100% Inverter Based Resource Generation Study – Tasmanian Region

March 2024

Summary Report

A preliminary investigation into the barriers to operation of the Tasmanian power system with 100% electricity supply from IBR generation sources

Important notice

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Acknowledgement

AEMO acknowledges:

- the work of TasNetworks in co-authoring this report; and
- the support, co-operation and contribution of Entura in providing data and information used in this publication.

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Executive summary

As the energy transition progresses, the National Electricity Market (**NEM**) is moving towards periods of 100% instantaneous penetration of renewables. Much of the renewable generation will be provided by inverter based resource (**IBR**) generation. Operating a power system at or near 100% IBR generation introduces new considerations for managing power system security and reliability.

This report summarises the findings of a study initiated by AEMO and TasNetworks which aimed to identify the most significant system security and reliability gaps arising from operation of the Tasmanian network without any synchronous generation, that is, scenarios with 100% IBR generation. While the focus of this work program is on the Tasmanian region, the intent is to identify common issues and areas of concern, and then develop learnings and mitigations that can be applied more broadly for the benefit of other IBR dominated regions, such as South Australia.

The work package was identified in the AEMO *Engineering Roadmap to 100% Renewables – FY2024 Priority Actions Report*[1], with the objective to uplift operational capabilities by improving practical understanding of what 100% IBR generation scenarios mean for day-to-day operation of the NEM.

The study was primarily focused on the performance and capabilities of the existing Tasmanian system, as of June 2023. In some instances, it also considered the addition of one new large-scale wind development, to create a scenario where IBR generation exceeded operational demand on a regular basis, thereby allowing analysis of other system security constraints in isolation. The study also considered the potential benefits delivered from a transmission connected battery energy storage system (**BESS**) in easing frequency related constraints. The study did not consider the addition of Marinus Link, because a final investment decision had not been reached at the time of undertaking this study. The longer-term objective for both AEMO and TasNetworks continues to be how to support operation of the Tasmanian network when significantly more IBR generation is developed in line with forecast expectations driven by the Tasmanian Renewable Energy Target.

The key findings from the scoping study, which will now drive more directed, in-depth analysis, are:

- A viable Tasmanian power system can be 'formed' using a combination of only IBR generation and synchronous condensers (**SC**s). Such a power system can be made robust enough to manage the 'normal suite' of credible contingency events involving the loss of single network or generation assets (N-1 security criteria).
- Current Tasmanian IBR generation capacity is only sufficient to meet near minimum operational demand. An additional large scale solar or wind facility would be needed to satisfy operational demand on a regular basis if system security conditions permit.
- TasNetworks data shows that, based on operational history to date, IBR generation is likely to be limited to less than 95% considering the various limitations within the existing network. Operation up to 92% has occurred in practice. With the mix of plant and equipment currently available, operation of the Tasmanian network at 100% IBR generation is **not currently achievable** for the following reasons:

[1] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/nem-engineering-roadmap-fy2024--priority-actions.pdf?la=en&hash=DED803FB758F555EE934A898367E66C6.

  - Frequency control related issues limit IBR generation, in particular:
    - Without the modelled transmission connected BESS, Tasmania would be heavily reliant on Basslink to provide both primary frequency response (**PFR**) and frequency control ancillary services (**FCAS**) in a 100% IBR scenario. In the event of an unexpected loss of Basslink and subsequent Frequency Control System Protection Scheme (**FCSPS**) action, frequency could not be reliably managed.
    - Compliance with existing rate of change of frequency (**ROCOF**) limit advice restricts the operational demand that can be satisfied using IBR generation and SCs alone. Inertia from available SC units is only sufficient to allow Tasmanian minimum demand levels to be met by IBR generation. There is currently no mechanism to obtain additional inertia services once the secure operating level of inertia[2] has been satisfied.
  - System strength requirements in southern Tasmania cannot currently be met without support from synchronous generation.
- Operating at 100% IBR generation in Tasmania would require proper consideration and mitigation (where determined to be necessary) in order to avoid negative impacts on network resilience, especially following non-credible contingency events. Action may be needed to manage any increased risk of major supply disruptions during periods of very high IBR generation contributions, noting that low probability risks already exist in today's network. There is a need to carefully consider the impact of new operating scenarios on emergency frequency control schemes, and other protection schemes, once high IBR generation scenarios can occur on a more frequent basis.

Tasmania presents a unique opportunity to demonstrate operation with 100% IBR generation before any other gigawatt-scale Australian power system. This work aims to identify issues and areas of concern, and then develop learnings and mitigations that can be applied more broadly, for the benefit of other NEM regions, as IBR generation increases across the NEM.

[2] Secure operating level of inertia defined in NER 4.4.4, at https://energy-rules.aemc.gov.au/ner/514/339409#4.4.4

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Acronyms

AGC	Automatic Generation Control
BESS	Battery Energy Storage System
DER	Distributed Energy Resource
EFC	Emergency Frequency Control
FCAS	Frequency Control Ancillary Services
FCSPS	Frequency Control System Protection Scheme
FFR	Fast Frequency Response
FLN	Fault Level Node
FOS	Frequency Operating Standard
GFM	Grid Forming
HVDC	High Voltage Direct Current
IBR	Inverter Based Resource
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	Normal Operating Frequency Band
OFGS	Over Frequency Generator Shedding
PFR	Primary Frequency Response
PMU	Phasor Measurement Unit
PV	Photovoltaic
REZ	Renewable Energy Zone
ROCOF	Rate of Change of Frequency
SC	Synchronous Condenser
SSSP	System Strength Service Provider
TNSP	Transmission Network Service Provider
TRET	Tasmanian Renewable Energy Target
UFLS	Under Frequency Load Shedding
VSC	Voltage Source Converter

1 Preparing for 100% IBR generation

As the National Electricity Market (**NEM**) undergoes a profound transformation towards periods of 100% instantaneous penetration of renewables, the conditions in which AEMO manages power system security and reliability are rapidly changing. Operating the NEM at 100% instantaneous penetration of renewables will necessarily require operation at very high levels of inverter based resource (**IBR**) generation.

To date, no gigawatt-scale energy system globally has operated with 100% of its generation coming from IBR, as far as AEMO is aware.

While some regions of the NEM are likely to achieve their 100% renewable penetration targets using a mix of IBR and traditional synchronous generators including pumped hydro, there may be times when the generated output of wind, large-scale solar and distributed energy resources (**DER**) will be sufficient to meet the majority, or even all, of a region's electricity demand. This allows for a possible future scenario where, when conditions allow, the entire NEM might operate without any synchronous generation.

Recognising the significant role that IBR technologies will play in the future energy mix, expected to be dominated by wind, solar, and battery energy storage systems (**BESS**), AEMO and transmission network service providers (**TNSPs**) are proactively investigating various engineering challenges associated with operating a power system at very high IBR generation levels. Systematic analysis is required to consider all potential security and reliability impacts, especially considering the variable nature of wind and solar. The increased use of high voltage direct current (**HVDC**) transmission should also not be dismissed, bringing with it benefits and additional challenges for the networks in which it is deployed.

Along with South Australia, Tasmania has been identified as a region where many of the issues foreseeable across the broader NEM will need to be addressed in the near term. With sufficient IBR generation capacity already installed to meet minimum demand, and a high renewable energy growth target legislated by the Tasmanian State Government, the prospect of 100% IBR generation scenario is increasingly credible.

This report summarises a study initiated by AEMO and TasNetworks which aimed to identify the most significant system security and reliability concerns arising from operation of the Tasmanian network without any energy contributions coming from synchronous generators. The objective of the analysis was to identify rather than solve potential issues, with subsequent detailed analysis to be undertaken focusing on any areas of concern. The work package was identified in AEMO's *Engineering Roadmap to 100% Renewables – FY2024 Priority Actions Report*[3] published on 12 July 2023, and aims to uplift operational capabilities by improving practical understanding of what 100% IBR generation scenarios mean for day-to-day operation of the NEM.

[3] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/nem-engineering-roadmap-fy2024--priority-actions.pdf?la=en&hash=DED803FB758F555EE934A898367E66C6.

2 The Tasmanian power system

2.1 Tasmanian power system background

As a hydro dominated power system, Tasmania has historically operated for extended periods of time relying only on renewable generation. In November 2020, following the commissioning of Wild Cattle Hill and Granville Harbour Wind Farms, Tasmania also achieved its 100% renewable energy target, with sufficient hydro and wind capacity installed to meet the state's energy consumption of approximately 10,500 gigawatt hours (**GWh**) per annum. In practice, the milestone means less ongoing reliance on local gas generation and energy imports across the Basslink HVDC interconnector, recognising the role that both energy sources continue to play in helping mitigate periods of low rainfall and storage inflows.

In the same year, the Tasmanian Government released its Renewable Energy Action Plan[4], which included a legislated Tasmanian Renewable Energy Target (**TRET**) to increase renewable energy generation in the state by 200% by 2040 against a baseline of 10,500 GWh. An interim target of 150% was also defined for the end of 2030, which, according to the Tasmanian Government's Renewable Energy Coordination Framework[5], will be facilitated by substantial changes in the Tasmanian power system, including commissioning of Marinus Link, new variable renewable generation and new storage.

2.1.1 The Tasmanian power system in 2023

To provide context for the changes forecast, Table 1 summarises statistics for the Tasmanian power system as it exists in 2023.

Table 1 Key attributes of the Tasmanian power system in 2023

Description	Statistic	Explanation
Annual electricity consumption [A]	10,468 GWh	For financial year 2023
Average operational demand [B]	1,190 MW	50 percentile operational demand for calendar year 2022
Minimum operational demand [B]	937 MW	Ten year average 1 percentile minimum operational demand as measured October 2023
Maximum operational demand [C]	1,669 MW	For financial year 2022
Small scale solar installations [D]	314 MW	From AEMO DER data dashboard (Dec 23).
Basslink HVDC interconnector nominal rating	±500 MW	478 MW delivered into Tasmania during import accounting for losses.
Nameplate capacity of installed wind generation [E]	568 MW	
Hydro generation capacity [E]	2,295 MW	Includes both scheduled and non-scheduled hydro generation
Large scale BESS capacity	0 MW	Potential third-party developments pending.

A. See https://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.
B. Data provided by TasNetworks
C. See https://forecasting.aemo.com.au/Electricity/MaximumDemand/Operational.
D. See https://aemo.com.au/en/energy-systems/electricity/der-register/data-der/data-dashboard.
E. Based on information provided by TasNetworks

[4] See https://recfit.tas.gov.au/renewables/tasmanian_renewable_energy_action_plan.

[5] At https://www.stategrowth.tas.gov.au/__data/assets/pdf_file/0007/343618/Renewable_Energy_Coordination_Framework_May_2022_web.pdf.

Minimum demand periods have historically occurred overnight during shoulder or summer seasons. As a winter peaking system driven by heating requirements, Tasmania typically experiences lower electricity demands during summer. This is in contrast to other mainland states where significant air-conditioning load is more prevalent during the summer months, driving up demand.

In combination, these circumstances lead to the following observations:

(a) The ongoing growth of local small-scale rooftop photovoltaics (**PV**) will continue to reduce daytime operational demand, particularly during the summer and shoulder months. It is expected that Tasmania will increasingly experience low operational demand periods during both the day and night.

(b) The ability to import low, often negatively priced surplus energy from the mainland at the same time could lead to a reduction in operation from Tasmanian hydro generators. Surplus solar and wind capacity is already resulting in extended periods of negative pricing in Victoria, especially during daylight hours. The tendency is for Basslink to import at such times given the flexibility of hydro generators to withdraw from the market on a short-term basis to conserve water for commercial reasons.

(c) Transmission-connected IBR generation capacity exceeds minimum operational demand. When favourable wind conditions in Tasmania combine with low operational demand, there is already the theoretical potential, from an energy adequacy perspective, to satisfy demand without reliance on any contributions from hydro generation.

Transmission-connected IBR capacity	=	Basslink import + Tasmanian wind generation
	=	478 MW + 568 MW
	=	1,046 MW

2.1.2 IBR generation in Tasmania to date

The metric used by TasNetworks to describe and monitor the level of IBR generation in real time is the System Non-Synchronous Penetration (**SNSP**[6][7]) ratio. Mathematically, SNSP is defined as follows:

$$SNSP_{RT}(\%) = \frac{\sum Wind_{MW} + \sum Solar_{MW} + \sum HVDC\_Import_{MW} + \sum BESS\_Discharge_{MW}}{OP\_Demand_{MW} + \sum HVDC\_Export_{MW}} \times 100$$

In simple terms, the SNSP percentage describes what proportion of Tasmanian system generation (in terms of MW output) is IBR rather than synchronous. In this formulation, $Solar_{MW}$ refers to large-scale solar farms rather than DER. Rooftop PV is accounted for as a reduction in operational demand.

TasNetworks data shows that Tasmania is experiencing regular operation above 70% SNSP, with periods above 80% also being relatively common. To date, Tasmanian SNSP has reached a peak of approximately 92%, occurring at a time of strong local wind conditions coupled with high HVDC import (driven by suppressed mainland energy prices). TasNetworks' view is that the development of one additional wind or solar facility in the

[6] SNSP is the ratio of generation from wind and HVDC imports to demand and HVDC exports

[7] Note that the SNSP differs from renewable penetration. Instantaneous renewable penetration is calculated as the renewable generation share of total large- and small-scale generation. The measure is calculated on a half-hourly basis because this is the granularity of estimated output data for historical distributed PV output. For this calculation, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping.

order of several hundred MW will provide sufficient additional capacity to enable 100% SNSP to be readily achievable. Establishing how to manage power system security and reliability under such operating conditions is a necessary pre-condition before allowing it to occur in practice.

Tasmania was one of the first NEM regions to be issued with inertia and system strength shortfall notices in 2019. Prior to this, TasNetworks had proactively managed minimum short circuit ratio requirements for HVDC, as well as rate of change of frequency (**ROCOF**) limits. It has been recognised for some time that high IBR generation levels bring with them challenging system dynamics.

2.2 IBR generation projections for Tasmania

The *2023 System Strength Report*[8] provides IBR generation capacity forecasts for the Tasmanian region, as shown in Table 2. The new capacity has been grouped by renewable energy zone (**REZ**), with three onshore zones expected to host new wind projects in the coming years. As the System Strength Service Provider (**SSSP**) in Tasmania, TasNetworks is required by the National Electricity Rules (**NER**) to ensure that sufficient system strength is provided to support these forecast developments.

Table 2 Forecast IBR developments for Tasmania – new MW capacity

REZ	Existing	2024	2025	2026	2027	2028	2029	2030	2031	2032
T1 – North East	168	0	0	0	41	41	41	41	53	53
T2 – North West	251	0	0	0	5	5	181	703	703	703
T3 - Central	149	0	0	0	603	603	612	1,362	1,362	1,370
Aggregate (MW)	568	0	0	0	649	649	834	2,106	2,118	2,126

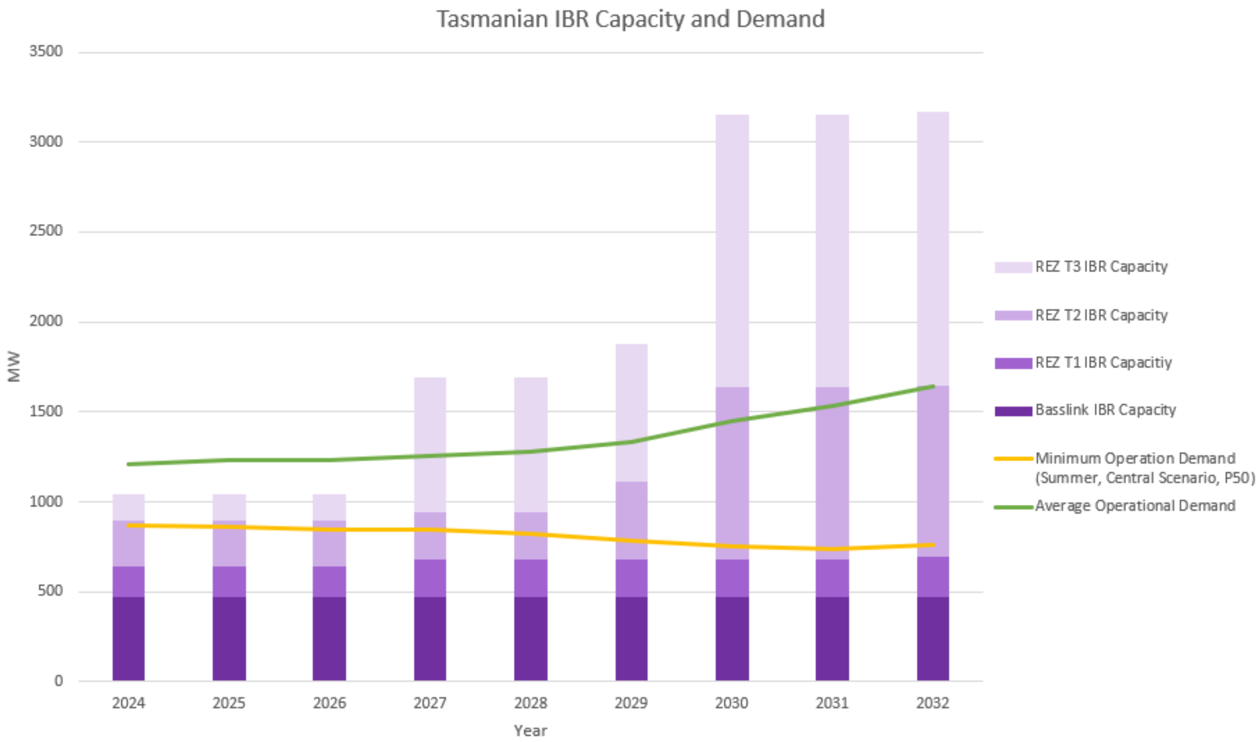
As shown in Figure 1, combined data from the 2023 *System Strength Report* and the 2023 *Electricity Statement of Opportunities* (ESOO) for the NEM[9] projects that the forecast installed IBR[10] generation could exceed the average operational demand by 2027, thus regularly enabling potential 100% IBR operating scenarios. This indicates that there is a relatively short window of opportunity to identify and appropriately address any system security and reliability issues that may occur as a result of such operating conditions.

[8] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-system-strength-report.pdf?la=en.

[9] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en.

[10] The values of installed IBR reflect the Step Change scenario which is considered the most likely, as defined in the AEMO 2024 Draft Integrated System Plan at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf?la=en

Figure 1 Tasmanian IBR capacity and demand



2.3 Transferring learnings from Tasmania to other NEM regions

Tasmania presents a unique opportunity to demonstrate operation with 100% IBR generation before any other gigawatt-scale Australian power system. While the focus of this work program is on the Tasmanian region, the intent is to identify common issues and areas of concern, and then develop learnings and mitigations that can be applied more broadly for the benefit of other IBR dominated regions, such as South Australia.

Comparisons are sometimes drawn between Tasmania and South Australia in terms of IBR generation levels; a comparison between key features of the two regions is shown in Table 1. South Australia also has an HVDC interconnection with Victoria (MurrayLink). Both regions were early adopters of large scale wind generation, though, in recent years, South Australia has accelerated away in terms of transmission connected wind, solar and BESS. Notable for South Australia is the significant take-up of DER, with the volume of small scale PV now reaching 2,700 MW[11]. Operational demand is now regularly approaching and falling below zero[12] as DER obviates the need for energy to be supplied from transmission-connected generators.

[11] As installed Nov 2023. Sourced at https://aemo.com.au/en/energy-systems/electricity/der-register/data-der/data-dashboard

[12] See https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf?la=en

Table 3 Comparison of Tasmanian and South Australian network properties

	Tasmania	South Australia
Annual electricity consumption[A]	10,468 GWh	11,546 GWh
Minimum operational demand	937 MW	21 MW [B]
HVDC link to Victoria	Basslink 500 MW	Murraylink 220 MW
AC link to Victoria	-	Heywood 600 MW VIC->SA 550 MW SA->VIC
Transmission-connected[C]: • **Wind** • **PV** • **BESS** • **Hydro**	 568 MW 0 MW 0 MW 2,295 MW	 2,346 MW 661 MW 512 MW 0 MW
Small-scale PV[D]	314 MW	2,700 MW

A. See https://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.
B. See https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf?la=en
C. See Table 1 and https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.
D. As installed Nov 2023. Sourced at https://aemo.com.au/en/energy-systems/electricity/der-register/data-der/data-dashboard.

Unlike Tasmania, the SNSP metric is not typically calculated for South Australia. Instantaneous renewable penetration[13] in South Australia is typically calculated, and regularly exceeds 100%[14]. This illustrates that South Australia is already operating at very high IBR generation penetration.

There are several key differences between Tasmania and South Australia that should be kept in mind when taking learnings from Tasmania for application in other regions:

(a) Tasmania has no synchronous electrical connection to the mainland, relying only on HVDC transmission to enable power exchange with Victoria. As a result, Tasmania must be self-sufficient in terms of inertia and system strength provisioning, as these services are not transferrable with the technology used by Basslink. For South Australia, the Heywood Interconnector provides a double circuit 275 kV tie into Victoria which synchronously couples South Australia to the rest of the eastern seaboard. Completion of Project EnergyConnect will further enhance this coupling, with a double circuit 330 kV connection to New South Wales currently under construction.

While local grid support provisions are still required within South Australia, driving the installation and commissioning of four high-inertia SCs by ElectraNet in 2021, being synchronously connected to a much larger region provides some advantages.

(b) Due to the characteristics and design of the Basslink HVDC interconnector, Tasmania must be capable of operating as a self-supporting synchronous island at any point in time.

- As a monopole HVDC interconnector, Basslink, is always classified as a single credible contingency event for the purposes of managing power system security.

[13] Instantaneous renewable penetration is calculated as the renewable generation share of total large- and small-scale generation. The measure is calculated on a half-hourly basis because this is the granularity of estimated output data for historical distributed PV output. For this calculation, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping.

[14] At https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf?la=en

- For power flow to reverse from export to import and vice-versa, Basslink must be temporarily ‘blocked’ and maintained at zero power transfer for a short period of time (upwards of five minutes). Power flow reversals can typically occur several times a day.

The implications are that with Basslink out of service, either due to forced or planned outages (including reversals), Tasmania becomes an isolated standalone power system that must continue to be operated in accordance with all the technical requirements of the NER.

While the eventual development of Marinus Link will bring certain advantages – for example, it will provide additional HVDC transfer capacity across Bass Strait using contemporary voltage source converter (**VSC**) technology – Tasmania will remain reliant on non-synchronous interconnections.

3 Tasmanian 100% IBR generation feasibility study

3.1 Scope of work

The objective of the preliminary study was to investigate the feasibility of operating the Tasmanian power system at 100% IBR generation, that is, operation without any energy contributions coming from synchronous generators.

While the study was primarily focused on the performance and capabilities of the existing system, it also considered the addition of one new large-scale IBR generator development, being a wind farm located in the Central Highlands REZ[15] (REZ T3) shown in Figure 2, and rated at 290 MW. The benefits of a 120 MW transmission-connected, grid-following BESS connected at Palmerston Substation were also investigated[16].

Power system modelling was undertaken using both PSS®E and PSCAD™, with the following assessments given initial priority:

(a) Ability to achieve a secure operating state assuming that Tasmanian operational demand is satisfied using only wind generation and Basslink import, with essential system security services (such as inertia and system strength) being provided from existing SCs[17]. Considerations included:

- Network stability following credible contingency events, including loss of Basslink and subsequent operation of the FCSPS[18].
- Mechanisms to manage system frequency during normal variations in load and generation.
- Network resilience when exposed to a selection of non-credible contingency events.

(b) Identification of any barriers that would currently prevent operation of the Tasmanian power system at 100% IBR generation.

(c) Consideration of what additional infrastructure might be necessary to overcome any such barriers and thereby allow operation up to 100% whenever the market supported such a dispatch outcome.

As alluded to above, a key assumption underpinning the studies was ongoing access to SC capabilities as currently contracted from Hydro Tasmania. TasNetworks has entered into a commercial agreement with Hydro Tasmania to provide non-network services to meet inertia and system strength shortfalls as declared by AEMO

[15] This is a notional representation of the future St Patricks Plains Wind Farm (SPWF) which is currently proceeding through approvals processes. Details available at www.arkenergy.com.au/wind/st-patricks-plains/.

[16] This is a notional representation of a Tasmanian BESS as proposed separately by NEOEN and Akaysha Energy. It is anticipated that any BESS installed in Tasmania would be grid-forming, however access to suitable models was a limiting factor for these studies. Specific details for each project are available at www.greatlakesbattery.com.au and www.akayshaenergy.com/projects/palmerston-bess. This is referred to later in the report as the future transmission connected BESS.

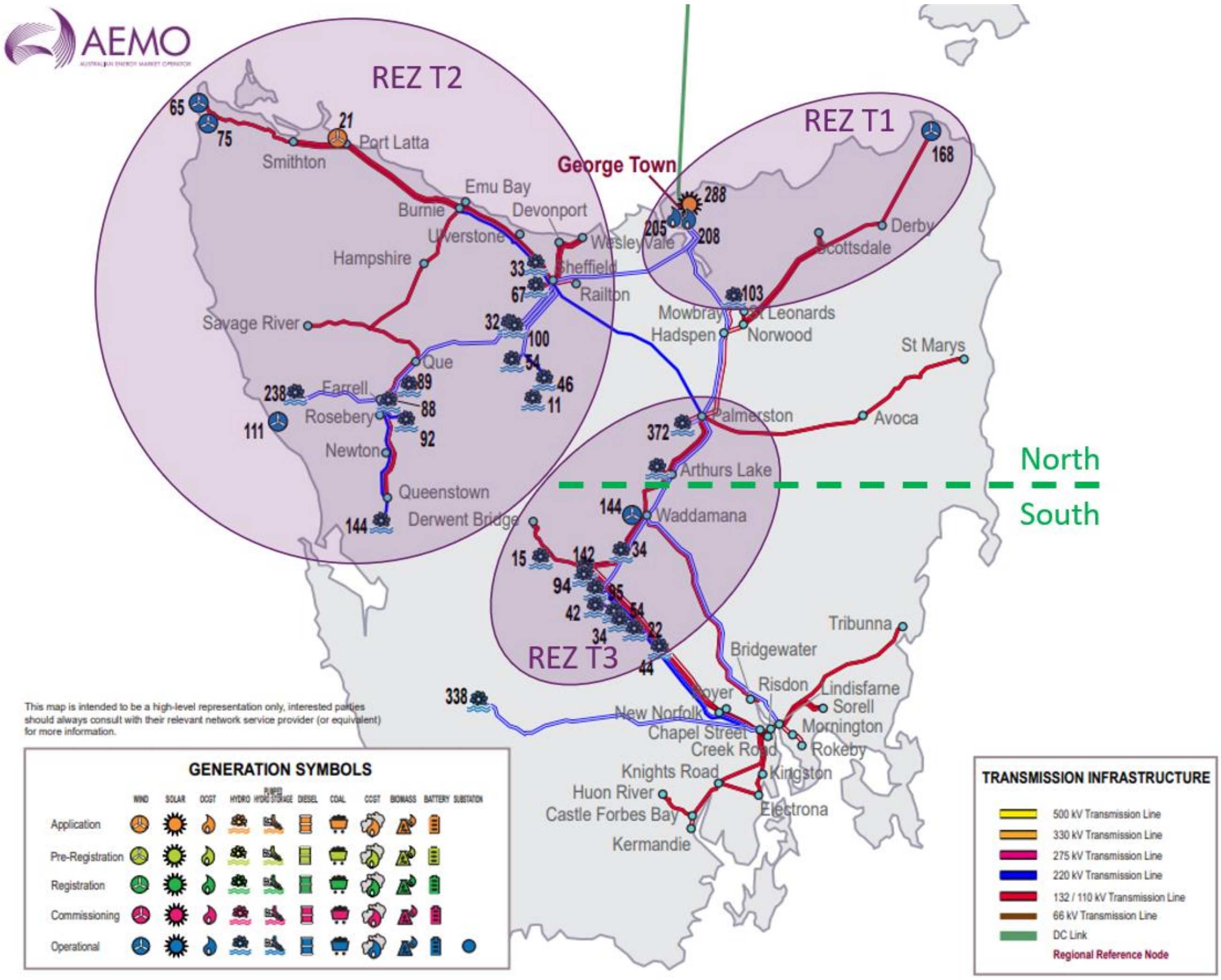
[17] Being hydro generators that are capable of SC operation and that are currently contracted by TasNetworks for the delivery of such services.

[18] FCSPS provides high speed tripping of load or generation in Tasmania following an unplanned outage of Basslink to help manage system frequency. When power is imported into Tasmania, FCSPS is required to trip the same amount of load as the imported power. When power is exported from Tasmania, FCSPS is required to trip the same amount of generation exported ± 40 MW.

through its system security planning processes. The most recent shortfall declaration was issued to TasNetworks on 15 December 2022.

The available SC units were dispatched in simulations to achieve, as far as practical, the minimum three phase fault levels as currently defined for each *fault level node* (**FLN**), as well as the *secure operating level of inertia* for the Tasmanian region. Existing system security criteria were thus used as a reference for creating 100% IBR scenarios for analysis. The performance of network protection has therefore not been considered in the study, as sufficient synchronous machine capacity was retained online in the simulations. This issue will be examined more extensively if economic or technical drivers emerge to encourage operation of the network at lower fault levels.

Figure 2 Tasmanian power system (as of October 2023) including already defined REZs



3.2 Initial findings and observations

3.2.1 Maintaining adequate system strength in southern Tasmania

The Risdon FLN is located in Hobart and currently has a minimum (synchronous) three phase fault level requirement of 1,330 megavolt amperes (**MVA**) for intact network conditions, driven primarily by power quality considerations and some uncertainties associated with distribution network protection. Using only the hydro SCs currently available under contract, it is not possible to satisfy this criterion without support from synchronous generation assets. Inertia and system strength requirements elsewhere in the network can be met with the available hydro SCs, although a significant number need to be online (as shown in Figure 5 below with respect to inertia).

The initial steady state analysis demonstrated that the geographical distribution of existing SC assets is a limiting factor when considering 100% IBR scenarios. All but one SC units are located in the northern half of the state, furthermore, only one hydro unit south of Palmerston Substation is capable of running in true SC mode, leaving southern Tasmania exposed without additional reinforcements. At present, operational issues do not arise because there are a number of southern hydro generating units which operate on a near continuous basis due to hydrological constraints. Cluny and Tarraleah Power Stations are notable examples having very high utilisation.

Thus, at the present time the system must continue relying on support from synchronous generators, although they are operating at relatively low power output. While this may preclude a theoretical 100% scenario in the short term, the aggregate contribution from synchronous generators could be relatively small, potentially in the order of 50-60 MW at times of high IBR generation.

3.2.2 Ability to form and maintain a stable grid at 100% IBR generation

Notwithstanding the system strength limitations outlined, a number of 100% IBR scenarios were investigated to explore other system security aspects. Steady state and dynamic simulations were conducted in both PSS®E and PSCAD™ with the following notable outcomes:

(a) A viable Tasmanian power system can be 'formed' using a combination of IBR generation and SCs, which are still required to supply various system security services.

(b) Operation can be made robust enough to manage the 'normal suite' of credible contingency events involving the loss of single network or generation assets (N-1 security criteria). It appears possible to manage power system stability within such an operating regime, albeit requiring that the *technical envelope*[19] is properly defined (being no different to the system that is currently being operated).

(c) In context of the existing Tasmanian power system, the frequency control capability of Basslink becomes critical for maintaining a 50 hertz (Hz) reference. The specifics of network frequency control are discussed separately in Section 3.2.3 below.

Consideration of operating the Tasmanian power system without synchronous generation has highlighted the need to explore alternate, cost-effective solutions to issues which are currently managed via the capabilities of synchronous generators. As outlined in Section 3.2.1, some issues are location specific (such as system strength

[19] As described in NER 4.2.5.

and dynamic reactive power control), whereas other issues such as frequency control (including ROCOF) are more wide reaching and require a regional perspective.

3.2.3 The need for PFR and FCAS capabilities

Simulation of credible contingency events considered the need for PFR capability and sufficient FCAS, specifically fast and slow contingency services. With Basslink importing power into Tasmania and assuming no online synchronous generation[20], sufficient PFR and FCAS could be made available using the following frequency control sources:

(a) Solutions to provide PFR for typical variations in the supply-demand balance in the absence of a contingency event:

- Sufficient headroom maintained on Basslink to allow for additional power import when needed to maintain frequency within the *normal operating frequency band* (**NOFB**)[21].
- Future transmission-connected BESS[22].

(b) Solutions to provide FCAS raise to manage unexpected loss of generation in Tasmania:

- Sufficient headroom maintained on Basslink to allow for additional power import if needed.
- FCAS switching controllers operated by Tasmanian customers (coordinated demand side response delivered in discrete blocks).
- FCAS switching controllers installed on two hydro units allowing fast changeover from SC operation back to generation mode to provide frequency control support via conventional governor control action.
- Future transmission-connected BESS.

(c) FCAS lower to manage unexpected loss of customer load in Tasmania:

- Reduction of Basslink power import.
- Future transmission-connected BESS.

Importantly, the capabilities of Tasmanian wind farms to help manage network frequency were deliberately ignored during the studies, for the following reasons:

(a) Fast FCAS (raise or lower) are critical services to arrest the immediate change in frequency following a contingency event. No wind farms are presently registered to provide these services.

[20] Noting that when operating in synchronous condenser mode, generating units cannot provide PFR.

[21] The Basslink Frequency Controller (**BFC**) aims to maintain a 1:1 relationship between Tasmanian and Victorian frequencies while both networks are operating within the range 49.85 Hz to 50.15 Hz (NOFB). In this way, the HVDC link approximates an AC interconnector during normal network operation. Due to there being different frequency standards in Tasmania following credible and non-credible contingency events, the BFC manages frequency within the respective standards during network disturbances. This requires the two ends of Basslink to operate at different frequencies until both return to within the NOFB.

[22] AEMO. 2023 Transition to Fewer Synchronous Generators in South Australia report details how BESS has aided primary frequency control in South Australia. See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/sa-transition-to-fewer-synch-gen-grid-reference.pdf

(b) Any future provision of FCAS by wind farms is likely to be limited to the lower services; that is, the deliberate curtailment of generation output to provide raise services is expected to be an unattractive option much of the time. The same issue limits the symmetrical provision of PFR.

(c) Both AEMO and TasNetworks have observed various challenges[23] for wind farm operators to comply with primary frequency response requirements first introduced under the mandatory primary frequency response rule change[24], resulting in a lower level of confidence being attributed to wind farm contributions at the present time. How to improve this situation once wind farms represent a significant portion of the total online PFR capability is a matter for ongoing consideration.

Prior to the development of any BESS, the studies have demonstrated the significant reliance that Tasmania would have on Basslink to provide both PFR and FCAS in a 100% IBR scenario. Without any online synchronous generation, Basslink could represent the only source of fast, proportional[25] frequency control capable of responding in both directions (raise and lower). Basslink has been shown capable of controlling Tasmanian frequency while appropriate headroom is available; that is, the HVDC controls are not forced against operating limits that prevent further changes in active power transfer.

The key issue arises when the contingency event impacting Tasmania is loss of Basslink itself, especially when importing. While the unexpected loss of Basslink would result in activation of the FCSPS, the scheme is not capable of exactly balancing the amount of load (or generation) tripped compared to pre-contingent Basslink flow. During import to Tasmania, contracted load blocks are pre-emptively armed and tripped when needed to rapidly compensate for loss of Basslink. The FCSPS algorithm attempts to maintain the error between ± 15 MW by continuously optimising which blocks are selected for tripping as both load demand and Basslink power flow vary.

Specific observations related to the Basslink contingency event are:

(a) Post event, the lack of any PFR capability would jeopardise frequency stability. Any residual supply-demand imbalance following FCSPS action would be observable as a frequency deviation, as shown in Figure 3, with no proportional control available to counteract frequency 'drift'. Even if Regulation FCAS was available on one or more Tasmanian wind farms, the speed of response and stability of the centralised automatic generation control (**AGC**) system is not considered sufficient to reliably manage frequency under such circumstances, without PFR support. Figure 4 shows how a BESS with PFR could counteract this frequency drift.

It should be specifically noted that Regulation FCAS and PFR are **not** interchangeable[26]. Furthermore, there are currently no mechanisms to directly ensure the availability of PFR.

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[23] To comply with the requirements of the Mandatory PFR rule, semi-scheduled generators, including wind, must be capable of automatic active power control allowing for simultaneous MW curtailment, MW ramping, frequency response outside a relatively small frequency deadband, and ongoing variation in input energy. It has been identified through testing that many existing semi-scheduled generators are unable to simultaneously coordinate these various requirements around overall active power control. These sites will require updates to control software, particularly to Power Plant Controllers (PPCs) or similar, to comply with these requirements of the Mandatory PFR rule.

[24] See https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

[25] Proportional controllers have the capability to continuously self-adjust and deliver a response that is commensurate with the immediate needs of the system. In contrast, switching controllers will generally deliver a fixed quantity of service once activated, and may not be able to subsequently adjust regardless of how the system responds.

[26] PFR is delivered by local speed/frequency controllers installed as part of each *generating system.* It is delivered on a continuous basis, with fully compliant installations having a very small frequency dead band (±0.015 Hz). Regulation FCAS is delivered via AGC. The scheme uses a representative frequency signal within each control area and has an inherent response delay of at least 8 seconds. This is the time required to calculate and communicate power set point changes to *generating systems* after a frequency disturbance is detected. Set point changes are delivered in a stepwise manner every 8 seconds, rather than in a continuous fashion.

Figure 3 Tasmania frequency following clean trip of Basslink with 1:0.95 FCSPS while importing at 380MW

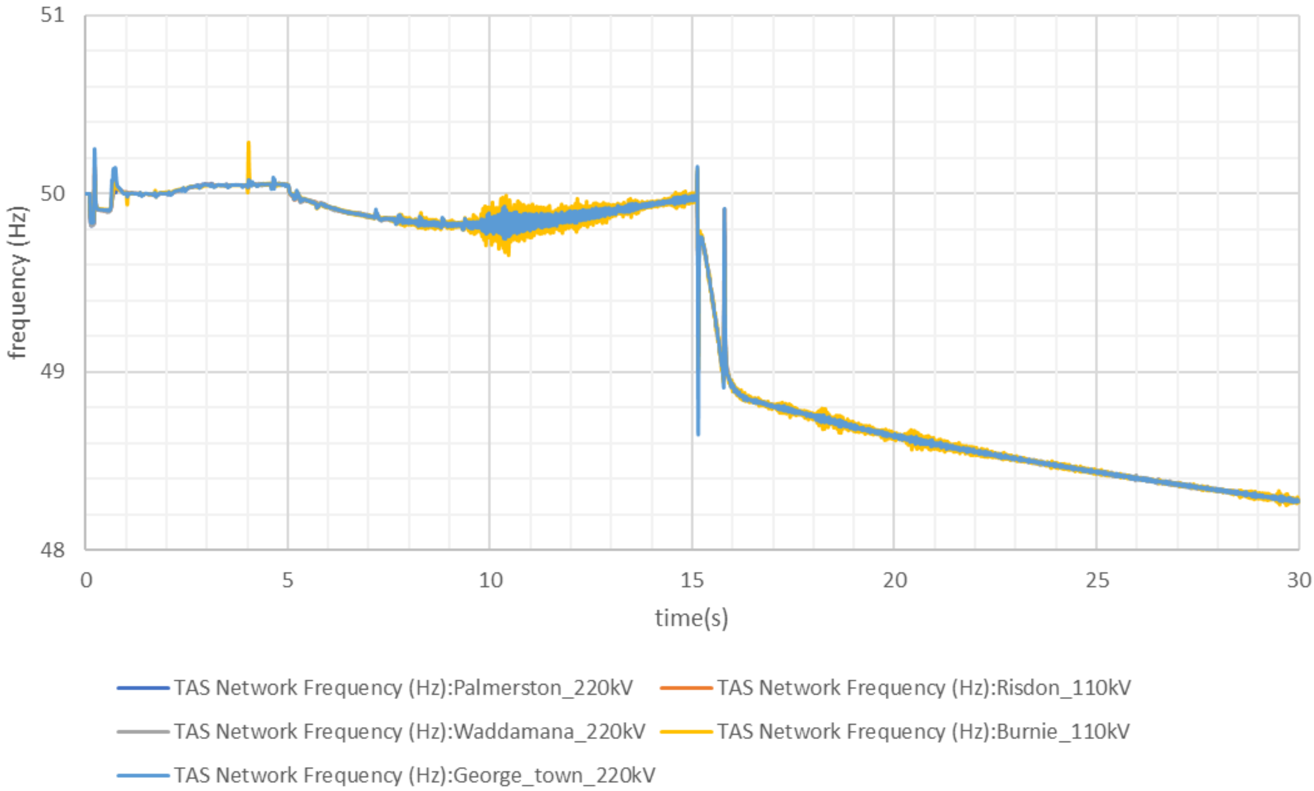
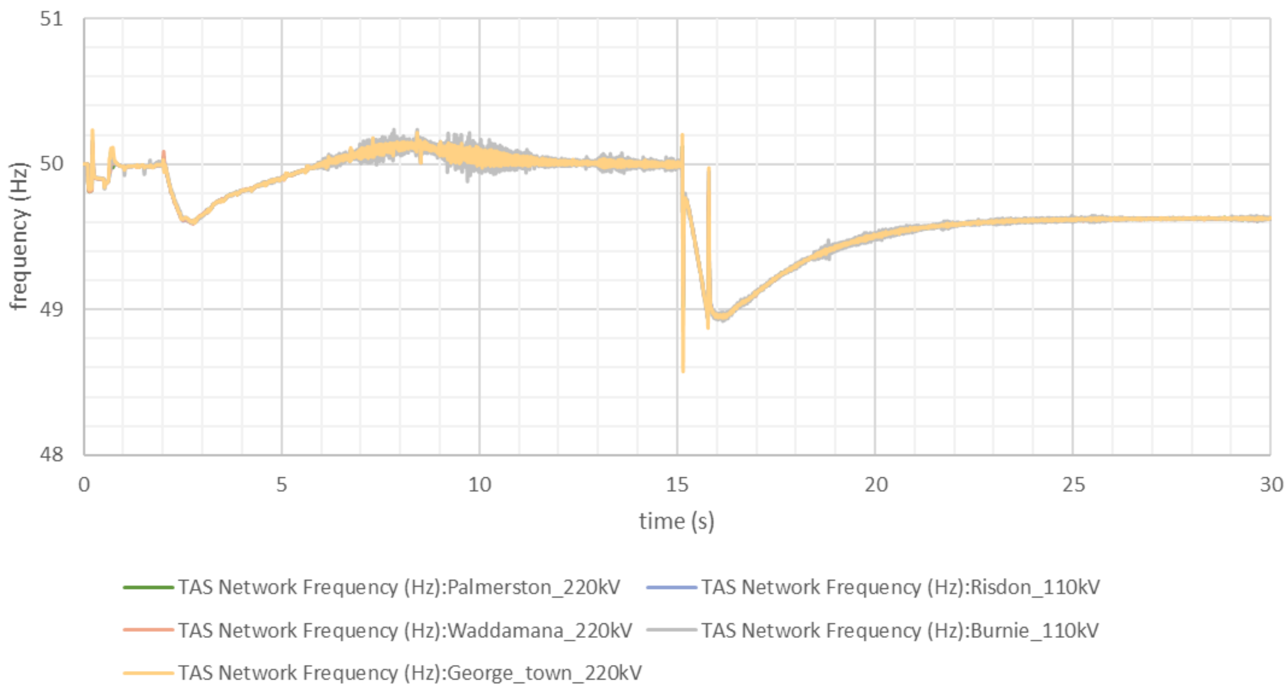


Figure 4 Tasmania frequency following clean trip of Basslink with 1:0.95 FCSPS while importing at 380MW with additional 65MW BESS providing PFR



(b) Following a Basslink contingency event, a lack of PFR and FCAS capability could persist for up to 10-20 minutes until alternate generation is brought online. It is reasonable to assume that this would be hydro generation in Tasmania's case. Within that time window, any of the following could occur as part of normal ongoing operation of the network:

- Changes to the output of variable IBR generation (including embedded PV).
- Changes in the output of semi-scheduled IBR generation due to market driven events, such as volatility in energy or FCAS prices.
- Variations in system demand, including load switching events within major industrial facilities.

This particular issue has highlighted the need to carefully consider what is required to remain in a satisfactory operating state, and, return to a secure operating state within 30 minutes as required by the NER[27]. Even if the initial contingency event can be successfully managed, TasNetworks notes that the system must remain viable for a reasonable period thereafter until either automatic market responses or manual control actions can be implemented. As a minimum, there is a need for post-contingency PFR capability to support whatever Regulation FCAS remains available for AGC. This observation would be equally applicable to other NEM regions.

3.2.4 Management of ROCOF and provision of sufficient inertia under 100% IBR scenarios

Simulations have demonstrated that the 3 hertz per second (Hz/s) ROCOF limit now defined for Tasmania within the Frequency Operating Standard (**FOS**)[28] can be breached under high IBR generation scenarios if sufficient inertia is not available. High ROCOF is driven not only by the direct loss of load or generation, but also via the fault ride through response of IBR which can contribute to an additional and significant transient energy deficit immediately following a network disturbance.

TasNetworks first prepared ROCOF limit advice in 2013 following the commissioning of Musselroe Wind Farm. AEMO subsequently developed constraint equations, with the general equation most likely to bind described in the following manner:

ROCOF_3: $Tas\_Wind_{MW} + Basslink\_Import_{MW} \leq 0.17 \times Tas\_Inertia_{MWs}$

While the current equations require updating to better account for new FOS changes (see Section 3.4.2), as well as integrate more recent learnings, they provide a reasonable indication of how inertia requirements increase at high IBR generation.

TasNetworks has a portfolio of hydroelectric SCs currently under contract for the provision of a total of 4,844 megawatt seconds (**MW.s**) of inertia. This would limit the maximum IBR generation contribution to approximately 823 MW. This increases to 867 MW if three open-cycle gas turbines also capable of SC operation (but not currently contracted) are placed into service.

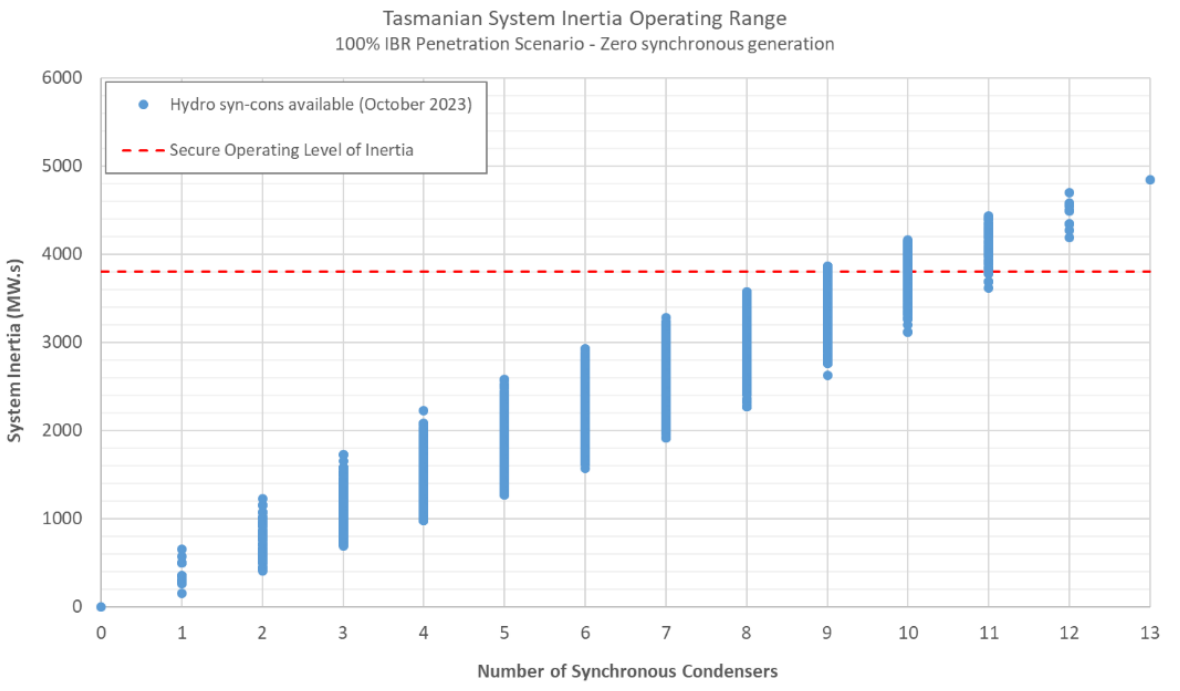
The addition of inertia via synchronous generating units operating at minimum output (**PMIN**) has been the mechanism to support the high IBR generation scenarios so far experienced. Such provisions include by-products of the energy market outcome, which are not financially compensated for at the present time. TasNetworks

[27] At https://energy-rules.aemc.gov.au/ner/477/272454#4.2.6

[28] AEMC. Frequency Operating Standard, October 2023, at https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf.

obligation as the *inertia service provider* is to ensure that the *secure operating level of inertia* can be satisfied, which is currently set by AEMO at 3,800 MWs. As shown in Figure 5, this requires at least nine out of the 13 SC units to be online if no synchronous generation is dispatched. A high level of SC unit availability is therefore required to support significant IBR generation without other forms of inertia support.

Figure 5 Inertia available from hydro synchronous condenser fleet (as of October 2023)



The practical outcome of these observations is that ongoing compliance with existing ROCOF limit advice would very much limit what operational demand could be satisfied using IBR generation and SCs alone. Inertia from SC units, assuming all are available for service, would only just be sufficient to allow minimum Tasmanian demand conditions to be met. Inertia could be increased by running additional synchronous generators at PMIN, however this is not an outcome that can be directly influenced by TasNetworks once the *secure operating level of inertia* is satisfied, nor does it facilitate a 100% IBR dispatch outcome.

Note that the peak IBR generation experienced to date of 92%, as discussed in Section 2.1.2, was possible due to additional inertia provision from the synchronous generation providing the remaining 8% of generation at that instance.

3.2.5 Network resilience impacts due to geographical distribution of services

The network studies so far completed have highlighted how the geographical distribution of essential services will impact overall system resilience, with a subsequent need to consider the location of future support assets such as BESS and additional SCs. While discussions in Section 3.2.1 focused on the delivery of system strength under intact network conditions, investigations into how specific non-credible contingency events will impact the system under 100% IBR generation scenarios have raised additional concerns.

For context, it is important to recognise that a significant number of IBR generator developments are being planned in the northern half of Tasmania, including the proposed Marinus Link HVDC interconnector. For the existing Tasmanian system, all but one of the large-scale transmission-connected IBR generators are located in the north, the exception being Wild Cattle Hill Wind Farm located just south of Waddamana Switching Station in the Central Highlands. The electrical separation of northern and southern Tasmania is shown in Figure 2.

A theoretical 100% IBR generation scenario therefore requires the following network conditions:

(a) High north to south power transfer between Palmerston Substation (**PM**) and Waddamana Switching Station (**WA**).

This connection is comprised of a double circuit 220 kV transmission line (on common towers) running in parallel with a much lower capacity single circuit 110 kV transmission line. The 220 kV transmission line is 'hard connected' at Waddamana using only line disconnectors (no circuit breakers) and extends through to Liapootah Substation (**LI**).

(b) Rated output from Wild Cattle Hill Wind Farm (148 MW).

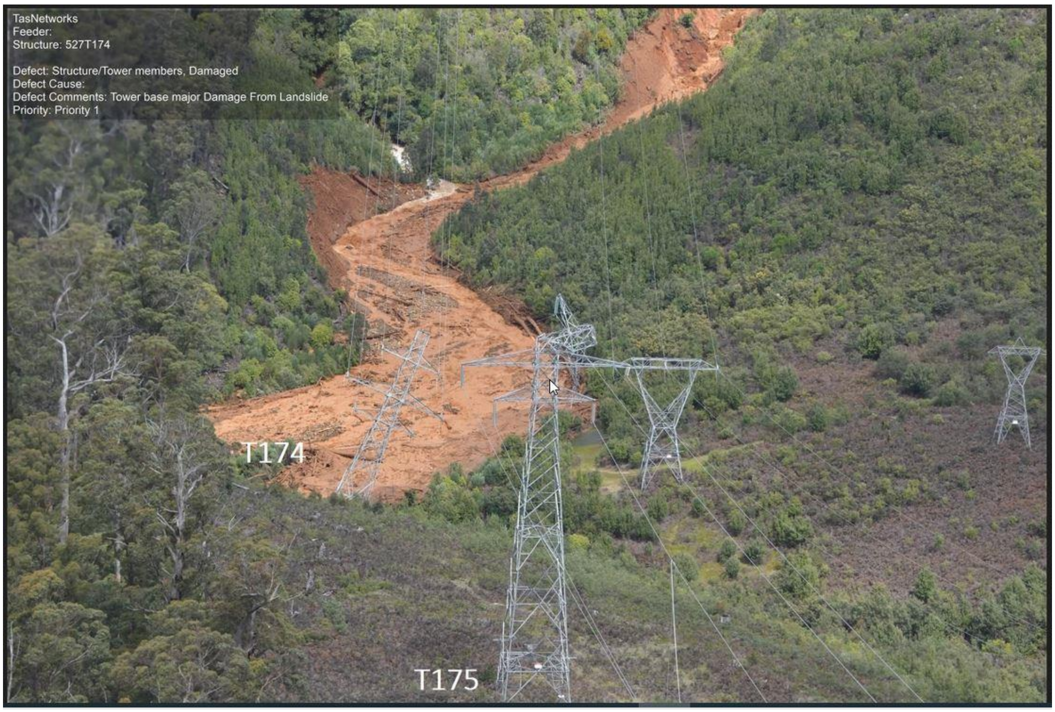
(c) Operation of the only SC unit in southern Tasmania located at Gordon Power Station.

In practice, a small number of additional synchronous generating units operating at PMIN would be needed to lift the Risdon FLN above its minimum requirements as outlined in Section 3.2.1.

Time domain simulations have shown that for the non-credible loss of both PM-WA-LI 220 kV circuits during such operating conditions, the remaining 110 kV circuit is unable to support the southern network, with transient and/or voltage stability being the observed failure mechanisms. As a result, it could be reasonably expected that southern Tasmania would be 'blacked out' for such an event, with coordinated tripping of the remaining PM-WA 110 kV circuit necessary to mitigate the risks then posed to the northern network.

While rare in occurrence, non-credible contingency events do happen. The scenario described above played out in practice on Friday 14 October 2022 following a significant rain event throughout the Central Highlands area. A landslide which passed through TasNetworks' transmission line easement to the south of Palmerston Substation resulted in one 220 kV transmission line tower being destroyed and another being severely damaged (as shown in Figure 6 below). Both 220kV circuits were tripped by protection systems almost simultaneously.

Figure 6 Damage to transmission line TL527 on 14 October 2022 due to a landslide event



Following the loss of the transmission line, the southern network remained stable and energised, with few customers being aware of the significant incident until reported by local media. The synchronous generation profile at the time (state wide, but especially in the south) was sufficient to preserve the integrity of the network even following what was a major transmission network disturbance.

It is important to note that an unstable outcome as predicted by simulations is possible even in today's network without the addition of any further large-scale IBR. Network security assessments do not consider non-credible contingency events until they occur or unless specifically reclassified as credible due to heightened levels of known risk, most typically associated with fire (due to smoke and airborne ash) and lightning activity. What the studies have shown is that with increasing levels of IBR, especially developments in the northern half of the state, the probability of the network being unviable after the occurrence of some non-credible contingency events will likely rise unless mitigation measures are introduced. Without this, studies strongly suggest that the network will tend to become less resilient even though power system security will continue to be managed in accordance with the NER.

A key outcome from the studies has been a heightened awareness of the risks that new IBR operating regimes create and/or elevate in the network. This should be reflected in network planning activities, with increased consideration given to issues such as:

(a) Geographical location of PFR, FCAS, inertia, system strength and dynamic reactive support relative to IBR, as well as load centres, as synchronous generation dispatch profiles change over time.

(b) The need to modify network protection arrangements and/or install fast acting wide area protection schemes to help mitigate the increasing impacts of certain non-credible contingency events, for example, in the case of the PM-WA-LI 220 kV contingency event, a review of out-of-step protection on the PM-WA 110 kV circuit, and/or other fast, coordinated control actions such as under voltage load shedding in the south.

3.3 Analysis of limitations preventing 100% IBR generation under current conditions

The analysis completed to date has demonstrated that 100% IBR generation in Tasmania is not currently possible for the following key reasons:

(a) Inability to guarantee adequate frequency control and thereby remain in a satisfactory operating state immediately following a *credible contingency event*, and to return to a secure operating state within 30 minutes. This issue is particularly relevant for the loss of Basslink with subsequent FCSPS action.

To manage power system security at the present time, market constraints have been implemented to guarantee the dispatch of ±50 MW of regulation FCAS in the Tasmanian region. As well as ensuring consistent availability of regulation FCAS within Tasmania for secondary frequency control via AGC, these constraints also indirectly ensure availability of PFR, noting that the supply of regulation FCAS is currently dominated by synchronous generation. At present, these constraints would prevent the de-commitment of all synchronous generators in Tasmania. The objective is to ensure that sufficient PFR remains available in the absence of Basslink's frequency control capability post-contingency.

(b) Inability to supply sufficient inertia from SC units alone to support peak generation from IBR sources (including Basslink import) to manage ROCOF requirements. Additional support is required from synchronous generators operating at PMIN, which in some cases will be above 0 MW.

It can be noted that AEMO and TasNetworks currently have no mechanisms to force the dispatch of additional inertia services once the secure operating level of inertia has been satisfied, which is below that needed to achieve 100% IBR generation.

(c) Inability to maintain sufficient system strength at the Risdon FLN using existing SC units alone. Additional support is required from synchronous generators operating at PMIN, which is above 0 MW for all machines contracted to provide these services under NER Transitional Rule, efficient management of system strength on the power system[29].

Based on operational history to date, IBR generation is likely to be limited to less than 95% considering the various limitations within the existing network. Operation up to 92% has already been achieved in practice.

The three issues highlighted above will continue to be limiting factors even when more large-scale IBR becomes available in coming years to support practical dispatch outcomes. At the present time, there is only sufficient IBR capacity available to meet relatively low Tasmanian operational demand conditions. With the addition of one new large solar or wind farm (of say >200 MW capacity), there will be sufficient IBR generation to satisfy operational demand on a regular basis if system security conditions permit.

[29] Referenced to NER Version 202.

3.4 Future considerations to enable 100% IBR generation

3.4.1 Further consideration of PFR requirements and BESS opportunities

The addition of at least one grid-forming (**GFM**) BESS into the Tasmanian network would facilitate an increase in the permissible range of IBR generation.

(a) To support high IBR generation scenarios, a BESS would need to be operated with a reserved level of active power headroom and an energy buffer. This would be needed to serve FCAS, in both raise and lower directions, and PFR capability, which is particularly important following the contingent loss of Basslink.

(b) It follows that a BESS would need to be operated in an appropriate frequency control mode at such times.

(c) The reserved active power headroom would need to be large enough to cover the potential sources of active power mismatch in Tasmania following a Basslink trip, until other generation can be brought back online. This would include supply-demand imbalances created by synchronising hydro generation (and bringing up to minimum stable load). BESS active power headroom would also need to help cover normal load variations, FCSPS load tripping mismatches, typical wind output variations, potential market responses from non-scheduled and semi-scheduled generators etc for a period of up to 30 minutes. Further consideration is needed on these issues, however preliminary analysis of the existing Tasmanian network suggests that changes in the supply-demand balance over any 10-minute period are typically within ±50 MW (≈95% probability).

(d) Mechanisms for holding active power headroom for frequency control would need to be determined. They might include FCAS and/or energy market constraints, in which case consideration would need to be given as to how to define such constraints going forward so as to manage system security without unnecessarily imposing enduring market impacts on a small number of service providers. Other mechanisms within the NER may be considered as an alternative to market constraints.

(e) To help manage the impact of ROCOF constraints, each BESS should be capable of providing an instantaneous inertial contribution in response to changes in voltage angle. The AEMO *Voluntary Specification for Grid-forming Inverters*[30] (Voluntary Specification) published in May 2023 describes the properties required of grid-forming inverters to provide grid support attributes. It is considered unlikely that fast frequency response (**FFR**) capability, as deliverable from a grid-following BESS, would be sufficient given the high ROCOF conditions possible in Tasmania and the specific technical requirements now included in the FOS.

3.4.2 Review of ROCOF constraint equations

The existing constraint formulations were developed in 2013 when ROCOF was first identified by TasNetworks as a material system security concern. Definitions and general understanding have progressed significantly since that time, including introduction of formal requirements in the FOS to limit the maximum ROCOF that can be reasonably expected in different regions of the NEM (in effect from 9 October 2023[31]).

[30] At https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf.

[31] See https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022.

TasNetworks has identified a need to review the existing ROCOF constraints with the aim to include its own learnings as well as contemporary understandings coming from industry. This includes formalising calculation methods, noting that network frequency, whether measured or simulated, is an inherently 'noisy' signal that varies across the network during system transients. As part of the update, TasNetworks plans to investigate the 'centre of inertia' concept as described by ENTSOE[32] , as well as the potential use of simulated 'average synchronous speed' to help describe ROCOF in a practical and repeatable manner. It is not yet clear whether inertia requirements will increase or decrease as a result of intended changes to the analysis process.

An agreed methodology on how to calculate ROCOF is recommended for the NEM given recent changes to the FOS. It is impractical to carry out a ROCOF assessment for every bus in each region. The objective should be to develop a method that allows ROCOF assessments to be undertaken in a consistent manner and without undue complexity. It should be noted that changes to existing constraint formulations may impact the quantity of inertia required to achieve 100% IBR generation, as described in this report.

3.4.3 Potential alternate sources of system strength for southern Tasmania

TasNetworks will continue to work with existing and potential non-network service providers to identify technically credible and economically efficient solutions to meet existing and future system strength requirements across the state, including southern Tasmania. As the SSSP, TasNetworks commenced a Regulatory Investment Test for Transmission (**RIT-T**) in August 2023 to begin addressing the forecast system strength requirements from 2 December 2025 onward[33]. A Project Assessment Draft Report is expected to be published by late 2024.

Whether new SC or IBR based solutions emerge during this process that are capable of helping support southern Tasmania is yet to be seen. Considerations will also include timing of any potential new developments, as well as capacity, availability and service costs. This is true for both network and non-network solutions, with the installation of network-owned SC units being one credible option.

3.4.4 Review of UFLS and OFGS schemes in Tasmania

While not specifically examined as part of the preliminary scoping study, the efficacy of the existing under frequency load shedding (**UFLS**) and over frequency generator shedding (**OFGS**) schemes now require review as the probability of high IBR generation scenarios increase, and the future prospect of achieving 100% becomes more credible. While ROCOF will ultimately be contained for credible contingency events via the use of inertia-based constraints, the possibility of experiencing very high ROCOF following non-credible contingency events is growing, as seen in various simulation results. Under NER S5.1.8[34] TasNetworks is required to consider non-credible contingency events. It can be noted that new FOS requirements also now exist which impose 'best endeavours' obligations to manage ROCOF following non-credible contingency events to within ±3 Hz/s measured over any 300 millisecond period.

This issue has strong links to network resilience, as described in Section 3.2.5, especially when new IBR that displaces existing synchronous generation is not located in a similar geographical region of the network (that is,

[32] European Network of Transmission System Operators for Electricity (ENTSOE); "*Inertia and Rate of Change of Frequency (RoCoF)*", Version 17, 16 December 2020.

[33] See http://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Our-current-projects/Meeting-System-Strength-Requirements.

[34] At https://energy-rules.aemc.gov.au/ner/477/272940#S5.1.8

IBR developments in REZ T1, T2, and the northern section of T3 displace synchronous generation located in the south).

An outcome from the preliminary scoping study is a highlighted need to undertake more extensive analysis of non-credible contingency events, including formal consideration of UFLS and OFGS performance. The need for other forms of emergency control/protection schemes should also be considered as part of this review.

3.4.5 Ongoing rollout of phasor measurement units for IBR generator connections

Planning studies and operational experiences from Tasmania continue to underline the importance of two key elements:

(a) The availability of high quality, field verified models which can be used to confidently predict the behaviour of the existing network, as well as provide reasonable insight as to what future issues the network may experience as new equipment is introduced.

(b) The benefits of high speed measurement equipment such as phasor measurement units (**PMUs**) which allow for both real time monitoring and visualisation of the existing network, as well as post-event analysis including dynamic model validation.

Investigation of 100% IBR generation scenarios has been made possible because of the efforts over many years in Tasmania to establish quality processes to deliver both (a) and (b) above. In preparing for an extension to the allowable IBR operating range up to 100%, it is important that the criticality of accurate modelling data is not misunderstood or diluted, and that practical means of validating not only individual models, but the response of the entire closed loop power system, continue to be developed.

A further outcome of the preliminary scoping study has therefore been a strengthened resolve for AEMO and TasNetworks to strategically rollout additional PMUs to not only support operation of the existing Tasmanian network at very high IBR generation levels, but also prepare for an eventual increase to 100% as other system security issues are progressively addressed.

4 Conclusions

The preliminary scoping study was undertaken to identify the most significant system security and reliability concerns arising from operation of the existing Tasmanian network at 100% IBR generation.

From the studies completed thus far, it can be concluded that:

(a) Secure operation of the Tasmanian network at 100% IBR generation is not achievable with the mix of plant and equipment currently available.

(b) Frequency control related issues are a dominating factor, including how to remain in a *satisfactory operating state* following a *credible contingency event* and return to a *secure operating state* within 30 minutes, as well as access to sufficient *inertia* to manage ROCOF.

(c) The geographical distribution of SCs currently available results in system strength deficiencies in southern Tasmania. The issue is currently managed via synchronous generators, with services being delivered from both typical energy market outcomes and contracted capabilities.

(d) Operation of the Tasmanian network at 100% IBR is theoretically achievable with a sufficiently large BESS to manage frequency control requirements across a range of timeframes. A second such unit would provide important redundancy and potentially provide increased inertia support.

(e) From a technical perspective, the need for additional inertial support in Tasmania strongly supports the view that any future BESS should be GFM rather than grid-following.

(f) The market benefit coming from the release of additional IBR capacity, and the corresponding value delivered by one or more GFM BESS, has not been considered thus far. Mechanisms to not only manage headroom in real time, but also how to financially compensate for inertia provisions over and above minimum requirements[35], are issues to be further explored.

(g) The development of one or more BESS installations may assist with providing some system strength support into southern Tasmania, especially if connected at 220 kV. If not, this particular network requirement may continue to drive some minor energy contributions from hydro generating units located in the south of the state, until such time that alternative solutions become available.

(h) Operation at 100% IBR generation in Tasmania would require proper consideration and mitigation (where determined to be necessary) in order to avoid negative impacts on network resilience, especially following non-credible contingency events. Action may be needed to manage any increased risk of major supply disruptions during periods of very high IBR operation. There is a need to carefully consider the impact on emergency frequency control (**EFC**) schemes and other protection schemes as high IBR generation scenarios begin to occur on a more frequent basis.

[35] As defined by the *secure operating level of inertia* in the NER.