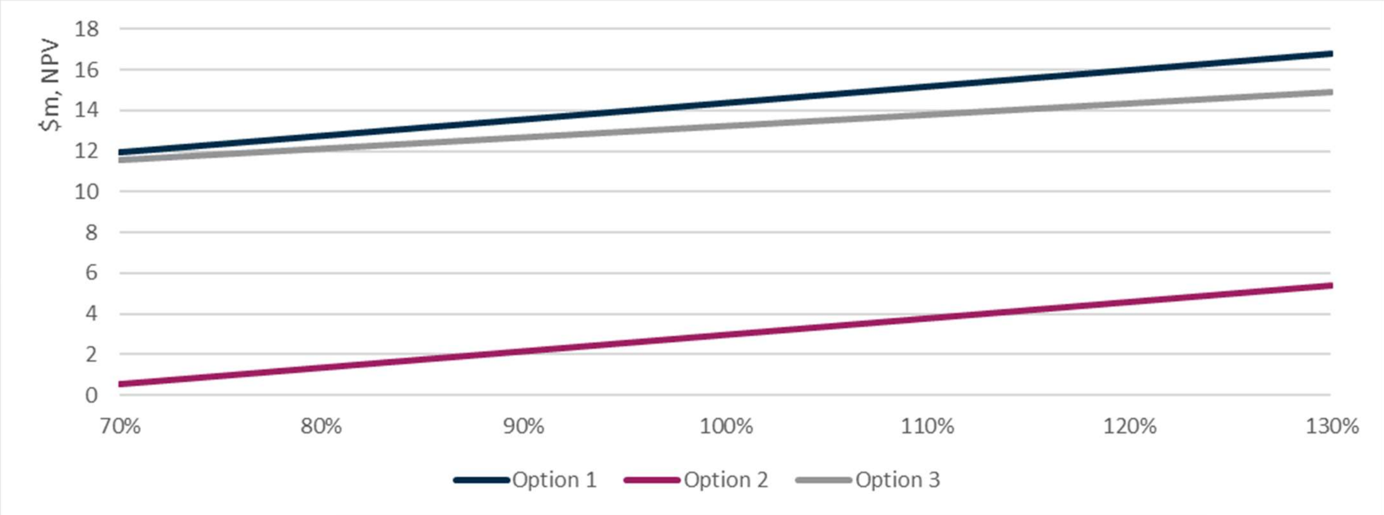
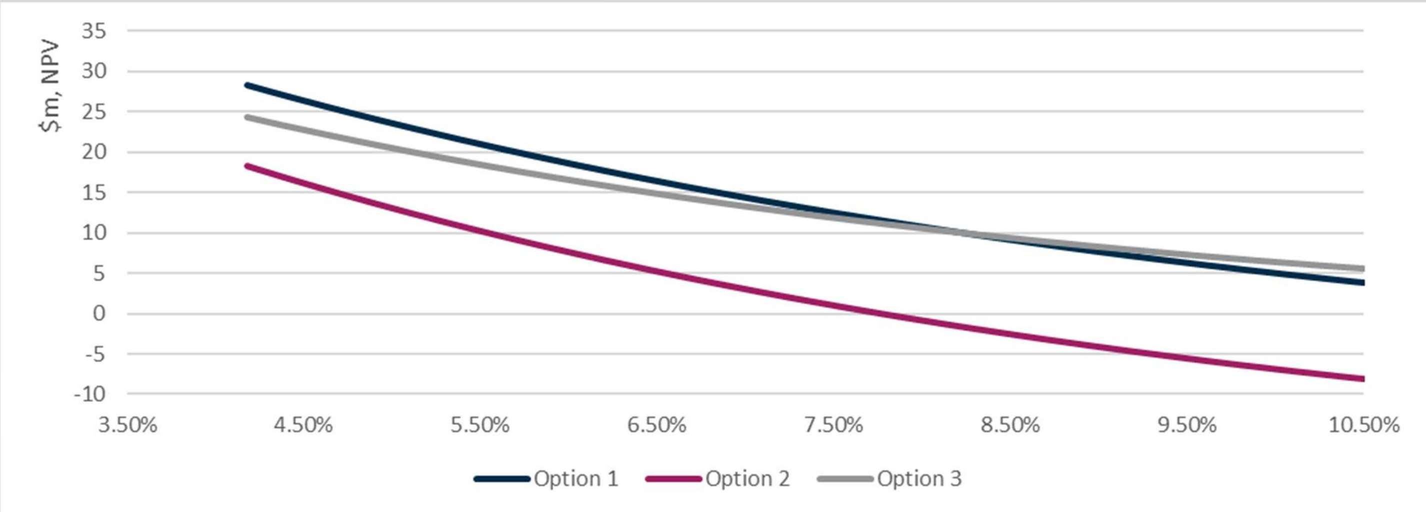


Figure 13 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the commercial discount rate (i.e. 4.18 per cent to 10.50 per cent), while Option 3 delivers higher expected benefits when the commercial discount rate is greater than 8.30 per cent.

Figure 13: Commercial discount rate sensitivity testing



Option 1 and Option 3 are both expected to deliver positive benefits higher than Option 2 in all sensitivities. Option 1 is expected to deliver higher positive benefits than Option 3 in the majority of sensitivities, although there still remain circumstances in which Option 3 delivers the highest positive benefits.

In terms of boundary testing, we find that the following would need to occur for Option 1 to have negative expected net benefits:

- assumed network capital costs would need to increase by approximately 88 per cent, which is substantially outside of TasNetworks' cost accuracy estimate for the network options considered in this RIT-T of 15 per cent;

- the VCR would need to decrease by approximately 58 per cent (i.e. go below $2.22/kWh), which is below the VNR multiplier (0.5) of the lowest VCR of any load type currently served by Rosebery Substation (mines with a VCR of $10.63/kWh, or $5.31/kWh when adjusted by the VNR);[36]
- the estimated environmental, safety and financial risk costs (in aggregate) would need to decrease by 179 per cent (i.e. go below zero); or
- a discount rate of over 12.4 per cent.

We therefore consider the finding that Option 1 being the preferred option is robust to the key assumptions. Although Option 3 delivers higher net economic benefits under some sensitivities, this result is principally driven by how close the net benefit of the options are in present value terms due to the lack of real cost escalation applied to Option 3.

[36] See Table 3

Draft conclusion and exemption from preparing a PADR

Under the NER, the preferred option is the credible option that maximises the present value of the net economic benefit. Applying this definition, Option 1 is the preferred option at this draft stage of the RIT-T because it has the highest net economic benefit. Option 1 is expected to deliver net economic benefits that are 7.8 per cent greater than the second-ranked option, Option 3, on weighted basis.

Scenario and sensitivity analysis was undertaken across a range of assumptions, and Option 1 was ranked highest across all scenarios and in the majority of sensitivities. Notwithstanding that Option 3 is highest ranked in a minority of sensitivities, we consider Option 1 is the preferred option because, in addition to having the highest net economic benefits (based on weighting the scenarios considered):

- Option 1 is already ranked above Option 3 even though we have not applied real cost escalation to the costs of Option 3 despite construction commencing later – some degree of cost escalation is likely and would increase the extent to which Option 1 results in higher net economic benefits relative to Option 3; and
- TasNetworks is expecting additional mining load in the area in the near-to-short term, meaning earlier investment will support accommodating that increased load in the network without risk of even greater unserved energy in the future.

Option 1 involves the replacement of both T1 and T2 transformers and 44 kV switchgear in R24, commissioning the assets at the end of the regulatory control period, R29. The estimated capital expenditure associated with Option 1 is $24.1 million (in 2024/25 dollars).

The works are estimated to take place between financial years 2026 and 2029, with practical completion and commissioning towards the end of financial year 2029. The optimal timing of Option 1 is found to be the beginning of FY30, consistent with the proposed commissioning year .

NER 5.16.4(z1) provides for a TNSP to be exempt from producing a Project Assessment Draft Report (PADR) for a particular RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $54 million;[37]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

[37] NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $54m based on the AER Final Determination: 2024 RIT and APR cost threshold review – final determination, November 2024, available at: https://www.aer.gov.au/documents/2024-rit-and-apr-cost-threshold-review-final-determination-12-november-2024, accessed 3 June 2024.

We consider that the investment in relation to Option 1 and the analysis in this PSCR meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR will no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period.

Accordingly, if we consider that any such additional credible options are identified, we will produce a PADR which includes an NPV assessment of the net economic benefit of each additional credible option.

However if no additional credible options are identified during the consultation period that we consider could have material market benefits, we intend to produce a PACR in November 2025 that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period, and presents our final conclusion on the preferred option for this RIT-T.

Appendices

Appendix 1 Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 230.

Rules clause	Summary of requirements	Relevant section
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	
	(1) a description of the identified need;	The identified need
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	The identified need
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	Non-Network options
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	Credible options
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Credible options and Materiality of market benefits
5.16.4(z1)	A RIT-T proponent is exempt from paragraphs (j) to (s) if:	Draft conclusion and exemption

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		(1) the estimated capital cost of the proposed preferred option is less than $35 million[38] (as varied in accordance with a cost threshold determination); (2) the relevant Network Service Provider has identified in its project specification consultation report: (i) its proposed preferred option;(ii) its reasons for the proposed preferred option; and (iii) that its RIT-T project has the benefit of this exemption; (3) the RIT-T proponent considers, in accordance with clause 5.15A.2(b)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4) except those classes specified in clauses 5.15A.2(b)(4)(ii) and (iii), and has stated this in its project specification consultation report; and (4) the RIT-T proponent forms the view that no submissions were received on the project specification consultation report which identified additional credible options that could deliver a material market benefit.	from preparing a PADR

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

Section of guidelines	#	Provision	Relevant section(s)
3.2		Credible options	
3.2.5		Incorporating social licence principles into credible option identification	
	i	A RIT-T proponent must consider social licence issues in the identification of credible options. A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.	Credible options
3.4		Selecting reasonable inputs	
3.4.3		Value of emissions reduction	
	ii	The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO_2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	Assumptions underpinning the identified need
3.5		Valuing costs	

[38] The cost threshold was varied to $54m based on the AER's most recent cost threshold determination: AER, 2024 RIT and APR cost thresholds review – Final determination, November 2024, available at: https://www.aer.gov.au/documents/2024-rit-and-apr-cost-threshold-review-final-determination-12-november-2024, accessed 3 June 2025.

	iii	In the RIT-T, costs must include the following classes: • Costs incurred in constructing or providing the credible option • Operating and maintenance costs over the credible option's operating life • Costs of complying with relevant laws, regulations and administrative requirements For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	Credible options
3.5.3		Social licence	
	1	The RIT-T proponent is required to provide the basis for any social licence costs in their RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	
3.5A		Cost estimation	
3.5A.1		Cost estimation accuracy	
	2	Where the estimated capital costs of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination as contemplated by clause 5.16.4(k)(10)(i) of the NER), a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T, and • for all credible options (including the preferred option), either: o apply the cost estimate classification system published by the Association for the Advancement of Cost Engineering (AACE), or o if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate. This requirement does not apply where the preferred option or credible option relates to a program of works, but where no individual component of that program has an estimated capital cost in excess of $103 million (as varied in accordance with a cost threshold determination as contemplated by clause 5.16.4(k)(10)(i) of the NER).	N/A
3.5A.2		Additional cost estimation information and contingency allowances	

	v	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	Credible options
3.6		Market benefit classes	
		RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	Assessment of credible options
3.7		Methodology for valuing market benefits	
3.7.3		Categories of market benefits	
		Where calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: • include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome: o direct emissions from generation o direct emissions other than from generation, e.g. sulphur hexafluoride estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions	Market benefits considered material
3.8		Reasonable scenarios and sensitivities	Overview of the assessment approach
3.8.2		Testing sensitivities to select reasonable scenarios	Overview of the assessment approach
	3	Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination as contemplated by clause 5.16.4(k)(10)(i) of the NER), a RIT-T proponent is required to undertake sensitivity analysis on all credible options by varying one or more inputs and/or assumptions.	N/A
3.9		Uncertainty and risk	
3.9.4		Contingency allowances	

	vi	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and how the level or quantum of the contingency allowance was determined.	N/A
3.11		Externalities	
3.11.2		Concessional finance agreements	
	4	Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement such that it can articulate how the value of the concession is to or would be shared with consumers. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	N/A
4.1		Consumer and non-network engagement	
	5	RIT-T proponents are required to describe in each RIT-T report • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or why this project does not require community engagement.	Approach to estimating option costs

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