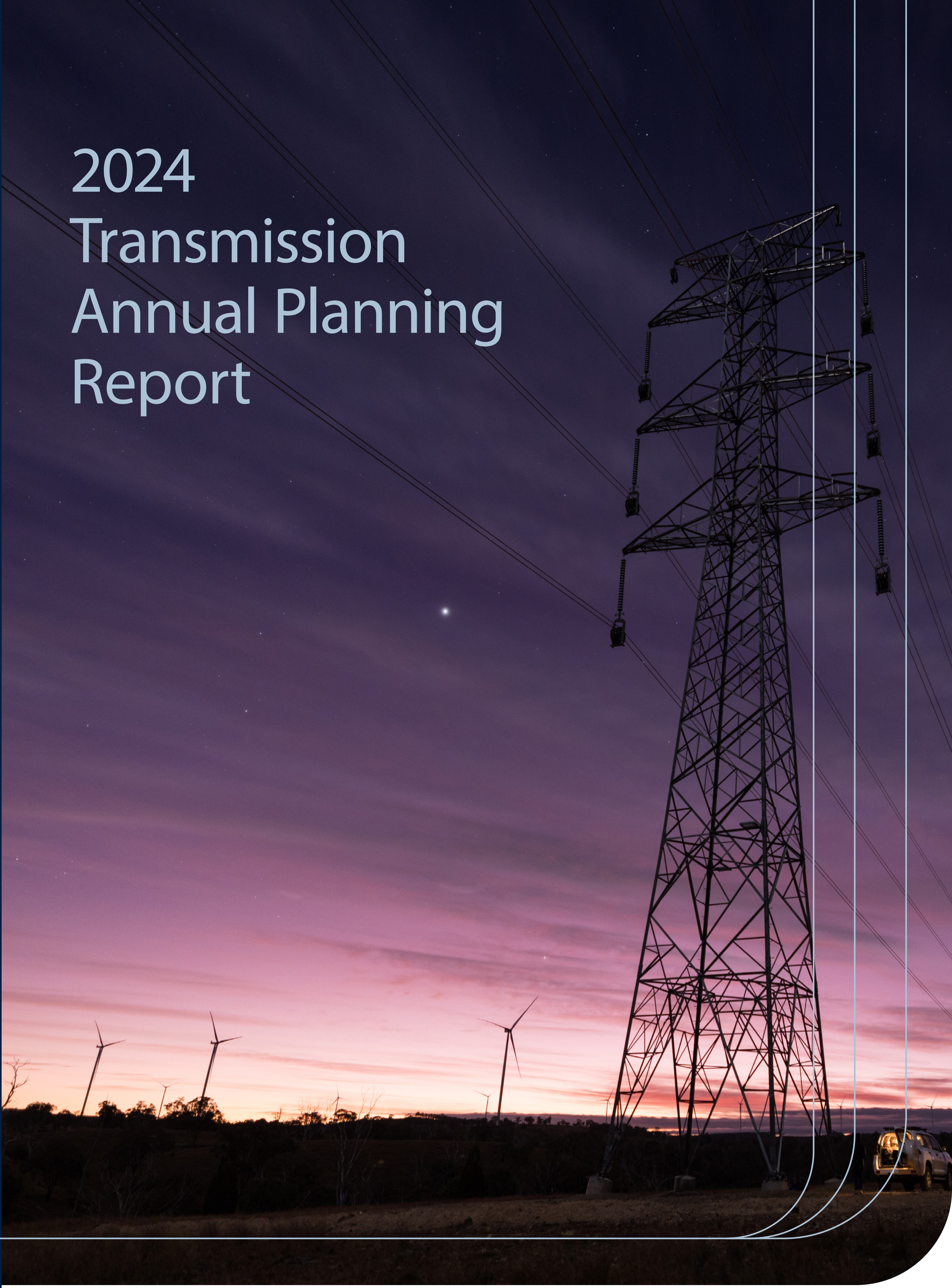
# 2024 Transmission Annual Planning Report



Please direct Transmission Annual Planning Report enquiries to:

Dr Stewart Bell
Executive General Manager
Network and Business Development Division
Powerlink Queensland

Telephone: +61 7 3860 2111
Email: NetworkAssessments@powerlink.com.au

# About Powerlink

## Our network

- 1,700km north of Cairns to NSW border
- 2 completed Renewable Energy Zones
- 9,429MW max demand
- 2,389MW min demand

## Customer connections

- 22 solar and wind projects in operation at 3,155MW
- Over 2GW of wind and solar generation under construction
- 50 enquiries and 34 connection applications during 2023/24

## Consultation

- Customer Panel
- Gladstone Project and SuperGrid webinars during 2023/24
- Transmission Network Forum
- Completed 33 regulatory consultations since 2018

## Our people and the community

- Work across the state of Queensland with hubs in Townsville, Gladstone and Brisbane
- Ensuring a safe and reliable supply to communities
- Committed to better energy outcomes through the Energy Charter
- Providing support to landholders under the SuperGrid Landholder Payment Framework

Powerlink acknowledges the Traditional Owners and their custodianship of the lands and waters of Queensland and in particular, the lands on which we operate. We pay our respect to their Ancestors, Elders and knowledge holders and recognise their deep history and on-going connection to Country.

*Artwork by Aaliyah Chambers and Gabriel Pilkington*

*My name is Aaliyah Chambers. I am a proud Aboriginal woman born in Brisbane, Queensland. My name is Gabriel Pilkington. I am a proud Aboriginal man born in Perth, Western Australia and living in Brisbane, Queensland. I have been painting since I was a young kid. I am in collaboration with my partner, Aaliyah and we have created this painting for the Powerlink Reconciliation Action Plan (RAP) project to represent our vision of Brisbane and surrounding areas in all of its beauty.*

# Foreword

'Welcome to Queensland!'

The transformation of Queensland's electricity industry to clean, renewable energy continued at pace in 2023/24. Since the release of the Queensland Energy and Jobs Plan (QEJP) and Queensland SuperGrid Infrastructure Blueprint in 2022, and key enabling legislation earlier this year, Powerlink has seen increased interest in renewable generation and storage investment proposals, with over 67GW at the enquiry and application stage. Similarly, there is over 10GW of electrification of existing loads and new loads wanting to connect in Queensland.

*Benefiting Queenslanders by optimising planning and investment opportunities*

Powerlink has an unprecedented opportunity to leverage off multiple investment pathways, such as the Queensland SuperGrid Infrastructure Blueprint (to be updated in 2025), planning the regulated shared network and through the connection of non-regulated renewable energy and firming projects. With communities front of mind, the co-ordinated, optimised and least-regret planning of all three investment pathways will deliver the transmission network of the future that is needed to provide clean, affordable and reliable electricity to Queenslanders.

*Building the SuperGrid and realising Renewable Energy Zones (REZ)*

As a key component of the energy transformation, the Queensland SuperGrid is a new high capacity transmission backbone to enable the efficient transportation and storage of renewable energy across the state, starting in southern Queensland, extending to central Queensland and then Townsville, with a final stage to Hughenden as part of the CopperString 2032 project. Recent market information indicates greater benefits can be achieved through construction of a transmission line along a more inland route than originally proposed, allowing for connection to be built in stages at a lower capacity initially, and paced to align with interest from renewable energy proponents which will deliver cost savings through investment deferral.

As the recently appointed REZ Delivery Body for Queensland, Powerlink will make recommendations which identify suitable areas of Queensland for REZs. Genuine and transparent engagement with communities to prepare and develop REZ Management Plans will support the optimisation of renewable generation projects located within REZs.

REZ delivery is well underway with the Far North REZ commissioned in July 2024, energisation of the Southern Downs REZ, and the near completion of construction of the Western Downs REZ. Powerlink is currently investigating the potential for the development of the next three REZs with developers.

*Identifying opportunities in a dynamic external environment*

Queensland has abundant renewable resources, and solar and wind projects specifically, to deliver cost-effective generation solutions. Powerlink is focussed on delivering strategies which will ensure electricity customers receive cost effective and efficient services.

Implementing innovative solutions and leveraging digital technologies will continue to be central to Powerlink enabling the transformation. This includes shared network replacements to ensure reliability for customers, implementing non-network solutions, particularly for system strength to support future grid operation, increasing the capacity of the shared network to reduce congestion by implementing Wide Area Monitoring, Protection and Control systems, and investigating dynamic real-time ratings and Frequency Control and Ancillary Services to facilitate larger REZs.

The Transmission Annual Planning Report presents Powerlink's current view of the development of the Queensland transmission network over the next ten years. No doubt that view will change and evolve as the energy transformation is realised and becomes embedded in the way we plan and develop the transmission network of the future. What won't change is Powerlink's commitment to supporting communities, customers and industry while delivering safe, reliable and cost effective electricity to Queenslanders.

Dr Stewart Bell
Executive General Manager
Network and Business Development
Powerlink Queensland

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# Executive Summary

Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and owns, develops, operates and maintains Queensland's high voltage (HV) transmission network. It has been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB), Renewable Energy Zone (REZ) Delivery Body (RDB) and REZ TNSP responsible for transmission network planning and development within the State.

## About the Transmission Annual Planning Report

Planning and development of the transmission network is integral to Powerlink Queensland meeting its obligations under the National Electricity Rules (NER), Queensland's Electricity Act 1994, its Transmission Authority and the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act).

The Transmission Annual Planning Report (TAPR) is a key part of the planning process and provides stakeholders and customers with important information about the existing and future transmission network in Queensland. The report is targeted at everyone interested or involved in the NEM including the Australian Energy Market Operator (AEMO), Registered Participants and interested parties. The TAPR also provides stakeholders with an overview of Powerlink's planning processes and decision-making on potential future investments.

The 2024 TAPR includes information on electricity energy and demand forecasts, existing and committed generation and outlines the key factors impacting Powerlink's transmission network development and operations. It discusses the energy transformation and how Powerlink is proactively planning and engaging with communities to support the rapidly changing power system while providing a valued service to customers. The TAPR also provides estimates of transmission grid capability and discusses the potential network and non-network developments required in the future to continue to meet electricity demand in a timely manner.

## Overview

Based on Powerlink's 2024 Central scenario forecast reported in this TAPR, the summer maximum demand is expected to grow steadily over the next 10 years, but show further reductions in the minimum delivered demand. The forecast delivered energy from the transmission network over the 10-year outlook period shows a steady increase mainly due to new anticipated loads and electrification of existing loads to meet emission reduction targets.

Powerlink has continued to work closely with the Queensland Government and market participants in developing and actioning the Queensland Energy and Jobs Plan (QEJP), including the establishment of a new SuperGrid transmission backbone and establishment of new REZs. Powerlink continues to guide the market and provide context to broader technical aspects associated with the energy transformation.

The capital expenditure required to manage emerging risks related to assets reaching the end of their technical service life continues to represent a substantial program of regulated work over the outlook period. Network planning studies for the 2024 TAPR have focussed on evaluating the enduring need for existing assets and the possible need for new assets to ensure network resilience in the context of increasing diversity of generation, long-term growth in demand outlook and the potential for network reconfiguration, coupled with alternative non-network solutions. Powerlink will also consider these potential needs holistically as part of the longer term planning process and in conjunction with the QEJP and AEMO's Integrated System Plan (ISP).

Powerlink's focus on stakeholder engagement has continued, with a range of activities undertaken to seek feedback and input into Powerlink's network investment decision making and planning. This includes regular meetings of Powerlink's Customer Panel across a range of topics, including Powerlink's activities relating to the QEJP, in particular REZs and Priority Transmission Investment (PTI), changing network operating conditions, Powerlink's work as part of the Energy Charter and an update on progress in implementing the recommendations of the Asset Reinvestment Review Working Group Report. Powerlink also held webinars on the Gladstone Project candidate Priority Transmission Investment and Queensland's SuperGrid planning update.

As a founding participant since 2018, Powerlink has continued its commitment to the whole of sector Energy Charter initiative. The charter is focussed on driving a customer-centric culture and conduct in energy businesses to create price and service delivery improvements for customers.

## Moving to 80% renewables by 2035

The transmission system plays a critical role as the platform for the efficient large-scale transportation of renewable energy and storage. The energy system of the future will be characterised by a mix of technologies and infrastructure along the entire energy supply chain to transform to net zero emissions. It will look considerably different to the energy system of the past with large-scale renewable energy generation, long-duration Pumped Hydro Energy Storage (PHES) and Battery Energy Storage Systems (BESS), increased electricity demand from electrified industrial and transport sectors and emerging green industrial loads, consumer energy resources, and intelligent control and orchestration being integral components of the decarbonised energy system.

Since publication of the QEJP in September 2022 and 2023 TAPR, Powerlink has continued to work closely with the Queensland Government and market participants providing technical insights on transmission network development for the Optimal Infrastructure Pathway (OIP) to 80% renewables by 2035.

A key component of the OIP is the establishment of a new high capacity transmission backbone to enable large-scale efficient transportation of renewable energy and storage across the state. The SuperGrid transmission backbone has four stages of development to provide connection capacity for new long duration PHES facilities and access to Queensland's high quality renewable energy resources[1]. Powerlink is well progressed with preparatory activities for the first stage of the SuperGrid transmission backbone (Halys to Woolooga, which also enables the Borumba PHES connection).

In July 2024, an update was made to the second stage of the SuperGrid strategy to shift the original location from a coastal to an inland route. This alignment change is based on the significant interest from renewable energy companies to develop wind farms to the west of the original alignment. This will result in a more coordinated solution and a significant reduction in the overall footprint of transmission infrastructure.

Powerlink commissioned the Far North Queensland REZ in July 2024 and there are currently two inflight REZs, the Southern Downs and Western Downs REZ located in South Queensland. Powerlink is now negotiating with foundation customers for the next three REZs.

### Legislative developments since publication of the 2023 TAPR

On the 18 April 2024, the Queensland Government passed the Clean Economy Jobs Act 2024 making a significant move towards realising a clean economy future for Queensland and enshrining in legislation Queensland's commitment to net zero emissions by 2050.

The Queensland Government also passed the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act) on the 18 April 2024. The Act enshrines three State Renewable Energy Targets in legislation and creates frameworks for building the Queensland SuperGrid. The Act also sets out the process to allow the Queensland Government to identify and assess Priority Transmission Investment (PTI) projects within a new State-based planning and investment framework.

In July 2024, Powerlink commenced consultation on the first candidate PTI as referenced in the QEJP, namely the Gladstone Project for the reinforcement of the Gladstone network to support decarbonisation in the region.

### Delivering a transmission network that will support the energy transformation

Powerlink is implementing new approaches and technologies, as well as guiding and shaping developments in the market to optimise performance and utilisation of the transmission system. Powerlink is progressively implementing the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the utilisation of the network and provide an additional layer of security and resilience to system disturbances and events. The uptake of rooftop photovoltaic (PV) systems within Queensland continues to be strong and is significantly changing the daily load profile and operating profiles of existing synchronous generation. Powerlink is also progressing consultation processes to identify non-network solutions to help address emerging technical challenges associated with the energy transformation.

[1] SuperGrid stages are subject to shareholding Minister approval.

## Electricity energy and demand forecasts

The 2023/24 summer in Queensland had above average daily maximum and minimum temperatures, which saw an overall summer peak transmission delivered demand of 9,429MW at 5.00pm on 22 January, 513MW above the 2022/23 maximum transmission delivered demand. Operational 'as generated' peak demand was recorded at the same time reaching 11,005MW (refer to Figure 3.9 for load measurement definitions).

The 2024 Queensland minimum transmission delivered demand was recorded at 10.00pm on 5 October 2024, when only 2,389MW was delivered from the transmission grid. Operational 'as generated' minimum demand was recorded at the same time and set a new record for Queensland of 3,091MW, passing the previous annual minimum record of 3,387MW set in September 2023.

The 2024 TAPR reports on the Low, Central and High scenario forecasts produced by Powerlink. The load forecast takes into consideration AEMO's demand and energy forecasts, published for the 2024 Electricity Statement of Opportunities (ESOO) as well as EQL's Customer Energy Resource (DER) forecasts and block loads. Powerlink's forecast allows a more granular focus on potential load developments in the Queensland region.

### Electricity energy forecast

Based on Powerlink's Central scenario forecast, Queensland's delivered energy consumption is forecast to increase at an average of 2.5% per annum over the next 10 years from 47,477GWh in 2023/24 to 60,516GWh in 2033/34. The increase in energy consumption is mainly due to new anticipated loads and industries beginning to electrify their operations to meet their emission reduction targets.

### Electricity demand forecast

Based on Powerlink's Central scenario forecast, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 3.1% per annum over the next 10 years, from 9,218MW (weather corrected) in 2023/24 to 12,524 in 2033/34. Annual minimum transmission delivered demands are expected to decrease in all forecast scenarios presented in the 2024 TAPR. These Powerlink minimum demand forecasts are provided with simulated solar traces which do not account for economic curtailment or operational measures required to maintain reliability and security. The anticipated electrification of load, historically supplied by fossil fuels, could see a large increase in demand that may require significant investment in the transmission and distribution networks.

## Focussing on a future network that supports the needs of customers

Powerlink undertakes long-term network planning to ensure the long-term needs of customers are met. Powerlink is continuing to:

- ensure its approach to investment decisions delivers positive outcomes for customers
- focus on developing options that deliver safe, reliable and cost effective transmission services
- undertake on-going active community, customer and stakeholder engagement for informed decision making and planning for transmission and related developments
- provide guidance to enable the energy transformation, to improve wholesale electricity prices and a sustainable energy future
- engage and inform various NEM rule changes and market guideline reviews and implement the recommendations
- emphasise an integrated, flexible and holistic analysis of future investment needs
- support diverse generation connections and technologies
- adapt to changes in customer behaviour and the evolving economic outlook
- ensure compliance with legislation, regulations and operating standards.

Through the information and context provided, the 2024 TAPR continues to support the connection of variable renewable energy (VRE) generation to Powerlink's transmission network, enabling the power system transformation.

Notwithstanding the QEJP network developments required to support the decarbonisation of the electricity industry and the Gladstone Project PTI, there are no other significant network augmentations to meet load growth forecast to occur within the 10-year outlook of this TAPR under Powerlink's 2024 Central scenario forecast.

### Proactively planning to address potential shifts in the external environment

There are proposals for large mining, metal processing and other industrial loads including emerging green industries that have not reached a committed development status and are not included in the forecast. These loads have the potential to significantly impact the performance and adequacy of the transmission network. This TAPR outlines the potential network investment and development required in response to these loads emerging in line with a high economic outlook.

Since January 2016, Queensland has seen an unprecedented level of renewable energy investment activity. These investments in VRE generation are changing the dispatch and consequently the energy flows on the transmission network. This is leading to increased utilisation of several grid sections (in particular the Central West to Gladstone grid section). It is also important that the high voltage transmission network has the capacity to unlock VRE investment opportunities that enable market efficiencies and deliver benefits to customers. Powerlink will consider these potential transmission needs, holistically with the emerging condition based drivers as part of the planning process. Feasible network solutions are outlined within the TAPR.

### Applying a flexible and integrated approach when reinvesting in the existing network

The Queensland transmission network experienced significant growth from the 1960s to the 1980s. The capital expenditure needed to manage the condition risks related to this asset base, some of which is now reaching end of technical service life, represents a sizeable portion of Powerlink's program of work within the outlook period.

Considerable emphasis has been given to a flexible and integrated approach to the analysis of future reinvestment needs and options. Powerlink has systematically assessed the enduring need for assets at the end of their technical service life taking into account future renewable generation and considered a broad range of options including non-network solutions, network reconfiguration, refit strategies which extend the service life of transmission lines and transformers, and asset retirement.

### Renewable energy and generation capacity

To date Powerlink has completed connection[2] of 22 large-scale solar and wind farm projects in Queensland, adding 3,155MW of renewable generation capacity to the grid. In addition, a significant number of connection applications, totalling 16,846MW of new generation capacity, have been received to date and are at varying stages of progress. This includes connections under construction of approximately 2,615MW of VRE and 755MW of BESS.

To ensure sufficient system strength for the current and future VRE network requirements, Powerlink is working closely with customers, suppliers and AEMO to model system strength in the Queensland network. This work has provided important insights into the complexity of system strength and how it can be managed with changing technologies moving forward. Powerlink will apply this integrated system strength model to existing and new connection applications and engage through its regulatory consultations to ensure there is adequate system strength in Queensland.

### Grid section and zone performance

During 2023/24, the Powerlink transmission network performed reliably. Record peak transmission delivered demand was recorded for the Far North, Wide Bay, Surat, Moreton, and Gold Coast zones. Minimum transmission delivered demand was recorded for the Far North, North, South West, Moreton and Gold Coast zones. The Ross, Wide Bay and South West zones all continue experiencing periods of negative transmission delivered demand.

Inverter-based resources in northern Queensland experienced approximately 310 hours of network constrained[3] operation during 2023/24.

### Consultation on network investments

Powerlink is committed to regularly reviewing and developing its transmission network in a timely manner to meet the required levels of reliability and manage the risks arising from aged assets remaining in-service.

[2] For the purposes of customer connection statistics, Powerlink defines: 'completed projects' as those for which Powerlink's scope of works has been completed. However, generation may not be at full capacity as remaining works associated with generation connection may not yet be complete (e.g. construction and/or commissioning), 'fully operational' as customer connections where all works are complete, commissioned and capable of delivering to full generation potential.

[3] Constrained operation includes both full or partial generation constraints.

The TAPR highlights anticipated upcoming Regulatory Investment Tests for Transmission (RIT-Ts) for which Powerlink intends to seek solutions and/or initiate consultation with AEMO, Registered Participants and interested parties in the near future (refer to Section 6.6.2). To enhance the value and outcomes of the Regulatory Investment Test for Transmission (RIT-T) process to customers, Powerlink undertakes a range of engagement activities for each RIT-T, determined on a case by case basis. This engagement matrix for RIT-Ts was developed in consultation with Powerlink's Customer Panel.

Powerlink remains consistent with this approach, applying a similar range of engagement activities to consultations which are being/or will be undertaken as part of the PTI framework.

### Power system security services

*Power system security services in central, southern and broader Queensland regions*

Since publication of the 2023 TAPR, Powerlink has concluded the engagement activities and assessment in relation to the system strength shortfall at the Gin Gin fault level node declared in AEMO's 2021 System Security Reports. In January 2024, Powerlink published a report identifying the non-network solution of the addition of a clutch to the Townsville Power Station, owned by Ratch Australia, by mid-2025 as the option which meets the system strength shortfall.

*Addressing system strength requirements in Queensland from December 2025*

As the System Strength Service Provider for Queensland, Powerlink commenced the RIT-T process, publishing a Project Specification Consultation Report (PSCR), Addressing System Strength Requirements in Queensland from December 2025, calling for submissions from non-network solution providers to meet the minimum and efficient fault levels of system strength identified in AEMO's 2023 System Strength Report.

Powerlink is progressing the technical and economic analysis for the optimal portfolio of solutions anticipated to be required and expects publication of the Project Assessment Draft Report (PADR) in November 2024.

## Integrated System Plan projects in Queensland

### Expanding New South Wales to Queensland transmission transfer capacity

The Queensland to New South Wales Interconnector (QNI) 'minor' upgrade construction works are complete and inter-network testing is progressing to release additional capacity to the market in a staged approach. These tests are expected to continue until mid-2025.

### Future actionable Integrated System Plan projects

The 2024 Integrated System Plan (ISP) identified upgrades in Queensland as part of the optimal development path for the NEM. It identified three projects in Queensland as requiring action prior to the release of the 2026 ISP. These projects include:

- Gladstone Grid Reinforcement (now referred to as the Gladstone Project)
- Queensland SuperGrid South
- QNI Connect.

Powerlink had already identified the need for the first two projects. These projects will progress under the candidate PTI framework (refer to Section 6.16), with the Gladstone Project consultation currently in progress.

## Committed and commissioned projects

Powerlink continues to ensure the safe and reliable supply of electricity to townships, local communities, industry and businesses across Queensland with 11 reinvestment projects completed since publication of the 2023 TAPR.

Projects completed in 2023/24 include:

- Strathmore transformer establishment
- Strathmore secondary systems replacement
- Calvale and Callide B secondary systems replacement
- Nebo primary plant and secondary systems replacement
- Lilyvale transformers replacement
- Boyne Island secondary systems replacement
- Wurdong secondary systems replacement
- Line refit works on the transmission line between Woolooga and Palmwoods
- Line refit works on the transmission lines between West Darra and Sumner
- Line refit works on the transmission lines between Rocklea and Sumner
- Abermain secondary systems replacement

As at the publication of the 2024 TAPR and having finalised the necessary regulatory processes, the committed projects for investment across Powerlink's network include:

- Maintaining power transfer capability and reliability of supply at Kemmis
- Addressing the reliability of supply to Nebo local area
- Addressing the secondary systems condition risks at Sumner.

## Increasing opportunities for non-network solutions

As the power system transforms, non-network solutions will be essential to address the changing needs of the power system.

Powerlink is committed to genuine engagement with providers of non-network solutions and the implementation of these solutions where technically feasible and economic to ensure reliable and cost effective transmission services for customers. Future non-network solutions may be implemented to:

- address inertia, system strength and Network Support and Control Ancillary Services requirements, ensuring the secure operation of the transmission network
- address future network limitations or address the risks arising from ageing assets remaining in-service within the transmission network
- more broadly, in combination with network developments as part of an integrated solution to complement an overall network reconfiguration strategy
- provide demand management and load balancing.

## Engaging with customers, community and other stakeholders

Powerlink customers include more than five million Queenslanders and 241,000 businesses in the State. Powerlink is committed to proactively engaging with customers, communities, First Nations Peoples and other stakeholders in seeking their input into Powerlink's business processes and decision-making. All engagement activities are undertaken in accordance with Powerlink's Stakeholder Engagement Framework and Community Engagement Strategy, which set out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions with stakeholders and the broader communities in which Powerlink operates. A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement performance goals. In particular, Powerlink undertakes a comprehensive annual stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed in September 2024, it provides important data to inform engagement strategies with individual stakeholders.

Engaging with communities is essential to providing transmission services that are safe, reliable and cost effective. Transmission network infrastructure stays in-service for around 50 years and Powerlink is focussed on building positive relationships and partnering with local communities to deliver benefits for the longer term. Powerlink's Community Engagement Strategy was developed and implemented to support delivery of the energy transformation and ensure Powerlink is focussed on driving mutually beneficial outcomes for impacted communities.

Throughout the year, Powerlink undertook targeted community engagement research across the state to gauge community acceptability of renewable development and related transmission infrastructure. The research findings support Powerlink's engagement going forward and ensure a focus on key factors that are important to communities. Powerlink is undertaking a new round of community sentiment research across the state in late 2024.

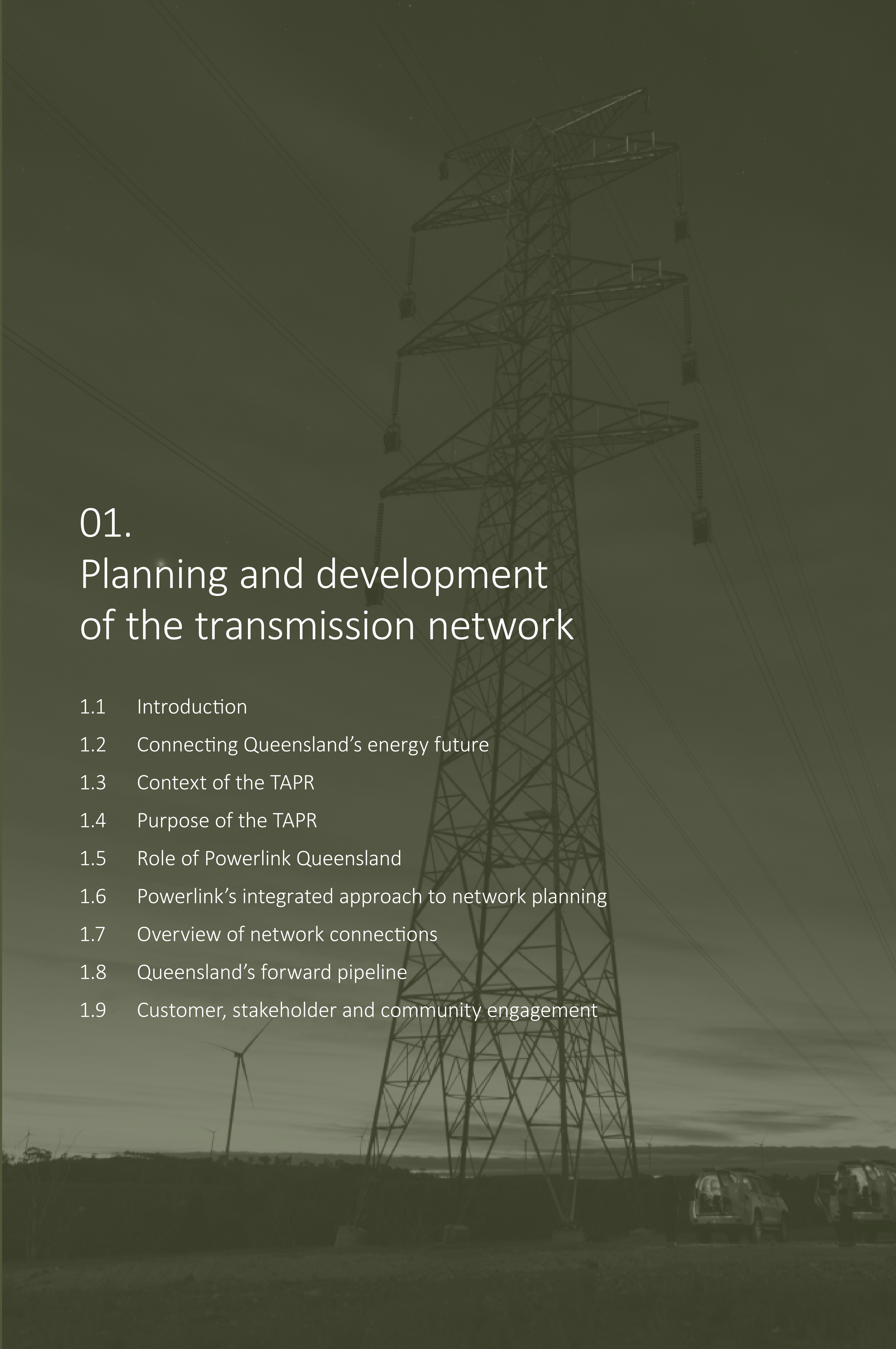
Since publication of the 2023 TAPR, Powerlink has been embedding the Transmission Easement Engagement Process established in the previous year. Work is also continuing to roll out the new SuperGrid Landholder Payment Framework that increases payments to landholders hosting new transmission infrastructure. Powerlink is also now the first transmission company in Australia to offer payments to landholders on properties adjacent to transmission infrastructure.

As Powerlink continues to operate and maintain the existing network through to embarking on planning and building the transformational network of the future, local communities will be front and centre in Powerlink's planning and decision-making.

Powerlink recognises the importance of transparency for stakeholders, particularly when:

- undertaking transmission network planning
- developing meaningful and relevant data for publication in the TAPR portal in relation to potential future investments
- engaging in public consultation under the PTI framework, RIT-T and other regulatory processes.

Powerlink will also discuss the technical information provided in the TAPR with stakeholders at a dedicated session at the Transmission Network Forum to be held in November 2024.



# 01.
# Planning and development of the transmission network

*Powerlink Queensland's (Powerlink) annual planning review and Transmission Annual Planning Report (TAPR) play an important role helping to ensure the transmission network continues to meet the needs of Queensland customers and National Electricity Market (NEM) participants into the future. This chapter discusses Powerlink's planning obligations and role in supporting the energy transformation in Queensland, an update on the development of connection projects currently underway and Powerlink's most recent stakeholder engagement activities.*

### Key highlights

- The purpose of Powerlink's TAPR under the National Electricity Rules (NER) is to provide information about the Queensland transmission network, including key areas forecast to require expenditure in the 10-year outlook period.
- Powerlink is responsible for planning the shared transmission network within Queensland, including the development of new connections to the network.
- Local communities are front and centre in Powerlink's planning and decision making as Powerlink continues to operate and maintain the existing network as well as planning and building the transformational network of the future.
- Powerlink has developed demand and energy forecasts for the 2024 TAPR. The load forecast takes into consideration AEMO's demand and energy forecasts, published for the 2024 Electricity Statement of Opportunities (ESOO), and allows a more granular focus on potential load developments in the Queensland region.
- Powerlink has a central role in enabling the connection of variable renewable energy (VRE) in Queensland and continues to actively collaborate with solar and wind farm, and Battery Energy Storage System (BESS) proponents, who will help provide the firming services that are integral to the future mix of technologies in Queensland.
- As the REZ Delivery Body (RDB) for Queensland, Powerlink is working closely with the Queensland Government to establish Renewable Energy Zones (REZs) and deliver major projects referenced in the Queensland Energy and Jobs Plan (QEJP).
- Powerlink continues to proactively engage with communities, customers and other stakeholders, seeking their input into Powerlink's network development, on-going operations and new investment decisions.

## 1.1 Introduction

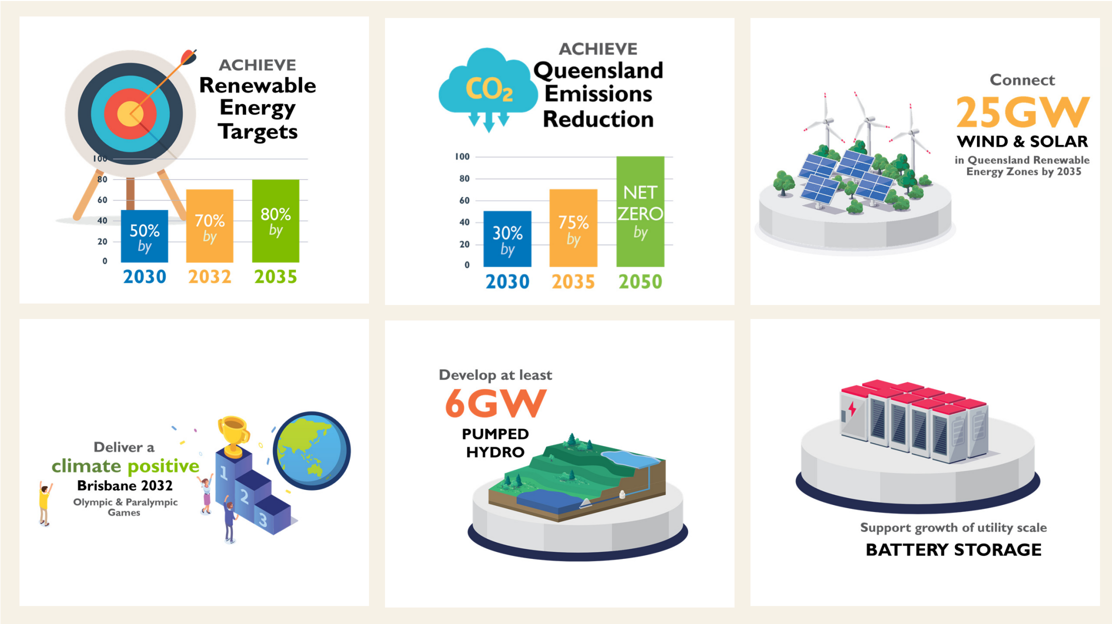
Powerlink is a Transmission Network Service Provider (TNSP) in the NEM and owns, develops, operates and maintains Queensland's high voltage (HV) transmission network. It has been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB) and RDB responsible for transmission network planning and development within the State.

## 1.2 Connecting Queensland's energy future

The pace and scale of change in Australia's power system is one of the fastest in the world. Powerlink's transmission network plays a critical role in connecting Queenslanders to a world-class energy future and supporting key Government targets including new Renewable Energy Targets (RET) and net zero emissions by 2050.

Powerlink is pursuing a reliable, least-cost power system transformation for customers and driving the coordinated and efficient development of REZs, while working positively with communities to achieve the objectives and goals set out in the QEJP (refer to Figure 1.1 and Chapter 2).

Figure 1.1 QEJP Targets




## 1.3 Context of the TAPR

As part of its planning responsibilities, Powerlink undertakes an annual planning review in accordance with the requirements of the NER[1] and publishes the findings of this review in its TAPR, and associated templates made available in the TAPR portal.

Information from this process is provided to Australian Energy Market Operator (AEMO) to assist in the preparation of its Integrated System Plan (ISP). The ISP sets out a roadmap for the eastern and south-eastern seaboard's power system over the next two decades. It establishes a whole-of-system plan for an efficient transformation by identifying the optimal development path over this planning horizon for the strategic and long-term development of the NEM. The ISP identifies actionable and future projects requiring regulatory consultation, and informs market participants, investors, policy makers and customers about a range of potential future development opportunities. Queensland to New South Wales Interconnector (QNI) Connect has been identified as an actionable project in the most recent ISP released in July 2024, with a Project Assessment Draft Report to be published by Powerlink and Transgrid by 25 June 2026 (refer to Section 6.17.3). The ISP noted the Queensland Government had passed the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act) and that the Gladstone Grid Reinforcement[2] (refer to Section 1.5.2) and Queensland SuperGrid South projects will progress under the State framework rather than the ISP framework[3].

Powerlink has developed demand and energy forecasts for the 2024 TAPR. While this load forecast takes into consideration AEMO's demand and energy forecasts, published for the 2024 ESOO it allows a more granular focus on potential load developments within Queensland. With market engagement data, sourced from Powerlink's business development activities and Energy Queensland, Powerlink is well placed to forecast future load (new and/or as a result of decarbonisation) in the Central load forecast scenario. Powerlink's forecast also includes sub-regional areas, otherwise known as TAPR zones (refer to Appendix F) and delivers the added benefit of forecasts at all levels of the transmission network in the state.

1 For the purposes of Powerlink's 2024 TAPR, Version 214 of the NER in place from July 2024.
2 The scope of works for Gladstone Grid Reinforcement is captured within the Gladstone Project in the QEJP.
3 2024 Integrated System Plan for the National Electricity Market, page 63.

The primary purpose of the TAPR is to provide information on the short to medium-term planning activities of TNSPs, whereas the focus of the ISP is more strategic and longer term. Further, the ISP, System Strength, Inertia and Network Support and Control Ancillary Service (NSCAS) Reports and the TAPR are intended to complement each other in informing stakeholders and promoting efficient investment decisions. In supporting this complementary approach, the current published versions of these documents and reports are considered in this TAPR and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2024 TAPR in conjunction with 2024 ESOO. The most recent ISP was released on 30 June 2024 and the 2023 System Strength, Inertia and NSCAS Reports were published on 1 December 2023.

## 1.4 Purpose of the TAPR

The purpose of Powerlink's TAPR under the NER is to provide information about the Queensland transmission network to those interested or involved in the NEM, including AEMO, Registered Participants and interested parties. The TAPR also provides customers, communities and other stakeholders with an overview of Powerlink's planning processes and decision making on future investment.

It aims to provide information that assists to:

- identify locations that would benefit from significant electricity supply capability or demand side management (DSM) initiatives
- identify locations where major industrial loads could be connected
- identify locations where capacity for new generation developments exist, in particular VRE generation and REZs
- understand how the electricity supply system affects customers, stakeholders and communities
- understand the transmission network's capability to transfer quantities of bulk electrical energy
- provide input into the future development of the transmission network.

Readers should note this document and supporting TAPR templates and TAPR portal are not intended to be relied upon explicitly for the evaluation of participants' investment decisions. Interested parties are encouraged to contact Powerlink directly for more detailed information[4].

## 1.5 Role of Powerlink Queensland

### 1.5.1 Jurisdictional network planning and development in the NEM

As the owner and operator of the transmission network in Queensland, Powerlink is registered with AEMO as a TNSP under the NER. In this role, and in the context of this TAPR, Powerlink's transmission network planning and development responsibilities include:

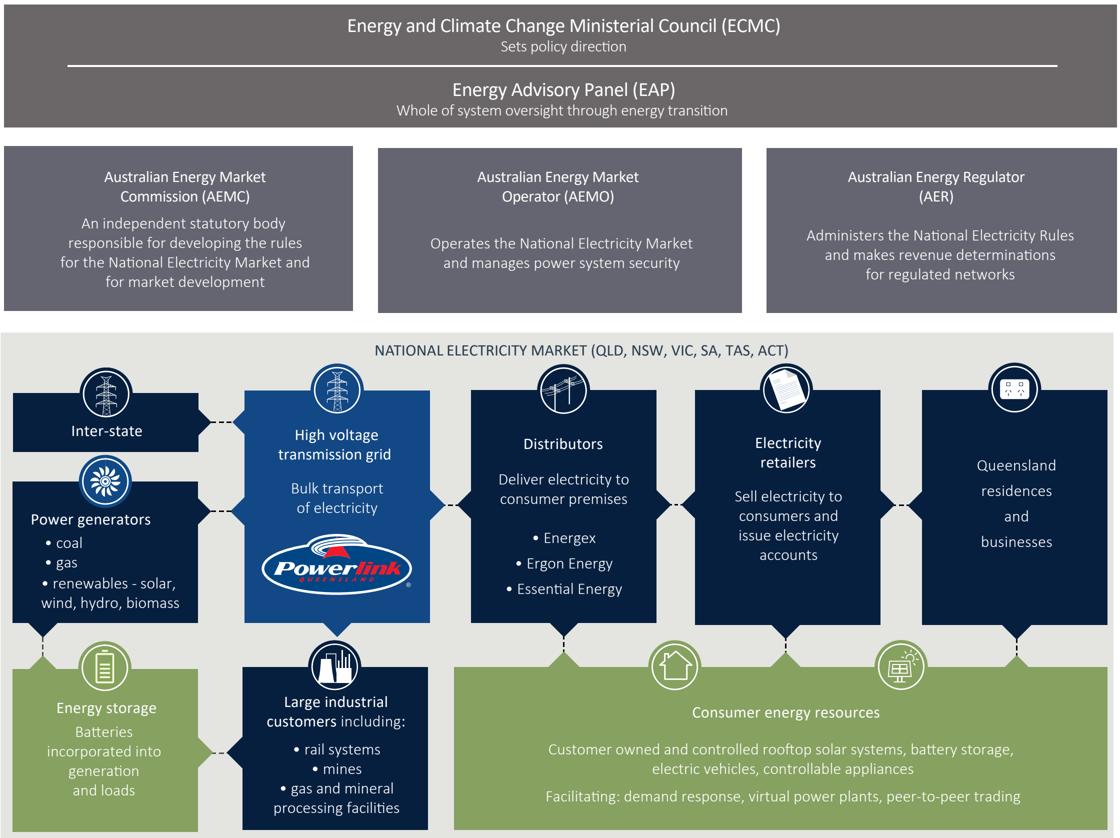
- ensuring the network is able to operate with sufficient capability and if necessary, is augmented to provide network services to customers in accordance with Powerlink's Transmission Authority and associated reliability standard
- ensuring the risks arising from the condition and performance of existing assets are appropriately managed
- ensuring the network complies with technical and reliability standards contained in the NER and jurisdictional instruments including the requirement to maintain minimum fault levels as prescribed by AEMO
- conducting annual planning reviews with Distribution Network Service Providers (DNSPs) and other TNSPs whose networks are connected to Powerlink's transmission network, that is Energex and Ergon Energy (part of the Energy Queensland Group), Essential Energy and Transgrid
- advising AEMO, Registered Participants and interested parties of asset reinvestment needs within the time required for action

[4] Unless stated otherwise, the information published within the 2024 TAPR is current as at 30 September 2024.

- developing recommendations to address emerging network limitations or the need to address the risks arising from ageing network assets remaining inservice through joint planning with DNSPs and TNSPs, and consultation with AEMO, Registered Participants and interested parties, with potential solutions including network upgrades or non-network options such as local generation (including battery installation) and DSM initiatives
- examining options and developing recommendations to address transmission constraints and economic limitations across intra-regional grid sections and interconnectors through joint planning with other Network Service Providers (NSP), and consultation with AEMO, Registered Participants and interested parties
- assessing whether a proposed transmission network augmentation has a material impact on networks owned by other TNSPs, and in assessing this impact Powerlink must have regard to the objective set of criteria published by AEMO in accordance with Clause 5.21 of the NER
- undertaking the role of the proponent for regulated or funded[5] transmission augmentations and the replacement of transmission network assets in Queensland
- undertaking the role of System Strength and Inertia Service Provider in Queensland, providing the services required to meet system strength and inertia requirements.

Powerlink's role in the Queensland power system is shown in Figure 1.2.

Figure 1.2 Powerlink's role in the Queensland power supply industry




### 1.5.2 State-based planning and development under the ERTJ Act

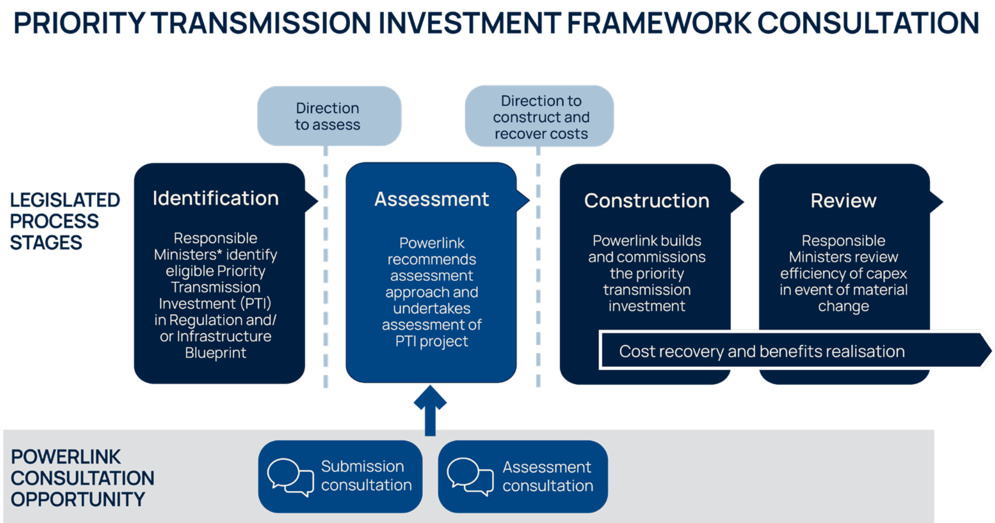
The ERTJ Act was passed in April 2024 and is a key enabler of the transformation, placing the Queensland Renewable Energy Targets into law and establishing new arrangements to deliver major transmission investments in Queensland (Refer to Section 2.3).

[5] Where applicable, in accordance with NER, Clause 5.18.

The ERTJ Act sets out the process to allow the Queensland Government to identify and assess Priority Transmission Investment (PTI) projects within a new State-based planning and investment framework. As directed by the Queensland Government, Powerlink is required to carry out the public consultation and assessment process for candidate PTIs and the subsequent construction and commissioning of PTI projects, including contracting for non-network solutions where technically and economically feasible. In July 2024, Powerlink commenced the first PTI public consultation under the new framework for the Gladstone Project (refer to Section 8.2.5).

Powerlink's role in the PTI process is shown in Figure 1.3.

Figure 1.3 Powerlink's role in the PTI process




More information on the PTI process is available on Powerlink's website.

**RDB and REZ TNSP roles**

Powerlink has been appointed to undertake two distinct roles within the ERTJ ACT that are responsible for Queensland REZs, being:

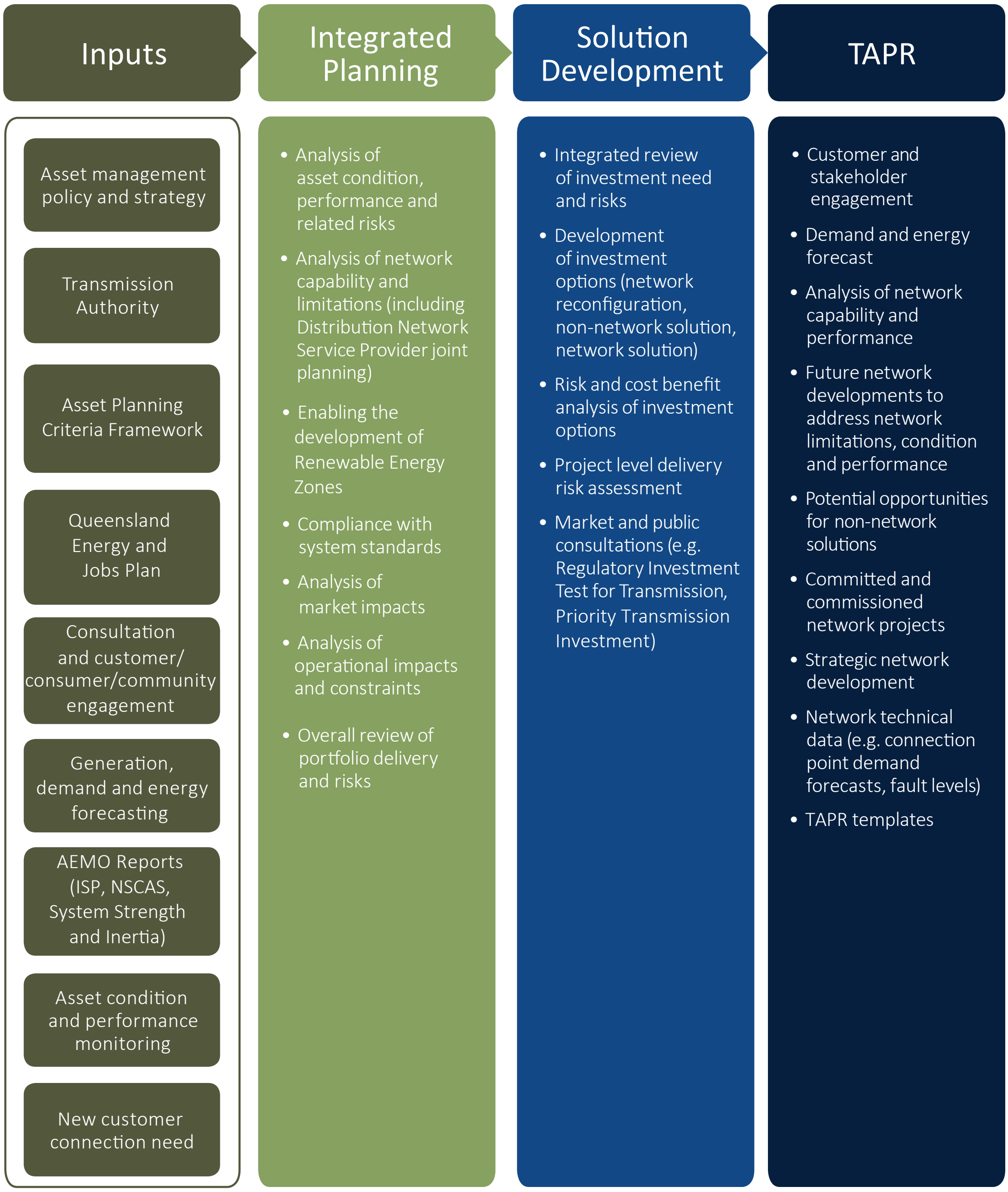
- RDB, with the responsibility of identifying areas suitable to be a REZ, developing draft and final REZ Management Plans (RMP) to enable the declaration of the REZ, and consulting with communities and stakeholders and
- REZ TNSP, with the responsibility of planning, design, owning, constructing, operating and maintaining REZ transmission infrastructure and undertaking processes for the connection of renewable generation.

Further information on the development of REZ in Queensland is available in Section 2.5.

## 1.6 Powerlink's integrated approach to network planning

An overview of Powerlink's integrated planning approach, taking into account the energy transformation, network capacity needs and end of technical service life related issues is presented in Figure 1.4.

Figure 1.4 Overview of Powerlink's TAPR planning process




Further information on Powerlink's planning responsibilities and processes as well as information on the principles and approach which guide Powerlink's analysis of future network investment needs and key investment drivers is available in Chapter 6 and Appendix A.

## 1.7 Overview of network connections

### 1.7.1 Summary of connection projects

Interest remains high from VRE generation and storage projects connecting in Queensland and Powerlink is progressing a significant pipeline of connections (refer to Section 6.6.3). Table 1.1 provides an overview of the development of connection projects undertaken or being undertaken by Powerlink since 2018.

Table 1.1 Summary of connection projects

| Solar/Wind Projects | 2024 TAPR status | |
|---|---|---|
| Total completed to date | 22 | 3,155MW |
| Under construction | 7 | 2,615MW |
| Connection Applications to date | 66 | 16,846MW |

Notes:

(1) A 250MW committed pumped hydro storage project is underway at the time of 2024 TAPR publication.

(2) To date Powerlink has completed two storage projects, totalling 250MW and a further 755MW of storage projects are under construction.

### 1.7.2 Status of connection projects

To date Powerlink has completed connection of 25 (22 VRE + 3 BESS) large-scale solar, wind farm and BESS projects in Queensland, adding 3,405MW of generation capacity to the grid. A significant number of formal connection applications, totalling 16,846MW of new generation capacity, have been received and are at varying stages of progress.

During 2023/24, 1,930MW[6] of semi-scheduled VRE generation capacity has been committed in the Queensland region, taking the total VRE generation capacity to 7,261MW[7] that is connected, or committed to connect, to the Queensland transmission and distribution networks.

Approximately 1,491MW of embedded semi-scheduled renewable energy projects exist or are committed to Energy Queensland's network. In addition to the large-scale VRE generation development projects, rooftop photovoltaic (PV) in Queensland exceeded 6,400MW in June 2024.

Figure 1.5 shows the location and type of generators connected and committed to connect to Powerlink's network. The Department of Energy and Climate (DEC) also provides mapping information on proposed (future) VRE projects, together with existing generation facilities (and other information) on its website. For the latest information on proposed VRE projects and locations in Queensland, refer to the DEC website.

6 Comprised of MacIntyre Wind Farm, Lotus Creek Wind Farm, Boulder Creek Wind Farm, Broadsound Solar Farm and Wambo 2 Wind Farm (Powerlink).

7 Comprised of Powerlink and Energy Queensland Group committed and completed solar and wind projects. There are a number of projects under construction that have not yet reached committed status.

Figure 1.5 Existing, Committed, and under construction connection projects since 2018

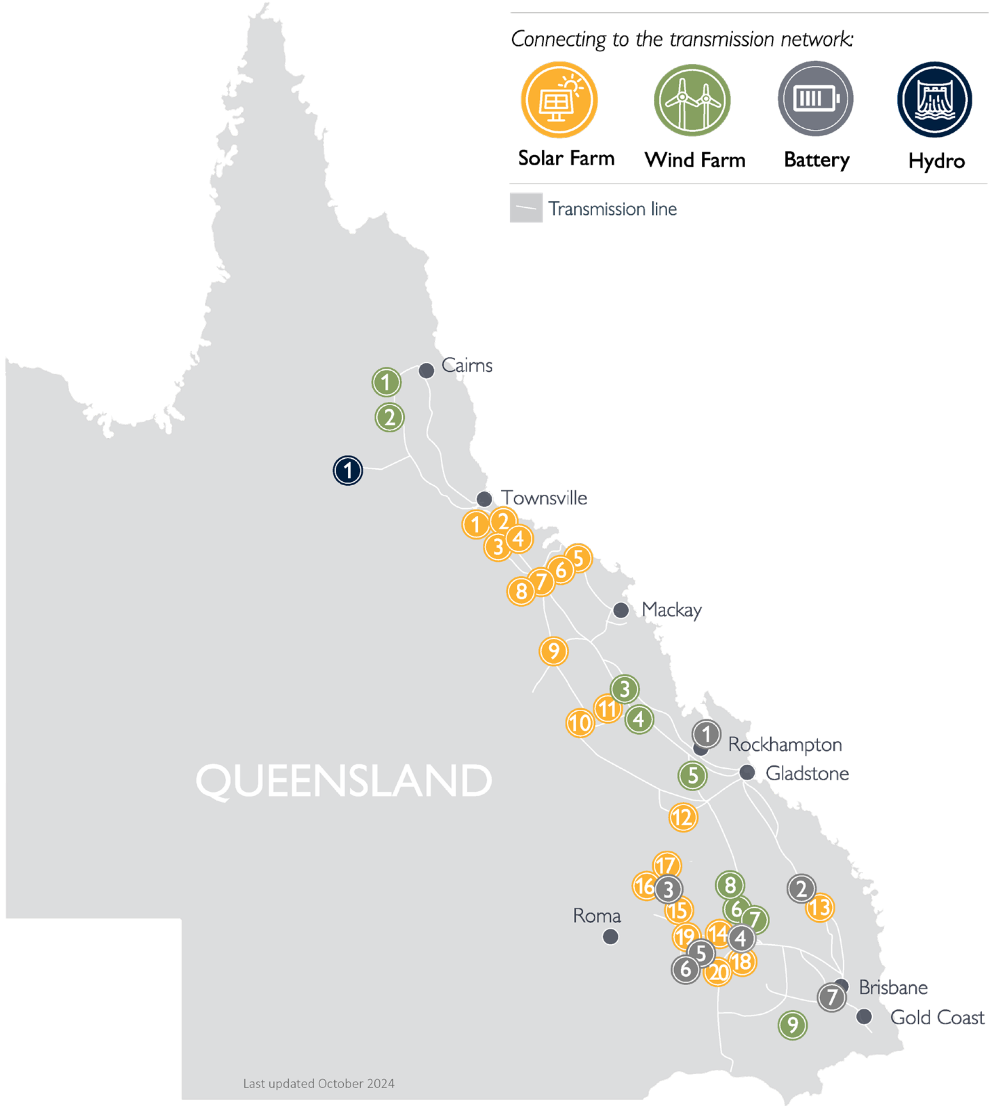


**Table 1.2** Existing, Committed and under construction connection projects since 2018

| Map ID | Generator | Location | Available capacity MW generated |
|---|---|---|---|
| Hydro-electric (1) | | | |
| 1 | Kidston Pumped Hydro Storage (2) | Kidston | 250 |
| Solar PV (3) | | | |
| 1 | Ross River | Ross | 116 |
| 2 | Sun Metals | Townsville Zinc | 121 |
| 3 | Haughton | Haughton River | 100 |
| 4 | Clare | Clare South | 100 |
| 5 | Whitsunday | Strathmore | 57 |
| 6 | Hamilton | Strathmore | 57 |
| 7 | Daydream | Strathmore | 150 |
| 8 | Hayman | Strathmore | 50 |
| 9 | Rugby Run | Moranbah | 65 |
| 10 | Lilyvale | Lilyvale | 100 |
| 11 | Broadsound (2) | Broadsound | 296 |
| 12 | Moura | Moura | 82 |
| 13 | Woolooga Energy Park | Woolooga | 176 |
| 14 | Blue grass | Chinchilla | 148 |
| 15 | Columboola | Columboola | 162 |
| 16 | Gangarri | Wandoan South | 120 |
| 17 | Wandoan | Wandoan South | 125 |
| 18 | Edenvale Solar Park | Orana | 146 |
| 19 | Western Downs Green Power Hub | Western Downs | 400 |
| 20 | Darling Downs | Braemar | 108 |
| Wind (3) | | | |
| 1 | Mt Emerald | Walkamin | 180 |
| 2 | Kaban | Tumoulin | 152 |
| 3 | Lotus Creek (2) | Nebo-Broadsound | 276 |
| 4 | Clarke Creek (2) | Broadsound | 440 |
| 5 | Boulder Creek (2) | Stanwell-Calvale | 221 |
| 6 | Wambo (2) | Halys | 245 |
| 7 | Wambo 2 (2) | Halys | 247 |
| 8 | Coopers Gap | Coopers Gap | 440 |
| 9 | MacIntyre (2) | Tummaville | 890 |
| Battery (3) | | | |
| 1 | Bouldercombe 2h BESS | Bouldercombe | 50 |
| 2 | Woolooga 2h BESS (2) | Woolooga | 200 |
| 3 | Wandoan 1.5h BESS | Wandoan South | 100 |
| 4 | Chinchilla 2h BESS (2) | Western Downs | 100 |
| 5 | Western Downs 2h BESS (2) | Western Downs | 200 |
| 6 | Ulinda Park 2h BESS (2) | Western Downs | 155 |
| 7 | Greenbank 2h BESS (2) | Greenbank | 200 |

Notes:

(1) Shown at full capacity. However, output can be limited depending on water storage levels.

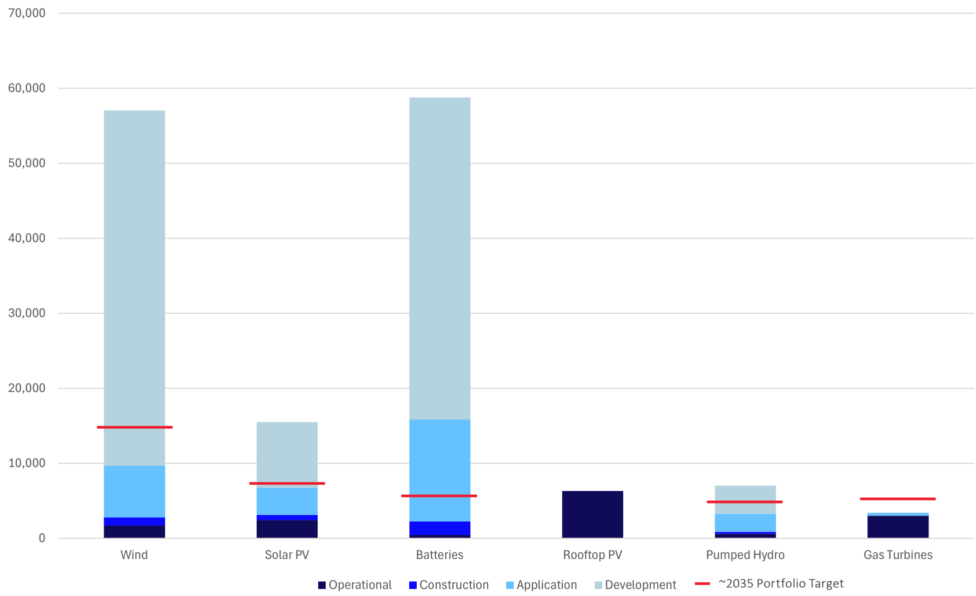
(2) Generators that are committed or undergoing construction are shown at future maximum expected capacity at the point of connection. Actual available generating capacity will vary over the course of the commissioning program.

(3) VRE generators and batteries shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

## 1.8 Queensland's forward pipeline

Queensland has experienced strong interest in the development of generation, firming and storage projects needed to enable the energy transformation. The forward pipeline of projects in various stages of development by technology are shown in Figure 1.6. The Infrastructure Blueprint outlines targets for each of the technologies to meet 80% renewable energy by 2035.

Figure 1.6 Powerlink's forward pipeline of projects by development stage (1)




Note:

(1) Forward pipeline of projects and anticipated capacity as of 1 October 2024.

### 1.8.1 The connections process

Participants wishing to connect to the Queensland transmission network include new and existing generators, storage, major loads and other NSPs. New connections or alterations to existing connections involves consultation in accordance with the NER Chapter 5 connection process between Powerlink and the connecting party to negotiate an Offer to Connect and Connection and Access Agreement (CAA). Negotiation of the CAA requires the specification and then compliance by the generator or load to the required technical standards. The process of agreeing to technical standards also involves AEMO. The services provided can be prescribed for DNSPs (regulated), negotiated or non-regulated services in accordance with the definitions in the NER or the framework for provision of such services.

#### Categories of Connection Assets

*Dedicated Connection Assets (DCA)*

All new Dedicated Connection Asset services, including design, construction, ownership, and operation and maintenance are non-regulated services.

*Identified User Shared Assets (IUSA)*

Identified User Shared Asset services are either negotiated or non-regulated services, depending on specific requirements set out in Chapter 5 of the NER. Powerlink remains accountable for operation and maintenance of all IUSAs as part of the transmission network.

*Designated Network Assets (DNA)*

Designated Network Assets (DNA) include radial transmission extensions greater than 30km in length. Unlike DCAs, DNAs are part of the transmission network, with design, construction, and ownership as non-regulated services. Powerlink remains accountable for the operation and maintenance of all DNAs.

Powerlink remains committed to transparent and efficient connection services and will continue to work collaboratively with market participants and interested parties across the renewables sector to better understand the potential for VRE generation, and to identify opportunities and emerging limitations as they occur. The NER (Clause 5.3) prescribes procedures and processes that NSPs must apply when dealing with connection enquiries.

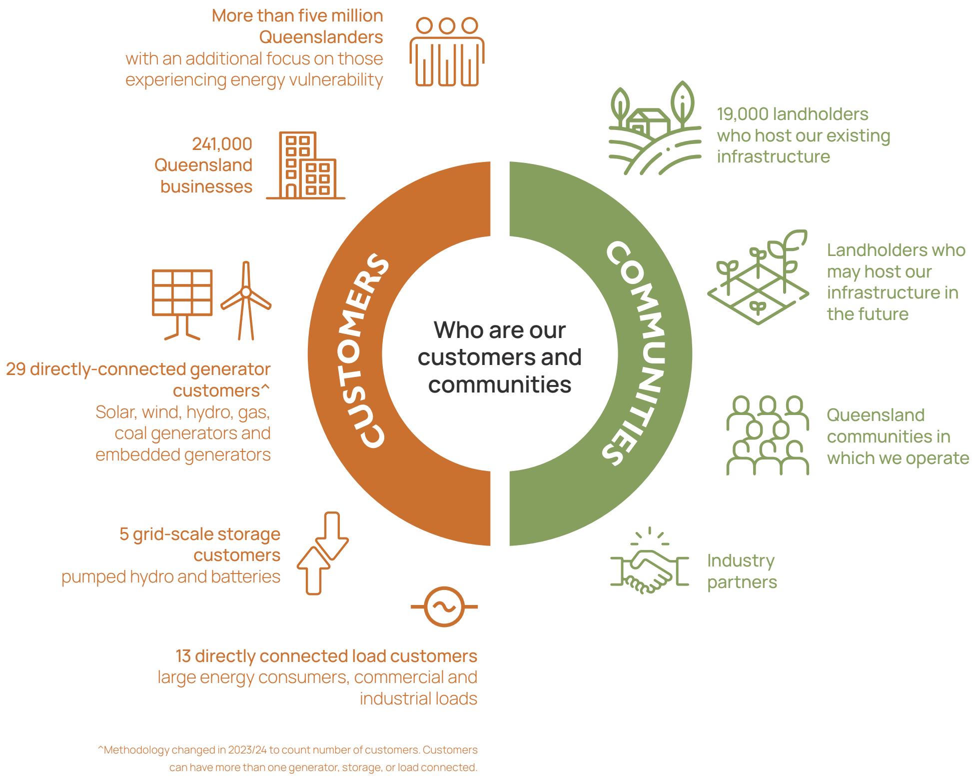
Figure 1.7 Overview of Powerlink's existing network connection process


Proponents who wish to connect to Powerlink's transmission network are encouraged to contact BusinessDevelopment@powerlink.com.au. For further information on Powerlink's network connection process please refer to Powerlink's website.

## 1.9 Customer, stakeholder and community engagement

Powerlink shares targeted, timely and transparent information with its customers, communities, First Nations Peoples and other stakeholders using a range of engagement approaches. Powerlink customers include more than five million Queenslanders and 241,000 businesses who receive electricity through the energy network. Directly-connected customers include Queensland's generators and storage proponents and large industrial energy users (refer to Figure 1.8).

Figure 1.8 Powerlink's customers and communities



There are also stakeholders who provide Powerlink with non-network solutions that can either connect directly to Powerlink's transmission network, or to the distribution network (refer to Chapter 5).

The TAPR is an important tool Powerlink uses to communicate information about transmission planning in the NEM. Through the TAPR, Powerlink aims to increase stakeholder and customer, stakeholder and community understanding and awareness of key updates and external shifts, including load forecasting, transmission network planning and the energy transformation.

### 1.9.1 Engagement activities

All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework and Community Engagement Strategy, which set out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions with stakeholders and the broader communities in which it operates. A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement goals. In particular, Powerlink undertakes a comprehensive stakeholder survey to gain insights about stakeholder perceptions of Powerlink, including key factors driving trust and reputation. Most recently completed in August 2024, it provides comparisons and year-on-year trends to inform engagement strategies with stakeholders. More detailed information on Powerlink's engagement activities is available on the Powerlink website.

Engagement activities Powerlink has undertaken since the publication of the 2023 TAPR are outlined in the remainder of this section.

#### Community engagement

Engaging with communities is essential to providing transmission services that are safe, reliable and cost effective. Transmission infrastructure stays inservice for up to 50 years and Powerlink is focussed on building positive relationships and partnering with local communities to deliver benefits for the longer term. The dedicated Community Engagement Strategy developed in 2021 continues to support delivery of the energy transformation and ensure Powerlink is focussed on driving mutually beneficial outcomes for communities. The strategy is driving the business focus on engaging early and often, particularly with communities where Powerlink is building new infrastructure and connecting renewable development projects. This early engagement approach includes seeking feedback and input earlier in the project development process and incorporating these insights into Powerlink's planning and decision making. The strategy is currently being reviewed and refreshed to ensure our approach meets community expectations going forward.

#### Targeted research

Powerlink also undertook targeted community engagement research across the state to gauge community acceptability of renewable development and related transmission infrastructure. The research findings support Powerlink's future engagement and ensures a focus on key factors that are important to communities. As Powerlink continues to operate and maintain the existing network through to embarking on planning and building the transformational network of the future, local communities will remain front and centre in our planning and decision making.

Powerlink supported the University of Queensland and Curtin University to undertake independent desktop reviews of global studies on the social, economic and technical aspects of underground and overheard transmission infrastructure. A comprehensive report was released in November 2023 to inform a clear and consistent approach.

In addition, Powerlink played a key role in the development of the Energy Charter Better Practice Social Licence Guideline released in May 2023. In June 2024, a 12-month Independent Review of the guideline was completed to test the progress of transmission businesses against the priority actions. The review found there was notable progress and also identified areas for on-going improvement.

Powerlink was also part of the Stakeholder Reference Group that worked with the Commonwealth Government to develop the national guidelines for community engagement and benefits for transmission.

### 2023 Transmission Network Forum

In November 2023, more than 450 customers attended (in person and virtually) Powerlink's annual Transmission Network Forum. The forum provided updates on the state of the network, an industry panel discussion on social licence, an interactive workshop on delivering REZ's and a technical session on the 2023 TAPR. The live stream recordings, presentations and questions raised, and answers discussed are available on Powerlink's website.

### Review of Network Development Process

Powerlink launched the new Transmission Easement Engagement Process (TEEP) in August 2023. The TEEP outlines how we engage with communities and other stakeholders as we develop, operate and maintain the transmission network. It is the result of a co-design process with stakeholders – including the Local Government Association of Queensland, and Queensland Farmers' Federation – based on a 2023 review of corridor selection processes from study area phase through to securing final easements.

The engagement process is built on early and meaningful engagement practices with landholders, Traditional Owner groups, the community and other stakeholders. Once a project is identified, we will engage through a number of stages and work collaboratively to carefully assess locations for a new transmission line easement, with the potential social, environmental and economic considerations in mind.

As part of this review, Powerlink also launched a new SuperGrid Landholder Payment Framework that significantly boosted payments to landholders hosting new transmission infrastructure. The increase in payments is based on property-specific values and impacts, as opposed to a flat rate used previously. Under this framework, Powerlink was the first transmission company in Australia to offer payments to landholders on neighbouring properties adjacent to transmission infrastructure.

In addition to this, in February 2024 Powerlink renewed its commitment to landholders by launching its new Project Participation and Access Allowance. It allows eligible landholders to apply for a $5,000 payment to recognise their participation if Powerlink needs to access their land for on-ground information as part of project development.

### Customer Panel

Powerlink hosts a Customer Panel that provides an interactive forum for its stakeholders and customers to give input and feedback to Powerlink regarding decision making, processes and methodologies. Comprised of members from a range of sectors including industry associations, resources, community advocacy groups, directly connected customers and distribution representatives, the panel provides an important avenue to keep Powerlink's stakeholders better informed about operational and strategic topics of relevance. The panel met in March, May and September 2024. Key topics for discussion included Powerlink's activities relating to the QEJP, in particular REZs and PTI, changing network operating conditions, Powerlink's work as part of the Energy Charter and an update on Powerlink's progress in implementing the recommendations of the Asset Reinvestment Review Working Group Report.

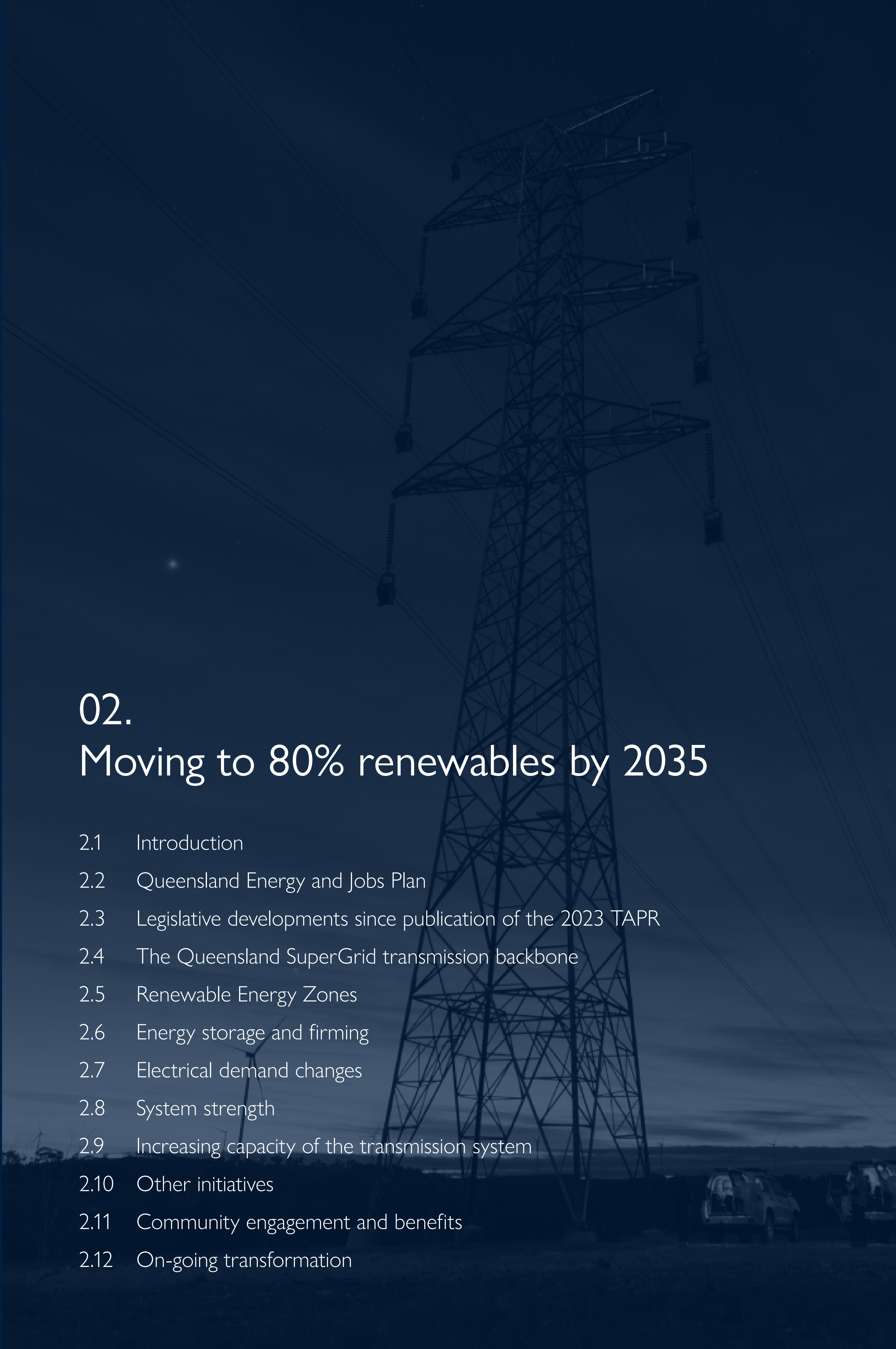
### Stakeholder engagement for public consultation processes

Powerlink recognises the importance of transparency for stakeholders and customers, particularly when undertaking transmission network planning and engaging in public consultation processes, such as the Regulatory Investment Test for Transmission (RIT-T), PTI, an Expression of Interest or Funded Augmentation.

Powerlink is guided by the Australian Energy Regulator (AER) Stakeholder Engagement Framework and Consumer Engagement Guideline for Network Service Providers as the benchmarks when undertaking public consultations.

Since publication of the 2023 TAPR, to ensure transparency and that customers remain up to date with the most recent developments, Powerlink has held webinars on the Gladstone Project and Queensland's SuperGrid Planning Update. The webinars and presentations are available on Powerlink's website.

The most frequent public consultation process undertaken by Powerlink is the RIT-T and further information on the proposed engagement activities for RIT-Ts is published on Powerlink's website.



# 02.
# Moving to 80% renewables by 2035

*This chapter discusses Powerlink's critical and active role in the energy transformation. In developing the future network to support a move to net zero emissions, Powerlink is enabling diversity of generation and storage, supporting industry and load growth, exploring new technologies, and working closely with Queenslanders to ensure a cost effective, reliable, and secure electricity supply. The information discussed in this Chapter is provided in the context of the Queensland Energy and Jobs Plan (QEJP) and Queensland SuperGrid Infrastructure Blueprint (Infrastructure Blueprint) published in September 2022. The Infrastructure Blueprint is a point in time plan scheduled to be updated in May 2025.*

### Key highlights

- Powerlink is playing an active role in the energy transformation by strategically planning the transmission network, guiding and shaping the power system, and enabling opportunities as Queensland moves to a lower emissions future.
- Powerlink is working closely with the Queensland Government in developing and actioning the Queensland Energy and Jobs Plan (QEJP) including the establishment of new Renewable Energy Zones (REZ) and providing input on transmission development considerations and broader technical aspects associated with the energy transformation.
- Powerlink's long-term strategic planning approach comprises a series of staged low regret investments and remains focussed on delivering safe, reliable and affordable services taking into account:
  - the central role the transmission network will play in enabling the transformation to a lower emissions future
  - dynamic changes in the external environment including continued growth in Variable Renewable Energy (VRE), Consumer Energy Resources (CER) including rooftop photovoltaic (PV) systems, large and small-scale firming technologies, as well as broader shifts to electrification and decarbonisation within Queensland industries
  - the condition and performance of existing transmission network assets to plan the network in such a way that it is best configured to meet current and future energy needs while maintaining the flexibility to adapt as the transmission network need evolves.

## 2.1 Introduction

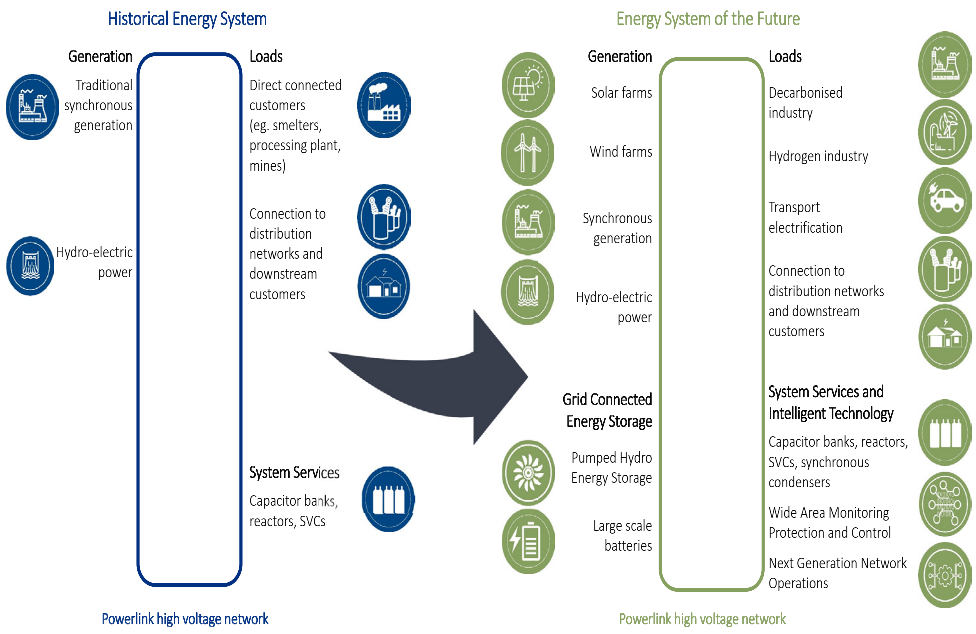
The transformation of the energy system within Queensland to one underpinned by clean, sustainable and affordable renewable energy is well underway. This is evident with an increasing share of large-scale VRE within the State and continued strong growth in the uptake of rooftop PV systems and large-scale batteries. Many corporations are committing to the decarbonisation of existing fossil fuelled operations and processes either through electrification or clean fuel substitution to leverage Queensland's abundant renewable energy resources.

The energy system of the future will be characterised by a mix of technologies and infrastructure along the entire energy supply chain to transform to net zero emissions. It will look considerably different to the energy system of the past with large-scale renewable energy generation, long-duration Pumped Hydro Energy Storage (PHES) and Battery Energy Storage Systems (BESS), electrified industrial and transport sectors, emerging green industries, CER, and intelligent control and orchestration being integral components of the decarbonised energy system (refer to Figure 2.1).

The transmission system plays a critical role as the platform for the efficient large-scale transportation of renewable energy and storage. As the Jurisdictional Planning Body (JPB) and Transmission Network Service Provider (TNSP) within Queensland, Powerlink is playing an active role in shaping and enabling the power system of the future.

Powerlink has also been designated new roles under legislation recently enacted by the Queensland Government in April 2024. These roles comprise the REZ Delivery Body (RDB) and REZ TNSP for Queensland. Powerlink continues to work closely with the Queensland Government providing technical insights on transmission network developments on optimal pathways to achieve 80% renewables by 2035, 75% economy-wide carbon emissions reductions on 2005 levels by 2035, and net zero emissions by 2050.

Figure 2.1 Energy system of the future




## 2.2 Queensland Energy and Jobs Plan

In September 2022, the Queensland Government published the Queensland Energy and Jobs Plan (QEJP). This plan sets out the roadmap for the transformation of the energy system and adds to Queensland's existing renewable energy targets. The plan also details a range of initiatives and foundational investments to achieve these targets.

The Queensland SuperGrid Infrastructure Blueprint ("Infrastructure Blueprint") was published by the Queensland Government in conjunction with the QEJP. The Infrastructure Blueprint outlines the Optimal Infrastructure Pathway (OIP) to deliver a clean, reliable and affordable power system. Powerlink continues to inform and provide context to the broader technical aspects associated with the energy transformation.

### 2.2.1 Adapting to changes in the external environment

The Infrastructure Blueprint is a point in time plan with the underlying inputs, assumptions and future scenarios continually monitored as the market evolves and the quality of available information improves as part of detailed design and planning phases. The Queensland Government is required to update its Infrastructure Blueprint every two years with the OIP to reflect new infrastructure investments, changing market conditions, and the market outlook. The next update to the Infrastructure Blueprint is scheduled for May 2025 and will be discussed in Powerlink's 2025 Transmission Annual Planning Report.

## 2.3 Legislative developments since publication of the 2023 TAPR

The Queensland Government has passed new legislation to drive clean economy investments, support new green industries and jobs, and lay the pathway for transformation of the energy system to one underpinned by reliable and affordable renewable energy.

On the 18 April 2024, the Queensland Government passed the Clean Economy Jobs Act 2024 making a significant move towards realising a clean economy future for Queensland. This legislation aims to drive investment and jobs with a new emissions reduction target of 75% below 2005 levels by 2035 as well as enshrining in legislation Queensland's commitment to net zero emissions by 2050.

The Queensland Government also passed the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act) on the 18 April 2024. The Act enshrines three State Renewable Energy Targets in legislation and creates frameworks for building the Queensland SuperGrid. The Act establishes governance and advisory bodies to ensure a smooth and co-ordinated energy transformation providing crucial steps towards a clean, reliable, and affordable energy future for Queensland. The Act also sets out the process to allow the Queensland Government to identify and assess Priority Transmission Investment (PTI) projects within a new State-based planning and investment framework, and to direct Powerlink to construct these projects and recover its costs following completion of assessment activities.

The Infrastructure Blueprint identifies eligible PTIs. Powerlink is required to undertake public consultation processes as part of the assessment stages of the PTI process and will invite written responses to consultations from energy industry participants, energy market bodies, potential non-network solution providers, and any other interested parties. PTIs may provide opportunities for non-network solutions and providers of potential solutions are encouraged to provide a written response to PTI consultations to enable a full assessment of all credible options.

In July 2024, Powerlink commenced consultation on the Gladstone Project as a candidate PTI under the ERTJ Act. This consultation is being undertaken to ensure that on-going reliability and security of supply is available to meet forecast electrical load in the Gladstone area and support the decarbonisation of major industries in anticipation of the closure of the Gladstone Power Station. Further details on this consultation and next steps are provided within Section 6.6.2 and Powerlink's website[1].

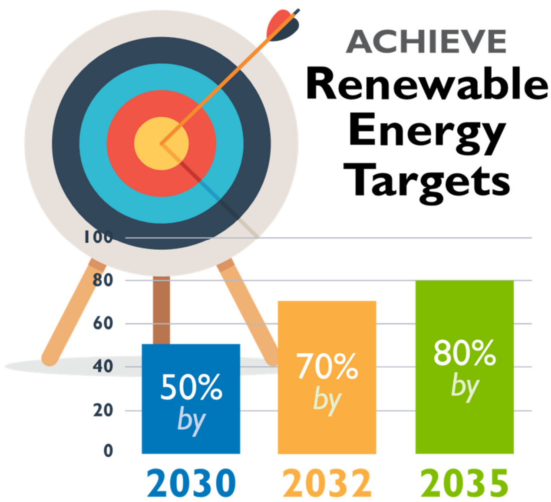
### 2.3.1 Renewable Energy Targets

The ERTJ Act 2024 enshrines State Renewable Energy Targets into legislation (refer to Figure 2.2).

Queensland is well on track to meeting these renewable energy targets. The construction of a number of large-scale renewable energy projects within Queensland and the continued strong uptake of rooftop solar PV systems has meant that steady progress is being made towards meeting these targets.

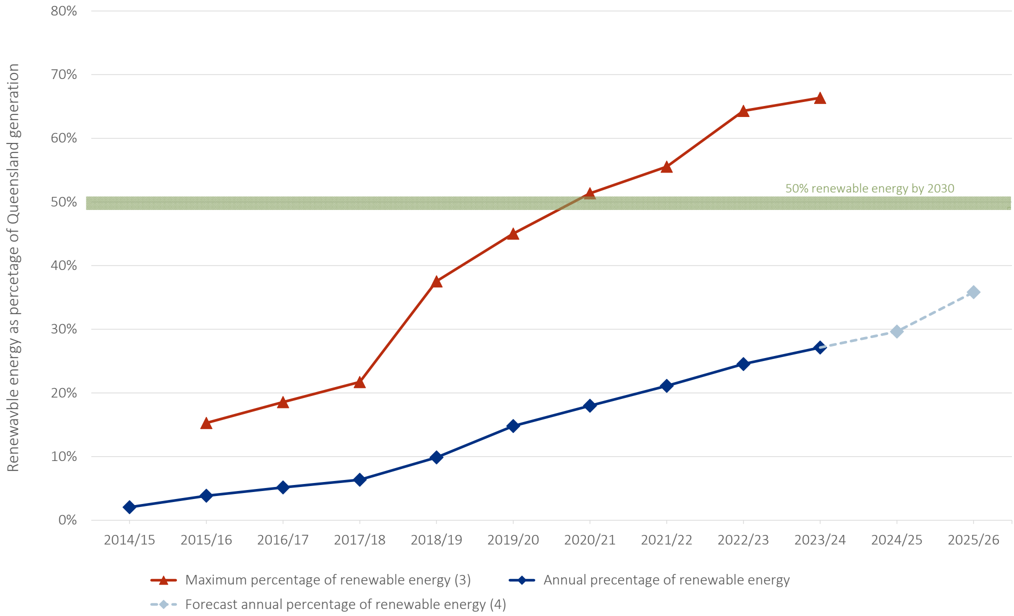
The maximum percentage of renewable energy generation has also been steadily increasing. The peak percentage of renewable energy across the most recent financial year has now exceeded 65% (refer to Figure 2.3).

Figure 2.2 Queensland renewable energy targets[2]




1 Refer www.powerlink.com.au/priority-transmission-investment-gladstone-project.
2 Source: Queensland Energy and Jobs Plan Overview.

Figure 2.3 Queensland percentage of renewable energy generation (1) (2)




Notes:

(1) Annual average and maximum percentage of renewable energy generation based on AEMO and Clean Energy Regulator data.

(2) Percentage of renewable energy calculation methodology as per Queensland Government website. Refer www.energyandclimate.qld.gov.au/about/initiatives/renewable-energy-targets

(3) Maximum percentage of renewable energy refers to the highest percentage of renewable energy generated in a trading interval during the financial year.

(4) Forecast annual percentage of renewable energy includes renewable generation projects currently under construction and undergoing commissioning. Capacity factors for new renewable generating stations are based on existing stations of similar technology within the vicinity. Rooftop PV is included within renewable energy generation with forecasts based on the AEMO 2024 ISP Step Change scenario.

## 2.4 The Queensland SuperGrid transmission backbone

The Queensland SuperGrid detailed within the Infrastructure Blueprint includes a number of inter-related elements comprising renewable generation, firming of intermittent generation, and the transmission network.

A key part of the OIP transmission infrastructure detailed within the Infrastructure Blueprint is a new high capacity transmission backbone to enable the efficient transportation of renewable energy and storage across the State taking advantage of daily and seasonal diversity of renewable energy resources. The Infrastructure Blueprint provides foundations for the next stages of optimisation whilst acknowledging the need to take account the dynamic nature of the power system including market development opportunities, technical performance, and technology changes.

Subject to shareholding Minister approval, the SuperGrid transmission backbone will be developed in stages to provide connection capacity for new PHES facilities and access to Queensland's high quality renewable energy resources. The Infrastructure Blueprint currently identifies the first stage as the delivery of a high capacity transmission line connection between Halys (near Kingaroy) and Woolooga (near Gympie) for the bulk transfer of power. The transmission line would also serve to connect Borumba Pumped Hydro Energy Storage (PHES) into the transmission network.

The second stage of the SuperGrid provides a high capacity transmission line between Southern Queensland (SQ) and Central Queensland (CQ). The connection is planned to increase transfer capacity between SQ and CQ and support predicted load growth in the Gladstone region. The augmentation will also further support the hosting of renewable generation connections in South and Central Queensland.

The third stage of the SuperGrid transmission backbone involves transmission connections from Townsville through to Central Queensland, enabling connection of the proposed PHES to load within the Gladstone area as well as harnessing the diverse and high quality wind resource in northern and western Queensland.

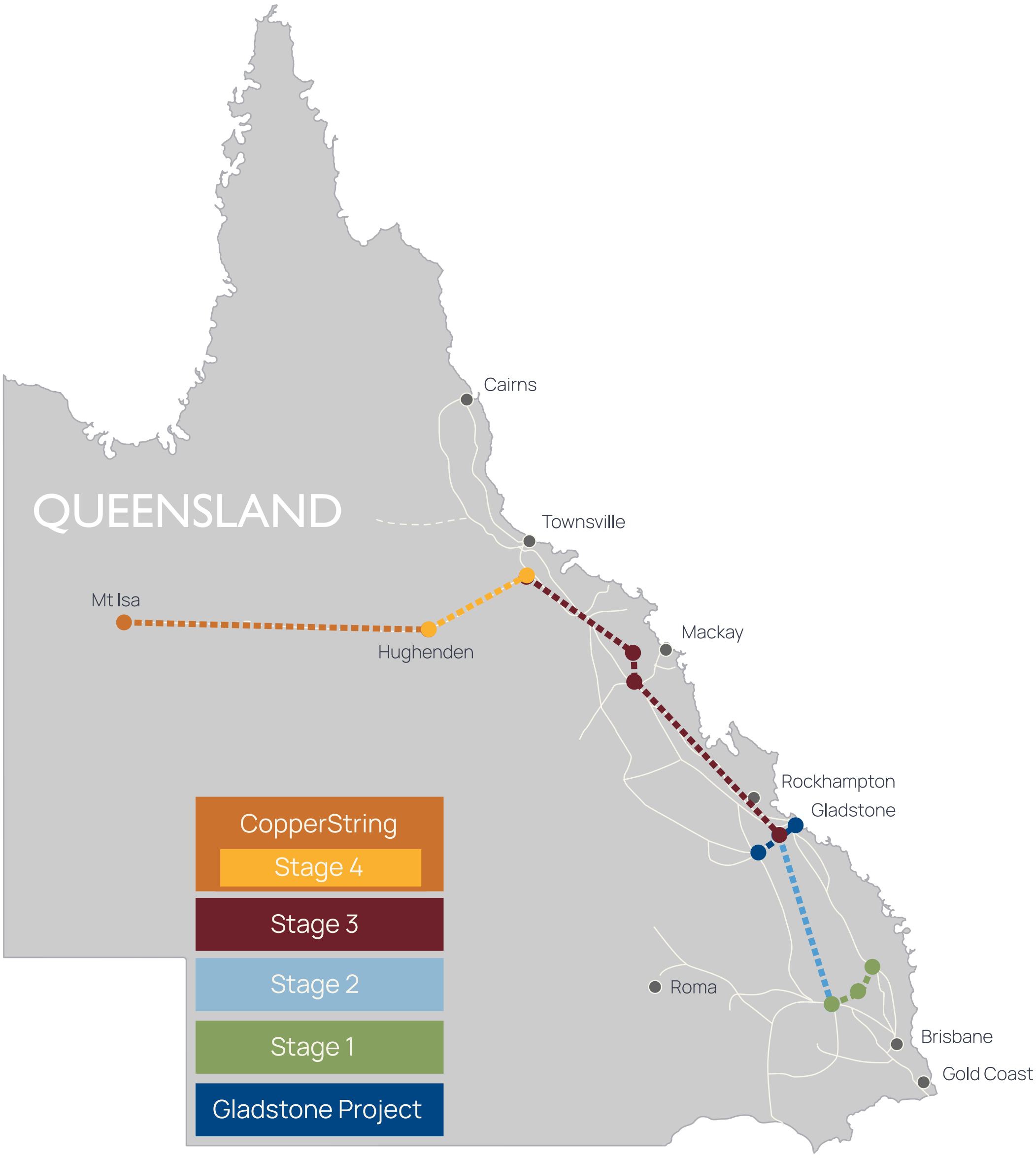
The fourth stage of the SuperGrid is the Townsville to Hughenden transmission development. In June 2023, the Queensland Government announced that the fourth stage of the SuperGrid will be advanced and form part of CopperString 2032. This critical infrastructure development will be publicly owned with Powerlink building and operating the new transmission connection (refer to Section 2.4.1).

In July 2024, an update was made to the second stage of the SuperGrid strategy to shift the original location from a coastal to an inland route. This alignment change is based on the significant interest from renewable energy companies to develop wind farms to the west of the original alignment. The ability to leverage this wind resource through an altered alignment will benefit Queensland by reducing the costs of connecting transmission infrastructure, increasing the pace of renewable development and associated decarbonisation. That is, routing the SuperGrid connection via an inland alignment will result in a more coordinated solution with shorter transmission connections to each wind farm and a significant reduction in the overall footprint of transmission infrastructure. This strategy also allows transmission development to be built in stages and paced to align with interest for renewable connections.

Powerlink will commence planning a high capacity transmission line between Halys and the Gladstone area as part of the updated SuperGrid transmission backbone strategy. Powerlink will engage extensively with the community and stakeholders during Transmission Easement Engagement Processes to identify a corridor that leads to the best overall outcomes from a social, environmental and economic perspective.

The establishment of a transmission line of up to 500kV along the inland corridor between South Queensland and Central Queensland enables the first stage of the SuperGrid transmission backbone from Halys to Woolooga to be constructed at 275kV rather than 500kV. The updated Queensland SuperGrid transmission backbone is shown in Figure 2.4.

Figure 2.4 Queensland SuperGrid transmission backbone




Note: Powerlink is currently progressing consultation on the Gladstone Project as a candidate PTI (refer to sections 2.3 and 6.6).

### 2.4.1 CopperString 2032

The CopperString 2032 project involves constructing 840km of high voltage transmission line from Townsville to Mount Isa that will connect the North West Mineral Province (NWMP) to the National Electricity Market (NEM). CopperString 2032 will form an essential part of the Queensland SuperGrid transmission backbone. Powerlink took ownership of the project from CuString Pty Ltd in March 2023, and will build and own CopperString 2032, leading delivery of the project to completion.

The connection of the NWMP will link one of the richest mineral deposits in the world to the NEM. These minerals are essential for the production of components within electric vehicles, battery systems, and other products to aid the shift to decarbonisation.

CopperString 2032 is anticipated to significantly bolster new industries and facilities for minerals mining and processing in north west Queensland. For example, a consortium of three major companies has recently signed a collaboration agreement to build an end-to-end manufacturing chain for vanadium flow batteries in north Queensland.

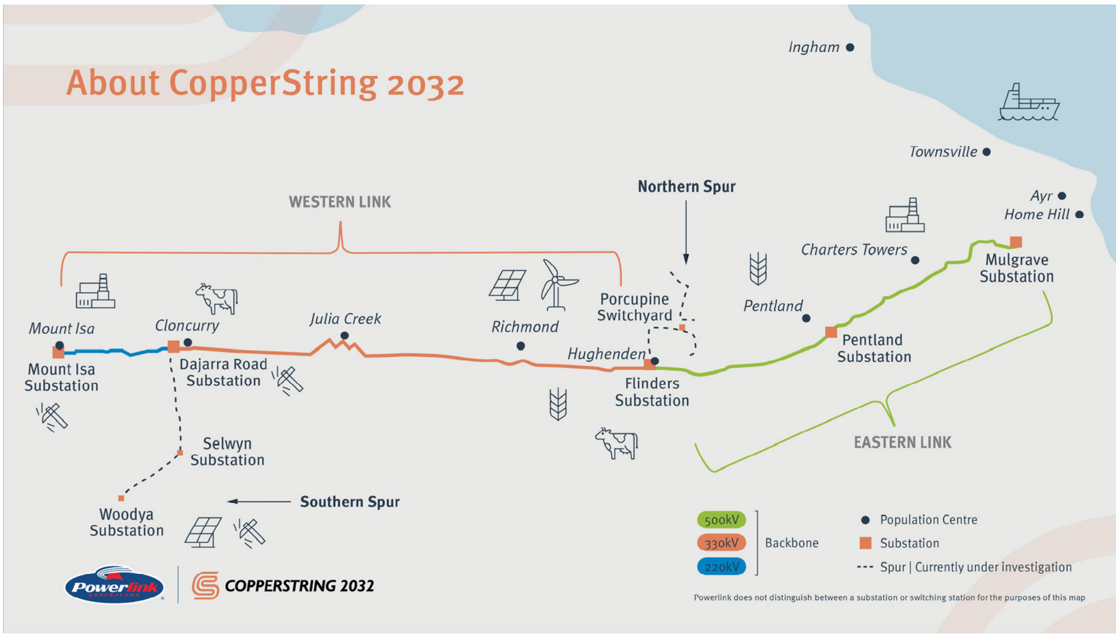
CopperString 2032 will also enable the connection of significant quantities of renewable energy from north west Queensland to the rest of Queensland. The Hughenden region has the potential to host significant levels of new wind generation which has complementary properties to wind output in other parts of the State particularly during winter and night time periods. The Hughenden region has been designated as Flinders REZ within the 2024 Queensland Government REZ Roadmap (refer to Section 2.5.5).

The CopperString 2032 project includes the following core transmission infrastructure components:

- construction of new 500kV double circuit transmission line from Townsville to Hughenden (Stage 4)
- construction of new 330kV double circuit transmission line from Hughenden to Cloncurry
- construction of new 220kV double circuit transmission line from Cloncurry to Mount Isa
- establishment of new substations, and installation of transformers and reactive plant.

It is also anticipated that further transmission lines will be constructed to connect diverse wind renewable energy to Flinders Substation following the CopperString 2032 project.

Figure 2.5 CopperString 2032 transmission development




The Australian Energy Market Operator (AEMO) has included the CopperString 2032 project as an Anticipated Project within the recently published AEMO 2024 Integrated System Plan.

## 2.5 Renewable Energy Zones

A REZ is a geographic area which has significant high quality renewable resources, suitable topography, and available land to support the efficient connection of a number of large-scale renewable energy projects. Development of a REZ allows multiple grid-scale renewable energy developments to be connected in the one location realising economies of scale and enabling the connection of grid-connected renewable energy in a more cost effective and streamlined manner therefore benefiting communities, developers and consumers. The development of REZs streamlines implementation of renewable energy projects by leveraging common infrastructure.

Queensland is an attractive location for grid-scale VRE generation as the state is rich in a diverse range of renewable resources. The establishment of REZs enables optimisation through co-ordination of large-scale renewable generation, transmission network, energy storage and firming, and ancillary system services to maximise the potential capacity of renewable energy in a cost-efficient manner, while reducing investment risk and financing cost for developers.

The Queensland Government has undertaken a range of initiatives to make the connection process to REZs smoother and simpler for developers, and to establish on-going benefits for landholders, communities, and other stakeholders in these areas. Powerlink has worked closely with the Queensland Government on these initiatives.

### 2.5.1 Queensland's REZ Model

Queensland has implemented a market-led REZ approach. This model is characterised by Powerlink working with renewable energy companies to identify projects which are of a size and maturity to drive efficient development of REZs. The model helps reduce landholder, environmental and community impacts as well as risk and costs, and is funded by the renewable energy companies connecting to the REZ.

This approach delivers benefits for developers by unlocking additional streamlined opportunities to connect to the network increasing the cost effectiveness of connecting and optimising the capability of the system. Key principles of this approach include:

- supporting connection of new generation at locations with high resource quality relatively close to the transmission network
- using existing network capacity
- developing REZs in a scale-efficient way to maximise hosting capacity and system strength at lowest cost
- reduced individual proponent connection costs
- simplicity and transparency in the connection process
- clear and consistent community engagement requirements
- speed of connections.

While REZs aim to achieve similar energy transformation goals, each declared REZ in Queensland will be unique. The approach and design of each REZ will consider specific locational characteristics, geography, connection into shared transmission infrastructure, resource availability and community context.

### 2.5.2 Queensland REZ Roadmap

In March 2024, the Queensland Government published the 2024 Queensland Renewable Energy Zone Roadmap following extensive consultation with stakeholders and communities across the State. The Roadmap outlines the pathway for connecting 25GW of large-scale renewable energy by 2035 and is a key component of the QEJP and commitment to meet Queensland's renewable energy targets. The Roadmap provides transparency over likely future REZ locations in Queensland to help improve long-term regional planning and co-ordination.

The Queensland Government has published key insights and lessons from consultation with local communities on the draft 2023 REZ Roadmap. The Stakeholder Insights on the Energy Transformation provides critical insights on how to best deliver the energy transformation for regional communities and improve outcomes. The Queensland Government has committed to updating the Queensland REZ Roadmap every two years aligned with the Queensland SuperGrid Infrastructure Blueprint to reflect the latest market outlook and developments.

Powerlink provided significant input to developing the Queensland REZ Roadmap. The Queensland Government and Powerlink have undertaken analysis to determine where potential REZs could be established. The analysis has identified 12 potential REZ locations across the Far North, North, Central and Southern regions of the state (refer to Figure 2.6). These indicative REZ locations have been identified based on analysis of a range of factors. As the jurisdictional planning body for Queensland, Powerlink has examined the capability of the transmission network to determine optimal locations for development of REZs. The assessment also included an appraisal of renewable investor development interest.

The identified REZs will be developed over three phases to facilitate staged implementation of large-scale renewable generation:

- Phase 1 – Building on our strong foundations (early to mid 2020s)
- Phase 2 – Scaling and expanding opportunities (mid to late 2020s)
- Phase 3 – Preparing for net zero by 2050 (early 2030s).

The three phases take into account the sequencing of other large-scale energy infrastructure developments including the SuperGrid transmission backbone, and long duration PHES facilities.

It should be noted that the hosting capacity, location, and timing of REZs may change over time based on analysis of market forces, available network capacity, renewable resources, investor interest, land use, and other factors. The precise footprint of REZ infrastructure, including network, generation, storage, and system services facilities, will be developed on a case by case basis. Additional future REZs may also be identified to meet growing demand from decarbonisation and electrification of existing industries, new green industries, and other load developments.

### 2.5.3 New Roles for Powerlink

There are two new distinct roles for the delivery of Queensland REZs within the ERTJ Act 2024.

The first role is performing the function of RDB. The Queensland Government has appointed Powerlink as the RDB effective from 1 July 2024. The RDB is responsible for identifying areas suitable to be a REZ, developing draft and final REZ Management Plans (RMP) to enable the declaration of the REZ, and consulting with communities and stakeholders.

The second role involves Powerlink performing the function of the REZ TNSP. Powerlink will be responsible for planning, design, owning, constructing, operating and maintaining REZ transmission infrastructure and undertaking processes for the connection of renewable generation. It should be noted that infrastructure linked to REZs will not be open access and will follow processes prescribed in the RMP to optimise Queensland renewable generation.

### 2.5.4 Delivery of Renewable Energy Zones

The delivery of REZs within Queensland is well underway. In June 2024, Powerlink commissioned the Far North Queensland REZ with the Kaban Green Power Hub as the foundation customer. The development of this REZ commenced prior to the establishment of provisions contained within the ERTJ Act 2024, and hence was designated as one of the inflight REZs within the Queensland 2024 REZ Roadmap.

Southern Downs and Western Downs REZ in southern Queensland have also been significantly progressed. These REZs have also been designated as inflight REZs within the Queensland 2024 REZ Roadmap. Powerlink completed construction and energised the 330kV transmission network for the Southern Downs REZ in December 2023. The Western Downs REZ is scheduled to be energised towards the end of 2024.

Powerlink is also progressing the planning for Callide REZ located in Central Queensland. The development of this REZ and enabling infrastructure will be carried out under provisions within the new ERTJ Act 2024. Powerlink will develop this REZ and enabling infrastructures as part of RDB and REZ TNSP responsibilities.

### 2.5.5 Potential Queensland Renewable Energy Zones

The Queensland Government REZ Roadmap contained 12 potential REZs. Further details on these REZs are provided below and in Table 2.1.

#### Far North and North Queensland

The Far North and North Queensland areas offer rich wind and solar renewable energy resources. The CopperString 2032 project is set to open up the Hughenden region for substantial wind and solar renewable energy development. Renewable energy in this area is in proximity to the planned development of PHES and emerging green industry within the Townsville and Bowen areas. Powerlink has also established an interim transmission and training hub in Townsville to provide local engineering and field services to support development and maintenance of the transmission network in North Queensland (refer to Section 2.10). A permanent hub will be established in Townsville in coming years.

Powerlink commissioned the Far North Queensland REZ in June 2024. Two additional REZs are earmarked for this area. The Collinsville and Flinders REZs are anticipated to provide around 4GW of hosting capacity.

#### Central Queensland

The Central Queensland region offers strong opportunities for both wind and solar renewable energy and is well placed to capitalise on the decarbonisation and electrification of industrial and metals processing facilities and emergence of new green industry within the Gladstone area.

There are four candidate REZs proposed for Central Queensland. The Callide and Calliope REZs will form the first stages of REZ developments anticipated to provide more than 4GW of combined hosting capacity.

The Isaac and Capricorn REZs are anticipated to form the second stage of REZ development providing around 3GW of hosting capacity.

### Southern Queensland

Southern Queensland also provides attractive opportunities for large-scale wind and solar renewable energy generation particularly within the south western part of the region. A number of wind farms have recently been commissioned or are in advanced stages of construction within this area. Renewable energy resources in south west Queensland are in proximity to energy intensive agribusinesses in the region that are looking to decarbonise. The south west Queensland area is also expected to provide renewable energy to major load centres within South East Queensland via the SuperGrid.

There are currently two inflight REZs for South Queensland. The Southern Downs and Western Downs REZs are expected to have a combined network hosting capacity exceeding 4GW. Powerlink has completed construction and energised the 330kV transmission network for the Southern Downs REZ and is progressing the construction of 275kV network for the Western Downs REZ.

There are three additional REZs proposed for south Queensland. The Woolooga and Darling Downs REZs form part of the second stage of REZ development within the Roadmap and are expected to provide around 4GW of combined hosting capacity. The Tarong REZ forms part of the third stage of REZ development and will be developed to align with the establishment of other large-scale energy infrastructure.

Table 2.1 Expected REZ installed generation within the 2024 Queensland REZ Roadmap (1)

| Region | REZ | Expected installed generation | In-flight | Phase 1 | Phase 2 | Phase 3 |
|---|---|---|---|---|---|---|
| Far North and North Queensland | Far North Queensland | 500 to 700MW | ✓ (2) | | | |
| | Collinsville | 1600 to 2000MW | | | ✓ | |
| | Flinders | 2000 to 2400MW | | | ✓ | |
| Central Queensland | Callide | 2000 to 2600MW | | ✓ | | |
| | Calliope | 1500 to 2000MW | | ✓ | | |
| | Isaac | 1400 to 1800MW | | | ✓ | |
| | Capricorn | 1400 to 1800MW | | | ✓ | |
| Southern Queensland | Southern Downs | 2000 to 2600MW | ✓ (3) | | | |
| | Western Downs | 2000 to 2600MW | ✓ | | | |
| | Woolooga | 1600 to 2000MW | | | ✓ | |
| | Darling Downs | 1600 to 2000MW | | | ✓ | |
| | Tarong | 2000 to 2400MW | | | | ✓ |

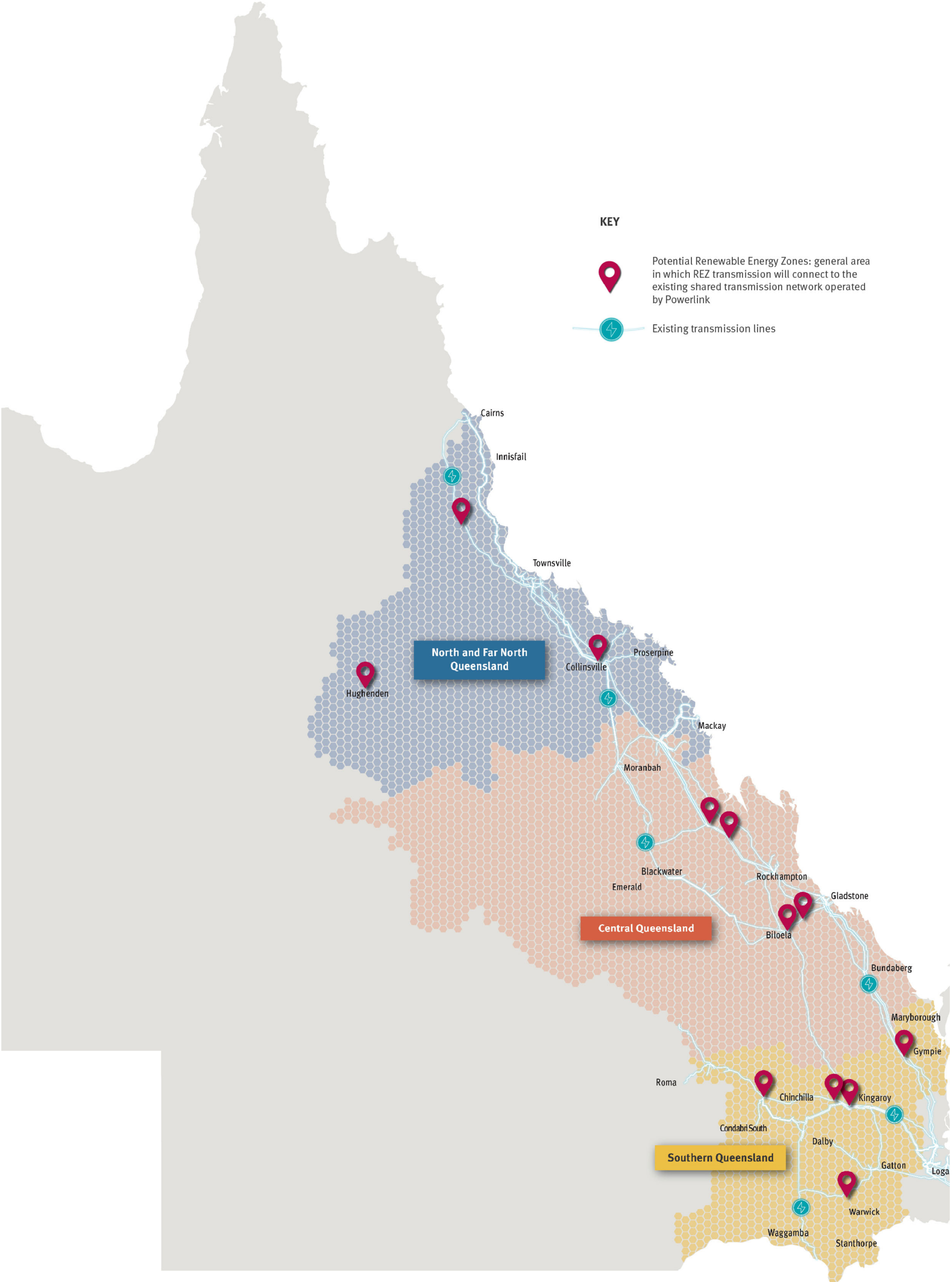
Notes:

(1) Source: Queensland Government 2024 REZ Roadmap.

(2) Powerlink commissioned the Far North Queensland REZ in June 2024.

(3) Powerlink completed construction of the 330kV transmission network for the Southern Downs REZ in December 2023.

Figure 2.6 Potential REZs outlined within the 2024 Queensland Government REZ Roadmap (1)




Source: Queensland Government 2024 REZ Roadmap.

## 2.6 Energy storage and firming

The ability for large-scale electrified industrial processes to operate more flexibly in response to an abundance or scarcity of renewable generation can help reduce the need for additional firming and storage. There is currently limited (continuous) demand side participation within the Queensland energy system. However, the value of demand-side responses is expected to increase as the supply-side becomes dominated by weather-dependent intermittent sources. The potential for load flexibility is expected to increase as more industrial processes decarbonise and transform to electrified operation, and new green industries are established.

Demand response through CER, including household battery systems, electric vehicles, and household electric usage patterns, have played a limited role in firming to date. However, there are opportunities for CER to play a greater and more integral role in the energy transformation.

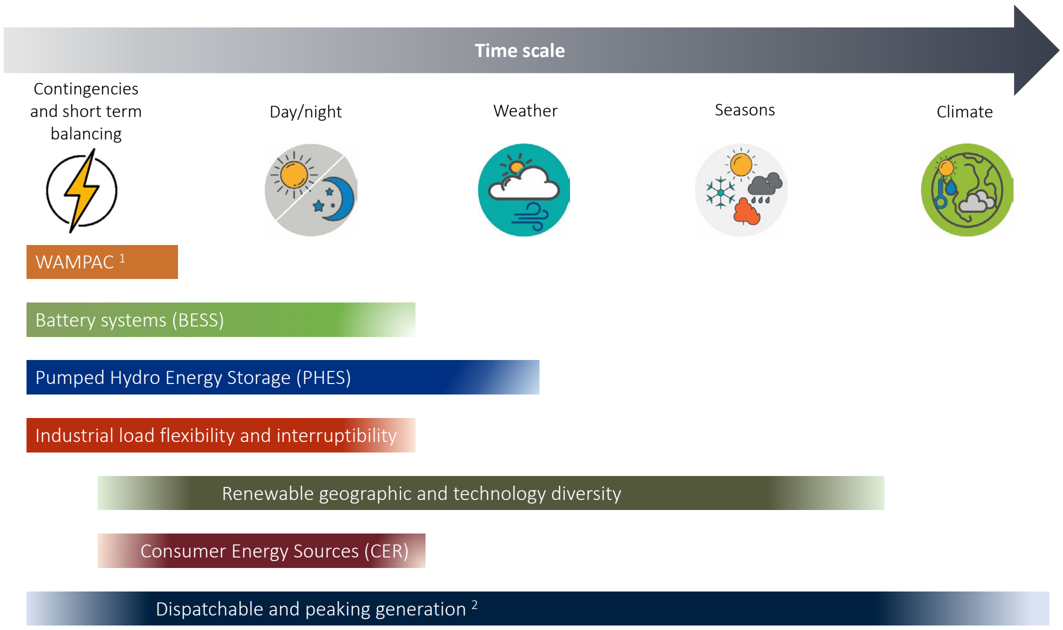
Energy storage and firming services will form an integral part of the future mix of technologies in Queensland. Energy storage services appropriately located and sized will increase the reliability of supply from intermittent generation sources by shifting energy to manage peaks and troughs associated with weather conditions and consumer demand, whilst also providing a number of ancillary services to keep the energy system secure. The energy system of the future will require a mix of energy storage services including PHES, large-scale grid-connected BESS, community battery systems, and residential battery systems.

PHES are utility-scale energy storage systems which deliver hydro-electric power generated through the release of water from an upper reservoir to a lower elevation reservoir, and store energy by using the same machines to pump water from the lower reservoir to the upper reservoir. These systems are generally larger in scale and provide longer duration energy storage whereas battery systems provide energy at smaller storage scales with a faster response over shorter periods. Both technologies will provide a critical role in energy firming and addressing challenges of minimum demand through the ability to pump or charge during periods of abundant renewable energy output to store energy. These technologies will also provide critical system security services necessary to support the power system including voltage and frequency control, system strength, and inertia.

The optimal mix of technologies and services involves an economic trade-off whilst also taking into account environmental and social factors. The use of dispatchable generating sources including natural gas, renewable fuels, and hydrogen generation is expected to play an important role in addressing extremities with weather and climatic conditions. A renewable generation mix which is both geographic and technologically diverse through prudent subscription of REZs, development of appropriately sized intra-regional transmission and interconnections with other regions will also help address and manage supply intermittency.

The nature and mix of energy storage and firming services within Queensland will be required to operate across a range of time scales and operating conditions to ensure reliability of supply. These operating horizons range from very short response periods (e.g. such as those during network contingencies) to longer periods across seasons and multi-year periods reflecting climate variations. Potential technologies likely to play an integral role in the firming of energy across the range of time scales are outlined in Figure 2.7.

Figure 2.7 Potential roles of firming technologies and services across time scale ranges




Notes:

(1) Further information on WAMPAC (Wide Area Monitoring Protection and Control) provided within Section 2.9.

(2) Dispatchable and peaking generation includes natural gas, renewable fuels, and hydrogen generation.

### 2.6.1 Pumped Hydro Energy Storage

The QEJP details the establishment of two publicly owned long duration PHES facilities. Large-scale deep storage facilities are essential for the energy transformation and facilitate the integration of large amounts of renewable energy. Subject to planning approvals, the two facilities comprise the Borumba PHES located south west of Gympie and the proposed Pioneer-Burdekin PHES located within North Queensland.

#### Borumba PHES

The Borumba PHES was selected as the first site for development following a state-wide assessment of potential pumped hydro locations. The facility is expected to be capable of generating up to 2GW of power for a period of 24 hours. The site is located in close proximity to several existing transmission corridors within southern Queensland and is strategically located to provide firming and system support services for significant renewable energy generation development within South Queensland. Queensland Hydro is undertaking environmental impact assessments, detailed engineering, geo-technical testing, civil infrastructure upgrades, and other delivery activities for the facility.

The Borumba PHES is planned to connect to the new high capacity transmission line between Halys and Woolooga substations, established as the first stage of the SuperGrid (refer to Section 2.4). The Borumba PHES and associated connections will provide long duration deep firming services essential to support the transformation to net zero emissions.

#### Pioneer-Burdekin PHES

The Pioneer Valley and adjacent ranges located approximately 75km west of Mackay were identified as an area with significant potential for a long-duration PHES facility. This was due to its favourable topography and proximity to high quality wind and solar generation sources in central and north Queensland.

The proposed Pioneer-Burdekin PHES is anticipated to have an energy storage capacity of up to 120GWh, allowing generating or pumping at 5GW over 24 hours. This PHES enables large-scale storage and transportation of renewable energy to support the decarbonisation and electrification of existing industrial processes and enable the development of new green industries. Queensland Hydro is undertaking a range of investigations to gain a comprehensive understanding of the project site.

#### Other PHES developments

Powerlink has been engaged by Genex Power Limited (Genex) to undertake a range of activities relating to the development of a 275kV electricity transmission line and associated substations for the connection of the Kidston Clean Energy Hub located in north Queensland (approximately 270km north west of Townsville). This renewable energy facility includes the construction of a 250MW / 2000MWh PHES facility (K2-Hydro) expected to commence operations in 2025.

There are numerous other PHES projects being progressed by the private sector which are in various stages of development. These projects will also form key infrastructure facilities to enable the energy transformation within Queensland.

### 2.6.2 Battery Energy Storage Systems

Grid-scale BESS, including those supported by advanced grid-forming inverter technology, will play a greater role in the transmission network and in providing system security services such as ramping support, managing shorter-term energy balancing, frequency regulation, voltage control, virtual inertia, and system strength. Grid-forming batteries can play an important role in increasing the hosting capability of inverter-based renewable generation and supporting the secure operation of the power system.

Grid-scale batteries can also play a role as Virtual Transmission Lines (VTLs). This offers the potential to alleviate transmission congestion and defer the need for network augmentations. Furthermore, large-scale battery services can be used to manage the impact of network outages by reducing constraints on generation, and potentially provide other support and ancillary services for the transmission network.

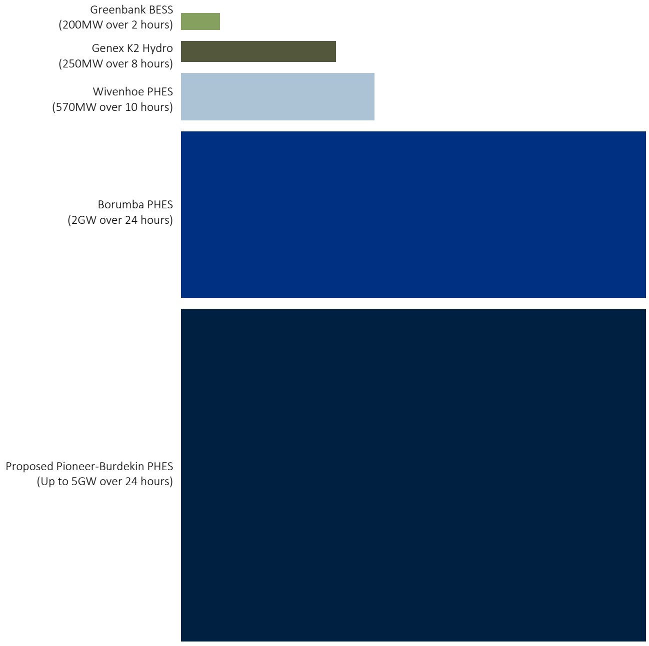
Queensland's first large-scale BESS (100MW / 150MWh) was connected to Powerlink's transmission network at Wandoan South Substation in 2022. A second large-scale BESS built by Genex Power (50MW / 100MWh) connected to Powerlink's transmission network at Bouldercombe substation near Rockhampton commencing operation in June 2023.

Powerlink is continuing to experience strong interest in the development and connection of large-scale BESS facilities across Queensland. There are a significant number of additional large-scale grid connected BESS in advanced stages of construction which are expected to be operational over the near term. Powerlink is currently progressing construction works for 755MW of large-scale BESS projects with total energy storage capacity of 1098MWh. These projects are under construction in a number of locations across the State (refer to Section 9.2).

### 2.6.3 Comparison of energy storage systems

An indication of the relative sizes of energy storage for existing and proposed storage infrastructure projects within Queensland are shown in Figure 2.8.

Figure 2.8 Relative energy storage capacities of PHES and BESS




## 2.7 Electrical demand changes

The electrification of major industrial processes, mining operations, and transportation will be an integral component of Australia's pathway to net zero emissions. Access to a safe, cost effective and reliable transmission network will be pivotal in enabling sectors to electrify operations with renewable generation sources, and for Queensland to transform into a renewable energy exporter.

The electrification of existing fossil fuel operations and processes present the primary avenue for decarbonisation. It has been estimated that around 20% of the energy needs of existing Queensland industries are currently met through electricity, and that around 60% of Queensland's energy consumption has the potential for direct electrical substitution through use of existing and emerging commercialised technologies. The remaining 20% of consumption within the state comprises of energy that is expected to require further technological development for energy substitution.

### 2.7.1 Decarbonisation through electrification

The nature and concentration of energy use across the State varies considerably depending on the category of customer. There are significant mining operations within the central west and north Queensland zones, and electrification of mining operations will impact on transmission capacity requirements to these areas. LNG extraction and compression facilities are concentrated within the Surat and Gladstone zones, and there are significant opportunities to decarbonise these processes through electrification.

Powerlink has experienced significant interest from large industrial customers looking to decarbonise their operations through electrification, and the emergence of new hydrogen and ammonia based industries and associated manufacturing facilities. In aggregate these developments can require significant increases to transmission capacity, with demand potentially exceeding several gigawatts ramping over time from the 2030s. They also have the potential to significantly alter energy flow patterns and power transfer capability requirements across Powerlink's high voltage network (refer to Chapter 8).

The degree of flexibility of these processes in terms of electrical demand consumption and interruptibility under contingency or outage conditions will be an important consideration in transmission network design and firming resources to support the energy transformation (refer to Section 2.6).

The transport sector presents one of the largest opportunities for decarbonisation. The adoption of electric vehicles (EVs) presents a near term opportunity for increasing electrification and decarbonisation. The charging behaviour and patterns for EVs has the potential to either support or challenge network requirements. The management of EV charging will be important to optimising the utilisation of the network.

EVs have the potential for dual purpose application in terms of providing both transportation and a household energy source. Vehicle battery capacities are generally larger than typical household daily use, and over time it may be possible to leverage this capacity back into the system to smooth daily demand usage patterns and rooftop PV output. Both residential battery systems and EVs have the potential to increase transmission and distribution network utilisation under appropriately designed orchestration incentives and mechanisms.

### 2.7.2 Emerging hydrogen industry

The Queensland Government has stated that it is committed to working with industry to accelerate the development of hydrogen related industries, including the production and export of hydrogen and manufacturing of associated hydrogen industrial components. Queensland is well placed for the development of a range of hydrogen production and secondary supporting manufacturing industries due to the prevalence of large-scale renewable energy development, available land, and proximity to ports particularly within the Townsville, Bowen, Gladstone, and Brisbane Trade Coast areas. Potential markets include both domestic hydrogen to decarbonise existing industrial processes and the establishment of new hydrogen export markets.

### 2.7.3 Rooftop photovoltaic systems

The uptake of rooftop PV systems within both residential and commercial premises in Queensland continues to be strong. There is now around 6.4GW of household and commercial rooftop systems connected to the network (refer to Section 3.2.1).

The uptake and development of distribution level renewable energy and rooftop PV systems continues to progressively deepen the characteristic duck curve observed during the day, most prominently during the autumn and spring periods (refer to Section 3.2.1). This continues to present challenges to the power system in terms of voltage control, ramping between minimum and maximum demand, frequency control services, system strength, and inertia.

Powerlink has contracted a Network Support Agreement with CleanCo Queensland for the provision of Network Support and Control Ancillary Services (NSCAS) for the management and control of voltages. Powerlink has also recently commissioned a new reactor in central Queensland and for voltage control and management during periods of low demand (refer to sections 7.6.2 and 7.7.10 and Table 9.3) and another new reactor is under construction in southern Queensland (refer to Table 9.4).

Powerlink is actively collaborating with Australian Energy Market Operator (AEMO) and participating in national industry working groups to develop strategies and implement measures to address the technical challenges and issues associated with changing grid demand profiles including minimum demand (refer to Appendix B).

## 2.8 System strength

System strength is a measure of the ability of the power system to remain stable by maintaining the voltage waveform at any given location. The power system is required to remain stable for both normal operating conditions and following system events and disturbances to the power system. System strength has traditionally been provided through energy dispatch and the electrical characteristics of coal, gas-fired and hydro-electric power generation (synchronous generation) which are electrically coupled to the power system. However, many non-synchronous generation technologies, such as large-scale solar and wind, do not inherently provide system strength due to the use of grid-following inverters.

Given the scale of the energy transformation, rapid uptake of VRE resources, and changing synchronous generation operation, it is critical to plan for and procure in advance alternate solutions to address system strength needs to ensure the power system remains secure. As the System Strength Service Provider (SSSP) for Queensland, Powerlink is required to plan and make services available to meet minimum and efficient levels of system strength.

The establishment of the SuperGrid transmission backbone and new PHES facilities detailed within the QEJP will support an increase in system strength across the network. However, these developments are not projected to be fully operational until the early to mid-2030s, and there are expected to be periods prior to this time where minimum system strength gaps may occur.

It is expected that non-network solutions will play an important role in the provision of system strength services to support the energy transformation, including existing and planned PHES solutions, grid-forming BESS, synchronous generation, and synchronous condensers. The optimum mix of technologies is expected to change over time alongside the accelerating development of new technologies and facilities.

Powerlink has completed consultation processes to address an immediate system strength gap within Queensland and entered into a non-network solution with Ratch Australia Corporation to enable Townsville Power Station to operate in synchronous condenser mode where required. Powerlink is also progressing a Regulatory Investment Test for Transmission (RIT-T) consultation to identify network and non-network solutions to address minimum and efficient requirements for system strength until the early 2030s.

Further information on system strength planning and activities currently being undertaken by Powerlink are detailed within Chapter 4 and Section 6.6.2.

## 2.9 Increasing capacity of the transmission system

Given the step change in the energy landscape, Powerlink is at the forefront of implementing new approaches and technologies and guiding and shaping developments in the market to increase the capability and performance of the transmission system.

Powerlink is continuing to develop the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events. WAMPAC rapidly detects specific conditions over geographically diverse transmission assets and initiates appropriate action to adapt to system conditions such as changing the network configuration or altering generation and load characteristics. Its speed enables the platform to be effective in sub-second timeframes and can remediate dynamic conditions to secure the network and avoid adverse operating conditions.

WAMPAC has been implemented for system protection services across the Central Queensland to South Queensland (CQ-SQ) grid section. Further applications for the technology are progressing in north Queensland to more effectively manage and operate the transmission network during outages. It is also anticipated that WAMPAC will be instrumental in increasing the hosting capacity of REZs and mitigating the impacts of network contingencies and planned outages within the SuperGrid transmission backbone in the future (refer to sections 6.12.2 and 7.3).

Powerlink is implementing new technology to optimise the performance and capacity of the high voltage network to enable the energy transformation. Detailed assessments have been completed for the adoption of advanced conductor technology, and Powerlink anticipates utilising this technology within 275kV transmission infrastructure in central and south Queensland to increase the thermal ratings of transmission lines and maximise REZ hosting capacity.

Powerlink has commenced field trials of equipment to enable real time ratings for overhead conductor to increase the thermal capability of the transmission network during times of elevated wind speeds. Artificial intelligence (AI) techniques and tools are also being investigated by Powerlink to help optimise the operation and performance of the high voltage system.

## 2.10 Other initiatives

In coming years there will be significant changes in transmission flow patterns as coal generators are progressively withdrawn or change their operational dispatch patterns, new sources of generation and storage are developed, and as the loads change in quantum, shape and distribution. Matters such as marginal loss factors, network charges, and transmission congestion are all sensitive to these changes, and proponents are encouraged to take these into consideration when making decisions on future investments. Powerlink has developed a Fact Sheet available on its website to help proponents understand the possible effects of changes in transmission flow patterns.

Powerlink has continued its close collaboration with the Australian Bureau of Meteorology over the past year undertaking joint analysis into the characteristics of the renewable resources throughout the State. These important insights will help Powerlink better understand weather changes and intermittency and develop the network to progress the energy transformation as seamlessly as possible.

AEMO has designated a number of transmission infrastructure projects as actionable within the 2024 Integrated System Plan (ISP). These projects are located in central and south Queensland and include an upgrade to the transfer capacity across Queensland to New South Wales Interconnector (QNI). Powerlink is progressing these projects through a range of planning and consultation activities and continues to collaborate closely with AEMO on transmission planning through technical working groups and other related activities (refer to Appendix B).

Powerlink opened the Gladstone SuperGrid Training Centre and Transmission Hub in 2023. The centre will support the development of important skills that will be needed to enable the energy transformation. A range of roles will be located at the hubs including community relations, cultural heritage relations, project management, field staff, health and safety officers, training personnel, engineers, support services staff, and trades people to provide local communication, engagement, construction management, and engineering field support.

Powerlink has also established a new office for CopperString 2032 in Townsville. The office will be colocated with a new SuperGrid Training Centre and Transmission Hub, and will provide services including community relations and support, cultural heritage relations, and project management. The training hub will provide specialist high voltage skills to build, operate and maintain the northern parts of the SuperGrid transmission network including CopperString 2032.

## 2.11 Community engagement and benefits

There is a significant amount of new transmission infrastructure that is needed to be built as part of the energy transformation. Powerlink recognises that regional communities play an important role in hosting the essential infrastructure necessary to support the energy transition. Through these activities, there is also potential to create sustainable and legacy opportunities for regional Queensland, and Powerlink will continue to work closely with communities to identify and deliver benefits in these areas.

Powerlink's Community Engagement Strategy drives early and authentic engagement to listen to landholders and communities to better understand their needs and priorities. The main goal is to develop co-existence arrangements with landholders and seek to provide long-term benefits for the communities in which we operate.

In 2023, Powerlink announced a new framework that significantly boosts payments to landholders hosting new transmission infrastructure. The SuperGrid Landholder Payment Framework provides higher payments for Queensland landholders that host new transmission infrastructure. The new framework now provides increased flexibility with landholders able to choose upfront or on-going annual payments. Powerlink also became the first transmission company in Australia to offer payments to landholders with properties adjacent to new transmission infrastructure.

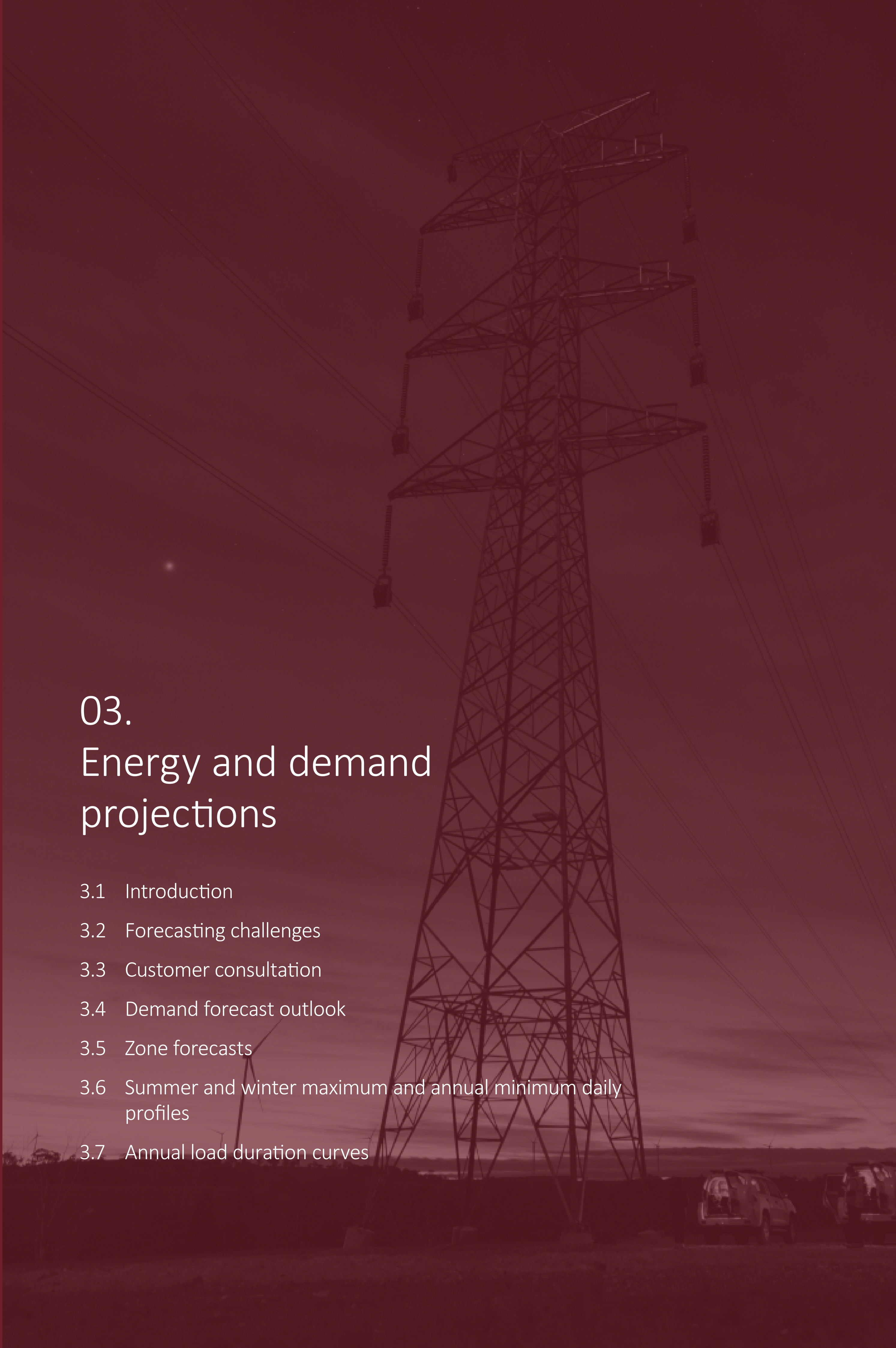
Powerlink's Community Investment Framework ensures local benefits and community investment go hand in hand with delivering Queensland's new energy future. A key pillar is the new SuperGrid Telecommunications Program. As part of this program Powerlink will work with its subsidiary QCN to boost internet connectivity and mobile coverage in regional communities hosting SuperGrid infrastructure and REZs. High-speed internet can be supplied using fibre optic cables installed within overhead earthwires on top of new transmission infrastructure.

The development of new transmission infrastructure within regional areas will also provide additional benefits including new employment and jobs opportunities. The Queensland Government and Powerlink aim to source material and labour requirements to enable the energy transformation from locally produced sources and manufacturers where practical.

## 2.12 On-going transformation

Along with opportunities, the power system of the future will present operational, planning, regulatory and market challenges. New frameworks, strategies and infrastructure are being developed and implemented to enable an efficient and orderly transformation of the energy system to achieve net zero emissions.

The QEJP underpinned by the Infrastructure Blueprint provides a roadmap to a decarbonised energy future, and Powerlink is actively progressing key activities to transform the energy system to one underpinned by clean, sustainable, cost effective, and reliable energy supply.



# 03.
# Energy and demand projections

*This chapter describes the historical energy and demand, and provides forecast regional data disaggregated by zone.*

## Key highlights

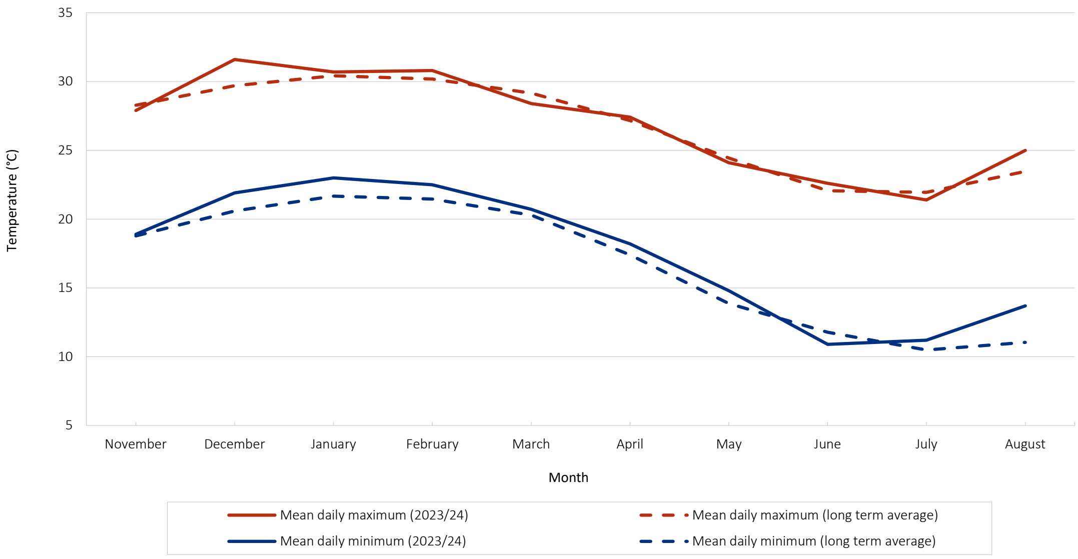
- Queensland's maximum transmission delivered demand for 2023/24 was 9,429MW on 22 January 2024. This maximum demand occurred at 5.00pm and was 513MW greater than the record maximum delivered demand set in 2023.
- Queensland set a new record minimum transmission delivered demand of 2,389MW on 5 October 2024. This minimum demand occurred at 10.00am and was 149MW lower than the previous record minimum set in August 2023.
- Powerlink has produced the load forecast for the 2024 Transmission Annual Planning Report (TAPR) instead of adopting Australian Energy Market Operator's (AEMO's) forecast published in their 2024 Energy Statement of Opportunity (ESOO). This decision was driven by a need to have more granular forecasts at the sub-regional level and the ability to better focus on Queensland consumer behaviour and potential market development in the forecast input assumptions.
- Based on Powerlink's Central scenario forecast, Queensland's transmission delivered maximum demand is expected to have steady growth with an average annual increase of 3.1% per annum over the next 10 years.
- The uptake of rooftop photovoltaic (PV) and distribution connected solar systems is further reducing delivered demand during the day. The rate at which minimum demand declines over the coming years will be closely related to the rate at which rooftop PV systems are installed. Falling minimum demand will result in a variety of impacts on the power system, some of which may necessitate investment on the transmission system.
- Queensland's transmission delivered energy is expected to increase over the next 10 years predominantly due to the electrification of load within a number of Queensland industries. Based on Powerlink's Central scenario forecast, transmission delivered energy consumption is expected to increase at an average rate of 2.5% per annum over the next 10 years.

## 3.1 Introduction

The 2023/24 summer Queensland maximum transmission delivered demand occurred at 5.00pm on 22 January 2024, when 9,429MW was delivered from the transmission grid (refer to Figure 3.9 for load measurement definitions). Operational 'as generated' peak demand was recorded at the same time, reaching 11,005MW. After weather correction, the 2023/24 summer maximum transmission delivered demand was 9,795MW, 4.0% higher than forecast in the 2023 ESOO Step Change scenario forecast.

Figure 3.1 shows observed mean temperatures for Brisbane during November 2023 to August 2024 compared with long-term averages. The comparison reveals a hotter summer than average in south east Queensland and the winter temperatures in July and August were also warmer than the long-term average. The high summer temperatures were also accompanied by extreme relative humidity, especially in January, which was the primary cause of the record maximum demand that month.

**Figure 3.1** Brisbane temperature ranges over November 2023 to August 2024 (1)




Note:

(1) Long-term average based on years 2000 to 2023/24.

The 2024 Queensland minimum transmission delivered demand occurred at 10.00am on 5 October 2024, when only 2,389MW was delivered from the transmission grid (refer to Figure 3.9 for load measurement definitions). Operational 'as generated' minimum demand was recorded at the same time and set a new record for Queensland of 3,091MW, passing the previous minimum record of 3,387MW set in September 2023.

At the time of minimum transmission delivered demand, directly connected loads made up about 83.6% of the transmission delivered demand with Distribution Network Service Provider (DNSP) customers making up the remainder. Mild weather conditions, during a weekend (Sunday) in combination with strong contribution from rooftop PV were contributors to this minimum demand.

Powerlink has developed a transmission delivered demand and energy forecast tool working closely with AEMO and EQL. The decision to move away from adopting AEMO's ESOO forecast was driven by the need for sub regional forecasts. Powerlink is also better placed to forecast future load (new and/or as a result of decarbonisation) in the High, Central and Low scenario forecasts. Powerlink's forecast also includes sub-regional areas, otherwise known as TAPR zones (refer to Appendix F) and delivers the added benefit of forecasts at all levels of the transmission network in the state. The Powerlink forecasting tool uses inputs from a variety of sources listed in Appendix C.

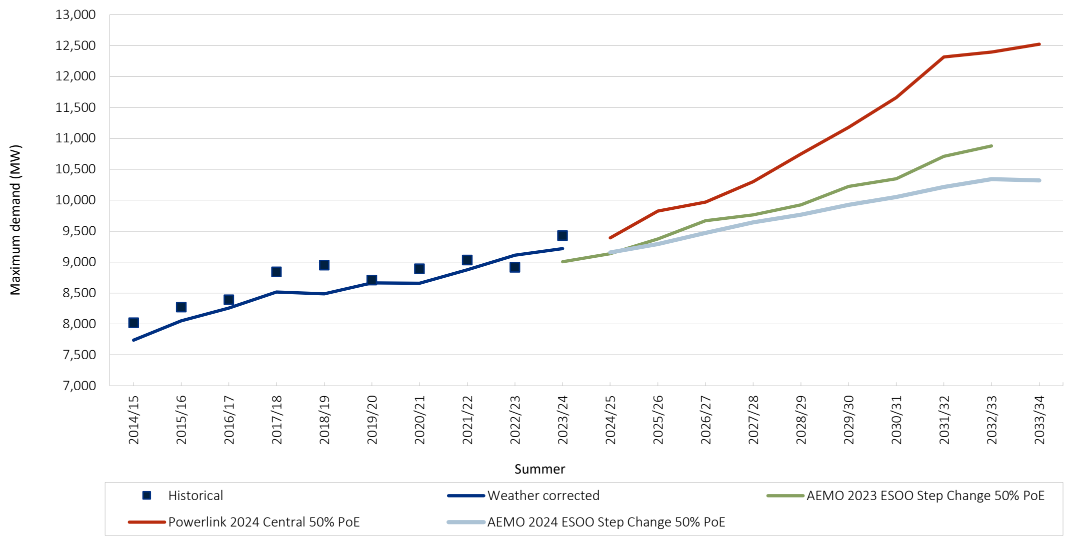
The Queensland Government's 50% renewable energy target by 2030 (QRET) and net zero by 2050 has driven renewable capacity in the form of solar PV and wind farms to connect to the Queensland transmission and distribution networks (refer to tables 7.1 and 7.2). Additional uncommitted distribution connected solar and wind farm capacity has been included into the 10-year outlook period from 2025 to model the Queensland Government's targets.

At the end of June 2024, Queensland reached 6,464MW of installed rooftop PV capacity[1]. Growth in rooftop PV capacity remains strong at around 68MW per month in 2023/24. An impact of rooftop PV has been to time shift both the state's minimum and maximum demands. The minimum demand now occurs during the day rather than night time. The maximum demand now occurs between 5.00pm and 7.00pm. As a result of significant capacity increases in rooftop PV and PV non-scheduled generation (PVNSG), maximum demand is unlikely to reoccur in the day time.

[1] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/06/2024, August 2024. Whilst RET legislation allows a 12 month creation period for registered persons to create their certificates, updates for the first nine months of this window are generally not material.

Figure 3.2 shows a comparison of AEMO's 2023 and 2024 ESOO delivered summer maximum demand forecasts based on the Step Change scenario with Powerlink's 2024 Central scenario, both with 50% Probability of Exceedance (PoE). The increase in the forecast maximum demand is due to an increase in the pace of electrification, new and anticipated block loads in several zones. The Powerlink forecast also considered the connection of Mt Isa on the completion of the Copper String 2032 project from Winter 2031.

Figure 3.2 Comparison of AEMO's 2023 ESOO Step Change scenario delivered demand forecast with the 2024 Powerlink Central scenario (1)

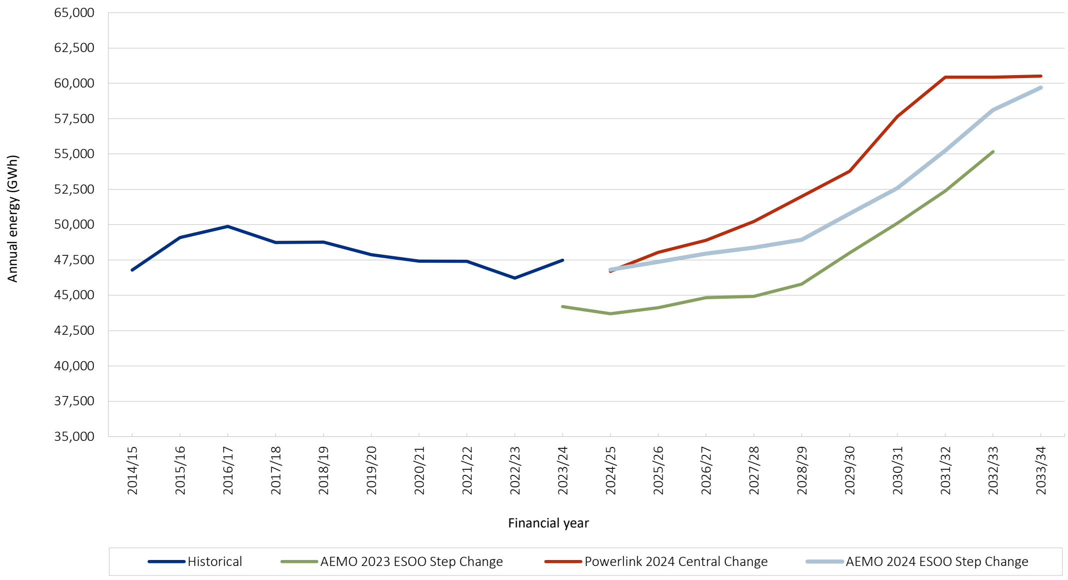



Note:

(1) AEMO's 2023 and 2024 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.9 for further details.

Figure 3.3 shows a comparison of AEMO's 2023 ESOO delivered energy forecasts based on the Step Change scenario with Powerlink's 2024 Central scenario. Section 3.4 discusses updates included in Powerlink's 2024 forecasts. The steady increase in delivered energy is due to new anticipated loads and electrification of existing loads.

Figure 3.3 Comparison of AEMO's 2023 ESOO Step Change scenario delivered energy forecast with the 2024 Powerlink Central scenario (1)

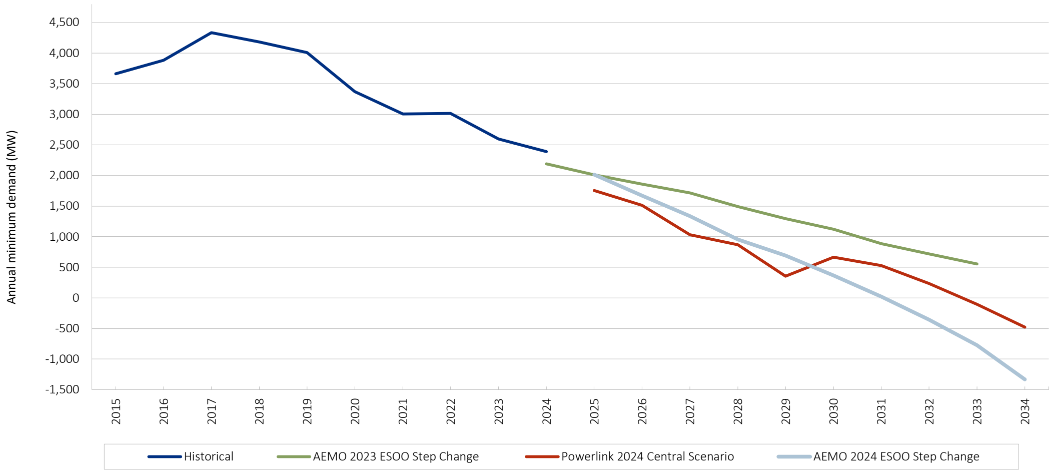



Note:

(1) AEMO's 2023 and 2024 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.9 for further details.

Figure 3.4 shows a comparison of AEMO's 2023 ESOO annual delivered minimum demand forecast based on the Step Change scenario with Powerlink's Central scenario. The drop in minimum demand is due to increases in embedded generation and continued growth in rooftop PV. The increase in 2030/31 is due to new and anticipated ~750MW of block loads coming online and offsetting the PV installation, from 2031/32 the PV generation increases beyond the scale of the block load. The minimum demand forecast does not factor in any market intervention to prevent the grid from becoming unstable under the minimum system load conditions. Market interventions could include directing on grid-scale Battery Energy Storage System (BESS) and PHES systems to increase demand.

Figure 3.4 Comparison of AEMO's 2023 ESOO Step Change scenario minimum delivered demand forecast with the Powerlink 2024 Central scenario (1)




Note:

(1) AEMO's 2023 and 2034 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.9 for further details.

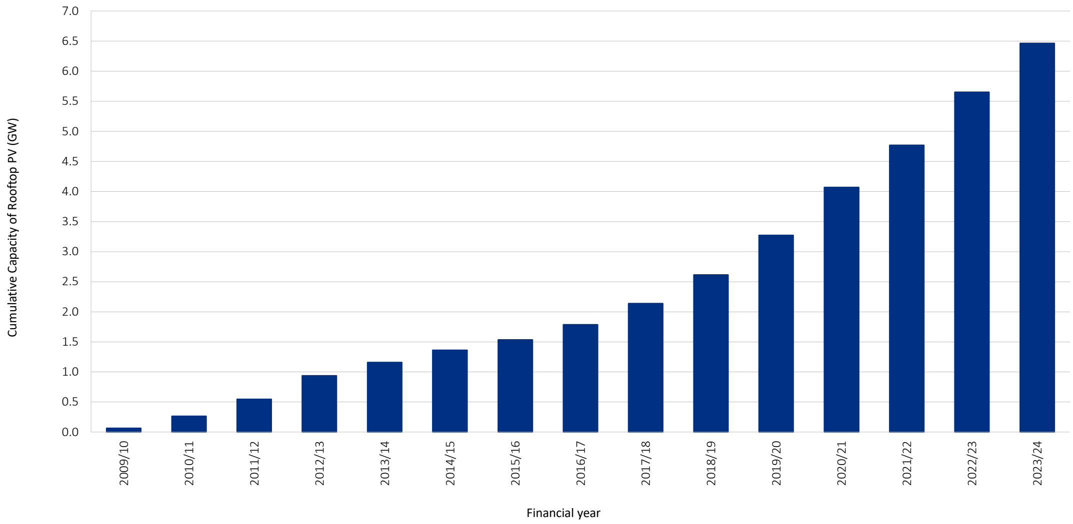
## 3.2 Forecasting challenges

### 3.2.1 Rooftop photovoltaic and Distributed Energy Sources

Residential and commercial loads are generally located within built up urban and township areas, with continued uptake of rooftop PV systems and distributed energy sources having the greatest impact to demand and energy patterns in these areas.

Queensland has the highest adoption rate of rooftop PV systems in the world on a per capita basis. The current installation rate has increased slightly over the last two years and is approximately 810MW per annum with the average installation size within residential households increasing over time (refer Figure 3.5). The uptake of rooftop PV systems is expected to continue with the most recent 2024 Queensland Household Energy Survey (QHES) indicating that 27% of respondents intend to purchase new or upgrade rooftop PV systems in the next three years (refer Figure 3.6). Of the reasons for having or intending to purchase a battery in the next three years, 47% indicated it is to store excess solar energy and use it later during peak times to reduce electricity use from the grid. 38% of respondents have high interest in community batteries. Of those yet to do so, 59% would consider purchasing an electric vehicle or plug-in hybrid in the next 3 years. Of the households with Electric Vehicle (EV) ownership 64% are open to the concept of their EV charging being managed by a third party. It is also expected that there will also be an increase in PV installations in 2027/28 when customers stop receiving the 44-cent feed in tariff and upgrade their systems.

Figure 3.5 Cumulative capacity of Queensland rooftop PV (1) (2)

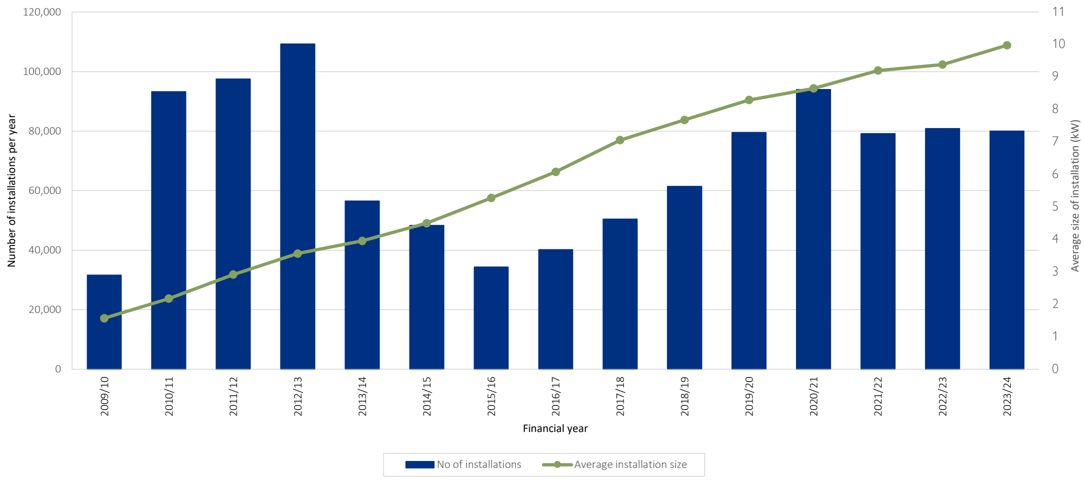



Notes:

(1) Source: Clean Energy Regulator.

(2) Registrations generally lag installations and hence data for FY2024 may be slightly understated.

Figure 3.6 Annual installation rates and average sizes for Queensland rooftop PV (1) (2)




Notes:

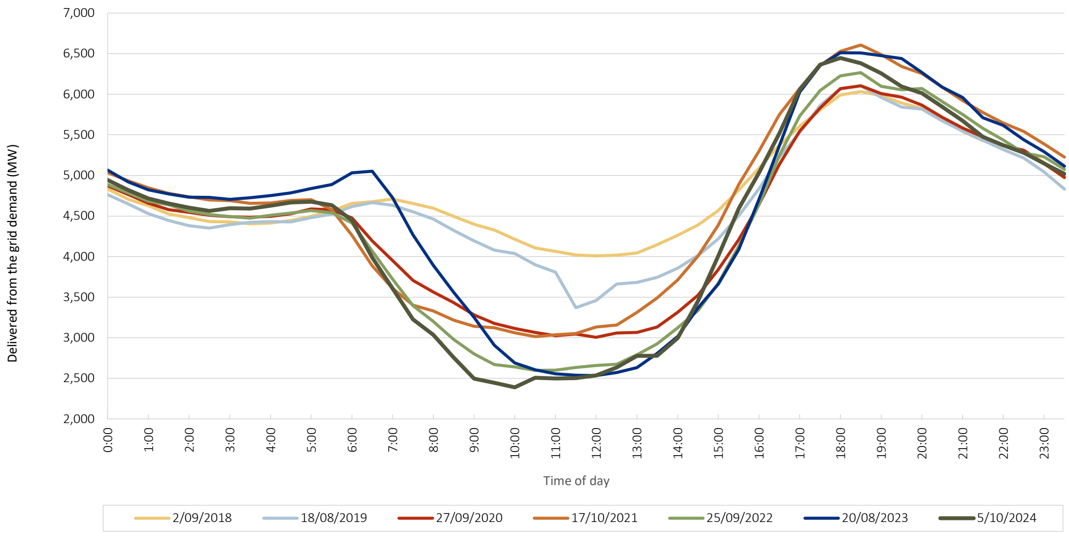
(1) Source: Clean Energy Regulator.

(2) Registrations generally lag installations and hence data for FY2024 may be slightly understated.

The installation of rooftop PV systems and distribution connected solar farms has progressively changed the characteristics of daily demand required to be supplied by Powerlink's transmission network. Historically the delivered load profile has generally seen daily peaks occur during the mid afternoon or evening periods. However, the cumulative impact of embedded solar renewable energy results in a hollowing of the daytime daily demand profile, which diminishes as the sun sets in the evening.

This effect is more likely to be prominent within Queensland during the lower day time demand in the winter and spring seasons. The term 'duck curve' was first coined by the Californian Independent System Operator to describe the effects of utility-scale solar power generation on the shape of the daily net load profile, and is a characteristic experienced by transmission networks globally where there has been a significant level of embedded highly correlated PV renewable energy systems. Figure 3.7 depicts the change in daily load profile of the transmission delivered profile within Queensland.

Figure 3.7 Transmission delivered annual minimum demand for the Queensland region (1) (2)




Note:

(1) Minimum demand can be caused by abnormal conditions as depicted in the 2019 trace when lowest demand coincided with a large industrial load being out of service.

Minimum demand during the day has continued to decrease with the progressive installation of rooftop PV and distribution network solar system connections. However, maximum daily demand has continued to increase in line with underlying load growth since the contribution of rooftop PV tapers off towards the evening. This has resulted in an increasing divergence between minimum and maximum demand which needs to be met and managed by large-scale generation and the transmission network. With the expected continued uptake of residential and commercial rooftop PV installations, and in the absence of significant levels of demand shifting or distributed energy storage, minimum demand levels are expected to further decrease with a continued widening between maximum and minimum demand.

### 3.2.2 Minimum demand

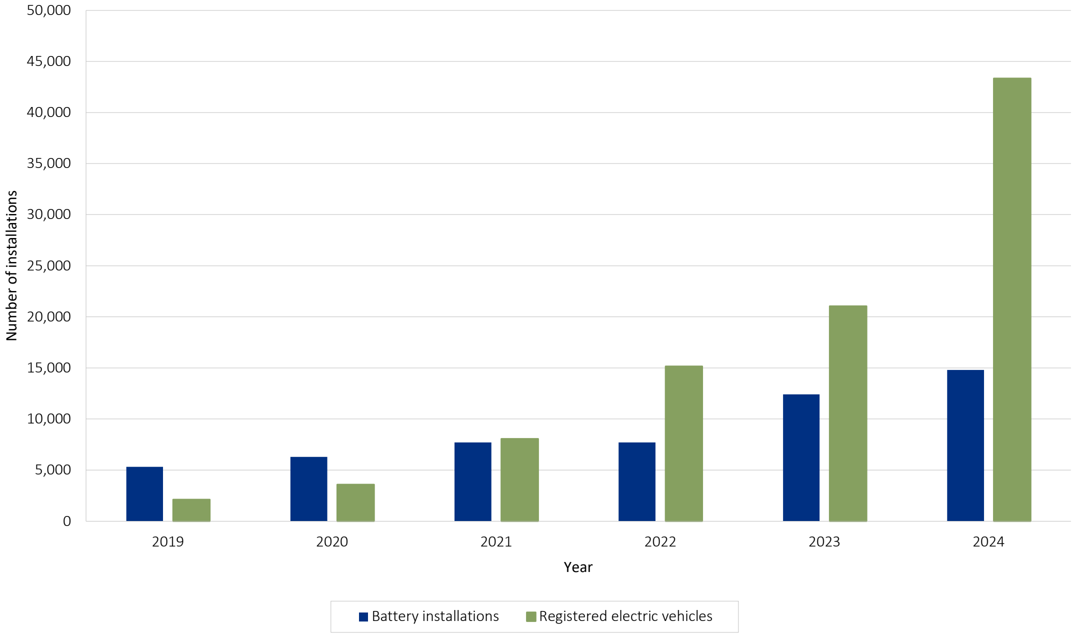
Continuation of the minimum demand trend is likely to present challenges to the power system. Generators are increasingly required to ramp up and down in response to daily demand variations more steeply. Decreasing minimum demand will lead a lower number of units of synchronous generation that are able to be online and this could further impact on voltage control, stability, system strength, inertia and the ability for available generators to meet evening peak demand. During very low load periods, semi-scheduled generation will reduce output (spilling the available resource) to ensure sufficient demand is available to preserve the minimum levels of synchronous generation required to maintain system security. In extreme cases, AEMO will follow its minimum system load market notification framework and operating protocol[2].

There may be opportunities for new technologies and non-network solutions to assist with these power system security challenges, and these type of services could offer a number of benefits to the power system including reducing the need for additional transmission network investment.

Residential household batteries and EVs have the potential to help smooth daily demand profiles and improve the utilisation of the network where appropriate incentives are in place. Without such incentives, batteries may be fully charged in the early morning, exposing the same minimum demand through the middle and latter part of the day. The small-scale battery segment is continuing to build steadily in Queensland with almost 15,000 battery installations currently reported within residential households and over 40,000 registered electric vehicles (refer to Figure 3.8). Appendix C lists the forecast assumptions for electric vehicle uptake over the forecast period.

[2] Department of Energy and Public Works, Emergency backstop mechanism, 6 February 2023.

Figure 3.8 Queensland residential battery uptake (1) and number of registered electric vehicles (2)




Notes:

(1) Source: Clean Energy Regulator.

(2) Source: Queensland Government – Electric vehicle snapshot.

### 3.2.3 Electrification of load and decentralisation

Decentralisation, driven by future developments in battery storage technology coupled with rooftop PV and EVs, could see significant changes to future electricity usage patterns. With appropriate consumer behaviour reinforced by tariff reforms, this could reduce the need to develop transmission services to cover short duration peaks.

In 2021 approximately 20% of final energy consumption in Queensland is from electricity and this electrical energy is predominantly supplied from the interconnected power system. Therefore, the electrification of load historically supplied by the combustion of fossil fuels in various sectors of the economy such as transport, agriculture, mining and manufacturing may require a significant investment in the transmission and distribution networks. The drivers for electrification of these sectors largely relate to the need to reduce carbon emissions for a variety of reasons including environmental, community and corporate expectations or the international treatment of exports with implicit emissions.

The growth in grid-supplied electricity through electrification will, to some extent, be offset by reductions in grid-supplied energy due to decentralisation. However, the geospatial distribution of these two effects are not expected to be uniform. There may be areas where net demand for grid-supplied electricity significantly increases, and other areas where it may decrease.

Powerlink is committed to developing an understanding of the future impacts of emerging technologies and electrification, and to work with our customers and AEMO so that these are accounted geospatially within future forecasts. This will allow transmission network services to be developed in ways that are valued by customers. It is uncertain whether new hydrogen load will be flexible; the forecast assumes it is inflexible due to this uncertainty. However, new electrification loads that have indicated a portion of load to be flexible (non-firm) it is assumed that this will not contribute to peak demand in the forecast.

## 3.3 Customer consultation

In accordance with the National Electricity Rules (NER), Powerlink has obtained summer and winter maximum demand forecasts over a 10-year outlook period from Queensland's DNSPs, Energex and Ergon Energy (part of the Energy Queensland group). Powerlink has produced transmission connection supply point forecasts that incorporate Energex and Ergon's inputs. These connection supply point forecasts are presented in Appendix C. Also in accordance with the NER, Powerlink has obtained summer and winter maximum demand forecasts from other customers that connect directly to the Powerlink transmission network.

Powerlink, Energex and Ergon Energy jointly conduct the Queensland Household Energy Survey (QHES) to improve understanding of consumer behaviours and intentions. This survey provides comprehensive insights on consumer intentions on electricity usage.

Powerlink is proactively engaging with customers to understand their decarbonisation plans. To enable efficient planning of the network, early customer consultation is required to allow transmission network services to be developed in ways that are valued by customers.

### 3.3.1 Transmission customer forecasts

#### New large loads

One large load has connected in the past 12 months, the Fitzroy mine in the Northern Bowen Basin.

#### Possible new large loads

There are several proposals under development for new large mining, metal processing, other industrial loads and for the electrification of existing loads. These proposed large loads total approximately 5,215MW with a high scenario of up to 9,637MW. The likely distribution of these loads is defined in Table 3.1. The majority of proposed loads have been included in Powerlink's High scenario forecast only. However, Powerlink's Central scenario forecast does allow for approximately 1,800MW of anticipated electrification and hydrogen load in the Gladstone zone (refer to sections 6.10.2 and 8.2.5). This anticipated load ramps up to the 1,800MW over the forecast period beginning from 2026/27. The loads in the Gladstone zone in Table 3.1 exclude this 1,800MW.

Table 3.1 Possible large loads excluded from the Low and Central scenario forecasts

| Zone | Description | Possible load |
|---|---|---|
| North Queensland | Electrification | 1,609MW |
| | Manufacturing | |
| Central Queensland | Hydrogen production and liquefaction | 3,330MW to 7,7752MW (1) |
| | Electrification | |
| Southern Queensland | Data Centre and Industrial | 276MW |

Note:

(1) This represents a high scenario.

## 3.4 Demand forecast outlook

The following sections outline the Queensland forecasts for energy, summer maximum demand, winter maximum demand and annual minimum demand. Annual maximum demands continue to be expected in the summer period. Annual minimum demands previously occurred in winter and have now shifted to the shoulder seasons.

The forecast for minimum delivered demand is closely correlated to rooftop PV installations and embedded variable renewable energy (VRE) generators. Forecasts in this chapter are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but impact on the output of these embedded VRE generators.

The 2024 TAPR reports on the Low, Central and High scenario forecasts produced by Powerlink. Demand forecasts are also prepared to account for seasonal variation. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent load conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

The forecast average annual growth rates for the Queensland region over the next 10 years under Low, Central and High scenarios are shown in Table 3.2. These growth rates refer to transmission delivered quantities as described in Section 3.4.1. The summer and winter maximum demand growth rates are based on 50% PoE corrected values for 2023/24 and 2024 respectively.

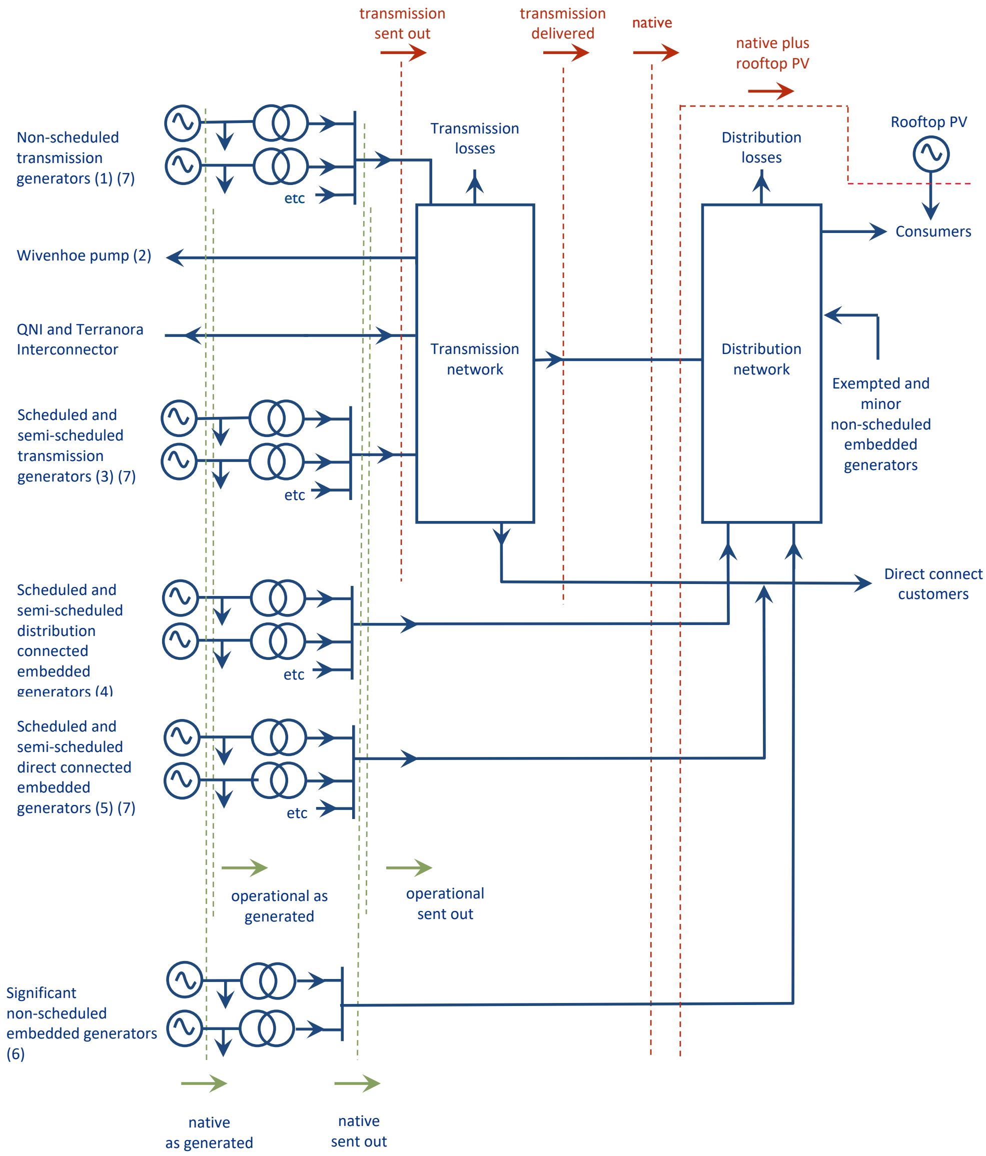
Table 3.2 Average annual growth rate over next 10 years

| | Powerlink future scenario outlooks | | |
|---|---|---|---|
| | High | Central | Low |
| Delivered energy | 6.0% | 2.5% | 0.4% |
| Delivered summer maximum demand (50% PoE) | 5.5% | 3.1% | 1.5% |
| Delivered winter maximum demand (50% PoE) | 5.5% | 3.0% | 2.0% |

### 3.4.1 Demand and energy terminology

The reported demand and energy on the network depends on where it is being measured. Individual stakeholders have reasons to measure demand and energy at different points. Figure 3.9 shows the common ways demand and energy measurements are defined, with this terminology used consistently throughout the TAPR.

Figure 3.9 Load measurement definitions




Notes:

(1) Includes Invicta and Koombooloomba.

(2) Depends on Wivenhoe generation.

(3) Includes Yarwun which is non-scheduled.

(4) For a full list of scheduled and semi-scheduled distribution connected generators refer to Table 7.2.

(5) Sun Metals Solar Farm and Condamine.

(6) Lakeland Solar and Storage, Hughenden Solar Farm, Pioneer Mill, Moranbah North, Racecourse Mill, Barcaldine Solar Farm, Longreach Solar Farm, German Creek, Oaky Creek, Baking Board Solar Farm, Sunshine Coast Solar Farm and Rocky Point.

(7) For a full list of transmission network connected generators and scheduled and semi-scheduled direct connected embedded generators refer to Table 7.1.

### 3.4.2 Energy forecast

Historical Queensland energy measurements are presented in Table 3.3. They are recorded at various levels in the network as defined in Figure 3.10.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled Power Station (PS) auxiliaries are the difference between operational 'as generated' and operational sent out energy.

Table 3.3 Historical energy (GWh)

| Financial year | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Native | Native plus rooftop PV |
|---|---|---|---|---|---|---|---|---|
| 2014/15 | 51,855 | 48,402 | 53,349 | 50,047 | 48,332 | 46,780 | 48,495 | 49,952 |
| 2015/16 | 54,238 | 50,599 | 55,752 | 52,223 | 50,573 | 49,094 | 50,744 | 52,509 |
| 2016/17 | 55,101 | 51,323 | 56,674 | 53,017 | 51,262 | 49,880 | 51,635 | 53,506 |
| 2017/18 | 54,538 | 50,198 | 56,139 | 51,918 | 50,172 | 48,739 | 50,925 | 53,406 |
| 2018/19 | 54,861 | 50,473 | 56,381 | 52,118 | 50,163 | 48,764 | 51,240 | 54,529 |
| 2019/20 | 54,179 | 50,039 | 55,776 | 51,740 | 49,248 | 47,860 | 50,804 | 54,449 |
| 2020/21 | 53,415 | 49,727 | 54,710 | 51,140 | 48,608 | 47,421 | 50,107 | 55,232 |
| 2021/22 | 53,737 | 49,940 | 54,744 | 51,052 | 48,625 | 47,405 | 50,081 | 56,162 |
| 2022/23 | 52,692 | 48,906 | 53,690 | 49,998 | 47,422 | 46,214 | 49,047 | 55,714 |
| 2023/24 | 54,827 | 50,154 | 55,858 | 51,272 | 48,753 | 47,477 | 50,251 | 58,010 |

The transmission delivered energy forecasts are presented in Table 3.4.

Table 3.4 Forecast annual transmission delivered energy (GWh)

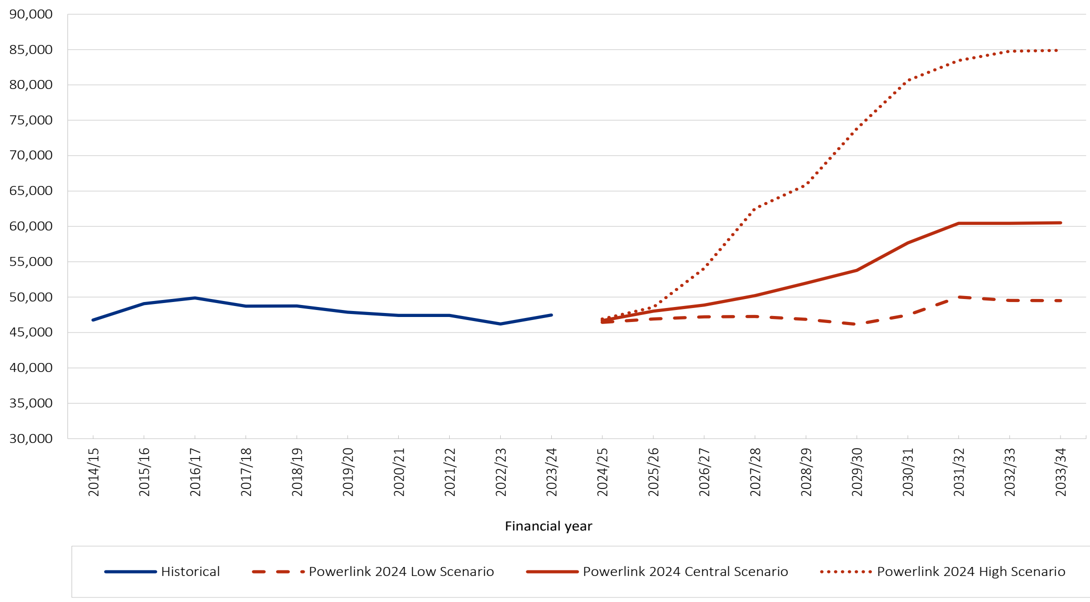
| Financial year | High | Central | Low |
|---|---|---|---|
| 2024/25 | 46,923 | 46,697 | 46,435 |
| 2025/26 | 48,569 | 48,032 | 46,931 |
| 2026/27 | 54,071 | 48,883 | 47,240 |
| 2027/28 | 62,554 | 50,217 | 47,267 |
| 2028/29 | 65,852 | 52,000 | 46,871 |
| 2029/30 | 73,836 | 53,785 | 46,176 |
| 2030/31 | 80,632 (1) | 57,650 (1) | 47,468 |
| 2031/32 | 83,468 | 60,434 | 50,017 |
| 2032/33 | 84,780 | 60,437 | 49,544 |
| 2033/34 | 84,880 | 60,516 | 49,527 |

Note:

(1) Large industrial block load connected in 2030/31

The historical annual transmission delivered energy from Table 3.3 and the forecast transmission delivered energy for the High, Central and Low scenarios from Table 3.4 are shown plotted in Figure 3.11.

Figure 3.10 Historical and forecast transmission delivered energy




The native energy forecasts are presented in Table 3.5.

Table 3.5 Forecast annual native energy (GWh)

| Financial Year | High | Central | Low |
|---|---|---|---|
| 2024/25 | 51,208 | 50,987 | 50,725 |
| 2025/26 | 53,169 | 52,517 | 51,518 |
| 2026/27 | 58,674 | 53,368 | 51,834 |
| 2027/28 | 67,160 | 54,702 | 51,858 |
| 2028/29 | 70,460 | 56,491 | 51,464 |
| 2029/30 | 78,445 | 58,280 | 50,775 |
| 2030/31 | 85,241 | 62,146 | 52,069 |
| 2031/32 | 88,089 | 64,939 | 54,628 |
| 2032/33 | 89,391 | 64,933 | 54,143 |
| 2033/34 | 89,480 | 65,002 | 54,118 |

### 3.4.3 Summer maximum demand forecast

Historical Queensland summer maximum demand measurements at time of transmission delivered peak are presented in Table 3.6.

Table 3.6 Historical summer maximum demand at time of transmission delivered peak (MW)

| Summer | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Transmission delivered corrected to 50% PoE | Native | Native plus solar PV |
|---|---|---|---|---|---|---|---|---|---|
| 2014/15 | 8,809 | 8,360 | 9,024 | 8,623 | 8,276 | 7,983 | 7,737 | 8,330 | 8,524 |
| 2015/16 | 9,154 | 8,620 | 9,332 | 8,850 | 8,532 | 8,222 | 8,050 | 8,541 | 9,021 |
| 2016/17 | 9,412 | 8,856 | 9,572 | 9,078 | 8,694 | 8,347 | 8,257 | 8,731 | 8,817 |
| 2017/18 | 9,798 | 9,211 | 10,015 | 9,489 | 9,080 | 8,789 | 8,515 | 9,198 | 9,602 |
| 2018/19 | 10,010 | 9,433 | 10,173 | 9,666 | 9,248 | 8,969 | 8,488 | 9,387 | 9,523 |
| 2019/20 | 9,836 | 9,283 | 10,052 | 9,544 | 9,056 | 8,766 | 8,662 | 9,255 | 9,453 |
| 2020/21 | 9,473 | 8,954 | 9,627 | 9,161 | 8,711 | 8,479 | 8,660 | 8,929 | 9,256 |
| 2021/22 | 10,058 | 9,503 | 10,126 | 9,624 | 9,332 | 9,031 | 8,876 | 9,323 | 9,323 |
| 2022/23 | 9,873 | 9,363 | 9,985 | 9,487 | 9,202 | 8,916 | 9,110 | 9,413 | 9,395 |
| 2023/24 | 11,005 | 10,359 | 11,136 | 10,587 | 9,807 | 9,429 | 9,218 | 11,149 | 9,998 |

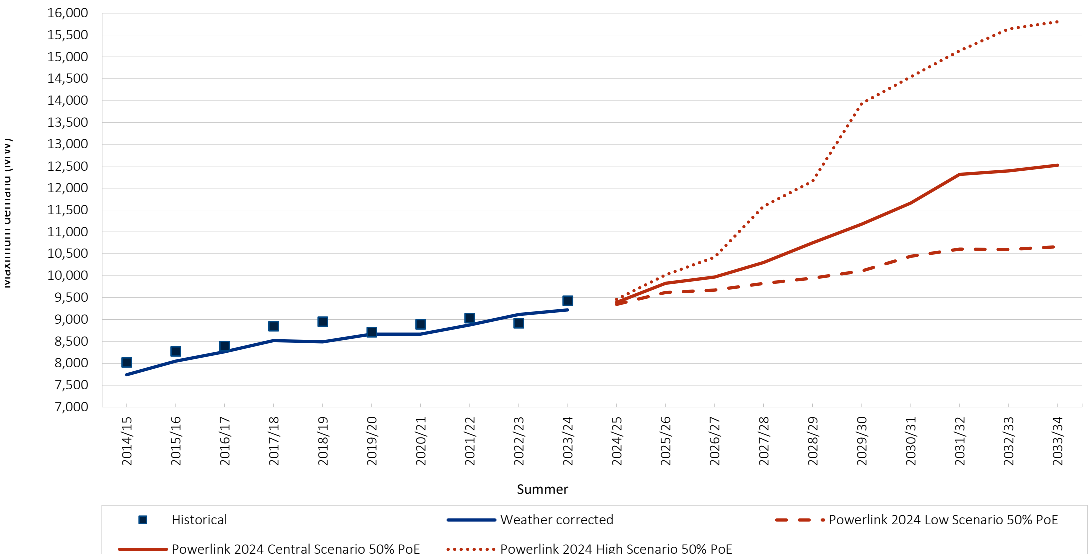
The summer transmission delivered maximum demand forecasts are presented in Table 3.7.

Table 3.7 Forecast summer transmission delivered maximum demand (MW)

| Summer | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2024/25 | 8,948 | 9,459 | 10,092 | 8,914 | 9,392 | 10,015 | 8,887 | 9,342 | 9,990 |
| 2025/26 | 9,509 | 10,021 | 10,621 | 9,345 | 9,828 | 10,422 | 9,148 | 9,617 | 10,216 |
| 2026/27 | 9,902 | 10,419 | 11,055 | 9,489 | 9,969 | 10,548 | 9,201 | 9,670 | 10,220 |
| 2027/28 | 11,054 | 11,585 | 12,181 | 9,812 | 10,301 | 10,864 | 9,351 | 9,823 | 10,353 |
| 2028/29 | 11,618 | 12,153 | 12,724 | 10,241 | 10,749 | 11,312 | 9,460 | 9,941 | 10,457 |
| 2029/30 | 13,369 | 13,934 | 14,509 | 10,667 | 11,179 | 11,726 | 9,615 | 10,111 | 10,605 |
| 2030/31 | 13,978 | 14,544 | 15,134 | 11,166 | 11,660 | 12,214 | 9,978 | 10,441 | 10,986 |
| 2031/32 | 14,579 | 15,138 | 15,736 | 11,771 | 12,317 | 12,890 | 10,123 | 10,609 | 11,089 |
| 2032/33 | 15,059 | 15,634 | 16,259 | 11,840 | 12,398 | 12,961 | 10,112 | 10,598 | 11,063 |
| 2033/34 | 15,211 | 15,799 | 16,421 | 11,955 | 12,524 | 13,076 | 10,183 | 10,661 | 11,123 |

The summer historical transmission delivered maximum demands from Table 3.11 and the forecast 50% PoE summer transmission delivered maximum demands for the High, Central and Low scenarios from Table 3.7 are shown in Figure 3.11. The large-scale anticipated new load from electrification and hydrogen is assumed to be inflexible.

Figure 3.11 Historical and forecast transmission delivered summer maximum demand




Historical Queensland summer maximum demand measurements at time of native peak are presented in Table 3.8.

Table 3.8 Historical summer maximum demand at time of native peak (MW)

| Summer | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Native | Native plus rooftop PV | Native corrected to 50% PoE |
|---|---|---|---|---|---|---|---|---|---|
| 2014/15 | 8,831 | 8,398 | 9,000 | 8,589 | 8,311 | 8,019 | 8,326 | 8,512 | 8,084 |
| 2015/16 | 9,154 | 8,668 | 9,272 | 8,848 | 8,580 | 8,271 | 8,539 | 8,783 | 8,369 |
| 2016/17 | 9,412 | 8,886 | 9,584 | 9,062 | 8,698 | 8,392 | 8,756 | 8,899 | 8,666 |
| 2017/18 | 9,796 | 9,262 | 10,010 | 9,480 | 9,133 | 8,842 | 9,189 | 9,594 | 8,924 |
| 2018/19 | 10,044 | 9,450 | 10,216 | 9,626 | 9,240 | 8,951 | 9,415 | 9,685 | 8,930 |
| 2019/20 | 9,853 | 9,294 | 10,074 | 9,515 | 9,011 | 8,710 | 9,268 | 9,652 | 9,163 |
| 2020/21 | 9,473 | 8,954 | 9,627 | 9,161 | 8,711 | 8,479 | 8,929 | 9,254 | 9,110 |
| 2021/22 | 10,013 | 9,475 | 10,089 | 9,615 | 9,196 | 8,907 | 9,326 | 9,468 | 9,295 |
| 2022/23 | 10,070 | 9,537 | 10,196 | 9,689 | 9,224 | 8,909 | 9,374 | 9,940 | 9,575 |
| 2023/24 | 11,005 | 10,359 | 11,136 | 10,587 | 9,807 | 9,429 | 10,209 | 11,149 | 9,998 |

The summer native maximum demand forecasts are presented in Table 3.9.

Table 3.9 Forecast summer native maximum demand (MW)

| Summer | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2024/25 | 9,445 | 9,936 | 10,504 | 9,388 | 9,883 | 10,458 | 9,349 | 9,825 | 10,404 |
| 2025/26 | 9,991 | 10,503 | 11,047 | 9,812 | 10,328 | 10,890 | 9,617 | 10,095 | 10,637 |
| 2026/27 | 10,380 | 10,890 | 11,486 | 9,948 | 10,471 | 11,015 | 9,661 | 10,141 | 10,655 |
| 2027/28 | 11,521 | 12,045 | 12,599 | 10,257 | 10,797 | 11,342 | 9,816 | 10,287 | 10,783 |
| 2028/29 | 12,062 | 12,610 | 13,175 | 10,680 | 11,242 | 11,797 | 9,920 | 10,412 | 10,901 |
| 2029/30 | 13,802 | 14,385 | 14,960 | 11,109 | 11,663 | 12,208 | 10,071 | 10,575 | 11,052 |
| 2030/31 | 14,410 | 14,988 | 15,564 | 11,608 | 12,135 | 12,703 | 10,426 | 10,916 | 11,413 |
| 2031/32 | 15,022 | 15,583 | 16,169 | 12,218 | 12,792 | 13,383 | 10,582 | 11,077 | 11,539 |
| 2032/33 | 15,493 | 16,085 | 16,684 | 12,295 | 12,869 | 13,458 | 10,583 | 11,069 | 11,534 |
| 2033/34 | 15,649 | 16,262 | 16,856 | 12,416 | 12,988 | 13,585 | 10,654 | 11,131 | 11,601 |

### 3.4.4 Winter maximum demand forecast

Historical Queensland winter maximum demand measurements at time of transmission delivered peak are presented in Table 3.10. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 3.10 Historical winter maximum demand at time of transmission delivered peak (MW)

| Winter | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Transmission delivered corrected to 50% PoE | Native | Native plus rooftop PV |
|---|---|---|---|---|---|---|---|---|---|
| 2015 | 7,816 | 7,334 | 8,027 | 7,624 | 7,299 | 7,090 | 6,976 | 7,415 | 7,415 |
| 2016 | 8,017 | 7,469 | 8,176 | 7,678 | 7,398 | 7,176 | 7,198 | 7,456 | 7,456 |
| 2017 | 7,595 | 7,063 | 7,756 | 7,282 | 7,067 | 6,870 | 7,138 | 7,085 | 7,085 |
| 2018 | 8,172 | 7,623 | 8,295 | 7,803 | 7,554 | 7,331 | 7,654 | 7,580 | 7,580 |
| 2019 | 7,898 | 7,446 | 8,096 | 7,735 | 7,486 | 7,296 | 7,289 | 7,544 | 7,544 |
| 2020 | 8,143 | 7,671 | 8,320 | 7,941 | 7,673 | 7,483 | 7,276 | 7,751 | 7,751 |
| 2021 | 8,143 | 7,677 | 8,279 | 7,901 | 7,659 | 7,472 | 7,376 | 7,714 | 7,725 |
| 2022 | 8,625 | 8,216 | 8,701 | 8,347 | 8,141 | 7,921 | 7,571 | 8,127 | 8,127 |
| 2023 | 8,137 | 7,601 | 8,223 | 7,738 | 7,585 | 7,399 | 7,556 | 7,553 | 7,553 |
| 2024 | 8,728 | 8,190 | 8,728 | 8,152 | 8,196 | 7,970 | | 7,927 | 7,513 |

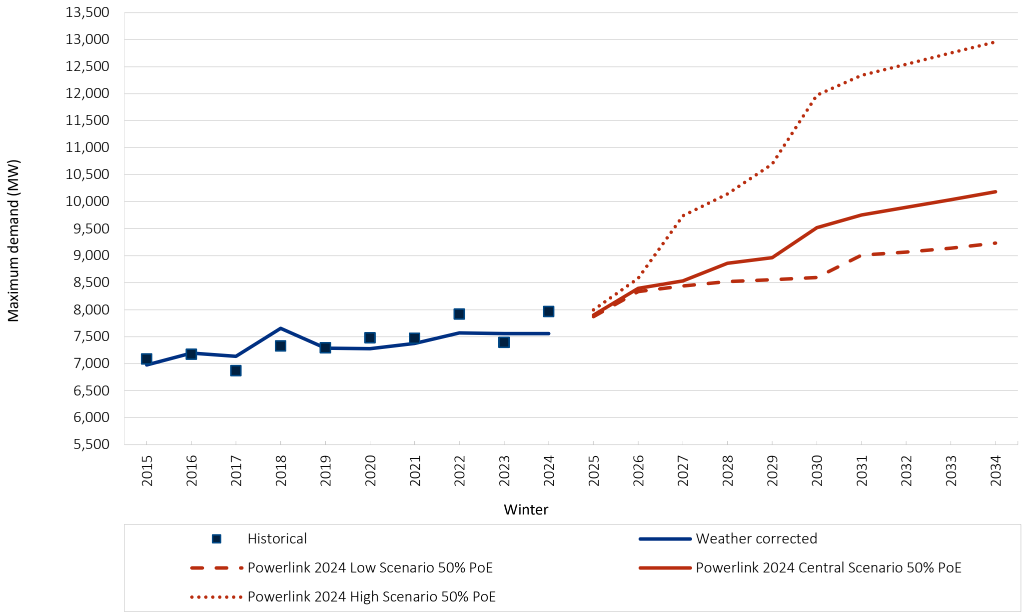
The winter transmission delivered maximum demand forecasts are presented in Table 3.11.

Table 3.11 Forecast winter transmission delivered maximum demand (MW)

| Winter | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2025 | 7,621 | 7,996 | 8,542 | 7,536 | 7,900 | 8,474 | 7,490 | 7,871 | 8,424 |
| 2026 | 8,194 | 8,581 | 9,136 | 8,023 | 8,396 | 8,973 | 7,948 | 8,336 | 8,895 |
| 2027 | 9,305 | 9,741 | 10,228 | 8,152 | 8,532 | 9,112 | 8,052 | 8,443 | 9,014 |
| 2028 | 9,707 | 10,144 | 10,626 | 8,481 | 8,860 | 9,431 | 8,131 | 8,520 | 9,091 |
| 2029 | 10,274 | 10,694 | 11,194 | 8,579 | 8,962 | 9,517 | 8,165 | 8,556 | 9,122 |
| 2030 | 11,528 | 11,974 | 12,501 | 9,242 | 9,520 | 10,172 | 8,208 | 8,594 | 9,153 |
| 2031 | 11,899 | 12,342 | 12,848 | 9,356 | 9,755 | 10,272 | 8,626 | 9,011 | 9,560 |
| 2032 | 12,097 | 12,542 | 13,010 | 9,498 | 9,894 | 10,397 | 8,677 | 9,068 | 9,603 |
| 2033 | 12,303 | 12,753 | 13,207 | 9,645 | 10,037 | 10,514 | 8,750 | 9,142 | 9,650 |
| 2034 | 12,506 | 12,959 | 13,403 | 9,806 | 10,814 | 10,640 | 8,831 | 9,233 | 9,709 |

The winter historical transmission delivered maximum demands from Table 3.10 and the forecast 50% PoE summer transmission delivered maximum demands for the High, Central and Low scenarios from Table 3.11 are shown in Figure 3.12.

Figure 3.12 Historical and forecast winter transmission delivered maximum demand




Historical Queensland winter maximum demand measurements at time of native peak are presented in Table 3.12. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 3.12 Historical winter maximum demand at time of native peak (MW)

| Winter | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Native | Native plus rooftop PV | Native corrected to 50 % PoE |
|---|---|---|---|---|---|---|---|---|---|
| 2015 | 7,822 | 7,369 | 8,027 | 7,620 | 7,334 | 7,126 | 7,411 | 7,412 | 7,301 |
| 2016 | 8,017 | 7,513 | 8,188 | 7,686 | 7,439 | 7,207 | 7,454 | 7,454 | 7,479 |
| 2017 | 7,723 | 7,221 | 7,874 | 7,374 | 7,111 | 6,894 | 7,157 | 7,157 | 7,433 |
| 2018 | 8,172 | 7,623 | 8,295 | 7,750 | 7,554 | 7,383 | 7,633 | 7,633 | 7,904 |
| 2019 | 8,073 | 7,559 | 8,286 | 7,778 | 7,416 | 7,208 | 7,624 | 7,624 | 7,617 |
| 2020 | 8,143 | 7,671 | 8,320 | 7,885 | 7,673 | 7,441 | 7,708 | 7,708 | 7,544 |
| 2021 | 8,162 | 7,699 | 8,324 | 7,948 | 7,663 | 7,468 | 7,758 | 7,754 | 7,830 |
| 2022 | 8,625 | 8,216 | 8,701 | 8,347 | 8,141 | 7,921 | 8,125 | 8,127 | 7,571 |
| 2023 | 8,137 | 7,601 | 8,223 | 7,738 | 7,585 | 7,399 | 7,552 | 7,553 | 7,556 |
| 2024 | 8,728 | 8,190 | 8,728 | 8,152 | 8,196 | 7,970 | 7,928 | 7,927 | (1) |

Note:

(1) The winter 2024 weather corrected demand was not available at time of publication.

The winter native maximum demand forecasts are presented in Table 3.13.

Table 3.13 Forecast winter native maximum demand (MW)

| Winter | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2025 | 8,131 | 8,499 | 9,120 | 8,034 | 8,404 | 9,002 | 7,994 | 8,351 | 8,980 |
| 2026 | 8,707 | 9,082 | 9,711 | 8,518 | 8,899 | 9,501 | 8,458 | 8,815 | 9,451 |
| 2027 | 9,805 | 10,193 | 10,807 | 8,652 | 9,031 | 9,640 | 8,560 | 8,926 | 9,570 |
| 2028 | 10,202 | 10,600 | 11,201 | 8,970 | 9,360 | 9,958 | 8,638 | 9,001 | 9,647 |
| 2029 | 10,779 | 11,163 | 11,767 | 9,063 | 9,457 | 10,041 | 8,673 | 9,039 | 9,677 |
| 2030 | 12,011 | 12,406 | 12,988 | 9,729 | 10,005 | 10,694 | 8,708 | 9,074 | 9,711 |
| 2031 | 12,399 | 12,795 | 13,353 | 9,847 | 10,238 | 10,784 | 9,119 | 9,493 | 10,121 |
| 2032 | 12,606 | 13,000 | 13,543 | 9,995 | 10,373 | 10,899 | 9,169 | 9,548 | 10,168 |
| 2033 | 12,815 | 13,213 | 13,721 | 10,142 | 10,516 | 11,019 | 9,252 | 9,617 | 10,222 |
| 2034 | 13,019 | 13,419 | 13,925 | 10,289 | 10,663 | 11,143 | 9,330 | 9,698 | 10,277 |

Note:

(1) Shutdown of a large industrial load is assumed in the Progressive Change scenario in summer 2029/30.

### 3.4.5 Annual minimum demand forecast

Historical Queensland annual minimum demand measurements at time of transmission delivered minimum are presented in Table 3.14.

Table 3.14 Historical annual minimum demand (MW)

| Summer | Operational as generated | Operational sent out | Native as generated | Native sent out | Transmission sent out | Transmission delivered | Native | Native plus rooftop PV |
|---|---|---|---|---|---|---|---|---|
| 2015 | 4,281 | 3,946 | 4,476 | 4,178 | 3,983 | 3,884 | 4,079 | 4,079 |
| 2016 | 4,944 | 4,470 | 5,101 | 4,686 | 4,471 | 4,336 | 4,552 | 4,552 |
| 2017 | 4,791 | 4,313 | 4,942 | 4,526 | 4,318 | 4,181 | 4,389 | 4,389 |
| 2018 | 4,647 | 4,165 | 4,868 | 4,501 | 4,143 | 4,008 | 4,366 | 5,572 |
| 2019 | 4,211 | 3,712 | 4,441 | 4,112 | 3,528 | 3,370 | 3,953 | 5,323 |
| 2020 | 3,897 | 3,493 | 4,094 | 3,767 | 3,097 | 3,006 | 3,675 | 5,882 |
| 2021 | 3,869 | 3,480 | 3,958 | 3,701 | 3,043 | 3,014 | 3,671 | 6,804 |
| 2022 | 3,504 | 3,065 | 3,617 | 3,283 | 2,707 | 2,597 | 3,173 | 6,457 |
| 2023 | 3,490 | 2,973 | 3,655 | 3,277 | 2,634 | 2,538 | 3,181 | 6,232 |
| 2024 | 3,091 | 2,647 | 3,655 | 2,650 | 6,650 | 2,389 | 2,430 | 6,741 |

Annual transmission delivered minimum demand forecasts are presented in Table 3.15.

Table 3.15 Forecast annual transmission delivered minimum demand (MW) (1)

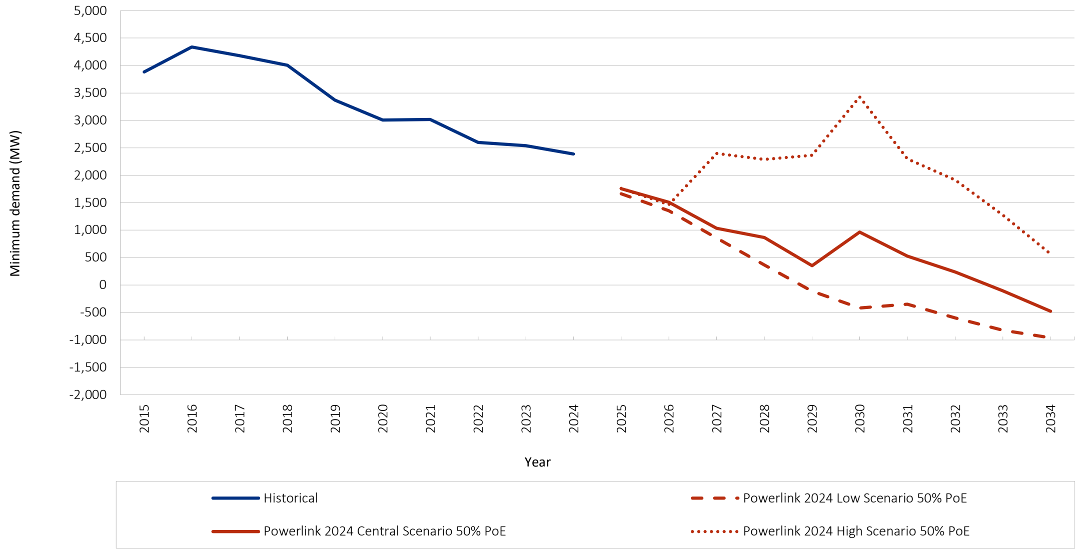
| Annual | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2024/25 | 1,279 | 1,761 | 2,414 | 1,300 | 1,756 | 2,404 | 1,222 | 1,663 | 2,306 |
| 2025/26 | 981 | 1,465 | 2,171 | 1,038 | 1,510 | 2,204 | 916 | 1,354 | 2,035 |
| 2026/27 | 1,892 | 2,398 | 3,117 | 545 | 1,034 | 1,734 | 409 | 854 | 1,538 |
| 2027/28 | 1,769 | 2,290 | 3,035 | 362 | 868 | 1,584 | -82 | 365 | 1,058 |
| 2028/29 | 1,822 | 2,366 | 3,145 | -160 | 353 | 1,076 | -559 | -112 | 580 |
| 2029/30 | 2,869 | 3,430 | 4,244 | 439 | 967 | 1,684 | -875 | -419 | 268 |
| 2030/31 | 1,663 | 2,297 | 2,864 | -14 | 527 | 1,263 | -825 | -349 | 325 |
| 2031/32 | 1,349 | 1,915 | 2,371 | -340 | 235 | 993 | -1,083 | -600 | 64 |
| 2032/33 | 766 | 1,277 | 1,764 | -699 | -105 | 661 | -1,308 | -821 | -153 |
| 2033/34 | 41 | 567 | 1,063 | -1,066 | -478 | 303 | -1,447 | -960 | -292 |

Note:

(1) Forecasts are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but will impact the output of embedded VRE generators and, as a consequence, transmission delivered demand.

The annual historical transmission delivered minimum demands from Table 3.14 and the forecast 50% PoE annual transmission delivered minimum demands for the High, Central and Low scenarios from Table 3.15 are shown in Figure 3.13. The minimum demand forecast does not factor in any market intervention to prevent the grid from becoming unstable under the minimum system load conditions. Market interventions could include directing on grid-scale BESS and Pumped Hydro Energy Storage (PHES) systems to increase demand.

Figure 3.13 Historical and forecast transmission delivered annual minimum demand




Annual native minimum demand forecasts are presented in Table 3.16.

Table 3.16 Forecast annual native minimum demand (MW) (1)

| Annual | High | | | Central | | | Low | | |
|---|---|---|---|---|---|---|---|---|---|
| | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE | 90% PoE | 50% PoE | 10% PoE |
| 2024/25 | 2,176 | 2,491 | 3,007 | 2,277 | 2,582 | 3,088 | 2,281 | 2,588 | 3,092 |
| 2025/26 | 1,941 | 2,274 | 2,785 | 2,067 | 2,410 | 2,931 | 2,052 | 2,422 | 2,920 |
| 2026/27 | 1,644 | 2,123 | 2,816 | 1,571 | 1,892 | 2,402 | 1,642 | 1,962 | 2,444 |
| 2027/28 | 2,464 | 2,891 | 3,439 | 1,226 | 1,622 | 2,120 | 1,114 | 1,436 | 1,905 |
| 2028/29 | 2,204 | 2,654 | 3,306 | 749 | 1,099 | 1,584 | 639 | 955 | 1,415 |
| 2029/30 | 2,302 | 2,876 | 3,536 | 603 | 1,091 | 1,827 | 202 | 543 | 985 |
| 2030/31 | 2,790 | 3,305 | 3,903 | 787 | 1,273 | 1,744 | -262 | 284 | 967 |
| 2031/32 | 2,480 | 2,907 | 3,410 | 412 | 930 | 1,406 | 19 | 546 | 1,082 |
| 2032/33 | 1,880 | 2,266 | 2,789 | 40 | 596 | 1,105 | -189 | 339 | 889 |
| 2033/34 | 1,152 | 1,546 | 2,091 | -305 | 271 | 763 | -406 | 130 | 757 |

Note:

(1) Forecasts are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but impact on the output of these embedded VRE generators.

## 3.5 Zone forecasts

Powerlink's 2024 TAPR zone forecast are coincident with the state peak. This year's TAPR includes a new geographical zone called North West. The North West zone represents the connection of North West Minerals Province (NWMP), with includes Mt Isa, to the National Electricity Market (NEM). The North West loads are included in the forecast from 2029 following the completion of the Copper String 2032 project. The now 12 geographical zones are defined in Table F.1 and illustrated in Figure F.1 in Appendix F. Each zone normally experiences its own maximum demand, which is usually greater than that shown in tables 3.20 to 3.23.

Table 3.17 shows the average ratios of zone maximum transmission delivered demand to zone transmission delivered demand at the time of Queensland region maximum delivered demand. These values can be used to multiply demands in tables 3.20 and 3.22 to estimate each zone's individual maximum transmission delivered demand, the time of which is not coincident with the time of Queensland region maximum transmission delivered demand. The ratios are based on historical trends.

Table 3.17 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum delivered demand

| Zone | Winter | Summer |
|---|---|---|
| Far North | 1.15 | 1.22 |
| Ross | 1.48 | 1.50 |
| North | 1.17 | 1.13 |
| North West | 1.32 | 1.12 |
| Central West | 1.02 | 1.03 |
| Gladstone | 1.03 | 1.02 |
| Wide Bay | 1.01 | 1.20 |
| Surat | 1.20 | 1.21 |
| Bulli | 1.07 | 1.14 |
| South West | 1.04 | 1.21 |
| Moreton | 1.00 | 1.03 |
| Gold Coast | 1.04 | 1.12 |

Tables 3.18 and 3.19 show the historical and forecast of transmission delivered energy and native energy for the Central scenario for each of the 12 zones in the Queensland region.

Table 3.18 Annual transmission delivered energy by zone (GWh)

| Financial Year | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2014/15 | 1,697 | 2,977 | - | 2,884 | 3,414 | 10,660 | 1,266 | 821 | 647 | 1,224 | 18,049 | 3,141 | 46,780 |
| 2015/16 | 1,724 | 2,944 | - | 2,876 | 3,327 | 10,721 | 1,272 | 2,633 | 1,290 | 1,224 | 17,944 | 3,139 | 49,094 |
| 2016/17 | 1,704 | 2,682 | - | 2,661 | 3,098 | 10,196 | 1,305 | 4,154 | 1,524 | 1,308 | 18,103 | 3,145 | 49,880 |
| 2017/18 | 1,657 | 2,645 | - | 2,650 | 3,027 | 9,362 | 1,238 | 4,383 | 1,497 | 1,315 | 17,873 | 3,092 | 48,739 |
| 2018/19 | 1,648 | 2,338 | - | 2,621 | 2,996 | 9,349 | 1,198 | 4,805 | 1,519 | 1,376 | 17,849 | 3,065 | 48,764 |
| 2019/20 | 1,594 | 2,466 | - | 2,495 | 2,859 | 9,303 | 1,031 | 5,025 | 1,580 | 1,141 | 17,395 | 2,971 | 47,860 |
| 2020/21 | 1,519 | 2,569 | - | 2,413 | 2,813 | 9,383 | 970 | 5,241 | 1,491 | 993 | 16,807 | 3,222 | 47,421 |
| 2021/22 | 1,598 | 2,418 | - | 2,755 | 2,776 | 9,124 | 904 | 5,420 | 1,395 | 990 | 17,101 | 2,924 | 47,405 |
| 2022/23 | 1,602 | 2,074 | - | 2,668 | 2,783 | 8,898 | 898 | 5,279 | 1,334 | 971 | 16,829 | 2,878 | 46,214 |
| 2023/24 | 1,566 | 2,286 | - | 2,548 | 2,866 | 9,368 | 951 | 5,376 | 1,481 | 991 | 17,093 | 2,948 | 47,474 |
| Forecasts | | | | | | | | | | | | | |
| 2024/25 | 1,583 | 2,531 | - | 2,036 | 2,969 | 9,345 | 1,720 | 4,721 | 1,377 | 1,349 | 15,897 | 3,170 | 46,697 |
| 2025/26 | 1,546 | 2,565 | - | 2,050 | 3,047 | 9,751 | 1,500 | 4,400 | 1,363 | 1,332 | 17,342 | 3,136 | 48,032 |
| 2026/27 | 1,495 | 2,702 | - | 2,132 | 3,209 | 9,914 | 1,429 | 4,254 | 1,352 | 1,367 | 17,952 | 3,078 | 48,883 |
| 2027/28 | 1,435 | 2,663 | - | 2,442 | 3,519 | 10,954 | 1,345 | 4,535 | 1,333 | 1,343 | 17,653 | 2,995 | 50,217 |
| 2028/29 | 1,389 | 2,608 | - | 2,489 | 3,529 | 13,267 | 1,275 | 4,640 | 1,320 | 1,304 | 17,251 | 2,927 | 52,000 |
| 2029/30 | 1,358 | 2,580 | - | 2,467 | 3,509 | 15,579 | 1,222 | 4,562 | 1,298 | 1,279 | 17,049 | 2,883 | 53,785 |
| 2030/31 | 1,344 | 2,565 | - | 2,457 | 3,496 | 19,752 | 1,193 | 4,422 | 1,282 | 1,266 | 17,000 | 2,873 | 57,650 |
| 2031/32 | 1,337 | 2,565 | 901 | 2,507 | 3,499 | 21,703 | 1,171 | 4,266 | 1,266 | 1,265 | 17,079 | 2,876 | 60,434 |
| 2032/33 | 1,336 | 2,558 | 901 | 2,505 | 3,483 | 21,978 | 1,158 | 4,045 | 1,257 | 1,253 | 17,077 | 2,887 | 60,437 |
| 2033/34 | 1,339 | 2,561 | 900 | 2,508 | 3,486 | 21,981 | 1,152 | 4,005 | 1,256 | 1,253 | 17,170 | 2,904 | 60,516 |

Table 3.19 Annual native energy by zone (GWh)

| Financial Year | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2014/15 | 1,697 | 3,163 | - | 3,434 | 3,841 | 10,660 | 1,285 | 1,022 | 647 | 1,468 | 18,137 | 3,141 | 48,495 |
| 2015/16 | 1,724 | 3,141 | - | 3,444 | 3,767 | 10,721 | 1,293 | 2,739 | 1,290 | 1,475 | 18,011 | 3,139 | 50,744 |
| 2016/17 | 1,704 | 2,999 | - | 3,320 | 3,541 | 10,196 | 1,329 | 4,194 | 1,524 | 1,549 | 18,134 | 3,145 | 51,635 |
| 2017/18 | 1,667 | 2,935 | - | 3,296 | 3,493 | 9,362 | 1,259 | 4,853 | 1,497 | 1,527 | 17,944 | 3,092 | 50,925 |
| 2018/19 | 1,670 | 2,894 | - | 3,211 | 3,608 | 9,349 | 1,266 | 5,163 | 1,519 | 1,550 | 17,945 | 3,065 | 51,240 |
| 2019/20 | 1,614 | 2,899 | - | 3,159 | 3,656 | 9,303 | 1,282 | 5,395 | 1,580 | 1,479 | 17,466 | 2,971 | 50,804 |
| 2020/21 | 1,539 | 2,904 | - | 2,982 | 3,552 | 9,383 | 1,234 | 5,451 | 1,491 | 1,476 | 17,152 | 2,943 | 50,107 |
| 2021/22 | 1,618 | 2,900 | - | 3,212 | 3,515 | 9,124 | 1,164 | 5,626 | 1,395 | 1,454 | 17,149 | 2,924 | 50,081 |
| 2022/23 | 1,621 | 2,714 | - | 3,230 | 3,415 | 8,898 | 1,148 | 5,446 | 1,334 | 1,490 | 16,872 | 2,878 | 49,047 |
| 2023/24 | 1,584 | 2,855 | - | 3,156 | 3,453 | 9,368 | 1,182 | 5,594 | 1,481 | 1,473 | 17,156 | 2,948 | 50,251 |
| Forecasts | | | | | | | | | | | | | |
| 2024/25 | 1,599 | 4,097 | - | 2,292 | 3,561 | 9,345 | 1,911 | 5,657 | 1,377 | 1,901 | 16,077 | 3,170 | 50,987 |
| 2025/26 | 1,562 | 4,127 | - | 2,306 | 3,639 | 9,751 | 1,860 | 5,339 | 1,363 | 1,913 | 17,522 | 3,136 | 52,517 |
| 2026/27 | 1,511 | 4,267 | - | 2,388 | 3,801 | 9,914 | 1,791 | 5,186 | 1,352 | 1,948 | 18,133 | 3,078 | 53,368 |
| 2027/28 | 1,451 | 4,233 | - | 2,698 | 4,112 | 10,954 | 1,708 | 5,461 | 1,333 | 1,924 | 17,833 | 2,995 | 54,702 |
| 2028/29 | 1,405 | 4,179 | - | 2,745 | 4,122 | 13,267 | 1,639 | 5,569 | 1,320 | 1,886 | 17,433 | 2,927 | 56,491 |
| 2029/30 | 1,374 | 4,149 | - | 2,722 | 4,101 | 15,579 | 1,588 | 5,493 | 1,298 | 1,862 | 17,232 | 2,883 | 58,280 |
| 2030/31 | 1,360 | 4,133 | - | 2,713 | 4,088 | 19,752 | 1,558 | 5,353 | 1,282 | 1,849 | 17,184 | 2,873 | 62,146 |
| 2031/32 | 1,353 | 4,136 | 901 | 2,765 | 4,092 | 21,702 | 1,537 | 5,200 | 1,266 | 1,849 | 17,264 | 2,876 | 64,939 |
| 2032/33 | 1,352 | 4,123 | 901 | 2,761 | 4,075 | 21,978 | 1,524 | 4,978 | 1,257 | 1,837 | 17,260 | 2,887 | 64,933 |
| 2033/34 | 1,355 | 4,125 | 900 | 2,764 | 4,076 | 21,981 | 1,518 | 4,934 | 1,256 | 1,836 | 17,353 | 2,904 | 65,002 |

Tables 3.20 and 3.21 show the historical and forecast of transmission delivered summer maximum demand and native summer maximum demand for each of the 12 zones in the Queensland region. It is based on the Central scenario and average (50% PoE) summer weather.

Table 3.20 State summer maximum transmission delivered demand by zone (MW)

| Summer | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2014/15 | 278 | 381 | - | 399 | 466 | 1,254 | 263 | 96 | 81 | 227 | 3,846 | 692 | 7,983 |
| 2015/16 | 308 | 392 | - | 411 | 443 | 1,189 | 214 | 265 | 155 | 231 | 3,953 | 661 | 8,222 |
| 2016/17 | 258 | 222 | - | 378 | 429 | 1,193 | 270 | 421 | 178 | 286 | 3,993 | 719 | 8,347 |
| 2017/18 | 304 | 376 | - | 413 | 463 | 1,102 | 278 | 504 | 183 | 301 | 4,147 | 718 | 8,789 |
| 2018/19 | 342 | 339 | - | 400 | 484 | 1,096 | 285 | 526 | 191 | 312 | 4,270 | 724 | 8,969 |
| 2019/20 | 286 | 325 | - | 391 | 368 | 1,080 | 263 | 610 | 191 | 267 | 4,276 | 709 | 8,766 |
| 2020/21 | 254 | 405 | - | 431 | 471 | 1,111 | 298 | 588 | 165 | 248 | 3,894 | 614 | 8,479 |
| 2021/22 | 363 | 441 | - | 473 | 518 | 1,103 | 269 | 594 | 174 | 253 | 4,146 | 697 | 9,031 |
| 2022/23 | 305 | 365 | - | 414 | 418 | 1,091 | 283 | 547 | 132 | 276 | 4,359 | 725 | 8,916 |
| 2023/24 | 294 | 321 | - | 423 | 372 | 1,098 | 214 | 608 | 177 | 270 | 4,907 | 742 | 9,429 |
| Forecasts | | | | | | | | | | | | | |
| 2024/25 | 328 | 466 | - | 430 | 501 | 1,135 | 442 | 535 | 169 | 311 | 4,188 | 886 | 9,392 |
| 2025/26 | 338 | 547 | - | 436 | 528 | 1,141 | 462 | 351 | 167 | 359 | 4,509 | 990 | 9,828 |
| 2026/27 | 337 | 589 | - | 474 | 552 | 1,180 | 460 | 370 | 162 | 367 | 4,506 | 971 | 9,969 |
| 2027/28 | 341 | 561 | - | 482 | 482 | 1,442 | 485 | 412 | 165 | 413 | 4,572 | 946 | 10,301 |
| 2028/29 | 360 | 634 | - | 504 | 556 | 1,578 | 472 | 432 | 160 | 492 | 4,622 | 939 | 10,749 |
| 2029/30 | 340 | 674 | - | 487 | 566 | 2,006 | 427 | 520 | 159 | 337 | 4,641 | 1,021 | 11,179 |
| 2030/31 | 351 | 691 | - | 495 | 608 | 2,297 | 430 | 535 | 151 | 348 | 4,697 | 1,056 | 11,660 |
| 2031/32 | 353 | 592 | 260 | 575 | 631 | 2,614 | 473 | 398 | 156 | 360 | 4,811 | 1,094 | 12,317 |
| 2032/33 | 370 | 838 | 260 | 516 | 631 | 2,356 | 508 | 356 | 160 | 410 | 4,881 | 1,113 | 12,398 |
| 2033/34 | 365 | 754 | 260 | 501 | 605 | 2,476 | 504 | 300 | 153 | 412 | 5,074 | 1,145 | 12,524 |

Table 3.21 State summer maximum native demand by zone (MW)

| Summer | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2014/15 | 278 | 399 | - | 479 | 548 | 1,254 | 263 | 189 | 81 | 254 | 3,889 | 692 | 8,326 |
| 2015/16 | 308 | 423 | - | 491 | 519 | 1,189 | 214 | 370 | 155 | 257 | 3,952 | 661 | 8,539 |
| 2016/17 | 269 | 364 | - | 512 | 559 | 1,088 | 276 | 498 | 175 | 329 | 3,974 | 712 | 8,756 |
| 2017/18 | 310 | 480 | - | 486 | 508 | 1,102 | 278 | 617 | 183 | 328 | 4,179 | 718 | 9,189 |
| 2018/19 | 338 | 456 | - | 432 | 562 | 1,104 | 293 | 630 | 191 | 340 | 4,338 | 731 | 9,415 |
| 2019/20 | 287 | 451 | - | 441 | 530 | 1,084 | 277 | 660 | 191 | 305 | 4,322 | 720 | 9,268 |
| 2020/21 | 256 | 508 | - | 483 | 596 | 1,111 | 314 | 681 | 165 | 307 | 3,894 | 614 | 8,929 |
| 2021/22 | 363 | 516 | - | 504 | 591 | 1,103 | 269 | 708 | 174 | 254 | 4,143 | 697 | 9,326 |
| 2022/23 | 307 | 400 | - | 489 | 512 | 1,091 | 286 | 609 | 132 | 290 | 4,359 | 725 | 9,374 |
| 2023/24 | 298 | 497 | - | 505 | 563 | 1,098 | 302 | 732 | 177 | 382 | 4,912 | 742 | 10,209 |
| Forecasts | | | | | | | | | | | | | |
| 2024/25 | 334 | 677 | - | 430 | 564 | 1,135 | 454 | 685 | 169 | 359 | 4,190 | 886 | 9,883 |
| 2025/26 | 338 | 674 | - | 436 | 571 | 1,141 | 463 | 644 | 167 | 360 | 4,544 | 990 | 10,328 |
| 2026/27 | 338 | 698 | - | 474 | 594 | 1,180 | 461 | 660 | 162 | 369 | 4,564 | 971 | 10,471 |
| 2027/28 | 349 | 712 | - | 482 | 616 | 1,442 | 454 | 666 | 165 | 366 | 4,600 | 946 | 10,797 |
| 2028/29 | 366 | 777 | - | 504 | 620 | 1,578 | 473 | 696 | 160 | 339 | 4,789 | 939 | 11,242 |
| 2029/30 | 346 | 852 | - | 487 | 629 | 2,006 | 474 | 654 | 159 | 385 | 4,650 | 1,021 | 11,663 |
| 2030/31 | 357 | 838 | - | 495 | 634 | 2,297 | 477 | 646 | 151 | 395 | 4,789 | 1,056 | 12,135 |
| 2031/32 | 361 | 905 | 260 | 475 | 665 | 2,414 | 501 | 629 | 156 | 417 | 4,915 | 1,094 | 12,792 |
| 2032/33 | 370 | 889 | 260 | 516 | 675 | 2,356 | 510 | 623 | 160 | 412 | 4,984 | 1,113 | 12,869 |
| 2033/34 | 366 | 881 | 260 | 501 | 649 | 2,376 | 506 | 621 | 153 | 414 | 5,116 | 1,145 | 12,988 |

Tables 3.22 and 3.23 show the historical and forecast of transmission delivered winter maximum demand and native winter maximum demand for each of the 12 zones in the Queensland region. It is based on the Central scenario and average (50% PoE) winter weather.

Table 3.22 State winter maximum transmission delivered demand by zone (MW)

| Winter | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2015 | 192 | 289 | - | 332 | 429 | 1,249 | 203 | 137 | 137 | 258 | 3,267 | 597 | 7,090 |
| 2016 | 226 | 249 | - | 370 | 417 | 1,242 | 206 | 390 | 181 | 279 | 3,079 | 537 | 7,176 |
| 2017 | 241 | 368 | - | 366 | 377 | 1,074 | 216 | 513 | 187 | 248 | 2,797 | 483 | 6,870 |
| 2018 | 242 | 366 | - | 335 | 439 | 1,091 | 235 | 475 | 186 | 336 | 3,086 | 540 | 7,331 |
| 2019 | 234 | 284 | - | 362 | 419 | 1,037 | 239 | 615 | 195 | 293 | 3,078 | 540 | 7,296 |
| 2020 | 227 | 306 | - | 327 | 449 | 1,104 | 246 | 531 | 191 | 313 | 3,274 | 515 | 7,483 |
| 2021 | 204 | 296 | - | 334 | 383 | 1,075 | 250 | 592 | 179 | 339 | 3,275 | 545 | 7,472 |
| 2022 | 230 | 246 | - | 322 | 431 | 991 | 280 | 508 | 162 | 360 | 3,780 | 611 | 7,921 |
| 2023 | 217 | 237 | - | 352 | 418 | 1,069 | 252 | 606 | 167 | 321 | 3,225 | 537 | 7,399 |
| 2024 | 221 | 187 | - | 367 | 441 | 1,071 | 270 | 473 | 193 | 396 | 3,728 | 624 | 7,970 |
| Forecasts | | | | | | | | | | | | | |
| 2025 | 269 | 381 | - | 352 | 409 | 928 | 362 | 438 | 138 | 255 | 3,525 | 844 | 7,900 |
| 2026 | 280 | 454 | - | 362 | 438 | 1,047 | 383 | 321 | 139 | 348 | 3,742 | 882 | 8,396 |
| 2027 | 279 | 488 | - | 393 | 457 | 1,077 | 381 | 347 | 134 | 354 | 3,733 | 889 | 8,532 |
| 2028 | 288 | 473 | - | 407 | 456 | 1,216 | 409 | 347 | 139 | 348 | 3,855 | 922 | 8,860 |
| 2029 | 298 | 524 | - | 417 | 460 | 1,304 | 390 | 357 | 132 | 406 | 3,820 | 854 | 8,962 |
| 2030 | 294 | 583 | - | 421 | 489 | 1,585 | 369 | 450 | 137 | 292 | 4,015 | 883 | 9,520 |
| 2031 | 294 | 578 | 220 | 414 | 509 | 1,701 | 360 | 448 | 126 | 291 | 3,930 | 884 | 9,755 |
| 2032 | 296 | 446 | 220 | 433 | 519 | 1,942 | 387 | 334 | 131 | 302 | 3,987 | 898 | 9,894 |
| 2033 | 310 | 464 | 220 | 434 | 530 | 1,979 | 397 | 299 | 134 | 314 | 4,021 | 935 | 10,037 |
| 2034 | 308 | 485 | 220 | 422 | 509 | 2,001 | 424 | 253 | 129 | 347 | 4,122 | 964 | 10,184 |

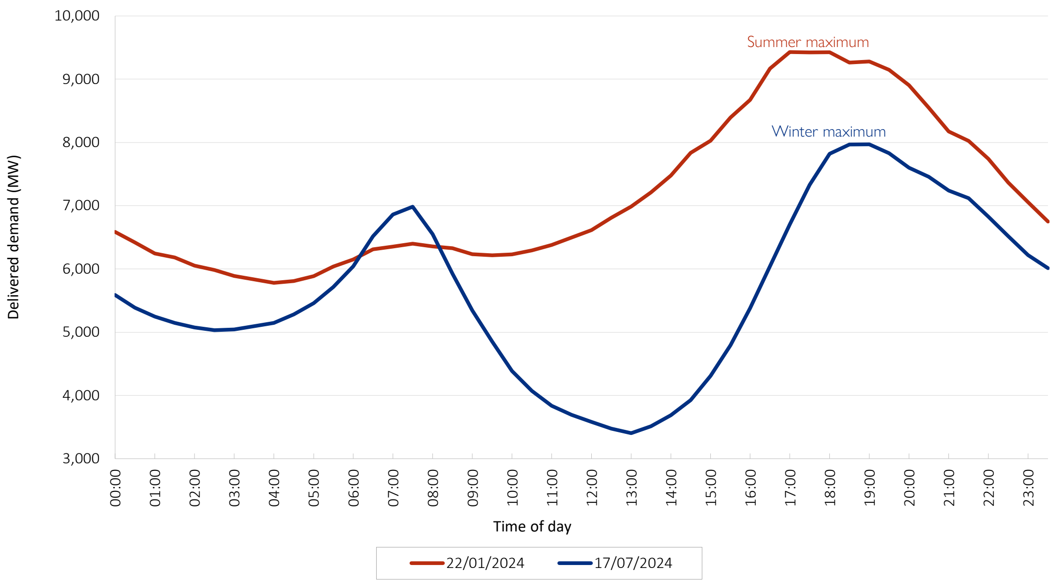
Table 3.23 State winter maximum native demand by zone (MW)

| Winter | Far North | Ross | North West | North | Central West | Gladstone | Wide Bay | Surat | Bulli | South West | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | | | |
| 2015 | 192 | 334 | - | 404 | 518 | 1,249 | 203 | 208 | 137 | 288 | 3,281 | 597 | 7,411 |
| 2016 | 216 | 358 | - | 419 | 504 | 1,229 | 200 | 467 | 193 | 310 | 3,008 | 550 | 7,454 |
| 2017 | 218 | 367 | - | 416 | 415 | 1,070 | 220 | 554 | 182 | 276 | 2,913 | 526 | 7,157 |
| 2018 | 242 | 360 | - | 410 | 494 | 1,091 | 235 | 654 | 186 | 336 | 3,085 | 540 | 7,633 |
| 2019 | 230 | 307 | - | 408 | 483 | 1,066 | 241 | 628 | 207 | 346 | 3,176 | 532 | 7,624 |
| 2020 | 227 | 329 | - | 406 | 492 | 1,104 | 247 | 624 | 191 | 342 | 3,231 | 515 | 7,708 |
| 2021 | 206 | 255 | - | 366 | 459 | 1,079 | 232 | 691 | 181 | 357 | 3,373 | 559 | 7,758 |
| 2022 | 230 | 248 | - | 375 | 458 | 991 | 280 | 634 | 162 | 357 | 3,779 | 611 | 8,125 |
| 2023 | 217 | 223 | - | 408 | 441 | 1,069 | 251 | 697 | 167 | 318 | 3,224 | 537 | 7,552 |
| 2024 | 221 | 187 | - | 367 | 441 | 1,071 | 270 | 430 | 193 | 396 | 3,728 | 624 | 7,928 |
| Forecasts | | | | | | | | | | | | | |
| 2025 | 276 | 560 | - | 356 | 466 | 938 | 376 | 567 | 140 | 297 | 3,565 | 865 | 8,404 |
| 2026 | 283 | 565 | - | 365 | 478 | 956 | 388 | 540 | 140 | 302 | 3,950 | 930 | 8,899 |
| 2027 | 282 | 584 | - | 396 | 497 | 987 | 386 | 552 | 136 | 308 | 3,991 | 912 | 9,031 |
| 2028 | 297 | 605 | - | 410 | 524 | 1,227 | 386 | 566 | 141 | 311 | 3,958 | 935 | 9,360 |
| 2029 | 306 | 649 | - | 421 | 517 | 1,318 | 395 | 581 | 134 | 283 | 3,999 | 853 | 9,457 |
| 2030 | 302 | 643 | - | 424 | 548 | 1,687 | 413 | 570 | 138 | 335 | 4,053 | 890 | 10,005 |
| 2031 | 302 | 678 | 220 | 419 | 536 | 1,729 | 403 | 547 | 128 | 334 | 4,050 | 893 | 10,238 |
| 2032 | 306 | 667 | 220 | 403 | 534 | 1,946 | 410 | 517 | 132 | 344 | 4,017 | 877 | 10,373 |
| 2033 | 314 | 655 | 220 | 419 | 543 | 1,953 | 413 | 530 | 136 | 350 | 4,085 | 898 | 10,516 |
| 2034 | 311 | 649 | 220 | 426 | 552 | 2,010 | 420 | 528 | 130 | 352 | 4,110 | 953 | 10,663 |

## 3.6 Summer and winter maximum and annual minimum daily profiles

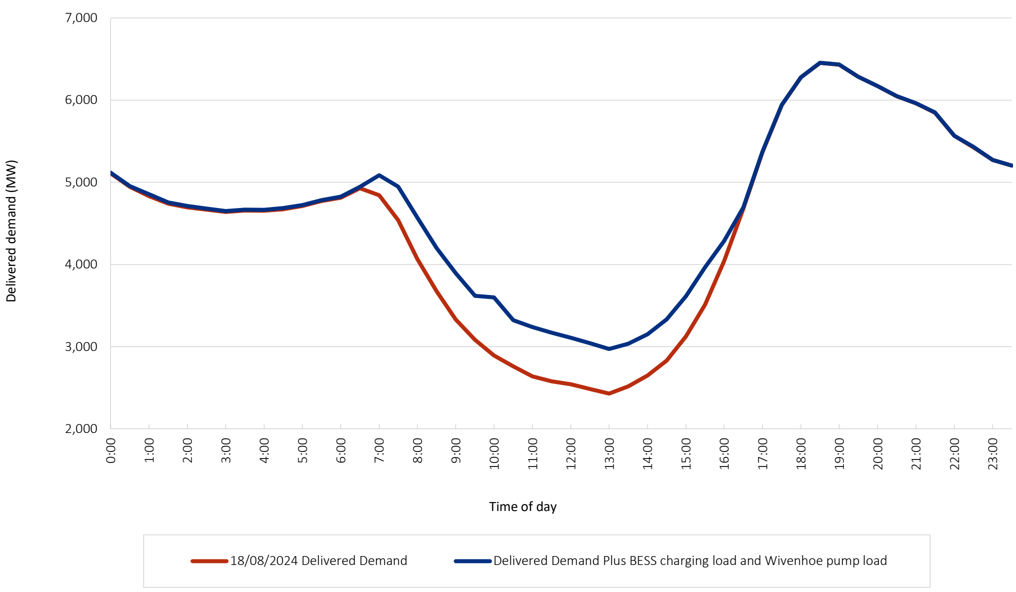
The daily load profiles (transmission delivered) for the Queensland region on the days of summer 2023/24 and winter 2024 maximum demands are shown in Figure 3.14.

Figure 3.14 Daily load profile of summer 2023/24 and winter 2024 maximum transmission delivered demand days




The 2024 annual minimum (transmission delivered) daily load profile for the Queensland region delivered demand plus BESS charging load and Wivenhoe pump load is shown in Figure 3.15.

Figure 3.15 Daily load profile of 2024 minimum transmission delivered day and minimum delivered demand plus BESS charging load and Wivenhoe pump load (1)




Note:

(1) Based on preliminary meter data up to 20 October 2024.

## 3.7 Annual load duration curves

The annual historical load duration curves for the Queensland region transmission delivered demand since 2019/20 is shown in Figure 3.16.

Figure 3.16 Historical transmission delivered load duration curve

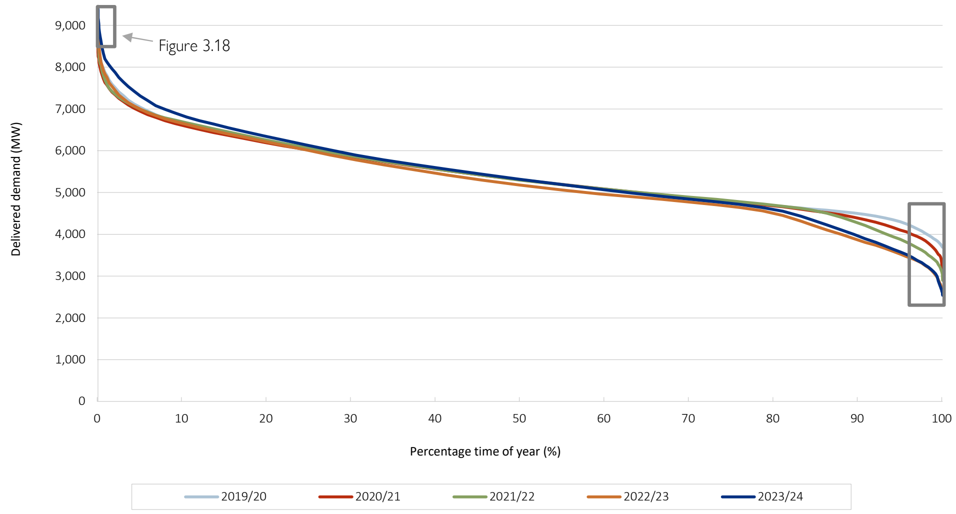



Figure 3.17 Historical transmission delivered load duration curves (95-100%)

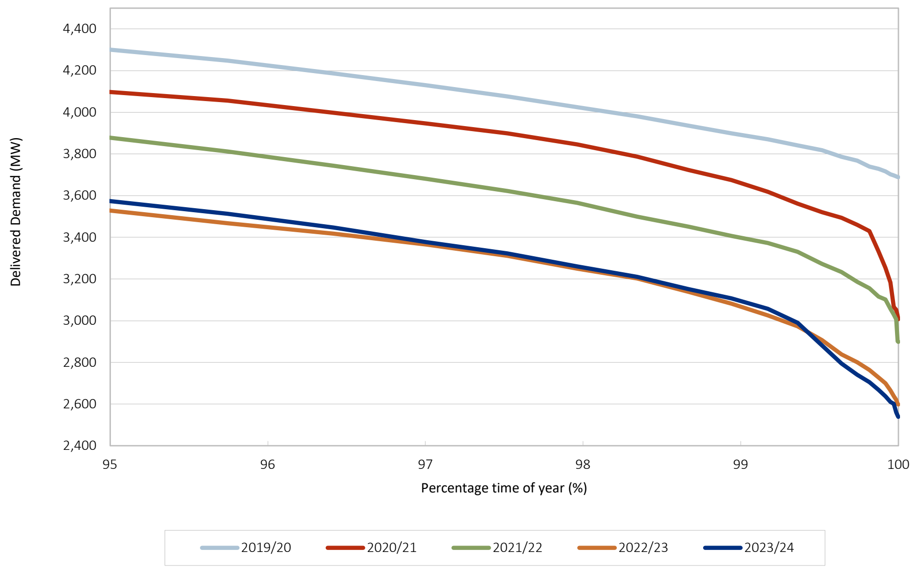
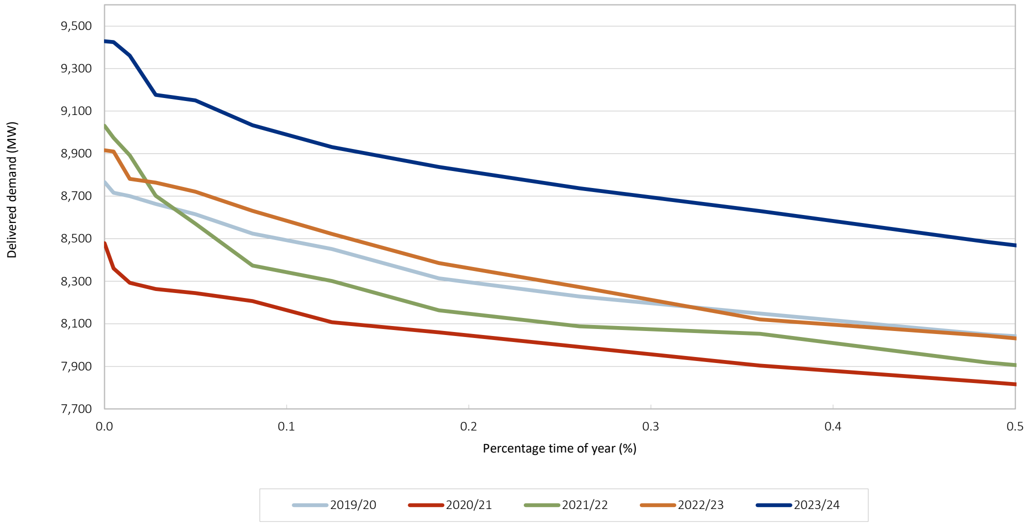
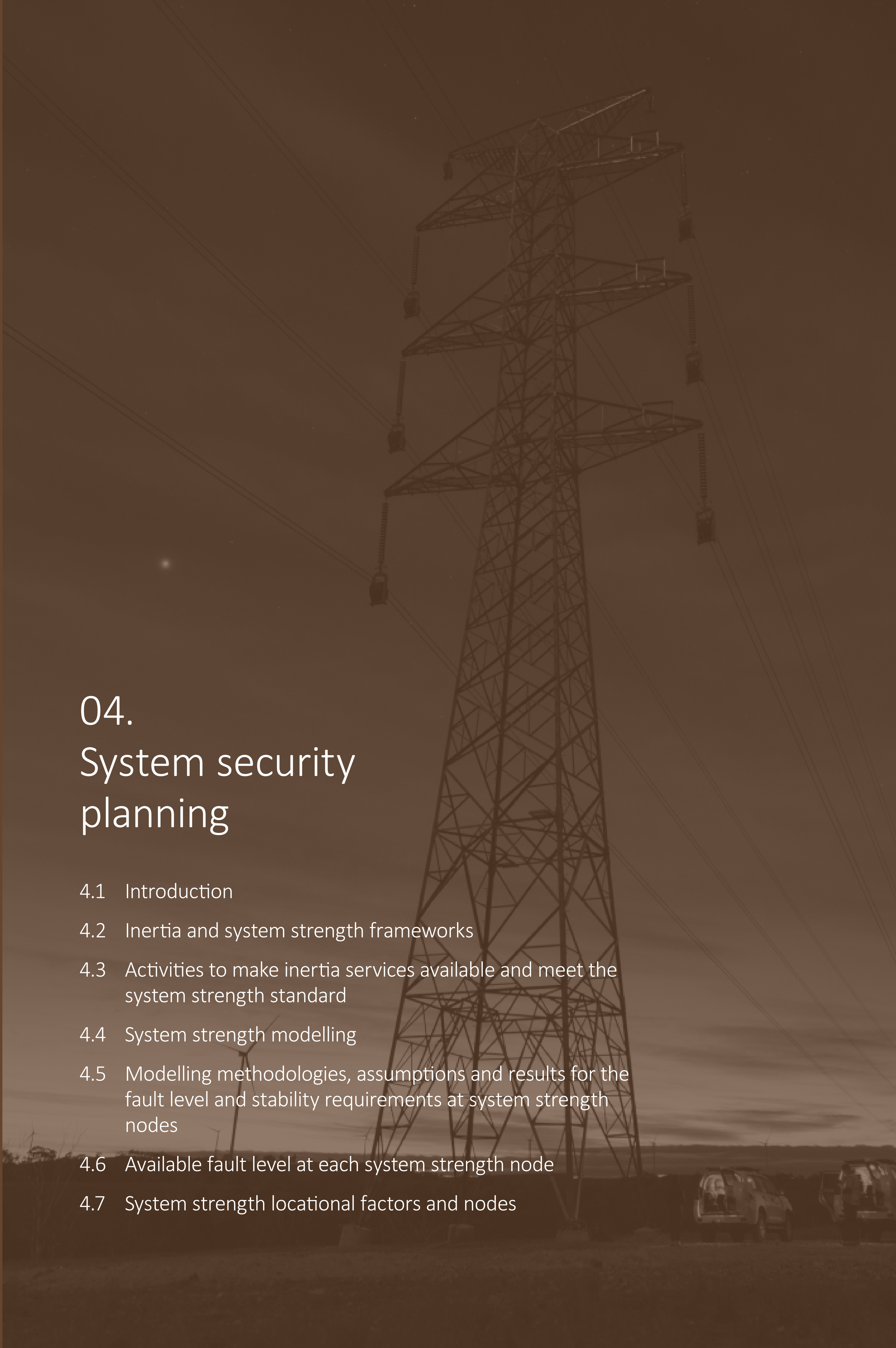


Figure 3.18 Historical transmission delivered load duration curves (0-0.5%)





# 04. System security planning

*The transformation of Queensland's power system from synchronous generation to variable renewable energy (VRE) is changing the way essential system services are planned for, procured and managed. This chapter discusses the planning and delivery of essential system services in Queensland.*

## Key highlights

- System security services have traditionally been provided as a by-product of synchronous generation.
- The transformation of Queensland's power system toward VRE necessitates new approaches to the planning and delivery of system security services.
- Significant changes to power system security frameworks have been made in recent years.
- Powerlink is seeking to deliver system security services for customers in a cost effective manner.

# 4.1 Introduction

Queensland's power system has historically comprised dispatchable generation such as coal-fired generators, gas turbines and hydro-electric plants. These large synchronous generating units have inherently provided various services, such as voltage regulation, inertia and system strength, to maintain power system security. However, many non-synchronous generation technologies, such as large-scale solar and wind, do not inherently provide system strength because the majority to date have used grid-following inverter technology to generate electricity. The transformation of the power system to VRE generation necessitates new approaches to the planning and delivery of system security services. Planning for minimum and efficient levels of system strength and providing minimum levels of inertia in the transmission network are the focus of this chapter.

System strength can broadly be described as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance[1]. System strength has traditionally been provided by conventional forms of generation, not because of their fuel source (such as coal, gas and hydro) but because of their 'synchronous' design.

Inertia is an instantaneous rapid and automatic injection of energy to suppress sudden frequency deviations and slow the rate of change of frequency. Inertia allows a power system to resist large changes in frequency arising from an imbalance in power supply and demand due to a contingency event. Like system strength, inertia has traditionally been provided by synchronous generators, and additional remediation is needed to ensure the power system has sufficient inertia to remain secure as the power system transforms[2].

This chapter provides an overview of the frameworks for providing system strength and inertia in the National Electricity Market (NEM), and addresses requirements in the National Electricity Rules (NER) for the Transmission Annual Planning Report (TAPR) to provide information on:

- the activities Powerlink has undertaken to make system strength and inertia network services available;
- the modelling methodologies, assumptions and results used by Powerlink to plan activities to meet the system strength standard;
- the system strength locational factor and corresponding system strength node for each connection point for which Powerlink is the Network Service Provider[3].

[1] AEMO, System Strength Requirements Methodology, version 2.0, December 2022, p. 6.
[2] AEMO, 2021 System Security Reports, December 2021, p. 18; AEMO, 2022 Inertia Report, December 2022, p. 8.
[3] NER, Clause 5.12.2(c)(8)(ii), which references Powerlink's obligations as the inertia and system strength service provider for Queensland under clauses 5.20B.4(h) and (i), and 5.20C.3(f) and (g), of the NER.

## 4.2 Inertia and system strength frameworks

The Australian Energy Market Operator (AEMO) and Powerlink are responsible for the planning and delivery of power system security services in Queensland. AEMO's System Security Reports consider the need for services in Queensland, and other regions of the NEM, over a five to ten year horizon. The reports assess system strength requirements, inertia shortfalls and Network Support and Control Ancillary Services (NSCAS) needs. Where AEMO declares a gap/shortfall for a power system security service(s) in Queensland, Powerlink is obliged to make services available within the timeframe stipulated by AEMO.

### 4.2.1 Inertia

In September 2017, the Australian Energy Market Commission (AEMC) made the Managing the Rate of Change of Power System Frequency Rule (Inertia Services Rule). The Inertia Services Rule requires the Australian Energy Market Operator (AEMO) to assess whether shortfalls in inertia exist (or are likely to exist), and obliges Transmission Network Service Providers (TNSPs) to make continuously available minimum levels of inertia[4].

AEMO's most recent Inertia Report, released in December 2023, changed the identified inertia shortfall in Queensland from a range of 8,200 to 10,352 megawatt seconds (MWs) from 1 July 2026, to up to 1,660MWs from 2027/28. The one-year delay reflected updates to the delivery timing of several major generation, transmission and Renewable Energy Zone (REZ) development projects which resulted in utilisation of synchronous generation increasing in the near term. AEMO also indicated that the changed assessment represented a deferred onset of the shortfall, rather than a long-term reduction[5].

Powerlink is taking a prudent approach as to the timing of the commencement of the RIT-T consultation process to meet the declared inertia shortfall. Powerlink is currently progressing a system strength RIT-T (refer to Section 4.3). Given the potential for system strength solutions to contribute to inertia, the preferred option for Powerlink's system strength RIT-T (Section 4.3) may address, either in part or in full, the timing and size of the inertia shortfall.

### 4.2.2 System Strength

In December 2021, AEMO declared an immediate system strength shortfall of 44 to 65 megavolt-amperes (MVA) at the Gin Gin 275 kilovolt (kV) system strength node for the period 2021/22 to 2026/27, against the minimum (postcontingency) three phase fault level of 2,250MVA at the node[6]. AEMO declared the shortfall as it projected a decline in the number of synchronous generators online in Central Queensland in response to declining minimum demand and increasing VRE and distributed solar photovoltaic (PV) generation[7]. AEMO declared the shortfall on the basis that it forecast system strength services would fall below the minimum requirements for more than 1% of the time under typical dispatch patterns[8].

In May 2022, AEMO updated the declaration to account for its replacement of the Progressive Change scenario with the Step Change scenario for the 2022 Integrated System Plan. The update increased the size of the shortfall at Gin Gin from 33MVA in 2022/23 to 90MVA in 2026/27[9]. AEMO's System Strength Reports released in December 2022 and December 2023 stated that the shortfall at the Gin Gin node was 64MVA until 1 December 2025, at which time new requirements for the provision of system strength services would commence[10].

4 AEMC, Managing the Rate of Change of Power System Frequency, information sheet, September 2017, p. 2; NER, clauses 4.3.4(j) and 5.20B.4(b).

5 AEMO, 2022 Inertia Report, December 2022, p. 22; AEMO, 2023 Inertia Report, December 2023, p. 14.

6 AEMO, 2021 System Security Reports, December 2021, pp. 42 and 49.

7 AEMO, 2021 System Security Reports, December 2021, p. 42. The declaration was made under Clause 5.20C.2 (Fault Level Shortfalls) of the NER, as in force at the time. Transitional arrangements in Clause 11.143.13(a)(1) of the NER to support the Efficient Management of System Strength on the Power System Rule required Powerlink to continue to comply with the declaration.

8 AEMO, 2021 System Security Reports, December 2021, pp. 11 and 102.

9 AEMO, Update to 2021 System Security Reports, May 2022, p. 23.

10 AEMO, 2022 System Strength Report, December 2022, p. 41; AEMO, 2023 System Strength Report, December 2023, pp. 28 and 56.

Although the fault level shortfall declared by AEMO was at the Gin Gin node, the shortfall location does not necessarily capture technical components of the system strength shortfall, or indicate from where the particular problem is most efficiently addressed. That is, options which address the technical power system performance issues elsewhere in Central and North Queensland may reduce or remove the fault level shortfall at the Gin Gin 275kV fault level node. Technical components of the shortfall, and the location from which it should be addressed, can only be informed through system-wide Electromagnetic Transient (EMT-type) type analysis.

Powerlink was required to use reasonable endeavours to make system strength services available to AEMO by 31 March 2023, being the date by which AEMO requested Powerlink provide the services[11]. Immediately following the fault level shortfall declaration, Powerlink commenced an Expression of Interest process for short and long-term non-network solutions to the fault level shortfall at the Gin Gin node[12].

Only one of the four options was able to commence operation by 31 March 2023. However, this solution would not have provided a material increase in system strength at the Gin Gin node to address the required need. Of the three remaining options, Powerlink concluded the addition of a clutch to the shaft between the gas turbine and the synchronous generator at the Townsville Power Station was the least cost option to address the need. The Townsville Power Station is owned by Ratch Australia (Ratch), and Powerlink has entered into a System Strength Services Agreement with Ratch for the provision of system strength services. The addition of the clutch is expected to be delivered by mid-2025. Powerlink expects that operation of the Townsville Power Station as either a generator or as a synchronous condenser will provide sufficient system strength for inverter-based generation facilities in North and Central Queensland to operate stably from mid-2025. In December 2023 AEMO provided its approval of the arrangements to Powerlink, as required under the NER[13]. Powerlink published a final report on the response to the shortfall at the Gin Gin node in January 2024.

In October 2021, the AEMC introduced the Efficient Management of System Strength on the Power System Rule (System Strength Rule). The System Strength Rule:

- evolved the ‘do no harm’ framework which required connecting generators to self-assess their impact on the local network’s system strength levels, and self-remediate any adverse impacts ; and
- established a new framework for the supply, demand and coordination of system strength in the NEM[14].

The System Strength Rule established Powerlink as the System Strength Service Provider (SSSP) for Queensland[15]. Under the new framework, parties who submit an application to connect on or after 15 March 2023 are able to choose to remediate their system strength impact, or pay for their use of system strength resources procured by Powerlink. From 1 July 2023, system strength charges apply to connecting parties who come under this new framework and use system strength but choose not to remediate their system strength impact on the network. The System Strength Unit Prices for each node are based on long run average costs. The prices apply for a five-year period and are indexed by the consumer price index in each of the four remaining years.

In December 2022, AEMO published the first System Strength Report under the evolved framework. The report set out the minimum pre- and post-contingent fault levels, and 10-year forecast of inverter-based resources (IBR) for each of Queensland’s five system strength nodes to be used by Powerlink for the purposes of meeting system strength standard specification under Clause S5.1.14 of the NER[16].

### 4.2.3 Improving Security Frameworks for the Energy Transition

In March 2024, the AEMC made the Improving Security Frameworks for the Energy Transition Rule (ISFET Rule) which aimed to enhance arrangements to value, procure and schedule system security services – which includes system strength, inertia and Network Support and Control Ancillary Services – in the NEM.

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11 AEMO, Update to 2021 System Security Reports, May 2022, page 23. The reasonable endeavours requirement was in Clause 5.20C.3(c)(1) of the NER when the shortfall was declared, and is now in Clause S5.1.14(b) of the NER.
12 National Electricity Rules, Clause 5.20C.3(e).
13 National Electricity Rules, Clause 5.20C.4(e).
14 AEMC, Efficient Management of System Strength on the Power System, Final Determination, October 2021, p. 13.
15 NER, Clause 5.20C.3(a).
16 AEMO, 2022 System Strength Report, December 2022, pp. 37 and 40.

Among other things, the ISFET Rule will align the system strength and inertia procurement frameworks from December 2024, with Powerlink required to ensure sufficient inertia is continuously available to meet projected inertia needs for Queensland from December 2027. The ISFET Rule also included transitional provisions to preserve Powerlink's obligation to address the already-declared shortfall[17].

## 4.3 Activities to make inertia services available and meet the system strength standard

In March 2023, Powerlink commenced a RIT-T to address system strength requirements in Queensland from December 2025. The RIT-T is a key part of Powerlink's implementation of the System Strength Rule. In the Project Specification Consultation Report (PSCR), Powerlink invited submissions from proponents who considered they could offer a potential non-network solution(s) that was both technically and economically feasible by 2030. In response to the PSCR, Powerlink received close to 80 unique non-network solutions from more than 20 proponents.

Submissions on the PSCR were due in July 2023, meaning the Project Assessment Draft Report (PADR) was due for publication in July 2024 unless a longer period was agreed by the Australian Energy Regulator (AER). Given the complexity and scale of the System Strength RIT-T, in April 2024 Powerlink requested, and the AER agreed to, an extension of the date by which the PADR was to be published to November 2024.

## 4.4 System strength modelling

Powerlink has developed an EMT-type model that extends from Far North Queensland to the Hunter Valley in New South Wales. It includes plant specific models for all VRE and synchronous generators (including voltage control systems) and transmission connected dynamic voltage control plant (Static VAr Compensators and STATCOMs). This is a comprehensive model with inverter-based plant modelled at the controller level and simulation time steps in micro-seconds. The model allows Powerlink to conduct system strength assessments for generator connections.

Powerlink undertakes a Full Impact Assessment (FIA) or stability assessment using the systemwide EMT-type model for all VRE generation applying to connect to the Powerlink network, regardless of the size of the proposed plant. This is because only an EMT-type analysis can provide information on the impact of potentially unstable interactions with other generators and dynamic voltage control plant. Powerlink is exploring a novel method using small signal analysis to understand the impact of potentially unstable interactions with other generators. The FIA or stability assessment is carried out as part of the connection process as per AEMO's System Strength Impact Assessment Guidelines (SSIAG). This ensures that any adverse system strength impact is identified and addressed as part of the connection application.

The SSIAG provides additional details regarding the assessment process and methodology, while AEMO's Power System Model Guidelines provides additional information on modelling requirements.

## 4.5 Modelling methodologies, assumptions and results for the fault level and stability requirements at system strength nodes

In December 2023, AEMO reviewed minimum system strength requirements in each region of the NEM. The report did not change the minimum pre or post-contingent fault levels for system strength nodes in Queensland from the 2022 System Strength Report, but did include estimates of the typical levels of fault level available. In this context, AEMO noted that 'typical' referred to the 99th percentile of availability[18].

17 NER, Clause 11.168.9.
18 AEMO, 2023 System Strength Report, December 2023, p. 10.

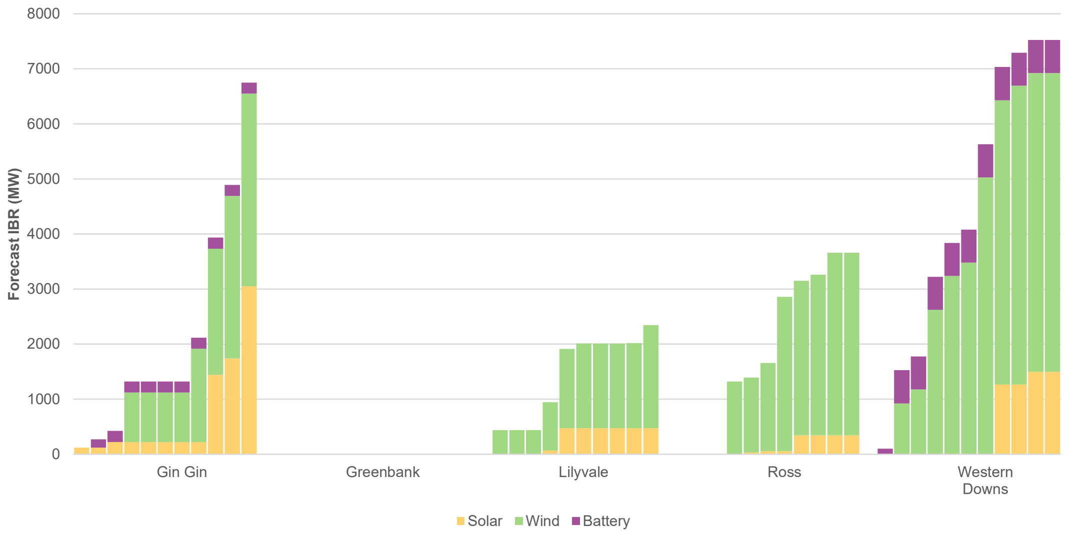
As SSSP for Queensland, Powerlink is required to maintain the three phase fault level specified by AEMO for the system strength nodes in Queensland and maintain stable voltage waveforms for the level and type of IBR and market network service facilities projected by AEMO for the relevant year. The relevant year for the 2023 TAPR would be 2 December 2025 to 1 December 2026. Table 4.1 shows, for each system strength nodes, the pre- and post-contingent minimum fault level, and minimum fault level expected 99% of the time from 2023/24 to 2028/29.

Table 4.1 AEMO minimum three phase fault level expected 99% of the time, December 2023

| Node | Pre-contingent minimum fault level (MVA) | Post-contingent minimum fault level (MVA) | Minimum three phase fault current (MVA) expected 99% of the time, financial year ending | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
| Gin Gin | 2,800 | 2,250 | 2,192 | 2,201 | 2,201 | 2,195 | 2,083 | 2,093 |
| Greenbank | 4,350 | 3,750 | 4,642 | 4,590 | 4,679 | 4,626 | 3,126 | 3,205 |
| Lilyvale | 1,400 | 1,150 | 1,172 | 1,182 | 1,183 | 1,179 | 1,146 | 1,149 |
| Ross | 1,350 | 1,175 | 1,327 | 1,321 | 1,336 | 1,332 | 1,306 | 1,300 |
| Western Downs | 4,000 | 2,550 | 2,858 | 2,830 | 2,863 | 2,843 | 2,112 | 2,144 |

The 2023 System Strength Report also included updated IBR projections for Queensland over the 11-year period from 2023/24.

Figure 4.1 AEMO 11-year forecast of level and type of IBR at system strength nodes, December 2023




Note: Forecasts excluded existing IBR.

Source: AEMO, 2023 System Strength Report, page 27.

The three phase fault level requirements at each node in Queensland in 2025/26 (the relevant year) is unchanged. At the time of 2024 TAPR, two hydro machines in North Queensland, seven coal-fired synchronous machines in Central Queensland and four coal-fired synchronous machines in Southern Queensland provide the minimum fault level requirements in Queensland, noting that sources of minimum fault level can change as the system evolves.

In March 2023 Powerlink commenced a RIT-T to identify a portfolio of solutions to meet the minimum and efficient levels of system strength. To meet the minimum system strength requirements identified by AEMO, the PSCR indicated that the following sources would be necessary in each region:

- seven synchronous machines or equivalent plant online in Central Queensland, in the order of 350MVA each
- two hydro-electric machines or equivalent plant in North Queensland, in the order of 20MVA each
- four synchronous machines or equivalent plant online in Southern Queensland, in the order of 400MVA each.

AEMO's forecast of VRE and Battery Energy Storage Systems (BESS), as at December 2023, is approximately 16.6GW by 2030 and approximately 25GW by 2034. The 2030 VRE forecast consists of more than 70% of wind farms and less than 30% of solar farms. Existing experience in Queensland indicates that assumptions of system strength requirements based primarily on the three phase fault level calculations can differ from the detailed assessment and therefore can be misleading.

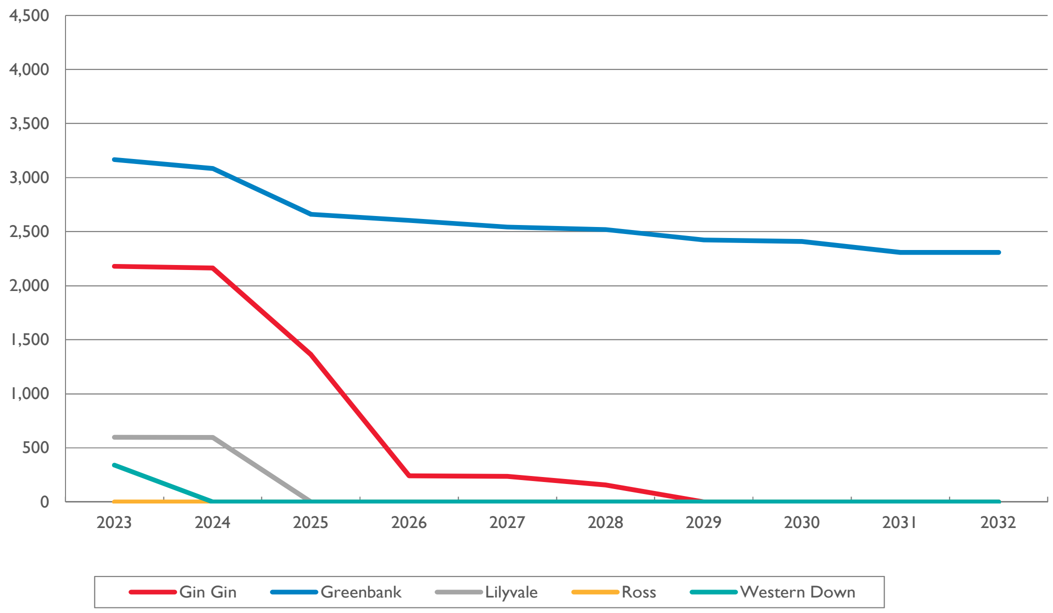
As part of the System Strength RIT-T Powerlink mapped its market intelligence of connection applications and enquiries against the forecast provided in AEMO's System Strength Report. Subsequently, Powerlink performed detailed EMT-type studies to assess system strength requirements, focussing on both the minimum level and efficient level of system strength support needed for the existing and projected VRE generation in Queensland over the 2025 to 2030 planning horizon.

The findings from the studies indicated that additional system strength resources will be necessary in specific regions of North, Central, and South Queensland to ensure stable voltage waveforms as the integration of VRE into the network increases. The studies also confirmed that grid-forming BESS could provide the efficient level of system strength for future VRE connections. Powerlink anticipates that grid-forming BESS will play a vital role in the future power system to obtain the stable voltage waveform support.

## 4.6 Available fault level at each system strength node

Figure 4.2 shows the Available Fault Level (AFL) at each system strength node.

Figure 4.2 Available Fault Level

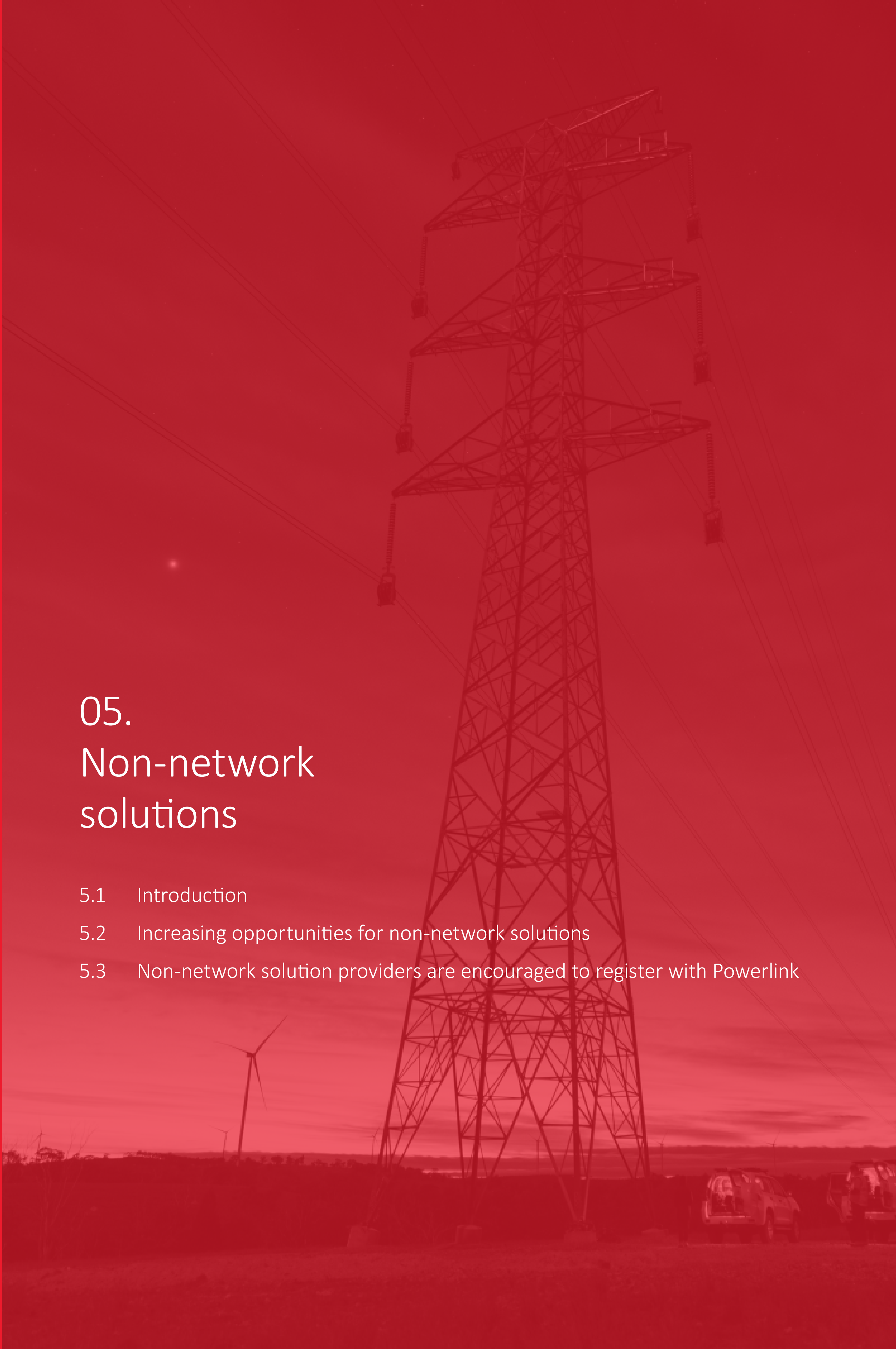


The AFLs at each node were calculated as per the SSIAG. Calculation of AFL works in such a way that it will reduce as more VRE is connected in the region. The above AFL is based on the minimum fault level as the source of the efficient level of system strength for future VRE connection is not confirmed at the time of publication of this report. It should be noted that while it is a requirement of the NER to publish the AFL to provide an indication of available system strength in the region, experience in Queensland has been that AFL does not reflect the available quantity of system strength required to maintain stable voltage waveforms. The highest amount of VRE is forecast at Western Downs in AEMO's report and therefore the AFL at Western Downs becomes zero very early. However, the actual requirements for system strength support at Western Downs does not follow the trend of AFL and therefore the System Strength Unit Prices (SSUP) at Western Downs is the lowest in Queensland.

## 4.7 System strength locational factors and nodes

System strength locational factors are part of the formula for system strength charges. The NER requires Powerlink to list the system strength locational factor for each connection point for which Powerlink is the Network Service Provider, and the corresponding system strength node.[19] System strength locational factors and nodes are included in Appendix H and shown in the TAPR portal.

[19] NER, Clause 5.12.2(c)(13).



# 05. Non-network solutions

*The use of non-network solutions is essential to provide reliable and cost effective transmission services for customers. This chapter discusses Powerlink's approach and process for engaging with non-network solution providers and provides a summary of potential non-network solution opportunities anticipated to become available over the next five years.*

## Key highlights

- As the power system transforms, non-network solutions will be essential to address network needs such as inertia, system strength, Network Support and Control Ancillary Services (NSCAS) and voltage control.
- Flexible demand in a renewable generation future will be essential and non-network solutions will play a key role in managing daily peaks and troughs where economic, delivering positive outcomes for customers.
- Non-network solutions, in part or full, may also contribute to a network strategy by maintaining a balance between reliability and the cost of transmission services for customers.

# 5.1 Introduction

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the National Electricity Rules (NER). For a given network limitation or potential asset replacement, the viability and an indicative specification of non-network solutions are first introduced in the Transmission Annual Planning Report (TAPR) and TAPR templates. As the identified need date approaches and detailed planning analysis is undertaken, further opportunities are explored in the consultation and stakeholder engagement processes undertaken as part of the Regulatory Investment Test for Transmission (RIT-T).

In the past, Powerlink has implemented a range of non-network solutions in various areas in Queensland to assist, support or augment the power transfer capability of the high voltage transmission network. Most recently, as an outcome of the Managing voltages in South East Queensland RIT-T, Powerlink has an agreement in place for network support services from CleanCo to operate during times of reactive power absorption, avoiding the need for additional bus reactors in South East Queensland.

Powerlink is continuing discussions with proponents of potential non-network solutions that are expected to materially contribute to meet both the forecast minimum and efficient system strength requirements in Queensland (refer to Addressing system strength requirements in Queensland from December 2025 and Section 6.8.2).

# 5.2 Increasing opportunities for non-network solutions

Given the scale of the energy transformation, rapid uptake of variable renewable energy (VRE) resources and signalled retirement of synchronous generators, it is critical to find alternate solutions and to procure services to address future power system security requirements such as inertia, system strength and NSCAS. Powerlink expects that non-network solutions will materially contribute to the provision of these services through a suite of solutions with, but not limited to, existing synchronous generation plant, dedicated synchronous condensers, pumped hydro energy storage and grid-forming asynchronous plant.

The uptake of rooftop photovoltaic (PV) systems is expected to continue within residential and commercial premises. Should this trend progress in the absence of energy storage devices (such as household battery systems) or significant levels of demand time of day shifting, minimum demand will further decrease and there will be a continued widening between maximum and minimum demand (refer to Section 3.2). The installation of additional reactive devices and/or non-network solutions are likely to be required to manage high voltages during minimum demand conditions.

Continuation of this trend is likely to present further challenges to the transmission system. Generating stations will be required to ramp up and down in response to daily demand variations more frequently. Decreasing minimum demand will lower the amount of synchronous generation that is online, and this could further impact on voltage control, system strength, and inertia.

Powerlink expects there will also be future opportunities for new technologies and flexible loads, which will be capable of providing non-network solutions to assist with managing daily peaks and troughs in the renewable generation future. Demand shifting and storage solutions have the potential to smooth the daily load profile and could offer a number of benefits to the power system including reducing the need for additional transmission network investments. More information on these emerging issues is available in Chapter 3 and sections 6.9.1 to 6.11.6.

Powerlink is committed to genuine engagement with providers of non-network solutions and the implementation of these solutions where technically feasible and economic to:

- address inertia, system strength and NSCAS requirements, ensuring the secure operation of the transmission network
- address future network limitations or address the risks arising from ageing assets remaining in-service within the transmission network
- complement network developments as part of an integrated solution to deliver an overall network strategy
- provide demand management and load balancing.

Potential non-network solution opportunities within the next five years are described in Table 5.1.

## 5.3 Non-network solution providers are encouraged to register with Powerlink

Powerlink has established a Non-network Engagement Stakeholder Register (NNESR) to convey non-network solution providers the details of potential non-network solution opportunities. The NNESR is comprised of a variety of interested stakeholders who have the potential to offer network support and/or system security services through alternate technologies, existing and/or new generation or demand side management (DSM) initiatives (either as individual providers or aggregators).

More information on potential non-network solutions is available on Powerlink's website, including details regarding current candidate Priority Transmission Investment and RIT-T consultations and Powerlink's Network Support Contracting Framework.

Interested parties are encouraged to contact NetworkAssessments@powerlink.com.au to become a member of Powerlink's NNESR.

Table 5.1 Potential non-network solution opportunities within the next five years

| Potential project | Indicative cost (most likely network option) | Zone | Indicative non-network requirement | Possible commissioning date | TAPR Reference |
|---|---|---|---|---|---|
| Joint planning projects | | | | | |
| Woree to Kamerunga 132kV transmission line replacement, substation establishment on a new site and associated Ergon 22kV works | $200m | Far North | Up to 70MW at peak and up to 1,200MWh per day on a continuous basis to provide supply to the 22kV network | December 2028 | Section 6.9.1<br><br>Anticipated RIT-T |
| Transmission lines | | | | | |
| Line refit works on the 275kV transmission lines between Ross and Chalumbin | $35m | Far North | The Ross to Chalumbin transmission lines provide injection to the north area of close to 400MW at peak and up to 3,000MWh per day. The network configuration also facilitates generator connections in the area and provides system strength and voltage support for the region. | June 2029 | Section 6.9.1 |
| Line refit works on the 132kV transmission lines between Ross and Dan Gleeson | $8m | Ross | Provide close to 130MW at peak and up to 800MWh per day | June 2028 | Section 6.9.2 |
| Line refit works on the 132kV transmission lines between Nebo Substation and Eton Tee | $31m | North | Provide close to 80MW at peak and up to 200MWh per day for the region | December 2027 | Section 6.9.3 |
| Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations | $15m | Central West | Up to 90MW on the network and up to 450MWh per day on a continuous basis to Nebo and North Queensland loads | December 2026 | Section 6.10.1 |
| Rebuild the 132kV transmission line between Calliope River and Gladstone South substations | $53m | Gladstone | Up to 160MW and up to 1,820MWh per day | June 2030 | Section 6.10.2 |
| Line refit works on the 275kV transmission line between Woolooga and South Pine substations by June 2029 | $39m | Wide Bay | Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in south east Queensland | June 2029 | Section 6.11.1 |

Table 5.1 Potential non-network solution opportunities within the next five years *(continued)*

| Potential project | Indicative cost (most likely network option) | Zone | Indicative non-network requirement | Possible commissioning date | TAPR Reference |
|---|---|---|---|---|---|
| Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations | $31m | Moreton | Up to 220MW at peak to Brisbane's inner north west suburb (potentially coupled with network reconfiguration) | June 2028 | Section 6.11.5<br><br>Anticipated RIT-T |
| Line refit works on the 275kV transmission line between Karana Downs and South Pine substations | $14m | Moreton | Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region | June 2030 | Section 6.11.5 |
| Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations | $37m | Gold Coast | Proposals which may significantly contribute to reducing the requirements in the southern Gold Coast and northern NSW area | June 2029 | Section 6.11.6 |
| Substations - primary plant and secondary systems | | | | | |
| Chalumbin 275kV and 132kV primary plant replacement | $9m | Far North | Up to 100MW and up to a peak of 65MWh per day on a continuous basis to provide supply to the 132kV network at Chalumbin | June 2028 | Section 6.9.1 |
| Tully 132/22kV transformer replacement | $6m | Far North | Up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully | June 2029 | Appendix D, Table D.1 |
| Alan Sherriff 132kV secondary systems replacement | $14m | Ross | Up to 35MW and up to 225MWh per day to provide supply to the 66kV network at Alan Sheriff | June 2027 | Section 6.9.2 |
| Ingham South 132kV primary plant and secondary systems replacement | $27m | Ross | Up to 20MW at peak and up to 280MWh per day on a continuous basis to provide supply to the 66kV network at Ingham South | December 2027 | Section 6.9.2 |
| Garbutt 132kV secondary systems replacement | $10m | Ross | Up o 120MW and up to 860MWh per day to provide supply to the 66kV network at Garbutt | June 2027 | Section 6.9.2 |

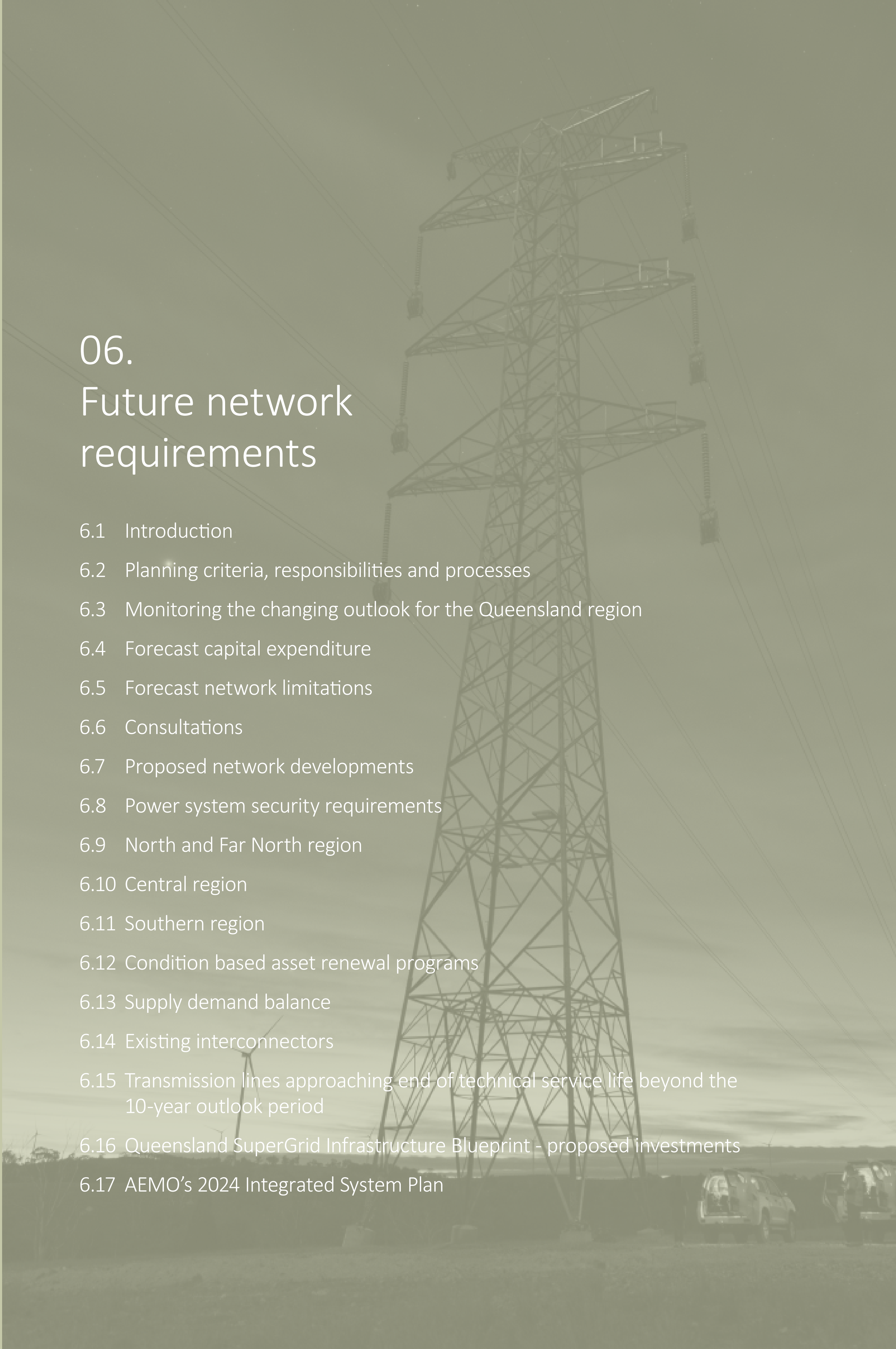
Table 5.1 Potential non-network solution opportunities within the next five years *(continued)*

| Potential project | Indicative cost (most likely network option) | Zone | Indicative non-network requirement | Possible commissioning date | TAPR Reference |
|---|---|---|---|---|---|
| Strathmore SVC secondary systems replacement | $12m | North | Up to 260MVArs capacitive and 80MVArs inductive support at Strathmore | June 2026 | Section 6.9.3 |
| Nebo SVC primary plant and SVC transformer replacement | $8m | North | Up to 260MVArs capacitive and 80MVArs inductive support at Nebo | December 2029 | Section 6.9.3 |
| Calvale 275kV primary plant replacement | $18m | Central West | More than 100MW and up to 2,000MWh per day on a continuous basis to provide supply to the 132kV network at Moura and Biloela | December 2027 | Section 6.10.1 |
| Broadsound 275kV primary plant replacement | $19m | Central West | Up to 250MW and up to 6,000MWh per day on a continuous basis to provide supply to the 275kV network at Broadsound | June 2028 | Section 6.10.1 |
| Ashgrove West 110kV secondary systems replacement | $22m | Moreton | Up to 220MW at peak to Brisbane's inner north west suburbs | June 2027 | Section 6.11.5 |
| Murarrie 275kV and 110kV secondary systems replacement | $21m | Moreton | Up to 500MW and a peak of 5,700MWh per day on a continuous basis | December 2027 | Section 6.11.5 |
| Abermain 275kV and 110kV primary plant replacement | $8m | Moreton | Up to a peak of 140MW and a peak of 1,050MWh per day on a continuous basis | June 2030 | Section 6.11.5 |
| Molendinar 275kV secondary systems | $28m | Gold Coast | Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in the Gold Coast region | December 2027 | Section 6.11.6 |
| System services | | | | | |
| To be identified through the RIT-T process | | State-wide | To address the minimum and efficient levels of system strength in Queensland | From December 2025 | Section 6.8.2<br>Current RIT-T |

Notes:

(1) TAPR template data associated with emerging constraints which may require future capital expenditure, including potential projects which fall below the RIT-T cost threshold of $7m, is available on Powerlink's TAPR portal (refer to Appendix E, in particular transmission connection points and transmission line segments, regarding Powerlink's methodology for template data development).

(2) Refer to Powerlink's website for information regarding potential non-network solution opportunities for the Gladstone Project.



# 06.
# Future network requirements

*This chapter discusses potential investments required on the transmission network within the 10-year outlook period. It includes information on forecast network limitations, supporting planning criteria and processes, the management of assets and network risks, Regulatory Investment Tests for Transmission (RIT-Ts), Priority Transmission Investments (PTIs), and the most recent connection point proposals anticipated to require connection to the transmission network. This chapter also discusses major projects referenced in the 2024 Integrated System Plan (ISP).*

### Key highlights

- As we move towards 80% renewables by 2035, Powerlink continues to be proactive and adapt to shifts in an increasingly uncertain, technically complex and dynamic operating environment.
- Powerlink applies a flexible and integrated approach to efficient investment decision making, taking into consideration multiple factors including:
  - assessing whether an enduring need exists for assets and investigating alternate network configuration opportunities and/or non-network solutions, where feasible, to manage asset and network risks, including the potential impacts of the energy transformation
  - the role of emerging technologies and assessing a range of technical factors and dynamic changes in Powerlink's operating environment to ensure network resilience
  - enabling opportunities for the connection of new firming generation and variable renewable energy (VRE) generation where technically and economically feasible
  - actively seeking opportunities to identify and implement more cost effective solutions as demonstrated by Powerlink's Asset Reinvestment Review (ARR), and whenever possible, making use of transmission line and transformer refits or non-network solutions (and services) that avoid or delay the need to establish new transmission network infrastructure.
- The changing generation mix (and associated peak to average production ratios of VRE plant) may lead to increased constraints across critical grid sections. Powerlink considers these potential constraints holistically as part of the planning process and in conjunction with the Queensland Energy and Jobs Plan (QEJP) and findings of the most recent Integrated System Plan (ISP).

## 6.1 Introduction

Powerlink Queensland (Powerlink) is the appointed Jurisdictional Planning Body (JPB) by the Queensland Government and is therefore responsible for transmission network planning within Queensland. Powerlink's obligation is to plan the transmission system to reliably and economically supply load, while managing risks associated with the condition and performance of existing assets in accordance with the requirements of the National Electricity Rules (NER), Queensland's *Electricity Act 1994* (the Act) and its Transmission Authority. As the designated Renewable Energy Zone (REZ) Delivery Body (RDB) for Queensland, Powerlink is also responsible for the planning and development of Renewable Energy Zones (REZs) in the state.

The NER[1] requires the Transmission Annual Planning Report (TAPR) to provide a forecast of constraints and inability to meet the network performance requirements set out in Schedule 5.1 of the NER, or relevant legislation or regulations of a participating jurisdiction over one, three and five years. In addition, there is a requirement[2] to provide estimated load reductions that would defer forecast limitations for a period of 12 months and to state any intent to issue request for proposals for augmentation, replacement of network assets or non-network alternatives. The TAPR must be consistent with the TAPR Guidelines[3] and include information pertinent to all proposed:

- augmentations to the network and replacements of network assets[4]
- network asset retirements or asset de-ratings that would result in a network constraint in the 10-year outlook period[5]
- inertia and system strength requirements[6].

1 NER, Clause 5.12.2(c)(3).
2 NER, Clause 5.12.2(c)(4).
3 NER, Clause 5.12.2(c).
4 NER, Clause 5.12.2(c)(5).
5 NER, Clause 5.12.2(c)(1A).
6 NER, Clause 5.20B.4(h) and 5.20C.3(f) and (g).

This chapter on proposed future network developments contains:

- discussion on Powerlink's planning criteria, processes and integrated planning approach to network development
- information regarding assets reaching the end of their technical service life and options to address the risks arising from ageing assets remaining in-service, including asset reinvestment, non-network solutions, potential network reconfigurations, asset retirements or de-ratings
- identification of emerging future limitations[7] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months[8]
- a statement of intent to issue request for proposals for augmentation, the proposed replacement of ageing network assets or non-network alternatives identified as part of the annual planning review[9]
- a summary of network limitations over the next five years[10]
- a table summarising possible connection point proposals
- the manner in which proposed augmentations and the replacement of network assets relate to AEMO's most recent ISP[11] and 2023 System Security Reports.

Where appropriate, all transmission network, distribution network or non-network alternatives are considered as options for investment. Submissions for non-network alternatives to proposed investments are invited by contacting NetworkAssessments@powerlink.com.au.

## 6.2 Planning criteria, responsibilities and processes

### 6.2.1 Powerlink's asset planning criteria

The Queensland Government amended Powerlink's N-1 criterion in 2014 to allow for increased flexibility. The planning standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event. The following limits are placed on the maximum load and energy that may be at risk of not being supplied during a critical contingency:

- will not exceed 50MW at any one time
- will not be more than 600MWh in aggregate.

The risk limits can be varied by:

- a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services, or
- agreement with the Queensland Energy Regulator.

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits set out above are exceeded or when the probability weighted economic cost of load at risk of not being supplied justifies the cost of the investment. Therefore, the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required. Powerlink will continue to maintain and operate its transmission network to maximise reliability to customers.

Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations, or the need to address the risks arising from ageing network assets remaining in-service, through joint planning.

7 Identification of forecast limitations in this chapter does not mean that there is an imminent supply reliability risk. The NER requires identification of limitations which are expected to occur some years into the future, assuming that demand for electricity is consistent with the forecast in this TAPR.
8 NER, Clause 5.12.2(c)(4)(iii).
9 NER, Clause 5.12.2(c)(4)(iv).
10 NER, Clause 5.12.2(c)(3).
11 NER, Clause 5.12.2(c)(6).

Energex and Ergon Energy (part of the Energy Queensland Group) are the two major Distribution Network Service Providers (DNSPs) in Queensland and were issued amended Distribution Authorities from July 2014. The service levels defined in their respective Distribution Authorities differ to that of Powerlink's authority. Joint planning accommodates these different planning standards by applying the planning standard consistently with the owner of the asset which places load at risk during a contingency event.

Powerlink has established policy frameworks and methodologies in place to support its planning standard. These are being applied in various parts of the Powerlink network where possible emerging limitations are being monitored.

### 6.2.2 Planning processes

Powerlink has obligations that govern how it should address forecast network limitations. These obligations are prescribed by the Act, the NER and Powerlink's Transmission Authority.

The Act requires that Powerlink 'ensure as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid'[12].

It is a condition of Powerlink's Transmission Authority that it meets licence and NER requirements relating to technical performance standards during intact and contingency conditions. The NER sets out minimum performance requirements of the network and connections and requires that reliability standards at each connection point be included in the relevant connection agreement.

The requirements for initiating solutions to meet forecast network limitations, procurement of system strength or inertia services, or the need to address the risks arising from ageing network assets remaining in-service, including new regulated network developments or non-network solutions, are set out in the NER[13]. Planning processes require consultation with Australian Energy Market Operator (AEMO), Registered Participants and interested parties, including customers, generators, DNSPs and other Transmission Network Service Providers (TNSPs).

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Each of these clauses prescribes a slightly different consultation process. The RIT-T is the most common NER consultation process undertaken by Powerlink and is discussed further in Section 6.6. In July 2024, Powerlink commenced consultation on the first candidate Priority Transmission Investment (PTI) under the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act) (refer to Section 6.10). Powerlink continues to publish information and consult with potential providers of non-network solutions for the provision system security service needs as notified by AEMO.

### 6.2.3 Integrated planning of the shared network

Significant inputs to the network planning process are the:

- forecast of customer electricity demand, including demand side management (DSM), and its location
- location, capacity and arrangement of existing, new and retiring generation (including embedded generation)
- condition and performance of assets and an assessment of risks arising from ageing network assets remaining in-service
- assessment of future network capacity to meet the required planning criteria and efficient market outcomes, including limiting transmission losses, system strength and the potential to facilitate future storage requirements to firm intermittent renewable generation and help address minimum demand.

12 Refer to Section 34(2) of the Act.
13 NER, clauses 5.14.1, 5.16.4, 5.16A, 5.20B, 5.20C and 5.22.14.

The 10-year forecasts of electrical demand and energy across Queensland are used, together with forecast generation patterns, to determine potential flows on transmission network elements. The location and capacity of existing, retiring and committed generation in Queensland is sourced from AEMO, unless modified following advice from relevant market participants. Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSPs and AEMO.

Powerlink examines the capability of its existing network and the future capability following any changes resulting from:

- committed network projects (for both augmentation and to address the risks arising from ageing network assets remaining in-service)
- the impact of generation retirements on transmission network power flows, system strength and reactive power capability
- existing and future renewable developments including REZs
- variances in Powerlink's operating environment or changes in technical characteristics such as minimum demand, inertia and system strength as the power system continues to evolve.

This includes consultation with the relevant DNSP in situations where the performance of the transmission network may impact on, or be impacted by, the distribution network, for example where the two networks operate in parallel.

Where potential flows could exceed network capability, Powerlink notifies market participants of these forecast emerging network limitations. If the capability violation exceeds the required reliability standard, joint planning investigations are carried out with DNSPs (or other TNSPs if relevant) in accordance with the NER[14]. The objective of this joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions.

Powerlink must maintain its current network so that the risks arising from the condition and performance of existing assets are appropriately managed. Powerlink undertakes a program of asset condition assessments to identify emerging asset condition related risks.

As assets approach the end of their technical service life, Powerlink examines a range of options to determine the most appropriate reinvestment strategy, applying a flexible and integrated approach which takes into account multiple factors. Consideration is given to optimising the topography and capacity of the network, taking into account current and future network needs, including future renewable generation and other developments associated with the transforming energy system such as decarbonisation through electrification and emerging industries relating to hydrogen.

In many cases, power system flows and patterns have changed over time. As a result, the on-going network capacity requirements need to be re-evaluated. Individual asset reinvestment decisions are not made in isolation, and reinvestment in assets is not necessarily undertaken on a like-for-like basis. Rather, asset reinvestment strategies and decisions take into account enduring need, the role of transmission in the energy transformation and the inter-related connectivity and characteristics of the high voltage (HV) system that are considered across an area or transmission corridor. The consideration of potential non-network solutions forms an important part of this flexible and integrated planning approach.

The integration of condition, demand based limitations and energy transformation objectives delivers cost effective solutions that address both reliability of supply and risks arising from assets approaching end of technical service life.

Powerlink considers a range of strategies and options to address emerging asset related condition and performance issues. This planning process includes consideration of a broad range of options to address identified needs described in Table 6.1. Powerlink considers options in the context of future capacity, together with opportunities to implement new cost efficient and technically feasible technologies where appropriate.

In accordance with the NER, information regarding proposed transmission reinvestments within the 10-year outlook period must be published in the TAPR and TAPR templates.

Table 6.1 Examples of planning options

| Option | Description |
|---|---|
| Non-network alternatives | Non-network solutions are not limited to but may include network support and system services from existing and/or new generation, DSM initiatives (either from individual providers or aggregators), and other forms of technologies (such as battery installations). These solutions may reduce, negate or defer the need for network investments. |
| Network reconfiguration | The assessment of future network requirements may identify the reconfiguration of existing assets as the most economical option. This may involve asset retirement coupled with the installation of plant or equipment at an alternative location that offers a lower cost substitute for the required network functionality. |
| Asset de-rating or retirement | May include strategies to de-rate, decommission and/or demolish an asset and is considered in cases where needs have diminished in order to achieve long-term economic benefits. |
| Augmentation | Increases the capacity of the existing transmission network, e.g. the establishment of a new substation, installation of additional plant at existing substations or construction of new transmission lines. This is driven by the need to meet prevailing network limitations and customer supply requirements, or where there may be net economic benefits to customers. An increase in network capacity may also unlock synergies to support the development of a REZ. |
| System services | The assessment of future network requirements to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services, inertia and reactive power services. |
| Reinvestment | Asset reinvestment planning ensures that existing network assets are assessed for their enduring network requirements in a manner that is economic, safe and reliable. This may result in like-for-like replacement, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity. Condition and risk assessment of individual components may also result in the staged replacement of an asset where it is technically and economically feasible. |
| Line refit | Powerlink utilises a line reinvestment strategy called line refit to extend the service life of a transmission line and provide cost benefits through the deferral of future transmission line rebuilds. Line refit may include structural repairs, foundation works, replacement of line components and hardware, abrasive blasting and painting. |
| Transformer refit | Powerlink utilises a transformer reinvestment strategy called transformer refit to extend the service life of a transformer to provide cost benefits through the deferral of the timing for a future transformer replacement. Transformer refit may include replacement of components such as high voltage bushings, tap changers and instruments, addressing sources of oil leaks such as replacement of gaskets and main lid sealing, replacement of transformer oil, and addressing radiator corrosion. |
| Operational measures | Network constraints may be managed during specific periods using short-term operational measures, e.g. switching of transmission lines or redispatch of generation in order to defer or negate network investment. |

### 6.2.4 Powerlink's reinvestment criteria

Powerlink is committed to ensuring the sustainable long-term performance of its assets to deliver safe, reliable and cost effective transmission services to customers, stakeholders and communities across Queensland. Powerlink demonstrates this by adopting a proactive approach to asset management that optimises whole of life cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

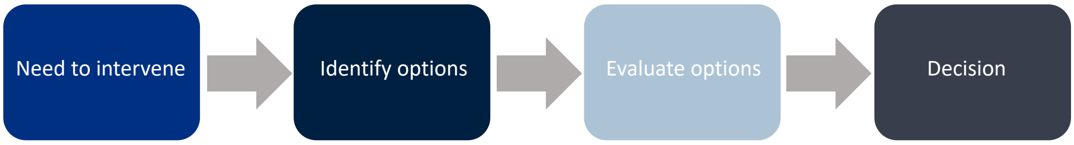
### The reinvestment criteria framework

The reinvestment criteria framework defines the methodology that Powerlink uses to assess the need and timing for intervention on network assets to ensure industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling Powerlink's customers and stakeholders to better understand the criteria to determine the need and timing for asset intervention. The reinvestment criteria framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention is defined when business as usual activities (including routine inspections, minor condition based and corrective maintenance and operational refurbishment projects) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Powerlink's asset reinvestment process (refer to Figure 6.1) enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure 6.1 Asset Reinvestment Process




### Asset reinvestment review

During 2023 Powerlink completed a review of its asset reinvestment approach and criteria to ensure consistency with contemporary asset management and risk-based decision frameworks. The ARR Working Group was established to ensure customers and the Australian Energy Regulator (AER) were actively involved in the review and its recommendations.

The aim of the review was to consider the prudency and efficiency of network reinvestment and the associated risk-based economic assessments[14]. The ARR Working Group Report was published on 30 May 2023. A key recommendation included modelling existing and alternative bundling approaches for future transmission line refit investment decisions, and to progress the most cost effective solution based upon detailed condition and cost information, while allowing for the developing network needs to support the energy transformation. It was also recommended that compliance works are only undertaken on structures where condition based work is to be performed, and that Powerlink retain the existing asset definition for transmission lines.

In September 2024, Powerlink reported back to the Customer Panel on progress made in embedding the recommendations from this review into business processes.

## 6.3 Monitoring the changing outlook for the Queensland region

Powerlink is actively monitoring the changing outlook for the Queensland region and considering the impact of emerging technologies, withdrawal of coal-fired generation and the integration of VRE and firming generation in future transmission plans. These plans include:

- non-network solutions
- reinvesting in assets to extend their end of technical service life
- removing some assets without replacement
- determining optimal parts of the network for new connection (in particular renewable generation) as discussed in Chapter 2
- replacing existing assets with assets of a different type, configuration or capacity
- investing in assets to maintain planning standards and deliver efficient market outcomes
- investing in assets and/or non-network solutions to meet Powerlink's obligations for inertia, system strength and voltage control (refer to Section 6.8).

14 Refer to the AER's Industry practice application note for asset replacement planning.

Powerlink anticipates that there will be significant expansion of the transmission network required over the next 10 years to achieve 80% renewables by 2035. Powerlink is committed to early engagement and working in partnership with communities, local government and other stakeholders to deliver the new energy future. This includes working together to identify opportunities which deliver positive outcomes and long-term benefits as the energy system evolves, particularly in developing new transmission infrastructure in key parts of the state.

### 6.3.1 Possible impacts of the energy transformation

Due to the energy transformation, there is the potential to have significantly changed requirements for transmission infrastructure in the 10-year outlook period. Given Powerlink's integrated planning approach (refer to Section 6.2.3), these requirements may result in the need for new or alternate investments that impact the proposed future network and non-network solutions discussed in this Chapter and possible non-network solutions identified in Chapter 5. Any changes will be updated in subsequent TAPRs.

## 6.4 Forecast capital expenditure

The external environment in which Powerlink operates continues has become more complex in recent years with challenges such as rising inflation and interest rates, and disruption to supply chains and materials shortages, intensifying.

In a report for Energy Networks Australia and the Clean Energy Council, KPMG observed in August 2022 that as Australia constructs more transmission projects to meet the needs of the energy system, the availability of highly-trained engineers and other specialists needed for the projects will become more limited. KPMG also indicated that, for major projects, supply chain pressure was resulting in up to 40% increases in capital expenditure and at least a 5% increase in operational expenditure[15].

In September 2023, AEMO reported that transmission cost estimates had increased approximately 30% in real terms compared to equivalent cost estimates for the 2022 ISP and, in the 2024 ISP, added that future cost reductions were unlikely. Also in the 2024 ISP, AEMO commented that the investments required by the ISP imply the need for thousands of critical energy assets – including utility-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers – and the people needed to install and operate them. Further, AEMO noted that international demand for the materials, technologies and expertise to deliver a global energy transformation could increase Australia's exposure to risks associated with competition for investment and skills[16].

The Reserve Bank of Australia (RBA) recently reported that global inflation has eased in most economies in 2024, however growth in China has significantly declined in the June quarter. The RBA also noted that inflationary pressures are expected to take longer than expected to return to target in Australia and are anticipated to decrease circa mid-2026 while the demand for goods and services continues to exceed supply[17].

## 6.5 Forecast network limitations

Forward planning allows Powerlink adequate time to identify emerging limitations and to implement appropriate network and/or non-network solutions to maintain transmission services which meet the planning standard in its Transmission Authority (refer to Section 6.2.1).

Emerging limitations may be triggered by thermal plant ratings (including fault current ratings), protection relay load limits, voltage stability and/or transient stability. Appendix H lists the indicative maximum short circuit currents and fault rating of the lowest rated plant at each Powerlink substation and voltage level, accounting for committed projects listed in Chapter 9 and existing and committed generation listed in Chapter 7.

[15] KPMG, Market sounding report on transmission, report for Energy Networks Australia and the Clean Energy Council, August 2022.
[16] AEMO, 2023 Transmission Expansion Options Report, September 2023; AEMO, 2024 Integrated System Plan, final report, June 2024.
[17] Reserve Bank of Australia, Statement on Monetary Policy, August 2024.

Based on Powerlink's Central scenario forecast, Queensland's transmission delivered maximum demand is expected to have steady growth with an average annual increase of 3.1% per annum over the next 10-years.

Notwithstanding network limitations which may result from new loads, such as in the Gladstone zone due to electrification of industry, Powerlink does not anticipate undertaking any significant augmentation works during this period based on load growth alone. However, the changing generation mix (and associated peak to average production ratios of VRE plant) may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints, including the effects of falling minimum demand, holistically with the emerging condition based drivers as part of the planning process and in conjunction with the most recent QEJP and ISP.

In Powerlink's Revenue Determination 2023-27[18], projects that could be triggered by the commitment of large mining or industrial block loads were identified as contingent projects. Contingent projects and their triggers are discussed in detail in Chapter 8.

### 6.5.1 Summary of forecast system security limitations within the next five years

Powerlink has identified that due to declining minimum demand, changing nature of load and increasing penetration of VRE generation, there is an emerging need for additional reactive plant in various zones in Queensland to manage potential over-voltages[19].

Table 6.2 summarises limitations identified in Powerlink's transmission network.

Table 6.2 Limitations in the five-year outlook period

| Limitation | Zone | Reason for anticipated limitation | Time limitation may be reached | | | Reference |
|---|---|---|---|---|---|---|
| | | | 1-year outlook (2024/25) | 3-year outlook (up to 2027/28) | 5-year outlook (up to 2029/30) | |
| System strength shortfall at Gin Gin | Central West | AEMO declared system strength shortfall December 2021 | From 31 March 2023 (1) | | | Section 6.8.1 |
| Inertia shortfall | State-wide | AEMO declared system strength shortfall December 2022 | | From 2027/28 (2) | | Section 4.2.1 |

Notes:

(1) Refer to AEMO's December 2021 System Security Reports and Update to 2021 System Security Reports and Powerlink's Expression of Interest (EOI), Request for System Security Services in central, southern and the broader Queensland regions. Powerlink published a Final Report in December 2023 and has entered into a System Strength Services Agreement with the Townsville Power Station owner, Ratch Australia as discussed in Section 6.8.1.

(2) AEMO's December 2023 Inertia Report reduced the quantum and delayed the timing (by one year) of the previously identified inertia shortfall declared in December 2022 to 1,660MWs as discussed in Section 4.2.1.

Based on AEMO's Step Change scenario forecast there are no other network limitations forecast to occur in Queensland in the next five years[20].

18 Information on Powerlink's Revenue Proposal for the regulatory period is available on Powerlink's website.
19 Refer to NER Clause 5.12.2(c)(3).
20 Refer to NER Clause 5.12.2(c)(3).

### 6.5.2 Summary of forecast network limitations beyond five years

The timing of forecast network limitations may be influenced by a number of factors such as load growth, industrial developments (including electrification of existing industrial processes), new and retiring generation, the planning standard and joint planning with other Network Service Providers (NSP). As a result, it is possible for the timing of forecast network limitations identified in a previous year's TAPR to change. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2023 TAPR which fall into this category in 2024.

Based on Powerlink's Central scenario forecast there is approximately 1,000MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of existing customers' processes. The impact of this additional load is discussed in sections 6.10.2 and 8.2.3.

## 6.6 Consultations

Consultation processes for proposed transmission investments and funded augmentations are conducted under the NER. These processes include:

- RIT-Ts
- Expressions of Interest (EOIs), and
- Funded augmentations.

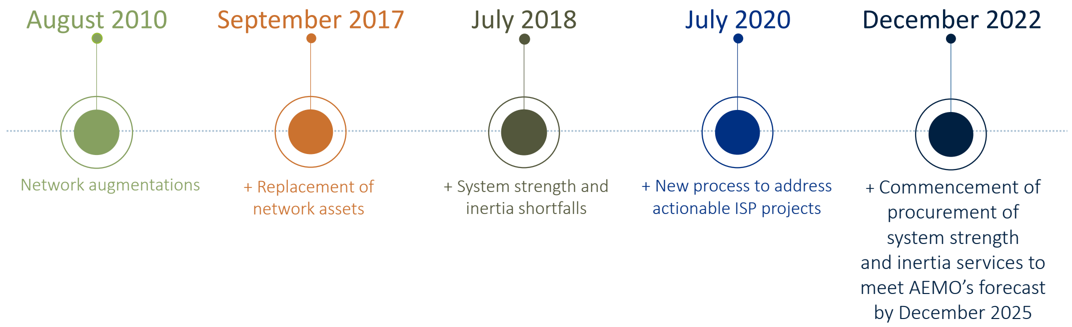
All consultation documents are published and made available on Powerlink's website.

Section 1.5.2 describes the PTI consultation process in relation to state-based planning and development under the ERTJ Act.

### 6.6.1 RIT-T consultation process

Since commencement of the RIT-T consultation process in 2010, the requirements to call for proposals for transmission investments over the RIT-T cost threshold (currently $7 million) have been incrementally extended to address a range of transmission investment needs (refer to Figure 6.2) and are progressed under the provisions of clauses 5.16.4 and 5.16A.4 of the NER.

Figure 6.2 Chronological development and expansion of the RIT-T process for proposed transmission network investments




### 6.6.2 Current consultations – proposed transmission investments

Powerlink carries out separate consultation processes for each proposed regulated transmission investment where the estimated capital cost of the most expensive credible option is over $7 million by utilising the applicable RIT-T consultation process. The majority of RIT-T consultations undertaken by Powerlink relate to projects which are not actionable ISP projects (refer to Figure 6.3).

Figure 6.3 Overview of the RIT-T consultation process for projects which are not actionable ISP projects


The consultations completed since publication of the 2023 TAPR are listed in Table 6.3 (refer to Table 9.7).

Table 6.3 RIT-T consultations completed since publication of the 2023 TAPR

| Consultation |
|---|
| Maintaining power transfer capability and reliability of supply at Kemmis |
| Addressing the reliability of supply to Nebo local area |
| Addressing the secondary systems condition risks at Sumner |

RIT-T consultations currently underway are listed in Table 6.4.

Table 6.4 RIT-T consultations currently underway

| Consultation (1) | Reference |
|---|---|
| Addressing system strength requirements in Queensland from December 2025 | Section 6.8.2 |
| Maintaining reliability of supply to Mansfield | Section 6.11.5 |

PTI consultations currently underway are listed in Table 6.5.

Table 6.5 PTI consultations currently underway

| Consultation (1) | Reference |
|---|---|
| Gladstone Project | Section 6.10.2 |

Note:

(1) The public consultations listed reflect the status as at 30 September 2024.

### 6.6.3 Future consultations – proposed transmission investments

#### Anticipated consultations

Notwithstanding consideration of the QEJP and power system security requirements, Powerlink's capital expenditure program of work in the 10-year outlook period will focus on investment in the transmission network to manage the risks arising from ageing assets remaining in-service. These emerging risks are discussed in Section 6.9 to 6.11. Table 6.6 summarises consultations Powerlink anticipates undertaking within the next 12 months under the RIT-T to address either the proposed investment in a network asset or limitation.

Table 6.6 Anticipated consultations in the forthcoming 12 months (to October 2025)

| Consultation (1) | Reference |
|---|---|
| Maintaining reliability of supply to Kamerunga and Cairns northern beaches | Section 6.9.1 |
| Maintaining reliability of supply and addressing condition risks at Ingham South | Section 6.9.2 |
| Addressing the secondary systems condition risks of the Strathmore SVC | Section 6.9.3 |
| Maintaining reliability of supply to Gladstone South | Section 6.10.2 |
| Maintaining reliability of supply at Ashgrove | Section 6.11.5 |
| Addressing the secondary systems condition risks at Molendinar | Section 6.11.6 |
| Managing the risk of Trench Capacitive Voltage Transformer Failure | Section 6.12 |

Notes:

(1) The anticipated consultations listed in Table 6.6 reflect the RIT-T status as of 30 September 2024.

(2) Future candidate PTIs are discussed in the Queensland SuperGrid Infrastructure Blueprint and commencement of consultation is subject to government direction.

#### Actionable and future ISP projects

The 2024 ISP identified Queensland to New South Wales Interconnector (QNI) Connect as an 'actionable' project to support the expected increase in renewable generation in Queensland and New South Wales, and to share renewable energy and firming services between the states as a means of displacing high fuel cost generation with lower cost VRE generation (refer to Section 6.17.3). Powerlink and Transgrid are required to publish a Project Assessment Draft Report by 25 June 2026.

The 2024 ISP did not identify additional preparatory activities for any future ISP projects.

### 6.6.4 Connection point proposals

Planning of new or augmented connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements. New connections can result from joint planning with the relevant DNSP (Energex or Ergon Energy) or be initiated by generators or customers.

Table 6.7 lists connection works that are anticipated to be required within the 10-year outlook period.

Table 6.7 Connection point commitments (1)

| Connection point name (2) | Proposal | Zone |
|---|---|---|
| Broadsound Solar Farm | New Solar Farm | Central West |
| Lotus Creek Wind Farm | New Wind Farm | Central West |
| Boulder Creek Wind Farm | New Wind Farm | Central West |
| Woolooga Battery energy storage system (BESS) | New BESS | Wide Bay |
| Western Downs BESS | New BESS | Bulli |
| Ulinda Park BESS | New BESS | Bulli |
| MacIntyre Wind Farm (3) | New Wind Farm | Bulli |
| Wambo Wind Farm Stage 2 | New Wind Farm | South West |
| Greenbank BESS (3) | New BESS | Moreton |

Notes:

(1) AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines Version 2.2 (effective 1 July 2024) has been adopted for connection point proposals identified in the TAPR. The connection point proposals listed are as at 9 October 2024.

(2) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. conventional generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(3) The listed connection point commitment is in progress (refer to Table 9.2).

Table 6.8 summarises connection point activities[21] undertaken by Powerlink since publication of the 2023 TAPR. Powerlink has also received a record number of customer enquiries during 2023/24 (refer to Figure 6.4). Figure 6.5 shows the cumulative number of customer applications per month since publication of the 2023 TAPR. Further details on potential new generation connections are available in the relevant TAPR template located on Powerlink's TAPR portal as noted in Appendix E.

Table 6.8 Connection point activities

| Generator Location | Number of Applications | Number of Connection Agreements | Generator Type and Technology |
|---|---|---|---|
| North | 4 | 0 | BESS |
| Central | 14 | 3 | Load, Wind Farm, Solar Farm and BESS |
| South | 16 | 6 | Load, Wind Farm, Solar Farm, BESS and Gas |
| Total | 34 | 9 | |

21 More broadly, key connection information in relation to the NEM can be found on AEMO's website.

Figure 6.4 Customer enquiries per month since publication of the 2023 TAPR

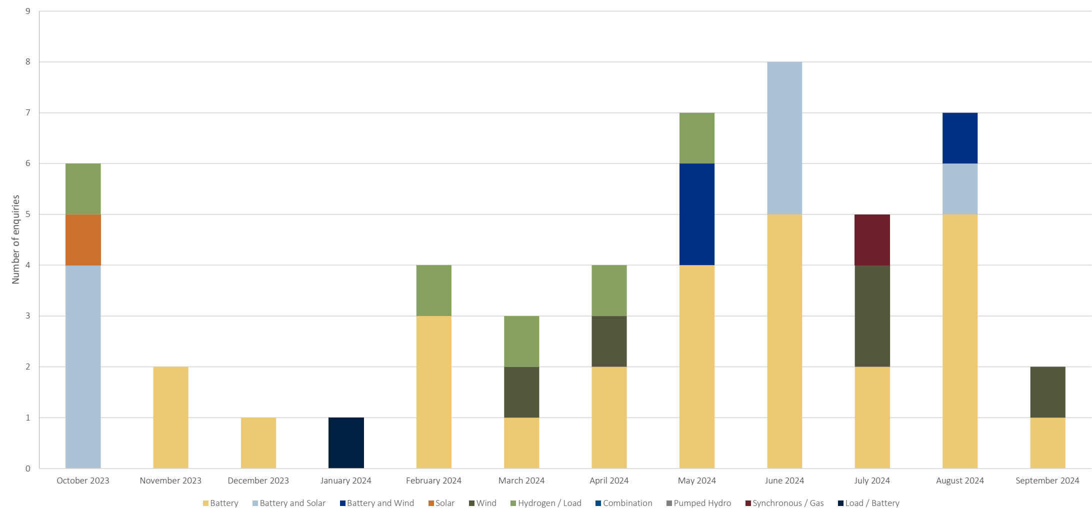
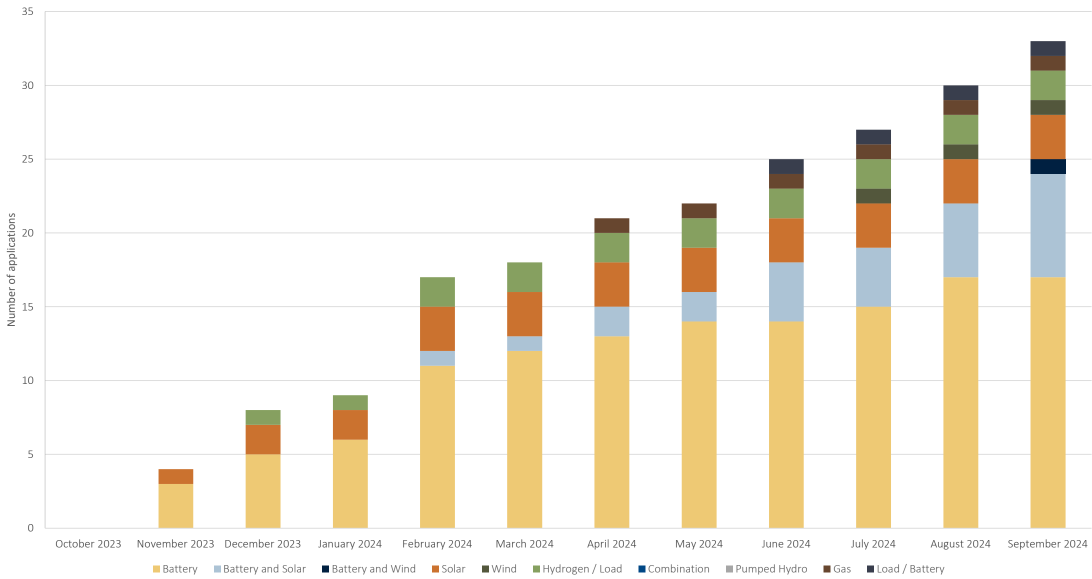



Figure 6.5 Cumulative customer applications per month since publication of the 2023 TAPR




## 6.7 Proposed network developments

Powerlink's regulated capital expenditure program of work will continue to focus on risks arising from the condition and performance of existing aged assets, as well as emerging limitations in the capability of the network as the external environment shifts to net zero emissions. Other than the Gladstone Project which commenced the PTI consultation process in July 2024, the proposed future network developments discussed in this chapter do not include investments in new transmission is needed under the energy transformation as discussed in the QEJP and set out in the Queensland SuperGrid Infrastructure Blueprint (Infrastructure Blueprint) released by the Queensland Government in September 2022 (refer to sections 2.2 to 2.5 and Chapter 8).

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are a large number of transmission assets ranging from 40 to just beyond 60 years old. A number of these assets are approaching the end of their technical service life and investment in some form is required within the 10-year outlook period to manage risks related to safety, reliability and other factors.

In conjunction with condition assessments and risk identification, as assets approach their anticipated end of technical service life, possible investment options undergo detailed planning studies to confirm alignment with future investment, optimisation and delivery strategies. These studies enable Powerlink to:

- improve and further refine options under consideration
- identify other options from those originally specified, including a consideration of the broader energy transformation where appropriate, which may deliver a greater benefit to customers.

Information regarding possible investment alternatives, network limitations and anticipated timing is updated annually in the TAPR and includes discussion on significant changes which have occurred since publication of the previous year's TAPR.

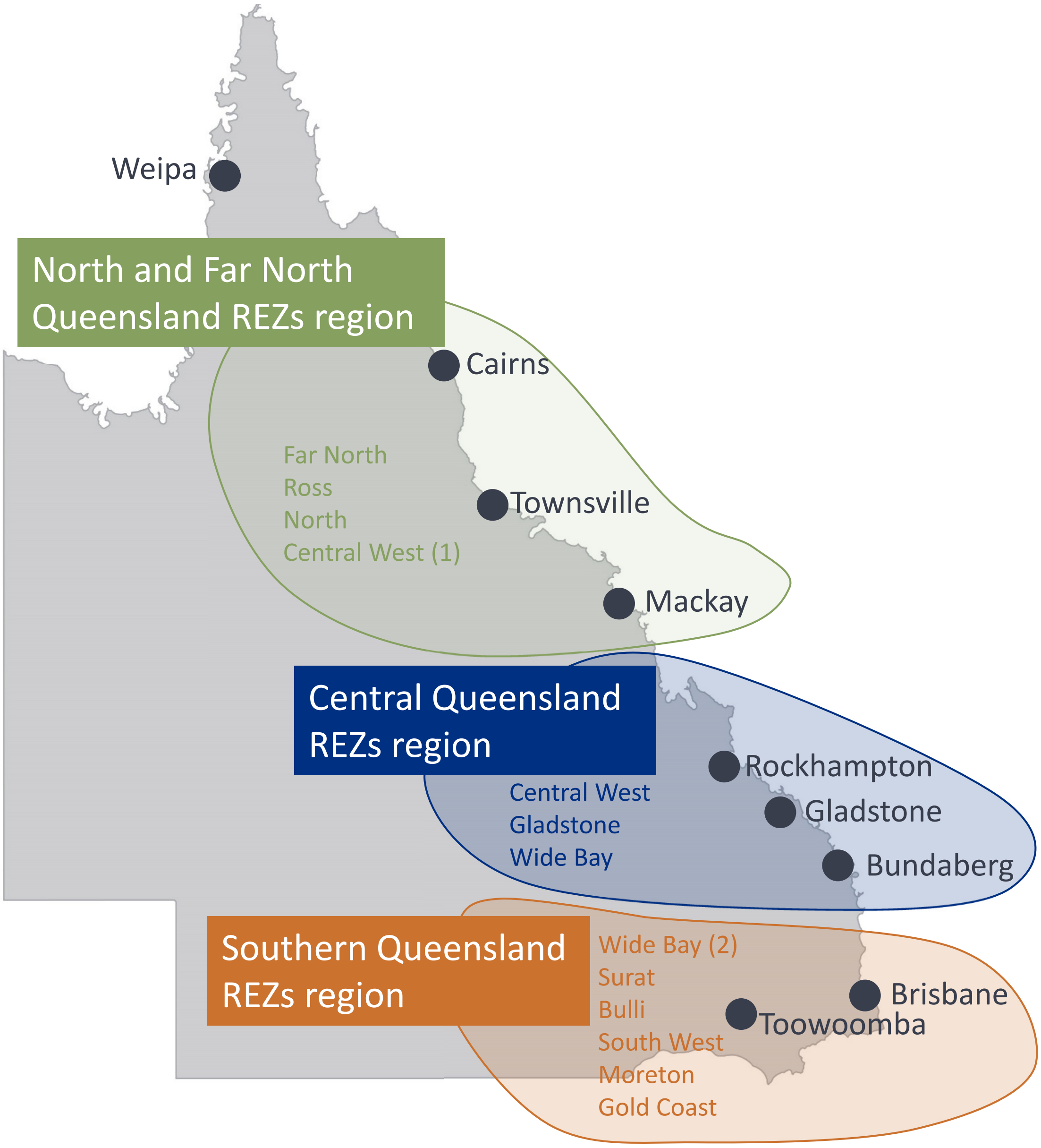
The indicative cost of potential projects identified in this chapter are updated each year to keep pace with external project cost increases being experienced broadly across many industries (refer to Section 6.4). Where there may be other factors materially influencing the updated indicative cost, such as a more granular view of condition and project scope, these factors are noted in the summary table in Appendix D which summarises all proposed network investments for the 10-year outlook period. It should be noted that the indicative cost of potential projects also excludes known and unknown contingencies.

Other than the outcomes set out in the 2023 System Security and Inertia Reports (refer to Section 6.8) and actionable projects identified in AEMO's 2024 ISP (refer to Section 6.17), based on the current information available, the possible network developments discussed in this chapter are not recommended or required as a result of the findings of the General Power System Risk Review and ISP. Powerlink also reviews the rating of assets throughout the transmission network periodically and has not identified any required asset de-ratings that would result in a system limitation as part of the 2024 annual planning review.

### 6.7.1 Geographical context

Powerlink has analysed investment needs and potential limitations across Powerlink's standard geographic zones (refer to sections 6.9 to 6.11). To provide geographical context, the reinvestment needs, and network limitations are broadly aligned with Queensland's renewable energy regions in Queensland, as shown in Figure 6.6.

Figure 6.6 Queensland's renewable energy regions




Notes:

(1) The Central West zone traverses the Northern and Central regions

(2) The Wide Bay zone traverses the Central and Southern regions

### 6.7.2 Investment context, timeframes and description

Powerlink's planning overview (10-year outlook period of the TAPR) considers a range of options to address identified needs. When considering the replacement of existing assets, in conjunction with the broader network topology and changing external environment, Powerlink may also identify potential network reconfigurations or other options to realise synergies and efficiencies in developing the transmission network which would be economically assessed under the RIT-T (if applicable).

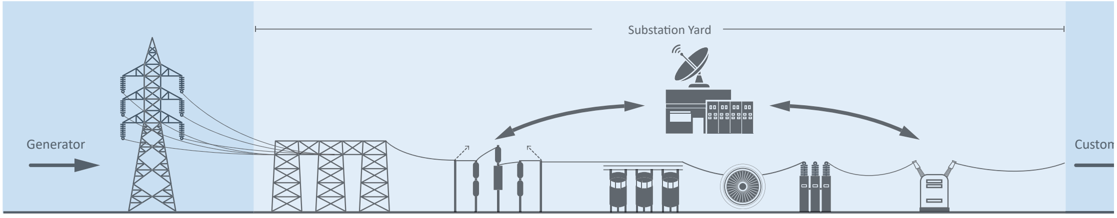
Information in relation to potential projects, alternatives and possible commissioning needs is revised annually based on the latest information available at the time of publication. Refer to Appendix D for the complete list of proposed network investments within the 10-year outlook period. Significant timing and cost differences are noted in the analysis of this program of work.

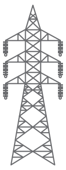
Possible network investments needs (which includes reinvestment, augmentations and/or the procurement of power system security services) likely to require RIT-T consultation within the five-year outlook period, from July 2024 to June 2030 are discussed in this Chapter. Where applicable PTI consultation is also discussed.

Powerlink takes a value-driven approach to the management of asset risks to ensure an appropriate balance between reliability and the cost of transmission services which ultimately benefits customers. Each year, taking the most recent assessment of asset condition and risk into consideration, Powerlink reviews possible commissioning dates and, where safe, technically feasible and prudent, capital expenditure is delayed. As a result, there may be timing variances between the possible commissioning dates identified in the 2023 TAPR and 2024 TAPR and TAPR Templates.

The functions performed by the major transmission network assets discussed in this chapter are illustrated in Figure 6.7.

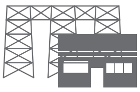
**Figure 6.7** The functions of major transmission assets



### Transmission line

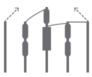
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



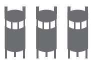
### Substation

A substation, which is made up of primary plant, secondary systems, telecommunications equipment and buildings, connects two or more transmission lines to the transmission network and usually includes at least one transformer at the site.

A substation that connects to transmission lines, but does not include a transformer, is known as a switching station.

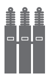


- Substation bay
  A substation bay connects and disconnects network assets during faults and also allows maintenance and repairs to occur. A typical substation bay is made up of a circuit breaker (opened to disconnect a network element), isolators and earth switches (to ensure that maintenance and repairs can be carried out safely), and equipment to monitor and control the bay components.



- Static VAR Compensator (SVC)
  A SVC is used where needed, to smooth voltage fluctuations, which may occur from time-to-time on the transmission network. This enables more power to be transferred on the transmission network and also assists in the control of voltage.

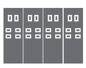
- Synchronous condenser
  A synchronous condenser is a large rotating machine connected to the transmission network with no driving force (spins freely). It is similar to a synchronous generator but does not produce energy. It helps the power system with voltage control, system strength, and inertia.



- Capacitor Bank
  A capacitor bank maintains voltage levels by improving the 'power factor'. This enables more power to be transferred on the transmission network.

- Transformer
  A transformer is used to change the voltage of the electricity flowing on the network. At the generation connection point, the voltage is 'stepped up' to transport higher levels of electricity at a higher voltage, usually 132kV or 275kV, along the transmission network. Typically at a distribution point, the voltage is 'stepped down' to allow the transfer of electricity to the distribution system, which operates at a lower voltage than the transmission network.

- Reactor
  Reactors may be connected directly to a transmission line or a bus at the substation. Line reactors are used to limit the remote end voltage of a long high voltage line when energising (and carrying no load). Bus reactors are typically higher rated and used especially during light load conditions to avoid high voltages which may occur on the network.



### Secondary systems

Secondary systems equipment assists in the control, protection and safe operation of transmission assets that transfer electricity in the transmission network.

### Telecommunication systems

Telecommunication systems are used to transfer a variety of data about the operation and security of the transmission network including metering data for AEMO.

## 6.8 Power system security requirements

### 6.8.1 Power system security services in central, southern and broader Queensland regions

AEMO and Powerlink are responsible for the planning and delivery of power system security services in Queensland. In December 2021 AEMO declared an immediate:

- Reliability and Security Ancillary Service (RSAS) gap of approximately 120 Megavolt Ampere absorbing reactive (MVAr) power in South East Queensland (SEQ), increasing to 250MVAr absorbing reactive power by 2026, and
- system strength shortfall of 44 to 65MVA at the Gin Gin system strength node for the period 2021/22 to 2026/27, against the minimum (post-contingency) three phase fault level of 2,250MVA at the node[22].

Powerlink's final reports identified non-network solutions to address the AEMO declarations, specifically:

- a Network Support Agreement with CleanCo Queensland for the operation of CleanCo's Wivenhoe Pumped Hydro Power Station to absorb reactive power, and
- the addition of a clutch to the Townsville Power Station, owned by Ratch Australia, by mid-2025 to meet the system strength shortfall[23].

### 6.8.2 Addressing system strength requirements in Queensland from December 2025

In October 2021, the Australian Energy Market Commission (AEMC) made the Efficient Management of System Strength on the Power System Rule (System Strength Rule)[24]. The System Strength Rule:

- evolved the 'do no harm' framework which required connecting generators to self-assess their impact on the local network's system strength levels, and self-remediate any adverse impacts, and
- established a new framework for the supply and demand of system strength in the National Electricity Market (NEM).

As of 2 December 2022, Powerlink, as the System Strength Service Provider (SSSP) in Queensland, is required to take action to plan, procure and make available system strength services as set out in the 10-year forecast provided in AEMO's annual System Strength Reports[25].

AEMO published the first System Strength Report under the new framework in December 2022. The report set minimum three phase fault level requirements, and provided a 10-year forecast of utility-scale inverter-based resource (IBR) generation, for each of Queensland's five system strength nodes[26]. Powerlink must meet minimum fault level requirements by December 2025, and procure system strength to meet the efficient level of IBR in the 10-year forecast. In March 2023, Powerlink commenced the RIT-T process, publishing a Project Specification Consultation Report (PSCR). The PSCR sought to identify solutions to meet the minimum and efficient fault levels of system strength.

To replicate dispatch that has historically met minimum fault level requirements, and deliver sufficient system strength to meet the minimum system strength requirements identified by AEMO, the PSCR indicated Powerlink sought:

- seven synchronous machines or equivalent plant online in Central Queensland, in the order of 350MVA each
- two hydro-electric machines or equivalent plant in North Queensland, in the order of 20MVA each
- four synchronous machines or equivalent plant online in Southern Queensland, in the order of 400MVA each.

To meet efficient system strength requirements, Powerlink estimated that up to a further eight synchronous machines or equivalent plant are required within the 10-year outlook period, comprising four by 2030, and four by 2033.

22 AEMO, 2021 System Security Reports, December 2021.
23 Powerlink, Power System Security Consultations.
24 AEMC, Efficient Management of System Strength on the Power System, October 2021.
25 Refer to Schedule 5.1.14 of the NER.
26 AEMO, 2022 System Strength Report, December 2022.

The PSCR proposed two credible options to address the minimum and efficient levels of system strength:

- seek to procure system strength services to meet the identified need in its entirety for both the minimum and efficient levels of system strength
- hybrid solution to procure system strength services together with the installation and commissioning of up to eight 200MVA synchronous condensers (network component) for both the minimum and efficient levels of system strength required by December 2030. The number of synchronous condensers actually required would depend on Powerlink's assessment of submissions received to the PSCR. The PSCR provided an indicative capital cost of the network component of this option of up to $752 million (2023/24 prices). Annual operating and maintenance costs were anticipated to be up to approximately $15 million (2023/24 prices).

For both options, Powerlink indicated system strength services would need to be able to commence availability in the period between December 2025 and December 2030.

The PSCR also noted the potential for the credible options to have a material inter-network[27] impact by increasing the fault level by at least 10MVA on the Queensland to New South Wales Interconnector.

Submissions to the PSCR closed in July 2023 and since that time Powerlink has been working with proponents of non-network solutions to inform the technical and economic analysis for the optimal portfolio of solutions anticipated to be required. Powerlink will publish the Project Assessment Draft Report (PADR) in November 2024, which will identify the proposed preferred option to provide minimum and efficient levels of system strength.

## 6.9 North and Far North region

The North and Far North region includes proposed network investments located within the Far North, Ross and North zones and broadly aligns with the North and Far North Queensland REZs region stretching between Mackay and Cairns, encompassing the northern most extent of Powerlink's transmission network (refer to Figure 6.6). The North and Far North region also includes a number of candidate REZ areas in North and Far North Queensland identified in the Queensland Renewable Energy Zone Roadmap and the 2024 ISP optimal development pathway.

### 6.9.1 Far North zone

#### Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at Chalumbin, Tully South and Woree, and a coastal 132kV network from Yabulu South to Woree. This network supplies the Ergon Energy distribution network feeding the surrounding areas of Turkinje and Cairns, from Tully to Cooktown. The network also connects various renewable generators including the hydro power stations at Barron Gorge and Kareeya, Mt Emerald Wind Farm near Walkamin and Kaban Wind Farm near Tumoulin (refer to Figure 6.8).

27 Refer to NER rule 5.21.

Figure 6.8 Far North zone transmission network


### Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional capacity forecast to be required as a result of load driven network limitations in the Far North zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.9 lists existing generators connected to the Powerlink transmission network in the Far North zone.

Table 6.9 Existing generators in the Far North zone

| Name | Technology | Capacity (MW) (1) |
|---|---|---|
| Barron Gorge | Hydro-electric | 66 |
| Kareeya (including Koombooloomba) | Hydro-electric | 93 |
| Mt Emerald Wind Farm | Wind | 180 |
| Kaban Wind Farm | Wind | 152 |

Note:

(1) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within five years

Network investments (which include reinvestments and augmentations) in the Far North zone are related to addressing the risks arising from the condition of the existing network assets which, without corrective action, could result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and NER obligations.

By addressing the condition of these assets, Powerlink is seeking to ensure it can deliver a safe, cost effective and reliable supply of electricity to customers in the Far North zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Joint RIT-T consultation – Maintaining reliability of supply to Kamerunga and Cairns northern beaches area

*Woree to Kamerunga 132kV transmission lines and Kamerunga 132/22kV Substation*

| Anticipated joint RIT-T consultation with Ergon Energy | |
|---|---|
| Asset details | Transmission line constructed in 1963<br>Life extension in 2014 on certain components nearing end of technical service life<br>Kamerunga Substation established in 1976 |
| Project driver | Transmission line - emerging condition risks due to structural corrosion<br>Substation – emerging condition, obsolescence and compliance risks on 132kV primary plant and secondary systems and risks related to a potential future flood event |
| Project timing | December 2028 |
| Proposed network solution | Rebuild the existing double circuit transmission line with a new double circuit transmission line (overhead/underground alignment) from Woree to Kamerunga substations and associated Ergon works<br>Replacement of primary plant including additional switching functionality and secondary systems upfront with AIS technology on an adjacent substation site at Kamerunga and associated Ergon works<br>Construction of a new building to contain 22kV primary and secondary systems by December 2028 at an estimated cost of $200 million |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to the 22kV network of up to a peak 70MW, and up to a peak 1,200MWh per day on a continuous basis. This transmission line also facilitates the Barron Gorge Hydro Power Station connection in the area |

The Woree to Kamerunga 132kV double circuit transmission lines, provides critical supply to the Cairns northern beaches region, as well as connecting the Barron Gorge Hydro Power Station to the transmission network. A significant proportion of the transmission line traverses built-up residential areas, including a significant number of encroachments on the existing feeder easement. There are a number of major and minor road crossings causing access and construction work challenges. Replacement on a new easement has potential construction and social benefits with investigations for easement alternatives currently underway.

Kamerunga Substation is located in western Cairns and provides bulk electricity supply to Ergon Energy's distribution network in the northern Cairns region which includes Kamerunga, Smithfield and the northern beach areas, and also provides connection to the Barron Gorge Power Station. The area surrounding the substation is residential and located along the flood plain of the Barron River.

In August 2019, Powerlink published a Project Assessment Conclusions Report (PACR) to address the emerging condition risks at Kamerunga Substation. Based on information received subsequent to the conclusion of the consultation process, Powerlink has identified a material change in circumstances[28] which has resulted in the identification of an additional credible option not assessed under the RIT-T and significant cost increases across all options. This has resulted in a change to the preferred option recommended in the PACR requiring reapplication of the RIT-T.

Given this change and the network requirements in the area to address the emerging transmission line structural corrosion risks between Woree and Kamerunga substations in a similar timeframe, Powerlink is undertaking a RIT-T which captures the broader network need in the Kamerunga, Cairns and northern beaches area[29].

Possible network solutions

- Maintaining the existing 132kV network topology by replacing the existing double circuit transmission line with a new double circuit transmission line from Woree and Kamerunga substations by December 2028
- Replacement of primary plant including additional switching functionality and secondary systems upfront with AIS technology on an adjacent substation site by December 2028, and
- Construction of a new building to contain 22kV primary and secondary systems by December 2028.

or

[28] Refer to NER Clause 5.16.4(z3).
[29] Refer to NER Clause 5.16.3(e).

- Replacing the existing 132kV double circuit transmission line with a new double circuit 132kV transmission line, part underground on a new alignment, and part overhead from Woree and Kamerunga substations by December 2028
- Establish a new substation to replace existing primary plant including additional switching functionality with AIS technology and secondary systems on an adjacent site by December 2028, and
- Construction of a new building to contain 22kV primary plant and secondary systems by December 2028.

As a joint planning project with Ergon Energy (Ergon), and given the credible options identified include potential works by Ergon over the Regulatory Investment Test for Distribution (RIT-D) minimum cost threshold (currently $6 million), this RIT-T is also being undertaken to discharge Ergon from its obligation to undertake a RIT-D[30].

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Transmission lines

*Ross to Chalumbin to Woree 275kV transmission lines*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply in the Cairns region Stage 2<br>- Addressing the condition risks of the transmission towers between Ross and Chalumbin |
| Asset details | Constructed in 1989 |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | June 2029 |
| Proposed network solution | Refit the double circuit transmission line between Ross (via Guybal Munjan) and Chalumbin substations, at an estimated cost of $35 million by June 2029 |
| Possible non-network solutions | The Ross to Chalumbin transmission lines provide injection to the north area of close to 400MW at peak and up to 3,000MWh per day. The network configuration also facilitates generator connections in the area and provides system strength and voltage support for the region. |

Although renewable generation in Far North Queensland is increasingly suppling load in the Cairns region (refer to Figure 7.11), the 275kV and 132kV transmission system plays a critical role in maintaining reliability of supply by connecting generation in Central and North Queensland to this region.

Remote supply to the Cairns region is delivered through the inland 275kV network to Ross, near Townsville. From Ross it is transferred via a 275kV transmission line to Chalumbin, continuing via a second 275kV transmission line from Chalumbin to the Woree Substation on the outskirts of Cairns[31]. These 275kV transmission lines also provide connections to the Mt Emerald Wind Farm, the Kaban Wind Farm and Kareeya Power Station. As a result of the funded augmentation consultation undertaken by Powerlink to facilitate the development of Stage 1 of the Far North Queensland REZ, a third 275kV connection into Woree Substation was energised in June 2024, with the remaining works at Tully and Yabulu South substations expected to be completed by December 2024.

Due to environmental sensitivities and geographic conditions in the Cairns region, to ensure reliability of supply to customers, the delivery of the required renewal works will be complex and need to be completed outside of summer peak load and the wet season.

The double circuit 275kV transmission lines between Ross and Chalumbin (via Guybal Munjan) substations is 244km in length and comprises 528 steel lattice towers. The line traverses the rugged terrain of the northern Queensland tropical rainforest, passing through environmentally sensitive, protected areas and crossing numerous regional roads and rivers. This section of the transmission line is deteriorating at a slower rate than assets on the Chalumbin to Woree section due to its location on the western side of the Great Dividing Range.

30 Refer to NER Clause 5.14.1(e).
31 In June 2022 Powerlink completed the RIT-T, Maintaining Reliability of Supply in the Cairns region Stage 1 to address the more complex and advanced condition risks of the transmission towers between Davies Creek and Bayview Heights which form part of Chalumbin to Woree section of the transmission line (refer to Table 9.5).

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Substations

*Chalumbin 275/132kV Substation*

| | |
|---|---|
| Anticipated consultation | Maintaining reliability of supply at Chalumbin |
| Asset details | Established in 1988 |
| Project driver | Condition driven replacement to address risks on 275/132kV primary plant |
| Project timing | June 2028 |
| Proposed network solution | Selective 275/132kV primary plant replacement at an estimated cost of $9 million by June 2028 |
| Possible non-network solutions | Powerlink is not aware of any non-network proposals that can address this requirement in its entirety. Potential non-network options would need to provide supply to the 132kV network of up to a peak 100MW, and up to a peak 965MWh per day on a continuous basis. |

Chalumbin Substation is a major substation in the 275kV power transfer corridor between Ross and Far North zones and provides supply to the local 132kV network in the Cairns and Atherton tablelands regions.

### Possible network solutions

- Replacement of all 275/132kV primary plant by June 2028
- Selective replacement of 275/132kV primary plant by June 2028.

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Possible asset retirements in the 10-year outlook period[32]

*Retirement of the 132kV transmission lines between Chalumbin and Turkinje substations.*

Condition assessment has identified emerging condition risks arising from the condition of the 132kV transmission line between Chalumbin and Turkinje around 2030. At this time, an option would be to establish a 275kV substation and cut into an existing 275kV circuit between Chalumbin and Woree substations. Should this option proceed, there will be an opportunity to retire the existing 132kV transmission line from Chalumbin to Turkinje substations.

Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period.

## 6.9.2 Ross zone

### Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville and Far North Queensland. Parts of the 132kV network are located closer to the coast in a high salt laden wind environment leading to accelerated structural corrosion. Townsville is supplied by a 132kV transmission network to the south and west of the greater load area providing supply to Ergon Energy's 66kV distribution network. Connection points are located at the Townsville South 132/66kV, Townsville East 132/66kV, Dan Gleeson 132/66kV, Garbutt 132/66kV, and Alan Sherriff 132/11kV substations (refer to figures 6.9 and 6.10).

[32] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 6.9 Northern Ross zone transmission network

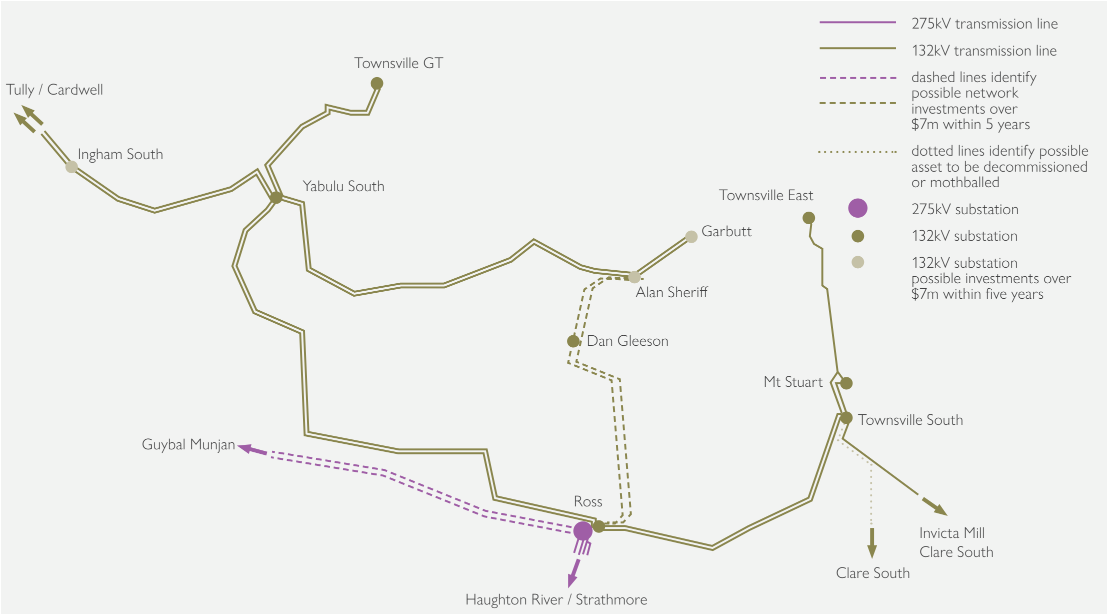



Figure 6.10 Southern Ross zone transmission network


### Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional capacity forecast to be required as a result of load driven network limitations in the Ross zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.10 lists existing and committed generators or direct connect customers connected to the Powerlink transmission network and connection applications.

Table 6.10 Existing and committed generators or direct connect customers and connection applications in the Ross zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Forecast completion date |
|---|---|---|---|---|
| Townsville | Existing | Gas turbine | 150 | |
| Mt Stuart | Existing | Gas turbine | 387 | |
| Clare | Existing | Solar PV | 100 | |
| Haughton | Existing | Solar PV | 100 | |
| Ross River | Existing | Solar PV | 116 | |
| Sun Metals | Existing | Solar PV | 121 | |
| Kidston Pumped Hydro Storage | Committed | Hydro-electric | 250 | 2025 |
| Yabulu Battery Energy Storage System (BESS) | Application | BESS | 200 | 2025 |
| Mt Fox Energy Park BESS | Application | BESS | 300 | 2026 |
| Pinnacles BESS | Application | BESS | 400 | 2027 |
| Burdekin BESS | Application | BESS | 500 | 2027 |
| Pacific Hydro - Haughton BESS | Application | BESS | 200 | 2027 |
| Yabulu Solar PV Farm | Application | Solar PV | 75 | 2025 |
| Pacific Hydro - Haughton SF - Stage 2 | Application | Solar PV | 300 | 2027 |
| Gawara Baya (Upper Burdekin Wind Farm) | Application | Wind | 400 | 2026 |
| Mt Fox Energy Park Wind Farm | Application | Wind | 291 | 2026 |
| Kidston Wind Farm | Application | Wind | 204 | 2026 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in the Ross zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and NER obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Ross zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

### Transmission lines

*Ross to Dan Gleeson 132kV transmission line*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply to between Ross and Dan Gleeson |
| Asset details | Constructed in 1963 and operates in an aggressive tropical coast environment |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | June 2028 |
| Proposed network solution | Refit of the transmission line between Ross and Dan Gleeson substations, at an estimated cost of $8 million by June 2028 |
| Possible non-network solutions | The Ross to Dan Gleeson transmission lines provide part of the injection to the Townsville Central Business area. Potential non-network solutions would need to provide equivalent support of close to 130MW at peak and up to 800MWh per day. |

Electricity supply to the Townsville Central Business District is provided from Ross Substation by 132kV transmission lines to Dan Gleeson, Alan Sherriff and Garbutt substations.

#### Possible network solutions

- Line refit works on steel lattice structures by June 2028
- Rebuild the 132kV transmission line between Ross and Dan Gleeson substations by June 2028.

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Substations

*Ingham South 132kV Substation*

| | |
|---|---|
| Anticipated consultation | Maintaining reliability of supply and addressing condition risks at Ingham South |
| Asset details | Established in 2005 |
| Project driver | Condition driven replacement to address emerging obsolescence and compliance risks on 132kV primary plant and secondary systems |
| Project timing | December 2027 |
| Proposed network solution | Full replacement of primary plant and secondary systems at an estimated cost of $27 million by December 2027 |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to the 66kV network at Ingham South of up to 20MW and up to 280MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages. |

Ingham South Substation is a major injection point into Ergon Energy's 66kV distribution network providing supply to Ingham and the surrounding area.

#### Possible network solutions

- In-situ replacement of primary plant and secondary systems by December 2027
- Minimum extension of the substation platform to replace primary plant and secondary systems by December 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Garbutt 132kV Substation*

| | |
|---|---|
| Anticipated consultation | Addressing the secondary systems condition risks at Garbutt |
| Asset details | Established in late 1950s, last replacement in 2004 |
| Project driver | Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems |
| Project timing | June 2027 |
| Proposed network solution | Full replacement of primary plant and secondary systems at an estimated cost of $10 million by June 2027 |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to the 66kV network at Garbutt Substation of up to 120MW and up to 860MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages. |

Garbutt Substation is a major injection point into Ergon Energy's 66kV distribution network providing supply to the Townsville area.

Possible network solutions

- In-situ replacement of secondary systems by June 2027
- Full secondary systems replacement by June 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Alan Sherriff 132kV Substation*

132kV secondary systems replacement

| | |
|---|---|
| Anticipated consultation | Addressing the secondary systems condition risks at Alan Sherriff |
| Asset details | Established in 2002 |
| Project driver | Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems |
| Project timing | June 2027 |
| Proposed network solution | Full replacement of primary plant and secondary systems at an estimated cost of $14 million by June 2027 |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to the 66kV network at Alan Sherriff of up to 35MW and up to 225MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages. |

Alan Sherriff Substation is a major injection point into Ergon Energy's 11kV distribution network providing supply to the Townsville area.

Possible network solutions may include:

- In-situ replacement of secondary systems by June 2027
- Full secondary systems replacement by June 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements within the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the Ross zone within the 10-year outlook period. Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period.

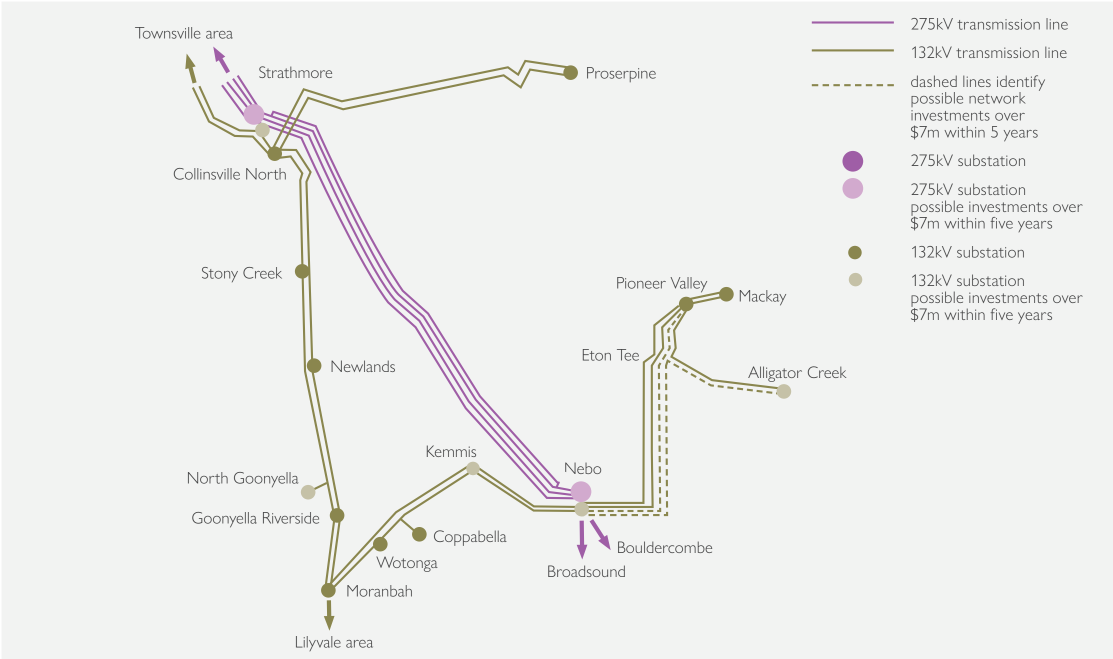
### 6.9.3 North zone

#### Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form part of the 275kV transmission network supplying the North zone. Double circuit inland and coastal 132kV transmission lines supply regional centres and infrastructure related to mines, coal haulage and ports arising from the Bowen Basin mines (refer to Figure 6.11).

The coastal network in this zone is characterised by transmission line infrastructure in a corrosive environment which make it susceptible to premature ageing.

Figure 6.11 North zone transmission network




#### Possible load driven limitations

Powerlink's Central scenario forecast has approximately 100MW of additional load connected in the Northern Bowen Basin by 2033. This is associated with load increases on EQL's network and from Powerlink's direct connected customers. Taking into consideration the risks associated with the condition of the ageing network assets in the Northern Bowen Basin, and the magnitude and location of load, possible network options to, and within the Northern Bowen Basin may include:

- Installation of flow control devices on the 132kV network to improve the sharing of power flow in the Bowen Basin within the capability of the existing transmission assets
- Construction of new 132kV transmission lines between the Nebo, Broadlea and Peak Downs areas
- Construction of 132kV transmission line between Moranbah and a future substation north of Moranbah
- Advance the rebuild of the 132kV transmission lines that supply the Northern Bowen Basin area as higher capacity 132kV lines with associated capacitive compensation for voltage control. The existing 132kV lines are forecast to reach their end of technical service in the 2040s.

Powerlink will undertake further planning studies and provide an update in the 2025 TAPR, which may identify the need to undertake a RIT-T.

High voltages associated with light load and low power transfer conditions are currently managed with existing reactive sources. As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in Section 7.6.2.

#### Existing and committed generation and connection applications

Table 6.11 lists existing generators connected to the Powerlink transmission network and connection applications in the North zone.

Table 6.11 Existing generators and connection applications in the North zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Forecast completion date |
|---|---|---|---|---|
| Daydream | Existing | Solar PV | 150 | |
| Hamilton | Existing | Solar PV | 57 | |
| Hayman | Existing | Solar PV | 50 | |
| Whitsunday | Existing | Solar PV | 57 | |
| Rugby Run | Existing | Solar PV | 65 | |
| The Central BESS | Application | BESS | 500 | 2026 |
| Nebo BESS | Application | BESS | 900 | 2028 |
| Bowen Basin Sun Farm | Application | Solar PV | 130 | 2026 |
| Brampton Solar PV Farm | Application | Solar PV | 58 | 2027 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in the North zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and NER obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the North zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

### Transmission lines

*Nebo to Eton Tee 132kV transmission line*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply in the Nebo area |
| Asset details | Constructed in 1977 |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | December 2027 |
| Proposed network solution | Refit the transmission line between Nebo Substation and Eton Tee, at an estimated cost of $31 million by December 2027 |
| Possible non-network solutions | The Nebo to Eton Tee transmission lines provides part of the injection to the Mackay area. A non-network solution would need to supply close to 80MW at peak and up to 200MWh per day. |

Nebo Substation forms part of the interconnected 275kV network between Gladstone and North Queensland and is a transformation point to 132kV, to allow supply to local mining and domestic loads in the Central Queensland area. The establishment of Alligator Creek Substation in 1982 resulted in one circuit in and out at the Eton Tee point, followed by a reconfiguration in 2007 when Pioneer Valley Substation was established.

### Possible network solutions

- Line refit works on steel lattice structures between Nebo Substation and Eton Tee by December 2027
- Rebuild the 132kV transmission line between Nebo Substation and Eton Tee by December 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Substations

*Strathmore 275/132kV Substation*

| | |
|---|---|
| Anticipated consultation | Addressing the Static VAr Compensator (SVC) secondary systems condition risks at Strathmore |
| Asset details | Established in 2007 |
| Project driver | SVC secondary systems condition risks at Strathmore Substation |
| Project timing | June 2026 |
| Proposed network solution | Full replacement of secondary systems associated with the SVC at Strathmore at an estimated cost of $12 million by June 2026 |
| Proposed non-network solutions | Potential non-network solutions would need to provide dynamic voltage support of up to 260MVAr capacitive and 80MVArs inductive. |

Strathmore Substation is a major injection point to supply Ergon Energy's distribution network and Powerlink's direct connected customers in the Northern Bowen Basin.

Possible network solutions may include:

- Secondary systems replacement while retaining the existing thyristor valves and SVC cooling system by June 2026
- Secondary systems replacement and replacing the thyristor valves including associated cooling system by June 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Nebo 275/132kV Substation*

| | |
|---|---|
| Anticipated consultation | Addressing the Static VAr Compensator (SVC) primary plant and SVC transformer condition risks at Nebo |
| Asset details | Established in 1987 |
| Project driver | SVC primary plant and SVC transformer condition risks at Nebo Substation |
| Project timing | December 2029 |
| Proposed network solution | Full replacement of primary plant and transformer associated with the SVC at Nebo at an estimated cost of $8 million by December 2029 |
| Proposed non-network solutions | Potential non-network solutions would need to provide dynamic voltage support of up to 260MVAr capacitive and 80MVArs inductive. |

Nebo Substation forms part of the interconnected 275kV network between Gladstone and North Queensland and is a transformation point to 132kV, to allow supply to local mining and domestic loads in the Central Queensland area.

Possible network solutions

- Selected replacement of SVC 275kV primary plant and associated transformer by December 2029
- Full replacement of SVC 275kV primary plant and associated transformer by December 2029.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Possible asset retirements within the 10-year outlook period*

*Pioneer Valley to Eton tee 132kV transmission line*

Subject to the outcome of further analysis, Powerlink may retire this inland transmission line at the end of its service life anticipated around 2028. Should it proceed, the retirement will also result in the 132kV network reconfiguration from Nebo to Pioneer Valley and Alligator Creek substations, essentially creating a separate double circuit line into each substation.

Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period and Table 9.8 for confirmed asset retirements in the North zone.

## 6.10 Central region

The Central region includes proposed network investments located within the Central West and Gladstone zones that broadly align with the Central Queensland REZs region (refer to Figure 6.6). This region:

- hosts some of Powerlink's largest industrial customers together with significant coal-fired generation
- offers considerable opportunities for the development of new industries
- is pivotal to supply power to northern and southern Queensland
- plays a major role in supporting industry, rail systems and mines, and
- includes several potential future REZs to be developed in the next 10 years as outlined in the updated REZ Roadmap released in March 2024 (refer to Section 2.5.2).

The Central region has high quality solar and wind resources and long-term industrial and hydrogen production potential, as well as existing energy-intensive industries that are seeking to decarbonise through either electrification of existing processing facilities and/or conversion to loads powered by VRE generation. These factors, in combination with the anticipated reduced operation of existing coal-fired power stations, will significantly impact the transmission capacity required to maintain reliability of supply in the Gladstone zone and power system security. Powerlink anticipates that power transfers will reach the secure limits and result in network congestion (refer to Section 8.2.5).

The utilisation of the transmission network in the Central region depends on both the generation dispatch and supply and demand balance within the Central West and Gladstone zones, and northern and southern Queensland. In addition, the significant increase in VRE generation is changing the generation mix and impacting the operation of existing coal-fired generators within the region, which in turn, is further affecting the utilisation of existing transmission infrastructure. This has been most evident across the Central to North Queensland and Central to South Queensland grid sections and the Queensland to New South Wales Interconnector (QNI) (refer to sections 7.6.2, 7.6.5 and 7.6.10 respectively).

A shift in utilisation and material change in supply demand balance within the Gladstone zone has implications for investment in the transmission network. In July 2024, Powerlink commenced consultation on the Gladstone Project as a candidate Priority Transmission Investment (PTI) under the ERTJ Act (refer to Section 6.10.2).

Aligned with this need, the Gladstone Project has also been declared a Queensland Actionable Project in Australian Energy Market Operator's (AEMO) 2024 Integrated System Plan (ISP).

Potential future investments for the Central region are outlined in Section 8.2.5.

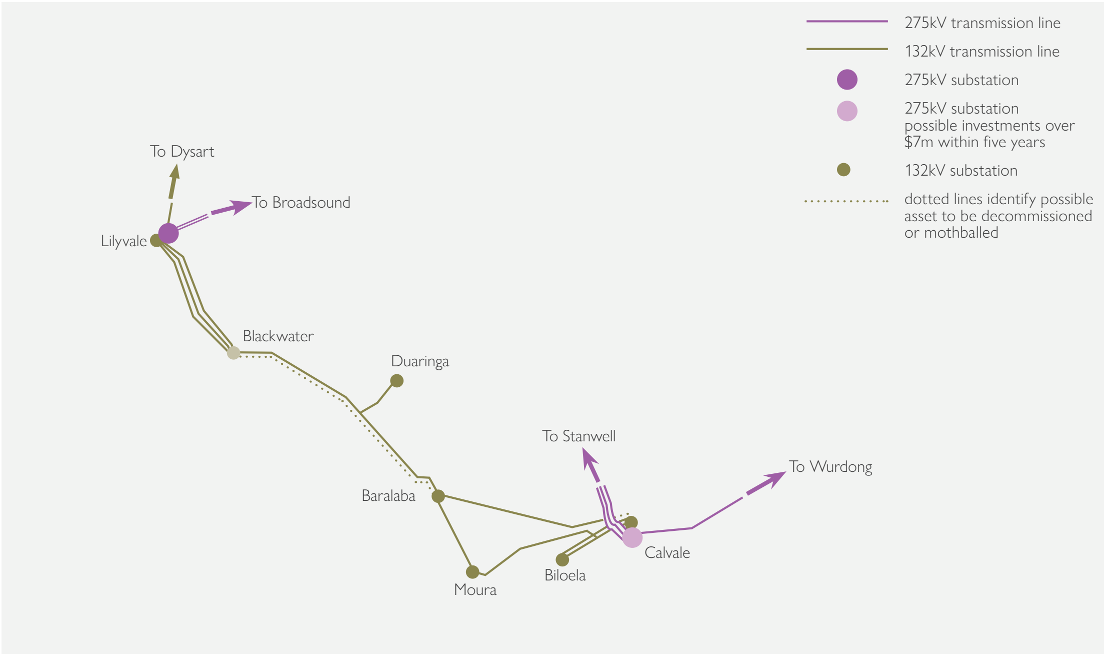
The investments outlined in Section 6.10 are based on Powerlink's Central scenario forecast in the 10-year outlook period. These requirements may result in the need for new investments that impact the proposed future network and non-network solutions identified in the geographical zones located within this region (refer to sections 6.10.1 to 6.11.1) and the Queensland SuperGrid Infrastructure Blueprint. Updates will be included in subsequent TAPR reviews.

### 6.10.1 Central West zone

#### Existing network

The Central West 132kV network was developed between the mid-1960s and late 1970s to meet the requirements of mining activity in the southern Bowen Basin. The 132kV injection points for the network are taken from Calvale and Lilyvale 275kV substations (refer to Figure 6.12). The network is located more than 150km from the coast in a dry environment, making infrastructure less susceptible to corrosion. As a result, transmission lines and substations in this region have met (and in many instances exceeded) their anticipated service life but will still require replacement or rebuilding in the near future.

Figure 6.12 Central West 132kV transmission network




#### Possible load driven limitations

Based on Powerlink's Central scenario forecast and the committed generation described in tables 7.1 and 7.2, there is no additional capacity forecast to be required in the Central West zone within the next five years to meet load driven reliability obligations. Discussions are continuing with potential large load customers in the area to firm up new load requirements.

#### Existing and committed generation and connection applications

Table 6.12 lists existing and committed generators connected to the Powerlink transmission network and connection applications.

Table 6.12 Existing and committed generators and connection applications in the Central West zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Stanwell | Existing | Coal-fired | 1,460 | |
| Callide B | Existing | Coal-fired | 700 | |
| Callide Power Plant | Existing | Coal-fired | 868 | |
| Moura | Existing | Solar PV | 82 | |
| Lilyvale Solar PV Farm | Existing | Solar PV | 100 | |
| Bouldercombe BESS | Existing | BESS | 50 | |
| Broadsound Solar PV Farm | Committed | Solar PV | 296 | 2026 |
| Clarke Creek | Committed | Wind | 440 | 2025 |
| Lotus Creek Wind Farm | Committed | Wind | 276 | 2027 |
| Boulder Creek | Committed | Wind | 221 | 2027 |
| Stanwell Power Station BESS | Application | BESS | 350 | 2026 |
| Moah Creek Solar Farm | Application | Solar PV | 390 | 2028 |
| Mount Hopeful Wind Farm | Application | Wind | 350 | 2026 |
| Specimen Hill Wind Farm | Application | Wind | 323 | 2027 |
| Banana Range Wind Farm | Application | Wind | 480 | 2027 |
| Blackwater Solar Farm and BESS | Application | Solar PV; BESS | 270 | 2026 |
| Boomer Green Energy Hub | Application | Wind; BESS | 1,100 | 2027 |
| Isaac Wind Farm- Clarke Creek Stage 2 | Application | Wind | 1,064 | 2028 |
| Moah Creek Wind Farm | Application | Wind | 415 | 2028 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation over summer 2024/25.

### Possible network investments within five years

Any forecast network investments in the Central West zone are related to addressing the risks arising from the condition of the existing network assets which, without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Central West zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

### Transmission lines

*Bouldercombe to Nebo 275kV transmission line*

| | |
|---|---|
| Anticipated consultation | Maintaining reliability of supply to North Queensland |
| Asset details | Constructed in 1980 |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | December 2026 |
| Proposed network solution | Refit the single circuit transmission line between Bouldercombe and Nebo substations, at an estimated cost of $15 million by December 2026 |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to Nebo and North Queensland loads of up to 90MW on the network, and up to 450MWh per day on a continuous basis. It would also need to provide equivalent system strength services. |
| Other possible network solutions considered include: | Rebuild the 275kV transmission line between Bouldercombe and Nebo substations |
| Market Impacts | Powerlink considers the proposed network solution will not have a material inter-network impact. |

The 275kV transmission line between Bouldercombe and Nebo forms part of the Central Queensland to North Queensland (CQ-NQ) transmission network supplying North Queensland and FNQ. Built Section 1132 between Funnel Creek and Bouldercombe Substation is in an elevated position and is exposed to high rainfall and salt laden winds.

#### Possible network solutions

- Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations
- Rebuild the 275kV transmission line between Bouldercombe and Nebo substations.

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Substations

*Calvale 275/132kV Substation*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply at Calvale |
| Asset details | Established in the mid-1980s |
| Project driver | Addressing the 275kV primary plant condition risks |
| Project timing | December 2027 |
| Proposed network solution | Selected primary plant replacement at Calvale Substation at an estimated cost of $18 million by December 2027 |
| Possible non-network solutions | Calvale Substation is also a major transmission node in Central Queensland connecting power flows between northern, central and southern Queensland. It also facilitates connection of Callide B and Callide C generation and proposed Callide REZ (refer to Section 2.5.4), and also provides voltage support for the region. Potential non-network solutions would need as a minimum, to provide, supply to Moura and Biloela loads of more than 100MW on the 132kV network, and up to 2,000MWh per day on a continuous basis. |
| Other possible network solutions considered include: | Full primary plant replacement by December 2029 |
| Market Impacts | Powerlink considers the proposed network solution will not have a material inter-network impact |

Calvale Substation is a critical part of the Central West Queensland transmission network and provides connection to Callide B and Callide C generators and the proposed Callide REZ.

Possible network solutions

- Selected primary plant replacement by December 2029
- Full primary plant replacement by December 2029.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Broadsound 275kV Substation*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply at Broadsound |
| Asset details | Established in 1983. Further extensions have been made with additions of 275kV feeders to the West, South and North |
| Project driver | Addressing the 275kV primary plant condition risks |
| Project timing | June 2028 |
| Proposed network solution | Selected primary plant replacement at Broadsound Substation at an estimated cost of $19 million by June 2028 |
| Possible non-network solutions | Broadsound Substation is primarily a major transmission node connecting power flows between north and central Queensland. It is also the hub to Lilyvale and central west loads. Potential non-network solutions would need as a minimum, to provide supply to Lilyvale and Blackwater loads of up to 250MW, and up to 6,000MWh per day on a continuous basis. |
| Other possible network solutions considered include: | Full primary plant replacement by June 2028 |
| Market Impacts | Powerlink considers the proposed network solution will not have a material inter-network impact |

Possible network solutions

- Selected primary plant replacement by June 2028
- Full primary plant replacement by June 2028.

Possible asset retirements within the 10-year outlook period[33]

*Calvale to Moura to Baralaba 132kV transmission lines*

Subject to the outcome of further analysis and RIT-T consultation, a new 132kV double circuit transmission line may be constructed between Calvale and Moura substations due to a step change in load growth at Moura Substation or end of technical service life of the existing single circuit transmission lines within the 10-year outlook period. The reconfiguration would allow Powerlink to mothball the existing single circuit transmission lines between Calvale and Baralaba, and Baralaba and Moura substations, and the Baralaba Substation, at the end of their technical service lives and be retired from service.

*Baralaba to Blackwater 132kV transmission line*

The 132kV inland transmission line was constructed in the mid-1960s to support the loads in the Central West area and due to network reconfiguration has no enduring need. This transmission line is mothballed as part of the economic end of technical service life strategy and is energised from Blackwater Substation (and disconnected at the Baralaba Substation) for maintenance purposes. The transmission line may be repurposed or rebuilt in part to facilitate new connections to Blackwater Substation in the future.

Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period.

33 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

### 6.10.2 Gladstone zone

#### Existing network

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station and has evolved over time with the addition of the Wurdong Substation and 275kV supply into Boyne Smelters Limited in the early 1990s (refer to Figure 6.13).

Figure 6.13 Gladstone transmission network


#### Possible load driven limitations

Powerlink's Central scenario forecast (discussed in Chapter 3) has approximately 1,800MW of additional anticipated load connected in the Gladstone zone by 2031. This load is associated with electrification of a component of the existing industrial processes and early stages of hydrogen production within the area. While Powerlink has no commitment from any direct connect customers to electrify existing industrial process, Powerlink is engaging with customers that appear committed to decarbonising their existing fossil fuelled operations and processes, with some uncertainty over time frames. There has also been a significant number of enquiries for the connection of new industrial processing loads in the Gladstone zone (refer to Table 3.1 and Section 8.2.5).

With reduced operation of Gladstone Power Station as the electricity industry transforms to a lower carbon future, in combination with electrification of existing industrial processes and development of new industry load, there will be a significant impact on the transmission capacity required to maintain reliability of supply in the Gladstone zone and power system security.

In response to these emerging limitations, Powerlink commenced consultation on the Gladstone project PTI under the ERTJ Act. This consultation commenced in July 2024 and is being undertaken to ensure that on-going reliability and security of supply is available to meet forecast electrical load in the Gladstone area and support the decarbonisation of major industries in anticipation of the closure of the Gladstone Power Station (refer to Section 8.2.5).

#### Existing and committed generation and connection applications

Table 6.13 lists existing generators connected to the Powerlink transmission network and connection applications.

Table 6.13 Existing generators and connection applications in the Gladstone zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Gladstone | Existing | Coal-fired | 1,680 | |
| Yarwun | Existing | Gas turbine | 160 | |
| Aldoga BESS (Larcom Creek Facility 1 BESS) | Application | BESS | 400 | 2025 |
| Wurdong BESS | Application | BESS | 150 | 2026 |
| Miriam Vale Renewable Energy Hub | Application | Solar PV; BESS | 400 | 2027 |
| Eurimbula Hybrid Facility | Application | Solar PV; BESS | 1,186 | 2027 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in Gladstone zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and NER obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can deliver a safe, cost effective and reliable supply of electricity to meet the load requirements of customers in the Gladstone zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

### Transmission lines

*Calliope River to Gladstone South 132kV transmission lines*

| | |
|---|---|
| Anticipated consultation | Maintaining reliability of supply to Gladstone South |
| Asset details | Constructed in 1977 |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | June 2030 |
| Proposed network solution | Rebuild the double circuit transmission line between Calliope River and Gladstone South substations, at an estimated cost of $53 million by June 2030 |
| Possible non-network solutions | Potential non-network solutions would need to provide supply to the 132kV network at Gladstone South of up to 160MW at peak and up to 1,820MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages. |

The Calliope River to Gladstone South 132kV double circuit transmission line facilitates supply to Gladstone South Substation which is an Ergon Energy bulk supply point and the connection point for Queensland Alumina Limited (QAL).

### Possible network solutions

- Rebuild the 132kV transmission line between Calliope River and Gladstone South substations
- Line refit works on steel lattice structures.

In making this investment decision Powerlink will also take into account the possible decarbonisation of existing fossil fuelled operations and processes that are currently supplied from this network. This may impact the scale and configuration of the optimal network investment. These development plans will be reported in subsequent TAPRs as more certainty and commitment of these additional loads emerge.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements within the 10-year outlook period[34]

*Callide A to Gladstone South 132kV transmission double circuit line*

The 132kV transmission line was constructed in the mid-1960s to support the loads in the Gladstone area. Due to reconfiguration in the area, this transmission line will be retired from service at the end of technical service life within the 10-year outlook period.

Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period.

## 6.11 Southern region

The Southern region includes proposed network investments located within the Wide Bay, Surat, Bulli, South West, Moreton and Gold Coast zones and broadly aligns with the Southern Queensland REZs region (refer to Figure 6.6). The Southern region includes a diverse range of industries and large load centres with considerable opportunity to connect renewable energy resources to the transmission network. It also includes the Queensland section of QNI. The Southern region also includes a number of candidate REZ areas in southern Queensland identified in the updated REZ Roadmap (refer to Section 2.5.2) and 2024 ISP.

The investments outlined in Section 6.11 are based on Powerlink's Central scenario forecast in the 10-year outlook period. Given Powerlink's integrated planning approach, and the rapidly evolving environment of the energy transformation, these requirements may result in the need for new investments that impact the proposed future network and non-network solutions identified in the geographical zones located within this region (refer to sections 6.16 and 8.3), including the Queensland SuperGrid Infrastructure Blueprint and will be updated in subsequent reviews.

### 6.11.1 Wide Bay zone

Existing network

The Wide Bay zone supplies loads in the Bundaberg and Maryborough region and also forms part of Powerlink's eastern Central Queensland to South Queensland (CQ-SQ) transmission corridor. This corridor was constructed in the 1970s and 1980s and consists of single circuit 275kV transmission lines between Calliope River and South Pine (refer to Figure 6.14). These transmission lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 6.14 CQ-SQ transmission network


[34] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

### Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is no additional load driven capacity forecast to be required in the Wide Bay zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.14 lists existing and committed generators connected to the Powerlink transmission network and connection applications.

Table 6.14 Existing and committed generators and connection applications in the Wide Bay zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
| --- | --- | --- | --- | --- |
| Woolooga Energy Park | Existing | Solar PV | 176 | |
| Woolooga BESS | Committed | BESS | 200 | 2025 |
| Gin Gin BESS | Application | BESS | 270 | 2026 |
| Lower Wonga BESS | Application | BESS | 200 | 2026 |
| Teebar BESS | Application | BESS | 400 | 2027 |
| North Burnett Renewable Hub | Application | BESS | 720 | 2027 |
| Lower Wonga Solar Farm | Application | Solar PV | 300 | 2025 |
| Mt Rawdon Pump Hydro | Application | Hydro-electric | 2,000 | 2029 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Transmission network overview

In the NEM, generators compete for dispatch. Briefly, a generator's dispatch level depends on its bid in relation to other generators' bids, demand and available transmission capacity. Congestion occurs when transmission capacity prevents the optimum economic dispatch. Affected generators are said to be 'constrained' by the amount unable to be economically dispatched. Forecast of market constraint durations and levels are sensitive to highly uncertain variables including changes in bid behaviour, investment patterns, fuel cost dynamics, plant outages, weather conditions and demand levels. It is important to note that network congestion does not necessarily signal there is any load at risk or potential for loss of supply to customers.

In its current form, the CQ-SQ transmission network offers a great deal of flexibility for possible generation dispatches. However, it occasionally imposes constraints to market operation. In order for power from new and existing North Queensland (NQ) and Central Queensland (CQ) generating systems to make its way to southern Queensland and the southern states, it must be transferred through the CQ-SQ grid section. The utilisation may increase following the final releases of capacity associated with the commissioning of the QNI Minor project (refer to Section 6.14). In the future, pressure may build in transmitting power in a northerly direction with the advent of ubiquitous VRE and storage in SQ, providing supply to future expansive Gladstone demand (refer to Section 8.2.5).

### Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in the Wide Bay zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Wide Bay zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit, augmentation or replacement with an asset of lower capacity.

Transmission Lines

*CQ-SQ transmission lines*

The 2024 ISP identified the Central to Southern Queensland network project as an actionable Queensland project (Queensland SuperGrid South) that is anticipated to progress under the Energy (Renewable Transformation and Jobs) Bill 2023 (Qld), rather than under the ISP framework.[35] In July 2024, the Queensland Government announced an update to the SuperGrid strategy, with the second stage of the SuperGrid between Southern and Central Queensland to shift from the original coastal location to an inland route (refer to Section 2.4). Powerlink subsequently held the Queensland SuperGrid planning update webinar to share the outcome of the most recent planning studies and the anticipated benefits this change will provide by unlocking significant amounts of new renewable energy in the State, lowering costs for wind generation connections and reducing overall energy costs for Queenslanders.

Powerlink and AEMO (through the ISP process) will continue to investigate the impact of large-scale VRE generation investment in the Queensland region.

The coastal CQ-SQ transmission network between Calliope River and South Pine substations provides essential supply sharing between the generation in central and north Queensland and the loads in central and southern Queensland.

This corridor provides the major injection points at Gin Gin, Teebar Creek, Woolooga and Palmwoods 275/132kV for the Wide Bay and Sunshine Coast areas. The Ergon Energy 132kV and Energex 132/110kV sub-transmission systems supply bulk supply points along these areas. The corridor also provides connection to large-scale VRE and storage projects.

The coastal CQ-SQ transmission network assets are expected to reach the end of their technical service life within the next 20 years. A key consideration is that this corridor is comprised solely of single circuit 275kV towers that may make cost-effective refit strategies less viable compared to double circuit tower rebuilds in targeted sections.

With varying distance from the ocean, and localised industrial pollution, the Calliope River to South Pine 275kV single circuit transmission lines are subject to different environmental and atmospheric conditions and have, over time, experienced structural degradation at different rates.

Emerging condition and compliance risks have been identified on the following assets:

Within the next five years:

- One 275kV single circuit transmission line from Woolooga to South Pine built in 1972 (structural repair due to above ground corrosion).

Within the next six to 10 years:

- Three 275kV single circuit transmission lines from Calliope River to Wurdong Tee built in 1972, 1976 and 1981 (structural repair due to above ground corrosion)
- Three 275kV single circuit transmission lines from Wurdong Tee to Gin Gin built in 1972, 1976 and 1981 (structural repair due to above ground corrosion)
- One 275kV single circuit transmission lines from Gin Gin to Woolooga built in 1972 (structural repair due to above ground corrosion)
- One 275kV single circuit transmission line from Palmwoods to South Pine built in 1976 (structural repair due to above ground corrosion).

[35] 2024 ISP, p. 57.

The current long-term network strategy is to rebuild two of the 275kV single circuit transmission lines from Calliope River to South Pine as a high capacity double circuit at end of technical service life utilising high temperature conductor (HTC) technology. The third circuit between Calliope and Woolooga substations is expected to be economic to maintain in the medium-term through targeted refit. When this circuit is dismantled, Wurdong Substation would be supplied from Calliope River via a dedicated 275kV double circuit transmission line and single circuit 275kV transmission line from Calvale Substation.

Strategies to address the transmission line sections with advanced corrosion in the five-year outlook will be economically assessed in consideration of longer-term network needs based on future generation and network requirements. This will also consider increasing line ratings by increasing ground clearances where it is economic to do so. Given Powerlink's integrated planning approach and the fast evolving environment of the energy transition, these requirements may result in the need for new investments that impact the proposed future network and non-network solutions identified and will be updated in subsequent reviews of the Infrastructure Blueprint and TAPR. Such decisions will be undertaken using the PTI or RIT-T consultation process, where the benefits of non-network options will also be assessed.

The longer-term network solution options to address the condition based drivers include:

- network rationalisation (potentially three single circuits to one double circuit) involving a staged program of line rebuild of the coastal corridor as a new double circuit (HTC) 275kV transmission line at the end of the technical service life of the existing circuits
- network rationalisation (potentially three single circuits to one double circuit) involving a staged program of line rebuild of the coastal corridor as a new double circuit (HTC) 275kV transmission line at the end of the technical service life of the existing circuits, using a program of targeted line refits to defer rebuild of individual CQ-SQ sections (where this deferral is economic)
- network rationalisation (potentially three single circuits to one double circuit) at the end of the technical service life of the existing single circuits, followed by construction of a second (HTC) 275kV double circuit line (potentially staged in sections) to support load and generation development
- maintaining the existing three single circuit 275kV transmission lines through a combination of staged rebuild and line refit projects.

Powerlink will consider whether the proposed preferred option will have a material inter-network impact closer to the timing of the investment decision and as part of the option analysis.

*Woolooga to South Pine 275kV transmission line*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply between Woolooga and South Pine |
| Asset details | Constructed in 1972 |
| Project driver | Emerging condition and compliance risks related to structural corrosion |
| Project timing | June 2029 |
| Proposed network solution | Line refit works on the 275kV transmission single circuit transmission line between Woolooga and South Pine substations at an estimated cost of $39 million by June 2029 |
| Possible non-network solutions | Powerlink is not aware of any non-network proposals that can address this requirement in its entirety Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirements of south-east Queensland. |

The 275kV transmission line between Woolooga and South Pine forms part of the critical CQ-SQ transmission network as discussed in this section.

Possible network solutions

- Rebuild the 275kV transmission lines between Woolooga and South Pine substations by June 2029, utilising HTC
- Line refit works on steel lattice structures by June 2029.

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Possible asset retirements within the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the Wide Bay zone within the next 10 years.

Refer to Table 6.21 for possible asset retirements beyond the 10-year outlook period.

## 6.11.2 Surat zone

### Existing network

The Surat zone is defined as the area north west of Western Downs Substation. The area has significant development potential given the vast reserves of gas and more recently VRE. Utilisation of assets in the area is forecast to continue due to new developments of VRE projects, coal seam gas upstream processing facilities by multiple proponents, together with the supporting infrastructure and services (refer to Figure 6.15).

Figure 6.15 Surat Basin North West area transmission network


### Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is no additional load driven capacity forecast to be required as a result of network limitations in the Surat zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.15 lists existing generators connected to the Powerlink transmission network and connection applications.

Table 6.15 Existing generators and connection applications in the Surat zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Condamine | Existing | Gas turbine | 139 | |
| Columboola | Existing | Solar PV | 162 | |
| Gangarri | Existing | Solar PV | 120 | |
| Blue grass | Existing | Solar PV | 148 | |
| Edenvale Solar Park | Existing | Solar PV | 146 | |
| Wandoan | Existing | Solar PV | 125 | |
| Miles South BESS | Application | BESS | 500 | 2026 |
| Hopeland Solar Farm (Ulinda Park) | Application | Solar PV | 250 | 2026 |
| Pleasant Hills Solar Farm | Application | Solar PV | 80 | 2026 |
| Miles South Solar Project | Application | Solar PV | 500 | 2026 |
| Brigalow GT (Kogan Creek GT) | Application | Gas turbine | 400 | 2026 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

#### Possible network investments within the five-year outlook period

Current planning analysis has not identified any assets requiring investment in the Surat zone within the five-year outlook period.

#### Possible asset retirements within the 10-year outlook period

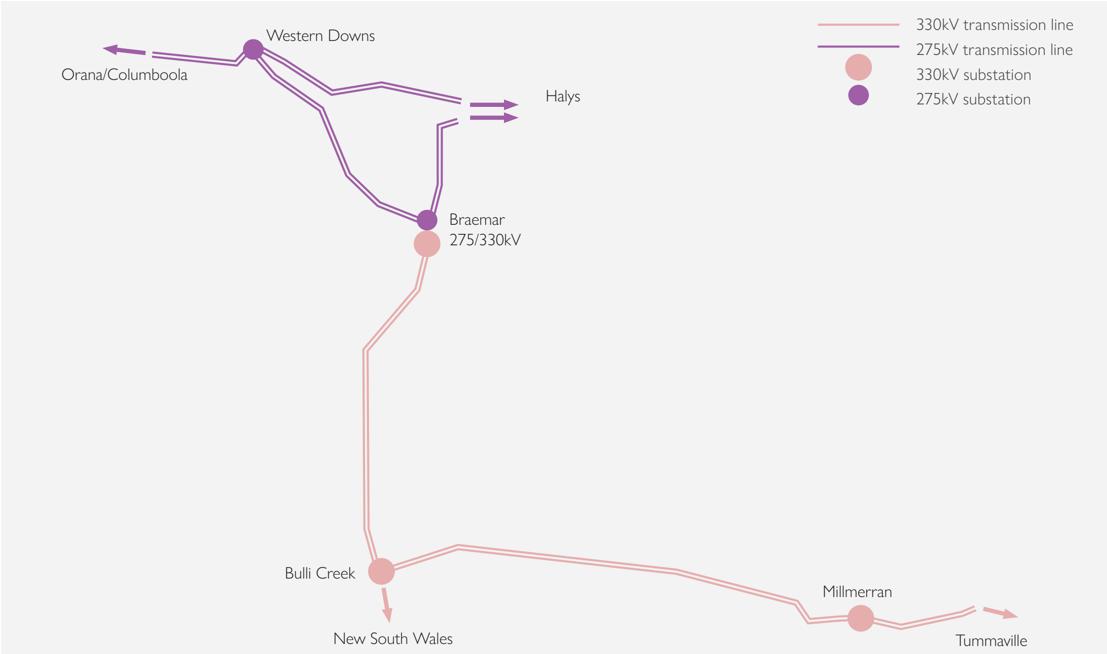
Current planning analysis has not identified any potential asset retirements in the Surat zone within the 10-year outlook period.

### 6.11.3 Bulli zone

#### Existing network

The Bulli zone is defined as the area surrounding Goondiwindi and the 330kV and 275kV network south of Kogan Creek Power Station and west of Millmerran Power Station (refer to Figure 6.16).

Figure 6.16 Bulli area transmission network




### Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is no additional load driven capacity forecast to be required as a result of network limitations in the Bulli zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.16 lists existing and committed generators connected to the Powerlink transmission network and connection applications.

Table 6.16 Existing and committed generators and connection applications in the Bulli zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Kogan Creek | Existing | Coal-fired | 710 | |
| Millmerran | Existing | Coal-fired | 670 | |
| Braemar 1 | Existing | Gas turbine | 501 | |
| Braemar 2 | Existing | Gas turbine | 480 | |
| Darling Downs | Existing | Gas turbine | 563 | |
| Western Downs Green Power Hub | Existing | Solar PV | 400 | |
| Chinchilla BESS | Existing | BESS | 100 | |
| Western Downs BESS | Committed | BESS | 200 | 2024 |
| Ulinda Park BESS | Committed | BESS | 155 | 2025 |
| MacIntyre Wind Farm | Committed | Wind | 890 | 2025 |
| Hopeland BESS | Application | BESS | 175 | 2025 |
| AGL - Madeline Downs BESS | Application | BESS | 500 | 2026 |
| Origin - Darling Downs BESS | Application | BESS | 250 | 2026 |
| Punchs Creek (Millmerran) Solar Farm | Application | Solar PV | 600 | 2026 |
| Hopeland Solar Farm (Ulinda Park) | Application | Solar PV | 250 | 2026 |
| Sixteen Mile Solar Farm and BESS | Application | Solar PV; BESS | 350 | 2026 |
| Dunmore Solar Farm and BESS | Application | Solar PV; BESS | 400 | 2027 |
| Beebo Solar Farm and BESS | Application | Solar PV; BESS | 600 | 2028 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within the five-year outlook period

The power transfer from the Bulli zone to south east Queensland can be limited by the thermal rating of a 1,300MVA 330/275kV transformer at Middle Ridge Substation. The incidence of congestion across this transformer is highly dependent on the amount of generation in the Bulli zone (including northerly power transfers on QNI) and the load in south east Queensland.

Two projects that can have a material impact on the incidence of congestion across Middle Ridge that are now committed include:

- QNI-Minor upgrade project
  Powerlink, Transgrid and AEMO are currently undertaking system tests to release additional capacity on QNI (both in a northerly and southerly direction). The final hold-point test, in a northerly direction, is planned to be at 950MW (refer to Section 6.14).
- 890MW MacIntyre Wind Farm (refer to tables 6.16 and 7.1).

Both these developments contribute to creating market conditions where limitations across the Middle Ridge transformer will likely emerge.

Powerlink is monitoring the utilisation and incidence of congestion across this corridor.

In order to provide additional transmission capacity to the market, Powerlink is designing a special protection scheme (SPS) that increases the allowable pre-contingent flow through the Middle Ridge transformers. The proposed SPS opens a 275kV circuit between Middle Ridge and Greenbank substations, combined with a run-back of generation following an outage of one of these transformers.

If further generation connects to the 330kV network near and between Bulli Creek and Middle Ridge substations, the incidence and severity of congestion across the Middle Ridge transformer is expected to increase to the point where the magnitude of required run-back will no longer be operationally viable.

Further options that will avail the market with additional transmission capacity include:

- a system splitting scheme coupled with a run-back of generation. The technical viability of a splitting scheme will take account of the impact on the system strength requirements of the inverter-based renewables connected in this zone.
- Implement a virtual transmission line option between the Bulli zone and south east Queensland by pairing a run-back of generation with a battery response in south east Queensland.
- Replace the existing 1,300MVA 330/275kV transformer at Middle Ridge with 1,500MVA 330/275kV transformer.

#### Possible asset retirements within the 10-year outlook period

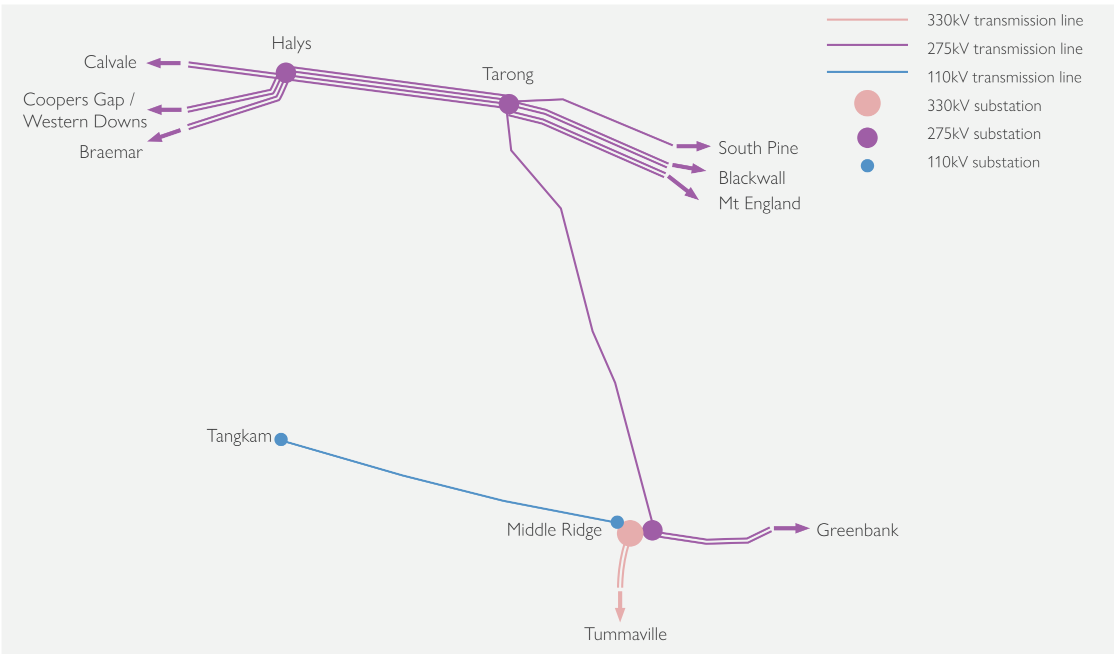
Current planning analysis has not identified any potential asset retirements in the Bulli zone within the 10-year outlook period.

### 6.11.4 South West zone

#### Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge (refer to Figure 6.17).

Figure 6.17 South West area 330kV and 275kV network




#### Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is no additional load driven capacity forecast to be required as a result of network limitations in the South West zone within the next five years to meet reliability obligations.

#### Existing and committed generation and connection applications

Table 6.17 lists existing and committed generators connected to the Powerlink transmission network and connection applications.

Table 6.17 Existing and committed generators and connection applications in the South West zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Tarong North | Existing | Coal-fired | 443 | |
| Tarong | Existing | Coal-fired | 1,400 | |
| Oakey | Existing | Gas turbine | 288 | |
| Coopers Gap | Existing | Wind | 440 | |
| Wambo Wind Farm | Committed | Wind | 245 | 2025 |
| Wambo Wind Farm 2 | Committed | Wind | 247 | 2026 |
| Tarong BESS | Application | BESS | 300 | 2024 |
| Tangkam BESS | Application | BESS | 100 | 2025 |
| Tumuruu Solar Farm and BESS | Application | BESS | 464 | 2026 |
| South Burnett BESS | Application | BESS | 300 | 2027 |
| Harlin Solar Farm | Application | Solar PV | 400 | 2027 |
| Tarong West Wind Farm | Application | Wind | 436 | 2026 |
| Toowoomba Pumped Hydro Storage Project (Big T) | Application | Hydro-electric | 400 | 2026 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

#### Possible network investments within the five-year outlook period

Current planning analysis has not identified any assets requiring investment above the RIT-T cost threshold in the South West zone within the five-year outlook period.

#### Possible asset retirements within the 10-year outlook period[36]

Refer to Table 11.7 for confirmed asset retirements in the South West zone and Table 6.21 for possible asset retirements beyond the 10-year outlook period.

### 6.11.5 Moreton zone

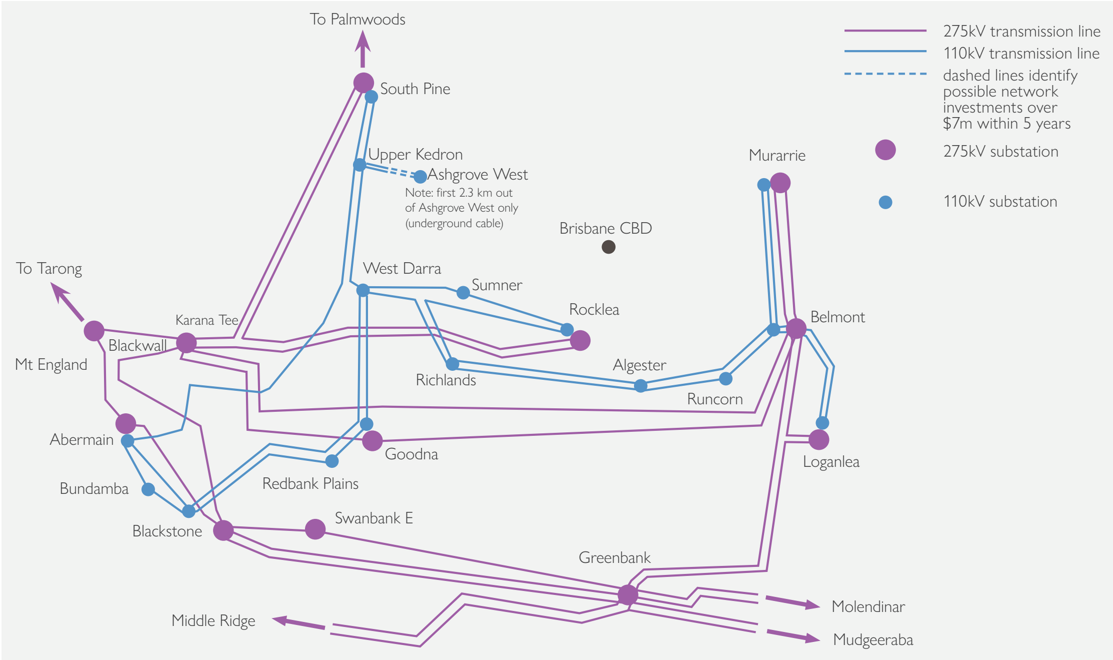
#### Existing network

The Moreton zone includes a mix of 275kV and 110kV transmission networks servicing a number of significant load centres in SEQ, including the Sunshine Coast, greater Brisbane, Ipswich and northern Gold Coast regions (refer to Figure 6.18).

Future investment needs in the Moreton zone are substantially arising from the condition and performance of 275kV and 110kV assets in the greater Brisbane area. The 110kV network in the greater Brisbane area was progressively developed from the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth from the early 1970s. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane Central Business District (CBD).

[36] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 6.18 Greater Brisbane transmission network




### Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3 and the committed generation described in tables 7.1 and 7.2, there is no additional load driven capacity forecast to be required in the Moreton zone within the next five years to meet reliability obligations.

### Existing and committed generation and connection applications

Table 6.18 lists existing and committed generators connected to the Powerlink transmission network and connection applications.

Table 6.18 Existing and committed generators and connection applications in the Moreton zone

| Name | Status (1) | Technology | Capacity (MW) (2) | Timing |
|---|---|---|---|---|
| Swanbank E | Existing | Gas turbine | 350 | |
| Wivenhoe | Existing | Hydro-electric | 570 | |
| Greenbank BESS | Committed | BESS | 200 | 2025 |
| Brendale (South Pine) BESS | Application | BESS | 205 | 2026 |
| Blackstone BESS 1 | Application | BESS | 250 | 2026 |
| Abermain BESS | Application | BESS | 125 | 2026 |
| Blackstone BESS 2 | Application | BESS | 250 | 2027 |

Notes:

(1) Application information is sourced from AEMO's Key Connection Information Data File August 2024.

(2) Capacity listed for existing generation as expected over summer 2024/25.

### Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in the Moreton zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Moreton zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

#### Transmission lines

The 110kV and 275kV transmission lines in the greater Brisbane area are located between 20km and 40km from the coast, traversing a mix of industrial, high density urban and semi-urban areas. The majority of assets are reasonably protected from the prevailing coastal winds and are exposed to moderate levels of pollution related to the urban environment. These assets have, over time, experienced structural corrosion at similar rates, with end of technical service life for most transmission line assets expected to occur towards the end of the 2020s and into the early 2030s.

With maximum demand expected to maintain low growth over the next 10 years and based on the development of the network over the last 40 years, planning studies have identified a number of 110kV transmission line assets that could potentially be retired. Given the uncertainty in future demand growth, Powerlink proposes to implement low cost maintenance strategies to keep the transmission lines inservice for a reasonable period. Future decommissioning remains an option once demand growth is better understood.

Detailed analysis will be on-going to evaluate the possible retirement of the following transmission lines at the end of technical service life:

- West Darra to Upper Kedron
- West Darra to Goodna
- Richlands to Algester.

This on-going review, together with further joint planning with Energex, may result in a future RIT-T.

*Underground 110kV cable between Upper Kedron and Ashgrove West*

| | |
|---|---|
| Anticipated consultation | Maintain reliability of supply at Ashgrove |
| Asset details | Constructed in 1978 |
| Project driver | Emerging condition, end of technical service life and compliance risks for the Upper Kedron to Ashgrove West underground cables |
| Project timing | June 2028 |
| Proposed network solution | Replacement of the oil-filled cables with new cables in a new easement at an estimated cost of $31 million by June 2028 |
| Possible non-network solutions | The Upper Kedron to Ashgrove West cables provide supply of up to 220MW at peak to Brisbane's inner north-west suburbs. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include but are not limited to local generation or DSM initiatives in the area. |

The 110kV transmission line between Upper Kedron and Ashgrove West substations is one of the principal sources of supply to the north-west Brisbane area. The transmission line is predominantly overhead, with the final 2.3km long section to Ashgrove West Substation being underground cable.

#### Possible network solutions

- Replacement of existing cables with new cables in a new easement by June 2028
- Replacement of existing cables with new cables in the existing easement by June 2028.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Karana Downs to South Pine 275kV transmission lines*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply to the western Moreton area |
| Asset details | Constructed in the mid-1970s |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | June 2030 |
| Proposed network solution | Line refit works on the 275kV transmission lines between Karana Downs and South Pine Substation at an estimated cost of $14m by June 2030 |
| Possible non-network solutions | Powerlink is not aware of any non-network proposals that can address this requirement in its entirety. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region. |

The 275kV double circuit transmission lines between Blackwall, South Pine and Rocklea substations support supply to the west and north of the Moreton zone.

Under certain load development scenarios and dispatch conditions, network limitations may emerge between Blackwall/Mt England and South Pine substations. These limitations may be addressed with the first stage of the SuperGrid (refer to Section 2.4 - high capacity 275kV double circuit line between Halys, Borumba and Woolooga substations). Prior to the commissioning of these transmission lines the limitations could be addressed by:

- Reconfiguring by establishing two tees at Karana Downs to form a double circuit between Blackwall and Rocklea and a double circuit from the Karana Downs tees to South Pine
- Constructing a new 275kV double circuit line from Blackwall to Karana Downs (on a vacant easement) and then reconfigure the network to form a double circuit line between Blackwall and Rocklea substations and a second double circuit line between Blackwall and South Pine substations.

Feasible network solutions to address the risks arising from these transmission lines may include:

- Maintaining the existing 275kV transmission line topography and capacity by way of a targeted line refit by June 2030
- Replacement at the end of technical service life of the existing single circuits between Karana Downs and South Pine with a new double circuit line, through staged rebuild.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Substations

*Ashgrove West 110/33kV Substation*

| | |
|---|---|
| Potential consultation | Addressing the secondary systems condition risks at Ashgrove West |
| Asset details | Established 1979 |
| Project driver | Emerging condition and 110kV secondary systems compliance risks |
| Project timing | June 2027 |
| Proposed network solution | Full replacement of the 110kV secondary systems at Ashgrove West Substation at an estimated cost of $22 million by June 2027 |
| Possible non-network solutions | Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region. Potential non-network options would need to provide supply of up to 220MW at peak to Brisbane's inner north west suburbs |

Ashgrove West Substation was established to meet increased demand in the Brisbane CBD and the expanding residential areas to the north and west of Brisbane.

Possible network solutions

- Full replacement of all of the 110kV secondary systems upfront by December 2026
- Staged replacement on 110kV secondary systems by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Murarrie 275/110kV Substation*

| | |
|---|---|
| Potential consultation | Addressing the secondary systems condition risks at Murarrie |
| Asset details | Established in 2003 |
| Project driver | Condition driven replacement to address risks on the 275kV and 110kV secondary systems |
| Project timing | December 2027 |
| Proposed network solution | Selected replacement of the 110kV secondary systems at an estimated cost of $22 million by December 2027 |
| Possible non-network solutions | Potential non-network options would need to provide supply into Murrarrie and the Central Business District. This can be up to 500MW and a peak of 5,700MWh per day on a continuus basis. |

Murarrie Substation, located approximately 8km from the Brisbane CBD, was originally established to operate as a bulk supply point for industrial load around the Brisbane River and port area. Along with Belmont Substation, Murarrie provides supply to the eastern areas of Brisbane CBD.

Possible network solutions

- Replacement of all 110kV secondary systems by December 2027
- Selective replacement of 110kV secondary systems by December 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Abermain 275/110kV Substation*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply at Abermain |
| Asset details | Established in 1962 |
| Project driver | Condition driven replacement to address risks on 275/110/33kV primary plant |
| Project timing | June 2030 |
| Proposed network solution | Selective replacement of 275/110/33kV primary plant at an estimated cost of $8 million by June 2030 |
| Possible non-network solutions | Potential non-network options would need to provide supply to the 110kV network of up to a peak 140MW, and up to a peak 1,050MWh per day on a continuous basis. |

Abermain Substation is located approximately 40km south west of the Brisbane central business district and operates as a bulk supply point to the Energex 33kV network.

Possible network solutions

- Replacement of all 275/110/33kV primary plant by June 2030
- Selective replacement of 275/110/33kV primary plant by June 2030.

Powerlink considers the proposed network solution will not have a material inter-network impact.

*Greenbank 275kV Substation*

| | |
|---|---|
| Potential consultation | Addressing the SVC secondary systems condition risks at Greenbank |
| Asset details | Installed in 2008 |
| Project driver | Condition driven replacement to address risks on the 275kV SVC secondary systems |
| Project timing | June 2029 |
| Proposed network solution | Full replacement of the 275kV SVC secondary systems at an estimated cost of $26 million by June 2029 |
| Possible non-network solutions | Potential non-network options would need to provide equivalent dynamic voltage support of up to 400MVAr capacitive and 100MVArs inductive |

Greenbank Substation, located approximately 40km from the coast, is a major node in the transmission network connecting the 330kV network from the Southern Downs area into south east Queensland. It is also the major switching station for the 275kV transmission lines supplying the Gold Coast and South Moreton areas.

#### Possible network solutions

- Replacement of all 275kV SVC secondary systems by June 2029
- Selective replacement of 275kV SVC secondary systems by June 2029.

Powerlink considers the proposed network solution will not have a material inter-network impact.

#### Possible asset retirements within the 10-year outlook period

*Loganlea 110/33kV transformer*

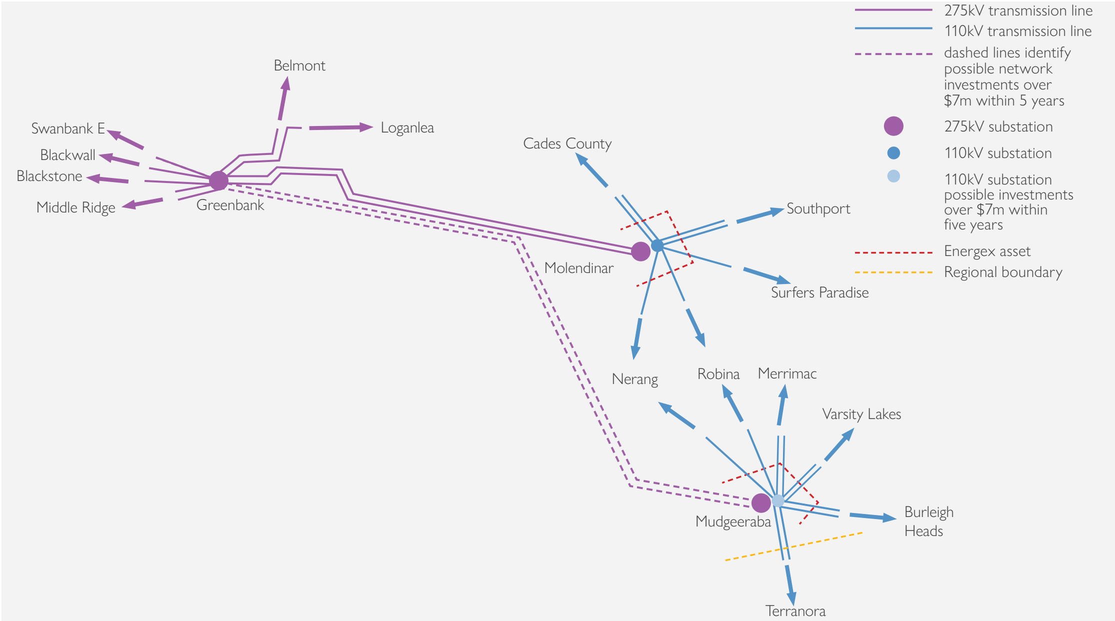
Based on the condition of one of the 110/33kV transformers at Loganlea, it is proposed to retire this transformer at the end of technical service life by June 2026. Powerlink considers that this will not impact on the ability to meet the obligations of Powerlink's reliability criteria. Since publication of the 2023 TAPR, joint planning with Energex has confirmed that based on the most recent load forecast, there is no enduring requirement for the transformer.

### 6.11.6 Gold Coast zone

#### Existing network

The Powerlink transmission system in the Gold Coast zone was originally constructed in the 1970s and 1980s. The Molendinar and Mudgeeraba substations are the two major injection points into the area via a double circuit 275kV transmission line between Greenbank and Molendinar substations, and two single circuit 275kV transmission lines between Greenbank and Mudgeeraba substations (refer to Figure 6.19).

Figure 6.19 Gold Coast transmission network




## Possible load driven limitations

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is no additional load driven capacity forecast to be required as a result of load driven network limitations in the Gold Coast zone within the next five years to meet reliability obligations.

## Possible network investments within five years

Network investments (which includes reinvestment and augmentations) in the Gold Coast zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Gold Coast zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

### Transmission lines

*Greenbank to Mudgeeraba 275kV transmission lines*

| | |
|---|---|
| Potential consultation | Maintaining reliability of supply to the southern Gold Coast area |
| Asset details | Constructed in the mid-1970s |
| Project driver | Emerging condition risks due to structural corrosion |
| Project timing | June 2029 |
| Proposed network solution | Maintain the existing topography by way of a targeted line refit at an estimated cost of $53 million by June 2029 |
| Possible non-network solutions | The Greenbank to Mudgeeraba 275kV transmission lines provide injection to the southern Gold Coast and northern NSW area. Powerlink is not aware of any non-network proposals in this area that can address this requirement in its entirety. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in the Gold Coast region. |

The two 275kV single circuit transmission lines between Greenbank and Mudgeeraba substations support the supply to Gold Coast and northern NSW.

Feasible network solutions to address the risks arising from these transmission lines may include:

- Maintaining the existing 275kV transmission line topography and capacity by way of a targeted line refit by June 2029
- Replacement at the end of technical service life of the existing single circuits between Mudgeeraba and Greenbank with a new double circuit line, through staged rebuild.

To ensure reliability of supply to customers, the required renewal works will need to be completed in stages outside of summer peak load and outage co-ordination will be complex due to the significant renewal program in the Gold Coast area within the 10-year outlook period.

Powerlink considers the proposed network solution will not have a material inter-network impact.

### Substations

*Molendinar 275/110kV Substation*

| | |
|---|---|
| Anticipated consultation | Addressing the secondary systems condition risks at Molendinar |
| Asset details | Established in 2003 |
| Project driver | Emerging condition risks arising from the condition of the 275kV secondary systems |
| Project timing | December 2027 |
| Proposed network solution | Selected replacement of secondary systems at an estimated cost of $28 million |
| Possible non-network solutions | Molendinar Substation provides injection and switching to the southern Gold Coast and northern NSW area. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in the Gold Coast region. |

Molendinar 275/110kV Substation, located approximately 75km south west of the Brisbane CBD, is one of two major connection points for supply into the Gold Coast area. The 110kV network from Molendinar to Mudgeeraba links the coastal bulk supply points at Southport, Surfers Paradise and Broadbeach via underground cable. An inland overhead 110kV network supplies Robina and Nerang substations.

#### Possible network solutions

- Selected replacement of 275kV secondary systems by December 2027
- Full replacement of 275kV secondary systems by December 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

**Possible asset retirements within the 10-year outlook period**

Current planning analysis has not identified any potential asset retirements in the Gold Coast zone within the 10-year outlook period.

## 6.12 Programs of work

### 6.12.1 Condition based asset renewal programs

To ensure a safe, reliable electricity supply to customers, Powerlink monitors and undertakes a regular program of condition assessments of all network assets, including minor value asset classes or subpopulations across the transmission network e.g. capacitive voltage transformers (CVTs). This ensures the risks arising from asset condition and performance are appropriately managed in a safe, cost effective manner. Taking into consideration the planning options discussed in Table 6.1, where a significant portion of an asset class or subpopulation has been identified as requiring investment across the network in a similar timeframe, programs of work may be undertaken given costs savings derived from economies of scale, efficiencies in resource allocation and as a strategy for proactive replacement.

Table 6.19 identifies potential programs of work over the next five years which will be subject to the RIT-T[37].

Table 6.19 Potential programs of work over the next five years

| Program | Consultation | High level scope | Purpose | Earliest possible commissioning date | Indicative cost |
|---|---|---|---|---|---|
| Capacitive Voltage Transformers Replacement Program | Managing the risk of Capacitive Voltage Transformer Failure | Staged replacement of 546 Trench capacitive voltage transformers at 42 substations throughout Queensland | Maintain supply reliability to Queensland | December 2030 | $60m |
| IMB300 Current Transformer Replacement Program | Managing the risk of Current Transformer Failure | Staged replacement of 523 current transformers at 24 substations throughout Queensland | Maintain supply reliability to Queensland | June 2029 | $70m |

### 6.12.2 Wide Area Monitoring, Protection and Control platform roll-out

Powerlink is progressing with the development and roll out of the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events.

WAMPAC rapidly detects specific conditions over geographically diverse transmission assets and initiates appropriate action to rapidly respond to changed power system conditions. The platform is capable of operating in sub-second timeframes enabling the system to dynamically respond to changes in the power system and to avoid adverse operating conditions.

WAMPAC has been implemented for system protection services across the Central Queensland to South Queensland (CQ-SQ) grid section to increase the resilience and security of the network under non-credible contingencies. Powerlink is progressing the implementation in other parts of the network to increase transmission capability, improve security and resilience, and more effectively manage and operate the transmission network during outages.

The planned roll out of WAMPAC across the State is outlined within Table 6.20.

[37] Excludes programs of work funded through operational and maintenance expenditure.

Table 6.20 WAMPAC platform roll-out

| Status | Zone/Grid Section | Application |
|---|---|---|
| Completed | CQ-SQ | Improve security and resilience under non-credible contingencies (tranche 1) |
| In Progress | Far North and North Queensland | Managing system strength and reduce impacts of network outages |
| | CQ-SQ | Improve security and resilience under non-credible contingencies (tranche 2) |
| | Surat | Improve security and resilience under non-credible contingencies |
| Short to longer term | Various Grid Sections and REZs | Run-back schemes to provide additional network capacity of the shared grid (e.g. Virtual Transmission Lines) |
| | REZs | Increase hosting capacity of REZs (roll-out aligned within 2024 Queensland REZ Roadmap) |
| | SuperGrid | Increase capability, security and resilience of SuperGrid backbone transmission (roll-out aligned with QEJP) |
| | Various locations | Provision of non-firm capacity to urgent load connections (e.g. electrification, hydrogen, etc) |
| | Various locations | Anti-islanding capability (various timings) |

## 6.13 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO ESOO[38]. Interested parties who require information regarding future supply demand balance should consult this document.

## 6.14 Existing interconnectors

Powerlink and Transgrid completed a RIT-T in December 2019 on 'Expanding NSW-Queensland transmission transfer capacity'. The recommended QNI Minor Project included uprating the 330kV Liddell to Tamworth 330kV lines and installing SVCs at Tamworth and Dumaresq substations and capacitor banks at Tamworth, Armidale and Dumaresq substations. Transgrid completed commissioning these works by May 2022.

After consultation and in accordance with Clause 5.7.7(p) of the NER, Transgrid, Powerlink and AEMO published a final inter-network test program in May 2022 and commenced monitoring test opportunities from June 2022. The Test Plan requires the flows on the interconnector to reach specific levels (hold points) for a period of approximately three hours to allow switching tests and monitoring of damping levels using the online Oscillatory Stability Monitoring with comparative small signal stability assessment using system snapshots to occur. Normal market dispatch is being relied on to deliver these required transfer levels.

AEMO, Transgrid and Powerlink aimed to achieve full commercial service of the QNI upgrade by mid-2023. However, due to non-availability of favourable market and test conditions, the full QNI transfer capability has not been released. The northerly hold point has now been increased from 600MW to 850MW and the southerly hold point from 1,200MW to 1,400MW. These tests are expected to continue until mid-2025.

38 Published by AEMO in August 2024.

## 6.15 Transmission lines approaching end of technical service life beyond the 10-year outlook period

As transmission lines approach their anticipated end of technical service life, detailed planning studies are undertaken to confirm the asset's enduring need taking into consideration asset condition and risk as well as alignment with future investment or possible network optimisation strategies. Options considered may include line refit, targeted and/or staged refit or replacement, upfront replacement or rebuild, network reconfiguration, non-network alternatives, asset de-rating or retirement.

The information contained in Table 6.21 which goes five years beyond the 10-year outlook period of the 2024 TAPR, is provided in good faith[39] as a snapshot, and is the best information available at the time of TAPR publication. Transmission equipment and line ratings information is available on AEMO's website and can also be accessed via the link in the TAPR Portal.

Given the rapid speed of the energy transformation, proponents who wish to connect to Powerlink's transmission network are strongly encouraged to contact BusinessDevelopment@powerlink.com.au in the first instance.

[39] For completeness, please refer to Powerlink's Disclaimer on page 2.

Table 6.21 Transmission lines approaching end of technical service: 10-15 years (July 2035 – June 2040)

| Region | Zone | Feeder | Voltage | General location |
|---|---|---|---|---|
| Northern | Far North | 7165,7166 | 132kV | Between Chalumbin and Turkinje substations |
| Northern | Far North | 7227 | 132kV | Between Cairns and Woree substations |
| Northern | Far North | 7191,7192 | 132kV | Kareeya to Chalumbin substations |
| Northern | Ross | 879,8911 | 275kV | Between Strathmore and Ross Substation |
| Northern | Ross | 7130,7131 | 132kV | Between Clare South and Townsville South substations |
| Northern | North | 7120,7304,7305 | 132kV | Between Nebo and Pioneer Valley substations |
| Northern | North | 7152 | 132kV | Between Pioneer Valley and Alligator Creek substation |
| Northern | North | 7119 | 132kV | Between Nebo and Alligator Creek substations |
| Northern | North | 7238 | 132kV | Between Pioneer Valley and Mackay substations |
| Northern | Central West | 820 | 275kV | Between Bouldercombe and Broadsound substations |
| Central | Central West | 833 | 275kV | Between Broadsound and Lilyvale substations |
| Central | Central West | 7150 | 132kV | Between Lilyvale and Dysart substations |
| Central | Central West | 7109 | 132kV | Between Baralaba and Calvale substations |
| Central | Central West | 7110 | 132kV | Between Calvale and Moura substations |
| Central | Central West | 7112 | 132kV | Between Baralaba and Moura substations |
| Central | Central West | 7124 | 132kV | Between Moranbah and Dysart substations |
| Central | Gladstone | 848,849 | 275kV | Between Stanwell and Bouldercombe substations |
| Central | Gladstone | 7145,7146 | 132kV | Between Calliope River and Boyne Island substations |
| Central | Gladstone | 7221 | 132kV | Between Bouldercombe and Egans Hill substations |
| Central | Gladstone | 871 | 275kV | Between Calvale and Wurdong substations |
| Central | Gladstone | 848,849 | 275kV | Between Stanwell and Bouldercombe substations |
| Southern | Wide Bay | 8850 | 275kV | Between Woolooga and Teebar Creek substations |
| Southern | Wide Bay | 813,814 | 275kV | Between Woolooga, Gin Gin and Calliope River substations |
| Southern | Wide Bay | 819 | 275kV | Between Teebar Creek and Wurdong substations |
| Southern | Wide Bay | 807 | 275kV | Between South Pine and Woolooga substations |
| Southern | Wide Bay | 810 | 275kV | Between Woolooga and Palmwoods substations |
| Southern | Wide Bay | 808 | 275kV | Between South Pine and Palmwoods substations |
| Southern | South West | 831 | 275kV | Between Tarong and Middle Ridge substations |
| Southern | Moreton | 827 | 275kV | Between Tarong and Blackwall substations |
| Southern | Moreton | 832 | 275kV | Between Tarong and South Pine substations |
| Southern | Moreton | 825 | 275kV | Between Mt England and South Pine substations |
| Southern | Moreton | 8819 | 275kV | Between Blackwall and Goodna substations |
| Southern | Moreton | 829 | 275kV | Between Loganlea and Belmont substations |
| Southern | Moreton | 8822 | 275kV | Between Greenbank and Belmont substations |

## 6.16 Queensland SuperGrid Infrastructure Blueprint - proposed investments

In July 2024, Powerlink commenced consultation on the Gladstone Project as a candidate PTI under the ERTJ Act. This consultation is being undertaken to ensure that on-going reliability and security of supply is available to meet forecast electrical load in the Gladstone area and support the decarbonisation of major industries in anticipation of the closure of the Gladstone Power Station (refer to sections 8.2.5 and 6.6 and Powerlink's website[40]).

Feasible network solutions to deliver reliability of supply obligations in the Gladstone zone and facilitate efficient market operation may include:

- new 275kV high capacity double circuit line between Calvale and Calliope River
- rebuild Calliope River to Larcom Creek 275kV high capacity double circuit line
- rebuild Larcom Creek to Bouldercombe 275kV high capacity double circuit line
- a new (third) 275/132kV transformer at Calliope River.

As discussed in sections 2.4 and 8.3, subject to shareholding Minister approval, the Queensland SuperGrid Infrastructure Blueprint detailed a new high capacity transmission backbone to be developed in four stages which will enable renewable energy and storage across Queensland.

Stage 1 involves the delivery of a high capacity transmission line connection between Halys and Woolooga which will also connect the Borumba Pumped Hydro Energy Storage (PHES) project into the transmission network. The second stage of the SuperGrid provides a high capacity transmission line between Southern Queensland (SQ) and Central Queensland (CQ).

In July 2024 an update was made to the SuperGrid strategy for stages 1 and 2. The change to Stage 2 is to shift the original location to a more inland route. This alignment change is driven by the significant interest from renewable energy companies to develop wind farms to the west. This strategy also allows the western CQ-SQ transmission development to be built in stages and paced to align with interest for renewable connections.

The establishment of a transmission line of up to 500kV along an inland corridor between South Queensland and Central Queensland enables the first stage of the SuperGrid transmission backbone from Halys to Woolooga to be constructed at 275kV rather than 500kV.

Powerlink will commence a consultation on the Queensland SuperGrid South project as a candidate PTI under the ERTJ Act. This consultation will be undertaken to:

- ensure efficient levels to power transfer capacity between Halys and Woolooga substations and that the connection allows full operation and capacity from the Borumba PHES
- ensure the western South Queensland and Central Queensland transmission delivers efficient levels to power transfer capacity and efficiently integrates renewable energy developments to the west consistent with Powerlink meeting Queensland's renewable energy targets.

The third stage of the SuperGrid transmission backbone involves transmission connections from Townsville through to Central Queensland, enabling connection of the proposed PHES to load within the Gladstone area as well as harnessing the diverse and high quality wind resource in northern and western Queensland.

The fourth stage of the SuperGrid is the Townsville to Hughenden transmission development.

## 6.17 AEMO's 2024 Integrated System Plan

Powerlink, through the QEJP and associated modelling continues to investigate the impact of investment in large-scale VRE generation and firming generation in the Queensland region on the utilisation and economic performance of the Powerlink network. Powerlink also considers the emerging condition-based drivers and market facing proponent interest as part of the integrated planning process to ensure that overall, the most cost effective solutions are delivered for customers. Through joint planning processes with AEMO the outcomes from this work are taken as inputs into the analysis for the ISP.

[40] Refer to PTI Gladstone project.

The 2024 ISP published by AEMO in June 2024 provides a strategic view of the efficient development of the NEM transmission network to 2050. It reinforced that to deliver low-cost, secure and reliable energy, investments in transmission are needed. It identified three projects in Queensland as requiring action prior to the release of the 2026 ISP. These projects include:

- Gladstone Grid Reinforcement (now referred to as the Gladstone Project)
- Queensland SuperGrid South
- QNI Connect.

As identified in sections 2.4 and 6.16, Powerlink had already identified the need for the first two projects. These projects will progress under the candidate PTI framework (refer to Section 6.16).

QNI Connect requires the publication of a PADR by 25 June 2026.

Powerlink will continue to work closely with AEMO to inform the development of future ISPs and ensure continuing alignment of development pathways as updates to the Blueprint are released and renewable energy development continues in Queensland.

### 6.17.1 Gladstone grid section reinforcement

The 2024 ISP also identified that the transmission network which supplies the Gladstone area will not be adequate to maintain the required reliability of supply to customers in the Gladstone zone as the generation mix transitions away from coal. If major industrial loads are electrified, or if large hydrogen projects progress, there will be a further material shift in the supply demand balance in the Gladstone area requiring further investment.

Specifically, under the Step Change scenario forecast, the 2024 ISP identified a need to upgrade the transmission capacity from Calvale and Bouldercombe substations into the Gladstone zone and also increase the 275/132kV transformation capacity in the Gladstone zone by 2030-31.

AEMO has declared this as an actionable Queensland project. AEMO's assessment is fully aligned with the need identified by Powerlink. The required timing for these transmission reinforcements is however subject to when the supply and demand balance changes in the Gladstone zone.

### 6.17.2 CQ-SQ grid section reinforcement

The Borumba Pumped Hydro Energy Storage (PHES) scheme was classified as an anticipated project for the 2024 ISP. The subsequent modelling confirmed the Borumba PHES and connecting network in the optimal development path (ODP). The 2024 ISP connected the Borumba PHES into the transmission system via a 500kV double circuit line from Halys Substation, through Borumba to Woolooga Substation and then to a new substation west of Gladstone. This 500kV transmission was consistent with Stage 1 and Stage 2 of the 2022 Queensland Energy and Jobs Plan (QEJP) and Infrastructure Blueprint (refer to Figure 2.4). AEMO referred to this connection of Borumba PHES and connection to the Gladstone area as the Queensland SuperGrid South (QEJP Stage 2) project.

As with the SuperGrid Blueprint, AEMO also identified that the Queensland SuperGrid South project was required to increase power transfer capability of the transmission network to:

- support the expected increase in renewable generation in Central and Northern Queensland to support growing demand in Southern Queensland
- supply the large industrial loads in Central Queensland with renewable energy especially after significant amounts of coal generation in Central Queensland are decommitted or withdrawn, and
- provide the necessary infrastructure required to adequately host the large Borumba pumped hydro project.

Under AEMO's Step Change scenario the optimal timing of this project was 2031-32. AEMO has declared the Queensland SuperGrid South project this as an actionable Queensland project.

As outlined in Section 6.16 Powerlink's alignment for the SuperGrid South project will be further west to capture synergies with proponent interest to develop large-scale wind farms, together with delivering increased power transfer capacity. The change in alignment also avails a lower cost connection for the Borumba PHES at 275kV. Together this delivers greater value to customers.

These changes in detail will be captured in the 2026 ISP.

### 6.17.3 Expanding NSW-Queensland transmission transfer capacity

Increasing the capacity of interconnection between NEM regions is essential to support efficient sharing of new renewable generation, enable integration of REZs into existing networks by providing alternative flow paths for REZ generation and firming support between NEM regions. Appropriate intra-regional transmission capacity is required to support these objectives.

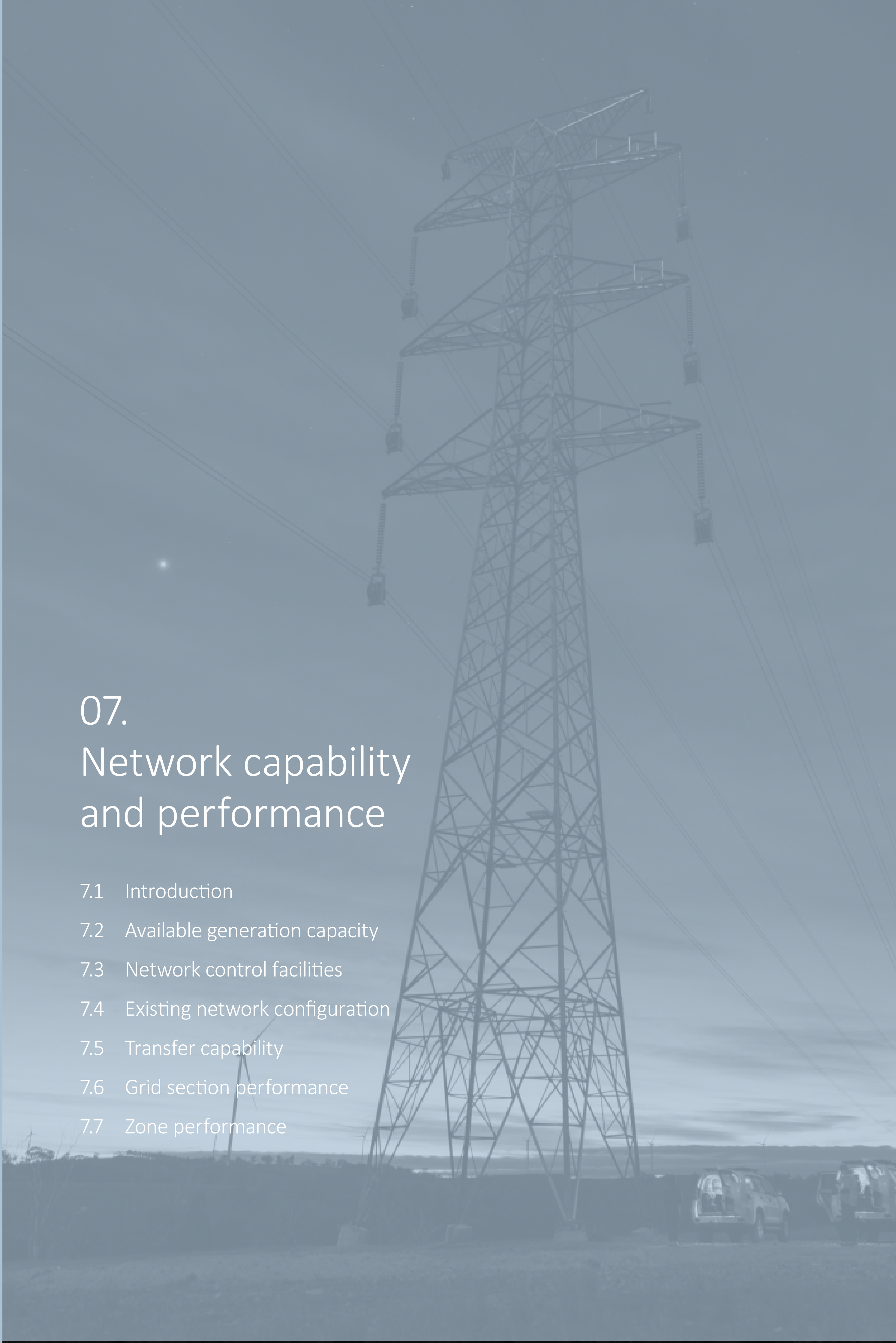
The 2024 ISP identified that further upgrade of the transmission capacity between Queensland and NSW (coined 'QNI Connect') is an integral part of the optimal development plan with a timing of 2034-35 across all three scenario forecasts.

Given the complexity in engagement and delivery of this project AEMO has declared this as an actionable ISP project. Powerlink and Transgrid are the proponents for this RIT-T. The PADR must be published by 25 June 2026.

Consistent with this recommendation the 2024 ISP has called for submissions on non-network options for this project with the potential to satisfy, or contribute to satisfying, the identified need. The process is that AEMO will provide all submissions to the Powerlink and Transgrid for consideration in the PADR.

The PADR will consider the following possible network solutions:

- Construct a 330kV single circuit between Powerlink's Bulli Creek Substation and follow the existing 330kV line except traversing to the west and then south-west of Armidale to connect to the New South Wales (NSW) planned New England Central Hub Substation. The single circuit line would be switched at Transgrid's Dumaresq and the New England Central Hub Substation connecting to Transgrid's existing Armidale and Tamworth substations. The proposed route traverses the New England REZ (within AEMO's North West NSW) and Darling Downs REZs.
- A variation to the option above is to connect the 330kV single circuit line from Powerlink's Braemar Substation and then to the NSW border (via Bulli Creek Substation) and beyond as per the option above.
- Construct a 330kV double circuit between Powerlink's Bulli Creek Substation and follow the existing 330kV line except traversing to the west and then south-west of Armidale to connect to the New England Central Hub Substation, as per the single circuit options above.
- Construct a double circuit 500kV line between Powerlink's Halys Substation and Transgrid's New England Hub Substation and connecting at 330kV to Transgrid's Dumaresq Substation with associated supporting plant.



# 07. Network capability and performance

*This chapter discusses the evolving generation mix and demand profiles and how these changes impact the power flows across the transmission network.*

## Key highlights

- Generation commitments since the 2023 Transmission Annual Planning Report (TAPR) add 1,930MW to Queensland's semi-scheduled variable renewable energy (VRE) generation capacity taking the total existing and committed semi-scheduled VRE generation capacity to 7,260MW.
- Storage commitments since the 2023 TAPR add 755MW of two hour Battery Energy Storage Systems (BESS).
- Record maximum transmission delivered demands were experienced in Far North, Wide Bay, Surat, Moreton and Gold Coast zones during 2023/24.
- Record minimum transmission delivered demands were recorded in Far North, North, South West, Moreton and Gold Coast zones during 2023/24.
- The transmission network has performed reliably during 2023/24, with Queensland grid sections largely unconstrained.

# 7.1 Introduction

This chapter on network capability and performance provides:

- an outline of existing and committed generation capacity over the next three years
- a summary of network control facilities configured to disconnect load as a consequence of non-credible events
- single line diagrams of the existing high voltage (HV) network configuration
- background on factors that influence network capability
- zonal energy transfers for the two most recent years
- historical constraint times and power flow duration curves at key sections of Powerlink Queensland's transmission network
- a qualitative explanation of factors affecting power transfer capability at key sections of Powerlink's transmission network
- historical constraint times and load duration curves at key zones of Powerlink's transmission network
- double circuit transmission lines categorised as vulnerable by the Australian Energy Market Operator (AEMO).

The capability of Powerlink's transmission network to meet forecast demand is dependent on a number of factors. Queensland's transmission network is predominantly utilised more during summer than winter. During higher summer temperatures transmission plant has lower power carrying capability which is also when demand is higher as shown in Figure 3.14.

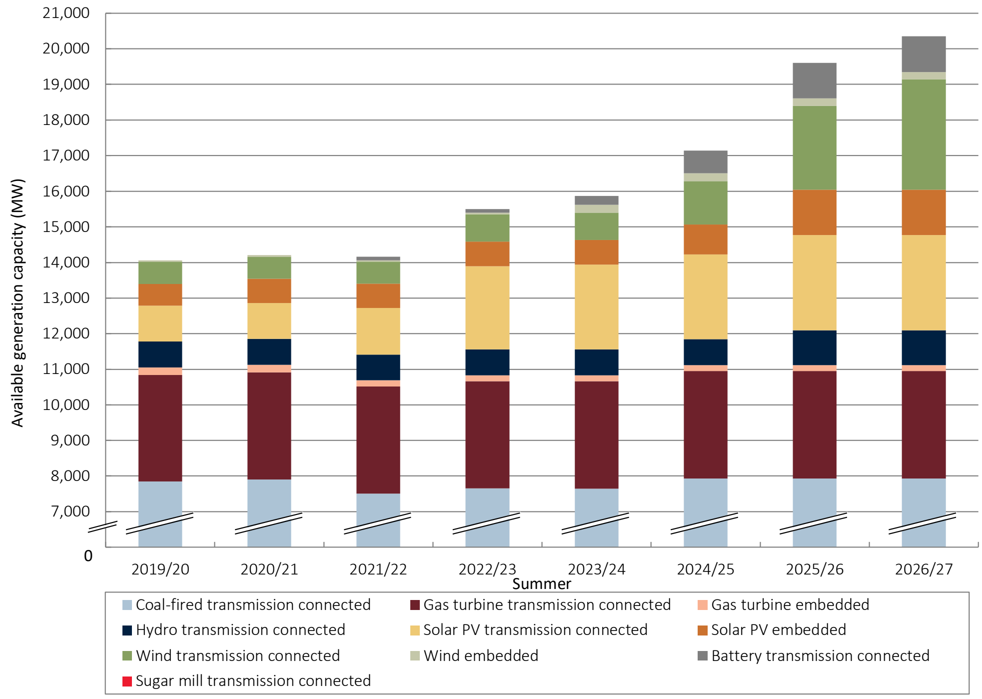
The location and pattern of generation dispatch influences power flows across the Queensland network. Future generation dispatch patterns and interconnector flows are uncertain in the deregulated electricity market and will vary substantially due to output of VRE generation and because of planned or unplanned outages of generation plant. Power flows can also vary substantially with planned or unplanned outages of transmission network elements. Power flows may also be higher at times of local area or zone maximum demands (refer to Table 3.17) and/or when embedded generation output is lower.

# 7.2 Available generation capacity

Scheduled generation in Queensland is predominantly a combination of coal-fired, gas turbine and hydro-electric generators with an increasing share coming from battery and pumped hydro energy storage systems. Semi-scheduled generation in Queensland is a combination of wind and solar generation.

AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines[1] (effective 28 June 2024) has been adopted for the purposes of this year's TAPR. During 2023/24, commitments have added 1,930MW of semi-scheduled VRE capacity, taking Queensland's semi-scheduled VRE generation capacity to 7,260MW. In addition to this, 755MW of BESS capacity has been committed, taking the total BESS capacity to 1,005MW. In August 2024, Callide C3 and C4 units began the recommissioning process following long-term outages, bringing an additional 868MW of coal-fired generating capacity back online. Figure 7.1 illustrates the expected changes to available and committed large-scale generation capacity in Queensland from summer 2019/20 to summer 2026/27.

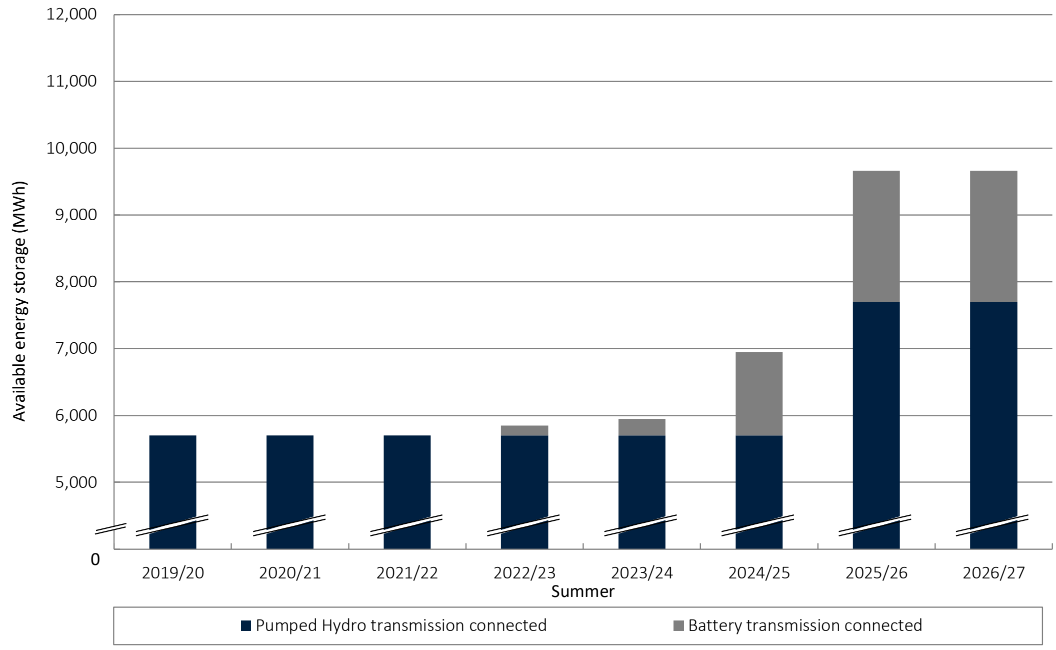
Figure 7.1 Summer available generation capacity by energy source




Storage is an essential component to enable the energy transition. Up until two years ago, Wivenhoe Pumped Storage Hydroelectric Power Station was the only transmission connected energy storage in Queensland. However, recent years have seen the rapid roll out of BESS across the National Electricity Market (NEM). In Queensland, Wandoan, Bouldercombe, Chinchilla and Western Downs batteries are online or in commissioning with others committed. Additionally, the Kidston pumped hydro station is committed and under construction and various pumped hydro stations are in the development pipeline. Figure 7.2 shows the recent increases in energy storage capacity and the new capacity that will be available in the coming years based on project commitments.

1 AEMO, System Strength Impact Assessment Guidelines, June 2024.

Figure 7.2 Available storage capacity by type




### 7.2.1 Existing and committed transmission connected and direct connect embedded generation

Table 7.1 summarises the available generation capacity of power stations connected or committed to be connected to Powerlink's transmission network (including the non-scheduled generators at Yarwun, Invicta and Koombooloomba) or to Powerlink's direct connect customers.

Semi-scheduled transmission connected MacIntyre Wind Farm, Lotus Creek Wind Farm, Broadsound Solar Farm, Boulder Creek Wind Farm and Wambo 2 Wind Farm have reached committed status since the 2023 TAPR.

Scheduled transmission connected Greenbank, Ulinda Park, Woolooga and Western Downs BESS have reached committed status since the 2023 TAPR.

Information in this table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website. In accordance with Clause 5.18A of the National Electricity Rules (NER), Powerlink's Register of Large Generator Connections with information on generators connected to Powerlink's network can be found on Powerlink's website.

Table 7.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers

| Generator | Location | Available capacity MW generated (1) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Summer 2024/25 | Winter 2025 | Summer 2025/26 | Winter 2026 | Summer 2026/27 | Winter 2027 |
| Coal-fired | | | | | | | |
| Stanwell | Stanwell | 1,460 | 1,460 | 1,460 | 1,460 | 1,460 | 1,460 |
| Gladstone | Calliope River | 1,680 | 1,680 | 1,680 | 1,680 | 1,680 | 1,680 |
| Callide B | Calvale | 700 | 700 | 700 | 700 | 700 | 700 |
| Callide Power Plant | Calvale | 868 | 932 | 868 | 932 | 868 | 932 |
| Tarong North | Tarong | 443 | 443 | 443 | 443 | 443 | 443 |
| Tarong | Tarong | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 |
| Kogan Creek | Kogan Creek PS | 710 | 750 | 710 | 750 | 710 | 750 |
| Millmerran | Millmerran PS | 670 | 852 | 670 | 852 | 670 | 852 |
| Total coal-fired | | 7,931 | 8,217 | 7,931 | 8,217 | 7,931 | 8,217 |
| Gas turbine | | | | | | | |
| Townsville 132kV | Townsville GT PS | 150 | 165 | 150 | 165 | 150 | 165 |
| Mt Stuart | Townsville South | 387 | 400 | 387 | 400 | 387 | 400 |
| Yarwun (2) | Yarwun | 160 | 155 | 160 | 155 | 160 | 155 |
| Condamine (3) | Columboola | 139 | 144 | 139 | 144 | 139 | 144 |
| Braemar 1 | Braemar | 501 | 543 | 501 | 543 | 501 | 543 |
| Braemar 2 | Braemar | 480 | 519 | 480 | 519 | 480 | 519 |
| Darling Downs | Braemar | 563 | 630 | 563 | 630 | 563 | 630 |
| Oakey (4) | Tangkam | 288 | 346 | 288 | 346 | 288 | 346 |
| Swanbank E | Swanbank E PS | 350 | 365 | 350 | 365 | 350 | 365 |
| Total gas turbine | | 3,018 | 3,267 | 3,018 | 3,267 | 3,018 | 3,267 |
| Hydro-electric | | | | | | | |
| Barron Gorge | Kamerunga | 66 | 66 | 66 | 66 | 66 | 66 |
| Kareeya (including Koombooloomba) (5) | Chalumbin | 93 | 93 | 93 | 93 | 93 | 93 |
| Wivenhoe (6) | Mt. England | 570 | 570 | 570 | 570 | 570 | 570 |
| Kidston Pumped Hydro Storage (6) | Kidston | | | 250 | 250 | 250 | 250 |
| Total hydro-electric | | 729 | 729 | 979 | 979 | 979 | 979 |
| Solar PV (7) | | | | | | | |
| Ross River | Ross | 116 | 116 | 116 | 116 | 116 | 116 |
| Sun Metals (3) | Townsville Zinc | 121 | 121 | 121 | 121 | 121 | 121 |
| Haughton | Haughton River | 100 | 100 | 100 | 100 | 100 | 100 |
| Clare | Clare South | 100 | 100 | 100 | 100 | 100 | 100 |

Table 7.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers *(continued)*

| Generator | Location | Available capacity MW generated (1) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Summer 2024/25 | Winter 2025 | Summer 2025/26 | Winter 2026 | Summer 2026/27 | Winter 2027 |
| Whitsunday | Strathmore | 57 | 57 | 57 | 57 | 57 | 57 |
| Hamilton | Strathmore | 57 | 57 | 57 | 57 | 57 | 57 |
| Daydream | Strathmore | 150 | 150 | 150 | 150 | 150 | 150 |
| Hayman | Strathmore | 50 | 50 | 50 | 50 | 50 | 50 |
| Rugby Run | Moranbah | 65 | 65 | 65 | 65 | 65 | 65 |
| Broadsound | Broadsound | | | 296 | 296 | 296 | 296 |
| Lilyvale | Lilyvale | 100 | 100 | 100 | 100 | 100 | 100 |
| Moura | Moura | 82 | 82 | 82 | 82 | 82 | 82 |
| Woolooga Energy Park | Woolooga | 176 | 176 | 176 | 176 | 176 | 176 |
| Blue grass | Chinchilla | 148 | 148 | 148 | 148 | 148 | 148 |
| Columboola | Columboola | 162 | 162 | 162 | 162 | 162 | 162 |
| Gangarri | Wandoan South | 120 | 120 | 120 | 120 | 120 | 120 |
| Wandoan | Wandoan South | 125 | 125 | 125 | 125 | 125 | 125 |
| Edenvale Solar Park | Orana | 146 | 146 | 146 | 146 | 146 | 146 |
| Western Downs Green Power Hub | Western Downs | 400 | 400 | 400 | 400 | 400 | 400 |
| Darling Downs | Braemar | 108 | 108 | 108 | 108 | 108 | 108 |
| Total solar PV | | 2,383 | 2,383 | 2,679 | 2,679 | 2,679 | 2,679 |
| Wind (7) | | | | | | | |
| Mt Emerald | Walkamin | 180 | 180 | 180 | 180 | 180 | 180 |
| Kaban | Tumoulin | 152 | 152 | 152 | 152 | 152 | 152 |
| Lotus Creek | Glencoe | | | | | 276 | 276 |
| Clarke Creek | Broadsound | 440 | 440 | 440 | 440 | 440 | 440 |
| Boulder Creek | Muranu | | | | | 221 | 221 |
| Wambo | Halys | | 245 | 245 | 245 | 245 | 245 |
| Wambo 2 | Halys | | | | 247 | 247 | 247 |
| Coopers Gap | Coopers Gap | 440 | 440 | 440 | 440 | 440 | 440 |
| MacIntyre | Tummaville | | 890 | 890 | 890 | 890 | 890 |
| Total wind | | 1,212 | 2,347 | 2,347 | 2,594 | 3,091 | 3,091 |
| Battery (7) | | | | | | | |
| Bouldercombe 2h | Bouldercombe | 50 | 50 | 50 | 50 | 50 | 50 |
| Woolooga 2h | Woolooga | | | 200 | 200 | 200 | 200 |
| Wandoan 1.5h | Wandoan South | 100 | 100 | 100 | 100 | 100 | 100 |
| Chinchilla 2h | Western Downs | 100 | 100 | 100 | 100 | 100 | 100 |

Table 7.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers *(continued)*

| Generator | Location | Available capacity MW generated (1) Summer 2024/25 | Winter 2025 | Summer 2025/26 | Winter 2026 | Summer 2026/27 | Winter 2027 |
|---|---|---|---|---|---|---|---|
| Western Downs 2h | Western Downs | 200 | 200 | 200 | 200 | 200 | 200 |
| Ulinda Park 2h | Western Downs | | 155 | 155 | 155 | 155 | 155 |
| Greenbank 2h | Greenbank | 200 | 200 | 200 | 200 | 200 | 200 |
| Total battery | | 650 | 805 | 1,005 | 1,005 | 1,005 | 1,005 |
| Sugar mill | | | | | | | |
| Invicta (5) | Invicta Mill | 0 | 34 | 0 | 34 | 0 | 34 |
| Total sugar mill | | 0 | 34 | 0 | 34 | 0 | 34 |
| Total all stations | | 15,923 | 17,782 | 17,959 | 18,775 | 18,703 | 19,272 |

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than Power Station (PS) net sent out nominal capacity due to station auxiliary loads and step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) Yarwun is a non-scheduled generator but is required to comply with some of the obligations of a scheduled generator.

(3) Condamine and Sun Metals are direct connected embedded generators.

(4) Oakey PS is an open-cycle, dual-fuel, gas-fired PS. The generated capacity quoted is based on gas fuel operation.

(5) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(6) Wivenhoe and Kidston Pumped Hydro Storage are shown at full capacity. However, output can be limited depending on water storage levels.

(7) VRE generators and batteries are shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

### 7.2.2 Existing and committed scheduled and semi-scheduled distribution connected embedded generation

Table 7.2 summarises the available generation capacity of embedded scheduled and semi-scheduled power stations connected or committed to be connected to Queensland's distribution network.

Information in this Table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website.

Table 7.2 Available generation capacity – existing and committed scheduled or semi-scheduled generators connected to the Ergon Energy and Energex (part of the Energy Queensland Group) distribution networks

| Generator | Location | Available capacity MW generated | | | | | |
|---|---|---|---|---|---|---|---|
| | | Summer 2024/25 | Winter 2025 | Summer 2025/26 | Winter 2026 | Summer 2026/27 | Winter 2027 |
| Combustion turbine (1) | | | | | | | |
| Townsville 66kV | Townsville GT PS | 78 | 82 | 78 | 82 | 78 | 82 |
| Barcaldine | Barcaldine | 32 | 37 | 32 | 37 | 32 | 37 |
| Roma | Roma | 54 | 68 | 54 | 68 | 54 | 68 |
| Total combustion turbine | | 164 | 187 | 164 | 187 | 164 | 187 |
| Solar PV (2) | | | | | | | |
| Kidston | Kidston | 50 | 50 | 50 | 50 | 50 | 50 |
| Kennedy Energy Park | Hughenden | 15 | 15 | 15 | 15 | 15 | 15 |
| Collinsville | Collinsville North | 42 | 42 | 42 | 42 | 42 | 42 |
| Clermont | Clermont | 75 | 75 | 75 | 75 | 75 | 75 |
| Emerald | Emerald | 72 | 72 | 72 | 72 | 72 | 72 |
| Middlemount | Lilyvale | 26 | 26 | 26 | 26 | 26 | 26 |
| Bundaberg | Gin Gin | | 78 | 78 | 78 | 78 | 78 |
| Bullyard | Gin Gin | | | 97 | 97 | 97 | 97 |
| Banksia | Isis | | 60 | 60 | 60 | 60 | 60 |
| Aramara | Aramara | | 101 | 101 | 101 | 101 | 101 |
| Susan River | Maryborough | 75 | 75 | 75 | 75 | 75 | 75 |
| Childers | Isis | 56 | 56 | 56 | 56 | 56 | 56 |
| Munna Creek | Kilkivan | 120 | 120 | 120 | 120 | 120 | 120 |
| Kingaroy | Kingaroy | 40 | 40 | 40 | 40 | 40 | 40 |
| Maryrorough | Yarranlea | 27 | 27 | 27 | 27 | 27 | 27 |
| Yarranlea | Yarranlea | 103 | 103 | 103 | 103 | 103 | 103 |
| Oakey 1 | Oakey | 25 | 25 | 25 | 25 | 25 | 25 |
| Oakey 2 | Oakey | 55 | 55 | 55 | 55 | 55 | 55 |
| Warwick | Warwick | 64 | 64 | 64 | 64 | 64 | 64 |
| Gunsynd | Waggamba | | 94 | 94 | 94 | 94 | 94 |
| Total solar PV | | 845 | 1,178 | 1,275 | 1,275 | 1,275 | 1,275 |
| Wind (2) | | | | | | | |
| Kennedy Energy Park | Hughenden | 43 | 43 | 43 | 43 | 43 | 43 |
| Dulacca | Roma | 173 | 173 | 173 | 173 | 173 | 173 |
| Total wind | | 216 | 216 | 216 | 216 | 216 | 216 |
| Total all stations | | 1,225 | 1,581 | 1,655 | 1,678 | 1,655 | 1,678 |

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than PS net sent out nominal capacity due to station auxiliary loads and step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) VRE generators shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

### 7.2.3 Information of generation and storage projects yet to be committed

The information provided in tables 7.1 and 7.2 relate only to existing and committed projects in Queensland. Details of projects at earlier stages of development are available from the Queensland Government's Power plants map of Queensland or from AEMOs NEM generation maps.

## 7.3 Network control facilities

Powerlink participated in the 2024 General Power System Risk Review[2] (GPSRR), published by AEMO in July 2024.

No new recommendations were made specifically for Powerlink. However, work is continuing for the following recommendations from previous years:

- Establishment of an Over Frequency Generation Shedding (OFGS) scheme to manage over frequency if Queensland to New South Wales Interconnector (QNI) separates. AEMO and Powerlink are collaborating on the design of this scheme.
- Identification and implementation of measures to restore Under Frequency Load Shedding (UFLS).
- Review and expansion of Wide Area Monitoring, Protection and Control (WAMPAC) for the non-credible loss of both Calvale – Halys 275kV lines. The scheme will be improved to manage higher flows on the Central Queensland to South Queensland (CQ-SQ) grid section and also loss of both Columboola to Western Downs 275kV lines.
- Investigation, and if found viable, design and implementation of a special protection scheme to mitigate the risk of QNI instability and synchronous separation of Queensland following a range of non-credible contingencies.

Powerlink owns other network control facilities that minimise or reduce the consequences of multiple contingency events. Network control facilities owned by Powerlink which may disconnect load following a multiple non-credible contingency event are listed in Table 7.3.

Table 7.3 Powerlink owned network control facilities configured to disconnect load as a consequence of non-credible events during system normal conditions

| Scheme | Purpose |
|---|---|
| FNQ Under Voltage Load Shed (UVLS) scheme | Minimise risk of voltage collapse in FNQ |
| North Goonyella Under Frequency Load Shed (UFLS) relay | Raise system frequency |
| Dysart UVLS | Minimise risk of voltage collapse in Dysart area |
| Eagle Downs UVLS | Minimise risk of voltage collapse in Eagle Downs area |
| Boyne Island UFLS relay | Raise system frequency |
| Queensland UFLS inhibit scheme | Minimise risk of QNI separation for an UFLS event for moderate to high southern transfers on QNI compared to Queensland demand |
| CQ-SQ N-2 WAMPAC scheme | Minimise risk of CQ-SQ separation for a non-credible loss of the Calvale to Halys 275kV double circuit transmission line |
| Tarong UFLS relay | Raise system frequency |
| Middle Ridge UFLS relays | Raise system frequency |
| Mudgeeraba Emergency Control Scheme (ECS) | Minimise risk of voltage collapse in the Gold Coast zone |

2 AEMO, 2024 General Power System Risk Review, July 2024.

## 7.4 Existing network configuration

Figures 7.3, 7.4, 7.5 and 7.6 illustrate Powerlink's system intact network as of July 2024.

Figure 7.3 Existing HV network July 2024 – North Queensland

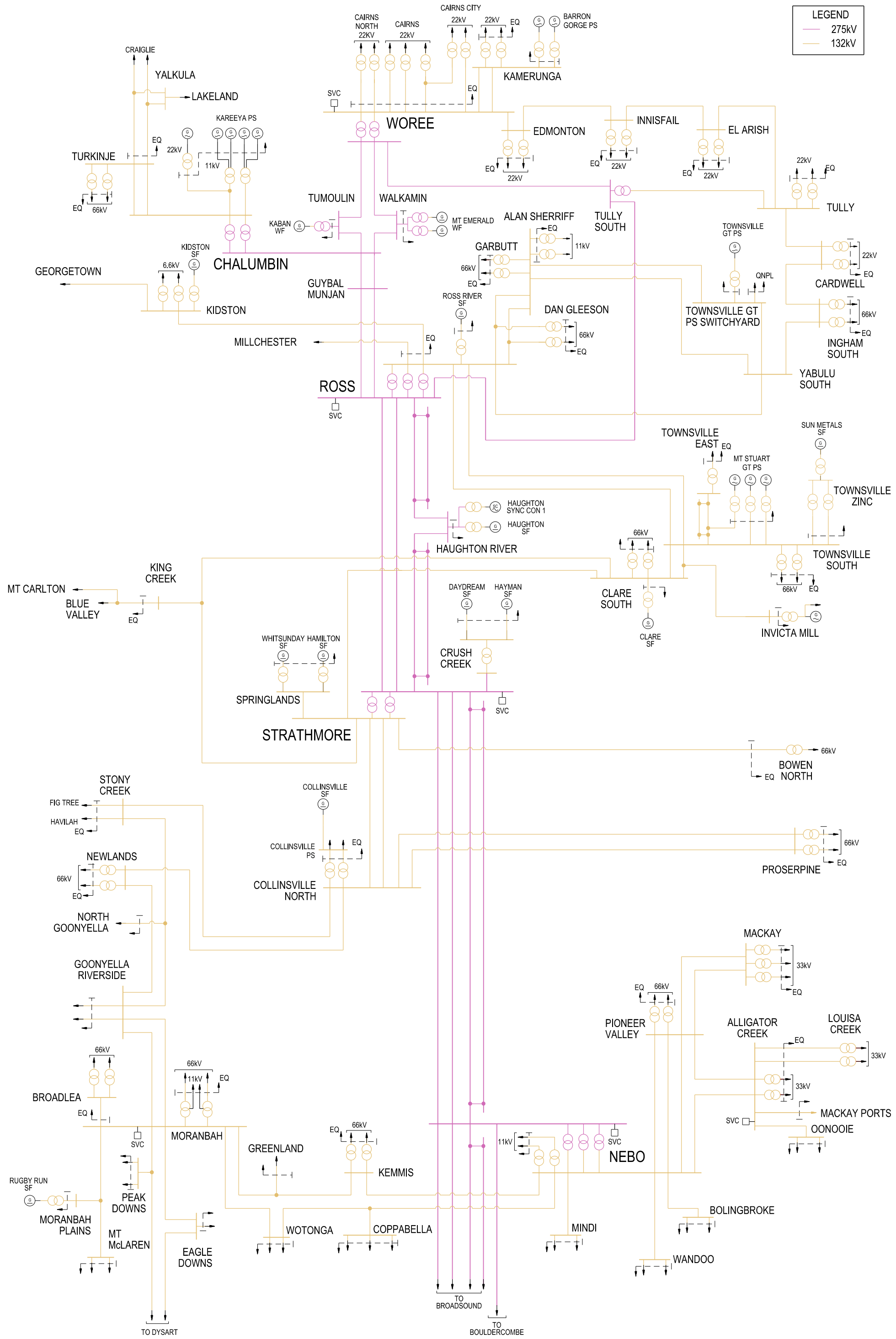


Figure 7.4 Existing HV network July 2024 – Central Queensland

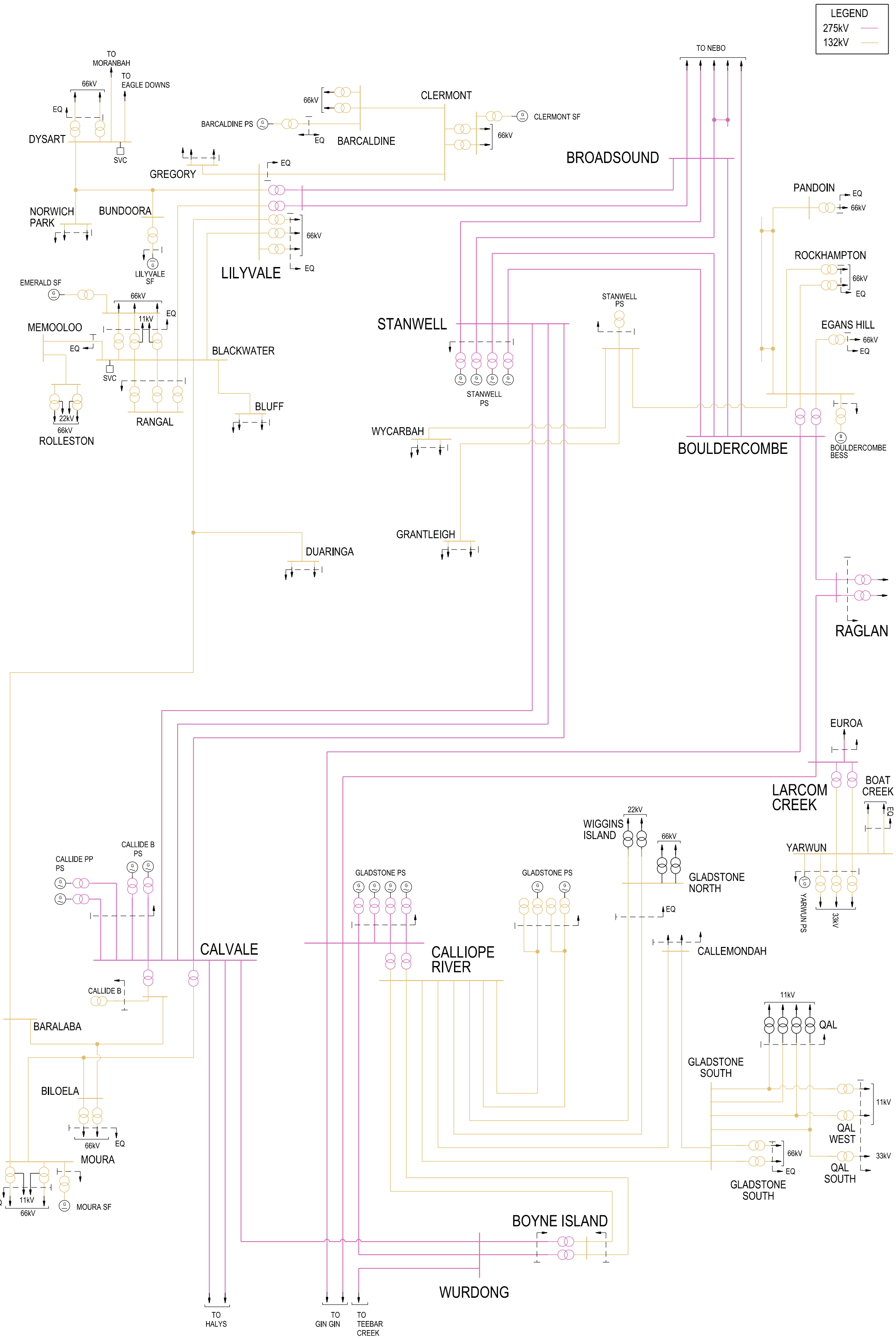


Figure 7.5 Existing HV network July 2024 - South West Queensland

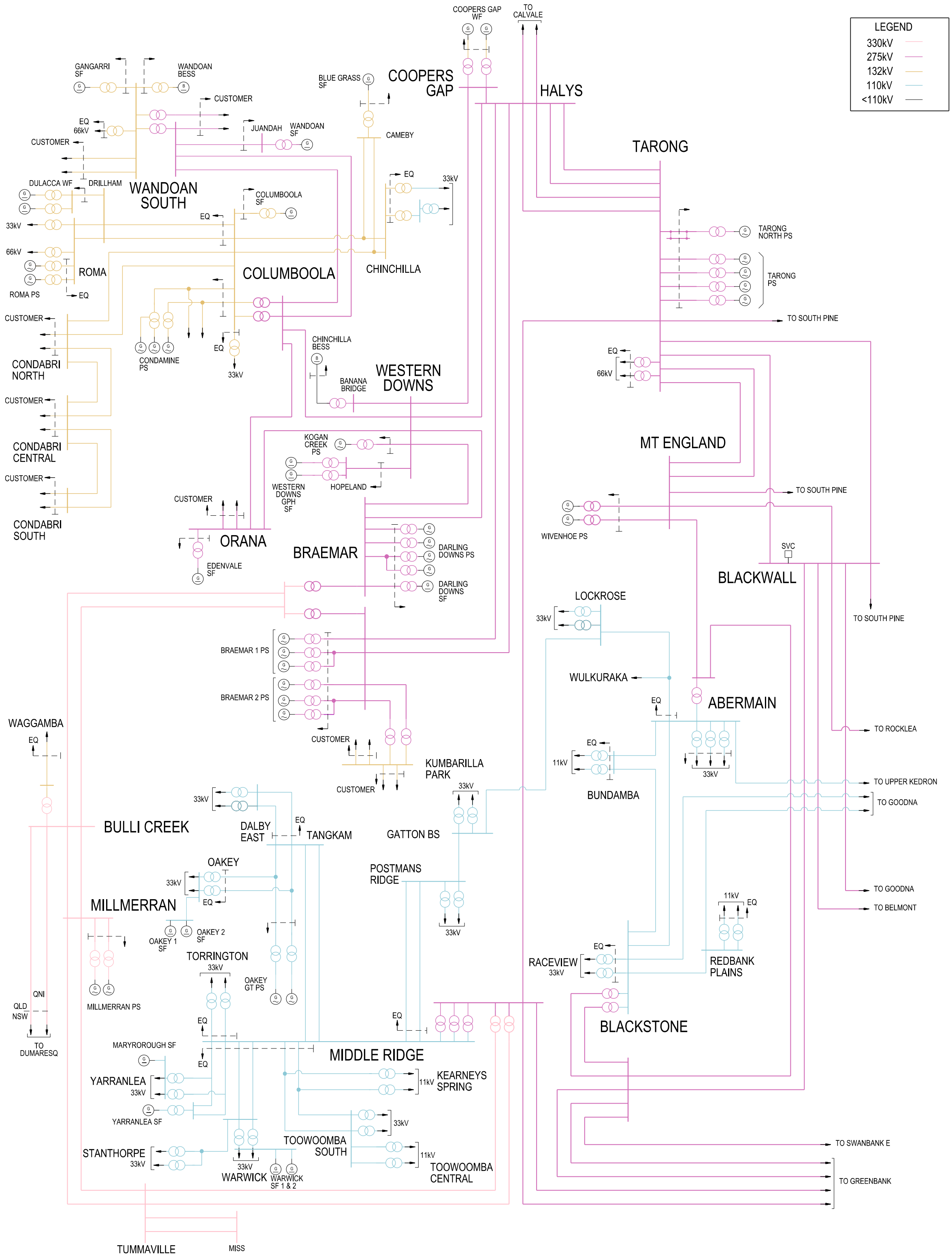
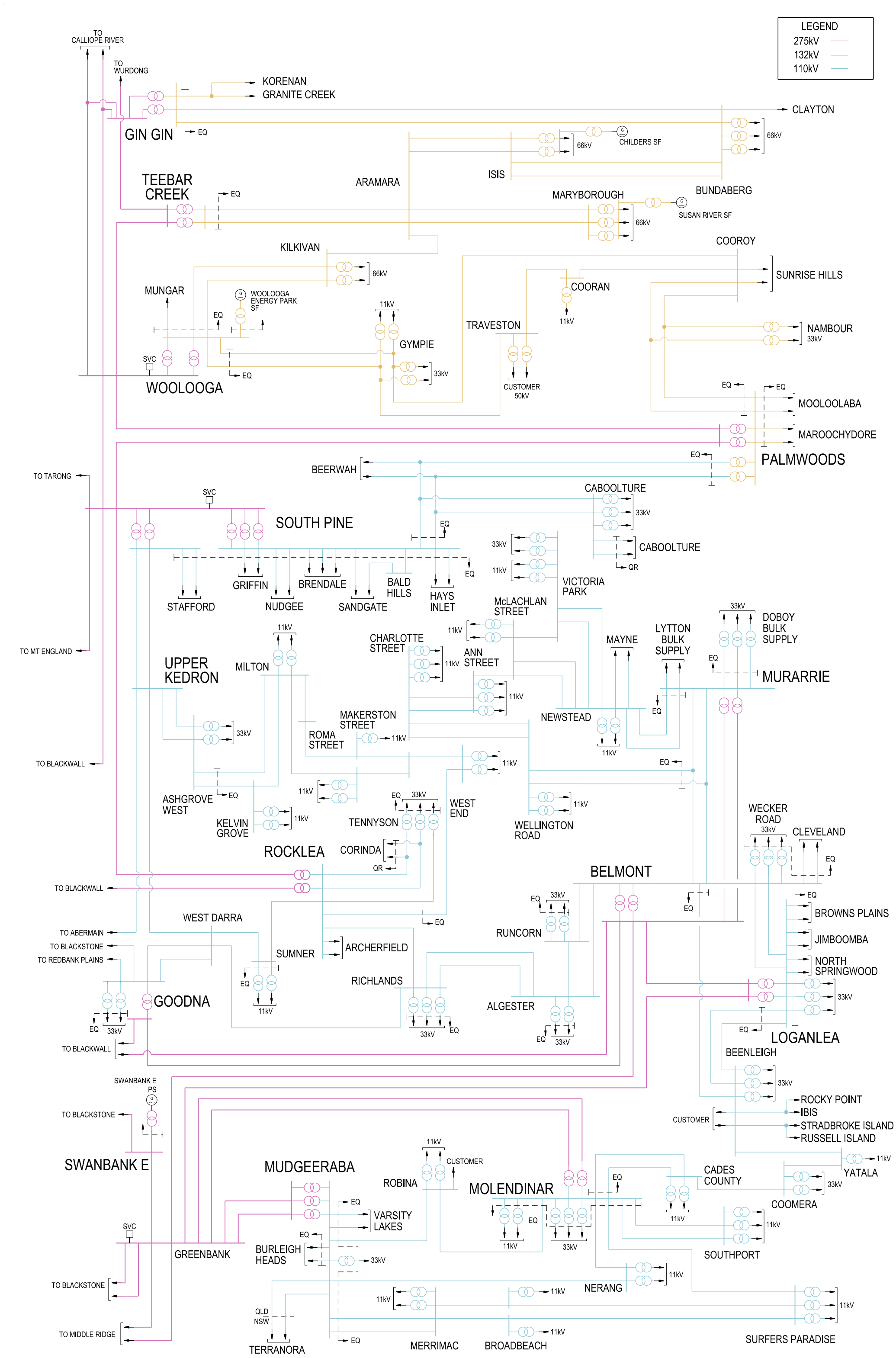


**Figure 7.6** Existing HV network July 2024 - South East Queensland



## 7.5 Transfer capability

### 7.5.1 Location of grid sections

Powerlink has identified a number of grid sections that allow the assessment of network capability and to forecast limitations in a structured manner. Maximum power transfer capability may be set by transient stability, voltage stability, thermal plant ratings or protection relay load limits. Powerlink develops and maintains limit equations for these grid sections to quantify maximum secure power transfer. AEMO then incorporates these limit equations into constraint equations within the National Electricity Market Dispatch Engine (NEMDE). Table F.2 and Figure F.1 in Appendix F define and illustrate the location of relevant grid sections on the Queensland network.

### 7.5.2 Determining transfer capability

Transfer capability across each grid section varies with different system operating conditions. Transfer limits in the National Electricity Market (NEM) are not generally amenable to definition by a single number. Instead, TNSPs define the capability of their network using multi-term equations. These equations quantify the relationship between system operating conditions and transfer capability, and are implemented into NEMDE, following AEMO's due diligence, for optimal dispatch of generation. In Queensland the transfer capability is highly dependent on which generators are inservice and their dispatch level. The limit equations maximise transmission capability available to electricity market participants under prevailing system conditions.

Limit equations derived by Powerlink are provided in Appendix G. These limit equations are current at the time of publication of this TAPR but will change over time with demand, generation and network development, and/or network reconfiguration. For example, the commissioning of the third 275kV circuit into Cairns in late 2023 triggered an update to the FNQ grid section voltage stability equation. Additionally, expected limit improvements for committed works are incorporated in all future planning. Section 7.6 includes a qualitative description of the main system conditions that affect the capability of each grid section.

## 7.6 Grid section performance

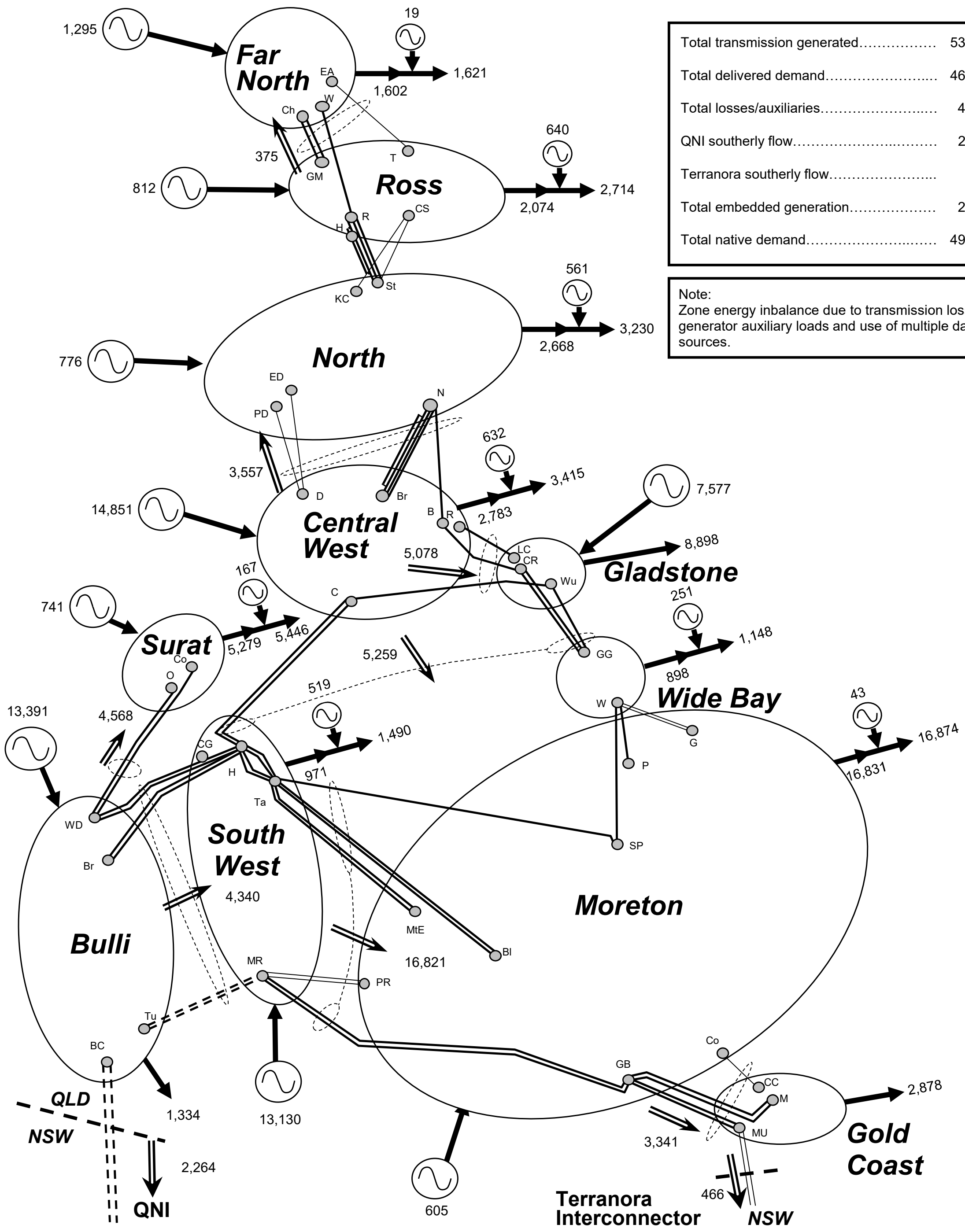
This section is a summary of the changing flows on the key grid sections of the Queensland network and the system conditions with major effects on their transfer capability.

Historical transfer duration curves for the last five years are included for each grid section. Grid section transfers are affected by load, generation and transfers to neighbouring zones. Figures 7.7 and 7.8 provide 2022/23 and 2023/24 zonal energy flows. This includes transmission connected generation, major embedded generators, transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers as well as energy transfers for each grid section. Figure 7.9 provides the changes in energy transfers from 2022/23 to 2023/24. These figures assist in the explanation of differences between grid section transfer duration curves over the last two years. A breakdown of transmission connected generation by generation type and zone is provided in Table F.3 in Appendix F.

Along with the grid section transfer duration curves, the time that the associated constraint equations have bound over the last 10 years is provided. These are categorised as occurring during intact or outage conditions based on AEMO's constraint description. Constraint times can be associated with a combination of generator unavailability, network outages, unfavourable dispatches and/or high loads. Constraint times do not include occurrences of binding constraints associated with network support agreements. Binding constraints whilst network support is dispatched are not classed as congestion. Although high constraint times may not be indicative of the cost of market impact, they serve as a trigger for the analysis of the economics for overcoming the congestion.

Binding constraint information is sourced from AEMO. Historical binding constraint information is not intended to imply a prediction of constraints in the future.

Figure 7.7 2022/23 zonal electrical energy transfers (GWh)




| | |
|---|---|
| Total transmission generated | 53,179 GWh |
| Total delivered demand | 46,214 GWh |
| Total losses/auxiliaries | 4,235 GWh |
| QNI southerly flow | 2,264 GWh |
| Terranora southerly flow | 466 GWh |
| Total embedded generation | 2,833 GWh |
| Total native demand | 49,047 GWh |

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

Figure 7.8 2023/24 zonal electrical energy transfers (GWh)

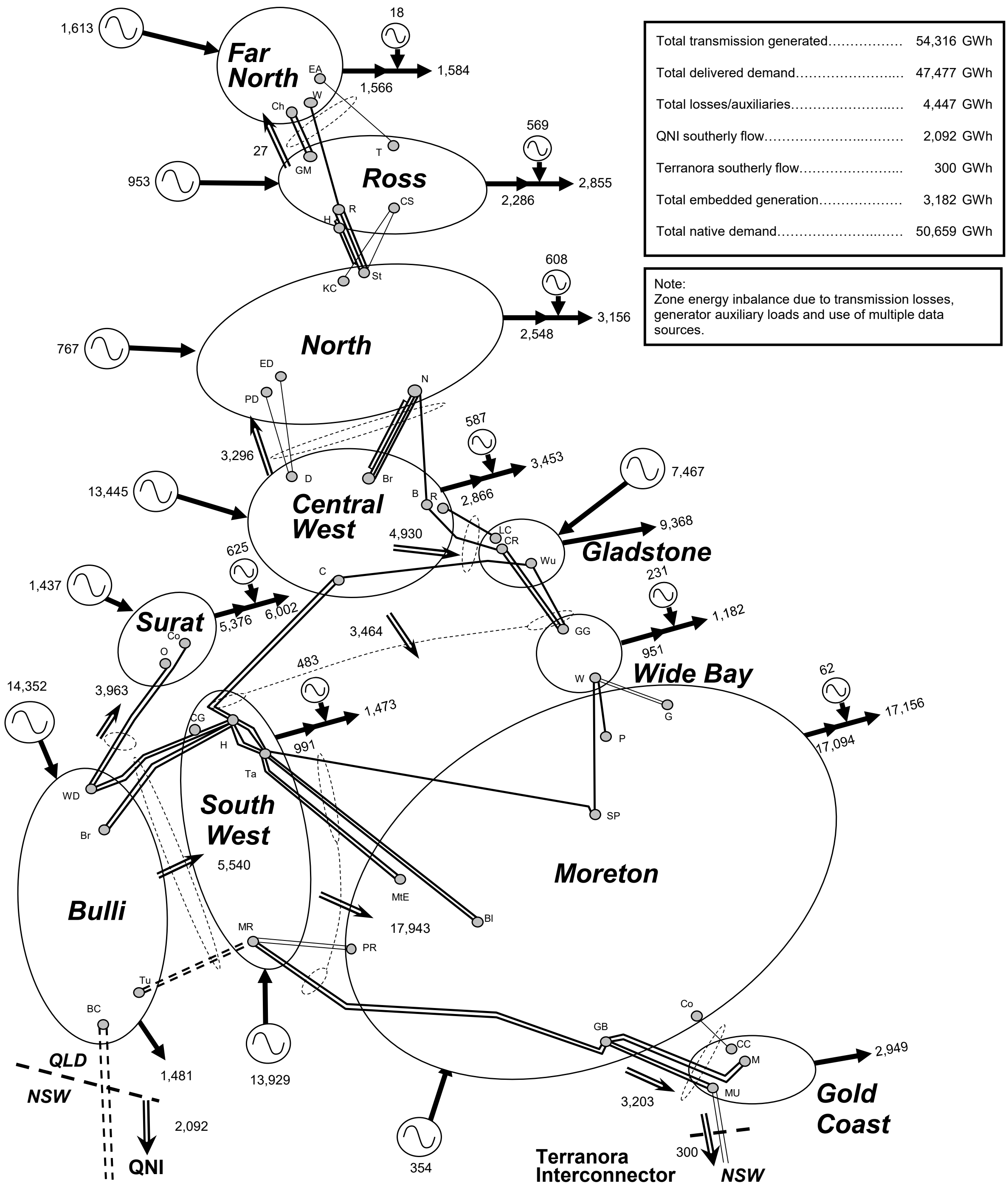
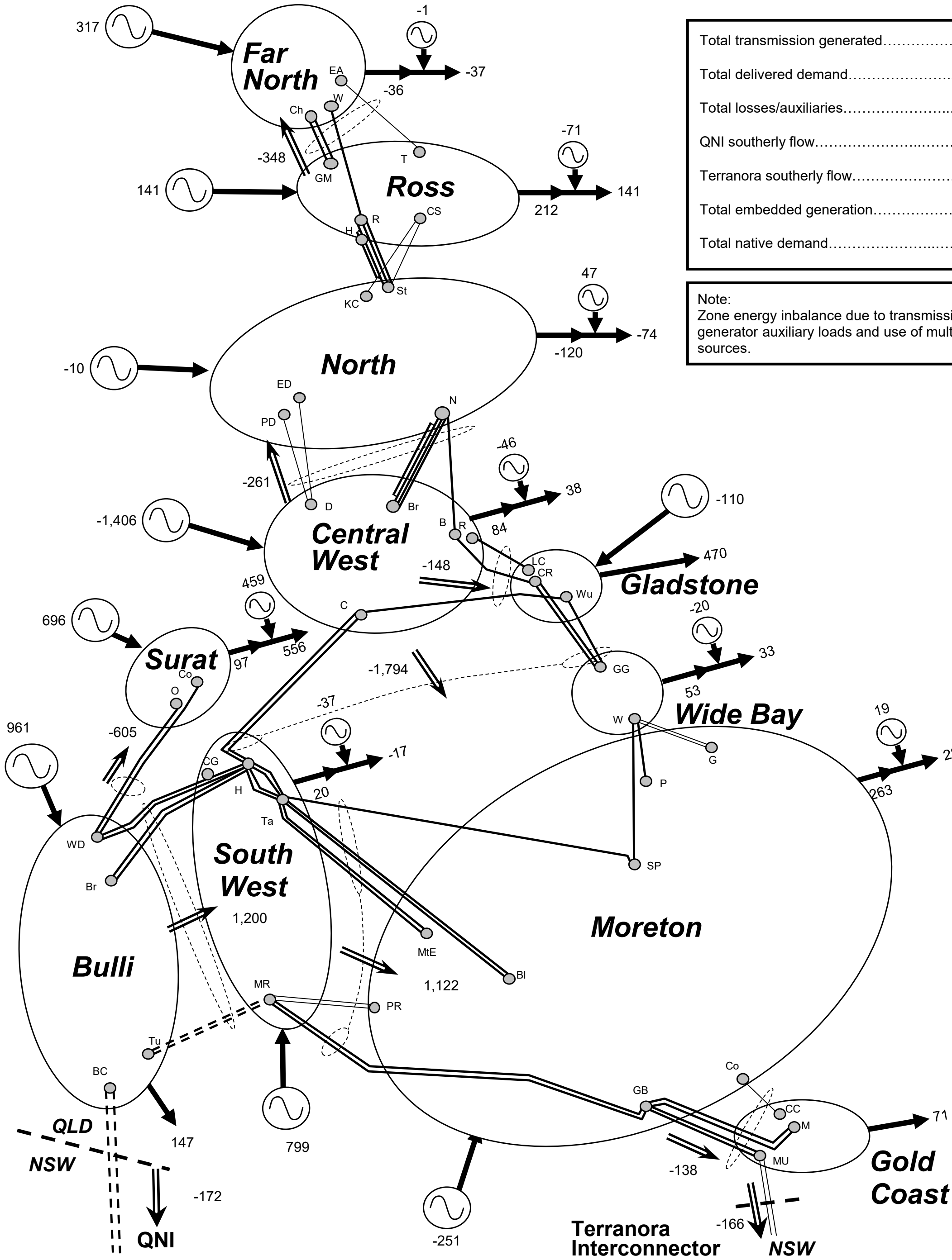


Figure 7.9 Change in zonal electrical energy transfers (GWh)




| Total transmission generated................. | 1,137 GWh |
|---|---|
| Total delivered demand......................... | 1,262 GWh |
| Total losses/auxiliaries.......................... | 213 GWh |
| QNI southerly flow................................. | -172 GWh |
| Terranora southerly flow........................ | -166 GWh |
| Total embedded generation.................. | 349 GWh |
| Total native demand............................. | 1,612 GWh |

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

### 7.6.1 Far North Queensland grid section

Maximum power transfer across the Far North Queensland (FNQ) grid section is set by voltage stability associated with an outage of the Ross to Woree tee Tully South 275kV circuit. This circuit was established by energising one side of the existing 132kV coastal double circuit transmission line at 275kV, creating a third 275kV transmission line into Woree Substation in Cairns. This augmentation is part of the Far North Queensland Renewable Energy Zone (REZ) development.

The limit equation in Table G.1 of Appendix G shows that the following variables have a significant effect on transfer capability:

- Far North zone generation
- Far North zone shunt compensation levels.

Local hydro and wind generation reduces transfer capability but allows more demand to be securely supported in the Far North zone. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The FNQ grid section was constrained for a single, five minute dispatch interval in 2023/24. The historical duration of constrained operation for the FNQ grid section is summarised in Figure 7.10.

Figure 7.10 Historical FNQ grid section constraint times

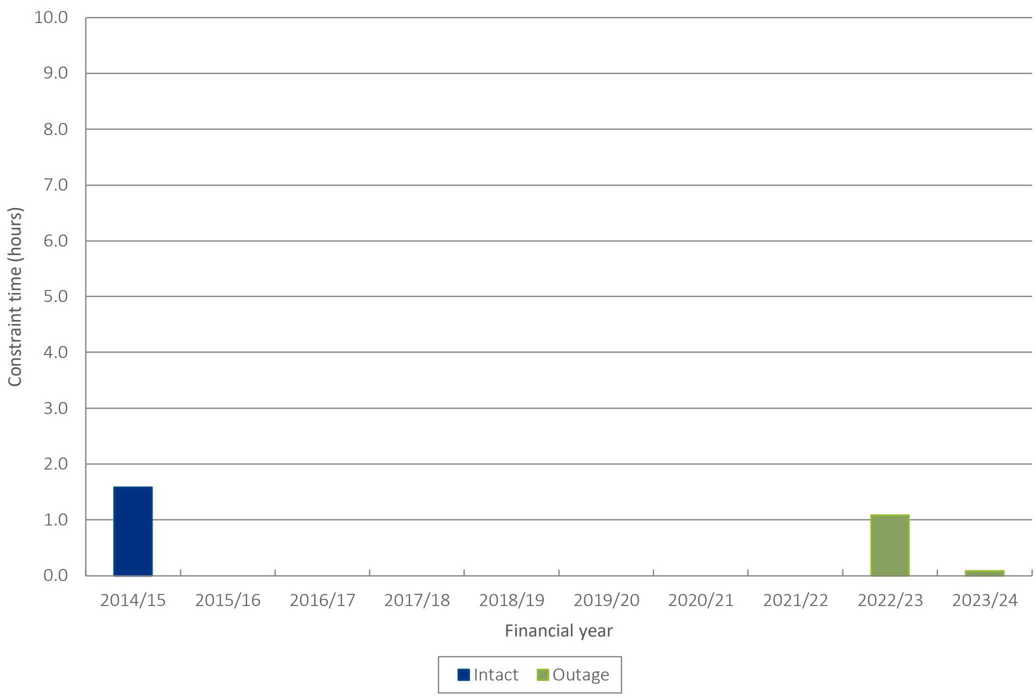
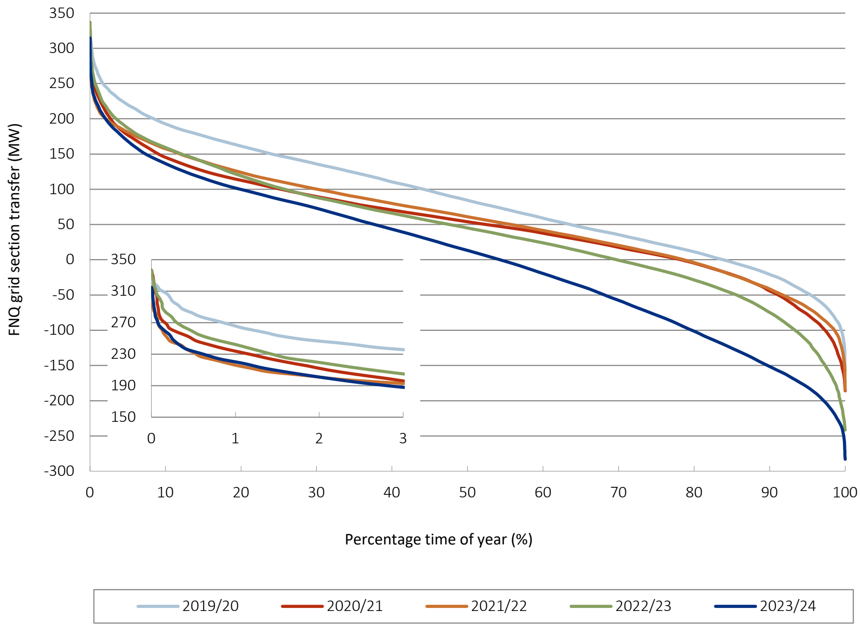


Figure 7.11 provides historical transfer duration curves showing the FNQ grid section is increasingly flowing in the southerly direction during 2023/24. This year the continued increase in the available generation in the Far North zone has resulted in a corresponding decrease in northerly delivered energy across the Far North Queensland grid section (refer to figures 7.7, 7.8 and 7.9).

Figure 7.11 Historical FNQ grid section transfer duration curves




### 7.6.2 Central Queensland to North Queensland grid section

Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations associated with the contingency of the Townsville gas turbine or a Stanwell to Broadsound 275kV circuit.

The limit equations in Table G.2 of Appendix G show that the following variables have a significant effect on transfer capability:

- level of Townsville gas turbine generation
- Ross and North zones shunt compensation levels.

The CQ-NQ grid section was unconstrained in 2023/24. The historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 7.12.

Figure 7.12 Historical CQ-NQ grid section constraint times

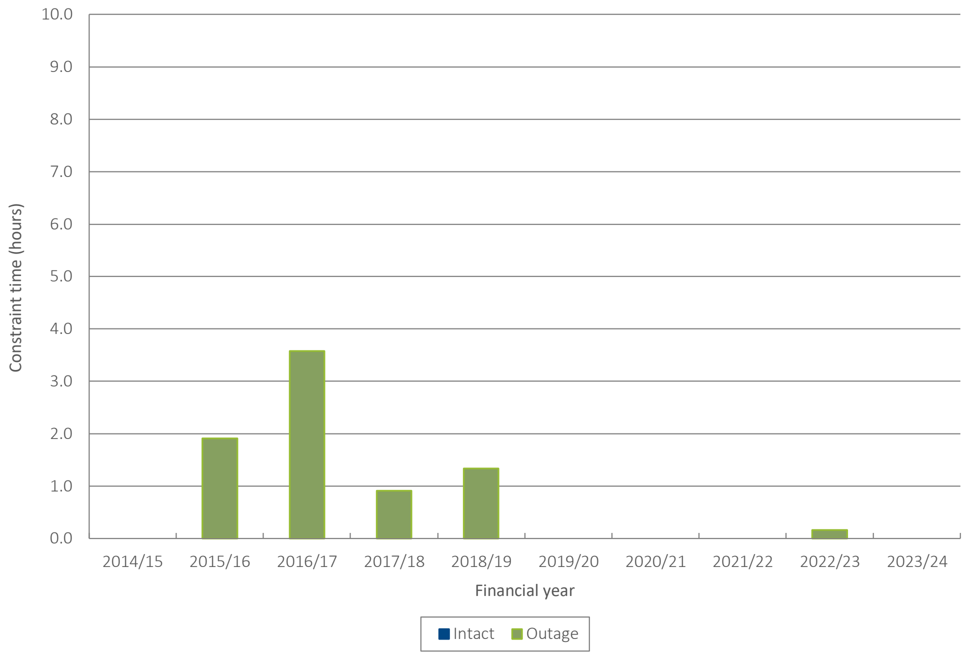



Figure 7.13 provides historical transfer duration curves showing decreases in energy transfer over recent years. This decrease is predominantly attributed to the addition of renewable generation in the Far North, Ross and North zones. Despite reductions in total energy transfer, the peak power transfer in 2023/24 is similar to previous years.

Figure 7.13 Historical CQ-NQ grid section transfer duration curves

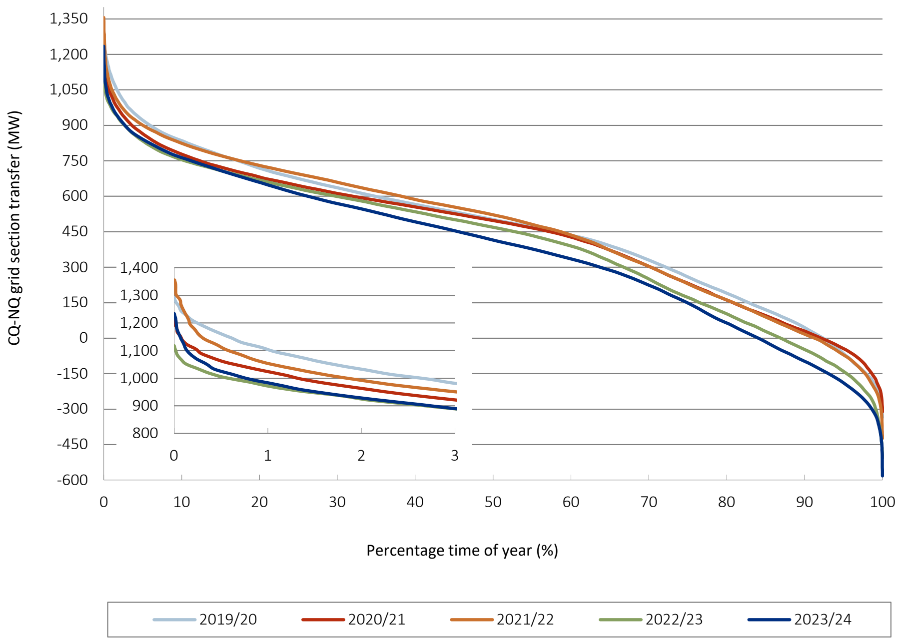
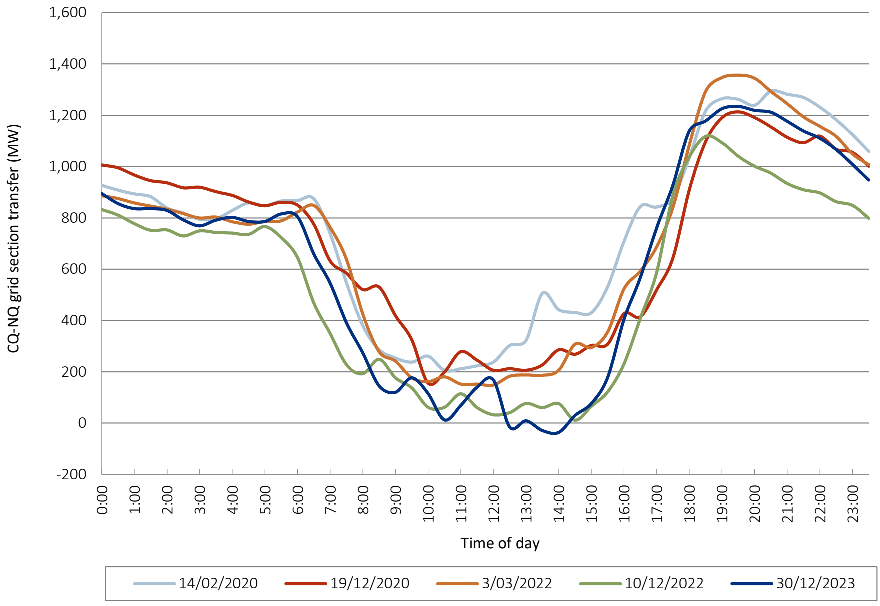


Figure 7.14 provides a different view of the altered power flows experienced over the last years for the day corresponding to the annual peak CQ-NQ transfer. This shows the impact of solar generation in creating minimum demands and network transfers during the middle of the day.

Figure 7.14 Historical CQ-NQ peak grid section transfer daily profile




These midday reductions in transfers have introduced operational challenges in voltage control. In June 2024, Powerlink commissioned a 126MVAr bus reactor at Broadsound to address these challenges.

### 7.6.3 North Queensland system strength

System strength is a measure of the ability of a power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance. System strength can be considered low in areas with low levels of synchronous generation and deteriorates further with high penetration of inverter-based resources.

Powerlink has determined that the dominant limitation to VRE hosting capacity is the potential for multiple generators, and other transmission-connected dynamic plant, to interact in an unstable manner. These dynamic plant control interactions manifest as an unstable or undamped oscillation in the power system voltage. The frequency of the oscillation is dependent on the participating plants but is broadly characterised as between 8Hz and 15Hz.

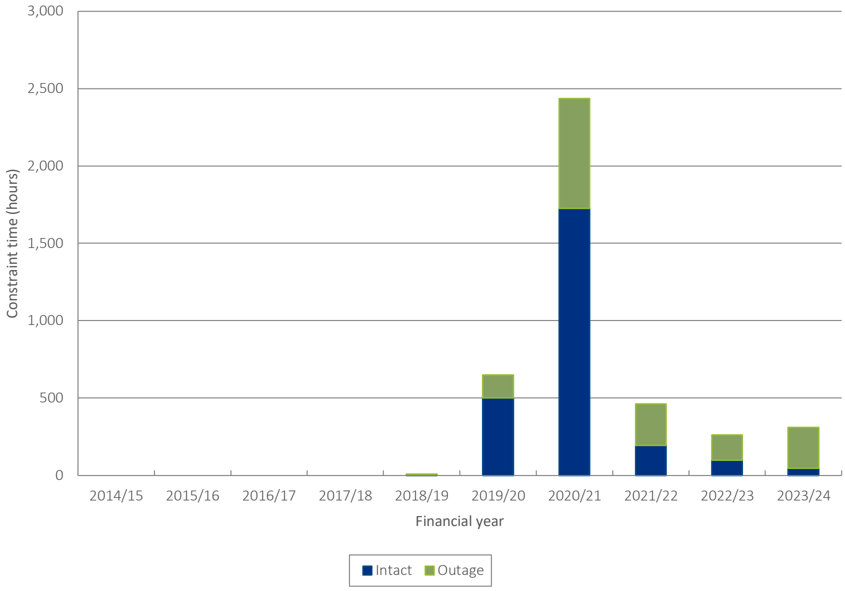
North Queensland (NQ) has been the focus of system strength limitations in Queensland due to the high number of VRE plants and relatively low synchronous fault levels. Electromagnetic Transient-type (EMT-type) analysis has been performed to determine the system conditions that could result in unstable operation of VRE plant. The limit equations in Table G.3 of Appendix G reflect the output of this analysis. The limit equations show that the following variables have a significant effect on NQ system strength:

- number of synchronous units online in CQ and NQ
- NQ demand
- status of Haughton Synchronous Condenser.

The historical duration of constrained operation for inverter-based resources in NQ is summarised in Figure 7.15. During 2023/24, inverter-based resources in NQ experienced 310 hours of constrained operation, of which 46 hours occurred during intact system conditions.

In December 2021, AEMO declared a fault level shortfall at the Gin Gin node in the Wide Bay zone. Subsequently Powerlink initiated an Expression of Interest (EOI) for services to address this fault level shortfall. Powerlink reviewed all submissions to the EOI and concluded that a non-network solution to modify the Townsville Power Station to allow it to operate in synchronous condenser mode when not generating was the least cost option. Powerlink has entered into a System Strength Services Agreement with the power station owner, Ratch Australia, to facilitate modification of the power station by mid-2025[3].

Figure 7.15 Historical NQ system strength constraint times




### 7.6.4 Gladstone grid section

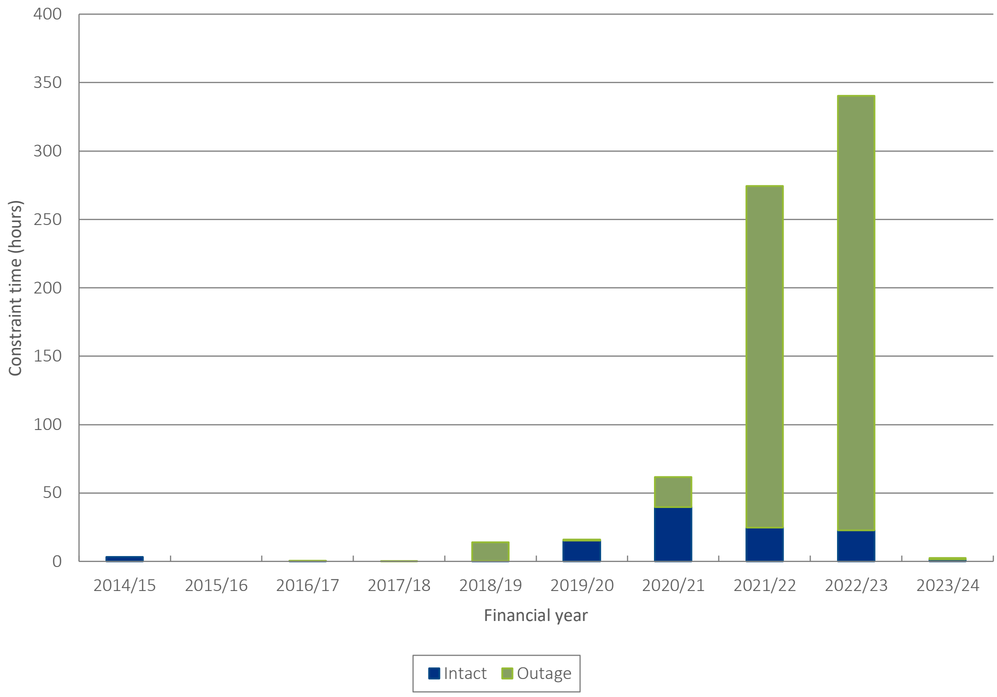
Maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits.

If the rating would otherwise be exceeded following a critical contingency, generation is constrained to reduce power transfers. Powerlink makes use of dynamic line ratings and rates the relevant circuits to take account of prevailing ambient weather conditions to maximise the available capacity of this grid section and, as a result, reduce market impacts. The appropriate ratings are updated in National Electricity Market Dispatch Engine (NEMDE).

The historical duration of constrained operation for the Gladstone grid section is summarised in Figure 7.16. During 2023/24, the Gladstone grid section experienced 3 hours of constrained operation, with 2 hours during intact system conditions.

[3] Powerlink, Request for Power System Security Services – Final Report Part 2 – System Strength at Gin Gin, January 2024.

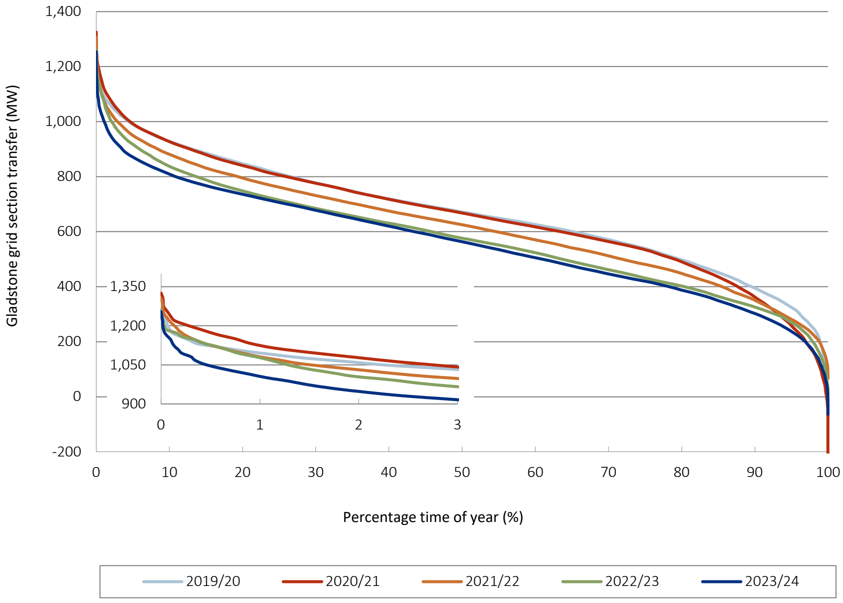
Figure 7.16 Historical Gladstone grid section constraint times




Power flows across this grid section are highly dependent on the balance of generation and demand in Gladstone and transfers to between Central Queensland (CQ) and SQ. Figure 7.17 provides historical transfer duration curves showing slightly decreased utilisation in 2023/24 compared to 2022/23. Even though demand increased and generation decreased in the Gladstone zone, this was more than offset by the decrease in CQ-SQ grid section flows resulting in lower Gladstone grid section flows (refer to figures 7.7, 7.8 and 7.9).

Powerlink has developed a strategy to increase the capacity of the Gladstone grid section as the generation and demand balance in the Gladstone zone changes with potential new loads and generation changes. The Gladstone Project has been declared a Queensland Actionable Project in AEMO's 2024 Integrated System Plan (ISP) and consultation has begun for this project to be a Priority Transmission Investment (PTI). See Section 8.2.5 for more detail.

Figure 7.17 Historical Gladstone grid section transfer duration curves




### 7.6.5 Central Queensland to Southern Queensland grid section

Maximum power transfer across the CQ-SQ grid section is set by transient or voltage stability following a Calvale to Halys 275kV circuit contingency.

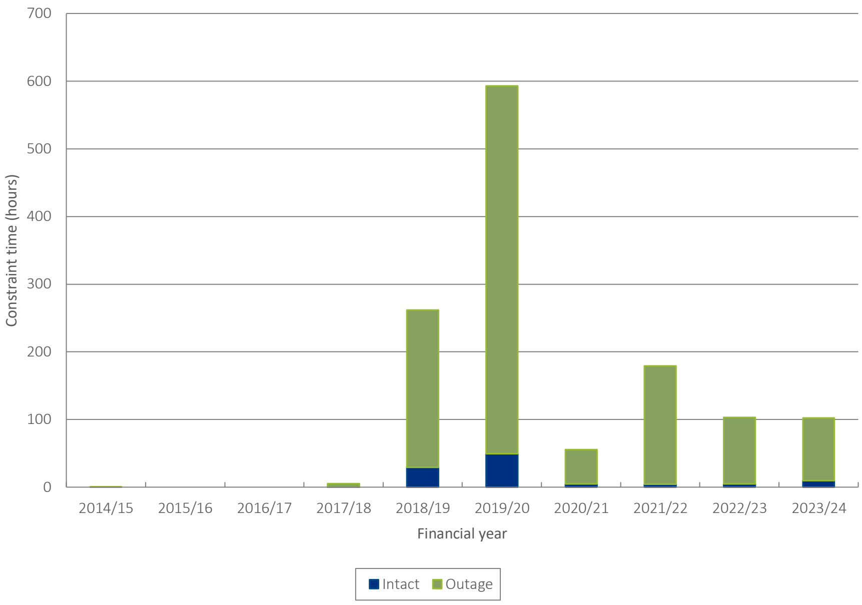
The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

The limit equation in Table G.4 of Appendix G shows that the following variables have significant effect on transfer capability:

- number of generating units online in the Central West and Gladstone zones
- level of Gladstone PS generation.

The historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 7.18. During 2023/24, the CQ-SQ grid section experienced 103 hours of constrained operation. Constrained operation was due to outages associated with planned maintenance activities. Only 10 hours of constrained operation was during intact system conditions.

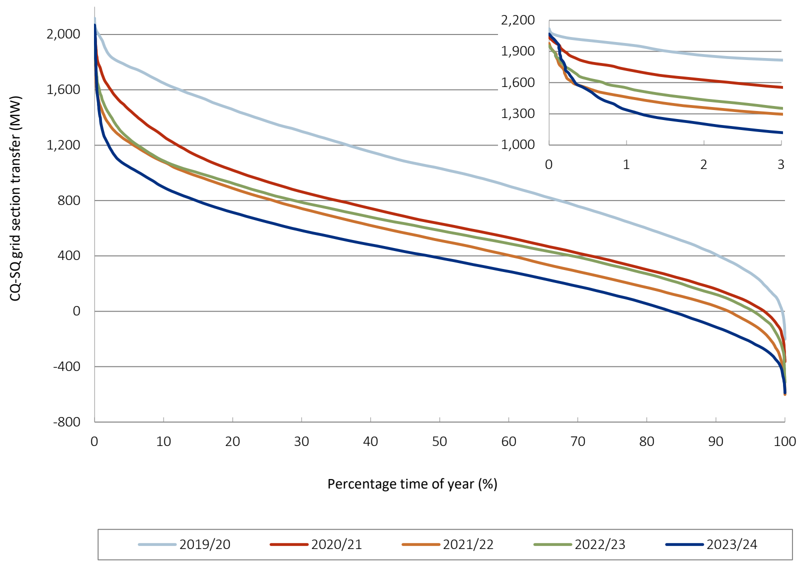
Figure 7.18 Historical CQ-SQ grid section constraint times




As discussed in Chapter 2, augmentation of the network between SQ and CQ is part of the Queensland SuperGrid. This augmentation will increase transfer limits on this grid section, support new load developments and increase the hosting capacity of renewable generation in these regions.

Figure 7.19 provides historical transfer duration curves showing the lowest transfers over the last five years. In the 2023/24 year there was a decrease in output from generation in central Queensland, but this was offset by an increase in output from generation in south Queensland (refer to figures 7.7, 7.8 and 7.9).

Figure 7.19 Historical CQ-SQ grid section transfer duration curves



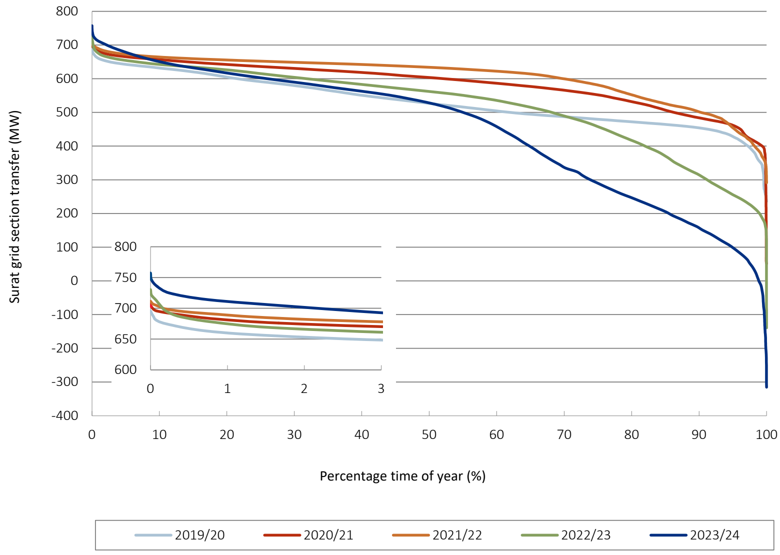

The eastern single circuit transmission lines of CQ-SQ traverse a variety of environmental conditions that have different rates of corrosion resulting in varied risk levels across the transmission lines. Depending on transmission line location, it is expected that sections of lines will be at end of technical service life from the next five to 10 years.

### 7.6.6 Surat grid section

The maximum power transfer across the Surat grid section is set by voltage stability associated with insufficient reactive power reserves in the Surat zone following an outage of a Western Downs to Orana 275kV circuit[4]. More generating units online in the zone increases reactive power support and therefore transfer capability. Local generation reduces transfer capability but allows more demand to be securely supported in the Surat zone. There have been no constraints recorded over the history of the Surat grid section.

Figure 7.20 provides the transfer duration curves for the last five years. Energy transfers have reduced in the last year due to the increased output of the solar and wind farms in the Surat zone.

Figure 7.20 Historical Surat grid section transfer duration curve




### 7.6.7 South West Queensland grid section

The South West Queensland (SWQ) grid section defines the capability of the transmission network to transfer power from generating stations located in the Bulli zone and northerly flow on QNI to the rest of Queensland. The thermal rating of the Middle Ridge 330/275kV transformer sets maximum power transfer across the SWQ grid section.

The historical duration of constrained operation for the SWQ grid section is summarised in Figure 7.21. After many years of unconstrained operation, the SWQ grid section experienced four and a half hours of constrained operation in 2023/24. Constrained operation was due to outages associated with planned maintenance activities.

[4] The Orana Substation is connected to one of the Western Downs to Columboola 275kV transmission lines (refer to Figure 7.5).

Figure 7.21 Historical South West Queensland grid section constraint times

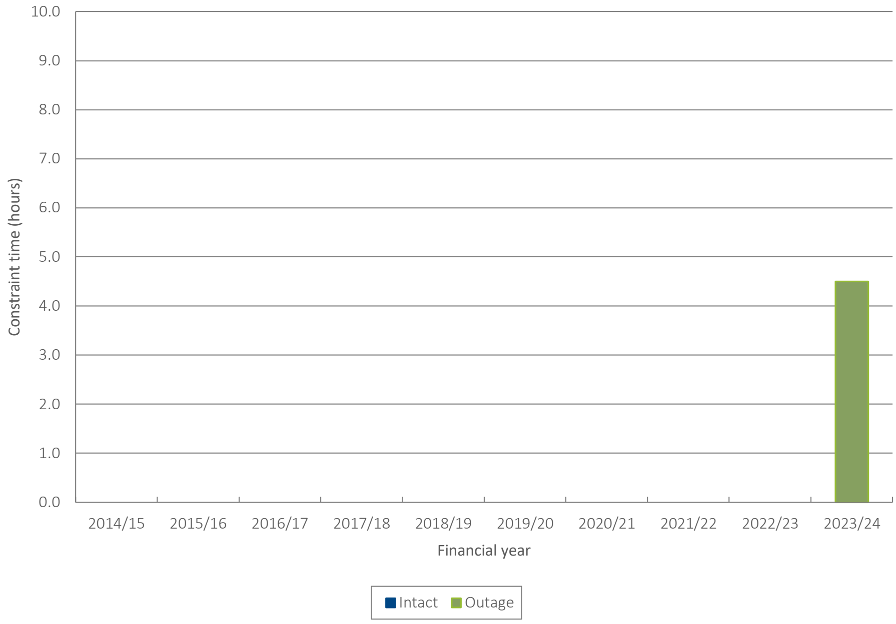
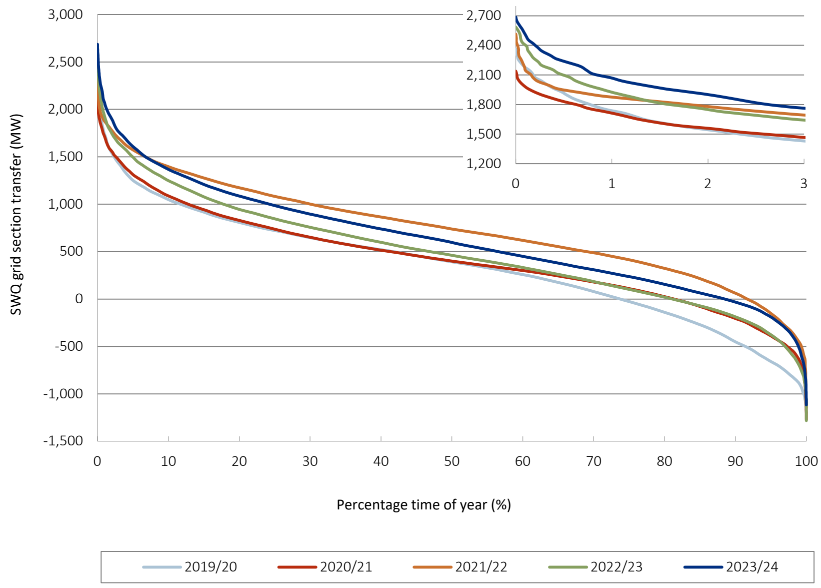



Figure 7.22 provides historical transfer duration curves for the SWQ grid section. Flows have increased compared to 2022/23 due to lower CQ-SQ flows and higher generation in the Bulli and Surat zones (refer to figures 7.7, 7.8 and 7.9).

Figure 7.22 Historical SWQ grid section transfer duration curves




AEMO's 2024 Integrated System Plan[5] (ISP) identified stage 1 of the Darling Downs REZ Expansion as a future ISP project. This project involves an upgrade to the transformer capacity at Middle Ridge Substation. However, the ISP identified that this increase in capacity would not be required before 2034/35.

### 7.6.8 Tarong grid section

Maximum power transfer across the Tarong grid section is set by voltage stability associated with the loss of a Calvale to Halys 275kV circuit or a Tarong to Blackwall 275kV circuit. The limitation arises from insufficient reactive power reserves in southern Queensland.

5 AEMO, 2024 Integrated System Plan (ISP), June 2024.

Limit equations in Table G.5 of Appendix G show that the following variables have a significant effect on transfer capability:

- QNI transfer and South West and Bulli zones generation
- level of Moreton zone generation
- Moreton and Gold Coast zones capacitive compensation levels.

Any increase in generation west of this grid section, with a corresponding reduction in generation north of the grid section, reduces the CQ-SQ power flow and increases the Tarong limit. Increasing generation east of the grid section reduces the transfer capability, but increases the overall amount of supportable South East Queensland (SEQ) demand. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The Tarong grid section was unconstrained in 2023/24. The historical duration of constrained operation for the Tarong grid section is summarised in Figure 7.23. Constraint times have been minimal over the last 10 years.

Figure 7.23 Historical Tarong grid section constraint times

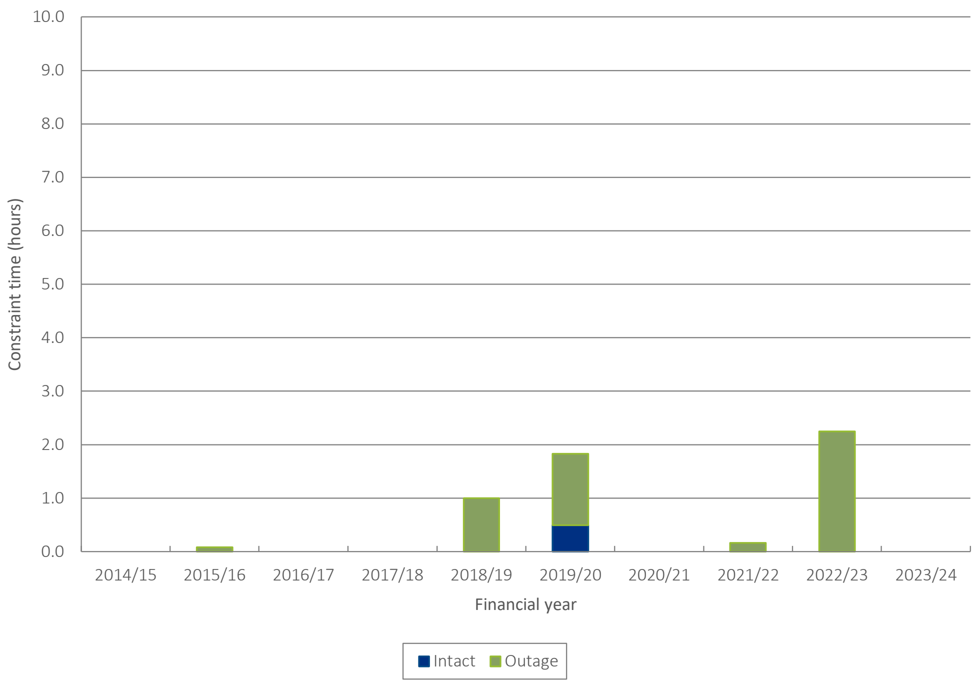
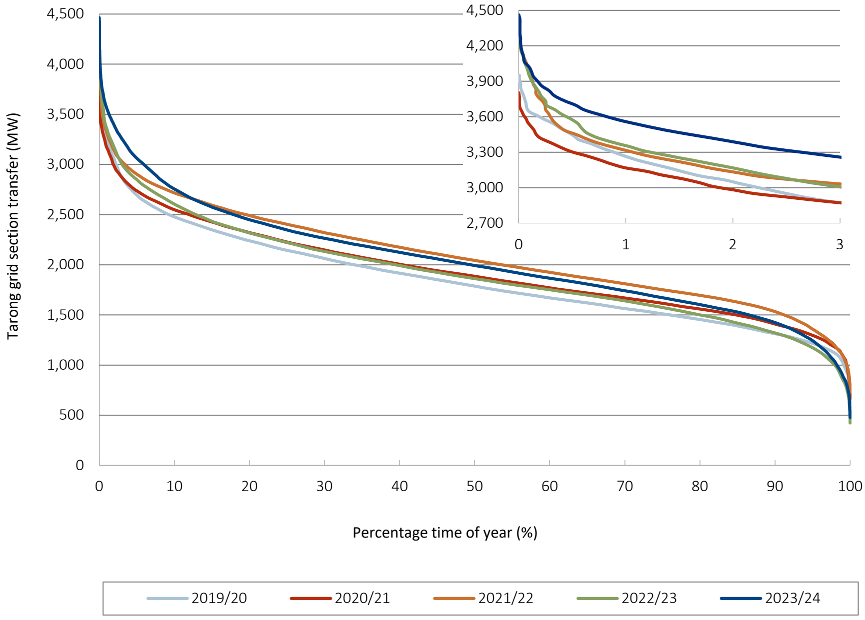



Figure 7.24 provides historical transfer duration curves for the Tarong grid section. Similar to the SWQ grid section, flows have increased compared to 2022/23 due to lower CQ-SQ flows and higher generation in the South West, Bulli and Surat zones (refer to figures 7.7, 7.8 and 7.9).

Figure 7.24 Historical Tarong grid section transfer duration curves




### 7.6.9 Gold Coast grid section

Maximum power transfer across the Gold Coast grid section is set by voltage stability associated with the loss of a Greenbank to Molendinar 275kV circuit, or a Greenbank to Mudgeeraba 275kV circuit.

The limit equation in Table G.6 of Appendix G shows that the following variables have a significant effect on transfer capability:

- number of generating units online in Moreton zone
- level of Terranora Interconnector transmission line transfer
- Moreton and Gold Coast zones capacitive compensation levels
- Moreton zone to the Gold Coast zone demand ratio.

Reducing southerly flow on Terranora Interconnector reduces transfer capability but increases the overall amount of supportable Gold Coast demand. This is because reactive margins increase with reductions in southerly Terranora Interconnector flow, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the reduction in Terranora Interconnector southerly transfer. Limiting power transfers are thereby lower with reduced Terranora Interconnector southerly transfer but a greater load can be delivered.

The historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 7.25. After many years of unconstrained operation, the Gold Coast grid section experienced 20 minutes of constrained operation in 2023/24. Constrained operation was due to outages associated with planned maintenance activities.

Figure 7.25 Historical Gold Coast Queensland grid section constraint times

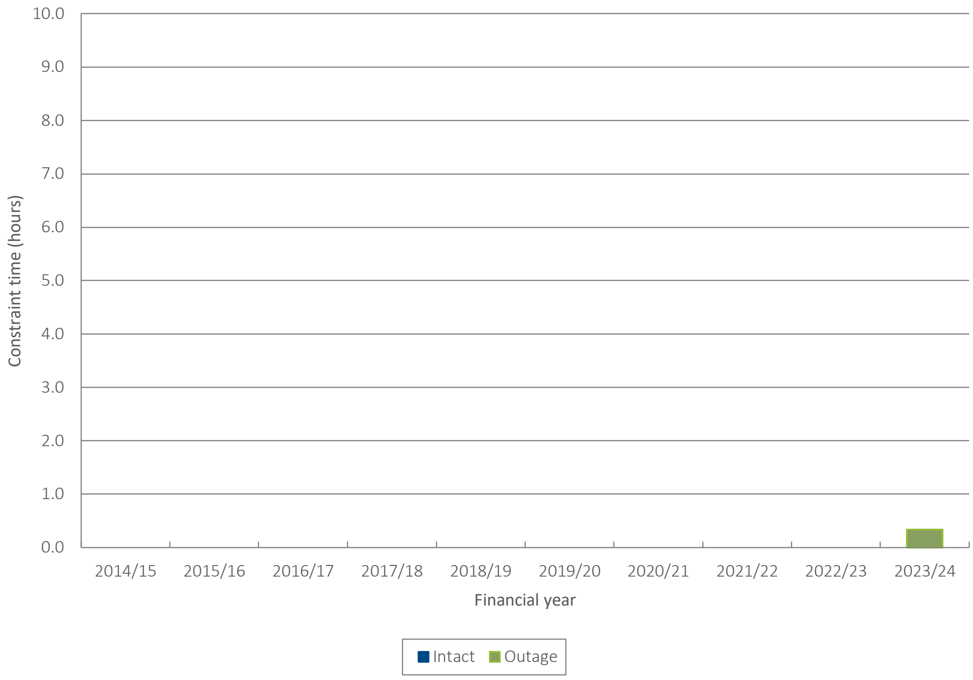
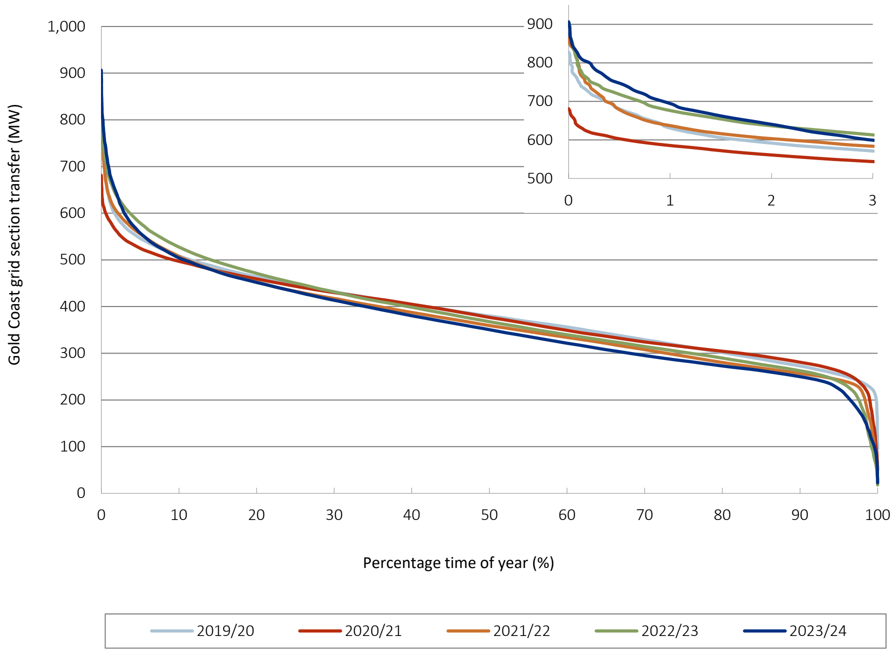



Figure 7.26 provides historical transfer duration curves showing changes in grid section transfer demands and energy in line with changes in transfer to northern NSW and changes in Gold Coast loads (refer to figures 7.7, 7.8 and 7.9).

Figure 7.26 Historical Gold Coast grid section transfer duration curves



### 7.6.10 QNI and Terranora interconnector

The transfer capability across QNI is limited by voltage stability, transient stability, oscillatory stability, and line thermal rating considerations. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

AEMO publishes Monthly Constraint Reports which includes a section examining each of the NEM interconnectors, including QNI and Terranora Interconnector. Information pertaining to the historical duration of constrained operation for QNI and Terranora Interconnector is contained in these Monthly Constraint Reports. The Monthly Constraint Report can be found on AEMO's website.

For intact system operation, the southerly transfer capability of QNI is most likely to be set by the following:

- voltage stability associated with a fault on the Sapphire to Armidale 330kV transmission line in New South Wales (NSW)
- thermal capacity of the 330kV transmission network between Dumaresq and Liddell in NSW.

For intact system operation, the combined northerly transfer capability of QNI and Terranora Interconnector is most likely to be set by the following:

- transient and voltage stability associated with transmission line faults in NSW
- transient and voltage stability associated with loss of the largest generating unit in Queensland
- thermal capacity of the 330kV and 132kV transmission network within northern NSW.

The QNI Minor project is complete and inter-network testing activities, as required by NER 5.7.7, are progressing.

AEMO's 2024 Integrated System Plan[6] (ISP) considered the QNI Connect project that would increase transfer capacity between Queensland and New South Wales. This project has been deemed an Actionable Project and Powerlink will be working with Transgrid to commence the Regulatory Investment Test for Transmission (RIT-T) process.

## 7.7 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver loads
- historical zonal transmission delivered loads
- intra-zonal system normal constraints
- double circuit transmission lines categorised as vulnerable by AEMO[7]
- Powerlink's management of high voltages associated with light load conditions.

Double circuit transmission lines that experience a lightning trip of all phases of both circuits (where its magnitude or degree is not considered an Exceptional Event[8]) are categorised by AEMO as vulnerable. A double circuit transmission line in the vulnerable list is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected close to the line. A double circuit transmission line will remain on the vulnerable list until it is demonstrated that the asset characteristics have been improved to make the likelihood of a double circuit lightning trip no longer reasonably likely to occur or until the Lightning Trip Time Window (LTTW) expires from the last double circuit lightning trip. The LTTW is three years for a single double circuit trip event or five years where multiple double circuit trip events have occurred during the LTTW.

6 AEMO, 2024 Integrated System Plan (ISP), June 2024.
7 AEMO, List of Vulnerable Transmission Lines, effective March 2024.
8 An Exceptional Event is defined in AEMO's Power System Security Guidelines (SO_OP_3715) as a simultaneous trip of a double circuit transmission line during a lightning storm caused by an event that is far beyond what is usual in magnitude or degree for what could be reasonably expected to occur during a lightning storm.

Statewide delivered energy has increase slightly from 2022/23 to 2023/24. Many zones experienced either record maximum demand or record minimum demand (both is some cases). This is a trend that has continued from recent years driven by the growth of rooftop photovoltaic (PV). As at 30 June 2024 there was 6,400MW of rooftop PV generating capacity in the state[9]. This is an increase of 817MW over the year. The following sections show load duration curves for each zone. See Figure 3.16 for annual transmission delivered demand load duration curves for the Queensland region as a whole.

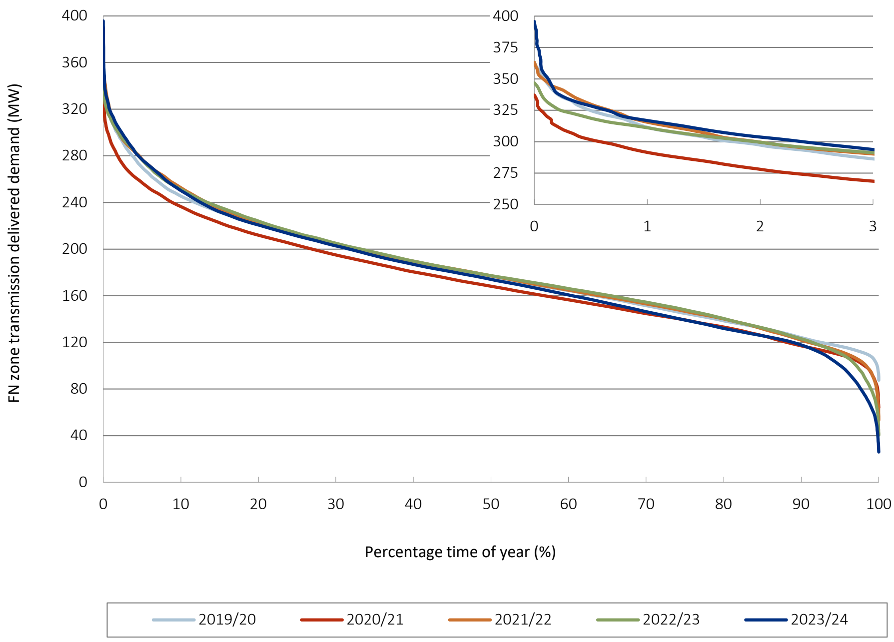
### 7.7.1 Far North zone

The Far North zone experienced one load loss for a single network element outage during 2023/24. The total duration of the outage was 14 minutes and approximately 7MWh of energy was lost. The load loss was caused by the loss of a single element outage which then triggered the Edmonton Special Protection Scheme. This scheme was put in place to manage FNQ voltages during the period where the Ross to Woree tee Tully South 275kV feeder was operational without the Tully South transformer. Since the commissioning of the Tully South transformer in June 2024 this Edmonton Special Protection Scheme has been disarmed.

The Far North zone includes the non-scheduled embedded generator Lakeland Solar and Storage as defined in Figure 3.9. This embedded generator provided 18GWh during 2023/24.

Figure 7.27 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has decreased by 2.2% between 2022/23 and 2023/24. The maximum transmission delivered demand in the zone was 396MW, which is the highest maximum demand in the last decade. The minimum transmission delivered demand in the zone was 26MW, which is the lowest minimum demand on record.

Figure 7.27 Historical Far North zone transmission delivered load duration curves




As a result of double circuit outages associated with lightning strikes, AEMO includes following double circuits in the North zone in the vulnerable list:

- Chalumbin to Turkinje 132kV double circuit transmission line, last tripped November 2022.
- Ross to Woree tee Tully South 275kV circuit and Cardwell to Tully 132kV circuit, last tripped February 2024. These lines share the same transmission towers.

[9] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2024, August 2024.

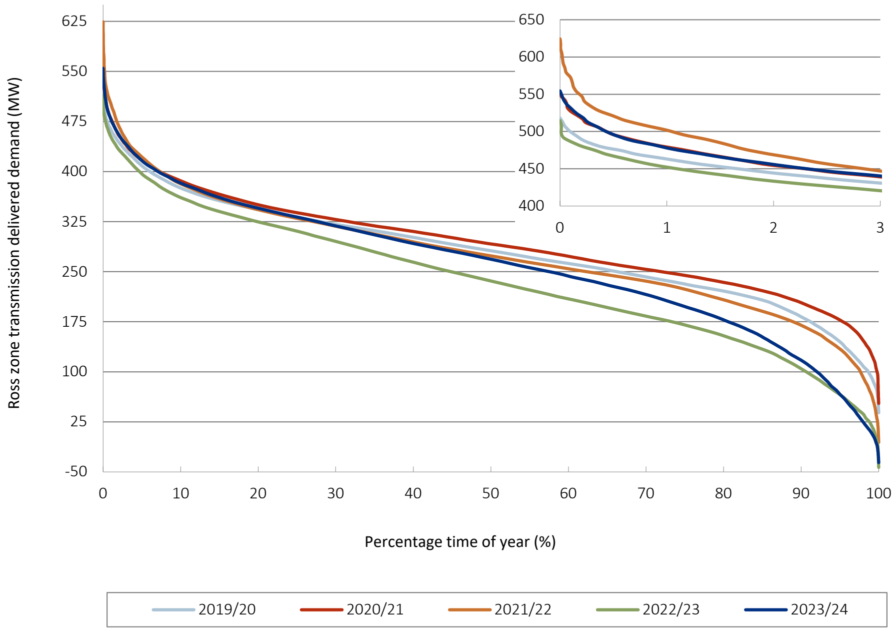
### 7.7.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2023/24.

The Ross zone includes the scheduled embedded Townsville PS 66kV component (steam turbine component of the CCGT), semi-scheduled distribution connected embedded Kidston Solar Farm, Kennedy Energy Park and direct connected embedded Sun Metals Solar Farm, and the significant non-scheduled embedded generators Hughenden Solar Farm and Pioneer Mill as defined in Figure 3.9. These embedded generators provided 569GWh during 2023/24.

Figure 7.28 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has increased by 10.2% between 2022/23 and 2023/24. The increase in energy delivered is due to the combination of increase in native load and decrease in energy from embedded generation. The peak transmission delivered demand in the zone was 555MW, which is below the highest maximum demand over the last five years of 624MW set in 2021/22. The minimum transmission delivered demand in the zone was -36MW, which is the slightly higher than the record minimum set last year.

Figure 7.28 Historical Ross zone transmission delivered load duration curves




As a result of double circuit outages associated with lightning strikes, AEMO includes the Ross to Chalumbin 275kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in January 2020 and again in November 2022.

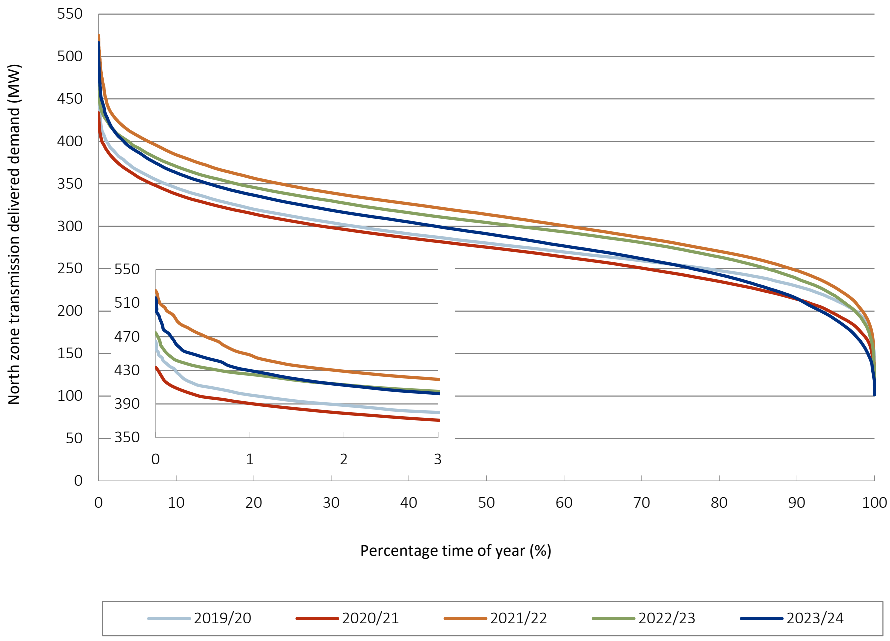
### 7.7.3 North zone

The North zone experienced two load losses for a single network element outage during 2023/24. The total duration of the outages was approximately 3 hours and 5MWh of energy was lost. The loads impacted by these outages are supplied by a single radial connection under intact system conditions.

The North zone includes semi-scheduled embedded generator Collinsville Solar Farm and significant nonscheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 3.9. These embedded generators provided 608GWh during 2023/24.

Figure 7.29 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has decreased by 4.5% between 2022/23 and 2023/24. The peak transmission delivered demand in the zone was 516MW, below the highest maximum demand over the last five years of 525MW set in 2021/22. The minimum transmission delivered demand in the zone was 101MW, which is the lowest minimum demand in the last five years.

Figure 7.29 Historical North zone transmission delivered load duration curves




As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the North zone in the vulnerable list:

- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 2023
- Collinsville North to Stony Creek and Collinsville North to Newlands lines, last tipped November 2022
- Strathmore to Clare South and Strathmore to Clare South tee King Creek 132kV double circuit transmission line, last tripped December 2023.

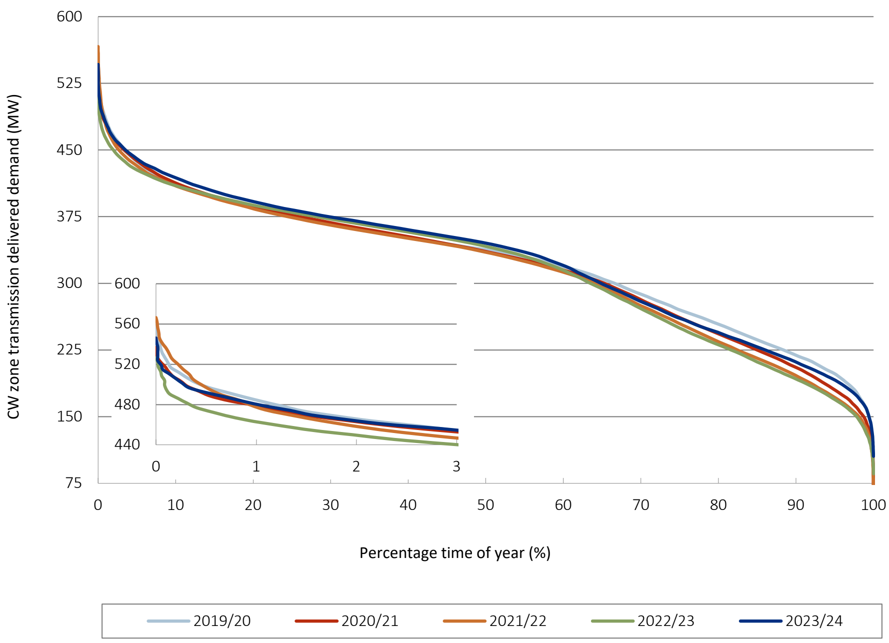
### 7.7.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2023/24.

The Central West zone includes the scheduled embedded Barcaldine generator, semi-scheduled embedded generators Clermont Solar Farm, Emerald Solar Farm and Middlemount Solar Farm and significant non-scheduled embedded generators Barcaldine Solar Farm, Longreach Solar Farm, German Creek and Oaky Creek as defined in Figure 3.9. These embedded generators provided 587GWh during 2023/24.

Figure 7.30 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has increased by 3.0% between 2022/23 and 2023/24, which is the highest in the last five years. The peak transmission delivered demand in the zone was 546MW, below the highest maximum demand over the last five years of 566MW set in 2021/22. The minimum transmission delivered demand in the zone was 105MW, which is higher than the lowest minimum demand over the last decade, which was 64MW recorded in 2020/21.

Figure 7.30 Historical Central West zone transmission delivered load duration curves




EDL has advised AEMO of its intention to retire Oaky Creek non-scheduled embedded generators in 2025.

There are currently no double circuits in the Central West zone in AEMO's lightning vulnerable transmission line list.

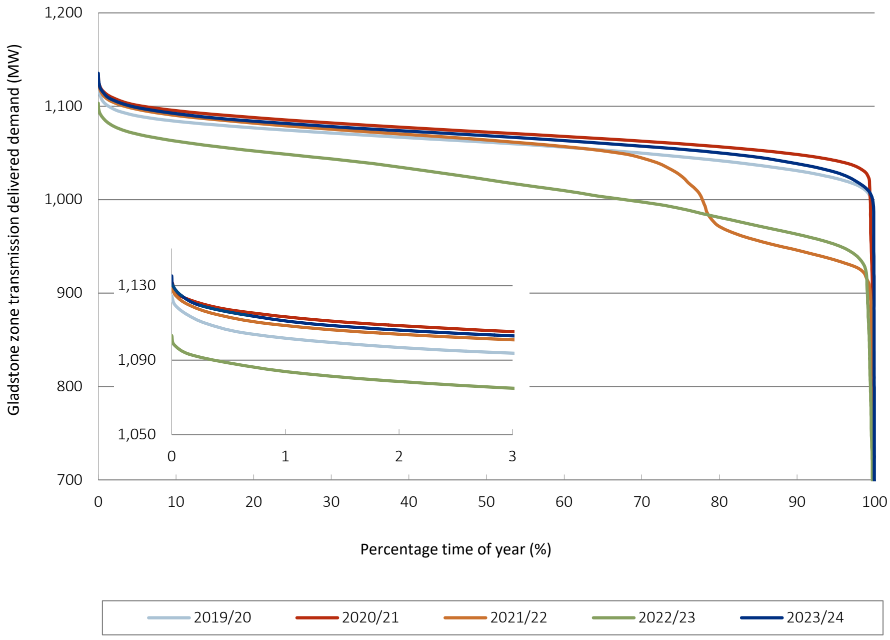
### 7.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2023/24.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Figure 7.31 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has increased by 2.9% between 2022/23 and 2023/24 which is the highest in the last five years. The peak transmission delivered demand in the zone was 1,135MW, which is the highest maximum demand over the last five years. Minimum demand coincides with small periods when one or more of potlines at Boyne Smelters Limited (BSL) are out of service. The minimum transmission delivered demand in the zone was 616MW.

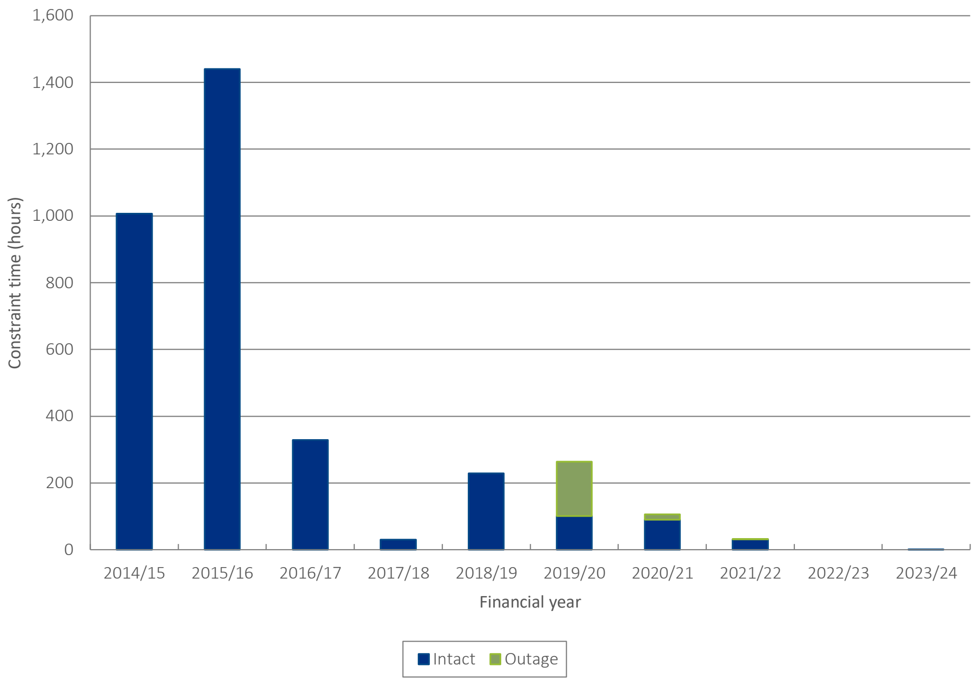
Figure 7.31 Historical Gladstone zone transmission delivered load duration curves




Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing within BSL's substation. The constraint limits generation from Gladstone PS, mainly from the units connected at 132kV. AEMO identifies the system intact constraint by constraint identifier Q>NIL_BI_FB. This constraint was implemented in AEMO's market system from September 2011.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 7.32. During 2023/24, the feeder bushing constraint experienced 20 minutes of constrained operation.

Figure 7.32 Historical Boyne Island feeder bushing constraint times




There are currently no double circuits in the Gladstone zone in AEMO's lightning vulnerable transmission line list.

### 7.7.6 Wide Bay zone

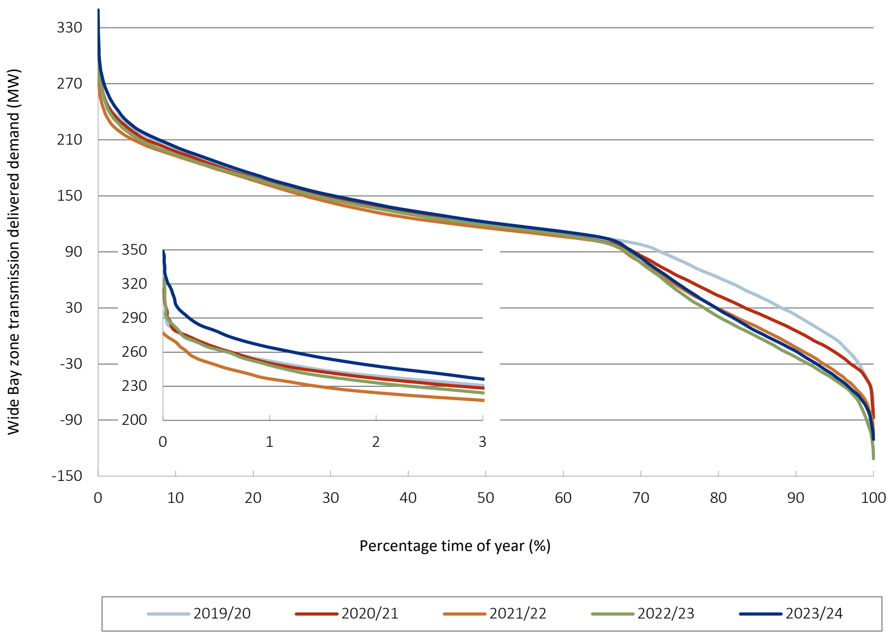
The Wide Bay zone experienced no load loss for a single network element outage during 2023/24.

The Wide Bay zone includes the semi-scheduled embedded generators Childers Solar Farm and Susan River Solar Farm, and significant non-scheduled embedded generator Isis Central Sugar Mill as defined in Figure 3.9. These embedded generators provided 231GWh during 2023/24.

Figure 7.33 provides historical transmission delivered load duration curves for the Wide Bay zone. The Wide Bay zone is one of three zones in Queensland where the delivered demand reaches negative values, meaning that, at times, the embedded generation exceeds the native load. The transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to supply loads in other zones.

While energy has seen significant reductions in recent years, the energy delivered from the transmission network increased by 5.9% between 2022/23 and 2023/24. The peak transmission delivered demand in the zone was 349MW, which is highest maximum demand in the last decade. The minimum transmission delivered demand in the zone was -111MW, which is higher than the lowest minimum demand over the last decade, which was -131MW recorded in 2022/23.

Figure 7.33 Historical Wide Bay zone transmission delivered load duration curves




There are currently no double circuits in the Wide Bay zone in AEMO's lightning vulnerable transmission line list.

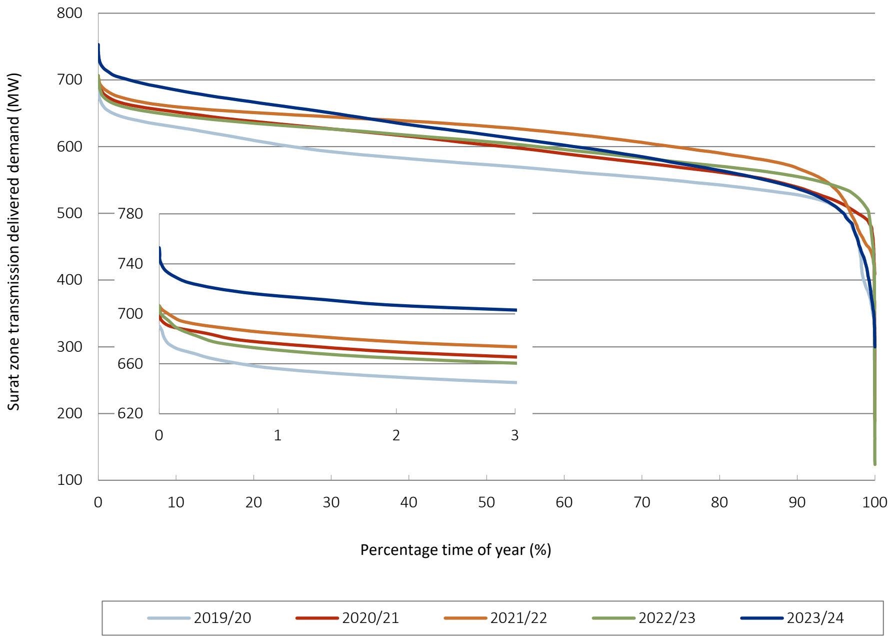
### 7.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2023/24.

The Surat zone includes the scheduled embedded Roma and direct connected embedded Condamine generators, semi-scheduled Dulacca Wind Farm and significant non-scheduled embedded generator Baking Board Solar Farm as defined in Figure 3.9. These embedded generators supplied 625GWh during 2023/24.

Figure 7.34 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has increased by 1.8% between 2022/23 and 2023/24. The peak transmission delivered demand in the zone was 753MW, which is a record maximum demand for the zone. The minimum transmission delivered demand in the zone was 300MW.

Figure 7.34 Historical Surat zone transmission delivered load duration curves




There are currently no double circuits in the Surat zone in AEMO's lightning vulnerable transmission line list.

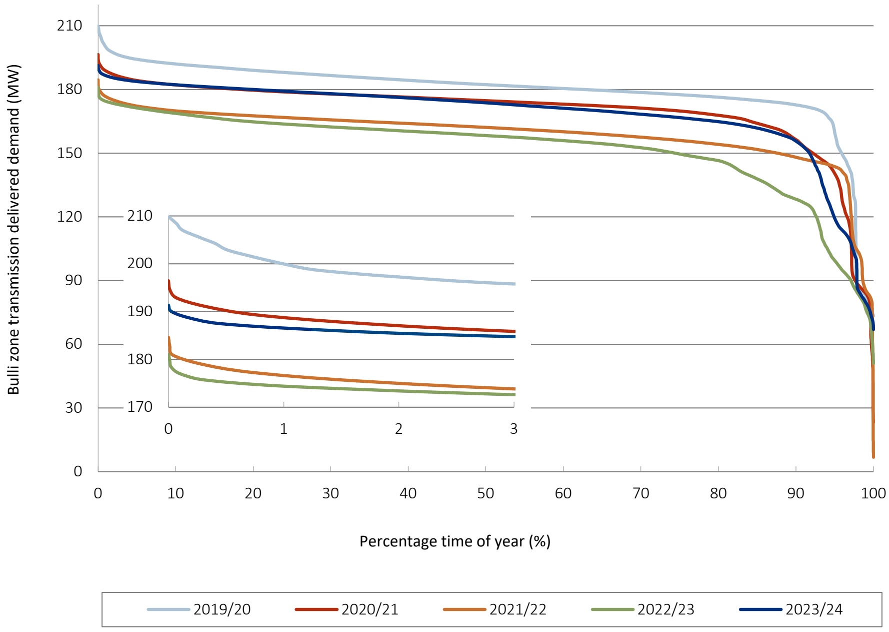
### 7.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2023/24.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Figure 7.35 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by 11.0% between 2022/23 and 2023/24, returning to historical typical levels. The peak transmission delivered demand in the zone was 191MW which is below the highest maximum demand over the last five years of 210MW set in 2019/20. The minimum transmission delivered demand in the zone was 67MW.

Figure 7.35 Historical Bulli zone transmission delivered load duration curves




There are currently no double circuits in the Bulli zone in AEMO's lightning vulnerable transmission line list.

### 7.7.9 South West zone

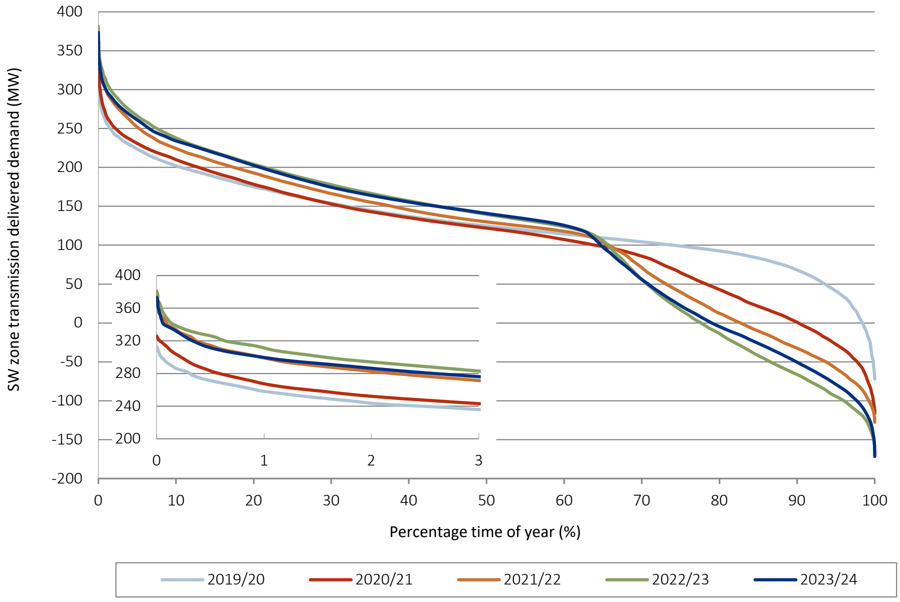
The South West zone experienced no load loss for a single network element outage during 2023/24.

The South West zone includes the semi-scheduled embedded generators Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm and Warwick Solar Farm as defined in Figure 3.9. These embedded generators provided 483GWh during 2023/24.

Figure 7.36 provides historical transmission delivered load duration curves for the South West zone. The South West zone is one of three zones in Queensland where the delivered demand reaches negative values, meaning that the embedded generation exceeds the native load, the transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to supply loads in other zones.

Energy delivered from the transmission network has reduced by 2.0% between 2022/23 and 2023/24, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 372MW, which is slightly below the record maximum demand of 381MW recorded in 2022/23. The minimum transmission delivered demand in the zone was -172MW, which is the lowest demand on record.

Figure 7.36 Historical South West zone transmission delivered load duration curves




There are currently no double circuits in the South West zone in AEMO's lightning vulnerable transmission line list.

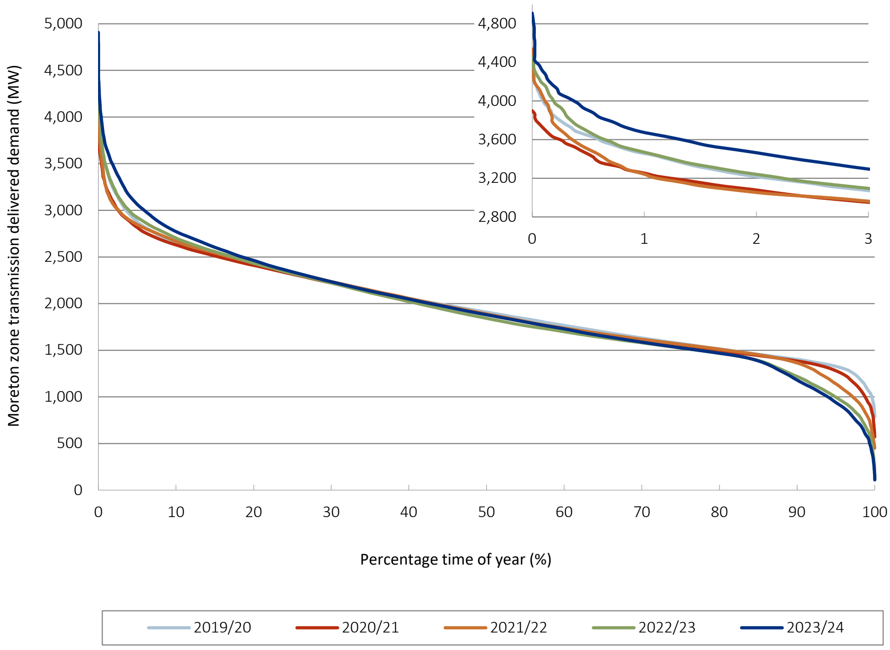
### 7.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2023/24.

The Moreton zone includes the significant non-scheduled embedded generators Sunshine Coast Solar Farm, Bromelton and Rocky Point as defined in Figure 3.9. These embedded generators provided 62GWh during 2023/24.

Figure 7.37 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has increased by 1.6% between 2022/23 and 2023/24. The peak transmission delivered demand in the zone was 4,908MW, which is highest maximum demand on record. The minimum transmission delivered demand in the zone was 110MW, which is the lowest demand on record. In late 2024 a bus reactor is expected to be commissioned at Belmont Substation.

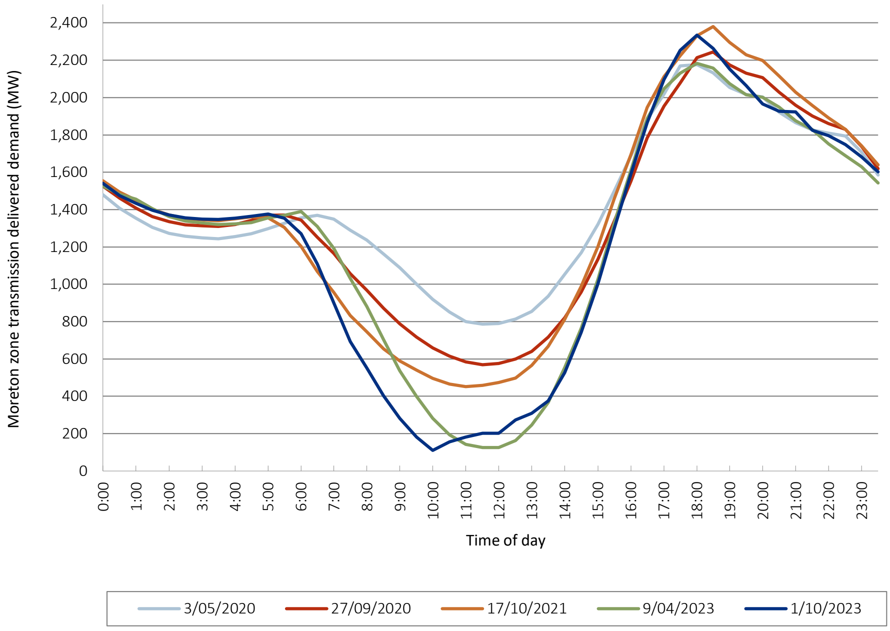
Figure 7.37 Historical Moreton zone transmission delivered load duration curves




High voltages associated with these light load conditions are currently managed with existing reactive sources. However, voltage control within Powerlink's and Energex's network is forecast to become increasingly challenging for longer durations. In 2021, AEMO identified an Network Support and Control Ancillary Service (NSCAS) gap of up to 250 Megavolt Ampere reactive (MVAr) of reactive power absorption in the southern Queensland. Due to this gap, Powerlink initiated an EOI to identify network and non-network options to address this gap. Powerlink has now entered into a Network Support Agreement with CleanCo Queensland to address the immediate gap. In late 2024 a bus reactor will be commissioned at Belmont Substation to address the long-term reactive requirements.

Figure 7.38 provides the daily load profile for the minimum transmission delivered days for the Moreton zone over the last five years. This Figure shows that in 2023/24 the minimum demand would have been significantly lower without Energy Queensland managing demand in the middle of the day. The figure also highlights the increasing gap between minimum and maximum demand on these days.

Figure 7.38 Historical Moreton zone minimum transmission delivered daily profile




There are currently no double circuits in the Moreton zone in AEMO's lightning vulnerable transmission line list.

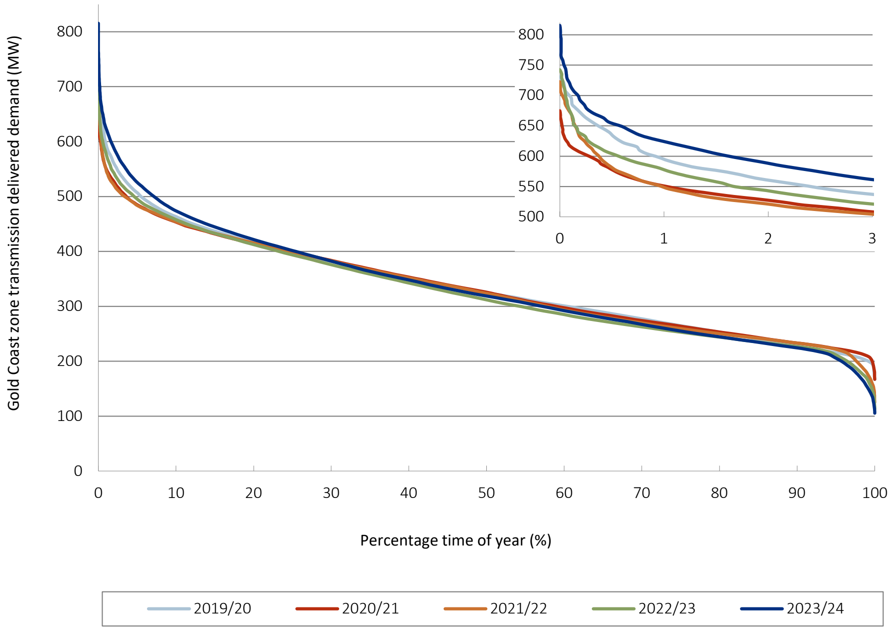
### 7.7.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2023/24.

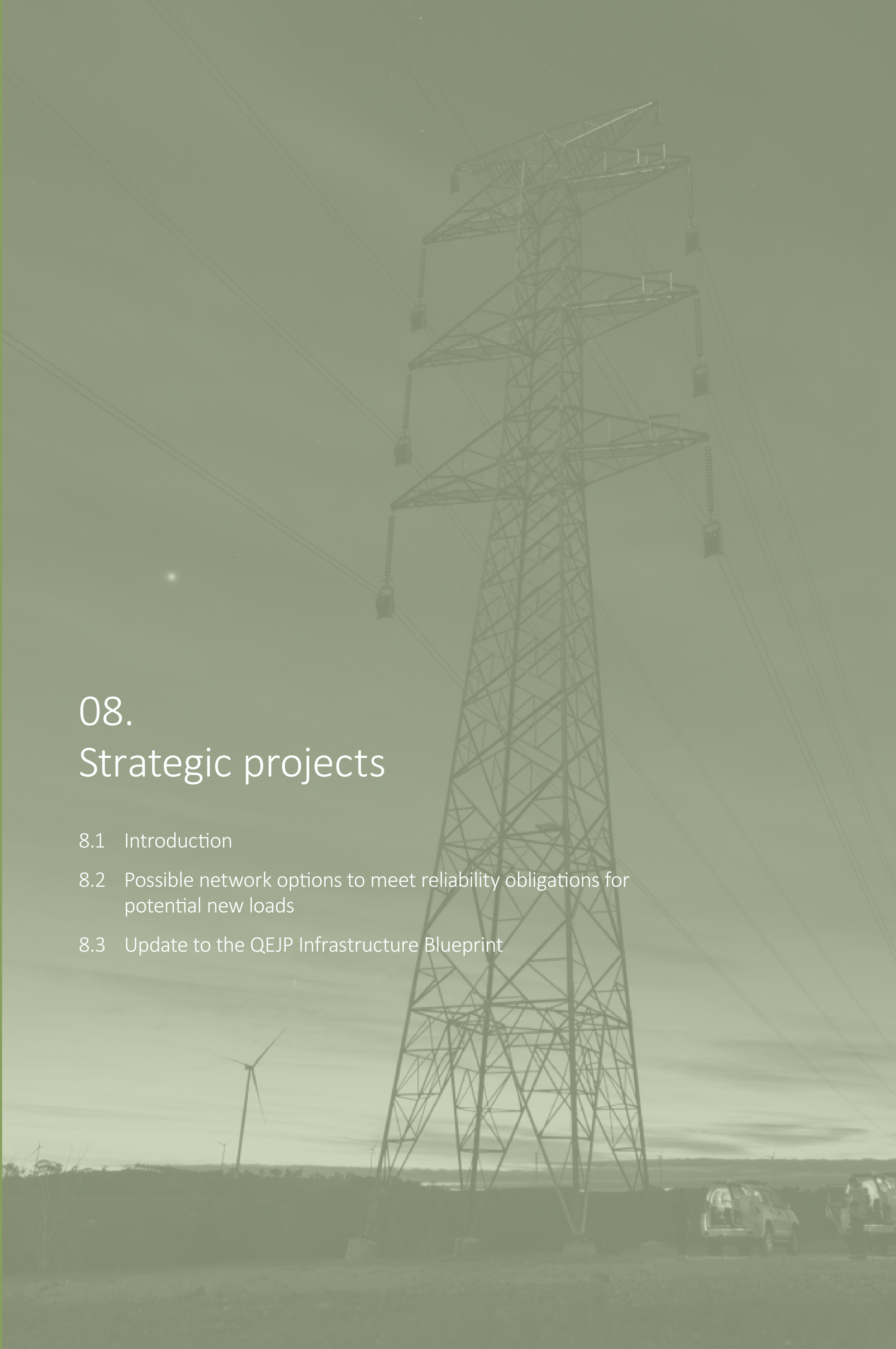
The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Figure 7.39 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network increased by 2.5% between 2022/23 and 2023/24. The peak transmission delivered demand in the zone was 815MW, which is the highest maximum demand on record. The minimum transmission delivered demand in the zone was 105MW which is the lowest demand on record.

Figure 7.39 Historical Gold Coast zone transmission delivered load duration curves




There are currently no double circuits in the Gold Coast zone in AEMO's lightning vulnerable transmission line list.



# 08.
# Strategic projects

*This chapter discusses plausible new loads within the resource rich areas of Queensland and the associated coastal port facilities, as well as the potential future electrification of mining and industrial processing loads that may cause network limitations to emerge within the 10-year outlook period. It also discusses updates to major projects referenced in the Queensland Energy and Jobs Plan (QEJP).*

Key highlights

- Possible loads associated with new industrial processes, including industry based on hydrogen, and electrification of major industrial processes and mining operations, are emerging within the 10-year outlook period.
- Possible network impacts and options are provided for the Northern Bowen Basin coal mining area, North West Mineral Province, Central Queensland to North Queensland (CQ-NQ) and Central West to Gladstone grid sections.
- Through market engagements an opportunity was identified to more efficiently access potential large wind resources along the Great Dividing Range, west of the Calvale to Halys transmission corridor. This requires a revision to stage 2 of the SuperGrid and enables a revised voltage and topology to effect the stage 1 connection of the Borumba Pumped Hydro Energy Storage project.

## 8.1 Introduction

Chapter 3 provides details of several proposals for large mining, metal processing and other industrial loads whose development status is not yet at the stage that they have been included (either wholly or in part) in Powerlink's Central scenario forecast. These load developments are listed in Table 3.1.

The possible impact these uncertain loads may have on the performance and adequacy of the transmission system is discussed in Section 8.2. This assessment is made taking into account the existing and committed network and those network developments proposed in the QEJP.

In September 2022 the Queensland Government published the QEJP and associated Queensland SuperGrid Infrastructure Blueprint ("Infrastructure Blueprint"). The Infrastructure Blueprint outlines the Optimal Infrastructure Pathway (OIP) to deliver a clean, reliable and affordable power system. The Infrastructure Blueprint is a point in time plan with the underlying inputs, assumptions and future scenarios continually monitored as the market evolves and available information improves as part of detailed design and planning phases. The Queensland Government is required to update its Infrastructure Blueprint every two years with the OIP to reflect new infrastructure investments, changing market conditions, and the market outlook. The next update to the Infrastructure Blueprint is scheduled for May 2025.

### 8.1.1 Stakeholder and community engagement

Powerlink is committed to genuine and timely stakeholder engagement and as described in Section 1.8.1, all engagement activities are undertaken in accordance with our Stakeholder Engagement Framework and Community Engagement Strategy. Where applicable, planning approval for transmission lines will be facilitated under the Ministerial Infrastructure Designation process, as per the Queensland Planning Act 2016 and where new easements are required Powerlink will apply the new SuperGrid Landholder Payment Framework that significantly boosts payments to landholders hosting new transmission infrastructure and offers payments to landholders on neighbouring adjacent properties.

## 8.2 Possible network options to meet reliability obligations for potential new loads

The proposals for the connection of new industrial processing loads, including new industry based on hydrogen, and electrification of major industrial processes and mining operations are emerging as the broader economy transforms to a lower carbon future.

In North Queensland there is considerable interest from customers investigating electrification to their mining operations in the Northern Bowen Basin. Approximately 40km south of Townsville the Lansdown Eco Industrial Precinct has been envisioned to become Northern Australia's foremost precinct for advanced manufacturing, processing, technology and emerging industries. Also in North Queensland, Powerlink is working towards final approval by the Queensland Government of the CopperString 2032 project. This will connect the current NWMP load to the National Electricity Market (NEM).

More broadly across the state, there is also the potential for conversion of existing industrial and manufacturing processes from coal, gas and/or diesel to electricity. Many of these loads are in the Gladstone zone. New industry loads based on hydrogen are also potentially located in the Gladstone and Townsville zones.

These potential loads, including possible locations, are listed in Table 3.1. Together, these loads have the potential to significantly impact the performance of the transmission network supplying these areas, including power transfers that exceed the capability of the network. This could be due to plant ratings, voltage stability and/or transient stability. However, all of these loads will have a positive impact on the minimum load issues discussed in Section 3.2. This is particularly the case since the load profile for these mining, metal processing and industrial loads are typically relatively flat.

Powerlink has analysed the impact of these new loads on power transfers and assessed the adequacy of the network capability to meet the required needs. Where the capability of the regulated network is forecast to be exceeded, network developments that could be required to meet those needs have been identified. Options to address the network limitations can also include demand side management (DSM) and non-network solutions.

This section focuses on the most likely network development options only. As the proposed loads become committed, detailed planning analysis will inform and optimise the project scopes and cost estimates. Powerlink will undertake the relevant approval process to identify the preferred option (which may include a non-network option or component) that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The emergence and magnitude of network limitations resulting from the commitment of these loads will also depend on the location, type and capacity of new or withdrawn generation. For the purpose of this assessment the existing and committed generation in tables 7.1 and 7.2 has been taken into account when discussing the possible network limitations. However, where current interest in connecting further variable renewable energy (VRE) generation has occurred, that has the potential to materially impact the magnitude of the emerging limitation, this is also discussed in the following sections.

The emergence and magnitude of network limitations resulting from the commitment of these loads will also depend on the relative timing of the new high voltage SuperGrid transmission system that is required to transport large quantities of renewable energy and storage across the state. Powerlink will also consider these potential limitations holistically with any emerging condition based drivers as part of the longer term planning process and in conjunction with the Integrated System Plan (ISP) and QEJP.

Details of feasible network options are provided in sections 8.2.1 to 8.2.4, for the transmission grid sections potentially impacted by the possible new large loads in Table 3.1.

### 8.2.1 Northern Bowen Basin coal mining area

Based on Powerlink's Central scenario forecast discussed in Chapter 3, and the committed generation listed in tables 7.1 and 7.2, network limitations are forecast to exceed network reliability requirements established under Powerlink's planning standard (refer to Section 6.9.3).

There have also been early discussions on new and expanded mining operations and on electrification of existing mining processes in the Northern Bowen Basin in line with global efforts to reduce carbon emissions. To achieve this, mines will need to replace diesel fuel within their operations through the introduction of a modern electrified mining fleet or the substitution of diesel fuel with hydrogen. Either way, fuel substitution may lead to significant increases in electrical demand and require significant supplies of renewable electricity. Early discussions with proponents indicate that significant investment in renewable energy supply is unlikely to be "behind the meter". As such, new and expanded mining operations, combined with electrification of existing mining processes could see load increase by up to approximately 600MW. These loads have not reached the required development status to be included in Powerlink's Central scenario forecast for this Transmission Annual Planning Report (TAPR).

This additional load within the Northern Bowen Basin area would result in voltage and thermal limitations on the 132kV transmission system upstream of their connection points. Critical contingencies include an outage of a 132kV transmission line between Nebo and Moranbah substations, or the 132kV transmission line between Lilyvale and Dysart substations (refer to Figure 6.11).

The impacts these loads may have on the CQ-NQ grid section and possible network solutions to address these is discussed in Section 8.2.4.

#### Possible network solutions

Mining operations in the Northern Bowen Basin rely heavily on the existing 132kV network to deliver electricity to the area. Much of this infrastructure has limited thermal capacity. To address the potential shortfall in capacity in the transmission and distribution networks, consultation with the customers in the Bowen Basin is required to assess the likely decarbonisation pathways under consideration (electrification or hydrogen), in order to forecast the potential energy demand, VRE supply, and transmission requirements.

Given this 132kV network is west of the existing 275kV backbone it is unlikely that the Queensland SuperGrid Infrastructure can address the local supply limitations within the Northern Bowen Basin. Components of the Infrastructure Blueprint may however address resulting CQ-NQ grid section limitations, depending on the relative timings of the load increase and Infrastructure Blueprint augmentations.

Depending on the magnitude and location of load, possible network options to, and within the Northern Bowen Basin may include one or more of the following:

- Installation of flow control devices on the 132kV network to improve the sharing of power flow in the Northern Bowen Basin
- Construction of new 132kV transmission lines between the Nebo, Broadlea and Peak Downs areas
- Construction of 132kV transmission line between Moranbah and a future substation north of Moranbah
- Advance the rebuild of the 132kV transmission lines that supply the Northern Bowen Basin area as higher capacity 132kV lines with associated capacitive compensation for voltage control. The existing 132kV lines are forecast to reach their end of technical service in the 2040s.

Powerlink has a vacant transmission corridor between Nebo and Broadlea and a double width easement from Moranbah to north of Newlands substations. New strategic easements would need to be obtained to deliver the other network options described above.

### 8.2.2 CopperString 2032

In March 2023, the Queensland Government announced that it will build and own the network to the NWMP (referred to as CopperString 2032 and formerly known as the CopperString 2.0 project). Powerlink is currently working with impacted landholders, equipment suppliers and Construction Partners to finalise the scope, estimate and construction schedule for final project approval by the Queensland Government.

The CopperString 2032 project will allow the NWMP to access lower cost electricity sources from the NEM. The existing NWMP load that would directly connect to the NEM is approximately 160MW.

During the development of this project there has been significant interest in connecting new mining loads within the NWMP (including existing load supplied from separate islanded systems) and at various locations along the length of the project. In consideration of this load potential proceeding, the scope of the initial project has been designed to support approximately 450MW of load. As further load commits, augmentation of the CopperString 2032 network and/or to Energy Queensland's network in the NWMP will be required.

As outlined in Section 2.4.1, CopperString 2032 will also enable the connection of significant quantities of high quality wind energy in the Hughenden region for export to the coastal Queensland transmission system. The Hughenden region has been named the Flinders Renewable Energy Zone (REZ) within the draft Queensland Government REZ Roadmap (refer Section 2.4.1). As a result, the section of CopperString 2032 between Hughenden and the coastal Queensland transmission system (south of Ross Substation) is planned to be constructed at 500kV which will enable higher levels of hosting and transfer of renewable energy to the interconnected eastern transmission system.

#### Possible network solutions

CopperString 2032 involves building approximately 840 km of new electricity transmission line from near Townsville to Mount Isa and includes the following core transmission infrastructure components:

- 360km of 500kV double circuit transmission line from Townsville to Hughenden
- 400km of 330kV double circuit transmission line from Hughenden to Cloncurry
- 100km of 220kV double circuit transmission line from Cloncurry to Mount Isa
- Establishment of new substations, and installation of transformers and reactive plant.

CopperString 2032 will connect to a new 500/275kV substation south of Powerlink's existing Ross Substation by cutting into two of the existing 275kV circuits between Strathmore and Ross substations (refer to Figure 2.5).

### 8.2.3 Lansdown Eco Industrial Precinct

The Lansdown Eco Industrial Precinct (LEIP) is located near Woodstock, 40km south of Townsville. The 2200-hectare (22km$^2$) precinct is primarily a high impact industrial zone away from residential areas. It is a "greenfield development" with the vision to become Northern Australia's foremost precinct for advanced manufacturing, processing, technology, and emerging industries. A Taskforce was established by the Office of the Coordinator-General (OCG) in March 2023 to assist Townsville City Council accelerate the development of the LEIP to service the proponents that have been allocated land within the precinct.

There have been early discussions with possible tenants of the LEIP, including for hydrogen production facilities, energy chemicals and quartz manufacturing.

The impacts of this additional load south of Townsville may have on the CQ-NQ grid section and possible network solutions to address these is discussed in Section 8.2.4.

#### Possible network solutions

This is a "greenfield" development area with significant potential load. Table 3.1 has assumed a possible load within the 10-year outlook of up to approximately 1,000MW. Supply to this precinct would be at 275kV by establishing a 275/132kV substation (including lower voltage as required) at the LEIP:

- by cutting into two of the existing 275kV circuits between Strathmore and Ross substations, and
- depending on load growth and relative timing, reinforcement via a second double circuit 275kV line from the Copperstring 2032 500/275kV most eastern substation to LEIP. This could increase the network capacity between the CopperString network and LEIP to approximately 3GW.

Components of the Infrastructure Blueprint may also address resulting CQ-NQ grid section limitations, depending on the relative timings of the load increase and Infrastructure Blueprint augmentations.

### 8.2.4 CQ-NQ grid section transfer limit

Based on Powerlink's Central scenario forecast outlined in Chapter 3 and the existing and committed generation listed in tables 7.1 and 7.2, network limitations impacting reliability are not forecast to occur within the 10-year outlook period.

Midday power transfer levels are reversing from northern to southern transfers. The incidence of light loading on the transmission system is forecast to increase as additional VRE generators are fully commissioned in North Queensland (NQ) (refer to tables 7.1 and 7.2). Voltage control is therefore becoming increasingly challenging and leading to high voltage violations. As outlined in Section 9.3, Powerlink completed a RIT-T consultation recommending the installation of a 275kV shunt reactor at the Broadsound Substation. This reactor was commissioned in June 2024 (refer to Table 9.3).

As discussed in sections 8.2.1 to 8.2.3, there is the likelihood of significant additional load in North Queensland from new and expanded mines and electrification of existing mining operations in the Northern Bowen Basin, the connection of the NWMP to the NEM through CopperString 2032 and development of new load within the Lansdown Eco Industrial Precinct may proceed (refer to Table 3.1).

These could result in an increase in northern Queensland demand of greater than 1,000MW. However, the majority of these loads have not reached the required development status to be included in Powerlink's Central scenario forecast for this TAPR.

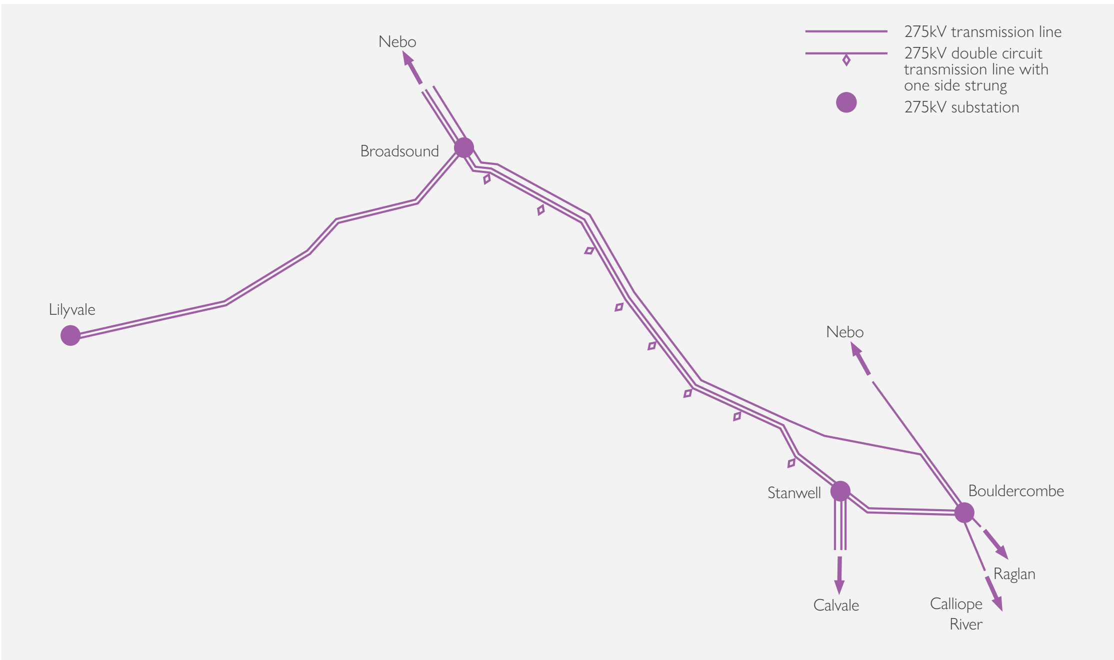
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings, voltage and transient stability. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line following a critical contingency of a Stanwell to Broadsound 275kV transmission line. Voltage and transient stability limitations may occur following the trip of the Townsville gas turbine or fault and trip of a 275kV transmission line supplying northern Queensland.

Network congestion between central Queensland and north Queensland will require dispatch of additional, out-of-merit-order generation in North Queensland. As generation costs are higher in northern Queensland, due to reliance on liquid fuels, it may be economic to advance the timing of augmentation to deliver positive net market benefits.

### Possible network solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with one circuit strung (refer to Figure 8.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second side of this transmission line. No easement is required for this scope of work.

Figure 8.1 Stanwell/Broadsound area transmission network




Components of the Infrastructure Blueprint between Central and Northern Queensland may also address the CQ-NQ grid section limitations, depending on the relative timings of the load increase and Infrastructure Blueprint augmentations.

Powerlink will also consider the emerging condition based drivers as part of the planning process to ensure the most cost effective solutions are delivered for customers, including working with the proponent to identify mutually beneficial non-network options.

### 8.2.5 Gladstone grid section transfer limit

Based on Powerlink's Central scenario forecast discussed in Chapter 3, there is approximately 1,800MW of additional load expected to connect in the Gladstone zone by 2034. This load is associated with electrification of components of the existing industrial processes and initial stages of hydrogen development within the area.

While Powerlink has no connection point commitments from any direct connect customers in the Gladstone zone at the time of the publication of 2024 TAPR, Powerlink is engaging with customers that appear committed to decarbonising their existing fossil fuelled operations and processes - with some level of uncertainty over timeframes. There has also been a significant number of enquiries for the connection of new industrial processing loads in the Gladstone zone. The magnitude and timing of new and/or electrification load is uncertain. The quantity could range from 3.3GW to over 7.7GW (refer to Table 3.1).

With reduced operation of Gladstone Power Station (GPS) as the electricity industry transforms to a lower carbon future, in combination with electrification of existing industrial processes, and development of new industry load, there will be a significant impact on the transmission capacity required to maintain reliability of supply in the Gladstone zone and power system security.

In July 2024, Powerlink commenced consultation on the Gladstone Project as a candidate Priority Transmission Investment (PTI) under the Energy (Renewable Transformation and Jobs) Act 2024 (ERTJ Act). This consultation is being undertaken to ensure that on-going reliability and security of supply is available to meet forecast electrical load in the Gladstone area and support the decarbonisation of major industries in anticipation of the closure of the Gladstone Power Station. Further details on this consultation, consultation paper and next steps are available on Powerlink's website[1].

Aligned with this need, the Gladstone Project has also been declared a Queensland Actionable Project in Australian Energy Market Operator's (AEMO) 2024 Integrated System Plan (ISP).

Connecting additional load in the Gladstone zone will require further investment in transmission, both into and within the Gladstone zone. The additional transmission capacity required to meet this increase in load will only be considered in the context of the main network supplying the Gladstone zone. Network limitations downstream of the main transmission system would also need to be assessed based on specific customer load.

The network augmentations will also be considered holistically with end of technical life drivers and alignment with hosting renewable energy generation.

#### Possible network solutions

Subject to shareholding Minister approval, the initial stages of Powerlink's plan are to increase the transmission capacity to the Gladstone area are outlined in the recently published "Gladstone Project - Candidate Priority Transmission Investment – Consultation Paper". This consultation paper provides an overview of the objectives Powerlink seeks to achieve by investing in the Gladstone Project, and the timeframes by which each element of the project need to be completed to meet those objectives.

The projects described in this consultation paper are the initial stages of possible development. They provide sufficient power transfer capability to reliably supply the forecast electrical load in the Gladstone area in anticipation of the closure of the Gladstone Power Station and support the initial decarbonisation of major industries in the Gladstone area. The initial transmission projects proposed include:

- build a new 275kV high capacity double-circuit line between Calvale and Calliope River and install a new 275/132kV transformer at Calliope River Substation. These projects are required to reliably supply the forecast electrical load in the Gladstone area in anticipation of the closure of the Gladstone Power Station.

[1] Refer PTI Gladstone project.

- rebuild Bouldercombe to Calliope River transmission line as a 275kV high capacity double circuit line and rebuild Calliope River to Larcom Creek transmission line as a 275kV high capacity double circuit line. These projects are required to support the decarbonisation of major industries in the Gladstone area.

Both the new Calvale to Calliope River and Bouldercombe to Larcom Creek transmission lines traverse a common area west of Gladstone. Powerlink is in the process of acquiring land suitable for establishing a major new substation in this area. These new 275kV circuits could be switched at this new substation (establishing high capacity double circuit spokes to Larcom Creek and Calliope River respectively). The 275kV bus could be a feasible alternative to, or defer the need for, the rebuild between Calliope River to Larcom Creek substations.

The amount of additional load that may be supplied in the Gladstone zone following these works will depend on the relative distribution of the load between the Larcom Creek, Calliope River and Wurdong substation and location of new generation development. Further network augmentations would be required within the Gladstone zone as the load increases. Feasible network solutions include:

- constructing a new high capacity 275kV double circuit transmission line between Stanwell and Bouldercombe substations.
- establishing the 500/275kV substation west of Gladstone and associated 500kV connections to deliver power from variable renewable energy generation and firming resources
- additional 275kV connections from the 500/275kV Gladstone West Substation to Calliope River and/or Larcom Creek
- additional 275kV tie capacity between Calliope River and Larcom Creek substations.

Managing power transfers on the existing lower rated 275kV single circuit between Calvale and Wurdong substations will also need to be addressed as the supply/demand balance changes in the Gladstone zone. This circuit was initially constructed in two stages. Firstly in 1987 the western section was built from Calvale Substation to a tee point (on feeder 812 between Bouldercombe to Calliope River) at Cedar Vale (west of Gladstone). Then in 1998 the tee was disconnected, and the single circuit line was extended to Wurdong Substation coincident with the expansion of the Boyne Island Smelter. Options to address limitations across this circuit include:

- installation of flow control devices (e.g. SmartValve[2] or phase shifting transformer) at Wurdong Substation
- restring with high temperature conductor (HTC)
- rebuild whole or sections[3] of the circuit as a new high capacity 275kV double circuit transmission line.

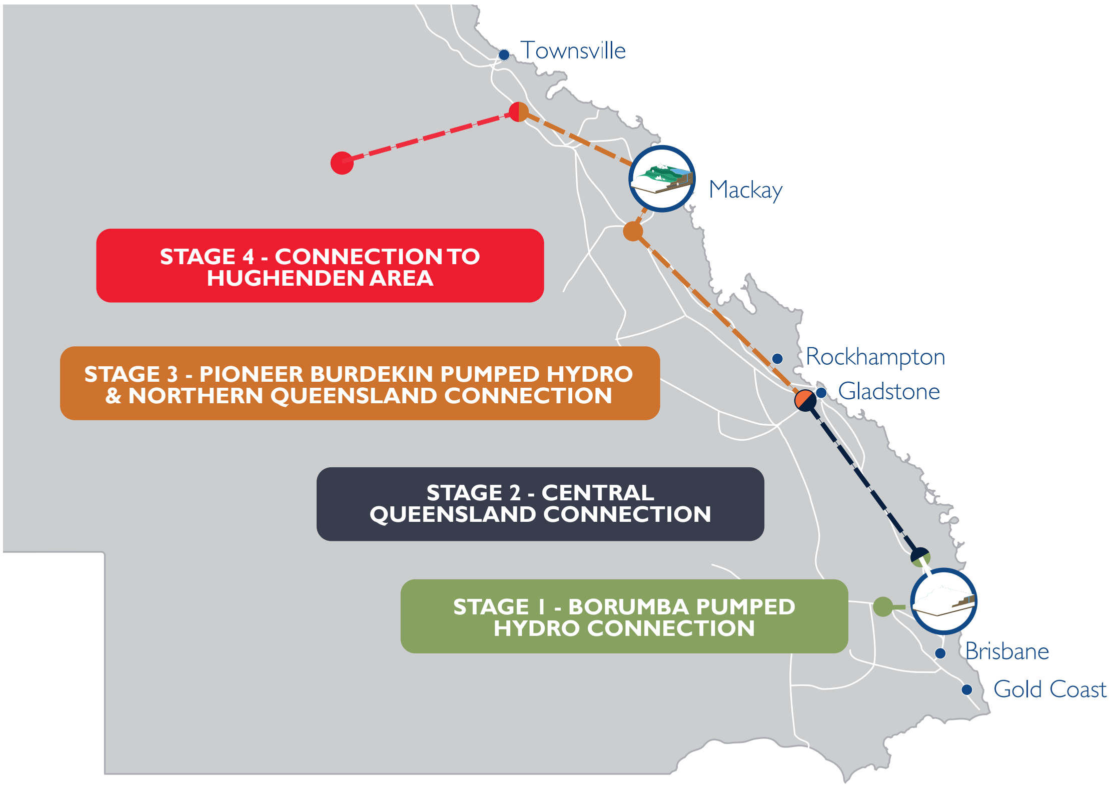
Powerlink will also consider the emerging condition-based drivers as part of the planning process to ensure the most cost effective solutions are delivered for customers, including working with the proponent to identify mutually beneficial non-network options.

## 8.3 Update to the QEJP Infrastructure Blueprint

As outlined in Section 2.4, the Queensland Government's QEJP and Infrastructure Blueprint identified the need to establish a high capacity backbone transmission network to enable the connection of renewable generation and large-scale Pumped Hydro Energy Storage (PHES) to support the decarbonisation of the energy system (refer to Figure 8.2). The SuperGrid Strategy demonstrated that establishing the high capacity transmission backbone at 500kV was the lowest cost solution for electricity customers under the majority of credible scenarios.

[2] SmartValve™ is an advanced power flow control solution developed by SmartWires.
[3] If the circuit is switched in the future 500/275kV substation west of Gladstone.

Figure 8.2 Original Queensland Blueprint SuperGrid Stages




Note:

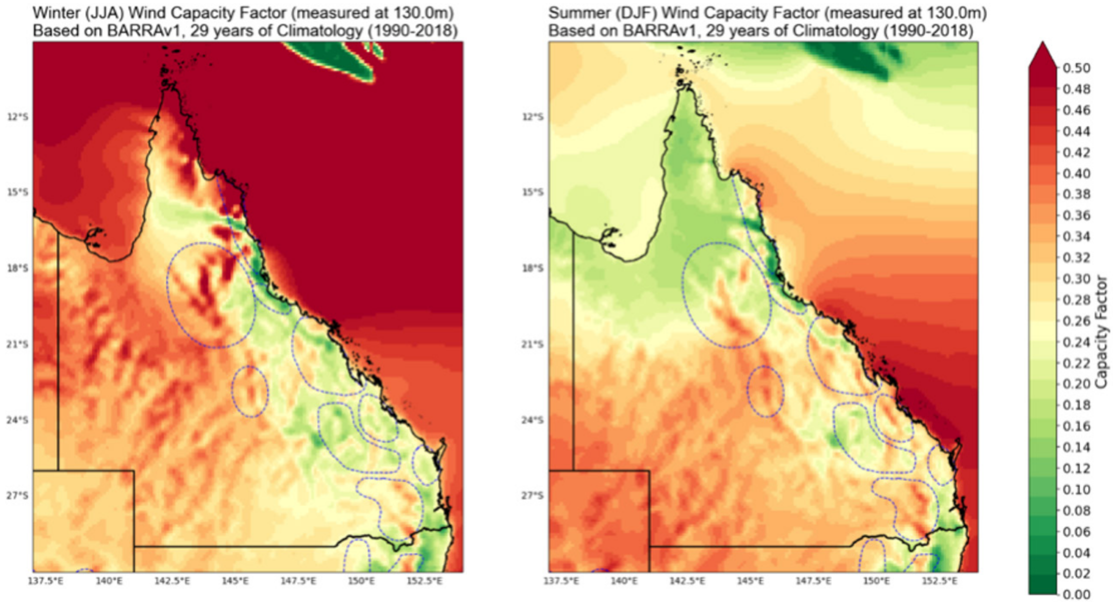
(1) The Infrastructure Blueprint is a point in time plan scheduled to be updated in May 2025.

The ability to connect wind generation and PHES is the fundamental role of the transmission network of the future. Wind generation and PHES must be located where the wind resources and topography enable them. By comparison, there is far more flexibility in the location of large-scale solar and batteries.

The wind resources along the Great Dividing Range offer consistently higher capacity factor than those along the coast for both summer and winter seasons (refer to Figure 8.3). This has been reinforced through market engagements.

In response Powerlink identified an opportunity to more efficiently access potential large wind resources along the Great Dividing Range, west of the Calvale to Halys transmission corridor, whilst delivering greater power transfer capability and assist in the supply of significant new load predicted in the Gladstone zone (refer to Section 8.2.5). This requires changing Stage 2 of the SuperGrid from the original coastal alignment to a more inland route. The western Central Queensland to South Queensland (CQ-SQ) transmission development can also be built in stages and paced to align with interest for renewable connections.

Figure 8.3 Seasonal wind capacity factor data (1)

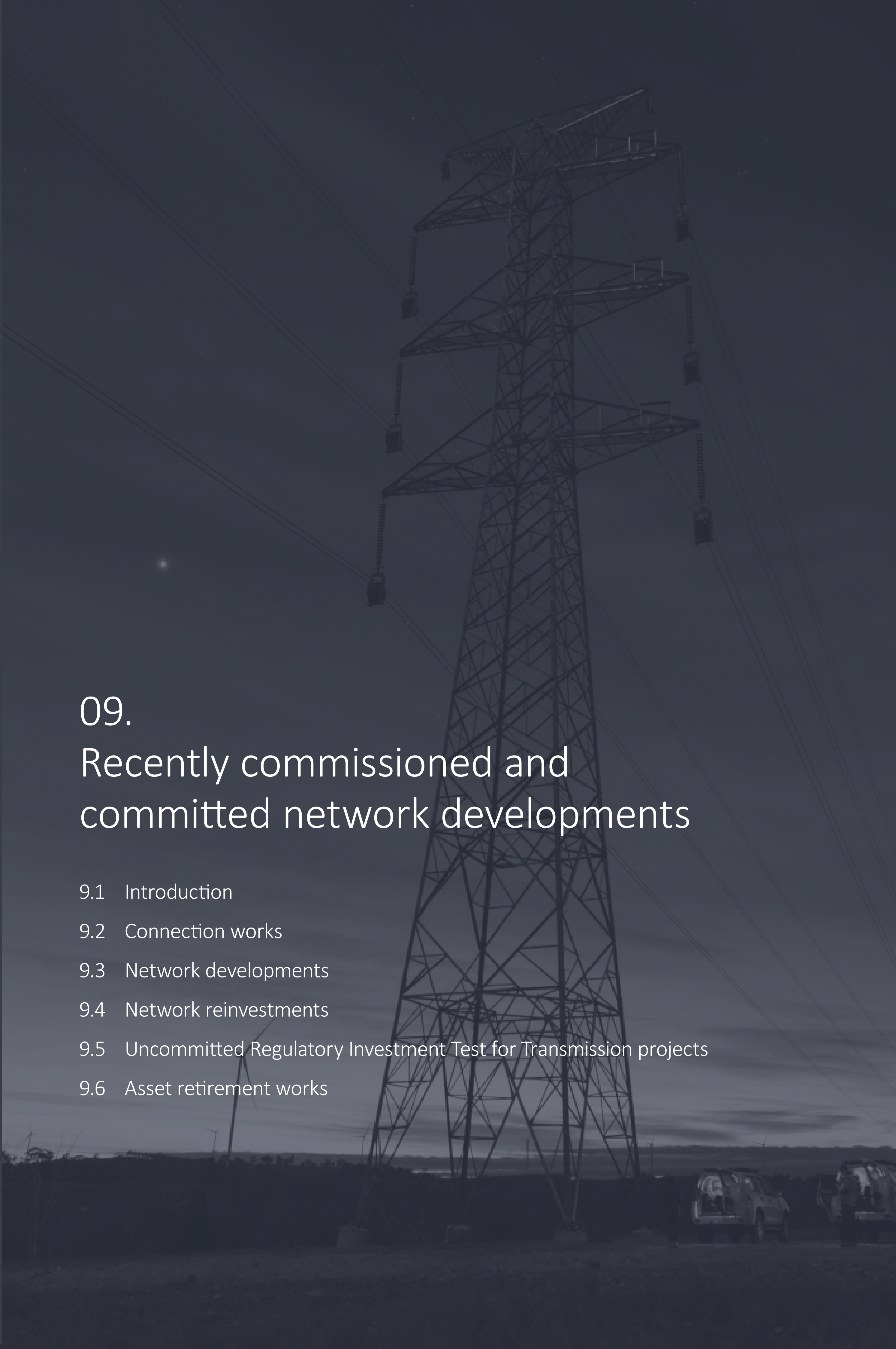



Note:

(1) Bureau of Meteorology.

Subject to shareholding Minister approval, the establishment of a transmission line of up to 500kV along an inland corridor between South Queensland and Central Queensland also enables the first stage of the SuperGrid transmission backbone from Halys to Woolooga to be constructed at 275kV rather than 500kV as the western 500kV transmission line effectively supplants the proposed coastal 500kV transmission line between Woolooga and Gladstone (refer to Stage 2 in Figure 8.2).

Powerlink will commence a consultation on the Queensland SuperGrid South project as a candidate PTI under the ERTJ Act (refer to Section 6.16).



# 09.
# Recently commissioned and committed network developments

*This chapter provides information on the status of customer connection works and transmission network projects since publication of the 2023 Transmission Annual Planning Report (TAPR). It presents a snapshot of recently commissioned projects and projects that are committed or awaiting commencement since completion of the Regulatory Investment Test for Transmission (RIT-T) as well as the status of asset retirement works.*

## Key highlights

- During 2023/24, Powerlink's delivery efforts remained predominantly directed towards connecting renewable generators and reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's regulated investment program focusses on reducing the identified risks arising from assets reaching the end of technical service life and maintaining network resilience while continuing to deliver safe, reliable and cost efficient transmission services to our customers.
- Powerlink continues to ensure the safe and reliable supply of electricity to townships, local communities, industry and businesses across Queensland with 11 reinvestment projects completed since publication of the 2023 TAPR.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland, with connection works of approximately 820MW of variable renewable energy (VRE) generation developments underway at the time of the 2024 TAPR publication.
- The 2024 TAPR includes the connection of an additional 300MW of generation capacity compared to that reported in the 2023 TAPR.

# 9.1 Introduction

Powerlink Queensland's network traverses 1,700km from north of Cairns to the New South Wales (NSW) border. The Queensland transmission network comprises transmission lines constructed and operated at 330kV, 275kV, 132kV and 110kV. The 275kV transmission network connects Cairns in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones and providing support to the 275kV network. A 330kV network connects the New South Wales (NSW) transmission network to Powerlink's 275kV network at Braemar and Middle Ridge substations.

A geographic representation of Powerlink's transmission network is shown in Figure 9.1.

The status of projects reported in this Chapter is as at 30 September 2024.

# 9.2 Connection works

Table 9.1 lists connection works commissioned since Powerlink's 2023 TAPR was published.

Table 9.1 Commissioned connection works since October 2023

| Project (1) | Purpose | Zone | Date commissioned |
|---|---|---|---|
| Clarke Creek Wind Farm | New Wind Farm (2) | Central West | Quarter 3 2023 |
| Chinchilla 200MW/400MWh Battery Energy Storage System (BESS) | New BESS | Bulli | Quarter 2 2023 (3) |
| MacIntyre Wind Farm | New Wind Farm (4) | Bulli | Quarter 1 2024 |
| Western Downs 200MW/400WWh BESS | New BESS | Bulli | Quarter 2 2024 |

Notes:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(2) Powerlink has completed the scope of works for this project. Remaining works associated with generation connection are being coordinated with the customer.

(3) Project Commissioning Notice issued subsequent to 2023 TAPR publication.

(4) Powerlink has completed the construction of assets in south-west Queensland to enable the connection of the MacIntyre Wind Precinct proposed renewable development and Queensland's second Renewable Energy Zone. Refer to Section 6.6.3 and Powerlink's website.

Table 9.2 lists new transmission connection works for generating systems, which are committed, and under construction at October 2024. These connection projects resulted from agreements reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 9.2 Committed and under construction connection works at October 2024

| Project (1) | Purpose | Zone | Proposed commissioning date |
|---|---|---|---|
| Kidston Pumped Storage Hydro | New pumped hydro energy storage | Ross | Quarter 1 2025 |
| Broadsound Solar Farm | New Solar Farm | Central West | Quarter 4 2025 |
| Lotus Creek Wind Farm | New Wind Farm | Central West | Quarter 3 2026 |
| Woolooga 200MW/400MWh BESS | New BESS | Wide Bay | Quarter 3 2025 |
| Wambo Wind Farm Stage 1 | New Wind Farm | South West | Quarter 4 2024 |
| Ulinda Park 155MW/298MWh BESS | New BESS | South West | Quarter 1 2025 |
| Greenbank 200MW/400MWh BESS | New BESS | Moreton | Quarter 1 2025 |

Note:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, industrial development or mine), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

## 9.3 Network developments

Table 9.3 list network developments which have been commissioned since October 2023.

Table 9.3 Commissioned network developments at October 2024

| Project | Purpose | Zone | Date commissioned |
|---|---|---|---|
| Broadsound 275kV bus reactor | Maintain voltages in the Central West zone | Central West | June 2024 |

Table 9.4 list network developments which are committed and under construction at October 2024.

Table 9.4 Committed network developments at October 2024

| Project | Purpose | Zone | Proposed commissioning date |
|---|---|---|---|
| Establishment of a 3rd 275kV connection into Woree | Enable development of the Northern Queensland Renewable Energy Zone and increase supply reliability in the Far North zone | Far North | December 2024 (1) |
| Belmont 275kV bus reactor | Maintain voltages in the Moreton zone | Moreton | December 2024 |

Note:

(1) The 3rd circuit was energised in June 2024 and completion of the remaining minor works at Yabulu South substation is expected by December 2024.

## 9.4 Network reinvestments

Table 9.5 lists network reinvestments commissioned since Powerlink's 2023 TAPR was published.

Table 9.5 Commissioned network reinvestments since October 2023

| Project | Purpose | Zone | Date commissioned |
|---|---|---|---|
| Strathmore 275/132kV transformer establishment | Maintain supply reliability in the North zone | North | September 2023 (1) |
| Strathmore 132kV secondary systems replacement | Maintain supply reliability in the North zone | North | September 2023 (1) |
| Nebo primary plant and secondary systems replacement | Maintain supply reliability in the North zone (2) | North | June 2024 |
| Lilyvale 132/66kV transformers replacement | Maintain supply reliability in the Central West zone (2) | Central West | June 2023 (1) |
| Calvale and Callide B secondary systems replacement | Maintain supply reliability in the Central West zone (1)(2)(3) | Central West | September 2023 (1)(3) |
| Boyne Island secondary systems replacement | Maintain supply reliability in the Gladstone zone | Gladstone | September 2023 (1) |
| Wurdong secondary systems replacement | Maintain supply reliability in the Gladstone zone | Gladstone | October 2023 (1) |
| Line refit works on 275kV transmission line between Woolooga and Palmwoods | Maintain supply reliability in the Wide Bay zone (1) | Wide Bay | September 2023 (1) |
| Line refit works on the 110kV transmission lines between West Darra and Sumner | Maintain supply reliability in the Moreton zone | Moreton | September 2023 (1) |
| Line refit works on the 110kV transmission lines between Rocklea and Sumner | Maintain supply reliability in the Moreton zone | Moreton | October 2023 (1) |
| Abermain 110kV secondary systems replacement | Maintain supply reliability in the Moreton zone (2) | Moreton | November 2023 |

Notes:

(1) Project Commissioning Notice issued subsequent to 2023 TAPR publication.

(2) Major works were completed in October 2017. Minor works were coordinated with Energy Queensland (Energex and Ergon Energy are part of the Energy Queensland Group) and have now been completed.

(3) Projects impacted by restrictions related to COVID-19.

Table 9.6 lists network reinvestments which are committed at October 2024.

Table 9.6 Committed network reinvestments at October 2024

| Project | Purpose | Zone | Proposed commissioning date |
|---|---|---|---|
| Woree secondary systems replacement | Maintain supply reliability in the Far North zone | Far North | September 2025 |
| Woree SVC secondary systems replacement | Maintain supply reliability in the Far North zone | Far North | March 2025 |
| Chalumbin secondary systems replacement | Maintain supply reliability in the Far North zone | Far North | December 2025 |
| Cairns secondary systems replacement | Maintain supply reliability in the Far North zone | Far North | December 2025 |
| Line refit works on the 275kV transmission lines between Chalumbin and Woree substations (section between Davies Creek and Bayview Heights) | Maintain supply reliability to the Far North and Ross zones (1) | Far North | January 2026 |
| Innisfail 132kV secondary systems replacement | Maintain supply reliability in the Far North zone | Far North | June 2027 |
| Line refit works on the 132kV transmission line between Townsville South and Clare South substations | Maintain supply reliability in the Ross zone | Ross | December 2024 |
| Garbutt configuration change | Maintain supply reliability in the Ross zone | Ross | January 2025 |
| Ross 275/132kV transformers life extension | Maintain supply reliability in the Ross zone | Ross | January 2025 |
| Townsville South secondary systems replacement Stage 1 | Maintain supply reliability in the Ross zone | Ross | February 2026 |
| Townsville South 132kV primary plant replacement | Maintain supply reliability in the Ross zone | Ross | July 2026 |
| Ross 132kV primary plant replacement | Maintain supply reliability in the Ross zone | Ross | September 2025 |
| Ross 275kV primary plant replacement | Maintain supply reliability in the Ross zone | Ross | November 2025 |
| Kemmis secondary systems replacement | Maintain supply reliability in the North zone | North | December 2024 |
| Nebo 132/11kV transformers replacement | Maintain supply reliability in the North zone | North | September 2025 |
| Line refit works on the 132kV transmission line between Eton tee and Alligator Creek substations | Maintain supply reliability in the North zone (1) | North | September 2025 |
| Newlands 132kV primary plant replacement | Maintain supply reliability in the North zone | North | December 2026 |
| Dysart 132/66kV transformers replacement | Maintain supply reliability in the Central West zone (1) | Central West | December 2024 |
| Blackwater 66kV CT and VT replacement | Maintain supply reliability in the Central West zone | Central West | December 2024 |
| Blackwater 132/66kV transformers replacement | Maintain supply reliability in the Central West zone | Central West | December 2024 |

Table 9.6 Committed network reinvestments at October 2024 (*continued*)

| Project | Purpose | Zone | Proposed commissioning date |
|---|---|---|---|
| Lilyvale 275kV and 132kV primary plant replacement | Maintain supply reliability in the Central West zone (2) | Central West | June 2026 |
| Egans Hill secondary systems replacement | Maintain supply reliability in the Gladstone zone | Gladstone | March 2025 |
| Gladstone South secondary systems replacement | Maintain supply reliability in the Gladstone zone | Gladstone | February 2027 |
| QAL West secondary systems replacement | Maintain supply reliability in the Gladstone zone | Gladstone | February 2027 |
| Redbank Plains 110/11kV transformers and selected primary plant replacement | Maintain supply reliability in the Moreton zone (1) | Moreton | October 2026 |
| Mt England 275kV secondary systems replacement | Maintain supply reliability in the Moreton zone | Moreton | December 2026 |
| Mudgeeraba 275kV secondary systems replacement | Maintain supply reliability in the Gold Coast zone | Gold Coast | December 2024 |

Notes:

(1) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

(2) Projects impacted by restrictions related to COVID-19. A number of projects have also been deferred 12+ months.

## 9.5 Uncommitted Regulatory Investment Test for Transmission projects

Table 9.7 lists network investments which have undergone the RIT-T and are not fully committed at October 2024.

Table 9.7 Uncommitted network investments at October 2024

| Project | Purpose | Zone | Proposed commissioning date |
|---|---|---|---|
| Kemmis 132/66kV transformer replacement | Maintain supply reliability in the North zone (1) | North | November 2026 |
| Tarong 275/66kV transformers and selected primary plant replacement | Maintain supply reliability in the South West zone (1) | South West | July 2025 |
| Tangkam 110kV secondary systems replacement | Maintain supply reliability in the South West zone (1) | South West | September 2026 |
| Chinchilla 132kV primary plant and secondary systems replacement | Maintain supply reliability in the South West zone (1) | South West | June 2027 |
| Sumner 110kV secondary systems replacement | Maintain supply reliability in the Moreton zone (1) | Moreton | October 2025 |

Notes:

(1) Capital expenditure in relation to network asset replacement.

## 9.6 Asset retirement works

Table 9.8 lists asset retirement completed since October 2023.

Table 9.8 Asset retirement works completed at October 2024 (1)

| Project | Purpose | Zone | Proposed retirement date |
|---|---|---|---|
| Mudgeeraba 275/110kV Transformer 3 retirement | Removal of asset at the end of technical life | Gold Coast | September 2023 (2) |

Notes:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

(2) Project completion notification subsequent to 2023 TAPR publication.

Table 9.9 lists asset retirement works at October 2024.

Table 9.9 Asset retirement works at October 2024 (1)

| Project | Purpose | Zone | Proposed retirement date |
|---|---|---|---|
| Cairns 132/22kV Transformer 4 retirement | Removal of asset at the end of technical life | Far North | December 2027 |
| 132kV transmission line retirement between Townsville South and Clare South substations | Removal of assets at the end of technical life | Ross | June 2029 |
| Tarong 275/132kV transformers retirement | Removal of assets at the end of technical life | South West | June 2025 |

Note:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 9.1 Existing Powerlink Queensland transmission network October 2024

# Appendices

# Appendix A Asset management overview

## A.1 Introduction

Powerlink's Asset Management System forms part of Powerlink's Business Strategy and is integral to managing and monitoring assets across the asset lifecycle and captures key internal and external drivers and initiatives for the business.

Factors that influence network development, such as energy and demand forecasts, generation development (including asynchronous generation development and potential synchronous generation withdrawal), emerging industry trends and technology, and risks arising from the condition and performance of the existing asset base are analysed collectively to support integrated network planning over a 10-year period.

## A.2 Overview of approach to asset management

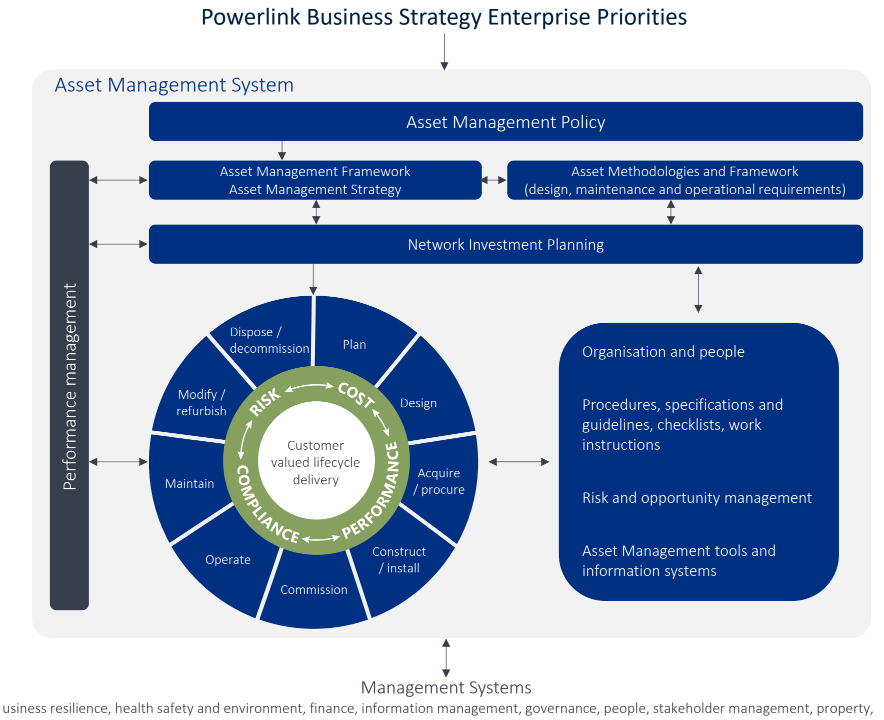
Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver safe, cost effective, reliable and sustainable services.

Asset management is a critical aspect of Powerlink's operations, ensuring efficient management of assets and optimal utilisation of resources. Figure A.1 illustrates the relationships and linkages between the Asset Management Policy, Strategy, and other components of the Asset Management System.

Powerlink's asset management and joint planning approach ensures asset reinvestment needs consider the enduring need and most cost effective options as opposed considering only like-for-like replacements. A detailed analysis of both asset condition and network capability is performed prior to proposed reinvestment and where applicable, a Regulatory Investment Test for Transmission (RIT-T) is undertaken in order to bring about optimised solutions that may involve network reconfiguration, retirement and/or non-network solutions (Refer to sections 6.2 and 6.6).

Powerlink's asset management approach is committed to achieving sustainable practices that ensure Powerlink provides a valued transmission service to meet customers' needs by optimising whole of life cycle costs, benefits and risks and ensuring compliance with applicable legislation, regulations and standards.

Figure A.1 Asset Management Overview



## A.3 Powerlink's Asset Management System

Powerlink's Asset Management System ensures assets are managed in a manner consistent with business strategy while supporting and informing other business management systems. Underpinning this system is the Asset Management Policy which sets out the principles to be applied for making asset management decisions as well as ensuring delivery of these decisions. The Asset Management Policy aligns Powerlink's strategic objectives with customer and stakeholder requirements.

The Asset Management Framework and Asset Management Strategy are developed based on Asset Management Policy principles which are used to inform asset management methodologies and activities. The Asset Management Strategy sets the longterm focus for managing assets. Both of these consider the need to continually improve asset management practices.

Powerlink undertake periodic reviews of network assets considering a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and on-going supportability.

Asset Methodologies provide whole of life cycle management for each asset category (transmission lines, substations, digital assets, land assets and underground cables) to inform the delivery of asset life cycle stages.

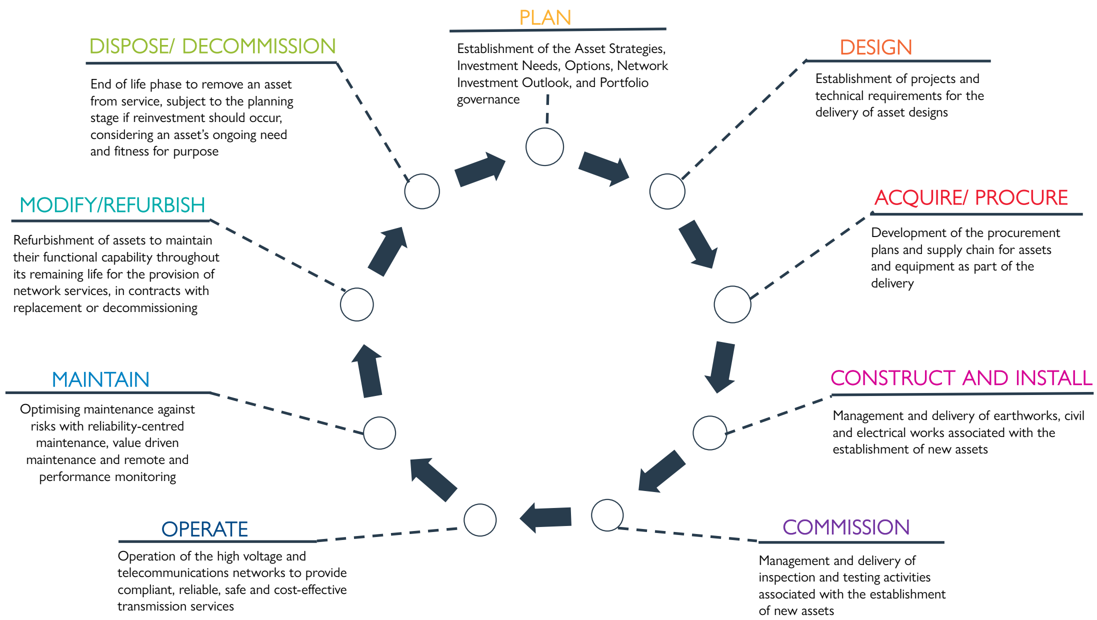
All asset management related activities are undertaken by applying relevant procedures, specifications and guidelines for delivering each stage of an asset life cycle activity.

Asset information is key for Powerlink's asset management with asset data, information and knowledge used to inform a range of asset management and investment decision making processes. Asset information comes from the analysis of asset data which is used to inform decisions on how Powerlink's assets are managed for both short-term operational purposes and longer term strategic plans.

### A.3.1 Life cycle delivery

Life cycle delivery establishes how and what is needed for asset decisions and activities in consideration of the Asset Management System. Powerlink defines asset life cycle and main activities throughout the nine stages shown in Figure A.2.

Figure A.2 Powerlink's asset life cycle stages



## A.4 Flexible and integrated network investment planning

A fundamental element of the Asset Management System involves processes to manage the life cycle of assets, from planning and investment to operation, maintenance and refurbishment, and end of technical service life.

A range of options are considered as part of a flexible and integrated approach to network investment planning. These options may include retiring or decommissioning assets where there is unlikely to be an on-going future need, refurbishing to maintain the service life of assets, replacing assets with different capacity or type to match needs, alternate network configuration opportunities, and non-network solutions.

The purpose of Powerlink's network investment planning is to:

- apply the principles set out in Powerlink's Asset Management Policy, Framework, Strategy and related processes to guide network asset planning and reinvestment decisions
- provide an overview of asset condition and health, life cycle plans and emerging risks related to factors such as safety, network reliability, resilience and obsolescence
- provide an overview and analysis of factors that impact network development, including energy and demand forecasts, generation developments, forecast network performance and capability, and the condition and performance of Powerlink's existing asset base
- identify potential opportunities for optimisation of the transmission network
- provide the platform to enable the transformation to a more sustainable, cost efficient and climate resilient power system.

## A.5 Asset management implementation

Powerlink has adopted implementation strategies across its portfolio of projects and maintenance activities aimed at efficiently delivering the overall work program, including prudent design standardisation by considering emerging trends in technology, portfolio management and supply chain management.

One of Powerlink's objectives includes the efficient implementation of work associated with network operation, field maintenance and project delivery. Powerlink continues to pursue innovative work techniques that:

- reduce risk to personal safety
- optimise maintenance and/or operating costs
- reduce the requirement for and minimise the impacts of planned outages on the transmission network.

In line with good practice, Powerlink also undertakes regular auditing of work performed to facilitate the continuous improvement of the overall Asset Management System.

## A.6 Further information

Further information on Powerlink's Asset Management System may be obtained by emailing NetworkAssessments@powerlink.com.au.

# Appendix B Joint planning

## B.1 Introduction

The objective of joint planning is to collaboratively identify network and non-network solutions to limitations which best serve the long-term interests of customers, irrespective of the asset boundaries (including those between jurisdictions).

Powerlink's joint planning framework with Australian Energy Market Operator (AEMO) and other Network Service Providers (NSP) is in accordance with the requirements set out in Clause 5.14.3 and 5.14.4 of National Electricity Rules (NER). The joint planning process results in integrated area and inter-regional strategies which optimise asset investment needs and decisions consistent with whole of life asset planning.

Joint planning begins several years in advance of an investment decision. Depending upon the nature of the limitation or asset condition driver to be addressed and the complexity of the proposed corrective action, the nature and timing of future investment needs are reviewed at least on an annual basis utilising an interactive joint planning approach.

In general, joint planning seeks to:

- understand the issues faced by the different network owners and operators
- understand existing and forecast network limitations between neighbouring NSPs
- help identify the most efficient options to address these issues, irrespective of the asset boundaries (including those between jurisdictions)
- influence how networks are operated and managed, and what network changes are required.

Projects where a feasible network option exists which is greater than $7 million are subject to a formal consultation process under the applicable regulatory investment test mechanism. The owner of the asset where the limitation emerges will determine whether a Regulatory Investment Test for Transmission (RIT-T) or Regulatory Investment Test for Distribution (RIT-D) is used to progress the investment recommendation under the joint planning framework. This provides customers, stakeholders and interested parties the opportunity to provide feedback and discuss alternative solutions to address network needs. Ultimately, this process results in investment decisions which are prudent, transparent and aligned with stakeholder expectations.

## B.2 Working and regular engagement groups

Powerlink regularly undertakes joint planning meetings with AEMO, Energy Queensland and Jurisdictional Planning Bodies (JPB) from across the National Electricity Market (NEM). There are a number of working groups and reference groups which Powerlink contributes to:

- Executive Joint Planning Committee (EJPC)
- Joint Planning Committee (JPC)
- Regulatory Working Group (RWG)
- Forecasting Reference Group (FRG)
- Power System Modelling Reference Group (PSMRG)
- NEM Working Groups of the Energy Networks Australia (ENA)
- 2022 General Power System Risk Review (GPSRR) (refer to Section 7.3)
- AEMO's System Security Reports
- Network Support and Control Ancillary Service (NSCAS)
- System Strength and Inertia requirements
- AEMO's Integrated System Plan (ISP) including joint planning and submissions to the ISP Inputs, Assumptions and Scenarios, ISP Methodology and development of ISP Preparatory Activity reports
- AEMO's System Strength Impact Assessment Guidelines and Methodology
- AEMO and jurisdictional planners to support and promote collaboration and coordination of model development, model management and test activities to facilitate the safe and expeditious release of inter-network capacity

- Transgrid when assessing the economic benefits of expanding the power transfer capability between Queensland and NSW
- Energex and Ergon Energy (as part of the Energy Queensland Group) for the purposes of efficiently planning developments and project delivery in the transmission and sub-transmission network.

### B.2.1 Executive Joint Planning Committee

The EJPC coordinates effective collaboration and consultation between JPBs and AEMO on electricity transmission network planning issues. The EJPC directs and coordinates the activities of the Forecasting Reference Group, and the Regulatory Working Group. These activities ensure effective consultation and coordination between JPB, Transmission System Operators and AEMO on a broad spectrum of perspectives on network planning, forecasting, market modelling, and market regulatory matters in order to deal with the challenges of a rapidly changing energy industry.

### B.2.2 Joint Planning Committee

The JPC is a working committee supporting the EJPC in achieving effective collaboration, consultation and coordination between JPB, Transmission System Operators and AEMO on electricity transmission network planning issues.

### B.2.3 Forecasting Reference Group

The FRG is a monthly forum with AEMO and industry forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

### B.2.4 Regulatory Reference Group

The RWG is a working group to support the EJPC in achieving effective collaboration, consultation and coordination between JPBs, Transmission System Operators and AEMO on key areas related to the application of the regulatory transmission framework and suggestions for improvement.

### B.2.5 Power System Modelling Reference Group

The PSMRG is a technical expert reference group which focuses on power system modelling and analysis techniques to ensure an accurate power system model is maintained for power system planning and operational analysis, establishing procedures and methodologies for power system analysis, plant commissioning and model validation.

## B.3 AEMO Integrated System Plan

Powerlink works closely with AEMO to support the development of the ISP. The ISP sets out a roadmap for the eastern seaboard's power system over the next two decades by establishing a whole of system plan for efficient development that achieves system needs through a period of transformational change.

During 2023 and 2024 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. Powerlink and the Department of Energy and Climate (DEC) have provided advice to AEMO on the status of projects, transmission and Pumped Energy Hydro Scheme (PHES) projects, defined in the Queensland Energy and Jobs Plan (QEJP) for inclusion in their ISP modelling. This resulted in the Borumba PHES and CopperString 2032 projects being modelled as anticipated projects in the 2024 ISP.

#### Process

Powerlink continues to provide a range of network planning inputs to AEMO's ISP consultation and modelling processes, via joint planning processes, regular engagement, workshops and various formal consultations.

#### Methodology

More information on the 2026 ISP including methodology and assumptions is available on AEMO's website.

#### Outcomes

The ISP attempts to identify a long-term plan for the efficient development of the NEM transmission network, and the connection of Renewable Energy Zones (REZ) over the coming 20 years. It is based on a set of assumptions and a range of scenarios.

## B.4 AEMO national planning – System strength, inertia and NSCAS reports

AEMO has identified system security needs across the NEM for the coming five-year period as the energy transformation continues at pace. Declining minimum operational demand, changing synchronous generator behaviour and rapid uptake of variable renewable energy (VRE) resources combine to present opportunities for delivery of innovative and essential power system security services. The 2023 System Security Report is part of the NER framework intended to plan for the security of the power system under these changing operating conditions.

### Process

Powerlink has worked closely with AEMO to determine the system strength, inertia and NSCAS requirements for the Queensland region. Powerlink and AEMO reviewed the Queensland fault level nodes and their minimum three phase fault levels and assessed the reactive power absorption requirements.

### Methodology

AEMO applied the System Strength Requirements Methodology[1] to determine the Queensland fault level nodes and their minimum three phase fault levels. More information on the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls is available on AEMO's website.

AEMO applied the Network Support and Control Ancillary Service Description and Quantity Procedure[2] to identify whether there are reactive power capability gaps.

### Outcomes

The 2023 System Security Report confirmed the existing minimum fault level requirements in Queensland and the system strength shortfall at the Gin Gin node. Powerlink commenced an Expression of Interest (EOI) process for short and long-term non-network solutions to the fault level shortfall at the Gin Gin node and expect to publish the response to the shortfall by December 2023 (refer to Section 6.8.1).

The 2023 System Security Report published the minimum fault level requirement at each system strength node and AEMO's forecast level and type of inverter-based resources (IBR) and market network service facilities over a 10-year period. Powerlink, as Queensland System Strength Service Provider, (SSSP), needs to procure system strength services to meet these requirements. In March 2023 Powerlink commenced a RIT-T to identify a portfolio of solutions to meet these minimum and efficient levels of system strength. Powerlink has been working with proponents of non-network solutions to inform the technical and economic analysis for the optimal portfolio of solutions anticipated to be required. Powerlink will publish the Project Assessment Draft Report (PADR) in November 2024, which will identify the proposed preferred option to provide minimum and efficient levels of system strength (refer to Section 6.8.2).

## B.5 General Power System Risk Review and Power System Frequency Risk Review

AEMO published the 2024 General Power System Risk Review (GPSRR) in July 2024.

### Process

In accordance with rule 5.20A of the NER, AEMO in consultation with TNSPs prepares a GPSRR for the NEM. The purpose of the GPSRR is to review:

- a prioritised set of risks comprising contingency events and other events and conditions that could lead to cascading outages or major supply disruptions
- the current arrangements for managing the identified priority risks and options for their future management
- the arrangements for management of existing protected events and consideration of any changes or revocation
- the performance of existing Emergency Frequency Control Schemes (EFCS) and the need for any modifications.

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1 System Security Market Frameworks Review.
System Strength Requirements Methodology - September 2022 (latest version).

2 Network Support and Control Ancillary Service Description and Quantity Procedure.

#### Methodology

With support from Powerlink, AEMO assessed the performance of existing EFCS. AEMO also assessed high priority non-credible contingency events identified in consultation with Powerlink. From these assessments AEMO determines whether further action may be justified to manage frequency risks.

#### Outcomes

The Final 2024 GPSRR report recommended:

- Powerlink and Transgrid investigate, design and implement a special protection scheme (SPS) to mitigate the risk of Queensland New South Wales Interconnector (QNI) instability and synchronous separation of Queensland following a range of non-credible contingencies
- Jurisdictions develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risk
- Powerlink and Energy Queensland to identify and implement measures to restore under frequency load shedding (UFLS) load, and to collaborate with AEMO on the design and implementation of remediation measures.
- NSPs manage risks associated with localised aggregated Battery Energy Storage System (BESS) response to remote frequency disturbances
- AEMO finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.

Carry-over recommendations from the 2022 Power System Frequency Risk Review and 2023 General Power System Risk Review include:

- NSPs evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training
- Implementation of a SPS for the loss of both Columboola to Western Downs 275kV lines. The loss of both of these lines, which supply the Surat zone, is non-credible but could cause QNI to lose stability
- Assessment of the risk and solution options to further mitigate instability for the non-credible loss of both Calvale to Halys 275kV lines following the QNI minor commissioning.

## B.6 Joint planning with Transgrid – Expanding the transmission transfer capacity between New South Wales and Queensland

In December 2019, Powerlink and Transgrid finalised a Project Assessment Conclusions Report (PACR) on 'Expanding NSW-Queensland transmission transfer capacity'. The recommended option includes uprating the 330kV Liddell to Tamworth 330kV lines and installing Static VAr Compensators (SVCs) at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations. All material works associated with this upgrade are within Transgrid's network. Transgrid has now commissioned these works and Powerlink is working with Transgrid and AEMO on QNI tests to facilitate the release of additional capacity (refer to Section 6.14).

## B.7 Joint planning with Energex and Ergon Energy

Queensland's Distribution Network Service Providers (DNSPs) Energex and Ergon Energy (part of the Energy Queensland Group) participate in regular joint planning and coordination meetings with Powerlink to assess emerging limitations, including asset condition drivers, to ensure the recommended solution is optimised for efficient expenditure outcomes[3]. These meetings are held regularly to assess, in advance of any requirement for an investment decision by either NSP, matters that are likely to impact on the other NSP. Powerlink and the DNSPs then initiate detailed discussions around addressing emerging limitations as required. Joint planning also ensures that interface works are planned to ensure efficient delivery.

Table B.1 provides a summary of activities that are utilised in joint planning. During preparation of respective regulatory submissions, the requirement for joint planning increases significantly and the frequency of some activities reflect this.

[3] Where applicable to inform and in conjunction with the appropriate RIT-T consultation process.

Table B.1 Joint planning activities

| Activity | Frequency | |
|---|---|---|
| | As required | Annual |
| Sharing and validating information covering specific issues | Y | |
| Sharing updates to network data and models | Y | |
| Identifying emerging limitations | Y | |
| Developing potential credible solutions | Y | |
| Estimating respective network cost estimates | Y | |
| Developing business cases | Y | |
| Preparing relevant regulatory documents | Y | |
| Sharing information for joint planning analysis | Y | |
| Sharing information for respective works plans | Y | Y |
| Sharing planning and fault level reports | | Y |
| Sharing information for Regulatory Information Notices | | Y |
| Sharing updates to demand forecasts | | Y |
| Joint planning workshops | Y | Y |

### B.7.1 Matters requiring joint planning

The following is a summary of projects where detailed joint planning with Energex and Ergon Energy (and other NSPs as required) has occurred since the publication of the 2023 TAPR (refer to Table B.2). There are a number of projects where Powerlink, Energex and Ergon Energy interface on delivery, changes to secondary systems or metering, and other relevant matters which are not covered in this Chapter. Further information on these projects, including timing and alternative options is discussed in Chapter 6.

Table B.2 Joint planning project references

| Project | Reference |
|---|---|
| Maintaining reliability of supply to Kamerunga and Cairns northern beaches | Section 6.9.1 |
| Maintaining reliability of supply and addressing condition risks at Ingham South | Section 6.9.2 |
| Maintaining reliability of supply to between Ross and Dan Gleeson | Section 6.9.2 |
| Maintaining reliability of supply to Gladstone South | Section 6.10.2 |
| Maintaining reliability of supply at Ashgrove | Section 6.11.5 |
| Maintain reliability of supply to the Brisbane metropolitan area | Section 6.11.5 |
| Possible retirement of Loganlea 110/33kV transformer | Section 6.11.5 |

Note:

(1) Operational works, such as Overload Management Systems, do not form part of Powerlink's capital expenditure budget.

# Appendix C Forecast of connection point maximum demands

Appendix C addresses National Electricity Rules (NER) (Clause 5.12.2(c)(1)[1] which requires the Transmission Annual Planning Report (TAPR) to provide 'the forecast loads submitted by a Distribution Network Service Provider (DNSP) in accordance with Clause 5.11.1 or as modified in accordance with Clause 5.11.1(d)'. This requirement is discussed below and includes a description of:

- the forecasting methodology, sources of input information and assumptions applied (Clause 5.12.2(c)(i)) (refer to Section C.1)
- a description of high, most likely and low growth scenarios (refer to Section C.2)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR that have changed significantly from forecasts provided in the TAPR from the previous year (refer to Section C.3)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR from the previous year which are significantly different from the actual outcome (refer to Section C.4).

## C.1 Forecasting methodology used by Blunomy for maximum demand

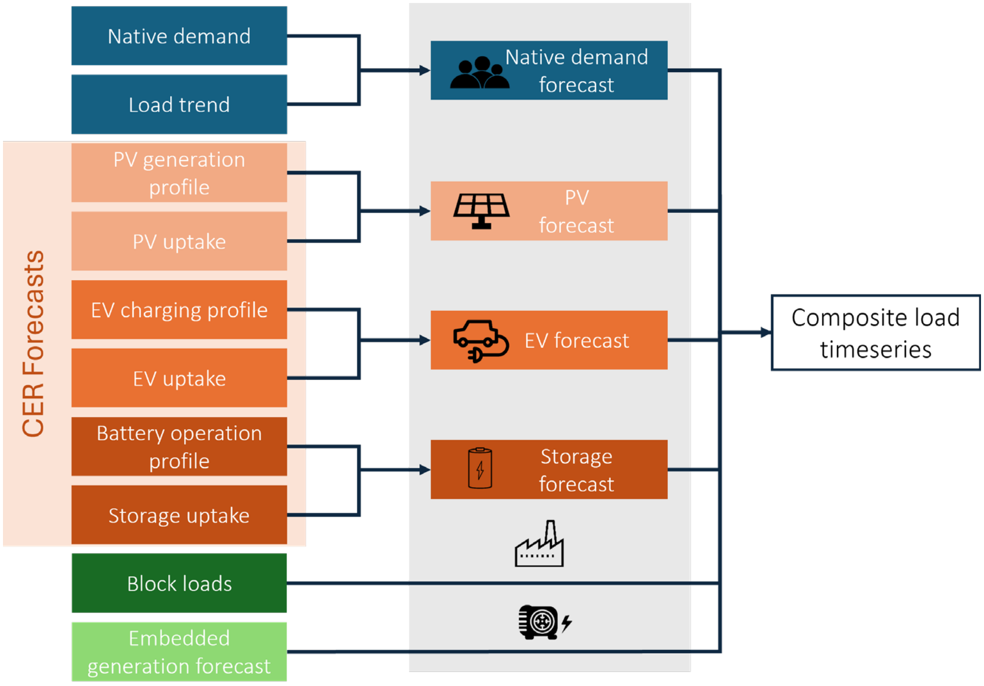
VISION forecasting and planning (by Blunomy) was leveraged by Powerlink to forecast maximum and minimum demand across its network. Blunomy is a consulting company focussed on developing tools to operationalise the energy transition. VISION forecasting and planning by Blunomy is a network planning tool that supports networks preparing for the decarbonised and decentralised grid of the future. Blunomy was also engaged to develop a Consumer Energy Resources (CER) forecasts for Energy Queensland. These CER forecasts were leveraged to provide Powerlink its maximum demand forecasts.

VISION provided Powerlink with 10-year forecasts of the 50% Probability of Exceedance[2] (PoE) and 10% PoE annual maximum demand. The forecast process individually models the different component of electricity demand: native demand, photovoltaic (PV), Electric vehicle (EV), BESS, block loads and embedded generation. It incorporates the latest assumptions for macro-economic factors and evolving trends in energy consumption and technology adoption, with sources including Australian Bureau of Statistics (ABS), Queensland Government, Australian Energy Market Operator (AEMO), Deloitte Access Economics economic forecasts, CSIRO GenCost reports, internal data from Energy Queensland and Powerlink.

The following sections provide a high-level overview of each sub model and the forecast process.

1 Where applicable, clauses 5.12.2 (1)(c)(iii) and (iv) are discussed in Chapter 3.
2 A 10% POE is a one in ten year maximum demand value: It would be expected, on average to observe a demand exceeding the 10% PoE once in ten years.

Figure C.1 Schematic of the building blocks of the forecast. Independent sub models are derived for the different CER technologies, native demand, trends, block loads and embedded generation. Composite load traces are constructed from the output of each sub model and used in a Monte-Carlo process to estimate Maximum Demand with PoE 10% and 50%.




### Native demand model – weather and calendar sensitivity

VISION develops a model to estimate a probability distribution of demand conditional on weather and calendar conditions. VISION trains its demand model on the past 4 years of actual metered data (at half-hourly granularity) and leverages weather data sourced from ERA5. ERA5 is a high-resolution global weather dataset produced by the European Centre for Medium-Range Weather Forecasts (ECMWF). It provides hourly weather data from 1979 to the present, with a spatial resolution of approximately 31km, and includes a wide range of atmospheric variables. The model allows to sample a full year of demand data, at half hourly granularity, for a given “weather year”, which is a realisation of past weather conditions.

### Load trends

VISION develops a regression model for average demand, incorporating historical population, GSP, Electricity prices, Energy Efficiency numbers from ABS, Queensland Government and AEMO, as well as Cooling Degree Days and Heating Degree Days. The trend is forecast for each scenario, with different assumptions made for these macro drivers. Vision applies a weighted trend for each asset in Powerlink’s network, based on a spatial forecast of population (at SA2 level from Queenland Government data) and the consumption split between residential, commercial and industrial customers (informed by EQL and Powerlink).

### CER uptakes (developed with Energy Queensland)

VISION forecasts CER in a bottom-up (from feeders) and top down (at the Energex and Ergon network level) process. The bottom-up forecast uses spatially granular information and a top-down forecast captures macro-economic and technology factors. We then map and aggregate the EQL’s zone substations to Powerlink’s substations.

The bottom-up forecast is a technology adoption model, using historical technology stock (CER register for PV and EV, vehicle registration data for EV), as well as Statistical Area Level 2 (SA2) level ABS data. It defines per feeder s-curves of technology adoption.

The top-down forecast defines an adoption curve using historical and future GSP, population and technology prices.

A reconciliation process ensures that the top-down forecast is spatially consistent with the bottom-up forecast.

**CER profiles (developed with Energy Queensland):**

VISION derives load profiles for EV charging modelled through simulation of driving and charging for different vehicle types. The simulation leverages vehicle driving data sourced by Energy Queensland. The simulations provide different profiles for collaborative and convenience charging. The scenarios further define a glide path between the two types of charging to model changing patterns over the forecast horizon.

VISION derives load profiles for BESS through:

- a simulation process for "solar soaking" patterns
- an optimisation of the battery dispatch for customers with fixed tariffs
- an optimisation of the battery dispatch in the NEM for systems operating in the wholesale electricity market, using historical prices in the NEM.

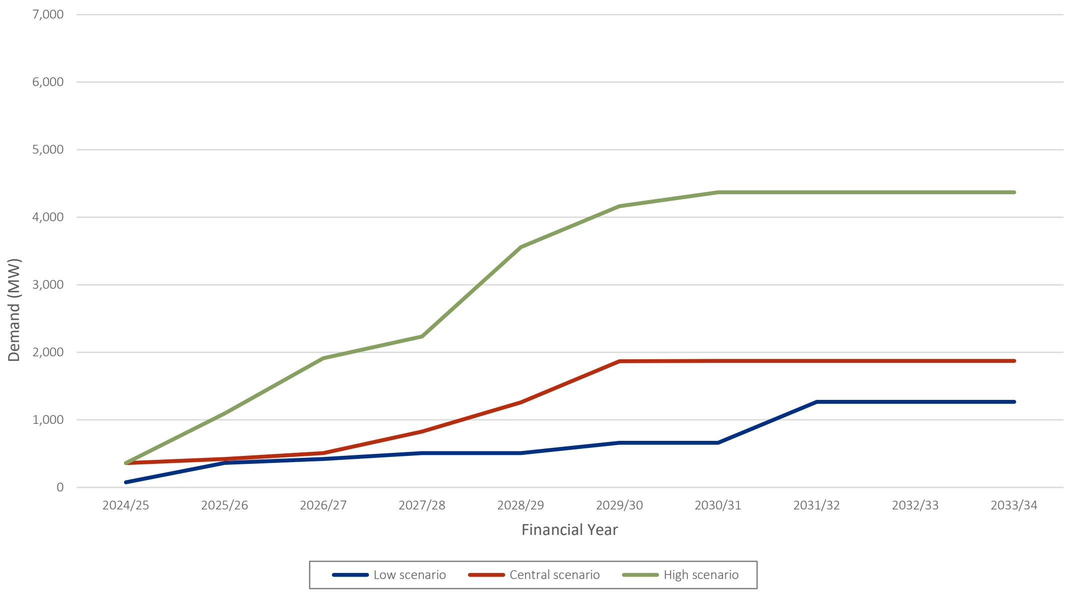
Similar to EVs, for each forecast scenario, a glide path between the different consumption patterns combines a nominal composite profile for BESS operation, evolving over the forecast horizon.

VISION estimates PV generation profiles using local historical weather conditions on each network asset.

### Block loads

Powerlink and Energy Queensland provides the list of block loads added to the relevant high, central and low scenarios based on consultations with their customers. Block loads are defined by their capacity as well as by a profile archetype, from which VISION derives a modelled timeseries. Figure C.2 shows the block loads for the Low, Central and High scenarios.

Figure C.2 Block Loads




### Generator model

VISION models embedded generators according to their types:

- non dispatchable renewable generation (PV and Wind) are modelled according to their capacity and historical weather conditions on site
- dispatchable generation is modelled through profile archetypes derived from historical meter data.

### Forecast process

VISION combines the above sub-models to estimate POE forecast by a Monte-Carlo approach:

- for 10 Weather Years, n estimates of demand are sampled from the modelled probability distribution (native demand model): each sample is a full year worth of load (30min interval)
- the samples are scaled by the trend modelled (energy consumption trend model)
- the CER profiles are multiplied by their forecast uptakes and are added to the timeseries (CER model)
- block loads, with capacity and profiles defined by Powerlink, are added to the timeseries
- the generation is added to the timeseries (for a forecast of delivered demand)
- the Maximum demand of each composite sample is recorded.

VISION derives the 50% and 10% POE maximum demand from these 10 x n samples of maximum demand.

## C.2 Description of Powerlink's high, central and low growth scenarios for maximum demand

The scenarios developed for the high, central and low case maximum demand forecasts were prepared in June 2024 based on the most recent information. The assumptions for the Powerlink forecast of demand are consistent with the assumptions for the CER forecast developed with Energy Queensland.

### High growth scenario assumptions for maximum demand

- GSP – High growth, averaging 2.8% per annum in the forecast horizon
- Queensland regional population growth – High growth, averaging 2% per annum in the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, stable afterwards
- Energy efficiency – AEMO's Green energy exports scenario (2023)
- EV price parity reached in 2027, share of collaborating charging growing from 10% to 50% by 2036
- Battery charging profiles – Fast increasing participation in VPP programs, from 20% to 65% in 2037
- PV prices – CSIRO Global NZE by 2050 scenario (GenCost 2023), rebased on historical retail prices.

### Central scenario assumptions for maximum demand

- GSP – Medium growth, averaging 2% per annum in the forecast horizon
- Queensland regional population growth – Medium growth, decreasing to 1.6% per annum in the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, followed by an increase at .7% per annum
- Energy efficiency – AEMO's Step change scenario (2023)
- EV price parity reached in 2030, share of collaborating charging growing from 8% to 40% by 2036
- Battery charging profiles –Increasing participation in VPP programs, from 17% to 55% in 2037
- PV prices –CSIRO Current Policies scenario (GenCost 2023), rebased on historical retail prices.

### Low growth scenario assumptions for maximum demand

- GSP – Slow growth, averaging 1.2% per annum in the forecast horizon
- Queensland regional population growth – Slow growth, decreasing from current levels to 1% per annum over the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, followed by a faster increase at 1.4 % per annum
- Energy efficiency – AEMO's Progressive change scenario (2023)
- EV price parity reached in 2033, share of collaborating charging growing from 5% to 15% by 2036
- Battery charging profiles – Low participation in VPP programs, increasing from 5% to 12% in 2037
- PV prices – CSIRO Global NZE post 2050 scenario (GenCost 2023), rebased on historical retail prices.

Figure C.3 Embedded battery energy storage system – Capacity

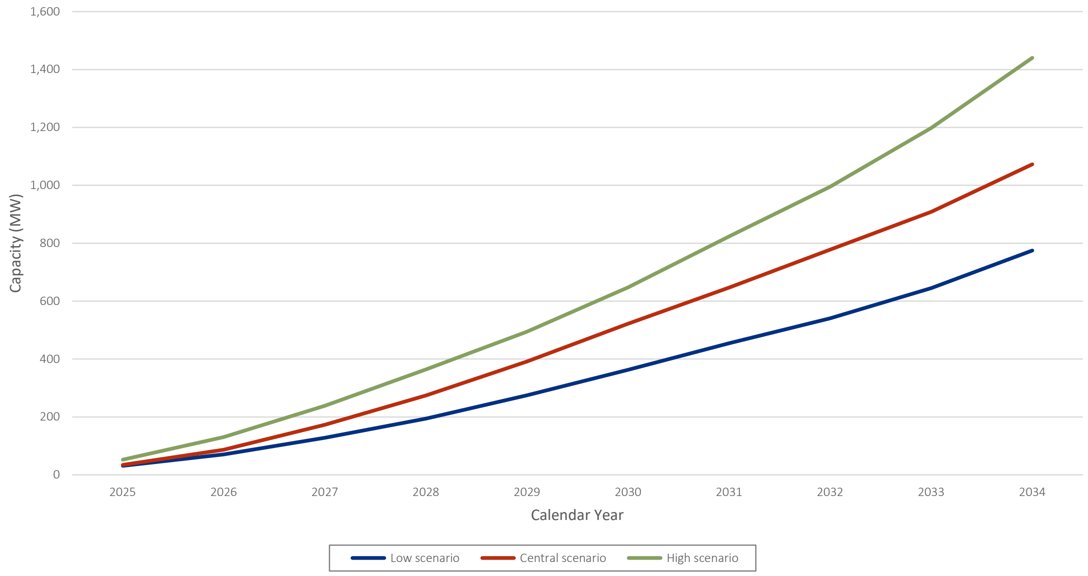
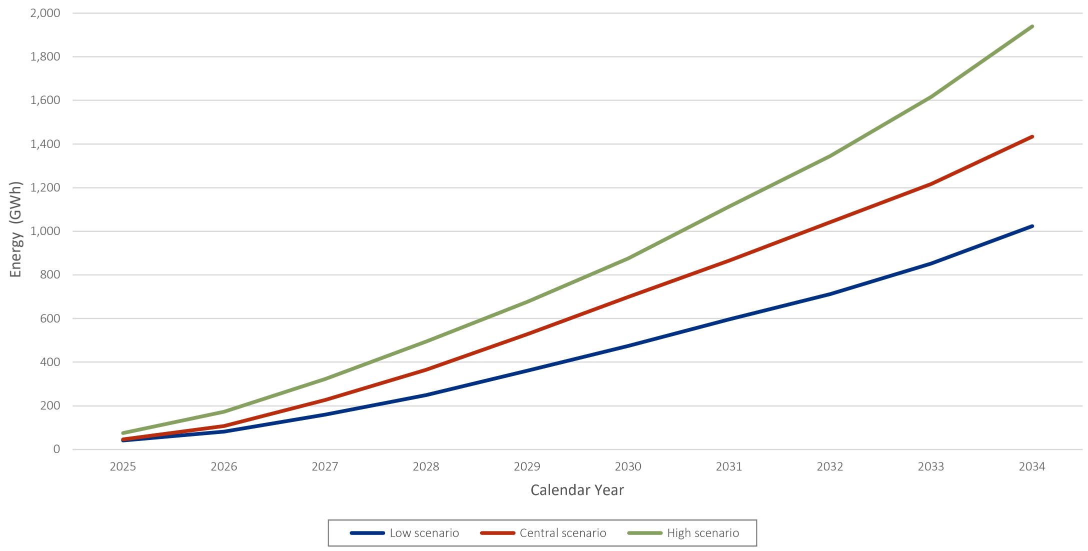
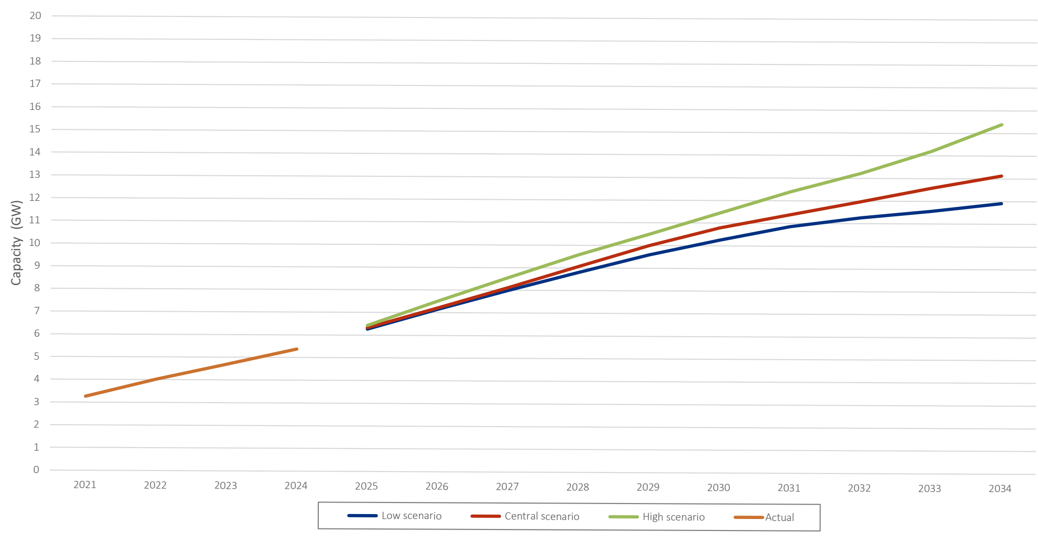


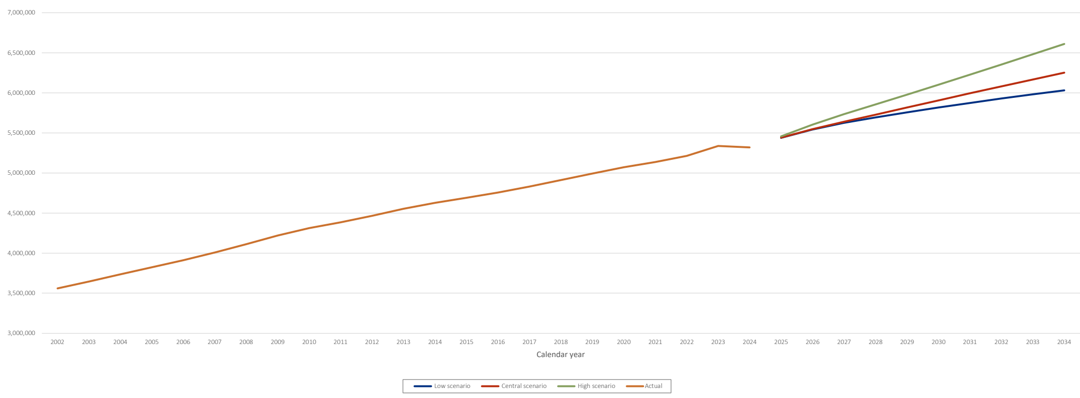

Figure C.4 Embedded battery energy storage system – Energy



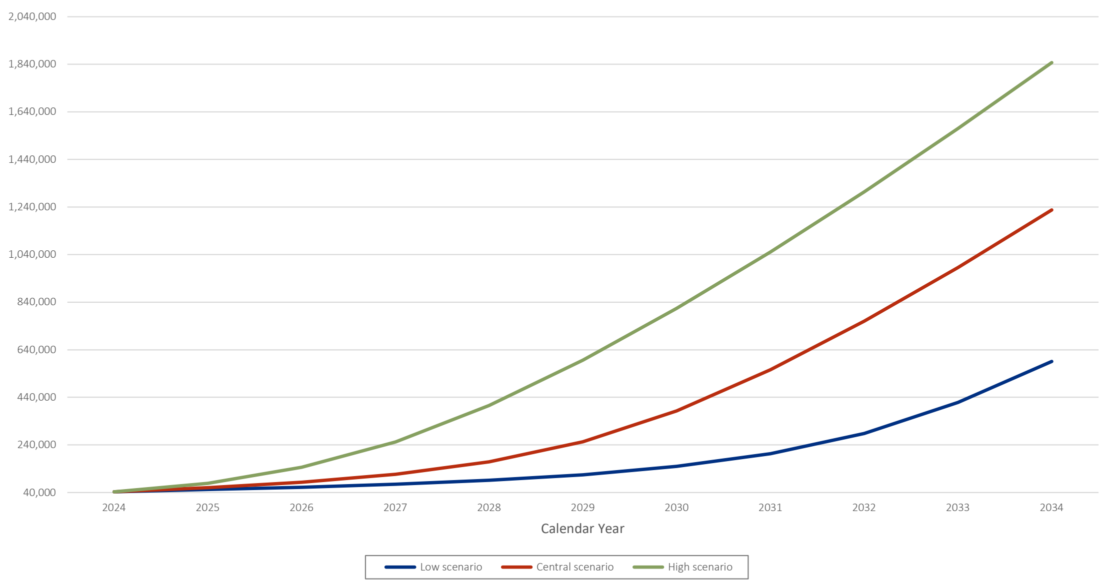
## Figure C.5 Rooftop PV uptake – Capacity




## Figure C.6 Population




## Figure C.7 Electric Vehicle uptake



## C.3 Significant changes to the connection point maximum demand forecasts

Major differences between the 2024 forecast and the 2023 forecast can generally be attributed to natural variation in peaks below the connection point level, which can result in displaying an associated variation in year on year changes at the connection point level, and with changes in the growth in the lower levels of the network rather than from any network configuration changes or significant block loads. Changes in proposed block loads also account for differences. These, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

**Table C.1** Ergon connection points with the greatest difference in growth between the 2024 and 2023 forecasts

| Connection Point | kV | Change in growth rate (per annum) |
|---|---|---|
| Blackwater | 132 | -8% |
| Turkinje (Craiglie and Lakeland) | 132 | -3% |

**Table C.2** Energex connection points with the greatest difference in growth between the 2024 and 2023 forecasts

| Connection Point | kV | Change in growth rate (per annum) |
|---|---|---|
| Abermain | 33 | -2% |
| Ashgrove West | 110 | -2% |
| Bundamba | 110 | -2% |
| Blackstone (Raceview) | 110 | -1% |

## C.4 Significant differences to actual observations

The 2023/24 summer was relatively hotter across large parts of Queensland when compared to recent seasons. This, combined with natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2023 forecast values for 2023/24 and what was observed.

**Table C.3** Ergon connection points with the greater than 10% absolute difference between the peak 2023/24 and corresponding base 2023 forecast for 2023/24

| Connection Point | 2023/24 forecast peak | 2023/24 actual peak | Difference |
|---|---|---|---|
| Ashgrove West | 78 | 112 | 44% |
| Woolooga (Gympie) | 228 | 265 | 19% |
| Molendinar | 536 | 596 | 11% |
| Sumner | 33 | 36 | 11% |
| Middle Ridge | 114 | 96 | -16% |

Table C.4 Energex connection points with the greater than 10 % absolute difference between the peak 2023/24 and corresponding base 2023 forecast for 2023/24

| Connection Point | 2023/24 forecast peak | 2023/24 actual peak | Difference |
|---|---|---|---|
| Chinchilla | 16 | 21 | 28% |
| Woree (Cairns North) | 51 | 62 | 21% |
| Oakey | 17 | 20 | 20% |
| Edmonton | 46 | 55 | 19% |
| Townsville East | 37 | 44 | 19% |
| Townsville South | 93 | 110 | 19% |
| Biloela | 29 | 34 | 19% |
| Tarong | 47 | 55 | 18% |
| Bulli Creek (Waggamba) | 20 | 23 | 16% |
| Middle Ridge | 229 | 265 | 15% |
| Gin Gin | 176 | 195 | 11% |
| Moranbah | 145 | 107 | -26% |
| Lilyvale | 141 | 103 | -27% |
| Newlands | 24 | 15 | -36% |

## C.5 Customer forecasts of connection point maximum demands

Tables C.1 to C.18 which are available on Powerlink's website, show 10-year forecasts of native summer and winter demand at connection point peak, for high, central and low growth scenarios (refer to Appendix C.2). These forecasts have been supplied by Powerlink direct connect customers and have been produced by Powerlink.

The connection point Megavolt Ampere reactive power (MVAr) forecast includes the effect of customer's downstream capacitive compensation.

Groupings (sums of non-coincident forecasts) of some connection points are used to protect the confidentiality of specific customer loads.

In tables C.1 to C.18 the zones in which connection points are located are abbreviated as follows:

| | |
|---|---|
| FN | Far North zone |
| R | Ross zone |
| N | North zone |
| NW | North West |
| CW | Central West zone |
| G | Gladstone zone |
| WB | Wide Bay zone |
| S | Surat zone |
| B | Bulli zone |
| SW | South West zone |
| M | Moreton zone |
| GC | Gold Coast zone |

# Appendix D Possible network investments for the 10-year outlook period

As a result of the annual planning review, Powerlink has identified that the investments listed in this appendix are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the 10-year outlook period. Potential projects have been grouped by Region and zone as described in Chapter 6. It should be noted that the indicative cost of potential projects also excludes known and unknown contingencies. Additional information on these potential projects, as required by the Australian Energy Regulator's Transmission Annual Planning Report Guidelines, is made available in the TAPR templates which can be accessed through Powerlink's TAPR portal. Where appropriate, the technical envelope for potential non-network solutions has been included in the relevant table.

## D.1 Northern Region

Table D.1 Possible network investments in the Far North zone in the 10-year outlook period

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Rebuild the 132kV transmission line between Woree and Kamerunga substations and Kamerunga 132kV Substation rebuild | New 132kV double circuit transmission line, substation establishment on a new site and associated Ergon 22kV works | Maintain supply reliability to the Far North zone | December 2028 | Two 132kV single circuit transmission lines, substation establishment on a new site and associated Ergon 22kV works (2) | $200m |
| Line refit works on the 275kV transmission lines between Ross and Chalumbin substations | Staged line refit works on steel lattice structures | Maintain supply reliability to the Far North and Ross zones | Staged works by June 2029 (1) | New transmission line (2) | $35m (3) |
| Substations | | | | | |
| Tully 132/22kV transformer replacement | Replacement of the transformer | Maintain supply reliability to the Far North zone | June 2029 | Life extension of the existing transformer or a non-network alternative of up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully | $6m |
| Edmonton 132kV secondary systems replacement | Full replacement of 132kV secondary systems | Maintain supply reliability to the Far North zone | December 2030 | Selected replacement of 132kV secondary systems | $9m (3) |
| Barron Gorge 132kV secondary systems replacement | Full replacement of 132kV secondary systems | Maintain supply reliability to the Far North zone | December 2031 | Selected replacement of 132kV secondary systems | $4m (3) |
| Chalumbin 275kV and 132kV primary plant replacement | Selected replacement of 275kV and 132kV primary plant | Maintain supply reliability to the Far North zone | June 2028 (1) | Full replacement of all 275kV and 132kV primary plant and secondary systems | $9m |
| 275/132kV substation establishment to maintain supply to Turkinje substation | Establishment of 275/132kV switching substation near Turkinje including two transformers | Maintain supply reliability to Turkinje area | June 2030 | Refit of the Chalumbin to Turkinje 132kV transmission line | $37m (3) |
| Woree 275kV and 132kV secondary systems replacement | Selected replacement of 275kV and 132kV secondary systems | Maintain supply reliability to the Far North zone | June 2034 | Full replacement of 275kV and 132kV secondary systems | $17m |
| El Arish 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Far North zone | June 2034 | Full replacement of 275kV and 132kV secondary systems | $10m (3) |

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.9.1.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects

### D.1.2 Ross zone

Table D.2 Possible network investments in the Ross zone in the 10-year outlook period

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Line refit works on the 132kV transmission line between Dan Gleeson and Alan Sherriff substations | Line refit works on steel lattice structures | Maintain supply reliability to the Ross zone | June 2028 (1) | New 132kV transmission line (2) | $5m |
| Line refit works on the 132kV transmission line between Ross and Dan Gleeson substations | Line refit works on steel lattice structures | Maintain supply reliability to the Ross zone | June 2028 (1) | New 132kV transmission line (2) | $8m |
| Targeted refit of the 275kV transmission line between Strathmore and Ross | Targeted refit of the 275kV transmission line between Strathmore and Ross | Maintain supply reliability to the Ross zone | June 2030 | New 132kV transmission line (2) | $10m |
| Substations | | | | | |
| Ingham South 132kV primary plant and secondary systems replacement | Full replacement of 132kV primary plant and secondary systems | Maintain supply reliability to the Ross zone | December 2027 | Selected replacement of 132kV primary plant and secondary systems<br><br>Up to 20MW at peak and up to 280MWh per day on a continuous basis to provide supply to the 66kV network at Ingham South | $27m (3) |
| Garbutt 132kV secondary systems replacement | Full replacement of 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2027 (1) | Selected replacement of 132kV secondary systems<br><br>Up to 120MW at peak and up to 860MWh per day to support the 66kV network in north east Townsville | $10m |
| Alan Sherriff 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2027 (1) | Full replacement of 132kV secondary systems<br><br>Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kv network in north east Townsville | $14m (3) |

Table D.2 Possible network investments in the Ross zone in the 10-year outlook period *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Townsville East 132kV secondary systems replacement | Staged replacement of secondary systems | Maintain supply reliability to the Ross zone | June 2033 | Full replacement of secondary systems | $4m |
| Townsville South 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2033 | Full replacement of 132kV secondary systems<br><br>Up to 150MW at peak and up to 3,000MWh per day to provide supply to Townsville East and Townsville South (including Sun Metals) | $11m |
| Yabulu South 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2034 | Full replacement of 132kV secondary systems | $14m (3) |
| Clare South 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2034 | Full replacement of 132kV secondary systems | $14m (3) |
| Ross 275kV and 132kV secondary systems replacement | Selected replacement of 275kV and 132kV secondary systems | Maintain supply reliability to the Ross zone | June 2035 | Full replacement of 275kV and 132kV secondary systems | $10m |

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in this Section 6.9.2

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects

### D.1.3 North zone

Table D.3 Possible network investments in the North zone in the 10-year outlook period

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Line refit works on the 132kV transmission line between Nebo Substation and Eton tee | Line refit works on steel lattice structures | Maintain supply reliability to the North zone | December 2027 (1) | New transmission line (2) | $31m (3) |
| Line refit works on the 132kV transmission line between Collinsville North, Strathmore and Clare South substations | Line refit works on the 132kV transmission line | Maintain supply reliability to the North zone | June 2035 | Rebuild of the 132kV transmission line between Collinsville North, Strathmore and Clare South substations (2) | $44m |

Table D.3 Possible network investments in the North zone in the 10-year outlook period *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Substations | | | | | |
| Alligator Creek 132kV primary plant and SVC secondary systems replacement | Selected replacement of 132kV primary plant and SVC secondary systems replacement | Maintain supply reliability to the North zone | June 2028 (1) | Full replacement of 132kV primary plant and SVC secondary systems replacement | $14m (3) |
| North Goonyella 132kV secondary systems replacement | Full replacement of 132kV secondary systems | Maintain supply reliability to the North zone | June 2027 (1) | Selected replacement of 132kV secondary systems | $6m |
| Strathmore SVC secondary systems replacement | Full replacement of secondary systems | Maintain supply reliability to the North zone | June 2026 | Staged replacement of secondary systems (2) | $12m |
| Pioneer Valley 132kV primary plant replacement | Selected replacement of 132kV primary plant | Maintain supply reliability to the North zone | June 2035 (1) | Full replacement of 132kV primary plant | $3m (3) |
| Strathmore 275kV and 132kV secondary systems replacement | Selected replacement of 275 and 132kV secondary systems in a new prefabricated building | Maintain supply reliability to the North zone | June 2034 | Selected replacement of 275kV and 132kV secondary systems in existing panels | $15m |
| Mackay 132/33kV transformer replacement | Replacement of one 132/33kV transformer | Maintain supply reliability to the North zone | June 2030 | Establish 33kV supply from surrounding network (2) | $5m (3) |
| Nebo SVC secondary systems replacement | Selected replacement of SVC secondary systems | Maintain supply reliability to the North zone and | June 2033 | Full replacement of SVC secondary systems | $7m |
| Nebo SVC selected primary plant replacement and SVC transformer life extension | Full replacement of primary plant and transformer associated with the SVC | Maintain supply reliability to the North zone | December 2029 | Full replacement of SVC primary plant and SVC transformer | $8m |
| Alligator Creek 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the North zone | June 2035 | Full replacement of 132kV secondary systems | $15m |

Notes:

(1) The revised timing from the 2023 TAPR is based upon the latest condition assessment.

(2) The envelope for non-network solutions is defined in Section 6.9.3.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

## D.2 Central region

### D.2.1 Central west zone

Table D.4 Possible network investments in the Central West zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission Lines | | | | | |
| Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations | Line refit works on the 275kV transmission line | Maintain supply reliability in the Central West zone and Northern region | December 2026 (1) | Stanwell to Broadsound second side stringing<br><br>New 275kV transmission line between Bouldercombe and Broadsound substation (2) | $15m (3) |
| Line refit works on the 132kV transmission line between Bouldercombe tee and Egans Hill Substation | Line refit works on the 275kV transmission line | Maintain supply reliability in the Central West zone | June 2033 | Rebuild the 275kV transmission line between Bouldercombe tee and Egans Hill Substation (2) | $4m |
| Line refit works on the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations | Line refit works on the 132kV transmission line | Maintain supply reliability in the Central West zone | June 2035 | Rebuild the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations (2) | $58m |
| Line refit works on the 132kV transmission line between Moranbah, Kemmis and Nebo substations | Line refit works on the 132kV transmission line | Maintain supply reliability in the Central West zone | June 2035 | Rebuild the 132kV transmission line between Moranbah, Kemmis and Nebo substations (2) | $40m |
| Substations | | | | | |
| Blackwater 132kV primary plant replacement | Selected replacement of 132kV primary plant | Maintain supply reliability to the Central West zone | June 2026 (1) | Full replacement of 132kV primary plant | $3m |
| Biloela 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Central West zone | June 2033 | Full replacement of 132kV secondary systems | $7m (3) |
| Broadsound 275kV secondary systems replacement | Selected replacement of 275kV secondary systems | Maintain supply reliability to the Central West zone | June 2032 | Full replacement of 275kV secondary systems | $10m (3) |
| Broadsound 275kV primary plant replacement | Selected replacement of 275kV primary plant | Maintain supply reliability to the Central West zone | June 2028 (1) | Full replacement of 275kV primary plant (2) | $19m |
| Lilyvale 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply to the Central West zone | June 2033 | Full replacement of 132kV secondary systems | $5m (3) |

Table D.4 Possible network investments in the Central West zone *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Calvale 275kV primary plant replacement | Selected replacement of 275kV primary plant | Maintain supply reliability to the Central West zone | December 2027 (1) | Full replacement of 275kV primary plant (2) | $18m |
| Blackwater 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability in the Central West zone | June 2034 | Full replacement of 132kV secondary systems | $19m (3) |
| Nebo 132kV and 275kV secondary systems replacement | Selected replacement of 132kV and 275kV secondary systems | Maintain supply reliability to the Central West and North zones | June 2034 | Full replacement of 132kV and 275kV secondary systems | $15m (3) |
| Stanwell 275kV selected primary plant replacement | Selected replacement of 275kV primary plant | Maintain supply reliability to the Central west zone and Northern region | December 2032 | Full replacement of 275kV primary plant | $22m |

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.10.1.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

## D.2.2 Gladstone zone

Table D.5 Possible network investments in the Gladstone zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Line refit works on the 275kV transmission line between Wurdong and Boyne Island | Line refit works on steel lattice structures | Maintain supply reliability in the Gladstone zone | December 2030 (1) | Rebuild the 275kV transmission line between Wurdong and Boyne Island (2) | $5m |
| Rebuild the 132kV transmission line between Calliope River and Gladstone South Substation | Rebuild the 132kV transmission line between Calliope River and Gladstone South substations | Maintain supply reliability in the Gladstone zone | June 2030 (1) | Line refit works on steel lattice structures (2) | $75m (3) |
| Line refit works on steel lattice structures on the 275kV transmission line between Raglan and Bouldercombe substations | Line refit works on steel lattice structures | Maintain supply reliability in the Gladstone zone | June 2031 (1) | Rebuild the 275kV transmission line between Raglan and Larcom Creek (2) | $19m (3) |

Table D.5 Possible network investments in the Gladstone zone *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Line refit works on the 132kV transmission line between Bouldercombe substation and Bouldercombe Tee | Line refit works on steel lattice structures | Maintain supply reliability in the Gladstone zone | June 2030 | Rebuild the 132kV transmission line between Bouldercombe and Bouldercombe Tee (2) | $3m |
| Line refit works on the 275kV transmission line between Calliope River and Boyne Island | Line refit works on steel lattice structures | Maintain supply reliability in the Gladstone zone | June 2032 | Rebuild the 275kV transmission line between Calliope River and Boyne Island (2) | $15m |
| Substations | | | | | |
| Callemondah selected 132kV primary plant and secondary systems replacement | Selected replacement of 132kV primary plant and secondary systems | Maintain supply reliability in the Gladstone zone | June 2027 (1) | Full replacement of 132kV primary plant and secondary systems | $7m (3) |
| Rockhampton 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain reliability in Rockhampton | June 2031 | Full replacement of 132kV secondary systems | $6m (3) |
| Larcom Creek 275kV secondary systems replacement | Selected replacement of 275kV secondary systems | Maintain supply reliability in the Gladstone zone | June 2034 | Full replacement of the 275kV secondary systems | $14m (3) |
| Pandoin 132kV secondary systems replacement | Full replacement of the 132kV secondary systems | Maintain supply reliability in the Gladstone zone | June 2034 | Selected replacement of 132kV secondary systems | $6m (3) |
| Wurdong 275kV selected primary plant replacement | Selected replacement of 275kV primary plant | Maintain supply reliability in the Gladstone zone | June 2032 | Full replacement of 275kV primary plant | $15m |
| Yarwun 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability in the Gladstone zone | June 2034 | Full replacement of 132kV secondary systems | $17m |

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.10.2.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

## D.3 Southern region

### D.3.1 Wide Bay zone

Table D.6 Possible network investments in the Wide Bay zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Rebuild of the 275kV transmission line between Calliope River Substation and the Wurdong Tee | New double circuit transmission line for the first 15km out of Calliope River substation | Maintain supply reliability to the CQ-SQ transmission corridor (and Gladstone zone) | December 2032 (2) | Refit the two single circuit 275kV transmission lines | $50m (1) |
| Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Substation | Refit the single circuit 275kV transmission line between Calliope River Substation and Wurdong Substation | Maintain supply reliability in the CQ-SQ transmission corridor (and Gladstone zone) | June 2031 (2) | Rebuild the 275kV transmission line as a double circuit | $14m (1) |
| Line refit works on the 275kV transmission line between Woolooga and South Pine substations | Refit the 275kV transmission line between Woolooga and South Pine substations | Maintain supply reliability to the Moreton zone | June 2029 | Rebuild the 275kV transmission line between Woolooga and South Pine substations | $20m (1) |
| Targeted reinvestment in the 275kV transmission lines between Wurdong Tee and Gin Gin substation | Refit the 275kV transmission line between Wurdong Tee and Gin Gin Substation | Maintain supply to the Wide Bay zone | December 2032 | Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation<br><br>New 275kV DCST transmission line | $85m (1) |
| Line refit works on the 275kV transmission line between South Pine and Palmwoods substations | Line refit works on steel lattice structures | Maintain supply to the Wide Bay zone | June 2032 | Rebuild 275kV transmission line between South Pine and Palmwoods substations | $12m (1) |
| Line refit works on the 275kV transmission line between Gin Gin and Woolooga substations | Rebuild the 275kV transmission line between Gin Gin and Woolooga substations | Maintain supply to the Wide Bay zone | June 2032 (2) | Refit the 275kV transmission line between Gin Gin and Woolooga substations | $37m (1) |
| Line refit works on the 275kV transmission line between Gin Gin and Calliope River substations | Refit the 275kV transmission line between Gin Gin and Calliope River substations | Maintain supply to the Wide Bay zone | June 2031 | Rebuild the 275kV transmission line between Gin Gin and Calliope River substations (2) | $4m |
| Substations | | | | | |
| Teebar Creek secondary systems replacement | Full replacement of 132kV and 275kV secondary systems | Maintain supply to the Wide Bay zone | June 2033 | Selected replacement of 132kV and 275kV secondary systems | $19m |

Table D.6 Possible network investments in the Wide Bay zone *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Woolooga 132kV primary plant replacement | Selected replacement of 132kV primary plant | Maintain supply to the Wide Bay zone | June 2030 (2) | | $3m (1) |
| Woolooga 275kV and 132kV and SVC secondary systems replacement | Full replacement of 275kV, 132kV and SVC secondary systems. | Maintain supply to the Wide Bay zone | December 2034 | Selected replacement of 275kV, 132kV and SVC secondary systems | $43m |
| Palmwoods 275kV and 132kV selected primary plant replacement | Selected replacement of 275kV and 132kV primary plant | Maintain supply reliability to the Wide Bay zone | June 2034 (2) | Full replacement of 275kV and 132kV primary plant | $15m |
| Palmwoods 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability to the Wide Bay zone | June 2035 | Full replacement of 132kV secondary systems | $21m |

Notes:

(1) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(2) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

### D.3.2 Surat zone

Table D.7 Possible network investments in the Surat zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Substations | | | | | |
| Columboola 132kV secondary systems replacement | Selected replacement of 132kV secondary systems | Maintain supply reliability in the Surat zone | June 2033 | Full replacement of secondary systems | $17m |

### D.3.3 Bulli zone

Table D.8 Possible network investments in the Bulli zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Substations | | | | | |
| Millmerran 330kV AIS secondary systems replacement | Selected replacement of 330kV secondary systems | Maintain supply reliability in the Bulli zone | December 2031 | Full replacement of secondary systems | $6m |
| Braemar 330kV secondary systems replacement non-iPASS | Selected replacement of 330kV secondary systems | Maintain supply reliability in the Bulli zone | June 2034 | Full replacement of secondary systems | $23m |
| Bulli Creek 330/132kV transformer replacement | Replace one 330/132kV transformer at Bulli Creek Substation | Maintain supply reliability in the Bulli zone | June 2031 | Retirement of 330/132kV transformers with non-network support | $7m |

### D.3.4 South West zone

Table D.9 Possible network investments in the South West zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Substations | | | | | |
| Middle Ridge 110kV primary plant replacement | Selected replacement of selected 110kV primary plant | Maintain reliability of supply in the South West zone | June 2028 | Full replacement of 110kV primary plant | $3m |
| Middle Ridge 275kV and 110kV secondary systems replacement | Selected replacement of 275kV and 110kV secondary systems | Maintain supply reliability in the South West zone | December 2033 | Full replacement of 275kV and 110kV secondary systems | $39m |
| Tarong 275kV, 132kV and 66kV secondary systems replacement | Selected replacement of 275kV, 132kV and 66kV secondary systems | Maintain supply reliability in the South West zone | June 2035 | Full replacement of 275kV, 132kV and 66kV secondary systems | $33m |

### D.3.5 Moreton zone

Table D.10 Possible network investments in the Moreton zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission Lines | | | | | |
| Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations | Replace the 110kV underground cable between Upper Kedron and Ashgrove West substations using an alternate easement | Maintain supply reliability in the Moreton zone | June 2028 | In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (2) | $31m(3) |
| Line refit works on the 110kV transmission line between Richlands and Algester substations | Refit the 110kV transmission line between Richlands and Algester substations | Maintain supply reliability in the Moreton zone | June 2028 | Potential retirement of the transmission line between Richlands and Algester substations | $2m |
| Line refit works on the 110kV transmission line between Blackstone and Abermain substations | Refit the 110kV transmission line between Blackstone and Abermain substations | Maintain supply reliability in the Moreton zone | June 2033 | Rebuild the 110kV transmission line between Blackstone and Abermain substations | $8m |
| Line refit works on the 275kV transmission line between Bergins Hill and Karana Downs | Refit the 275kV transmission line between Bergins Hill and Karana Downs substations | Maintain supply reliability in the Moreton zone | June 2030 | Rebuild or replace the transmission line between Bergins Hill and Karana Downs substations | $4m |
| Line refit works on the 275kV transmission line between Karana Downs and South Pine | Refit the 275kV transmission line between Karana Downs and South Pine substations | Maintain supply reliability in the Moreton zone | June 2030 | Rebuild the 275kV transmission line between Karana Downs and South Pine substations | $14m |

Table D.10 Possible network investments in the Moreton zone *(continued)*

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Line refit works on the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations | Refit the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations | Maintain supply reliability in the Moreton zone | June 2034 | Rebuild the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations | $14m |
| Line refit works on the 275kV transmission line between Bergins Hill, Goodna and Belmont substations | Refit the 275kV transmission line between Bergins Hill, Goodna and Belmont substations | Maintain supply reliability in the Moreton zone | December 2030 | Rebuild the 275kV transmission line between Bergins Hill, Goodna and Belmont substations | $20m |
| Line refit works on the 110kV transmission line between West Darra and Upper Kedron substations | Refit the 110kV transmission line between West Darra and Upper Kedron substations | Maintain supply reliability in the Moreton zone | June 2032 | Rebuild the 110kV transmission line between West Darra and Upper Kedron substations | $5m |
| Substations | | | | | |
| Ashgrove West 110kV secondary systems replacement | Full replacement of 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2027 (1) | Staged replacement of 110kV secondary systems | $22m |
| Murarrie 275kV and 110kV secondary systems replacement | Full replacement of 110kV secondary systems and selected replacement of 275kV secondary systems | Maintain supply reliability in the Moreton zone | December 2027 (1) | Staged replacement of 110kV secondary systems and selected 275kV secondary systems | $21m |
| Algester 110kV secondary systems replacements | Full replacement of 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2032 | Staged replacement of 110kV secondary systems | $14m (3) |
| Bundamba 110kV secondary systems replacement | Full replacement of 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 110kV secondary systems | $10m (3) |
| South Pine 275kV and SVC secondary systems replacement | Full replacement of 275kV and SVC secondary systems | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 275kV and SVC secondary systems | $57m (3) |
| Goodna 275kV and 110kV secondary systems replacement | Full replacement of 275kV and 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 275kV and 110kV secondary systems | $20m |
| West Darra 110kV secondary systems replacement | Full replacement of 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 110kV secondary systems | $12m (3) |
| Rocklea 275/110kV transformer replacement | Replacement of one 275/110kV transformer at Rocklea | Maintain supply reliability in the Moreton zone | June 2033 (1) | Life extension of one 275/110kV transformer at Rocklea | $5m |
| Loganlea 275kV primary plant replacement | Full replacement of 275kV primary plant | Maintain supply reliability in the Moreton zone | June 2031 (1) | Staged replacement of 275kV primary plant | $5m |

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Greenbank SVC secondary systems replacement | Full replacement of SVC secondary systems | Maintain supply reliability in the Moreton and Gold Coast zones | December 2029 | Staged replacement of SVC secondary systems | $8m (3) |
| Mount England 275kV primary plant and secondary systems replacement | Full replacement of 275kV secondary systems and staged replacement of primary plant | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 275kV secondary systems and primary plant | $10m (3) |
| Belmont 11kV underground cable and transformers replacement | Full replacement of two 11kV underground cables between Belmont and Mansfield and associated transformers | Maintain supply reliability in the Moreton zone | December 2026 | | $8m |
| Belmont 110kV and 275kV secondary systems replacement | Full replacement of secondary systems | Maintain supply reliability in the Moreton zone | June 2034 | Staged replacement of 275kV and 110kV secondary systems | $24m |
| Belmont 33kV and 11kV primary plant replacement | Full replacement of 33kV and 11kV primary plant | Maintain supply reliability in the Moreton zone | June 2032 | Staged replacement of 22kV and 11kV primary plant | $3m (3) |
| South Pine 275kV primary plant replacement | Staged replacement of 275kV primary plant | Maintain supply reliability in the Moreton zone | December 2030 (1) | Full replacement of 275kV primary plant | $5m |
| Abermain 275kV and 110kV secondary systems replacement | Full replacement of 275kV and 110kV secondary systems | Maintain supply reliability in the Moreton zone | June 2032 | Staged replacement of 275kV and 110kV secondary systems | $10m (3) |
| Abermain 275kV and 110kV primary plant replacement | Selected 275kV and 110kV primary plant replacement | Maintain supply reliability in the Moreton zone | June 2030 (1) | Full replacement of 275kV and 110kV primary plant | $8m |
| Greenbank 275kV secondary systems replacement | Full replacement of 275kV secondary systems | Maintain supply reliability in the Moreton and Gold Coast zones | June 2035 | Staged replacement of 275kV secondary systems | $30m |

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.11.5.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

### D.3.6 Gold Coast zone

Table D.11 Possible network investments in the Gold Coast zone

| Potential project | High level scope | Purpose | Earliest possible commissioning date | Alternatives | Indicative cost |
|---|---|---|---|---|---|
| Transmission lines | | | | | |
| Line refit works on the 110kV transmission line between Mudgeeraba Substation and Terranora | Targeted line refit works on steel lattice structures | Maintain supply reliability from Queensland to NSW Interconnector | June 2028 (2) | Full line refit<br><br>New transmission line (1) | $5m |
| Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations | Targeted line refit works on steel lattice structures | Maintain supply reliability in the Gold Coast zone | June 2029 (2) | New double circuit 275kV transmission line (1) | $37m (3) |
| Substations | | | | | |
| Molendinar 275kV secondary systems replacement | Full replacement of 275kV secondary systems | Maintain supply reliability in the Gold Coast zone | December 2027 (2) | Selected replacement of 275kV secondary systems | $23m |
| Mudgeeraba 110kV primary plant and secondary systems replacement and 275/110kV transformer replacement | Selected replacement of 110kV primary plant and staged replacement of 110kV secondary systems and replacement of the transformer | Maintain supply reliability in the Gold Coast zone | December 2030 (2) | Full replacement of 110kV secondary systems and replacement of the transformer(1) | $54m (3) |

Notes:

(1) The envelope for non-network solutions is defined in Section 6.11.6.

(2) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

# Appendix E TAPR templates methodology

The NER, the Australian Energy Regulator (AER) Transmission Annual Planning Report (TAPR) Guidelines[1] set out the required format of TAPRs, in particular the provision of TAPR templates to complement the TAPR document. The purpose of the TAPR templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are strongly encouraged to contact Powerlink in the first instance.

The TAPR template data may be directly accessed on Powerlink's TAPR portal[2]. Alternatively please contact NetworkAssessments@powerlink.com.au for assistance.

## E.1 Context

While care is taken in the preparation of TAPR templates, data is provided in good faith. Powerlink Queensland accepts no responsibility or liability for any loss or damage that may be incurred by persons acting in reliance on this information or assumptions drawn from it.

The proposed preferred investment and associated data is indicative, has the potential to change and will be technically and economically assessed under the Regulatory Investment Test for Transmission (RIT-T) consultation process as/if required at the appropriate time. TAPR templates may be updated at the time of RIT-T commencement to reflect the most recent data and to better inform non-network providers[3]. Changes may also be driven by the external environment, advances in technology, non-network solutions and outcomes of other RIT-T consultations which have the potential to shape the way in which the transmission network develops.

There is likely to be more certainty in the need to reinvest in key areas of the transmission network which have been identified in the TAPR in the near term, as assets approach their anticipated end of technical service life. However, the potential preferred investments (and alternative options) identified in the TAPR templates undergo detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This nearterm analysis provides Powerlink with an additional opportunity to deliver greater benefits to customers through improving and further refining options. In the medium to long-term, there is less certainty regarding the needs or drivers for reinvestments. As a result, considerations in the latter period of the annual planning review require more flexibility and have a greater potential to change in order to adapt to the external environment as the NEM evolves and customer behaviour changes.

Where an investment is primarily focussed on addressing asset condition issues, Powerlink has not attempted to quantify the impact on the market e.g. where there are market constraints arising from reconfiguration of the network around the investment and Powerlink considers that generation operating within the market can address this constraint.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

## E.2 Methodology/principles applied

The AER's TAPR Guidelines incorporate text to define or explain the different data fields in the template. Powerlink has used these definitions in the preparation of the data within the templates.

For connection point templates the expected unserved energy (EUSE) has been calculated using aggregated failure statistics for network assets, considering both momentary and sustained failures by the following expression:

EUSE = Probability of Asset Failure × Median Restoration time × MW @ Risk

For lines segments templates the expected unserved energy should be interpreted as then annual energy that cannot be supplied by that asset under system normal conditions.

Further to the AER's data field definitions, Powerlink provides details on the methodology used to forecast the daily demand profiles. Table B.1 also provides further context for some specific data fields.

The data fields are denoted by their respective AER Rule designation, TGCPXXX (TAPR Guideline Connection Point) and TGTLXXX (TAPR Guideline Transmission Line).

1 First published in December 2018.
2 Refer to the TAPR portal.
3 Separate to the publication of the TAPR document which occurs annually.

## E.3 Development of daily demand profiles

Forecasts of the daily demand profiles for the days of annual maximum and minimum demands over the next 10 years were developed using VISION forecasting and planning (by Blunomy). These daily demand profiles are an estimate and should only be used as a guide. For further context and explanation of the methodology used to develop minimum and maximum demand profiles refer to appendix C.1.

The 10-year forecasts of daily demand profiles that have been developed for the TAPR templates include:

- 50% probability of exceedance (PoE) maximum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- Minimum demand, MVA (TGCP008).

Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value.

- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011).

The maximum demand forecast on the minimum demand day (TGCP009) and the forecast daily demand profile on the minimum demand day (TGCP011) were determined from the minimum (annual) daily demand profiles.

Table E.1 Further definitions for specific data fields

| Data field | Definition |
|---|---|
| TGCP013 and TGTL008 Maximum load at risk per year | The load at risk takes into account both the network topology and aggregated outage and asset failure statistics for lines, transformers, and switching assets across the network. Where detailed project scopes and project requirements have not been determined, the aggregation of impacted loads were deemed at risk. |
| TGCP016 and TGTL011 Preferred investment - capital cost | The timing reflected for the estimated capital cost is the year of proposed project commissioning. RIT-Ts to identify the preferred option for implementation would typically commence three to five years prior to this date, relative to the complexity of the identified need, option analysis required and consideration of the necessary delivery timeframes to enable the identified need to be met. To assist non-network providers, RIT-Ts in the nearer term are identified in Table 6.6. |
| TGCP017 and TGTL012 Preferred investment - Annual operating cost | Powerlink has applied a standard 2% of the preferred investment capital cost to calculate indicative annual operating costs. |
| TGCP024 Historical connection point rating | Includes the summer and winter ratings for the past three years at the connection point. The historical connection point rating is based on the most limiting network component on Powerlink's network, in transferring power to a connection point. However lower downstream distribution connection point ratings could be more limiting than the connection point ratings on Powerlink's network. |
| TGCP026 Unplanned outages | Unplanned outage data relates to Powerlink's transmission network assets only.<br>Forced and faulted outages are included in the data provided.<br>Information provided is based on calendar years from January 2018 to December 2020. |
| TGPC028 and TGTL019 Annual economic cost of constraint | The annual economic cost of the constraint is the direct product of the annual expected unserved energy and the Value of Customer Reliability (VCR) related to the investment. It does not consider cost of safety risk or market impacts such as changes in the wholesale electricity cost or network losses. |
| TGTL005 Forecast 10-year asset rating | Asset rating is based on an enduring need for the asset's functionality and is assumed to be constant for the 10-year outlook period. |
| TGTL017 Historical line load trace | Due to the meshed nature of the transmission network and associated power transfers, the identification of load switching would be labour intensive and the results inconclusive. Therefore the data provided does not highlight load switching events. |

# Appendix F Zone and grid section definitions

This Appendix provides definitions of the 13 geographical zones and nine grid sections referenced in this Transmission Annual Planning Report (TAPR).

Tables F.1 and F.2 provide detailed definitions of zone and grid sections.

Table F.3 provides details of the name and type of generation connected to the transmission system in each zone.

Figure F.1 provides illustrations of the grid section definitions.

Table F.1 Zone definitions

| Zone | Area covered |
|---|---|
| Far North | North of Guybal Munjan and Tully |
| Ross | North of King Creek and Bowen North, excluding the Far North and North West zones |
| North West | Mount Isa and Cloncurry |
| North | North of Broadsound and Dysart, excluding the Far North, North West and Ross zones |
| Central West | South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone |
| Gladstone | South of Raglan, north of Gin Gin and east of Calvale |
| Wide Bay | Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie |
| Surat | West of Western Downs and south of Moura, excluding the Bulli zone |
| Bulli | Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Middle Ridge |
| South West | Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli zone |
| Moreton | South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone |
| Gold Coast | East of Greenbank, south of Coomera to the Queensland/New South Wales border |

Table F.2 Grid section definitions (1)

| Grid section | Definition |
|---|---|
| FNQ | Guybal Munjan into Chalumbin 275kV (2 circuits)<br>Ross/Tully into Woree 275kV (1 circuit)<br>Tully into El Arish 132kV (1 circuit) |
| NWQ | Flinders to Future 500kV substation in Ross area (2 circuits) |
| CQ-NQ | Bouldercombe into Nebo 275kV (1 circuit)<br>Broadsound into Nebo 275kV (3 circuits)<br>Dysart to Peak Downs/Moranbah 132kV (1 circuit)<br>Dysart to Eagle Downs 132kV (1 circuit) |
| Gladstone | Bouldercombe into Calliope River 275kV (1 circuit)<br>Raglan into Larcom Creek 275kV (1 circuit)<br>Calvale into Wurdong 275kV (1 circuit) |
| CQ-SQ | Wurdong to Teebar Creek 275kV (1 circuit)<br>Calliope River to Gin Gin/Woolooga 275kV (2 circuits)<br>Calvale into Halys 275kV (2 circuits) |
| Surat | Western Downs to Columboola 275kV (1 circuit)<br>Western Downs to Orana 275kV (1 circuit) |
| SWQ | Western Downs to Halys 275kV (1 circuit)<br>Western Downs to Coopers Gap 275kV (1 circuit)<br>Braemar (East) to Halys 275kV (2 circuits)<br>Tummaville to Middle Ridge 330kV (2 circuits) |
| Tarong | Tarong to South Pine 275kV (1 circuit)<br>Tarong to Mt England 275kV (2 circuits)<br>Tarong to Blackwall 275kV (2 circuits)<br>Middle Ridge to Greenbank 275kV (2 circuits) |
| Gold Coast | Greenbank into Mudgeeraba 275kV (2 circuits)<br>Greenbank into Molendinar 275kV (2 circuits)<br>Coomera into Cades County 110kV (1 circuit) |

Note:

(1) The grid sections defined are as illustrated in Figure F.1. X into Y – the MW flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

Table F.3 Zone Generation details

| Zone | Generator | Coal-fired | Gas turbine | Hydro-electric | Solar PV | Wind | Battery | Sugar mill |
|---|---|---|---|---|---|---|---|---|
| Far North | Barron Gorge | | | • | | | | |
| | Kareeya | | | • | | | | |
| | Koombooloomba | | | • | | | | |
| | Mt Emerald | | | | | • | | |
| | Kaban | | | | | • | | |
| Ross | Townsville | | • | | | | | |
| | Mt Stuart | | • | | | | | |
| | Kidston (1) | | | • | | | | |
| | Clare | | | | • | | | |
| | Haughton | | | | • | | | |
| | Ross River | | | | • | | | |
| | Sun Metals | | | | • | | | |
| | Invicta | | | | | | | • |
| North | Daydream | | | | • | | | |
| | Hamilton | | | | • | | | |
| | Hayman | | | | • | | | |
| | Whitsunday | | | | • | | | |
| | Rugby Run | | | | • | | | |
| Central West | Callide B | • | | | | | | |
| | Callide PP | • | | | | | | |
| | Stanwell | • | | | | | | |
| | Lilyvale | | | | • | | | |
| | Moura | | | | • | | | |
| | Broadsound (1) | | | | • | | | |
| | Lotus Creek (1) | | | | | • | | |
| | Clarke Creek (1) | | | | | • | | |
| | Boulder Creek (1) | | | | | • | | |
| | Bouldercombe | | | | | | • | |
| Gladstone | Gladstone | • | | | | | | |
| | Yarwun | | • | | | | | |
| Wide Bay | Woolooga Energy Park | | | | • | | | |
| | Woolooga (1) | | | | | | • | |
| Moreton | Swanbank E | | • | | | | | |
| | Wivenhoe | | | • | | | | |
| | Greenbank | | | | | | • | |

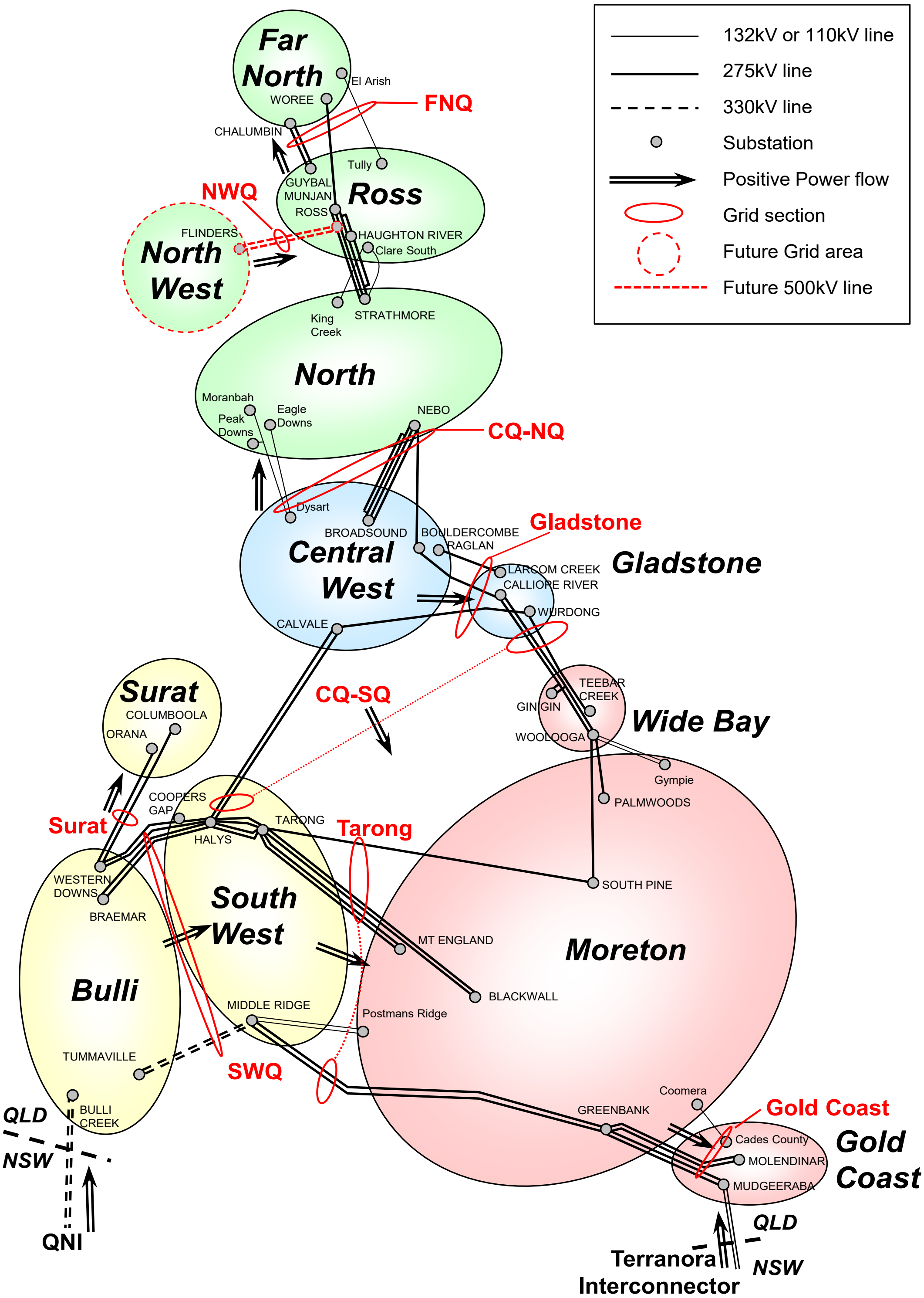
Table F.3 Zone Generation details *(continued)*

| Zone | Generator | Coal-fired | Gas turbine | Hydro-electric | Solar PV | Wind | Battery | Sugar mill |
|---|---|---|---|---|---|---|---|---|
| South West | Tarong | • | | | | | | |
| | Tarong North | • | | | | | | |
| | Oakey | | • | | | | | |
| | Wambo (1) | | | | | • | | |
| | Wambo 2 (1) | | | | | • | | |
| | Coopers Gap | | | | | • | | |
| Bulli | Kogan Creek | • | | | | | | |
| | Millmerran | • | | | | | | |
| | Braemar 1 | | • | | | | | |
| | Braemar 2 | | • | | | | | |
| | Darling Downs | | • | | | | | |
| | Darling Downs | | | | • | | | |
| | Western Downs Green Power Hub | | | | • | | | |
| | MacIntyre (1) | | | | | • | | |
| | Chinchilla | | | | | | • | |
| | Ulinda Park (1) | | | | | | • | |
| | Western Downs | | | | | | • | |
| Surat | Condamine | | • | | | | | |
| | Columboola | | | | • | | | |
| | Gangarri | | | | • | | | |
| | Blue grass | | | | • | | | |
| | Edenvale | | | | • | | | |
| | Wandoan | | | | • | | | |
| | Wandoan | | | | | | • | |

Note:

(1) Committed generation that is yet to begin production.

Figure F.1 Grid section legend



# Appendix G Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland Region in its market dispatch systems.

These equations are continually under review to consider changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table G.1 Far North Queensland (FNQ) grid section voltage stability equation

| Measured variable | Coefficient |
|---|---|
| Constant term (intercept) | 597 |
| Total MW generation at Mt Emerald Wind Farm | -0.55 |
| Total MW generation at Kaban Wind Farm | -0.64 |
| Total MW generation at Kareeya Power Station | -0.57 |
| Total MW generation in Ross zone (1) | 0.06 |
| Total nominal MVAr of 132kV shunt capacitors on line within nominated Cairns area locations (2) | 0.38 |
| Total nominal MVAr of 275kV shunt reactors on line within nominated Cairns area locations (3) | -0.38 |
| Total nominal MVAr of 132kV shunt reactors on line within nominated Chalumbin area locations (4) | -0.36 |
| Total nominal MVAr of 275kV shunt reactors on line within nominated Chalumbin area locations (5) | -0.46 |
| AEMO Constraint ID | Q^NIL_FNQ_8905 |

Notes:

(1) Ross generation term refers to summated active power generation at Mt Stuart, Townsville, Ross River Solar Farm, Sun Metals Solar Farm, Kidston Solar Farm, Hughenden Solar Farm, Clare Solar Farm, Haughton Solar Farm and Invicta Mill.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Cairns 132kV area comprise the following:

| | |
|---|---|
| Innisfail 132kV | 1 x 10MVAr |
| Edmonton 132kV | 1 x 13MVAr |
| Woree 132kV | 2 x 54MVAr |

(3) The shunt reactor location, nominal sizes and quantities for the Cairns 275kV area comprise the following:

| | |
|---|---|
| Woree 275kV | 2 x 20.17MVAr |

(4) The shunt reactor location, nominal size and quantities for the Chalumbin 132kV and below area comprise the following:

| | |
|---|---|
| Chalumbin tertiary | 1 x 20.2MVAr |

(5) The shunt reactor location, nominal sizes and quantities for the Chalumbin 275kV area comprise the following:

| | |
|---|---|
| Chalumbin 275kV | 2 x 29.4MVAr, 1 x 30MVAr |

Table G.2 Central to North Queensland grid section voltage stability equations

| Measured variable | Coefficient | |
|---|---|---|
| | Equation 1<br>Feeder contingency | Equation 2<br>Townsville contingency (1) |
| Constant term (intercept) | 1,500 | 1,650 |
| Total MW generation at Barron Gorge, Kareeya and Koombooloomba | 0.321 | – |
| Total MW generation at Townsville | 0.172 | 1.000 |
| Total MW generation at Mt Stuart | 0.092 | 0.136 |
| Number of Mt Stuart units on line [0 to 3] | 22.447 | 14.513 |
| Total MW northern VRE (2) | -1.00 | -1.00 |
| Total nominal MVAr shunt capacitors on line within nominated Ross area locations (3) | 0.453 | 0.440 |
| Total nominal MVAr shunt reactors on line within nominated Ross area locations (4) | -0.453 | -0.440 |
| Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (5) | 0.388 | 0.431 |
| Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (6) | -0.388 | -0.431 |
| Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (7) | 0.296 | 0.470 |
| Total nominal MVAr shunt reactors on line within nominated Nebo area locations (8) | -0.296 | -0.470 |
| Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (9) | 0.296 | 0.470 |
| Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (9) | 0.296 | 0.470 |
| AEMO Constraint ID | Q^NIL_CN_FDR | Q^NIL_CN_GT |

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) Northern VRE include:

Mt Emerald Wind Farm
Kaban Wind Farm
Ross River Solar Farm
Sun Metals Solar Farm
Haughton Solar Farm
Clare Solar Farm
Kidston Solar Farm
Kennedy Energy Park
Collinsville Solar Farm
Whitsunday Solar Farm
Hamilton Solar Farm
Hayman Solar Farm
Daydream Solar Farm
Rugby Run Solar Farm

(3) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:

| | |
|---|---|
| Ross 132kV | 1 x 50MVAr |
| Townsville South 132kV | 2 x 50MVAr |
| Dan Gleeson 66kV | 2 x 24MVAr |
| Garbutt 66kV | 2 x 15MVAr |

(4) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

| | |
|---|---|
| Ross 275kV | 2 x 84MVAr, 2 x 29.4MVAr |

(5) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

| | |
|---|---|
| Newlands 132kV | 1 x 25MVAr |
| Clare South 132kV | 1 x 20MVAr |
| Collinsville North 132kV | 1 x 20MVAr |

(6) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

| | |
|---|---|
| Strathmore 275kV | 1 x 84MVAr |

(7) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

| | |
|---|---|
| Moranbah 132kV | 1 x 52MVAr |
| Pioneer Valley 132kV | 1 x 30MVAr |
| Kemmis 132kV | 1 x 30MVAr |
| Dysart 132kV | 2 x 25MVAr |
| Alligator Creek 132kV | 1 x 20MVAr |
| Mackay 33kV | 2 x 15MVAr |

(8) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

| | |
|---|---|
| Nebo 275kV | 1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr |

(9) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:

| | |
|---|---|
| Nebo 275kV | 2 x 120MVAr |

The following table describes limit equations for the Inverter Based Resources (IBRs) in north Queensland. The Boolean AND operation is applied to the system conditions across a row, if the expression yields a True value then the maximum capacity quoted for the farm in question becomes an argument to a MAX function, if False then zero (0) becomes the argument to the MAX function. The maximum capacity is the result of the MAX function.

Table G.3 North Queensland system strength equations

| System Conditions | | | | | | | | Maximum Capacity (%) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of Stanwell units online | Number of Stanwell + Callide (1) units online | Number of Gladstone units online | Number of CQ units online (2) | Number of Kareeya units online | NQ Load | Ross + FNQ Load | Haughton Synchronous Condenser Status | Haughton SF | Kaban WF | Mt Emerald WF | Other NQ Plants |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 0 | > 350 | > 150 | OFF | 0 | 40 | 40 | 100 |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 0 | > 250 | > 100 | OFF | 0 | 25 | 25 | 100 |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 0 | > 250 | > 100 | ON | 100 | 100 | 100 | 100 |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 2 | > 350 | > 150 | OFF | 50 | 100 | 100 | 100 |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 2 | > 350 | > 150 | ON | 100 | 100 | 100 | 100 |
| ≥ 1 | ≥ 4 | ≥ 1 | ≥ 6 | ≥ 2 | > 350 | > 150 | OFF | 50 | 50 | 80 | 80 |
| ≥ 1 | ≥ 4 | ≥ 1 | ≥ 6 | ≥ 2 | > 350 | > 150 | ON | 100 | 100 | 100 | 100 |
| ≥ 2 | ≥ 3 | ≥ 1 | ≥ 7 | ≥ 2 | > 350 | > 150 | OFF | N/A | 100 | 100 | Wind = 100 Solar = N/A |
| AEMO Constraint ID | | | | | | | | Q_NIL_STRGTH_HAUSF | Q_NIL_STRGTH_KBWF | Q_NIL_STRGTH_MEWF | Various (3) |

Notes:

(1) Refers to the total number of Callide B and Callide C units online.

(2) Refers to the number of Gladstone, Stanwell and Callide units online.

(3) Q_NIL_STRGTH_CLRSF, Q_NIL_STRGTH_COLSF, Q_NIL_STRGTH_DAYSF, Q_NIL_STRGTH_HAMSF, Q_NIL_STRGTH_HAYSF, Q_NIL_STRGTH_KEP, Q_NIL_STRGTH_KIDSF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_RUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

Table G.4 Central to South Queensland grid section voltage stability equations

| Measured variable | Coefficient |
|---|---|
| Constant term (intercept) | 1,015 |
| Total MW generation at Gladstone 275kV and 132kV | 0.1407 |
| Number of Gladstone 275kV units on line [2 to 4] | 57.5992 |
| Number of Gladstone 132kV units on line [1 to 2] | 89.2898 |
| Total MW generation at Callide B and Callide C | 0.0901 |
| Number of Callide B units on line [0 to 2] | 29.8537 |
| Number of Callide C units on line [0 to 2] | 63.4098 |
| Total MW generation in southern Queensland (1) | 0.0650 |
| Number of 90MVAr capacitor banks available at Boyne Island [0 to 2] | 51.1534 |
| Number of 50MVAr capacitor banks available at Boyne Island [0 to 1] | 25.5767 |
| Number of 120MVAr capacitor banks available at Wurdong [0 to 3] | 52.2609 |
| Number of 50MVAr capacitor banks available at Gin Gin [0 to 1] | 31.5525 |
| Number of 120MVAr capacitor banks available at Woolooga [0 to 1] | 47.7050 |
| Number of 50MVAr capacitor banks available at Woolooga [0 to 2] | 22.9875 |
| Number of 120MVAr capacitor banks available at Palmwoods [0 to 1] | 30.7759 |
| Number of 50MVAr capacitor banks available at Palmwoods [0 to 4] | 14.2253 |
| Number of 120MVAr capacitor banks available at South Pine [0 to 4] | 9.0315 |
| Number of 50MVAr capacitor banks available at South Pine [0 to 4] | 3.2522 |
| Equation lower limit | 1,550 |
| Equation upper limit | 2,100 (2) |
| AEMO Constraint ID | Q^^NIL_CS, Q:NIL_CS |

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank E, Wivenhoe, Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Western Downs Solar Farm, Columboola Solar Farm, Gangarri Solar Farm, Wandoan BESS, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Coopers Gap Wind Farm, Millmerran, Susan River Solar Farm, Childers Solar Farm, Columboola Solar Farm, Blue Grass Solar Farm, Western Downs Green Power Hub, Edenvale Solar Farm, Gangarri Solar Farm, Wandoan Solar Farm, Dulacca Wind Farm, Woolooga Energy Park, Chinchilla BESS and Terranora Interconnector and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between central and southern Queensland areas.

Table G.5 Tarong grid section voltage stability equations

| Measured variable | Coefficient | |
|---|---|---|
| | Equation 1 | Equation 2 |
| | Calvale-Halys contingency | Tarong-Blackwall contingency |
| Constant term (intercept) (1) | 740 | 1,124 |
| Total MW generation at Callide B and Callide C | 0.0346 | 0.0797 |
| Total MW generation at Gladstone 275kV and 132kV | 0.0134 | – |
| Total MW in Surat, Bulli and South West and QNI transfer (2) | 0.8625 | 0.7945 |
| Surat/Braemar demand | -0.8625 | -0.7945 |
| Total MW generation at Wivenhoe and Swanbank E | -0.0517 | 0.0687 |
| Active power transfer (MW) across Terranora Interconnector | -0.0808 | -0.1287 |
| Number of 200MVAr capacitor banks available (3) | 7.6683 | 16.7396 |
| Number of 120MVAr capacitor banks available (4) | 4.6010 | 10.0438 |
| Number of 50MVAr capacitor banks available (5) | 1.9171 | 4.1849 |
| Reactive to active demand percentage (6) (7) | -2.9964 | -5.7927 |
| Equation lower limit | 3,200 | 3,200 |
| AEMO Constraint ID | Q^^NIL_TR_CLHA | Q^^NIL_TR_TRBK |

Notes:

(1) Equations 1 and 2 are offset by 100MW and 150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Surat, Bulli and South West generation term refers to summated active power generation at generation at Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Western Downs Green Power Hub, Columboola Solar Farm, Gangarri Solar Farm, Wandoan BESS, Wandoan Solar Farm, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Blue Grass Solar Farm, Edenvale Solar Farm, Coopers Gap Wind Farm, Dulacca Wind Farm, Millmerran, Chinchilla BESS, and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(3) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 17 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 37 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage = $\frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table G.6 Gold Coast grid section voltage stability equation

| Measured variable | Coefficient |
|---|---|
| Constant term (intercept) | 1,351 |
| Moreton to Gold Coast demand ratio (1) (2) | -137.50 |
| Number of Wivenhoe units on line [0 to 2] | 17.7695 |
| Number of Swanbank E units on line [0 to 1] | -20.0000 |
| Active power transfer (MW) across Terranora Interconnector (3) | -0.9029 |
| Reactive power transfer (MVAr) across Terranora Interconnector (3) | 0.1126 |
| Number of 200MVAr capacitor banks available (4) | 14.3339 |
| Number of 120MVAr capacitor banks available (5) | 10.3989 |
| Number of 50MVAr capacitor banks available (6) | 4.9412 |
| AEMO Constraint ID | Q^NIL_GC |

Notes:

(1) Moreton to Gold Coast demand ratio = $\frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 15 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 33 capacitor banks of nominal size 50MVAr which may be available within this area.

# Appendix H Indicative short circuit currents

Tables H.1 to H.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations. Appendix H also shows the indicative System Strength Locational Factor (SSLF) calculated as per the AEMO System Strength Impact Assessment Guidelines[1]. An overview of system strength pricing can be found on Powerlink's website[2].

### Indicative maximum short circuit currents

Tables H.1 to H.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2024/25, 2025/26 and 2026/27.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

The maximum short circuit currents were calculated using a system model:

- in which all generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with all model shunt elements removed.

The short circuit currents shown in tables H.1 to H.3 are based on generation shown in tables 7.1 and 7.2 (together with the more significant embedded non-scheduled generators) on the committed network development as forecast at the end of each calendar year. The tables also show the design rating of the Powerlink substation at each location. No assessment has been provided of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network; that is, all network elements are assumed to be in-service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create 'normally-open' point as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

### Indicative minimum short circuit currents

Minimum short circuit currents are used to inform the capacity of the system to accommodate fluctuating loads and power electronic connected systems (including non-synchronous generators and static VAr compensators (SVC)). Minimum short circuit currents are also important in ensuring power quality and system stability standards are met and for ensuring the proper operation of protection systems.

Tables H.1 to H.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by taking the existing intact network and setting the synchronous generator dispatch to align with AEMO's assumptions for minimum three phase fault level as described in AEMO's 2023 System Strength Report. The short circuit current is calculated, using the sub-transient machine impedances, with the system intact and with individual outages of each significant network element.

The lowest minimum short circuit current which results from these outages is reported.

The short circuit currents are calculated using the same methodology as the AEMO's assumptions.However, AEMO report on the highest of the calculated minimum fault levels of these agreed minimum generator dispatches.

These minimum short circuit currents are indicative only. The system strength available to new non-synchronous generators can only be assessed by a Full Impact Assessment using electro magnetic transient (EMT-type) modelling techniques.

1 AEMO System Strength Impact Assessment Guideline.
2 Overview of system strength pricing.

Table H.1 Indicative short circuit currents – northern Queensland

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alan Sherriff | 132 | 31.5 | 4.1 | 3.7 | 13.7 | 13.9 | 13.7 | 13.9 | 13.7 | 13.9 | 1.0346 | Ross 275kV |
| Alligator Creek | 132 | 31.5 | 3.1 | 1.8 | 4.4 | 5.9 | 4.5 | 5.9 | 4.5 | 5.9 | 1.1306 | Ross 275kV |
| Aurumfield | 275 | 40 | 1.2 | 1.1 | 3.7 | 4.7 | 3.7 | 4.7 | 3.7 | 4.7 | 1.1061 | Ross 275kV |
| Bolingbroke | 132 | 31.5 | 2.0 | 1.9 | 2.5 | 1.9 | 2.5 | 1.9 | 2.5 | 1.9 | 1.2139 | Ross 275kV |
| Bowen North | 132 | 31.5 | 2.1 | 0.7 | 3.0 | 3.2 | 3.0 | 3.2 | 3.0 | 3.2 | 1.1652 | Ross 275kV |
| Cairns (2T) | 132 | 31.5 | 3.1 | 0.5 | 6.8 | 8.9 | 6.8 | 8.9 | 6.8 | 8.9 | 1.0760 | Ross 275kV |
| Cairns (3T) | 132 | 31.5 | 3.1 | 0.5 | 6.8 | 8.9 | 6.8 | 8.9 | 6.8 | 8.9 | 1.0760 | Ross 275kV |
| Cairns (4T) | 132 | 31.5 | 3.1 | 0.5 | 6.8 | 9.0 | 6.8 | 9.0 | 6.8 | 9.0 | 1.0759 | Ross 275kV |
| Cardwell | 132 | 31.5 | 2.0 | 0.9 | 3.4 | 3.6 | 3.4 | 3.6 | 3.4 | 3.6 | 1.1442 | Ross 275kV |
| Chalumbin | 275 | 40 | 1.9 | 1.6 | 5.3 | 5.6 | 5.3 | 5.6 | 5.3 | 5.6 | 1.0453 | Ross 275kV |
| Chalumbin | 132 | 31.5 | 3.4 | 2.7 | 7.5 | 8.5 | 7.5 | 8.5 | 7.5 | 8.5 | 1.0790 | Ross 275kV |
| Clare South | 132 | 31.5 | 3.1 | 2.3 | 6.8 | 6.9 | 6.8 | 6.9 | 6.8 | 6.9 | 1.0898 | Ross 275kV |
| Collinsville North | 132 | 31.5 | 5.2 | 4.5 | 11.5 | 11.9 | 11.6 | 11.9 | 11.6 | 11.9 | 1.0446 | Ross 275kV |
| Coppabella | 132 | 31.5 | 2.2 | 1.5 | 3.0 | 3.4 | 3.0 | 3.4 | 3.0 | 3.4 | 1.1885 | Ross 275kV |
| Crush Creek | 275 | 40 | 3.5 | 3.0 | 10.8 | 11.9 | 10.8 | 12.0 | 10.9 | 12.0 | 1.0203 | Ross 275kV |
| Dan Gleeson (1T) | 132 | 31.5 | 4.0 | 3.7 | 13.0 | 13.3 | 13.0 | 13.3 | 13.1 | 13.3 | 1.0350 | Ross 275kV |
| Dan Gleeson (2T) | 132 | 31.5 | 4.0 | 3.7 | 13.0 | 13.4 | 13.0 | 13.4 | 13.1 | 13.4 | 1.0350 | Ross 275kV |
| Edmonton | 132 | 31.5 | 2.9 | 0.9 | 6.1 | 7.3 | 6.1 | 7.3 | 6.1 | 7.3 | 1.0835 | Ross 275kV |
| Eagle Downs | 132 | 31.5 | 3.0 | 1.5 | 4.6 | 4.4 | 4.6 | 4.4 | 4.6 | 4.4 | 1.1297 | Lilyvale 132kV |
| El Arish | 132 | 31.5 | 2.3 | 1.0 | 3.8 | 4.6 | 3.8 | 4.6 | 3.8 | 4.6 | 1.1213 | Ross 275kV |

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Garbutt | 132 | 31.5 | 3.8 | 1.7 | 11.2 | 11.0 | 11.2 | 11.1 | 11.2 | 11.1 | 1.0427 | Ross 275kV |
| Greenland | 132 | 31.5 | 3.4 | 2.1 | 5.5 | 5.1 | 5.5 | 5.1 | 5.5 | 5.1 | 1.1170 | Ross 275kV |
| Goonyella Riverside | 132 | 31.5 | 3.5 | 3.0 | 6.0 | 5.5 | 6.0 | 5.4 | 6.0 | 5.4 | 1.1096 | Ross 275kV |
| Guybal Munjan | 275 | 40 | 2.2 | 1.9 | 6.6 | 5.3 | 6.6 | 5.3 | 6.6 | 5.3 | 1.0266 | Ross 275kV |
| Haughton River | 275 | 40 | 2.7 | 2.0 | 8.4 | 8.6 | 8.5 | 8.6 | 8.5 | 8.6 | 1.0132 | Ross 275kV |
| Ingham South | 132 | 31.5 | 1.9 | 1.1 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 1.1542 | Ross 275kV |
| Innisfail | 132 | 31.5 | 2.1 | 1.3 | 3.3 | 3.9 | 3.3 | 3.9 | 3.3 | 3.9 | 1.1435 | Ross 275kV |
| Invicta | 132 | 31.5 | 2.5 | 2.4 | 5.3 | 4.8 | 5.3 | 4.8 | 5.3 | 4.8 | 1.1103 | Ross 275kV |
| Kamerunga (1T) | 132 | 31.5 | 2.6 | 0.6 | 5.0 | 5.8 | 5.0 | 5.8 | 5.0 | 5.8 | 1.1061 | Ross 275kV |
| Kamerunga (2T) | 132 | 31.5 | 2.6 | 0.6 | 5.0 | 5.9 | 5.0 | 5.9 | 5.0 | 5.9 | 1.1061 | Ross 275kV |
| Kareeya | 132 | 31.5 | 3.2 | 2.4 | 6.2 | 6.9 | 6.2 | 6.9 | 6.2 | 6.9 | 1.0957 | Ross 275kV |
| Kemmis | 132 | 31.5 | 3.9 | 1.6 | 6.1 | 6.6 | 6.1 | 6.7 | 6.2 | 6.7 | 1.1018 | Ross 275kV |
| King Creek | 132 | 31.5 | 3.1 | 1.3 | 5.4 | 4.4 | 5.4 | 4.4 | 5.4 | 4.4 | 1.0944 | Ross 275kV |
| Lake Ross | 132 | 31.5 | 4.6 | 4.2 | 18.2 | 20.1 | 18.2 | 20.2 | 18.3 | 20.2 | 1.0215 | Ross 275kV |
| Landers Creek | 132 | 31.5 | 2.9 | 1.4 | - | - | - | - | 5.7 | 5.0 | 1.1007 | Ross 275kV |
| Mackay | 132 | 31.5 | 3.4 | 2.9 | 5.1 | 6.1 | 5.1 | 6.1 | 5.1 | 6.1 | 1.1194 | Ross 275kV |
| Mackay Ports | 132 | 31.5 | 2.6 | 1.6 | 3.5 | 4.1 | 3.5 | 4.1 | 3.5 | 4.1 | 1.1616 | Ross 275kV |
| Mindi | 132 | 31.5 | 3.5 | 3.3 | 4.9 | 3.7 | 4.9 | 3.7 | 4.9 | 3.7 | 1.1171 | Ross 275kV |
| Moranbah | 132 | 31.5 | 4.0 | 3.3 | 8.0 | 9.5 | 8.0 | 9.6 | 8.0 | 9.6 | 1.0983 | Ross 275kV |
| Moranbah Plains | 132 | 31.5 | 2.7 | 2.3 | 4.4 | 4.8 | 4.4 | 4.8 | 4.4 | 4.8 | 1.1545 | Ross 275kV |
| Moranbah South | 132 | 31.5 | 3.3 | 2.8 | 5.7 | 5.2 | 5.7 | 5.3 | 5.7 | 5.3 | 1.1221 | Ross 275kV |

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mt Mclaren | 132 | 31.5 | 1.6 | 1.4 | 2.1 | 2.3 | 2.1 | 2.3 | 2.1 | 2.3 | 1.2718 | Ross 275kV |
| Nebo | 275 | 40 | 4.6 | 4.0 | 11.9 | 11.9 | 12.1 | 12.2 | 12.3 | 12.5 | 1.0374 | Ross 275kV |
| Nebo | 132 | 31.5 | 7.1 | 6.2 | 14.2 | 16.2 | 14.3 | 16.4 | 14.4 | 16.5 | 1.0529 | Ross 275kV |
| Newlands | 132 | 31.5 | 2.5 | 1.3 | 3.6 | 4.0 | 3.6 | 4.0 | 3.6 | 4.0 | 1.1498 | Ross 275kV |
| North Goonyella | 132 | 31.5 | 2.9 | 2.5 | 4.5 | 3.8 | 4.5 | 3.7 | 4.5 | 3.7 | 1.1338 | Ross 275kV |
| Oonooie | 132 | 31.5 | 2.4 | 1.5 | 3.1 | 3.7 | 3.1 | 3.7 | 3.1 | 3.7 | 1.1776 | Ross 275kV |
| Peak Downs | 132 | 31.5 | 2.8 | 2.1 | 4.2 | 3.7 | 4.2 | 3.7 | 4.2 | 3.7 | 1.1364 | Lilyvale 132kV |
| Pioneer Valley | 132 | 31.5 | 4.1 | 3.6 | 6.6 | 7.5 | 6.6 | 7.5 | 6.7 | 7.6 | 1.0970 | Ross 275kV |
| Proserpine | 132 | 31.5 | 2.5 | 1.8 | 3.5 | 4.1 | 3.5 | 4.1 | 3.5 | 4.1 | 1.1388 | Ross 275kV |
| Ross | 275 | 40 | 2.8 | 2.4 | 10.2 | 11.2 | 10.2 | 11.2 | 10.3 | 11.2 | 1.0000 | Ross 275kV |
| Ross | 132 | 31.5 | 4.7 | 4.2 | 18.8 | 21.0 | 18.8 | 21.0 | 18.9 | 21.0 | 1.0206 | Ross 275kV |
| Springlands | 132 | 31.5 | 5.5 | 4.6 | 12.7 | 14.3 | 12.8 | 14.4 | 12.8 | 14.4 | 1.0399 | Ross 275kV |
| Stony Creek | 132 | 31.5 | 2.7 | 1.2 | 3.8 | 3.7 | 3.8 | 3.7 | 3.8 | 3.7 | 1.1354 | Ross 275kV |
| Strathmore | 275 | 40 | 3.5 | 3.0 | 10.9 | 12.1 | 11.0 | 12.2 | 11.0 | 12.2 | 1.0200 | Ross 275kV |
| Strathmore | 132 | 31.5 | 5.6 | 4.7 | 13.2 | 15.3 | 13.2 | 15.3 | 13.3 | 15.3 | 1.0385 | Ross 275kV |
| Townsville East | 132 | 31.5 | 3.8 | 1.6 | 13.0 | 12.6 | 13.0 | 12.6 | 13.0 | 12.6 | 1.0435 | Ross 275kV |
| Townsville South | 132 | 31.5 | 4.1 | 3.8 | 17.5 | 21.0 | 17.6 | 21.0 | 17.6 | 21.0 | 1.0337 | Ross 275kV |
| Townsville GT PS | 132 | 31.5 | 3.4 | 2.4 | 10.1 | 10.7 | 10.1 | 10.7 | 10.1 | 10.7 | 1.0560 | Ross 275kV |
| Tully | 132 | 31.5 | 2.8 | 1.5 | 5.1 | 5.9 | 5.0 | 5.7 | 5.0 | 5.7 | 1.0892 | Ross 275kV |
| Tully South | 275 | 40 | 1.7 | 1.2 | 3.9 | 3.8 | 3.9 | 3.8 | 3.9 | 3.8 | 1.0506 | Ross 275kV |

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents | | | | | | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2024/25 | | 2025/26 | | 2026/27 | | | |
| | | | | | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | | |
| Tumoulin | 275 | 40 | 1.8 | 1.2 | 4.5 | 5.2 | 4.5 | 5.2 | 4.5 | 5.2 | 1.0540 | Ross 275kV |
| Turkinje | 132 | 31.5 | 1.8 | 1.2 | 2.8 | 3.1 | 2.8 | 3.1 | 2.8 | 3.1 | 1.1933 | Ross 275kV |
| Walkamin | 275 | 40 | 1.7 | 1.4 | 4.3 | 4.9 | 4.3 | 4.9 | 4.3 | 4.9 | 1.0575 | Ross 275kV |
| Wandoo | 132 | 31.5 | 3.3 | 3.1 | 4.6 | 3.3 | 4.6 | 3.3 | 4.6 | 3.3 | 1.1244 | Ross 275kV |
| Woree | 275 | 40 | 1.8 | 1.5 | 4.5 | 5.4 | 4.5 | 5.4 | 4.6 | 5.4 | 1.0531 | Ross 275kV |
| Woree | 132 | 31.5 | 3.2 | 2.7 | 7.1 | 9.6 | 7.1 | 9.6 | 7.1 | 9.6 | 1.0730 | Ross 275kV |
| Wotonga | 132 | 31.5 | 3.5 | 1.7 | 6.0 | 7.0 | 6.0 | 7.0 | 6.0 | 7.0 | 1.1137 | Ross 275kV |
| Yabulu South | 132 | 31.5 | 3.7 | 3.2 | 11.3 | 10.9 | 11.3 | 10.9 | 11.3 | 10.9 | 1.0448 | Ross 275kV |

Table H.2 Indicative short circuit currents – central Queensland

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Baralaba | 132 | 31.5 | 3.4 | 2.1 | 4.4 | 3.8 | 4.4 | 3.8 | 4.4 | 3.8 | 1.1421 | Lilyvale 132kV |
| Biloela | 132 | 31.5 | 6.1 | 3.5 | 8.2 | 8.4 | 8.2 | 8.4 | 8.2 | 8.4 | 1.0889 | Gin Gin 275kV |
| Blackwater | 132 | 31.5 | 4.0 | 3.3 | 6.0 | 7.1 | 6.0 | 7.2 | 6.0 | 7.2 | 1.0480 | Lilyvale 132kV |
| Bluff | 132 | 31.5 | 2.6 | 2.3 | 3.5 | 4.3 | 3.5 | 4.3 | 3.5 | 4.3 | 1.1057 | Lilyvale 132kV |
| Bouldercombe | 275 | 40.0 | 10.1 | 8.6 | 21.6 | 20.6 | 22.1 | 21.1 | 22.2 | 21.1 | 1.0375 | Gin Gin 275kV |
| Bouldercombe | 132 | 31.5 | 10.2 | 6.3 | 15.0 | 17.2 | 15.1 | 17.3 | 15.1 | 17.3 | 1.0595 | Gin Gin 275kV |
| Broadsound | 275 | 40.0 | 6.0 | 4.9 | 15.4 | 16.1 | 16.1 | 19.4 | 16.5 | 19.8 | 1.0434 | Lilyvale 132kV |
| Bundoora | 132 | 31.5 | 5.2 | 4.4 | 9.5 | 9.2 | 9.5 | 9.2 | 9.5 | 9.2 | 1.0120 | Lilyvale 132kV |
| Callemondah | 132 | 31.5 | 16.0 | 6.7 | 22.2 | 24.8 | 22.5 | 25.1 | 22.5 | 25.1 | 1.0397 | Gin Gin 275kV |
| Calliope River | 275 | 40.0 | 10.3 | 8.7 | 21.3 | 24.3 | 22.3 | 25.7 | 22.5 | 25.8 | 1.0231 | Gin Gin 275kV |
| Calliope River | 132 | 40.0 | 17.5 | 14.2 | 24.9 | 30.0 | 25.3 | 30.4 | 25.3 | 30.5 | 1.0372 | Gin Gin 275kV |
| Calvale | 275 | 40.0 | 10.1 | 8.3 | 24.2 | 26.5 | 24.4 | 26.7 | 24.4 | 26.7 | 1.0379 | Gin Gin 275kV |
| Calvale (1T) | 132 | 31.5 | 6.6 | 2.8 | 9.0 | 9.8 | 9.0 | 9.8 | 9.0 | 9.8 | 1.0839 | Gin Gin 275kV |
| Calvale (2T) | 132 | 31.5 | 6.8 | 3.1 | 8.6 | 9.4 | 8.6 | 9.4 | 8.6 | 9.4 | 1.0822 | Gin Gin 275kV |
| Duaringa | 132 | 31.5 | 1.9 | 1.6 | 2.3 | 2.9 | 2.3 | 2.9 | 2.3 | 2.9 | 1.2140 | Lilyvale 132kV |
| Dysart | 132 | 31.5 | 3.2 | 1.9 | 4.8 | 5.4 | 4.8 | 5.4 | 4.8 | 5.4 | 1.1041 | Lilyvale 132kV |
| Egans Hill | 132 | 31.5 | 6.4 | 1.6 | 8.5 | 8.3 | 8.5 | 8.3 | 8.5 | 8.3 | 1.0851 | Gin Gin 275kV |
| Gladstone PS | 275 | 40.0 | 9.9 | 8.4 | 19.8 | 22.0 | 20.7 | 23.2 | 20.8 | 23.3 | 1.0241 | Gin Gin 275kV |
| Gladstone PS | 132 | 40.0 | 16.0 | 12.6 | 21.9 | 25.1 | 22.2 | 25.4 | 22.2 | 25.4 | 1.0411 | Gin Gin 275kV |
| Gladstone South | 132 | 31.5 | 12.3 | 9.6 | 16.3 | 17.3 | 16.4 | 17.4 | 16.5 | 17.4 | 1.0479 | Gin Gin 275kV |
| Glencoe | 275 | 40.0 | 4.4 | 2.3 | - | - | - | - | 9.4 | 9.7 | 1.0568 | Lilyvale 132kV |

Table H.2 Indicative short circuit currents – central Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents | | | | | | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2024/25 | | 2025/26 | | 2026/27 | | | |
| | | | | | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | | |
| Grantleigh | 132 | 31.5 | 2.3 | 2.0 | 2.7 | 2.8 | 2.7 | 2.8 | 2.7 | 2.8 | 1.2084 | Gin Gin 275kV |
| Gregory | 132 | 31.5 | 5.7 | 4.7 | 10.5 | 11.8 | 10.6 | 11.9 | 10.7 | 11.9 | 1.0027 | Lilyvale 132kV |
| Larcom Creek | 275 | 40.0 | 9.2 | 3.3 | 15.7 | 15.9 | 17.0 | 19.2 | 17.1 | 19.2 | 1.0296 | Gin Gin 275kV |
| Larcom Creek | 132 | 31.5 | 7.9 | 4.2 | 12.4 | 13.9 | 12.6 | 14.4 | 12.6 | 14.4 | 1.0597 | Gin Gin 275kV |
| Lilyvale | 275 | 40.0 | 3.5 | 2.6 | 6.7 | 6.5 | 6.8 | 6.7 | 6.9 | 6.7 | 1.0216 | Lilyvale 132kV |
| Lilyvale | 132 | 31.5 | 5.9 | 4.8 | 11.2 | 12.9 | 11.3 | 13.0 | 11.3 | 13.1 | 1.0000 | Lilyvale 132kV |
| Moura | 132 | 31.5 | 3.2 | 1.5 | 4.4 | 5.4 | 4.4 | 5.4 | 4.4 | 5.4 | 1.1545 | Gin Gin 275kV |
| Norwich Park | 132 | 31.5 | 2.7 | 2.5 | 3.7 | 2.7 | 3.7 | 2.7 | 3.7 | 2.7 | 1.1087 | Lilyvale 132kV |
| Pandoin | 132 | 31.5 | 5.4 | 1.2 | 7.0 | 6.1 | 7.1 | 6.1 | 7.1 | 6.1 | 1.0971 | Gin Gin 275kV |
| Raglan | 275 | 40.0 | 7.7 | 4.3 | 12.2 | 10.6 | 12.6 | 11.3 | 12.6 | 11.4 | 1.0375 | Gin Gin 275kV |
| Rockhampton (1T) | 132 | 31.5 | 5.1 | 1.8 | 6.5 | 6.4 | 6.6 | 6.4 | 6.6 | 6.4 | 1.1022 | Gin Gin 275kV |
| Rockhampton (5T) | 132 | 31.5 | 5.0 | 1.8 | 6.3 | 6.2 | 6.3 | 6.2 | 6.4 | 6.2 | 1.1047 | Gin Gin 275kV |
| Stanwell | 275 | 40.0 | 10.8 | 9.0 | 24.7 | 25.9 | 25.2 | 26.5 | 25.4 | 26.6 | 1.0381 | Gin Gin 275kV |
| Stanwell | 132 | 31.5 | 4.8 | 3.7 | 6.0 | 6.5 | 6.0 | 6.5 | 6.0 | 6.5 | 1.1085 | Gin Gin 275kV |
| Wurdong | 275 | 40.0 | 9.4 | 6.4 | 17.0 | 16.9 | 17.5 | 17.3 | 17.5 | 17.3 | 1.0267 | Gin Gin 275kV |
| Wycarbah | 132 | 31.5 | 3.7 | 3.0 | 4.6 | 5.4 | 4.6 | 5.4 | 4.6 | 5.4 | 1.1346 | Gin Gin 275kV |
| Yarwun | 132 | 31.5 | 7.9 | 4.5 | 12.9 | 14.9 | 13.2 | 15.2 | 13.2 | 15.2 | 1.0617 | Gin Gin 275kV |

Table H.3 Indicative short circuit currents – southern Queensland

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Abermain | 275 | 40 | 8.0 | 6.3 | 19.1 | 19.4 | 19.2 | 19.4 | 19.2 | 19.4 | 1.0054 | Greenbank 275kV |
| Abermain | 110 | 31.5 | 12.9 | 10.4 | 21.8 | 24.7 | 21.9 | 24.8 | 21.9 | 24.8 | 1.0209 | Greenbank 275kV |
| Algester | 110 | 31.5 | 12.8 | 11.5 | 21.4 | 21.1 | 21.5 | 21.1 | 21.5 | 21.1 | 1.0207 | Greenbank 275kV |
| Ashgrove West | 110 | 31.5 | 12.1 | 9.2 | 19.4 | 20.2 | 19.4 | 20.4 | 19.4 | 20.4 | 1.0258 | Greenbank 275kV |
| Banana Bridge | 275 | 40 | 7.4 | 5.0 | 27.2 | 28.4 | 27.6 | 29.2 | 27.6 | 29.2 | 1.0007 | Western Downs 275kV |
| Belmont | 275 | 40 | 7.8 | 7.1 | 17.8 | 18.4 | 17.9 | 18.5 | 17.9 | 18.5 | 1.0051 | Greenbank 275kV |
| Belmont | 110 | 40 | 15.3 | 14.2 | 28.5 | 35.2 | 28.6 | 35.2 | 28.6 | 35.2 | 1.0128 | Greenbank 275kV |
| Blackstone | 275 | 40 | 8.6 | 7.8 | 22.6 | 24.7 | 22.8 | 24.8 | 22.8 | 24.8 | 1.0017 | Greenbank 275kV |
| Blackstone | 110 | 40 | 14.5 | 13.3 | 26.0 | 28.4 | 26.0 | 28.4 | 26.0 | 28.4 | 1.0160 | Greenbank 275kV |
| Blackwall | 275 | 40 | 9.9 | 8.3 | 23.7 | 25.2 | 23.9 | 25.3 | 23.9 | 25.3 | 1.0048 | Greenbank 275kV |
| Blythdale | 132 | 31.5 | 3.1 | 2.3 | 4.3 | 5.3 | 4.3 | 5.3 | 4.3 | 5.3 | 1.1113 | Western Downs 275kV |
| Braemar | 330 | 50 | 6.9 | 5.6 | 25.5 | 27.2 | 25.6 | 27.3 | 25.6 | 27.3 | 1.0086 | Western Downs 275kV |
| Braemar (1T) | 275 | 50 | 9.9 | 5.2 | 28.3 | 32.5 | 28.4 | 32.5 | 28.4 | 32.5 | 1.0118 | Western Downs 275kV |
| Braemar (2T) | 275 | 50 | 7.8 | 4.5 | 30.1 | 32.7 | 30.3 | 32.8 | 30.3 | 32.8 | 1.0048 | Western Downs 275kV |
| Bulli Creek | 330 | 50 | 6.7 | 6.1 | 20.3 | 15.8 | 20.3 | 15.8 | 20.3 | 15.8 | 1.0173 | Western Downs 275kV |
| Bulli Creek | 132 | 31.5 | 3.0 | 3.0 | 4.1 | 4.6 | 4.1 | 4.6 | 4.1 | 4.6 | 1.1368 | Western Downs 275kV |
| Bundamba | 110 | 31.5 | 11.1 | 7.6 | 17.5 | 16.7 | 17.5 | 16.7 | 17.5 | 16.7 | 1.0275 | Greenbank 275kV |
| Cameby | 132 | 31.5 | 4.7 | 3.6 | 9.1 | 8.6 | 9.1 | 8.6 | 9.1 | 8.6 | 1.0659 | Western Downs 275kV |

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chinchilla | 132 | 31.5 | 3.8 | 3.0 | 6.5 | 7.9 | 6.5 | 7.9 | 6.5 | 7.9 | 1.0873 | Western Downs 275kV |
| Clifford Creek | 132 | 31.5 | 4.0 | 3.3 | 5.9 | 5.3 | 6.0 | 5.3 | 6.0 | 5.3 | 1.0810 | Western Downs 275kV |
| Columboola | 275 | 40 | 5.2 | 3.9 | 14.3 | 13.4 | 14.3 | 13.4 | 14.3 | 13.4 | 1.0125 | Western Downs 275kV |
| Columboola | 132 | 31.5 | 6.7 | 4.9 | 17.3 | 20.4 | 17.3 | 20.4 | 17.3 | 20.4 | 1.0370 | Western Downs 275kV |
| Condabri Central | 132 | 31.5 | 4.9 | 3.9 | 9.2 | 6.8 | 9.2 | 6.8 | 9.2 | 6.8 | 1.0609 | Western Downs 275kV |
| Condabri North | 132 | 31.5 | 6.1 | 4.5 | 13.8 | 12.9 | 13.8 | 12.9 | 13.8 | 12.9 | 1.0438 | Western Downs 275kV |
| Condabri South | 132 | 31.5 | 4.0 | 3.3 | 6.7 | 4.5 | 6.7 | 4.5 | 6.7 | 4.5 | 1.0804 | Western Downs 275kV |
| Coopers Gap | 275 | 40 | 8.0 | 3.1 | 18.5 | 18.2 | 18.5 | 18.2 | 18.5 | 18.2 | 1.0158 | Western Downs 275kV |
| Diamondy | 275 | 40 | 7.9 | 6.7 | 15.1 | 11.5 | 15.1 | 11.5 | 15.1 | 11.5 | 1.0222 | Western Downs 275kV |
| Dinoun South | 132 | 31.5 | 4.4 | 3.6 | 6.8 | 7.1 | 6.8 | 7.1 | 6.8 | 7.1 | 1.0707 | Western Downs 275kV |
| Eurombah | 275 | 40 | 2.7 | 1.2 | 4.7 | 4.8 | 4.7 | 4.8 | 4.7 | 4.8 | 1.0491 | Western Downs 275kV |
| Eurombah | 132 | 31.5 | 4.6 | 3.4 | 7.3 | 8.9 | 7.3 | 8.9 | 7.3 | 8.9 | 1.0672 | Western Downs 275kV |
| Fairview | 132 | 31.5 | 3.0 | 2.5 | 4.1 | 5.2 | 4.1 | 5.2 | 4.1 | 5.2 | 1.1177 | Western Downs 275kV |
| Fairview South | 132 | 31.5 | 3.7 | 2.9 | 5.4 | 6.8 | 5.4 | 6.8 | 5.4 | 6.8 | 1.0895 | Western Downs 275kV |
| Gin Gin | 275 | 40 | 6.1 | 4.3 | 9.5 | 9.0 | 9.7 | 9.2 | 10.0 | 9.3 | 1.0000 | Gin Gin 275kV |
| Gin Gin | 132 | 31.5 | 8.6 | 6.7 | 12.4 | 13.6 | 12.6 | 13.8 | 13.1 | 14.3 | 1.0185 | Gin Gin 275kV |

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents | | | | | | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2024/25 | | 2025/26 | | 2026/27 | | | |
| | | | | | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | 3 phase (kA) | L – G (kA) | | |
| Goodna | 275 | 40 | 7.7 | 5.5 | 16.9 | 16.4 | 17.0 | 16.5 | 17.0 | 16.5 | 1.0078 | Greenbank 275kV |
| Goodna | 110 | 40 | 14.6 | 12.8 | 26.0 | 27.9 | 26.1 | 28.0 | 26.1 | 28.0 | 1.0164 | Greenbank 275kV |
| Greenbank | 275 | 50 | 8.4 | 7.7 | 22.0 | 24.6 | 22.1 | 24.7 | 22.1 | 24.7 | 1.0000 | Greenbank 275kV |
| Halys | 275 | 50 | 12.2 | 9.6 | 35.2 | 30.7 | 35.3 | 30.7 | 35.3 | 30.7 | 1.0129 | Western Downs 275kV |
| Kumbarilla Park | 275 | 40 | 6.6 | 1.7 | 17.2 | 16.4 | 17.2 | 16.4 | 17.2 | 16.4 | 1.0173 | Western Downs 275kV |
| Kumbarilla Park | 132 | 31.5 | 8.3 | 5.5 | 13.3 | 15.3 | 13.3 | 15.3 | 13.3 | 15.3 | 1.0385 | Western Downs 275kV |
| Loganlea | 275 | 40 | 7.2 | 6.0 | 15.7 | 15.9 | 15.7 | 16.0 | 15.7 | 16.0 | 1.0059 | Greenbank 275kV |
| Loganlea | 110 | 40 | 13.3 | 11.9 | 23.2 | 27.8 | 23.2 | 27.8 | 23.3 | 27.8 | 1.0170 | Greenbank 275kV |
| Middle Ridge (4T) | 330 | 50 | 5.7 | 3.5 | 14.0 | 13.3 | 14.0 | 13.3 | 14.0 | 13.3 | 1.0244 | Western Downs 275kV |
| Middle Ridge (5T) | 330 | 50 | 5.8 | 3.5 | 14.4 | 13.7 | 14.4 | 13.7 | 14.4 | 13.7 | 1.0240 | Western Downs 275kV |
| Middle Ridge | 275 | 40 | 7.6 | 6.7 | 20.0 | 19.6 | 20.0 | 19.7 | 20.0 | 19.7 | 1.0136 | Greenbank 275kV |
| Middle Ridge | 110 | 40 | 10.6 | 8.8 | 21.9 | 25.7 | 21.9 | 25.7 | 21.9 | 25.7 | 1.0350 | Greenbank 275kV |
| Millmerran | 330 | 50 | 6.3 | 5.8 | 21.6 | 23.4 | 21.6 | 23.4 | 21.6 | 23.4 | 1.0200 | Western Downs 275kV |
| Miss | 330 | 50 | 5.2 | 4.4 | 15.3 | 17.3 | 15.3 | 17.2 | 15.3 | 17.2 | 1.0265 | Western Downs 275kV |
| Molendinar (1T) | 275 | 40 | 5.0 | 2.1 | 8.4 | 8.2 | 8.5 | 8.2 | 8.5 | 8.2 | 1.0175 | Greenbank 275kV |
| Molendinar (2T) | 275 | 40 | 5.0 | 2.1 | 8.4 | 8.2 | 8.4 | 8.2 | 8.4 | 8.2 | 1.0176 | Greenbank 275kV |
| Molendinar | 110 | 31.5 | 11.8 | 10.2 | 19.7 | 24.9 | 19.7 | 24.8 | 19.7 | 24.8 | 1.0199 | Greenbank 275kV |
| Mt England | 275 | 40 | 9.6 | 8.1 | 23.9 | 23.7 | 24.1 | 23.8 | 24.1 | 23.8 | 1.0072 | Greenbank 275kV |
| Mudgeeraba | 275 | 40 | 5.4 | 4.3 | 9.5 | 8.7 | 9.5 | 8.7 | 9.5 | 8.7 | 1.0143 | Greenbank 275kV |

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mudgeeraba | 110 | 31.5 | 11.0 | 10.0 | 17.7 | 21.3 | 17.7 | 21.4 | 17.7 | 21.4 | 1.0233 | Greenbank 275kV |
| Murarrie (1T) | 275 | 40 | 6.8 | 2.3 | 13.7 | 13.5 | 13.7 | 13.5 | 13.7 | 13.5 | 1.0092 | Greenbank 275kV |
| Murarrie (2T) | 275 | 40 | 6.8 | 2.3 | 13.7 | 13.6 | 13.7 | 13.6 | 13.7 | 13.6 | 1.0092 | Greenbank 275kV |
| Murarrie | 110 | 40 | 13.8 | 12.7 | 24.3 | 29.2 | 24.4 | 29.3 | 24.4 | 29.3 | 1.0164 | Greenbank 275kV |
| Oakey | 110 | 31.5 | 5.1 | 3.7 | 11.5 | 12.5 | 11.5 | 12.5 | 11.5 | 12.5 | 1.0882 | Greenbank 275kV |
| Oakey Gt | 110 | 31.5 | 4.9 | 1.3 | 10.3 | 10.1 | 10.3 | 10.1 | 10.3 | 10.1 | 1.0935 | Greenbank 275kV |
| Orana | 275 | 40 | 6.0 | 3.0 | 16.9 | 16.3 | 17.0 | 16.4 | 17.0 | 16.4 | 1.0073 | Western Downs 275kV |
| Palmwoods | 275 | 40 | 5.6 | 3.4 | 8.8 | 9.2 | 9.0 | 9.3 | 9.0 | 9.3 | 1.0299 | Greenbank 275kV |
| Palmwoods | 132 | 31.5 | 9.1 | 6.8 | 13.4 | 16.2 | 13.7 | 16.5 | 13.8 | 16.5 | 1.0403 | Greenbank 275kV |
| Palmwoods (7T) | 110 | 31.5 | 5.7 | 2.6 | 7.3 | 7.6 | 7.3 | 7.6 | 7.3 | 7.6 | 1.0834 | Greenbank 275kV |
| Palmwoods (8T) | 110 | 31.5 | 5.7 | 2.6 | 7.3 | 7.6 | 7.3 | 7.6 | 7.3 | 7.6 | 1.0834 | Greenbank 275kV |
| Redbank Plains | 110 | 31.5 | 12.9 | 9.5 | 21.7 | 20.9 | 21.8 | 20.9 | 21.8 | 20.9 | 1.0207 | Greenbank 275kV |
| Richlands | 110 | 31.5 | 13.2 | 10.9 | 22.3 | 22.9 | 22.3 | 23.0 | 22.3 | 23.0 | 1.0202 | Greenbank 275kV |
| Rocklea (1T) | 275 | 40 | 6.9 | 2.3 | 13.6 | 12.5 | 13.7 | 12.6 | 13.7 | 12.6 | 1.0122 | Greenbank 275kV |
| Rocklea (2T) | 275 | 40 | 5.4 | 2.3 | 8.9 | 8.5 | 9.0 | 8.6 | 9.0 | 8.6 | 1.0235 | Greenbank 275kV |
| Rocklea | 110 | 40 | 14.5 | 12.8 | 25.5 | 29.2 | 25.6 | 29.4 | 25.6 | 29.5 | 1.0180 | Greenbank 275kV |
| Runcorn | 110 | 31.5 | 11.8 | 8.6 | 19.1 | 19.4 | 19.1 | 19.4 | 19.1 | 19.4 | 1.0237 | Greenbank 275kV |
| South Pine | 275 | 40 | 9.3 | 7.9 | 19.7 | 22.1 | 20.0 | 22.3 | 20.0 | 22.3 | 1.0099 | Greenbank 275kV |
| South Pine (East) | 110 | 40 | 13.5 | 11.5 | 21.9 | 28.0 | 22.1 | 28.1 | 22.1 | 28.2 | 1.0253 | Greenbank 275kV |
| South Pine (West) | 110 | 40 | 12.8 | 10.1 | 20.8 | 23.8 | 20.8 | 24.0 | 20.8 | 24.0 | 1.0249 | Greenbank 275kV |

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

| Substation | Voltage (kV) | Substation Design Rating (kA) | Indicative minimum system normal 3 phase fault level (kA) | Indicative minimum post-contingent 3 phase fault level (kA) | Indicative maximum short circuit currents 2024/25 3 phase (kA) | 2024/25 L – G (kA) | 2025/26 3 phase (kA) | 2025/26 L – G (kA) | 2026/27 3 phase (kA) | 2026/27 L – G (kA) | SSLF | Ref Node |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sumner | 110 | 31.5 | 12.7 | 9.1 | 21.0 | 20.4 | 21.1 | 21.0 | 21.1 | 21.0 | 1.0226 | Greenbank 275kV |
| Swanbank E | 275 | 40 | 8.5 | 7.2 | 22.3 | 24.2 | 22.4 | 24.3 | 22.4 | 24.3 | 1.0017 | Greenbank 275kV |
| Tangkam | 110 | 31.5 | 6.0 | 4.2 | 13.7 | 12.5 | 13.7 | 12.5 | 13.7 | 12.5 | 1.0729 | Greenbank 275kV |
| Tarong | 275 | 50 | 11.8 | 9.4 | 36.7 | 39.1 | 36.9 | 39.1 | 36.9 | 39.1 | 1.0111 | Greenbank 275kV |
| Tarong | 66 | 31.5 | 12.3 | 7.0 | 15.5 | 16.6 | 15.5 | 16.6 | 15.5 | 16.6 | 1.0642 | Greenbank 275kV |
| Teebar Creek | 275 | 40 | 4.9 | 2.3 | 7.4 | 7.2 | 7.6 | 7.3 | 7.7 | 7.4 | 1.0319 | Gin Gin 275kV |
| Teebar Creek | 132 | 31.5 | 7.2 | 4.5 | 10.0 | 11.1 | 10.2 | 11.2 | 10.3 | 11.3 | 1.0469 | Gin Gin 275kV |
| Tennyson | 110 | 31.5 | 10.7 | 1.8 | 16.4 | 16.5 | 16.5 | 16.6 | 16.5 | 16.6 | 1.0309 | Greenbank 275kV |
| Tummaville | 330 | 50 | 6.1 | 5.7 | 20.2 | 20.7 | 20.2 | 20.7 | 20.2 | 20.7 | 1.0210 | Western Downs 275kV |
| Upper Kedron | 110 | 40 | 13.1 | 11.3 | 21.6 | 18.9 | 21.7 | 19.5 | 21.7 | 19.5 | 1.0227 | Greenbank 275kV |
| Wandoan South | 275 | 40 | 3.8 | 3.0 | 8.3 | 9.4 | 8.3 | 9.4 | 8.3 | 9.4 | 1.0272 | Western Downs 275kV |
| Wandoan South | 132 | 31.5 | 5.5 | 4.2 | 10.3 | 13.2 | 10.3 | 13.2 | 10.3 | 13.2 | 1.0512 | Western Downs 275kV |
| West Darra | 110 | 40 | 14.4 | 13.2 | 25.4 | 24.1 | 25.5 | 24.4 | 25.5 | 24.4 | 1.0173 | Greenbank 275kV |
| Western Downs | 275 | 50 | 7.6 | 5.1 | 29.5 | 31.6 | 30.0 | 32.7 | 30.0 | 32.7 | 1.0000 | Western Downs 275kV |
| Woolooga | 275 | 40 | 6.4 | 5.4 | 10.6 | 12.1 | 11.3 | 13.0 | 11.4 | 13.1 | 1.0223 | Gin Gin 275kV |
| Woolooga | 132 | 31.5 | 9.0 | 7.1 | 14.3 | 17.7 | 16.2 | 20.5 | 16.3 | 20.6 | 1.0394 | Gin Gin 275kV |
| Yuleba North | 275 | 40 | 3.3 | 2.7 | 6.5 | 7.1 | 6.5 | 7.1 | 6.5 | 7.1 | 1.0349 | Western Downs 275kV |
| Yuleba North | 132 | 31.5 | 5.0 | 3.9 | 8.2 | 10.0 | 8.2 | 10.0 | 8.2 | 10.0 | 1.0590 | Western Downs 275kV |

# Appendix I Glossary

| | |
|---|---|
| ABS | Australian Bureau of Statistics |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AFL | Available Fault Level |
| AI | Artificial Intelligence |
| ARR | Asset Reinvestment Review |
| BSL | Boyne Smelters Limited |
| BESS | Battery Energy Storage System |
| CAA | Connection and Access Agreement |
| CBD | Central Business District |
| CER | Consumer Energy Resources |
| CQ | Central Queensland |
| CQ-SQ | Central Queensland to South Queensland |
| CQ-NQ | Central Queensland to North Queensland |
| CVTs | Capacitive voltage transformers |
| DCA | Dedicated Connection Assets |
| DEC | Department of Energy and Climate |
| DER | Distributed Energy Resources |
| DNA | Designated Network Assts |
| DNSP | Distribution Network Service Provider |
| DSM | Demand side management |
| EAP | Energy Advisory Panel |
| ECMC | Energy and Climate Ministerial Council |
| ECS | Emergency Control Scheme |
| EFCS | Emergency Frequency Control Schemes |
| EJPC | Executive Joint Planning Committee |
| ENA | Energy Networks Australia |
| EMT-type | Eletromagnetic Transient-type |
| EOI | Expresession of interest |
| ESOO | Electricity Statement of Opportunities |
| EV | Electric vehicle |
| EUSE | expected unserved energy |
| FIA | Full Impact Assessment |
| FNQ | Far North Queensland |
| FRG | Forecasting Reference Group |
| GPS | Gladstone Power Station |
| GPSRR | General Power System Risk Review |
| HTC | High Temperature Conductor |
| HV | High Voltage |
| IBR | Inverter-based Resources |
| ISP | Integrated System Plan |
| IUSA | Identified User Shared Assets |
| JPB | Jurisdictional Planning Body |
| JPC | Joint Planning Committee |
| kA | Kiloampere |
| kV | Kilovolts |
| LEIP | Lansdown Eco Industrial Precinct |
| LTTW | Lightning Trip Time Window |
| MLF | Marginal Loss Factors |
| MVA | Megavolt Ampere |
| MVAr | Megavolt Ampere reactive |
| MW | Megawatt |
| MWh | Megawatt hour |
| MWs | Megawatt seconds |
| NEM | National Electricity Market |
| NEMDE | National Electricity Market Dispatch Engine |
| NER | National Electricity Rules |
| NNESR | Non-network Engagement Stakeholder Register |
| NSCAS | Nework Support and Control Ancillary Service |
| NSP | Network Service Providers |

Appendix I Glossary *(continued)*

| | |
|---|---|
| NSW | New South Wales |
| NQ | North Queensland |
| NWMP | North West Mineral Province |
| OCG | Office of the Coordinator-General |
| ODP | Optimal Development Path |
| OFGS | Over Frequency Generation Shedding |
| OIP | Optimal Infrastructure Pathway |
| PACR | Project Assessment Conclusions Report |
| PADR | Project Assessment Draft Report |
| PHES | Pumped Hydro Energy Storage |
| PoE | Probability of Exceedance |
| PS | Power Station |
| PSCR | Project Specification Consultation Report |
| PSMRG | Power System Modelling Reference Group |
| PTI | Priority transmission investment |
| PV | Photovoltaic |
| PVNSG | Photovoltaic non-scheduled generation |
| QAL | Queensland Alumina Limited |
| QEJP | Queensland Energy and Jobs Plan |
| QHES | Queensland Household Energy Survey |
| QNI | Queensland to New South Wales Interconnector |
| QRET | Queensland Renewable Energy Target |
| RBA | Reserve Bank of Australia |
| RDB | REZ Delivery Body |
| RET | Renewable Energy Targets |
| REZ | Renewable Energy Zone |
| RIT-D | Regulatory Investment Test for Distribution |
| RIT-T | Regulatory Investment Test for Transmission |
| RMP | REZ Management Plans |
| RSAS | Reliability and Security Ancillary Service |
| RWG | Regulatory Working Group |
| SQ | Southern Queensland |
| SEQ | South East Queensland |
| SPS | Special Protection Scheme |
| SSIAG | System Strength Assessment Guidelines |
| SSLF | System Strength Locational Factor |
| SSSP | System Strength Service Provider |
| SSUP | System Strength Unit Prices |
| SVC | Static VAr Compensator |
| SWQ | South West Queensland |
| TAPR | Transmission Annual Planning Report |
| TEEP | Transmission Easement Engagement Process |
| TGCP | TAPR Guideline Connection Point |
| TNSP | Transmission Network Service Provider |
| UFLS | Under Frequency Load Shed |
| UVLS | Under Voltage Load Shed |
| VCR | Value of Customer Reliability |
| VRE | Variable renewable energy |
| WAMPAC | Wide area monitoring protection and control |

# Contact us


Registered office

33 Harold St Virginia
Queensland 4014 Australia
ABN 82 078 849 233

Postal address

PO Box 1193 Virginia
Queensland 4014 Australia

Telephone

+61 7 3860 2111
(during business hours)

Email

pqenquiries@powerlink.com.au

Website

www.powerlink.com.au