TasNetworks Annual Planning Report 2024

TasNetworks

Powering a Bright Future

Contents

Executive summary

Tasmanian Networks Pty Ltd (TasNetworks) is a Transmission and Distribution Network Service Provider within the Tasmanian jurisdiction of the National Electricity Market (NEM) and has been appointed by the Minister as the Jurisdictional Planning Body. We undertake continuous reviews of the adequacy of the Tasmanian electricity transmission and distribution networks to meet both current and future needs and to optimise network development plans. We are also the Tasmanian System Strength Service Provider and Inertia Service Provider.

This combined transmission and distribution Annual Planning Report (**APR**) has been prepared in accordance with the National Electricity Rules (**the Rules**) and jurisdictional requirements and provides an overview of our existing networks and considers several key developments and activities that will shape them over the next 10 years; chiefly:

- variable renewable energy generation growth;
- progression of development of a renewable hydrogen industry;
- increased interconnection capacity with the mainland; and
- contributions of the Tasmanian power system to national objectives, such as the Australian Energy Market Operator's Integrated System Plan (**ISP**).

Renewable energy development

The Tasmanian Government continues to progress the Tasmanian Renewable Energy Action Plan (**TREAP**) aimed at delivering the legislated Tasmanian Renewable Energy Target (**TRET**) of 21,000 GWh per year of renewable generation by 2040 and meeting "the State's strategic direction on climate change, renewable energy growth and emissions reduction while maintaining a secure, sustainable, and affordable energy system". Hydrogen is a key component of the TREAP and is guided by the Tasmanian Renewable Hydrogen Action Plan (**TRHAP**).

As an outcome of work completed under its Renewable Energy Coordination Framework the Tasmanian Government is developing a Renewable Energy Approval Pathway that will support projects entering the Major Projects assessment process. This should assist with significant augmentation the transmission network and development of up to 3,000 MW of new installed wind generation capacity needed to meet the TRET, achieve hydrogen ambitions as guided by TRHAP, and to take advantage of Tasmania's flexible hydropower to be a major contributor to firming variable renewable generation across the NEM.

Renewable energy zones

Four candidate Tasmanian Renewable Energy Zones (**REZ**) have been identified; being:

- North East Tasmania REZ;
- North West Tasmania REZ;
- Central Highlands REZ; and
- North Tasmania Coastal REZ.

After announcing the north-west of Tasmania to be the first region to be explored for the development of a REZ, the Tasmanian Government, through its REZ Coordinator, commenced consultation on the candidate REZ in north-west Tasmania to inform any REZ declaration and new legislation needed to support REZ objectives. Prospective wind developments proposed for the north-east and far north-east region of Tasmania have a combined capacity exceeding 2,000 MW. Hosting capacity of the overall REZ is currently limited to approximately 400 MW thus requiring substantial new transmission line or cable capacity to connect to the George Town area.

There is a combined interest of approximately 1,600 MW of new generation in the North West Tasmania REZ including Hydro Tasmania's preferred Lake Cethana

pumped hydro energy storage site. There is capability in the existing North West Tasmania REZ transmission network to accommodate approximately 277 MW of new generation into Burnie and Sheffield.

There are proposals for 1,544 MW of new wind generation in Central Highlands REZ and the Tarraleah power station repurposing to a 190 MW, 220 kV connection. The existing transmission network within the REZ has the capability to host approximately 530 MW of new generation, limited by both the Waddamana–Palmerston transmission corridor capability and the transmission network from the Central Highlands REZ to the rest of the network.

New industry

The development of Marinus Link and forecast large-scale hydrogen will more than double the energy transmitted through the network, forecast to exceed 20,000 GWh / annum, an increase of 200% over the next 20 years, requiring additional energy supply in excess of the legislated TRET.

The Tasmanian Government is highly supportive of a green hydrogen industry in Tasmania. The TRHAP identifies two locations for large-scale renewable hydrogen production and potential export facilities; the Bell Bay Advanced Manufacturing Zone, and industrial precincts in north-west Tasmania (such as Port Latta or Burnie).

The TRHAP presents a potential 1,000 MW of new demand supporting hydrogen production in Tasmania. This is significant in comparison with the size of the existing Tasmanian power system. As such, the integration requirements of large-scale hydrogen production into the Tasmanian network require careful consideration. The network requirements to facilitate hydrogen development will depend on the size, location, and technology of the loads.

Integrated System Plan

The Australian Energy Market Operator (**AEMO**) published its biennial Integrated System Plan (**ISP**) in June 2024, being a whole-of-system plan forecasting the generation mix and changes in consumer behaviour and develops an optimal development path to deliver reliable and affordable power to meet NEM needs for at least 20 years.

The ISP confirms Project Marinus as a single "actionable ISP project" without decision rules. Project Marinus includes Marinus Link and North West Transmission Developments (**NWTD**).

Three new projects in Tasmania are included in the optimal development path:

- Waddamana to Palmerston transfer capability upgrade (a newly actionable ISP project);
- North West Tasmania REZ Expansion (a future ISP project); and
- Central Highlands REZ Extension (a future ISP project).

The actionable status of the Waddamana to Palmerston transfer capability upgrade project means that TasNetworks is required to publish a Project Assessment Draft Report (**PADR**) by 26 June 2025.

In addition to the existing Tasmanian on island REZs identified in the 2022 ISP, the 2024 ISP amalgamates the offshore wind zones into a single North Tasmania Coast REZ.

Interconnection with the Mainland

Marinus Link Pty Limited (**MLPL**) continues to work toward making a final investment decision in May 2025 for Marinus Link, a 1,500 MW capacity electricity interconnector between Tasmania and Victoria, comprising two 750 MW staged cables along with advanced converter technology required to interface with the grid.

In April 2023, MLPL lodged with the Australian Energy Regulator (**AER**) an application for a revenue determination for Marinus Link. The AER's Commencement and Process Paper sets out a staged approach. MLPL executed a major contract with Prysmian to supply the project's high-voltage direct current cables covering the design, manufacture, supply and installation for the 750 MW Stage 1 for a 2030 completion.

MLPL separated from TasNetworks on 22 March 2024 and became a stand-alone entity under a new three-part equity ownership structure between the Australian Government (49%), the Victorian Government (33.3%) and the Tasmanian Government (17.7%).

Basslink is a nominal 500 MW interconnector connecting the 220 kV Tasmanian transmission network at George Town Substation with the 500 kV Victorian transmission network at Loy Yang Substation. Basslink also has a number of fibre optic assets that carry high speed bandwidth services.

Basslink owners, APA Group, applied for a determination from the AER that, from 1 July 2025, Basslink network service will cease to be classified as a market network service, and instead be classified as a prescribed transmission service. The AER is considering Basslink's Conversion Application and Transmission Revenue Proposal.

North West Transmission Developments

The development sequence of the NWTD supporting Marinus Link was reviewed to ensure that the minimum network requirements for the initial single Marinus Link cable are met at least cost with the ability to further develop the network to support Marinus Link's ultimate capability of 1,500 MW.

The outcome of this assessment was to prioritise the first stage of Marinus Link and a re-scoped first stage of the NWTD comprising:

- a new double circuit transmission coastal route between Sheffield and Burnie, with a cut in at Heybridge, and
- augmentation of the Palmerston–Sheffield 220 kV transmission corridor that is likely to be required under the majority of future scenarios—irrespective of which scenario(s) ensue or in what order.

The balance of the NWTD would be developed in support of the second Marinus Link cable and comprise:

- new double circuit transmission lines between Burnie, Hampshire, and Staverton.

Waddamana to Palmerston transfer capability upgrade

The ISP designates the Waddamana–Palmerston transfer capability upgrade as a newly actionable ISP project on the ISP optimal development path across all scenarios.

The identified credible option is to build:

- a new (second) Waddamana–Palmerston 220 kV transmission line; and
- two power flow controllers on the Sheffield–Palmerston 220 kV transmission line.

This option would occur with Marinus Link and North West Transmission Developments (NWTD) to provide a pathway for the new generation from the Central Highlands REZ to the rest of the transmission network.

North West Tasmania REZ Expansion

We are considering North West Tasmania REZ development scenarios where the network is augmented by means of bringing forward components of the balance of the NWTD ahead of Marinus Link stage 2. The ISP designates this North West Tasmania REZ Expansion as a future ISP project.

Central Highlands REZ Extension

The ISP identifies subsequent increases to network capacity, established through the initial Waddamana to Palmerston upgrades, as a future ISP project. The Central Highlands REZ extension comprises the construction of a second Palmerston to Sheffield transmission line, increasing the power transfer from the Central Highlands REZ to the North of the Tasmanian network and the broader NEM. This project is envisioned to be developed over the longer planning timeframe in 2042-43.

Community Batteries

Community batteries are emerging as an innovative solution to enhance energy resilience and sustainability. TasNetworks has successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program. The batteries will be located in Shorewell Park, in the north of the State, and Glebe Hill, in the south.

TasNetworks' Revenue Determination

Every five years, TasNetworks is required to prepare and submit revenue proposals to the AER outlining forecast expenditure to build, operate and maintain the distribution and transmission networks for the next regulatory control period. These proposals must also specify the proposed prices for network services and public lighting, and the network charges (tariffs) that will be used to recover revenue from customers.

To balance customer preferences, TasNetworks made strategic trade-offs in its Combined Transmission and Distribution Proposal to place downward pressure on costs without compromising reliability and safety or undermining other priorities. On 30 April 2024 the AER made its final determination on allowed transmission and distribution revenues for the period 1 July 2024 to 30 June 2029 tabled below.

AER's Final Determination for 2024-2029 regulatory control period

Final determination	Five-year capital expenditure ($m)	Five-year operating expenditure ($m)	Five-year revenue	Indicative prices ($m)
Transmission	287.8	209.2	819.1	$12.77/MWh[1]
Distribution	729.1	541.0	1,705.7	$933 p.a. – residential[2] $3,311 p.a. – small business[3]

1 The average $/MWh over the 2024-2029 regulatory control period

2 This represents average 2024-2029 prices ($ real) for a typical residential customer with an annual energy consumption of 7,834 kWh

3 This represents average 2024-2029 prices ($ real) for a typical small business customer with an annual energy consumption of 33,578 kWh

The revenue proposal process also provides for the consideration of contingent projects; being projects that are reasonably required during the regulatory period. The AER accepted six contingent projects at a total estimated potential investment of $955 million. These projects support the Tasmanian Government's renewable energy objectives, including the TRET and the TRHAP.

System strength and inertia

Careful management of power system security continues to be a high priority to enable connection of forecast levels of inverter-based resources. Modelling associated with the ISP forecasts ongoing shortfalls for both system strength and inertia network services in the Tasmanian region.

Contractual arrangements to address existing system strength and inertia network services shortfalls are currently in place until 1 December 2025

Through the *'Efficient Management of System Strength on the Power System'* initiative, the Rules' framework for managing system strength imposed new obligations for System Strength Service Providers that commence on 2 December 2025. Under transitional arrangements, network investments required to meet system strength service provider obligations are considered to be contingent projects.

We are in the process of considering investments required to meet, on a forward-looking basis, the *system strength standard specification* published by AEMO and are currently conducting a Regulatory Investment Test for Transmission (RIT-T) to procure additional system strength services under the new framework.

We welcome feedback

TasNetworks welcomes feedback and enquiries on our APR, particularly from anyone interested in discussing opportunities for alternate solutions to those identified in this APR. Please send feedback and enquiries to: **planning.enquiries@tasnetworks.com.au**

Potential demand management solution providers can also register with us via our Industry Engagement Register on our website at: **www.tasnetworks.com.au/forms/Industry-Engagement-Register/Industry-Engagement**

Chapter 1

Tasmanian renewable energy transformation

- The overarching direction of our company strategy is to deliver safe, reliable, and affordable electricity services to Tasmania.
- The Tasmanian Government, through Renewables, Climate and Future Industries Tasmania (**ReCFIT**), as the Renewable Energy Zone Coordinator, commenced consultation on the candidate Renewable Energy Zone (**REZ**) in north-west Tasmania.
- Funding of $70 million from the Australian Government's Regional Hydrogen Hubs program was confirmed to support investment in a Tasmanian Green Hydrogen Hub at Bell Bay.
- Government support continues for the development of Marinus Link, the North West Transmission Developments (**NWTD**), and Hydro Tasmania's Battery of the Nation (**BOTN**) and Tarraleah power station redevelopment.
- The Australian Energy Market Operator (**AEMO**) published the 2024 Integrated System Plan (**ISP**), in which Marinus Link is considered a single actionable ISP project and the Waddamana-Palmerston 220 kV transmission upgrade is included as a newly actionable ISP project.
- Marinus Link Pty Ltd (**MLPL**) separated from TasNetworks on 22 March 2024 to become a stand-alone transmission network service provider.
- The Australian Energy Regulator (**AER**) continues to consider MLPL's application for a revenue determination for the period 2025 to 2030.
- We successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program.
- The AER made its final determination on TasNetworks' transmission and distribution revenues for the period 1st July 2024 to 30th June 2029.

Chapter 2

Tasmanian power system

- Tasmanian generation (hydro, wind, gas and embedded generation) provided 94% of the State total energy requirements, with 6% or approximately 637 GWh of energy import into Tasmania in 2023.
- Our transmission–connected customers, dominated by four major industrial customers, were responsible for 37% of the total network maximum demand and consuming 51% of the total energy delivered through the transmission network in 2023.
- Under the step change scenario, presented in the Australian Energy Market Operator's (**AEMO**) 2024 Integrated System Plan (**ISP**), an increase in consumption is forecast for the second half of the decade largely due to the anticipated emergence of the hydrogen production industry.
- The development of Marinus Link and forecast large-scale hydrogen will more than double the energy transmitted through the network, with network maximum demand forecast to increase 250% over the next 20 years, requiring additional energy supply in excess of the legislated Tasmanian Renewable Energy Target (**TRET**).

Chapter 3

Transmission Network Developments

- Tasmanian transmission planning activities continue to focus on the optimum development path for the network to accommodate future large-scale renewable energy sources, new interconnection with Victoria, upgrading of existing power stations, export-scale hydrogen, and integration of energy "firming" facilities such as battery energy storage systems (**BESS**) and pumped hydro energy storage (**PHES**) stations.
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions to renewable energy sources, informed by the Tasmanian Renewable Energy Target (**TRET**), inclusive of plans to develop a renewable energy hydrogen industry, and identification by the Australian Energy Market Operator (**AEMO**) of Renewable Energy Zones (**REZs**) and transmission augmentation.
- The North West Transmission Developments (**NWTD**) project will be delivered across two stages, focusing on the delivery of stage 1 until a final investment decision is made on the second Marinus Link cable. Stage 1 is planned to commence construction in 2025-26 to align with construction of the first Marinus Link cable and will establish a connection between Sheffield, Burnie and Marinus Link via a coastal route.
- In mid-2023 we undertook the required steps to register a notified corridor for the proposed alignment of the NWTD in accordance with the Major Infrastructure Development Approvals Act 1999 (**MIDAA**).
- We reaffirmed that augmentation of the Palmerston–Sheffield 220 kV transmission corridor is likely to be required under the majority of future scenarios—irrespective of which scenario(s) develop or in what order.
- In addition to stages 1 and 2 of the Marinus Project, we note the inclusion of the Waddamana-Palmerston corridor upgrade as a newly actionable project in Tasmania in the 2024 Integrated System Plan.

Chapter 4

Area planning constraints and developments

- Four geographic planning areas are considered: North West and West Coast, Northern, Central, and South.
- Details of planned augmentations and replacements are provided by planning area.
- Targeted reliability improvement projects continue for specific reliability communities.
- Exemptions from jurisdictional planning requirements are retained for three locations, with a new five-year exemption of the Farrell-Savage River-Waratah line in the transmission network in the North West and West Coast planning area.
- Feedback is welcomed on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

Chapter 5

Network security performance

- Due to limited load growth over the last 12 months, Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources (**IBR**), predominantly comprising wind farm generation and Basslink import. Given that very little synchronous generation is being dispatched at these times, careful management of power system security continues to be a high priority.
- Modelling associated with AEMO's 2024 Integrated System Plan (**ISP**) forecasts ongoing shortfalls for both system strength and inertia network services in the Tasmanian region. Contractual arrangements to address existing shortfalls are currently in place until 1st December 2025.
- The National Electricity Rules (the Rules) framework for managing system strength introduced significant new obligations for System Strength Service Providers (**SSSP**) commencing on 2nd December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (**NEM**). The new framework introduces a completely new approach for the procurement and payment of system strength services, including proactive planning obligations for SSSPs which now form part of the System Standards within the Rules. TasNetworks is currently conducting a Regulatory Investment Test for Transmission (**RIT-T**) to procure additional system strength services under the new framework.

Chapter 6

Service delivery performance

- 2023 transmission system performance remained within target for transmission, transformer and capacitor circuit fault outage rate metrics. While transmission Loss of Supply (**LOS**) event counts over 0.1 and 1.0 system minutes were on target, the average outage duration of all LOS events was outside the target.
- Distribution network performance for 2023–24 was generally outside the Tasmanian Electricity Code (**the Code**) reliability standards as well as the Service Target Performance Incentive Scheme (**STPIS**) targets set by the Australian Energy Regulator (**AER**).
- There are over 55,000 Distributed Energy Resource (**DER**) systems with an installed capacity of 330 MW, a 16% increase over the course of 2023-24 financial year.

Chapter 1

Tasmanian renewable energy transformation

- The overarching direction of our company strategy is to deliver safe, reliable, and affordable electricity services to Tasmania.
- The Tasmanian Government, through Renewables, Climate and Future Industries Tasmania (**ReCFIT**), as the Renewable Energy Zone Coordinator, commenced consultation on the candidate Renewable Energy Zone (**REZ**) in north-west Tasmania.
- Funding of $70 million from the Australian Government's Regional Hydrogen Hubs program was confirmed to support investment in a Tasmanian Green Hydrogen Hub at Bell Bay.
- Government support continues for the development of Marinus Link, the North West Transmission Developments (**NWTD**), and Hydro Tasmania's Battery of the Nation (BOTN) and Tarraleah power station redevelopment.
- The Australian Energy Market Operator (**AEMO**) published the 2024 Integrated System Plan (**ISP**), in which Marinus Link is considered as a single actionable ISP project and the Waddamana-Palmerston 220 kV transmission upgrade is included as a newly actionable ISP project.
- Marinus Link Pty Ltd (**MLPL**) separated from TasNetworks on 22 March 2024 to become a stand-alone transmission network service provider.
- The Australian Energy Regulator (**AER**) continues to consider MLPL's application for a revenue determination for the period 2025 to 2030.
- We successfully acquired funding for multiple community batteries through the Australian Government's Community Batteries for Household Solar program.
- The AER made its final determination on TasNetworks' transmission and distribution revenues for the period 1st July 2024 to 30th June 2029.

Tasmanian renewable energy transformation

1.1. Introduction

Tasmanian Networks Pty Ltd (**TasNetworks**) is a Transmission and Distribution Network Service Provider within the Tasmanian jurisdiction of the National Electricity Market (**NEM**) and has been appointed by the Minister as the Jurisdictional Planning Body. Under the National Electricity Rules (**the Rules**), as the Jurisdictional Planning Body and the only Tasmanian Transmission Network Service Provider, we are also the System Strength Service Provider and Inertia Service Provider. Accordingly, we present our Annual Planning Report (**APR**) prepared in accordance with the Rules and Tasmanian jurisdictional requirements.

This Chapter outlines:

- Tasmania's role as a participant in the NEM;
- the preparedness of the Tasmanian network for the energy market transition;
- externalities that guide our planning;
- TasNetworks' customers and our interactions with them;
- the purpose of the report and our current consultations on major projects; and
- concludes with a description of significant changes and developments since our 2023 APR.

The Tasmanian Renewable Energy Target (**TRET**)[4] legislates, by the end of 2040, the delivery of 200% of Tasmania's 2020 baseline of 10,500 GWh of renewable generation per year. The 2040 target is therefore 21,000 GWh, with an interim target of 15,750 GWh by the end of 2030.

4 Part 1A – Renewable Energy, Energy Co-ordination and Planning Act 1995, Tasmania

The Tasmanian Government, through ReCFIT,[5] continues to progress the Tasmanian Renewable Energy Action Plan (**TREAP**)[6] aimed at delivering "the State's strategic direction on climate change, renewable energy growth and emissions reduction while maintaining a secure, sustainable, and affordable energy system."[7] Hydrogen is a key component of the TREAP and is guided by the Tasmanian Renewable Hydrogen Action Plan (**TRHAP**).[8]

As an outcome of work completed under its Renewable Energy Coordination Framework (**RECF**)[9] the Tasmanian Government is developing a Renewable Energy Approval Pathway (**REAP**)[10] that will support projects, such as wind farms and transmission lines, entering the Major Projects[11] assessment process under the Land Use Planning and Approvals Act 1993. Components of the REAP include a Renewable Energy Project case management function, provide for the development of sector specific renewable energy information requirements, resourcing of regulatory agencies, and coordinated pre-assessment process.

After announcing the north-west of Tasmania to be the first region to be explored for the development of a REZ,[12] engagement activities during 2023 considered what a REZ could mean to local communities. Subsequently, ReCFIT, as the REZ Coordinator, commenced consultation on the candidate REZ in north-west Tasmania to inform any REZ declaration, including any new legislation needed to support REZ objectives.[13]

5 https://recfit.tas.gov.au/home

6 https://recfit.tas.gov.au/renewables/tasmanian_renewable_energy_action_plan

7 https://www.stategrowth.tas.gov.au/recfit/about_us

8 https://www.stategrowth.tas.gov.au/__data/assets/pdf_file/0013/313042/Tasmanian_Renewable_Hydrogen_Action_Plan_web_27_March_2020.pdf

9 https://recfit.tas.gov.au/__data/assets/pdf_file/0007/343618/Renewable_Energy_Coordination_Framework_May_2022_web.pdf

10 https://recfit.tas.gov.au/renewables/renewable_energy_approval_pathway

11 https://planningreform.tas.gov.au/planning/major-projects-assessment/major-projects-assessment-process

12 https://recfit.tas.gov.au/renewables/renewable_energy_zones

13 https://www.renewableenergyzones.tas.gov.au/consultation-hub/proposed-rez

TasNetworks supports ReCFIT in its investigations of REZ by providing wide-ranging advice that will inform scenario planning to identify:

- the hosting capability of the existing network for new renewable energy projects in each REZ;
- the network augmentations required once this existing capability is exhausted;
- the type and form of possible REZ transmission assets; and
- the possible delivery mechanisms for these works, including social licence, financing, regulatory and legislative opportunities, and limitations.

Government support continues for the development of Marinus Link, the NWTD, and Hydro Tasmania's Battery of the Nation (**BOTN**)[14] and Tarraleah power station redevelopment.[15] In this regard, the Tasmanian Government is developing a "Whole-of-State" business case in relation to Marinus Link and associated projects to assess their opportunities and risks.[16,17] The business case is to be completed prior to the Marinus Link final investment decision (**FID**).

1.2. What we do

TasNetworks owns, operates, and maintains the electricity transmission and distribution networks in Tasmania and a supporting telecommunications network. TasNetworks is a state-owned company operating as a commercial business with assets of over $3.5 billion.

1.2.1. Transmission and distribution networks

We deliver monopoly and competitive electricity supply services to more than 295,000 residential, commercial, and industrial customers. We undertake our monopoly service obligations in accordance with the Rules as outlined in Appendix A.

Our responsibilities include:

- keeping our people, customers, and the community safe and protecting the environment;
- undertaking the role of Tasmanian jurisdictional planning body in the NEM;
- maintaining and replacing network infrastructure to ensure reliable services for our customers;
- connecting new customers to the network (including small and large-scale generators);
- investing in the network to support capacity growth;
- operating the network on a day-to-day basis, including all fault restoration activities;
- maintaining a public lighting system;
- recording and providing regulated meter data to retailers; and
- providing telecommunications to participants in the Tasmanian electricity supply industry.

We charge for our electricity transport services through a component of prices paid by electricity end-users who purchase either from retailers or directly from the centrally controlled wholesale energy market. The transmission network transfers bulk power from generators, often in remote areas, to transmission-distribution connection points (substations) near load centres throughout Tasmania, and to large customers directly connected to the transmission network. The distribution network distributes electricity to smaller industrial and commercial users, as well as irrigation and residential customers.

We facilitate the transfer of electricity between Victoria and Tasmania via Basslink, a privately-owned, sub-sea high voltage direct current (**HVDC**) electricity interconnector. Our subsidiary businesses provide telecommunications, technology services and connections support.

Tasmania is part of the NEM's eastern Australian power system, which extends from north Queensland to South Australia. Tasmanian large-scale electricity generation is provided by hydro, wind, and thermal (gas-fired) generators located throughout the network. A number of other small generators are connected within the distribution network, termed 'embedded generation', including small hydro and rooftop solar-photovoltaics (**PVs**). The components of the Tasmanian power system are presented in Figure 1-1. The role of TasNetworks is highlighted in blue.

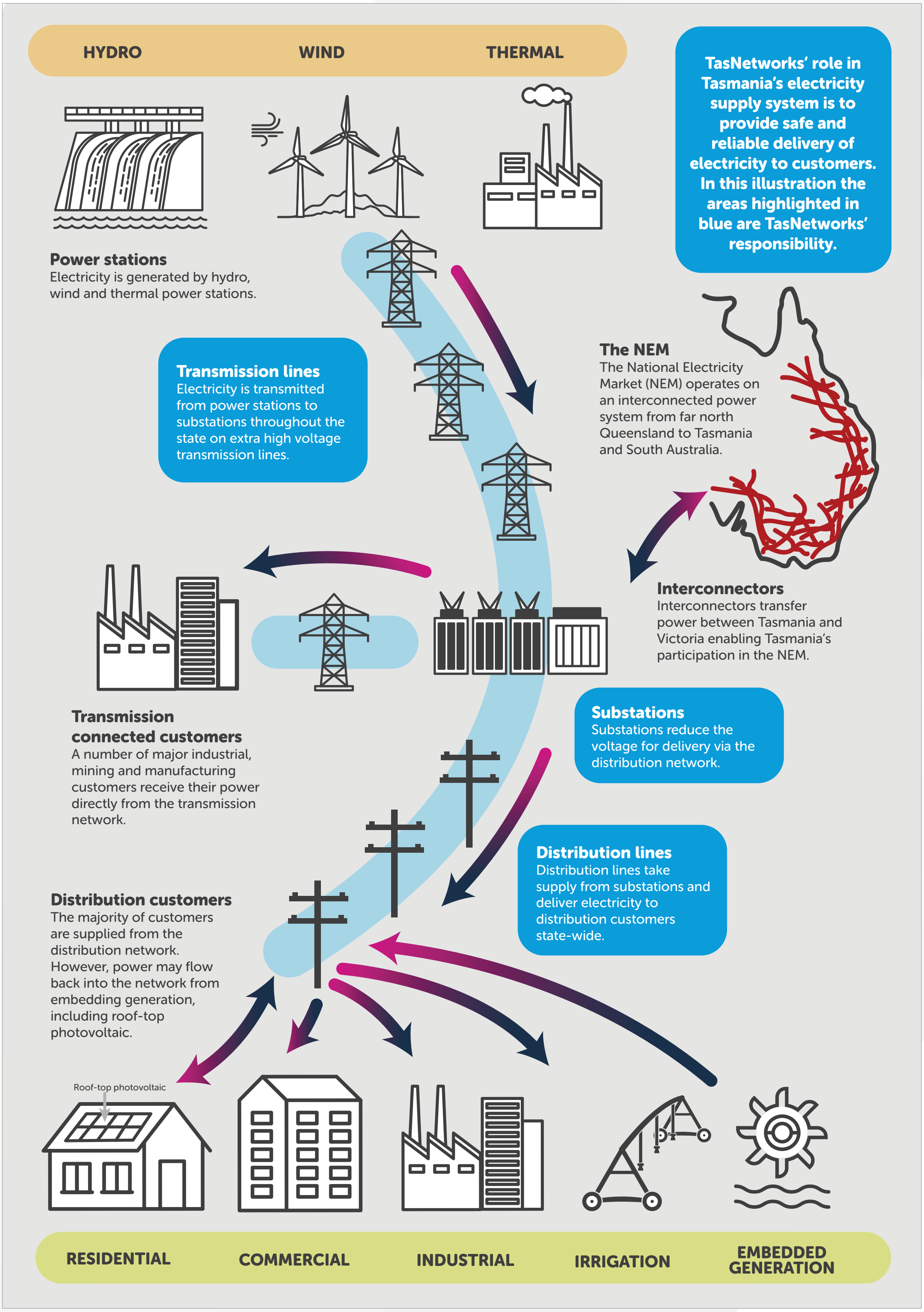
14 https://www.hydro.com.au/clean-energy/battery-of-the-nation

15 https://www.hydro.com.au/clean-energy/battery-of-the-nation/hydro-system-improvement/hydro-system-faqs

16 https://www.parliament.tas.gov.au/__data/assets/pdf_file/0019/74161/HA-Tuesday-5-September-2023.pdf

17 https://www.parliament.tas.gov.au/committees/joint-committees/select-committees/energy-matters-in-tasmania

Figure 1-1: Tasmania's power system



1.2.2. Telecommunications network

The telecommunications network supports the operation of our electricity network interfacing protection, control and data, telephone handsets and mobile radio transceivers. Further details are provided in Chapter 4.

In support of our telecommunications network, a number of telecommunications circuits are provided via a third-party network. This is generally outside our network's coverage area and includes all interstate services.

1.2.3. Subsidiary business functions

Our subsidiary 42-24 provides telecommunications, information technology and data centre services to customers. These are non-electricity services that are legally separated from our regulated distribution and transmission businesses.

TasNet Connections (**TNC**) operates as a fully owned subsidiary business of TasNetworks and is focused on the delivery of non-regulated connection infrastructure. TNC is positioned to build, own, operate, and manage high voltage energy assets and associated services.

1.3. Purpose of this Annual Planning Report

As a key business activity, TasNetworks continuously reviews the adequacy of the Tasmanian electricity networks for both current and future needs. The capabilities of the existing transmission and distribution networks are analysed for their abilities to accommodate changes to electricity load and generation, as well as understanding limitations to meeting the required performance standards. The APR combines our obligations to publish by 31 October each year a Transmission Annual Planning Report in accordance with clause 5.12.2 of the Rules, and a Distribution Annual Planning Report in accordance with clauses 5.13.2 of the Rules and 8.3.2 of the Tasmanian Electricity Code (**the Code**).

We assess both network and non-network options to address any emerging limitations and asset management issues. The intention is that our APR provides existing and potential customers and non-network solution providers with information to prompt discussion on:

- opportunities to address identified network limitations;
- locations that would benefit from supply capability improvements or network support initiatives; and
- locations where new loads or generation could be readily connected.

The APR provides information on our planning activities over a 10-year planning period through to 2034. Some aspects are based on shorter planning time frames. In particular, our distribution line loads are based on a 2- year planning horizon.

1.4. Strategic planning environment

As the jurisdictional planner in Tasmania, our planning activities are undertaken within the Rules' framework. Our network planning strategies consider and support the objectives of the Tasmanian Government's TREAP to utilise renewable energy as a key economic driver in Tasmania.

The following key objectives continue to provide us with guidance for our planning activities:

- enabling Tasmania to deliver the legislated TRET;
- progressing development of a renewable hydrogen industry as outlined in the TRHAP;
- supporting the ISP;[18]
- supporting BOTN initiatives;
- advancing Marinus Link; and
- delivering the NWTD.

Also relevant to the TREAP, is to reduce Tasmania's transport emissions and costs, and improve the State's energy security by supporting the uptake of electric vehicles (**EVs**) powered by locally-produced renewable energy.

1.4.1. Tasmanian Renewable Energy Target

The Tasmanian RECF focuses on how to deliver orderly, sustainable, and integrated large-scale renewable energy projects needed to unlock generation capacity to achieve the TRET. The Framework details four pillars to guide energy growth:

Integrated Infrastructure – to deliver the least cost and optimally located generation and transmission to meet load where it is needed.

Environment – to protect and enhance our State's environmental values – biodiversity, cultural and aboriginal heritage.

Economic – to stimulate job creation and business growth through renewable energy investment to build a skilled workforce for generations.

Community – to engage communities to ensure benefits are tangible and valued and make positive contributions to shaping their future.

18 https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

Tasmania has the key advantage of significant renewable hydropower capacity for firming variable renewable energy sources. To achieve the TRET of 21,000 GWh by 2040 using Tasmania's world leading wind resources, will require up to 3,000 MW of new installed wind capacity. This requirement will change if other renewable energy sources (solar-photovoltaic, ocean, biomass, geothermal) are also developed.

The integration of such large quantities of variable renewable energy (**VRE**) into the Tasmanian electricity system will involve significant developments and augmentation to the transmission network.

1.4.2. Renewable hydrogen and large-scale load connections

Funding of $70 million from the Australian Government's Regional Hydrogen Hubs program was confirmed in January 2024[19] to support investment in a Tasmanian Green Hydrogen Hub at Bell Bay.[20] The funding supports the development of a domestic market in Tasmania and shared-use infrastructure such as port facilities, water supply, and the electricity network.

The first stage will include a hydrogen production plant of up to 300 MW located within the Bell Bay Advanced Manufacturing Zone (**BBAMZ**). The Tasmanian Government continues to work with its consortium partners TasNetworks, TasWater, TasIrrigation, TasPorts, and the BBAMZ.

We continue to see interest from green hydrogen proponents, both for production and consumption, with proposals ranging from large-scale and small domestic consumers, to export-scale developments. Small-scale proposals are being received for connection within the distribution network, while export-scale developments are centred around the BBAMZ and the future north-west network. To reflect the scale of combined proposals in the region, we have considered the network augmentations associated with three tranches of new hydrogen production facilities of up to 1,000 MW in the medium to longer term.

We present more information on hydrogen developments in Chapter 3.

We have also seen interest relating to the establishment of new industries, such as carbon neutral fuel production, and planned demand increases coming from existing industrial customers which would increase energy consumption within Tasmania. We present more information on the impact of large-scale loads on energy forecasts in Chapter 2.

19 https://www.dcceew.gov.au/energy/hydrogen/building-regional-hydrogen-hubs

20 https://recfit.tas.gov.au/future_industries/green_hydrogen/tasmanias_green_hydrogen_hub_vision

1.4.3. Integrated System Plan

AEMO published its biennial ISP in June 2024, being a whole-of-system plan that provides a roadmap for the next 20 years. The objectives of the ISP align with the National Electricity Objectives:

"to promote efficient electricity services for the long-term interests of consumers. This takes in three sets of considerations: reliability and security, price and quality (affordability), and the need to reduce Australia's greenhouse gas emissions."

This objective includes the new emissions reduction element that came into force in the National Electricity Objective of the National Electricity Law in November 2023.[21]

The ISP forecasts the generation mix and changes in consumer behaviour then develops an optimal development path to deliver reliable and affordable power to meet NEM needs for at least 20 years, fulfil security and reliability requirements, meet government policy settings, and manage risk through a complex transformation.

The ISP identifies REZ candidates and Offshore Wind Zone (**OWZ**) candidates across the NEM.

REZs are high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale. New network investment will be required to connect these areas, and efficiently and reliably supply consumers. An efficiently located REZ can be identified by considering a range of factors, primarily the:

- quality of renewable resources, diversity relative to other renewable resources, and correlation with demand;
- cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers;
- proximity to load, and the network losses incurred to transport generated electricity to load centres; and
- critical physical requirements to enable the connection of new resources (particularly inverter-based equipment) and ensure continued power system security.

We present more information on the ISP in Section 3.

21 https://www.aemc.gov.au/regulation/neo#NEO

1.4.4. Marinus Link

MLPL[22] separated from TasNetworks on 22 March 2024 and became a stand-alone entity under a new three-part equity ownership structure between the Australian Government (49%), the Victorian Government (33.3%) and the Tasmanian Government (17.7%).

MLPL continues to work toward making a final investment decision in late 2024 for Marinus Link, a 1,500 MW capacity electricity interconnector between Tasmania and Victoria, comprising two 750 MW staged cables along with advanced converter technology required to interface with the grid.

MLPL selected Hitachi Energy to supply its advanced, high-voltage direct current (**HVDC**) Light® voltage source converter technology for the first stage of Marinus Link.

In April 2023, MLPL lodged with the Australian Energy Regulator (**AER**) an application for a revenue determination for Marinus Link.[23] The AER's Commencement and Process Paper[24] sets out a staged approach comprising:

- Stage 1, Part A (Early works): a revenue determination for pre-construction activities;
- Stage 1, Part B (Construction costs): a construction cost determination; and
- Stage 2: a full revenue determination.

The AER made its determination for Stage 1, Part A, accepting MLPL's proposed $196.5 million ($2022-23) in forecast capex for early works.[25]

We present more information on the progress of Marinus Link and NWTD in Section 1.8.2 and Section 3 of the APR, as well as on our website.[26]

1.4.5. Basslink

Basslink is a HVDC interconnector connecting the 220 kV Tasmanian transmission network at George Town Substation with the 500 kV Victorian transmission network at Loy Yang Substation. Basslink also has a number of fibre optic assets which carry high speed bandwidth services.

The APA Group applied for a determination from the AER that, from 1 July 2025, the Basslink network service will cease to be classified as a market network service, and instead be classified as a prescribed transmission service.[27] APA also submitted a revenue proposal for the five-year period from 1 July 2025 to 30 June 2030.[28] The AER is considering Basslink's Conversion Application and Transmission Revenue Proposal. It has issued a Commencement and Process paper[29] and an amendment[30] including a decision to commence a modified transmission determination process for Basslink.

1.5. Our customers

To help us better understand the varied needs of our customers, we have developed two customer segmentation models that group customers into categories based on similarities and characteristics. Our research included analysis of usage and billing data, behaviours, and attitudes from a cross section of Tasmania's residential and business communities.

The segmentation models enable us to shift to a more customer-centric culture by improving our engagement through targeted activities that are meaningful to each customer segment. We continue to explore ways to improve our customers' experience when they engage with us through continuous process and data improvements and tailored solutions.

Key insights across our customer base include:

- More than half of the energy delivered in Tasmania is to a small number of large industrial and commercial customers that are connected directly to our transmission network.
- The balance of Tasmania's energy consumers are connected to our distribution network and include residential, commercial, small-scale industrial, and irrigation customers, as well as embedded generators.
- While directly connected transmission customers use more energy, our distribution customers contribute more to Tasmanian peak demand.

22 https://www.marinuslink.com.au

23 https://www.aer.gov.au/all-aer-projects/marinus-link-intending-transmission-network-application

24 https://www.aer.gov.au/documents/aer-marinus-link-updated-commencement-and-process-paper-march-2024

25 https://www.aer.gov.au/industry/registers/determinations/marinus-link-determination-2025-28-stage-1-part-early-works/final-decision

26 https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/North-West-Transmission-Developments-and-Marinus-L

27 https://www.aer.gov.au/system/files/Basslink%20-%20Application%20for%20conversion%20and%20request%20to%20commence%20the%20process%20for%20making%20a%20transmission%20determinaton%20-%20May%202023%20%283%29.pdf

28 https://www.aer.gov.au/system/files/2023-09/Basslink%20-%20Conversion%20and%20transmission%20determination%202025-30%20-%2015%20September%202023.pdf

29 https://www.aer.gov.au/system/files/AER%20-%20APA%20Group%20Basslink%20-%20Notice%20of%20decision%20and%20commencement%20and%20process%20paper%20-%20July%202023.pdf

30 https://www.aer.gov.au/system/files/2024-05/AER%20-%20Basslink%20consultation%20paper%20-%20commencement%20and%20process%20paper%20amendment%20-%20May%202024.pdf

- Customers have different levels of engagement appetite with their energy consumption behaviours, which is often based on their lifestyle choices, application, and/or financial position.
- We also provide network access to hydro, wind, and grid-connected solar generation sources, a large capacity natural gas fired power station, and to the Basslink interconnector.

Rising cost of living pressures are elevating our customers' sensitivity to increasing utility prices. We are focused on keeping prices affordable for our customers and have also introduced programs like the Energy Support Program (in partnership with Uniting Tas) to help our customers better understand, manage, and reduce their household energy use.

Our revenue allowance is set by the AER. Each regulatory period is five years, and we submit a combined distribution and transmission revenue proposal to the AER for each new regulatory period. Our proposal sets out our capital expenditure plans and forecasts of operating expenditure, as well as the total revenue required to recover the costs of building, maintaining, and operating Tasmania's electricity transmission and distribution networks. It also balances keeping customer bills affordable with what our customers expect of us, including proactive investment in renewables, consistent service reliability statewide, and a transparent commitment to sustainability.

Each proposal takes several years to develop and requires specialist and focussed effort from across the business to carry out financial forecasting, asset planning, price and tariff modelling, reviews of existing services and policies, and customer and community engagement.

The current regulatory control period started on 1 July 2024. The AER completed its review of our proposal and finalised network charges in April 2024.

1.5.1. Industry Engagement Strategy and Industry Engagement Register

When the capacity of our network approaches a limit, TasNetworks can either increase the available capacity or pursue alternatives such as Stand Alone Power Systems (**SAPS**) and/or demand management to address asset and peak demand issues. Different types of solutions apply to the transmission and distribution networks given the functions of each.

Reducing peak demand is called demand management. Typically, this can be achieved by:

- shifting the demand of certain load segments from peak time to an off-peak time (for example, off-peak heating);
- shedding non-critical loads;
- reducing the electricity used by appliances for short periods (such as hot water load control);
- operating generators within a customer's installation; and
- installing battery storage and using some of the battery capacity to address peak demand issues (including customer-owned batteries).

Long power lines that traverse difficult terrain to serve remote customers must be maintained to the same standard as all other lines in our network. The ongoing cost required to keep such lines operational may be higher than the cost involved in constructing and maintaining a SAPS that provides an off-grid supply.

At TasNetworks we are currently investigating the development of a framework to support our analysis of non-network solutions. Our objective is to work with our customers to identify cost-effective non-network and SAPS solutions which allow us to defer or avoid the need for network investment and reduce the long-term costs of our network. We offer financial incentives to those who can provide solutions. Our current process for assessing these solutions is outlined in Appendix A.6.

Network support payments are available to our customers, or a third party contracted by us to provide network support services. This is subject to our network having an identified limitation and a formal agreement with the customer or provider.

To deliver solutions for our distribution network, we have developed an Industry Engagement Strategy that explains how we will engage and consult with our customers and suppliers. We encourage providers to register with us on our website:

https://www.tasnetworks.com.au/Forms/Demand-Management-Industry-Engagement-Register

1.5.2. Electric vehicles

Australia is increasing its uptake of EVs as part of a broader move towards decarbonisation and electrification. Roughly a third of light vehicle sales globally by 2030 will be EVs, which will have significant implications for electrical utilities such as TasNetworks. We are working towards better understanding our customers' expectations and evolving needs to determine the best way to integrate EVs and other emerging technologies into our network. Our vision is to be an enabler of EV uptake. We want our customers to easily connect to our network at an affordable price.

As part of this process, we are investigating what would be required to enable third parties to install EV chargers on existing power poles within the distribution network. This includes understanding the risks to safety and operation of the network, and how such devices could be integrated safely and efficiently. Uplift in the customer connection process, legal arrangements, and asset data management are also being considered to ensure pole mounted EV chargers can deliver benefits to end users. This EV charging infrastructure is generally targeted at residential areas or destinations where off-street parking and other public EV charging is not available. TasNetworks has received interest from equipment suppliers and the community around the deployment of this technology in Tasmania.

1.5.3. Community batteries

Community batteries are emerging as an innovative solution to enhance energy resilience and sustainability. These shared energy storage systems allow communities to store excess solar power generated during the day and use it during peak demand periods or at night. By doing so, they help reduce electricity costs, lower carbon emissions, and improve grid stability. Community batteries also facilitate greater participation in renewable energy initiatives, offering a practical way for communities to collectively manage and optimise their energy resources.

TasNetworks has successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program.[31] The batteries will be located in Shorewell Park, in the north of the State, and Glebe Hill, in the south.

1.6. TasNetworks' strategy

We have refreshed our company strategy to identify and focus on what is most important to our customers and the Tasmanian community to deliver safe, reliable, and affordable electricity services to Tasmania.

We consider external market trends that influence our business to clearly identify what we need to do to meet stakeholder expectations and deliver meaningful and sustainable change. Our strategy provides the framework to help us organise and track progress of the strategic pillars and priorities we need to focus on to continue Powering a Bright Future for Tasmania, chiefly;

- **To understand and respond to our customers and communities**

By better understanding what is important to our customers and the Tasmanian community, so we can deliver the services they value.

- **To deliver operational excellence**

We maintain our continued commitment to keep our people, the community, and the environment safe, deliver reliable and affordable electricity services, and manage our operations efficiently to keep our costs as low as possible.

- **To innovate in a targeted way**

We adapt to changing customer needs through innovation. We are targeting areas of our network and ways of working to improve our performance and keep prices affordable for customers.

We have also defined four key business objectives that have our core product of safe, reliable, and affordable power at the heart of them and puts our customers at the centre of our decision making. They also recognise the wider role that TasNetworks plays in the community.

- **Enhance the safety and wellbeing of our people**

We do not compromise the safety and wellbeing of our people, our customers, our communities, or the environment. Our performance metrics are focused on the physical, psychological, and environmental wellbeing of these stakeholders.

- **Deliver value for our customers**

We strive to deliver value for our customers and meet their expectations in every action we take. Our focus is on the quality of customers' and other stakeholders' experiences with us and how we perform against their needs and expectations.

- **Supply reliable essential services**

We understand our services are critical and need to be reliable, and we recognise our role to serve and create value for Tasmania. We have an opportunity to proactively drive reliability and sustainability for the Tasmanian community.

- **Provide a sustainable financial return**

We seek to balance affordable prices for customers and provide sustainable profits to our shareholder, the Tasmanian Government. We are focused on the efficiency of our operations, so our profits can be reinvested to benefit the Tasmanian community.

31 https://www.dcceew.gov.au/energy/renewable/community-batteries

1.7. TasNetworks' Revenue Determination

Every five years, TasNetworks is required to prepare and submit revenue proposals to the Australian Energy Regulator (**AER**) outlining forecast expenditure to build, operate and maintain the distribution and transmission networks for the next regulatory control period. These proposals must also specify the proposed prices for network services and public lighting, and the network charges (tariffs) that will be used to recover revenue from customers.

In developing its transmission and distribution regulatory proposal (**Combined Proposal**), TasNetworks engaged with its customers and stakeholders to identify and understand what is important to them, and to build their knowledge and understanding of the energy sector and TasNetworks' business. As summarised in Figure 1-2, their insights helped shape a Combined Proposal reflective of the key themes of affordability, managing the renewable energy transition, network reliability and resilience, and social responsibility and sustainability.

To balance these customer preferences, TasNetworks made strategic trade-offs in its Combined Proposal to place downward pressure on costs without compromising reliability and safety or undermining other priorities.

Figure 1-2: Key themes from customer engagement activities

On 30 April 2024 the AER made its final determination on allowed transmission and distribution revenues for the period 1 July 2024 to 30 June 2029.[32] The determination provides TasNetworks with the funding needed to balance cost, risk and performance while delivering safe, reliable, and affordable electricity to its transmission and distribution customers.

The AER sought to adopt a balanced approach in making its determination, accepting our proposed capital and operational expenditure as being likely to deliver efficient customer outcomes; that is, customers are only paying for what is both necessary and in their long-term interests. A summary of the AER's Final Determination and the projected impact on customer prices is provided in Table 1-1.

32 https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29

Table 1-1: AER's Final Determination for 2024-2029 regulatory control period

Final determination	Five-year capital expenditure ($m)	Five-year operating expenditure ($m)	Five-year revenue ($m)	Indicative prices
Transmission	287.8	209.2	819.1	$12.77/MWh[33]
Distribution	729.1	541.0	1,705.7	$933 p.a. – residential[34] $3,311 p.a. – small business[35]

Figure 1-3 and Figure 1-4 show the drivers of capital expenditure that TasNetworks' has forecast as being required in the 2024-2029 regulatory control period (excluding capitalised overheads). While TasNetworks' actual expenditure in the period is likely to vary from this forecast, it is still a valuable demonstration of the range of activities required to manage the transmission and distribution networks, and the balance of those investments.

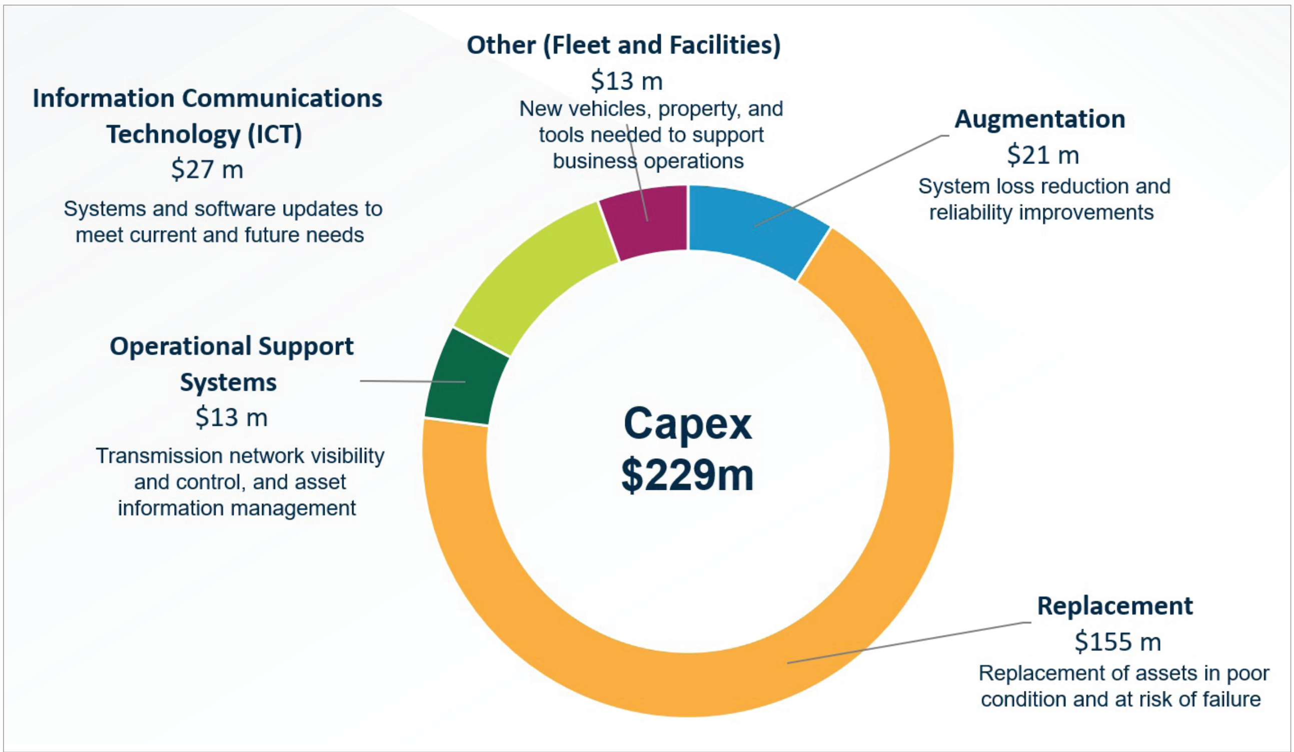


Figure 1-3: Forecast transmission CAPEX (excluding capitalised overheads)

33 The average $/MWh over the 2024-2029 regulatory control period

34 This represents average 2024-2029 prices ($ real) for a typical residential customer with an annual energy consumption of 7,834 kWh

35 This represents average 2024-2029 prices ($ real) for a typical small business customer with an annual energy consumption of 33,578 kWh

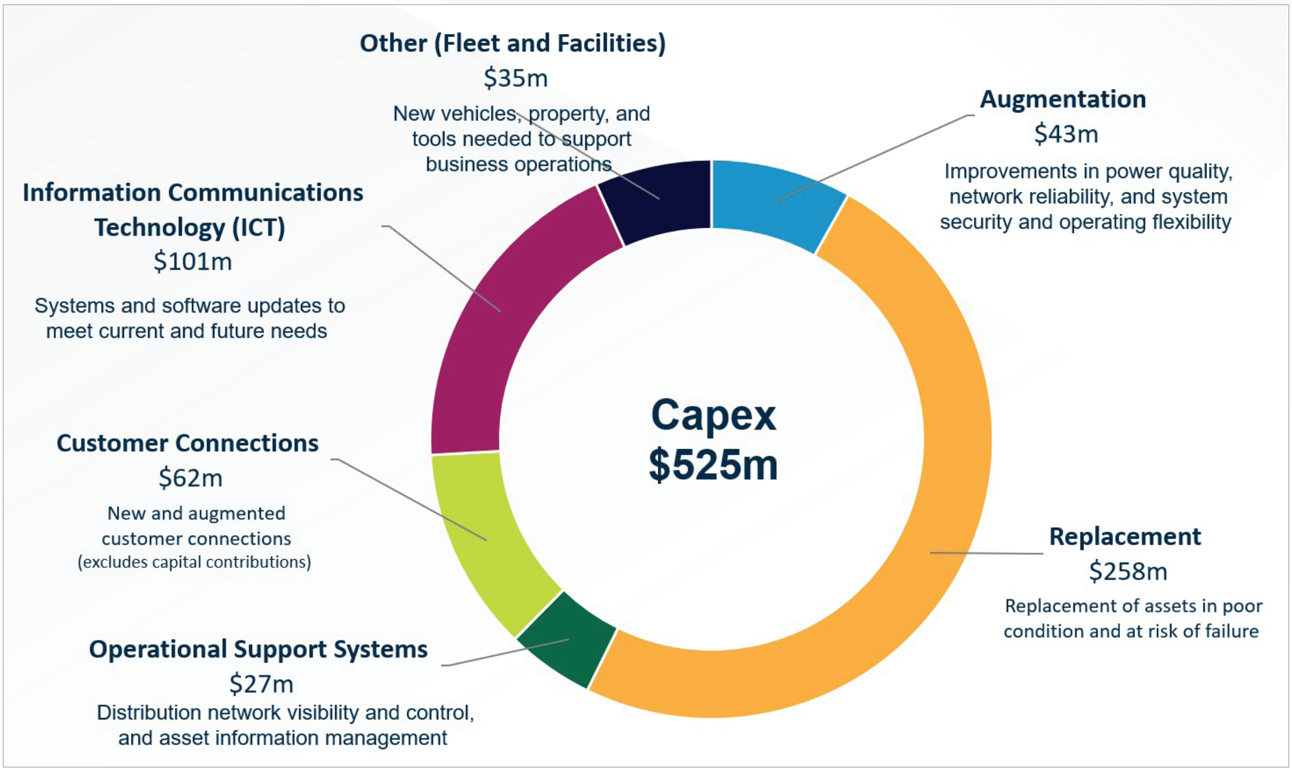


Figure 1-4: Forecast distribution CAPEX (excluding capitalised overheads)

The revenue proposal process also provides for the consideration of contingent projects, being projects that are reasonably foreseeable during the regulatory period, but where the need within the period, and associated costs, are not sufficiently certain. They are initiated by defined "trigger events" that are sufficiently likely to occur and are capable of being objectively observed in the regulatory period.

The AER accepted six contingent projects at a total estimated potential investment of $955 million. The cost allocation for each project is summarised in Table 1-2. These projects support the Tasmanian Government's renewable energy objectives, including the TRET and the TRHAP. For projects that are triggered by new load, it is expected that the network charges paid by the new customer(s)' will offset some of the costs experienced by the existing customer base.

Under the transitional arrangements established through the *Efficient Management for System Strength on the Power System* Rules change,[36] network investments required to meet TasNetworks' system strength service provider obligations are treated as contingent projects as detailed in Chapter 5.[37]

36 https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

37 The new system strength framework will come into effect on 2 December 2025 with new NER provisions. This may in turn affect the treatment of projects and the manner in which they are progressed.

Table 1-2: Transmission contingent projects

Contingent project	Driver	Project summary	Indicative cost ($m, 2023-24)
George Town Network Upgrade	New load connecting to the transmission network in the George Town-Bell Bay area	Install additional reactive support, rearrange the 220 kV connections at the existing George Town Substation and establish a new substation in the Bell Bay area to allow connection of new load while maintaining compliance with the (Network Planning Requirements) Regulations 2018 (ESI regulations).	135
Palmerston to Sheffield Network Upgrade		Upgrade the transmission corridor between Palmerston and Sheffield to allow connection of new load while maintaining compliance with the ESI regulations. This is a separate trigger event which differentiates the contingent project application from Marinus Link activities. This project also forms part of the network investment associated with the North West Transmission Developments to support Marinus Link.	240
George Town Reactive Support		Provide additional dynamic reactive support to meet power system voltage and system stability requirements following load connections in George Town. The load trigger for this project is in addition to that triggering the George Town Network Upgrade contingent project.	90
Sheffield to George Town Network Upgrade		Upgrade the transmission corridor between Sheffield and George Town to reduce thermal and stability constraints following new load connections in George Town. The load trigger for this project is in addition to that triggering the George Town Network Upgrade contingent project.	188
Waddamana to Palmerston Transfer Capability Upgrade	New generation in the Central Highlands or Southern Tasmania	Upgrade the transmission corridor between Waddamana and Palmerston to maintain power flows within thermal and/or stability limits following connection of new generation in central or southern Tasmania.	128
North West Network Upgrade	New generation and/or load in the north west of Tasmania	Following changes to the proposed North West Transmission Developments to support Marinus Link, upgrade the transmission corridor between Burnie and Hampshire to support additional power flows following connection of new generation and/or load in North West Tasmania.	174

1.8. Project consultations

We undertake RIT**s** for both transmission (**RIT-T**) and distribution (**RIT-D**) network investments that exceed the cost threshold of $7 million and $6 million respectively. Projects required to address an urgent and unforeseen network issue and would otherwise be subject to an RIT, are reported in the APR. We did not have any urgent or unforeseen network issues arising in the past year.

A key part of the RIT process is to undertake consultations in accordance with the provisions of the Rules. We welcome feedback and enquiries on this APR including any listed projects, not only those subject to a RIT. During 2023, we did not complete any RITs.

Nine RIT-Ts are identified for our forthcoming 2024–29 revenue period as presented in Table 1-3, three of which have been initiated. We do not plan to initiate any RIT-Ds.

Table 1-3: Summary of proposed RIT-T and RIT-D investments

RIT-T Investment	Identified Need	Indicative Timing
Managing safe and reliable operation of Chapel St substation	Address escalating risk costs associated with aging switchgear at Chapel St substation.	2024
Managing risk on the George Town – TEMCO transmission line	Address escalating risk costs associated with the aging George Town-TEMCO transmission line.	2024
Managing safe and reliable operation of St Marys substation	Address escalating risk costs associated with aging transformers at St Marys substation.	2024
Meeting the System Strength Standard in Tasmania from December 2025 onward	From 2 December 2025, provide sufficient system strength to satisfy minimum fault level requirements and facilitate forecast developments of IBR in Tasmania.	2024-25
Meeting network planning requirements at George Town	Address minimum network performance requirements following connection of new load at George Town substation.	2024-2026
Improving transfer capacity between Waddamana and Palmerston	Address constraints in the Waddamana to Palmerston corridor following connection of new renewable generation in the Central Highlands REZ.	2025-2026
Reducing line losses in the Upper Derwent	Reduce power system losses in the Upper Derwent transmission network.	2025
Managing safe and reliable operation of Sheffield substation	Address escalating risk costs associated with aging transformers at Sheffield substation.	2026
Managing safe and reliable operation of Rosebury substation	Address escalating risk costs associated with aging transformers at Rosebury substation.	2027

1.9. What has changed since 2023

1.9.1. Integrated System Plan

The 2024 ISP confirms that urgent investment is needed in new renewable energy generation, transmission, storage and flexible gas generation to continue to deliver secure, reliable and affordable energy, and reach the renewable electricity generation targets of NEM jurisdictions.

The 2024 ISP confirms Project Marinus as a single "actionable ISP project" without decision rules. Project Marinus includes Marinus Link and NWTD projects.

Two new projects in Tasmania are included in the optimal development path, being the Waddamana to Palmerston transfer capability upgrade (an actionable project) and North West REZ Expansion (a future project). As such, the actionable status of the Waddamana to Palmerston transfer capability upgrade project means that TasNetworks is required to publish a Project Assessment Draft Report by 26 June 2025.

In addition to the existing Tasmanian on-island REZs identified in the 2022 ISP, the 2024 ISP amalgamates the off-shore wind zones into a single North Tasmania Coast REZ.

1.9.2. Marinus Link

MLPL separated from TasNetworks on 22 March 2024 and became a stand-alone transmission network service provider.

As part of Project Marinus, we continue to progress the NWTD through landowner, community, and other stakeholder consultation activities, as well as field surveys to support the planning, heritage and environmental approvals processes and final technical design.[38]

38 https://talkwith.tasnetworks.com.au/north-west-transmission-developments-2

1.9.3. North West Transmission Developments

In September 2023, MLPL announced that the Marinus Link project will be executed with a staged approach, focusing on delivering the first cable by the end of the decade, or earlier if possible. The development sequence for the north west supporting network was reviewed to ensure that the minimum network requirements for the first cable could be met at least cost to our customers. The strategy retained a pathway for further development of the transmission system to eventually support the final 1,500 MW interconnection.

The outcome of this assessment was prioritisation of the first stage of the interconnector, supported by network upgrades in the north west of Tasmania, following a coastal route.

The revised scope for the first stage of the North West Transmission Developments comprises a new double circuit transmission corridor between Palmerston, Sheffield and Burnie, with an interim tee connection to Heybridge to connect the first 750 MW stage of Marinus Link. More information on this project is provided in Chapter 3.

1.9.4. Renewable Energy Zones

TasNetworks continues to work closely with ReCFIT to provide support and guidance towards future transformation of the network to support significant renewable energy developments.

The Tasmanian Government, through ReCFIT as the REZ Coordinator, commenced consultation on the candidate REZ in north-west to inform any REZ declaration and new legislation needed to support REZ objectives. Commencing engagement activities on Tasmania's first priority REZ is an action under the RECF that supports a coordinated approach to the development of new renewable energy sources to meet the TRET.

1.9.5. Load forecasts

For the 2024 Annual Planning Report (**APR**), TasNetworks has prepared a 20-year energy and maximum demand forecast for the existing customer base. Transmission-connected customers (excluding Basslink) account for a large portion of the demand within Tasmania, currently over 50% of on-island energy consumption (refer Section 2.1.1). For the distribution network, maximum demand is temperature sensitive, with increased heating load observed at times of low ambient temperatures.

TasNetworks' forecasting methodology consists of a top-down approach, utilising AEMO's state-level forecasting as a basis for developing individual connection point forecasts.

The AEMO state-level forecast serves as the foundation for TasNetworks connection point demand forecasts. AEMO, through its annual Electricity Statement Of Opportunities (**ESOO**) publication, provides maximum demand forecasts for all regions in the NEM. The state-level forecast referred to as the native demand forecast, comprises distribution total demand, major industrial transmission customers demand, and transmission losses components.

The key scenarios used by AEMO for forecasting are the Progressive and Central (step-change). For each of these scenarios, 10%, 50% and 90% probability of exceedance (POE) forecasts are utilised.

In addition to the step change and progressive change scenarios, TasNetworks also considers the impacts of new, large scale customer developments on future energy consumption. The development of new large-scale hydrogen production facilities in Tasmania will significantly increase the energy transfer requirements across the transmission network if realised. Depending on the scale of developments, this could also require additional energy supply in excess of that legislated by TRET.

Tasmania's state-level forecast prepared previously for the 2023 APR is included for comparison.

1.9.6. Inertia and system strength

The Australian Energy Market Commission's (**AEMC**) Reliability Panel revised the Frequency Operating Standard (**FOS**) to adapt to changes occurring in the power system. A new rate of change of frequency (**ROCOF**) limit has been introduced, with a different limit defined for Tasmania compared to the mainland given the characteristics of our system.

Due to limited load growth over the last 12 months, Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources (**IBR**), predominantly comprising wind farm generation and Basslink import. Given that very little synchronous generation is being dispatched at various times, careful management of power system security continues to be a high priority.

Modelling associated with AEMO's 2024 ISP forecasts ongoing shortfalls for both system strength and inertia network services in the Tasmanian region. Contractual arrangements to address existing shortfalls are currently in place until 1 December 2025.

The Rules framework for managing system strength has changed, with significant new obligations for System Strength Service Providers (**SSSP**) commencing on 2 December 2025. TasNetworks is the SSSP for the Tasmanian region of the NEM.

The new framework introduces a completely new approach for the procurement and payment of system strength services, including proactive planning obligations for SSSPs which now form part of Schedule 5.1 requirements within the Rules. Details of the new framework are outlined in Chapter 5.

1.9.7. Planned investments and forecast limitations

Material differences between planned investments and forecast limitations from those reported in our 2023 APR are summarised in Table 1-4. The table also provides references to the relevant sections of this APR where we present the actual investment or forecast limitation.

Table 1-4: Differences in planned investments and forecast limitations reported in 2023 APR

Location	Summary of change	APR Reference
Now completed		
Emu Bay	Emu Bay Substation conversion from 11 kV to 22 kV	Table 4-4
Risdon	Risdon–East Hobart 33 kV sub-transmission line capacity increase	Table 4-4
Zeehan	Zeehan reliability improvement (44 kV sub-transmission line switching augmentation)	Table 4-4
Emu Bay	New 22 kV new feeders from Emu Bay Substation	Table 4-4
Kermandie	Kermandie Substation supply transformers replacement	Table 4-10
Port Latta	Port Latta Substation supply transformers replacement	Table 4-10
Ulverstone	Ulverstone Substation 22 kV switchgear replacement	Table 4-11
Rosebery	Rosebery Substation 44 kV disconnectors replacement	Table 4-11
Burnie	Burnie Substation 110 kV disconnectors replacement	Table 4-11
Hadspen Substation	220 kV and 110 kV busbar protection replacement	Table 4-12
Statewide	T60 transformer relays	Table 4-12
Now committed		
Gordon	Gordon Substation 220 kV switchgear	Table 4-11
Norwood	Norwood Substation 110 kV switchgear	Table 4-11
Farrell	Farrell Substation 220 kV switchgear	Table 4-11
Chapel Street	Chapel Street Substation 110 kV disconnectors	Table 4-11
George Town	George Town Substation 220 kV disconnectors	Table 4-11
Wesley Vale	Wesley Vale Substation 110 kV disconnectors	Table 4-11
Sorell	Sorell Substation 22 kV switchgear	Table 4-11
Savage River	Savage River Substation 110 kV disconnectors and gantry	Table 4-11
Sheffield	Sheffield Substation 220 kV disconnectors and current transformers	Table 4-11
Sheffield	Sheffield Substation 110 kV disconnectors	Table 4-11
Hadspen	Hadspen Substation 220 kV and 110 kV busbar protection	Table 4-12
Statewide	Statewide protection relays	Table 4-12
Statewide	Statewide SCADA scheme (part replacements Gateway RTU only)	Table 4-12

Chapter 2

Tasmanian power system

- During 2023, Tasmanian generation (hydro, wind, gas and embedded generation) provided 94% of the State total energy requirements, with 6% (or approximately 637 GWh) of electrical energy imported into Tasmania over Basslink.
- Our transmission–connected customers, dominated by four major industrial sites, were responsible for 37% of the network's maximum demand and consuming 51% of the total energy delivered through the transmission network in 2023.
- Under the step change scenario, presented in the Australian Energy Market Operator's (**AEMO**) 2024 Integrated System Plan (**ISP**), an increase in consumption is forecast for the second half of the decade, largely due to the anticipated emergence of a new hydrogen industry.
- The development of Marinus Link and forecast large-scale hydrogen will more than double the energy transmitted through the network, with network maximum demand forecast to increase 250% over the next 20 years. Depending on the scale of hydrogen developments eventually realised, additional energy supply in excess of the legislated Tasmanian Renewable Energy Target (**TRET**) may be required if Tasmania is to avoid becoming reliant on energy imports from Victoria.

2.1. Load and generation characteristics

2.1.1. Load characteristics

The Tasmanian transmission network conveys electricity to Tasmanian customers and to the rest of the National Electricity Market (**NEM**) via Basslink.

Tasmania has a small load demand compared to other NEM regions, typically ranging between approximately 780 – 1,780 MW. The load duration characteristic for Tasmanian customers and total network (including Basslink export) during 2023 is presented in Table 2-1.

Table 2-1: Tasmanian load duration characteristic for 2023.

Duration / operating point	Tasmanian customers (MW)	Total operational demand (MW) (including Basslink export) (MW)
Maximum	1,720	2,137
25th percentile	1,279	1,553
50th percentile	1,182	1,228
75th percentile	1,104	1,116
Minimum	750	750[39]

The maximum demand on the transmission network during 2023 to supply Tasmanian customers only was 1,720 MW, with the total network maximum demand of 2,137 MW including power transfers across Basslink. Peak demand in Tasmania occurs during winter, driven by heating load. Figure 2-1 presents the transmission network demand duration curves for supply of Tasmanian customers, as well as total network demand inclusive of Basslink exports.

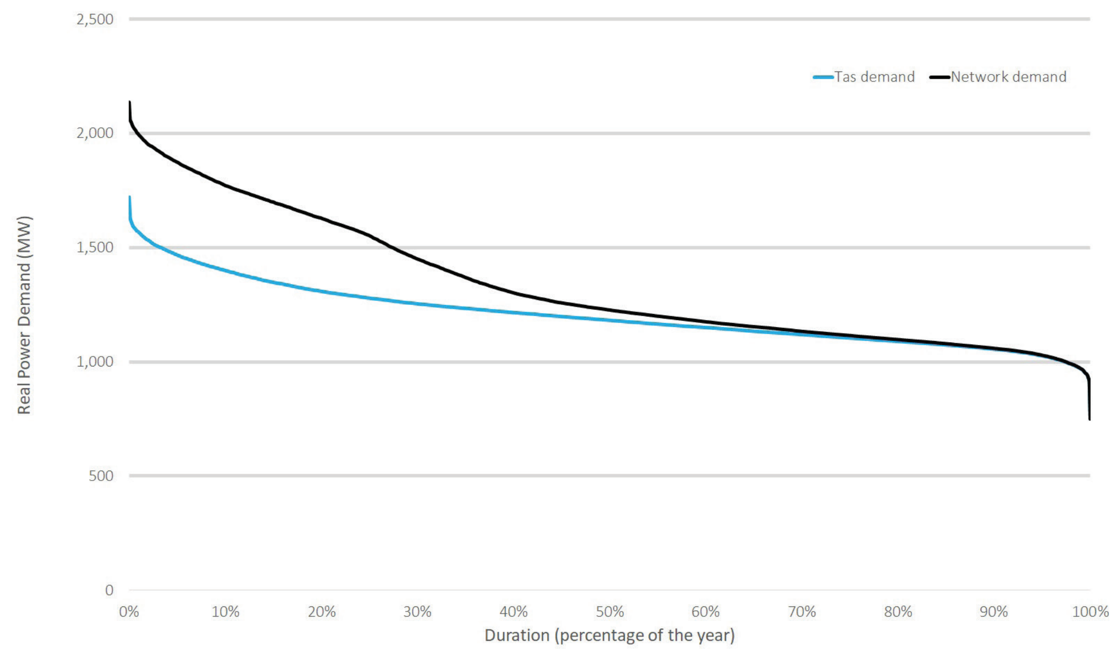


Figure 2-1: Transmission network demand duration curves 2023

Trends suggest an ongoing reduction in the reactive power demands of Tasmanian customers as measured at their connection points. Over the past 12 months, the peak reactive demand has reduced by approximately 6.5% from the previous year. This is being partially attributed to an increased proportion of energy efficient loads, including those interfaced through 'smart' power electronics, that tend to operate much closer to unity power factor. The 5-year reactive demand duration characteristic, inclusive of customer and broader transmission network needs is presented in Figure 2-2.

39 Derived with the assumption of 0 MW through Basslink.

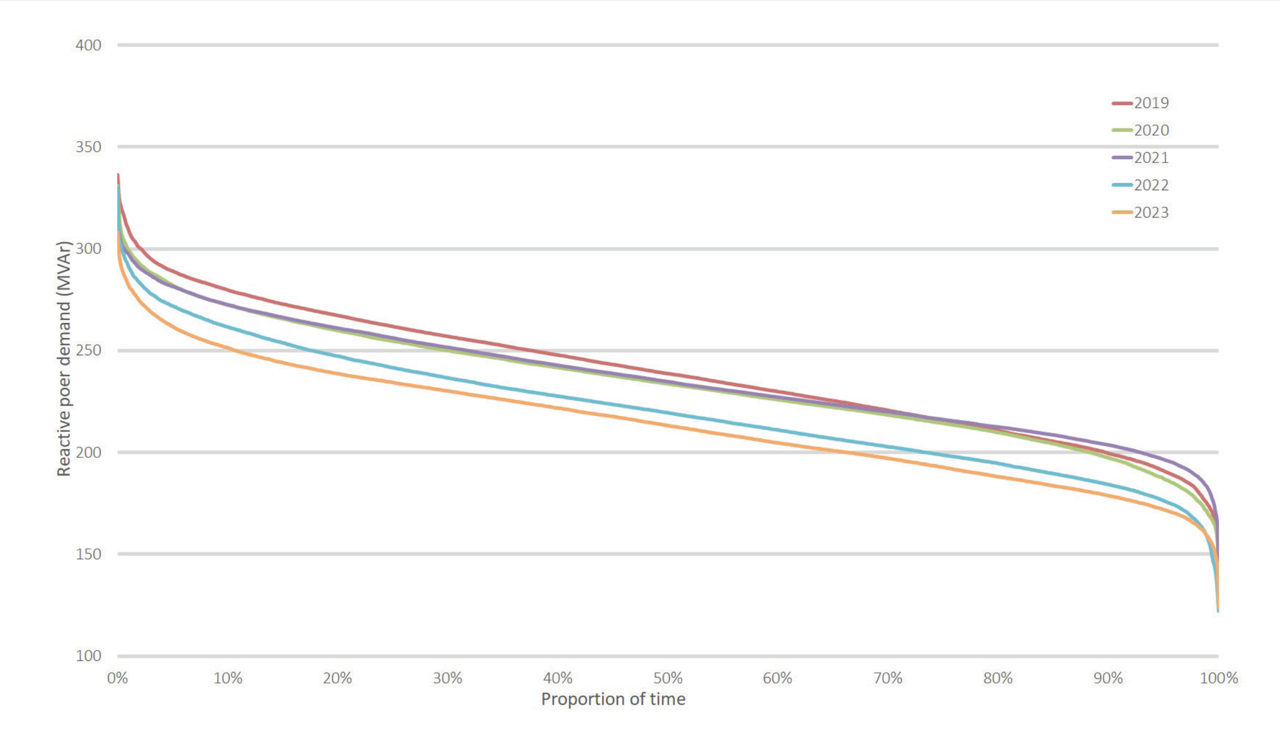


Figure 2-2: Total network reactive demand duration curves 2019-2023

A relatively high proportion of the energy flow through the Tasmanian network supplies customers directly connected to our transmission network. Four major industrial customers consumed 47% of the total energy flow delivered through the transmission network, with all remaining transmission customers adding a further 4.2%. Transmission customers contributed to 37% of the network maximum demand in 2023. The relative energy use in 2023 supplied from our transmission network is presented in Figure 2-3.

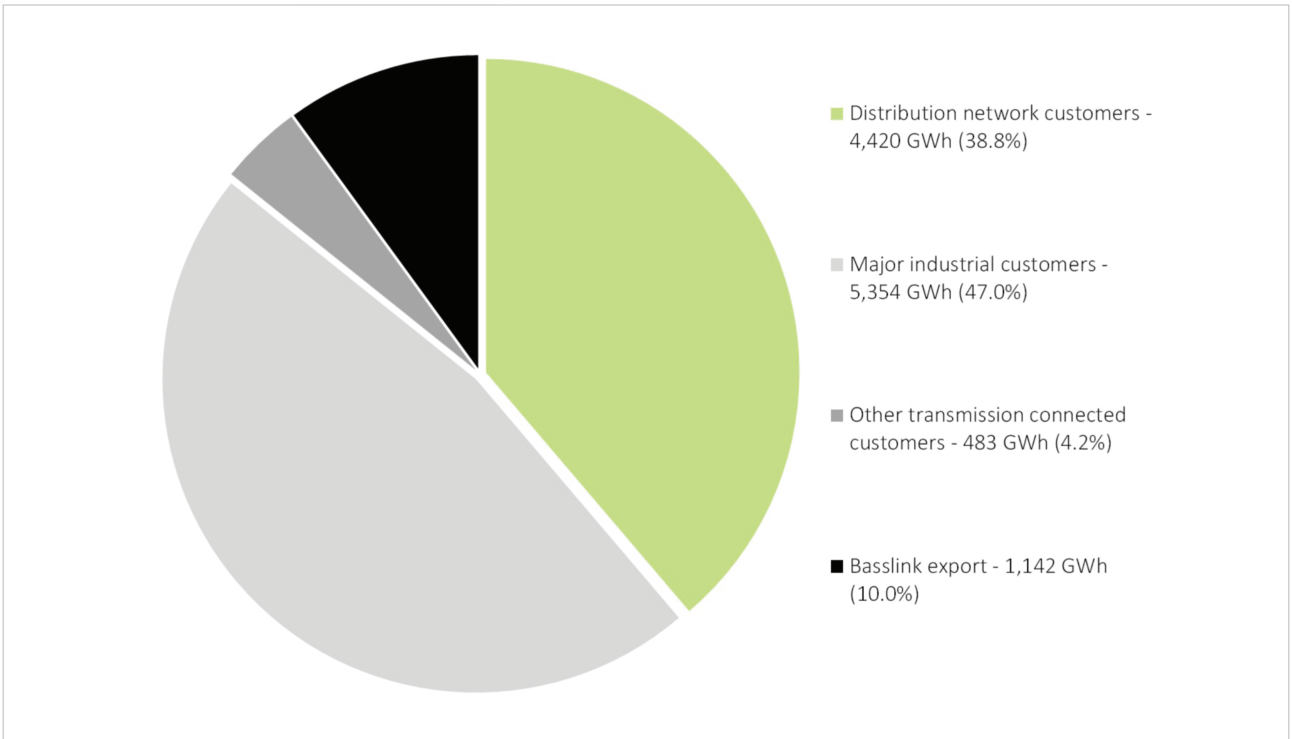


Figure 2-3: Relative transmission network use in 2023

2.1.2. Energy and maximum demand forecasts

2.1.2.1. Introduction

This section presents the Tasmanian energy and maximum demand forecast attributable to the existing customer base and scenarios under the Tasmanian Renewable Energy Action Plan (**TREAP**) including Marinus Link and large-scale renewable hydrogen. Forecasts present the demand on the transmission and distribution networks, as measured at the network entry points. Transmission network demand is determined by the sum of on-island generation contributions and Basslink import into Tasmania. Distribution network demand is measured at the interfaces with the transmission network.

Forecasts provide both an indication of the future energy requirements within Tasmania, and the increased demand on the transmission and distribution networks to support energy transfer.

For the 2024 Annual Planning Report (**APR**), TasNetworks prepared a 20-year energy and maximum demand forecast for the existing customer base. Transmission-connected customers (excluding Basslink) account for a large proportion of the demand, currently sitting at over 50% of on-island energy consumption (refer Section 2.1.1). For the distribution network, maximum demand is temperature sensitive, with increased load observed at times of low ambient temperatures. For planning activities, we apply a 50% probability of exceedance (**POE**) maximum demand forecast. Temperature sensitivity is not as acute as for other NEM states which experience their maximum demand during extreme summer temperatures.

Substations, zone substations, feeder maximum demand forecasts and substation load profiles are available as downloadable appendices to this APR on our website: **www.tasnetworks.com.au/apr**

2.1.2.2. Forecast scenarios

TasNetworks' forecasting methodology comprises a top-down approach, utilising AEMO's state-level forecast as the basis for developing individual connection point forecasts.

AEMO's state-level forecast serves as the foundation for TasNetworks' connection point demand forecasts. AEMO, through its annual Electricity Statement Of Opportunities (**ESOO**), provides maximum demand forecasts for all regions in the NEM. The state-level forecast referred to as native demand forecast constitutes distribution total demand, major industrial transmission customer demand, and transmission losses. Three key scenarios used by AEMO for forecasting are the Progressive, Central (Step Change) and Green Energy Exports. For each of these scenarios, 10%, 50% and 90% probability of exceedance (**POE**) are utilised. Table 2-2 presents an overview of forecast scenarios.

Table 2-2: Forecast scenarios[40]

Scenario	Description
Progressive Change	Progressive Change meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher technology costs and more supply chain challenges relative to other scenarios.
Step Change	Step Change (ESOO 2023 Central scenario) achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this with broader decarbonisation outcomes in other sectors, aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in Consumer Energy Resources (**CER**), including electrification of the transportation sector.
Green Energy Exports	Green Energy Exports reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The electricity sector plays a very significant role in decarbonisation.

40 https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

The distribution component is extracted from Tasmania's state-level demand forecast and aligned with historical actual demands. This is then used to model individual connection point demand projections.

2.1.2.3. Annual energy forecast

Figure 2-4 presents the historical actuals and forecast Tasmanian energy requirements on the transmission network over the next 20 years to 2044. Forecasts are presented for the distribution network and whole of State. Forecasts from our 2023 APR are included for comparison.

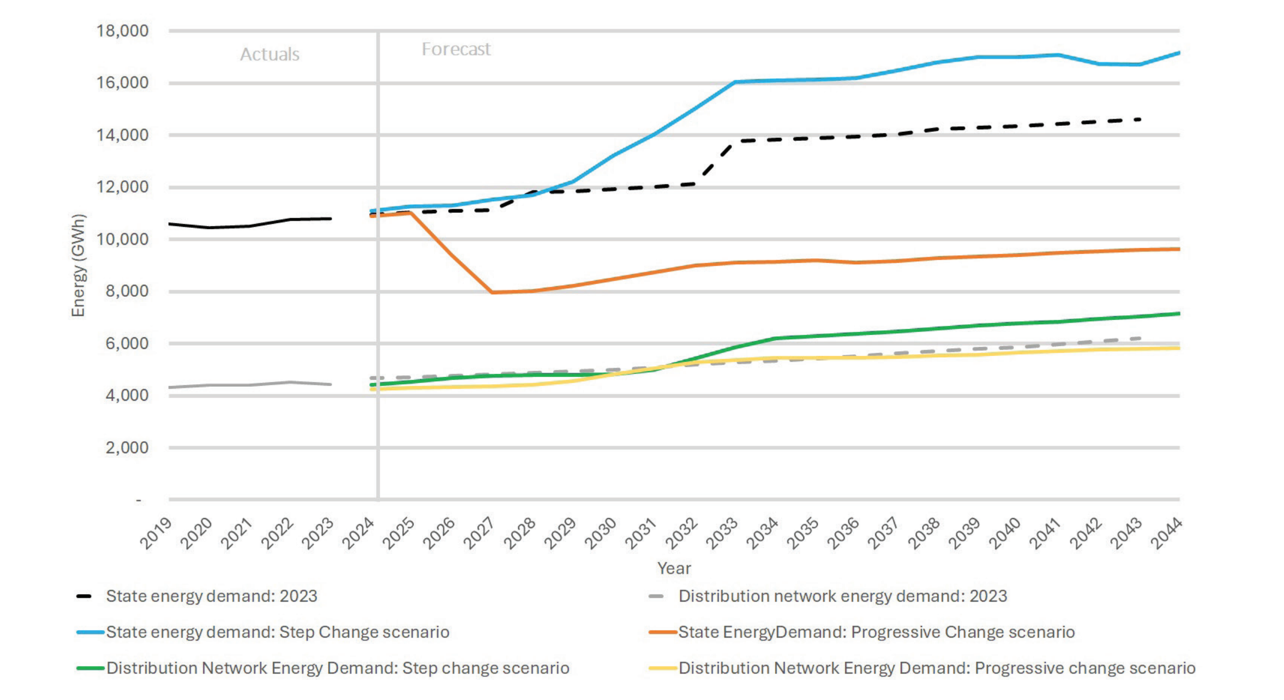


Figure 2-4: Annual energy forecast

In 2023, recorded energy consumption was comparable with 2022 for transmission-connected customers (including major industrial loads) and distribution customers.

The key insights across the step change and progressive change forecasting scenarios are as follows:

Timeframe	Description
1-10 Years	An increase in consumption is forecast for the second half of the decade largely due to the anticipated emergence of a hydrogen production industry. Progressive Change explores the impact of potential large industrial load closure risks. This scenario includes some business electrification and hydrogen production for the domestic market, consistent with Australia's efforts to meet its 43% reduction targets in emissions levels by 2030 relative to 2005 levels and achieving net zero emissions by 2050. Progressive Change is notable for the early retirement of large industrial load in the first half of the decade.
11-20 Years	Slowing growth in consumption is forecast across both Progressive and Step Change scenarios, with positive growth driven by an increase in business electrification in agriculture and the uptake of Electric Vehicles (**EVs**), offset with increased penetration of distributed PV and energy efficiency investment.

In addition to the Step Change and Progressive Change scenarios, TasNetworks also considers the impacts of new, large scale hydrogen developments on the future energy consumption within Tasmania. Figure 2-5 presents a projection of the State's forecast consumption under the Step Change scenario, compared against the total Tasmanian energy production capability described by the TRET. Also included is the ISP Step Change generation forecast, and a scenario to consider the energy demands of hydrogen production facilities, should they eventuate.

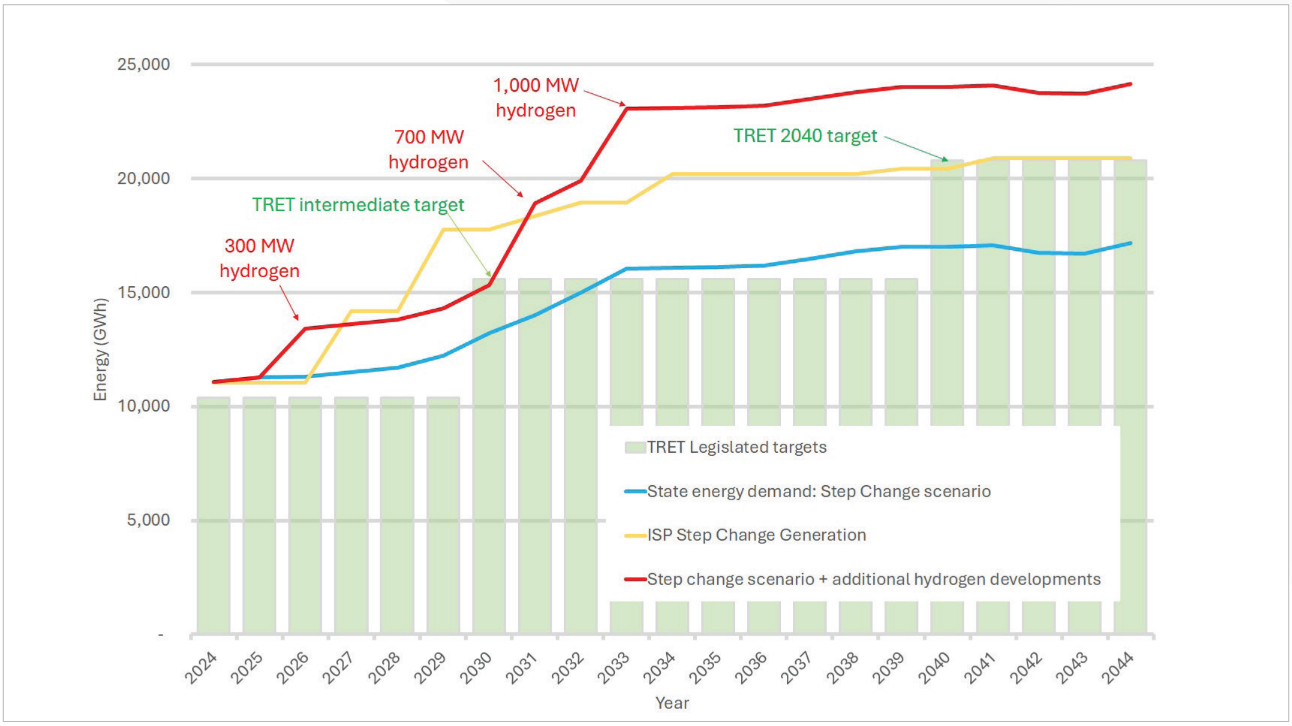


Figure 2-5: Annual energy forecast – impacts of new hydrogen developments

The TRET sets energy production targets as follows:

- An interim target of achieving 150% of Tasmania's existing renewable generation by 2030; and
- A 2040 target of achieving 200% of Tasmania's current energy needs, equating to a renewable generation capability of 21,000 GWh per annum.

When compared against the State energy demand forecast under the Step Change scenario, the TRET mandated REZ build across Tasmania progresses at a pace to meet or exceed the future consumption requirements over the next 20 years. With the development of new large-scale hydrogen production facilities in Tasmania, there would be a significant increase in energy generation and transfer requirements across the transmission network. If realised, this will require additional energy supply in excess of the legislated TRET if Tasmania is to remain 'energy neutral' on average.

2.1.2.4. Annual maximum demand forecast

Figure 2-6 presents the historical actuals and forecast peak demand requirements at 50% POE on the transmission network over the next 20 years to 2044. Forecasts are presented for the distribution network and whole of State, with additional scenarios included to illustrate the impact of new hydrogen developments and the Marinus Link interconnection. As with the energy forecasts, the Central State scenario from our previous 2023 APR and the latest AEMO State demand forecasts are included for comparison.

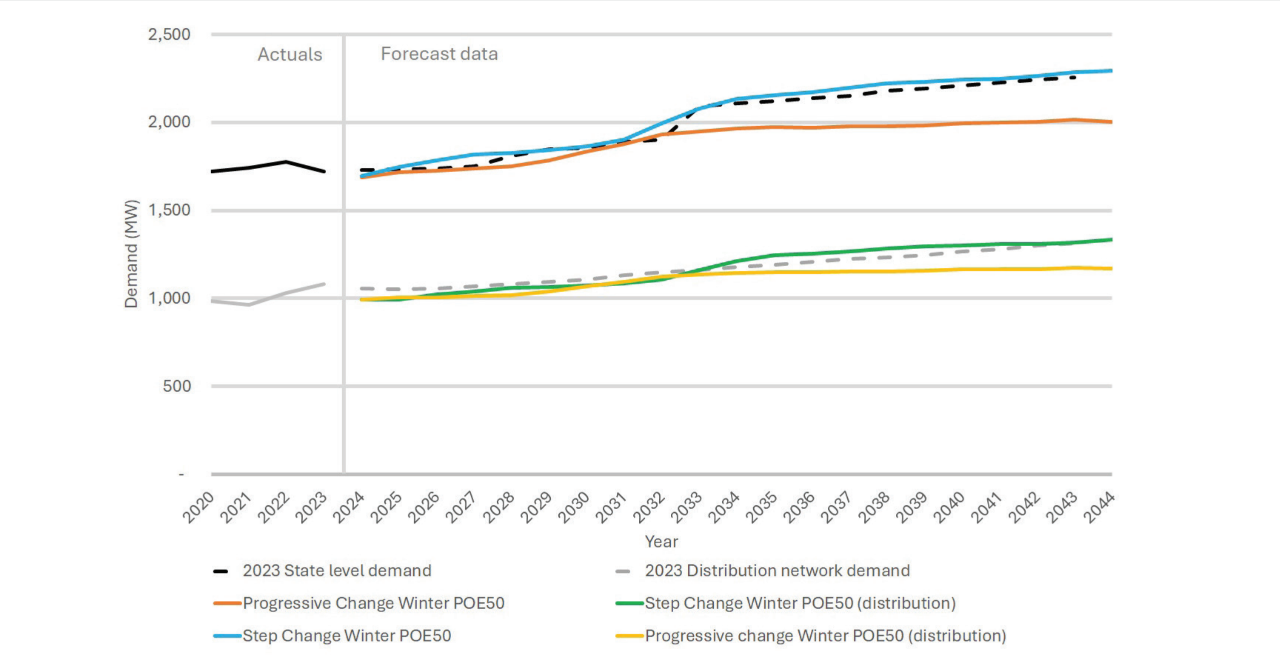


Figure 2-6: Maximum Demand forecast

The key insights across the Step Change and Progressive Change scenarios are as follows:

Timeframe	Description
1-10 Years	Maximum operational demand is forecast to start lower than in the 2023 demand forecast. This is as a result of reductions in the pace of electrification investment that has not yet impacted actual outcomes as forecast originally, partially offset by lower energy efficiency investment. The Step Change scenario follows a similar trend to the 2023 demand forecast with growth over the decade largely driven by electrification and growth in large industrial load consumption in the later years. The Progressive Change scenario also considers the impact of large industrial load closures that may result in reduced forecast maximum operational demand.
11-20 Years	Maximum operational demand is forecast to remain relatively flat in all scenarios as the increasing underlying demand is offset by lower energy efficiency investment. Despite the increasing demand for EVs, their impact on maximum demand is expected to be weaker compared to projections in previous years, with greater expectations for smarter charging profiles.

2.2. Generation characteristics

Table 2-3 presents the total existing and committed generation capacity connected to the transmission network, including Basslink import. The impact of embedded generation in the distribution network is reflected as a reduction in connection point demand and is outlined in Chapter 6.

Table 2-3: Existing generation capacity

Generation type	Number of sites	Total nameplate rating (MW)	Proportion of installed capacity (%)	Contribution to Tasmanian network energy demand in 2023 (%)
Hydro	25	2267	56.5	73.6
Wind	5	568	14.2	17.0
Gas	1	386	9.8	0.5
Basslink import	1	478[41]	11.9	3.0
Embedded generation	51,206	314	7.8	5.8

The generation mix in Tasmania over the past five years is presented in Figure 2-7. This includes generation within Tasmania and net interconnector flows.

41 Dynamic capacity was made available on Basslink for commercial operations from 17th June 2024

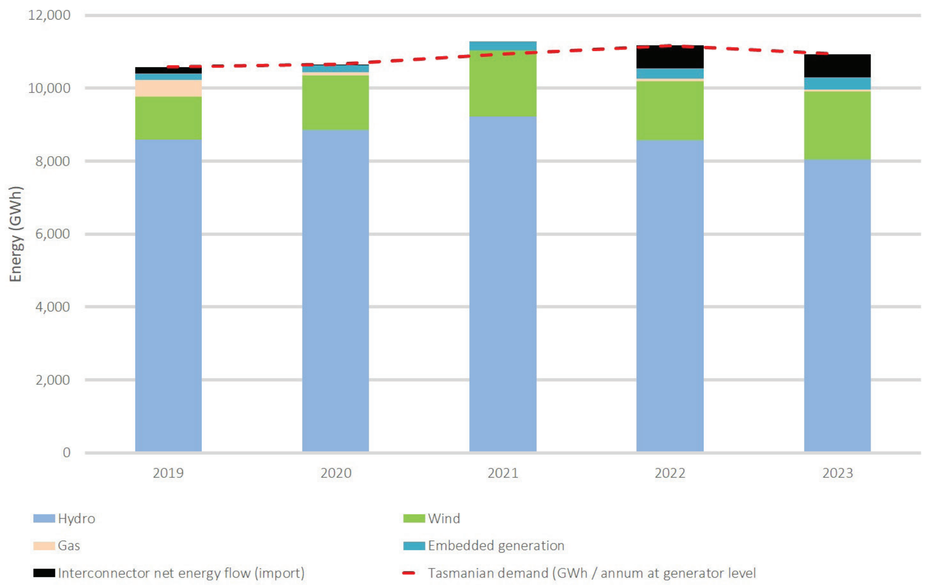


Figure 2-7: Supply contribution by type: 2019 to 2023

Tasmania has come close to maintaining a state of "energy neutrality", whereby the on-island generation is sufficient to meet or exceed Tasmania's annual energy requirements. 2023 saw a reduction in hydro energy production, an increase in wind energy and Basslink energy import similar to 2022. The overall state level energy demand for 2023 was approximately 10,808 GWh, 2.7% lower than in 2022.

2.3. Transmission network

The Tasmanian transmission network comprises:

- a 220 kV, and some parallel 110 kV, bulk transmission network that provides corridors for transferring power from several major generation centres to major load centres and Basslink;
- a peripheral 110 kV transmission network that connects smaller load centres and generators to the bulk transmission network; and
- substations that form interconnections within the 110 kV and 220 kV transmission network and provide transmission connection points for the distribution network and transmission connected customers.

Most customer connections are concentrated in the north and south-east of the State. Bulk 220 kV supply points are located at Burnie and Sheffield (supplying the north-west), George Town and Hadspen (supplying Launceston and the north-east), and Chapel Street and Lindisfarne (supplying Hobart and the south-east). Smaller load centres are supplied via the 110 kV transmission network on the periphery.

Our transmission network map is presented in Figure 2-9, and a summary of the transmission network infrastructure is provided in Table 2-4.

Table 2-4: Transmission infrastructure

Asset	Quantity
Substations	49
Switching stations	8
Circuit kilometres of transmission lines	3,312
Route kilometres of transmission lines	2,361
Circuit kilometres of transmission cable	25.2
Transmission line support structures (towers and poles)	7,700
Easement area (Hectares)	11,176

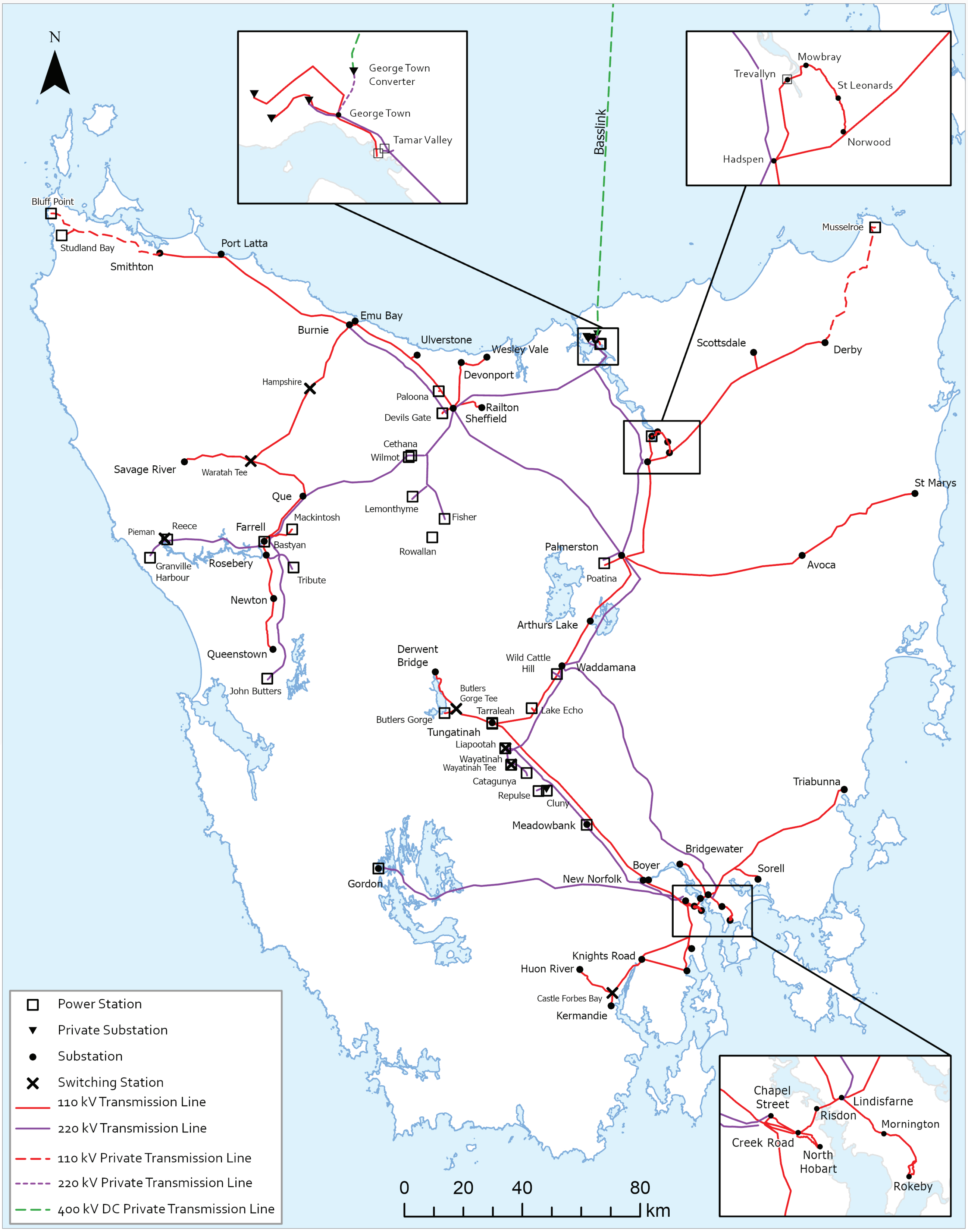


Figure 2-8: Tasmania's electricity transmission network

2.4. Distribution network

TasNetworks is responsible for delivering electricity to homes and businesses on mainland Tasmania. Our distribution network provides power to more than 295,000 residential, commercial and industrial customers and comprises:

- a sub-transmission network in the greater Hobart area, including Kingston, and one sub-transmission line on the West Coast that, in addition to transmission-distribution connection points, provide supply to the high voltage distribution network;
- a high voltage network of distribution lines that distribute electricity from transmission-distribution connection points and zone substations to the low voltage network and a small number of customers connected directly to the high voltage network; and
- distribution substations and low voltage circuits providing supply to the majority of Tasmanian customers.

Figure 2-9 presents our distribution network map by voltage.

Distribution lines are classified as supplying either rural or urban areas, and these tend to have different characteristics. Urban areas are outlined in the figure and exist in the surrounds of greater Hobart, Launceston and the north-west of Tasmania; all other areas are classified as rural.

Rural areas generally have low load demand, low customer connection density, and smaller rural population centres remote from major supply points. Distribution lines supplying rural areas tend to cover wide geographic areas and can have a total route length of between 50 km and 500 km. This significant route length creates a high exposure to external influences such as storm damage, interactions with trees and tree branches, as well as lightning. Additionally, rural lines are generally radial in nature, with limited ability to interconnect with alternate supply options. These characteristics tend to result in more frequent and longer duration interruptions for rural customers.

Urban areas have higher load and customer connection density. Distribution lines supplying urban areas are generally much shorter than rural lines. They tend to have more underground assets and more interconnections with other supply points. Restoration following supply interruptions is usually quicker than in rural areas.

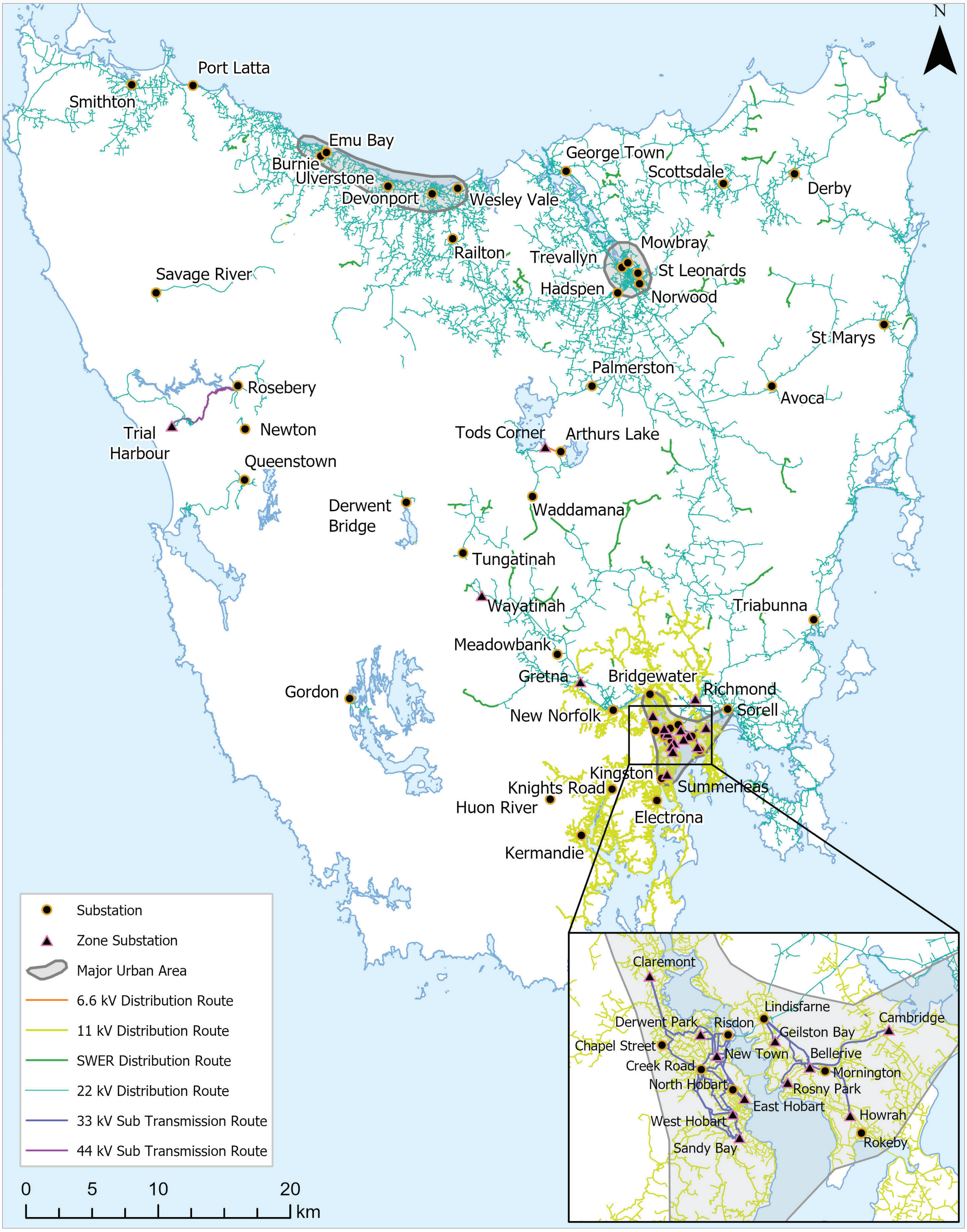


Figure 2-9: Tasmanian distribution voltage areas

A summary of our distribution network infrastructure is presented Table 2-5.

Table 2-5: Distribution network infrastructure

Infrastructure	Voltage (kV)	Quantity
Connection points		
Sites	44, 33, 22, 11 and 6.6	46
Sub-transmission lines	44, 33 and 22	27
Minor zone substation source lines[42]	22 and 11	7
Distribution lines	22, 11 and 6.6	247
Zone substations		
Major zone substations	44, 33 and 22	13
Major zone distribution lines	22 and 11	123
Minor zone substations	22 and 11	4
Minor zone distribution lines	22 and 11	8
Distribution substations		
Overhead		30,789
Ground mounted		2,081
Route data		
High-voltage overhead (km)	6.6 to 44	15,415
High-voltage underground (km)		1,303
Low-voltage overhead (km)[43]	0.4	4,562
Low-voltage underground (km)		1,452
Poles	All voltages	231,643

42 Includes minor zone alternate-supply lines.

43 Excludes customer service lines.

Chapter 3

Transmission network development

- Tasmanian transmission network planning activities continue to focus on identifying the optimum development path to accommodate future large-scale renewable energy resources, a new interconnection with Victoria, upgrading of existing power stations, connection of export-scale hydrogen, and integration of energy "firming" facilities such as battery energy storage systems (**BESS**) and pumped hydro energy storage (**PHES**).
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions towards more renewable energy sources, informed by the Tasmanian Renewable Energy Target (**TRET**), plans to develop a renewables based hydrogen industry, and identification by the Australian Energy Market Operator (**AEMO**) of Renewable Energy Zones (**REZs**) and associated transmission augmentations.
- The North West Transmission Developments (**NWTD**) project will be delivered across two stages, with a focus on Stage 1 until a final investment decision is made for the second Marinus Link interconnector. Construction of Stage 1 is planned to commence in 2025-26 to align with the start of Marinus Link works, and will establish a connection between Sheffield, Burnie and Marinus Link via a coastal route.
- In mid-2023 we undertook the required steps to register a notified corridor for the proposed alignment of the NWTD in accordance with the Major Infrastructure Development Approvals Act 1999 (**MIDAA**).
- We reaffirmed that augmentation of the Palmerston–Sheffield 220 kV transmission corridor is likely to be required for the majority of future scenarios – irrespective of which scenario(s) eventuate or in what order.
- In addition to Stages 1 and 2 of the Marinus Link Project, we note the inclusion of the Waddamana-Palmerston 220 kV corridor upgrade as a new actionable project within Tasmania in the 2024 Integrated System Plan (ISP).
- In terms of TRET mandated energy production, TasNetworks note the following of the 2024 ISP:
  - The Progressive Change generation build falls short of both the interim and final target; and
  - while the Step Change generation build trajectory has the capability to meet the 2030 TRET interim target, additional generation may be required to meet the 2040 target.

3.1. Introduction

This Chapter provides information on our plans to develop the backbone transmission network in accordance with regulatory requirements as outlined in Appendix A. It presents our plans to support new renewable energy generation required to achieve the TRET in the three Tasmanian onshore REZs in the north-west, the north-east and Central Highlands regions.

The Tasmanian Renewable Hydrogen Action Plan previously identified potential locations for large-scale renewable hydrogen production and export. Since then, TasNetworks has progressed planning strategies prioritised for hydrogen integration within the Bell Bay Advanced Manufacturing Zone (**BBAMZ**).

3.2. The backbone transmission network

The backbone of the Tasmanian transmission system comprises a 220 kV network, with some parallel 110 kV transmission assets. Its role is to facilitate the intra-regional transfer of electricity from generation sources to Tasmanian load centres, as well as support inter-regional power flows to and from the mainland via our interconnection with Victoria. The main considerations when planning the backbone transmission network are the technical requirements of the National Electricity Rules (**the Rules**) and opportunities for development that deliver market benefits to customers. The Rules set how we determine the technical envelope within which the power system must be operated. Market benefits may be delivered by increasing access to lower-cost generation or by reducing the risk of unserved energy to customers. Our jurisdictional network planning requirements also need to be considered, with further details available in Appendix A.3.3.

3.3. Committed and Completed Projects

3.3.1. System strength remediation at Burnie 110 kV fault level node

AEMO determines system strength requirements, including fault level nodes and minimum three-phase fault levels, which must be maintained to manage power system security. The details of our system strength obligations are presented in Section 5.4 of this APR.

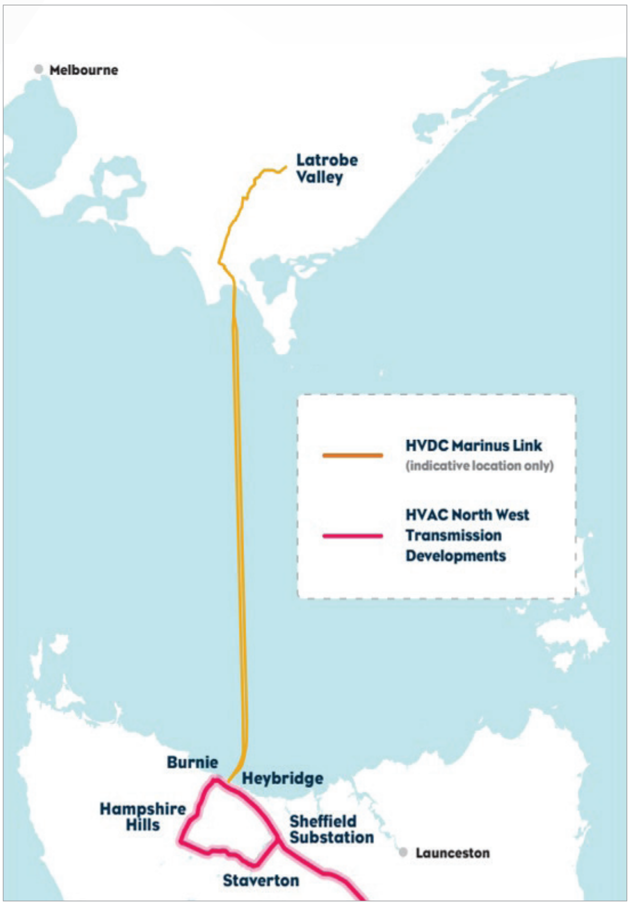
In 2021, TasNetworks progressed a project to install new dynamic reactive support in the north-west to address previously identified system strength limitations at Burnie 110 kV substation. The provision of fast acting dynamic support will allow the network to be successfully operated at a lower minimum pre-contingent fault level of 750 MVA (down from the 850 MVA currently required). Two 6 MVAr static synchronous compensators (**STATCOM**) will be installed at Port Latta Substation to deliver these benefits, at an expected cost of $7.0 million. The project has commenced the implementation phase and is planned for completion in Q4 2024.

3.4. Marinus Link

Marinus Link Pty Ltd (**MLPL**) is a three-part equity ownership between the Australian Government (49%), the Victorian Government (33.3%) and the Tasmanian Government (17.7%). The business has responsibility for progressing Marinus Link which is a new interconnection to Victoria that will comprise of two 750 MW High Voltage Direct Current (**HVDC**) transmission systems which use voltage source converter (**VSC**) technology. Marinus Link will thus create a 1,500 MW transmission pathway, significantly increasing energy transfer capabilities between Tasmania and the rest of the National Electricity Market (**NEM**).

In anticipation of Marinus Link being classified as a prescribed transmission service, MLPL is now registered with AEMO as an Intending Participant in the Transmission Network Service Provider (**TNSP**) category. In addition, MLPL has an Electricity Supply Industry Transmission Licence issued by the Tasmanian Economic Regulator. Further information about Marinus Link is available from the Marinus Link website.

The existing 220 kV transmission network in north-west Tasmania will require augmentation to support the increased power flows to and from Marinus Link and a pipeline of renewable generation and storage projects proposed for the North West and Central Highlands REZs.



MLPL and TasNetworks continue to undertake joint planning activities for the integration of Marinus Link, with our core focus centred on the strategic developments required across the Tasmanian transmission network.

The proposed transmission network topology to accommodate both stages of Marinus Link, as well as associated renewable energy developments across the three Tasmania REZs, is outlined in Section 3.6.

3.5. Renewable energy developments

3.5.1. Renewable energy zones

REZs are "high renewable resource areas" identified by AEMO due to their weather patterns, existing land uses and proximity to grid infrastructure. They are considered areas best suited for the development of new renewable energy resources to support the NEM transition away from fossil fuel based generation.

AEMO's Integrated System Plan (**ISP**) identifies 43 potential REZ across the NEM, of which 41 are located onshore, with a further six being Offshore Wind Zones (**OWZs**). Tasmania has three onshore REZ and one OWZ, with the wind resource quality of the Tasmanian sites being amongst the highest across the NEM.[44] The locations of the four Tasmanian REZ are presented in Figure 3-1.

44 2024 ISP, Appendix A3: https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a3-renewable-energy-zones.pdf?la=en

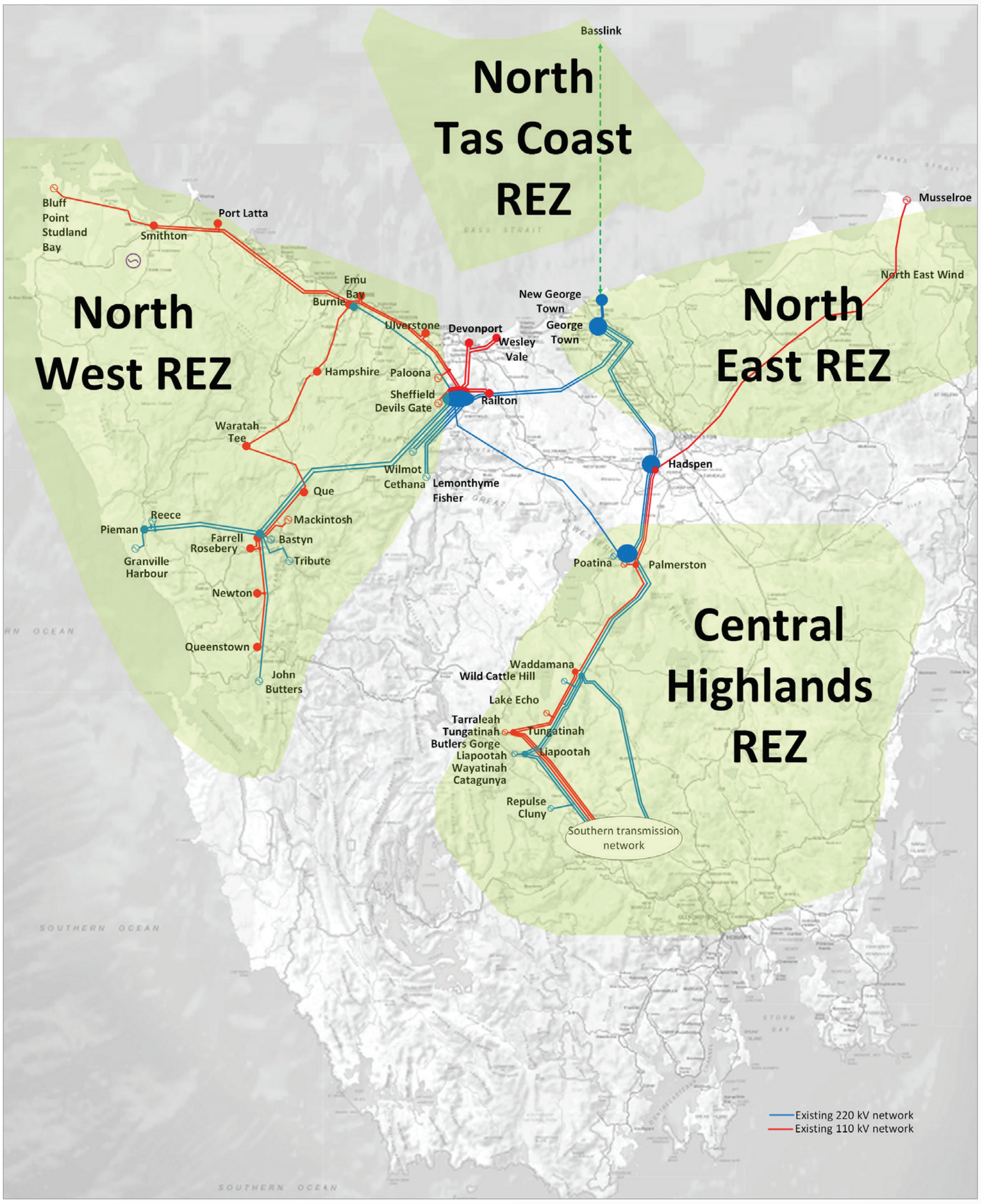


Figure 3-1: Tasmanian REZs

We take the view that the REZ concept does not restrict the development and connection of any new generation outside of these nominated areas.

New variable renewable energy (**VRE**) generation may utilise a variety of natural resources, however, in Tasmania, the ISP forecasts that wind will be the dominant energy source that is developed. In addition, repurposing and expansion of the existing hydropower system in Tasmania, including future PHES, will support REZ development.

We continue to review and refine our network planning strategy to support each REZ, as well as the core grid, to meet the objectives of the Tasmanian Renewable Energy Action Plan (**TREAP**) which includes the following elements:

- the TRET;
- Marinus Link;
- establishment of a renewable (green) export hydrogen industry in Tasmania; and
- Hydro Tasmania's Battery of the Nation (**BOTN**)[45] initiative.

The TREAP is presented in detail in Section 1.4 of this APR.

45 https://www.hydro.com.au/clean-energy/battery-of-the-nation

3.5.2. Tasmanian Renewable Energy Target

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.

The Tasmanian Government has legislated the TRET, setting targets for renewable electricity generation by 2030 and 2040, which was captured as a key input to the 2022 and 2024 ISP documents. To meet these targets, significant new generation sources are required within the Tasmanian region, with the majority expected to be wind farm developments. To meet the TRET, the required new wind capacity needing to be installed is approximately:

- 1,500 MW by 2030 to meet the interim target of an additional 5,250 GWh (more than twice the existing annual wind energy production in Tasmania); and
- 3,000 MW by 2040 to meet the full target of an additional 10,500 GWh (twice the total existing Tasmanian annual energy consumption in 2020).

The estimated installed capacity of new wind to meet the TRET is dependent on the assumed capacity factor, with 40% being a typical 'annual' value used for network planning purposes in Tasmania. The required installed capacity would change if other renewable energy sources (e.g. solar) are also developed.

Importantly, while the TRET defines a minimum requirement for new renewable energy generation, the resulting developments may not be sufficient to meet the full extent of the TREAP. As presented in the 'energy and demand forecasts' described in Section 2.1.2, the energy requirements to supply large-scale hydrogen developments exceed the TRET by a significant margin if Tasmania is to remain 'energy balanced', i.e. not reliant on electrical energy imports from Victoria.

3.5.3. Establishing Tasmania's first REZ

In December 2022, The Tasmanian Government announced that the north-west of Tasmania would be explored for its potential to host the state's first REZ. Renewables, Climate and Future Industries Tasmania (**ReCFIT**) is progressing the evaluation through community engagement, a detailed examination of how any future REZ might overlap with existing land uses and values, the ability of the electricity network to host more renewables, and market interest in new generation. ReCFIT, with the support of TasNetworks, has now initiated targeted activities such as hosting capacity assessments.

Ultimately, new VRE is expected to be developed across all identified Tasmanian REZ to meet the TREAP objectives. The strategic plan for the future North West REZ, with its anticipated generation, load and interconnector developments is outlined in Section 3.6.2.

3.5.4. Battery of the Nation

Hydro Tasmania is progressing with its Battery of the Nation clean energy initiative. This initiative includes a number of different proposals which look to repurpose existing hydropower assets and establish PHES. BOTN, along with increased interconnection provided by Marinus Link, will enable Tasmania to provide firming services—both dispatchable capacity and deep storage—to the mainland NEM as it transitions to a future dominated by VRE generation.

The current proposals under the BOTN initiative aim to increase the dispatchable capacity of renewable energy resources in Tasmania to meet short-term energy deficits on the mainland. BOTN proposals include:

- repurposing the Tarraleah hydropower scheme, including replacement of the existing Tarraleah Power Station (capacity increase from 90 MW to approximately 210 MW);
- opportunistic upgrades undertaken as part of mid-life refurbishment of power stations located on the West Coast of Tasmania[46] (100 MW capacity increase), with planned commencement in late 2027; and
- establishing a PHES system at Lake Cethana[47] (750 MW capacity).

The replacement of Tarraleah Power Station and upgrade to West Coast hydro generators are expected to be developed in the same timeframe as the first stage of Marinus Link. Cethana PHES is anticipated to occur in parallel with the second 750 MW stage.

3.6. Tasmanian REZ and associated network developments

This section describes each Tasmanian REZ, the capability of each REZ to host new VRE with existing network assets, and potential augmentations required to support further VRE development.

The ISP outlook for VRE in Tasmania, with consideration also given to publicly announced proposals, is used as the basis for our REZ development plans presented in this section. Network augmentations will only be developed as the actual investment need arises, including as new generation develops, and each will be subject to the Regulatory Investment Test for Transmission (**RIT-T**).

For each REZ, TasNetworks also maintains a register of proposed generation developments which is used to help inform the potential utilisation of the existing network and determine future network augmentation requirements. The aggregate generation profiles comprise proposals in various stages of development, including active connection enquiries and applications.

Hosting capacity of each REZ depends on a number of factors, such as thermal capacity of the network, system strength limitations, and the distance of new generation developments from the existing network. This represents an ongoing work stream for TasNetworks. Detailed investigations will occur as the sequence of development across each REZ becomes clearer, along with the timing of individual projects.

The difference between the total generation being forecast and the existing hosting capacity signals the extent of new investment that is needed in the network if operational constraints are to be minimised (noting that it may not be economical to eliminate all future constraints).

As part of the analysis presented, we have included the 2024 ISP Step Change and Progressive Change scenario projections for comparison for each REZ.

3.6.1. North East REZ

The existing transmission network from George Town Substation to the rest of the network has strong thermal capability, with four 220 kV transmission circuits and the Basslink HVDC interconnector terminating at this location. George Town is a large load centre which supports two large major industrial customers.

Figure 3-2 presents the North East REZ and the existing transmission network. Also highlighted are possible new VRE resource locations that may seek connection to the network over time. New VRE from the far north-east, as well as the north-east offshore area, must connect to the 220 kV network. The existing 110 kV network has limited capability to support new connections at any significant scale.

46 https://connect.hydro.com.au/wcpowerhouse

47 https://connect.hydro.com.au/cethana-pumpedhydro

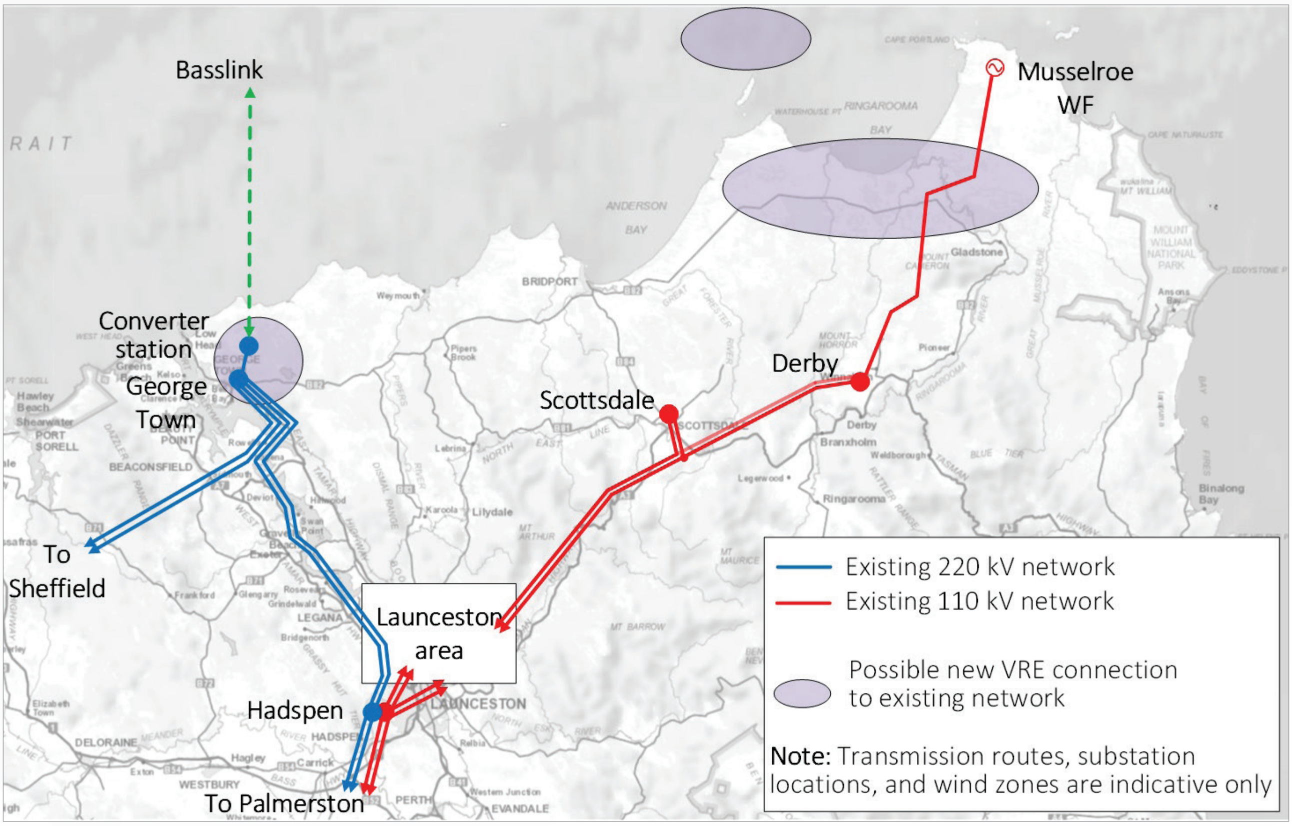


Figure 3-2: North East Tasmania REZ transmission network

Figure 3-3 presents the existing hosting capacity of the North East transmission network from George Town, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive change scenarios.

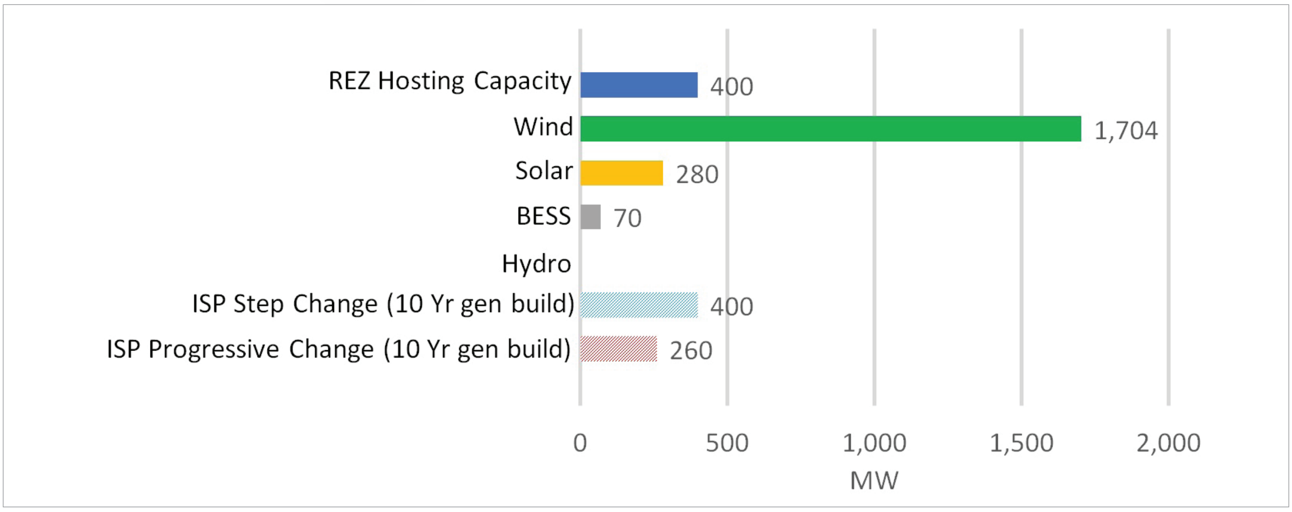


Figure 3-3: North East Tasmania REZ forecast generation and hosting capacity

Prospective VRE developments in the north-east and far north-east region of Tasmania have a combined capacity approaching 2,000 MW. Hosting capacity of the overall REZ is currently limited to approximately 400 MW. VRE resources in the far north-east and north-east offshore area would require substantial new transmission assets to connect to the George Town area. This is a factor which limits the projected generation build in the ISP.

3.6.2. North West REZ

The North West REZ has significant potential for new wind generation developments. The connection location for Marinus Link is within this REZ at Heybridge (near Burnie). There is significant interest to develop new generation in the area, as well as the first tranche of PHES. Hydro Tasmania has announced Lake Cethana as its preferred PHES site and is progressing it to final feasibility.[48]

Figure 3-4 presents the North West REZ transmission network, including NWTD.

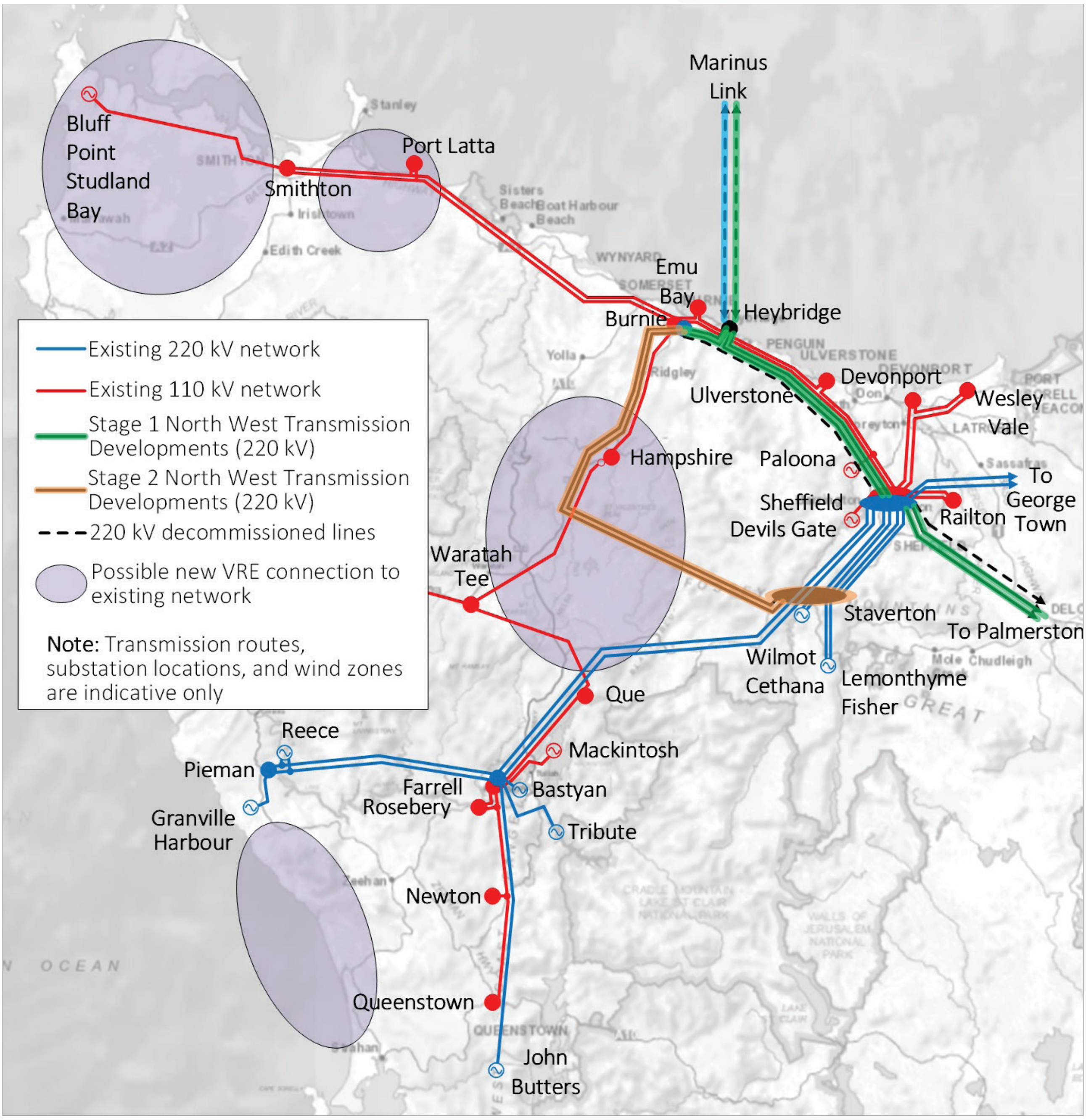


Figure 3-4: North West Tasmania REZ transmission network with NWTD

Figure 3-5 summarises the existing hosting capacity of the North West REZ transmission network, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive change scenarios.

48 https://www.hydro.com.au/clean-energy/battery-of-the-nation/pumped-hydro

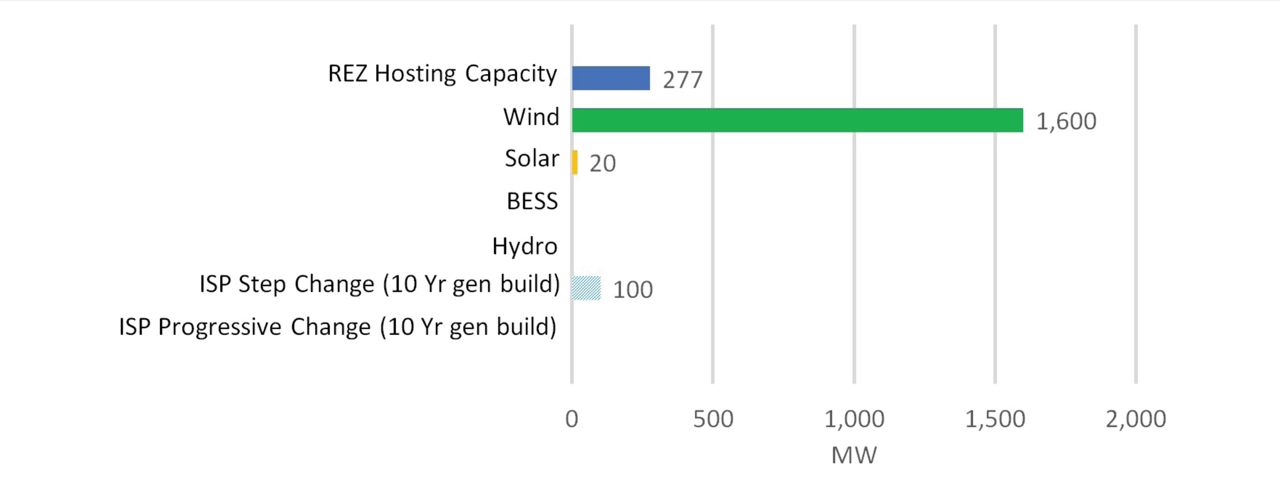


Figure 3-5: North West Tasmania REZ forecast generation and hosting capacity

There is capability in the existing North West REZ transmission network to accommodate approximately 277 MW of new VRE subject to a number of already identified limitations being adequately addressed including provision of adequate system strength.

There is a combined interest of approximately 1,600 MW of new generation in this REZ, the vast majority being wind generation.

The Step Change scenario of the ISP forecasts a slower uptake of new generation in this area compared with the other land based REZs. Only 100 MW of new generation is predicted in the next 10 years. The Progressive Change scenario forecasts no new generation over the same period.

3.6.3. North West Transmission Developments

To support the 1,500 MW transfer capability of Marinus Link, the construction of two new double-circuit, 220 kV transmission lines from Sheffield Substation to the Marinus Link converter stations at Heybridge, together with augmentation of the 220 kV transmission line from Sheffield to Palmerston Substations, will be required. Developing separate corridors for the two transmission lines between Sheffield and Heybridge substations which traverse coastal and inland routes, allows for route diversity and for the efficient connection of new generation in the North West REZ.

The optimal transmission development for the north west is a new 220 kV transmission 'rectangle', plus increased transmission capacity between Sheffield and Palmerston substations, specifically:

- **New 220 kV switching stations:** at Staverton, Hampshire Hills and Heybridge;
- **New 220 kV double-circuit transmission ring:** Sheffield–Heybridge–Burnie–(via Hampshire)–Staverton;
- **New 220 kV double-circuit transmission line:** Palmerston–Sheffield; and
- **Decommission:** existing single-circuit Palmerston–Sheffield and Sheffield–Burnie 220 kV transmission lines.

More information on the North West Transmission Developments (NWTD), as well as progress on the design and approvals phase, is available from the TasNetworks website at:

https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/North-West-Transmission-Developments

The NWTD project has three distinct phases:

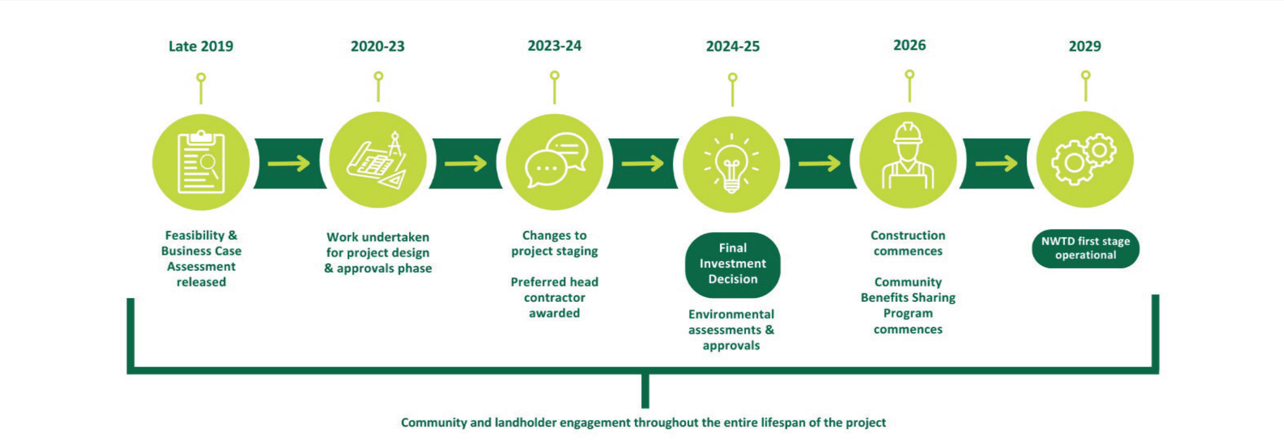
Design and Approvals	During this phase, the project develops all the necessary plans and technical designs, undertakes land-use planning activities, and completes comprehensive approvals processes at local Council, Tasmanian Government and Federal Government levels. The project also undergoes a rigorous economic cost-benefit analysis. The NWTD is subject to a final investment decision (**FID**) which is scheduled for December 2024 and will only progress to the construction phase once all the necessary approvals are in place.
Construction	It is anticipated that the main construction activities will commence in 2025-2026, following FID approval.
Operation and Maintenance	Once construction has been completed, TasNetworks will operate and maintain the new transmission infrastructure as regulated assets.

3.6.3.1. Project staging

The NWTD project will be delivered across two stages, focusing on the delivery of Stage 1 until a final investment decision is made for the second Marinus Link cable. Construction of Stage 1 is planned to commence in 2025-26 to align with the start of Marinus Link works, and will establish a connection between Sheffield, Burnie and Marinus Link via a coastal route. Stage 1 also includes replacement of the existing Palmerston to Sheffield 220 kV transmission line.

Stage 2 will deliver the balance of the NWTD project scope, which includes the new transmission sections between Staverton and Burnie via Hampshire Hills. The timing of these developments is intended to align with the second Marinus Link cable.

This approach will see approximately 60 per cent of the NWTD built in the first stage. All stages of the project are subject to Development and Environmental Approvals and Final Investment Decisions.



In mid-2023, TasNetworks undertook the required steps to register a notified corridor for the proposed alignment of the NWTD in accordance with MIDAA.

The MIDAA process requires that a notified corridor must be in place before TasNetworks can submit a Development Application and Environmental Impact Statement for assessment. At TasNetworks' request, the notified corridor was made by the Minister for Planning.

The development sequence of the NWTD has been reviewed to ensure that the minimum network requirements for Marinus Link Stage 1 can be met at the least cost for our customers. The sequencing also allows for the network to be further expanded to deliver that necessary to support Marinus Link Stage 2 which will see the interconnector reach its full 1,500 MW transfer capacity.

Stage 1 of the NWTD comprises a new double circuit transmission corridor between Palmerston, Sheffield and Burnie, with an interim tee arrangement to allow connection of Heybridge Switching Station and the first 750 MW Marinus Link interconnector. Redevelopment of the Palmerston to Sheffield transmission corridor from single circuit to double circuit will occur under Stage 1.

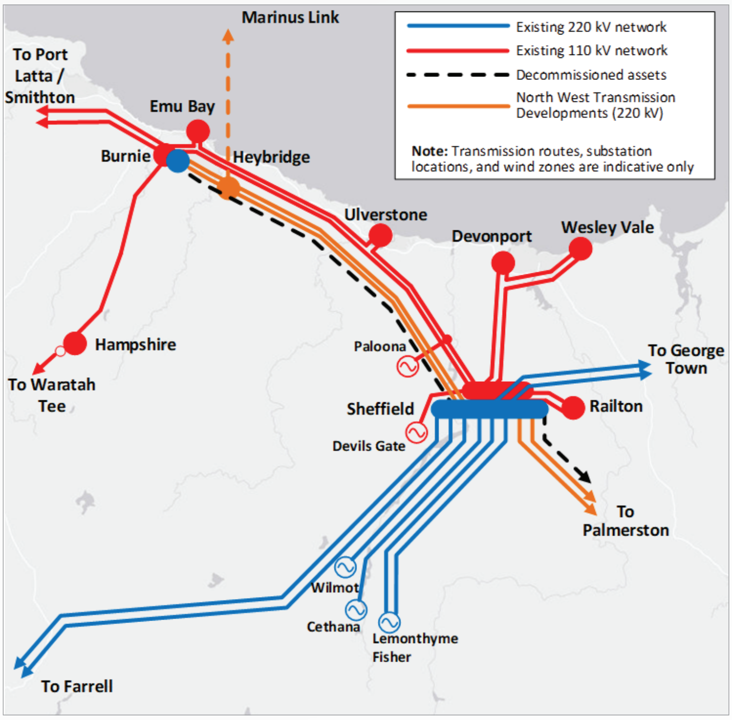


Figure 3-6: Marinus NWTD Stage 1

Stage 1 of the NWTD comprises the following assets:

- **One new 220 kV switching station** at Heybridge;
- **One new 220 kV double-circuit transmission line** between Sheffield, Heybridge and Burnie;
- **One new 220 kV double-circuit transmission line** between Palmerston and Sheffield; and
- **Decommissioning** of the existing Palmerston-Sheffield and Sheffield-Burnie 220 kV single-circuit transmission lines.

The estimated cost of this first stage of works is $950 Million.

The key assumptions which underpin the Stage 1 developments include:

- Construction of the new transmission lines will be undertaken in a manner that minimises the operational risk to customers and generators connected in the north west.
- Development of a double circuit 220 kV connection for the first stage of Marinus link is to ensure that the interconnector is not significantly impeded by transmission network capacity limitations.
- Upgrade works will be undertaken at Burnie and Sheffield substations to ensure that the security of the network is maintained, and that new generation and load can also be connected in the north west going forward.

3.6.3.2. Adjustments to notified transmission corridors

The new high-capacity corridor between Palmerston, Sheffield and Burnie will provide the means for harnessing renewable energy resources close to the network. Prior to the inland route being established as part of NWTD Stage 2, new resources in the north west REZ have the option to connect at Burnie in the first instance.

As a result of the decision to develop the coastal route first, it is now necessary to retain the existing 220 kV line between Sheffield and Burnie during construction to manage the risk of outages. It is still the case that the existing 220 kV line between Sheffield and Burnie will be removed post-construction. To allow the new 220 kV line to be erected while the existing one is in place, the proposed alignment of the new transmission line and the location of some towers has been adjusted in several locations. Other adjustments have also been made following discussions with landholders and ongoing line design work. This has meant that the notified corridor between Sheffield and Burnie needed to be adjusted and, in some areas, widened.

The existing notified corridor between Hampshire Hills and Burnie is also being amended in some locations to provide greater flexibility as we progress field investigations and further discussions with landholders.

TasNetworks recently requested that the Minister for Planning amend the notified corridors to allow for these adjustments.

In addition, we are further considering REZ development scenarios where components of the remaining NWTD strategy are brought forward ahead of Marinus Link Stage 2, including:

(1) Burnie approach: Developing the Burnie-Hampshire Hills 220 kV transmission line; or

(2) Sheffield approach: Developing the Hampshire Hills-Staverton 220 kV line, along with Staverton Switching Station.

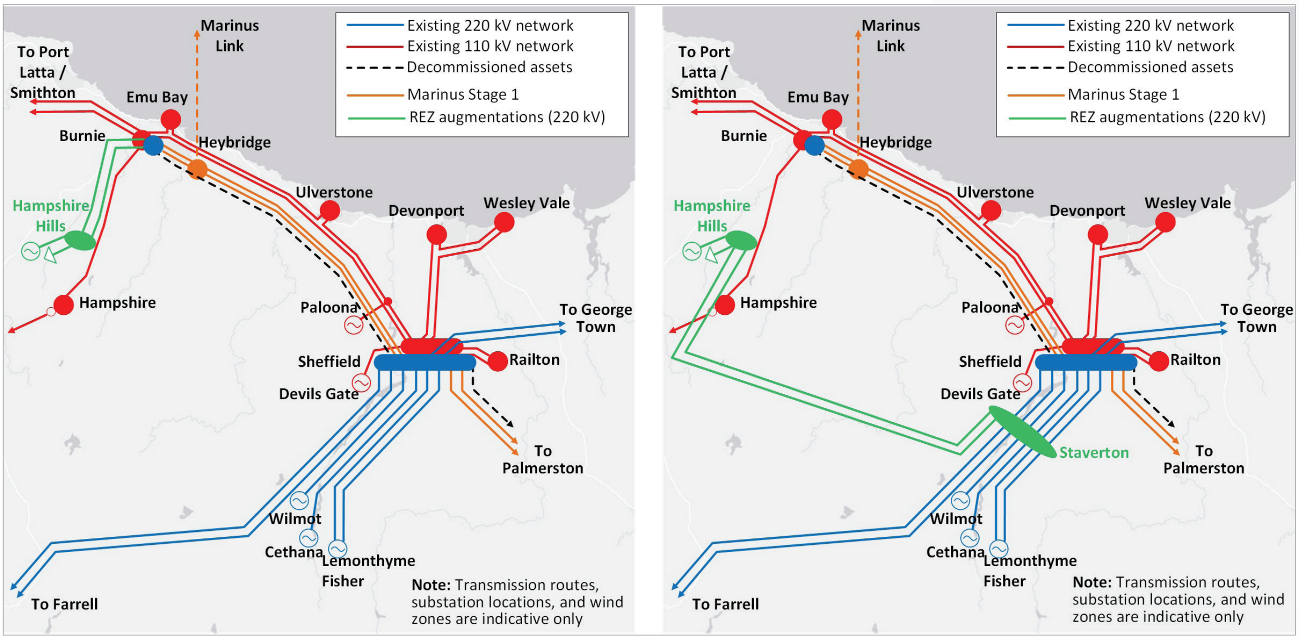


Figure 3-7: Potential investments driven by North West REZ

Either option may be progressed through various mechanisms, including:

- A contingent project with regulated funding, triggered by the commitment of new generation or load, and justified through a RIT-T;
- An actionable project identified in AEMO's Integrated System Plan (ISP), whereby a RIT-T is undertaken by TasNetworks and if successful, the preferred option is progressed as a regulated asset;
- A Designated Network Asset (DNA); whereby the augmentation is funded by the DNA owner; or
- REZ infrastructure utilising a REZ framework developed by the Tasmanian Government.

3.6.3.3. Specific considerations for the Palmerston–Sheffield 220 kV transmission line

The Palmerston–Sheffield 220 kV transmission line is a critical part of the existing transmission network. It forms part of the Palmerston–Sheffield–George Town triangle that:

- Connects the north west and west coast, George Town, and southern area networks;
- Supplies the major industrial customers located at George Town;
- Helps facilitate Basslink export and import from George Town Substation; and
- Transmits generation from the north-west and west coast to Hobart and southern Tasmania.

The Palmerston–Sheffield 220 kV transmission line is currently only single-circuit and has a lower thermal capacity than the other circuits in the triangle. It also plays a major role in transient stability constraints given that loss of this circuit dramatically increases the transmission distance between Sheffield and Palmerston. It will become a constraining element in a future network where increased power flows will be needed between the north and south of the state. Figure 3-8 presents the Palmerston–Sheffield 220 kV transmission line and Palmerston–Sheffield–George Town triangle.

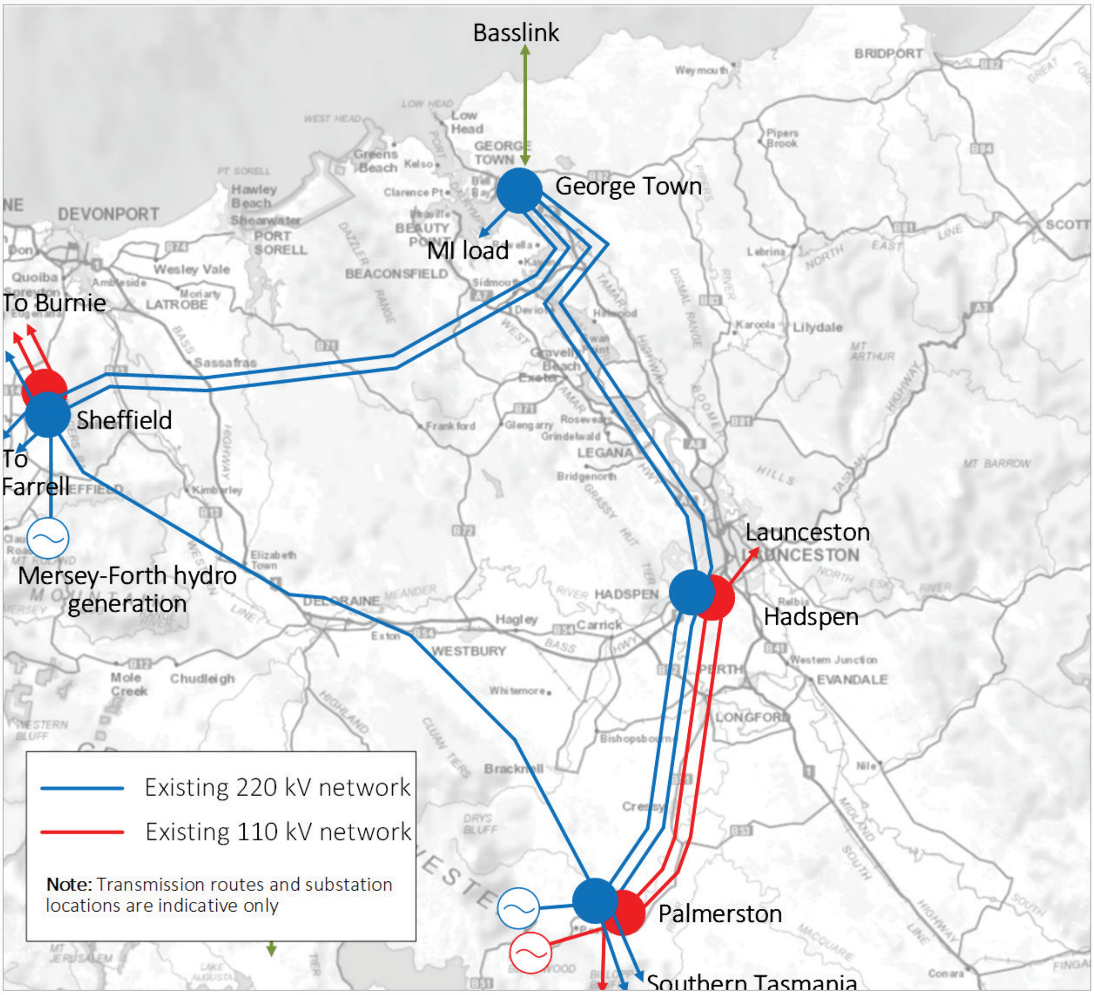


Figure 3-8: Network diagram showing the Palmerston to Sheffield 220 kV transmission line

As described throughout this Chapter, there are a number of future power system scenarios where augmentation of the Palmerston–Sheffield 220 kV transmission corridor is required:

- **Marinus Link and North West REZ**

  The existing transmission network in north-west Tasmania will require augmentation to support the increased power flows to and from Marinus Link. This includes augmentation of the Palmerston–Sheffield 220 kV corridor.

  If new large VRE develops in the North West REZ, the Palmerston–Sheffield 220 kV transmission line will become more congested. Augmentation can be triggered by 230 MW of new generation in the North West REZ, prior to Marinus Link.

- **Hydrogen developments**

  Augmentation of the Palmerston–Sheffield 220 kV transmission corridor will enable higher amounts of hydrogen load to be supported at George Town. Refer to Section 3.7 for more information.

3.6.4. Central Highlands REZ

The ISP identifies the capacity factor for new wind generation in the Central Highlands REZ as the highest in the NEM. Coupled with the existing transmission network capacity, there is significant opportunity for new wind generation to be developed within the REZ immediately.

Figure 3-9 presents the Central Highlands REZ transmission network, including the new Palmerston–Sheffield 220 kV transmission line as part of NWTD. The figure also shows possible connection locations that could utilise existing network capacity. We anticipate that new wind generation will be developed in the Waddamana area and surrounds, while new solar would more likely develop on flatter terrain around Palmerston at the base of the Western Tiers.

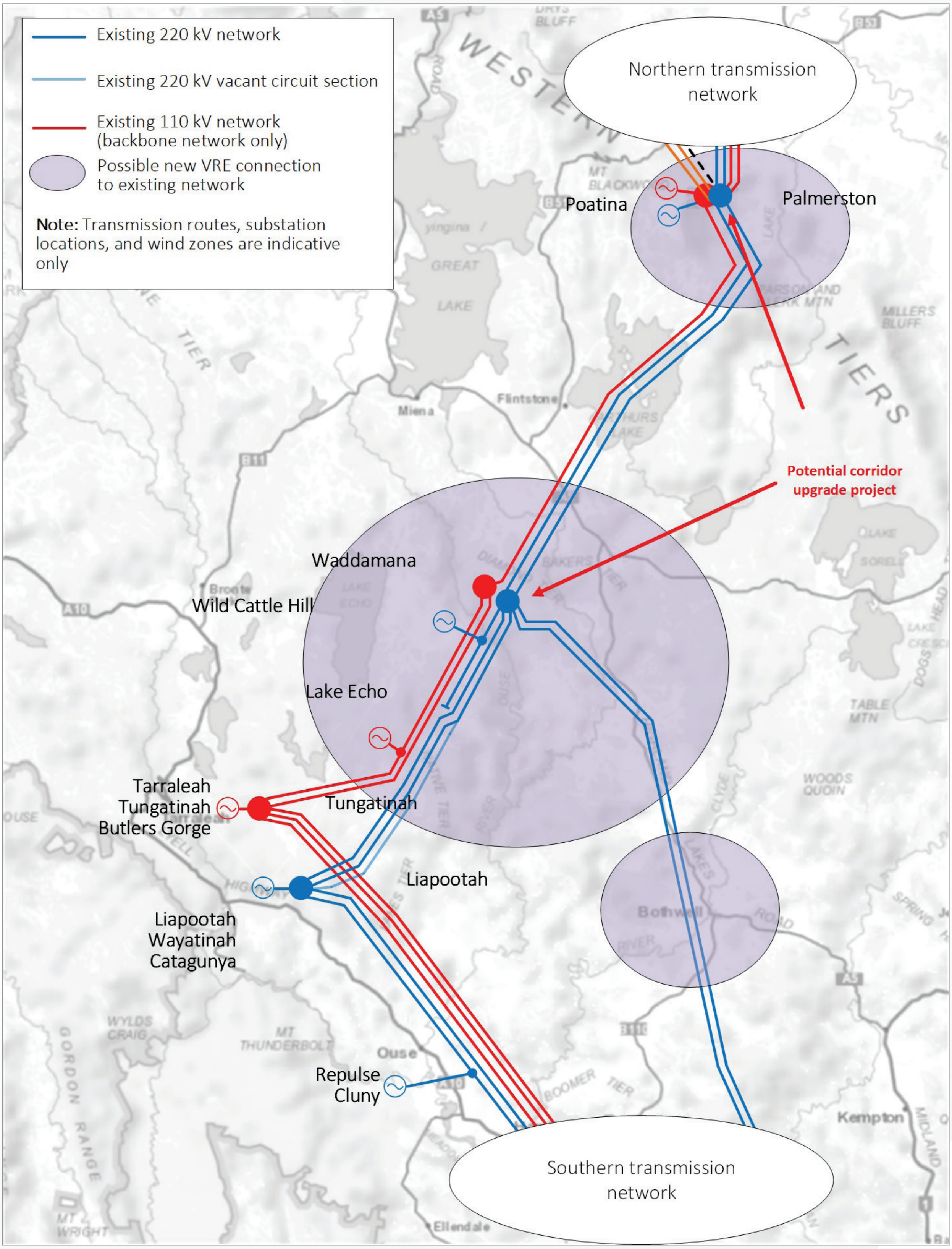


Figure 3-9: Central Highlands REZ transmission network

Figure 3-10 presents the existing hosting capacity of the Central Highlands REZ transmission network, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive change scenarios. The 2024 ISP only forecasts the development of wind generation in this REZ, without any solar.

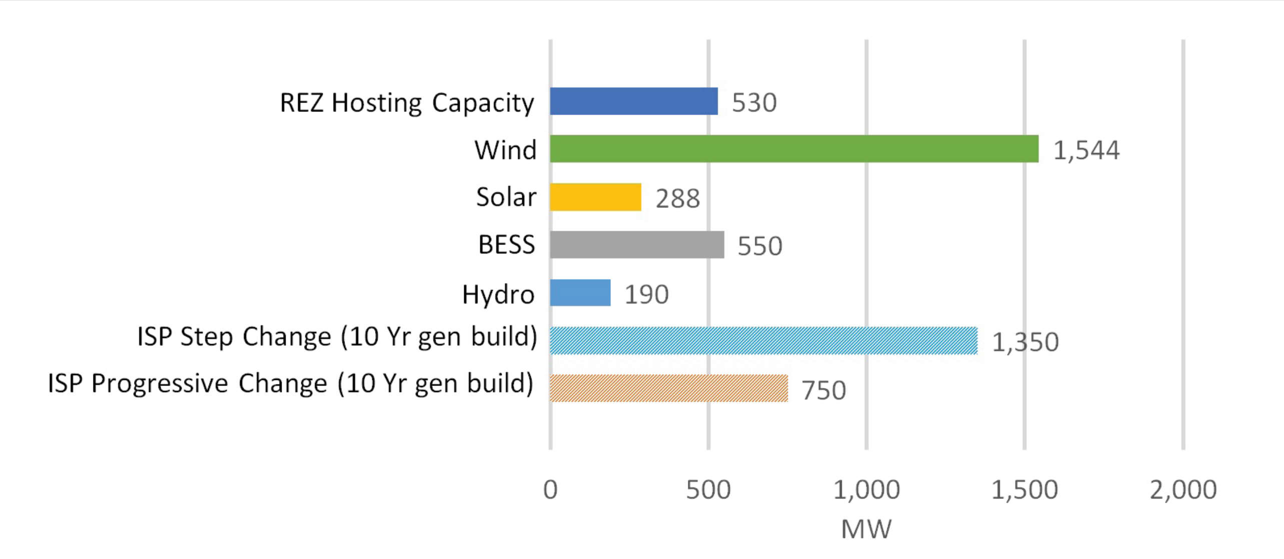


Figure 3-10: Central Highlands REZ forecast generation and hosting capacity

The existing transmission network within the REZ has the capability to host approximately 530 MW of new generation, limited by both the Waddamana–Palmerston transmission corridor capability and the transmission network from the Central Highlands REZ to the rest of the network.

3.6.4.1. Waddamana–Palmerston transfer capability upgrade

There is significant new wind generation proposed in the Central Highlands REZ over coming years. This is expected to occur in the Waddamana area and surrounds, including to the south along both the Waddamana–Liapootah and Waddamana–Lindisfarne transmission corridors (refer Figure 3-9). There are proposals for 1,544 MW of new wind generation in this area across several projects, as well as the Tarraleah Power Station replacement (refer Section 3.8.2).

The 2024 ISP has also identified significant wind developments in coming years, with augmentation of the Waddamana–Palmerston transmission corridor now an actionable project for all scenarios.[49] This is necessary to increase transfer capacity between the north and south of the state. With a Waddamana–Palmerston transfer capability upgrade, the outlook for wind generation in the Central Highlands REZ under the Step Change scenario is 1,350 MW by 2029–30 and 1,400 MW by 2039–40. For the Progressive Change scenario, the figures are slightly more modest with 750 MW by 2029–30 and 1,550 MW by 2039–40. An overall summary is presented in Table 3-1.

The credible option identified by AEMO is to build:

- a new (second) Waddamana–Palmerston 220 kV transmission line; and
- Install power flow controllers on the Sheffield–Palmerston 220 kV transmission line.

This option is expected to provide 690 MW of additional network capacity and cost $201 million. The ISP optimal timing for this development is 2029–30 under all three scenarios.

The project would occur with Marinus Link and NWTD and provide a pathway from the Central Highlands REZ to the rest of the transmission network, including to the mainland.

As an actionable ISP project, AEMO has identified TasNetworks as the RIT-T proponent. The Project Assessment Draft Report (PADR) is expected to be published by June 2025.

A new (second) Waddamana–Palmerston 220 kV transmission line was accepted by the Australian Energy Regulator (**AER**) as a contingent project in our 2024–29 regulatory determination. TasNetworks will not progress the contingent project application through the regulatory determination while also progressing the proposed development as an actionable ISP project.

49 https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

3.6.5. Summary of ISP forecasts

The ISP is published every 2 years, with the most recent version published in June 2024.[50] The 2024 ISP is the version considered throughout this Annual Planning Report.

The ISP produces an optimal development path for new generation (predominantly VRE), transmission, and storage across the NEM to replace existing thermal generation sources (coal and gas) as it retires over coming years. The ISP projects out to 2050, and across three scenarios. It identifies the Step Change scenario as the most probable, with this scenario having thermal generation retiring earlier than previously announced, and the subsequent rapid development of new VRE, transmission, and energy storage to replace it.

The ISP includes the TRET as a basis for its modelling across all scenarios, ensuring sufficient VRE is built in Tasmania to meet the legislated interim and final targets. It also assumes that the BOTN activities are developed.

The ISP considers VRE resource quality across each REZ, along with existing transmission capability and augmentation requirements. It does not consider the specific locations within the REZ where VRE might be developed. The ISP Step Change scenario considers some hydrogen developments, with the most pronounced changes seen in the Green Energy Exports scenario which involves very large hydrogen (and subsequent VRE) developments across the NEM.

In Tasmania, around 1.5 GW of new utility-scale wind generation is projected by 2030-31, utilising transmission capacity released by the development of Project Marinus Stage 1.

ISP modelling indicates:

- Over 600 MW of new wind generation is projected for the Central Highlands REZ by 2026-27, with around 1,300 MW projected by 2029-30 to utilise the full capacity of Project Marinus Stage 1. This REZ now has the highest VRE projection in the Tasmanian region, with nearly 2,300 MW forecast by 2046-47.
- The North West REZ sees a gradual increase of 380 MW of new wind generation by 2034-35, reaching a maximum of 500 MW by 2046-47.
- There is 400 MW of new wind projected for the North East REZ by 2031-32.
- There is no major change in forecast utility-scale VRE capacity beyond 2042-43.
- There is no utility scale solar or offshore wind development projected in the Step Change results for Tasmania. Small scale distributed solar will continue to grow in capacity.

Table 3-1 presents the ISP outlook for new large scale VRE under the Step Change and Progressive Change scenarios by REZ for 2029-30 and 2039-40.

Table 3-1: 2024 ISP VRE projections (MW)

	Step Change scenario		Progressive scenario	
REZ	**2029-30**	**2039-40**	**2029-30**	**2039-40**
North East Tasmania (T1)	250	400	250	350
North West Tasmania (T2)	0	400	0	0
Central Highlands (T3)	1,300	1,400	700	1,550
North Tasmanian Coast (T4)	0	0	0	0
Total	**1,550**	**2,200**	**950**	**1,900**

The 2024 ISP optimal development path further identifies the following transmission augmentations in Tasmania:

- Marinus Link Stages 1 and 2 are classified as a single actionable project, with full capacity timing of 2030 and 2032 assumed based on timing advised by the proponent;
- Waddamana- Palmerston upgrade is now an actionable project, with earliest feasible timing being July 2029; and
- North West and Central Highlands REZ expansion network upgrades as future ISP projects.

The ISP does not consider any of the currently proposed VRE developments in Tasmania to be sufficiently progressed to be included as 'anticipated' or 'committed' projects in its analysis, meaning that specific projects are not modelled in the ISP.

50 https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

In terms of TRET mandated energy production, TasNetworks note the following:

- The Progressive Change generation build falls short of both the interim and final target; and
- while the Step Change generation build trajectory has the capability to meet the 2030 TRET interim target, additional generation may be required to meet the 2040 target.[51]

3.7. Hydrogen development

The state government is actively pursuing the development of a green hydrogen industry in Tasmania through its Tasmanian Renewable Hydrogen Action Plan.[52] The plan identifies two locations for large-scale renewable hydrogen production and potential export facilities, being the Bell Bay Advanced Manufacturing Zone (BBAMZ), and industrial precincts in north-west Tasmania (such as Port Latta or Burnie).

The aspirational targets for future hydrogen load are significant in comparison to the size of the existing Tasmanian power system. As presented in Section 2.1.1, the median demand in Tasmania is approximately 1,200 MW, with the action plan presenting a potential 1,000 MW of total installed capacity. As such, the power system integration issues presented by large-scale hydrogen are being carefully considered. The network requirements to facilitate hydrogen development will depend on the size, location, and technology being deployed. It is assumed that the connection of future hydrogen projects is likely to occur in three tranches:

- Tranche 1, up to 300 MW;
- Tranche 2, a further increase of 400 MW to a total of approximately 700 MW; and
- Tranche 3, a final installed capacity of up to 1,000 MW.

The increase in Tasmanian operational demand currently being contemplated will need to be considered from four separate but highly interrelated perspectives:

- network capacity;
- the overall energy balance that can be achieved in Tasmania;
- access to sufficient levels of firming capacity; and
- power system security and resilience outcomes.

Bell Bay has been identified as the site for one of two potential hydrogen hubs in Tasmania due to access to:

- certifiable renewable energy;
- high-quality fresh water;
- deep-water port facilities; and
- significant vacant industrial land in close proximity to the port.

The George Town area is supplied via two double-circuit 220 kV transmission lines and the Basslink interconnector. There is also currently 386 MW of gas fuelled generation connected to George Town Substation. An overview of the northern network, with indicative future augmentations supporting the proposed tranches of hydrogen and future renewable energy developments, is shown in Figure 3-11.

51 Based on the ISP average capacity factor of at least 48% across North West, North East and Central Highlands REZs

52 https://recfit.tas.gov.au/__data/assets/pdf_file/0013/313042/Tasmanian_Renewable_Hydrogen_Action_Plan_web_27_March_2020.pdf

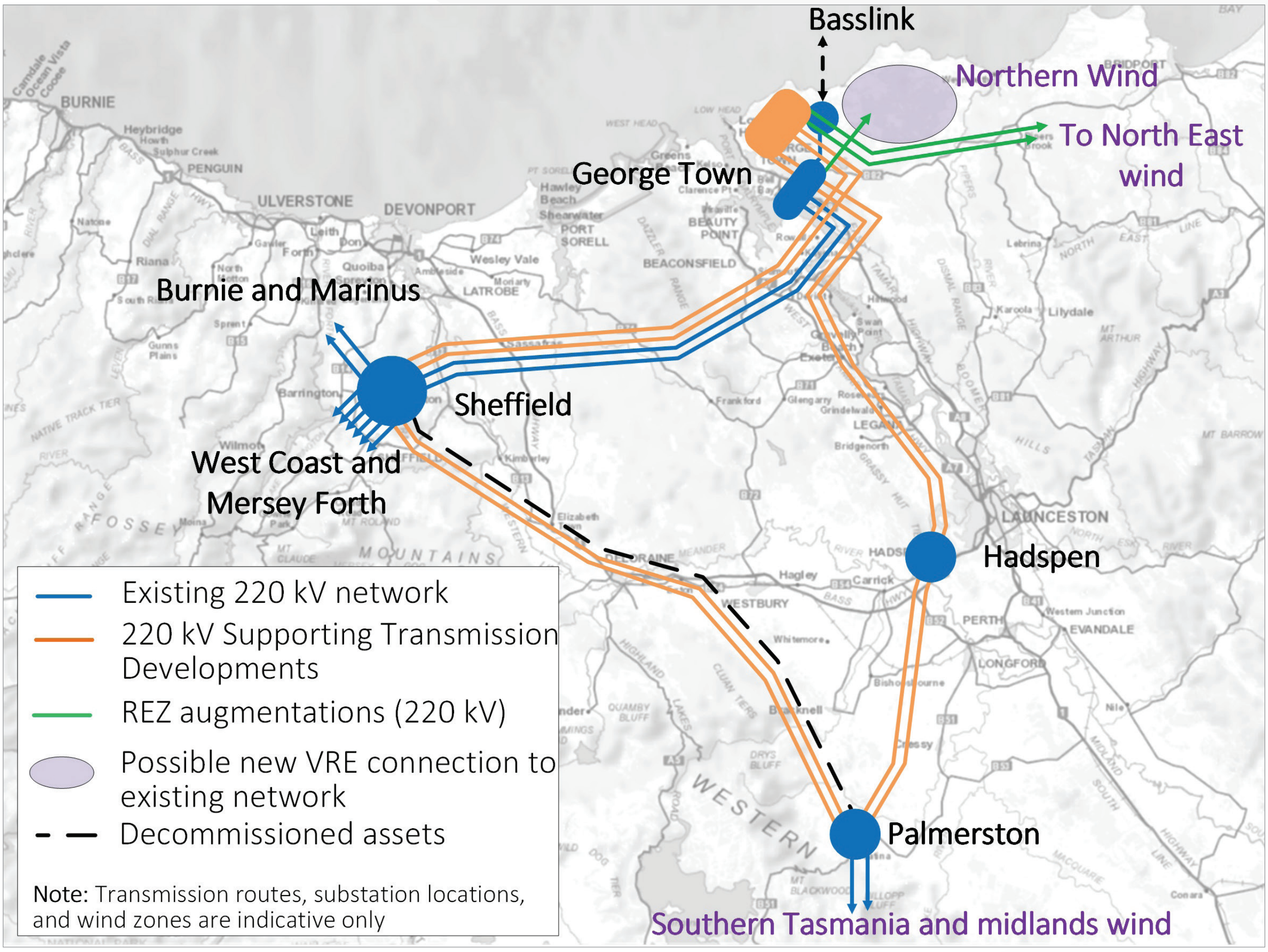


Figure 3-11: Transmission network developments supporting hydrogen load connections

The level of network augmentation required will very much depend on the capacity of the hydrogen projects wanting to connect, noting that TasNetworks is also considering what new generation may be developed in parallel, especially in the North East REZ. Table 3-2 describes the required augmentation associated with each new tranche of load connections.

Table 3-2: Future hydrogen driven network augmentations: Bell Bay region

Sequence	Development considerations
Tranche 1: Up to 300 MW	It is assumed that Tasmania will aim to maintain an energy balance[53] in the longer term and that the 300 MW of new load will be developed in parallel with 600 – 750 MW of new wind generation. One material consideration is where and when new Tasmanian generation will be developed. While it is possible to supply the load (when considered in isolation) without material network augmentation, in order to maintain an on-island energy balance, it is likely that an upgrade to the existing Palmerston–Sheffield 220 kV transmission line would be necessary. Augmentations at George Town Substation are also envisioned to satisfy Electricity Supply Industry (**ESI**) Regulations in relation to maintaining minimum levels of customer reliability. Power system security requirements are also likely to require augmentations at George Town. In addition to substation augmentation works, new dynamic reactive support will be required at George Town to help support the network under increased power flow conditions.
Tranche 2: Up to 700 MW	Additional reactive support at George Town Substation and duplication of the Sheffield–George Town 220 kV corridor will likely be required, along with further switchyard augmentations to address customer reliability requirements under ESI. New switchyards in the George Town area are also proposed to assist with the management of physical constraints and associated system risks that would come from connecting significant new customer loads into the existing substation. The location of the new switchyard(s) is currently being determined and will be dimensioned to accommodate all reasonably anticipated developments, including both load and any large-scale generation in the north east.
Tranche 3: Up to 1,000 MW	If sufficient hydrogen developments were to occur, the Palmerston–Hadspen–George Town 220 kV corridor will also need to be augmented to significantly increase its capacity.

TasNetworks has included a number of contingent projects into the 2024-2029 Revenue Reset, which include a number of the augmentations outlined in Table 3-2. The contingent projects take account of the forecast timeframes for hydrogen developments, namely the first two tranches of 300 MW and 700 MW over the next 5 years.

Further information on our regulatory proposal can be found in Section 1.7 and on the AER's website:

https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29

3.8. Upper Derwent 110 kV transmission network

The Upper Derwent 110 kV transmission network comprises the transmission lines and substations from Tungatinah to Waddamana Substations (northwards), as well as New Norfolk Substation in the south. This network is some of the oldest in Tasmania, with sections originating from the 1930s, constructed to support the Tarraleah hydropower scheme.

The 110 kV network operates in parallel with the 220 kV network in this area, with interconnection occurring at Palmerston Substation in the north and at Chapel Street and Lindisfarne Substations in the south. Figure 3-12 presents the key elements of the Upper Derwent 110 kV transmission network and surrounds.

53 Meaning that Tasmania, on average, can generate enough electrical energy to satisfy its own requirements. While net energy imports and exports will shift from year to year due to variations in renewable energy yield (including rainfall), the expectation is that Tasmania will not be long-term energy deficient.

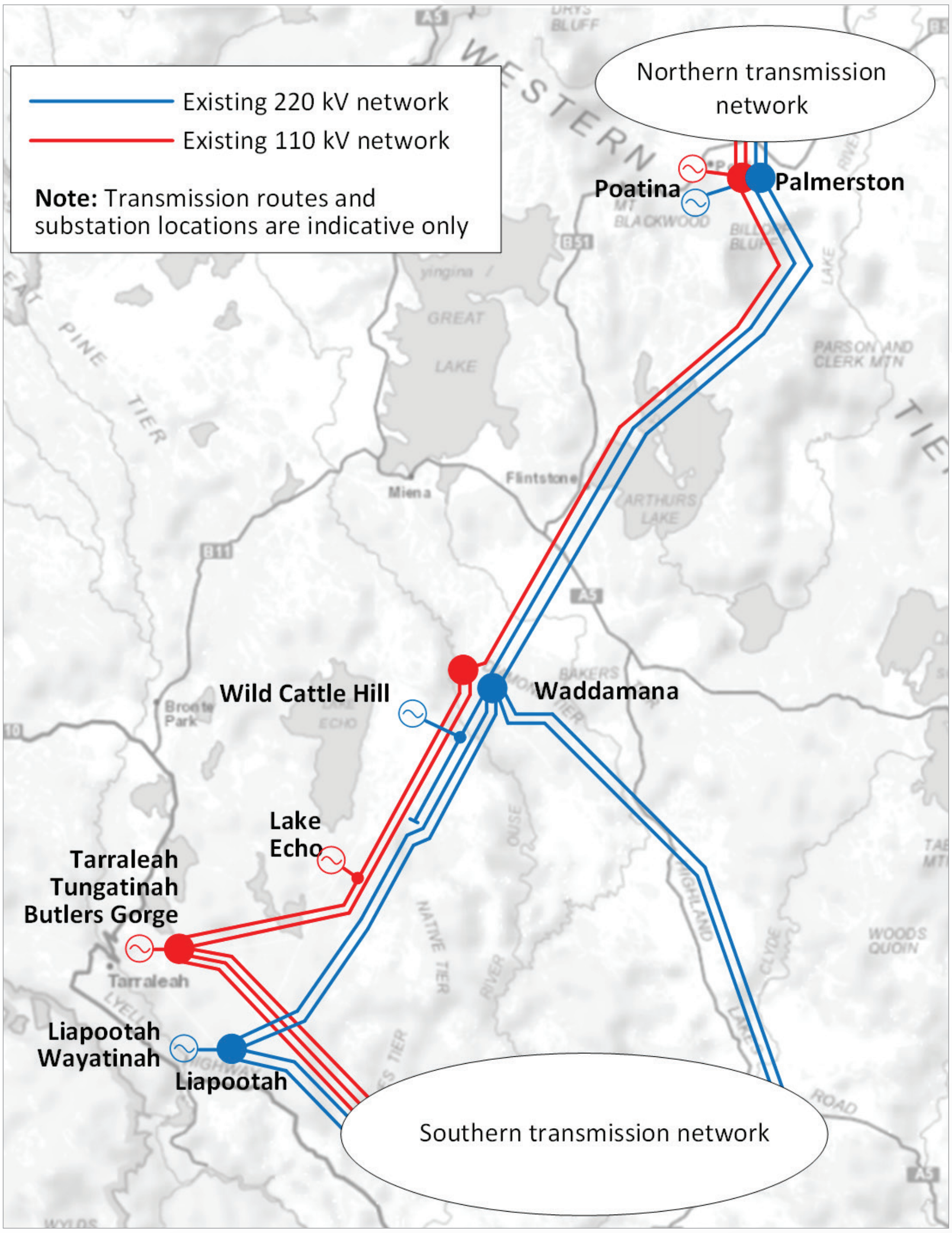


Figure 3-12: Upper Derwent area transmission network

3.8.1. Reducing losses in Upper Derwent 110 kV transmission network

We have identified an opportunity to significantly reduce transmission losses in the Upper Derwent 110 kV transmission network. There is 250 MW of generation capacity connected to Tungatinah Substation, which is transmitted via 110 kV assets to Palmerston and New Norfolk Substations. Providing a local interconnection between the 110 kV and 220 kV networks will allow for a more efficient transfer of power into the higher capacity 220 kV network, thereby reducing network losses.

We have assessed a number of options for the location and timing of this network augmentation to provide access for Upper Derwent 110 kV generation into the 220 kV network.

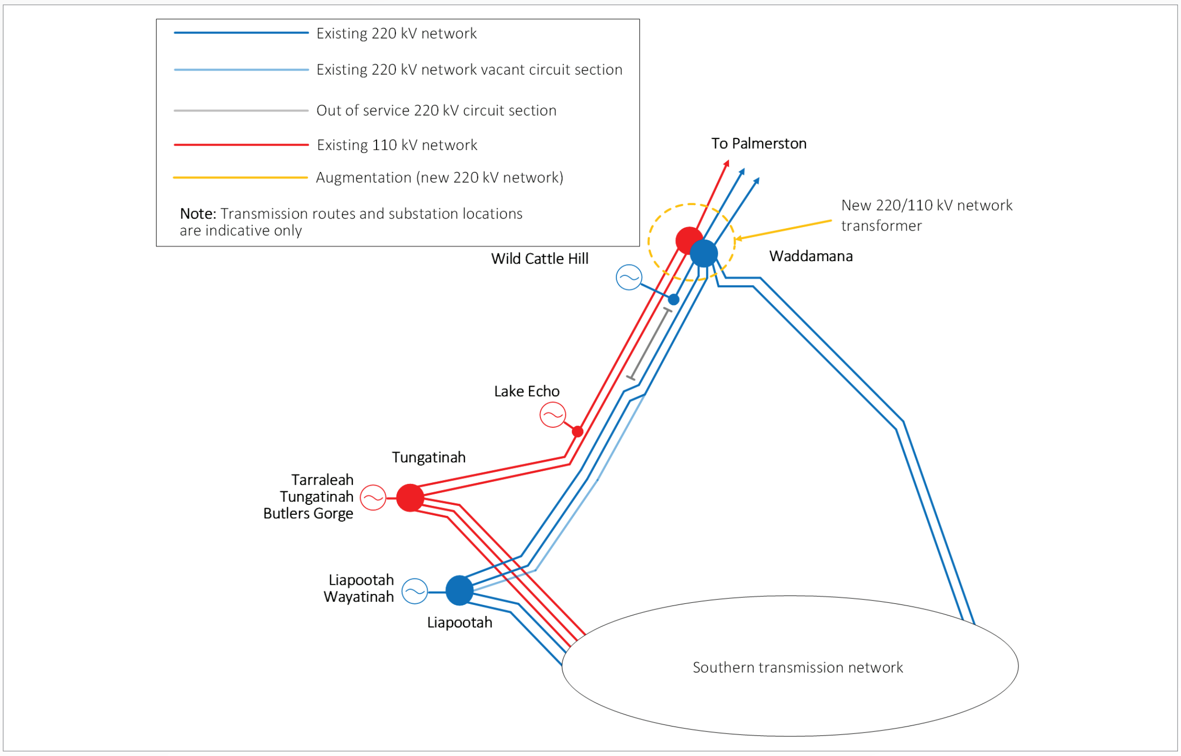


Figure 3-13: Option to reduce losses in Upper Derwent 110 kV transmission network

Our preferred option to reduce losses in the Upper Derwent 110 kV transmission network is to install a 220/110 kV network transformer at Waddamana Substation, as presented in Figure 3-13. It is a relatively simple solution and is economically justified through the savings in reduced network losses being greater than the cost of installing the transformer. The option is estimated to cost $10.9 million. The project has been accepted as part of our most recent regulatory proposal.[54]

3.8.2. Repurposing the Tarraleah hydropower scheme

As part of its BOTN initiative, Hydro Tasmania is proposing to repurpose the Tarraleah hydropower scheme.[55] Tarraleah Power Station currently has 90 MW of installed capacity, with no effective short-term flexibility to vary generation output. It is also one of Tasmania's oldest hydropower schemes and requires significant investment to ensure its reliable operation into the future. Repurposing the scheme will allow Tarraleah to meet the needs of the future power system by increasing the installed generation capacity and changing is operational role from a base-load power station to being fully flexible.

Hydro Tasmania is continuing to assess its preferred development options, including maintaining the existing station (though this option appears unlikely). A new Tarraleah Power Station could have an installed capacity of up to 190 MW, and include a 220 kV network connection. The project timing is proposed to align with the first stage of Marinus Link.

We are continuing to engage with Hydro Tasmania to determine the preferred option, including the transmission network connections and augmentation requirements to facilitate it.

54 If Tarraleah hydropower scheme repurposing occurs and a 220 kV connection is made to the Tarraleah/Tungatinah area, the preferred option for location of the network transformer may change.

55 https://www.hydro.com.au/clean-energy/battery-of-the-nation/hydro-system-improvement

3.9. Battery energy storage systems connections

TasNetworks has received a notable level of interest from battery energy storage systems (**BESS**) proponents, who can offer potential network services including congestion management, system strength and inertia support, voltage and frequency control capabilities and power quality support.

Some identified challenges to be managed include:

- impact on network thermal capability;
- steady state voltage control and reactive power requirements;
- power quality (including harmonics and dynamic voltage management); and
- transient and dynamic stability of the network (in particular, the fault ride through performance of such devices and their potential impact on frequency management).

We continue to consult with prospective BESS proponents to identify the optimal solutions for connection and integration into our network.

Chapter 4

Area planning constraints and development

- Four geographic planning areas are considered: North West and West Coast, Northern, Central, and South.
- Details of planned augmentations and replacements are provided by planning area.
- Targeted reliability improvement projects continue for specific reliability communities.
- Exemptions from jurisdictional planning requirements are retained for three locations, with a new five year exemption of the Farrell-Savage River-Waratah transmission line in the North West and West Coast planning area.
- Feedback is welcomed on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

4.1. Background to area planning constraints

In conjunction with our assessment of the backbone transmission network, we plan local transmission and distribution networks in accordance with regulatory requirements as outlined in Appendix A. In doing so, we address integrated planning considerations and technical analysis methodologies. Our plans are based on four geographical planning areas being:

- North West and West Coast planning area;
- Northern planning area;
- Central planning area; and
- Southern planning area.

This Chapter provides information on both the transmission and distribution networks within each planning area, including:

- availability to connect to the network;
- committed and completed projects;
- limitations and developments;
- future connection points;
- actions to address poor performing reliability communities; and
- deferred or averted limitations.

It also presents our asset retirement and replacement programs, our proposed investments in operational support systems, and the telecommunications network. These programs and investments are presented on a whole-of-state basis, by asset class.

4.2. Planning areas

The planning areas are defined by the core transmission network connecting major supply points, and the geographical coverage of the distribution network across the State. Figure 4-1 shows the geographic planning areas and Table 4-1 provides a brief description of each.

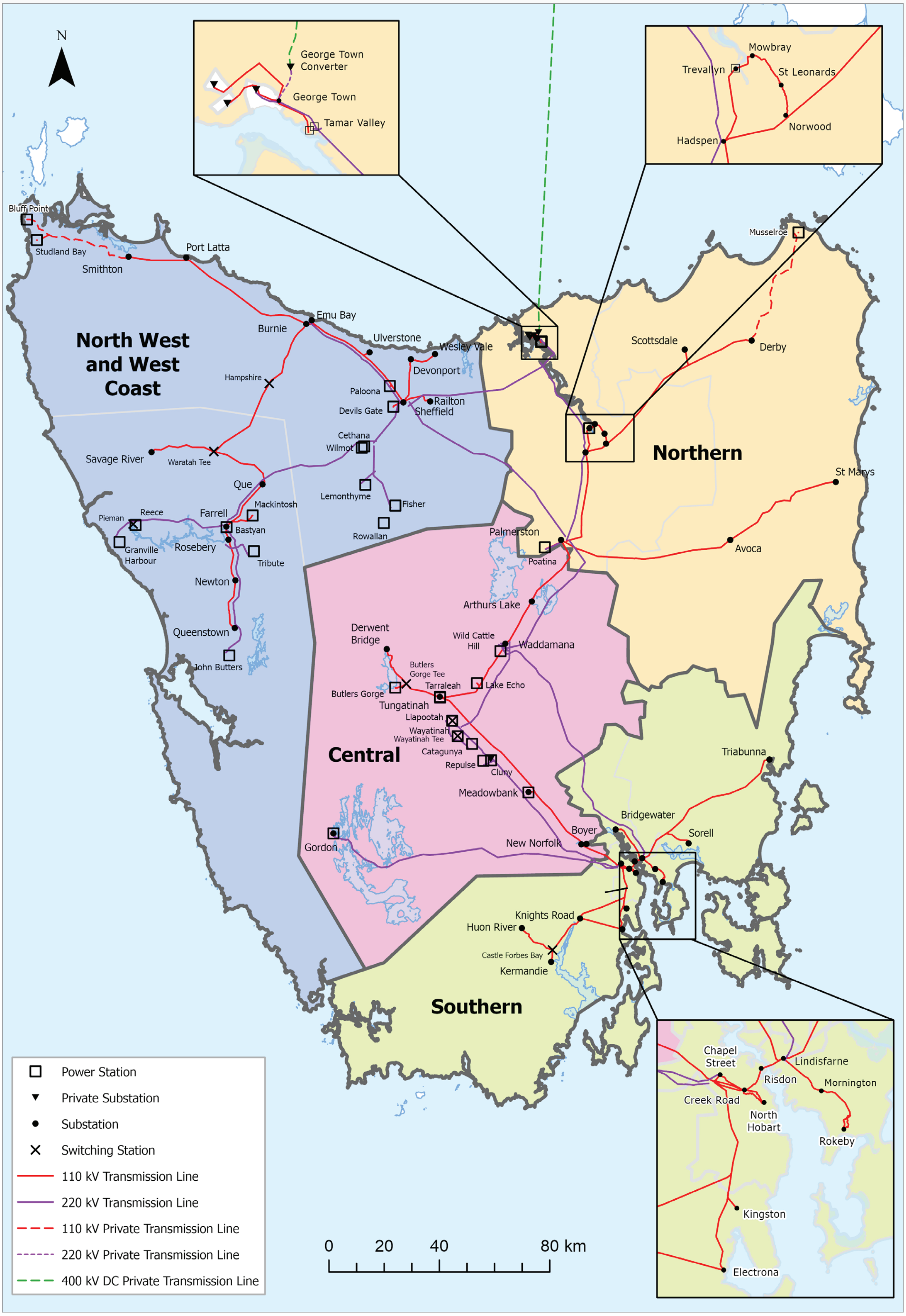


Figure 4-1: Geographical planning areas

Table 4-1: Network planning areas

Planning area	Description
North West and West Coast	The north-west of Tasmania from Deloraine and Port Sorell, to Smithton and the far north west. This area is supplied from the 220 kV backbone network at Burnie and Sheffield substations. The West Coast covers the network area supplied from Farrell Substation.
Northern	The greater Launceston area, George Town and north-east Tasmania. It includes the West Tamar, Hadspen, Northern Midlands and Break O'Day Local Government Areas, as far south as Coles Bay on the east coast. This area is supplied from the 220 kV backbone network at Hadspen, George Town and Palmerston Substations.
Central	The Central Highlands and Derwent Valley areas of Tasmania. This area also includes the supply point at Strathgordon. The area is generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah) and Waddamana substations.
Southern	The southern planning area covers Greater Hobart and the smaller communities of southern Tasmania. Localities outside of Hobart include Southern Midlands, Glamorgan-Spring Bay, Sorell and Tasman Local Government Areas to the north and east, as well as Kingborough and Huon Valley Local Government Areas to the south. The Southern area is supplied from three 220 kV connections emanating from Gordon, Liapootah and Waddamana Substations which connect to Chapel Street and Lindisfarne Substations located on the outskirts of Hobart. Major 110 kV substations in the Hobart area include Creek Road and Risdon. Areas to the east of Greater Hobart are supplied via the peripheral 110 kV network from Lindisfarne Substation. Areas to the south of Greater Hobart are supplied from the 110 kV network from Chapel Street Substation.

4.3. Notes for all geographic planning areas

The Annual Planning Report (**APR**) contains information on each planning area of the network, as summarised in the following table:

Table 4-2: General Notes for all Planning Areas

Component	Description
Committed and completed developments	This section presents the material network projects that are committed or that have been completed since our 2023 APR for each planning area. Our definition of 'committed' is as used in the Regulatory Investment Test (**RIT**). We will report on the progress of our committed projects in future APRs.
Planning area diagrams	The diagrams for each planning area show the transmission and sub-transmission networks, and the distribution supply area of each connection point substation.
Availability to connect to the network	We have connection points at both the transmission and sub-transmission levels across our network, with the capability to connect load and generation. Hosting capacity is dependent on factors that include the rating of equipment at each connection point and upstream network, network stability, security, and reliability considerations. These sections present the available firm headroom at the time of substation maximum demand for each connection point substation, based on the load forecast for 2025. It also provides the total and firm capacity of each substation. Capacity and headroom are based on substation continuous ratings. For single-transformer substations, the firm rating is inherently zero.
Network limitations and developments	The network limitations and development section provides details on our proposed augmentation projects over the next ten years which address forecast network limitations. Network limitations are identified under the Step Change scenario of the load forecast (refer Section 2.1.1). We identify points on the network that are inadequate to meet forecast generation or demand due to limited thermal capacity, a jurisdictional network planning requirement or other technical limits. Section 4.5 presents technical factors affecting the network in Tasmania. Reliability planning criteria are presented in Appendices A.3.3 (transmission) and A.3.4 (distribution). We include information on the type of limitation and our preferred network solution, with estimated timing and cost. We also identify other potential solutions wherever practical. We identify the opportunity for demand management solutions where a controlled reduction in load or improvement in power factor may defer the need for expenditure. None of our proposed network developments will have a material inter-network impact. Substation capacity headroom is assumed to be based on the 2025 forecast year for network demand with applicable asset ratings applied.
Additional information on limitations	We provide additional information on all connection point and transmission line limitations as supplementary information published as 'Transmission annual planning report data' and 'Distribution system limitations report'. These reports are required as part of publishing the APR and provide additional information on identified limitations, including geographic location, energy and demand requirements, identifying load at risk, and deferral value of projects, among others. The reports are provided to enable consistency of information for readers when comparing APRs of different transmission and distribution network service providers across the National Electricity Market (NEM). The reports are available as a downloadable appendix from our website: www.tasnetworks.com.au/apr
Future connection points	This section presents our forecast of future transmission-distribution connection points over the planning period for each planning area. Where applicable, we include the location and description of the future connection points, along with future loading levels and estimated timing and costs.
Targeted reliability corrective action	This section presents any targeted reliability corrective action projects in each planning area. Distribution reliability community performance, compliance and corrective action programs are presented in Chapter 6. In this Chapter, we present the larger targeted reliability improvement projects.

While the network maximum demand in Tasmania remains below its historic peak, the Australian Energy Market Operator's (AEMO) Step Change scenario forecasts ongoing growth for the decade, largely driven by electrification and expansion of large industrial load consumption in the later years.

Many of these prospective large scale load developments are concentrated at specific connection points in the network and will trigger augmentations to the backbone transmission network.

At a locality level, the network remains largely adequate to meet supply reliability requirements over the next 10 years, with a focus largely on distribution network asset management and reliability of supply issues at specific locations.

4.4. Overview of Planning Areas

4.4.1. North west and West Coast planning area

The North West and West Coast planning area covers two separate geographic locations with different network characteristics. The area is connected to the rest of the network through Sheffield Substation, with other 220 kV injection points at Burnie and Farrell substations. Figure 4-2 presents a diagram of the North West and West Coast planning area and substation supply areas.

The North West area comprises residential, commercial, and small to medium scale industries. There are two customers connected directly to the transmission network. Emu Bay Substation supplies part of the Burnie central business district and is the only 11 kV network in the area. The rest of the distribution network operates at 22 kV.

The West Coast area is characterised by mining loads, supplied from both the transmission and distribution networks, and tourism and aquaculture businesses. The area is supplied from the main transmission network at 110 kV from Farrell Substation (near Tullah), with a 110 kV transmission circuit from Burnie Substation available as an alternate supply. Rosebery Substation is supplied by two transmission circuits, with other substations radially supplied. Distribution feeders in the area are supplied from four substations and one zone substation, with no interconnection between substation supply areas.

There is a significant amount of transmission-connected generation in the North West and West Coast planning area. These include the Pieman and King-Yolande (through Farrell Substation) and Mersey-Forth (through Sheffield Substation) hydropower schemes, and wind farms in both the far north-west (Bluff Point and Studland Bay wind farms) and the West Coast (Granville Harbour Wind Farm) of Tasmania.

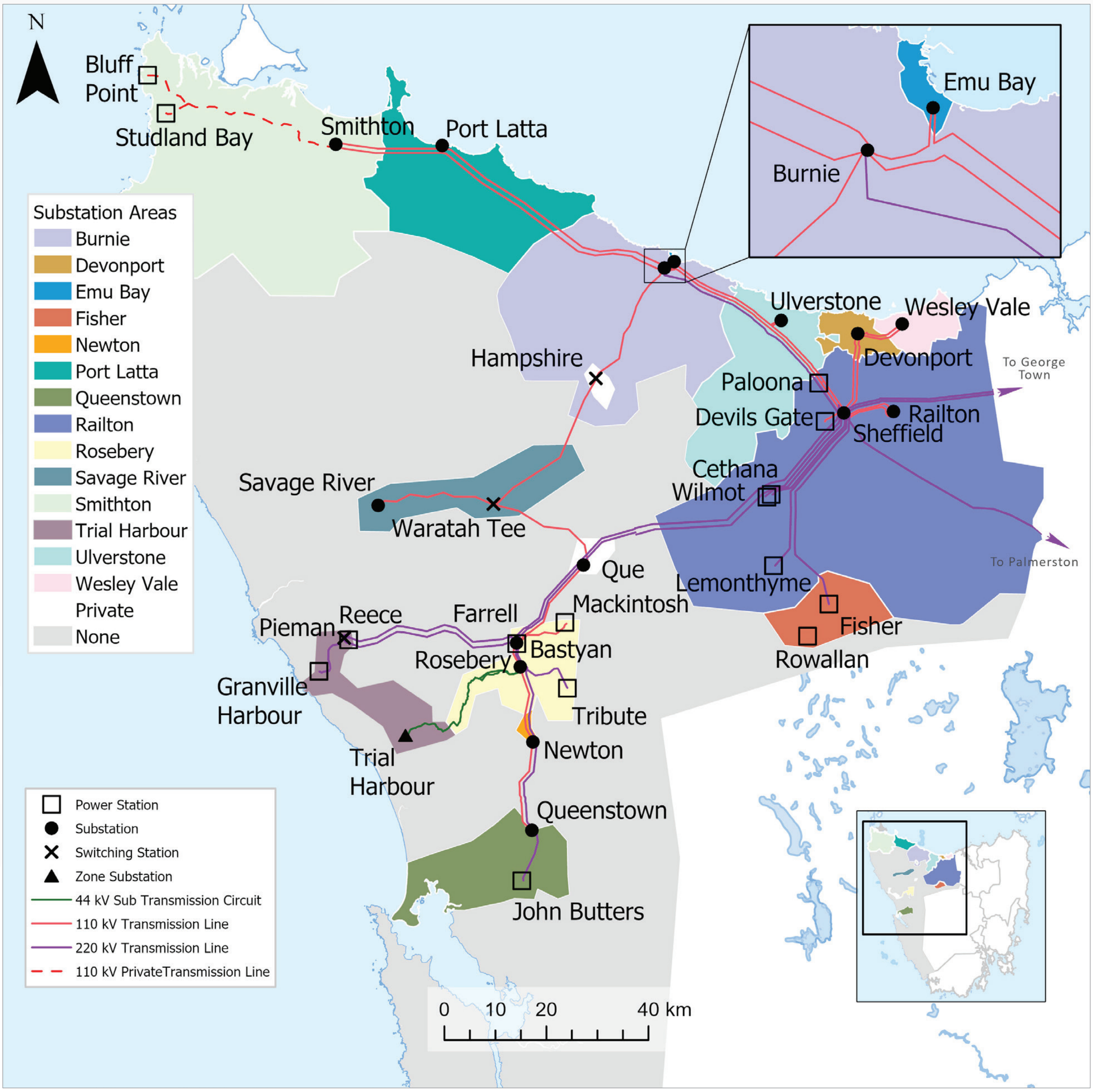


Figure 4-2: North West and West Coast planning area network

4.4.2. Northern planning area

The Northern planning area is diverse, with urban and commercial centres in and around Greater Launceston and the Tamar, industrial load in and around George Town including major energy users connected directly to the transmission network, and large rural areas of the northern midlands, the north-east, and east coast of Tasmania. Figure 4-3 presents a diagram of the Northern area with substation supply areas.

The area is supplied from the backbone 220 kV transmission network at Hadspen, George Town, and Palmerston substations. Hadspen Substation also provides a 110 kV supply to Launceston and north-east Tasmania, while Palmerston Substation provides supply to the Northern Midlands and east coast. George Town Substation predominantly supplies the industrial loads in the area, and also provides the connection point for the Basslink HVDC interconnector. There are two major energy users and one other transmission connected customer, all supplied from George Town Substation.

Musselroe Wind Farm is connected to Derby Substation via a private 110 kV transmission line. Tamar Valley, Trevallyn, and Poatina Power Stations provide generation directly into the network at George Town, Trevallyn, and Palmerston Substations respectively.

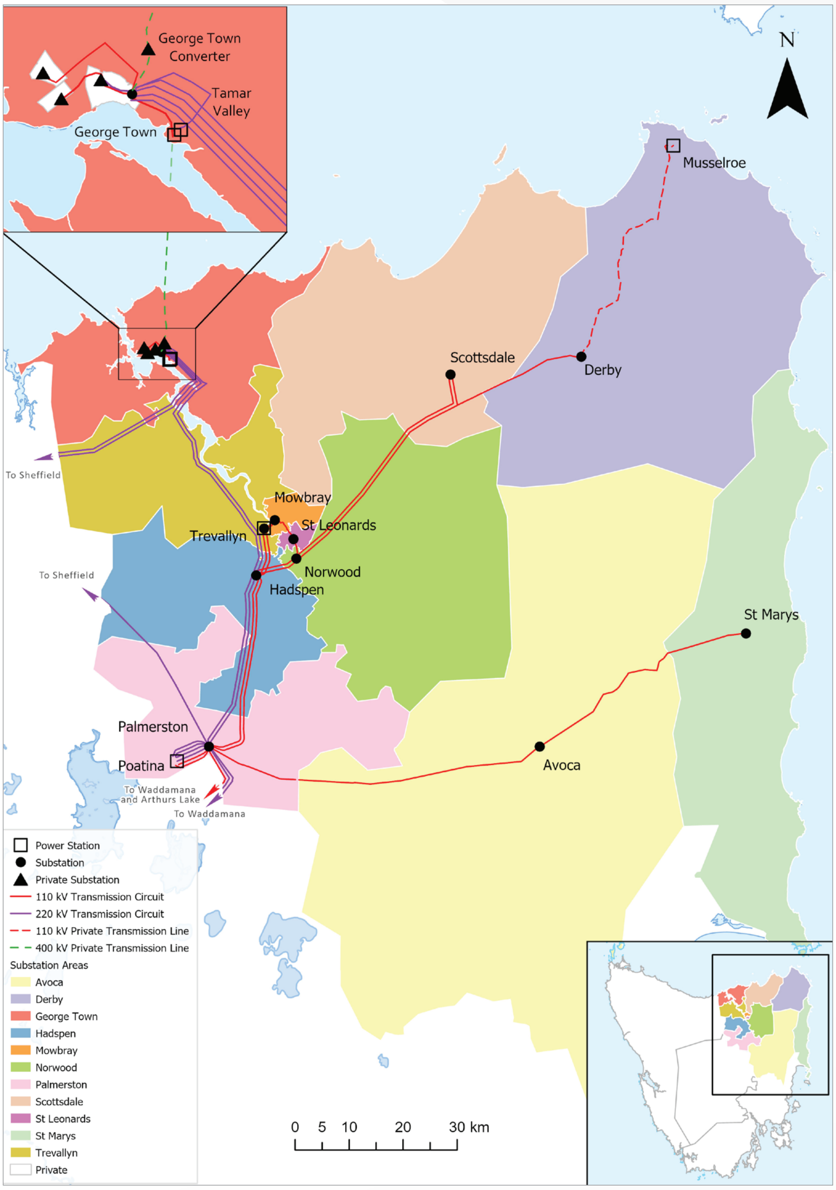


Figure 4-3: Northern planning area network

4.4.3. Central planning area

The Central planning area supplies the majority of the distribution-connected load in the New Norfolk township. The remaining substations supply low load density areas in the Central Highlands with limited, if any, transfer capability between feeders and substations. There is one major industrial customer supplied directly from the transmission network. Figure 4-4 presents a diagram of the Central planning area with substation supply areas.

The transmission-connected generation in the Central planning area is critical to supplying southern Tasmanian load, which includes the Derwent hydropower scheme connecting into both the 110 kV and 220 kV networks, as well as Gordon Power Station, which also connects at 220 kV. Wild Cattle Hill Wind Farm connects to Waddamana Substation.

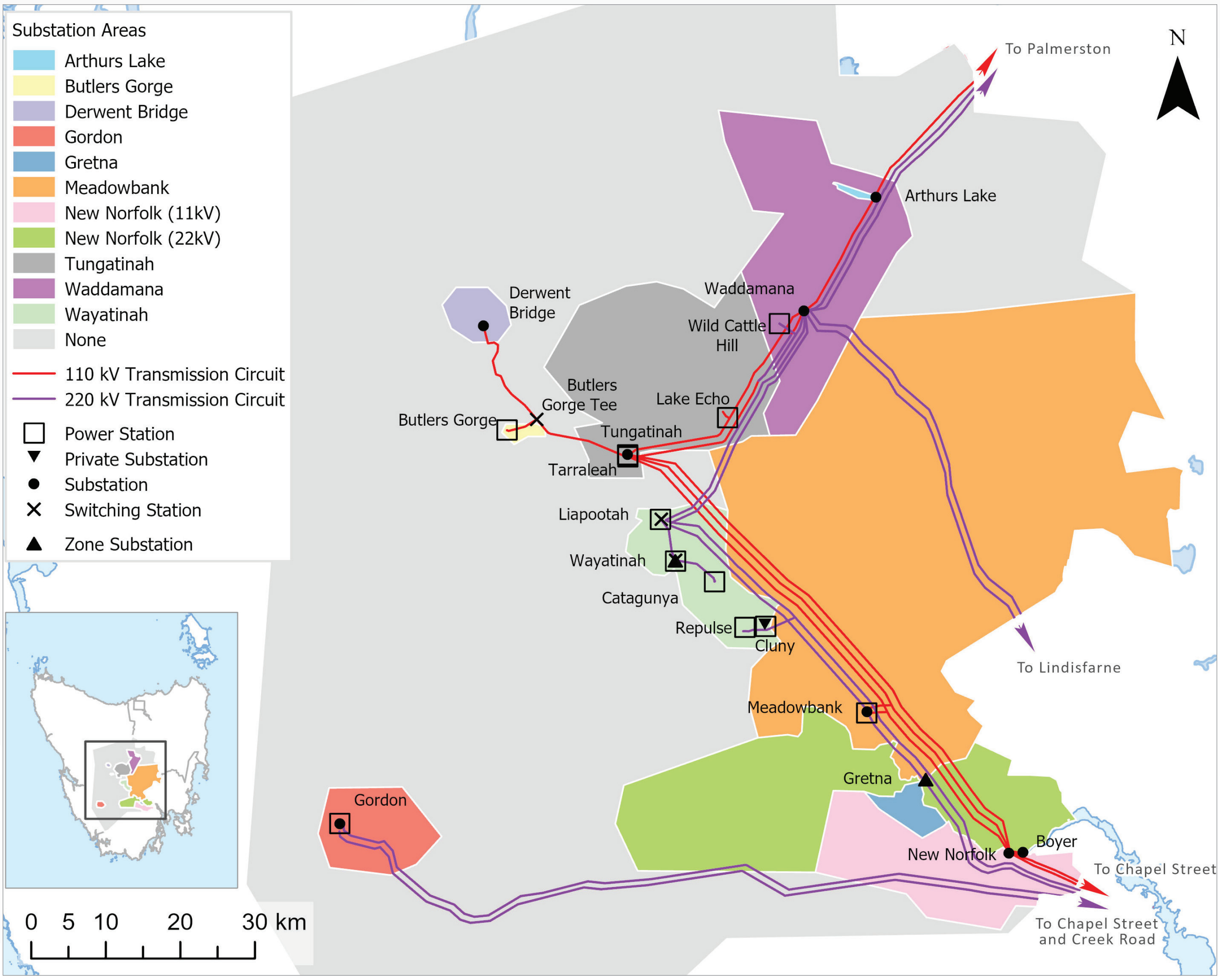


Figure 4-4: Central planning area network

4.4.4. Southern planning area

The Southern planning area covers the Greater Hobart region and the southern parts of Tasmania. The Greater Hobart area is mostly urban, with rural supplies to the outer southern reaches. Load in the Greater Hobart area is a mixture of commercial, industrial, and urban residential loads.

The Greater Hobart area is in most part supplied from the backbone transmission network terminating at Chapel Street and Lindisfarne substations. The Southern planning area is characterised by a substantial 33 kV sub-transmission network, along with zone substations that supply areas to the north, south and east of Hobart. Urban areas are supplied through a highly interconnected 11 kV distribution network. This allows load transfers between substations in outage and emergency situations. Rural areas are generally supplied via long 11 kV feeders with limited interconnection; however, Sorell and Triabunna substations provide supply at 22 kV. There is one major energy user directly connected to the transmission network.

The southern part of Tasmania covers the area from Kingston to Southport, including Bruny Island and the Huon Valley. This area is supplied through a 110 kV double-circuit transmission line from Chapel Street Substation. The area contains a mix of coastal, rural, and urban townships as well as moderate agriculture and aquaculture commercial precinct developments. Figure 4-5 presents a diagram of the Southern planning area with substation supply areas.

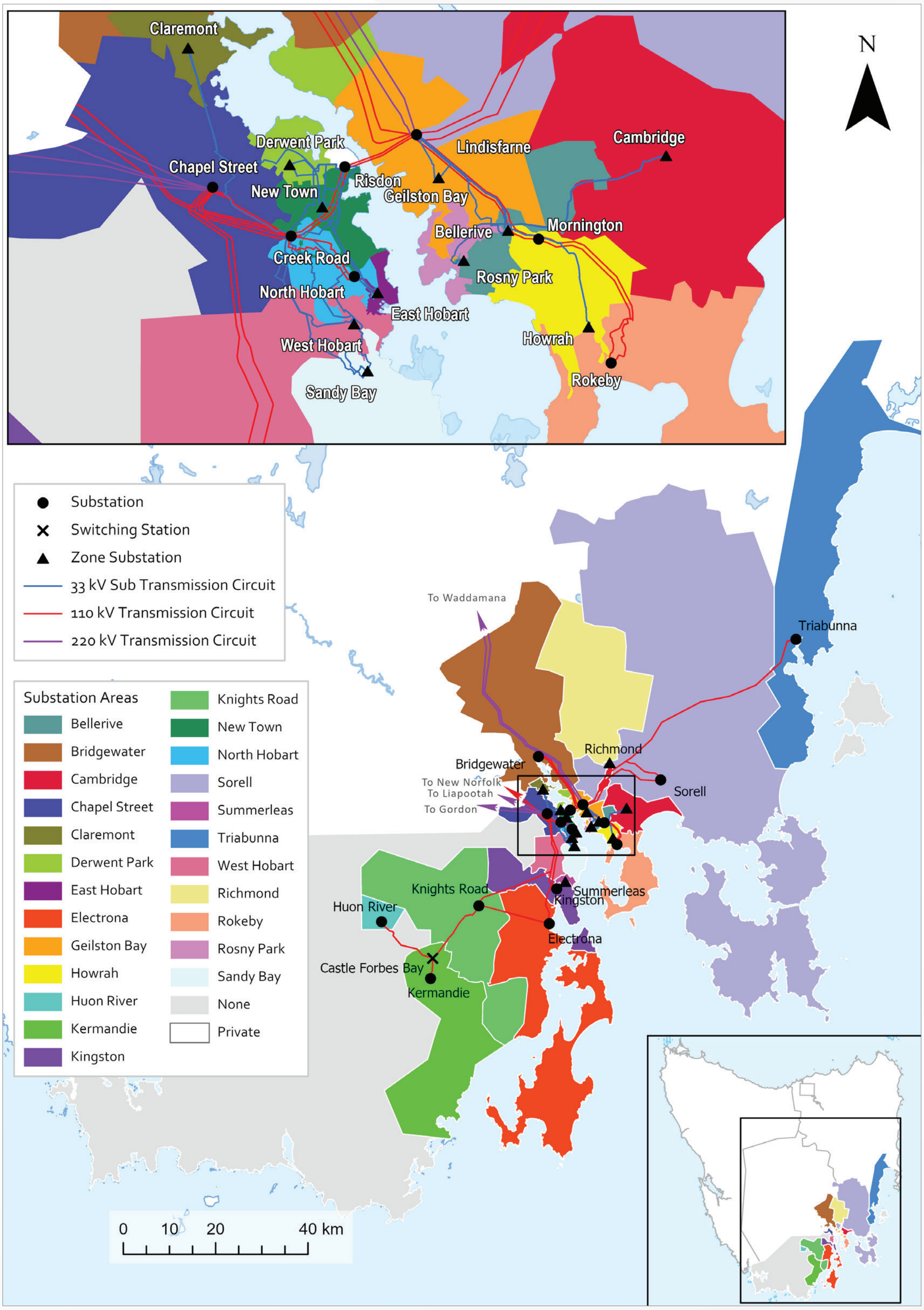


Figure 4-5: Southern planning area network

4.5. Availability to connect to network

Table 4-3 provides the available headroom to accommodate new load at each connection point substation in each planning area. The table also provides the total and firm capacity of each substation. For single-transformer substations and substations where existing demand already exceeds the firm capacity, the available headroom is zero.

Table 4-3: Substation available headroom by planning area.

		Installed capacity (MVA)		Available headroom (MVA)
Planning Area	Substation	Total	Firm	Firm
North West and West Coast	Emu Bay	76	38	28
	Queenstown	50	25	19*
	Trial Harbour Zone	40	20	17
	Rosebery (44 kV)	102	66	16
	Ulverstone	90	45	15
	Wesley Vale	50	25	13
	Smithton	70	35	10
	Devonport	110	60	2
	Port Latta	50	25	2
	Railton	100	50	2
	Rosebery (22 kV)	6	0	0
	Burnie	120	60	0
	Savage River	45	22.5	0*
	Sheffield	25	0	0
	Newton	22.5	0	0*
	Que	50	0	0*
North	George Town	96	48	28
	Trevallyn	150	100	26
	Norwood	100	50	20
	Scottsdale	63	31.5	19
	Mowbray	100	50	13
	Palmerston	50	25	12
	St Leonards	120	60	8
	Hadspen	100	50	0
	St Marys	20	10	0*
	Avoca	17	0	0*
	Derby	25	0	0*
Central	New Norfolk	60	30	11
	Arthurs Lake	25	0	0*
	Derwent Bridge	6	0	0*
	Meadowbank	25	0	0*
	Tungatinah	13	0	0*
	Waddamana	4	0	0*

Planning Area	Substation	Installed capacity (MVA)		Available headroom (MVA)
		Total	Firm	Firm
Southern	Kingston (33 kV)	120	60	49
	Creek Road	180	120	31
	Risdon	150	100	31
	Lindisfarne	120	60	24
	Sorell	120	60	23
	Mornington	120	60	21
	Chapel Street	120	60	21
	Kermandie	50	25	16*
	Triabunna	50	25	15*
	Rokeby	70	35	12
	East Hobart Zone	90	60	12**
	Sandy Bay Zone	90	60	12**
	Bellerive Zone	45	22.5	10**
	North Hobart	90	45	9
	Electrona	50	25	8
	Kingston (11 kV)	70	35	7
	West Hobart Zone	90	60	7**
	Howrah Zone	50	25	3
	Geilston Bay Zone	45	22.5	3**
	Cambridge Zone	40	20	1**
	Claremont Zone	50	25	0**
	Knights Road	40	20	0
	Bridgewater	70	35	0
	Derwent Park Zone	45	22.5	0**
	New Town Zone	45	22.5	0
	Rosny Park Zone	25	0	0*
	Huon River	25	0	0*
	Summerleas Zone	25	0	0*

* Non-firm transmission or sub-transmission network connection

** Headroom due to an applied sub-transmission network constraint.

4.6. Network limitations and developments

The following tables present our completed and committed projects, future connection points, network limitations and proposed solutions, and targeted reliability corrective actions for all planning areas over the next 10 years.

Table 4-4: Completed and committed projects

Planning Area	Project and description
	Completed
North West and West Coast	Emu Bay Substation conversion from 11 kV to 22 kV.
	Zeehan reliability improvement (additional generation support).
Northern	Nil
Central	Nil
Southern	Risdon–East Hobart 33 kV sub-transmission line capacity increase.
	Committed
North West and West Coast	North West Dynamic Reactive Support- Installation of 2 x $\pm$6 MVAr STATCOM at Port Latta Substation
	Zeehan reliability improvement (44 kV sub-transmission line switching augmentation).
	New 22 kV feeders from Emu Bay Substation
Northern	• Palmerston Feeder 4 Stage 2 (22 kV link) • Palmerston new 22 kV feeder
Central	Nil
Southern	Nil

Table 4-5: Network limitations and proposed solutions

Planning Area	Limitation	Deferral requirement (MVA)		Proposed solution	Timing	Cost ($m)
		1 year	5 years			
North West and West Coast	Nil					
Northern	**Palmerston–Avoca 110 kV transmission line** From 2031, loss of Palmerston–Avoca 110 kV transmission line may result in 25 MW load interruption to Avoca and St Marys substations. This will not meet the jurisdictional network planning requirements.	1.4	3.6	Options being considered are: • Distribution solutions to unload St Marys Substation and reduce the load at risk. • Non-network solutions to reduce load interruption following contingency events. • Transmission solutions to increase transmission reliability.	2031	TBA
Central	Nil					
Southern	**33 kV sub-transmission lines:**			Upgrade the overhead conductors to increase capacity of these sub-transmission corridors.		
	• Creek Road–Sandy Bay	1.4	7.3		2026	1.2
	• Creek Road–Claremont	1.6	4.6		2028	1.2
	In summer, these sub-transmission corridors operate non-firm.			No credible alternatives were identified.		
	Knights Road to Huonville (North)-Ranelagh-Judbury-Lonnavale 22 kV distribution line In summer, this distribution line is overloaded.	0.3	0.4	Establish a new distribution line from Knights Road Substation to relieve loading on the existing Knights Road to Huonville (North)-Ranelagh-Judbury-Lonnavale 22 kV distribution line. An alternate solution is to establish a new distribution feeder from Huon River Substation.	2025	1.0

Planning Area	Limitation	Deferral requirement (MVA)		Proposed solution	Timing	Cost ($m)
		1 year	5 years			
	Chapel Street–Kingston 110 kV transmission line From 2031, loss of the double-circuit Chapel Street–Kingston 110 kV transmission line may result in 3,000 MWh of unserved energy in Kingborough and Huon Valley areas. This will not meet the jurisdictional network planning requirements.	4	13	Extend the 33 kV sub-transmission network out of Sandy Bay to provide load transfer away from Kingston Substation and reduce unserved energy below 3,000 MWh. An alternate solution is to provide a third 110 kV circuit to the Kingston area.	2031	TBA

Table 4-6: Targeted reliability corrective action

Reliability community	Description
Zeehan	Zeehan reliability community is supplied from a single 22 kV distribution line from Trial Harbour Zone Substation, with that site being supplied via a single 35 km, 44 kV sub-transmission line from Rosebery Substation. Alternate supply is only available on the sub-transmission line for the first 10 km up to Renison Bell. Refer Figure 4-3 for feeders 97013 and 97014. Supply to the Zeehan reliability community does not meet the reliability standard. We are undertaking a program of works to improve supply reliability to meet the standard. As presented in Table 4-4, we have recently completed installation of additional mobile generation support and are currently installing additional switching capability between the 44 kV sub-transmission lines. We propose one further initiative to improve supply reliability. The proposed initiative is to install a semi-permanent diesel micro-grid for back-up supply for loss of the 44 kV sub-transmission line or 22 kV distribution line. The project is forecast for completion by June 2028 and is estimated to cost $3.8 million.

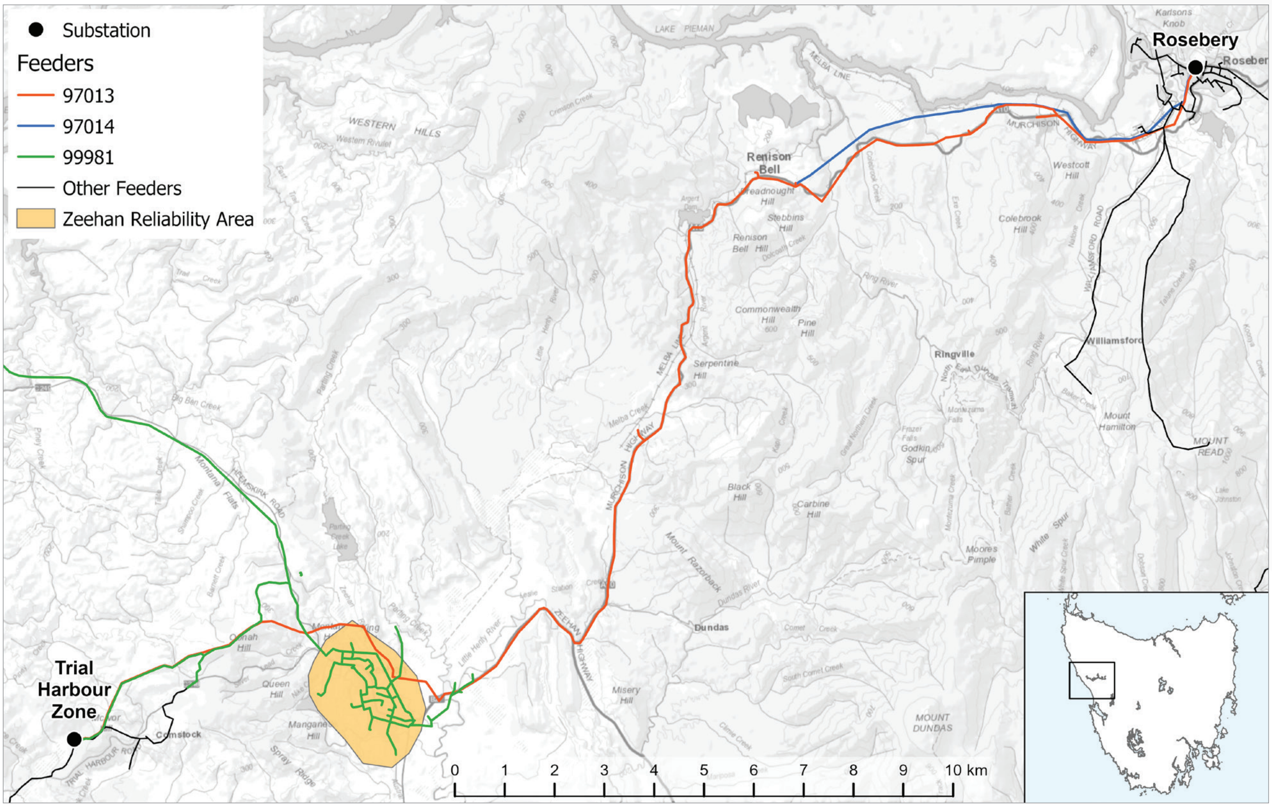


Figure 4-6: Zeehan reliability community

4.7. Deferred or averted limitations

4.7.1. Exemptions under jurisdictional network planning requirements

We have exemption agreements with affected customers which are permitted under the jurisdictional planning requirements. All relate to radial transmission supplies, where loss of the circuit may result in more than 300 MWh of unserved energy. Table 4-7 presents the assets for which we have agreed exemptions.

Table 4-7: Jurisdictional network planning requirement exemptions

Planning area	Asset	Location of affected customers	Performance requirement	Exemption ceases
North West and West Coast	Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit	Newton and Queenstown substations	Loss of circuit may exceed 300 MWh of unserved energy.	2025
	Newton Substation supply transformer	Newton Substation	Loss of supply transformer may exceed 300 MWh of unserved energy	2025
	Waratah–Savage River 110 kV transmission circuit section	Savage River Substation	Loss of circuit section may exceed 300 MWh of unserved energy	2029

Our agreements exist on the basis that there is insufficient benefit for a network augmentation solution to address these limitations. We are thus exempt under clause 8(4) of the network planning requirements from planning the network to meet this requirement. The exemption will cease by the dates identified in Table 4-7, or when an affected customer considers remedial action has sufficient benefit, or circumstances have materially changed. We do not consider that the circumstances have materially changed since the exemption period commenced and will consult the relevant customers at the time the current agreement ends.

4.7.2. Farrell–Que–Savage River–Hampshire transmission performance requirement

The combined loading on the 110 kV transmission line supplying customers at Que and Savage River Substations exceeds network planning performance requirements[56] (25 MW of lost load, and 300 MWh of unserved energy following a single element outage). In May 2024, TasNetworks obtained a new exemption for this transmission line, valid for 5 years.

4.7.3. Risdon–New Town 33 kV sub-transmission line limitation

Our 2023 APR identified limitations on the Risdon–New Town 33 kV sub-transmission line. It proposed a solution of replacing overhead conductor and re-rating underground cables to increase the line capacity. We have since identified an operational solution to provide 'switched firm' reliability to New Town Substation, moving load to other substations during periods of high demand when load is at risk. This has addressed the limitation, and it is no longer to be reported on the APR.

4.8. Other factors affecting the network

4.8.1. Fault levels

Network fault level is defined in terms of apparent power (mega-volt ampere (**MVA**)) or electrical current (usually expressed in kilo-amperes (**kA**)). The short-circuit fault current, defined at a given point in the network, is the current that flows if a solid fault occurs at that particular location. Determining the maximum fault currents within our network is important for the appropriate selection of equipment such as circuit breakers, switchgear, cables and busbars. This equipment is designed to withstand the thermal and mechanical stresses experienced due to the high currents that occur during short circuit conditions.

We require new connecting circuit breakers to meet a minimum fault clearance capability. For all voltage levels, circuit breakers require a minimum symmetrical three-phase fault current withstand capability of 25 kA for 1 second for connection to our transmission network. For the high-voltage side of our distribution network, it is 16 kA for 1 second.

Fault level data, a technical description of fault level quantities and our calculation methodology, are provided as a downloadable appendix and are available on our website:

www.tasnetworks.com.au/apr

Fault level data includes the existing maximum and minimum three-phase and single-phase fault levels, and positive, negative and zero sequence impedances, at all transmission substation busbars.

4.8.1.1. Connection point fault levels

Within our network, the maximum allowable fault current contribution at transmission-distribution connection points has historically been 13 kA. This has been determined on the assumption that the distribution network design fault current limit is 16 kA, with a 3 kA contribution margin allowed from any embedded generation that is not explicitly accounted for in network studies. We have a number of connection points where the maximum fault current contribution from the transmission network exceeds 13 kA, listed in Table 4-8. These sites are managed through appropriate operational strategies that we review as network changes occur.

Additional fault level constraints exist at two connection points. At Smithton Substation, a distribution earthing issue has required the fault level to be reduced until corrective action can be implemented. There is also a fault level limitation at Port Latta Substation to comply with a customer connection agreement. We recently completed a program to replace distribution fuse assemblies from Scottsdale Substation to improve fault level capability and allow the substation bus coupler to operate closed.

Table 4-8 presents the operational procedures in place to manage the fault level issues at these connection points in the meantime.

56 Our jurisdictional network planning requirements are in place to ensure that the network is planned to withstand credible and certain non-credible contingencies. Details are available in Appendix A.3.3

Table 4-8: Transmission-distribution connection points with open bus coupler

Substation (voltage [kV])	Issue	Management strategy
Bridgewater (11)	Fault level exceeds 13 kA	11 kV bus coupler operated normally-open with auto-close scheme to immediately restore supply to the other busbar following a supply transformer contingency.
Chapel Street (11)		
Kingston (11)		
Rokeby (11)		
Electrona (11)		
Smithton (22)	Distribution earthing issue	Bus coupler operated normally-open until a corrective action can be implemented.
Creek Road (33)	Fault level exceeds 13 kA	Supply transformer incoming circuit breaker opened when fault current exceeds 13 kA, with auto-close scheme to re-connect transformer following a contingency involving one of the other supply transformers.
Trevallyn (22)		
Port Latta (22)	Customer connection agreement	22 kV Port Latta bus coupler operated normally-open due to the rating of a 3.3 kV customer switchboard and at least one circuit breaker.

4.8.1.2. System strength

MVA fault levels are used as a proxy to define the strength of the power system during normal operation. Minimum fault levels may be used to determine the appropriateness of a connection point to accommodate a new load, or for planned switching considering impacts on voltage transients and power quality. Connection points with higher fault levels experience lower levels of voltage flicker for load switching events, compared to those with low fault levels.

Conventional high voltage direct current (**HVDC**) interconnection and inverter- based resources (**IBR**) such as wind and solar farms all require a certain level of system strength at their connection point. Basslink and the existing wind farms in Tasmania have ‘absorbed’ much of the available system strength in their locality.

Under the National Electricity Rules (**the Rules**), the Australian Energy Market Operator (**AEMO**) now publish a forecast of future system strength requirements, based on a projection of new IBR in the system. TasNetworks as the designated System Strength Service Provider (**SSSP**) is now responsible for addressing these future requirements.

Details of the system strength framework are outlined in Chapter 5.

4.8.2. Voltage management

Maintaining voltages within target ranges ensures the safety of our people and equipment, contributes to the efficient and secure operation the power system, and quality of supply to our customers. Exceeding the upper voltage limit may result in insulation breakdown and subsequent equipment damage. Operating below the lower limit impacts on power quality and could cause fuses to blow or equipment to trip.

We have a number of constraint equations to ensure transmission voltages are maintained within target ranges. Details of constraint equation performance is provided in Chapter 5.

Voltage management is a critical component of power quality, impacting all our customers. Voltage management in our distribution network is considered part of power quality. The network-wide and localised voltage limitations due to solar-photovoltaic (**PV**) installations are detailed in Appendix A.7.

Schedules 5.1a (System Standards) and 5.1 (Network Performance Requirements to be provided or Coordinated by Network Service Providers) of the Rules describe the planning, design and operating criteria applied to our transmission network for power quality. The quality of supply standards relevant to the distribution network are detailed in AS/NZS 61000 Electromagnetic compatibility (**EMC**), and Chapter 8 of the Tasmanian Electricity Code (**the Code**).

Our published planning limits are available via the Power Quality Planning Levels document on the TasNetworks website at:

https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Planning-our-network

4.8.3. Ageing and potentially unreliable assets

There are many ageing assets within our network and we undertake routine maintenance to reduce the probability of equipment failure. Factors that may impact on ageing and potentially unreliable assets are:

- location (whether the assets are located indoors or outdoors);
- operation (load utilisation, frequency of use and load profiles); and
- condition.

These are managed as part of our asset management strategy and are discussed in Appendix A.4, with planned investments to address asset management requirements identified in Section 4.8.3.

4.9. Network asset retirements and replacements

This section presents our forecast network asset retirements over the next 10 years. Almost all our retirements are due to assets reaching their end of service life based on condition. These are identified through our asset management process, outlined in Appendix A.4.

Following asset retirement, investment is almost always needed to maintain service levels. Where investment is required, we present the proposed solution, with forecast timing and cost, along with any other potential solutions considered. We welcome feedback on prospective alternative solutions.

We do not have any planned de-rating of network assets over the next 10 years.

Table 4-9: Network asset retirements and replacements – overhead lines and cables

Completed		
Nil		
Committed		
Nil		
Proposed	**Timing**	**Cost ($m)**
George Town–Temco 110 kV transmission line	2026	5.6
East Hobart 33 kV sub-transmission cable	2027	3.0
Claremont 33 kV sub-transmission cable	2030	3.1
New Town 33 kV sub-transmission cable	2031	2.2
Sandy Bay 33 kV sub-transmission cable	2032	1.7
Lindisfarne–Bellerive 33 kV sub-transmission cable	2032	2.7

Table 4-10: Network asset retirements and replacements – power transformers

Completed		
Port Latta Substation supply transformers		
Kermandie Substation supply transformers		
Committed		
Nil		
Proposed	**Timing**	**Cost ($m)**
Transmission substations		
St Marys Substation supply transformers	2026	8.0
Sheffield Substation network transformer T1	2027	10.7
Waddamana Substation supply transformer	2027	3.5
Rosebery Substation supply transformers and associated asset replacement	2028	17.5

Boyer Substation		
Supply transformers T13 and T14	2030	10.0
Supply transformer T2	2030	3.0
Savage River Substation supply transformers	2032	6.0
Burnie Substation supply transformers	2033	8.0
Zone substations		
Derwent Park Zone Substation supply transformers	2030	3.5
Bellerive Zone Substation supply transformers	2031	3.5
Geilston Bay Zone Substation supply transformers	2033	3.5

Table 4-11: Network asset retirements and replacements – switchgear and instrument transformers

Completed		
Ulverstone Substation 22 kV switchgear		
Rosebery Substation 44 kV disconnectors		
Burnie Substation 110 kV disconnectors		
Committed		
Gordon Substation 220 kV switchgear		
Norwood Substation 110 kV switchgear		
Railton Substation 22 kV switchgear		
Farrell Substation 220 kV switchgear		
Farrell and Ulverstone Substations 110 kV switchgear		
Chapel Street Substation 110 kV disconnectors		
George Town Substation 220 kV disconnectors		
Wesley Vale Substation 110 kV disconnectors		
Sorell Substation 22 kV switchgear		
Savage River Substation 110 kV disconnectors and gantry		
Sheffield Substation 220 kV disconnectors and current transformers		
Sheffield Substation 110 kV disconnectors		
Proposed	**Timing**	**Cost ($m)**
Chapel Street Substation 11 kV switchgear	2026	7.4
Boyer Substation 6.6 kV switchgear	2030	7.0
Bridgewater Substation 110 kV circuit breakers	2033	4.5
Kingston Substation 110 kV circuit breakers	2033	4.5

Table 4-12: Network asset retirements and replacements – protection and SCADA

Completed		
Hadspen Substation network transformer protection		
T60 transformer relays		
Committed		
Hadspen Substation 220 kV and 110 kV busbar protection		
Statewide protection relays		
Statewide SCADA scheme (part replacements Gateway RTU only)		
Proposed	**Timing**	**Cost ($m)**
Protection spares replenishments	2025–29	7.1
SCADA replacements	2025–29	13.9

Table 4-13 presents our investments in state-wide asset programs classified by network and asset class over the planning period to 2033. These investments are predominantly replacement programs for assets we have identified to be retired due to reaching end of life because of asset condition, economics, obsolescence and other factors defined in our asset management strategies. For these assets, our proposed solution is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified.

Table 4-13: State-wide asset investment programs

Network, asset class and description	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31	2031–32	2032–33
Distribution Network									
Distribution Overhead									
Asset replacement and refurbishment	28.5	29.5	30.6	30.5	30.9	30.9	30.9	30.9	30.9
Initiatives to limit the potential of assets initiating bushfires	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Innovations and equipment trials	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Threatened bird species fatality mitigation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
High Voltage Regulators									
Asset replacement and refurbishment	0.9	0.3	0.9	0.3	0.9	0.3	0.9	0.3	0.9
Safety and environmental programs	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
High Voltage and Low Voltage Cables									
Asset replacement	1.5	2.5	2.5	1.5	1.5	1.5	1.5	1.5	1.5
Ground Substations									
Asset replacement and refurbishment	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Safety and environmental programs	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Low Voltage Services									
New and replacement of assets to customer installations	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
New and replacement of public lighting assets	3.5	3.5	3.9	3.9	1.6	1.6	1.6	1.6	1.6
Meter panel replacement	1.5	1.5	0.4	0	0	0	0	0	0
Transmission Network									
Transmission Lines									
Asset replacement and refurbishment	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Substandard clearance rectification	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Network, asset class and description	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31	2031–32	2032–33
Transmission Substations									
Asset replacement and refurbishment	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Protection and Control (distribution and transmission)									
Asset replacement	4.0	4.0	4.2	4.4	4.5	4.3	4.4	4.4	4.4
Network Control Systems (distribution and transmission)									
Asset replacement	0.4	0.4	0	0.4	0.4	0	0.4	0.4	0.0

4.10. Investments in operational support systems and telecommunication systems

4.10.1. Operational support system programs

Operational support system programs are critical in enabling us to improve our performance, efficiencies and effectiveness in asset management and network operation. Operational support systems comprise network operational control systems (**NOCS**) and asset management systems (**AMS**). Elements of focus for successful information system programs are people, processes, data, and technology. The objectives of the AMS program are:

- to manage risk of asset failure;
- to enhance network performance;
- compliance with regulatory and governance requirements;
- effective collection and management of asset knowledge;
- effective resource utilisation;
- optimum infrastructure investment; and
- understanding risk at an individual asset level and asset portfolio level.

We are also building a network digital twin service to provide spatial, situational, and temporal network data across the transmission and distribution networks, funded through increased productivity and cost savings realised across the transmission and distribution capital and operating programs.

Investment within the NOCS is required to ensure that we can:

- operate the Tasmanian transmission system on a standalone basis, should the provision for Residual Power System Security (**RPSS**) be invoked;
- provide operating and market interfaces between AEMO and Tasmanian market participants; and
- provide a suite of online network modelling tools to assist us in ensuring the network is operated within its technical envelope.

This section details our investments in regulated operational support system programs in the transmission and distribution networks.

4.10.1.1. Investment in the past year

Our regulated investments in operational support system programs in 2022–23 are summarised in the following table:

Table 4-14: Regulated investment in operational support systems in the past year

Completed Projects	Description	Investment ($m)
Enterprise geographical information system strategy implementation	Consolidation and modernisation of the geographical information system and capability.	1.69
Asset risk management	Develop and enhance systems and models to assess asset criticality and failure probabilities, improving life-cycle management of network assets. It will enable key information about assets to be analysed and presented quantitatively.	1.1
Advanced Distribution Management System	Implementation of the fully integrated OSI Monarch Outage Management System to replace existing legacy systems. Delivery of real time integration between the Distribution Management System and Outage Management System and implementation of low-voltage Connectivity Model to manage customer outages.	3.69
Energy management system and distribution management system upgrade	Upgrade of the real-time system to current versions to provide new capability, improve cyber-security and resolve product defects.	0.3

4.10.1.2. Investment in forward planning period

Our planned investments in operational support system programs in the forward planning period to 2032–33 are summarised in the following table:

Table 4-15: Operational support systems expected investment forward planning period

Project	Description	Investment ($m)
Enterprise geographical information system strategy implementation	Consolidation and modernisation of the geographical information system and capability.	29.3
Network Operational Control System (NOCS) asset management	Maintenance and development of: • Advanced Distribution Management System (**ADMS**) • Energy Management System (**EMS**) • Tasmanian Integrated System Protection Scheme (**TISPS**)	26.0
Asset risk management	Develop and enhance systems and models to assess asset criticality and failure probabilities, improving life-cycle management of network assets. It will enable key information about assets to be analysed and presented quantitatively.	6.3

4.10.2. Telecommunications systems

The telecommunications network supports operation of the electricity network interfacing protection, control and data, telephone handsets and mobile radio transceivers. It also serves customers in the electricity supply industry and is utilised by other parties under commercial agreements. The telecommunications assets comprise communications rooms and associated ancillary equipment within substations and administrative buildings, optical fibre on transmission and distribution lines, underground optical fibre, digital microwave radios and associated repeater stations and some power line carrier equipment.

This section details our investments in regulated telecommunications systems programs in the distribution and transmission network.

4.10.2.1. Investment in the past year

Our regulated investments in telecommunications systems programs in 2023–24 are summarised in Table 4-16.

Table 4-16: Regulated investment in telecommunications systems in the past year

Project	Description	Investment ($m)
Infrastructure	Telecommunication sites	0.3
Bearer and management systems	Backbone bearers and Network Management Systems	0.74
Multiplexer systems	Multiplexer systems in the networks	0.91
Ethernet systems	Ethernet systems within the network	0.04

4.10.2.2. Investment in forward planning period

Our planned regulated investments in telecommunications systems programs in the forward planning period to 2033–34 is summarised in Table 4-17. The majority of these are ongoing programs, with the investment commitment over the duration of the program.

Table 4-17: Regulated investment in telecommunications systems in the forward planning period

Project	Description	Investment ($m)
Infrastructure	Telecommunication sites	4.8
Bearer and management systems	Backbone bearers and Network Management Systems	10.3
Multiplexer systems	Multiplexer systems in the networks	3.0
Ethernet systems	Ethernet systems within the network	1.0

Chapter 5

Network security performance

- Due to limited load growth over the last 12 months, Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources (**IBR**), predominantly comprising wind farm generation and Basslink import. Given that very little synchronous generation is being dispatched at various times, careful management of power system security continues to be a high priority.
- Modelling associated with AEMO's 2024 Integrated System Plan (**ISP**) forecasts ongoing shortfalls for both system strength and inertia network services in the Tasmanian region. Contractual arrangements to address existing shortfalls are currently in place until 1st December 2025.
- The National Electricity Rules (**the Rules**) framework for managing system strength introduced significant new obligations for System Strength Service Providers (SSSP) which commence on 2nd December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (**NEM**). The new framework introduces a completely new approach for the procurement and payment of system strength services, including proactive planning obligations for SSSPs which now form part of the System Standards within the Rules. TasNetworks is currently conducting a Regulatory Investment Test for Transmission (**RIT-T**) to procure additional system strength services under the new framework.
- The Australian Energy Market Operator (AEMO) has made progress towards introducing two new market ancillary services; being the very fast raise (R1) and very fast lower (L1) Frequency Control Ancillary Services (**FCAS**) markets.
- TasNetworks has been collaborating with AEMO on various aspects of this implementation, including investigating potential sources of very fast FCAS and engaging in the Market Ancillary Service Specification (**MASS**) consultation. In the current market, we will continue to assess how these new services may affect the existing minimum inertia requirements defined for Tasmania.

5.1. Introduction

Power system security involves the safe scheduling, operation, and control of the electrical power system on a continuous basis in accordance with the principles set out in Chapter 4 of the Rules. The growing penetration of IBR is a key issue impacting power system security in Australia. IBR, comprising wind and solar generation, as well as power exchanges across High Voltage Direct Current (HVDC) interconnectors, has led to a decrease in the dispatch of synchronous generation at times, resulting in very low levels of inertia and system strength across increasingly large areas of the NEM.

Given that the installed capacity of IBR energy sources in Tasmania (currently dominated by wind and imports across the Basslink HVDC interconnector) can be sufficient to supply a significant percentage of Tasmania's operational demand, there are times when the dispatch of synchronous generation is very limited. The issue is even more pertinent in Tasmania given the dominance of hydro generation. Hydroelectric generators are well suited to operating in a peaking capacity, unlike large thermal generators which are not well suited to load cycling (varying their power output) or being shut down and restarted within relatively short time frames. This creates opportunities to conserve water reserves when IBR energy sources are available and cost effective, but also creates challenges in that the system security services inherently provided by large synchronous hydro units are withdrawn from the network in the process.

Ongoing management of power system security, including understanding and dealing with the implications of an evolving generation mix, continue to remain at the forefront of TasNetworks' activities. The proceeding discussions present a combination of outcomes and observations from the last twelve months, as well as providing insights into work programs planned or already underway.

5.2. Updates on operational activities and specific events

5.2.1. System non-synchronous penetration ratio

TasNetworks employs the System Non-Synchronous Penetration (**SNSP**) ratio as a key metric to assess and manage challenging network operating conditions. This ratio indicates the extent to which Tasmania's operational demand is met by wind generation and imports through Basslink, as opposed to synchronous generation. As the SNSP ratio increases, there is a greater likelihood that real-time operator actions will be necessary to address issues such as inertia and system strength. Consequently, contracted services may be required to ensure the security of the power system, as elaborated in later sections of this chapter.

A summary of key SNSP statistics over the last three financial years are provided below in Table 5-1.

Table 5-1: SNSP statistics using system measurements having a 5-minute data resolution

Measure	2021–22	2022–23	2023-24
Peak SNSP recorded	83.6%	90.8%	88.7%
99th Percentile	73.3%	76.5%	80.9%
95th Percentile	61.9%	66.5%	73.4%
50th Percentile	22.4%	31.0%	40.2%

Over the past year, we have repeatedly encountered situations where close to 90% of Tasmania's electricity supply was derived from energy sources other than synchronous generating units. High SNSP conditions often occur overnight, when operational demand is lower, and from early to mid-afternoon. This pattern is now observable throughout the entire year. These conditions typically arise when high solar output on the mainland leads to lower market prices, frequently resulting in increased Basslink imports to Tasmania. When this aligns with high generation output from local wind farms, high SNSP conditions are formed.

As additional wind and solar power is integrated into Tasmania's energy mix, the likelihood of encountering high SNSP conditions will inevitably rise. In coordination with various initiatives across the NEM, we are actively exploring what is necessary to eventually allow the Tasmanian power system to operate at 100% instantaneous IBR.

5.2.2. AEMO Engineering Roadmap to 100% Renewables

Since 2021, TasNetworks has been actively involved in the NEM Engineering Framework Review.[57] This NEM-wide initiative was launched in response to projections indicating that *"the instantaneous penetration of renewables is increasing rapidly and, with proper preparation, could occasionally reach up to 100% by 2025."* In crafting their initial roadmap, AEMO highlighted that *"urgent and extensive industry collaboration and effort are required to engineer the power system to adapt to these new conditions in a timely and orderly manner, prioritizing positive consumer outcomes in all decision-making."*

AEMO's latest update, titled "Engineering Roadmap to 100% Renewables – FY2025 Priority Actions,[58]" outlines the activities AEMO plans to undertake in the 2024–25 financial year (FY2025) to help advance the operational capability of the NEM for times of high renewables contribution. We are collaborating closely with AEMO on this initiative and have published the report "100% Inverter Based Resource Generation Study – Tasmania Region." This document outlines the results of an extensive study that identifies key system security and reliability challenges when operating the Tasmanian network without synchronous generation.

The summary of the report indicates that maintaining network frequency control—encompassing both primary frequency regulation and contingency service management—will be challenging in a future energy mix that may at times lack hydro generation. Additionally, managing the Rate of Change of Frequency (**ROCOF**) poses difficulties, as TasNetworks currently lacks a mechanism to request inertia above the secure operating level of 3,800 MW.s. As we look ahead, the potential system security enhancements from large-scale Battery Energy Storage Systems (**BESS**) and the Marinus Link are under consideration in these investigations.

This effort is closely aligned with the state's goals to double its renewable energy generation by 2040, as outlined in the Tasmanian Renewable Energy Target (**TRET**). Given that the majority of TRET will be fulfilled by new wind generation, understanding the engineering required to achieve these practical outcomes is essential.

5.3. Important changes to power system security management

5.3.1. Frequency operating standards

Since Tasmania and the mainland power systems are not synchronously connected, and Tasmania has its own unique frequency control characteristics, separate frequency standards have been in place since the Basslink interconnector was commissioned in 2006. The AEMC Reliability Panel concluded its latest review of the Frequency Operating Standard (**FOS**) on 6th April, 2023[59], which led to a new standard effective as of 9th October 2023. This update introduces several significant changes to accommodate the evolving nature of the power system. The changes to the FOS require TasNetworks to formally address technical issues when designing and establishing network operational limits.

The main aspects of the revised FOS relevant to Tasmania include:

- After a credible contingency event, the Rate of Change of Frequency (**ROCOF**) must not exceed $\pm$3 Hz/s when measured over any 250 ms period, aligning with our previous general design approach based on engineering judgment.
- Following a non-credible contingency event, or multiple contingency events that are not protected, AEMO should make reasonable efforts to maintain ROCOF within $\pm$3 Hz/s over any 300 ms period.
- The existing 144 MW limit for generation events, originally introduced in December 2008, has been expanded to include load and network events. This limit applies to the design and operation of the intact network, with provisions to assist in managing planned and forced outages of short duration.
- The minimum threshold for a generation event has been lowered from 50 MW to 20 MW, aligning it with the current threshold for a load event.

57 Details available at: www.aemo.com.au/en/initiatives/major-programs/engineering-framework

58 https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/nem-engineering-roadmap-fy2025-priority-actions.pdf?la=en&hash=E934DFFF6D4544B9F117BAF6A6E4088D

59 Further details can be found at : https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard

- The operational frequency tolerance band during system restoration has been tightened from 48 Hz – 52 Hz to a more restricted range of 49 Hz – 51 Hz, to better align with Schedule 5.2 of the Rules, which specify generator connection requirements.
- The time error standard has been removed from the FOS.

There have been no additional changes to various frequency control bands that govern system performance during normal operations and after contingency events. The normal operating frequency band remains at 49.85 Hz – 50.15 Hz, which is the range frequency should remain within for most network operating conditions.

5.3.2. Rules framework for managing system strength

On 21st October, 2021, the AEMC finalized a Rule change determination for the "Efficient Management of System Strength on the Power System," initially proposed by TransGrid.[60] The new Rules established a System Standard and essentially a transmission network planning standard to govern the provision of system strength across the NEM. This Rule change imposes a proactive obligation on each System Strength Service Provider (**SSSP**) to plan for and ensure there is sufficient system strength available to support anticipated levels of Inverter-Based Resources (**IBR**) connecting to the power system. TasNetworks serves as the SSSP for the Tasmanian region of the NEM.

A key aspect of the framework is the requirement for SSSPs to guarantee that both the defined minimum and efficient levels of system strength are met independently of any coincidental system strength services provided by generators while operating in the energy market. As a result, SSSPs are mandated to procure the entire amount of system strength necessary to meet the standard.

Figure 5-1 illustrates the practical implications of this Rule change. Under the new framework, TasNetworks is accountable for securing the full volume of system strength needed to achieve both the minimum three-phase fault level requirement and the efficient level of system strength simultaneously. Previously, regulatory arrangements only required procurement of the shortfall volume as identified by AEMO.

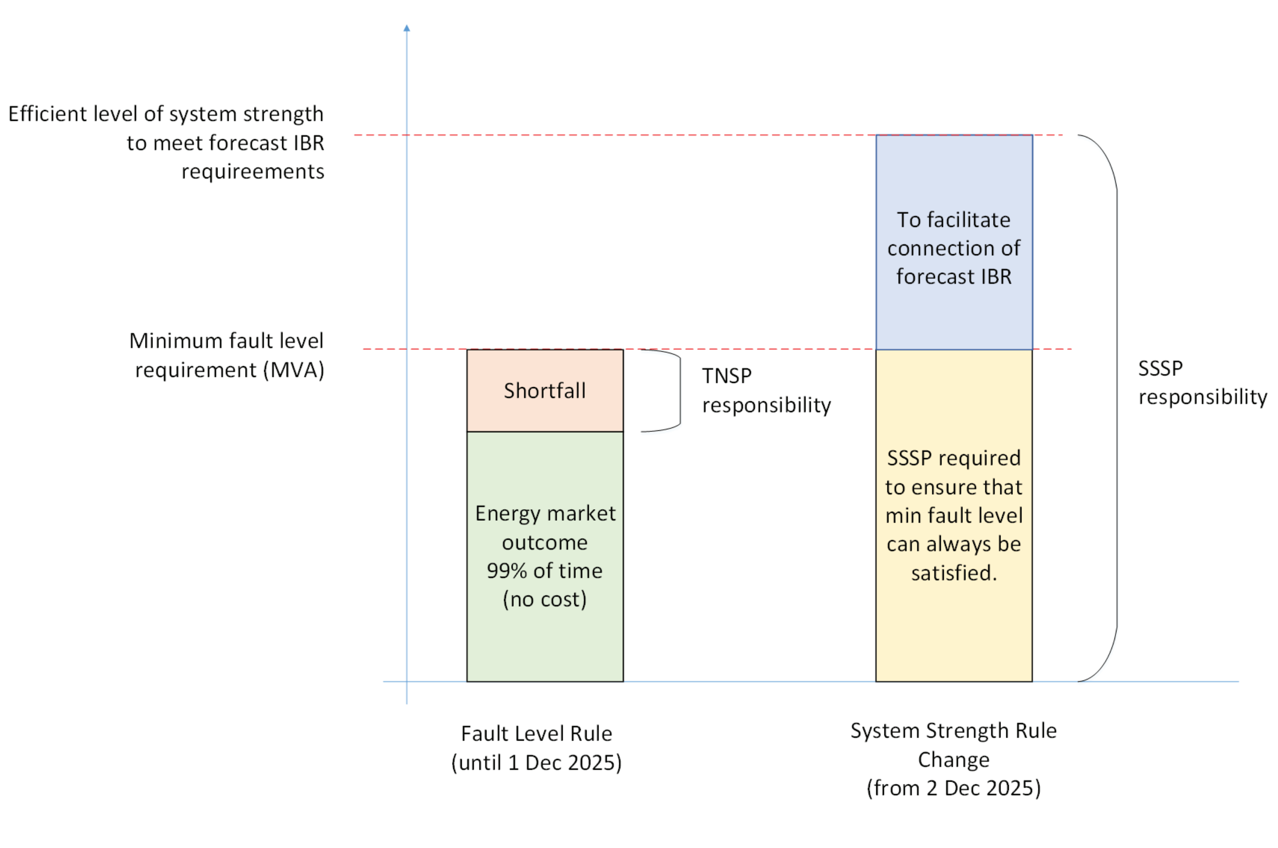


Figure 5-1: Comparison of system strength Rule frameworks

60 Available at https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

TasNetworks is currently evaluating the investments needed to comply with the new standards, which will take effect on 2nd December, 2025. As Tasmania's SSSP, we are responsible for ensuring system strength is delivered in a forward-planning manner to meet the system strength standard specifications published by AEMO, as outlined in Schedule 5.1.14 of the Rules.

5.3.3. AEMO's operational enablement of system strength from 2 December 2025

The Australian Energy Market Commission (**AEMC**) has made a final rule for the "Improving Security Frameworks for the Energy Transition" rule change, which aims to ensure the reliable and secure operation of the NEM as it transitions to net zero emissions. The rule, informed by stakeholder feedback, is intended to reduce the need for market interventions, increase transparency and provide incentives for participants to invest in system security.

Key changes to the existing security frameworks include the introduction of a mainland inertia floor to ensure that minimum inertia is available for interconnected operation, the alignment of inertia and system strength procurement timelines to promote efficiency and better coordination between TNSPs, and the introduction of a new transitional Non-Market Ancillary Services (**NMAS**) framework to address security needs arising from the transition and to trial new technologies.

The rule also provides that AEMO will be responsible for operationally enabling security contracts to reduce reliance on directions and improve efficiency. Additionally, AEMO will publish a new report called the *"Transition Plan for System Security,"* which outlines how AEMO intends to manage system security as the system transitions to net zero. The rule also requires AEMO to publish a report on directions that includes more details, a breakdown of the total compensation paid, and a timeline for reporting.

On 1st December 2024 the new inertia framework will commence, and AEMO must publish their transition plan by this date. On 2nd December 2025, the full enablement obligations on AEMO will commence. Further information on the actions TasNetworks is taking to address this is included in Section 5.4.4.5.

5.4. Meeting our power system security obligations

5.4.1. An overview of inertia and system strength

Inertia and frequency control are closely linked in a power system. After a disturbance that disrupts the balance between generation and demand, power systems with high inertia can better withstand rapid frequency changes, limiting the Rate of Change of Frequency (**ROCOF**). Conversely, systems with lower inertia are more prone to rapid frequency shifts, which can have harmful effects if not properly managed. The recent changes to the Frequency Operating Standard (**FOS**) specify acceptable levels of ROCOF for the Tasmanian power system, allowing for the determination of inertia requirements accordingly.

System strength encompasses various specific technical issues, but the key components are:

- Ensuring sufficient short circuit current is consistently available for the proper functioning of network protection systems, including those in downstream distribution networks and protection systems within customer premises, including generating systems.
- Guaranteeing stable voltage control throughout the network, both under normal conditions and following network contingency events and switching actions (like transformer and capacitor energisation). This is required even in areas far from devices capable of providing dynamic reactive power control, such as generators and Flexible Alternating Current Transmission System (**FACTS**) devices.
- Ensuring that the voltage at the connection points of grid-following IBR remains robust enough to support their continuous, uninterrupted operation during network faults and other credible disturbances.

Although there are various solutions to these challenges, it's important to recognise that synchronous generators have historically provided much of the capability needed in Tasmania's power system. As all regions of the NEM see greater integration of IBR, Tasmania will also experience this shift. While IBR technology offers numerous advantages in terms of configurability and rapid response, it operates differently to synchronous machines. These differences must be carefully integrated into the design and operation of the power system.

5.4.2. Latest shortfall declarations

As the Transmission Network Service Provider and Jurisdictional Planning Body, TasNetworks is both the Inertia Service Provider and SSSP for the Tasmanian region. As a result, we are responsible for providing sufficient capabilities to AEMO under the rules to ensure that the operational limits listed in Table 5-2 and Table 5-3 can be satisfied on a continuous basis.

Table 5-2: System inertia requirements

Rules term	Minimum requirement (MW.seconds)
Secure operating level of inertia	3,800
Minimum threshold level of inertia	3,200

Table 5-3: Minimum fault level requirements (intact network)

Fault Level Node	Minimum three phase fault level (MVA)
George Town 220 kV	1,450
Waddamana 220 kV	1,400
Burnie 110 kV	850
Risdon 110 kV	1,330

AEMO's most recent system security reports for inertia and system strength were published on 1st December 2023 and included forecasts of expected shortfalls out to 30th June 2026.[61] Following release of the two reports, TasNetworks was issued an updated shortfall notice by AEMO on 20th December 2023, the details of which are provided in Table 5-4.

As the Rules framework for system strength will change on 2nd December 2025, the latest AEMO notice requires that sufficient *system strength services* be made available until that time. In contrast, the existing shortfall mechanism to manage the provision of inertia will remain unchanged. TasNetworks is therefore required to make available sufficient *inertia network services* until 30th June 2028 to meet the updated requirements.

Table 5-4: Declared shortfalls for the Tasmanian region – previous and updated requirements

	15 December 2022	20 December 2023
Inertia level	**Inertia shortfall (MW.s)**	**Inertia shortfall (MW.s)**
To achieve Secure Operating Level of Inertia	2,509	1,866 (↓)
Fault Level Node	**Fault level shortfall (MVA)**	**Fault level shortfall (MVA)**
George Town 220 kV	827	665 (↓)
Waddamana 220 kV	594	375 (↓)
Burnie 110 kV	423	355 (↓)
Risdon 110 kV	511	360 (↓)

5.4.3. Managing declared shortfalls until December 2025

Since the initial AEMO shortfall notice received on 13th November 2019, TasNetworks has effectively managed shortfalls in both inertia and system strength. To date, we have issued two formal Expressions of Interest (**EOI**) aimed at identifying potential non-network options to support system security requirements. These EOIs contained comprehensive details as specified in Rules Clauses 5.20B.4(g) and 5.20C.3(e), facilitating responses from service providers. A new service contract, resulting from the most recent EOI first publicised on 13th May 2022, is set to deliver the necessary capabilities from 15th April 2024, to 1st December 2025.

61 Available from the AEMO website: www.aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

In response to the submissions from the 2022 EOI, TasNetworks secured adequate inertia and system strength services to fulfil our Rule obligations until 1st December 2025. The most cost-effective solution identified involved establishing a commercial agreement with an existing generator to supply services on an as-needed basis, aligned with market dispatch conditions. The solution comprises the operation of synchronous condensers and the dispatch of synchronous generating units at minimal power output. These units are strategically located to enhance system strength at key network sites and can maintain performance with little to no market distortion.

TasNetworks has limited the duration of the latest commercial contract to 1st December, 2025, in light of changes to the Rules. As detailed in Section 5.4.4, new agreements will be necessary beyond this date to meet the requirements of the revised system strength framework.

5.4.4. Longer term management of inertia and system strength

As discussed in Section 5.3.2, TasNetworks is currently assessing the forward-looking requirements for inertia and system strength and considering the need for future investments necessary to satisfy our responsibilities under the Rules.

5.4.4.1. System strength nodes

From 2nd December 2025, locations previously referred to as *fault level nodes* for the purposes of managing fault level shortfalls, will transition to *system strength nodes* (**SSN**) under the new Rules framework. In consultation with AEMO, the declared SSNs in the Tasmanian region are as listed in Table 5-5 and will serve the primary functions as indicated.

Table 5-5: System Strength Nodes (SSN) in the Tasmanian transmission network

System Strength Node	Minimum three phase fault level (MVA)	Purposes / Intention
George Town 220 kV	1,450	Reference SSN for North East Tasmania REZ (T1)
Waddamana 220 kV	1,400	Reference SSN for Central Highlands REZ (T3)
Burnie 110 kV	850	Reference SSN for North West Tasmania REZ (T2) – 110 kV
Risdon 110 kV	1,330	To maintain network security in southern Tasmania.
Proposed future SSN		
Hampshire Hills 220 kV	To be confirmed	Reference SSN for North West Tasmania REZ (T2) – 220 kV

The future proposed SSN at the Hampshire Hills 220 kV Switching Station is currently under evaluation and will ultimately be influenced by the timing of the North West Transmission Developments (NWTD). If this switching station is not built before a need arises in the north-west region—triggered by either the Marinus Link or the establishment of 220 kV connection points for wind farm projects—an alternative SSN could be located at Burnie 220 kV Substation. The distance between the two locations is approximately 29.6 km, which is not deemed significant considering the planned design of the interconnecting circuits. Nonetheless, once the new 220 kV SSN is established and made operational in the north-west, the necessity for the existing Burnie 110 kV SSN will be reassessed.

5.4.4.2. System strength locational factors

TasNetworks is obliged under Rules Clause 5.12.2(c)(13) to publish the *system strength locational factor* for each *system strength connection point* in the Tasmanian region. A system strength connection point is a connection point for IBR plant or equipment that has elected to pay the system strength charge and therefore relies upon centrally provided system strength services as opposed to self-mitigation.

At this point in time, TasNetworks has no registered *system strength connection points* in its transmission or distribution networks. As a result, no locational factors are considered in this year's Annual Planning Report.

5.4.4.3. Forecast IBR installations and efficient levels of system strength

Beginning 2nd December 2025, TasNetworks is obligated to provide adequate system strength services to meet two specific technical criteria:

- Ensuring the minimum *three phase fault level* specified by AEMO is maintained at each SSN; and
- Providing sufficient system strength services to support the forecasted IBR expected to connect to the network, referenced to each SSN, in order to achieve stable voltage waveforms across the network without the imposition of network constraints.

Both criteria are defined in terms of operating an intact network, but must take into account the effects of *credible contingency* events and *protected events*. Management of previous outage conditions—such as planned network outages or extended forced outages—may involve implementing network constraints to ensure power system security, as providing the required levels of system strength for unrestricted operation of all IBR under these circumstances may not be economically feasible.

The IBR forecast for Tasmania, as detailed in the System Strength Report published by AEMO on 1st December 2023, is presented in Table 5-6. For clarity, this forecast includes only anticipated future developments of wind, solar, and BESS. It is important to note that TasNetworks has proactively allocated some of the forecasted IBR to the forthcoming Hampshire Hills SSN (from Burnie 110 kV), based on certain identified projects being considered in future network planning studies. We understand that, due to Rule requirements, AEMO could not allocate future IBR to SSN that have not yet been formally declared.

Table 5-6: Forecast IBR developments (installed MW capacity) referenced to each Tasmanian SSN

Reference SSN	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Burnie 110 kV	0	0	5	5	181	181	181	181	181	181
George Town 220 kV	0	0	41	41	41	41	41	53	53	53
Waddamana 220 kV	0	0	603	603	612	612	1362	1370	1370	1370
Risdon 110 kV	0	0	0	0	0	0	0	0	0	0
Hampshire Hills 220 kV	0	0	0	0	0	522	522	522	522	522
Aggregate (MW)	**0**	**0**	**649**	**649**	**834**	**1356**	**2106**	**2126**	**2126**	**2126**

The minimum new renewable generation required in Tasmania to meet the TRET[62] is currently considered to be approximately 2,500 MW by 2040, based on an assumed capacity factor for large-scale wind farms. The 2024 ISP does not forecast any additional utility-scale wind or solar developments in Tasmania beyond 2032, with ongoing generation growth limited to distributed photovoltaics.

In line with the new Rule requirements, TasNetworks has translated the forecasted IBR developments into an equivalent *three-phase fault* level to represent the required *efficient level of system strength* at each SSN. Due to the absence of detailed design information for future IBR connection points, we have estimated the necessary system strength levels for the coming years using the *Available Fault Level* (**AFL**) methodology, as outlined in Section 3.4.3 of the AEMO System Strength Impact Assessment Guidelines.[63] Additionally, where future changes in network topology are known and have been communicated to AEMO and the wider industry,[64] these developments have been included in our modelling activities for the year we reasonably expect them to become operational.

TasNetworks acknowledges the limitations of the AFL methodology but considers it valuable for indicating the potential volume of services needed relative to the current proven network operating limits. We have compared the results from our current detailed preliminary system strength studies to the computed AFL values, and they are comparable. The AFL method is also helpful for understanding the relationships between IBR connection points across the network, giving insights into which areas might face challenges as more IBRs connect. This provides locational signals for future network planning activities.

62 TRET sets out renewable energy production capability of approximately 16,000 GWH / annum by 2030 and approximately 21,000 GWh / annum by 2040

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

64 Refer to chapter 3 for details on expected additional transmission network developments

By using the IBR forecast published by AEMO together with the AFL methodology, we have estimated the three-phase fault level requirements at each SSN for future years, extending out to 2033. The results of this analysis are illustrated in Figure 5-2. The analysis assumes 100% IBR-based grid following generation technology (worst case) in the Tasmanian region, with no fault level contributions from synchronous sources, making it a conservative estimate of the network's future needs. It is anticipated that the actual requirements at each SSN will be lower than those depicted in Figure 5-2.

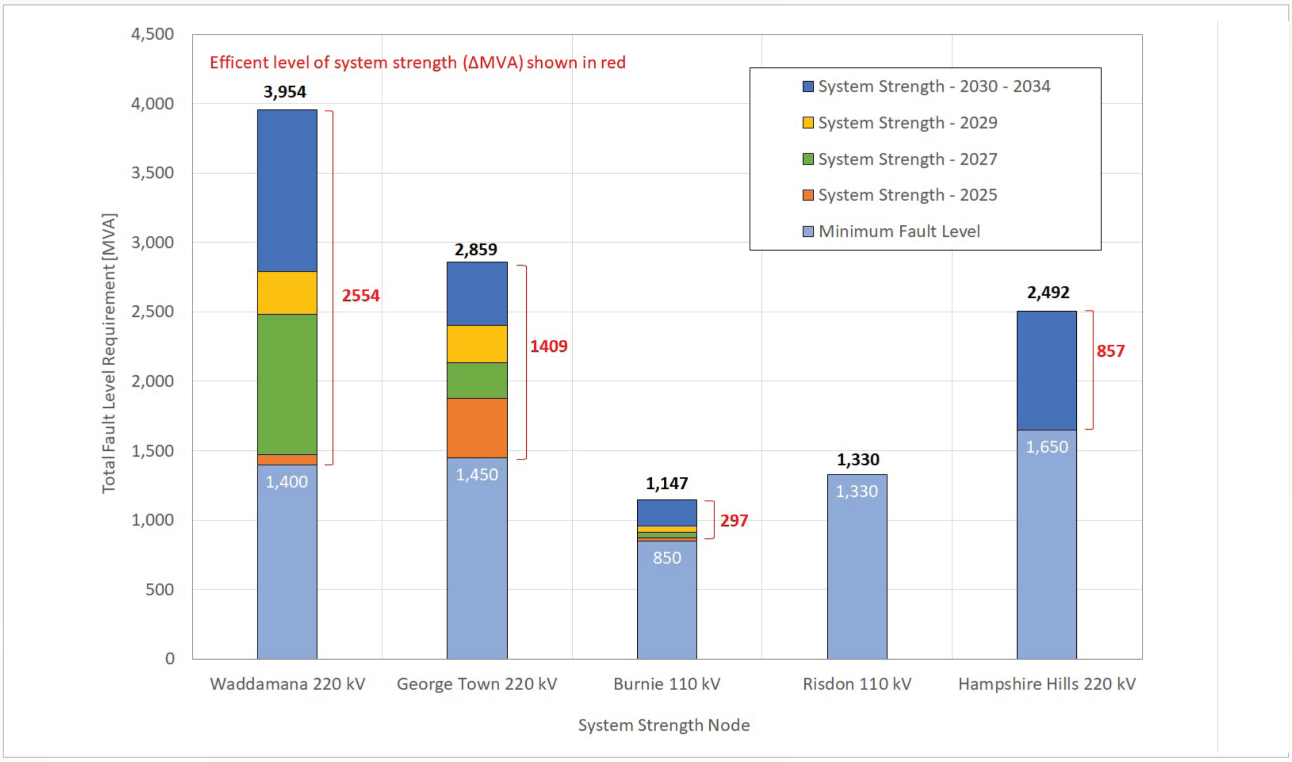


Figure 5-2: Estimated *efficient level of system strength* at each SSN, 2025-2034

The forecasts indicate an increase in system strength requirements between 2025 and 2030 corresponding to approximately 830 MW of new IBR connections across the North East, North West and Central Highlands Renewable Energy Zones (**REZ**). The George Town and Waddamana 220 kV SSNs experience the greatest relative increases during this period. Post 2030, following the expected commissioning of Marinus Link, the requirements increase again to support an additional 1,300 MW of new wind generation, the majority of which is forecast to be developed in the Central Highlands REZ, with Waddamana SSN as the reference location.

While the AFL methodology cannot predict the exact requirements, it is clear that additional system strength support will be required over and above that currently provided as the minimum three phase fault level. All SSNs will be materially impacted, with George Town, Waddamana and Hampshire Hills all exhibiting the most significant increases above the existing baseline requirements.

5.4.4.4. Forecast of available fault level at system strength nodes

A requirement of the Rules clause 5.20C.3(f)(3) requires the SSSP to provide a forecast of the AFL at each SSN over the period for which AEMO has determined system strength requirements, which is currently until 2034.

AFL is largely determined by the dispatch of synchronous generation at any point in time and is therefore not a fixed quantity. As an example, consider Figure 5-3 which presents a series of duration curves for the forecast three phase fault level at the Waddamana 220 kV SSN. Because Tasmania will not experience a permanent withdrawal of synchronous generation as is progressively occurring on the mainland (due to coal fired power stations being decommissioned as per the timeframes published by AEMO[65]), access to system strength support will continue to be available. However, as more IBR is connected, there will be increasing periods of time when that capability is not naturally dispatched in the energy market and alternate mechanisms will be required to maintain power system security. This is represented by an increasing duration below the minimum fault level requirement.

65 Generation closure year details are included in : https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/generating-unit-expected-closure-year.xlsx

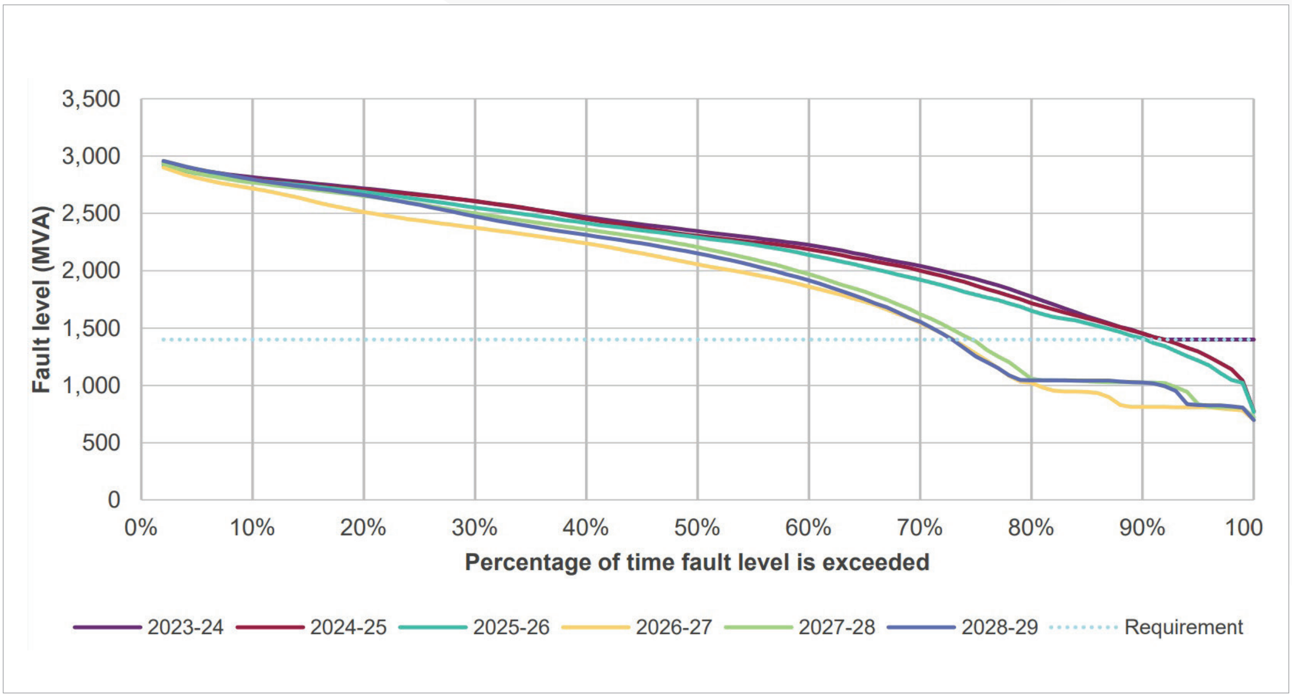


Figure 5-3: Forecast fault level at the Waddamana 220 kV SSN[66]

At present, during such operating periods, contracted system strength services are dispatched to raise the three-phase fault level to meet at least the minimum requirement. Moving ahead, it will be important to sustain not only the minimum fault level but also the efficient level of system strength, as illustrated in Figure 5-1.

In TasNetworks' view, the purpose of Rules clause 5.20C.3(f)(3) is to inform developers about which areas of the network are currently better suited to accommodate new IBR connections. Conversely, some parts of the network may already be nearing established performance limits and might pose a greater challenge when integrating new IBR.

The following AFL estimates for each SSN have been prepared based on these assumptions:

- Two minimum hydro generator dispatch scenarios have been explored as part of a sensitivity analysis. Both scenarios are more onerous than current operating practices but align with future planning scenarios currently under review.[67]
- Synchronous condensers currently contracted to TasNetworks will remain available to support the network.[68] For each generation scenario, a minimum number of synchronous condensers have been dispatched to meet the minimum three-phase fault level at each SSN. The results are based on one particular configuration of synchronous condensers in operation, although multiple credible variations are possible.
- The generation and synchronous condenser dispatch combinations have been developed for the network as of 2024 and remain constant in all future years. Anticipated future changes in network topology have been included as appropriate for each year. The impacts of increasing levels of IBR, as forecasted, are thus compared with the 2024 base case.
- The amount of additional generation post Marinus Link Stage 1 in 2030 is assumed to be zero, aligning with the current forecast additional generation projects TasNetworks has visibility of, and their expected timing which differs slightly from the system strength forecasts presented in Table 5-6, essentially bringing projects forward to 2030 from future years.

66 Extracted from AEMO 2023 System Strength Report

67 As described in Section 5.2.2.

68 Please note that this assumption has been used for study purposes, noting the current RIT-T for System Strength and Inertia procurement is currently underway and may result in a different outcome post 2 December 2025

For clarity, the forecast AFL for each SSN should be interpreted as follows:

- A large positive AFL indicates that adverse system impacts are unlikely (though not impossible), suggesting that the SSN is likely capable of supporting the proposed level of IBR under consideration.
- An AFL close to zero indicates a rising risk of adverse system impacts, necessitating detailed analysis to understand how IBR would perform under such operating conditions.
- An increasingly negative AFL indicates a high risk of adverse system impacts, with a growing likelihood that additional system strength support will be needed to maintain power system security.

The AFL methodology is not designed to provide a precise pass or fail outcome but rather to indicate risk. This information can be integrated into network planning activities, highlighting areas for more detailed analysis techniques that require additional time, personnel, and costs.

George Town 220 kV

The forecast AFL for the George Town 220 kV SSN is depicted in Figure 5-4. As anticipated, the analysis shows that the available operating margin is already quite low due to the impact of in-service IBR, especially the Basslink HVDC interconnector. As projected IBR developments are gradually introduced in the following years, the AFL deteriorates significantly, primarily from IBR growth within the Central Highlands REZ. Since George Town is situated near the electrical centre of the Tasmanian power system, almost all future IBR connections negatively affect the AFL; this is because the electrical distance from George Town to many proposed development sites is not substantial, increasing the risk of adverse interactions. Current analysis suggests that the George Town 220 kV SSN is a vulnerable location and will likely need additional system strength services beyond the current operational arrangements, potentially as soon as 2025. Such measures are also expected to positively affect other parts of the network.

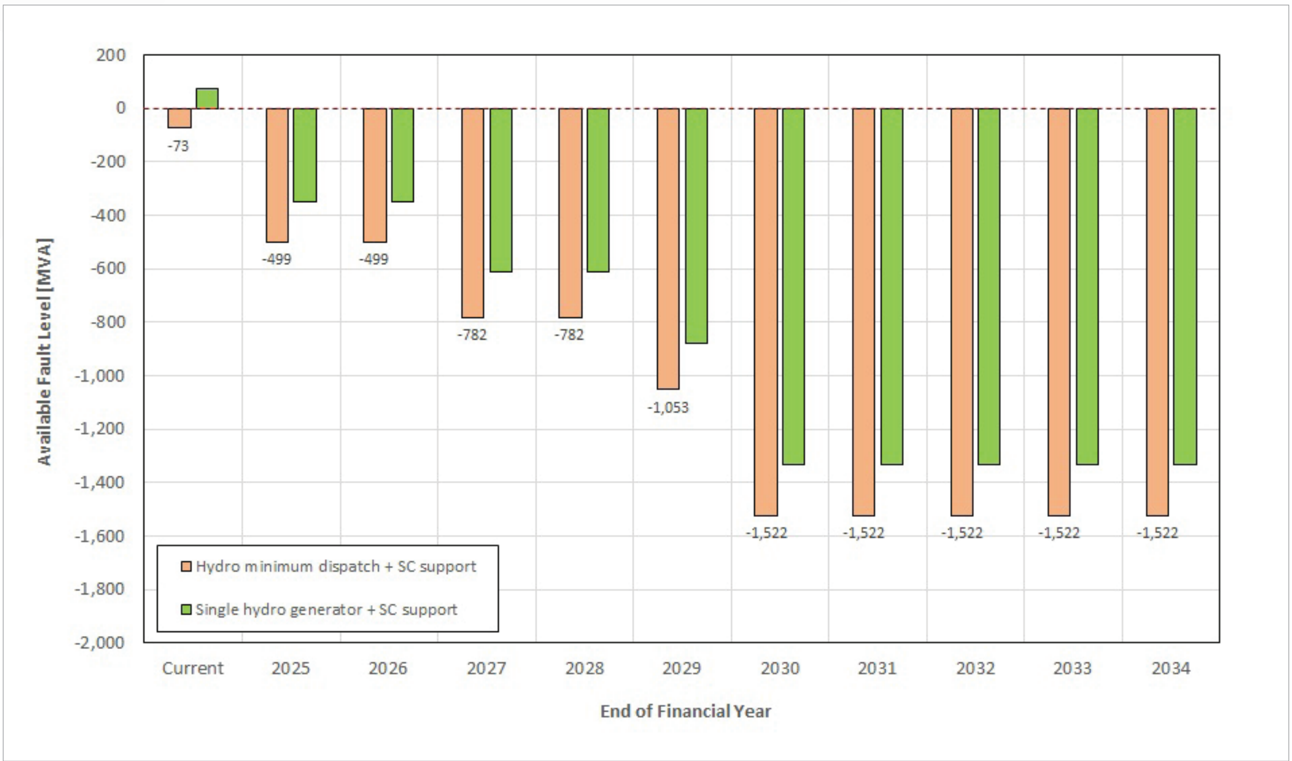


Figure 5-4: Forecast AFL at George Town 220 kV SSN

Waddamana 220 kV

The forecast AFL for the Waddamana 220 kV SSN is illustrated in Figure 5-5. Considering the system strength services already required to effectively manage areas like George Town, and the fact that only one wind farm is currently operating in the vicinity, Waddamana presently has sufficient margins. The AFL remains positive until the expected substantial IBR growth of approximately 650 MW, anticipated for 2027, is constructed near the Waddamana switching station as part of the Central Highlands REZ.

In 2030, there is a significant increase in the AFL deficit, aligning with further planned IBR developments in the order of 720 MW coinciding with the transmission augmentations for NWTD and Marinus Link Stage 1. Additional system strength support beyond the current operational arrangements will likely become necessary, most likely starting in 2030, depending on the precise scale and timing of IBR developments in the Central Highlands REZ.

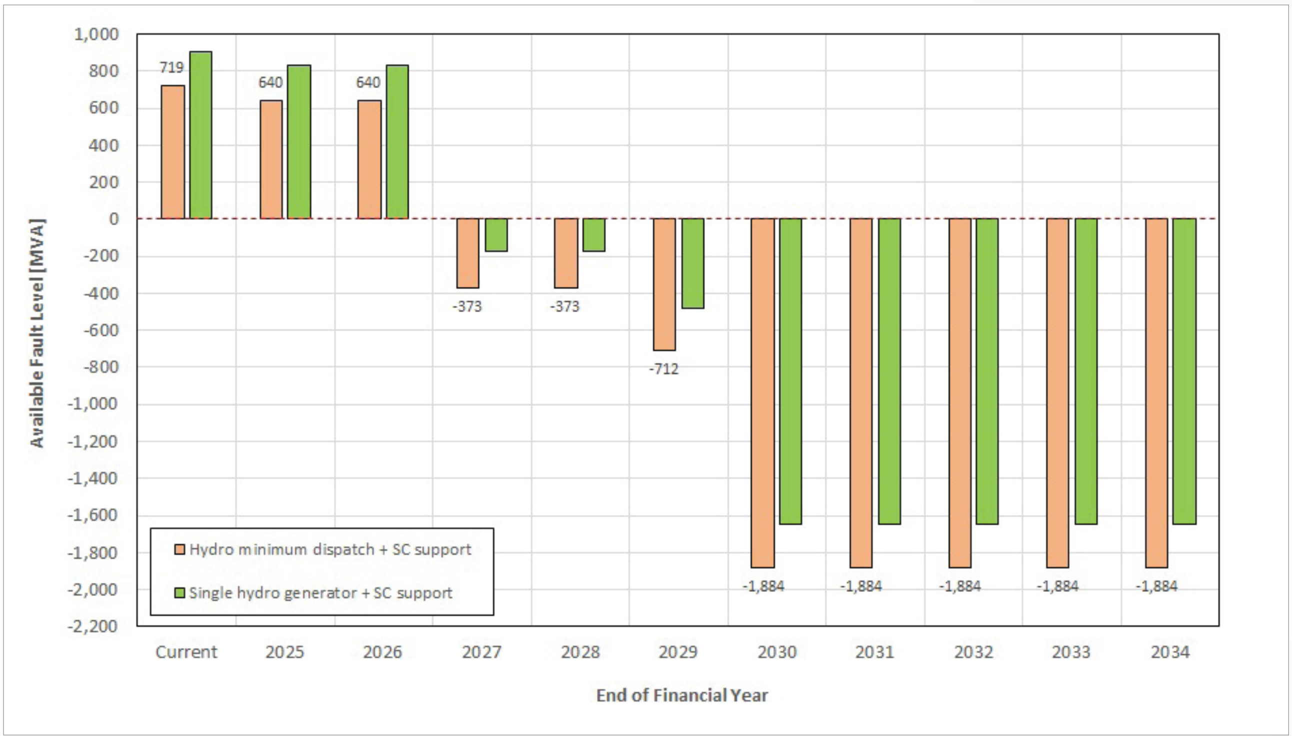


Figure 5-5: Forecast AFL at Waddamana 220 kV SSN

Burnie and Smithton 110 kV

The forecast AFL for the Burnie 110 kV SSN is shown in Figure 5-6. The results suggest a positive AFL through to 2034, even with a substantial rise in connected IBR across the Tasmanian network during this period. However, it's crucial to also consider the effects on an existing IBR connection point supplied from Burnie.

Smithton Substation serves as the connection point for Woolnorth Wind Farm, which includes the Bluff Point and Studland Bay wind farms, located adjacent to each other. The combined installed capacity of these sites is about 140 MW. The double-circuit 110 kV transmission line between Smithton and Burnie substations (via Port Latta) has very limited spare thermal capacity and spans a considerable length of 71.4 km. Therefore, the impact of a single credible contingency on the available system strength at Smithton is significant and requires specific attention.

The results in Figure 5-7 show that the AFL at Smithton is already very low after the critical credible contingency event of losing one 110 kV circuit to Burnie and becomes increasingly negative in future years. With both circuits operational, the AFL remains positive but deteriorates over time as substantial wind developments are introduced into the North West Tasmania REZ in the order of 750 MW in 2029 and 2030.

The conclusion for the Burnie SSN is that any network change that either restricts the ability to maintain the currently defined 850 MVA minimum fault level or directly impacts the existing AFL at Smithton Substation would need careful consideration. Potential adverse effects on an existing IBR connection point could increase the system strength requirements at this SSN.

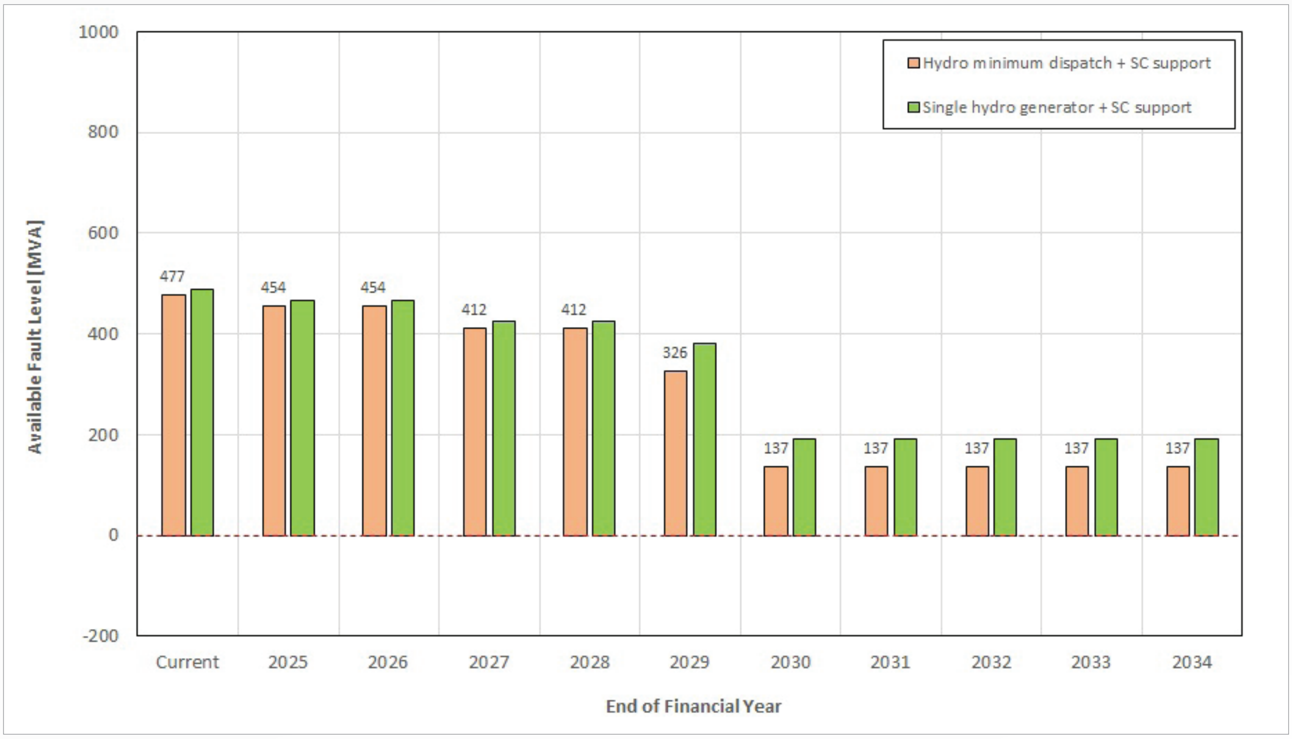


Figure 5-6: Forecast AFL at Burnie 110 kV SSN

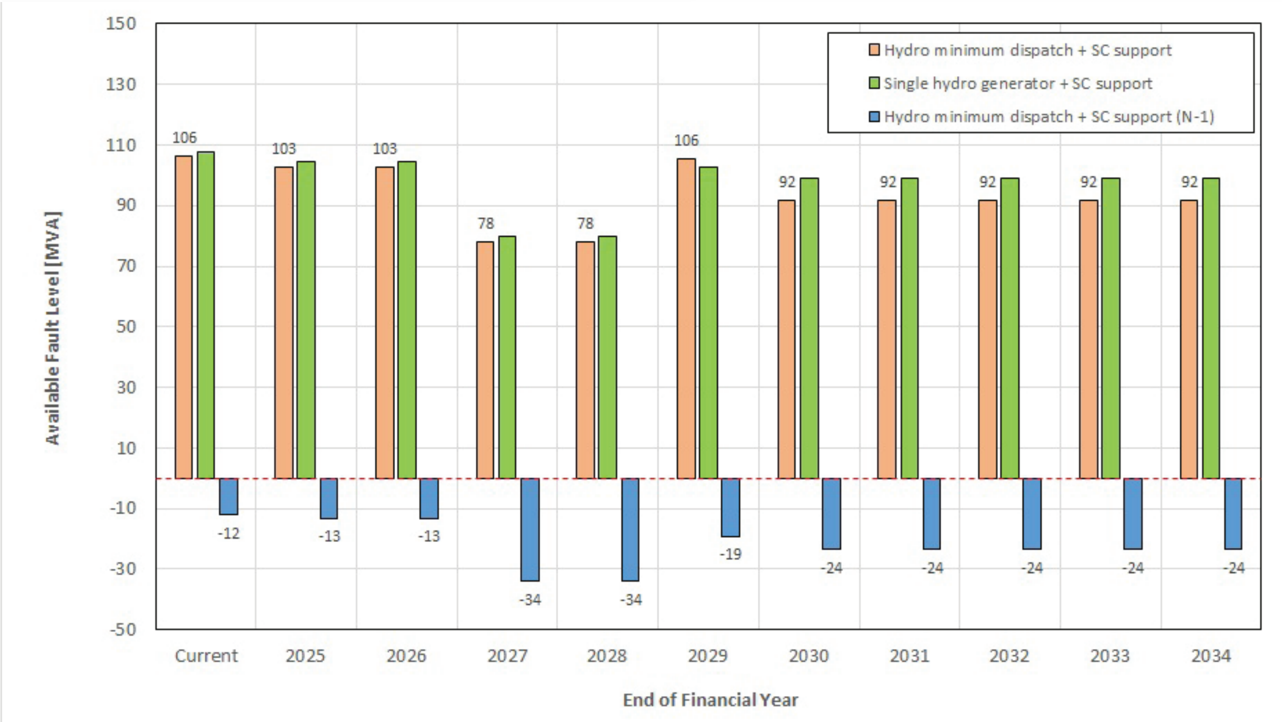


Figure 5-7: Forecast AFL at Smithton 110 kV IBR connection point

Risdon 110 kV

The forecast AFL for the Risdon 110 kV SSN is illustrated in Figure 5-8. Since Risdon Substation is situated in the southern part of Tasmania and is electrically isolated from most anticipated IBR developments, the AFL remains relatively high throughout the forward planning period.

However, a challenge already identified at Risdon is the ability to maintain the minimum fault level requirement of 1,330 MVA in future years, particularly if the hydro generation patterns in the south change significantly with the proposed construction of a new Tarraleah Power Station. This new station is designed to facilitate flexible operations, enabling it to be shut down based on market conditions. In contrast, the existing station lacks flexibility due to limitations in the water conveyancing system, leading to a relatively constant base load operation that provides various benefits to the network. TasNetworks is aware of this potential future change and is exploring various options to ensure power system security in southern Tasmania during periods of low or no hydro generation.

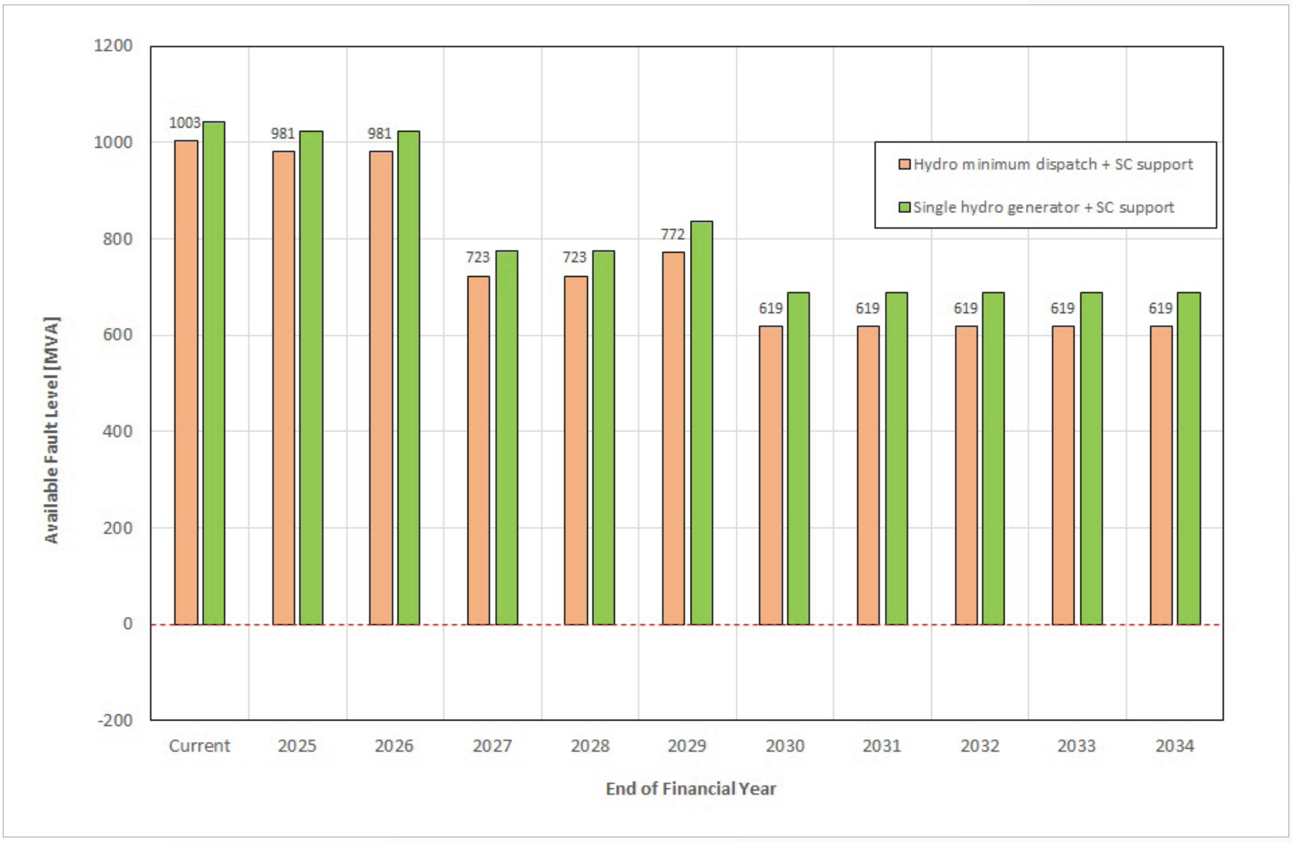


Figure 5-8: Forecast AFL at Risdon 110 kV SSN

Hampshire Hills 220 kV

As the Hampshire Hills 220 kV substation is not yet formally designated as an SSN, an AFL analysis has not been performed. TasNetworks will incorporate this site in future Transmission Annual Planning Reports as necessary to comply with the Rules.

Alignment with efficient levels of system strength

It is important to highlight an apparent discrepancy between the *efficient levels of system strength* presented in Figure 5-2 and the specific AFL results discussed earlier; specifically, the *efficient levels of system strength* seem to exceed what is necessary, with Burnie serving as a notable example.

This discrepancy arises from the limitations of a calculation methodology that uses fault level as a proxy for managing system strength. The fault level determined at any given point in the network depends on the number and location of all fault current sources. Additionally, there are interdependencies, meaning the contribution from one source is influenced by the contributions of other sources nearby. This calculation is often characterised as 'non-linear'.

To estimate the *efficient level of system strength*, TasNetworks assumed that no additional synchronous generation is connected to the network. This approach should yield a conservative estimate of the future requirements of the network, establishing an upper limit on expectations.

The AFL calculations presented were based on onerous yet credible dispatch scenarios for hydro generation and supporting synchronous condensers. As a result, the AFL outcomes serve as a 'snapshot' from a broad spectrum of potential results that vary according to the case assumptions.

Overall, both sets of results clearly demonstrate that locations expected to accommodate significant IBR developments in the future will almost certainly need additional system strength support beyond current operational practices. George Town, Waddamana, and Hampshire Hills 220 kV are particularly affected by the anticipated IBR connections, while ongoing management of the existing minimum fault levels at Burnie and Risdon 110 kV remains a priority at these sites.

5.4.4.5. Commencement of a RIT-T for the provision of future system strength requirements

To comply with the new system strength Rule requirements, TasNetworks has initiated a Regulatory Investment Test for Transmission (**RIT-T**), which included the publication of a Project Specification Consultation Report (**PSCR**) and a Request for Expression of Interest (**EOI**) in early August 2023[69]. The main aim of the PSCR and EOI was to identify credible network and non-network options that will enable us to manage our future system strength obligations in a technically efficient and cost-effective manner.

We also anticipate publishing a Project Assessment Draft Report (**PADR**), as the estimated capital cost for certain credible options is expected to exceed $46 million, and this need cannot be ruled out at this stage. The preparation of the PADR began in November 2023 and may take up to twelve months to complete, given the necessity of a detailed cost-benefit analysis to find the least-cost solution.

Since the Rule requirements related to system inertia have not changed, TasNetworks aims to optimise the PADR analysis processes. We believe that several potential credible solutions could simultaneously address both inertia and system strength requirements, thereby contributing to positive outcomes for consumers in line with the National Electricity Objective (**NEO**).

As previously mentioned, TasNetworks must have new agreements or network solutions in place to ensure adequate levels of inertia network services and system strength services by 2 December 2025.

5.4.4.6. Commencement of very fast FCAS market and implications for inertia requirements

Following the completion of the "Fast Frequency Response Market Ancillary Service" Rule Change in July 2021, AEMO has made progress towards introducing two new market ancillary services into the NEM. These new services are the very fast raise (R1) and very fast lower (L1) Frequency Control Ancillary Services (FCAS) markets, both of which are defined with a 1-second delivery timeframe. The new markets have now commenced operations as of 9th October 2023.

TasNetworks has been collaborating with AEMO on various aspects of this implementation, including investigating potential sources of very fast FCAS and engaging in the Market Ancillary Service Specification (**MASS**) consultation. In the current market, we will continue to assess how these new services may affect the existing minimum inertia requirements defined for Tasmania. While fast frequency response capability is not a direct substitute for inertia due to the typical measurement time delays involved, there may be opportunities to optimise Tasmanian inertia requirements further.

69 Further information can be obtained on the System Strength RIT-T progress is available at https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Our-current-projects/Meeting-System-Strength-Requirements

5.5. Transmission network constraints

A constraint occurs when the power flow through a section of the transmission network needs to be curtailed to prevent exceeding a known technical limit, which could jeopardise power system security. AEMO formulates constraint equations for use in its market systems that define how generation dispatch and Basslink must be coordinated to avoid breaching these technical limits. The equations are based on limit advice provided by us for our transmission network. Such advice is typically developed using power system simulation software that allows for the examination of a wide range of network operating conditions to identify acceptable scenarios and those that must be avoided.

Operating restrictions are often influenced by the status of critical network components and the control and protection schemes designed to extend the permissible operating boundaries of the network. For example, the Network Control System Protection Scheme (**NCSPS**) in the Tasmanian network enables various parts of the transmission system to operate in a 'non-firm' capacity. Additionally, TasNetworks utilises dynamic ratings for transmission lines, which depend on real-time measurements of ambient temperature and wind speed to determine the maximum allowable power flow through a specific circuit based on its design parameters. Depending on the status of these schemes and supporting infrastructure, different constraints are enabled to ensure the network maintains a secure operating state.

We conduct periodic reviews of all binding and violating constraints and provide AEMO with updated limit advice to modify, remove, or establish new constraints as network conditions change. This ensures that power system security is upheld while maximising available transmission capacity. The market impact component (**MIC**) of the Australian Energy Regulator's (**AER**) Service Target Performance Incentive Scheme (**STPIS**) creates a financial incentive for us to minimise the impact of transmission constraints.

Figure 5-9 illustrates constraints that were binding or violated due to thermal or stability issues during the calendar year 2023. Binding constraints affect generation output and/or Basslink power transfer through market re-dispatch, while violated constraints indicate instances where a technical limit was exceeded. The figure details the number of five-minute NEM trading intervals during which constraints occurred across different parts of the network. 'Thermal limit – no outage' signifies that the constraint was binding or violated without any corresponding outage event in the network, whereas 'Thermal limit – with outage' indicates that the constraint was affected by one or more transmission elements being out of service.

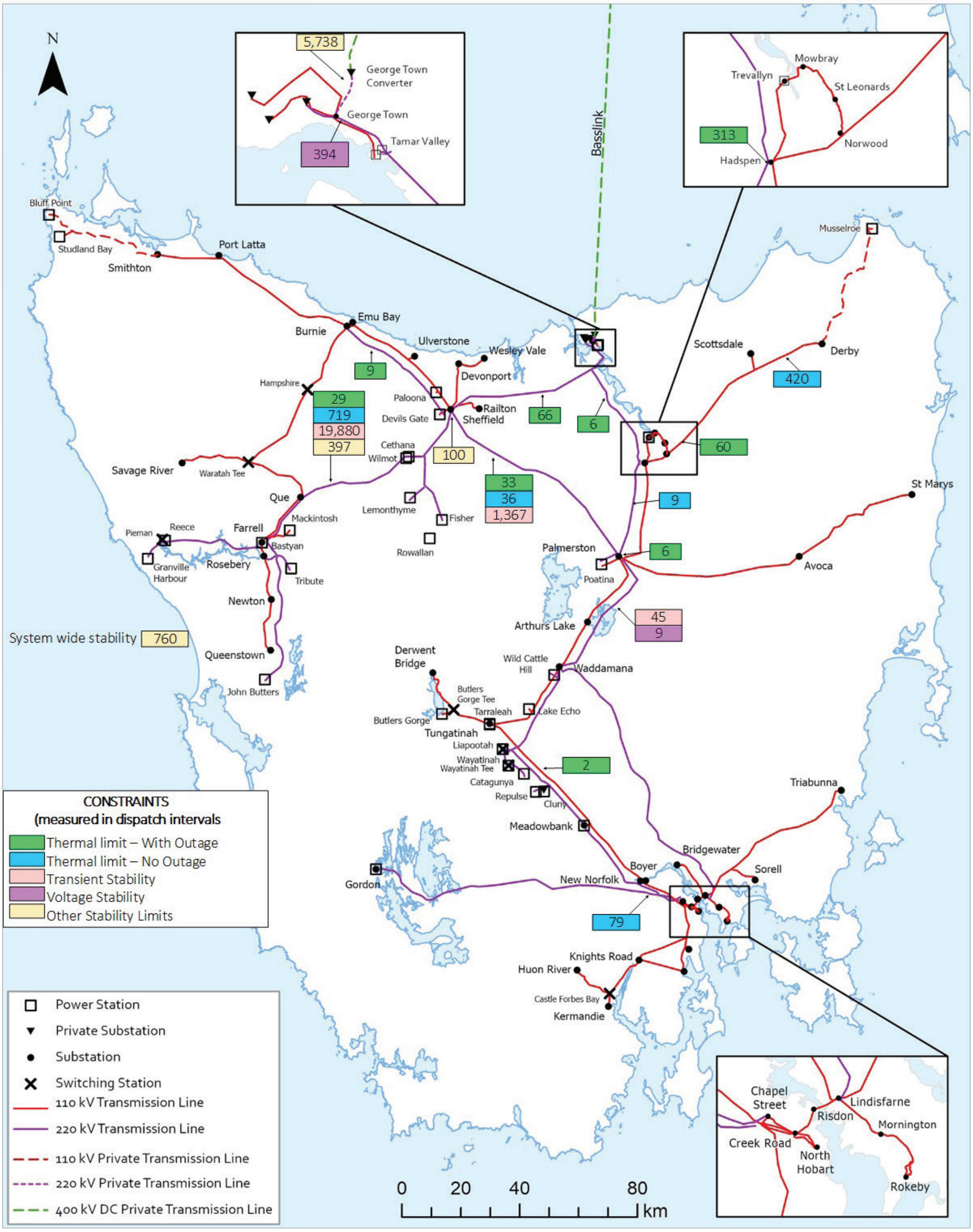


Figure 5-9: Transmission constraints during 2023 calendar year

Table 5-7 displays the number of trading intervals in which binding or violated constraints took place on major transmission corridors during the 2022 and 2023 calendar years, classified by whether the number of constraints increased or decreased compared to the previous year. It includes only those constraints where the total number of bound or violated periods surpassed 150 trading intervals, equivalent to 12.5 hours. The table encompasses both network constraints and those specifically associated with Basslink.

Table 5-7: Major binding constraints and significant changes in 2023

Constraint	Period constraint bound or violated			
	2022		2023	
	Trading intervals	Time (hours)	Trading intervals	Time (hours)
Constraints with increased prevalence in 2023				
Farrell–Sheffield 220 kV transient stability	3400	283	19880	1657
Basslink import limited due to load unavailability for FCSPS operation	2499	208	4936	411
Limit TAS non-synchronous generation and Basslink	103	9	726	61
Farrell–Sheffield 220 kV thermal limit with no outage	435	36	719	60
Basslink rate-of-change limit	509	42	680	57
Discretionary Limit on West Coast generation	8	1	364	30
Hadspen 220/110 kV transformer thermal limit with outage	89	7	313	26
Basslink Energy and FCAS related constraint (ie Basslink no go zone)	270	23	295	25
Constraints with decreased prevalence in 2023				
Palmerston–Sheffield 220 kV transient stability	1450	121	1367	114
Derby to Scottsdale Tee 110 kV thermal limit with no outage	597	50	420	35
George Town 220 kV bus voltage stability limit	528	44	394	33

The following sections present more information on our top three constraints from 2022 to 2023.

Summary

The 2023 calendar year was a more typical period than 2022 when the annual statistics were heavily impacted by one major incident, being the extended outage of both Palmerston-Waddamana 220 kV transmission circuits. This event had a significant impact on the type and frequency of binding constraints that were observed. Overall, the total number of trading intervals experiencing binding transmission constraints (both major and minor) decreased by approximately 20% from 37,434 in 2022 to 30,807 in 2023.

Farrell–Sheffield 220 kV transient stability

The most limiting constraint in 2023 was the 'Farrell–Sheffield transient stability' constraint. The constraint is primarily driven by generation output from the King and Pieman hydro schemes, as well as Granville Harbour Wind Farm. High power transfers from the West Coast into Sheffield Substation were more prevalent in 2023, hence the increased number of constrained trading intervals. TasNetworks will investigate if there are any economical options to reduce this constraint in the future, including revisiting the limit advice with updated generator models, or encouraging new load into the West Coast area.

Basslink import limited due to load unavailability for FCSPS operation

The second most limiting constraint in 2023 was the 'Basslink import limited due to load unavailability for frequency control system protection scheme (FCSPS) operation' constraint. This constraint limits the import from Victoria to Tasmania due to the unavailability of load blocks for the FCSPS to balance frequency for the loss of Basslink.[70]

Palmerston–Sheffield 220 kV transient stability

The third most limiting constraint in 2023 was the 'Palmerston-Sheffield 220 kV transient stability' constraint. This constraint prevents poorly damped North - South oscillations following the fault and trip of Palmerston to Sheffield 220 kV line. This was also one of the constraints with the largest decrease in binding intervals in 2023.[71]

70 TasNetworks has no control over this constraint as the FCSPS loads are contracted by other parties

71 This particular constraint will be positively impacted by the new PM-SH 220 kV upgrade which forms part of the NWTD

5.6. System stability and emergency controls

Instabilities in the power system can manifest in various forms and have the potential to cause significant disruptions to the network. Stability phenomena are generally classified into two broad categories: large signal and small signal. Large signal instabilities are typically linked to network contingency events, such as electrical faults, whereas small signal instabilities can arise at any time without any significant initiating disturbance.

The Rules require AEMO and TNSPs to operate the power system in a manner that maintains stability during both normal operations and following credible contingency events, including protected events. This is usually accomplished through the application of network constraints as well as the installation and maintenance of various network control and protection systems. Control systems are used to actively mitigate certain instability mechanisms and extend the network's capabilities, while protection systems detect unstable events (including electrical faults) and swiftly remove network elements from service to restore acceptable operation.

Furthermore, TNSPs are obligated to install, maintain, and upgrade emergency controls within their networks where the consequences of non-credible contingency events could lead to severe supply disruptions. The purpose of these emergency controls is *"to minimise disruption to any transmission or distribution network and to significantly reduce the likelihood of cascading failure."* The design and implementation of such schemes are carried out in consultation with AEMO.

TasNetworks has long had Emergency Frequency Control (**EFC**) schemes in place, designed to mitigate the impacts of non-credible contingency events that could severely disrupt the supply-demand balance. These two schemes have been developed on a 'best endeavours' basis, recognising that it is impractical to manage every potential combination of non-credible network events, such as the near-simultaneous disconnection of all generating units.

The two EFC schemes operating in the Tasmanian region are:

- Under Frequency Load Shedding (**UFLS**) Scheme: This scheme utilises the provisions of the Rules clause 4.3.5(a) to trip at least 60% of each market customer's load demand to manage severe under-frequency events.
- Over Frequency Generator Shedding (**OFGS**) Scheme: This scheme coordinates the disconnection of certain units based on the technical limitations of specific plants to provide a coordinated response to control severe over-frequency conditions.

The UFLS and OFGS schemes serve as the 'last line of defence' in many scenarios that could otherwise lead to the cascading failure of the entire Tasmanian power system.

Additionally, we operate and maintain several non-regulated protection schemes on behalf of specific network users under commercial agreements. These schemes are designed to mitigate specific credible contingency events and are generally required for network users to comply with the Frequency Operating Standards (FOS), particularly the 144 MW contingency size limit. The most notable of these schemes include:

- Frequency Control System Protection Scheme (**FCSPS**): Exclusively associated with the Basslink HVDC interconnector, this scheme addresses the instantaneous loss of Basslink, which is always considered a credible contingency event. The FCSPS allows power transfers significantly over 144 MW (both import and export) by promptly tripping loads or generation if Basslink power transfer is disrupted, thereby helping to maintain the supply-demand balance in Tasmania and preventing excessive frequency fluctuations.
- Tamar Valley Generator Contingency Scheme (**TVGCS**): To meet the FOS requirements, the effective size of the generator contingency event associated with the combined cycle gas turbine (CCGT) at Tamar Valley Power Station is limited to no more than 144 MW. With a rated capacity of 208 MW, the unit requires contracted load tripping services to support high generation output.
- Musselroe Wind Farm Generator Contingency Scheme (**MRWF GCS**): Similar to the situation at Tamar Valley, Musselroe Wind Farm faces the same issue. As the wind farm is rated at 168 MW and can export more than 144 MW through its registered connection point, it also requires contracted load tripping services to facilitate operation up to its installed capacity.

We continue to collaborate with network users to explore the availability and application of new technologies that can help address stability limitations, particularly focusing on the provision of frequency control capabilities that work in parallel with, or directly participate in, the FCAS markets operated by AEMO.

Chapter 6

Service delivery performance

- 2023 transmission system performance remained within target for transmission, transformer and capacitor circuit fault outage rate metrics. While transmission Loss of Supply (**LOS**) event counts over 0.1 and 1.0 system minutes were on target, the average outage duration of all LOS events was outside the target.
- Distribution network performance for 2023–24 was generally outside the Tasmanian Electricity Code (**the Code**) reliability standards as well as the Service Target Performance Incentive Scheme (**STPIS**) targets set by the Australian Energy Regulator (**AER**).
- There are over 55,000 Distributed Energy Resource (**DER**) systems with an installed capacity of 330 MW, a 16% increase over the course of 2023-24 financial year.

6.1. Service delivery introduction

We manage our network by balancing cost, risk and performance to deliver affordable levels of supply reliability and quality to our customers. Network service performance is a critical aspect of our customer service and must meet customer expectations and regulatory obligations.

Our objectives in relation to service performance are:

- safety is our top priority and we will endeavour to continue improving our safety performance;
- service performance will be maintained at current overall network service levels, while service to poor-performing reliability areas will be improved to meet regulatory requirements;
- cost performance improved through prioritisation and efficiency gains enabling us to provide predictable and lowest sustainable pricing to our customers;
- customer engagement will be improved to ensure our decision-making will maximise value to our customers and customer views are taken into account;
- our program of work will be developed and delivered on time and within budget; and
- our asset management improved to support our cost and service objectives and deliver efficiency improvements.

Reports are also provided on transmission asset outage occurrences and the reliability and quality of supply provided to our distribution customers. Issues associated with customer communities with service levels below target levels are discussed along with our strategy to undertake corrective actions.

Three major event days occurred during 2023-24, all resulting from inclement weather. On 31st July 2023, strong winds and rain affected the state with vegetation related incidents disrupting distribution supply and impacting customers. In response, we activated our Incident Contingency System enabling Regional Team Leaders to prioritise actions and accordingly deploy work crews to support timely and targeted supply restoration efforts. On 25th October 2023, severe winds mostly in southern Tasmania brought down trees and powerlines. Finally, on 31st May 2024, strong winds and rain again affected the state, prompting the activation of the Incident Contingency System to address the damage and prioritise response actions.

6.2. Tasmanian network and supply reliability

Reliability is measured in two ways:

- reliability of network elements; and
- impact of supply interruptions to customers.

Reliability considers both the frequency and duration of outages.

Outage frequency reflects the effectiveness of our asset management strategies in the prevention of outages. It is measured using the number of LOS events and average circuit outage rate for our transmission network, and a system average interruption frequency index (**SAIFI**) for our distribution network.

Outage duration reflects our effectiveness in responding to unplanned or forced outages. It is measured using the average outage duration of LOS events for our transmission network, and a system average customer supply interruption duration index (**SAIDI**) for our distribution network.

We have a requirement to monitor and report supply reliability (among other measures) to the AER and the Office of the Tasmanian Economic Regulator (**OTTER**). Relevant supply reliability performance metrics are used by the AER in the STPIS scheme for each of our distribution and transmission networks. Additionally, we have an obligation under the Code to use reasonable endeavours to meet jurisdictional reliability targets.

The following sections provide information on network reliability targets and current performance.

6.3. Transmission network reliability

Transmission network reliability is monitored and reported to the AER and OTTER. Under the STPIS and based on historical performance, the AER sets service targets in terms of the number of LOS events that occurred during the year, average circuit outage rate, and the average LOS event duration.

LOS is measured in system minutes and is calculated by dividing the total energy (**MWh**) not supplied to customers during an event by the energy supplied during one minute at the time of historical Tasmanian maximum demand.[72] LOS events are split into two categories:

- major events (exceeding 1.0 system minute); and
- all events exceeding 0.1 system minute, including major events.

Table 6-1 lists the performance of our transmission network over the past five years.[73] Performance measures are as defined by the AER in the STPIS.[74] Red values indicate where we did not meet our standard.

Table 6-1: Transmission network performance

	Regulatory period 2014–19		Regulatory period 2019–24				
Performance measure	**Target**	**2019**	**Target**	**2020**	**2021**	**2022**	**2023**
Transmission network reliability performance							
Number of LOS events >0.1 system minute	≤10	2	≤3	8	2	7	3
Number of LOS events >1.0 system minute	≤3	1	≤1	0	0	3	1
Transmission circuit outage rate							
Transformer circuit fault outage rate (%)	≤11.60	8.26	≤8.40	5.51	4.55	2.70	4.50
Transmission circuit fault outage rate (%)	≤31.17	21.70	≤16.90	13.21	13.08	15.89	12.15
Capacitor circuit fault outage rate (%)	≤3.33	0.00	≤17.90	23.08	7.69	15.38	7.69
Transmission average circuit outage duration							
Average of LOS duration (minutes)	≤112	273	≤149	105	19	204.6	394.5

In 2023, the transmission system fault outages were within target for transmission circuit, capacitor circuit and transformer circuits. The LOS event counts were on target, but the average duration of LOS events was outside the target.

The majority of outages contributing to these metrics were caused by environmental causes such as lightning and adverse weather.

72 In Tasmania, an event of one system minute equates to about 31.2 MWh of unserved energy

73 Performance reporting to the AER under STPIS can be viewed at https://www.aer.gov.au/networks-pipelines/compliance-reporting

74 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-version-5-september-2015-amendment

6.4. Distribution network reliability

We report distribution network reliability to OTTER and the AER on a geographic segmentation basis. For 2023–24, Tasmania was divided into 101 reliability areas and then to one of five reliability categories. The reliability category determination is based on energy use per unit area with boundaries defined by natural features (like roads, rivers and land) and municipal boundaries.

The five reliability categories are:

- critical infrastructure (1 area);
- high-density commercial (8 areas);
- urban and regional centres (32 areas);
- high-density rural (33 areas); and
- low-density rural (27 areas).

The Code specifies performance standards for each:

- category, representing the average level of service expected by areas of that category; and
- area, representing the minimum level of service expected by the areas in each category.

We report SAIFI and SAIDI at the reliability category level to the AER each financial year. The AER sets targets for reliability categories in each regulatory period as a part of our distribution STPIS. These targets are calculated from our average performance in the preceding five years.

6.4.1. Tasmanian Electricity Code standards and performance

Distribution performance against the Code standards is measured by excluding outages on major event days,[75] transmission network outages, environmental -fire, customer installation faults, total fire ban day-related outages and certain third party outages. The Code standards and performance during 2023–24 are presented in Table 6-2 at category level. Historic performance against the Code standards is in Appendix C. Red values indicate where we did not meet our standard. Our reliability compliance and corrective action programs are presented in Section 6.4.4.

Table 6-2: Code all supply reliability areas SAIFI and SAIDI standards and performance

	Annual frequency of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
Supply reliability category	**Standard**	**Performance**	**Standard**	**Performance**
Critical infrastructure	0.2	0.2	30	50
High-density commercial	1	0.7	60	72
Urban and regional centres	2	1.3	120	148
High-density rural	4	2.9	480	367
Low-density rural	6	3.9	600	611

Our performance in SAIFI (the frequency of outages measure), is within our standard in all categories. For SAIDI (the duration of outages measure), we did not meet our standard in Critical Infrastructure, High-density Commercial, Urban and Regional centres and Low-density rural category. Communities in these categories were impacted by planned work, equipment related issues, vegetation, environmental and unknown cause also contributing to the totals.

Table 6-3 presents the Code standard for our 101 reliability areas, and the number of communities that did not meet these in 2023-24. Twenty-eight did not meet their SAIDI standards and three did not meeting their SAIFI standards.

75 A major event day is a day when the number of system minutes caused by outages exceeds an annually calculated threshold. These are predominately a result of large storms across wide areas of the state

Table 6-3: Code each supply reliability area SAIFI and SAIDI standards and performance

Supply reliability category (number of communities)	Annual number of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
	Standard	Number of communities below standard	Standard	Number of communities below standard
Critical infrastructure (1)	0.2	0	30	1
High-density commercial (8)	2	0	120	1
Urban and regional centres (32)	4	2	240	9
High-density rural (33)	6	0	600	9
Low-density rural (27)	8	1	720	8
Total (101)		**3**		**28**

6.4.2. Distribution STPIS reliability targets and performance

The AER sets service component parameters of STPIS as part of our regulatory determination. They are based on historic performance and exclude planned outages, major event days, transmission network outages, customer installation faults, total fire ban day-related outages; and certain third party outages. The STPIS targets and our performance levels are provided in Table 6-4 and Table 6-5. A summary of historical performance against AER targets are provided in Appendix C, with details available in the regulatory information notices (**RIN**) on the AER's website.[76]

In 2023–24, we did not meet the SAIFI or SAIDI reliability targets in High-density commercial, Urban and Regional centres, High-density rural and Low-density rural category areas. These categories were heavily impacted by equipment related issues, vegetation and unknown causes (aligning with the causes outlined about in 6.4.1).
Our reliability compliance and corrective action programs are presented in Section 6.4.4.

6.4.2.1. Forecast distribution reliability performance

Table 6-4 and Table 6-5 also show our forecast reliability performance for regulatory period, 2024–25. We forecast our reliability performance in alignment with the AER's methodology, from a five-year historical average. This indicates that the forecast reliability performance will not meet the current target for High-density commercial (SAIFI and SAIDI) and Urban and regional centres (SAIFI and SAIDI), High-density rural (SAIFI and SAIDI) and Low-density rural (SAIFI and SAIDI) due to past poor performance in these categories. Red values indicate either where we did not meet or are not forecast to meet our standard.

Table 6-4: STPIS supply reliability category SAIFI targets and performance

Supply reliability category	Annual number of supply interruptions (on average) (SAIFI)			
	Target 2019-24	2023–24 performance	Target 2024-29	Forecast to 2024–25
Critical infrastructure	0.251	0.02	0.070	0.09
High-density commercial	0.260	0.65	0.377	0.46
Urban and regional centres	1.081	1.11	1.015	1.06
High-density rural	2.466	2.56	2.171	2.33
Low-density rural	3.219	3.48	2.948	3.16

76 TasNetworks (distribution) 2019–20 – Annual Reporting RIN – non-financial templates, https://www.aer.gov.au/publications/reports/performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses

Table 6-5: STPIS supply reliability category SAIDI targets and performance

Supply reliability category	Annual duration of supply interruptions (on average) (SAIDI) Target 2014-19	2023–24 performance	Target 2024-29	Forecast to 2024–25
Critical infrastructure	32.984	4.71	5.948	7.83
High-density commercial	20.074	57.79	38.012	46.00
Urban and regional centres	89.657	98.11	92.118	92.31
High-density rural	250.959	271.56	244.061	252.58
Low-density rural	400.401	475.14	398.899	419.42

6.4.3. Distribution AER STPIS reporting

As part of our RIN submissions, we submit to the AER data for STPIS compliance requirements. Under the STPIS the AER can apply three reliability parameters to each customer category:[77]

- SAIDI;
- SAIFI; and
- Momentary system average interruption frequency index (**MAIFI**).

The AER has not applied the MAIFI parameter to our STPIS; however we do include it in our performance reporting.

In addition to these reliability parameters, the AER has also applied a customer service performance parameter for call centre phone answering. From 2024/25, the call centre phone answering parameter is no longer measured by the AER.

The AER does not apply the guaranteed service level (**GSL**) component of the STPIS to TasNetworks because we are already subject to a jurisdictional GSL through OTTER as part of the Code.

A summary of our reported 2023–24 performance is presented in Table 6-6 and Table 6-7. Both 'total' and 'removing exclusions' measures are reported. Exclusions are defined as excluded events and major event days. In addition to the annual performance, daily performance for each supply reliability category is available on the AER website.[78]

Table 6-6: STPIS reliability parameter

Reliability measure	Measure	Critical infrastructure	High-density commercial	Urban	High-density rural	Low-density rural	Whole network
SAIDI	Total	68.773	78.213	171.579	469.906	790.130	310.404
	Removing exclusions	4.713	57.787	98.106	271.564	475.141	181.458
SAIFI	Total	0.330	0.769	1.455	3.627	4.866	2.428
	Removing exclusions	0.019	0.649	1.114	2.560	3.480	1.686
MAIFI	Total	1.295	7.534	7.755	13.345	15.242	9.725
	Removing exclusions	1.295	7.534	7.222	12.117	14.268	9.027
Average customer numbers and planned basis of future reporting ('000s)		1.99	4.55	203.77	47.69	46.32	304.33

The phone answering parameter is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

77 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-november-2009-amendment

78 TasNetworks (distribution) 2019–20 – Annual Reporting RIN – non-financial templates, http://www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses

Table 6-7: Customer Service performance

Phone answering	Total	Removing exclusions
Number of calls	32,445	28,909
Number of calls answered in 30 seconds	25,531	24,591
Percentage of calls answered within 30 seconds (%)	79	85
STPIS Target (%)		76.30

6.4.4. Network and supply reliability compliance

Our reliability strategy seeks to:

- maintain current overall network reliability performance;
- comply with regulation, codes, and legislation;
- manage our risk profile to maintain a safe and reliable network ; and
- reduce total outage costs for our network.

We undertake corrective action to improve and maintain the reliability of our distribution network under three streams:

- targeted investigations into our top 10 poorest performing reliability communities;
- network reinforcement; and
- ongoing asset management activities.

Reliability corrective action is targeted, with action coming from a variety of programs as presented in Table 6-8 (with their relative benefits). We also undertake larger targeted reliability improvement projects that may require significant investment. These larger reliability improvement projects are presented by the planning area in Chapter 4.

Table 6-8: Reliability corrective action programs

Program	Benefit
Line trunk reliability improvement (protection reviews, targeted vegetation management, and asset renewal/relocation)	Reducing the probability of an unplanned outage occurring.
Remote switching reinforcement (automatic restoration schemes and multiple switches)	Reducing supply restoration time following an unplanned outage.
Distribution line interconnections (including new lines)	Reducing customer exposure to unplanned outages.
Standby generation Reducing supply restoration time following an unplanned outage.	

We also have a number of ongoing asset management activities that drive reliability outcomes:

- vegetation management;
- prioritised defect rectification;
- review of protection settings;
- targeted and specialised inspection programs; and
- utilisation of new technologies that minimise the duration of supply interruptions.

6.5. Embedded generation connections

Applications to connect embedded generation to the network are continuing to grow. Table 6-9 presents the number of applications received in recent years, which are made up almost exclusively of rooftop photovoltaic (**PV**) applications. The average time between the submission of an application to approval for energisation is 63 days.

Table 6-9: Embedded generation connection applications

Year	2019-20	2020-21	2021-22	2022-23	2023-24
Number of applications	3,229	3,524	3,716	4,728	5,423

Small generators – less than 5 MW – are automatically exempt from full compliance with Chapter 5 of the National Electricity Rules (**the Rules**).[79] While this removes many administrative barriers, small systems still interact with the broader power system. This means that small systems are still required to obtain a connection agreement with us and must meet our connection guidelines. Some of the network factors that we consider when connecting embedded generation are outlined in Appendix A.7.

More information on connecting embedded generation is available on our website: **www.tasnetworks.com.au/embedded-generation**

There were no large-scale embedded generation installations in the last year.

Rooftop solar PV makes up the vast majority of all embedded generation and has seen steady growth in recent years, reaching a total of over under 55,000 systems with an installed capacity of approximately 330 MW by the end of April 2024. Figure 6-1 presents the growth in installed capacity and number of installations of rooftop PV since 2014. The average size of new solar PV systems has also steadily grown, from under 4 kW in 2014 to over 9 kW in 2023, as shown in Figure 6-2.[80]

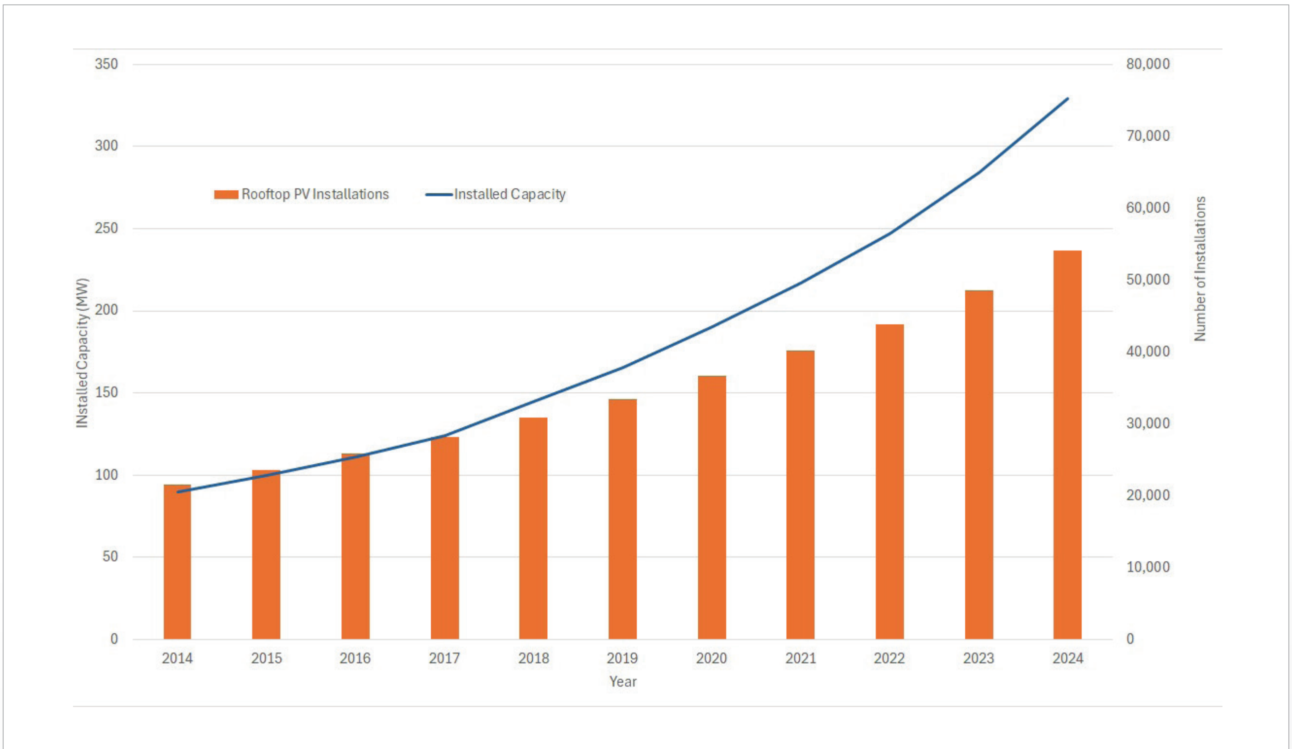


Figure 6-1: Solar PV penetration

79 https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/participate-in-the-market/networkconnections

80 This includes PV systems registered under the Small-scale Renewable Energy Scheme and batteries installed alongside solar PV systems. Figures excludes 2022 data. www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

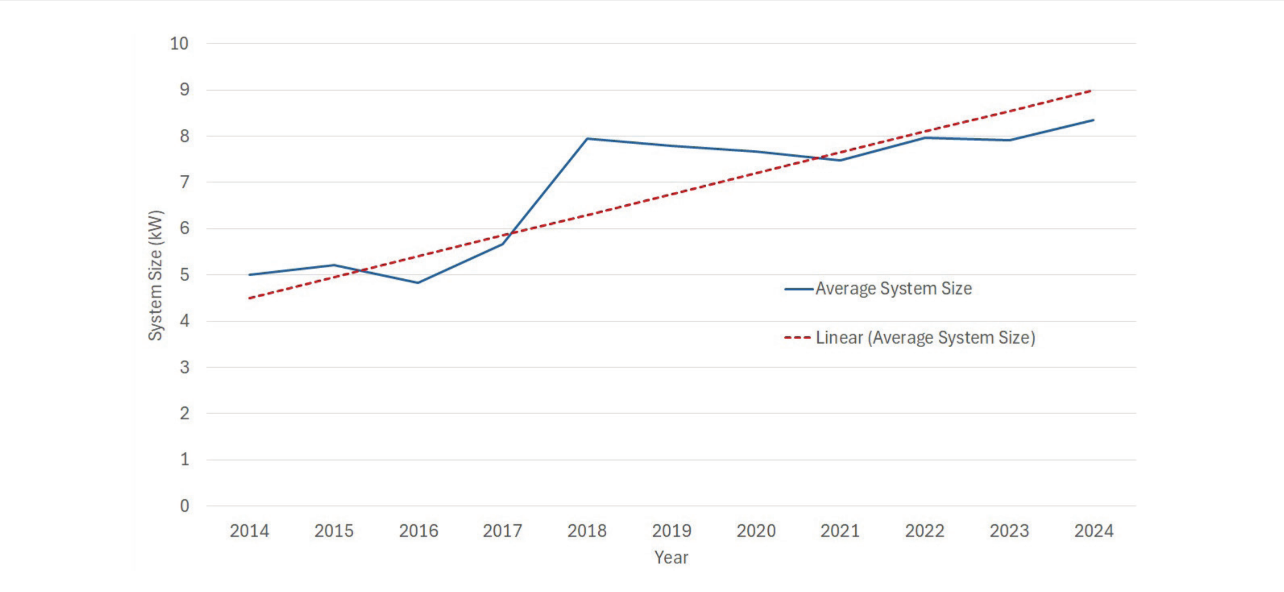


Figure 6-2: Average Solar PV system size

Residential battery storage has continued to grow, with new installations totalling nearly 1,400 across the state, as shown in Figure 6-3.[81]

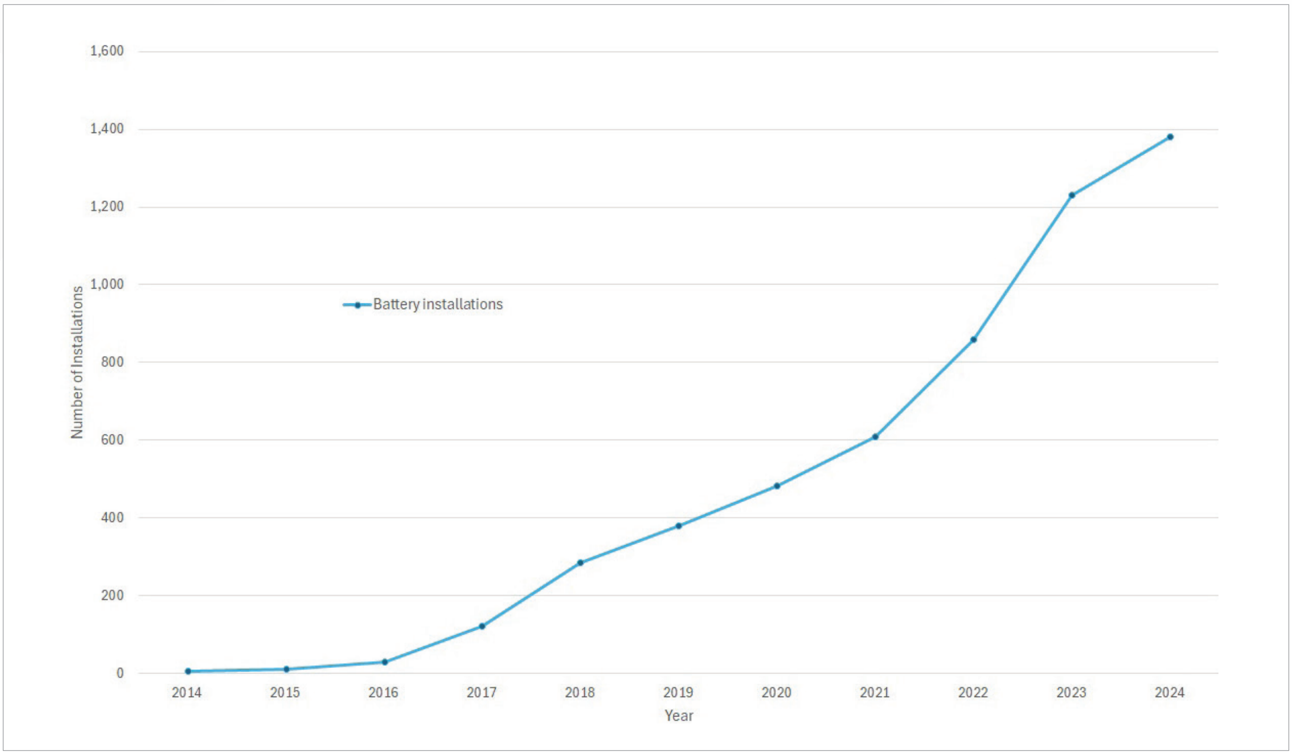


Figure 6-3: Residential battery penetration

81 This includes PV systems registered under the Small-scale Renewable Energy Scheme and batteries installed alongside solar PV systems. www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

6.6. Distribution quality of supply performance

Issues with distribution quality of supply are generally identified by:

- customer feedback that largely relates to voltage magnitude issues;
- proactive investigation of advanced meter data;
- operational limitations; and
- load or voltage studies arising from new connections or limitations.

Issues that are identified by customer feedback are resolved as a first priority. The issues that are identified through the analysis of advanced meter data are proactively addressed through our program of works. Supply impact studies and performance standards applied to customer installations are key preventative measures to maintain quality of supply across all of its dimensions.

The trend in customer feedback received in relation to over and under voltages is presented in Table 6-10. Where identified, we study these limitations and apply corrective action (if appropriate).

Table 6-10: Customer feedback on over and under voltages

Category	2018–19	2019–20	2020–21	2021–22	2022-23	2023-24
Over voltage	31	32	31	18	7	9
Under voltage	42	18	8	6	9	9
Total	73	51	39	24	16	18

Appendices

Appendix A Regulatory framework and planning process

This appendix outlines the National and jurisdictional frameworks under which TasNetworks plans the Tasmanian transmission and distribution systems. These frameworks include the integrated planning process, our asset management strategy, planning considerations and technical analysis - including demand forecasting.

The transition of the National Energy Market (**NEM**) to a lower emission generation mix is complex and multifaceted. Renewable generation needs to connect to the electricity network in a way that is coordinated and minimises costly augmentation of the transmission network. The transition of the NEM will continue to pose challenges and TasNetworks will continue to advocate for regulatory outcomes that will benefit all Tasmanians.

Sections A.6 and A.7 show how TasNetworks is using the regulatory environment to help customers identify cost-effective demand management solutions and connect embedded generation. Outlined is our demand management assessment process and common issues faced by the connection of embedded generation.

A.1. Regulatory framework

TasNetworks operates under both State and national regulatory regimes. As a registered participant in the NEM, TasNetworks is required to develop, operate and maintain the electricity supply system in accordance with the National Electricity Rules (**the Rules**), including the technical requirements of Schedule 5.1 System Standards. In addition, there are local requirements we must comply with under the terms of our licences, that are issued by the Office of the Tasmanian Economic Regulator (**OTTER**) under the *Electricity Supply Industry Act 1995*. TasNetworks is also subject to a number of other Acts and industry-specific regulations in planning our networks. These include:

- the *Electricity Supply Industry (Network Planning Requirements) Regulations 2018;*
- the Tasmanian Electricity Code (**the Code**); and
- a number of environmental, cultural, land use planning and other acts.

The revenue TasNetworks can recover from customers for the provision of prescribed transmission services and distribution network services in Tasmania is regulated by the Australian Energy Regulator (**AER**).

A.1.1. Tasmanian Electricity Code

The Code is published and maintained by OTTER.[82] It contains arrangements for the regulation of Tasmania's electricity supply industry in addition to those in the Rules. The Code largely relates to the operation of the distribution network. It contains technical standards for power quality, standards of service for embedded generators and distribution network reliability standards.

A.1.2. Revenue determination

As a monopoly provider of transmission and distribution network services, the revenue TasNetworks earns from its customers is determined by the AER. In setting TasNetworks' revenue allowances, the AER expects TasNetworks to improve its efficiency by reducing the costs of the services we provide, while maintaining or improving the quality and reliability of its services.

This regulation exists primarily to protect electricity customers by ensuring specific performance standards are met and capping revenues based on efficient costs - which are forecast, benchmarked and scrutinised by the AER before each regulatory period (usually five years).

The most recent determinations for TasNetworks were made by the AER in April 2024[83] for the 2024–2029 regulatory period. This revenue determination, together with the efficiencies achieved by TasNetworks since it took over running Tasmania's transmission and distribution networks in 2014, will help keep downward pressure on the delivered cost of electricity in Tasmania, while ensuring we have the resources needed to maintain a safe and reliable network. The capital expenditure program for network services in our revenue determination included many of the proposed investments identified in this APR.

82 https://www.economicregulator.tas.gov.au/electricity/regulatory-framework/codes/tasmanian-electricity-code-background

83 TasNetworks - Determination 2024–29 | Australian Energy Regulator (AER)

A.2. Integrated planning

TasNetworks is responsible for planning the future of the electricity transmission and distribution networks in Tasmania. This includes ensuring the networks remain safe and reliable, comply with relevant laws, the Rules, good electricity industry practice and other standards, and that they remain adequate to accommodate changes in both generation and load. We also identify network augmentations, and non-network alternatives, that will provide net economic benefit to all customers in the NEM. This is achieved through our network planning process, which ensures the solutions implemented by TasNetworks balance both the economic and technical requirements of customers and the network.

TasNetworks' annual planning process is informed by a number of strategies, including:

- TasNetworks' Transformation Roadmap 2025 and strategy to 2030, which ensure that we adapt to the changing operating environment and continue to provide cost-effective services to our customers. (An overview of TasNetworks' 2025 roadmap and 2030 strategy is presented in Section 1.6);
- TasNetworks' network reliability strategy, which aims to at least maintain current overall network reliability while reducing total outage costs;
- TasNetworks' asset management strategy, under which the replacement of transmission and distribution assets is based on asset condition and risk, rather than age; and
- TasNetworks' embedded generation connection and non-network and stand-alone power systems assessments that look to maximise benefits for our customers through the use of new technology.

A.2.1. The network planning process

We consider transmission and distribution planning as an integrated function, planning for one electricity network. Our network planning process aims to identify what changes to the electricity network will be required in future years in response to a number of factors:

- new generation, including embedded generators, may be constructed, or old ones removed from service. These changes influence where electricity flows in a network;
- as network equipment ages and its condition deteriorates, it becomes more likely to fail. We investigate whether it is best to continue maintenance, replace, or if it may be possible to decommission and use alternative parts of the network, or implement non-network solutions;
- electricity demand can change. For example, the existing network may not have sufficient capacity to supply additional electricity to a rapidly expanding suburban area. Or there may be a general overall increase – or decrease – in the amount of electricity used per household. A new large load, such as a data centre, or closure of large load, such as a mine, will also cause changes in electricity demand; and
- technological changes impact the network. Historically, residential customers only used electricity. Now with photovoltaic (**PV**) and battery storage technology, our customers are producing and storing electricity – and supplying into the network. This affects the way we plan and operate the network.

As part of our planning process, we consider the transmission and distribution network requirements with our customer and stakeholder requirements. The network planning process is ongoing and while the APR is a view at a particular point in time, the planning environment is dynamic and plans can and do adjust with changing circumstances.

From this, we create 15-year network strategies that inform the network limitations and developments included in our APR for a 10-year timeframe. As our annual planning review is for 15 years, we can revise our plans if forecast generation and load changes, or other factors change or do not eventuate.

We also identify the changes in the network that may be required in the long term (beyond 15 years), from different generation and load scenarios. From this, we ensure our development plans can accommodate a range of possible futures for the network and customers.

A.2.2. Annual planning review

We perform an annual planning review to identify and report on existing and future limitations in our network. A summary of the outcomes from our annual planning review forms the basis of our APR. Our APR presents the foreseeable network needs, the potential options to resolve them, and–where a particular option looks favourable–the likely cost and timing of that option. It is a summary of how things appear now. Because network planning is a recurring process, we may find the expected needs change from one year to the next–some proposed network changes may not be required, others may be required sooner.

The network planning process followed by the annual review is presented in Figure A-1 and outlined in the following sections.

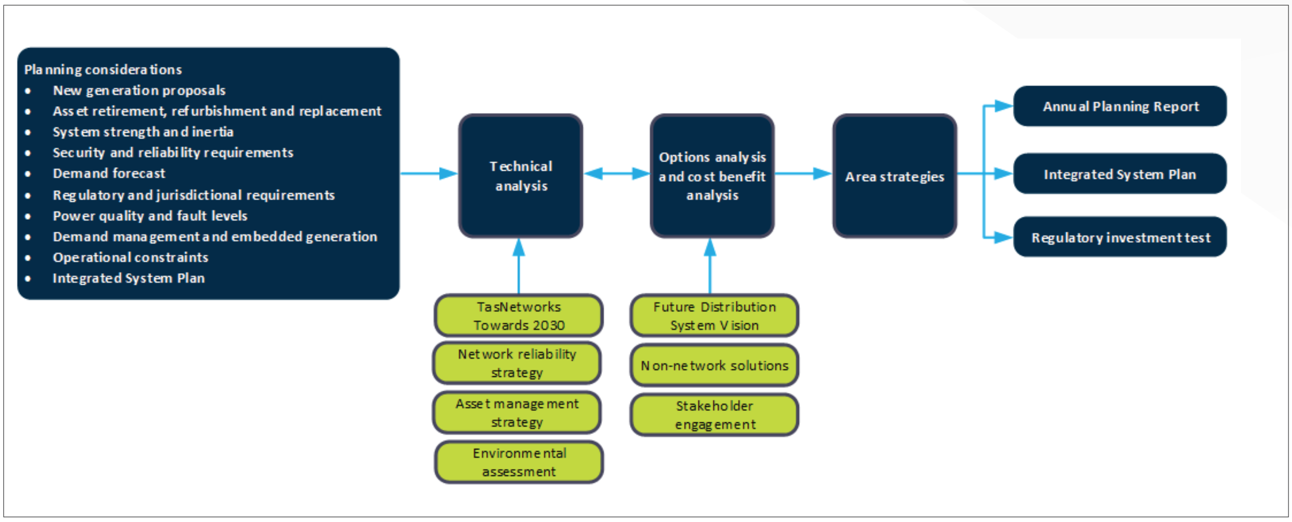


Figure A-1: The network planning process

A.3. Planning considerations and technical analysis

There are a number of planning considerations incorporated into our annual planning review. These include forecast factors that can change from year to year such as generation and demand changes and asset condition assessments, and planning and operation requirements that tend to remain constant against which we assess generation and load changes.

We become aware of new or changed generation developments through our connection process, and publicly announced information. We develop our demand forecasts for planning areas, zone substations, and sub-transmission and distribution feeders of the network from the Australian Energy Market Operator's (**AEMO**) Tasmanian regional forecast.

The power system is modelled to identify where the network will no longer be adequate with the planning considerations assessed. This includes where assets are planned to be retired due to condition and other issues. Limitations relate not only to the design capacity of equipment, but also to other regulations that dictate how the network must perform in the event of a fault.

Sensitivity analysis is conducted where a future network limitation is identified and where a change in the input assumptions may have a material impact on the timing or severity of the limitation occurring. We consult with our customers in accordance with our customer engagement policies, and including this APR, on the risk (probability and impact) associated with the limitation. The sensitivity analysis and consultation are key inputs into our decision of what solution, if any, is required and the optimal timing to implement it.

A.3.1. National Electricity Rules Schedule 5.1

Schedule 5.1 of the Rules describes the planning, design and operating criteria that must be applied by network service providers to the networks which they own, operate or control.[84] These criteria are quantitative and relate to electrical characteristics such as: voltage limits, voltage unbalance, short-term voltage fluctuations, harmonic voltage limits, protection operation times and power system stability.

A.3.2. Demand forecasts

The demand forecast is a key component of our network area planning process. We use the demand forecast to identify the timing of capacity and other technical limitations in the network. We plan our network to 50% probability of exceedance (**POE**) forecasts, for both winter and summer maximum demands. We conduct sensitivity analysis to determine the impact a change in the demand forecast may have on the timing of a limitation, its severity, or the preferred solution for addressing it.

Moderate forecast demand increases are expected across Tasmania over the medium to long term from increased residential consumption and continued electric vehicle (**EV**) uptake. The demand forecast also captures the effects of international geopolitics, and global economic conditions on the Australian economy. We then develop area and locality forecasts for transmission planning, and for sub-transmission, zone substation, and distribution feeder forecasts for distribution planning.

We also consider the AEMO State level forecast, that is produced as part of the annual electricity statement of opportunities (**ESOO**). The ESOO forecasts are limited to State level, and therefore cannot be used for connection point forecasting; however, they provide some insight into Tasmania's projected demand in the broader context of the NEM.

We use the connection point forecast to produce maximum demand forecasts for zone substations and distribution lines. The forecasts are determined by multiplying the historic demand by the ratio of the forecast maximum demand and the historic maximum demand of the associated transmission-distribution connection point. Post model adjustments are made to these zone substation and distribution line maximum demands to reflect known changes in point loads.

Substations, zone substations and feeder maximum demand forecasts, and substations load profiles are available as downloadable appendices to this APR on our website: **www.tasnetworks.com.au/apr**

84 https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current

A.3.3. Transmission system planning requirements

In planning our transmission network at a planning area level, our main considerations are our jurisdictional network planning requirements and opportunities for developments that provide a market benefit. The jurisdictional network planning requirements are to ensure that the network is planned to withstand credible and certain non-credible contingencies. Market benefit developments may either release lower cost generation or reduce the risk of unserved energy.

In planning the transmission network, we utilise the short-term rating (generally four-hour) for supply and network transformers where appropriate. These ratings depend on cyclic loads, so cannot be used for energy-intensive and continuous loads. We rate our transmission circuits to their seasonal static rating, with our first check for any limitation being how the limit is impacted when applying our dynamic ratings which are used in normal operation of the network.

The Electricity Supply Industry (Network Planning Requirements) Regulations 2018 specify the reliability standards we must use when planning the transmission network.[85] The regulations define the maximum extent of power interruptions following contingency events. They only apply to our transmission network, not our distribution network. They are referred to as "applicable regulatory instruments" under the Rules, being our jurisdictional network planning requirements (and are referred to that in this APR for the transmission network).

Minimum transmission network performance requirements

(1) Power system planning in respect of a relevant transmission system must be such that the system is likely to meet the following network performance requirements:

  (a) in respect of an **intact transmission system** –

    (i) no more than 25 MW of load is to be capable of being interrupted by a **credible contingency event**; and

    (ii) no more than 850 MW of load is to be capable of being interrupted by a **single asset failure**; and

    (iii) load that is interrupted by a **single asset failure** is not to be capable of resulting in a black system; and

    (iv) the unserved energy to load that is interrupted consequent on damage to a **network element** resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time; and

    (v) the unserved energy to load that is interrupted by a **single asset failure** is not to be capable of exceeding 3 000 MWh at any time;

  (b) in respect of a transmission system that is **not an intact transmission system**, the active energy exposed to interruption by a **credible contingency event** is not to be capable of exceeding 18,000 MWh at any time.

(2) The network performance requirements under subregulation (1) constitute the service standards that a Provider must take into account, for the purposes of the Regulatory Investment Test for Transmission (**RIT-T**) in carrying out power system planning in respect of a relevant transmission system.

(3) For the purpose of meeting the requirements under subregulation (1), a Provider may use load shedding –

  (a) to control network load after a **non-credible contingency event**; or

  (b) as specified in a contract, agreement or arrangement entered into by the Provider and a **Transmission Customer**.

(4) For the purpose of calculating unserved energy under subregulation (1), any replacements or repairs undertaken must be taken to not exceed –

  (a) 48 hours to repair a transmission line; or

  (b) 8 days to replace a transformer; or

  (c) 18 days to replace an autotransformer

85 https://www.legislation.tas.gov.au/view/html/inforce/current/sr-2018-002

A **credible contingency** event

Means a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope.

network element

A single identifiable major component of a transmission system or distribution system involving:

(a) an individual transmission or distribution circuit or a phase of that circuit; or

(b) a major item of apparatus or equipment associated with the function or operation of a transmission line, distribution line or an associated substation or switchyard which may include transformers, circuit breakers, synchronous condensers, reactive plant and monitoring equipment and control equipment.

transmission line

A power line that is part of a transmission network.

single asset

(a) one double transmission line circuit that contains 2 three-phase circuits; or

(b) one circuit breaker as defined in Australian Standard AS 1852-441 entitled “International Electrotechnical Vocabulary, Chapter 441 – switchgear, control gear and fuses” published by Standards Australia on 7 June 1985, as amended or substituted from time to time; or

(c) one substation busbar

Single asset failure

means one single incident (**other than a credible contingency event**) that results in the failure of one **single asset** to perform its intended function.

The following provides a perspective on the implications of the transmission network planning requirements as they relate to quantities of load demand.

Damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh

Transmission Line – 300 MWh over 48 hours equates to an average demand of 6.25 MW

Transformer – 300 MWh over 8 days equates to an average demand of 1.56 MW

Single asset failure is not to be capable of exceeding 3 000 MWh

Transmission Line – 3 000 MWh over 48 hours equates to an average demand of 62.5 MW

Circuit Breaker or Busbar – Period of time for calculation is not stipulated; however, circuit breaker and busbar replacements can take extended periods of time – 3 000 MWh over 8 days equates to an average demand of 15.6 MW

These regulations allow for exemptions from the performance requirements, based on consultation with our customers. If all transmission customers – whose supply reliability would be affected by a proposed network augmentation – consider it would not be beneficial, then we must report this in our APR. We are then exempt for five years from undertaking that augmentation and from meeting that network planning requirement. The exemption may end early if the circumstances surrounding the exemption change or if one of the affected transmission customers no longer wishes the exemption to remain.

A.3.4. Distribution System planning requirements

In our sub-transmission and distribution network, our reliability planning requirements are our System Average Interruption Frequency Index **(SAIFI)** and System Average Interruption Duration Index (**SAIDI**) targets under the Code. As part of our strategy to minimise outage impact on reliability, we plan our sub-transmission network and zone substations to firm (N-1) reliability. Switched firm – transferring interrupted load to an alternative supply in a short time – is generally acceptable.

In capacity planning of our distribution lines, we determine their capacity via simulation. We determine the capacity by identifying at what loading any element of the line trunk is at its limit for either thermal capacity or voltage compliance with the Code requirements.

Distribution system planning criteria are associated with augmentation of terminal and zone substations and sub-transmission assets aimed at meeting regional adequacy and security requirements.

Adequacy criteria relate to the capability to meet the demand within network element capacities (ratings), quality of supply limits, fault level, and accessibility expectations.

Security criteria relate to the ability of the power system to cope with incidents without the uncontrolled loss of load.

Security criteria are associated with supply survivability, being the ability to cope with incidents without the uncontrolled loss of load. Survivability comprises three elements:

- susceptibility – ability to avoid incidents (prevent),
- vulnerability – ability to withstand incidents; that is to maintain supply, (minimise) and
- recoverability – ability to restore functionality; that is to restore supply (respond).

Network planning criteria only cover vulnerability and recoverability. Susceptibility is the subject of detailed network element design.

Security network planning criteria are referenced by deterministic N, N-1, N-2 measures and the variants. Security planning philosophy is a conjunction of the deterministic standard as well as a group firm philosophy. The application of this approach allows deferment of major capital investment whilst understanding the level of risk that may result.

Three N-1 standards are applied representing the mechanism by which continuity of supply is maintained:

N-1 (A). Full N-1: Duplicate (parallel) supply at substation busbar (this level of security implies the parallel operation of critical elements under normal circumstances; a momentary outage of duration <60 seconds while automatic switching takes place may be necessary in specific circumstances).

N-1 (B). Remote Switch N-1: Short outage (restoration target ≤30 minutes) may occur while load transfers are undertaken via remote control.

N-1 (C). Manual Switch N-1: Medium outage (restoration target ≤3 hours) may occur while field switching is undertaken to effect load transfers.

N security restoration requires repair or reinstatement. Restoration targets are:

For loss of a substation ≤12 hours

For loss of a sub-transmission line ≤6 hours (loads greater than 5 MVA)

For loss of a sub-transmission line <12 hours (loads less than 5 MVA)

Terminal and zone substation and sub-transmission reliability normally have second order impacts on the overall service reliability. As a consequence, correlation between outcome reliability performance and planning criteria is second order. Thus the planning criteria concern the requirement for:

- transmission terminal substations,
- sub-transmission,
- zone substations, and
- numbers of feeders.

An underlying tenet of the required level of network service is that, with the network in its normal topological state, the network will have sufficient adequacy to meet all network loading demand; that is, no involuntary supply interruptions.

Distribution substation, feeder, and reticulation augmentations are largely required to meet situation-specific drivers with design criteria aimed at meeting quality of supply requirements. The outcome reliability is largely determined by distribution substation, feeder and reticulation performance which, in turn, is largely determined by operation, maintenance and fault response practices.

The service levels are those associated with Clause 8.6.11 of the Code, Interruptions to Supply. In addition to the Code requirements, we are subject to Guaranteed Service Level scheme agreed with OTTER[86] and in combination with other performance measures forms the Service Target Performance Incentive Scheme under the Rules.

Technical performance as required by the Rules and Code are mandated requirements and are not discussed specifically as application of the input reliability planning criteria largely delivers the required quality.

A.4. Asset management strategy

Managing our existing assets and the planning for future network requirements are processes that must be coordinated to deliver the required service levels in the most cost-efficient manner. The asset management strategy focuses on ensuring the repair andreplacement of assets are determined objectively by asset condition and risk, rather than simply age. Our Strategic Asset Management Plan outlines the systems and strategies developed to effectively and efficiently manage the delivery of electricity and telecommunication network services to our customers and to provide information to our stakeholders regarding the environment in which we operate.

Key themes supporting our asset management approach and associated levels of investment are:

- managing our assets to ensure safety and the environment are not compromised;
- maintaining the reliability of the network;
- where we can safely do so, running our network harder rather than building more;
- responding to the changing nature of customer behaviours and requirements by participating in trials;
- taking a whole of life (life cycle) approach to optimise cost and service outcomes for our customers;
- working hard to ensure we deliver the lowest sustainable prices; and
- understanding how we manage our assets with the changing use of our network from initiatives such as Marinus Link, AEMO's Integrated System Plan (**ISP**) and Battery of the Nation.

Our approach centres on asset life cycle management extending over five phases, as presented in Figure A-2.

Each phase of the life cycle has a corresponding life cycle strategy detailing our objectives and approach to the particular activities in that phase to ensure performance to required levels.

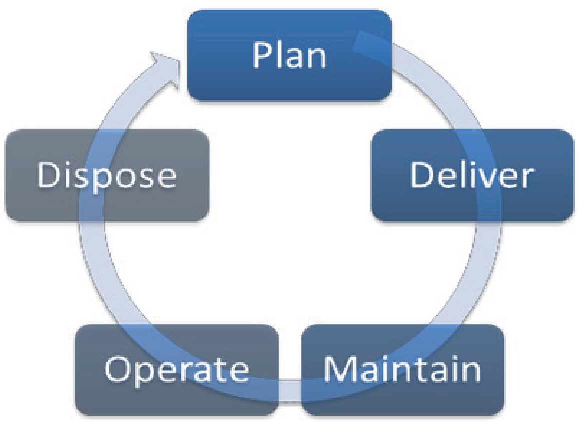


Figure A-2: Asset life cycle management

86 Guideline Guaranteed Service Level Scheme July 2012 https://www.economicregulator.tas.gov.au/electricity/regulatory-framework/guidelines

Most of our asset management activities are managed at an asset category level. The strategies for each asset category are contained in Asset Management Plans. These plans identify the performance and risks presented by each asset type within the category and define actions that must be undertaken to sustain asset and system performance. These actions can take the form of particular asset-based decision methods and include:

- age-based risk management;
- condition-based risk management;
- criticality- based risk management (current risk);
- mitigated risk-based management (reliability);
- optimisation of investment value (value Based); and
- run to failure.

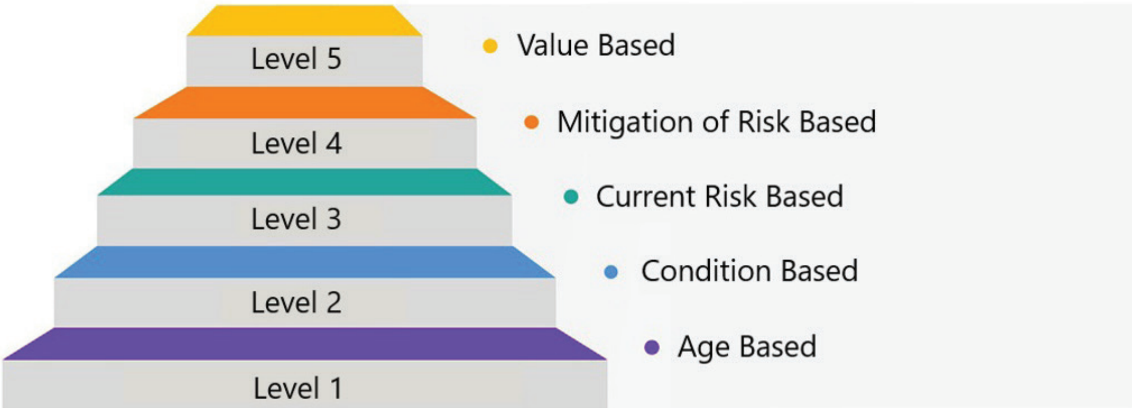


Figure A-3: Asset management decision making hierarchy

Our Strategic Asset Management Plan and Asset Management Policy are available on request.

A.5. Options and cost-benefit analysis

When we find network changes are required, we identify the possible options to address the need. Options could include expansion of the network, working with customers to reduce their energy or demand to defer the need, or other options. Only options that are economic and will meet the current and future needs of the network and customers are considered. We determine the advantages and disadvantages of each option and investigate each one in detail to confirm its feasibility. For feasible options, we estimate the cost and the potential economic benefits (for example, there may be an economic benefit in averting or reducing the loss of supply to a particular area) to identify the preferred solution.

Upon identification of a preferred solution, we consult with affected customers to confirm if there is sufficient benefit in proceeding.

A.5.1. Regulatory investment test

The regulatory investment test (**RIT**) defines the economic analysis and public consultation process a network service provider must undertake in selecting an option to address a need in the power system.

The RIT and application guidelines are published by the AER under clause 5.16 (transmission) and clause 5.17 (distribution) of the Rules. As a transmission and distribution network service provider, we are required to apply the test for all transmission (RIT-T) and distribution (RIT-D) projects that exceed the RIT expenditure thresholds. Some projects are exempt from the RIT, for example those that are in response to a customer's connection application.

A.5.2. Accounting for network losses

Network losses are electrical energy (active energy) losses incurred in transporting electricity over transmission and distribution networks. Electrical energy losses can be classified as:

- technical losses comprising:
  - series losses associated with the flow of electricity and the resistance of the electricity circuits; and
  - shunt losses which is "leakage" of electrical energy associated with "charging up" or "excitation" of the network and occur regardless of the amount of electrical power flowing through the network.
- non-technical losses due to metering data errors, un-metered supplies, unbilled customers, information system deficiencies, modelling assumptions and theft.

Each financial year we calculate distribution loss factors (**DLFs**)[87] that describe the average electrical energy lost in transporting electricity from a transmission network connection point (or virtual transmission node) to a distribution customer connection. These loss factors account for both technical and non-technical losses. AEMO uses these DLFs in market settlements to calculate the electrical energy attributed to each retailer at each transmission network connection point.

Similarly, AEMO calculates forward-looking transmission loss factors to facilitate efficient scheduling and settlement processes in the NEM.[88]

As losses impact the price of electricity, they are an important consideration when developing and implementing asset management and investment strategies. Loss management is an optimisation between cost of infrastructure and loss reduction and the management of quality of supply and electricity flows across the network. Losses are a consideration in the regulatory investment test in calculating the costs and benefits associated the economic justification of projects at both transmission and distribution levels.

A.6. Non-network and Stand Alone Power Systems assessments

We consider Stand Alone Power Systems (**SAPS**) and other non-network opportunities during the planning cycle when investigating solutions to network limitations, with particular focus on the distribution network. To that end, we have developed an Industry Engagement Strategy[89] that explains how we will engage and consult with our customers and suppliers to deliver solutions for our distribution network. We encourage non-network and SAPS resource providers to register with us on our website.[90]

An early analysis of possible solutions is completed at a high level and includes desktop studies, site visits and discussions with our customers and providers. The assessment of solutions comprises four stages and involves analysis of the costs, benefits, and risks of each option.

Stage 1: Investigation

We investigate the network issue and assess network, non-network, and SAPS options to solve it. If either a non-network or SAPS option is credible, we determine the economic benefit provided by deferring or avoiding any network solution.

Stage 2: Development

We then compare the non-network or SAPS options against network options and evaluate for cost, risk, and potential benefits. During this stage, if a non-network or SAPS project is subject to the regulatory investment test, we publish an options screening report (for distribution projects) or project specification consultation report (for transmission projects). The information enables proponents to assess their options.

Stage 3: Assessment

We ask for proposals from our customers and demand management providers to address an issue. These are evaluated against conventional project implementation criteria and costs and benefits.

87 https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Planning-our-network

88 http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

89 https://www.tasnetworks.com.au/Forms/Industry-Engagement-Register/Industry-Engagement

90 https://www.tasnetworks.com.au/Forms/Demand-Management-Industry-Engagement-Register

Stage 4: Reporting

All enquiries and proposals receive a written response and interested parties are advised of the status of their assessment at regular intervals. We publish the initial results in a draft project assessment report and allow our customers and providers to provide feedback. We consider feedback and then publish a final report for the preferred solution and the reason for its selection.

A.7. Connecting embedded generation

Connecting generation can be a complex process with electricians or retailers able to provide assistance with the process and determining the appropriate connection type. As part of the embedded generation connection process[91] TasNetworks is required to provide information on every Distributed Energy Resource (**DER**) connected to the distribution network to AEMO to feed into their DER Register.[92,93] 'As-built' information is a mandatory step in the application process prior to TasNetworks completing a connection.

A.7.1. Synchronous generators

Synchronous generators (rotating machines) can pose risks to other network users (and the synchronous generator) during islanding-type faults. An "island" is a situation where part of our network, which contains a generator, becomes disconnected from the remainder of our network. Should that generator continue to operate, the islanded part of our network will still be live, with possibly minimal control over the voltage and frequency unless operating as a dedicated microgrid. This would pose a danger to our people, customers, and electrical equipment. It is therefore necessary to ensure embedded generators are equipped with anti-islanding protection devices.[94] In addition to local anti-islanding protection devices, a telecommunications based anti-islanding inter-trip[95] may be required to ensure any generation is disconnected upon detection of an island.

We must approve the anti-islanding protection of the synchronous generator before network connection. Similarly, the nature of synchronous generation is that they cannot be re-connected to the network without firstly ensuring that conditions are suitable for them to do so. It is customary to have automatic reclose schemes on distribution feeders that can quickly restore supply. Before these schemes can restore supply, all sources of generation must be disconnected from the network. Sudden disconnection of distribution connected synchronous generation can lead to unacceptable reductions in local network voltage. In such circumstances, appropriate voltage control schemes approved by us will be required.

A.7.2. Asynchronous generators

Asynchronous generators connecting to our network are mainly inverter based systems, which use power electronics to convert electrical power from either direct current, or a variable frequency alternating current (**AC**) waveform, to a 50 Hz AC supply which allows connection to the main network.

There are both network-wide and local issues associated with PV installations. From a network-wide perspective, and for maintenance of power system security, it is important PV installations remain connected following frequency disturbances. This is a major issue because:

- being a relatively small power system, frequency disturbances are relatively common; and
- our operational frequency bands are wider than mainland Australia.

Disconnection of a high proportion of PV installations during a low-frequency disturbance would magnify the frequency excursion, which could lead to unanticipated load tripping. In the worst case, this could occur in response to even a single contingency event, which would be unacceptable for our customers and contravene the Rules.

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91 https://www.tasnetworks.com.au/embedded-generation

92 https://aemo.com.au/energy-systems/electricity/der-register

93 https://www.tasnetworks.com.au/connections/distributed-energy-resource-register

94 An anti-islanding protection device will cause the generator to shut down should its part of the network become disconnected from the rest of the network. All compliant grid-connected PV inverters are designed with anti-islanding protection

95 Local anti-islanding protection devices may not always detect an island situation. A telecommunications based inter-trip will ensure that generation will be disconnected by monitoring the status of the connecting distribution equipment.

High penetration of PV along with other asynchronous generation can result in reduction in system strength required to maintain a stable power system. As outlined in Section 5.2.2, a power system fault level framework sets out clear allocation of roles and responsibilities for AEMO and Network Service Providers in the management of system strength. It requires transmission network service providers (**TNSPs**) to procure system strength services needed to provide the levels determined by AEMO.

Local issues mainly relate to voltage regulation in our distribution network. Unlike mainland jurisdictions, in Tasmania PV contributes very little to reducing the maximum demand on the network. Maximum PV output usually occurs in the middle of the day in summer when solar radiation is highest. Maximum demand in Tasmania occurs during early mornings or evenings in winter, when there is virtually zero contribution from PV. Essentially, PV penetration further depresses the summer minimum load and a number of low-voltage circuits are becoming net generators with the result that voltages can rise to unacceptable levels.

A.8. Incentive schemes

As part of the regulatory framework, both the AER and OTTER apply a number of incentive schemes to encourage network service providers to make efficient spending decisions in the long-term interests of customers. Balanced incentives are designed to encourage businesses to continually improve spending efficiency without compromising network service and performance.

Most incentives are recovered through adjustments to our revenue allowances determined by the AER. Depending on the incentive scheme, these adjustments to TasNetworks' revenue are passed through to customers via annual increases or decreases in network charges, or as part of the AER's revenue setting process.

A.8.1. Service Target Performance Incentive Schemes

The Service Target Performance Incentive Schemes (**STPIS**) for transmission and distribution networks provide financial rewards to network businesses for improvements in performance, which are largely measured in terms of the frequency and duration of supply interruptions. Financial penalties are applied for reductions in performance.

The STPIS for transmission comprises three components: a service component, a market impact component and a network capability component. The STPIS for distribution has two components: reliability of supply and customer service, with customer service being assessed in terms of TasNetworks' performance in answering calls to its electrical emergency and outages call centre. For the 2024–2029 regulatory control period, TasNetworks, with approval from the AER, will replace the STPIS component applying to the answering of calls to its customer service centre with the Customer Service Incentive Scheme (**CSIS**) described in section A.8.3.

A.8.2. Guaranteed Service Level Scheme

TasNetworks' is subject to a guaranteed service level (**GSL**) scheme administered by OTTER. The purpose of the scheme is to ensure customers throughout Tasmania receive at least a minimum level of network reliability. Where the number of outages or the cumulative duration of outages experienced by a customer over a rolling 12month period exceeds the maximum number or duration of outages set under the Code, affected customers are entitled to a payment from TasNetworks. Under the Code, the State is divided into 121 geographical communities, with each community assigned to one of five reliability categories and different reliability standards applying to each category.

A.8.3. Customer Service Incentive Scheme

The AER has introduced the CSIS to encourage distribution businesses to improve the aspects of their service delivery that their customers want improved. TasNetworks has consulted with customers to determine the service parameters that best reflect their expectations and the AER has approved a CSIS for the 2024-2029 regulatory period which is based on measurements of:

- customers' satisfaction with TasNetworks' handling of complaints;
- customer satisfaction with TasNetworks' management of outages (both planned and unplanned);and
- customers' satisfaction with TasNetworks' provision of new connections.

A.8.4. Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (**EBSS**) provides financial rewards to network businesses that are able to reduce their operational expenditure (**OPEX**) on regulated services and sustain those savings over time. The EBSS also penalises network businesses that overspend against their OPEX allowance and/or do not sustain previously realised savings. There are separate schemes for transmission and distribution networks which, nonetheless, are based on very similar principles.

The EBSS works on the principle that OPEX in a year "resets" the efficient level of OPEX under the EBSS. Performance is measured against this new EBSS target and the operating allowance that is set as part of a regulatory determination cycle. A network may retain any annual efficiency gain for a period of five years or be penalised for any inefficiency for five years.

A.8.5. Capital Expenditure Sharing Scheme

The capital expenditure sharing scheme (**CESS**) creates an incentive for network businesses to undertake efficient capital expenditure (**CAPEX**) during each regulatory control period. Businesses are rewarded for spending less than their regulatory allowance or penalised for spending over the allowance.

The AER conducts reviews of networks' CAPEX in setting their CAPEX allowances as part of the regulatory determination process, and again at the end of each regulatory control period, to ensure customers do not bear the costs of inefficient spending. CESS bonuses or penalties are taken into account by the AER when calculating the allowed revenue for each network service provider in the next regulatory control period.

A.8.6. Incentives for Demand Management - Distribution

There are two demand management schemes for distribution businesses overseen by the AER. They are the:

- Demand Management Incentive Scheme (**DMIS**); and
- Demand Management Innovation Allowance Mechanism (**DMIAM**).

The DMIS provides distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

The DMIAM provides funding (through an ex-ante allowance) for research and development in demand management projects that have the potential to reduce long term network costs. TasNetworks has previously utilised the DMIAM to fund the development of customer-owned storage as a peak demand management tool and to investigate the potential for demand-based tariffs to be used to reduce peak demand.

A.8.7. Demand Management Innovation Allowance Mechanism - Transmission

For electricity transmission network service providers there is only one demand management related incentive scheme, the Demand Management Innovation Allowance Mechanism (**DMIAM**). The criteria for DMIAM funding is as for the Demand Management Innovation Allowance Mechanism for distribution network service providers, with the addition that demand management projects that also improve wholesale market outcomes should be considered. Transmission network businesses are also required, where requested, to share the results, learnings and insights gained from implementing any projects or programmes that receive funding under the DMIAM. The DMIAM for transmission was published in May 2021, mid-way through TasNetworks' 2019-2024 regulatory control period, and so will apply in Tasmania for the first time in the 2024-2029 regulatory control period.

Appendix B Generator information

Table B-1 lists the Tasmanian generators connected to the transmission network.[96] It includes committed generation developments.

Table B-1: Transmission-connected generation

Generator	Capacity (MW)	TasNetworks planning area	Connection to shared network
Gas			
Tamar Valley	386	Northern	George Town
Hydro			
Butlers Gorge and Nieterana[97]	14.9	Central	Butlers Gorge Tee
Catagunya	50		Liapootah
Cluny	19.7		Liapootah–Chapel Street 220 kV
Gordon	450		Gordon
Lake Echo	33.5		Tungatinah–Waddamana 110 kV
Liapootah	87.3		Liapootah
Meadowbank	43.8		Meadowbank
Repulse	29.1		Liapootah–Chapel Street 220 kV
Tarraleah	93.6		Tungatinah
Tungatinah	142.2		Tungatinah
Wayatinah	45		Liapootah
Poatina	363	Northern	Palmerston
Trevallyn	102.8		Trevallyn
Cethana	100	North West and West Coast	Sheffield
Devils Gate	63		
Fisher	46		
Lemonthyme	54		
Rowallan	11		
Wilmot	32		
Paloona	31.5		Sheffield–Ulverstone 110 kV
Bastyan	81		Farrell
John Butters	145		
Mackintosh	89		
Reece	244		
Tribute	92		
Wind			
Wild Cattle Hill	148	Central	Waddamana
Musselroe	168	Northern	Derby

96 Capacity information sourced from:

- https://www.hydro.com.au/clean-energy/our-power-stations
- http://www.cattlehillwindfarm.com/
- https://granvilleharbourwindfarm.com.au/

97 Nieterana is a mini-hydro power station, which is connected to Butlers Gorge Power Station. The total power generated by Butlers Gorge (capacity 12.7 MW) and Nieterana (2.2 MW) flows through this connection point to the network.

Generator	Capacity (MW)	TasNetworks planning area	Connection to shared network
Bluff Point	65	North West and West Coast	Smithton
Studland Bay	75		
Granville Harbour	112		Farrell

Table B-2 lists the embedded generation sites within the distribution network. Hydro Tasmania also operates two power stations, Upper Lake Margaret Power Station (8.3 MW) and Lower Lake Margaret mini-hydro (3.2 MW) that are connected to the switchboard at Mt Lyell copper mine. These are not classified as embedded generation as they are not connected within the distribution network, however may export to the transmission network.

Table B-2: Embedded generation over 0.5 MW

Location	Source	Capacity (MW)	Export (MW)	TasNetworks planning area	Connecting distribution line
Maydena	Hydro	0.56	0.56	Central	New Norfolk 39571
Tods Corner	Hydro	1.7	1.7		Arthurs Lake 49101
Ouse	Hydro	1.0	1.0		Wayatinah 49412
Derby	Hydro	1.12	1.12	Northern	Derby 55001
Herrick	Hydro	0.9	0.9		Derby 55002
Launceston	Natural gas	2.0	2.0		Trevallyn 61026
Mowbray	Biomass	2.2	1.1		Mowbray 62006
Tunbridge	Hydro	5.0	4.9		Avoca 56004
Little Fisher	Hydro	0.8	0.8	North West and West Coast	Railton 85001
Meander	Hydro	1.9	1.9		Railton 85006
Nietta	Hydro	0.9	0.9		Ulverstone 82004
Parangana Lake	Hydro	0.78	0.78		Railton 85001
Quoiba	Solar	0.51	0.51		Devonport 80011
Ulverstone	Natural gas	7.9	2.0		Ulverstone 82006
Woolnorth	Wind	0.6	0.55		Smithton 93005
Wynyard	Natural gas	2.0	0.0		Burnie 91004
Glenorchy	Biomass	1.7	1.5	Southern	Chapel Street 20551
South Hobart	Biomass	1.1	1.1		West Hobart 13045
Copping	Biomass	1.1	1.1		Sorell 41515

Appendix C Distribution network reliability performance measures and results

Historical distribution reliability performance is presented in this section. This is supporting information for the discussion in Section 6.4.1. The information presented here is our performance against the standards set out in the Tasmanian Electricity Code (**the Code**) and by the Australian Energy Market Operator (**AER**) over the last five years.

C.1. Performance against the Code standards

C.1.1. Supply reliability categories

Table C-1 and Table C-2 present our performance for reliability categories for system average interruption frequency index (**SAIFI**) and system average interruption duration index (**SAIDI**), respectively, against the standards specified in the Code. The performance presented here is what we provide to the Office of the Tasmanian Economic Regulator (**OTTER**) as part of our normal reporting process. The standards exclude outages on major event days; total fire ban day related outages, transmission network outages, fire and certain third party outages.

Table C-1: SAIFI supply reliability category performance (the Code)

Supply reliability category	Standard (interruptions)	2018–19	2019–20	2020-21	2021-22	2022-23	2023-24
Critical infrastructure	0.2	0.14	0.25	0.15	0.27	0.12	0.20
High density commercial	1	0.41	0.33	0.46	0.74	0.34	0.74
Urban and regional centres	2	1.25	1.28	1.42	1.19	1.14	1.30
High density rural	4	2.39	2.55	2.30	2.80	2.84	2.87
Low density rural	6	3.37	3.26	3.23	4.21	3.79	3.94

Table C-2: SAIDI supply reliability category performance (the Code)

Supply reliability category	Standard (minutes)	2018–19	2019–20	2020-21	2021-22	2022-23	2023-24
Critical infrastructure	30	40.90	26.62	15.10	69.76	27.84	50.04
High density commercial	60	49.66	55.62	62.04	86.31	42.87	72.42
Urban and regional centres	120	138.38	148.50	182.89	161.10	125.64	148.16
High density rural	480	291.35	321.20	309.57	503.94	342.49	366.91
Low density rural	600	527.03	544.40	549.10	1130.70	535.78	611.23

C.1.2. Supply reliability communities

In addition to performance requirements for supply reliability categories presented in Section C.1.1, the Code also sets performance standards for the supply reliability communities within the categories.

Table C-3 and Table C-4 present our performance for the 101 supply reliability communities against the SAIFI and SAIDI standards, respectively. The tables present the standards specified in the Code for each community across the five categories, and the number of communities in each category that is not meeting the standard.

Table C-3: Number of poor performing communities (SAIFI)

Supply reliability category (number of communities)	Standard (interruptions)	2019–20	2020-21	2021-22	2022-23	2023-24
Critical infrastructure (1)	0.2	1	0	1	0	0
High density commercial (8)	2	1	0	0	0	0
Urban and regional centres (32)	4	2	2	2	3	2
High density rural (33)	6	1	1	3	5	0
Low density rural (27)	8	1	0	2	0	1
Total (101)		**6**	**6**	**3**	**8**	**3**

Table C-4: Number of poor performing communities (SAIDI)

Supply reliability category (number of communities)	Standard (minutes)	2019–20	2020-21	2021-22	2022-23	2023-24
Critical infrastructure (1)	30	1	0	1	0	1
High density commercial (8)	120	2	2	2	1	1
Urban and regional centres (32)	240	11	10	11	7	9
High density rural (33)	600	4	3	10	6	9
Low density rural (27)	720	8	6	12	6	8
Total (101)		**19**	**26**	**21**	**36**	**28**

C.2. Performance against AER targets

C.2.1. Reliability of supply

At the commencement of each distribution regulatory period, the AER, as part of our revenue determination, sets standards for distribution network reliability. These standards form part of our Service Target Performance Incentive Scheme (**STPIS**) and are calculated on our actual performance for the preceding five years. The targets set by the AER exclude planned outages, major event days, total fire ban day related outages, transmission network outages, fire and certain third party outages.

Table C-5 and Table C-6 present our performance for reliability categories for SAIFI and SAIDI, respectively, against the standards specified by the AER.

Table C-5: SAIFI supply reliability category performance (AER)

Regulatory period				2019–24		
Supply reliability category	**Target**	**2019–20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**
Critical infrastructure	0.251	0.168	0.104	0.051	0.015	0.019
High density commercial	0.26	0.274	0.349	0.655	0.297	0.649
Urban and regional centres	1.081	1.074	1.186	1.019	0.948	1.114
High density rural	2.466	2.358	2.056	2.278	2.51	2.560
Low density rural	3.219	2.892	2.773	3.452	3.438	3.479

Table C-6: SAIDI supply reliability category performance (AER)

Regulatory period				2019–24		
Supply reliability category	**Target**	**2019–20**	**2020–21**	**2021-22**	**2022-23**	**2023-24**
Critical infrastructure	32.984	11.16	7.31	3.418	2.018	4.713
High density commercial	20.074	43.704	28.895	56.993	27.971	57.787
Urban and regional centres	89.657	90.638	107.493	96.858	75.236	98.106
High density rural	250.959	250.665	215.617	279.612	256.752	271.564
Low density rural	400.401	390.294	360.762	468.122	436.126	475.141

C.2.2. Customer service

As part of the AER's distribution STPIS and OTTER regulatory reporting requirements, we report on customer service performance in terms of a telephone answering parameter, Table C-7. This parameter is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

Table C-7: Customer service performance

Telephone answering	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Number of calls	37,433	31,402	21,943	32,582	26,371	28,909
Number of calls answered in 30 seconds	31,236	27,537	17,027	25,804	23,562	24,591
Percentage of calls answered within 30 seconds (%)	83.45	87.69	77.60	79.1	89.3	85.06
Performance target (%)	76.30	76.30	76.30	76.30	76.30	76.30

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