Managing safe and reliable operation of St Marys substation

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

Executive summary 7

Introduction 11

Purpose of this report 11

Exemption from preparing a PADR 12

Submissions and next steps 13

The identified need 14

Background to the identified need 14

Description of identified need 16

Assumptions underpinning the identified need 17

Credible options 21

Base case 21

Option 1 – Replace both T1 and T2 in R24 22

Option 2 – Replace T2 in R24 and T1 in R29 22

Option 3 – Replace T2 in R24 and T1 in R34 23

Option 4 – Replace T2 in R24 and T1 in R39 23

Options considered but not progressed 24

No material inter-network impact is expected 24

Non-Network options 26

Required technical characteristics of non-network options 26

Materiality of market benefits 27

Market benefits considered material 27

Market benefits not considered material 28

Overview of the assessment approach 30

Description of the base case 30

Assessment period and discount rate 30

Approach to estimating option costs 31

The options have been assessed against three reasonable scenarios 31

Sensitivity analysis 32

Assessment of credible options 33

Estimated gross benefits 33

Estimated gross costs 33
Estimated net market benefits 33
Sensitivity testing 34

Draft conclusion and exemption from preparing a PADR **38**

Appendices **39**
Appendix 1 Compliance checklist 39

Glossary

AACE	Association for the Advancement of Cost Engineering
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CNAIM	Common Network Asset Indices Methodology
IASR	Input Assumptions and Scenarios Report
ISP	Integrated System Plan
MVA	Megavolt Ampere
NER	National Electricity Rules
NPV	Net Present Value
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PoE	Probability of Exceedance
PoF	Probability of Failure
PSCR	Project Specification Consultation Report
R24	Regulatory control period 2024-2029
R29	Regulatory control period 2029-2034
R34	Regulatory control period 2034-2039
R39	Regulatory control period 2039-2044
RIT-T	Regulatory Investment Test for Transmission
SF6	Sulphur Hexafluoride
T1	Transformer 1
T2	Transformer 2
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
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 two 10 MVA transformers at St Marys substation.

St Marys substation is located on the east coast of Tasmania, south of the township of St Marys. The substation supplies approximately 6,636 customers along almost 130km of the north-east coast of Tasmania, stretching from Coles Bay in the south to Binalong Bay in the north.

St Marys substation currently operates with two 10 MVA transformers – T1 and T2 – that were commissioned in 1966. However, peak loading of the St Marys substation exceeds 10 MVA. As such, the load supplied from St Marys substation is non-firm.

TasNetworks has identified that the transformers at St Marys are approaching their end of life based on condition assessment. In the event of a failure in one transformer, the remaining unit would be forced to operate above its 100% nameplate rating during peak demand periods, jeopardizing its operational limits. During peak demand periods, this scenario would force load shedding until a system spare is commissioned. In addition, these transformers do not align with current standard fire mitigation requirements and a fire incident could lead to the simultaneous loss of both transformer assets.

More broadly, the bushings of T2 are original and in the case of catastrophic failure the porcelain may shatter sending sharp projectiles across the switchyard. This is a safety concern to operators or adjacent in-service equipment. Finally, the transformer's aged oil containment systems have deficiencies, which pose environmental risks in the event of oil leakages.

Identified need: managing risks at St Marys substation

If the condition issues of the transformers are not addressed, then the assets will operate with increasing risk of failure as they continue to deteriorate, leading to potential unserved energy as well as environmental and safety risk. The level of reactive corrective maintenance needed to keep the transformers operating within required standards may also increase, particularly when asset failures ultimately occur.

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

Addressing the condition issues of the transformers will enable us to manage reliability, financial, safety and environmental risks at St Marys 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 there to be four feasible options from a technical, commercial and project delivery perspective that can be implemented in sufficient time to meet the identified need. Specifically:

- Option 1 - Replacement of both transformers in the 2024-2029 regulatory control period (**R24**);
- Option 2 - Replacement of T2 in R24 and T1 in the 2029-34 regulatory control period;
- Option 3 - Replacement of T2 in R24 and T1 in the 2034-39 regulatory control period; and
- Option 4 - Replacement of T2 in R24 and T1 in the 2039-2044 regulatory control period.

The capital expenditure of these options is summarised in Table 1 below.

Table 1 Summary of the capital expenditure for credible options

Option	Description of works	Capital expenditure ($2023/24)
Option 1	Replace both T1 and T2 in R24	$7.0
Option 2	Replace T2 in R24 and T1 in R29	$7.9
Option 3	Replace T2 in R24 and T1 in R34	$7.9
Option 4	Replace T2 in R24 and T1 in R39	$7.9

No option will materially affect annual routine operating costs since they do not significantly alter the frequency of inspections or maintenance activities.

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

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

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

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

The options have been assessed against three reasonable scenarios

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the expected most likely scenario for the 2024 Integrated System Plan (**ISP**) (ie, 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 therefore been based on TasNetworks' analysis.

Table 2 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate	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 given there is nothing to suggest an alternate weighting would be more appropriate.

Option 1 delivers the greatest estimated net benefits

All four credible options are found to have positive benefits for all scenarios investigated. All scenarios find that Option 1 will deliver the greatest net economic benefits. On a weighted basis, the net economic benefits of Option 1 are approximately $6.5 million. Figure 1 below shows a breakdown of the weighted net economic benefits for each option.

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

Draft conclusion

This PSCR has found that Option 1 is the preferred option at this draft stage of the RIT-T. Option 1 involves the replacement of both T1 and T2 in financial year 2025/26.

The estimated capital expenditure associated with Option 1 is $7.0 million (in 2023/24 dollars).

The works are estimated to take place across financial years 2024/25 and 2025/26, with practical completion and commissioning in the first half of financial year 2025/26.

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 if certain criteria are met.

We consider that the investment in relation to Option 1 and the analysis in this PSCR meet these criteria and therefore that we are exempt from producing a PADR.

We therefore intend to publish a Project Assessment Conclusions Report (**PACR**) as the next and final step for this RIT-T, that addresses all submissions received and presents our conclusion on the preferred option.

The exemption from producing a PADR would no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period. In this case, we will then produce a PADR.

Introduction

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

St Marys substation currently operates with two 10 megavolt ampere (MVA) transformers – T1 and T2 – that were commissioned in 1966. Power transformers are critical to the reliable supply of electricity to consumers because they are used to change higher voltage electricity to a lower voltage for transportation through the distribution network. TasNetworks has identified through condition assessment that the power transformers at St Marys are approaching their end of life, which will affect the reliability of their performance now and into the future. These condition issues are consistent with the age of these assets and their usage since commissioning.

Peak loading of the St Marys substation exceeds 10 MVA, as such the load supplied is non-firm, ie, if one transformer fails the other is not capable of supplying the entire load of the substation. In the event of a failure of one transformer, the remaining unit would be forced to operate above its 100 per cent nameplate rating during peak demand periods, jeopardizing its operational limits. During peak demand periods, such a scenario would lead to involuntary load shedding until a system spare is commissioned, which is likely to take a minimum of two weeks.

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

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

Purpose of this report

The purpose of this PSCR[1] 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);

[1] See *Appendix 1 Compliance checklist* for the National Electricity Rules requirements. Note that National Electricity Rules Version 212 was referenced during the preparation of this document.

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- present the economic assessment of all credible options, as well as the assumptions feeding into the analysis, and identify a preferred option at this draft stage of the RIT-T; and
- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

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

Exemption from preparing a PADR

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

- if the estimated capital cost of the preferred option is less than $46 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 NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

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

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

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.

[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 $46m based on the AER Final Determination: Cost threshold review November 2021. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due by 18th October 2024.

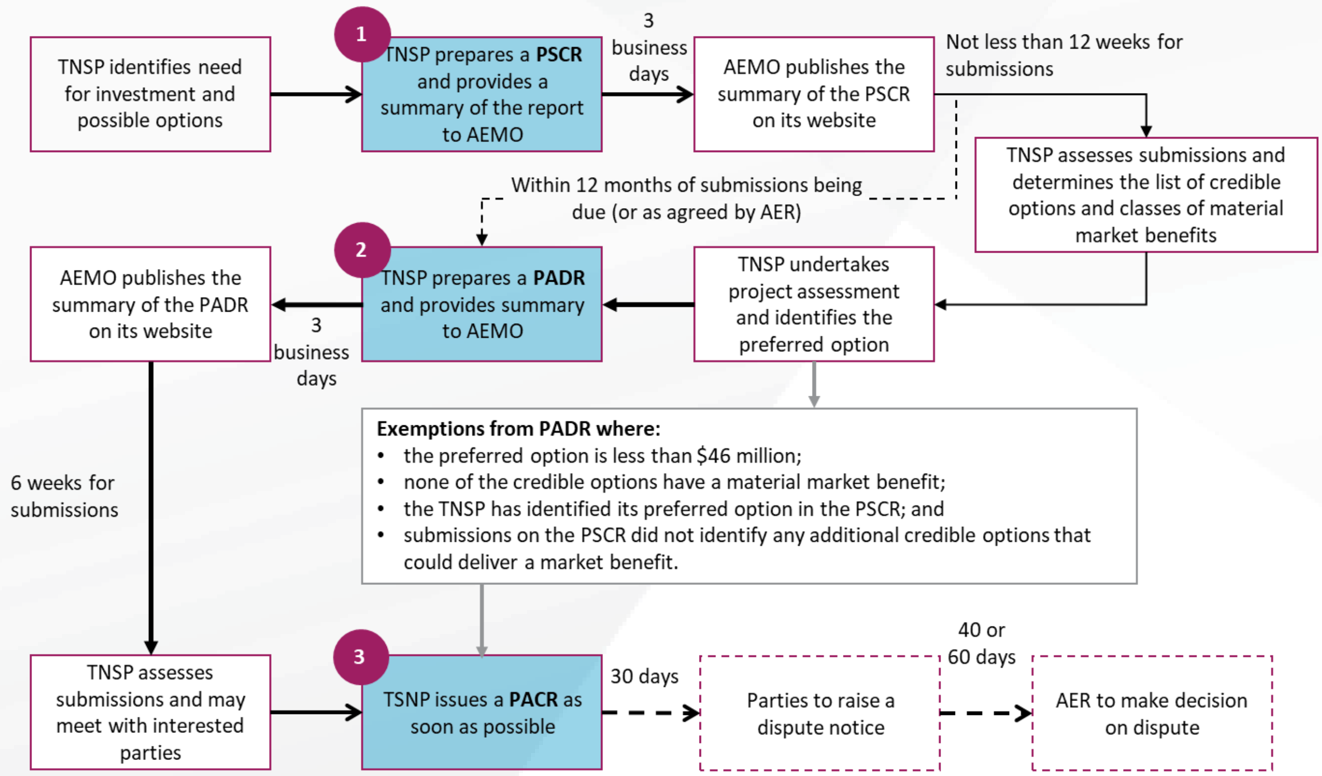
Submissions should be emailed to our Regulation team via regulation@tasnetworks.com.au.[3] In the subject field, please reference 'St Marys PSCR'.

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

Should we consider that no additional credible options were identified during the consultation period that could provide material market benefits, we intend to produce a Project Assessment Conclusions Report (**PACR**) that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.[4] Subject to no additional credible options being identified, we anticipate publication of a PACR in November 2024.

Figure 2 summarises the RIT-T process.

Figure 2: Overview of the RIT-T process



[3] 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.

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

The identified need

This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out background information related to St Marys substation and the relevant transformers.

Background to the identified need

Figure 3 provides an overview of TasNetworks' transmission network and illustrates that St Marys substation is located on the east coast of Tasmania, south of the township of St Marys in the northern planning area. The substation supplies approximately 6,636 customers along almost 130km of coast in north-east Tasmania, stretching from Coles Bay in the south to Binalong Bay in the north.

Figure 3: Tasmania's electricity transmission network

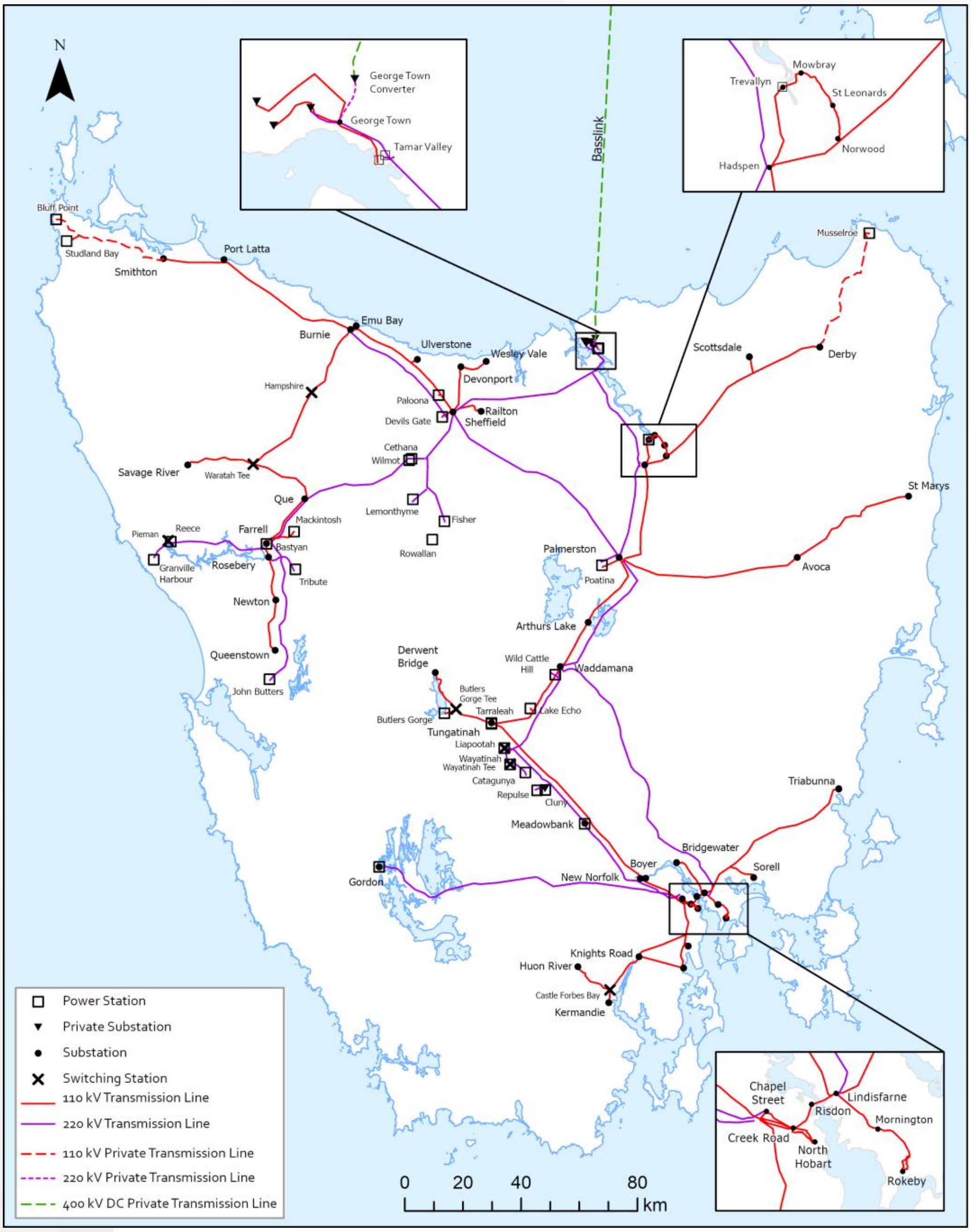
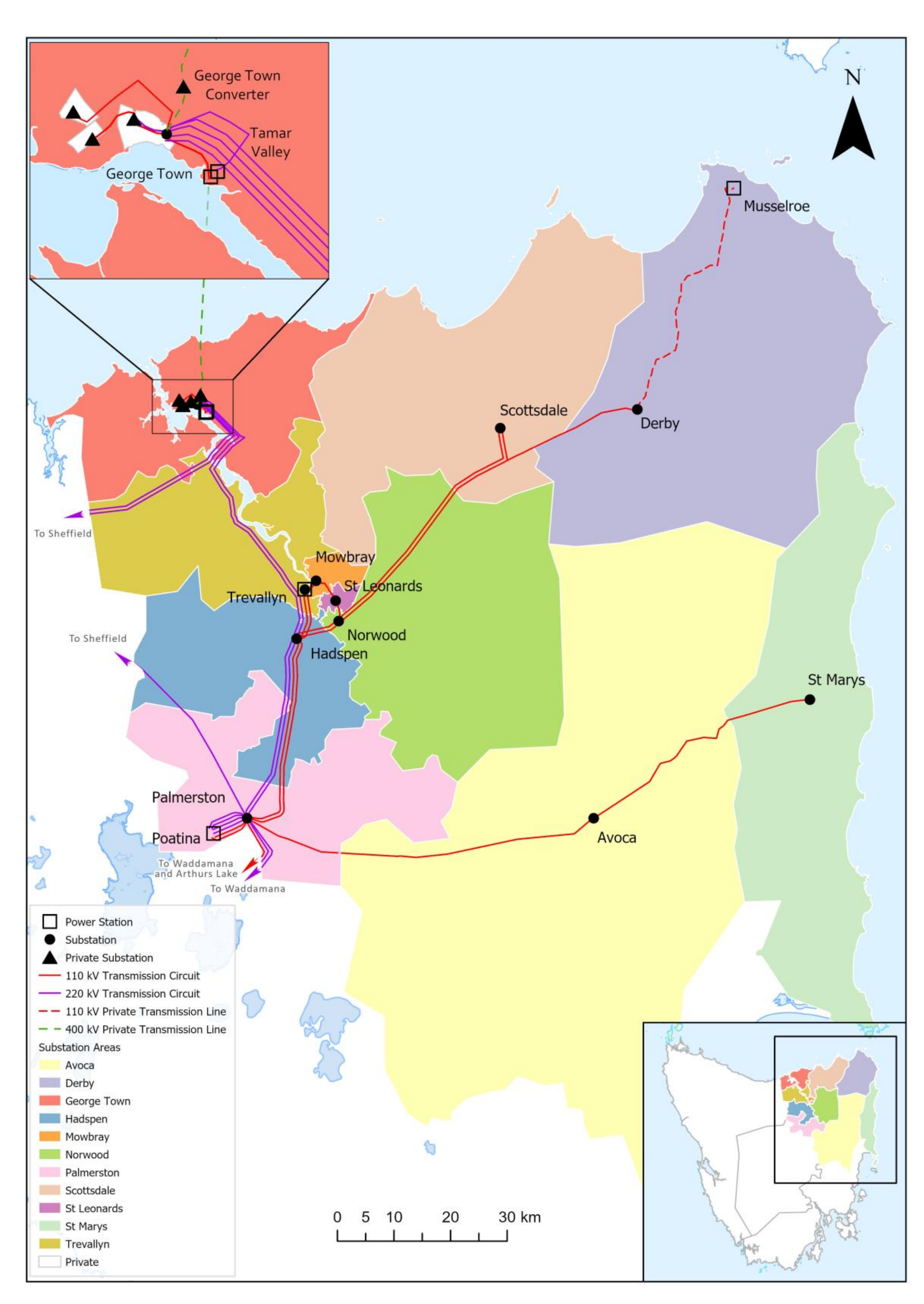


Figure 4: Northern planning area network



St Marys substation currently operates with two 10 MVA transformers – T1 and T2 – that were commissioned in 1966. Accordingly, the substation has an installed capacity of 20 MVA, with a firm capacity of 10 MVA. However, peak loading of the St Marys substation exceeds 10 MVA with peak demand recorded as 14.5 MVA, 16.8 MVA and 15.7 MVA in 2023, 2022 and 2021 respectively. As such, the load supplied from St Marys substation is non-firm.

TasNetworks has identified through our regular asset inspections that the power transformers at St Marys are approaching their end of life based on the Common Network Asset Indices Methodology (**CNAIM**). This condition, which will continue to deteriorate over time, will affect the reliability of their performance now and into the future. These condition issues are consistent with the age of these assets and their usage since commissioning.

In the event of a failure in one transformer, the remaining unit would be forced to operate above its 100% nameplate rating during peak demand periods, jeopardizing its operational limits. During peak demand periods, this scenario would force load shedding until a system spare is commissioned. Commissioning a spare transformer is likely to take a minimum of two weeks. During this time, we would act to restore supply via our distribution network, noting that the distribution feeder connections between St Marys and adjacent substations are long, so transfer capability is dependent on loading and network conditions.

In addition, these transformers do not align with current standard fire mitigation requirements and a fire incident could lead to the simultaneous loss of both transformer assets, affecting a greater number of customers than in the case of a single failure.

Further, the bushings of T2 are original and in the case of catastrophic failure the porcelain may shatter, sending sharp projectiles across the switchyard. This is a safety concern to operators or adjacent in-service equipment. Current TasNetworks' standards require the bushings to have polymeric housings, like those in T1, to mitigate the risk.

Finally, both transformers have identified issues with their oil containment systems, which poses environmental risks in the event of oil leakages.

If the condition issues of the transformers are not addressed in sufficient time, then the asset will operate with increasing risk of failure as it continues to deteriorate, leading to potential unserved energy as well as environmental and safety risk. The level of reactive corrective maintenance needed to keep the transformers operating within required standards may also increase, particularly when asset failures ultimately occur.

Description of identified need

If action is not taken, the condition of the transformers at St Marys substation will expose us and our customers to increasing levels of risk going forward, as deterioration increases the likelihood of failure.

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

Addressing the condition issues of the transformers will enable us to manage reliability, financial, safety and environmental risks at St Marys 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 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.[5]

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, and benchmarked against national and international standards;
- 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.

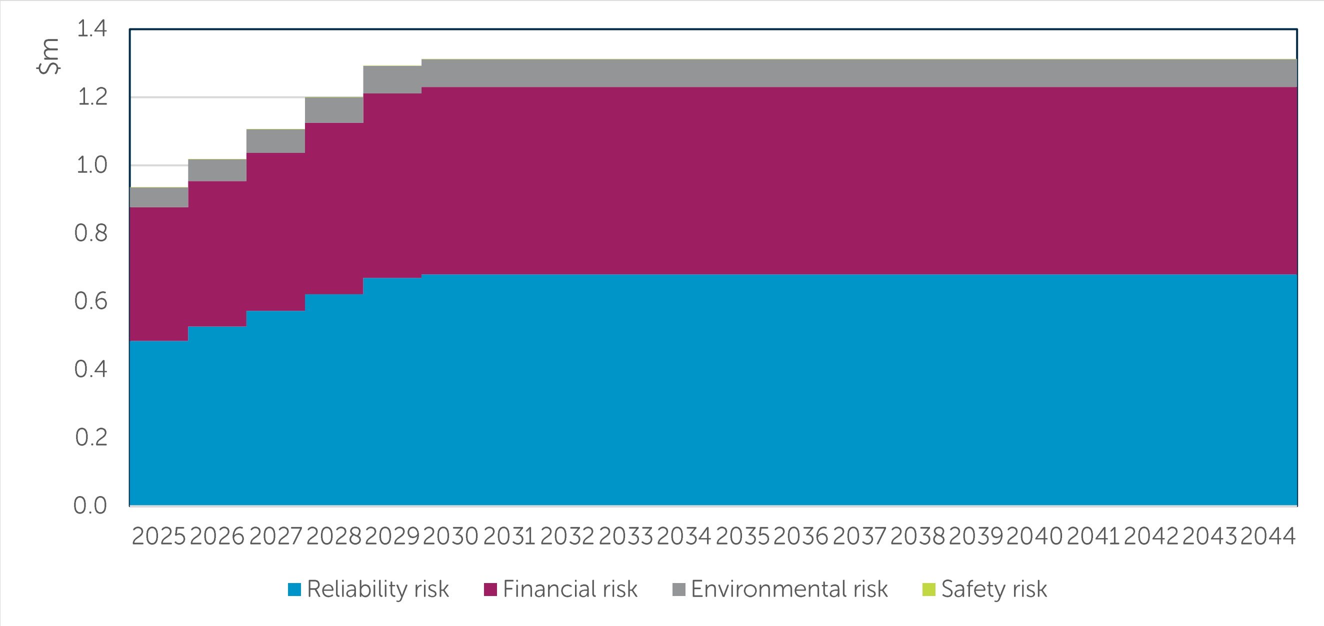
The key risks considered as part of this RIT-T are:

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

The remainder of this section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. Figure 5 summarises the increasing risk costs over the assessment period under the base case.

[5] 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 5: Estimated risk costs ($m real)



The aggregate risk cost under the base case is currently estimated (in 2023/24 dollars) at approximately $0.9 million in 2024/25, increasing to approximately $1.3 million by 2030/31.

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.[6] 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 0.5 to 10 using CNAIM.[7] The asset health ratings determine a health based PoF in line with industry standard.

The asset health issues identified at St Marys substation are summarised in Table 3.

Table 3 Asset health issues at St Marys 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	Involuntary load shedding and increased risk of simultaneous transformer failure
T2 porcelain bushings	Safety incident resulting in potential injury or death. Damage to surrounding assets
Connected and deficient oil containment system	Oil lost to environment. Fire spreading between transformers leading to loss of both assets

[6] 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

[7] 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.

Reliability risk

This risk refers to the consequence arising from a reduction in reliability of electricity supply for customers that result in involuntary load shedding and is valued using the AER's 2023 estimated Value of Customer Reliability (VCR) for Tasmania, weighted by load connected to the St Marys substation.[8] Table 4 summarises our calculation of the load-weighted VCR used in our analysis.

Table 4: Calculation of load-weighted VCR

Load type	VCR ($/kWh)	Weighting (%)
Residential	19.89	46
Business customer – agricultural	44.40	20
Business customer – commercial	52.20	34
Weighted VCR	**35.78**	-

As discussed above, if one or both transformers were to fail at St Marys substation, involuntary load shedding may occur because supply is not firm. For the purposes of this RIT-T we have calculated the level of load at risk by examining the minute-by-minute load profile at St Marys substation between 2021 to 2023 to identify how often and by how much demand exceeds the capacity of a single transformer operating under contingent conditions. This calculation also accounts for the transfer of load to adjacent substations, but as highlighted above this amount is limited by distribution network constraints. TasNetworks considers this to be a proportionate approach in the context of the identified need and, we note that, our methodology results in a conservative estimate of load at risk because it does not account for future load growth in the area, or the unlikely event that both transformers fail simultaneously.

Reliability risk is the largest of all risks quantified under the base case for this RIT-T, making up approximately 52 per cent of the total estimated risk cost in present value terms.

Financial risk

This risk refers to the direct financial consequence arising from the failure of an asset including the cost of replacement, which may need to be under emergency conditions. Our estimation of financial risk for this RIT-T does not include the expected escalating cost of reactive maintenance associated with aging transformers. It follows that our financial risk cost estimate is conservative and understates the true financial risk cost.

Financial risk is the second largest of all risks quantified under the base case for this RIT-T, making up approximately 42 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 oil containment systems at St Marys substation. While oil spills may have broader environmental impacts, for the purposes of the RIT-T we have only included the financial costs imposed on TasNetworks as a result of an oil spill, eg, clean-up costs. Further, as the St Marys transformers do not align with current standard fire mitigation requirements, a fire incident could lead to the simultaneous loss of both transformer assets. Specifically, they share an oil containment system and are not segregated by a firewall, which does not satisfy current standards for preventing the spread of fire between assets.[9]

[8] AER, *2023 Values of Customer Reliability Annual Adjustment*, 31 December 2023.

[9] See Australian Standard 2067 2016.

Under the TQR framework detailed above, the likelihood of an environmental consequence takes into account the location of the site and sensitivity of surrounding areas, the volume and type of contaminant, the effectiveness of control mechanisms, and the likelihood and impact of bushfires and other events. Further, the cost of an environmental consequence considers the cost associated with damage to the environment including compensation, clean-up costs, litigation fees, fines and any other related costs.

Environmental risk is the third largest of all risks quantified under the base case for this RIT-T, making up approximately 6 per cent of the total estimated risk cost in present value terms.

Safety risk

This risk refers to the safety consequence to our workforce, contractors and/or members of the public of an asset failure whose failure modes can create harm. The main safety risk associated with the transformers at St Marys substation is that workers in the area may be impacted by the catastrophic failure of a porcelain bushing if they are in the immediate vicinity.

Under the TQR framework detailed above, the likelihood of a safety consequence takes into account the frequency of workers on-site, the duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. Further, the cost of a safety consequence accounts for the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs.

Safety risk is the smallest of all risks quantified under the base case for this RIT-T and represents less than 1 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. Other options were considered but not progressed for various reasons that are outlined in Table 13.

Each credible option that we have assessed involves replacing the two existing 10 MVA transformers at St Marys with new 25 MVA transformers that meet the current design standards. The key difference between options is the timing of when the replacement of each transformer occurs, i.e., either concurrently or replacement that is split across regulatory periods. All options prioritise the replacement of T2 due to the worse condition and original porcelain bushings of this transformer.

TasNetworks notes that the increase in the capacity of the replacement transformers is not due to expected demand increases in the St Marys region. This type and size of transformer is TasNetworks' smallest capacity standard model. By utilising a standard model deployed elsewhere in the network we reduce reliability risk due to spares alignment, whilst simultaneously reducing the project cost as design of a new type is not required. This approach reflects industry best practice. Further, the cost differential between different size transformers is not linear.

For the purposes of this RIT-T we have not considered changes in routine operating costs. The routine maintenance requirements for new and old transformers are similar, so will not be material to the relative costs and benefits across the options.

All costs and benefits presented in this PSCR are in real 2023/2024 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 transformers at the St Marys substation. Both of the transformers at St Marys are left in service until they fail and require reactive replacement. Specifically, the condition of the insulating paper inside the transformers would continue to deteriorate until a flashover occurs. The most likely scenario is that the flashover occurs due to a transient overvoltage event such as lightning, a through fault, or as a result of switching. TasNetworks would then be forced to replace the assets under emergency conditions. As a result, the new transformer would be installed on an old plinth and oil containment structure while the second transformer remains in place. Several of the safety and environmental issues would therefore remain unaddressed.

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

Option 1 – Replace both T1 and T2 in R24

Option 1 involves the replacement of both T1 and T2 transformers in the 2024-2029 regulatory control period (**R24**). The works are estimated to take place between financial years 2024/25 and 2025/26, with practical completion and commissioning in the first half of financial year 2025/2026. The new transformers will align with TasNetworks' current standards and, as such, will address all the identified condition issues.

The estimated capital cost of this option is approximately $7 million. Table 5 provides a breakdown of these capital costs by category of expenditure.

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

Component	Procurement	Installation	Design	TasNetworks	Total
St Marys	4.3	2.3	0.3	0.1	7.0

The expenditure for Option 1 is expected to occur between 2023/24 and 2025/26, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 6 shows the expected expenditure profile of Option 1 across the construction period.

Table 6: Annual breakdown of Option 1's expected capital cost, $m real

Year	Capital cost
2023/24	0.7
2024/25	4.9
2025/26	1.4
Total	**7.0**

Option 2 – Replace T2 in R24 and T1 in R29

Option 2 involves the replacement of T2 in R24 while T1 is not replaced until the 2029-2034 regulatory control period (**R29**). Specifically, T2 will be replaced in financial year 2025/26 while T1 will be replaced in financial year 2031/32. The new transformers will align with TasNetworks' current standards and, as such, will address all the identified condition issues.

Compared to Option 1, Option 2 delays replacement of T1 by six years, ie, until the next regulatory control period. The estimated capital cost of this option is approximately $7.9 million. Table 7 provides a breakdown of these capital costs by category of expenditure.

Table 7: Breakdown of Option 2's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
St Marys	4.2	3.1	0.3	0.3	7.9

The expenditure for this option is expected to occur between 2023/24 and 2031/32, reflecting the procurement of long lead time equipment and the ultimate commissioning works during two regulatory control periods. Table 8 shows the expected expenditure profile of Option 2 across the construction period.

Table 8: Expected expenditure profile of Option 2

Year	Capital cost
2023/24	0.70
2024/25	2.66
2025/26	1.04
2029/30	0.50
2030/31	2.14

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Year	Capital cost
2031/32	0.87
Total	**7.9**

Option 3 – Replace T2 in R24 and T1 in R34

Option 3 involves the replacement of T2 in R24 while T1 is not replaced until the 2034-39 regulatory control period (R34). Specifically, T2 will be replaced in financial year 2025/26 while T1 will be replaced in financial year 2036/37. The new transformers will align with TasNetworks' current standards and, as such, will address all the identified condition issues.

Compared to Option 2, Option 3 delays replacement of T1 by an additional five years. The estimated capital cost of this option is approximately $7.9 million. Table 9 provides a breakdown of these capital costs by category of expenditure.

Table 9: Breakdown of Option 3's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
St Marys	4.2	3.1	0.3	0.3	7.9

The expenditure for this option is expected to occur between 2023/24 and 2036/37, reflecting the procurement of long lead time equipment and the ultimate commissioning works during two regulatory control periods. Table 10 shows the expected expenditure profile of Option 3 across the construction period.

Table 10: Expected expenditure profile of Option 3

Year	St Marys
2023/24	0.70
2024/25	2.66
2025/26	1.04
2034/35	0.50
2035/36	2.14
2036/37	0.87
Total	7.9

Option 4 – Replace T2 in R24 and T1 in R39

Option 4 involves the replacement of T2 in R24 while T1 is not replaced until the 2039-2044 regulatory control period (R39). Specifically, T2 will be replaced in financial year 2025/26 while T1 will be replaced in financial year 2041/42. The new transformers will align with TasNetworks' current standards and, as such, will address all the identified condition issues.

Compared to Option 3, Option 4 delays replacement of T1 by an additional five years. The estimated capital cost of this option is approximately $7.9 million. Table 11 provides a breakdown of these capital costs by category of expenditure.

Table 11: Breakdown of Option 3's expected capital cost, $m real

Component	Procurement	Installation	Design	TasNetworks	Total
St Marys	4.2	3.1	0.3	0.3	7.9

The expenditure for this option is expected to occur between 2023/24 and 2041/42, reflecting the procurement of long lead time equipment and the ultimate commissioning works during two regulatory control periods. Table 12 shows the expected expenditure profile of Option 4 across the construction period.

Table 12: Expected expenditure profile of Option 4

Year	Capital cost
2023/24	0.70
2024/25	2.66
2025/26	1.04
2039/40	0.50
2040/41	2.14
2041/42	0.87
Total	**7.9**

Options considered but not progressed

TasNetworks has considered several additional options to meet the identified need in this RIT-T. Table 13 summarises the reasons the following options were not progressed further.

Table 13 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 the asset is approaching failure, possibly enabling postponed replacement, increased inspections are not prudent in this situation.
Elimination of all associated risk	This can only be achieved through retirement and decommissioning of the associated assets. This option is therefore not technically feasible.
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.
Delay of options	TasNetworks has also considered delaying the start date of each of the identified credible options. These options do not sufficiently mitigate the environmental, safety, reliability and financial risks in a timely manner and result in lower market benefits than the credible options identified

No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[10] A "material inter-network impact" is defined by the NER in the following terms:[11]

> "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."

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

[11] Refer NER 10.

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:[12]

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

Each credible option satisfies these conditions as it does not modify any aspect of electrical or transmission assets. By reference to AEMO's screening criteria, there is therefore no material inter-network impacts associated with any of the credible options considered.

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

Non-Network options

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

For non-network options to assist, they would need to provide greater net economic benefits than the network options. That is, non-network options would need to reduce the environmental, safety, financial and reliability risk related costs (which in practice are not expected to be affected by non-network solutions).

Required technical characteristics of non-network options

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

The 2022 recorded maximum demand of St Marys Substation was 16.3 MVA, while our maximum demand 50% probability of exceedance (PoE) forecast for 2050 is 22.9 MW. Our assumption is that it would take no longer than 14 days to deploy a system spare transformer to the site. In the event of a single or double transformer failure, the non-network option would therefore be required to provide short term supply of this maximum demand until load resupply via the distribution network is achieved. Following this, the non-network option would be required to supply the remaining unserved energy until normal operating conditions are restored.

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

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

This is based on:

- non-network options being unable to address the risk of transformer failure, so will not substantially reduce environmental, safety, and financial risk related costs; and
- non-network options being unlikely to completely eliminate reliability risk costs 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.[13] Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why:[14]

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

There has recently been a law change to introduce an emissions reduction objective into the national energy objectives[15] and the NER have been updated to add a new category of market benefit to the RIT-T reflecting changes in Australia's greenhouse gas emissions.[16] While we acknowledge this important change to the RIT-T, we note that the four credible options for this RIT-T are not expected to affect the dispatch of generation in the wholesale market nor materially impact Australia's greenhouse gas emissions in any other way, including through changes in SF6 emissions. This new category of market benefit is therefore not expected to be material for this RIT-T and so has not been estimated.

Market benefits considered material

Changes in involuntary load shedding

The peak load at St Marys substation exceeds the substations firm capacity. As such, the load supplied from St Marys substation is non-firm.

In the event of a failure in one transformer, the remaining unit may be forced to operate above its 100 per cent nameplate rating during peak demand periods, jeopardizing its operational limits. During peak demand periods this situation would force load shedding until a system spare is commissioned. In addition, these transformers do not align with current standard fire mitigation requirements and a fire incident could lead to the simultaneous loss of both transformer assets, increasing unserved load.

Replacing one or both transformers at St Marys substation reduces the risk of failure and reduces the likelihood of involuntary load shedding. Reductions in expected involuntary load shedding are included as a market benefit for this RIT-T. Our approach to calculating this category of market benefit is outlined in our description of the identified need above, ie, using the probability of failure, a load-weighted VCR and demand at the St Marys substation over the past three years.

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

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

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

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

Market benefits not considered material

Wholesale market benefits

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[17]

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

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- changes in Australia's greenhouse gas emissions;
- changes in network losses; and
- competition benefits.

Differences in the timing of expenditure

Each credible option facilitates relocating one of the St Marys transformers to Waddamana in 2026/27. The transformer at Waddamana substation is approaching 75 years of age and is approaching end of life, with technical issues impacting reliability. Due to the limited loading of the Waddamana substation, TasNetworks considers it is prudent to relocate an existing transformer to Waddamana rather than to commission a new transformer at Waddamana, ie, relocating the transformer will facilitate the deferral of eventual replacement expenditure at Waddamana. The transformers at St Marys substation are 17 years younger than the existing transformer at Waddamana substation and represent a means of deferring expenditure to replace the Waddamana transformer while maintaining network performance in that area.

Option 1 involves relocating St Marys T1 to Waddamana while all other options involve relocating St Marys T2. St Marys T1 is in slightly better condition and does not have the original porcelain bushings, resulting in a slightly lower risk cost once it is relocated. However, due to the small load at Waddamana the difference in risk costs is not material.

It follows that the costs and benefits of relocating one of the St Marys transformers to replace the Waddamana transformer are similar across all credible options. We therefore consider that the deferred replacement cost of the Waddamana transformer is immaterial to the selection of the preferred option, and it has not been included as a market benefit for this RIT-T.

[17] 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

We note that inclusion of the deferred replacement cost of the Waddamana transformer as a market benefit would lead to a higher NPV for all options. Excluding the Waddamana transformer as a market benefit therefore gives a conservative estimate of total market benefits for all options.

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.[18]

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.

[18] 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.[19]

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 2024/25 to 2043/44 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**).[20] The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated Weighted Average Cost of Capital (**WACC**) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.63 per cent.[21] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest IASR).[20]

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[19] 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

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

[21] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis. See: https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29

Approach to estimating option costs

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

Specifically, we apply a bottom-up approach whereby the cost of each component within an option is individually estimated, and the cost of each of these components is then aggregated to provide a total central capital cost estimate for the option. This tool draws upon the latest quotes that we have received from our suppliers for the relevant equipment and the associated unit costs. For example, TasNetworks has recently completed two similar transformer replacements at Kermandie substation and Port Latta substation which provide accurate cost estimates for the St Marys transformer replacement. TasNetworks has escalated these costs to reflect the later timing of the options in this RIT-T, in line with our experience of increasing costs in the past.

TasNetworks considers the cost estimate for the St Mary's options to have a cost accuracy of 11 per cent, which reflects a level two estimate. 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 (PMBOK).

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, 2023/24 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials from the point at which they have been estimated.

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.

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).[22,23]

Table 14 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate	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 given there is nothing 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;
- 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.

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

23 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.

Assessment of credible options

This section outlines the assessment we have undertaken of the credible network options. The assessment compares the costs and benefits of the credible option to the base case. Benefits of the credible option are represented by reduction in costs or risks compared to the base case.

Estimated gross benefits

Table 15 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, ie, a reduction in reliability, financial, environmental and safety risks.

Table 15 Estimated gross benefits from credible options relative to the base case ($m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	11.9	10.5	13.4	11.9
Option 2	9.5	8.3	10.6	9.5
Option 3	7.8	6.8	8.7	7.8
Option 4	6.6	5.8	7.4	6.6

Estimated gross costs

Table 16 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. The capital costs are the same for each option across all scenarios.

Table 16 Costs of credible options relative to the base case ($m, PV)

Option/scenario	Central
Option 1	5.5
Option 2	5.0
Option 3	4.2
Option 4	3.7

Estimated net market benefits

The net economic benefits are the differences between the estimated gross benefits less the estimated costs. Table 17 below summarises the present value of the net economic benefits for each credible option across the three scenarios and the weighted net economic benefits.

Table 17: Weighted net economic benefits for credible options relative to the base case ($m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1	6.5	5.0	7.9	6.5
Option 2	4.5	3.3	5.6	4.5
Option 3	3.5	2.6	4.5	3.5
Option 4	2.9	2.1	3.7	2.9

All four credible options are found to have positive benefits for all scenarios investigated. All scenarios find that Option 1 will deliver the greatest net economic benefits. On a weighted basis, the net economic benefits of Option 1 are approximately $6.5 million. Figure 6 below shows a breakdown of the weighted net economic benefits for each option.

Figure 6 Weighted net economic benefits ($m, PV)

Sensitivity testing

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

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

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

Step 1 – sensitivity testing of the optimal timing

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

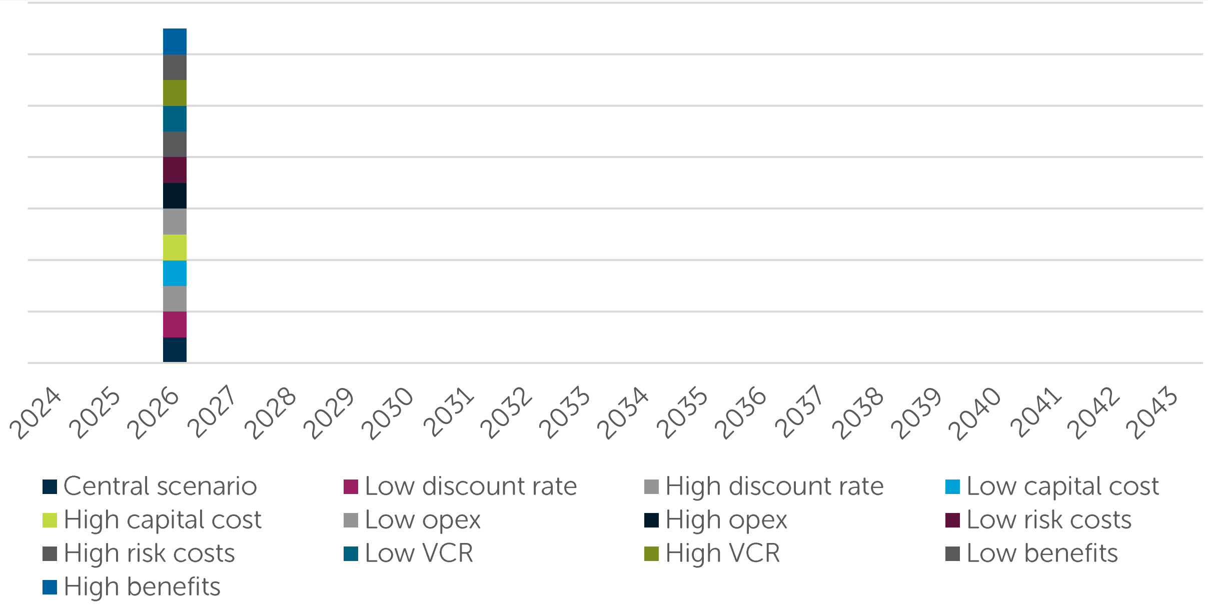
The optimal timing of Option 1 is found to be invariant to the assumptions of:

- an 11 per cent increase/decrease in the assumed network capital costs, which is in alignment with TasNetworks cost estimate accuracy for the options considered in this RIT-T;

- lower (or higher) weighted average VCR;
- lower (or higher) assumed reliability, financial, environmental and safety risks; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.50 per cent.

Specifically, Figure 7 below outlines the impact on the optimal commissioning year for each line, under a range of alternate assumptions. It demonstrates that the optimal timing for Option 1 is 2025/26.

Figure 7: Optimal timing for Option 1



Step 2 – sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit, based on undertaking the project in 2024/25 and completion in 2025/26. Specifically, we have investigated the following same sensitivities under this step as in the first step:

- an 11 per cent increase/decrease in the assumed network capital costs;
- lower (or higher) weighted average VCR;
- lower (or higher) assumed reliability, financial, environmental and safety risks; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.50 per cent.

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

Figure 8 shows that Option 1 delivers higher expected benefits than the other three options for all sensitivities of capital costs within TasNetworks 11 per cent cost accuracy for this RIT-T (ie 89 per cent to 111 per cent of estimated capital costs).

Figure 8 Capital costs sensitivity testing

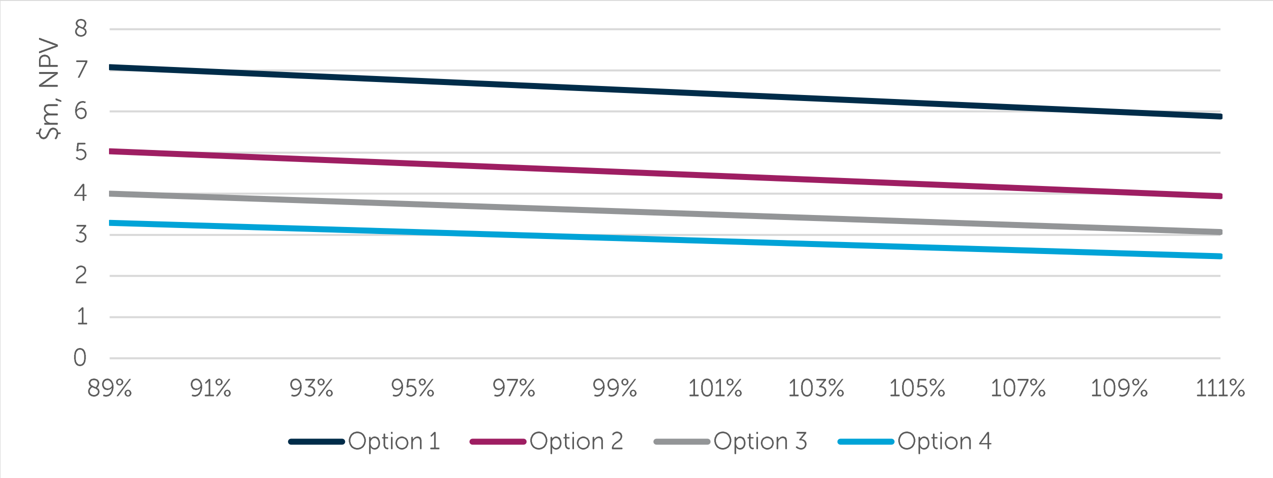


Figure 9 shows that Option 1 delivers higher expected benefits than the other three options for all sensitivities of the VCR (ie plus and minus 30 per cent, or $25.05/kWh to $46.51/kWh).

Figure 9 VCR sensitivity testing

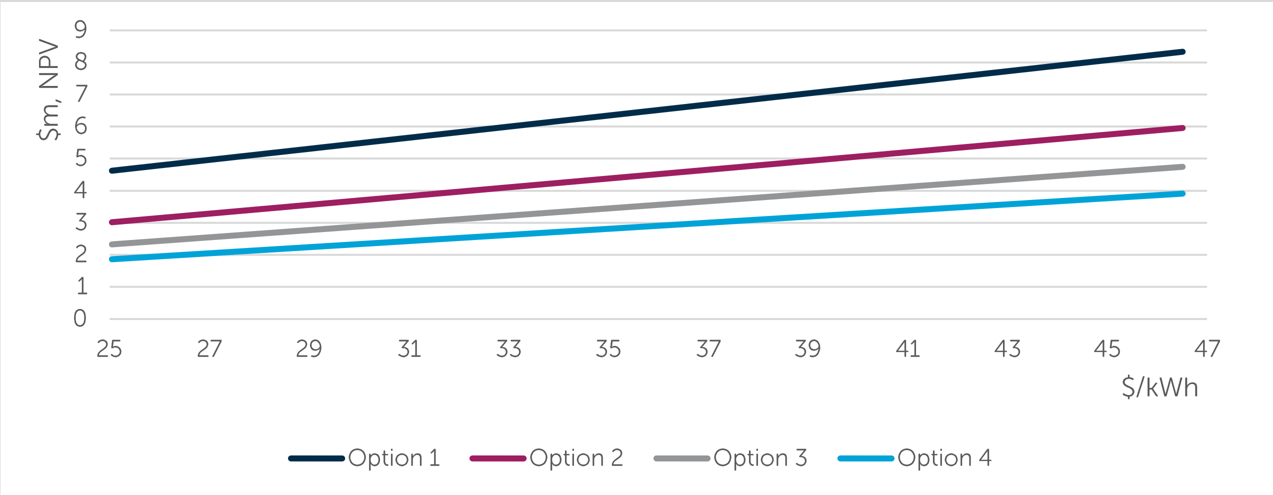


Figure 10 shows that Option 1 delivers higher expected benefits than the other three options for all sensitivities of the environmental, safety and financial risk costs (ie plus and minus 30 per cent).

Figure 10 Risk costs sensitivity testing

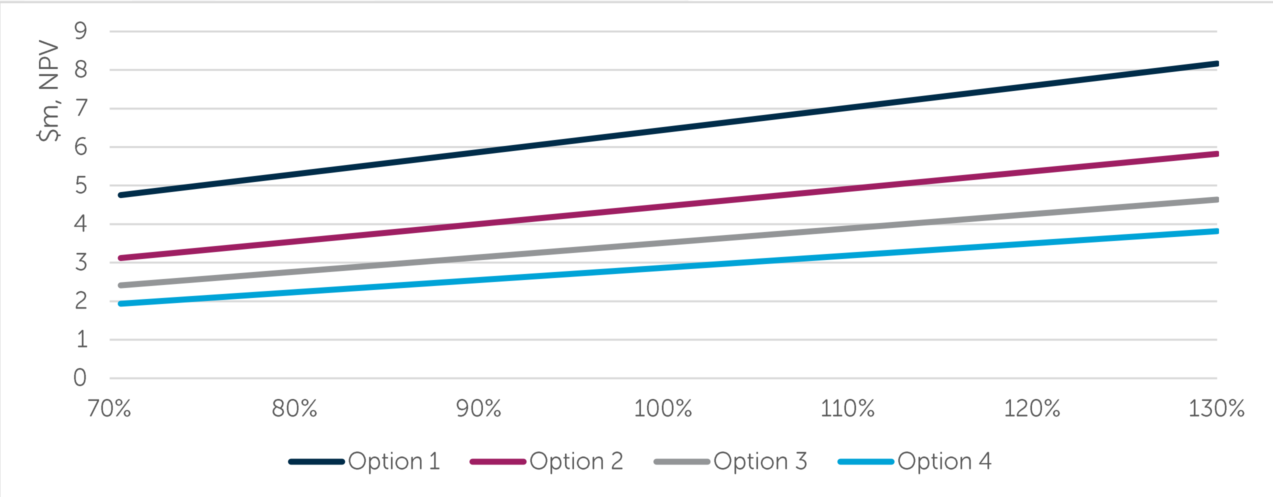
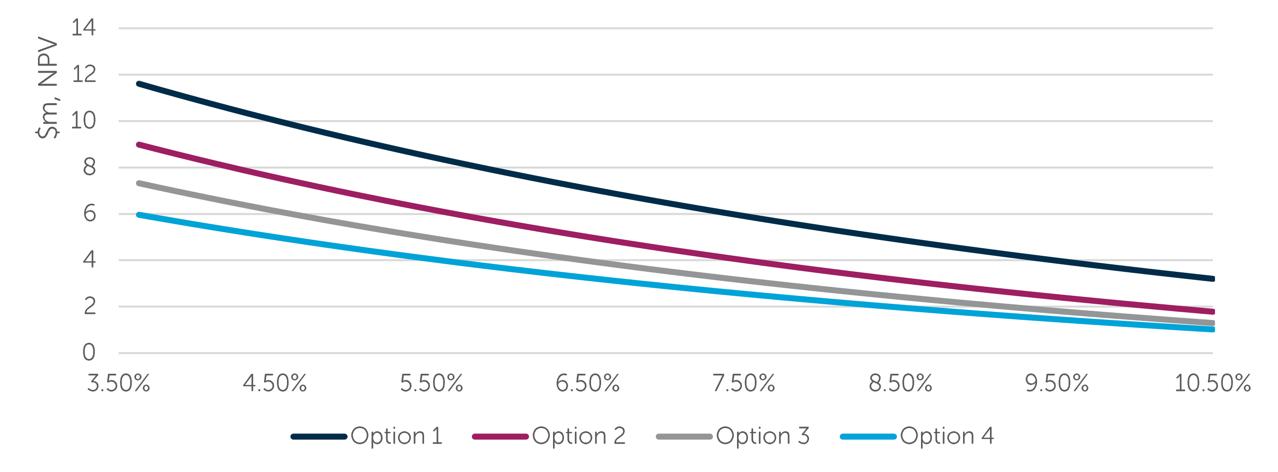


Figure 11 shows that Option 1 delivers higher expected benefits than the other three options for all sensitivities of the commercial discount rate (ie 3.63 per cent to 10.50 per cent).

Figure 11: Commercial discount rate sensitivity testing



Option 1 is expected to deliver positive benefits and is expected to deliver higher benefits than the other three options in all sensitivities.

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

- assumed network capital costs would need to increase by approximately 119 per cent, which is substantially outside of TasNetworks' cost accuracy estimate for the network options considered in this RIT-T of 11 per cent;
- the VCR would need to decrease by approximately 105 per cent (ie go below zero), which is below the lowest VCR of any load type currently served by St Marys substation (residential customers with a VCR of $19.98 /kWh);[24]
- the estimated risk costs (in aggregate) would need to decrease by 112 per cent (ie go below zero); or
- a discount rate of over 16.8 per cent.

We therefore consider the finding that Option 1 being the preferred option is robust to the key underlying assumptions.

[24] See table 4

Draft conclusion and exemption from preparing a PADR

This PSCR has found that Option 1 is the preferred option at this draft stage of the RIT-T. Option 1 involves the replacement of both T1 and T2 in financial year 2025/26.

The estimated capital expenditure associated with Option 1 is $7.0 million (in 2023/24 dollars).

The works are estimated to take place between financial years 2023/24 and 2025/26, with practical completion and commissioning in the first half of financial year 2025/2026.

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 $46 million;[25]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

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

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

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

However, if no additional credible options are identified during the consultation period that we consider could have material market benefits, we intend to produce a PACR in November 2024 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.

[25] 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 $46m based on the AER Final Determination: Cost threshold review November 2021. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

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 212.

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

Rules clause	Summary of requirements	Relevant section
5.16.4(z1)	A RIT-T proponent is exempt from paragraphs (j) to (s) if: (1) the estimated capital cost of the proposed preferred option is less than $35 million[26] (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.	Draft conclusion and exemption from preparing a PADR

[26] Varied to $46m based on the AER Final Determination: Cost threshold review November 2021. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

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