TasNetworks - Project Specification Consultation Report

Meeting the System Strength Standard in Tasmania from December 2025 onward.

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TasNetworks | Powering a Bright Future

Contents

Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level (methodology)
EOI	Expression of Interest
GWh	Gigawatt hours
HVDC	High Voltage Direct Current
ISP	Integrated System Plan
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (Version 200 referenced throughout this document)
OSM	Operational Security Mechanism
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SSN	System Strength Node
SSSP	System Strength Service Provider
tbc	To be Confirmed
TNSP	Transmission Network Service Provider

Disclaimer

Executive Summary

TasNetworks is the Transmission Network Service Provider (TNSP) and Jurisdictional Planner for the Tasmanian region of the National Electricity Market (NEM). As a result, we are also the *System Strength Service Provider* (SSSP) and *Inertia Service Provider* for Tasmania. We have prepared this Project Specification Consultation Report (PSCR) to address our National Electricity Rule (NER) obligations defined under Schedule 5.1.14 and Chapter 5.20B.4 (respectively) for the period from 2 December 2025 onwards. For ease of reference, a selection of pertinent rule clauses have been provided in Appendix A.1.

As part of this PSCR, we have also elected to consider the future requirements for system inertia. While the supply of *inertia network services* is currently exempt from the Regulatory Investment Test for Transmission (RIT-T) process, we are of the view that a number of potential credible solutions could address both requirements concurrently, and therefore contribute to efficient and cost effective outcomes consistent with the National Electricity Objective (NEO). This PSCR is the first step in the formal RIT-T process and is primarily intended to identify credible options that will allow us to manage our system strength obligations across planning timeframes. The subsequent cost benefit analysis will also consider our obligations as an *Inertia Service Provider*.

Tasmania's Energy Future

Although the smallest state, Tasmania has the potential to play a significant role in decarbonisation of the NEM, directly through the installation of significant renewable energy resources, and indirectly by providing access to flexible firming capacity and deep storage via existing (and new) hydro generation assets. Additional transmission interconnector capacity in the form of Marinus Link will enable Tasmania to contribute more significantly to the future needs of the NEM, as well as encourage local generation and customer developments.

Underpinning Tasmania's energy future is state government legislation which requires an increase in renewable generation from an existing baseline of 10,500 gigawatt hours (GWh) to 21,000 GWh by 2040. The Tasmanian Renewable Energy Target (TRET) requires the installation of at least 2,500 MW of new wind generation, which will increase the total installed wind capacity in Tasmania to over 3,000 MW. The 2022 Integrated System Plan (ISP) published by the Australian Energy Market Operator (AEMO) forecasts that the majority of this generation could be installed within the next ten years, coinciding with the expected completion of both stages of Marinus Link (2 x 750 MW).

The role of system strength services

TasNetworks is resolute in its commitment to power system security. We understand that a secure and reliable power system is a fundamental, non-negotiable expectation of modern society. However, it must be acknowledged that achieving such outcomes will necessitate both financial investment and innovation given the scale of the energy transition. A key attribute of a secure and resilient power system is the provision of sufficient system strength.

System strength is a broad term encapsulating a number of specific technical issues, however the core elements are:

(a) Ensuring that adequate short circuit current is always available to facilitate the correct operation of network protection systems.

(b) Ensuring that stable voltage control can be maintained across the network, both before and after network contingency events.

(c) Ensuring that the voltage at the connection point of grid-following inverter based resources (**IBR**) is sufficiently robust to allow for their continuous, uninterrupted operation, even when subjected to network faults and other credible disturbances.

Critically, many forms of IBR presently being connected to electricity networks rely on other grid-forming technologies to remain stable, operate in a predictable manner and provide the levels of short circuit current required to satisfy protection requirements. The traditional source of system strength has been synchronous generation (e.g. hydro, coal-fired power plants etc) which is inherently capable of addressing the core elements outlined above, as well as providing inertia. However, as the installed capacity of IBR continues to grow, there will be increasing periods where little, if any, synchronous generation will be required to remain online to satisfy electricity demand. In the context of the Tasmanian power system, any power imported across high voltage direct current (**HVDC**) interconnectors[1] also reduces the need for synchronous generation, exacerbating the issues further.

In a power system dominated by IBR, alternate mechanisms will be required to support system strength whenever the dispatch of synchronous generation (via the energy market) is insufficient to maintain network security. To date, the Tasmanian power system has been operated with up to 92% of its instantaneous demand being supplied by IBR energy sources, mostly comprised of Tasmanian wind farm output and HVDC import across Basslink. With forecast wind developments to meet the TRET, the ability to achieve 100% will become increasingly likely, further impacting system strength requirements and underlining the criticality of having adequate mitigation measures in place.

Why TasNetworks is applying the RIT-T process

In its final determination of the '*Efficient Management of System Strength on the Power System*[2]' rule change, the Australian Energy Market Commission (**AEMC**) confirmed its draft position that where applicable, each SSSP would apply the RIT-T to decide which investments should be pursued to meet the new system strength planning standard[3]. Consistent with NER Clause 5.10.2, TasNetworks is treating the resulting requirement as a 'reliability corrective action'.

As the estimated capital cost of the most expensive option to address the identified need will exceed the threshold[4] of $7 million, TasNetworks must undertake a RIT-T for this expenditure. The RIT-T is an opportunity for TasNetworks to engage closely with stakeholders, including providers of system strength solutions, to ensure we identify the best solution for our customers.

What is the identified need?

The identified need is to provide, from 2 December 2025, sufficient system strength at each system strength node (**SSN**) to satisfy minimum fault level requirements, as well as provide an efficient level of system strength, so as to maintain power system security while facilitating forecast developments of IBR in Tasmania. In doing so, TasNetworks will satisfy its obligations under NER S5.1.14(b).

For the purposes of this PSCR, TasNetworks has referenced the 2022 System Strength Report as published by AEMO [1]. The System Strength Report defines the requirements pertaining to each

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1 Basslink can be considered a form of grid-following IBR. The future capabilities of Marinus Link are still being defined.

2 Available at: [Efficient management of system strength on the power system | AEMC]

3 Refer NER Schedule 5.1.14, 'Minimum three phase fault levels and stability for system strength nodes'.

4 Refer: [Cost thresholds review for the regulatory investment tests 2021 | Australian Energy Regulator (aer.gov.au)]

category of service, as described more specifically by NER 5.20C.1(c)(2). As the System Strength Report is only mandated to forecast requirements for the proceeding ten years, TasNetworks has also considered potential longer term issues associated with meeting TRET. We have used the forecasts provided as part of the 2022 ISP for guidance on such matters, allowing us to consider the expected trajectory of various system metrics out to the end of 2040.

System strength requirements for the forward planning period

There are currently four SSNs defined across the Tasmanian power system. The existing minimum fault level[5] defined for each node to maintain secure operation is presented in Table 1. Unless otherwise noted and explained as part of this PSCR, the minimum three phase fault levels are expected to remain fixed over the forward planning period.

To provide further context, the most recent fault level shortfalls declared by AEMO in accordance with NER 11.143.14 are also provided in Table 1. The notice was issued to TasNetworks on 15 December 2022, with forecast shortfalls persisting from 15 April 2024 through to 30 June 2028 (and likely beyond in real terms).

Table 1: Minimum three phase fault levels and existing shortfalls.

System Strength Node (SSN)	Minimum Fault Level Requirement	AEMO Declared Shortfall (Dec 2022)	Corresponding Tasmanian REZ in 2022 ISP
Existing			
Burnie 110 kV	850 MVA	423 MVA	North West, T2
George Town 220 kV	1,450 MVA	827 MVA	North East, T1
Waddamana 220 kV	1,400 MVA	594 MVA	Central, T3
Risdon 110 kV	1,330 MVA	511 MVA	No REZ assigned.
Anticipated (not yet declared by AEMO).			
Hampshire Hills 220 kV	≤ 1,650 MVA (tbc)	n/a	T2, to address 220 kV network needs.

While not yet declared by AEMO, TasNetworks is progressing this PSCR on the basis that a fifth SSN will be required to manage operation of the North West Renewable Energy Zone (**REZ**) inclusive of Marinus Link. The north west REZ is identified as 'T2' in the 2022 ISP and System Strength Report.

The IBR forecast for Tasmania, as presented in the 2022 System Strength Report, is provided below in Table 2. For clarity, the forecast only considers future wind, solar and battery energy storage system (**BESS**) developments. Please note that TasNetworks has pre-emptively allocated some forecast IBR to the future Hampshire Hills SSN based on already identified projects which are being considered as part of future network planning studies. TasNetworks understands that due to NER requirements, AEMO was unable to allocate future IBR developments to nodes which had not yet been formally declared.

[5] Pre-contingent three phase fault levels which assume an initially intact network.

Table 2: Projected IBR developments for Tasmania (New MW capacity, cumulative totals by SSN).

Reference SSN	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Burnie 110 kV	0	0	0	0	0	83	83	83	83	83
George Town 220 kV	0	258	258	258	258	258	376	376	376	376
Waddamana 220 kV	0	0	275	275	275	279	768	768	823	823
Risdon 110 kV	0	0	0	0	0	0	0	0	0	0
Hampshire Hills 220 kV	0	0	0	0	0	0	268	268	1218	1218
Aggregate (MW)	0	258	533	533	533	620	1495	1495	2500	2500

TasNetworks notes that the minimum new renewable generation required in Tasmania to meet TRET is currently considered to be 2,500 MW based on the assumed capacity factors for large scale wind farms. The 2022 ISP does not forecast any additional utility scale wind or solar developments in Tasmania after 2033, with ongoing growth limited to distributed photovoltaics.

As discussed within this PSCR, TasNetworks has converted the forecast IBR developments described in Table 2 into an equivalent three phase fault level which represents the '*efficient level of system strength'* required at each SSN. A description of the methodology, supporting assumptions and accepted limitations are presented for review and critique as part of the consultation process.

What this PSCR presents for consultation

TasNetworks has prepared this PSCR in accordance with NER 5.16.4(b) and has specifically considered:

(a) The nature and timing of the identified need, including descriptions of necessary assumptions and calculation methodologies used to inform the quantum of need.

(b) The technical characteristics that non-network solutions would need to deliver to adequately address the identified need.

(c) Credible options that TasNetworks believe are capable of addressing the identified need, including non-network solutions (which we recognise as having significant potential based on our prior experiences with managing declared shortfalls).

(d) The relationship between system strength and inertia, specifically how TasNetworks might satisfy multiple NER obligations concurrently and at lowest cost for Tasmanian consumers.

(e) An overview of the analysis methodology intended to be applied during preparation of the PADR to identify the preferred option(s).

To provide context to help inform potential non-network proponents make submissions to this PSCR, TasNetworks has also included background material describing our management of system strength and inertia shortfalls to date. We have also outlined our preliminary expectations in regards to how non-network services might be operationalised, noting the recent forward direction note published by the AEMC in respect to the Operational Security Mechanism (OSM)[6].

[6] Refer: Forward direction note.pdf (aemc.gov.au)

Submissions to the PSCR

TasNetworks welcomes submissions from industry in response to this PSCR, specifically proponents who are in a position to offer credible non-network solutions capable of meeting the various requirements that have been defined. Without prejudice to any particular solution at this time, we anticipate that the optimal outcome will most likely involve a mix of network and non-network solutions. We thus consider it important to identify all such opportunities through this initial consultation process.

To support the preparation of submissions from intending non-network service providers (for both system strength and inertia network services), TasNetworks has developed an Expression of Interest (EOI) document with supporting templates for the provision of technical information. The templates have been developed to standardise the types of information submitted, which will ultimately be used as input data to the PADR modelling and analysis process.

TasNetworks is seeking written submissions to this PSCR over a twelve week period ending at 2 PM Thursday 9 November 2023.

For further information, please contact:

Chris Noye
Leader Regulation
Tasmanian Networks (TasNetworks)

Email submissions to this PSCR can be sent directly to:

regulation@tasnetworks.com.au

1 Introduction

TasNetworks owns, operates and maintains the transmission and distribution electricity networks in Tasmania. As the TNSP and Jurisdictional Planner for the Tasmanian region of the NEM, we are also the SSSP and *Inertia Service Provider* as defined by the NER.

System strength is a broad term encapsulating a number of specific technical issues. In context of the NER requirements, system strength addresses minimum three phase fault levels which are necessary to ensure power system security, as well as help maintain the stability of voltage waveforms. The latter issue can be significantly impacted by the connection of grid-following IBR technologies, being the typical solution implemented by wind and solar generators in today's market. It is especially challenging whenever the need to run traditional synchronous generators is diminished, i.e. when the output of IBR is a significant portion of the total energy demand.

On 21 October 2021, the AEMC made a final determination for the '*Efficient Management of System Strength on the Power System*[7]' rule change, as originally submitted by TransGrid. The new rules introduced both a System Standard and what is effectively a transmission network planning standard, to manage the provision of system strength across the NEM. The rule changes were specifically designed to support the ongoing connection of renewable energy technologies needed to support the NEM's transition away from carbon intensive, fossil fuelled generation as forecast by the AEMO ISP.

While Tasmania's generation outlook is vastly different to the rest of Australia, with little to no reliance on thermal generation given our significant hydro assets, management of system strength and inertia remains critically important as new on-island renewable energy developments occur. The TRET legislation requires that a minimum of 2,500 MW of new wind generation be constructed, with Tasmania's wind resources capable of supporting considerably more. Such capacity will at times be well in excess of Tasmania's needs, creating a situation where hydro units will not be required to generate. Ensuring that power system security and reliability are not compromised during such operating conditions, that are currently considered extreme, is of paramount importance to both TasNetworks and AEMO.

In light of Tasmania's forecast renewable energy developments, TasNetworks is now obligated to consider the investment needed to meet the new rule requirements.

To ensure that any required investment results in a least cost outcome for Tasmanian consumers, the NER requires that TNSP's undertake a RIT-T whenever a credible option has an estimated capital cost above $7 million. TasNetworks expects that at least one credible option will exceed this threshold when considered over the forward planning period. The RIT-T ensures that stakeholders have visibility of the process, understand the need for network expenditure, and are able to actively participate in helping identify potential solutions. This PSCR is the first step in that process.

The purpose of this PSCR is to:

- Describe why action needs to be taken (the 'identified need').
- Present credible options that we consider capable of addressing the identified need.
- Outline the technical characteristics that non-network options would need to provide.
- Allow interested parties to make submissions to the RIT-T assessment, especially in relation to the provision of non-network options.

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[7] Available at: Efficient management of system strength on the power system | AEMC

- Summarise how we intend to assess the options for addressing the identified need in the next stage of the process, being the PADR.

The next section of this PSCR describes how system strength is currently being managed in Tasmania, the relationship with inertia, and further expands on the new rule requirements now in effect. The overview is intended to provide necessary context for the forward looking requirements.

Section Three provides a description of the identified need and why meeting the system strength rule requirements are important for customers.

Section Four explores the various options considered by TasNetworks to be credible solutions to address the identified need, including:

- The required technical characteristics of credible options, including non-network options.
- Whether credible options are likely to have an inter-regional impact.
- The classes of market benefits that TasNetworks considers are likely to be material.
- The timeframes for when credible options would need to be made available.

Section Five outlines the assessment approach TasNetworks will apply when quantifying the costs and benefits of the credible options in the next stages of the RIT-T, specifically as part of the PADR.

Section Six outlines the submission process and provides a description of the EOI which has been developed for proponents of non-network solutions to respond to. The intention has been to standardise the types of information submitted by proponents, which will ultimately be used as input to the PADR modelling and analysis activities.

2 Tasmanian Context

2.1 The importance of managing system strength

System strength is a broad term encapsulating a number of specific technical issues, however the core elements are:

- Ensuring that adequate short circuit current is always available to facilitate the correct operation of network protection systems, including within downstream distribution networks and protection systems located within customer premises (including *generating systems*).
- Ensuring that stable voltage control can be maintained across the network, both before and after network contingency events. This includes parts of the network that may be remote from dynamically controllable reactive power devices (e.g. generators, STATCOMs and SVCs).
- Ensuring that the voltage at the connection point of grid-following IBR is sufficiently robust to allow for their continuous, uninterrupted operation, even when subjected to network faults and other credible disturbances. This being especially critical when multiple IBR are corralled into an electrically remote REZ.

While there are a number of solutions to each of these challenges, it is important to note that historically, synchronous generators have provided most of the required capability in the Tasmanian power system. Going forward, all NEM regions will experience an increasing penetration of IBR, predominantly in the form of wind and solar generation. Tasmania will be no exception and has the added complication of significant HVDC assets which require special consideration. While IBR technology brings with it many benefits in terms of configurability and speed of response, its operation is fundamentally different to that of synchronous machines and these differences need to be properly accounted for.

As examples, power electronic based equipment typically has limited overload capacity to provide high levels of short circuit current and their control architectures are often based on 'grid following' concepts. Grid following IBR located at 'weak connection points' are susceptible to poor fault ride through performance and can also exhibit oscillatory behaviour. It is not always possible to tune the control systems to cope with such network conditions without detrimental, and potentially unacceptable, impacts on other dynamic performance criteria, e.g. rate of active power recovery following network fault events (which subsequently impacts on network frequency control).

Recognising that power systems will need to evolve, rather than being fundamentally redesigned overnight, it will be important that system strength is actively managed as the penetration of IBR increases and the availability of synchronous generation support diminishes. Undoubtedly, technological advancements will help address many of these issues in future years, however system security and reliability must be adequately managed in the meantime.

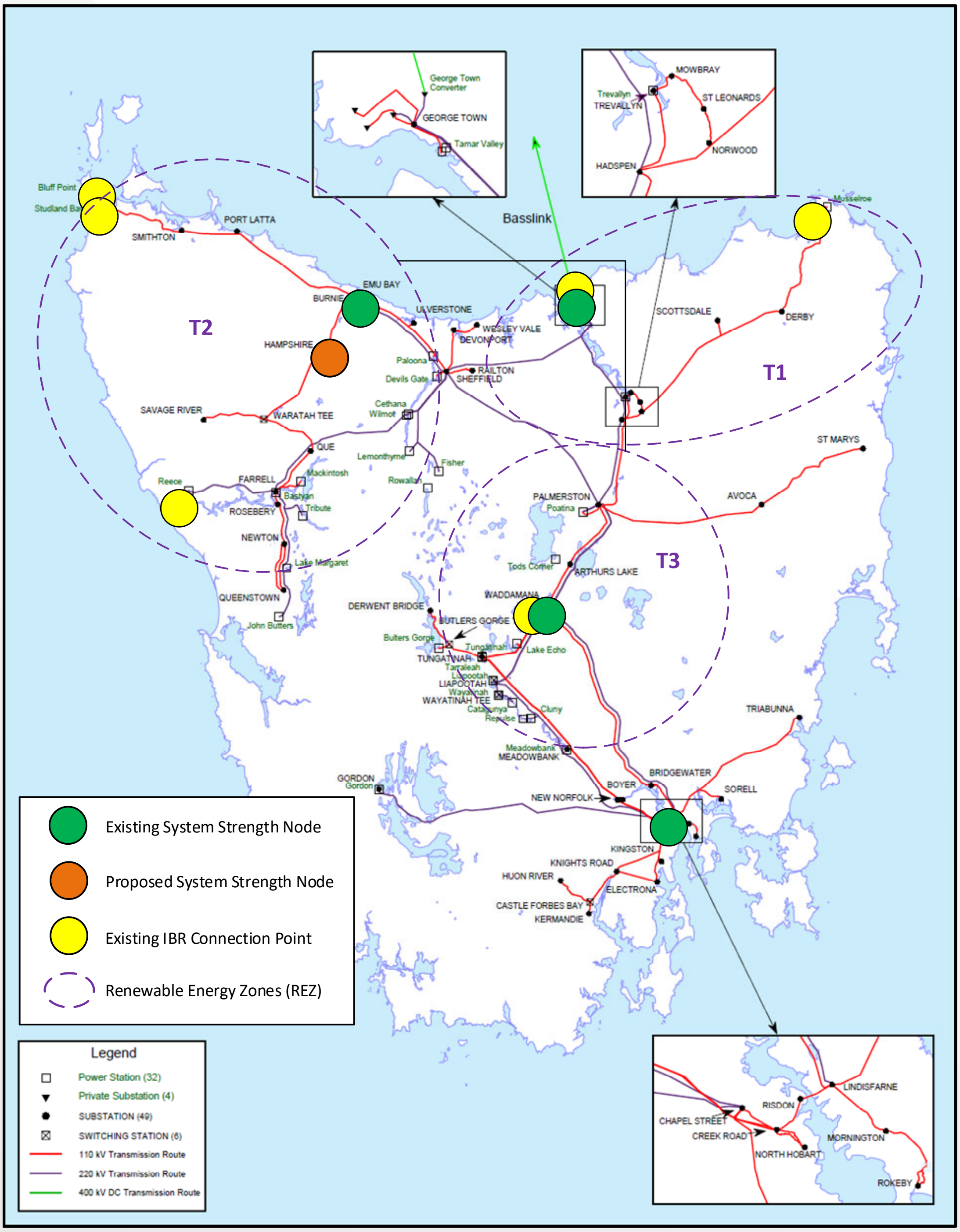
2.2 The Tasmanian network now and looking forward

A diagram of the Tasmanian power system is provided below in Figure 1 and shows the location of existing and proposed SSNs, as well as already established IBR connection points to the high voltage transmission network.

As of July 2023, the installed wind generation capacity in Tasmania is 568 MW, distributed across five wind farm sites. With the exception of Bluff Point and Studland Bay Wind Farms located in the far north west, the remaining three sites are geographically dispersed.

The other significant IBR asset which impacts on the requirements for system strength in Tasmania is the Basslink HVDC interconnector which has its connection point at George Town Substation in the north of the state.

Figure 1: Existing Tasmanian power system showing SSN and REZ locations.



Basslink is nominally rated at 500 MW and is capable of bi-directional power flow into and out of Tasmania. When able to operate at maximum power transfer, Basslink can import approximately 478 MW[8] into the Tasmanian power system from Victoria. When importing, there is a reduced need to run hydro generation, allowing water reserves to be conserved. A by-product of such dispatch outcomes is a further reduction of online synchronous generation to help support the network.

[8] This figure is after transmission losses in the HVDC interconnector itself.

It is important to note that Basslink was designed using line commuted converter (LCC) technology, with thyristors used to rectify and invert the alternating current (AC) to and from direct current (DC) for the purposes of long distance, sub-sea transmission. LCC HVDC is very sensitive to 'weak grid' operating conditions and needs a specific minimum level of system strength to operate within its required performance standards. In this sense, Basslink is a significant contributing factor when determining the overall system strength requirements for Tasmania. It can be noted that the design of the new Marinus Link HVDC interconnector is considering similar design issues as a matter of priority. It is anticipated that Marinus Link will have a much smaller impact on system strength requirements given the use of voltage source converter (VSC) rather than LCC technology, as well as use of advanced control solutions.

When Basslink import[9] overlaps with high local wind generation, there are already times when little hydro generation needs to run. The state has so far achieved an operational outcome where approximately 92% of Tasmania's electricity demand was met by a combination of wind generation and Basslink import. We are now regularly experiencing operating conditions where 75-90% of our electricity needs are being met by IBR energy sources rather than from synchronous generation. The potential to reach 100% theoretically exists, but is currently prohibited by a number of system security constraints. TasNetworks is actively working with AEMO on a number of projects examining what would be required to reach 100% IBR penetration, with system strength and inertia considerations being front and centre of those investigations.

As already outlined, AEMO's forecasts suggest that TRET will be achieved well before the 2040 target date, with approximately 2,500 MW of new wind generation installed by the end of 2033. The allocation of new IBR capacity across the three Tasmanian REZ is as follows, with existing installed capacity shown in brackets:

➢ North East (T1)	376 MW	(168 MW)
➢ North West (T2)	1,301 MW	(252 MW)
➢ Central (T3)	823 MW	(148 MW)
Total new IBR:	2,500 MW	(568 MW)

Total installed IBR generation capacity by 2033: ≥ 3,068 MW

A near five-fold increase in IBR generation capacity will not only allow Tasmania's electricity demands to be fully satisfied at times, but will also be sufficient to support significant levels of export to the mainland via Basslink and Marinus Link. The role of synchronous hydro generation in such a future will be very different, with the provision of flexible, dispatchable firming capacity, as well as a range of system security services, expected to become more critical (and valuable) than in today's market.

An important follow-on observation which differentiates Tasmania from virtually all other states is that while the role of our hydro synchronous generators will evolve, there is no expectation of mass withdrawal of capacity from the network. Being a hydro dominated power system, we are not exposed to the same issues being driven by large scale coal and gas retirements now needing to be planned for across the mainland states. The future need to procure, install and actively manage system security services like system strength and inertia will be a product of the concentrated IBR capacity proposed to be built in Tasmania as a means of contributing to broader NEM goals, including a transition away from fossil fuelled generation.

[9] Noting that the direction of Basslink power flow is a market outcome and not directly controllable by AEMO or TasNetworks. The magnitude of import or export can be limited when needed to maintain power system security.

2.3 Current regulatory arrangements and shortfall solutions

As outlined in Section 2.2, the Tasmanian power system is already experiencing periods of very high IBR penetration. In accordance with the existing system strength and inertia rules frameworks, AEMO has been identifying shortfalls for both services, with the most recent shortfall declaration issued on 15 December 2022[10] with magnitudes as shown below.

Table 3: Minimum three phase fault levels for an intact network and existing shortfalls.

System Strength Node (SSN)	Minimum Fault Level Requirement	AEMO Declared Shortfall (Dec 2022)	Corresponding Tasmanian REZ in 2022 ISP
Burnie 110 kV	850 MVA	423 MVA	North West, T2
George Town 220 kV	1,450 MVA	827 MVA	North East, T1
Waddamana 220 kV	1,400 MVA	594 MVA	Central, T3
Risdon 110 kV	1,330 MVA	511 MVA	No REZ assigned.

The corresponding inertia shortfall to maintain the *secure operating level of inertia* is 2,509 MW.s.

To date, the least cost approach to address the declared shortfalls has been to implement a non-network solution, specifically the contracting of synchronous machine capabilities from within the existing fleet of hydro units. TasNetworks has so far executed two separate EOI processes to identify the potential availability of credible non-network options and has awarded contracts on the basis of technical suitability, timing of service delivery, available capacity (allowing for required levels of redundancy) and overall service costs.

We have been formally providing contracted services to AEMO for use in an operational environment since April 2020 and have solutions in place to address declared shortfalls until 1 December 2025. We feel that our prior experiences will benefit this RIT-T and assist with our engagement with any non-network service providers who participate as part of the consultation process through the latest EOI.

[10] Following publication of the AEMO 2022 System Strength Report and corresponding 2022 Inertia Report.

3 Identified Need

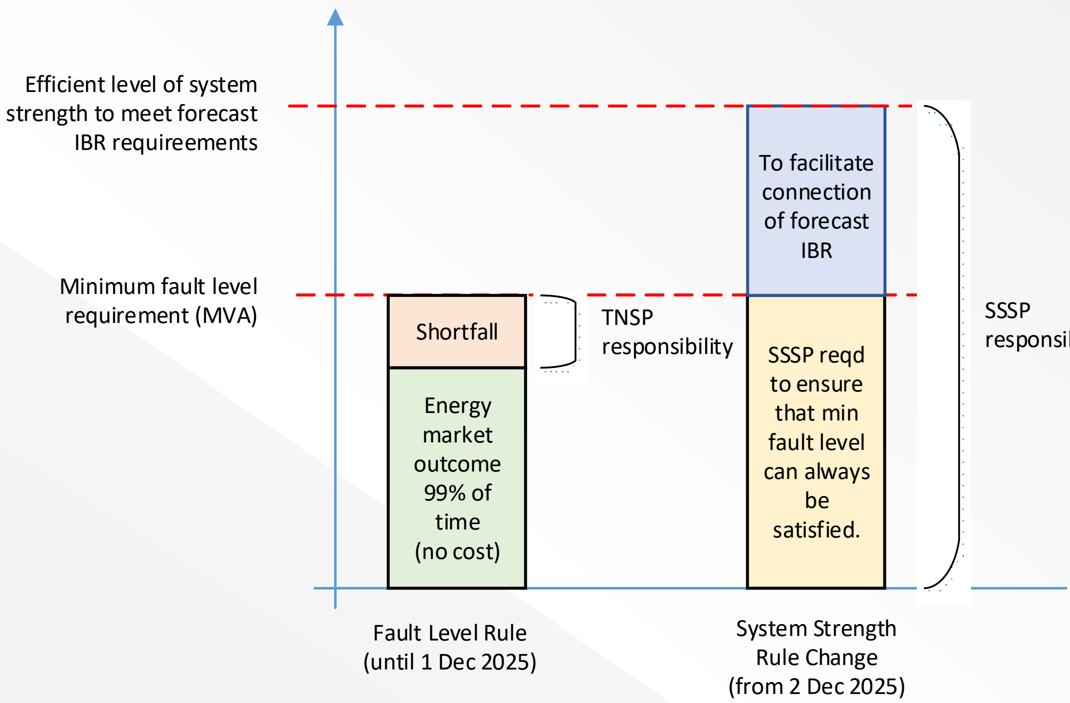
On 21 October 2021, the AEMC made a final determination for the '*Efficient Management of System Strength on the Power System*' rule change, as originally submitted by TransGrid[11]. The new rules introduced both a System Standard and what is effectively a transmission network planning standard, to manage the provision of system strength across the NEM. The rule change has placed positive obligations on each SSSP to proactively plan for and pre-emptively provide adequate system strength to enable forecast levels of IBR to connect to the power system. The existing shortfall mechanisms did not include the pre-emptive element and dealt more to the needs of the current system, albeit looking forward in time.

Importantly, the new framework requires each SSSP to ensure that both the minimum and efficient levels of system strength can be achieved in accordance with the rules without reliance on "*any system strength services that may be coincidentally provided by generators as a result of them being dispatched in the energy market in the operational timeframe*[12]".

That final determination therefore requires SSSP "*to procure the whole amount of system strength required to meet the standard*".

The practical implications of the rule change are shown diagrammatically in Figure 2. Under the new framework, we will be responsible for procuring the entire volume of system strength necessary to satisfy both the minimum fault level requirement and the *efficient level of system strength* concurrently. The current regulatory arrangements described in Section 2.3 required only the shortfall volume (as declared by AEMO) to be procured.

Figure 2: Comparison of system strength rule frameworks.



[11] Available at: [Efficient management of system strength on the power system | AEMC]

[12] Refer page 74 of AEMC Draft Determination which was reaffirmed on page 92 of the final determination.

TasNetworks now needs to consider the investments required to meet the new standards which will have effect from 2 December 2025. As the SSSP for Tasmania, we are responsible for delivering system strength on a forward-looking basis to meet the *system strength standard specification* published by AEMO as set out in NER S5.1.14.

3.1 Description of the identified need

The identified need is to provide, from 2 December 2025, sufficient system strength at each SSN to satisfy minimum fault level requirements, as well as provide an *efficient level of system strength*, so as to maintain power system security while facilitating forecast developments of IBR in Tasmania. In doing so, TasNetworks will satisfy its obligations under NER S5.1.14(b).

For the purposes of this PSCR, we have relied upon the 2022 System Strength Report published by AEMO to define the *system strength standard specification* to be achieved. Where appropriate, we have also considered longer term forecasts provided within the 2022 ISP to inform our view of how system strength requirements will continue to evolve.

Consistent with NER clause 5.10.2, TasNetworks is treating the rule based obligations to provide system strength as a 'reliability corrective action'. The required activities are not actionable ISP projects.

3.2 Specific requirements to be addressed

3.2.1 Minimum fault level requirement

The intent of the minimum fault level requirement is described in NER S5.1a.9.

In addition to the technical issues described in the rules, the minimum fault levels defined in Tasmania have also considered the system strength requirements for existing IBR connections, i.e. *network users* who have established connections pre-dating the rule requirements and who are exempt from system strength charges under the new framework. For clarity, satisfaction of the minimum fault levels as currently defined will be adequate to achieve secure operation of the intact network with the IBR connections already existing as of July 2023.

It follows that the minimum fault level requirements for each existing SSN are forecast to remain unchanged over the forward planning period. The values provided above in Table 3 of Section 2.3 therefore remain valid. The incremental increases in system strength requirements needed to support future IBR connections are captured by the *efficient level of system strength* discussed next.

While not yet declared by AEMO, TasNetworks is progressing this PSCR on the basis that a fifth SSN will be required to manage operation of the North West REZ which includes 220 kV transmission infrastructure to support Marinus Link. The north west REZ is identified as 'T2' in Figure 1, and the fifth SSN is proposed to be located at the yet-to-be-constructed Hampshire Hills 220 kV Switching Station. The Hampshire Hills SSN is anticipated to be needed from 2029 onward, corresponding with commissioning of Marinus Link Stage 1 and commencement of significant IBR capacity increases in T2. Note that an alternate location for the fifth SSN is likely to be Burnie 220 kV if Hampshire Hills is not constructed or is delayed for some reason. The need for a SSN at Burnie 110 kV would then be reassessed.

Preliminary modelling has suggested a minimum fault level requirement of up to 1,650 MVA at Hampshire Hills, however this figure is subject to further analysis and is dependent upon the exact sequence of transmission and REZ build out. For the purposes of providing meaningful signals to potential non-network service providers as part of this PSCR, we are applying 1,650 MVA as the expected upper limit at the Hampshire Hills SSN commencing in 2028. It is our intention to define the lowest technically acceptable value once network requirements can be better defined, with an objective to minimise service needs and resulting costs.

3.2.2 Efficient level of system strength

The *efficient level of system strength* required going forward will be a function of IBR capacity and its performance characteristics. The rule requirement in this regard is that the SSSP must provide sufficient system strength to ensure stable voltage waveforms both in steady state and following any *credible contingency event* or *protected event*. The underlying intent is to support the operation of future IBR connections while maintaining power system security and reliability.

As part of the 2022 System Strength Report, AEMO has provided a ten year forecast of future IBR connections in Tasmania. Table 4 summarises the projected developments against the most relevant SSN. The following should be noted:

- It is our understanding that due to NER requirements, AEMO was unable to allocate future IBR developments to the Hampshire Hills SSN which has not yet been formally declared. For the purposes of this PSCR, we have attributed IBR generation to this node as it is impractical to determine meaningful system strength requirements otherwise, i.e. connecting over 1,200 MW of generation to the existing 110 kV bus at Burnie is nonsensical.
- With reference to the 2022 ISP, no further large scale IBR is connected to the transmission network after 2033, i.e. once TRET is satisfied. Based on the 2022 AEMO forecasts, the requirements for SSSP supplied system strength reaches a maximum in 2033 and becomes an enduring requirement from that point onward.
- TasNetworks next revenue period is from 1 July 2024 to 30 June 2029. The forecast IBR developments in the upcoming period are modest (620 MW), whereas the following revenue period (2029-2034) will see the bulk of the TRET capacity installed.

Table 4: Projected IBR developments for Tasmania (New MW capacity, cumulative totals by SSN).

Reference SSN	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Burnie 110 kV	0	0	0	0	0	83	83	83	83	83
George Town 220 kV	0	258	258	258	258	258	376	376	376	376
Waddamana 220 kV	0	0	275	275	275	279	768	768	823	823
Risdon 110 kV	0	0	0	0	0	0	0	0	0	0
Hampshire Hills 220 kV	0	0	0	0	0	0	268	268	1218	1218
Aggregate (MW)	0	258	533	533	533	620	1495	1495	2500	2500

An inherent challenge for all SSSP’s is to convert the forecast IBR developments (described in terms of installed capacity, MW) into an equivalent *efficient level of system strength* (described in terms of three phase fault level, MVA). For forward planning studies, the technical characteristics of the plant to be connected and even the network connection arrangements, may not be known.

Given the lack of detailed design information for future IBR connection points, we have estimated the *efficient level of system strength* for future years using the Available Fault Level (**AFL**) methodology as described in Section 3.4.3 of the AEMO *System Strength Impact Assessment Guidelines* [2].

TasNetworks recognises that the AFL methodology has limitations. Its origins are known to us and its original purpose understood.

On that basis, we acknowledge that:

- The specific values calculated to be the *efficient level of system strength* may have little practical relevance to the eventual operational needs of the power system. We are of the view that the AFL methodology as implemented will deliver conservative estimates.
- The relative change from existing and proven network operating limits is useful for signalling the potential quantum of services needed going forward, noting the simplifying assumptions that are necessary to represent future IBR connections in a generic manner.
- The AFL method is useful for understanding the inter-relationship between IBR connection points located across a network and can provide insight as to which connection points may be susceptible to issues as more IBR connects. This acts to provide locational signals that can be considered as part of network planning exercises.
- An inherent assumption is that the efficient level of system strength calculated for the intact network is sufficient to ensure satisfactory operation following a credible contingency event, i.e. that the impact of any single contingency event is not so large as to invalidate the assumed system strength requirements for each IBR connection. There are no protected events defined for the Tasmanian region.

With those considerations in mind, the *efficient levels of system strength* determined for the period 2024 to 2033 are provided below in Table 5 and diagrammatically in Figure 3. The tabulated values are the overall three phase fault level needed to satisfy both the minimum and efficient levels of system strength as previously described in Figure 2.

Table 5: Calculated efficient level of system strength (in MVA) by SSN and financial year.

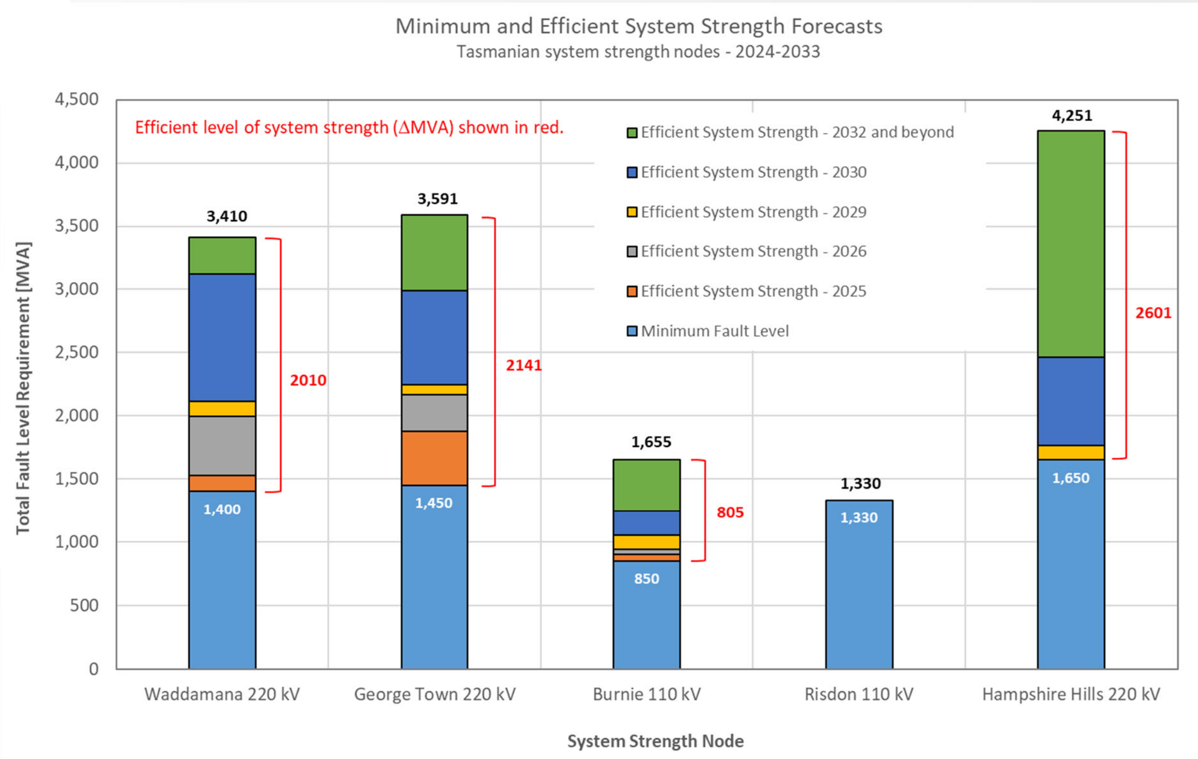
System Strength Node	2024[13]	2025	2026	2027	2028
Waddamana 220 kV	1,400	1,525	1,994	1,994	1,994
George Town 220 kV	1,450	1,876	2,170	2,170	2,170
Burnie 110 kV	850	902	944	944	944
Risdon 110 kV	1,330	1,330	1,330	1,330	1,330
Hampshire Hills 220 kV	0	0	0	0	1,650
Total New IBR Assumed (MW)	0	288	579	579	579
Total IBR Forecast by AEMO (MW)	0	258	533	533	533
System Strength Node	**2029**	**2030**	**2031**	**2032**	**2033**
Waddamana 220 kV	2,112	3,120	3,120	3,410	3,410
George Town 220 kV	2,248	2,989	2,989	3,591	3,591
Burnie 110 kV	1,052	1,244	1,244	1,655	1,655
Risdon 110 kV	1,330	1,330	1,330	1,330	1,330
Hampshire Hills 220 kV	1,767	2,465	2,465	4,251	4,251
Total New IBR Assumed (MW)	662	1,567	1,567	2,602	2,602
Total IBR Forecast by AEMO (MW)	620	1,495	1,495	2,500	2,500

[13] Minimum three phase fault levels provided for reference in year 2024.

In a practical sense, the development of IBR is unlikely to follow the exact trajectory as forecast by AEMO. We have thus opted to undertake the system strength calculations across future years using our industry insight where appropriate to do so. Where known IBR based projects have a proposed capacity and connection date that generally aligns with the forecasts as presented in the AEMO System Strength Report, those project(s) have been applied for modelling purposes. This is the origin of the small IBR capacity differences highlighted in Table 5 (assumed versus AEMO).

Furthermore, where future network topology changes are already known and have been communicated to AEMO and the broader industry[14], we have included those network developments in our modelling activities at the year when in-service operation can be reasonably expected. Reinforcement of the transmission network can have a notable impact on system strength requirements depending on the location of IBR connection points relative to support mechanisms including synchronous machines. This is consistent with the requirements of Step 1 in the AEMO AFL methodology.

Figure 3: Overall accumulation of system strength requirements by SSN.



3.2.3 Summary of forward looking system strength requirements

Based on our analysis to date, we expect that there will be a requirement for increased system strength services at the George Town, Waddamana and Burnie SSN within the next revenue reset period to support forecast IBR connections. The most significant increase is expected to be at George Town 220 kV, with a potential increase of up to ≈ 800 MVA from the existing minimum fault level requirement of 1,450 MVA. A similar increase at Waddamana is also suggested.

[14] Please reference TasNetworks Annual Planning Report 2022 for details on transmission network developments expected as part of Marinus Link.

Significant increases in system strength requirements are forecast from 2030 to 2032 corresponding to the remaining IBR build-out to satisfy TRET.

The quantum of potential increases at each SSN above minimum fault level requirements are:

- Waddamana 220 kV +243%
- George Town 220 kV +247%
- Burnie 110 kV +194%
- Hampshire Hills +257%

While the exact requirements will need to be established using more refined modelling and analysis techniques, it is evident that additional system strength support (above existing minimum fault levels) will be necessary in future years at all Tasmanian SSNs except for Risdon 110 kV.

3.3 Timing and duration of identified need

In accordance with NER S5.1.4(a), each SSSP "*must use reasonable endeavours to plan, design, maintain and operate its transmission network, or make system strength services available to AEMO*", to satisfy the expected system requirements at a point in time three years in advance of the latest AEMO forecasts, i.e. TasNetworks must currently plan to meet the forecast requirements for 2 December 2025, with the obligation extending to 2 December 2026 when the forecasts are updated again in December 2023.

Our intended approach to manage the evolving requirements for additional system strength is as follows:

- Acknowledge that the minimum three phase fault level requirements as currently stipulated are highly likely to be enduring. The risk of procuring services over extended timeframes carries a very low risk to consumers who are exposed to system strength implementation costs not able to be recovered through charges levied against IBR connections who choose not to self-remediate.
- Recognise that IBR developments forecast within the next five to six years necessitate more immediate planning given the potential lead times to implement physical solutions.
- Manage the risk of unnecessary over-procurement of system strength in future years (beyond 2029) by allowing technology to improve, new technologies to develop, and the industries general understanding of system strength related issues to mature, before committing to solutions.

As a result, the scope of this PSCR is focused on identifying credible options capable of satisfying the system strength requirements up to 30 June 2029.

We are of the view that this provides the right balance between encouraging the development of scale efficient solutions (which could include period contracts), and exposing network users to unnecessary, lasting financial costs. We intend to undertake a separate RIT-T to address the requirements forecast over future years once there is increased certainty and confidence surrounding the likely need.

We believe that this approach remains consistent with the requirements of the NER, while managing our obligations to customers as defined by the NEO.

3.4 Exclusions

Analysis of the identified need within this PSCR has been solely based on the 2022 System Strength Report published by AEMO.

On that basis, the following issues have been specifically excluded from consideration:

- Any system strength to support the operation of Marinus Link with the exception of minimum fault level requirements which have been stipulated as 1,000 MVA at the proposed Heybridge Converter Station[15].
- Any system strength requirements associated with future customer loads that utilise controllable IBR technologies, e.g. electrolysis processes. Large IBR loads have not been forecast by AEMO and would need to be considered on a case-by-case basis.
- Any system strength requirements to support future Battery Energy Storage Systems (BESS) which are operated as grid-following (rather than grid-forming) devices.
- Any system strength requirements associated with future dynamic reactive support devices installed as network assets. The intention would be to design such equipment to operate at the minimum three phase fault level and not materially add to the overall system strength requirement.
- IBR developments that are in excess of the forecasts published by AEMO, either in aggregate for any year, or any network location.

We reserve the right to amend any aspect of the identified need should the input assumptions to this PSCR change in any way.

[15] As confirmed by Marinus Link via email on 5/7/2023.

4 Identified Credible Options

4.1 Credible options to address the need

Under clause 5.15.2(a) of the NER a 'credible option' is an option that:

- Addresses the identified need.
- Is commercially and technically feasible.
- Can be implemented in sufficient time to meet the identified need.

TasNetworks must consider all options that it could reasonably classify as credible options for meeting the identified need, without bias to energy source, technology, ownership and whether it is a network or non-network option.

TasNetworks has identified a range of potential options to address the identified need over time.

4.1.1 Non-network options

As outlined in Section 2.3, we have already implemented non-network solutions to address system strength and inertia shortfalls declared by AEMO. We consider it likely that non-network solutions will continue to represent a technically efficient, cost effective solution to provide both system security services going forward. In respect to the provision of efficient levels of system strength, the scope of this solution may ultimately be limited by appropriately located capacity necessary to meet the evolving needs of the network, depending on what new assets are constructed and where.

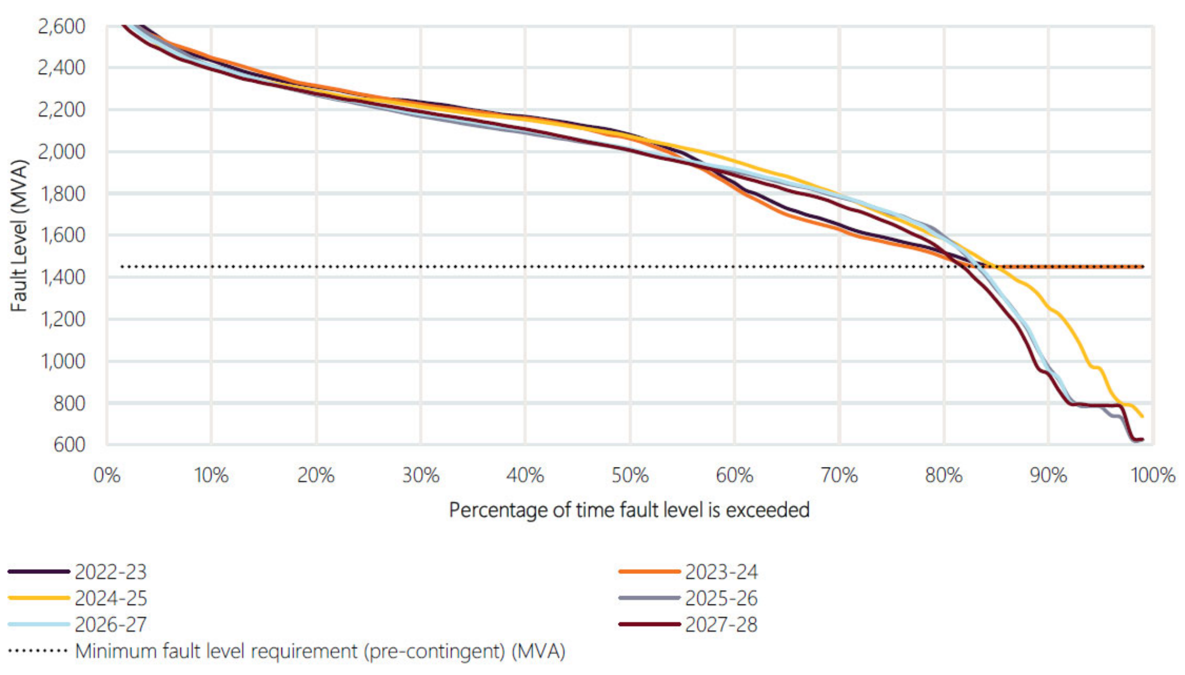
Subject to submissions received from potential service providers in response to this PSCR, the types of non-network solutions to be analysed during preparation of the PADR could include the following.

4.1.1.1 Synchronous generators continuing to participate in the energy market.

Unlike other regions in Australia, Tasmania is not expected to see a significant permanent withdrawal of synchronous generators from the energy market. While the role of hydro based synchronous generation will change as the capacity of IBR increases, there will continue to be substantial periods of normal market dispatch. This will be in response to variable IBR output, as well as hydrological requirements including the management of spill, as well as any downstream water use obligations that need to be satisfied, e.g. environmental flow requirements, irrigation, drinking water supply etc.

As an indication of the expected contributions coming from synchronous generation participating in the energy market, consider the histogram of three phase fault level forecast by AEMO [1] at the George Town SSN shown below in Figure 4.

Figure 4: George Town SSN duration curve with minimum fault level requirement shown.



The forecasts suggest that the 2025 fault level requirement described in Table 5 above could be satisfied for up 55% of the time, with the 2029 requirement satisfied for approximately 20% of the time without the need for deliberate, supplementary system strength support.

On the basis that each SSSP must "*procure the whole amount of system strength required to meet the standard*" as discussed in Section 3, there is an inherent obligation on us to consider contracting with operators of synchronous generation who will continue to participate in the energy market and inherently provide system strength and inertia while doing so.

As the provision of both system security services is inherent, the marginal cost of supply is expected to be negligible and should represent one of the lowest cost options to help meet the new standards. It should be noted that this form of non-network solution does not require the generator to act or operate in a different manner, with the services simply delivered as a bi-product of 'normal' energy market dispatch outcomes.

4.1.1.2 Synchronous condensers owned and operated by third parties.

We currently utilise third party synchronous condensers made available under contract to help manage system strength and inertia shortfall requirements. It is reasonable to expect that this particular non-network solution will continue to be available subject to PSCR submissions received. A limitation of this solution is the geographical distribution of existing synchronous condenser assets which may not be capable of fulfilling all future network requirements without some form of additional support. The provision of new synchronous condenser capabilities by third parties in alternate locations could form part of the longer term solution subject to the commercial terms offered.

4.1.1.3 Synchronous generators willing and able to operate at low power output.

As a distinct variant to generators operating normally in the energy market, a credible non-network solution is to contract with synchronous generators to come online specifically when required for the provision of additional system strength (and/or inertia). Such generators are subject to the spot market restrictions as described in NER 5.20C.4 and 5.20B.6 as they potentially send active power into the network out of merit order. It follows that the ability to operate for extended periods of time at very low power outputs is preferable, as this has less distortionary impact on the market without impeding the supply of system strength or inertia.

4.1.1.4 Contributions from BESS.

While there is still work to be done to describe the system strength benefits that can be delivered from large scale BESS, we recognise the potential contributions and encourage submissions from future operators of this technology[16]. It is our view that BESS fitted with grid-forming controls, which present to the network as a synchronised voltage source behind a reactance, are best placed to provide system strength benefits given their inherent response to changes in network voltage magnitude and angle. This is considered a mandatory requirement for any BESS wanting to offer *inertia network services* under contract.

4.1.2 Network options - Synchronous condensers installed as network assets

The potential advantage of purpose built synchronous condensers is the ability to locate them at points in the network where the need is highest and/or delivers the best distribution of system strength benefits. Such network assets could also be used to provide additional network services including inertia and reactive power compensation (both dynamic and steady state requirements).

4.1.3 Options considered but dismissed for forward planning purposes

4.1.3.1 Tuning of control systems associated with new IBR connections

Targeted control system tuning likely represents the lowest overall cost solution for managing future system strength requirements. The objective of this measure is to reduce the system strength impact of new connections as low as is reasonably possible without negatively impacting other performance measures.

While this solution is only possible once the specific technical details of a new connection application can be assessed, it prevents unnecessary system strength requirements from being carried forward as an enduring obligation on the SSSP. An alternate view is that it creates the possibility to connect more IBR within the capability of the system that has been provided for by proactive planning activities implemented to that point.

If the eventual system strength requirements of in-service IBRs are less than assumed during network planning studies, then the system is inherently better positioned to cope with future developments.

The merits of this approach are expected to become evident as the installation of IBR capacity increases, but clearly cannot assist with the provision of forward looking system strength given the lack of detailed design information available at the earliest stages of network planning.

4.1.3.2 Flexible AC Transmission Devices (FACTS)

Depending on the specific issue to be managed, FACTS devices such as STATCOMs and SVCs can extend the IBR hosting capacity of a network. They are not a material source of fault current, but their

[16] Noting that as of July 2023, there are no transmission connected BESS operating in Tasmania.

rapid reactive power control capabilities can help mitigate a variety of voltage control issues which are exacerbated at low system fault levels. This includes the FRT recovery of IBR technologies.

As with inverter control system tuning described in Section 4.1.3.1, it is difficult to account for the benefits of such solutions without undertaking detailed network performance investigations based on specific network configurations and the characteristics of installed plant. The proactive installation of FACTs to deliver system strength benefits would therefore be difficult to justify and carry some risk. Our proposed approach is therefore similar to that discussed in Section 4.1.3.1. Where the installation of such equipment is determined to be necessary for other reasons, any incremental benefits to system strength will be carried forward to help reduce the enduring requirements.

4.1.3.3 Transmission line construction or augmentation

While a recognised technical solution, we do not consider that the construction of transmission line assets purely for the purposes of providing additional system strength is credible in the Tasmanian context. Delivery time, stakeholder impacts (i.e. effected land owners) and costs will almost certainly limit application of this solution in a practical sense for all but the most significant needs.

Where transmission developments are assessed through a RIT-T to address different identified needs, it is proposed that the incremental benefits to system strength would be identified and included in the benefits analysis at that time.

4.1.4 Preferred option is likely to be a blended solution

Without prejudicing the outcome of the consultation process, we reasonably expect that the lowest cost, most technically efficient solution to address the *identified need* will be a combination of non-network and network options, with the latter phased in over time depending on how issues related to system strength evolve. In our view:

- Non-network solutions represent the only practical solution to address the bulk requirements of the Tasmanian network between 2 December 2025 and 2028. This is largely associated with the time frames to complete the RIT-T process and then procure/install/commission network assets, noting the significant supply chain issues effecting the industry at present.
- The justification for network solutions will become clearer once responses to this PSCR can be evaluated in terms of the location of willing participants, available capacity, future cost profiles for the various non-network services, timing of any expected future developments etc.

We are committed to keeping costs down for all *network users* and recognise that system strength represents a not-insignificant financial burden for generation developers and potentially, load customers to fund. Our role as the SSSP is to identify solutions which are not only rules compliant, but also navigate the uncertainties of the future power system without undue conservatism.

Given that it is unlikely that any single network or non-network option will address the entirety of the identified need, it is not practical to comment on costs of the various options prior to receiving information from potential system strength providers through the EOI process.

4.2 Materiality of inter-network impacts

A "*material inter-network impact*" is defined by the NER in the following terms.

> *"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 AEMO screening test[17] can be applied which describes the following considerations:

- 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.
- The investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

As Tasmania is coupled to Victoria via a HVDC interconnection, there will be no material inter-network impacts regardless of which credible options are eventually adopted. In this regard, the benefits of any solutions implemented for the provision of system strength are limited to our region, with the counterfactual being that Tasmania cannot rely on support from the mainland and must be self-sufficient in terms of providing the necessary services.

4.3 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[18]. Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why[19]:

- 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.

We have undertaken a preliminary review of the potential market benefits delivered by each of the credible options and, at this stage, do not consider that any credible option will have a material impact on the wholesale electricity market beyond that already assessed by AEMO through the ISP and System Strength Report. Therefore, we do not consider market modelling is a justified expense (either in terms of time or financial impost) when considered in the Tasmanian context.

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[17] Criterial for Assessing Material Inter-Network of Transmission Augmentations : Final Determination (aemo.com.au)

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

[19] Refer NER 5.15A.2(b)(6).

While we reserve the right to alter this view once preparation of the PADR commences, our position at the moment on each of the classes of market benefits is summarised below. The only benefits we consider could be material at this stage are; (i) Differences in timing of transmission expenditure, and (ii) Option value.

4.3.1 Market benefits considered material

4.3.1.1 Differences in timing of transmission expenditure

We have identified a potential overlap between proposed transmission expenditure included as a contingent project in our 2024 Combined Regulatory Proposal[20] and a number of credible options to supply future system strength, specifically in the George Town area.

The contingent project (defined in two stages) is for the installation of dynamic reactive support at George Town 220 kV Substation, with the identified trigger event being an increase in customer load sufficient to require mitigation of voltage stability issues. A number of credible options could provide both system strength contributions as well as contribute to the required increase in dynamic reactive capability. This includes both network and non-network solutions. Should the AER accept our contingent project, we will consider whether both these system requirements can be met with a common solution to deliver the least cost outcome for consumers in the longer term.

We also consider that there are a number of credible options capable of delivering both system strength and inertia services simultaneously. As with our current system strength obligation, TasNetworks is required to make *inertia network services* available that are sufficient to meet the forecast shortfalls as declared by AEMO. Similar to reactive support, we consider that inertia and system strength services, whether they be procured in the form of non-network solutions or provided by network assets, should be considered together in parallel. There is a significant prospect that 'common solutions' will deliver the overall least cost outcome for consumers. Details of our inertia obligation are discussed further in Section 5.5.

4.3.1.2 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.

We intend to consider option value benefits in a quantitative manner as part of preparing the PADR but without undertaking market modelling. As outlined above in Section 3.3, we intend to manage uncertainties related to the forward looking requirements for system strength by limiting the analysis period of this RIT-T to 30 June 2029. Consideration will however need to be given to the cost benefits of pursuing longer term solutions, especially for system strength requirements which can be reasonably expected to endure, e.g. potential cost savings delivered through the negotiation of longer term supply contracts from non-network service providers beyond the end of the 2024-2029 regulatory control period.

We are also cognisant of the value proposition outlined in Section 4.3.1.1 whereby a single transmission investment may help address multiple system requirements. Depending on the eventual treatment of the proposed contingent project included in our 2024-2029 Combined Revenue Proposal, this may be another candidate for quantitative assessment of likely options value.

[20] www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2024–29

4.3.2 Market benefits not considered material

4.3.2.1 Changes in fuel consumption arising from changes in generation dispatch patterns

Two aspects of this issue have been considered:

- The change in generation dispatch patterns due to the connection of new IBR that is facilitated by the provision of system strength services in accordance with the NER planning criteria.
- Changes in fuel consumption arising from synchronous generators being 'constrained-on' to provide system strength services under contract.

While there is no doubt that the release of IBR capacity through the provision of system strength services will alter generation dispatch profiles compared to the current status quo, we believe that the market benefits associated with this outcome have already been addressed through the ISP and resulting publication of the System Strength Report. The purpose of the reliability corrective action proposed by this RIT-T is to deliver the efficient least cost outcome that has already been defined by AEMO's modelling and forecasting. We do not believe that there is justification or any value for consumers in re-evaluating such outcomes.

In regards to fuel consumption changes due to the deliberate operation of generators out of merit order, we are of the view that any impact on electricity market dispatch resulting from the operation of generating units at minimum power outputs can be considered small enough to be reasonably discarded from the analysis on the basis that:

- If required, we will preferentially select generating units with a low minimum operating level as a way to minimise market distortion which may occur when requested to provide services.

  Given the Tasmanian context, our expectation is that only hydro generating units will be offered to provide system strength support in this manner. The minimum continuous output of hydro units typically varies from zero to approximately 15% of rated capacity depending on the design and individual characteristics of the machine (with some exceptions).
- Taking into account fuel input costs, the same approach is also likely to minimise the cost of procuring services from generating units operated in this way (noting any offset in gains due to reduced operational efficiency at such operating levels).

Furthermore, we consider changes in fuel consumption to be a cost that is to be defined by each generator as part of an offer to provide services, rather than a class of market benefit. Whereas other types of RIT-T assessments need to consider the upside of being able to access 'cheaper generation' and the resulting benefits which flow through to consumers, the potential change in fuel costs due to operation at inefficient power levels or at non-preferred times[21] is a matter for each generator to define and value, and is not a market benefit to be identified by the RIT-T proponent.

4.3.2.2 Changes in voluntary load curtailment

We do not consider this class of market benefit to be relevant in the context of choosing one credible option over another. As described in Section 5, the 'do nothing' option typically assessed during RIT-T scenario analysis is not considered applicable for this reliability corrective action given that it is necessary for us to satisfy a rules requirement.

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[21] Noting that both issues are pertinent in a hydro dominated system where the value of water is time variable and the efficient operating point of many units is well above minimum output.

On that basis, it is not considered worthwhile assessing the scenario of voluntary load curtailment as an outcome of generation supply shortfalls resulting from the inability of IBR to connect in a particular timeframe as forecast. The issue is even less relevant when considered in the Tasmanian context where there is no expected large scale withdrawal of synchronous generation from the system.

4.3.2.3 Changes in involuntary load shedding

The same assessment as outlined above for voluntary load curtailment applies to involuntary load shedding. We do not believe it is a relevant consideration for selecting a credible option.

4.3.2.4 Changes in costs for parties other than TasNetworks (timing of new plant etc)

Having considered the potential impact on other network users, we do not believe that there will be any market benefits resulting from the selection of one credible option over another.

Recognising that the purpose of the rule change is to enable new IBR connections to voluntarily purchase centrally provided system strength services, the cost benefits associated with each proponent not having to provide bespoke solutions for each individual connection have been excluded from our deliberations. In any case, consideration of such a criteria does not allow for an improved ranking of credible options, of which one or more need to be implemented in a proactive manner by December 2025 to satisfy NER requirements, even if no new IBR connects to the system.

4.3.2.5 Changes in network losses

Differences in network losses are most likely to be driven by significant changes in active power flow through the network, and to a lesser extent, changes in network voltage profile. Excluding the changes in network power flows that result from the connection of new IBR energy sources (given that the ISP has addressed this benefit as discussed above in Section 4.3.2.1), the credible options most likely to alter transmission losses are:

- Power flow changes due to the operation of new BESS.
- Synchronous generators willing and able to operate at low power output.

At this point in time, we do not intend to pursue the installation of a BESS as a network asset. Should such technology be installed by a third party at a suitable location and having the appropriate technical characteristics, we would consider any resulting offer to provide network services. As the installation of such equipment would therefore occur on a private commercial basis, there would be no need to assess changes in network losses for the provision of system strength as a contracted service.

Consistent with our approach in Section 4.3.2.1 for assessing changes in fuel costs from dispatching generators out of merit order, we consider that changes in network losses resulting from the operation of generating units at minimum power outputs can be considered small enough to be reasonably discarded from the analysis.

Therefore, we do not intend to assess changes in network losses as a class of market benefit that could materially impact the choice of credible option.

4.3.2.6 Changes in ancillary service costs

While a number of the identified credible solutions can provide ancillary services while supporting system strength requirements, it can be reasonably anticipated that the cost (price offering) of those services will be largely unaffected, i.e. they would continue to be offered into the respective markets (e.g. frequency control ancillary services) or other procurement mechanisms (e.g. network support and control ancillary services) as they normally would, irrespective of their simultaneous contribution to system strength.

4.3.2.7 Competition benefits

Excluding the changes in generation dispatch outcomes that will result from the connection of new IBR energy sources (given that the ISP has addressed this benefit as discussed above in Section 4.3.2.1), there are no foreseeable competition benefits delivered from the selection of one credible option over another.

4.3.2.8 Changes in the level of greenhouse gas emissions

Following inclusion of an emissions reduction objective in the NEO[22], we expect changes in greenhouse gas emissions to be added as a class of market benefit to be examined as part of the RIT-T process. As Tasmania is a hydro dominated power system, we do not expect that quantifying changes in greenhouse gas emissions will materially impact the ranking of the credible options that have been identified as part of this PSCR.

4.3.3 Summary

Having considered the various classes of market benefits and how they might impact the selection or prioritisation of identified credible solutions, we are of the view that:

- A process to identify the least cost solution can be undertaken using conventional cost benefit analysis techniques without requiring simulation of future wholesale market operating conditions, i.e. it is considered unlikely that any of the credible options will have a material impact on the future outcomes of the energy or ancillary service markets, noting that the ISP has already established the market benefits of 'releasing' IBR capacity through the provision of system strength services.
- We have identified potential investment overlap which will require appropriate consideration during preparation of the PADR to ensure that any opportunity to minimise additional future investment can be captured.

[22] Royal Assent of the Final Bill to amend the NEO is expected in September 2023 with amendments to the NER taking effect from January 2024. Under transitional arrangements, the amended NEO is expected to apply to RIT-T assessments that have not published a PADR two months after Royal Assent of the Bill.

4.4 Information for Non-Network Service Providers

As described in Section 4.1.4, we reasonably expect that non-network options will be a significant component of the preferred solution until at least 2028. Beyond this, there is increased scope to consider the role of future network assets to complement what can be made available on an ongoing basis from non-network service providers.

Recognising the importance of non-network solutions going forward, and taking into account our experiences to date with managing declared shortfalls for both system strength and inertia, we have published an EOI document in parallel with this PSCR. The EOI provides a detailed breakdown of technical requirements as well as descriptions of the commercial and legal frameworks being applied during the EOI process.

The published EOI has been specifically written to help address the requirements of NER Clause 5.16.4(b)(3) (Project specification consultation report), with the following information made available in regards to the requirements of non-network options:

- Location of services.
- Minimum technical requirements including participation in future scheduling and dispatch arrangements.
- Excluded services.
- Potential payment structures.
- Contracting periods.

Further information on the submissions process can be found in Section 6.

5 Overview of Assessment Approach

5.1 Base case and objective for PADR analysis

As defined in the AER's RIT-T Guidelines[23], "*the base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its business as usual activities*". Given that we are obligated to meet the rule requirements as the responsible SSSP for Tasmania, the base case itself is not a credible option. The guidelines acknowledge this situation and note that:

- "…the base case may reflect a state of the world in which those service standards are violated"; and,
- "…this does not alter the need to use a state of the world in which no credible options are incorporated to provide a consistent point of comparison across all credible options for meeting those mandatory requirements."

In our view, the relevant considerations for the development of a 'base case' for use during this RIT-T process are as follows:

- Accounting for the system strength that will continue to be provided by synchronous generators participating 'normally' as part of the wholesale energy market noting that, with all things being equal, the contracting of network services from such sources should be the least cost option.
- Sensitivity analysis will be required given that in a hydro dominated power system, there is significant potential for variations in dispatch outcomes depending on time of year and prevailing hydrological conditions, i.e. unlike in a system dominated by thermal generation where certain power stations may operate as base load energy sources, and thus have a predictable minimum number of units online at all times.

We propose to utilise the wholesale market modelling undertaken by AEMO and published as part of the 2022 System Strength Report to define the lowest three phase fault levels that can be reasonably expected without application of any credible options.

With reference to

Figure **4** as an example, we will assume the 100% probability outcome for these purposes, which will be lower than the minimum fault level requirement for all Tasmanian SSNs. It can be noted that at present, AEMO only publish five year forecasts for three phase fault levels at each SSN. Published system inertia forecasts are also limited to a 5-year horizon.

On the assumption that synchronous generators operating in the energy market are the lowest cost option and are willing/able to participate in operational systems to coordinate scheduling, dispatch and compensation payments, the base case(s) developed will provide a consistent platform from which to determine the need for higher cost options. Subsequent analysis will need to take into account issues including available capacity, redundancy provisions and locational factors.

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[23] Available at: www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf

To determine the appropriate combination of credible options, we will use power system modelling techniques including load flow and time domain simulations. Our intended approach should also enable the identified need to be further refined, especially in regards to the *efficient level of system strength* required to support future IBR. As discussed in previous sections, the AFL methodology used for preparation of this PSCR is useful in several respects, but has recognised limitations.

The overall objective of the cost benefit analysis undertaken during the PADR will be to determine which combination of credible options will enable us to satisfy our rule obligations at the lowest overall cost to consumers. Responses to this PSCR and associated EOI will be critical inputs to that analysis.

5.2 Analysis period and discount rate

TasNetworks is opting to undertake this RIT-T with a view to meeting its SSSP obligations between 2 December 2025 and 30 June 2029, aligning with our regulatory control period. As described in Section 3.3, we acknowledge that certain system strength requirements will endure beyond that date. A separate RIT-T is envisaged to address the ongoing needs of the system beyond 2029, as well as any new requirements that can be appropriately validated in the meantime.

Where long-lasting assets are to be considered in the cost benefit analysis, noting the practical limitations of delivery time for some credible options, the residual value will be calculated if needed to enable a like for like comparison of costs and benefits.

For the cost benefit analysis to be undertaken during the PADR, a real, pre-tax discount rate of 7% is proposed to be adopted consistent with the central estimate defined in the 2023 AEMO Input Assumptions and Scenarios Report[24]. The RIT-T requires that sensitivity testing be conducted on the discount rate. We propose to adopt the assumptions in the scenarios report and test the sensitivity of results to a lower bound discount rate of 3% and an upper bound discount rate of 10.5%. We will continue to assess out financial operating environment and intend to review the appropriateness of these assumptions once the PADR is ready to be commenced.

5.3 Efficient procurement for the future

5.3.1 Options value assessments

One example has been identified in this PSCR where there may be an opportunity to efficiently procure *system strength services* as part of addressing a different identified need under a separate RIT-T. While some uncertainties exist in regards to the exact quantum of future system strength needs, to not leverage an opportunity to help address a potential future need would also be inappropriate, irrespective of the analysis period being given priority.

Therefore, subject to further guidance becoming available in September 2023 on the likely outcomes of TasNetworks Combined Regulatory Proposal, we may undertake an options value assessment as part of the PADR with the objective of identifying an overall 'least regrets' network investment proposal taking into account parallel identified needs.

We are likely to seek AER advice on the best approach to manage this situation.

[24] Available at: www.aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

5.3.2 Structuring of commercial arrangements

In a similar vein, the PADR will also need to explore the benefits of different commercial frameworks, including the cost benefit of procuring services over longer time periods, i.e. beyond the end of the defined analysis period, where there is a low risk to consumers in doing so. Ongoing satisfaction of the minimum three phase fault level has already been sighted as a relevant example in this regard. It is credible that increased income security may incentivise proponents to offer network services at lower rates if longer contracting periods can be agreed to.

The other significant consideration to be fully explored in the PADR is the definition and application of separate 'availability' and 'enablement' charges (costs) as would likely be applied to non-network options made available under contract. The particular relevance of this issue in Tasmania is that reasonable levels of system strength that will continue to be provided via the energy market across not-insignificant periods of time (albeit needing to be contracted in its own right). As some non-network options may only be required for distinct periods of time, rather than on a continuous basis, determining fair and reasonable compensation arrangements for being 'available' versus actual delivery of a service via 'enablement', will need to be considered.

5.4 Application of reasonable endeavours criteria

NER S5.1.14(b) describes the planning obligations for SSSPs in regards to the forward looking provision of system strength. The relevant clauses have been provided in Appendix A.1 for reference. The overarching requirement is that:

> "A *Transmission Network Service Provider* who is a *System Strength Service Provider* must use reasonable endeavours to plan, design, maintain and operate its *transmission network*, or make *system strength services* available to *AEMO*, to meet the following requirements at *system strength nodes* on its *transmission network* in each relevant year:…"

At the current time, our interpretation of the requirements, including the 'reasonable endeavours' criteria, is as follows:

- The obligation is to provide sufficient system strength to support operation of the intact transmission network such that system security can be adequately maintained and that forecast IBR connections can be accommodated.
- The system strength provided must also be adequate to manage the occurrence of any credible contingency event or protected event.
- It is acceptable to apply market constraints to manage prior outage or post-contingency network operating conditions to maintain power system security.
- Unlike the previous shortfall framework which only considered 99% of forecast operating conditions, the system strength planning requirements apply to all times of the year.

As described for the base case development, we intend to take into account the 100% probability scenario when considering forecast contributions from synchronous generators continuing to operate in the energy market. This will help inform what additional contributions need to come from higher cost solutions predicated on the minimum contribution from the energy market.

However, there is an additional element that needs to be considered and this relates to service redundancy. It is expected to be particularly relevant when the contribution from non-network solutions is significant. Such assets will continue to be maintained and operated by third party providers and therefore beyond the immediate control of the SSSP. Even for network assets, the risk of unplanned outages, and the need for scheduled maintenance, still needs to be considered.

In our view, it is not economically feasible to plan for 100% redundancy. This would in theory necessitate the duplication of all required services, which is unrealistic. It is also likely to be insufficient to simply plan for an outage of the largest system strength source, as this may coincide with the planned or forced outage of another device. Determining what is 'reasonable' when it comes to meeting the ongoing needs of the future power system is a matter not yet formally resolved.

For the purposes of the PADR, we propose to examine the practical and cost implications of targeting 95% and 99% redundancy of system strength services. We will utilise offered 'plant availability' as an input to a statistical analysis and endeavour to take locational impacts into consideration where practical to do so. The objective of this analysis will be to determine how much 'additional' capability needs to be contracted over and above that which would be 'just' enough. The total amount of accepted over-procurement will be a function of the 'availability' that service providers feel confident to offer and will likely be impacted by technology type, maintenance profiles, age and condition of equipment, fuel source availability etc.

The cost to provide higher levels of redundancy will be a significant consideration in determining what is ultimately 'reasonable'. The overlap between this issue and that described in the previous Section is noteworthy, i.e. the need to separate availability and enablement compensation arrangements.

5.5 Consideration of future inertia network service requirements

Notwithstanding a number of rule change proposals in recent times wanting to create a spot market for inertia[25], the current rules framework continues to require *inertia service providers* to make services available that are sufficient to meet the forecast shortfalls as declared by AEMO. In the vast majority of cases, the *inertia service provider* will be exempt from the RIT-T process when identifying and implementing solutions to address a shortfall requirement[26]. The requirement to make available the least cost option or combination of options is addressed elsewhere in the rules[27].

TasNetworks currently utilises a network services agreement with a third party provider to make available sufficient inertia to manage power system security. A new agreement will be required from 2 December 2025. The contract period was deliberately aligned with the commencement of the new system strength framework so that the two network services could potentially be procured in parallel, as has been the practice in Tasmania to date.

The inertia shortfalls forecast by AEMO in the 2022 Inertia Report [3] are provided in Table 6.

Table 6: Forecast inertia shortfalls – Tasmanian region

Financial year	2023-24	2024-25	2025-26	2026-27	2027-28
Available inertia 99% of the time [MW.s]	1,939	1,495	1,291	1,291	1,291
Inertia shortfall against *secure operating level* [3,800 MW.s]	1,861	2,305	2,509	2,509	2,509

[25] Refer the most recent AEMC Rule Change Proposal (ERC0339), '*Efficient provision of inertia*', Australian Energy Council, AEMC initiation date 2 March 2023.

[26] Refer NER 5.16.3(a)(9) and (10).

[27] Refer NER 5.20B.4(f).

While not administered under the RIT-T process, we are of the view that inertia and system strength services, whether they be procured in the form of non-network solutions or provided by network assets, should be considered together in parallel. There are a number of credible options capable of delivering the services simultaneously, raising the prospect that 'common solutions' will deliver the least overall cost outcome for consumers. It can be noted that *inertia service payments* are currently recouped from network customers. We have structured the EOI that has been published with this PSCR to address both system strength and *inertia network services* as part of the one submission, noting that potential service providers may elect to offer only one of the services if they so desire.

Our intention is to consider how we manage forecast inertia shortfalls over the defined analysis period as a further input to the PADR cost benefit analysis. The objective in doing so will be to identify an overall least cost outcome for the provision of both system strength and inertia services going forward. Recognising that we will require new network services agreement(s) for both services from 2 December 2025, this will enable us to undertake efficient planning, followed by commercial negotiations to secure the necessary capabilities in a timely manner.

TasNetworks is of the view that this approach is supported by the NEO and is likely to result in a more favourable outcome for consumers than if each issue was to be addressed independently.

6 Submissions

TasNetworks is seeking stakeholder submissions on the various issues and credible options that have been presented as part of this PSCR. We are particularly interested in receiving submissions from non-network service providers who are welcome to prepare written feedback, but must also respond to the EOI that has been published in parallel if intending to offer services to address the identified need.

Stakeholders should be aware that submissions to the PSCR may be published by TasNetworks. Stakeholders should mark submissions as 'Confidential' if they do not wish them to be made publicly available. In the case of confidential submissions, TasNetworks may explore with the submitting party if a redacted or public version can be offered. Irrespective of the classification, we reserve the right to discuss the content of any submission with the AER and AEMO for the purposes of progressing the RIT-T through to conclusion, noting that all parties will be made aware of the confidential nature of any material prior to such discussions.

In accordance with the RIT-T Guidelines, we intend to publish a PADR within 12 months of the PSCR consultation period ending. Appendix A.3 provides a simplified flowchart of the RIT-T process expected to be followed for this activity. The PADR will include a summary of submissions received to this consultation report as well as responses and actions to any issues raised.

The PADR will also include:

- A description of which credible options have been assessed.
- Indicative costs of each credible option as informed by feedback to this PSCR (noting that commercially sensitive information will not be made public).
- A description of the methodologies used to quantify costs and benefits.
- A net present value analysis for each credible option.
- A proposed preferred option[28] taking into account the net present value analysis as well as any other considerations deemed appropriate and allowable within the RIT-T framework.

To support the preparation of submissions from intending non-network service providers, we have developed an EOI document with supporting templates for the provision of technical information. The templates have been developed to standardise the types of information to be submitted, which will ultimately be used as input data to the PADR modelling and analysis process.

EOIs will be treated as confidential and will not be disclosed outside TasNetworks except:

- As reasonably required for the purpose of assessing the proposed Services, including consultation with AEMO and the AER.
- When requested by any regulatory or other government authority having jurisdiction over TasNetworks, or its activities.
- As required by law, or in the course of legal proceedings.
- To TasNetworks' external advisers, consultants or insurers.

[28] Which may be a combination of credible options in this case of this particular RIT-T and identified need.

Submissions to the EOI should be made through TasNetworks' E-Procurement Portal, Tenderlink (Reference: TASNET-1068758).

TasNetworks is seeking written submissions to this PSCR over a twelve week period ending at 2 PM Thursday 9 November 2023.

For further information, please contact:

Chris Noye
Leader Regulation
Tasmanian Networks (TasNetworks)

Email submissions or queries in relation to this PSCR can be sent directly to:

regulation@tasnetworks.com.au

7 References

[1] Australian Energy Market Operator (AEMO); "*2022 System Strength Report – December 2022*", Version 1.0, 1 December 2022.

www.aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

[2] Australian Energy Market Operator (AEMO); "*System Strength Impact Assessment Guidelines*", Version 2.0, 15 March 2023.

www.aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/system-strength-impact-assessment-guidelines

[3] Australian Energy Market Operator (AEMO); "*2022 Inertia Report – December 2022*", Version 1.0, 1 December 2022.

www.aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

Please note that National Electricity Rules Version 200 was referenced during the preparation of this document.

Appendices

A.1 Relevant extracts from the National Electricity Rules

Schedule 5.1a System standards

S5.1a.9 Minimum three phase fault levels and stability for system strength nodes

(a) The *power system* should have minimum *three phase fault levels* sufficient to enable:

(1) the *protection systems* of *transmission networks*, *distribution networks*, *Transmission Network Users* and *Distribution Network Users* to operate correctly;

(2) *voltage control systems* (such as reactive bank switching and dynamic *voltage* control) to be stable; and

(3) the *power system* to remain stable following any *credible contingency event* or *protected event*.

(b) There should be stable *voltage* waveforms at *connection points* in the *power system* such that:

(1) in steady state conditions, *plant* does not create, amplify or reflect instabilities; and

(2) avoiding *voltage* waveform instability following any *credible contingency event* or *protected event* is not dependent on *plant disconnecting* from the *power system* or varying *active power* or *reactive power* transfer at *connection points* except in accordance with applicable *performance standards*.

Schedule 5.1 Network Performance Requirements to be Provided or Coordinated by Network Service Providers

S5.1.14 Minimum three phase fault levels and stability for system strength nodes

(a) In this clause:

relevant year means each period of 12 months commencing 2 December.

system strength standard specification means, for a *system strength node* at any time in a relevant year, the forecast system strength requirements for the *system strength node* determined for the relevant year three years prior (that is, in the *system strength requirements* due to be determined by 1 December falling three years before the relevant year commenced and disregarding any revision under clause 5.20C.1(e)).

forecast system strength requirements means, for a *system strength node* for a relevant year, *AEMO's* forecast under clause 5.20C.1(c) of:

(i) the minimum *three phase fault level* applicable at the *system strength node*; and

(ii) the level and type of *inverter based resources* and *market network service facilities* projected by *AEMO* for the *system strength node*.

(b) A *Transmission Network Service Provider* who is a *System Strength Service Provider* must use reasonable endeavours to plan, design, maintain and operate its *transmission network*, or make *system strength services* available to *AEMO*, to meet the following requirements at *system strength nodes* on its *transmission network* in each relevant year:

(1) maintain the minimum *three phase fault level* specified by *AEMO* for the *system strength node* in the system strength standard specification for the relevant year; and

(2) achieve stable *voltage* waveforms for the level and type of *inverter based resources* and *market network service facilities* projected by *AEMO* in the system strength standard specifications for the *system strength node* for the relevant year:

(i) in steady state conditions; and

(ii) following any *credible contingency event* described in clause S5.1.2.1 or any *protected event*.

(c) For paragraph (b)(2), *voltage* waveforms must be sufficiently stable such that:

(1) in steady state conditions, *inverter based resources* and *market network service facilities* do not create, amplify or reflect instabilities;

(2) avoiding *voltage* waveform instability following any *credible contingency event* described in clause S5.1.2.1 or any *protected event* is not dependent on any of the *inverter based resources* or *market network service facilities disconnecting* from the *power system* or significantly varying the *active power* or *reactive power* transfer at the *connection point* except in accordance with applicable *performance standards*; and

(3) the description of what is meant by stable *voltage* waveforms in the *system strength requirements methodology* is satisfied.

5.20B.4 Inertia Service Provider to make available inertia services

(c) For the purposes of paragraph (b), an *Inertia Service Provider* for an *inertia sub-network* must:

(1) use reasonable endeavours to make the *inertia network services* available by the date specified by *AEMO* in the notice under clause 5.20B.3(c);

(2) make a range and level of *inertia network services* available such that it is reasonably likely that *inertia network services* that provide the required level of *inertia* when *enabled* are continuously available, taking into account planned *outages* and the risk of unplanned *outages*;

(3) ensure that the *inertia network services* that when *enabled* provide *inertia* up to the *minimum threshold level of inertia* (as adjusted for *inertia support activities* if applicable) are qualifying *inertia network services* as specified in paragraph (d);

(4) ensure that the *inertia network services* that when enabled provide *inertia* beyond the *minimum threshold level of inertia* up to the *secure operating level of inertia* (as adjusted for *inertia support activities* if applicable), are qualifying *inertia network services* as specified in paragraph (e); and

(5) maintain the availability of those *inertia network services* until the date the *Inertia Service Provider's* obligation ceases, as specified by *AEMO* under clause 5.20B.3(d).

A.2 Project Specification Consultation Report Checklist

NER Requirement	Section and Page References
(1) a description of the identified need	Section 3 (pages 16-21)
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Section 3 (pages 16-21)
(3) the technical characteristics of the identified need that a non- network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	Section 4.4 (page 31) and accompanying Expression of Interest documentation.
(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	Section 3.1 (Page 16)
(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	Section 4.1 (pages 22-25)
(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT–T proponent considers are unlikely to be material and reasons why they are unlikely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	6(i) – Section 4.1 (pages 22-25) 6(ii) – Section 4.2 (page 25) 6(iii) – Section 4.3 (pages 26-30) 6(iv) – Section 4.1.4 (page 25) 6(v) – Section 4.1.4 (page 25)

A.3 Expected process for this RIT-T

TasNetworks is expecting to follow the RIT-T process as shown below given the complexity of the issues being addressed and the potential for significant network expenditure, subject to the availability of lower cost non-network solutions.