Rosebery Substation T1 & T2 and 44 kV switchgear replacement

RIT-T Project Assessment Conclusions Report

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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.

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Glossary

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

Disclaimer

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

Executive summary

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

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

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

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

Identified need: managing risks at Rosebery Substation

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

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

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

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

The need is therefore focussed on the replacement of ageing assets to continue to serve existing demand. The prospect of any future step change increase in demand due to load growth in the region remains uncertain and would therefore be considered in separate future regulatory processes as required, once any such load becomes more certain. TasNetworks notes that taking action to address the risks associated with ageing assets now does not preclude further future works to meet any committed future load increases.

One submission was received to the PSCR

We published a PSCR on 21 July 2025 and invited written submissions on the material presented within the document by 30 October 2025.

TasNetworks received one submission to the PSCR from BMTJV. We thank BMTJV for the submission. BMTJV's full submission can be provided upon request. We summarise BMTJV's key points and our high-level responses in the table below. Further detail is included in the body of the report under the heading 'Response to PSCR submission'.

Table 1 Summary of response to PSCR submission

Point raised in submission	TasNetworks response
The basis for the demand forecast is unrepresentative of future demand.	Use of 2024 maximum demand data as the basis for forecast demand is appropriate, as it reflects the most recent information i.e. the medium size mining customer referred to in the submission is not currently operational as it is under care and maintenance. Therefore, it is not expected to need continued supply. Changing the basis for the forecast to a prior year is unlikely to have a material impact on the RIT-T outcome (as the extent of that mining load was relatively small), nor will it improve accuracy of future forecast demand.
There is a prospect of future load growth that has not been accounted for and would exceed the firm capacity provided by the credible option.	TasNetworks notes that the potential new load referred to in the submission reflects an expansion of BMTJV's current operations, which is neither currently a committed nor anticipated project under the RIT-T. The credible options considered in this RIT-T are designed to replace the ageing assets currently in place. Any solution required to accommodate material new load will be assessed separately. TasNetworks has therefore not considered potential new load growth as part of this RIT-T but would do so as part of a separate RIT-T or other regulatory process, once the new load is more certain.

Firm capacity under the preferred option appears to be lower than existing firm capacity and is insufficient to accommodate future load growth.	Firm capacity under the preferred option is sufficient to meet all existing and committed load. The current switchyard setup with three supply transformers connecting to the 110 kV network is less reliable compared to what is proposed under the preferred option with two 60 MVA units, given the increased likelihood of concurrent transformer failure.
TasNetworks has not demonstrated how it will continue to serve existing customers during the construction of the preferred option (i.e., during potential outages).	TasNetworks will develop a plan for how the work can be sequenced to minimise disruption for existing customers whilst performing the work safely. TasNetworks will consult with all major customers that may be affected as part of developing the next level of detail for project delivery once it has completed the RIT-T stage.

There have been no other material developments in response to, and since, the PSCR. Notwithstanding the submission received, we have not identified any additional credible options or material changes that would impact which option was identified as the preferred option in the PSCR.

Updated capital cost estimates following the PSCR

Since the publication of the PSCR, TasNetworks has updated the capital cost estimates associated with the three credible options originally considered in the PSCR. The capital cost estimates of Option 1 and Option 3 have increased by 15.3 per cent, while the capital cost estimates of Option 2 have increased by 2.5 per cent. The economic assessment and associated sensitivity and optimal timing analysis presented in the PSCR has been updated as part of this PACR to reflect these updated cost estimates.

Three credible options have been considered

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

- Option 1 involves the replacement of T1 and T2 supply transformers and the 44 kV switchgear with commissioning in the beginning of FY31;
- Option 2 involves installing two new supply transformers at Farrell Substation with commissioning in the beginning of FY30; and
- Option 3 involves the replacement of T1 and T2 supply transformers and the 44 kV switchgear with commissioning in the beginning of FY35.

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 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. Consistent with this, there were no submissions from potential proponents of non-network options to the PSCR.

The options have been assessed against three reasonable scenarios

The credible options have been assessed under three scenarios as part of this PACR 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, we have not modelled the ISP scenarios. The three scenarios adopted for this RIT-T are consistent with the most likely scenario from the latest 2024 Integrated System Plan (**ISP**) (i.e., the 'Step Change' scenario). The updated 2026 ISP is not expected to have a material impact on the analysis for this RIT-T, particularly as the 7 per cent central discount rate has been retained. Other elements of each scenario for this RIT-T (i.e., demand forecasts, costs and risk cost estimates) are based on TasNetworks local demand forecasts and cost estimates, and so are not directly affected by the ISP.

The scenarios differ by the assumed level of risk costs, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of the Australian Energy Market Operator's (**AEMO**) ISP assumptions, and have been based on TasNetworks' analysis.

Table 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[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.

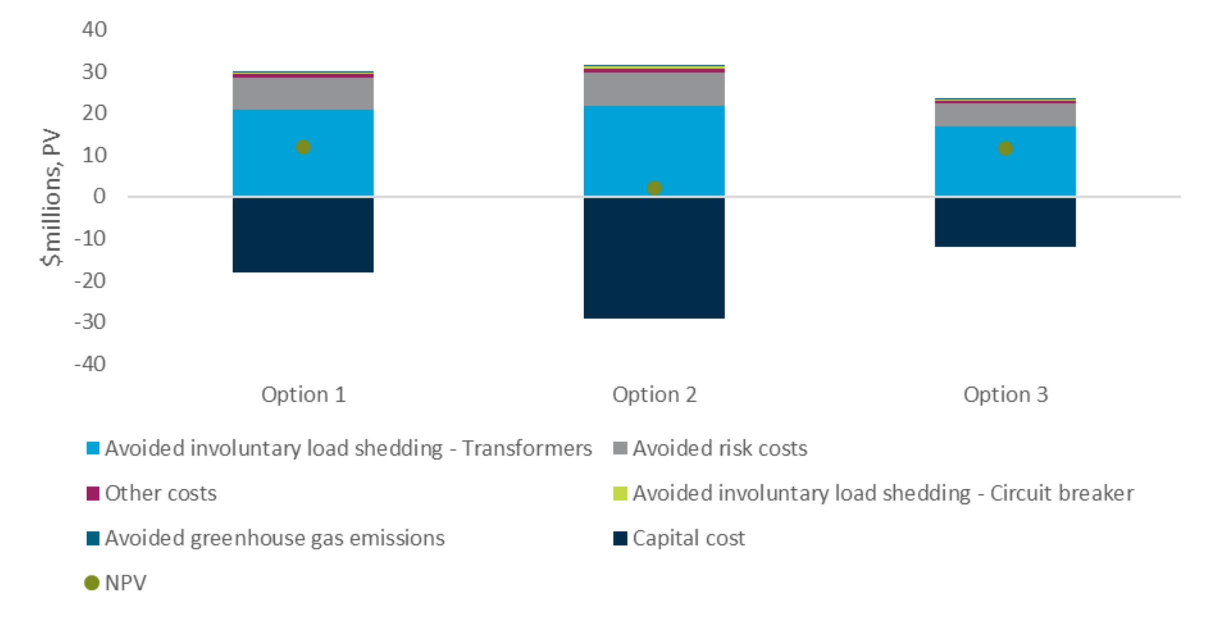
Option 1 delivers the greatest estimated net benefits

All three credible options are found to have positive benefits for all scenarios investigated. Option 1 and Option 3 are expected to deliver the greatest net economic benefits across all scenarios investigated, with Option 1 delivering marginally higher net economic benefits.[2] On a weighted basis, the net economic benefits of Option 1 are approximately $12.0 million, which is 3.1 per cent greater than the net economic benefits of the second-ranked option, Option 3 (with net benefits of approximately $11.6 million). Figure 1 below shows a breakdown of the weighted net economic benefits for each option.

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

[2] Option 1 is the top-ranked option in the high scenario and is expected to deliver net benefits 6.7 per cent greater than the second ranked option in that scenario. Option 1 and Option 3 are effectively ranked equally in the central and low scenarios given that there is only a 3.1 and 3.9 per cent difference between the two options in those scenarios respectively.

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



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

- Option 1 is already ranked above Option 3 even though we have not applied real cost escalation to the costs of Option 3 despite construction commencing later – some degree of cost escalation is likely and would increase the extent to which Option 1 results in higher net economic benefits relative to Option 3; and
- although the prospect of future load has not directly affected the analysis, TasNetworks is expecting at least some additional mining load in the area in the near-to-short term, meaning earlier investment in replacing the existing ageing assets will support accommodating that increased load in the network without risk of even greater unserved energy in the future. Further, Option 1 does not preclude future investment to allow additional load to be served via Rosebery Substation in the future, if required.

Final conclusion

This PACR has found that Option 1 is the preferred option, consistent with the draft conclusion in the PSCR. Option 1 involves the replacement of both T1 and T2 supply transformers and 44 kV switchgear, commissioning the assets at the beginning of FY31. The estimated capital expenditure associated with Option 1 is $27.8 million (in 2025/265 dollars). The works are estimated to take place between FY27 and FY30, with commissioning in the beginning of FY31.

Next steps

This PACR represents the final step of the RIT-T consultation process undertaken by TasNetworks.

Parties wishing to raise a dispute notice with the Australian Energy Regulator (**AER**) may do so prior to 07 June 2026 (30 days after publication of this PACR). The AER will address any dispute notices raised during this period within 40 to 120 days, after which the formal RIT-T process will conclude.

Further details on this RIT-T can be obtained by emailing our Regulation team via regulation@tasnetworks.com.au. In the subject field, please reference 'Rosebery PACR'.

Introduction

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

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

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

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

More broadly, the transformers at Rosebery Substation do not align with current standard fire mitigation requirements and a fire incident could lead to the simultaneous loss of multiple transformer assets. The bushings of T1/ T2 are also not to the current standard (polymeric housing) 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 transformers aged oil containment systems have deficiencies, which pose environmental risks in the event of oil leakages.

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

One submission was received in response to the PSCR

We published a PSCR on 21 July 2025 and invited written submissions on the material presented within the document by 30 October 2025. TasNetworks received one submission to the PSCR from BMTJV. We thank BMTJV for the submission and have responded to the points raised in their submission in the section below titled 'Response to PSCR submission'.

There have been no other material developments in response to, and since, the PSCR. Notwithstanding the submission received, we have not identified any additional credible options or material changes that would impact which option was identified as the preferred option since the PSCR.

Purpose of this report

The purpose of this PACR is to:[3]

- describe why action needs to be taken (the 'identified need');
- present credible options that we consider capable of addressing the identified need;
- present the economic assessment of all credible options, as well as the assumptions feeding into the analysis; and
- identify the preferred option at this final stage of the RIT-T.

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 the RIT-T process, 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.

Next steps

This PACR represents the final step of the RIT-T consultation process undertaken by TasNetworks.

The second step of the RIT-T process, production of a Project Assessment Draft Report (**PADR**), was not required as part of the RIT-T process under National Electricity Rule (**NER**) clause 5.16.4(z1). Specifically, it was not required due to:

- the estimated capital cost of the preferred option being less than $54 million;
- the PSCR stating:
  - the proposed preferred option, together with the reasons for the proposed preferred option;
  - that TasNetworks is exempt from producing a PADR for this RIT-T;
  - that the proposed preferred option (and the other credible options) will not have a material market benefit associated with any of the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in involuntary load shedding;
- there being no PSCR submissions that identified additional credible options that could deliver a material market benefit (see the section below responding to the submission received on the PSCR); and

[3] See appendix A.1 for the NER requirements. Note that the NER version 243 was referenced during the preparation of this document.

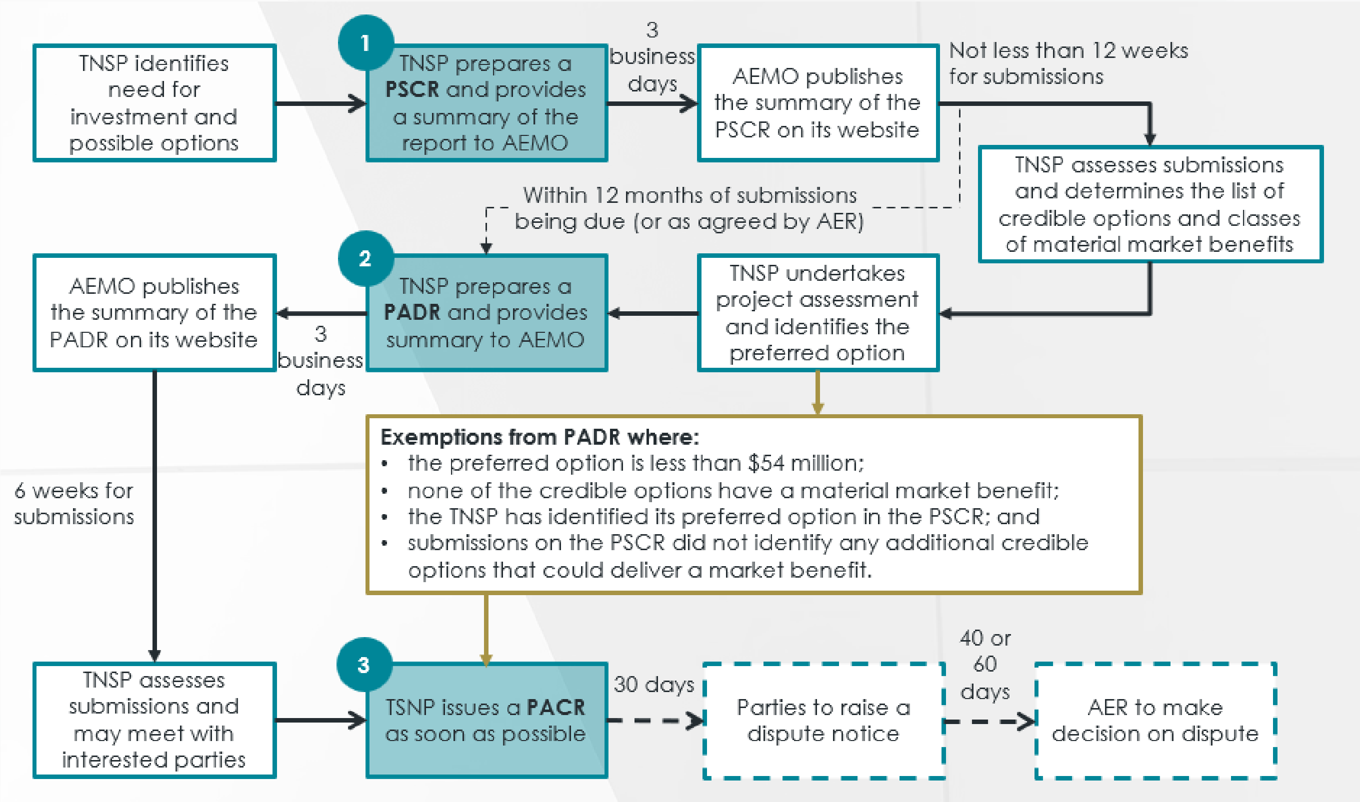
- the PACR addressing any issues raised in relation to the proposed preferred option during the PSCR consultation (noting that no issues have been raised).

Parties wishing to raise a dispute notice with the Australian Energy Regulator (**AER**) may do so prior to 07 June 2026 (30 days after publication of this PACR). The AER will address any dispute notices raised during this period within 40 to 120 days, after which the formal RIT-T process will conclude.

Further details on this RIT-T can be obtained by emailing our Regulation team via regulation@tasnetworks.com.au. In the subject field, please reference 'Rosebery PACR'.

Figure 2 summarises the RIT-T process.

Figure 2: Overview of the RIT-T process



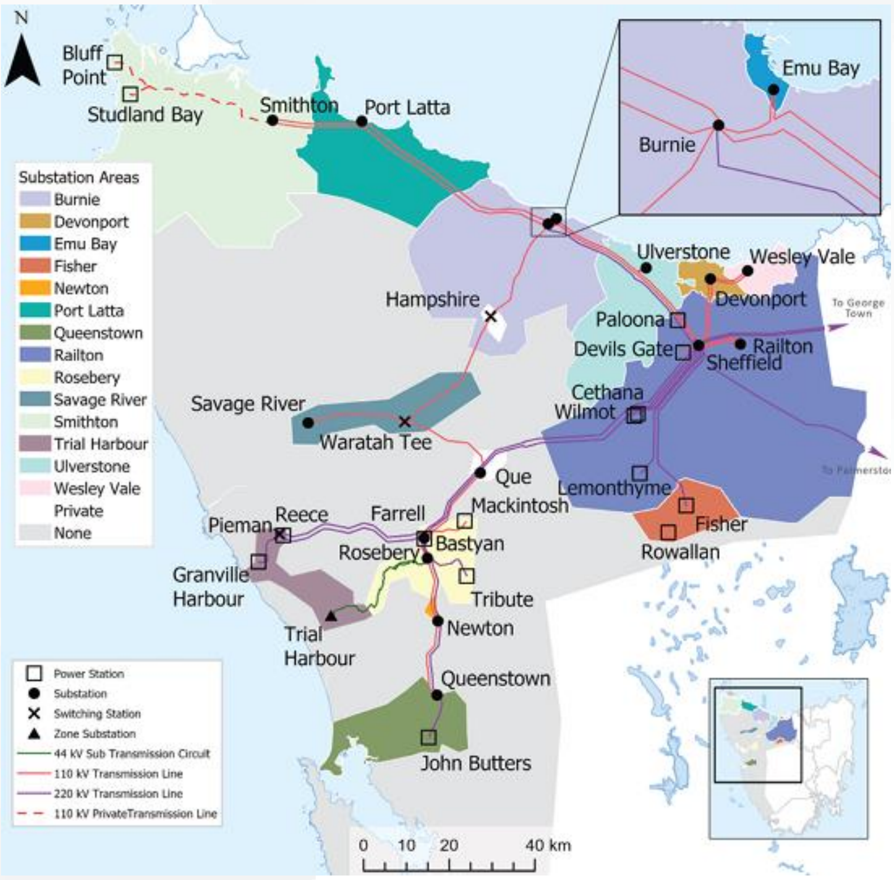
The identified need

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

Background to the identified need

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

Figure 3: North West and West Coast planning area



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

Network configuration

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

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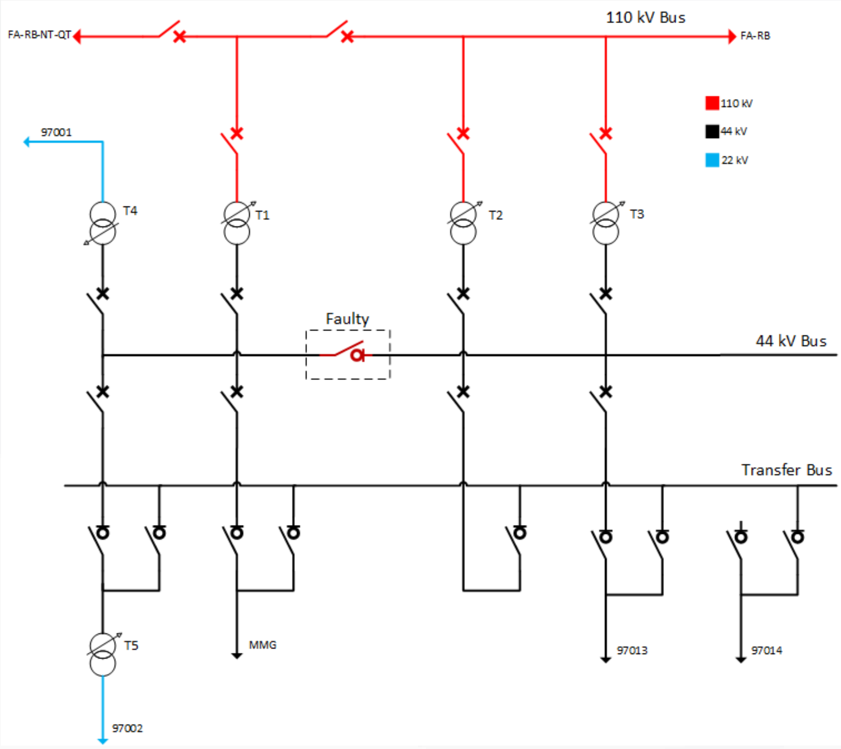
Figure 4: Current configuration of the Rosebery Substation one-line diagram



Transformer asset condition issues

At Rosebery Substation there are three operational supply transformers, T1, T2 and T3. T1 and T2 are rated at 36 MVA each and T3 is rated at 30 MVA, giving Rosebery Substation a firm rating of 66 MVA at 44 kV. Both T1 and T2 are 110/44-22 kV transformers that were manufactured in 1968 by Tyree and commissioned towards the end of that year. T1 and T2 have both previously received refurbishments, with T1 having received midlife refurbishments in 2000 and T2 having received a full refurbishment in 1994. The refurbishment of T1 included the replacement of transformer oil and the installation of new bushings, radiators and LV conductor terminations. The refurbishment of T2 included a redesign of the core and coil assembly, winding replacement, oil replacement and the replacement of cooling radiators. Leak repairs have been conducted on both T1 and T2 transformers in previous years. However, minor oil leaks persist on the lower flanges (main tank and radiator), Buchholz, main tank sight glass, 44 kV bushing turrets, pumps and around the pressure relief valves. The T1 and T2 transformers will be 60 years old by the end of financial year 2029 (FY29), while the T3 transformer will only be 46 years old. The age of the T1 and T2 transformers places them at a significantly higher risk of failure when compared to more recently commissioned transformers.

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

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

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

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

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

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

44 kV switchgear asset condition issues

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

As part of the switchgear at Rosebery, there are a total of nine circuit breakers, which are comprised of five Siemens SPS72 SF6 circuit breakers and four Sprecher & Schuh AR45 oil circuit breakers. The frequency of unplanned corrective maintenance to refill the Siemens SPS72 circuit breakers with SF6 is increasing due to the age of these assets. One specific SF6 circuit breaker (C252) has a persistent leak on the mechanism and interrupter housing connection, and due to the location of this leak, any local repair is not feasible. Currently the Sprecher & Schuh AR45 circuit breakers are in deteriorating condition. One specific circuit breaker (A552) had a very high contact resistance and was not repairable. One of the poles of an existing circuit breaker (E452) was removed and installed in circuit breaker A552. Now circuit breaker E452 is out of service which reduces supply security for one of the 44/22 kV supply transformers. In summary, the 44 kV rated circuit breakers are reaching end-of-life and maintenance requirements have increased and resulted in increased costs and reliability risks.

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

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

Figure 6: Persistent SF6 leak on switchgear

The higher risk of failure associated with the circuit breakers has led to an increased risk of unplanned maintenance of these assets. The risk of reactive replacement of circuit breakers has also increased. This is exacerbated by the fact that there are no dedicated spares for the 44 kV circuit breakers. While there is a spare circuit breaker in the Devonport store, substantial modifications to both the circuit breaker and the support structure at Rosebery Substation would need to be incurred. There is significant financial risk associated with increased unplanned maintenance and reactive replacement for TasNetworks. Furthermore, as the MMG mine has a dedicated 44 kV feeder, if the respective circuit breaker fails, we estimate that it would take approximately four hours to manually switch the network such that a by-pass setup feeder can supply the MMG mine. As a result, there would be approximately four hours of unserved energy.

Rosebery Substation customers

Rosebery Substation supplies approximately 40 MW of load, including:

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

- the remainder is residential load including the Rosebery and Zeehan communities.[4]

Residential load is expected to continue at a consistent level into the future, which is reflected in our demand forecasts. There is potential additional load in the near-to-short term due to underground mining expansion in the region however, this load increase is not yet committed or anticipated. While this could exacerbate load curtailment in the event that both transformers fail simultaneously, we have not included it as part of this analysis because the additional load is not yet committed and therefore is best addressed separately (see discussion in the 'Response to PSCR submission' section below).

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

Description of identified need

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

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

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

The need is therefore focussed on the replacement of ageing assets to continue to serve existing demand. The prospect of any future step change increase in demand due to load growth in the region remains uncertain and would therefore be considered in separate future regulatory processes as required, once any such load becomes more certain. TasNetworks notes that taking action to address the risks associated with aging assets now does not preclude further future works to meet any committed future load increases.

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.[5]

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

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

[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.

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

where:

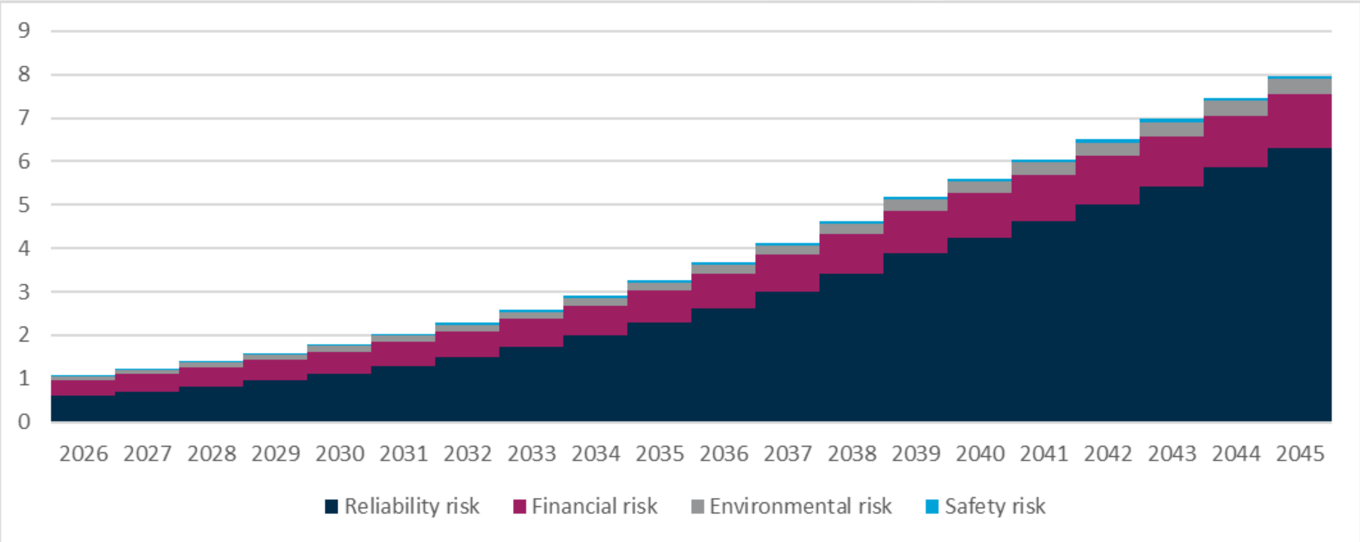
- TQR is the total quantified risk/risk cost per year of the event happening;
- PoF is the annual asset probability of failure, which is obtained from our asset performance records, as well as being benchmarked against national and international standards where applicable;
- No is the number of assets;
- 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 maintenance upon failure of the asset; and
- environmental and safety risks, e.g. oil spills from the containment system.

The remainder of this section describes the assumptions underpinning our assessment of the risk costs, i.e. the value of the risk avoided by undertaking each of the credible options. Figure 7 summarises the increasing risk costs over the assessment period under the base case.

Figure 7: Estimated risk costs ($m real)



Asset health and the probability of failure

Our asset health modelling aligns with Chapter 3.2 and 5.2 of the AER's 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

[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.

replacement or refurbishment intervention. Specifically, asset health is rated on a scale of one to ten using CNAIM.[7] The asset health ratings determine a health based PoF in line with industry standard.

The asset health issues identified at Rosebery Substation are summarised in Table 3.

Table 3 Asset health issues at Rosebery Substation and their consequences

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

Reliability risk

This risk refers to the consequence arising from a reduction in reliability of electricity supply for customers through involuntary load shedding and is valued using the AER's 2024 estimated Value of Customer Reliability (**VCR**) for Tasmania, weighted by load connected to the Rosebery Substation.[8] Table 4 summarises our calculation of the load-weighted VCR used in our analysis.[9]

We have multiplied the load-weighted VCR amount by 0.5 in accordance with the AER's Value of Network Resilience (**VNR**) for long-duration outages.[10]

Table 4: Calculated of load-weighted VCR

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

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

The reliability risk has been captured as avoided involuntary load shedding benefits in the net present value (**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.

[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.

[8] AER, *Values of customer reliability: Final report on VCR values*, December 2024, Table 1 and Table 3. We note that while the VCR values have since been updated for CPI as at December 2025, we have not used these updated values as it would be disproportionate to re-run the entire analysis. This reflects the fact that the updated VCR lies within the range of sensitivities assessed by TasNetworks.

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

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

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

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

Environmental risk

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

While oil spills may have broader environmental impacts, for the purposes of this RIT-T we have only included the financial costs imposed on TasNetworks as a result of an oil spill, e.g. clean-up costs. Further, since the T1 and T2 transformers at Rosebery Substation do not align with current standard fire mitigation requirements, a fire incident could lead to the simultaneous loss of multiple transformer assets and broader switchgear. Specifically, the current firewall is inadequate to prevent any fire spreading across the equipment.[11]

For the environmental risks associated with SF6 leakage, we calculate this following the AER's example in the 2024 RIT-T application guidelines.[12] The environmental risk associated with the SF6 circuit breakers has been captured as avoided greenhouse gas emissions benefits in the NPV analysis – see the assessment of credible options below.

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

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

Safety risk

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

Under the TQR framework detailed above, the likelihood of a safety consequence takes into account the frequency of workers on-site, the duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. Further, the cost of a safety consequence accounts for

[11] See Australian Standard 2067 2026.

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

the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs.

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

Response to PSCR submission

TasNetworks received one submission to the PSCR from BMTJV. We thank BMTJV for the submission. The submission raised four key areas of concern:

- the basis for demand forecasts used;
- the prospect of future demand increases;
- the reduction in firm capacity relative to the existing capacity following the substation upgrade; and
- TasNetworks approach to serving existing customers during the substation upgrade.

This section sets out a summary of the points raised by BMTJV within these four areas of concern along with TasNetworks' responses.

BMTJV's full submission can be provided upon request to TasNetworks.

Demand forecasting

BMTJV expressed concern that the demand forecast is not representative of likely future demand, and that there is limited basis provided for the forecast of future demand. In particular, BMTJV was concerned that the use of historical information from 2024 is not representative of full potential demand from all customers utilising Rosebery substation in the future.

TasNetworks has based its demand forecast for the PSCR and PACR on 2024 maximum demand data – the most recent yearly maximum demand data available when the RIT-T analysis was compiled. The 50% Probability of Exceedance (**POE**) forecast calculated on this basis increases steadily to 50MW by 2050.

TasNetworks considers that using 2025 data or using data from previous years such as 2023 would not increase the accuracy of the analysis, because:

- the current load of the substation is approximately 36 MVA (with the medium sized mining customer referred to in the submission not currently operational given it is under care and maintenance; it is therefore not expected to continue needing supply and so the use of more recent data would not change the selection of credible options;
- the large mining customer referred to in BMTJV's submission was online in 2023 – however, the additional load compared to 2024 was minor so there would be limited impact of changing the basis of the demand forecast to rely on 2023, and it is unclear that it would be more representative of future demand (given that a mining costumer that was adding small additional load in 2023 remains closed); and
- the use of any years prior to 2023 for demand forecasting is likely to be less representative of the future than 2024.

Therefore, TasNetworks considers that the basis for the demand forecast used in the PSCR, and in this PACR, is appropriate.

Prospect of future demand increases

BMTJV explains in its submission that it submitted a connection application to TasNetworks for a 26MW load increase for its Rentails Project. BMTJV calculated that the addition of this load being supplied through Rosebery Substation would increase to a total maximum demand above the firm capacity of the substation.

TasNetworks is aware of the Connection Enquiry submitted by BMTJV to increase its total maximum load to 44 MW (to incorporate the 26 MW increase associated with the Rentails Project). To fulfill this additional load, TasNetworks expects that either the existing 44 kV sub-transmission network would need to be significantly upgraded or a 110 kV connection would be required. In either case, this would occur in parallel to installing a larger new transformer or installing a current spare transformer at Rosebery Substation to ensure sufficient firm capacity.

Either of these approaches go beyond the scope of the credible options considered for this RIT-T, because this RIT-T is focussed on replacing ageing assets at the Rosebery Substation. Therefore, TasNetworks considers that these options are better assessed through a separate regulatory process once the additional load is sufficiently advanced and considered to be anticipated or committed.

Reduction in firm capacity

BMTJV identifies that the firm capacity of Rosebery Substation once the preferred option is implemented will be 60 MVA, which is lower than the existing 66 MVA firm capacity. BMTJV is concerned that the firm capacity will be insufficient to accommodate future load growth. BMTJV therefore recommends that the existing T3 be reinstalled (rather than becoming a spare transformer) to increase firm capacity at Rosebery to 90 MVA.

Consistent with the response above regarding future demand increases, TasNetworks does not consider it appropriate to design the credible options for this RIT-T to accommodate future load growth that is not yet committed.

Further, the current switchyard setup with three supply transformers connecting to the 110 kV network is less reliable compared to what is proposed under the preferred option with two 60 MVA units. In the current setup, a Farrell-Rosebery Substation 110 kV transmission line fault will result in two supply transformers out of service, leaving Rosebery Substation with a non-firm capacity of 36 MVA. With the new proposed setup, any transmission line fault will result in a non-firm capacity of 60 MVA, with the benefit that forced load curtailment will not be required.

In addition, the maximum demand 50% POE forecast for 2050 is 50 MW, which is within the proposed N-1 firm capacity of 60 MVA.

TasNetworks' standard supply transformer rating is 60 MVA, which is also one of the drivers to propose a 60 MVA rating transformer. This helps TasNetworks to maintain and manage spare transformers across its fleet in an efficient manner.

Serving existing customers during construction

BMTJV note that the PSCR has not addressed considerations for disruption of power supply to existing customers during the replacement work at Rosebery Substation and recommends that TasNetworks provide more information on this point.

The RIT-T documentation is designed to identify the preferred option but does not include the detailed scope, construction or outage details. TasNetworks is developing a plan for how the work can be sequenced to minimise disruption for existing customers whilst performing the work safely. TasNetworks will consult with all major customers that will be affected by the Rosebery Substation upgrade, to assist in developing the next level of detail to deliver the project once it has completed the RIT-T stage.

The approach to outages under each credible option is not expected to impact unserved energy in this RIT-T, and therefore is not expected to affect the outcome of the RIT-T. Developing the next level of detail regarding the outage management plan for this project at a future stage is therefore a proportionate approach and consistent with standard network investment processes.

Credible options

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

We consider that there are three credible options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need. Other options were considered but not progressed for various reasons that are outlined in Table 11.

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

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

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

Base case

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

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

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

Option 1 – Replace T1 and T2 supply transformers and 44 kV switchgear with commissioning in FY31

Option 1 involves the replacement of both T1 and T2 supply transformers and 44 kV switchgear with these assets being commissioned in FY31. The new transformers and switchgear will align with TasNetworks current standards and, as such, will address all the identified condition issues. Specifically, this option includes the:

- replacement of T1 and T2 with new 60 MVA 110-44 kV transformers;
- reconfiguration of the 110 kV switchgear;
- replacement and reconfiguration of 44 kV circuit breakers, busbar and disconnectors;
- relocation of T3 as a cold spare on the western side of the substation;
- installation of new firewalls between T1 and T2, T2 and T3 (cold spare) and T1 and T4;
- installation of new oil bunds and oil containment system;
- reconfiguration of the substation boundary fence on the northwestern side; and

- associated civil works for the transformer plinths, switchgear footings and other relevant items.

The estimated capital cost of this option is approximately $27.8 million. Table 5 provides a breakdown of these capital costs by category of expenditure. The costs of option 1 have increased by 15.3 per cent relative to those reported in the PSCR.

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

Component	Procurement	Installation	Design	TasNetworks labour	Total
Rosebery	11.7	13.4	1.5	1.2	27.8

The expenditure for Option 1 is expected to occur between FY27 and FY30, 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
FY27	0.6
FY28	6.4
FY29	15.0
FY30	5.8

Option 2 – Install two new supply transformers at Farrell Substation with commissioning in FY30

Option 2 involves supplying the connected customers' load from Farrell Substation by installing two new supply transformers at Farrell Substation and commissioning these assets in FY30. The new transformers and switchgear will align with TasNetworks current standards and, as such, will address all the identified condition issues. Specifically, this option includes the:

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

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

The estimated capital cost of this option is approximately $42.0 million. Table 7 provides a breakdown of these capital costs by category of expenditure. The costs of option 2 have increased by 2.5 per cent relative to those reported in the PSCR.

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

Component	Procurement	Installation	Design	TasNetworks labour	Total
Rosebery	16.0	22.0	2.5	1.5	42.0

The expenditure for this option is expected to occur between FY26 and FY29, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 8 shows the expected expenditure profile of Option 2 across the construction period.

Table 8: Annual breakdown of Option 2's expected capital cost, $m real

Year	Capital cost
FY26	0.6
FY27	9.5
FY28	22.0
FY29	9.8

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

Option 3 – Replace T1 and T2 supply transformers and 44 kV switchgear with commissioning in FY35

Option 3 involves all works outlined under Option 1 with works occurring between FY31 and FY34.

Compared to Option 1, Option 3 delays replacement of T1, T2 and 44 kV switchgear by four years. The estimated capital cost of this option is approximately $27.8 million. The costs of option 3 have increased by 15.3 per cent relative to those reported in the PSCR.

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 1.

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

Component	Procurement	Installation	Design	TasNetworks labour	Total
Rosebery	11.7	13.4	1.5	1.2	27.8

The expenditure for this option is expected to occur between FY31 and FY34, reflecting the procurement of long lead time equipment and the ultimate commissioning of the assets in FY35. Table 10 shows the expected expenditure profile of Option 3 across the construction period.

Table 10: Annual breakdown of Option 3's expected capital cost, $m real

Year	Capital cost
FY31	0.6
FY32	6.4
FY33	15.0
FY34	5.8

Options considered but not progressed

TasNetworks has considered several additional options to meet the identified need in this RIT-T. Table 11 summarises the reasons the following options were not progressed further.

Table 11 Options considered but not progressed

Description	Reason(s) for not progressing
Increased inspections	The condition issues have already been identified and cannot be rectified through increased inspections. While more frequent inspections may assist in identifying when an asset is approaching failure, possibly enabling postponed replacement, increased inspections are not prudent in this situation. Further, inspections may not identify failures in enough time to obtain replacements and avoid unserved energy, given the uniqueness of the 44 kV network.
Non-network solutions	We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need, as non-network options will not mitigate the environmental, safety, reliability and financial risks posed as a result of asset deterioration. Consistent with this, there were no submissions from potential proponents of non-network options to the PSCR.

No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[13] A "material inter-network impact" is defined by the NER in the following terms:[14]

> "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:[15]

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

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

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

[14] Refer NER Chapter 10.

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

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.[16] Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why:[17]

- 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 in the report.

Market benefits considered material

Changes in involuntary load shedding

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

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

The MMG mine is currently supplied through a dedicated 44 kV feeder. In the event of a failure pertaining to the specific circuit breaker which services the MMG mine's dedicated feeder, TasNetworks would have to manually adjust other circuit breakers at Rosebery to re-route electricity to the MMG mine. We estimate that the required manual adjustment would take approximately four hours, forcing load shedding until the circuit breakers have been manually adjusted.

Replacing both T1 and T2 transformers and the circuit breakers at Rosebery 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, i.e. using the probability of failure, a load-weighted VCR and the load reduction from a combined failure of T1 and T2 supply transformers.

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

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

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Avoided greenhouse gas emissions (SF6)

We note that following the 2023 law change to introduce an emissions reduction objective into the national energy objectives[18] the NER were updated to add changes in Australia's greenhouse gas emissions as market benefit category under the RIT-T.[19] There is a risk of greenhouse gas emissions in the form of SF6 leakages from the ageing 44 kV circuit breakers, which has been captured in the analysis.

The Rosebery Substation currently uses five circuit breakers which contain SF6. Due to the age of these assets the probability of catastrophic failure has increased substantially above that of a reasonably new circuit breaker containing SF6. In the event of catastrophic failure, the entire weight of SF6 contained within the circuit breaker would be emitted into the atmosphere. SF6 has a Global Warming Potential (**GWP**) value of 23,500 times CO2.[20] Replacing the existing end of life SF6 circuit breakers with new SF6-free circuit breakers at Rosebery reduces the likelihood of large greenhouse gas emissions and removes the existing leakage of SF6 due to the age of the assets. Reductions in expected greenhouse gas emissions are included as a market benefit for this RIT-T. Our approach to calculating this category of market benefit is outlined in our description of the identified need above, i.e. using the probability of failure, current leakage, SF6's GWP and the relevant Value of Emissions Reduction (**VER**) values.

Market benefits not considered material

Wholesale market benefits

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[21]

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

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- changes in network losses; and
- competition benefits.

[18] 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.

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

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

[21] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, November 2024, https://www.aer.gov.au/system/files/2025-05/AER%20-%20Regulatory%20Investment%20Test%20for%20Transmission%20application%20guidelines%20-%202024%20-%20Version%206..pdf

Differences in the timing of expenditure

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

Option value

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

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[22]

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.

[22] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, November 2024, pp 18-19.

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.[23]

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 PACR, consistent with AEMO's latest Input Assumptions and Scenarios Report (**IASR**).[24] 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.[25] We have also adopted an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest IASR).[26]

[23] 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*, November 2024, p 21.

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

[25] 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.

[26] 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 Substation and Port Latta Substation and St Marys Substation is undergoing replacements which provide increased accuracy cost estimates for the Rosebery Substation supply transformer replacements. TasNetworks has escalated these costs to reflect the changes in costs since the commissioning of those assets.

TasNetworks considers the cost estimate for the Rosebery Substation options to have a cost accuracy of 15 per cent, which reflects a level three estimate.[27] 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 have been prepared in real, 2025/26 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 licence costs. The exception is that the need to build new 44 kV lines as part of Option 2 could carry some social licence risk, due to some uncertainty over easements. However, this is not expected to materialise given that Option 2 is the lowest ranked option without the inclusion of social licence costs.

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

The options have been assessed against three reasonable scenarios

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

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

The credible options have been assessed under three scenarios as part of this PACR 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, we have not modelled the ISP scenarios. The three scenarios adopted for this RIT-T are consistent with the most likely scenario from the latest Integrated System Plan (**ISP**) (i.e., the 'Step Change' scenario). The updated 2026 ISP is not expected to have a material impact on the analysis for this RIT-T, particularly as the 7 per cent central discount rate has been retained. Other elements of each scenario for this RIT-T (i.e., demand forecasts, costs and risk cost estimates) are based on TasNetworks' local demand forecasts and cost estimates, and so are not directly affected by the ISP.

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).[28,29]

Table 12 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario
Scenario weighting	1/3	1/3	1/3
Discount rate[30]	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.

[28] AER, *Regulatory investment test for transmission Application guidelines*, November 2024, pp. 43-44.

[29] 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.

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

Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PACR are:

- lower and higher assumed capital costs;
- lower and higher weighted VCR;
- lower and higher estimated environmental, safety, reliability and financial risks; and
- alternate commercial discount rate assumptions.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The results of the sensitivity tests are set out as part of the following section.

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

Assessment of credible options

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

Estimated gross benefits

Table 13 below summarises the present value of the gross benefit estimates for each credible option relative to the base case under the three scenarios. The benefits included in this assessment consist of avoided risk, i.e. a reduction in reliability, financial, environmental and safety risks. It shows that Option 1 and Option 2 have similar gross market benefits. This reflects the fact that these options, although comprising different scopes, are commissioned only one year apart and therefore address the identified need in a similar manner. Option 3 has lower gross market benefits because it is commissioned later, meaning there is a longer period of reliability, financial, safety and environmental risk costs.

Table 13 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	29.3	27.4	31.1	29.3
Option 2	30.6	28.6	32.6	30.6
Option 3	23.0	21.6	24.4	23.0

Estimated gross costs

Table 14 below summarises the costs of the options, relative to the base case, in present value terms.

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

Table 14 Costs of credible options relative to the base case ($m, PV)

Option/scenario	Central
Option 1	17.3
Option 2	28.4
Option 3	11.4

Estimated net market benefits

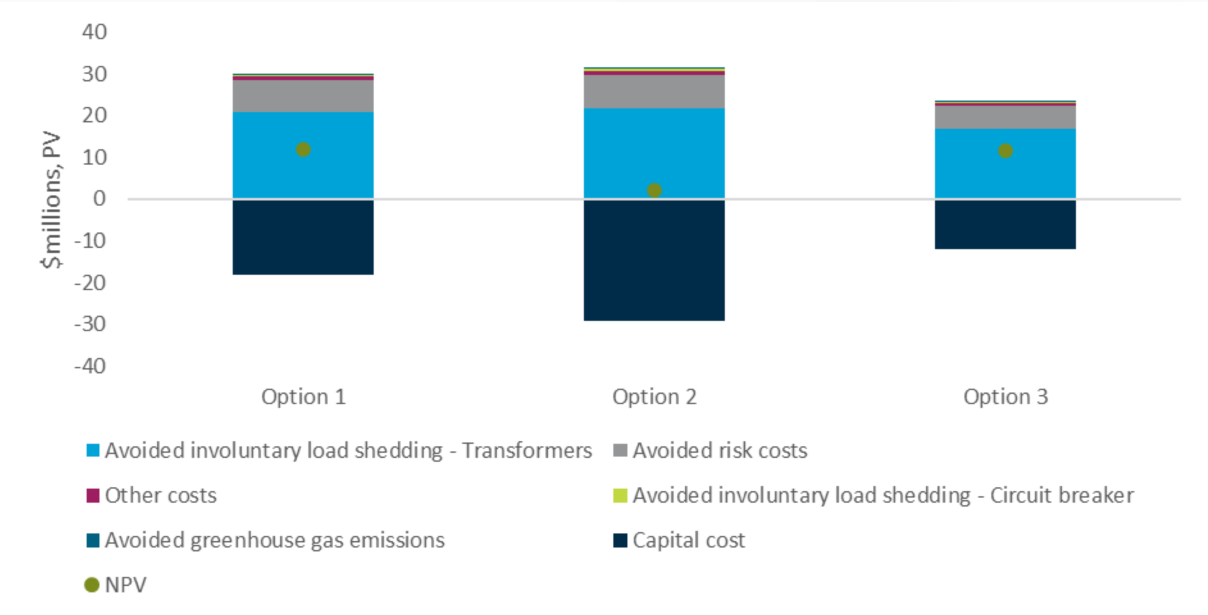
The net economic benefits are the differences between the estimated gross benefits less the estimated costs. Table 15 below summarises the present value of the net economic benefits for each credible option across the three scenarios and the weighted net economic benefits.

Table 15: 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	12.0	10.1	13.9	12.0
Option 2	2.2	0.2	4.2	2.2
Option 3	11.6	10.3	13.0	11.6

All three credible options are found to have positive benefits for all scenarios investigated. Option 1 and Option 3 are expected to deliver the greatest net economic benefits when weighted across all scenarios investigated.[31] On a weighted basis, the net economic benefits of Option 1 are approximately $12.0 million, which is 3.1 per cent greater than the net economic benefits of Option 3 (with net benefits of approximately $11.6 million). Figure 8 below shows a breakdown of the weighted net economic benefits for each option.

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



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

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

[31] Option 1 is the top-ranked option in the high scenario and is expected to deliver net benefits 6.7 per cent greater than the second ranked option in that scenario. Option 1 and Option 3 are effectively ranked equally in the central and low scenarios given that there is only a 3.1 and 3.9 per cent difference between the two options in those scenarios respectively.

- although the prospect of future load has not directly affected the analysis, TasNetworks is expecting at least some additional mining load in the area in the near-to-short term, meaning earlier investment will support accommodating that increased load in the network without risk of even greater unserved energy in the future.

Sensitivity testing

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

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

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

Step 1 – sensitivity testing of the optimal timing

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

The optimal timing of Option 1 is found to be at the beginning of FY31, consistent with the proposed commissioning year. This is one year later than stated in the earlier PSCR due to increased capital cost estimates. In determining the optimal timing of an option, the annualised cost is compared to the net operating benefits.[32]

When conducting sensitivity testing, the optimal timing of Option 1 varies between FY30 and FY33. The optimal timing of Option 1 is found to be equal to the proposed commissioning year, FY31, in the central scenario and under several sensitivities investigated, i.e.:

- high and low discount rate sensitivities;
- 15 per cent higher maintenance costs; and
- higher assumed reliability, financial, environmental and safety risks.

The optimal timing of Option 1 is found to be earlier than FY31 under the assumptions of:

- a higher weighted average VCR; and
- a 15 per cent decrease in the assumed network capital costs.

The optimal timing of Option 1 is found to be later than FY31 under the assumptions of:

- a 15 per cent increase in the assumed network capital costs;
- 15 per cent lower maintenance costs;

[32] The optimal timing assessment has been updated such that the optimal timing is defined as the point in time where if the option were to be commissioned in that specific year, the net operating benefits would exceed the annualised cost. This differs from prior analysis which defined the optimal timing as the point in time where the net operating benefits exceed the annualised cost, under an unchanged commissioning year. We note that for this RIT-T, the updated optimal timing analysis is immaterial, and the optimal timing of the preferred option has changed purely as a result of increased estimated capital costs.

- lower weighted average VCR; and
- lower assumed reliability, financial, environmental and safety risks.

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

Figure 9: Optimal timing for Option 1

Step 2 – sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit, based on undertaking the project in FY26 with completion of construction in FY30 (commissioning at the beginning of FY31). Specifically, we have investigated the following same sensitivities under this step as in the first step:

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

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

Figure 10 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of capital costs within TasNetworks 15 per cent cost accuracy for this RIT-T (i.e. 85 per cent to 115 per cent of estimated capital costs), while Option 3 delivers higher expected benefits for capital costs that are greater than 6 per cent or more of the estimated capital costs.

Figure 10: Capital costs sensitivity testing

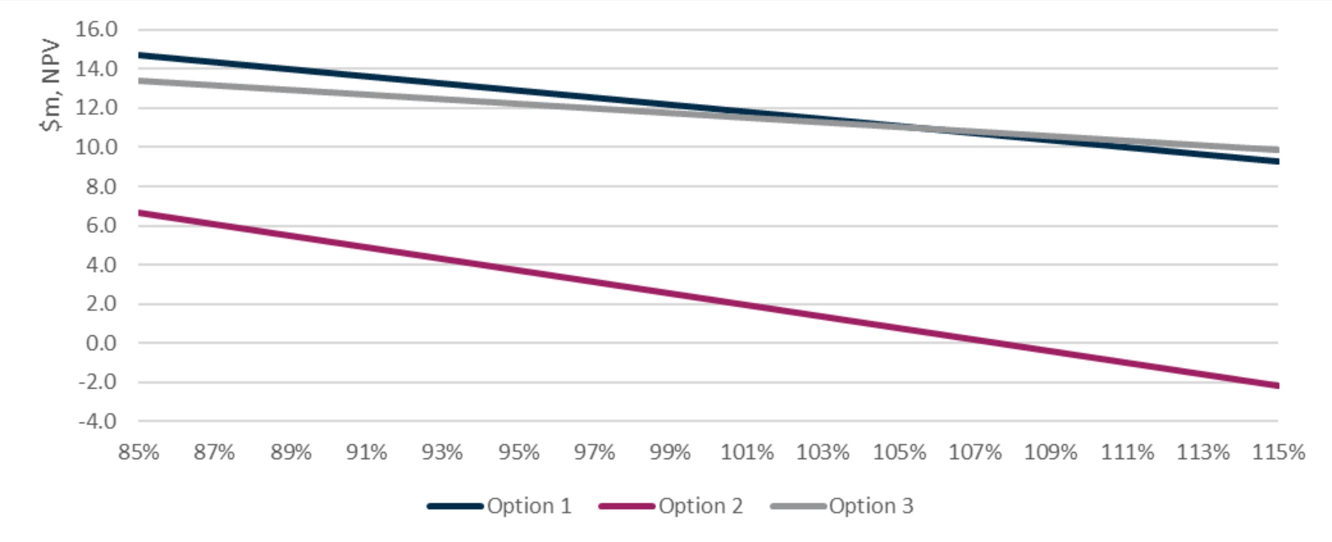


Figure 11 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the VCR (i.e. plus and minus 30 per cent, or $4.60/kWh to $8.54/kWh), while Option 3 delivers higher expected benefits for a VCR below $5.98/kWh (noting that the VCR values reported here include the VNR adjustment as explained in the 'Reliability risk' section under 'Assumptions underpinning the identified need' above).

Figure 11: VCR sensitivity testing

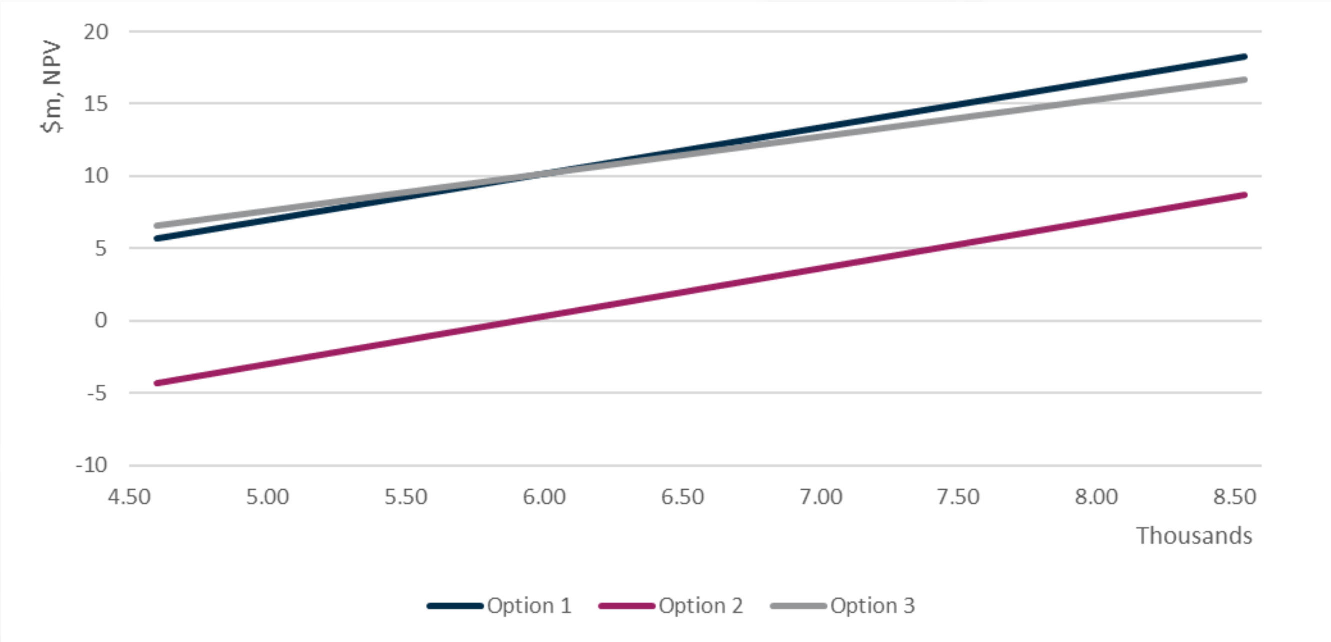


Figure 12 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the environmental, safety and financial risk costs (i.e. plus and minus 30 per cent), while Option 3 delivers higher expected benefits for environmental, safety and financial risk costs that are below 82.6 per cent of the base risk costs.

Figure 12: Risk costs sensitivity testing

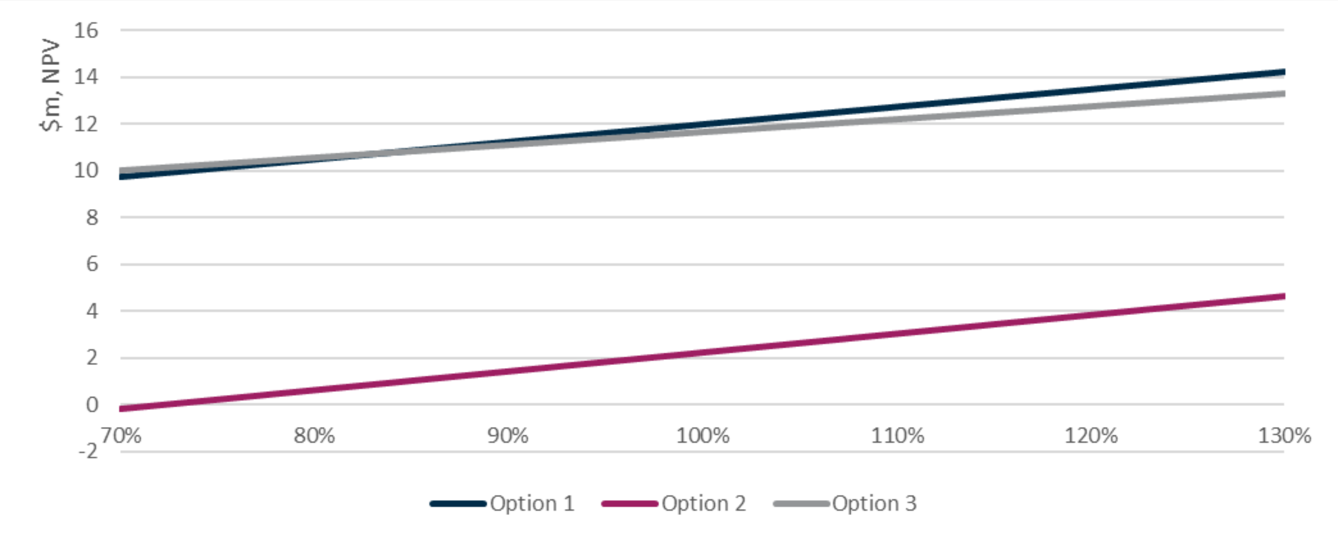
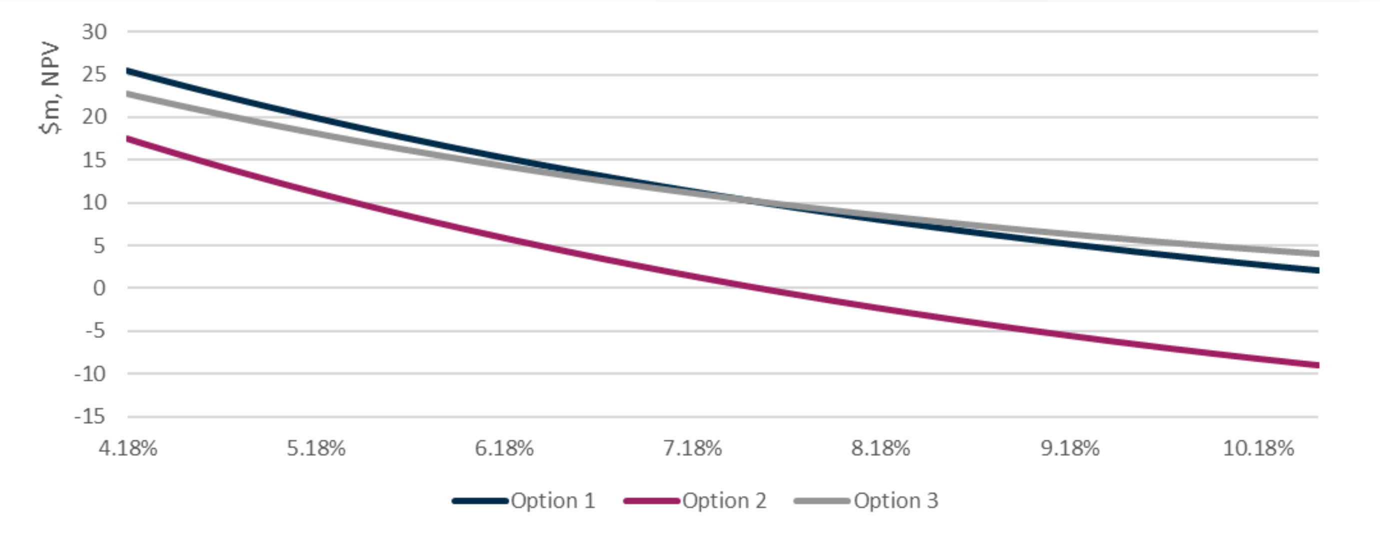


Figure 13 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the commercial discount rate (i.e. 4.18 per cent to 10.50 per cent), while Option 3 delivers higher expected benefits when the commercial discount rate is greater than 7.53 per cent.

Figure 13: Commercial discount rate sensitivity testing



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

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

- assumed network capital costs would need to increase by approximately 66 per cent, which is substantially outside of TasNetworks' cost accuracy estimate for the network options considered in this RIT-T of 15 per cent;
- the VCR associated with involuntary load shedding arising from transformers at Rosebery would need to decrease by approximately 57 per cent (i.e. go below $2.80/kWh), which is below the VNR

multiplier (0.5) of the lowest VCR of any load type currently served by Rosebery Substation (mines with a VCR of $10.63/kWh, or $5.31/kWh when adjusted by the VNR);[33]

- the VCR associated with involuntary load shedding arising from circuit breakers at Rosebery would need to decrease by approximately 2072 per cent (i.e., go below zero);
- the estimated environmental, safety and financial risk costs (in aggregate) would need to decrease by 159 per cent (i.e. go below zero); or
- a discount rate of over 11.6 per cent.

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

[33] See Table 4.

Final conclusion

This PACR has found that Option 1 is the preferred option, consistent with the draft conclusion in the earlier PSCR. However, the optimal timing for the commissioning of this option is one year later than stated in the earlier PSCR due to increased capital cost estimates. Option 1 involves the replacement of both T1 and T2 supply transformers and 44 kV switchgear, commissioning the assets at the beginning of FY31.

The estimated capital expenditure associated with Option 1 is $27.8 million (in 2025/26 dollars). The works are estimated to take place between financial years 2027 and 2030, with practical completion towards the end of FY30 and commissioning in the beginning of FY31. The optimal timing of Option 1 is found to be the beginning of FY31, consistent with the updated proposed commissioning year.

Option 1 maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market, as well as that arising from changes in Australia's greenhouse gas emissions, and is therefore the preferred option in accordance with NER clause 5.15A.2(b)(12). The analysis undertaken and the identification of Option 1 as the preferred option satisfies the RIT-T. Option 1 is expected to deliver net economic benefits that are 3.1 per cent greater than the second-ranked option, Option 3, on a weighted basis.

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

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

TasNetworks notes that taking action to address the risks associated with aging assets now does not preclude further future works to meet any committed future load increases affecting demand at Rosebery substation, which would form part of a separate regulatory process.

Appendices

Appendix 1 Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the NER version 243.

As per NER clause 5.16.4(v)(1), the PACR must set out the matters detailed in the PADR as required under NER clause 5.16.4(k), and a summary of submissions received on the PADR. As a PADR was not prepared due to the exemption under NER clause 5.16.4(z1), no submissions on the PADR were received.

The below table sets out the summary of requirements and the corresponding PACR sections.

Rules clause	Summary of requirements	Relevant section
5.16.4 (k)	The project assessment draft report must include:	–
	(1) a description of each credible option assessed;	Response to PSCR submission TasNetworks received one submission to the PSCR from BMTJV. We thank BMTJV for the submission. The submission raised four key areas of concern: • the basis for demand forecasts used; • the prospect of future demand increases; • the reduction in firm capacity relative to the existing capacity following the substation upgrade; and • TasNetworks approach to serving existing customers during the substation upgrade. This section sets out a summary of the points raised by BMTJV within these four areas of concern along with TasNetworks' responses.

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BMTJV's full submission can be provided upon request to TasNetworks.

Demand forecasting

BMTJV expressed concern that the demand forecast is not representative of likely future demand, and that there is limited basis provided for the forecast of future demand. In particular, BMTJV was concerned that the use of historical information from 2024 is not representative of full potential demand from all customers utilising Rosebery substation in the future.

TasNetworks has based its demand forecast for the PSCR and PACR on 2024 maximum demand data – the most recent yearly maximum demand data available when the RIT-T analysis was compiled. The 50% Probability of Exceedance (**POE**) forecast calculated on this basis increases steadily to 50MW by 2050.

TasNetworks considers that using 2025 data or using data from previous years such as 2023 would not increase the accuracy of the analysis, because:

- the current load of the substation is approximately 36 MVA (with the medium sized mining customer referred to in the submission not currently operational given it is under care and maintenance; it is therefore not expected to continue needing supply and so the use of more recent data would not change the selection of credible options;

- the large mining customer referred to in BMTJV's submission was online in 2023 – however, the additional load compared to 2024 was minor so there would be limited impact of changing the basis of the demand forecast to rely on 2023, and it is unclear that it would be more representative of future demand (given that a mining costumer that was adding small additional load in 2023 remains closed); and
- the use of any years prior to 2023 for demand forecasting is likely to be less representative of the future than 2024.

Therefore, TasNetworks considers that the basis for the demand forecast used in the PSCR, and in this PACR, is appropriate.

Prospect of future demand increases

BMTJV explains in its submission that it submitted a connection application to TasNetworks for a 26MW load increase for its Rentails Project. BMTJV calculated that the addition of this load being supplied through Rosebery Substation would increase to a total maximum demand above the firm capacity of the substation.

TasNetworks is aware of the Connection Enquiry submitted by BMTJV to increase its total maximum load to 44 MW (to incorporate the 26 MW increase associated with the Rentails Project). To fulfill this additional load, TasNetworks expects that either the existing 44 kV sub-transmission network would need to be significantly upgraded or a 110 kV connection would be required. In either case, this would occur in parallel to installing a larger new transformer or installing a current spare transformer at Rosebery Substation to ensure sufficient firm capacity.

Either of these approaches go beyond the scope of the credible options considered for this RIT-T, because this RIT-T is focussed on replacing ageing assets at the Rosebery Substation. Therefore, TasNetworks considers that these options are better assessed through a separate regulatory process once the additional load is sufficiently advanced and considered to be anticipated or committed.

Reduction in firm capacity

BMTJV identifies that the firm capacity of Rosebery Substation once the preferred option is implemented will be 60 MVA, which is lower than the existing 66 MVA firm capacity. BMTJV is concerned that the firm capacity will be insufficient to accommodate future load growth. BMTJV therefore recommends that the existing T3 be reinstalled (rather than becoming a spare transformer) to increase firm capacity at Rosebery to 90 MVA.

Consistent with the response above regarding future demand increases, TasNetworks does not consider it appropriate to design the credible options for this RIT-T to accommodate future load growth that is not yet committed.

Further, the current switchyard setup with three supply transformers connecting to the 110 kV network is less reliable compared to what is proposed under the preferred option with two 60 MVA units. In the current setup, a Farrell-

Rosebery Substation 110 kV transmission line fault will result in two supply transformers out of service, leaving Rosebery Substation with a non-firm capacity of 36 MVA. With the new proposed setup, any transmission line fault will result in a non-firm capacity of 60 MVA, with the benefit that forced load curtailment will not be required.

In addition, the maximum demand 50% POE forecast for 2050 is 50 MW, which is within the proposed N-1 firm capacity of 60 MVA.

TasNetworks' standard supply transformer rating is 60 MVA, which is also one of the drivers to propose a 60 MVA rating transformer. This helps TasNetworks to maintain and manage spare transformers across its fleet in an efficient manner.

Serving existing customers during construction

BMTJV note that the PSCR has not addressed considerations for disruption of power supply to existing customers during the replacement work at Rosebery Substation and recommends that TasNetworks provide more information on this point.

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	The RIT-T documentation is designed to identify the preferred option but does not include the detailed scope, construction or outage details. TasNetworks is developing a plan for how the work can be sequenced to minimise disruption for existing customers whilst performing the work safely. TasNetworks will consult with all major customers that will be affected by the Rosebery Substation upgrade, to assist in developing the next level of detail to deliver the project once it has completed the RIT-T stage. The approach to outages under each credible option is not expected to impact unserved energy in this RIT-T, and therefore is not expected to affect the outcome of the RIT-T. Developing the next level of detail regarding the outage management plan for this project at a future stage is therefore a proportionate approach and consistent with standard network investment processes. Credible options
(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Response to PSCR submission
(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefits for each credible option;	Credible options and Materiality of market benefits

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	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Materiality of market benefits, Overview of the assessment approach, and Reliability risk
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Materiality of market benefits
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	Materiality of market benefits
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Assessment of credible options
	(8) the identification of the proposed preferred option;	Assessment of credible options and Final conclusion
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	**Error! Reference source not found.**; Final conclusion; and No material inter-network impact is expected

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