Sheffield Substation T1 Transformer Replacement

RIT-T Project Specification Consultation Report

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Public

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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
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
RIT-T	Regulatory Investment Test for Transmission
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 the T1 transformer at Sheffield Substation.

Sheffield Substation is a key part of the 220 kV backbone network in Tasmania that supplies the North West and West Coast planning areas. Sheffield Substation currently has two 220/110 kV network transformers, T1 and T2. T1 is rated at 150 MVA and was manufactured in 1967 and commissioned the following year, making it 58 years old. The T1 transformer is approaching its end-of-life (TasNetworks' Asset Management Plan considers 60 years as the end of life for network transformers) and therefore faces a significantly higher risk of failure when compared to more recently commissioned transformers. Additionally, the T1 transformer has several design flaws that make it no longer compliant with TasNetworks' current network transformer standard. The T2 transformer was manufactured in 1985, making it approximately 40 years old, and faces a substantially lower risk of failure.

Sheffield Substation currently supplies several other substations in North West Tasmania, specifically, Railton, Wesley Vale, Devonport, Sheffield and Ulverstone substations. It is also the location at which several hydro generators connect to the electricity network.

Identified need: managing risks at Sheffield Substation

TasNetworks has identified an opportunity to increase market benefits by addressing reliability, financial, environmental and safety risks associated with the ageing T1 transformer at Sheffield Substation.

If action is not taken, the condition of the T1 transformer will expose TasNetworks and our customers to increasing levels of risk going forward, as deterioration increases the likelihood of transformer failure.

The higher risk of failure associated with the T1 transformer means there is an increased risk of unplanned maintenance of this asset. In the event of a failure of T1, TasNetworks would be required to conduct emergency works, which would incur substantial resource and labour costs. The risk that there will need to be a reactive replacement of the transformer has also increased. Together, these result in a significant financial risk associated with T1.

In addition, failure of T1 also raises 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.

Furthermore, if both T1 and T2 fail then all the 110 kV substations supplied by Sheffield Substation will be impacted while TasNetworks conducts emergency works and installs a spare transformer, which is likely to take around seven days. There is therefore an increasing reliability risk associated with the ageing transformer, in addition to the risk costs discussed above.

Addressing the condition issues of the T1 transformer will enable us to manage reliability, financial, safety and environmental risks at Sheffield 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.

Four credible options have been considered

We consider that there are four 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 transformer. The options vary based on the location of the replacement transformer within the Sheffield Substation and the timing of investment. Specifically:

- Option 1a involves replacing the T1 transformer in its current location by financial year (FY) 2029;
- Option 1b involves replacing the T1 transformer in its current location by FY 2032;
- Option 2a involves installing a new transformer to replace T1 in a new location within the Sheffield Substation by FY 2030 (**preferred option**); and
- Option 2b involves installing a new transformer to replace T1 in a new location within the Sheffield Substation by FY 2032.

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, financial, safety and environmental risks posed as a result of the deterioration of T1.

For non-network options to assist, they would need to provide greater net market benefits than the network options. That is, non-network options would need to reduce the risks associated with the ageing T1 at a lower cost than network options. We consider that non-network options are unable to sufficiently reduce risk costs and provide greater net market benefits than the network options because:

- non-network options are unable to address the risk of transformer 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 (i.e. seven days).

The options have been assessed against three reasonable scenarios

The credible options have been assessed under three scenarios as part of this PSCR, 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 the 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%
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.

Options are equally ranked

All four credible options are found to have positive net market benefits for all scenarios investigated. Further, all four credible options are ranked within 2.5 per cent of each other on a weighted basis, and so we consider them to be effectively equally ranked in the NPV analysis, given the accuracy of the cost estimates in the RIT-T.

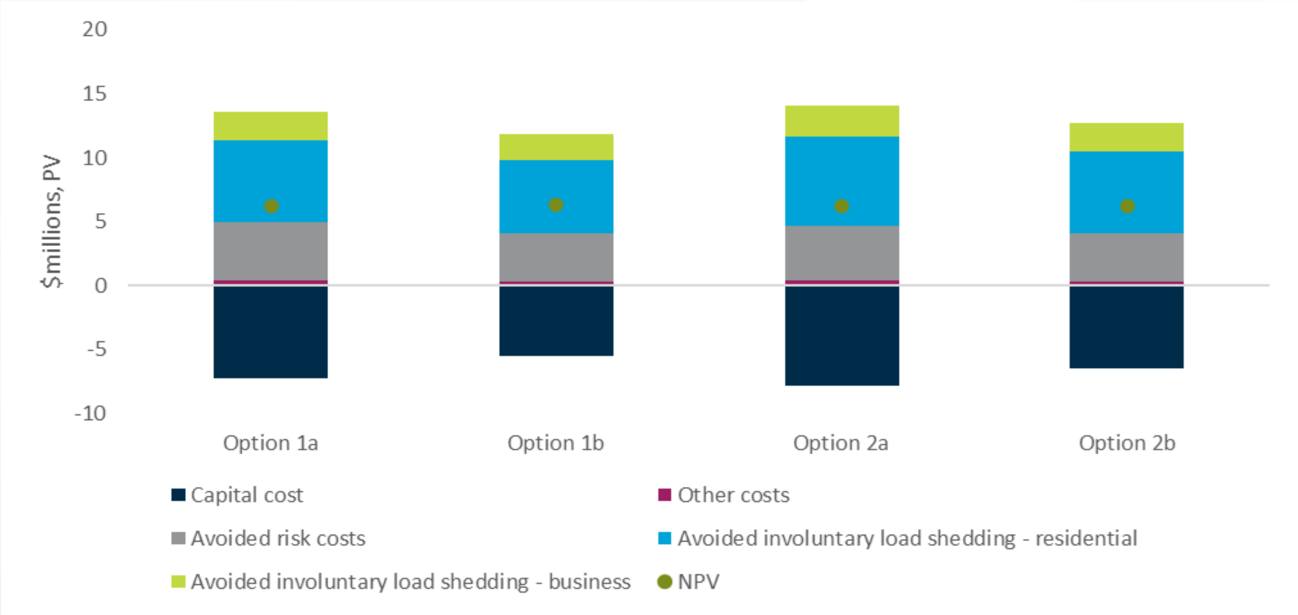
Table 2 presents the weighted net market benefit of each option, and also the percentage difference of the weighted net market benefits of each option compared to Option 1b.

Table 2: Difference in weighted net market benefits between options

Option	Weighted net market benefits ($m, PV)	Difference from highest ranked option (%)
Option 1b	6.33	-
Option 1a	6.26	1.17
Option 2b	6.22	1.71
Option 2a	6.19	2.24

Figure 1 shows the breakdown of the weighted net market benefits for each credible option.

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



[1] The discount rate of 7 per cent aligns with the discount rate in AEMO's most recent final Input, Assumptions and Scenarios Report (IASR) (published in July 2025), in line with the AER's RIT-T application guidelines.

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With the assessment indicating that all four credible options are effectively equally ranked, TasNetworks considers that Option 2a is the preferred option, as it has several, additional qualitative benefits. Replacing the transformer at a new location within Sheffield Substation (i.e., Options 2a and 2b) are preferred over replacing the transformer in the same position within the substation (i.e., Option 1a and Option 1b) because:

- it avoids the need for a 75 day outage during construction, which would compromise N-1 security and increase the risk of curtailment of local generators;
- it will reduce the risk of cascading transformer failure at Sheffield Substation, because under Options 2a and 2b the new transformer will be located further away from the existing T2 transformer, whereas the existing T1 transformer is located adjacent to the existing T2 transformer; and
- the T1 transformer will remain at Sheffield Substation, allowing it to be used as a spare in the event of an emergency.

Further, replacing T1 sooner (i.e., Option 2a) is preferred over a later replacement (i.e., Option 2b), as a delay in replacement raises the possibility of:

- uncertain and varying lead times for the procurement of required assets;
- the potential for macroeconomic shocks to increase input costs; and
- future changes to specialised labour costs, above those due to inflation.

These cost pressures are not reflected in the NPV assessment, which has assumed no real costs escalation for the later option (Option 2b).

Draft conclusion

This PSCR has found that Option 2a is the preferred option at this draft stage of the RIT-T, as it is ranked equal with the other options on a net market benefit basis, but has a number of additional, qualitative benefits. Option 2a involves installing a new 220/110 kV network transformer in a new location at Sheffield Substation by the beginning of FY 2030. The estimated capital expenditure associated with Option 2a is $11.8 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;[2]
- 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

[2] 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 8 September 2025.

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 2a 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.

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 reliability, financial, environmental, and safety risks caused by age-related condition issues of the T1 network transformer at Sheffield Substation.

Sheffield Substation currently operates with two network transformers (T1 and T2). T1 is a 150 megavolt ampere (MVA), 220/110 kilovolt (kV) transformer that was manufactured in 1967 and commissioned the following year, making it approximately 58 years old. T2 is also a 150MVA, 220/110 kV transformer, although it was manufactured and commissioned in 1985, making it approximately 40 years old. The T1 transformer is approaching its end-of-life and therefore faces a significantly higher risk of failure when compared to more recently commissioned transformers. Refurbishments to T1 in 1997 and 2017 effectively extended its useful life, however, as it approaches its 60th year it poses an increasing risk of failure – TasNetworks' Asset Management Plan considers 60 years as the end of life for network transformers.

Sheffield Substation is a critical substation in the context of the Tasmanian transmission network as it connects the North West and West Coast regions to the rest of the network. Sheffield Substation also transfers power to and from the North West and West Coast areas to the George Town Substation through the Sheffield-George Town 220 kV number 1 and 2 transmission circuits. Sheffield Substation supplies approximately 40,000 customers, including over 33,000 residential, 3,700 commercial, 2,000 industrial and 790 large industrial customers.

In the event of failure of T1, Sheffield Substation will fail to maintain N-1 redundancy for the transformation of power between 110 kV and 220 kV. This would increase the risk to the reliability of supply to customers, especially given that:

- the T2 transformer is also approaching the end of its economic life and has not yet had any major refurbishments;[3] and
- all load passing through a single transformer, naturally elevating the transformer oil and winding temperatures, increases the likelihood of failure, compared to having two transformers in-service.

TasNetworks regularly monitors the condition of T1, which has been found to continue to be in an acceptable condition – in June 2021, a detailed condition report found that T1 was expected to be fit for service for an expected 8-10 years (i.e., until between FY 2029 and FY 2031). Notwithstanding, continued operation of T1 poses a range of associated risks due to its older design, which does not align with TasNetworks' current design standards. In addition to reliability of supply risks mentioned above, the transformer does not align with the current bushing standard which poses fire and safety risks. Further:

- a fire incident at T1 may place multiple assets within the substation at risk;

[3] The economic life of a network transformer is 45 years, as detailed in the Assessment of Proposed Regulatory Assed Lives report prepared by Sinclair Knight Mertz in August 2013. The asset life of a network transformer at TasNetworks is 60 years. See TasNetworks, *Asset management plan – power transformers*, November 2022, p 6.

- the bushings of T1 are also hermetically sealed oil impregnated paper porcelain bushings and, in the case of catastrophic failure, the porcelain may shatter and send sharp projectiles across the switchyard – representing a safety risk to both operators and adjacent in-service equipment;
- the design of the transformer tank (bell type, bolted flange at 1m above ground level) of T1 is not compliant with the TasNetworks network transformer standard, and poses a risk of potentially large oil leaks;
- T1's oil condition is noted as poor and PCBs have been detected within the transformer oil at a level non-compliant with TasNetworks' standards; and
- T1's Bucholz relay isolation and pressure relief valves are non-compliant with TasNetworks' standards.

TasNetworks is therefore examining options for addressing the age-related condition issues of the transformer so that Sheffield Substation can continue to operate in a safe and reliable manner. We expect that addressing these issues will significantly reduce reliability, financial, 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.

[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.

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 each credible option 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.

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 05 March 2026.

Submissions should be emailed to the Regulation Team via regulation@tasnetworks.com.au.[6] In the subject field, please reference 'Sheffield Substation T1 Network Transformer 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

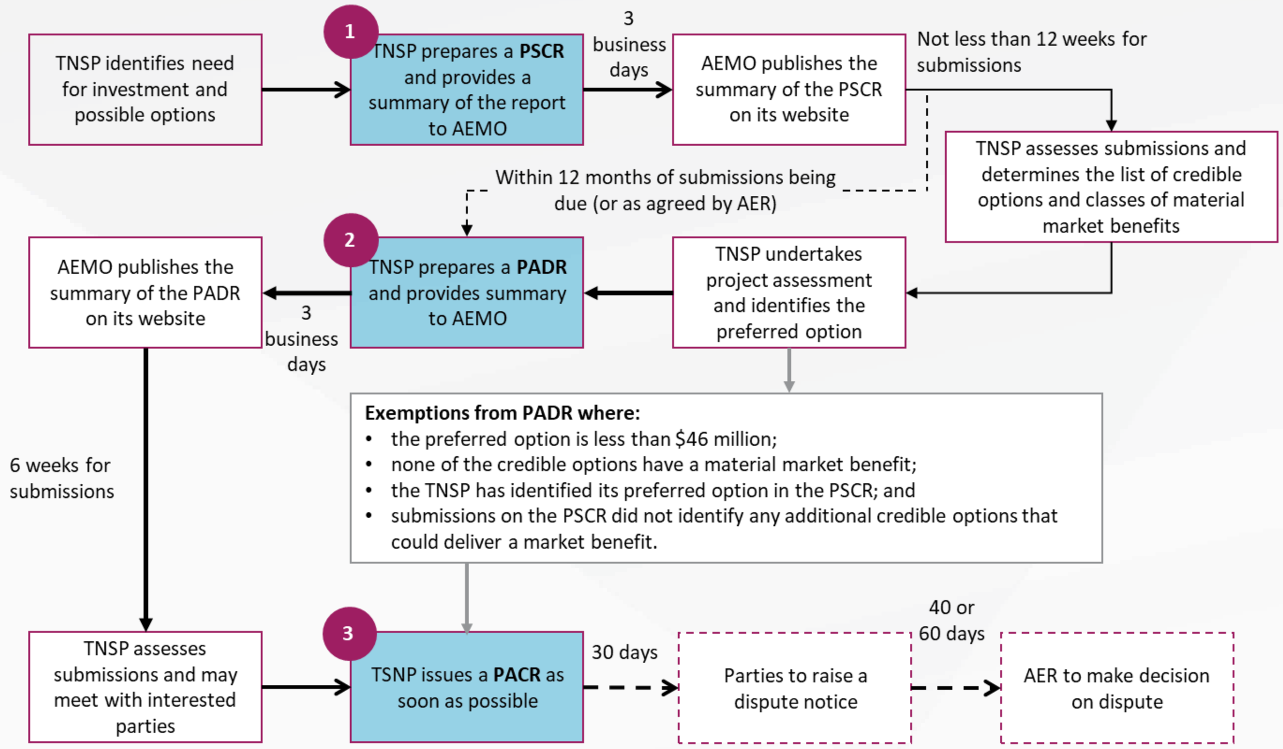
[5] NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $54m based on the AER's most recent cost threshold determination. See: AER, 2024 RIT and APR cost thresholds review – Final determination, 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.

[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.

RIT-T.[7] Subject to no additional credible options being identified, we anticipate publication of a PACR in April 2026.

Figure 2 summarises the RIT-T process.

Figure 2: Overview of the RIT-T process



7 In accordance with NER 5.16.4(z2).

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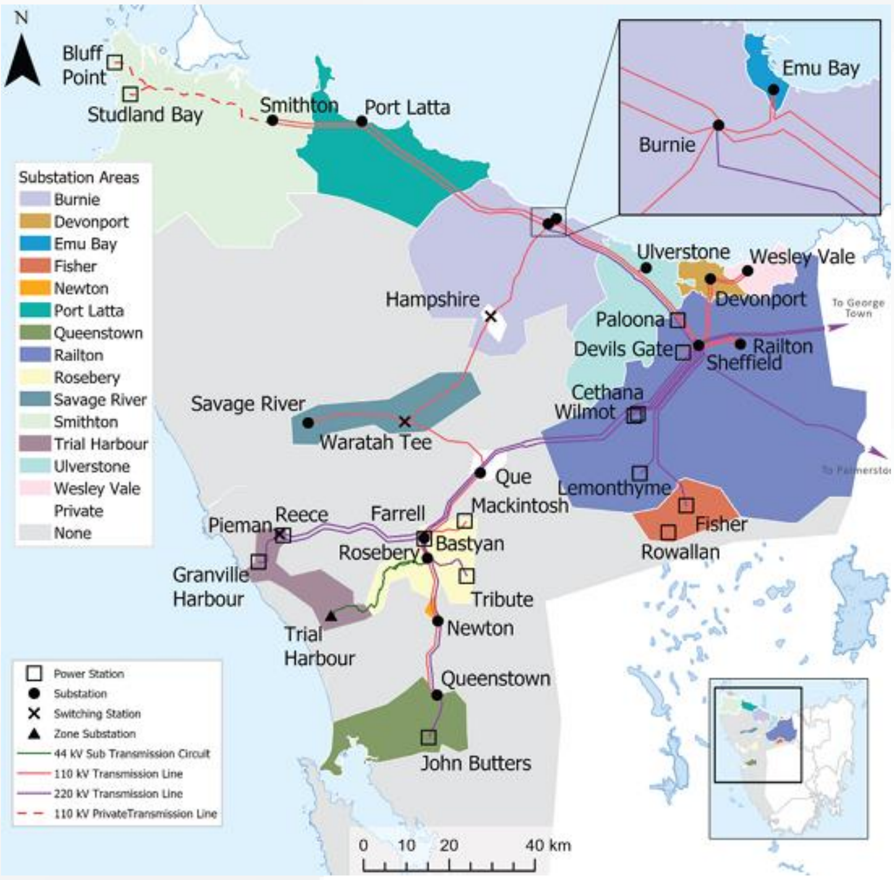
The identified need

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 Sheffield Substation and the T1 transformer.

Background to the identified need

Figure 3 provides an overview of TasNetworks' transmission network. It shows that Sheffield Substation is located in the north west of Tasmania in the township of Sheffield in the North West and West Coast planning area. The substation supplies the local Sheffield community, alongside several industrial and large industrial firms. Sheffield Substation also supplies power to other substations in the North West area via the 110 kV network, namely, Railton, Wesley Vale, Devonport and Ulverstone.

Figure 3: North West and West Coast planning area



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

There is several Hydro Tasmania generators connected to the network through Sheffield Substation. These generators and their respective capacities are shown in Table 3.

Table 3: Hydro generators connected to shared electricity network through Sheffield substation

Generator	Capacity (MW)
Cethana	100
Devils Gate	63
Fisher and Rowallan	46
Lemonthyme	54

Rowallan	11
Paloona (connected to Sheffield–Ulverstone 110 kV)	31.5

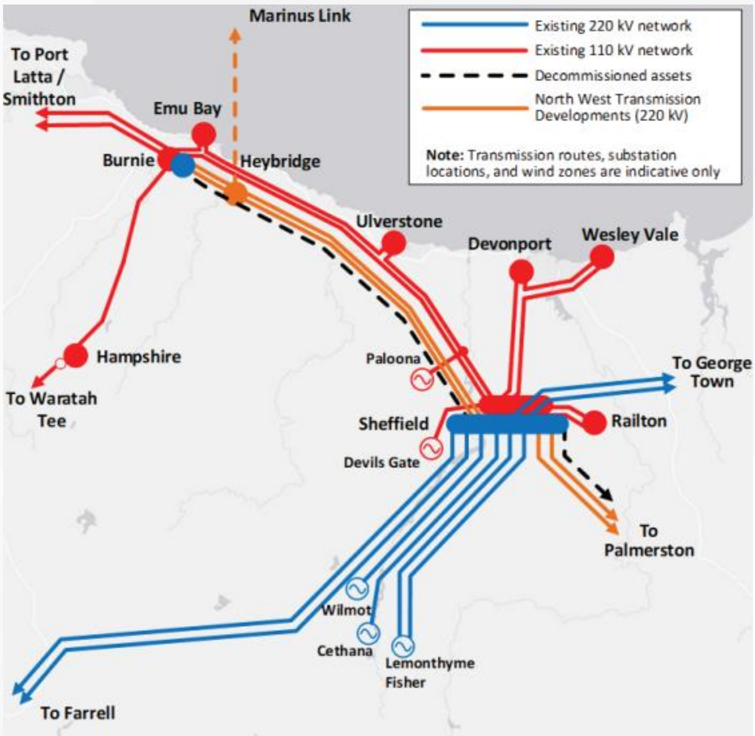
Source: TasNetworks, Annual Planning Report 2024 ,p 127, table B-1.

Network configuration

Sheffield Substation is a part of the 220 kV backbone network that supplies the North West and West Coast planning area. It is one of two substations responsible for supply in the north west of Tasmania from Deloraine and Port Sorell, to Smithton and the far north west.[8]

Going forward, the future Marinus Link related North West Transmission Developments (**NWTD**) will connect through Sheffield Substation, thereby further increasing the role of Sheffield Substation within the North West planning area and in providing access to the mainland through Marinus Link. A network map showing Sheffield Substation's connections to the Tasmanian network under the NWTD Stage 1 is shown in Figure 4.

Figure 4: Network map under NWTD Stage 1



Source: TasNetworks, Annual Planning Report 2024, p 47.

Supply to Sheffield Substation is from Palmerston Substation in the central region and Farrell Substation in the west region as well as through the network connection to the George Town Substation. Sheffield Substation then supplies several other substations in the North West planning area. As part of NWTD, a range of new 220 kV equipment will be added to Sheffield Substation to increase the reliability of the incoming/outgoing 220 kV transmission lines as part of integrating Marinus Link into the transmission

[8] TasNetworks, *Annual Planning Report 2024*, p 62, table 4-1.

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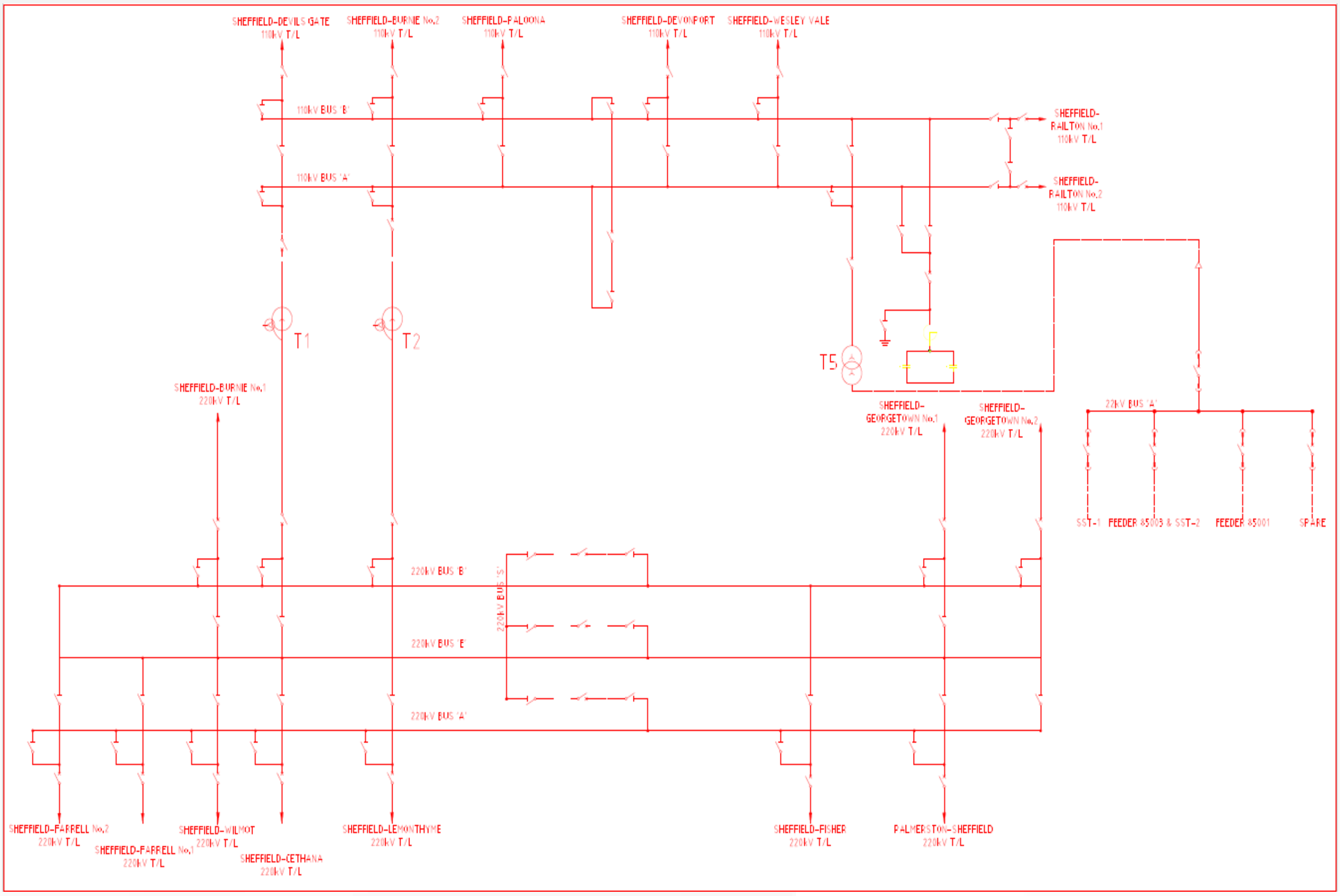
network and providing a new renewable generation path to connect to mainland Australia. A simplified one-line diagram of the current Sheffield substation layout is shown in Figure 5.

Figure 5: Current configuration of the Sheffield Substation – one-line diagram



Sheffield Substation currently has two 220/110 kV network transformers which are positioned next to one another. This poses a risk of cascading outages in the event of a catastrophic failure of one of the transformers.

An aerial view of Sheffield Substation is shown in Figure 6.

Figure 6: Aerial view of Sheffield Substation

Transformer asset condition issues

There are two operational network transformers at Sheffield Substation – T1 and T2. T1 is rated at 150 MVA and T2 is rated at 150 MVA, giving Sheffield Substation a firm rating of 150 MVA at 220/110 kV. Both T1 and T2 are 220/110 kV transformers, with T1 being manufactured in 1967 by ASEA and commissioned the following year and T2 being manufactured in 1985 by Stromberg and commissioned later that year.

T1 has previously received refurbishments in 1997 and 2017. The refurbishments in 1997 included an internal inspection, re-clamping of the windings, re-gasketing, replacement of radiators and the removal of moisture from the windings. In 2017, T1 was repainted. T2 is yet to receive any major refurbishments. The T1 transformer is currently 58 years old, while the T2 transformer is only 40 years old. The age of the T1 transformer places it at a significantly higher risk of failure when compared to more recently commissioned transformers.

The T1 transformer has inherent design deficiencies that reflect practices at the time of its manufacture, such as the transformer tank being a 'bell type tank' with bolted flanges, the main tank and tapchanger tank sharing the same conservator, hermetically sealed oil impregnated paper porcelain bushings, an external cooling tower, insufficient Buchholz relay isolation valves. These deficiencies increase the likelihood and consequence of asset failures.

TasNetworks has identified through our regular asset management activities that the T1 transformer at Sheffield Substation is approaching its end of life and does not meet the TasNetworks Network Transformer Standard in several areas. The condition of the asset, which will continue to deteriorate over time, will affect the reliability of its performance now and into the future. These condition issues are consistent with the age of the asset and its usage since commissioning.

The higher risk of failure associated with the T1 transformer has led to an increased risk of unplanned maintenance of this asset. The risk of reactive replacement of the transformer has also increased. There is significant financial risk associated with both increased unplanned maintenance and reactive replacement. In the event of a failure of T1, TasNetworks would be required to conduct emergency works which would incur substantial resource and labour costs.

Further, if both T1 and T2 fail at the same time, then all the 110 kV substations supplied by Sheffield Substation would be impacted for seven days while TasNetworks conducts emergency works and installs a spare transformer. The fault level at Burnie Substation (connected to Sheffield Substation) would also be below AEMO's N-1 system security requirement of 560 MVA fault level in the event that both transformers were not operational.[9]

Customers supplied via Sheffield Substation

Load

Sheffield Substation supplies an average load of 95 MW to several other substations in the North West planning area, specifically:[10]

- 38 MW to Railton Substation;

[9] AEMO, 2024 system strength report, February 2025, p 47.

[10] The average load has been calculated using the daily load from 27 August 2024 to 27 August 2025.

- 8 MW to Wesley Vale Substation;
- 26 MW to Devonport Substation; and
- 23 MW to Ulverstone Substation.

Sheffield Substation supplies approximately 40,000 residential, commercial, industrial and large industrial customers both directly and indirectly through the other substations that are reliant on Sheffield. The breakdown of these customers is:

- 33,142 residential;
- 3,711 commercial;
- 2,010 industrial; and
- 790 large industrial.

Generation

The West Coast and Mersey Forth generation schemes are directly connected to the electricity network at the Sheffield Substation.

Wind generation in North West Tasmania also relies on Sheffield Substation in order to supply electricity. In particular, a reduction of fault levels in the network due to a transformer outage at Sheffield Substation may lead to curtailment of wind generation in North West Tasmania. In the event that T1 transformer is not operational, the combined output of the connected wind farms, Studland Bay and Bluff Point, would be curtailed to 100 MW. Further, if both transformers are not operational, the fault levels would be such that Studland Bay and Bluff Point would be curtailed off completely.

As these wind farms were constructed prior to development of the NEM, they are 'grandfathered' and do not have fault level ride-through capabilities. While allowed to remain connected to the electricity network, they would face limitations on the amount of energy they can provide to the network in certain circumstances. Given this, TasNetworks is not liable for reduced output from those generators but we note that it may have a financial impact on these wind farms. This has not been considered as part of the quantitative analysis below but TasNetworks considers this to be an additional concern associated with the ageing T1 transformer.

Description of identified need

If action is not taken, the condition of the T1 transformer at Sheffield Substation will expose us and our customers to increasing levels of risk going forward, as further deterioration due to age increases the likelihood of failure.

Under the 'do nothing' base case, there is an increasing risk of transformer 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 T1 transformer will enable us to manage reliability, financial, safety and environmental risks at Sheffield 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.[11]

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;
- 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:

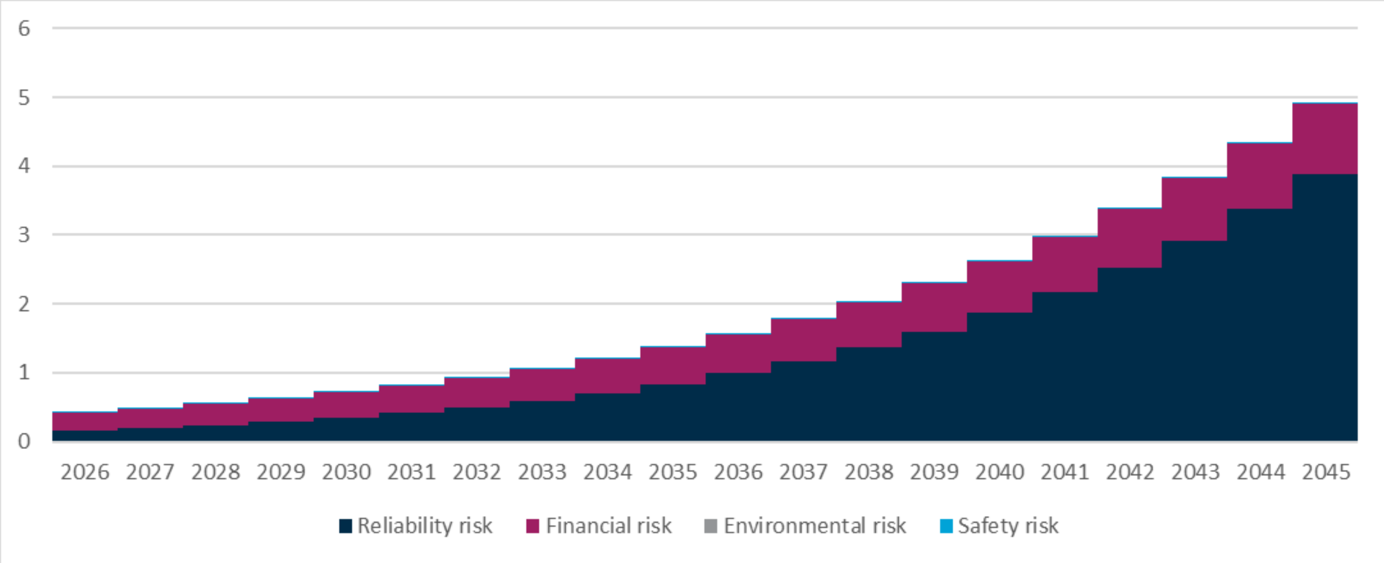
- network performance risk, i.e. involuntary load shedding;
- direct financial costs risk, e.g. reactive replacement upon failure of the asset; and
- environmental and safety risks, e.g. oil leaks from the transformer tank.

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.

[11] 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 .

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.[12] 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.[13] The asset health ratings determine a health based PoF in line with industry standards.

The asset health issues identified at Sheffield Substation are summarised in Table 4.

Table 4 Asset health issues at Sheffield Substation and their consequences

Issue	Consequences if not remediated
Increasing risk of transformer 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 residential customers in Tasmania and for very large business customers.[14]

We explain above that if both T1 and T2 fail then all the 110 kV substations supplied by Sheffield Substation will be impacted for seven days while TasNetworks conducts emergency works and installs a spare transformer. The risk of transformer failure leading to a seven-day outage means that we have applied the

[12] 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

[13] 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.

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

AER's Value of Network Resilience (**VNR**) as an adjustment to the VCR. We separate the load at risk due to involuntary load shedding between residential and business customers in order to apply a specific VCR adjusted by the relevant VNR calculated following the AER's methodology for residential and business customers.

We calculate the business VCR by taking the weighted average of the VCR for Services and Industrial customers based on the respective proportion of load for each group supplied by Sheffield substation. Table 5 summarises the VCR values used in our analysis.

Table 5: Calculated business load-weighted VCR and residential VCR

Load type	VCR ($/kWh)	Weighting (%)
Residential – Tasmania	35.690	50%
Business – Weighted	24.748	50%
- Very large business customers: Services	33.100	30%
- Very large business customers: Industrial	12.220	20%

We have multiplied the residential and business VCR amounts by the residential and business VNR multipliers respectively, calculating adjusted residential and business VCR amounts weighted by the proportion of hours of the outage associated with different levels of the VNR multiplier, consistent with the AER's guidance.[15]

Table 6 shows our calculations for the VNR adjusted VCR amounts for residential and business customers.

Table 6: Calculated VNR adjusted average VCR for residential and business customers

Time	Proportion of hours	Business VNR multiplier	Business VCR	Residential VNR multiplier	Residential VCR
0-12 hours	7%	1.0	24,748	1.0	35,690
12-24 hours	7%	1.5	24,748	2.0	35,690
1-3 day(s)	29%	1.0	24,748	1.5	35,690
3-7 days	57%	0.5	24,748	1.5	35,690
Average VCR across outage			18,561		53,535[16]

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 the T1 and T2 transformers were to fail simultaneously. This results in a load at risk of 95 MW – see the 'Customers supplied via Sheffield Substation ' section above.[17]

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, with approximately 40 per cent from the reliability risk to residential customers and 31 per cent from the reliability risk to business customers.

[15] AER, *Value of Network Resilience 2024*, Final Decision, September 2024, pp 24 and 28.

[16] We note that there are approximately 40,000 total customers served by Sheffield substation, meaning that this VCR does not exceed the upper bound of $3,500 per customer applied to the residential VNR. See AER, *Value of Network Resilience 2024*, Final Decision, September 2024, p 28.

[17] This accounts for the load supplied to 110 kV substations from Sheffield.

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 ageing transformers and switchgear. Instead, we assume a flat cost overtime for regular maintenance of the ageing transformer 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 29 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 risks associated with the transformer at Sheffield Substation is that workers in the area may be impacted by the catastrophic failure causing porcelain bushings to explode and send sharp projectiles across the switchyard and the oil from this starting a fire.

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

Environmental risk

This risk refers to the consequence arising from fire risk and loss of oil due to the degraded transformer at Sheffield 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 transformer at Sheffield has porcelain bushings, in the event of catastrophic failure these bushings may explode and send sharp projectiles across the switchyard and the oil may start a fire.

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

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 four credible options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need. The other options that were considered but not progressed for various reasons are outlined in Table 15.

Each credible option involves replacement of the ageing T1 transformer. The options vary based on the location of the replacement transformer within the Sheffield Substation 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 transformer. Under this 'do nothing' base case, there is an increasing risk of failure of T1 and the associated reliability, financial, safety and environmental risks.

Further, in the event of a failure of T1, TasNetworks would then be forced to replace the failed asset under emergency conditions. Several of the safety and environmental issues would be expected to remain – the plinth would need to be modified very quickly to accommodate a spare transformer in an emergency, and the bunding area may not be sufficient leading to a risk of oil spills outside the bunding area.

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 1a – Replace the existing T1 transformer by FY 2029

Option 1a involves the replacement of the T1 transformer and associated switchgear, in its existing location, by FY 2029. The build period is expected to occur between FY 2026 and FY 2028 with the replacement transformer being commissioned in FY 2029. The new transformer and associated switchgear will align with TasNetworks' current standards and, as such, will address all the identified design deficiency issues. Specifically, this option includes:

- the replacement of the T1 transformer with a new 220/110 kV 150/260 MVA autotransformer;
- new 220 kV circuit breaker required for point on wave switching on the new transformer;
- new 95,000 litre oil containment tank located outside of the fence;
- the replacement and upgrade of bunding and plinth to cater for a new transformer footprint, in the existing location;

- the replacement and extension of the firewall as required to suit the new transformer;[18] and
- associated civil works for the transformer plinths, switchgear footings and other relevant items.

The estimated capital cost of this option is approximately $10.5 million. Table 7 provides a breakdown of these capital costs by category of expenditure.

Table 7: Breakdown of Option 1's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
New transformer at Sheffield	7.3	2.3	0.6	0.3	10.5

The expenditure for Option 1a is expected to occur between FY 2026 and FY 2028, reflecting the procurement time for long lead time equipment and the ultimate commissioning works. Table 8 shows the expected expenditure profile of Option 1a across the construction period.

We note that in the final year of construction, T1 would be out of service for approximately 75 days while replacement works are occurring. During this time, T2 would continue to serve the customers of Sheffield Substation, but without N-1 security, significantly increasing reliability risks in the event that any fault were to occur on T2. We discuss this issue further in the assessment of credible options, below.

Table 8: Annual breakdown of Option 1a's expected capital cost, $m real

Year	Capital cost
FY26	0.5
FY27	4.8
FY28	5.2

Option 1b – Replace the existing T1 transformer by FY 2032

Option 1b involves all works outlined under Option 1a but with works occurring between FY 2029 and FY 2031 and the replacement transformer being commissioned in FY 2032. Compared to Option 1a, Option 1b delays replacement of T1 by 3 years, i.e. until the next regulatory control period. The estimated capital cost of this option is approximately $10.5 million. Table 9 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 1a.[19]

Table 9: Breakdown of Option 1b's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
New transformer at Sheffield	7.3	2.3	0.6	0.3	10.5

The expenditure for this option is expected to occur between FY 2029 and FY 2031, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 10 shows the expected expenditure profile of Option 1b across the construction period.

[18] In accordance with the Australian Standard for Substations, AS 2067.

[19] We are currently developing our approach to real cost escalation as part of our upcoming regulatory proposal.

Consistent with Option 1a, we note that in the final year of construction, T1 would be out of service for approximately 75 days while replacement works are occurring. During this time, T2 would continue to serve the customers of Sheffield Substation, but without N-1 security in the event that any fault were to occur on T2. We discuss this issue further in the assessment of credible options, below.

Table 10: Expected expenditure profile of Option 1b

Year	Capital cost
FY29	0.5
FY30	4.8
FY31	5.2

Option 2a – Install a new transformer in a new location within Sheffield Substation by FY 2030 (preferred option)

Option 2a involves the installation of a new transformer and associated switchgear in a new location within Sheffield Substation by FY 2030. The build period is expected to occur between FY 2026 and FY 2029 with the replacement transformer being commissioned at the beginning of FY 2030. The new transformer and associated switchgear will align with TasNetworks' current standards and, as such, will address all the identified condition issues. Specifically, this option includes:

- the installation of a new 220/110 kV 150/260 MVA autotransformer in a new transformer bay;
- new transformer bunding, plinth and firewalls on east and west sides;
- new 95,000 litre oil containment tank outside the switchyard fence;
- new 220 kV and 110 kV switch bays and protection panels;
- new 220 kV and 110 kV cable ducts, conduits and pits;
- two new gantries and towers each side of the transformer track with associated overhead conductors;
- the removal of a fence and internal gate of the eastern portion of the switchyard for clear access to the transformer; and
- associated civil works for the transformer plinths, switchgear footings and other relevant items.

As outlined earlier, qualitative benefits for this option (replacing the transformer at a new location) include:

- it avoids the need for a 75 day outage during construction, which would compromise N-1 security and increase the risk of curtailment of local generators;
- it will reduce the risk of cascading transformer failure at Sheffield Substation, because under Options 2a and 2b the new transformer will be located further away from the existing T2 transformer, whereas the existing T1 transformer is located adjacent to the existing T2 transformer; and
- the T1 transformer will remain at Sheffield Substation, allowing it to be used as a spare in the event of an emergency.

Further, replacing T1 sooner (i.e., Option 2a) is preferred over a later replacement (i.e., Option 2b), as a delay in replacement raises the possibility of:

- uncertain and varying lead times for the procurement of required assets;
- the potential for macroeconomic shocks to increase input costs; and

- future changes to specialised labour costs, above those due to inflation.

These cost pressures are not reflected in the NPV assessment, which has assumed no real costs escalation for the later option (Option 2b).

The estimated capital cost of this option is approximately $11.8 million. Table 11 provides a breakdown of these capital costs by category of expenditure.

Table 11: Breakdown of Option 2a's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
New transformer at Sheffield	7.7	3.0	0.7	0.4	11.8

The expenditure for this option is expected to occur between FY 2026 and FY 2029, reflecting the procurement of long lead time equipment and the ultimate commissioning works during one regulatory control period. Table 12 shows the expected expenditure profile of Option 2a across the construction period.

Table 12: Expected expenditure profile of Option 2a

Year	Capital cost
FY26	0.5
FY27	4.2
FY28	4.2
FY29	3.0

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

Option 2b – Install a new transformer in a new location within Sheffield Substation by FY 2032

Option 2b involves all works outlined under Option 2a but with works occurring between FY 2028 and FY 2031 and the new transformer being commissioned at the beginning of FY 2032. Compared to Option 2a, Option 2b delays the installation of the new transformer and associated switchgear by 2 years, i.e. beginning works FY 2028 but commissioning the transformer in FY 2032. The estimated capital cost of this option is approximately $11.8 million. Table 13 provides a breakdown of these capital costs by category of expenditure.

Qualitative benefits for network security for Option 2a also apply to Option 2b.

TasNetworks has not applied any real cost escalation to these costs relative to Option 2b.[20]

Table 13: Breakdown of Option 2b's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
New transformer at Sheffield	7.7	3.0	0.7	0.4	11.8

The expenditure for this option is expected to occur between FY 2028 and FY 2031, reflecting the procurement of long lead time equipment and the ultimate commissioning works during two regulatory control periods.

[20] We are currently developing our approach to real cost escalation as part of our upcoming regulatory proposal.

Table 14 shows the expected expenditure profile of Option 2b across the construction period.

Table 14: Expected expenditure profile of Option 2b

Year	Capital cost
FY28	0.5
FY29	4.2
FY30	4.2
FY31	3.0

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 15 summarises the reasons the following options were not progressed further.

Table 15 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 substantial lead time required to procure the appropriate asset.
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-network impact.[21] A "material inter-network impact" is defined by the NER in the following terms:[22]

> "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:[23]

- 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;

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

[22] Refer NER Chapter 10.

[23] 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 4 September 2025. https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

- 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.

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 market 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 Sheffield Substation was 88 MVA, while our maximum demand 50% probability of exceedance (PoE) forecast for 2050 is 112 MVA.

In the event of double transformer failure, our assumption is that it would take seven days to deploy a system spare transformer to the site. In the event of 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 market 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.[24] Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why:[25]

- 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.

Changes in involuntary load shedding is considered material

In the event of a failure of both 220/110 kV transformers at Sheffield Substation, TasNetworks would need to urgently source and install a spare transformer. As a spare 220/110 kV transformer currently exists in the North West and West Coast planning area, specifically at Burnie Substation, we estimate that it would take approximately seven days to obtain and install this spare at Sheffield Substation. This outage would force load shedding until the spare transformer could be installed (i.e. seven days).

Specifically, load shedding would occur on the 110 kV network in North West Tasmania, affecting approximately 95 MW on average. This is discussed further in the identified need section above.

While there is some Hydro generation at Devils Gate and Paloona that could provide some supply to the local areas at times, reducing the load at risk, practically this would require substantive works and face a multitude of technical difficulties that means this is not a practical avenue for mitigation of the load at risk. Moreover, the existing hydro generation would still not be able to completely mitigate the load at risk from the Sheffield Substation.

Replacing the T1 transformer at Sheffield Substation reduces the risk of transformer failure and therefore 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, the VNR multiplier and the load reduction from a combined failure of T1 and T2 transformers.

In addition, we note that while Sheffield Substation would be able to meet current demand if the ageing T1 transformer were to fail, it would not be able to meet current demand if both transformers were to fail simultaneously. With the only two 220/110 kV transformers currently positioned adjacent to each other, there exists an increased risk of cascading failure in the event of one transformer failing. Specifically, if T1 were to suffer catastrophic failure, the porcelain bushings could explode sending shrapnel across the switchyard causing damage to surrounding assets and possibly starting a fire due to the oil contained

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

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

within them. The close proximity of the T2 transformer to the ageing T1 transformer places it at higher risk of failure following the catastrophic failure of T1. We note that while cascading failure risk is present under the current configuration at Sheffield Substation, we have not quantified this cascading failure risk in assessing involuntary load shedding. Market benefits not considered material.

Wholesale market benefits are not considered material

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[26]

The credible options considered in this RIT-T will not address network constraints between competing generating centres and are therefore are not expected to result in any change in dispatch outcomes and wholesale market prices. The potential curtailment of wind generation discussed in the 'Background to the identified need' section above is not expected to have a material impact on the wholesale market because other wind generation would likely displace the curtailed generators.

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 Australia's greenhouse gas emissions;
- changes in network losses; and
- competition benefits.

No other classes of market benefit are considered material

Changes in Australia's greenhouse gas emissions

None of the credible options are expected to materially impact Australia's greenhouse gas emissions in any way, including through the dispatch of generation in the wholesale market (as discussed above) or through changes in Sulphur Hexaflouride (SF6) emissions.

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.

[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

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.[27]

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.

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[27] 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.[28]

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**).[29] The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated Weighted Average Cost of Capital (**WACC**) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 4.18 per cent.[30] We have also adopted an upper bound discount rate of 10.0 per cent (i.e., the upper bound in the latest IASR).[31]

[28] 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

[29] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, August 2025, p 158, table 31.

[30] 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.

[31] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, August 2025, p 158, table 31.

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 and Port Latta substations, and two further similar transformer replacements are ongoing at St Marys Substation, which provide increased accuracy of cost estimates for the Sheffield transformer. TasNetworks has escalated these costs to reflect the changes in costs since the commissioning of the commissioned transformer replacements at Kermandie and Port Latta substations.

TasNetworks considers the cost estimate for the Sheffield Substation options to have a cost accuracy of 10-11 per cent, which reflects a level three estimate.[32] 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.

[32] Our cost estimate for Option 2a and 2b is at an accuracy of 11 per cent, while the estimate for Option 1a and 1b is at an accuracy of 10 per cent, reflecting the slightly higher uncertainty associated with adding a transformer into a new location within the substation relative to replacing at this existing location.

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).[33,34]

Table 16 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate[35]	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:

- lower and higher assumed capital costs;
- lower and higher weighted VCR;

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

34 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.

35 The discount rate of 7 per cent aligns with the discount rate in AEMO's most recent final Input, Assumptions and Scenarios Report (IASR) (published in July 2025), in line with the AER's RIT-T application guidelines.

- 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 reductions in costs or risks compared to the base case.

Estimated gross benefits

Table 17 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 2a and Option 1a have similar gross market benefits, with Option 2a having $0.56 million greater market benefits. This reflects the fact that these options, although comprising different scopes, are commissioned at similar times and therefore address the identified need in a similar manner. The additional benefit that Option 2a has over Option 1a, while being commissioned a year later, reflects the additional reliability risk that occurs under Option 1a due to the need to have a 75 day period where only T2 is operational at Sheffield Substation.

Both Option 1b and 2b have substantially lower gross market benefits than their respective 'a' counterparts, reflecting the additional risks incurred by delaying the replacement of the T1 transformer. Similar to the difference between gross market benefits for Option 1a and Option 2a, Option 1b has less gross market benefits than Option 2b, reflecting the additional risk incurred by Option 1b due to a 75-day period where only T2 is operational at Sheffield Substation.

Table 17 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 1a	13.17	12.02	14.32	13.17
Option 1b	11.53	10.58	12.48	11.53
Option 2a	13.73	12.64	14.81	13.73
Option 2b	12.46	11.51	13.41	12.46

Estimated gross costs

Table 18 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.[36] Option 2a is the highest cost option, which reflects the additional works that are required to install a new transformer in a new location at the Sheffield Substation, instead of replacing the T1 transformer in the existing location. Relative to Option 2b, the higher cost of Option 2a reflects beginning the works earlier, i.e. while both options have the same real cost, construction of Option 2b occurs further into the future and so its costs

[36] The costs also capture the small difference in planned routine maintenance and refurbishment costs, which are approximately $50k per annum higher when the ageing transformer is in place.

are more heavily discounted in PV terms. A similar dynamic is reflected in Option 1a and Option 1b, in that Option 1a has a higher cost than Option 1b due to the earlier timing of the works. However, in both cases, the lower cost of Option 1b and Option 2b compared to Option 1a and Option 2a respectively, also reflects the fact that we have not applied any real cost escalation to our cost estimates for these works. We are currently developing our approach to real cost escalation as part of our upcoming revenue proposal.

Table 18 Costs of credible options relative to the base case ($m, PV)

Option/scenario	Central
Option 1a	-6.91
Option 1b	-5.20
Option 2a	-7.54
Option 2b	-6.24

Estimated net market benefits

The net market benefits are the differences between the estimated gross benefits less the estimated costs. Table 19 below summarises the present value of the net market benefits for each credible option across the three scenarios and the weighted net market benefits.

Table 19: Weighted net market benefits for credible options relative to the base case ($m, PV)

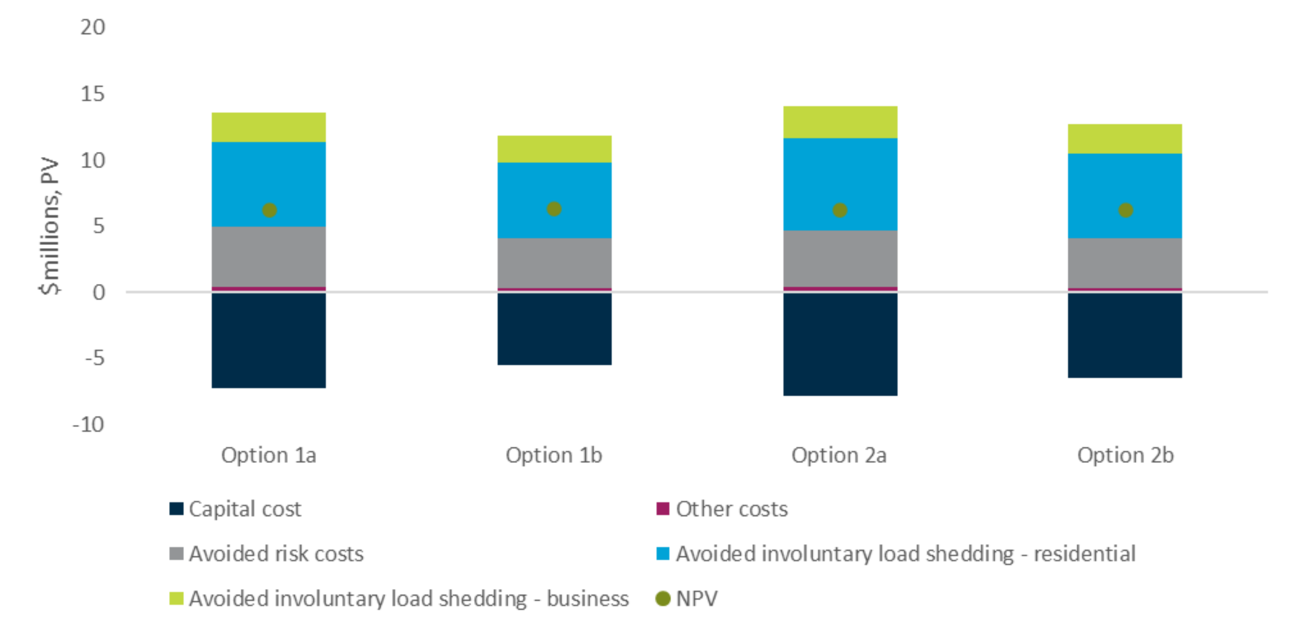
Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1a	6.26	5.11	7.41	6.26
Option 1b	6.33	5.38	7.28	6.33
Option 2a	6.19	5.10	7.27	6.19
Option 2b	6.22	5.27	7.17	6.22

All four credible options are found to have positive benefits for all scenarios investigated. Further, all four credible options are ranked within 2.5 per cent of each other on a weighted basis, and so we consider them to be effectively equally ranked in the NPV analysis. On a weighted basis, the net market benefits of Option 1b are approximately $6.33 million, which is only 1.17 per cent greater than those of Option 1a, 1.71 per cent greater than those of Option 2b and 2.24 per cent greater than those of Option 2a.

All four options are ranked within 2.2 per cent of each other in the central scenario, within 3.2 per cent of each other in the high risk cost scenario, and within 5.1 per cent of each other in the low risk cost scenario.

Figure 8 below shows a breakdown of the weighted net market benefits for each option.

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



As all identified credible options are equally ranked, we have identified Option 2a as the preferred option at this draft stage, as it has several qualitative advantages over the other options. We explain why Option 2a is the preferred option by first providing qualitative reasoning as to why options involving a replacement of T1 at a different location within Sheffield substation are preferred over the options that replace T1 in the same location (i.e., Option 1a and Option 1b). This is followed by qualitative reasoning as to why replacement of T1 on an earlier timing (i.e., Option 2a) is preferred over later timing (i.e., Option 2b).

New location at Sheffield Substation (i.e., Option 2a) preferred over existing location (i.e. Option 1a/ Option 1b)

TasNetworks considers that installing the replacement transformer at a new location within Sheffield Substation (i.e. Option 2a) is preferable to installing the replacement transformer at the existing location (i.e. Option 1a and Option 1b). Installing the replacement transformer at a new location at Sheffield Substation has three key qualitative benefits.

First, it avoids the need for a 75-day outage during construction, which would compromise N-1 security and increase the risk of curtailment of local generators. The 75-day outage of T1 required during the construction period, if the transformer were replaced in its existing location, would create a lack of N-1 security during this period. It would also increase the risk of needing to curtail wind generation during this time, as discussed above in the section on 'customers supplied via Sheffield Substation'. Option 2a does not require a 75-day outage and so maintains N-1 security at all times during the construction period.

Second, as discussed above, the existing 220/110 kV transformers at Sheffield Substation are located adjacent to each other leading to a higher risk of cascading failure. Following the replacement of the T1 transformer, T2 will continue to age and if the transformers remain adjacent to each other (i.e., Option 1a and Option 1b) the risk of cascading failure will persist. By installing the new transformer in a new location at Sheffield Substation (i.e., Option 2a), the new transformer will be configured away from the existing T2 transformer, substantially reducing any risk of cascading failure. We note that while we have not quantified this risk, it is nevertheless an important consideration in our option analysis. For example, in March 2025 a transformer fire incident at Hayes Substation which supplies Heathrow Airport, England led to substantial damage to surrounding transformers resulting in further outages.[37] In August 2025 at the Reece Power Station in Tasmania, a fire resulted in damage to a transformer, however, the second transformer was not impacted as it was positioned away from the one in which the fire started.

Third, by installing the replacement transformer in a new location at Sheffield Substation (i.e., Option 2a) the existing T1 transformer will remain at Sheffield Substation, and could be used to maintain security levels, in the event of a compromised network configuration, e.g. faults and outages. While we have not quantified this benefit, it is nevertheless another important consideration in our option analysis. We do note though, that the extent to this benefit is limited as the T1 transformer is at its end-of-life and therefore the ability to be in service for a prolonged period of time is substantially limited.

Replacing the T1 transformer sooner (i.e., Option 2a) is preferred over replacing it later (i.e. Option 2b)

TasNetworks considers that replacing the T1 transformer sooner (i.e. Option 2a) is preferred over replacing the T1 transformer later (i.e. Option 2b). Delaying the works by several years and commissioning the new transformer in the beginning of FY 2032 instead of FY 2030 raises the possibility of:

- uncertain and varying lead times for the procurement of required assets;
- the potential for macroeconomic shocks to increase input costs; and
- future changes to specialised labour costs, above those due to inflation.

These cost pressures are not reflected in the NPV assessment, which has assumed no real costs escalation for conducting the works at a later date (i.e. Option 2b).

Further, replacement in the current regulatory period is consistent with TasNetworks' regulatory proposal and asset management plan, given the age of the T1 transformer.[38]

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 optimal timing of the project ('trigger year') to different assumptions in relation to key variables; and
- Step 2 – testing the sensitivity of the total NPV benefit associated with the investment proceeding in the optimal 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 – optimal timing

In determining the optimal timing of an option, the annualised cost is compared to the net operating benefits.

The net operating benefits are expected to exceed the annualised cost of the proposed works under Option 2a and Option 2b at the beginning of FY 2032 (the proposed commissioning year of Option 2b).

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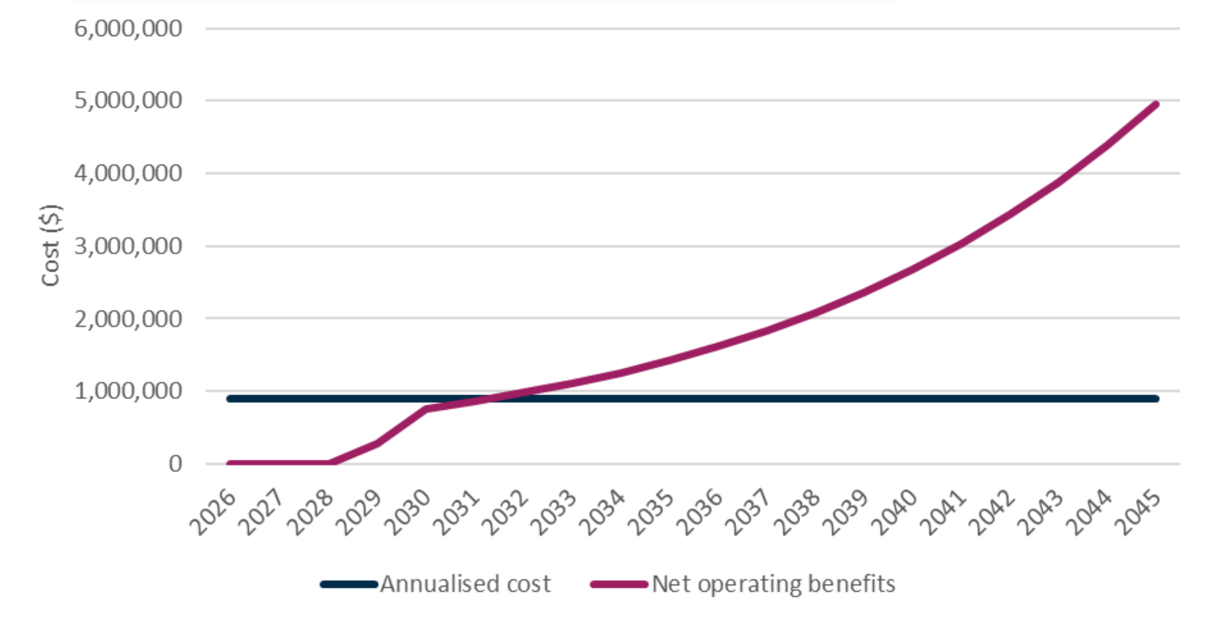
[37] BBC, *Five things we now know about the fire that shut Heathrow down*, 3 July 2025, available at: https://www.bbc.com/news/articles/c2eznzp0w7ko, accessed 19 September 2025.

[38] TasNetworks, *Annual Planning Report 2024*, p 77, table 4-9.

This is known as the 'trigger year'. However, as shown in Table 19 above, commissioning in 2030 (Option 2a) and commissioning in 2032 (Option 2b) are equally ranked. Therefore, we consider these options to be equally ranked from an optimal timing perspective.

Figure 9 reinforces that in the target commissioning year of FY 2030 the difference between annualised cost and net operating benefits is expected to be small and close to FY 2032 – reflecting the fact that commissioning in FY 2030 (Option 2a) and commissioning in FY 2032 (Option 2b) are equally ranked in the NPV analysis presented above. TasNetworks considers that conducting the proposed works sooner rather than later (i.e., Option 2a) is the preferred option for the qualitative reasons discussed above.

Figure 9: Optimal commissioning date for Option 2a



Sensitivity testing shows that the trigger year (and therefore optimal timing) for the proposed works under Options 2a and 2b is no later than FY 2033 across all sensitivities investigated, i.e.:

- a 10 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 10.0 per cent.

Step 2 – sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net market benefit, based on commencing the project in FY 2026 with completion of construction in FY 2029 (commissioning at the beginning of FY 2030). Specifically, we have investigated the following same sensitivities under this step as in the first step:

- a 10 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 10.0 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 market benefits for each option if separate key assumptions in the central scenario are varied individually.

Figure 10 shows that all options deliver similar expected net benefits for all sensitivities of capital costs within TasNetworks' 10 per cent cost accuracy for this RIT-T (i.e. 90 per cent to 110 per cent of estimated capital costs). Option 2a delivers marginally higher expected net benefits for capital cost sensitivities between 80 per cent and 98 per cent, while from 98 per cent to 110 per cent Option 1a delivers marginally higher expected net benefits.

Figure 10: Capital costs sensitivity testing

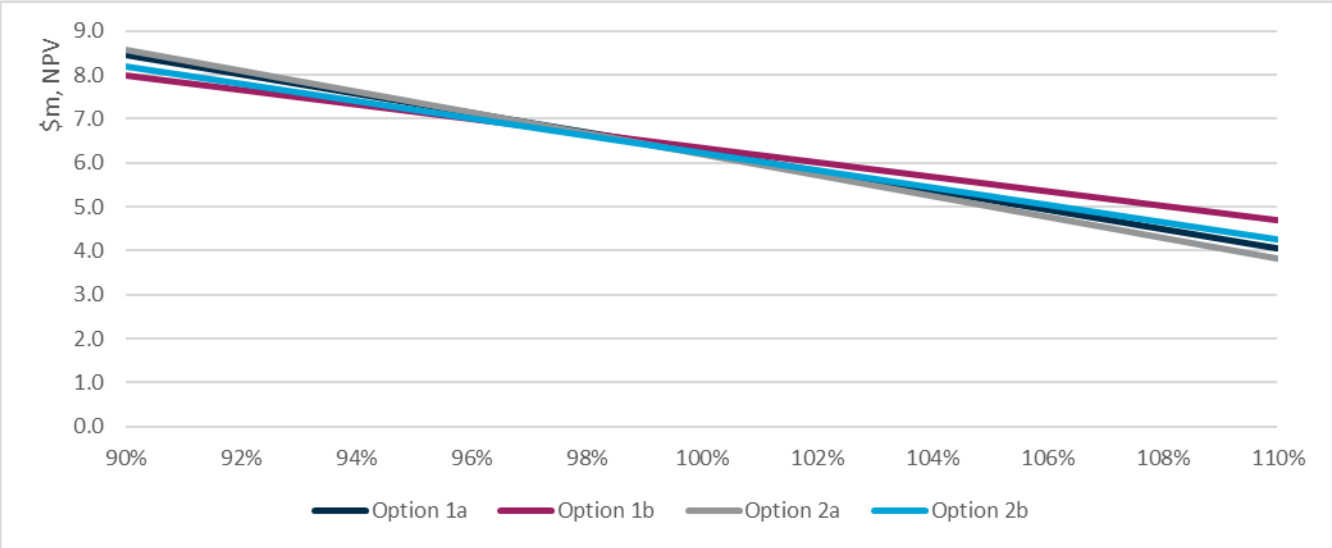


Figure 11 shows that all options deliver similar expected net benefits for all sensitivities of the VCR for residential customers (i.e. plus and minus 30 per cent, or \$37.48/kWh to \$69.60/kWh). Option 2a delivers marginally higher expected net benefits for VCR sensitivities for residential customers from \$59.96/kWh and above, while Option 1b delivers marginally higher expected net benefits for VCR sensitivities for residential customers from \$59.64/kWh and below (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 (residential) sensitivity testing

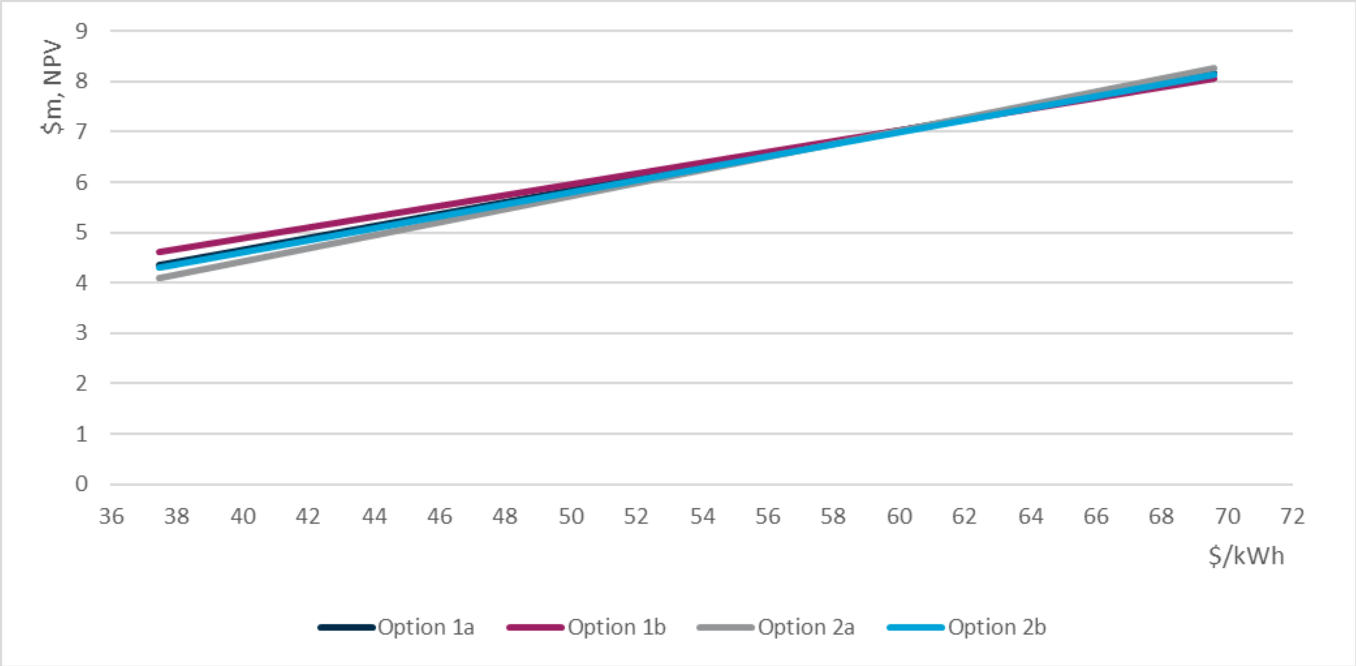


Figure 12 shows that all options deliver similar expected net benefits for all sensitivities of the VCR for business customers (i.e. plus and minus 30 per cent, or $13.00/kWh to $24.13/kWh).

Figure 12: VCR (business) sensitivity testing

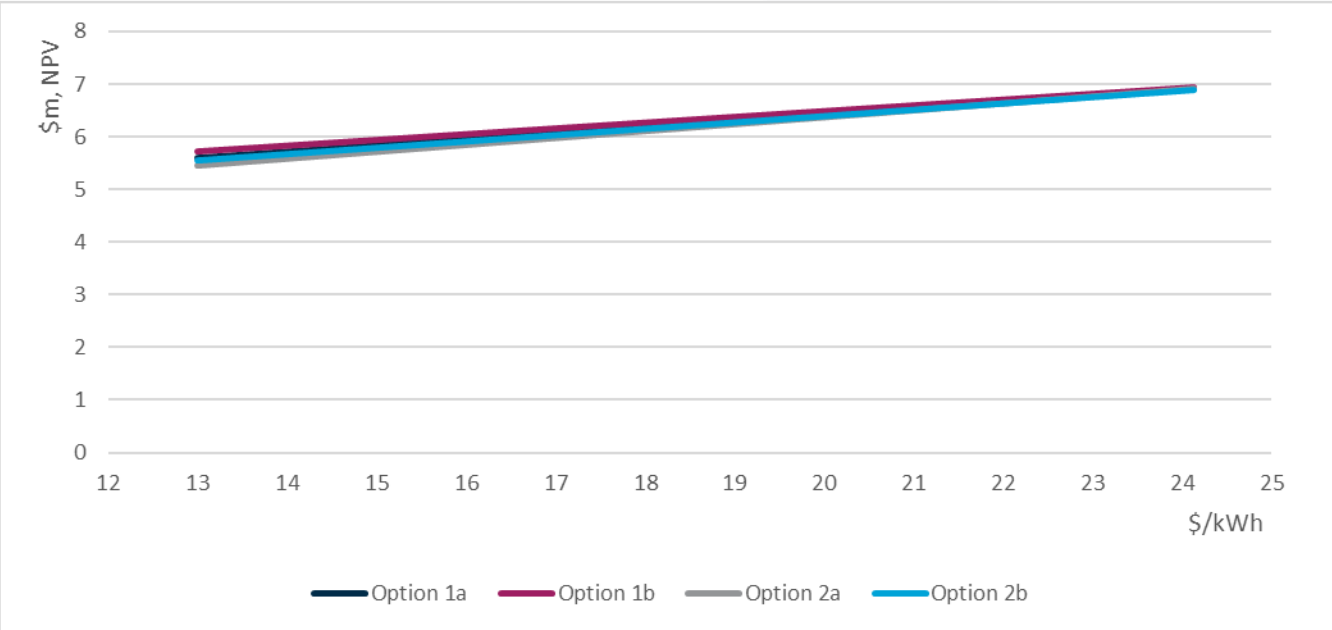


Figure 13 shows that all options deliver similar expected net benefits for all sensitivities of the environmental, safety and financial risk costs (i.e. plus and minus 30 per cent).

Figure 13: Risk costs sensitivity testing

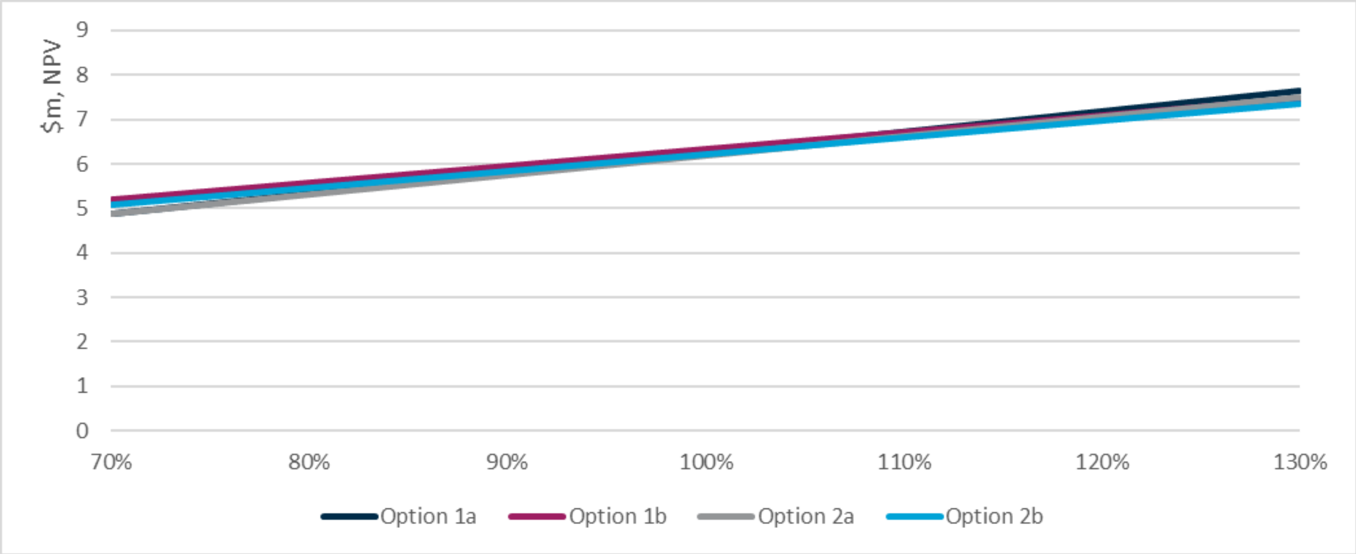
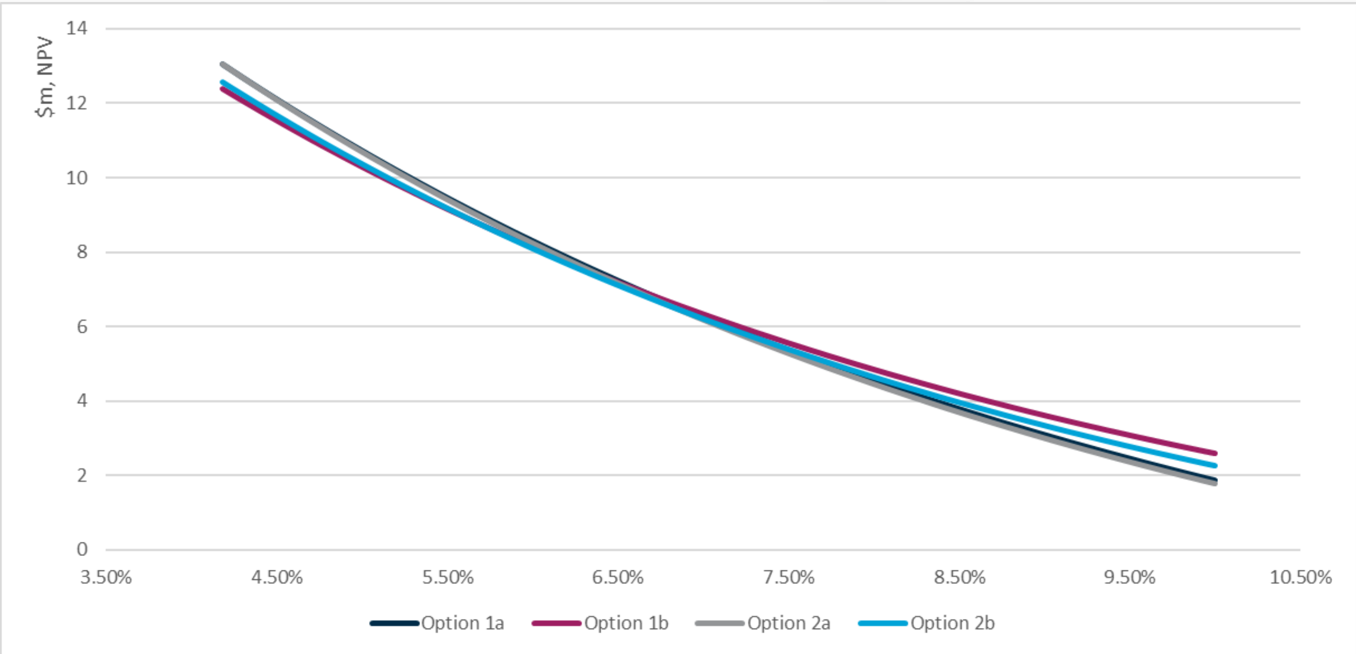


Figure 14 shows that all options deliver similar expected net benefits for all sensitivities of the commercial discount rate (i.e. 4.18 per cent to 10.00 per cent). Unsurprisingly, the only clear change across the range of commercial discount rates applied is that using a lower discount rate results in earlier commissioning (Option 1a and Option 2a) being marginally above later commissioning (Option 1b and Option 2b). Similarly, when using a higher discount rate, Option 1b and Option 2b are marginally above Option 1a and Option 2a.

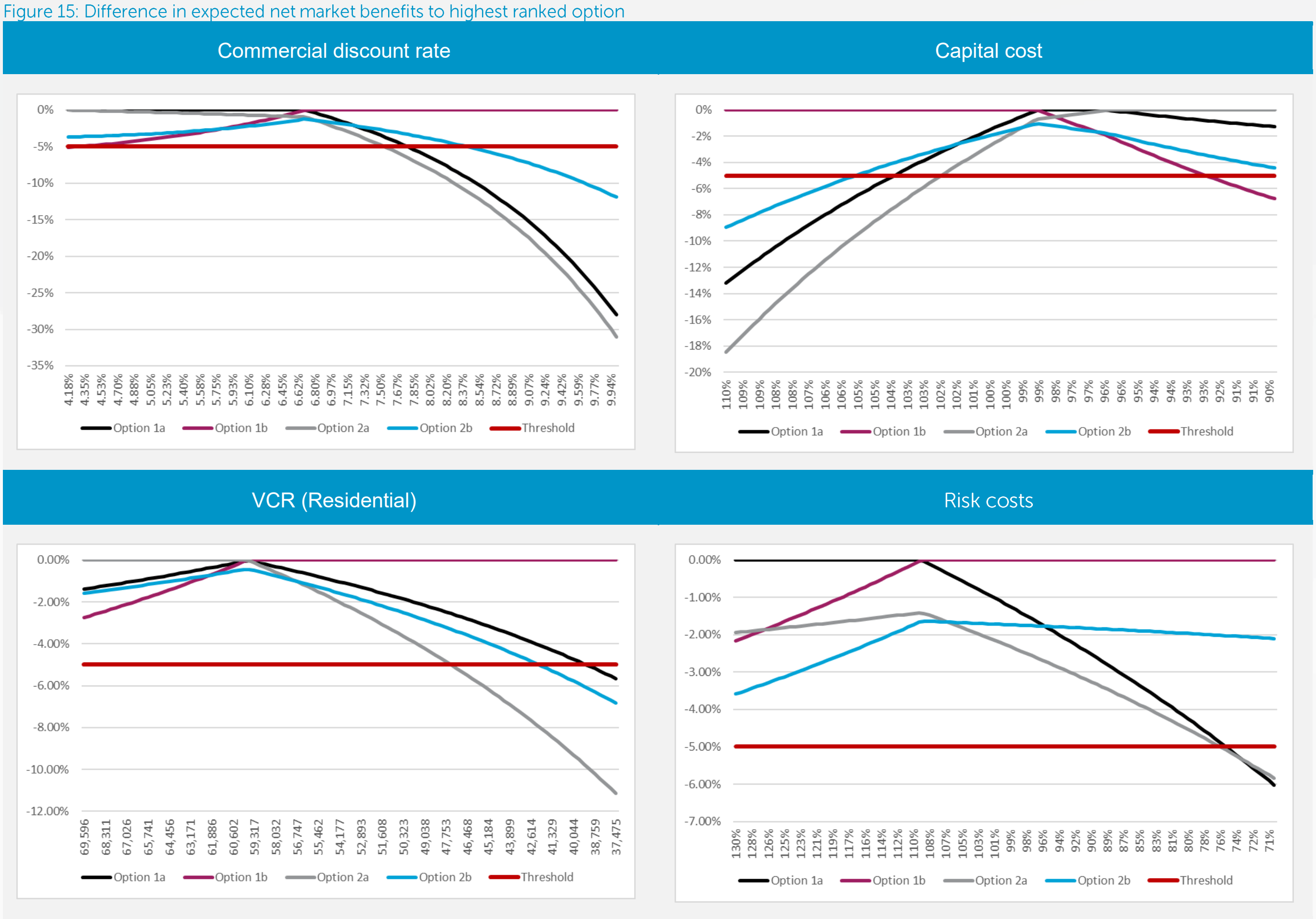
Figure 14: Commercial discount rate sensitivity testing



Across all sensitivities, all options deliver very similar positive net benefits. In some cases, Option 2a marginally delivers the highest net benefits, while in other cases Option 1a and Option 1b marginally deliver the highest net benefits. All options are within five per cent of the highest ranked option for the respective sensitivity in the majority of circumstances.

Figure 15 shows the relative difference between each option and the highest ranked option for the respective sensitivity being tested.

Figure 15: Difference in expected net market benefits to highest ranked option



In terms of boundary testing, we find that the following would need to occur for Option 2a to have negative expected net benefits:

- assumed network capital costs would need to increase by approximately 82 per cent, which is substantially outside of TasNetworks' cost accuracy estimate for the network options considered in this RIT-T of 10 per cent;
- the VCR for residential customers would need to decrease by approximately 89 per cent (i.e. go below \$6.03/kWh), which is below the lowest VNR multiplier (0.5) of the lowest VCR of any load type currently served by Sheffield substation (large industrial customers with a VCR of \$12.22/kWh, or \$6.11/kWh when adjusted by the lowest VNR multiplier);[39]
- the VCR for business customers would need to decrease by approximately 256 per cent (i.e. go below zero);
- the estimated environmental, safety and financial risk costs (in aggregate) would need to decrease by 143 per cent (i.e. go below zero); or
- a discount rate of over 11.9 per cent.

[39] See Table 5

We therefore consider the finding that Option 2a being the preferred option is robust to the key assumptions. Although all other options deliver similar net market benefits and are therefore equally ranked, this result is driven by key qualitative reasons that have not been quantified.

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 market benefit. Applying this definition, Option 2a is the preferred option at this draft stage of the RIT-T because it is equally ranked amongst the other options with respect to net market benefits and has important qualitative reasons supporting it. Option 2a is expected to deliver net market benefits of approximately $6.19 million.

Scenario and sensitivity analysis was undertaken across a range of assumptions, and all options were still equally ranked for the majority of sensitivities. Notwithstanding the equal ranking, we consider Option 2a the preferred option because, in addition to having positive net market benefits it also has several key qualitative benefits supporting it over other options, including maintaining N-1 security during the construction period, lower risk of cascading failure, the temporary addition of supply security during compromised network configurations , and lower levels of uncertainty relating to capital costs.

Option 2a involves the installation of a new transformer in a new location at Sheffield substation by FY 2030. The estimated capital expenditure associated with Option 2a is $11.8 million (in 2024/25 dollars).

The works are expected to take place between financial years 2026 and 2029, with practical completion and commissioning at the beginning of FY 2030. The optimal timing of Option 2a is found to be effectively equal between 2030 and 2032, and no later than 2033 under all sensitivities investigated. Based on the qualitative reasons discussed above, we propose that Option 2a is commissioned in the beginning of FY 2030.

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;[40]
- 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).

[40] 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 8 September 2025.

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.

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 May 2026 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 236.

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[41] (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.	NA (see 'No other classes of market benefit are considered material'

[41] 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.

		A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	
3.5		Valuing costs	
	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	NA

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	accordance with a cost threshold determination as contemplated by clause 5.16.4(k)(10)(i) of the NER).	
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	NA (see 'No other classes of market benefit are 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	NA

		undertake sensitivity analysis on all credible options by varying one or more inputs and/or assumptions.	
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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