

Meeting Network Planning Requirements at George Town

Project Assessment Draft Report

29 May 2026

Official



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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
AIS	Air insulated switchgear
BBPF	Bell Bay Power Fuels
BESS	Battery energy storage systems
GHG	Greenhouse gas
HVDC	High Voltage Direct Current
IASR	Inputs Assumptions and Scenarios Report
ISP	Integrated System Plan
MVA	Megavolt-Ampere
MVA _r	Megavolt-Ampere reactive
NCSPS	Network Control System Protection Scheme
NEM	National Electricity Market
NER	National Electricity Rules (Version 244 referenced throughout this document)
NPR	<i>Electricity Supply Industry (Network Planning Requirements) Regulations 2018</i> (Tas)
NPV	Net present value
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
ReCFIT	Renewables, Climate and Future Industries Tasmania
RIT-T	Regulatory Investment Test for Transmission
STATCOM	Static synchronous compensator
TGHH	Tasmanian Green Hydrogen Hub
TRET	Tasmanian Renewable Energy Target
TRHAP	Tasmanian Renewable Hydrogen Action Plan
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 Draft Report (PADR) represents the second step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for addressing minimum network performance requirements following connection of new large scale load at George Town in the north-east of Tasmania. The PADR follows the first stage of the RIT-T, the Project Specification Consultation Report (PSCR)¹, which TasNetworks completed in 2024.

George Town Substation is the sole substation supplying the George Town area. It is the connection point for Basslink, the High Voltage Direct Current (HVDC) interconnector which links the Tasmanian and Victorian networks. It also supplies transmission connected customers at Bell Bay, a major industrial area in Tasmania.

The Australian and Tasmanian Governments have agreed to develop Bell Bay as one of Australia's first Hydrogen Hubs. This follows the Tasmanian Government publishing the Tasmanian Renewable Hydrogen Action Plan (TRHAP)² in 2020 that envisions Tasmania as a major producer and exporter of hydrogen by 2030. In response, TasNetworks received a number of connection enquires from proponents seeking to establish hydrogen production facilities in Bell Bay, supplied out of George Town substation. TasNetworks has similarly received interest from other large load proponents, including data centres.

As load increases at George Town, issues begin to emerge on the shared transmission network. Specifically, the power system begins to approach operating conditions that are no longer compliant with the minimum network performance requirements outlined in the *Electricity Supply Industry (Network Planning Requirements) Regulations 2018 (Tas) (NPR)*.³

The NPR provide the customer reliability levels to be considered in planning Tasmania's transmission network. Importantly, regulation 5 of the NPR specifies that power system planning must be such that load that is interrupted by a single asset failure is not to be capable of resulting in a black system.

Identified need: meeting network planning requirements

As new load connects at George Town, management of voltage stability is necessary to ensure secure operation of the power system. Specifically, Schedule 5.1.8 of the National Electricity Rules (NER) requires that the reactive margin (expressed as a capacitive reactive power in Megavolt-Ampere reactive (MVar)) must not be less than one per cent of the maximum fault level (in Megavolt-Ampere (MVA)) at the connection point.

Under existing operating conditions, to ensure compliance with the NER, a constraint is applied to Basslink export to maintain acceptable voltage stability at George Town. However, following the connection of sufficient new load, without intervention, these constraints will severely limit Basslink export and may not fully mitigate voltage stability issues (including the risk of a black system) under all operating conditions.

Following the connection of sufficient new load, additional reactive power support is required to avoid non-compliance with NER Schedule 5.1.8, which if left unaddressed, could result in black system

¹ TasNetworks, [Meeting Network Planning Requirements at George Town PSCR](#), 29 November 2024.

² Renewables, Climate and Future Industries Tasmania, [Renewable Hydrogen Action Plan](#).

³ Tasmanian Legislation, [Electricity Supply Industry \(Network Planning Requirements\) Regulations 2018](#).

following one or more contingencies. Under Regulation 5 of the NPR, TasNetworks is required to plan the power system to avoid a single asset failure resulting in a black system.

A black system refers to loss of more than 60 per cent of regional load. Following the connection of 210 MW of new load at George Town, the maximum percentage of load connected to the George Town substation can reach this 60 per cent threshold.

Investment is therefore required to maintain voltage stability and ensure ongoing compliance with the NER and network planning requirements. The investment will also ensure Basslink is not unduly constrained on an ongoing basis.

Developments since publication of the PSCR

Since publishing the PSCR, TasNetworks has continued to progress discussions with prospective load proponents and has undertaken further analysis to better understand the risk of a single asset failure at George Town.

Expectations of new load

TasNetworks continues to engage with Renewables, Climate and Future Industries Tasmania (ReCFIT) and potential hydrogen proponents under the Tasmanian Green Hydrogen Hub (TGHH) program⁴. In 2025, Bell Bay Power Fuels (BBPF) was selected as a Provisional Proponent to deliver a green methanol project at Bell Bay. The plant will integrate green hydrogen produced via a 300 MW water electrolysis facility with synthesis gas from a biomass gasifier to manufacture green methanol.

Furthermore, George Town has emerged as a prospective connection point for data centres. This includes interest from developers with load requirements up to 600 MW. For these reasons, we consider it likely that at least 300 MW of new load at George Town will connect in the near future.

As the size of any new load dictates reactive power requirements, we have decided to specifically address this load uncertainty in the 'Option flexibility given load uncertainty' section of this report.

Risk of single asset failure

Undertaking further analysis has resulted in a better understanding of the risk of a single asset failure at George Town. TasNetworks has previously considered the possibility that a transformer fire could result in de-energisation of the George Town substation and a subsequent black system event. Upon further investigations, TasNetworks now considers that, although possible, it is unlikely that an event of that nature would occur.

However, consistent with the PSCR, TasNetworks still considers that there are single contingency events also capable of resulting in a black system due to voltage instability. This means the identified need ultimately remains unchanged from the PSCR insofar as investment is required to meet network planning requirements following the connection of new load at George Town.

Options assessed

TasNetworks has identified one credible network option to address the identified need that emerges as a result of new load connections. This option will enable full unconstrained operation of Basslink and accounts for uncertainty in the precise size and location of new connections.

⁴ [Tasmania's Green Hydrogen Hub Vision | ReCFIT](#).

The credible option is presented in Table 1 below.

Table 1 Summary of credible option

Option	Description	Estimated Capex (24-25 \$M)	Estimated completion date
1	Establishment of a new air insulated switchgear (AIS) substation, installation of 550 MVar of reactive support in the new substation, and reconfiguration of the 220 kV switchyard at the existing George Town substation.	370.6	2030

Preferred option at this stage

This PADR assessment finds that option 1 is the preferred option given it is the only credible option to meet our externally imposed service standard. Option 1 is expected to provide approximately \$234 million in weighted net market benefits over the assessment period.

Submissions and next steps

TasNetworks now welcomes submissions from interested parties on the analysis and information contained within this PADR. Submissions will be open for 12 weeks from 29 May 2026 until 21 August 2026. TasNetworks remains interested in hearing from any non-network service providers capable of addressing the identified need. Submissions should be addressed to Matthew Clarke, Leader Large Regulated Investment and emailed to regulation@tasnetworks.com.au.

Following completion of the consultation period, we will update the RIT-T analysis with any new information including that received from submissions.

We will then publish a Project Assessment Conclusions Report (PACR) to close out the RIT-T process.

Introduction

This PADR represents the second step in the application of the RIT-T to assess options for addressing minimum network performance requirements following connection of new large scale load at George Town in the north-east of Tasmania.

In accordance with the NER⁵, a RIT-T is required when the estimated capital cost of the most expensive option to address the identified is greater than or equal to \$8 million.

George Town Substation is the sole substation supplying the George Town area. It is the connection point for Basslink, the HVDC interconnector which links the Tasmanian and Victorian networks. It also supplies Bell Bay, a major industrial area in Tasmania. As such, it is the largest single load centre in the Tasmanian region.

The Australian and Tasmanian Governments have recently agreed to develop Bell Bay as one of Australia's first Hydrogen Hubs. This follows the Tasmanian Government publishing the TRHAP that envisions Tasmania as a major producer and exporter of hydrogen by 2030. In response, TasNetworks has received a number of connection enquires from proponents seeking to establish hydrogen production facilities in Bell Bay. TasNetworks has similarly received interest from other large load proponents, including data centres.

As load increases in George Town, issues begin to emerge on the shared transmission network. Specifically, the power system begins to approach the minimum network performance requirements outlined in the NPR.⁶

The NPR provide the customer reliability levels to be considered in planning Tasmania's transmission network. Importantly, Regulation 5 of the NPR specifies that power system planning must be such that load that is interrupted by a single asset failure is not to be capable of resulting in a black system.

Should sufficient new load eventuate in George Town, TasNetworks would not meet this obligation because, at times of operation, a loss of George Town substation load resulting from a single asset failure would result in a black system.

TasNetworks is therefore examining options for addressing minimum network performance requirements to ensure reliability of the power system following large scale load connections in George Town. TasNetworks is undertaking this RIT-T to meet the externally imposed service standards outlined in the NPR. Consequently, we consider the identified need for this investment is for reliability corrective action.

This PADR follows the PSCR that was published by TasNetworks in November 2024. The purpose of this PADR is to:

- summarise the reasons why this investment is necessary (the 'identified need');
- describe the credible options that TasNetworks considers may address the identified need;
- provide a description of the methodologies used in quantifying each class of material market benefit and cost;
- present the net present value (NPV) economic assessment of each of the credible options, including the assumptions underpinning this analysis;

⁵ Clause 5.16.3(2).

⁶ Tasmanian Legislation, [Electricity Supply Industry \(Network Planning Requirements\) Regulations 2018](#).

- identify and provide a detailed description of the credible option that satisfies the RIT-T, and is therefore the preferred option at this draft stage;
- set out the proposed re-opening triggers, building on the sensitivity assessments undertaken, to provide transparency to stakeholders on what may constitute a later material change in circumstance for this RIT-T; and
- provide stakeholders with the opportunity to comment on this assessment so that TasNetworks can refine the analysis (if required) as part of the PACR, which is the final step in the RIT-T process.

The report also provides information on the next steps in the RIT-T process.

Appendix A provides references to information that must be included in this PADR. The report also provides information on the next steps of the RIT-T process and the process itself is outlined in Appendix B to this report.

Identified need

The purpose of this RIT-T is to identify the investment option that meets the identified need while maximising net economic benefits to the National Electricity Market (NEM) and meeting reliability standards imposed through Tasmanian legislation and the NER.

This section provides a description of the identified need and information on new load developments in the George Town area since publication of the PSCR.

Description of the identified need

Under the NPR, TasNetworks is obliged to plan the Tasmanian power system to avoid a single asset failure being capable of resulting in a black system. A black system refers to loss of more than 60 per cent of regional load. Following the connection of 210 MW of new load at George Town, the maximum percentage of load connected to the George Town substation can reach the 60 per cent threshold.

Since publishing the PSCR, TasNetworks has undertaken further work to refine the identified need. This has resulted in a better understanding of the risk of a single asset failure at George Town. TasNetworks has previously considered the possibility that a transformer fire could result in de-energisation of the George Town substation and a subsequent black system event. Upon further investigations, TasNetworks now considers that, although possible, it is unlikely that an event of that nature would occur. However, consistent with the PSCR, TasNetworks still considers that there are single contingency events capable of resulting in a black system due to voltage instability.

As new load connects at George Town, management of voltage stability is necessary to ensure secure operation of the power system. Specifically, Schedule 5.1.8 of the NER requires that the reactive margin (expressed as a capacitive reactive power in MVAR) must not be less than one per cent of the maximum fault level (in MVA) at the connection point. The network is currently unable to achieve this reactive margin following connection of sufficient new load at George Town. Additional reactive power support is required to avoid non-compliance with NER Schedule 5.1.8, which if left unaddressed, could result in a black system following one or more contingencies (i.e. the failure of a double transmission line circuit, circuit breaker or substation busbar).

As noted above, such a contingency would also result in non-compliance with Regulation 5 of the NPR as a single asset failure would result in a black system due to the loss of more than 60 per cent of regional load.

Reactive margin provides an indication of the stability of the network at George Town, reflecting the network's ability to maintain a stable voltage waveform following a disturbance. The maximum three-phase fault level of 4,877 MVA has been computed for the George Town 220 kV substation with a corresponding standard reactive margin (i.e. a reactive surplus) requirement of 50 MVar.

As there is limited generation connected directly at George Town that is regularly utilised, the substation relies on bulk power transfer through two 220 kV transmission corridors to meet the supply requirements for connected load:

- Palmerston-Hadspen-George Town; and
- Sheffield-George Town.

Due to the remoteness of generation from George Town, reactive support procured from Tasmania's generation fleet is also less effective in supporting voltage in the North of the state.

Under existing operating conditions, a constraint is applied to Basslink export to maintain acceptable voltage stability at George Town. Without intervention following the connection of sufficient new load these constraints will severely limit Basslink export and may not fully mitigate the risk of a black system under all operating conditions. Therefore, investment is required to maintain voltage stability and ensure Basslink is not constrained.

Voltage stability studies undertaken by TasNetworks in 2024 indicate that to avoid any constraint on Basslink export, approximately 550 MVar of additional reactive support would be required to support 300 MW of new load at George Town.

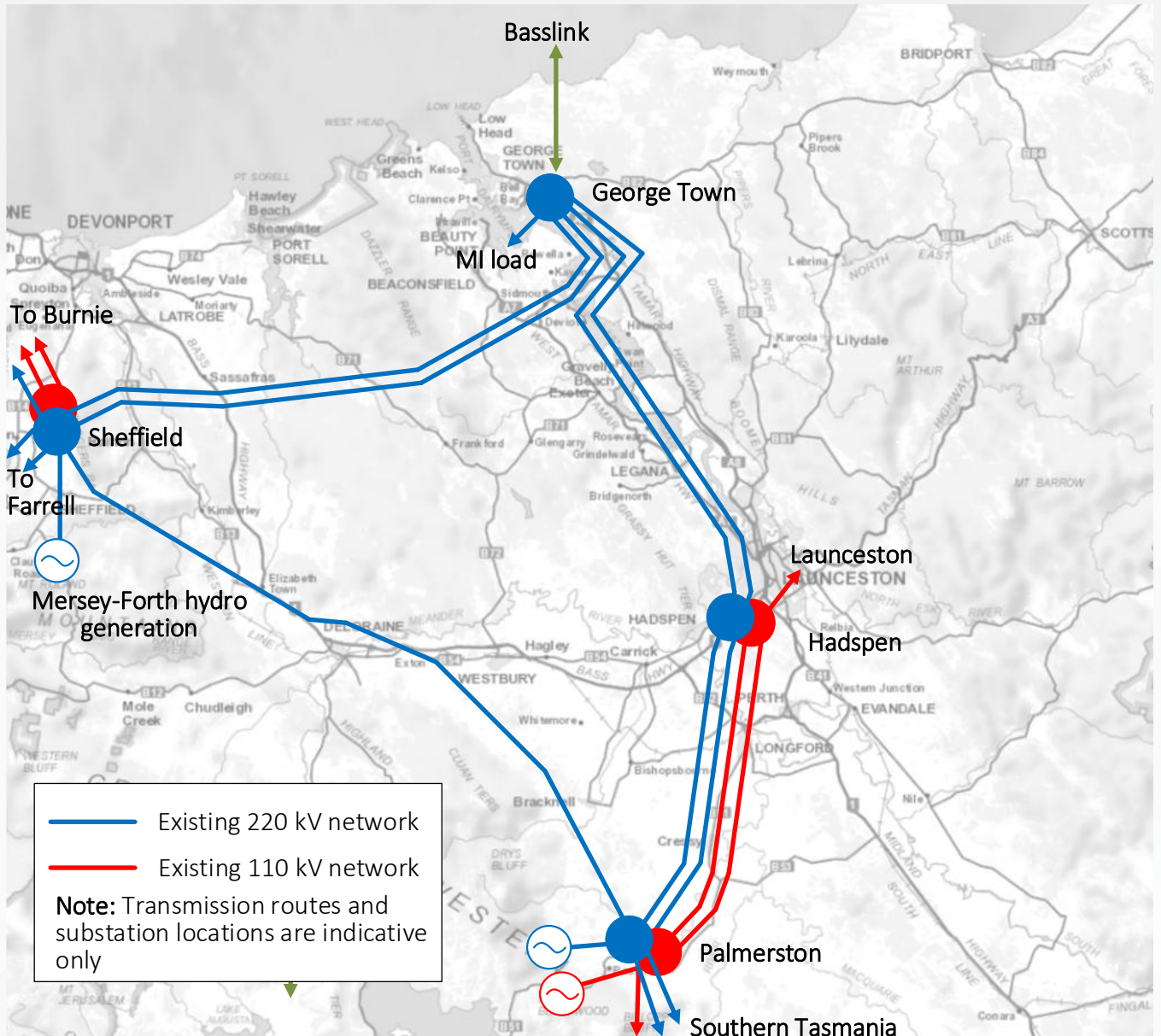
Overview of the George Town Transmission Network

Figure 1 on the following page provides an overview of TasNetworks' transmission network supplying the George Town area.

George Town substation supplies load in and around George Town and Bell Bay. It provides connection to load and generation customers and Basslink, the HVDC interconnector which links the Tasmanian and Victorian networks.

As noted above, George Town substation is supplied from two 220 kV main corridors (i.e. Sheffield-George Town and Palmerston Hadspen-George Town) and these two corridors are interconnected through the Palmerston-Sheffield 220 kV line.

Figure 1 Network supplying the George Town area



New load developments in George Town

As noted in the PSCR, TasNetworks has received considerable interest from new load proponents looking to connect to the transmission network in and around George Town in Tasmania’s Northeast. Most of the connection enquiries relate to proponents seeking to establish large scale hydrogen production facilities or data centres.

Since publishing the PSCR, TasNetworks has continued discussions with several load proponents within the George Town area. Although engagement from several potential hydrogen proponents has reduced due to ongoing commercial challenges within the industry, we have continued to progress discussions with the TGHH provisional proponents.⁷

⁷ Tasmania's Green Hydrogen Hub Vision | ReCFIT.

TasNetworks is also in discussions with prospective data centre proponents. This includes an enquiry for connection of up to 600 MW of new load in the Bell Bay area (which is the 'MI Load' area in Figure 1 above). The proponent has indicated that a staged approach is likely to be pursued, with the facility drawing approximately 300 MW in the first stage and connecting to the network over the coming years.

We consider that this additional interest materially increases the probability for new load equalling or exceeding 300 MW at George Town in the foreseeable future. A degree of uncertainty continues to remain around the magnitude and timing of these new load connections, and we have undertaken analysis to look at reactive support requirements at different loading levels. This analysis is covered in the 'Option flexibility given load uncertainty' section of this report.

Responses to Project Specification Consultation Report

This section summarises the responses TasNetworks received to the PSCR and outlines TasNetworks' response to the matters raised.

TasNetworks received three submissions to the PSCR:

- A combined submission from Zen Energy and BBPF.
- A submission from Equis.
- A submission from ACEN.

A summary of the submissions and TasNetworks' response to the submissions is outlined below.

ACEN submission

The submission was supportive of TasNetworks' investment in George Town, however requested that TasNetworks consider the following in the context of their North East Wind project:

- the location and specifications of the new George Town Substation with the aim to minimise augmentation; and
- consultation with all relevant renewable energy proponents regarding network solutions and connection points at George Town.

TasNetworks response

TasNetworks works productively with all proponents looking to connect to our network. The site of the new George Town substation will be determined with reference to the George Town strategy that includes consideration of future connections to minimise overall system costs.

Zen Energy, BBPF and Equis submissions

The submissions raised concerns about:

- a lack of an available, compliant, and cost-effective connection point, causing uncertainty for project developers;

- the chicken and egg situation where no augmentation work is achieved at George Town until projects become committed, but the projects cannot become committed until the George Town substation works are completed;
- the RIT-T process being too long, such that developers will not obtain certainty to pursue project developments. Further stressing that traditional planning methods are inadequate in this scenario where several generation, load and storage projects are seeking connection at the same time and instead requires planning adaptation and a more holistic approach; and
- the commissioning date of 2028-2032 will potentially hinder the achievement of government renewable energy targets such as the Tasmanian Renewable Energy Target (TRET).

As part of their submission, Zen Energy and BBPF also suggested that some future proponents may implement behind-the-meter solutions that mitigate the issues they introduce on the shared network.

TasNetworks response

Connection points

George Town substation, in its existing configuration, functions as a connection point for Basslink and existing major industrial loads. The site is spatially constrained, with limited options to host new connections. TasNetworks does not consider these substation limitations to be a barrier to new proponent connections to this region of the network. TasNetworks, in this RIT-T, has nominated a connection option that provides a technical solution for hosting new connections and addresses the physical constraints of George Town substation to allow proponents to connect in and around the area north of the site.

South of George Town, proponents have access to two 220 kV double circuit transmission lines that can be cut in with a switching station to provide a connection point.

New load prior to network augmentation

TasNetworks confirms that load proponents can connect to the network in George Town prior to the required augmentation works being completed. If this were to happen, TasNetworks would continue to manage voltage stability through the constraint of Basslink export and would work with the new proponent to ensure safe operation of the network under all operating conditions until the augmentation works are complete.

RIT-T process

TasNetworks is required to apply the RIT-T in accordance with the NER. By progressing this RIT-T now, TasNetworks aims to ensure voltage stability is managed prudently and efficiently in preparation for the commitment of new load.

Hindering TRET

TasNetworks is diligently progressing this RIT-T to ensure we will be well placed to deliver the required network augmentations following the commitment of new load at George Town.

We will continue to work with generation proponents and the Tasmanian Government on renewable energy policy objectives.

Behind-the-meter solutions

TasNetworks supports connecting parties minimising their impact on the shared network, especially where this avoids the need for shared network augmentation. However, as part of this RIT-T, TasNetworks is exploring options that can supply front-of-meter load of 300 MW. Should a connecting party implement a behind-the-meter solution that wholly or partially mitigates their impact on the shared network, TasNetworks will reassess the need for investment.

Should BBPF become a committed load connection, TasNetworks will work with the proponent to assess the impacts of its connection on voltage stability at George Town. This will inform whether augmentation works are still required if the proponent connects a behind-the-meter solution as part of its project.

Key changes since the Project Specification Consultation Report

Since the publication and consultation on the PSCR, new information has become available to TasNetworks that impacts the PADR analysis. This is discussed in the following section.

Expectations of new load

As noted in the 'New load developments in George Town' section of this report, TasNetworks has commenced discussions with a potential data centre load proponent who is seeking up to a 600 MW connection in the Bell Bay area near George Town. This 600 MW connection is expected to be delivered over multiple stages, with the first stage of approximately 300 MW planned to connect to the network over the coming years.

Due to this connection enquiry and continued discussions with TGHH provisional proponents, we consider there to be an increase in the probability for at least 300 MW of new load connecting at George Town in the foreseeable future. As the size of any new load dictates reactive power requirements, we specifically address this load uncertainty in the 'Option flexibility given load uncertainty' section of this report.

Risk of single asset failure

Since publishing the PSCR, TasNetworks has undertaken further work to refine the identified need. This has resulted in a better understanding of the risk of a single asset failure at George Town. TasNetworks has previously considered the possibility that a transformer fire could result in de-energisation of the George Town substation and a subsequent black system event. Upon further investigations, TasNetworks now considers that, although possible, it is unlikely that an event of that nature would occur. However, consistent the PSCR, TasNetworks still considers that there are single contingency events also capable of resulting in a black system due to voltage instability.

Credible options assessed

TasNetworks has identified one credible network option to address the identified need. This option will enable full unconstrained operation of Basslink and accounts for the uncertainty of the precise size and location of new connections.

We have developed a solution that is proponent agnostic, while considering the complexity of the existing George Town substation (i.e. its limited capacity and existing connections held by potential load proponents). In doing so, we have ensured the solution places no reliance on proponent infrastructure and therefore reflects the maximum amount of investment required to address the identified need following the connection of 300 MW of new load.

Following the commitment of new load, we will endeavour to explore opportunities with the proponent to optimise the solution. This may include reducing the footprint of the solution by utilising existing or planned infrastructure, therefore reducing the scale of investment required by TasNetworks to address the identified need.

The credible option is presented in Table 2 below.

Table 2 Summary of credible option

Option	Description	Estimated Capex (24-25 \$M)	Estimated completion date
1	Establishment of a new AIS substation, installation of 550 MVar of reactive support in the new substation, and reconfiguration of the 220 kV switchyard at the existing George Town substation.	370.6	2030

Option 1 – Substation works and reactive support

Option 1 (the George Town Network Upgrade project solution) will provide sufficient reactive support to address the identified need following the connection of 300 MW of new load at George Town. This option comprises the following augmentation works:

Establishment of a new AIS substation, located near the existing George Town substation comprising:

- 4 x breaker and half capable diameters, populated with 2 breakers;
- construction of a control building at the new AIS substation site; and
- construction of 1.5 km of double circuit 220 kV overhead line back to the existing George Town substation.

At this new substation, installation of +550/-300 MVar of reactive support comprising:

- two +75 MVar capacitor banks;
- two +50 MVar capacitor banks; and
- two +-150 MVar static synchronous compensators (STATCOMs).

The existing George Town substation site presents potential challenges from the perspective of substation augmentation and transmission circuit ingress/egress due to the relatively high volume of existing

overhead/underground connections at 220 kV, 110 kV and 22 kV. To provide the means to connect the new substation to George Town substation, reconfiguration works will be undertaken on the existing 220 kV switchyard and will comprise the following:

- extension of the 220 kV buses to accommodate one additional diameter at the end of the switchyard;
- conversion of two 220 kV diameters to breaker and half configuration;
- segmentation of the 220 kV bus into four sections to reduce affected elements during fault events; and
- re-allocation of connecting 220 kV transmission corridors to Sheffield and Hadspen to opposite ends of the 220 kV switchyard.

Further information on the cost of this option can be found in the 'Cost estimate for credible option' section of this report.

The option will take approximately three years to construct. For the purposes of the PADR, TasNetworks included an indicative completion year of 2030, however this will be dictated by the timing of customer connections. Importantly, TasNetworks will not commence construction prior to receiving firm commitment from load proponents.

Non-network solutions

In the PSCR, TasNetworks indicated it would consider any non-network solutions submitted by non-network proponents as part of this PADR. Although Zen Energy and BBPF did suggest they may implement a behind-the-meter solution to mitigate the impact of their connection, we do not consider this a viable non-network solution because this RIT-T is:

- only for solutions that can supply 300 MW of front-of-meter load. If connecting parties bring their own behind-the-meter solutions, this will not trigger the need for investment; and
- proponent agnostic and the solution proposed by Zen Energy and BBPF is contingent on the BBPF load project proceeding. Given this is not a committed project, we cannot be satisfied that the non-network solution will be available to address the identified need if other loads connect.

TasNetworks remains interested in hearing from any non-network service providers capable of avoiding the need for capital expenditure.

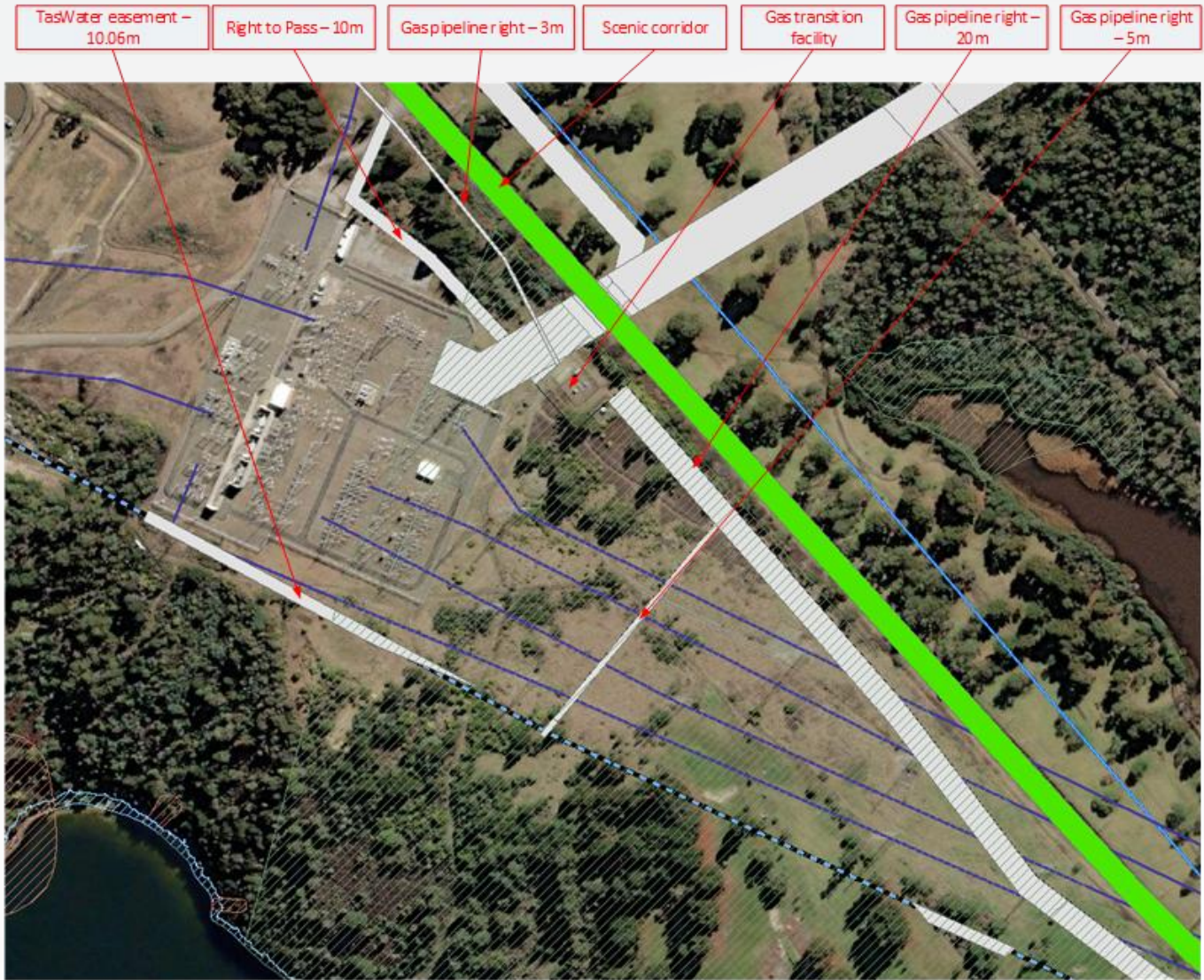
Options considered but not progressed

We have considered a range of other options but have not progressed these on the grounds that they are not technically feasible, or do not address the identified need and are therefore not credible options. A summary of these options is provided in Table 3 below.

Table 3 Summary of options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
Install reactive support in the existing substation	Augment the existing substation to house the reactive support instead of building a new substation.	<p>To accommodate the reactive support, the existing George Town substation would require expansion to either the east or west. This work is necessary to avoid placing the reactive support equipment under transmission lines, which may impact minimum overhead line clearances and introduce the risk of common mode failure risk, such as fallen conductors onto live equipment.</p> <p>As shown in Figure 2 below, existing easements and gas pipelines restrict east or west expansion.</p>
Scale the solution towards further static reactive support	This option considered scaling the solution towards further static reactive support which comes at a lower cost than dynamic reactive support.	<p>Static reactive support provides fixed, discrete amounts of compensation suited for long-term, steady-state conditions.</p> <p>The voltage instability at George Town resulting from the connection of new load will, at times, require rapid, real-time adjustment to maintain secure operation of the network. As such, an appropriate combination of both dynamic and static reactive support is required to fully address the identified need.</p>
Install a battery energy storage system (BESS) to provide dynamic reactive support	This option considered the use of a BESS to provide dynamic reactive support instead of a STATCOM.	While BESS facilities can provide real and reactive power modulation, this function is primarily designed around energy storage and release, rather than dedicated to rapid, significant response to network disturbances. This makes a BESS, by itself unsuited to address the requirements for the identified need. Furthermore, there are no BESS currently operating in Tasmania. However, TasNetworks is still interested in hearing from any BESS providers that believe they can reduce the need for capital expenditure.
Install a synchronous condenser to provide dynamic reactive support	This option considered the deployment of a synchronous condenser to provide dynamic reactive support instead of a STATCOM.	<p>Synchronous condensers are rotating synchronous machines that have the capability to absorb or inject reactive power to the network. However, they are slower acting compared to STATCOMs and windage losses are exacerbated at high revolutions.</p> <p>Given they are slower acting, they would not provide sufficient dynamic reactive support to address the identified need.</p>

Figure 2 Overview of the existing George Town Substation



Option flexibility given load uncertainty

This section provides a summary of TasNetworks' considerations for load variation at George Town and the efficacy of the preferred solution based on analysis undertaken by TasNetworks.

Reactive support analysis

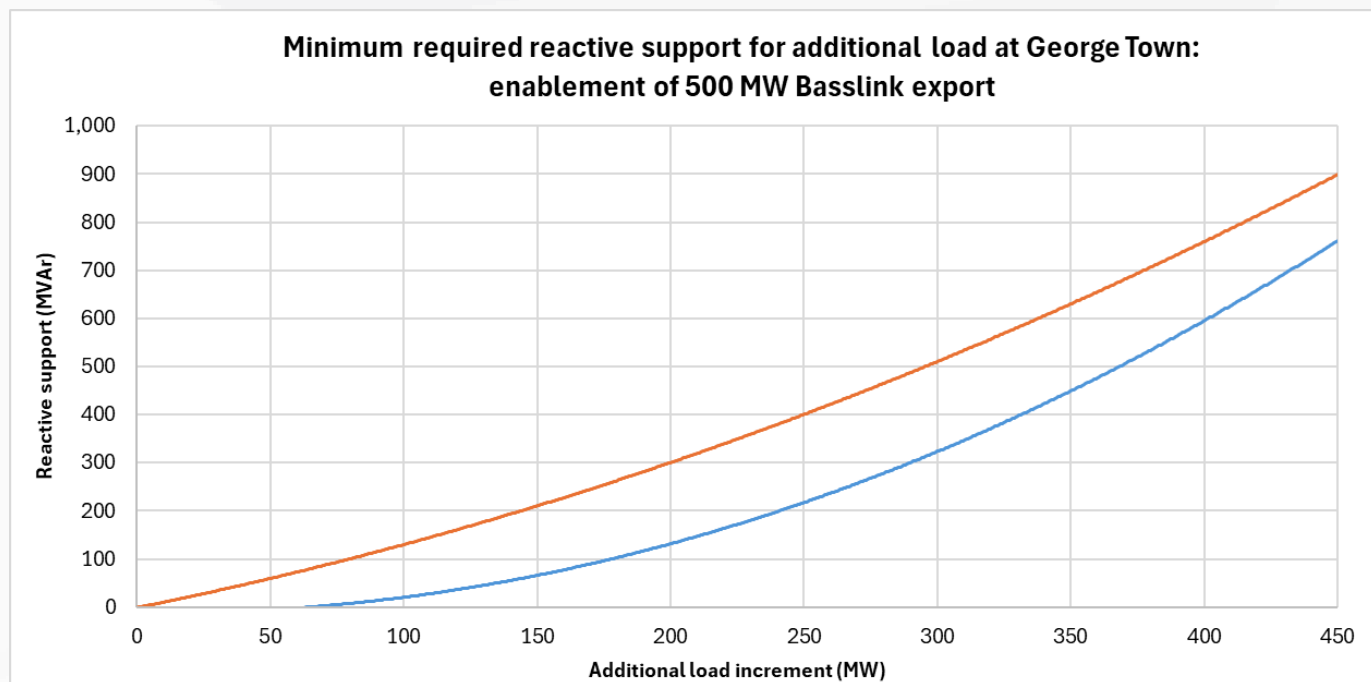
The design objective of the required reactive support solution (comprising both dynamic and static reactive support) at George Town is to ensure that a minimum reactive margin is maintained for both intact (N) and N-1 system conditions to allow Basslink to export unconstrained under standard operating conditions.

TasNetworks has undertaken analysis to determine the minimum reactive support requirements for 0-450 MW of additional load at George Town, whilst maintaining unconstrained Basslink export capability

(i.e. 500 MW, noting the maximum export capability is currently 594 MW⁸) under the most onerous single element contingency which TasNetworks considers to be an outage of one of the Sheffield-George Town 220 kV transmission circuits (which would reflect an N-1 system). The blue curve indicates the minimum reactive support under “N” system conditions and the orange curve indicates the minimum reactive support under (n-1) contingency conditions, the most severe case being a loss of one of the Sheffield-George Town 220 kV transmission circuits.

Figure 3 below shows the results of this analysis. The blue curve indicates the minimum reactive support under “N” system conditions and the orange curve indicates the minimum reactive support under (n-1) contingency conditions, the most severe case being a loss of one of the Sheffield-George Town 220 kV transmission circuits.

Figure 3 Minimum reactive support requirements by load increment



Scaling of credible option

As noted above in the ‘Key changes since the Project Specification Consultation Report’ section, we now consider it possible that upwards of 300 MW of new load connects at George Town in the foreseeable future. The blue curve indicates the minimum reactive support under “N” system conditions and the orange curve indicates the minimum reactive support under (n-1) contingency conditions, the most severe case being a loss of one of the Sheffield-George Town 220 kV transmission circuits.

Figure 3 shows that if 300 MW of new load connects at George Town, approximately 500-550 MVar of reactive support is required to address the identified need whilst enabling at least 500 MW of Basslink export (noting Basslink’s maximum export capacity is 594 MW).

Whilst we have developed a credible option that provides sufficient reactive support to support the connection of 300 MW of new load at George Town (as we consider this the most likely connection size at this point), the analysis shown in Figure 3 demonstrates that a different amount of reactive support

⁸ AEMO, [Interconnector Capabilities](#).

would be required under a different connection size to maintain at least 500 MW of Basslink export and ensure voltage stability is maintained under N-1 system conditions.

If a differently sized load was to connect (or loads, if within a short timeframe of each other and committed at a similar time), TasNetworks would look to scale the implemented solution to ensure sufficient reactive support is installed to fully address the identified need. This would mean a smaller amount of reactive support if the load size was less than 300 MW or a larger amount of reactive support if the load size was greater than 300 MW.

This will ensure the installed solution provides sufficient reactive support to meet NPR and NER requirements and enable unconstrained operation of Basslink, irrespective of the size of the new load that connects. While a smaller or larger solution may result in a different NPV, this will be driven by cost only (as gross market benefits will remain unchanged) and will not impact the outcome of this RIT-T as a reliability corrective action RIT-T with a single credible option.

As noted in the 'Credible options assessed' section of this report, following the commitment of new load, we will endeavour to explore opportunities with proponents to optimise the solution and reduce the scale of investment required by TasNetworks to address the identified need.

Estimating market benefits

This section outlines the materiality of market benefits for this RIT-T and how the material benefits have been estimated.

As a reliability corrective action RIT-T, the aim of this RIT-T is to identify the least cost option to meet the identified need (i.e. ensure compliance with NPR and NER obligations). Although only one credible option has been identified, given the size of the investment, TasNetworks considered it prudent to undertake market modelling to understand market operation and development should Basslink export be indefinitely constrained.

Approach and material benefits

For the purposes of this PADR, market benefits have been assessed for the credible option by analysing the Australian Energy Market Operator's (AEMO) draft 2026 Integrated System Plan (ISP) scenarios with and without (i.e. base case) the option.

The credible option was modelled by assuming Basslink was able to export fully unconstrained while the base case was modelled by assuming Basslink export was fully constrained (as this is what would be required to maintain network integrity in the absence of the installing reactive support following the connection of 300 MW of new load). Exports limits are discussed in the section below.

TasNetworks appointed Amplitude Consultants (now DNV) to undertake the wholesale market modelling and derive gross market benefits for the credible option. Amplitude utilised the PLEXOS simulation model to quantify the impacts on the wholesale market of the credible option and used the AEMO draft 2026 ISP database as the basis for the simulations, adjusted as required to reflect the credible option.

The modelling process entailed running multiple simulations of the NEM based on states of the world with or without the option to understand market outcomes (i.e. dispatch, spot prices, operational costs, capital costs, energy losses, renewable generation percentages, carbon emission profiles etc.).

For each state of the world (with or without credible option), Amplitude determined the following (which are the following classes of material market benefits):

- the likely pattern of future renewable resource developments in Tasmania and Victoria, including the developments of wind farms (i.e. changes in costs for parties due to differences in the timing of new plant, capital costs and operating and maintenance costs);
- the alternative transmission developments required to facilitate renewable resource developments within Tasmania and Victoria (i.e. unrelated transmission expenditure required to support variable renewable energy development); and
- operational fuel costs (i.e. changes in fuel consumption arising through different patterns of generation dispatch), greenhouse gas (GHG) emissions (i.e. changes in Australia’s GHG emissions, quantified using carbon price footprint) and network losses (i.e. changes in network losses).

Amplitude then evaluated the gross market benefits of implementing the option by evaluating the difference in the total system costs across the NEM under each scenario against equivalent scenario without implementation of the option (i.e. with Basslink export constrained).

Further information on the scenarios and assumptions we have adopted can be found in the ‘General cost benefit parameters adopted’ section of this report. Further information on the drivers behind the material market benefits can be found in the ‘Market benefits of network investment’ section of this report.

Interconnector Export limits

The market modelling assumes that implementation of the credible option fully unlocks Basslink’s export capability. Table 4 outlines the assumptions we have made in respect of the combined export (i.e. Tasmania to Victoria power transfer) capability of Basslink and Marinus Link Stages 1 and 2 under the base case and credible option case.

Table 4 Combined Export Limits of Interconnectors

Interconnector	Base case	Credible option case
	Total Export Limit (MW)	Total Export Limit (MW)
Basslink	0	594
Basslink and Marinus Link Stage 1	750	1,344
Basslink and Marinus Link Stage 1 and Stage 2	1,500	2,094

Market benefits not considered material

Although Amplitude quantified several classes of market benefits, we have determined that some of them are not material or cannot not be explicitly calculated for the purpose of this RIT-T. These include:

- **changes in voluntary load curtailment:** as noted in the ‘Base case’ section of this report, the constraint of Basslink export may limit the use of the Network Control System Protection Scheme (NCSPS) and result in voluntary load curtailment at times. Implementation of the credible option would therefore result in positive voluntary load curtailment market benefits. We have opted not to calculate this class of market benefit due to the expected complexity of doing so. As a reliability corrective action RIT-T with only one credible option, the calculation and inclusion of this market benefit would not change the outcome.

- **changes in involuntary load shedding:** although the identified need for this RIT-T relates to avoiding a black system, we do not consider that this benefit category is material for the purposes of this assessment. This is because, operationally, the risk of involuntary load shedding due to voltage collapse is managed through Basslink’s undervoltage limitation control. As described in the “Base case” section of this report, we do not consider this a viable long-term solution to managing the risk of a black system.
- **changes in ancillary service costs:** implementation of the credible option will provide the mainland NEM with greater access to Tasmanian ancillary services. Although the credible option may have an impact on ancillary service costs, we understand that hydropower units (being the main source of ancillary services in Tasmania) can be relatively more expensive at providing some ancillary services compared to supply via Basslink⁹ (from the mainland NEM). Therefore, we do not consider this class of market benefit to be material in this scenario (i.e. constrained vs unconstrained Basslink export).
- **competition benefits:** we do not consider this class of market benefit to be material as implementation of the credible option will not materially affect competition between generators due to the localised nature of the issue.
- **network losses:** in the market modelling approach, changes in network losses are internalised within the fuel and operating cost line item. This is because generation output is assessed on a sent-out basis, and network losses are reflected in the demand curve that is an input to each of the scenarios.
- **option value:** option value is likely to arise in a RIT-T assessment where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered are sufficiently flexible to respond to that change. Although there is uncertainty regarding the future level of demand growth in George Town, the proposed credible option is specifically designed to facilitate connection of 300 MW of new load. As noted in the “Option flexibility given load uncertainty” section of this report, we consider the credible option can be scaled to appropriately accommodate the eventual size of new load. This flexibility is related to the modular nature of reactive support devices rather than inherent to the credible option. For this reason, we do not consider option value to be material benefit category for this RIT-T.

Overview of the assessment approach

This section outlines the approach TasNetworks has applied in assessing the net market benefits of each credible option against the base case.

Base case

Consistent with the RIT-T requirements, the RIT-T assessment will compare the costs and benefits of each option to a base case ‘do nothing’ option.

The base case is the (hypothetical) projected case if no action is taken, i.e.:

“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’. ‘BAU activities’ are ongoing, economically prudent activities that occur in absence of a credible option being implemented”

⁹ Tasmanian Economic Regulator, [Energy In Tasmania Report 2024-25](#), p.13.

Under the base case scenario, TasNetworks will be unable to maintain the necessary reactive margin to meet our NER obligations following the connection of additional load at George Town. If the load increases by 210 MW or more, the total George Town load will equal or exceed 60 per cent of the state demand. This will result in non-compliance with the NPR as, under these low stability conditions, a single asset failure will be capable of causing a black system (loss of 60 per cent of regional load).

Although TasNetworks may operationally manage this increased voltage instability (in real time) through network constraints (i.e. constraining Basslink export up to the point of full constraint), we do not consider it prudent to plan the network around long-term, ongoing outages. We also consider that operating the network in this manner would not be economically prudent (and therefore not a feasible base case to continue with) as this would not allow the NEM to operate via least-cost dispatch, ultimately placing greater costs on consumers.

Furthermore, these network constraints may not fully mitigate the risk of a black system under all operating conditions and would cause deeper network issues such as limiting the use of the NCSPS.¹⁰ The NCSPS allows some transmission circuits in the Tasmanian power system to operate up to 95 per cent above their firm rating by arming Basslink export to runback following a credible contingency. If Basslink export is constrained, the transmission network could not be utilised to the same extent it currently is, which could in turn impact the flexibility for generation dispatch across the network.

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

General cost benefit parameters adopted

Assessment period and terminal value

The RIT-T analysis considers a 24-year assessment period from 2026-27 to 2049-50. A 24-year period considers the size, complexity and expected lives of the options and provides for a reasonable indication of the costs and benefits over a long outlook period.

Given capital components of the credible option have asset lives extending beyond the end of the assessment period, the NPV analysis includes a terminal value to capture the remaining economic life. This ensures that the capital and operating costs of long-lived options over the assessment period are appropriately captured. The terminal values have been calculated as the undepreciated value of capital costs at the end of the analysis period less the ongoing operating costs through to the end of the asset's economic life.

Discount rate

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 PADR, consistent with the assumptions adopted in the latest AEMO Inputs Assumptions and Scenarios Report (IASR).¹¹ The RIT-T also 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

¹⁰ The NCSPS allows dual circuit transmission corridors to substantially increase their 'non-firm' operational capacity. In the event of a transmission line contingency event that results in overloading of surrounding circuits, the NCSPS will issue runback or trip commands to selected generators to relieve the overload conditions.

¹¹ The latest IASR at the time of publication is the [2025 IASR](#).

bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.51 per cent¹² and an upper bound discount rate of 10 per cent (being the upper bound in the latest IASR).

Scenarios

The scenarios from the latest IASR and the weightings from the cost benefit analysis undertaken by AEMO for the draft 2026 ISP¹³ have both been adopted without modification. The scenarios and weightings are outlined in Table 5 below.

Table 5 Scenarios and weightings

Scenario	Scenario purpose (as per draft 2026 ISP)	Weighting
Step Change	To explore the investment needs in a world with strong decarbonisation of the electricity sector, supporting other sectors decarbonising their current energy activities through electrification. Consumers increase their investment in consumer energy resources, potentially reducing the need for utility-scale alternatives, with emerging coordination of these resources that grows cautiously in the short term.	46%
Slower Growth	To explore investment needs in a world with headwinds to decarbonisation, including lesser growth across Australia's economy. As a consequence, despite the scenario driving to achieve current government policy, this scenario examines possible over-investment risks in a more slowly growing economy.	27%
Accelerated Transition	To explore investment needs in a world embracing very rapid decarbonisation, with strong potential economic benefits for Australia given its high renewable generation potential and the potential this offers to support commoditisation of its minerals and resources. It will therefore identify the scale and speed of investments that may be required to realise this potential in a rapidly decarbonising global economy.	27%

The additional assumptions we have made in respect of the new load and the timing of Marinus Link are outlined in Table 6 below. These have been adopted across the three ISP scenarios modelled.

Table 6 Additional assumptions adopted

New load size	Load connection (year)	Demand type of new load
300 MW	2030	Fixed

Sensitivities

We have modelled several sensitivities to understand the NPV implications of changing specific assumptions.

Table 7 outlines the assumptions we have changed and remodelled on the Step Change scenario (as the highest weighted scenario).

¹² Based on TasNetworks' pre-tax, real WACC at the time of publication, from *AER - TasNetworks Transmission 2024-29 - Final decision - PTRM - 2025-26 RoD update - NWTD Stage 1*, at [Final Decision | Australian Energy Regulator \(AER\)](#).

¹³ AEMO, [Appendix A6. Cost-Benefit Analysis](#), p.22.

Table 7 Summary of change in assumption by sensitivity

Sensitivity	Changed assumption	Details
Flexible demand	Demand type of new load	New load follows a flexible demand profile (i.e. a price taker) instead of fixed. Although proponents have previously requested very high capacity factors, some load types may more closely follow movements in the wholesale energy price. This sensitivity is expected to lower the benefits of the option as Basslink could still export under low load conditions.
No Marinus Link Stage 2	Marinus Link Stage 2 timing	The ISP scenarios assume a Marinus Link Stage 2 timing of 2034. This sensitivity assumes Marinus Link Stage 2 does not proceed at all. This sensitivity is expected to increase the benefits of the option as a greater proportion of total export will occur over Basslink.
Lower bound discount rate	Discount rate	Uses a discount rate of 3.51% instead of 7%.
Upper bound discount rate	Discount rate	Uses a discount rate of 10% instead of 7%.

Approach to estimating costs

TasNetworks has prepared a cost estimate reflecting the Association for the Advancement of Cost Engineering (AACE) cost estimate classification system. The credible option in this RIT-T reflects an AACE class 4 cost estimate, which has an expected accuracy range of -30 per cent to +60 per cent.

The cost estimate has been prepared by a third-party estimator using a technical specification prepared by TasNetworks. Cost information has been sourced from recent similar projects or directly from suppliers (i.e. STATCOMs) and a design and construction delivery model has been assumed. The cost estimate has been prepared in real, 2024-25 dollars.

An AACE class 4 cost estimate is typically a feasibility estimate and reflects a project definition maturity level of one per cent to 15 per cent. As a result, explicit contractor and principal contingency allowances have been included. A contractor contingency allowance of 8.5 per cent (or \$18.2 million) has been applied to all contractor costs (i.e design, direct construction and contractor overheads). A principal's contingency allowance of 20 per cent (or \$61.8 million) has been applied to all costs within the cost estimate. These contingency allowances are intended to capture the degree of uncertainty associated with the project definition and scope at this point in time. The particular costs these allowances may cover primarily include costs associated with materials and labour escalation, and scope refinement that may occur during the design phase.

The cost estimate includes costs related to the acquisition of land and easements. Based on the proposed location of the new substation and transmission line (that will link the new substation to the existing substation), land and easement acquisition will only be required from a single landholder. To not prejudice

negotiations with this landholder, land and easement acquisition costs have not been reflected as a single cost item in the following section and have instead been included within the Owners Costs.

For the NPV analysis of the credible option, TasNetworks has assumed that 0.5 per cent of its initial capital cost represents the yearly cost incurred to operate and maintain the assets across their lifespan. The present value of the operating costs associated with this option (discounted using a real, pre-tax discount rate of 7.0 per cent) is \$14.5 million (inclusive of the operating costs terminal value).

There are differences between the costing in our previous PSCR and this PADR. The main reason for this is that the PSCR estimate was prepared based on a high-level scope utilising AEMO's 2023 Transmission Cost Database, whilst this PADR estimate has been prepared based on a more detailed scope utilising a bottom-up build and more recent cost information. The PADR estimate also reflects \$80 million of contingency allowance which, as noted above, has been included to capture the degree of uncertainty at this point in time. Given there is a single credible option, we have chosen to include the contingency within the estimate for the purpose of this RIT-T to be transparent with stakeholders, as its inclusion will not impact the determination of the preferred option.

The resulting cost estimate is presented in the next section.

Cost estimate for credible option

Table 8 outlines the cost of option 1 by cost category. All costs in this table are reflected in real, 2024-25 dollars. Further information on the scope of this option can be found in the 'Option 1 – Substation works and reactive support' section of this report.

Table 8 Estimated costs for option 1 (AACE Class 4, -30 per cent to +60 per cent)

Cost category	Description	Estimated Capex (24-25 \$M)
Design	Design fee	8.7
Direct costs	Transmission lines	7.2
Direct costs	Substations	161.7
Direct costs	Total direct costs	168.9
Contractor indirects	Includes indirects, margin and contingency	84.9
Owners costs	All owners costs including land and easement compensation	46.4
Owners contingency	Risk and contingency	61.8
Total	Total cost of option 1	370.6

For the purposes of the NPV analysis, the present value of this option (discounted using a real, pre-tax discount rate of 7.0 per cent) is \$317.1 million and the terminal value associated with these capital costs is \$30.7 million.

Cost of scaling option

As discussed in the 'Option flexibility given load uncertainty' section of this report, if a different sized load connects (other than a 300 MW load), we would scale the reactive support solution such that it provides sufficient reactive support to meet NPR and NER requirements and enable unconstrained operation of Basslink.

While analysis would be required to confirm the split of dynamic and static reactive support once the load size was known, Table 9 provides information on the cost per MVar of dynamic and static reactive support devices to provide an understanding of how the cost of the option may vary based on an increase or decrease in the reactive support requirements.

Table 9 Cost of reactive support devices per MVar

Reactive support	Cost/MVar (24-25 \$)
Dynamic (STATCOM)	\$270,000 - \$380,000
Static (capacitor bank)	\$30,000 - \$35,000

Economic assessment results

This section outlines the economic assessment we have undertaken to determine the net benefits of addressing the identified need following the connection of 300 MW of new load at George Town.

The assessment compares the costs and benefits of the credible option to the base case. Benefits of the credible option are represented by the wholesale market benefits of unconstrained Basslink export compared to the base case (which assumes fully constrained Basslink export following the connection of 300 MW of new load).

Market benefits of network investment

Across all scenarios, the market benefits accrue from fuel consumption cost savings, generator capital expenditure (capex) deferrals on the mainland (primarily in Victoria) and a reduction in GHG emissions costs. There are also two classes of material market benefits that produce negative benefits under some scenarios (i.e. implementation of the credible option increases that class of costs across the NEM), being higher network capex and higher network losses. An explanation of the driver behind each class of material market benefit is outlined below.

- **changes in fuel consumption arising through different patterns of generation dispatch:** Under the base case, mainland Australia must meet demand without any contribution from Tasmanian generation. Unconstraining Basslink following implementation of option 1 in 2030 reduces total fuel consumption costs across the NEM, as hydro generation is able to displace coal and gas generation on the mainland. This is a consistent net benefit across all scenarios.
- **changes in costs for parties, other than the RIT-T proponent, due to differences in the timing of new plant, capital costs, and operating and maintenance costs:** This is the largest contributor to benefits across all scenarios and is made up of generation and network capex deferral. Under the base case, generation capacity must be built to meet demand and government policy targets. By enabling full Basslink export capacity, the need for new generation capacity in Victoria is reduced, as a cheaper

combination of wind and solar PV investments in Tasmania can meet demand. Under the Accelerated Transition scenario, some mainland network investments are accelerated under option 1 contributing to higher system costs as shown in Figure 4.

- **changes in Australia’s GHG emissions:** Under the base case, peak demand must be met by more carbon intensive generation sources such as gas. By implementing option 1, Tasmanian renewable generation displaces more carbon intensive Victorian supply.

Table 10 provides the present value of market benefits accruing from the implementation of the credible option across all three scenarios, along with the weighted average present value of market benefits. As shown, option 1 delivers positive market benefits across all scenarios and a weighted average benefit of \$538 million (excluding terminal value).

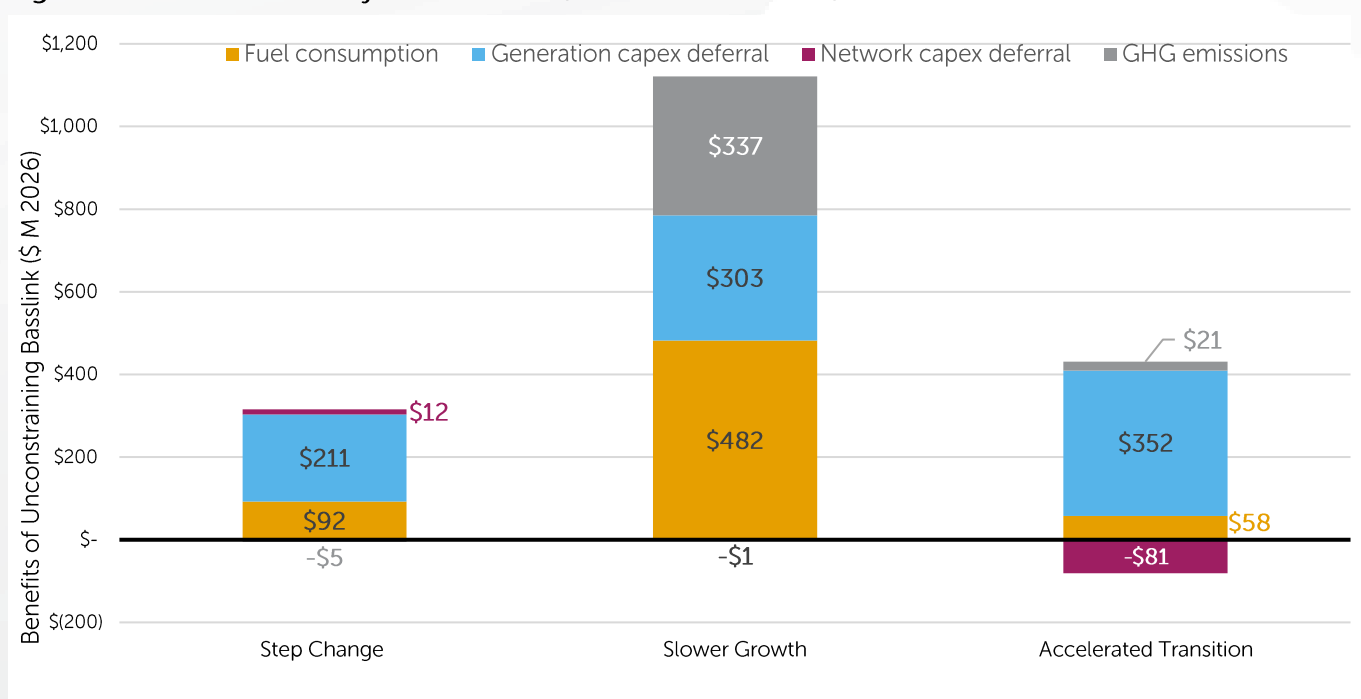
Benefits are significantly higher under the Slower Growth scenario as shown in Table 10 and Figure 4. This is driven by lower Tasmanian demand under this scenario resulting in greater export from Tasmania to mainland Australia. Specifically, option 1 enables hydro and wind generation flows to Victoria which displaces brown coal and gas generation resulting in significant fuel cost savings and avoided GHG emissions.

Table 10 Sum of present value of market benefits (excl. terminal value) for option 1

Scenario	Weighting	Benefits (2030 – 2050) (25-26 \$M)
Step Change	46%	309
Slower Growth	27%	1,117
Accelerated Transition	27%	350
Weighted Average	N/A	538

The contribution to total market benefits by each class of market benefit is illustrated in Figure 4 below.

Figure 4 Market benefits by benefit class (excl. terminal value) – scenarios



Net Present Value

Table 11 provides the NPV results for the credible option, where option 1 is shown to deliver positive net benefits across all scenarios and a weighted NPV of \$234 million. The results have been calculated as the present value of market benefits, less the present value of the costs associated with the implementation of the option (inclusive of both capital and operating costs), plus a terminal value to capture the remaining economic life of the option post assessment period. Further information on the assessment approach is outlined in the 'Overview of the assessment approach' section of this report.

Table 11 Net Present Value results for option 1

Scenario	Weighting	NPV (25-26 \$M)
Step Change	46%	4
Slower Growth	27%	812
Accelerated Transition	27%	46
Weighted Average	N/A	234

Sensitivity analysis

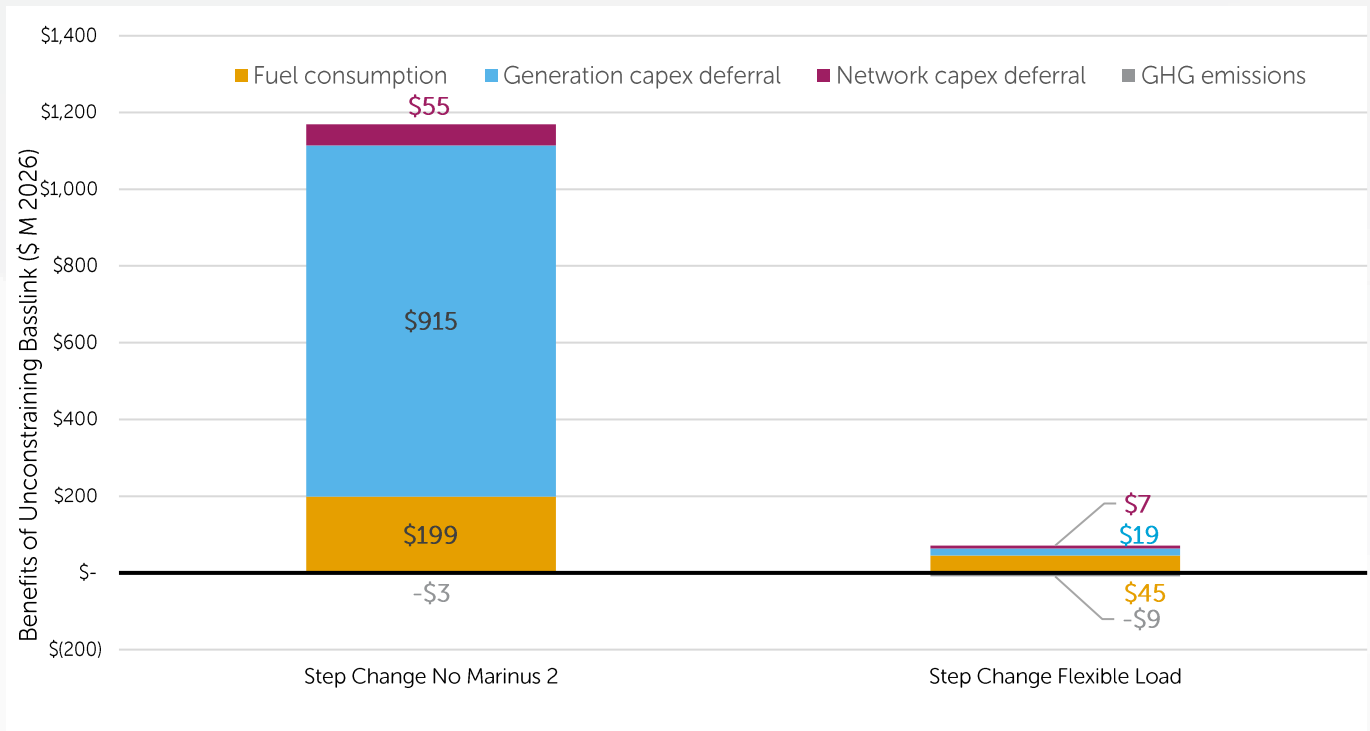
As detailed in Table 7 we have undertaken sensitivity analysis on several key assumptions to understand how changes in these assumptions may impact the NPV.

Table 12 below present the results of the flexible demand, no Marinus Link Stage 2 and discount rate sensitivities. All sensitivities have been modelled on the Step Change scenario (as the highest weighted scenario).

Table 12 Results for sensitivity analysis

Sensitivity	Gross benefits (excl. terminal value) (25-26 \$M)	NPV (25-26 \$M)
Flexible demand	61	-260
No Marinus Link Stage 2	1,163	859
Lower bound discount rate	515	207
Upper bound discount rate	208	-86

Figure 5 Market benefits by benefit class – sensitivities



Flexible demand

The results show a reduction in benefits under a scenario where the new load follows a flexible demand profile. This is because, under this scenario, Basslink remains available for export during certain high price periods when load is reduced. As a result, option 1 results in lower benefits from fuel consumption and capex deferral as shown in Figure 5. As shown in Table 12, should the load follow a flexible demand profile, the preferred option would be delivered at a net cost of \$243 million.

No Marinus Link Stage 2

The results demonstrate significant additional benefits under a scenario where the second stage of Marinus Link does not proceed. This is because total interconnection capacity under this scenario is reduced so the relative reliance on Basslink for export is increased. As a result, option 1 results in significantly greater benefits from reduced fuel consumption and deferred capex as shown in Figure 5. Should Marinus Link Stage 2 not proceed, option 1 would provide net market benefits of \$859 million.

Discount rate

Table 12 shows that a lower and higher discount rate increases and decreases the benefits of the option respectively. This is expected as the benefits accrue over a longer time horizon than the costs and are therefore more sensitive to discounting.

Reopening triggers

Where the estimated capital cost of the proposed preferred option is greater than \$103 million, TasNetworks must include RIT reopening triggers. Reopening triggers are the events, factors, or circumstances which, if they occur or eventuate, would mean that the preferred option may change. Given this is a reliability corrective action RIT-T and there is only a single credible option, TasNetworks

does not consider there are any reopening triggers for this RIT-T and no event, factor or circumstance could change the preferred option.

Conclusion

This PADR assessment finds that option 1 is the preferred option and the only credible option to meet our externally imposed service standard. Option 1 involves establishment of a new AIS substation, installation of 550 MVAR of reactive support in the new substation, and reconfiguration of the 220 kV switchyard at the existing George Town substation. Option 1 is expected to provide approximately \$234 million in weighted net market benefits over the assessment period. The PADR includes an indicative completion date of 2030, however this will be dictated by the timing of proponent connections.

We consider that option 1 is likely to have a material inter-network impact as it will enable unconstrained operation of Basslink. However, we have not sought an augmentation technical report as implementation of the option will simply allow Basslink to operate as intended following the connection of new load at George Town.

Based on the analysis within this PADR, we consider that the preferred option satisfies the RIT-T.

Next steps

TasNetworks now welcomes submissions from interested parties on the analysis and information contained within this PADR. Submissions will be open for 12 weeks from 29 May 2026 until 21 August 2026. TasNetworks remains interested in hearing from any non-network service providers capable of addressing the identified need. Submissions should be addressed to Matthew Clarke, Leader Large Regulated Investment and emailed to regulation@tasnetworks.com.au.

Following completion of the consultation period, we will update the RIT-T analysis with any new information including that received from submissions.

We will then publish a PACR to close out the RIT-T process.

Appendix A: Compliance checklist

This section provides a compliance checklist which demonstrates this PADR complies with all relevant requirements under clause 5.16.4(k) of the National Electricity Rules version 244.

Rules Clause	Summary of requirements	Relevant section(s) in the PADR
5.16.4(k)	The project assessment draft report must:	-
	1) a description of each credible option assessed	Credible options assessed
	2) a summary of, and commentary on, the submissions to the project specification consultation report	Responses to Project Specification Consultation Report
	3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option	Estimating market benefits, Cost estimate for credible option & Market benefits of network investment
	4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost	Estimating market benefits & Overview of the assessment approach
	5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material	Market benefits not considered material
	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)	Market benefits of network investment
	7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Net Present Value
	8) the identification of the proposed preferred option	Conclusion
	9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: <ul style="list-style-type: none"> i) details of the technical characteristics; 	Conclusion Credible options assessed

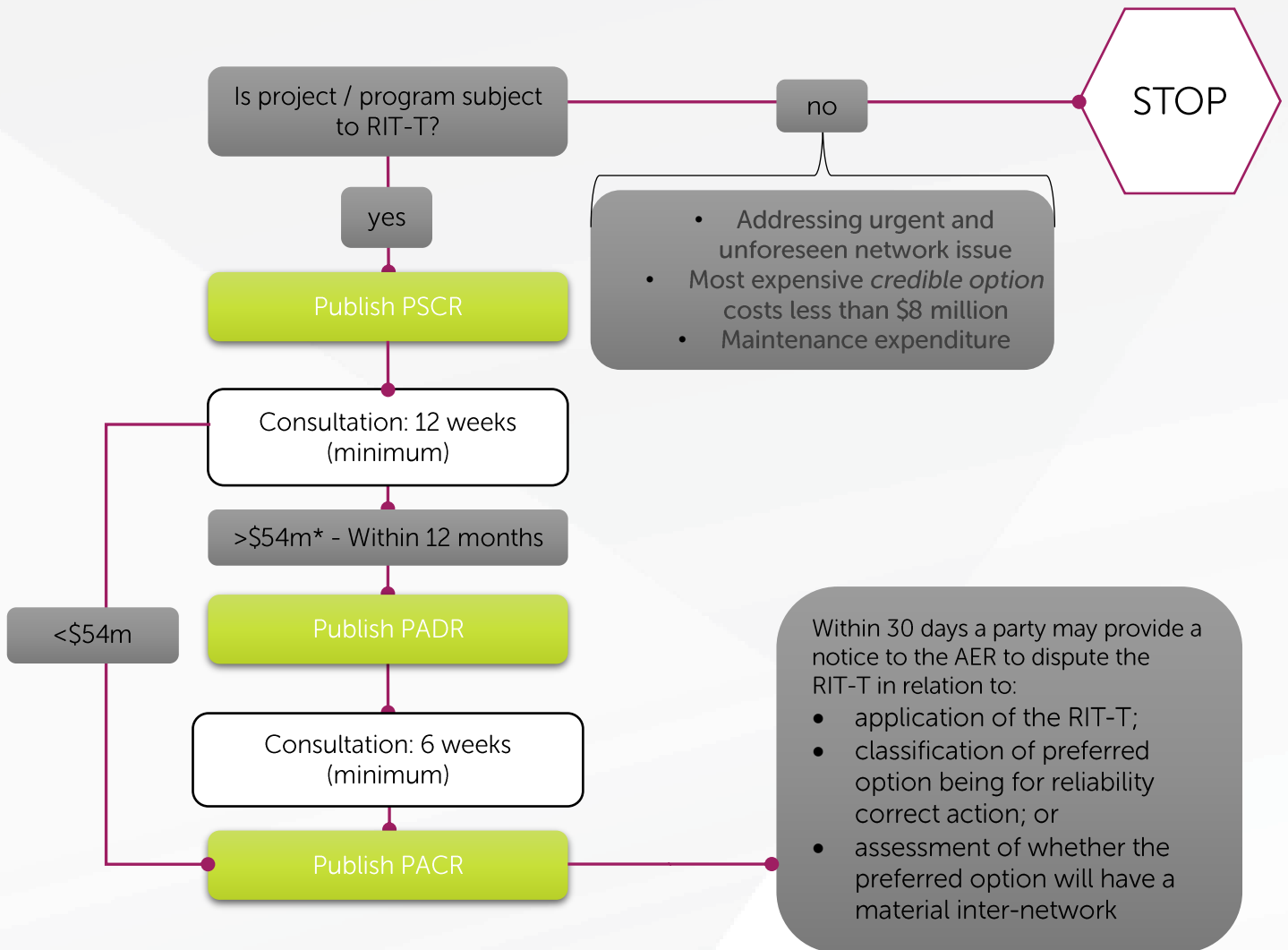
- ii) the estimated construction timetable and commissioning date;
- iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and
- iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission

Economic assessment results

- 10) if each of the following apply to the RIT-T project:
- i. the estimated capital cost of the proposed preferred option is greater than \$103 million (as varied in accordance with a cost threshold determination); and
 - ii. AEMO is not the sole RIT-T proponent,
- the RIT reopening triggers applying to the RIT-T project.

Reopening triggers

Appendix B: RIT-T process





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Meeting Network Planning Requirements at George Town
Official