2023

Transmission Annual Planning Report

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About Powerlink

Our network

1,700km north of Cairns to NSW border

3 in-flight Renewable Energy Zones

8,916MW max demand

2,597MW min demand

Customer connections

22 solar and wind projects in operation at 3,155MW

One PHES in operation

Approximately 70GW of wind and solar generation planning to connect to the transmission network

24 connection applications during 2022/23

Consultation

Customer Panel

Asset Reinvestment Review Working Group

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 ongoing connection to Country.

Foreword

'On track for 80% renewables by 2035'

It has never been so exciting to be in the electricity industry. Since the release of the Queensland Energy and Jobs Plan (QEJP) last year we have seen an increased interest in renewable generation, storage solutions, electrification of existing loads and new loads wanting to connect in Queensland. Powerlink has taken this unprecedented interest into account in its planning activities focusing on the delivery of a safe, reliable, cost effective and sustainable energy supply for Queenslanders.

Social license is so important and essential to the energy transformation. Powerlink is committed to genuine, transparent and honest consultation with landholders and communities, as we recognise the potential impacts of the delivery of new electricity transmission infrastructure and the need to share in the benefits it provides.

We are on track for 80% renewables by 2035 with Queensland reaching a significant milestone in August with over 25% renewable energy generation over the previous 12 months. Interest from proponents of variable renewable energy (VRE) generation has increased during 2023 with now over 37GW of wind generation and 30GW of solar generation with plans to connect to the transmission network.

In collaboration with the Queensland Government and Industry, Powerlink continues to progress the development of Renewable Energy Zones (REZs) across the State, with the Far North Queensland, Southern Downs and Western Downs Renewable Energy Zones (REZ) already in-flight. Taking advantage of existing transmission network infrastructure to facilitate development, these REZs will be completed in 2023/24 and 2024/25 and will enable up to 5,900MW of renewable generation, driving economic growth in the regions and delivering value for communities, industries and stakeholders.

With change comes opportunity, as the demand for decarbonised energy is expected to continue to grow in Queensland as industry moves to electrification. We have over 3GW of existing loads investigating electrification options and new loads seeking to connect in Queensland. This step change in the energy landscape is anticipated to bring significant benefits to Queenslanders by helping safeguard manufacturing jobs and creating new low-carbon domestic export markets.

Acknowledging the importance of maximizing the capacity of the transmission network and reducing the amount of infrastructure we need to build, Powerlink continues to find innovative solutions. This includes implementing non-network solutions to support future grid operation; implementing Wide Area Monitoring, Protection and Control (WAMPAC) systems to increase network capacity and reduce generator constraints; and investigating dynamic real-time ratings and Frequency Control and Ancillary Services to enable larger REZs.

Taking into consideration a diversified generation mix and potential future pathways, the Transmission Annual Planning Report sets the scene and represents Powerlink's current view of the development of the Queensland transmission network over the next ten years. Most importantly, creating value for communities, customers and industry while delivering safe, reliable and cost effective electricity to Queenslanders remains front of mind for Powerlink during the energy transformation.

Dr Stewart Bell
Executive General Manager
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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) responsible for transmission network planning 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* and its Transmission Authority.

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 2023 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

The forecasts presented in this TAPR indicate mild growth for summer maximum demand, and further reductions in the minimum delivered demand. The forecast delivered energy from the transmission network over the 10-year outlook period remains relatively unchanged but with a slight upward trajectory mainly due to industries beginning to electrify their operations to meet their emission reduction targets from 2030.

Powerlink is playing an active role in shaping and enabling the Queensland power system of the future. Powerlink has continued to work closely with the Queensland Government in developing and actioning the Queensland Energy and Jobs Plan (QEJP), including the establishment of a new SuperGrid transmission backbone and establishment of new Renewable Energy Zones (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 2023 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 AEMO's ISP and QEJP.

Powerlink's focus on community, customer and stakeholder engagement has continued over the last year, 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 the Asset Reinvestment Review, a review of Powerlink's Network Development Process and the introduction of a new SuperGrid Landholder Payment Framework to assist landholders and landholders on neighbouring properties adjacent to transmission infrastructure.

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 the benefit of customers. Powerlink played a key role in the development of the Energy Charter Better Practice Social Licence Guideline released in May 2023. This work was completed within an Energy Charter #BetterTogether collaborative innovation project. The guideline focusses on identifying impacts and opportunities for the communities affected by the energy transformation.

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 hydrogen markets, 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 2022 TAPR, Powerlink has continued to work closely with the Queensland Government 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. Powerlink is well progressed with preparatory activities for the first stage of the SuperGrid transmission backbone (Borumba PHES connection). Subject to planning approvals, the proposed Borumba PHES is scheduled to be operational circa 2030 and is a cornerstone of Queensland's future clean energy system, providing critical storage and firming for increasing levels of variable renewable generation.

In June 2023, the Queensland Government announced that the fourth stage of the SuperGrid transmission backbone will be advanced and form part of CopperString 2032. The project initially involves constructing 840km of high voltage transmission line from Townsville to Mount Isa that will connect the North West Mineral Province (NWMP) to the NEM. CopperString 2032 is anticipated to significantly bolster new industries and facilities for minerals mining and processing in north west Queensland, and enable the connection of significant quantities of renewable energy to the coastal Queensland transmission backbone. Powerlink will own and lead delivery of CopperString 2032 to completion.

In June 2023, the Queensland Government published the draft 2023 Queensland REZ Roadmap. This Roadmap outlines the pathway for connecting 22GW of new large-scale renewable energy by 2035 and is a key component of the QEJP. Powerlink provided significant input to developing the draft 2023 Queensland REZ Roadmap. The Queensland Government and Powerlink have undertaken analysis to determine where potential REZs could be established. The REZs will be developed over three phases taking into account the sequencing of other large-scale energy infrastructure developments including the SuperGrid transmission backbone, and proposed Borumba and Pioneer-Burdekin PHES facilities. Powerlink is progressing the development of three in-flight REZs located within north and south west Queensland, with the first located in north Queensland scheduled to become operational in early 2024.

Powerlink is implementing new approaches and technologies, and 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.

Electricity energy and demand forecasts

The 2022/23 summer in Queensland had below average daily maximum and minimum temperatures and above average temperatures in March, which saw an overall summer peak delivered demand of 8,916MW at 6.00pm on 17 March, 116MW below the 2021/22 maximum delivered demand. Operational 'as generated' peak was recorded 30 minutes earlier at 5.30pm reaching 10,070MW.

The 2023 Queensland minimum delivered demand was recorded at 12.30pm on 20 August 2023, when only 2,538MW was delivered from the transmission grid (refer to Figure 3.9 for load measurement definitions). Operational 'as generated' minimum demand was recorded on 17 September 2023 at 11.00am and set a new record for Queensland of 3,387MW, passing the previous minimum record of 3,469MW set in September 2022.

Powerlink has adopted AEMO's 2023 Electricity Statement of Opportunities (ESOO) forecasts in its planning analysis for the 2023 TAPR. The forecast captures impacts of growth in rooftop PV installations, changing Queensland economic growth conditions, energy efficiency initiatives, battery storage and electric vehicles (EV), electrification and tariffs through Step Change, Progressive Change and Hydrogen Export scenarios. Bottom-up forecasts are derived through reconciliation of AEMO's forecast with those from Distribution Network Service Providers at each transmission connection supply point.

Electricity energy forecast

Based on the Step Change scenario forecast, Queensland's delivered energy consumption is forecast to increase at an average of 1.8% per annum over the next 10 years from 46,214GWh in 2022/23 to 55,157GWh in 2033/34. The increase in energy consumption is mainly due to industries beginning to electrify their operations to meet their emission reduction targets.

Electricity demand forecast

Based on the Step Change scenario forecast, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 1.8% per annum over the next 10 years, from 9,201MW (weather corrected) in 2022/23 to 10,879MW in 2032/33. Annual minimum transmission delivered demands are expected to decrease in all forecast scenarios presented in the 2023 TAPR. These AEMO 2023 ESOO minimum demand forecasts are provided with simulated solar traces which do not account for economic curtailment or operational measures required to maintain reliability and system 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. Powerlink is committed to working with AEMO and customers to better understand the future impacts that electrification will have on demand and energy forecasts.

Focussing on a future network that supports the long-term 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 ongoing 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 including support for the QEJP and Queensland SuperGrid Infrastructure Blueprint
- 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 2023 TAPR continues to support the connection of variable renewable energy (VRE) generation to Powerlink's transmission network, enabling the power system transformation.

Based on the Step Change scenario forecast, the planning standard and committed network solutions, there are no significant network augmentations to meet load growth forecast to occur within the 10-year outlook period of this TAPR.

Proactively planning to address potential shifts in the external environment

There are proposals for large mining, metal processing and other industrial loads including hydrogen that have not reached a committed development status and are not included in the AEMO ESOO forecasts. 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[1] 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 14,543MW of new generation capacity, have been received to date and are at varying stages of progress. This includes under construction connections for approximately 1,675MW of VRE.

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 2022/23, the Powerlink transmission network performed reliably. Record peak transmission delivered demand was recorded for the Wide Bay, South West and Gold Coast zones. Minimum transmission delivered demand levels continued to reach record lows in the majority of zones with Ross, Wide Bay and South West zones all experiencing periods of negative transmission delivered demand.

Inverter-based resources in northern Queensland experienced approximately 262 hours of constrained operation during 2022/23. This is a reduction in the constraint times experienced over the last two years.

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.

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 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.

[1] 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.

Power system security services

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

In May 2022, Powerlink published an Expression of Interest (EOI) Request for Power System Security Services in central, southern and broader Queensland regions to address an immediate Network Support Control and Ancillary Services (NSCAS) gap in southern Queensland and a system strength shortfall at the Gin Gin fault level node. Powerlink published the findings for the NSCAS gap in December 2022 and has entered into a Network Support Agreement with CleanCo Queensland to address the immediate gap. Longer term NSCAS requirements have been considered in conjunction with the Managing voltages in South East Queensland RIT-T which has recommended installation of a 120MVAr bus reactor at Belmont Substation in 2024 and network support services from CleanCo Queensland to operate during times of reactive power shortfall as the preferred option for implementation.

Discussions with proponents of non-network solutions to address the system strength shortfall are continuing as at the publication of the 2023 TAPR and Powerlink continues to work closely with non-network solution proponents and AEMO to meet the declared system strength gap.

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 2022 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 the second quarter of 2024.

Integrated System Plan projects in Queensland

Expanding New South Wales to Queensland transmission transfer capacity

The 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-2024.

Future actionable Integrated System Plan projects

The 2022 Integrated System Plan (ISP) identified upgrades in Queensland as part of the optimal development path for the NEM. Although no 'actionable' projects were identified for Queensland, several Queensland projects were identified as part of the optimal development path that may become 'actionable' in future ISPs. These projects will be vital to achieving lower cost solutions that meet security, reliability, affordability and reduced emissions.

Two projects were nominated for preparatory activities. These include:

- Darling Downs REZ Expansion (Stage 1)
- QNI Connect (500kV option).

Preparatory activities for these projects were provided to AEMO to inform the development of the 2024 ISP by June 2023.

Three additional projects were identified as requiring no action as AEMO will leverage the estimated project costs from previous preparatory activities. These include:

- Central to Southern Queensland reinforcement
- Gladstone Grid reinforcement
- QNI Connect (330kV option).

For Gladstone Grid reinforcement and QNI Connect (330kV option) Powerlink has provided AEMO with updates to the project scopes to enable AEMO to reflect these changes into its updated project estimates.

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 five reinvestment projects completed since publication of the 2022 TAPR.

Projects completed in 2022/23 include:

- Baralaba secondary systems replacement
- Bouldercombe primary plant replacement
- Tarong secondary systems replacement
- Palmwoods secondary systems replacement
- Line refit works between South Pine and Upper Kedron.

As at the publication of the 2023 TAPR and having finalised the necessary regulatory processes, the committed projects for investment across Powerlink's network include:

- Establishment of a 3rd connection into Woree (Stage 1 Northern Queensland REZ)
- Broadsound bus reactor
- Line refit works between Townsville South and Clare South substations
- Townsville South primary plant and secondary systems replacement
- Ross 275/132kV primary plant and transformers replacement
- Strathmore transformer establishment and secondary systems replacement
- Nebo primary plant, secondary systems and transformer replacements
- Blackwater transformers replacement
- Lilyvale primary plant and transformer replacement
- Several secondary system replacements including Cairns, Woree, Chalumbin, Mt England and Mudgeeraba.

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 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
- 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 253,000 businesses who receive electricity through the energy network. 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 biennial stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed in November 2022, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders.

Engaging with communities is essential to providing electricity transmission services that are safe, reliable and cost effective. Transmission network infrastructure stays in-service 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. 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 2021/22 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 looking to undertake another round of community sentiment research across the state in late 2023.

Since publication of the 2022 TAPR, Powerlink has undertaken a review of the process formerly called the Network Development Process used to secure new easements as part of its project delivery. The process has been renamed to the Transmission Easement Engagement Process. As part of this review, Powerlink has launched a new SuperGrid Landholder Payment Framework that significantly boosts payments to landholders hosting new transmission infrastructure. Powerlink will also become 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 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 2023.

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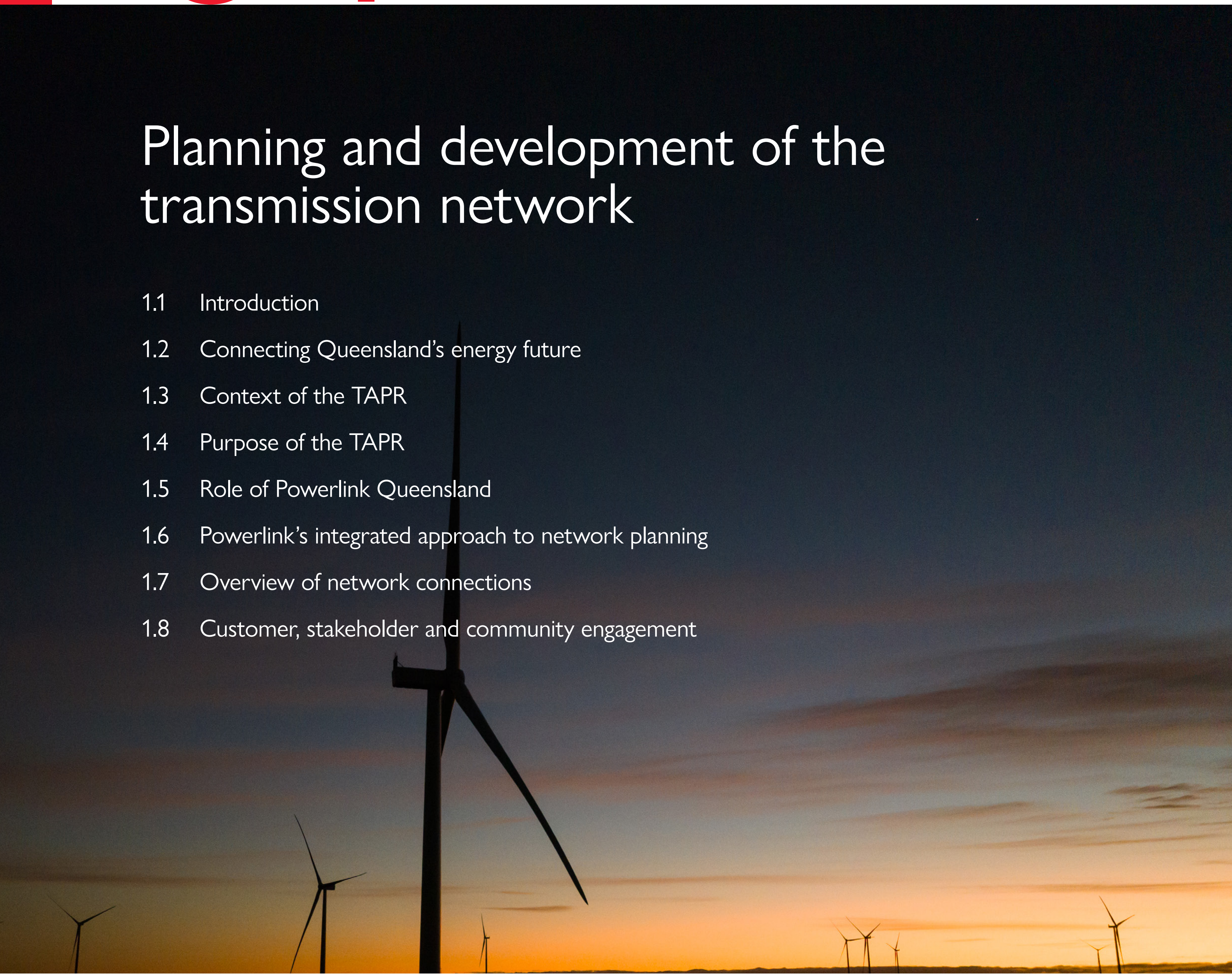


Planning and development of the transmission network

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.
- Since publication of the 2022 TAPR, Powerlink has proactively engaged with communities, customers and other stakeholders, seeking their input into Powerlink's network development, ongoing operations and new investment decisions.
- Local communities will be 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.
- Given the ongoing scale and pace of the transformation of Queensland's power system, Powerlink is maintaining an integrated approach to future network planning to ensure the transmission network is developed in a safe, reliable, secure and cost effective manner.
- 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 proponents as well as proponents, of Battery energy storage systems (BESS) that will provide firming services which will form an integral part of the future mix of technologies in Queensland.
- Powerlink is working closely with the Queensland Government on the establishment of Renewable Energy Zone (REZ) development areas and other major projects referenced in the Queensland Energy and Jobs Plan (QEJP).

1.1 Introduction

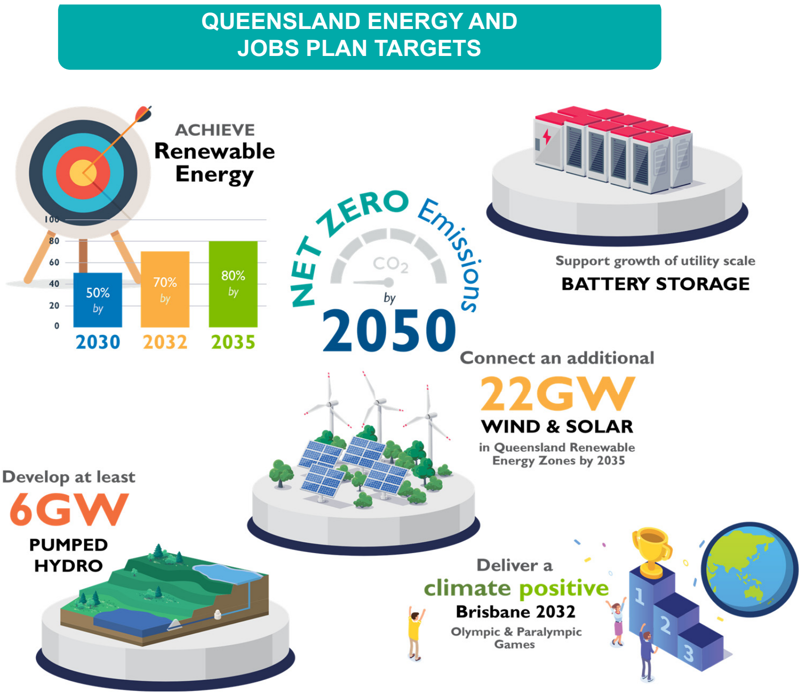
Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the NEM and owns, develops, operates and maintains Queensland's high voltage (HV) transmission network. It has been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB) responsible for transmission network planning 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 achieving net zero emissions by 2050.

Powerlink is pursuing a 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 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.

The 2023 TAPR incorporates AEMO's demand and energy forecasts, consistent with those published for the 2023 Electricity Statement of Opportunities (ESOO). The ESOO examines electricity supply and demand issues across all regions in the NEM.

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 2023 TAPR in conjunction with AEMO's 2023 ESOO which was published in August 2023. The most recent ISP was released on 30 June 2022 and the 2022 System Strength, Inertia and NSCAS Reports were published on 1 December 2022.

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, stakeholders and communities with an overview of Powerlink's planning processes and decision making on future investment.

1 For the purposes of Powerlink's 2023 TAPR, Version 201 of the NER in place from September 2023.

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[2].

1.5 Role of Powerlink Queensland

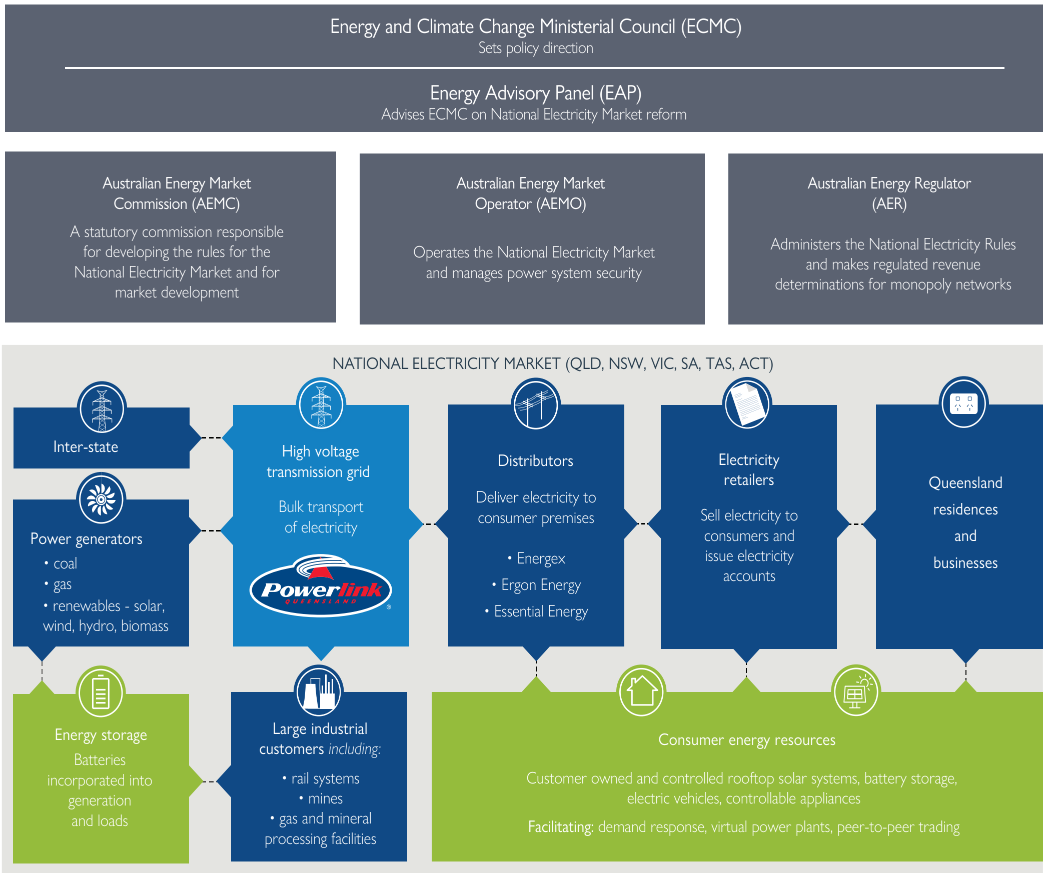
Powerlink's role in the Queensland power system is shown in Figure 1.2.

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
- 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 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[3] 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.

2 The information published within the 2023 TAPR is current as at 30 September 2023.
3 Where applicable, in accordance with Clause 5.18 of the NER.

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



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 1.3.

Figure 1.3 Overview of Powerlink's TAPR planning process

Inputs

- Asset management policy and strategy
- Transmission Authority
- Asset Planning Criteria Framework
- Queensland Energy and Jobs Plan
- Consultation and customer/consumer/community engagement
- Generation, demand and energy forecasting
- AEMO Reports (ISP, NSCAS, System Strength and Inertia)
- Asset condition and performance monitoring
- New customer connection need

Integrated Planning

- Analysis of asset condition, performance and related risks
- Analysis of network capability and limitations (including Distribution Network Service Provider joint planning)
- Enabling the development of Renewable Energy Zones
- Compliance with system standards
- Analysis of market impacts
- Analysis of operational impacts and constraints
- Overall review of portfolio delivery and risks

Solution Development

- Integrated review of investment need and risks
- Development of investment options (network reconfiguration, non-network solution, network solution)
- Risk and cost benefit analysis of investment options
- Project level delivery risk assessment
- Market and regulatory consultation (e.g. Regulatory Investment Test for Transmission)

TAPR

- Customer and stakeholder engagement
- Demand and energy forecast
- Analysis of network capability and performance
- Future network developments to address network limitations, condition and performance
- Potential opportunities for non-network solutions
- Committed and commissioned network projects
- Strategic network development
- Network technical data (e.g. connection point demand forecasts, fault levels)
- TAPR templates

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 number of connection applications which are well advanced (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	2023 TAPR status	
Total completed to date	22	3,155MW
Under construction (1)	4	1,675MW
Existing and under construction	26	4,830MW
Connection Applications to date	56	14,543MW

Notes:

(1) Early works under construction at the time of 2023 TAPR publication.

(2) A 250MW committed pumped hydro storage project is underway at the time of 2023 TAPR publication.

(3) To date Powerlink has completed two storage projects, totalling 150MW and a further 500MW of storage projects are under construction.

1.7.2 Status of connection projects

To date Powerlink has completed connection of 24 (22 VRE + 2 BESS) large-scale solar, wind farm and BESS projects in Queensland, adding 3,305MW of generation capacity to the grid. A significant number of formal connection applications, totalling 14,543MW of new generation capacity, have been received and are at varying stages of progress.

During 2022/23, 399MW[4] of semi-scheduled VRE generation capacity has been committed in the Queensland region, taking the total VRE generation capacity to 5,334MW[5] that is connected, or committed to connect, to the Queensland transmission and distribution networks.

Approximately 1,494MW 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 5,500MW in July 2023.

Figure 1.4 shows the location and type of generators connected and committed to connect to Powerlink's network. The Department of Energy and Public Works (DEPW) 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 DEPW website.

[4] Comprised of Wambo Wind Farm (Powerlink) and Banksia and Gunsynd Solar Farms connected to the distribution network (Energy Queensland Group).

[5] 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 1.4 Under construction and existing connection projects since 2018

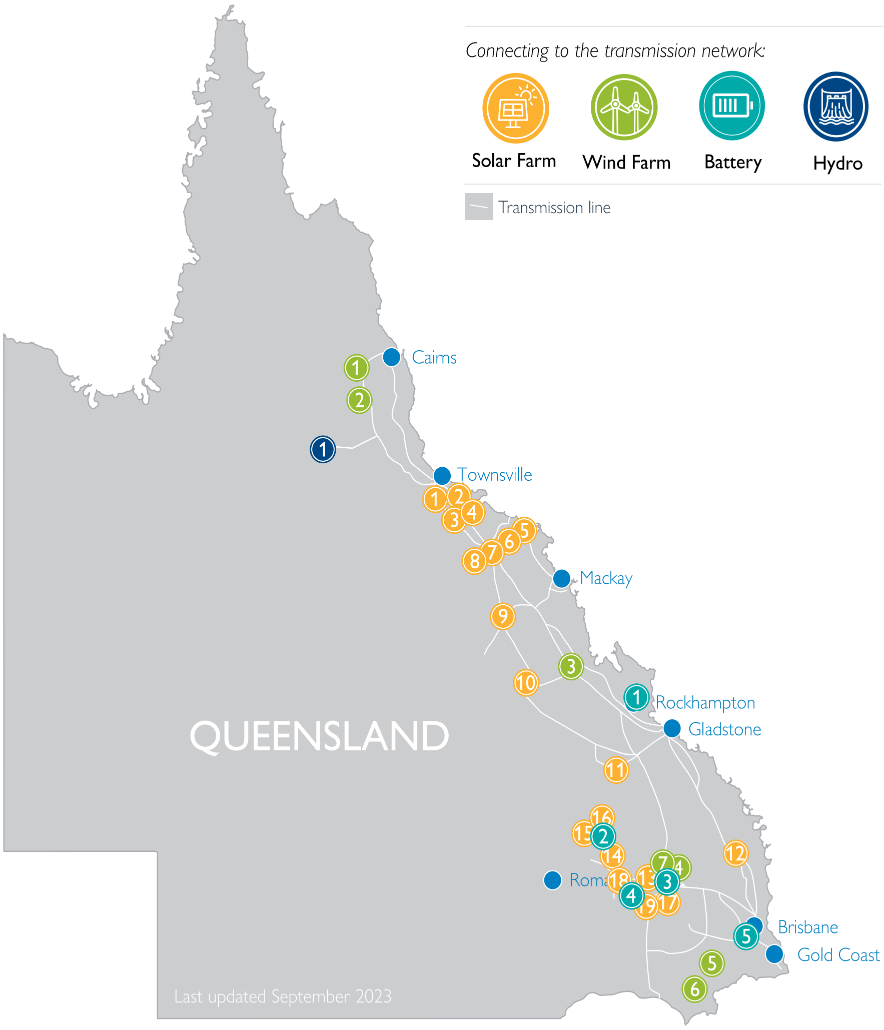


Table 1.2 Under construction and existing connection projects since 2018

Map ID	Generator	Location	Available capacity MW generated
Hydro-electric (1)			
1	Kidston Pumped Hydro Storage	Kidston	250
Solar PV (2)			
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	Moura	Moura	82
12	Woolooga Energy Park	Woolooga	176
13	Blue grass	Chinchilla	148
14	Columboola	Columboola	162
15	Gangarri	Wandoan South	120
16	Wandoan	Wandoan South	125
17	Edenvale Solar Park	Orana	146
18	Western Downs Green Power Hub	Western Downs	400
19	Darling Downs	Braemar	108
Wind (2)			
1	Mt Emerald	Walkamin	180
2	Kaban	Tumoulin	152
3	Clarke Creek (3)	Broadsound	440
4	Coopers Gap	Coopers Gap	440
5	MacIntyre (3)	Tummaville	890
6	Karara (3)	Tummaville	100
7	Wambo (3)	Halys	245
Battery (2)			
1	Bouldercombe 2h BESS	Bouldercombe	50
2	Wandoan 1.5h BESS	Wandoan South	100
3	Chinchilla 2h BESS (3)	Western Downs	100
4	Western Downs 2h BESS (3)	Western Downs	200
5	Greenbank 2h BESS (3)	Greenbank	200

Notes:

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

(2) 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.

(3) Generators 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.

1.7.3 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.

From July 2018 new categories of connection assets were defined, namely Identified User Shared Assets (IUSA) and Dedicated Connection Assets (DCA). All new DCA services, including design, construction, ownership and operation and maintenance are non-regulated services. IUSA assets with capital costs less than $10 million are negotiated services that can only be provided by Powerlink. IUSA assets with capital costs above $10 million are non-regulated services. Powerlink remains accountable for operation of all IUSAs and any above $10 million must enter into a Network Operating Agreement to provide operations and maintenance services.

From July 2021 Large Dedicated Connection Assets were replaced with Designated Network Assets (DNA). A DNA is a radial transmission extension greater than 30km in length. DCAs remain for connections less than 30km. A DNA is not a connection asset, but rather a transmission network. It differs to the shared transmission network as the design, construction and ownership of the DNA are non-regulated services. As for IUSAs, Powerlink remains accountable for operation and maintenance of all DNAs. A special access framework for DNAs is set out in the NER Chapter 5.

As DNAs will form part of the transmission network operated by a TNSP, the point where an individual proponent connects to a DNA will be a transmission network connection point. This allows for the application of existing arrangements for settlement, metering, calculation of loss factors, transmission use of system charges, system strength and performance standards, with only minor modifications.

Powerlink will continue to work 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.

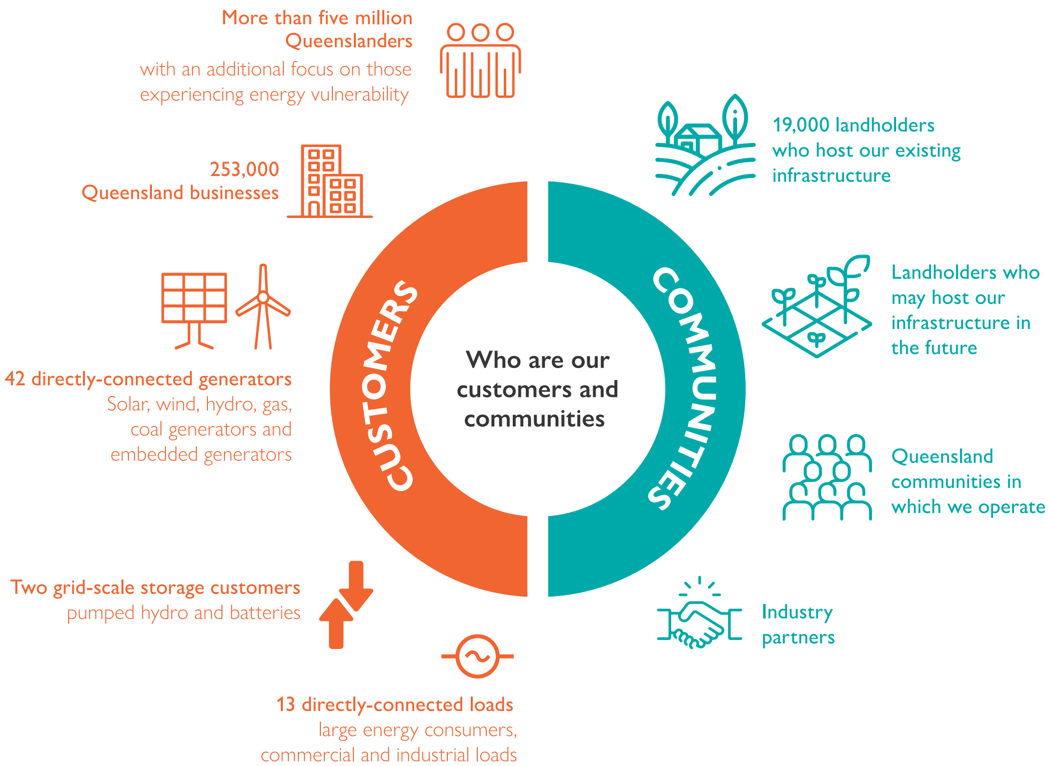
Figure 1.5 Overview of Powerlink's existing network connection process

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.

1.8 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 253,000 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 1.6).

Figure 1.6 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.

1.8.1 2022/23 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 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 biennial stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed in November 2022, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual 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 2022 TAPR are outlined in the remainder of this section.

2022/23 Community engagement

Engaging with communities is essential to providing transmission services that are safe, reliable and cost effective. Transmission infrastructure stays in-service 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. In 2021, a new Community Engagement Strategy was developed and implemented to support delivery of the energy transformation and ensure Powerlink was focussed on driving mutually beneficial outcomes for impacted communities.

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 engagement going forward and ensures a focus on key factors that are important to communities. Powerlink is looking to undertake another round of community sentiment research in late 2023. 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 our planning and decision making.

In 2022, work continued to embed the Community Engagement Strategy to further guide engagement activities across the state and set expectations for how Powerlink wants to proactively engage to drive a positive social licence to operate in key 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.

In addition, Powerlink played a key role in the development of the Energy Charter Better Practice Social Licence Guideline released in May 2023. This work was completed within an Energy Charter #BetterTogether collaborative innovation project. The guideline focusses on identifying impacts and opportunities for the communities affected by the energy transformation.

2022 Transmission Network Forum

In November 2022, 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, an interactive workshop to explore and investigate Powerlink's response to the QEJP and a technical session on the 2022 TAPR. The live stream recordings, presentations and questions raised and answers discussed are available on Powerlink's website.

Review of Network Development Process

Since publication of the 2022 TAPR, Powerlink has undertaken a review of the process formerly called the Network Development Process used to secure new easements as part of its project delivery. A Stakeholder Reference Group was established to provide input into the review, including the Queensland Farmers' Federation, Local Government Association of Queensland, RE-Alliance and Energy Users Association of Australia.

Over nine months, the reference group focussed on key areas to improve the process including engagement, land access and landholder payments. The review changed the focus of the process from formal planning approval milestones to engagement opportunities for landholders and the wider community. The process has been renamed to the Transmission Easement Engagement Process to reflect this change.

As part of this review, Powerlink also launched a new SuperGrid Landholder Payment Framework that significantly boosts 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. Powerlink will become the first transmission company in Australia to offer payments to landholders on neighbouring properties adjacent to transmission infrastructure.

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 February, March, June and September 2023. Key topics for discussion included Powerlink's activities relating to the QEJP, changing network operating conditions and Powerlink's customer focus maturity and priorities under The Energy Charter.

Asset Reinvestment Review Working Group

In 2022 Powerlink established an Asset Reinvestment Review (ARR) Working Group, made up of representatives from the Australian Energy Regulator (AER), key customer advocates and members of Powerlink's Customer Panel, to shape and participate in a review of its asset reinvestment approach. A co-designed scope for the review was developed with the ARR Working Group to guide discussions. The scope includes both the prudency and efficiency elements of reinvestment capital expenditure, with a focus on Powerlink's approach to transmission line refit projects. The first of the review deliverables, an ARR Working Group Report, was published in May 2023 (refer to Section 6.3.4).

Stakeholder engagement for regulatory 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), an Expression of Interest or Funded Augmentation.

Powerlink is committed to a balanced approach in public consultation processes as determined with its Customer Panel. In addition, Powerlink is guided by the AER Stakeholder Engagement Framework and Consumer Engagement Guideline for Network Service Providers as the benchmarks when undertaking public consultations.

The most frequent public consultation process undertaken by Powerlink is the RIT-T and further information on the proposed engagement activities for RIT-Ts can be found 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 supply.

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 carbon future.
- Powerlink has worked 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 for the power system. Powerlink continues to inform and provide context to broader technical aspects associated with the energy transformation.
- Powerlink's long-term strategic planning considers a staged approach of 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 carbon 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 network evolves.

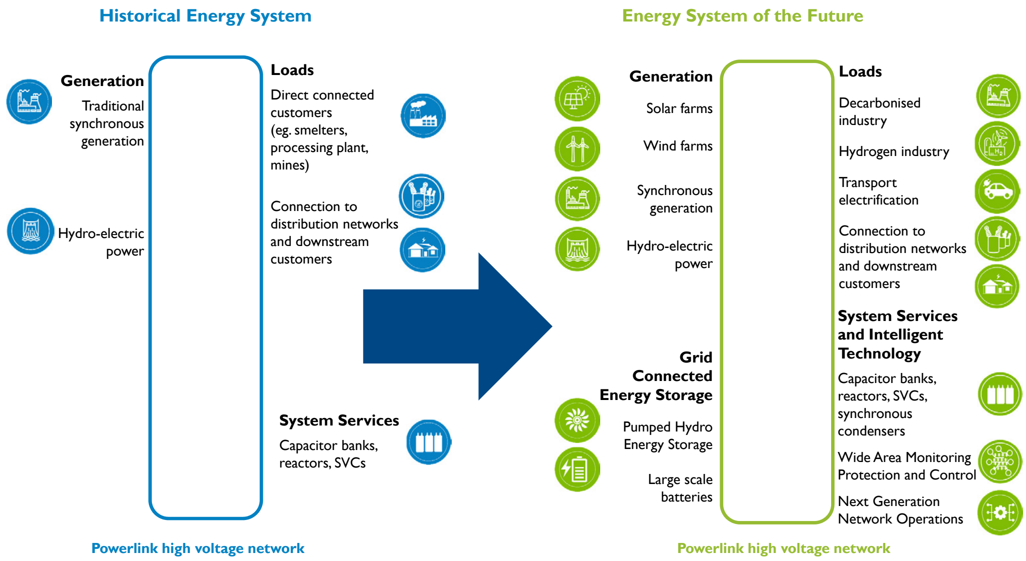
2.1 Introduction

The transformation of the energy system within Queensland to one underpinned by clean, sustainable and affordable renewable energy is well underway. This is prevalent with an increasing share of large-scale VRE within the state and continued strong growth in the uptake of rooftop PV systems. 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. A new industry based on hydrogen is also emerging.

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 hydrogen markets, consumer energy sources, and intelligent control and orchestration being integral components of the decarbonised energy system (refer 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. Since publication of the QEJP in September 2022 and 2022 Transmission Annual Planning Report (TAPR), Powerlink has contined to work closely with the Queensland Government providing technical insights on transmission network development for optimal pathways to 80% renewables by 2035 and net zero emissions.

Figure 2.1 Energy system of the future



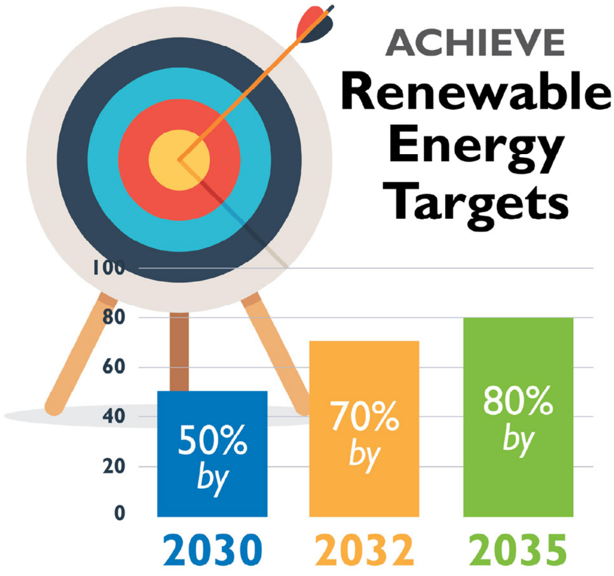
2.2 Queensland Energy and Jobs Plan

The QEJP sets out the roadmap for the transformation of the energy system, and adds to Queensland's existing renewable energy target of 50% by 2030 with new targets of 70% by 2032 and 80% by 2035 (refer Figure 2.2). The plan also details a range of initiatives and foundational investments to achieve these targets.

The Queensland SuperGrid Infrastructure Blueprint ("Infrastructure Blueprint") was published in conjunction with the QEJP. The Infrastructure Blueprint outlines the Optimal Infrastructure Pathway (OIP) to deliver a clean, reliable and affordable electricity system.Powerlink continues to inform and provide context to the broader technical aspects associated with the energy transformation. In November 2022, Powerlink published a report on Actioning the Queensland Energy and Jobs Plan. This document outlines initiatives and steps that Powerlink intends to undertake to enable the QEJP.

The Queensland SuperGrid Infrastructure Blueprint is a point in time plan. Powerlink continues to monitor the underlying assumptions forming the Infrastructure Blueprint, and test future scenarios as the market evolves and the quality of available information improves as part of detailed design and planning phases. The Infrastructure Blueprint will be updated every two years with the OIP to reflect new infrastructure investments, changing market conditions, and the market outlook.

Figure 2.2 Queensland renewable energy targets[1]



2.3 The Queensland SuperGrid transmission backbone

The Queensland SuperGrid detailed within the Infrastructure Blueprint includes a number of inter-related elements spanning renewable generation, firming of the intermittent generation, and the transmission network to connect this all together.

A key part of the OIP transmission infrastructure detailed within the Infrastructure Blueprint is 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 PHES facilities and access to Queensland's high quality renewable energy resources. These stages comprise of the following:

- Stage 1 – Borumba Connections
- Stage 2 – Central Queensland Connection
- Stage 3 – Pioneer Burdekin PHES and North Queensland Connection
- Stage 4 – Townsville to Hughenden Connection.

Given the capacity requirements, changes in power flows, longer distances and future use, the SuperGrid is proposed to be constructed using 500kV High Voltage Alternating Current (HVAC) technology. The system will be complemented by the use of contemporary and emerging technologies to limit the scale of investment required to deliver the necessary reliability and resilience (refer Section 2.8). For sections of the network with lower load transfer requirements, lower voltages such as 275kV will continue to be most economic and appropriate.

The implementation of 500kV provides a number of benefits compared to the 275kV backbone voltage currently operating within Queensland. These include the requirements for narrower easements and more timely constructability compared to the two or more overhead 275kV transmission lines that would otherwise be required. The use of a 500kV voltage level is also aligned with that used within the New South Wales (NSW) and Victorian networks, and enables the Queensland transmission grid to more readily interconnect with the southern states in the future to access greater shares of geographically diversified renewable generation sources.

Powerlink has also considered High Voltage Direct Current (HVDC) technology for the SuperGrid transmission backbone. HVDC technology is continually evolving and currently has applications including submarine and long distance point-to-point connections. HVDC Voltage Source Converter (VSC) technology also offers a set of beneficial functionalities made possible by sophisticated advancements in control and power electronics located at the converter terminal stations. HVDC is in high demand globally for offshore wind farms and undersea interconnectors, and the technology and costs will be monitored closely as it is deployed around the world. A disadvantage of HVDC is the high cost of converter stations and technical complexity associated with intermediate terminal stations.

[1] Source: Queensland Energy and Jobs Plan Overview.

The proposed SuperGrid transmission backbone will require a number of intermediate stations to integrate into the existing transmission system, marshalling power from renewable sources distributed along its length and de-loading the parallel 275kV network thereby maximising renewable hosting capacity. Following extensive power system modelling and financial modelling, HVAC has been demonstrated to be more cost effective under this network topography for the SuperGrid transmission backbone.

Powerlink is well progressed with preparatory activities for the first stage of the SuperGrid transmission backbone (Borumba PHES connections). Subject to planning approvals, the Borumba PHES is scheduled to be operational circa 2030 and is a cornerstone of Queensland's future clean energy system, providing critical storage and firming for increasing levels of variable renewable generation. With a planned capacity of up to 2GW and 24 hour storage, the proposed Borumba PHES requires a connection to the network that delivers reliability and network security commensurate with the role that Borumba PHES needs to play in the firming the future VRE mix.

The connection architecture for Borumba PHES has been chosen to diversify connection paths and leverage existing and planned network capacity upgrades linked to condition based drivers to maximise network benefits from the connection. There will be two connection paths for Borumba PHES. The first connects to Powerlink's existing substation site located at Halys in south west Queensland, and the second connects to Powerlink's existing substation site at Woolooga.

The Halys Substation connection also provides access to high-quality renewables in south west Queensland to help supply the Borumba pumping load and facilitate strong intra-regional connections with the rest of the National Electricity Market (NEM). The connection to Woolooga Substation allows for increased utilisation of the coastal 275kV Central to Southern Queensland (CQ-SQ) corridor to supply load growth in Southeast Queensland (SEQ) while providing access to future renewable energy developments in the Wide Bay region.

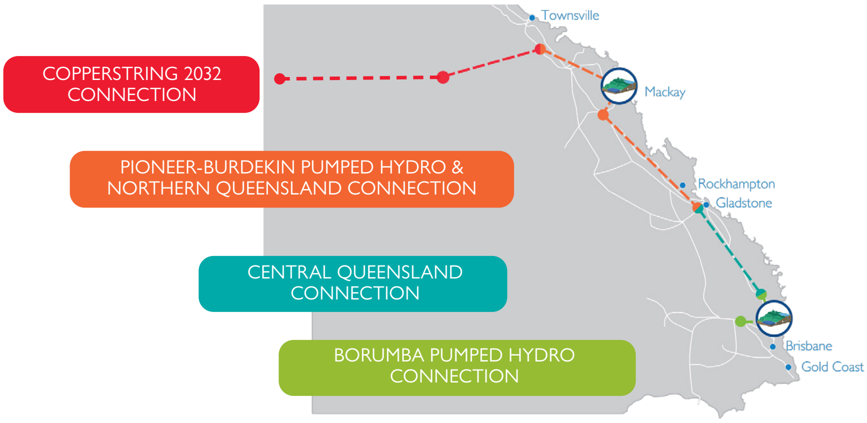
The second stage of the SuperGrid transmission backbone will comprise of high voltage transmission to connect Borumba PHES to the central Queensland REZs and load centres. This connection provides important storage and firming capacity for the area.

The third stage of the SuperGrid transmission backbone is aligned with the establishment of the proposed Pioneer-Burdekin PHES in North Queensland. This involves transmission connections from Townsville to the proposed PHES and onwards to Central Queensland. Powerlink intends to deliver this stage in three parts with the initial connection to the Pioneer-Burdekin PHES before its target commencement of operations during the early to mid-2030s.

The fourth stage of the SuperGrid is the Townsville to Hughenden transmission development. The Queensland Government has reassessed opportunities that a high-capacity transmission network can provide for critical minerals processing and mining areas within the North West Minerals Province (NWMP) and the rich renewables resources available in the Hughenden area.

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 for commissioning from 2029 (refer Section 2.3.1).

Figure 2.3 Queensland SuperGrid transmission backbone



2.3.1 CopperString 2032

The CopperString 2032 project, formerly known as CopperString 2.0, initially involves constructing 840km of high voltage transmission line from Townsville to Mount Isa that will connect the NWMP to the NEM. CopperString 2032 will form an essential part of the Queensland SuperGrid transmission backbone. Powerlink has taken 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, encompassing towns such as Mount Isa and Cloncurry, will provide reliable renewable power to one of the richest deposits in the world of minerals 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.

CopperString 2032 will also enable the connection of significant quantities of renewable energy from north west Queensland to the coastal Queensland transmission backbone. The Hughenden region has the potential to host significant levels of new wind generation which has complementary properties to renewable generation within the rest of the state. The Hughenden region has been designated as Flinders REZ within the draft Queensland Government REZ Roadmap (refer Section 2.4.2).

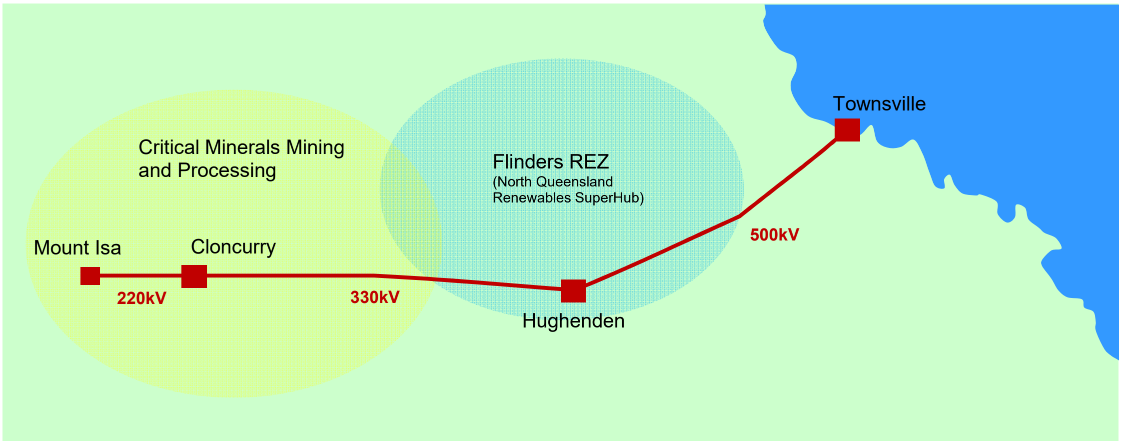
CopperString 2032 will have a higher transmission capacity than the previously announced CopperString 2.0. The transmission line from Townsville to Hughenden is planned to be constructed at 500kV which will enable higher levels of hosting for renewable energy.

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

- Construction of new 500kV double circuit transmission line from Townsville to Hughenden
- 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 Hughenden Substation following the CopperString 2032 project.

Figure 2.4 CopperString 2032 transmission development



Powerlink is currently progressing early works for CopperString 2032 ahead of construction commencing in 2024. Powerlink has commenced field and geo-technical investigations, cultural heritage and ecological surveys, transmission line designs, statutory approvals, and engagement with landholders, communities and other key stakeholders.

Due to the size and scope of CopperString 2032, the project will be broken down into several work fronts with construction occurring in multiple locations at the same time to ensure safe travel distances for workers and timely project delivery. Powerlink anticipates that CopperString 2032 will be commissioned during 2029.

The Australian Energy Market Operator (AEMO) has included CopperString 2032 project as an Anticipated Project within the recently published AEMO 2023 Transmission Expansion Options Report.

2.4 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 to the transmission network. 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 coordinated manner, 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 coordination 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 whilst reducing investment risk and financing cost for developers.

The Queensland Government has undertaken a range of initiatives to make the connection process for renewable energy proponents to REZs smoother and simpler, and for establishing on-going benefits for landholders, communities, and regional areas. Powerlink has worked closely with the Queensland Government on these initiatives which are outlined below and within Section 2.9.

2.4.1 Renewable Energy Zone Roadmap

The Queensland Government published the draft 2023 Queensland REZ Roadmap in June this year. The Roadmap outlines the pathway for connecting 22GW of additional 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 coordination.

Powerlink has provided significant input to developing the draft 2023 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. These indicative REZ locations have been identified based on analysis of a range of factors. As Queensland's JPB, 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 (2022-2024) - Building strong foundations
- Phase 2 (2024-2028) - Scaling and expanding opportunities
- Phase 3 (2028-2035) - Preparing for net zero by 2050.

The three phases take into account the sequencing of other large-scale energy infrastructure developments including the SuperGrid transmission backbone, and the Borumba and Pioneer-Burdekin 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 REZs may also be identified in future to meet growing demand from green hydrogen, decarbonisation, electrification of existing industrial processes, and other load developments. It is anticipated that the REZ Roadmap will be updated every two years and aligned with the Infrastructure Blueprint to reflect latest market outlook and developments.

2.4.2 Potential Queensland Renewable Energy Zones

As detailed in the draft 2023 Queensland REZ Roadmap, a framework is being developed across the development stages for engagement with communities, landholders, First Nations Peoples, and key stakeholders to inform the rollout of REZ across the state. This includes REZ Roadmap consultation, REZ Delivery Body REZ Management Plan planning activities, and the establishment of and engagement with Regional Energy Reference Groups throughout the project lifecycle.

The 12 potential REZs noted in Section 4.2.1 are outlined below within their respective regions. Further details are provided 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 also in proximity to the planned development of the Pioneer-Burdekin PHES and emerging hydrogen hubs within Townsville and the Bowen regions. Powerlink is also establishing a new transmission and training hub in Townsville to provide local engineering and field services to support the transmission network in North Queensland (refer Section 2.8).

There is currently one in-flight REZ under construction in Far North Queensland. This REZ is scheduled for completion by April 2024 (refer Table 9.3). In-flight REZs are renewable energy developments that are already progressing under the existing NER and may be converted to declared REZs in the future.

Two additional REZs are earmarked for this area. The Collinsville and Flinders REZs are anticipated to provide up to 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 decarbonisation and electrification of industrial and metals processing facilities and the emergence of new hydrogen hubs 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, and are anticipated to provide more than 4GW of combined hosting capacity. Powerlink is currently progressing planning activities for new transmission infrastructure to enable these REZs (refer Section 8.2.3).

The Isaac and Capricorn REZs are anticipated to form the second stage of REZ development, and provide 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. Renewable energy resources within 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 in-flight REZs for South Queensland. The Southern Downs and Western Downs REZs are expected to have a combined network hosting capacity exceeding 4GW. Powerlink is providing transmission capacity to enable these REZs through the construction of dedicated 275kV transmission lines to several wind developments in the area.

Powerlink has also completed preparatory activities set out in AEMO's 2022 Integrated System Plan (ISP) for increasing the transfer capacity of the transmission network from south west to south east Queensland, and increasing the hosting capacity of renewable energy in south west Queensland (refer to Section 6.15).

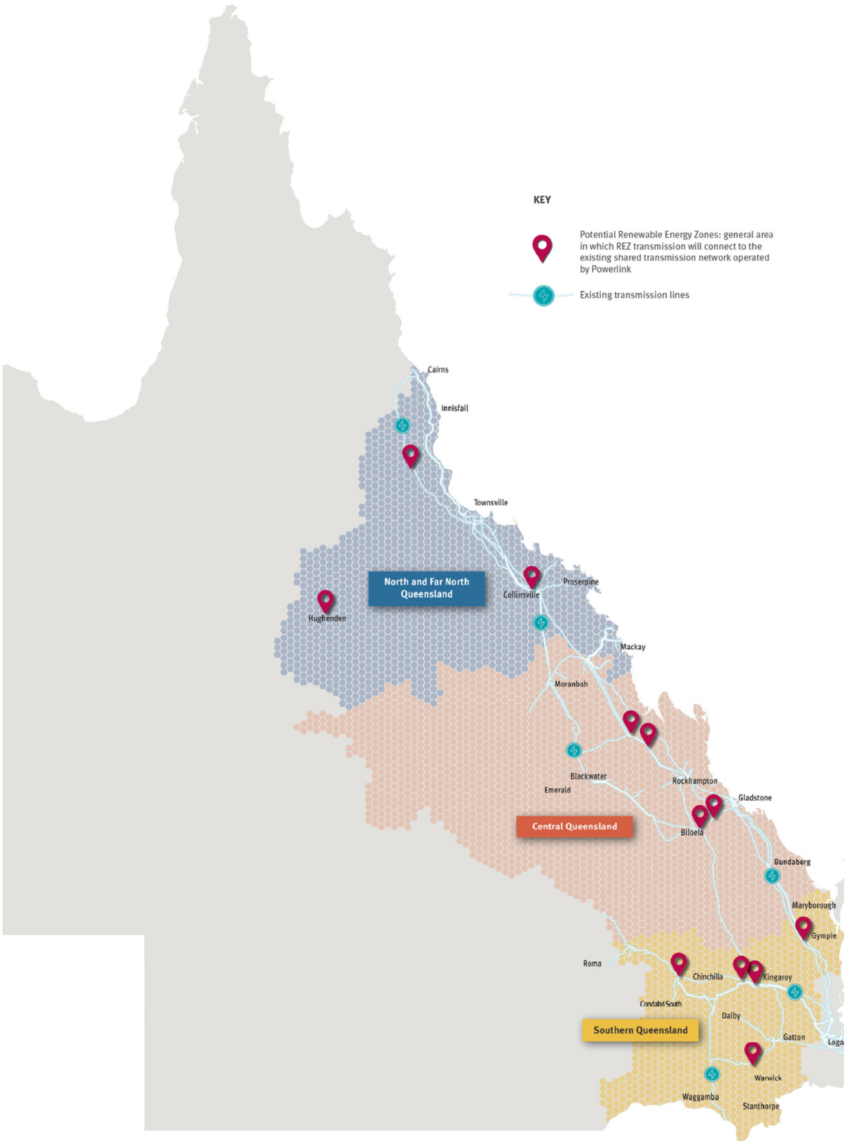
There are three additional REZs proposed for south Queensland. The Woolooga and Darling Downs REZs form part of the second stage of REZ development within the Roadmap, and are expected to provide around 4GW of combined hosting capacity. The Tarong REZ forms part of the third stage of REZ development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

Table 2.1 Expected REZ installed generation within the draft 2023 Queensland REZ Roadmap[2]

Region	REZ	Expected installed generation	In-flight	Phase 1	Phase 2	Phase 3
Far North and North Queensland	Far North Queensland	500 to 700MW	✓			
	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	✓			
	Western Downs	2000 to 2600MW	✓			
	Woolooga	1600 to 2000MW			✓	
	Darling Downs	1600 to 2000MW			✓	
	Tarong	2000 to 2400MW				✓

2 Source: Draft 2023 Queensland Government REZ Roadmap.

Figure 2.5 Potential REZs outlined within the draft 2023 Queensland Government REZ Roadmap[3]



2.4.3 Delivery of Renewable Energy Zones

There are two distinct roles in Queensland REZ delivery under the draft Queensland Government Energy (Renewable Transformation and Jobs) Bill.

The first role is the function of REZ Delivery Body (RDB). The RDB would be responsible for providing advice on proposed REZ to government, developing draft and final REZ Management Plans (RMP) for each REZ to enable the declaration of the REZ, and consulting with community.

The second role would involve Powerlink performing the function of the REZ Transmission Network Service Provider. This role would be responsible for planning, design, owning, constructing, operating and maintaining REZ transmission infrastructure, and undertaking processes for the connection of renewable generation projects to the REZ.

[3] Queensland Government REZ Roadmap.

2.5 Energy storage and firming

Energy storage and firming services will form an integral part of the future mix of technologies in Queensland. These 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, consumer demand, and other factors. The energy system of the future will require a mix of firming services ranging from PHES, large-scale grid-connected BESS, community battery systems, residential household batteries, and dispatchable generation sources (such as generation fuelled by natural gas, hydrogen or renewable fuels).

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 over shorter periods. Both technologies will provide critical system security services necessary to support the power system as part of the energy transformation.

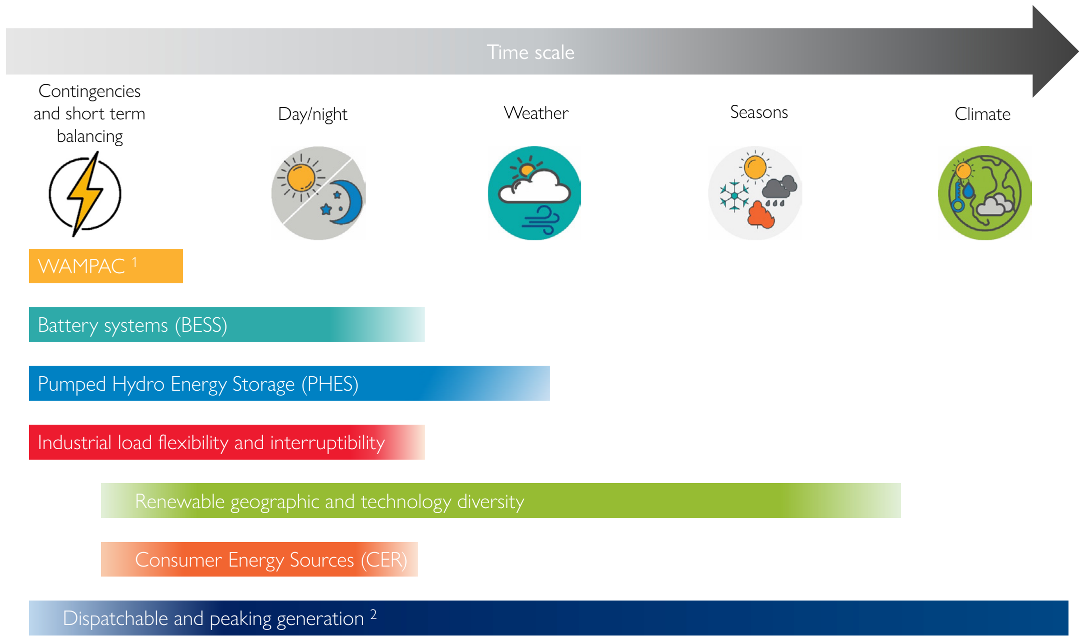
The nature and mix of energy firming services within Queensland will be required to operate across a range of time scales and operating conditions to ensure reliability of supply. These operating horizons range from very short response periods (e.g. such as those during network contingencies) to longer periods across seasons and multi-year periods reflecting climate variations. Potential technologies which are likely to play an integral role in firming across the range of time scales are outlined in Figure 2.6.

The optimal mix of technologies involves an economic trade-off. Non-weather dependent or energy-limited generation sources (such as gas or potential hydrogen or renewable fuelled generating stations) are likely to play an important role to address extremities in weather and climatic conditions. Another important aspect involves pursuing 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.

There are also increasing drivers for large-scale electrified industrial processes to be capable of operating more flexibly to take advantage of wholesale market pool prices when there may be an abundance or scarcity of renewable generation. There is currently limited demand side participation and management within the Queensland energy system, however, this is expected to increase as more industrial processes transform to electrified operation, and new green hydrogen and other decarbonised facilities are established.

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

Figure 2.6 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 2.8.

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

2.5.1 Pumped Hydro Energy Storage

The QEJP details the investment of two publicly owned long-duration PHES facilities. These large-scale deep storage facilities will be cornerstone infrastructure development for the energy transformation and moving to 80% renewable energy by 2035. Subject to planning approvals, the two facilities comprise the Borumba PHES located south west of Gympie and the Pioneer-Burdekin PHES located within North Queensland near Mackay.

Borumba PHES

The Borumba PHES was selected as the first site for development following a state-wide assessment of potential pumped hydro locations across the state. 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.

Previously Powerlink had been conducting a range of detailed design, business case development, and other preparatory activities for the Borumba PHES. In November 2022, the Queensland Government established a new publicly owned entity (Queensland Hydro) to design, deliver, operate and maintain long duration pumped hydro storage assets for the energy transformation. Queensland Hydro has now taken on further works, environmental impact assessments, detailed engineering, geo-technical testing, civil infrastructure upgrades, and other delivery activities for Borumba PHES.

Powerlink has been engaged by Queensland Hydro to develop potential transmission line corridors to connect Borumba PHES to the existing electricity transmission network. Due to the potential generation and storage capacity of the Borumba Pumped Hydro Project, new transmission infrastructure will be needed from the proposed pumped hydro facility at Lake Borumba to Halys Substation in the south-west part of Powerlink's network, and to Woolooga Substation to the north of the proposed facility. The Borumba PHES and associated connections will form part of the Queensland SuperGrid transmission backbone providing long duration deep firming services 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 Pioneer-Burdekin PHES is anticipated to have an energy storage capacity of up to 5GW over 24 hours, with the facility scheduled to commence operations circa 2032. The PHES will form a foundational component of the SuperGrid transmission backbone enabling large-scale transportation and firming for renewable energy to support the decarbonisation and electrification of existing industrial processes, and enable the development of new green hydrogen and other manufacturing industries.

Queensland Hydro will carry out detailed analytical studies to refine knowledge of pumped hydro potential between the proposed upper reservoirs in the Burdekin catchment, and the lower reservoir proposed in the Pioneer Valley near Netherdale. Studies will also include geotechnical investigations, environmental, social and cultural heritage assessments.

Other PHES developments

Powerlink has also been engaged by Genex Power Limited (Genex) to undertake a range of activities relating to 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) currently scheduled for completion during 2024 (refer Table 9.2).

In addition to the above, there are numerous other PHES projects being proposed by the private sector. These proposals will also form important components of the Queensland energy transformation.

2.5.2 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 future network augmentations. Furthermore, 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.

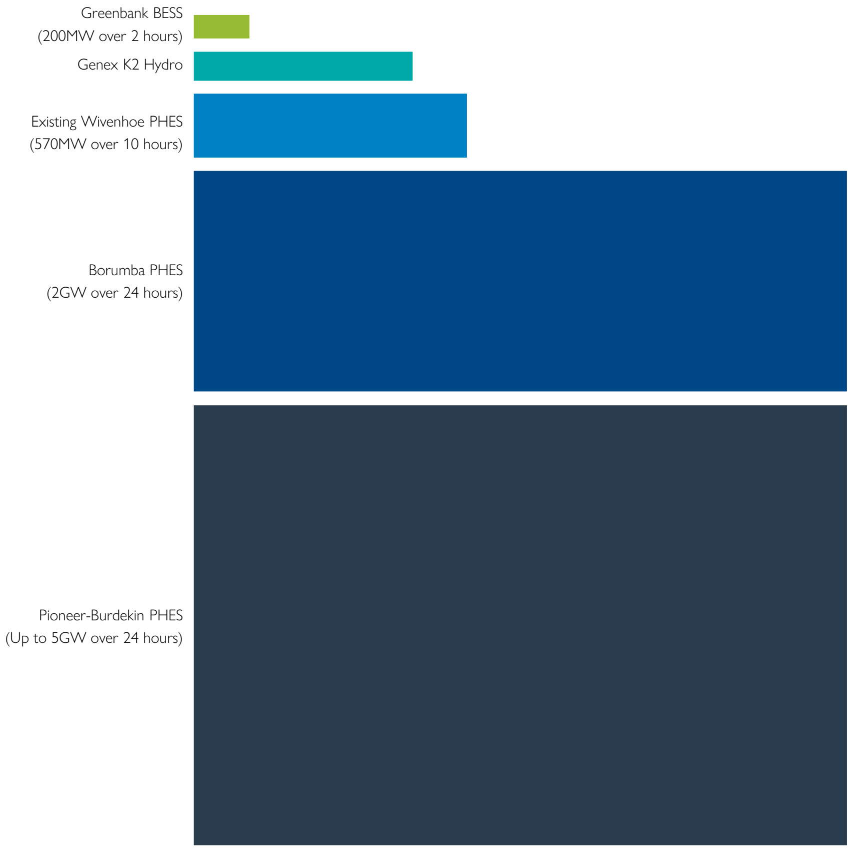
Queensland's first large-scale BESS (100MW/150MWh) was connected to Powerlink's transmission network at Wandoan South Substation in August 2022. A second large-scale BESS built by Genex Power (50MW/100MWh) connected to Powerlink's transmission network at Bouldercombe substation near Rockhampton, commencing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

A number of additional large-scale grid connected BESS are in advanced stages of construction, and are expected to be operational over the near term. These include Powerlink connections for the Western Downs BESS (200MW/400MWh), Greenbank BESS (200MW/400MWh) and Chinchilla BESS (100MW/200MWh) in southern Queensland. Powerlink has experienced continued strong interest in BESS installations across the state.

2.5.3 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 2.7. PHES and BESS are also able to provide a range of transmission and system security services, including system strength, inertia, frequency and ancillary control. These services are critical for the secure operation of a decarbonised energy system.

Figure 2.7 Relative energy storage capacities of PHES and BESS



2.6 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 secure, cost effective and reliable transmission network will be pivotal in enabling sectors the opportunity to electrify operations with renewable generation sources, and for Queensland to transform into a renewable energy exporter.

The electrification of existing fossil fuel operation 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.

2.6.1 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 zones, and electrification of mining operations will impact on transmission capacity requirements to these areas (refer to sections 8.2.1 and 8.2.2). 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 in transmission capacity with demand potentially exceeding several giggawatts ramping over time from the 2030s. These developments also have the potential to significantly alter energy flow patterns and power transfer capability requirements across Powerlink's high voltage network.

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 the design of the high voltage transmission network and firming resources to support the energy transformation.

The transportation sector presents one of the largest opportunities for decarbonisation. The adoption of electric vehicles (EVs) presents the shortest term opportunity for increasing electrification and decarbonisation. The charging behaviour and patterns for EVs has the potential to either support or challenge network requirements from the grid. The management of EV charging will be important to optimising the utilisation of the existing network, particularly within the Moreton and Gold Coast zones.

EVs have the potential for dual purpose application in terms of being both mobility and household distributed energy sources. EV battery capacities are generally larger than required for typical household daily use, and over time it may be possible to leverage this capacity to smooth daily demand usage patterns and rooftop PV output. Both residential battery systems and EVs have the potential to optimise transmission and distribution network utilisation under appropriately designed orchestration incentives and mechanisms.

Powerlink, Energy Queensland and the Queensland Government recognise the need to ensure that investments and measures to address minimum demand are complementary, and that energy storage across the supply chain (transmission, distribution and consumer level) need to operate in a coordinated manner. Orchestration of technologies across the different supply chain levels, including large-scale generation and storage, demand side management (DSM) and time of day shifting, customer energy and storage resources, will be key to optimising utilisation and performance of the energy system.

2.6.2 Emerging hydrogen industry

The Queensland Government 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, Gladstone, and Brisbane Trade Coast areas. Potential markets include both domestic hydrogen to decarbonise existing industrial processes and establishment of new hydrogen export markets.

Powerlink and the Queensland Government are supporting a range of significant hydrogen development activities in Queensland including the connection of renewable hydrogen facilities within the Brisbane Trade Coast area, and potential connection of green hydrogen and ammonia production facilities in Central and North Queensland.

The Queensland Government is also progressing the establishment of hydrogen hubs. Hydrogen hubs are regions where producers, users and/or exporters of hydrogen are co-located. This lowers infrastructure needs, reduces costs, and supports hydrogen production at scale which helps reduce the price customers will pay for hydrogen. Central Queensland has been identified as a potential hydrogen hub because of the availability of:

- sufficient land, electricity transmission, gas infrastructure and port capacity to meet international export and local industry demand
- skilled workforce and investment environment which supports innovation
- state development area that supports the development of industrial hubs, infrastructure corridors and major development sites
- proximity to REZs (including the Callide and Calliope REZs).

2.6.3 Rooftop photovoltaic systems

The uptake of rooftop PV systems within both residential and commercial premises in Queensland continues to be strong. There is now over 5.5GW of household rooftop systems connected to the network (refer Section 3.2.1).

The uptake and development of distribution network connected 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. This continues to present challenges relating to voltage control, ramping between minimum and maximum demand, frequency control services, system strength, and inertia.

Powerlink has completed regulatory consultation processes to address voltage control within South East Queensland during periods of minimum demand (refer to Section 6.6). Powerlink has also entered into a Network Support Agreement with CleanCo Queensland for the provision of network support and control ancillary services (NSCAS) to address an immediate gap for the management and control of voltages.

Powerlink is actively collaborating with AEMO and participating in national industry working groups to develop strategies and implement measures to address technical challenges associated with the changing grid demand profile (refer to Appendix B).

2.7 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, both with and without the occurrence of an event or disturbance or fluctuations in supply or demand. System strength has traditionally been provided through energy dispatch by 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 use of grid-following power electronics technology to generate electricity.

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 levels across the network. However, these developments are not projected to be fully operational until the early 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 contribute to the provision of system strength 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 also expected to change over time alongside the accelerating development of new technologies.

Further information on system strength planning and activities currently being undertaken by Powerlink are detailed within Chapter 4 and Section 6.8.2.

2.8 Other initiatives

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 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. 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 or load characteristics of connections. 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 CQ-SQ grid section (refer to Section 7.3), and further applications for the technology are progressing to more effectively manage the performance of the transmission network. 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.

Powerlink has also continued to collaborate closely with AEMO on transmission expansion options for the 2024 ISP through technical working groups and other related activities. Powerlink has completed preparatory activities identified within the 2022 ISP (refer Section 6.15).

Powerlink opened the Gladstone SuperGrid Training Centre and Transmission Hub in May 2023. The centre is generating 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 co-located with a new SuperGrid Training Centre and Transmission Hub. The office will provide similar services to the Gladstone Training Centre 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.

2.9 Community engagement and benefits

New transmission infrastructure that is needed to be built as part of the energy transformation has the potential to create long-lasting benefits for Queensland communities. Powerlink will continue to work closely with Queensland communities to deliver benefits for those impacted by energy infrastructure.

Powerlink is undertaking early and authentic engagement to listen to landholders, communities and other stakeholders 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. Powerlink's Community Engagement Strategy underpins this focus on ensuring local benefits and community investment go hand in hand with delivering Queensland's new energy future.

In May 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 increase in payments is based on property-specific values and impacts, as opposed to using a flat rate. Powerlink also became the first transmission company in Australia to offer payments to landholders with properties adjacent to 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.

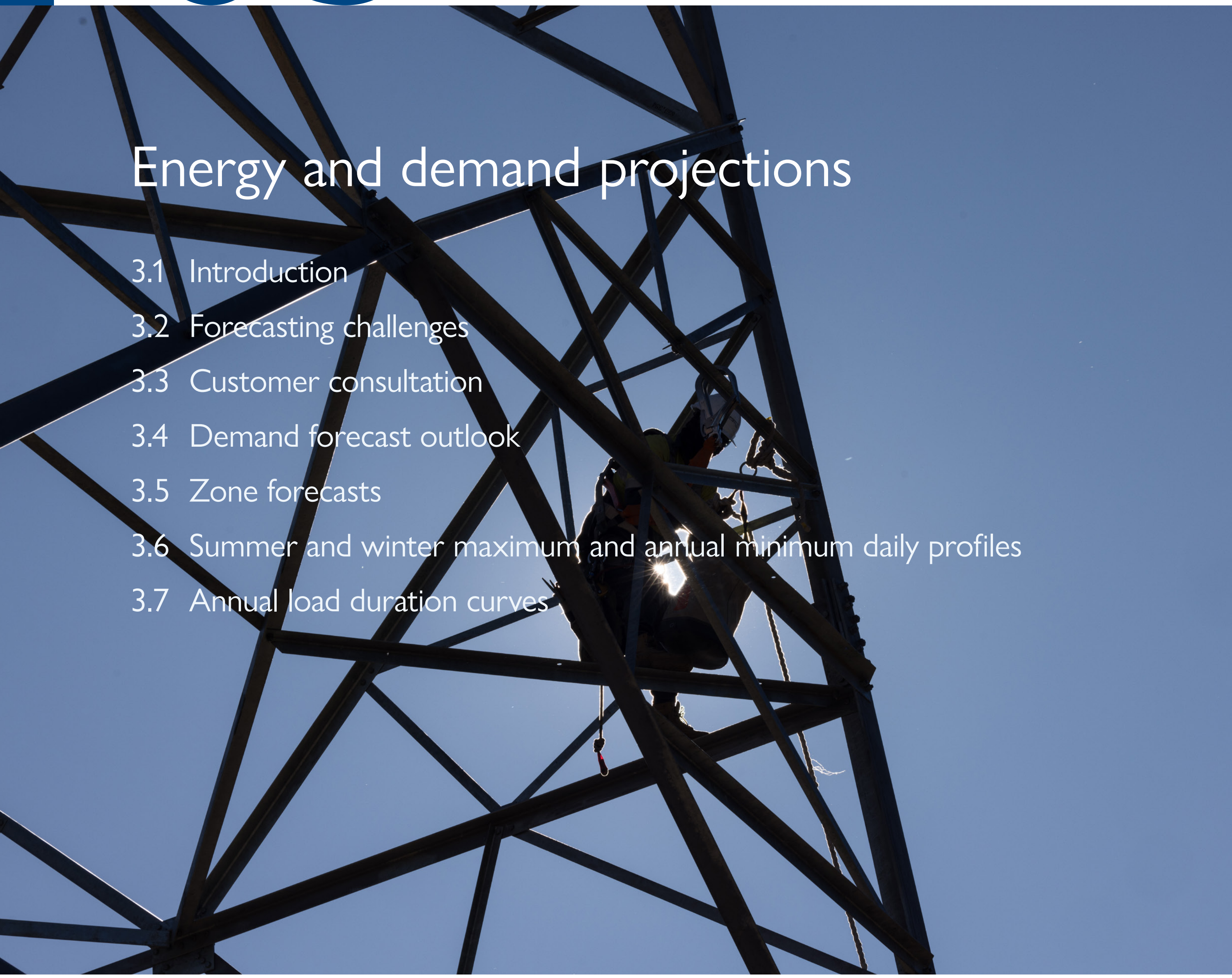
Powerlink is also working with its subsidiary QCN on how best to connect regional townships and areas within Queensland with high-speed internet using fibre optic cables installed within overhead earthwires on top of transmission infrastructure.

2.10 On-going transformation

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

The Queensland Energy and Jobs Plan 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, resilient 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

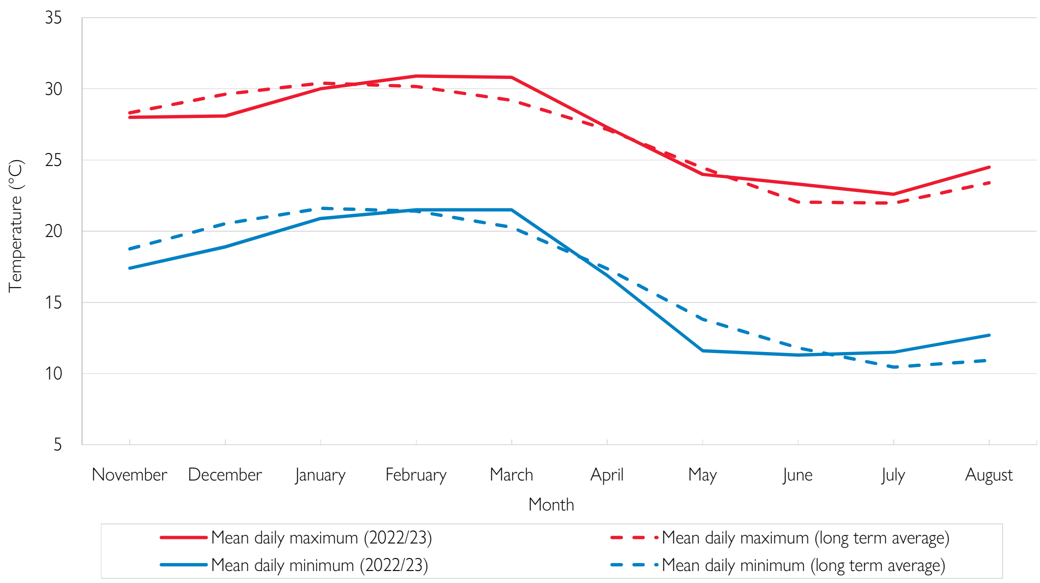
- Queensland's maximum transmission delivered demand for 2022/23 was 8,916MW on 17 March 2023. This maximum demand occurred at 6.00pm and was 116MW lower than the record maximum delivered demand set in 2022.
- Queensland set a new record minimum transmission delivered demand of 2,538MW on 20 August 2023. This minimum demand occurred at 12.30pm and was 59MW lower than the previous record minimum set in September 2022.
- Powerlink has adopted the Australian Energy Market Operator's (AEMO) 2023 Electricity Statement of Opportunity (ESOO) forecasts in its planning analysis for the 2023 Transmission Annual Planning Report (TAPR). Powerlink is focussed on working with AEMO and EQL to understand the potential impacts of emerging technologies (e.g. electric vehicles and electrification of broader industry processes) and new industries to develop transmission network services in ways that are valued by customers.
- Based on AEMO's Step Change scenario forecast, Queensland's transmission delivered maximum demand is expected to have mild growth with an average annual increase of 1.8% 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 AEMO's Step Change scenario, transmission delivered energy consumption is expected to increase at an average rate of 1.8% per annum over the next 10 years.

3.1 Introduction

The 2022/23 summer Queensland maximum transmission delivered demand occurred at 6.00pm on 17 March 2023, when 8,916MW was delivered from the transmission grid (refer to Figure 3.9 for load measurement definitions). Operational 'as generated' peak was recorded 30 minutes earlier at 5.30pm, reaching 10,070MW. After weather correction, the 2022/23 summer maximum transmission delivered demand was 9,110MW, 0.7% higher than that forecast in the 2022 ESOO Step Change scenario.

Figure 3.1 shows observed mean temperatures for Brisbane during November 2022 to August 2023 compared with long-term averages. The comparison reveals a slightly cooler summer than average in south east Queensland, whilst daily maximum temperatures in March 2023 were slightly higher than the long-term average. Winter temperatures were also slightly warmer than the long-term average.

Figure 3.1 Brisbane temperature ranges over November 2022 to August 2023 (1)



Note:

(1) Long-term average based on years 2000 to 2022/23.

The 2023 Queensland minimum delivered demand occurred at 12.30pm on 20 August 2023, when only 2,538MW was delivered from the transmission grid (refer to Figure 3.9 for load measurement definitions). Operational 'as generated' minimum demand was recorded on 17 September 2023 at 11.00am and set a new record for Queensland of 3,387MW, passing the previous minimum record of 3,469MW set in September 2022.

At the time of minimum delivered demand, directly connected loads made up about 73.5% 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 worked with AEMO to derive transmission delivered equivalent demand and energy forecasts based on the forecast operational sent out quantities defined in AEMO's 2023 ESOO. Further information on the development of AEMO's 2023 ESOO is available on AEMO's website[1].

The AEMO 2023 ESOO forecasts provide the top-down, whole of state maximum demand forecast for the Queensland region. These are reconciled with bottom-up forecasts from DNSPs and directly connected customers to create the granular models needed to inform zonal or more localised issues.

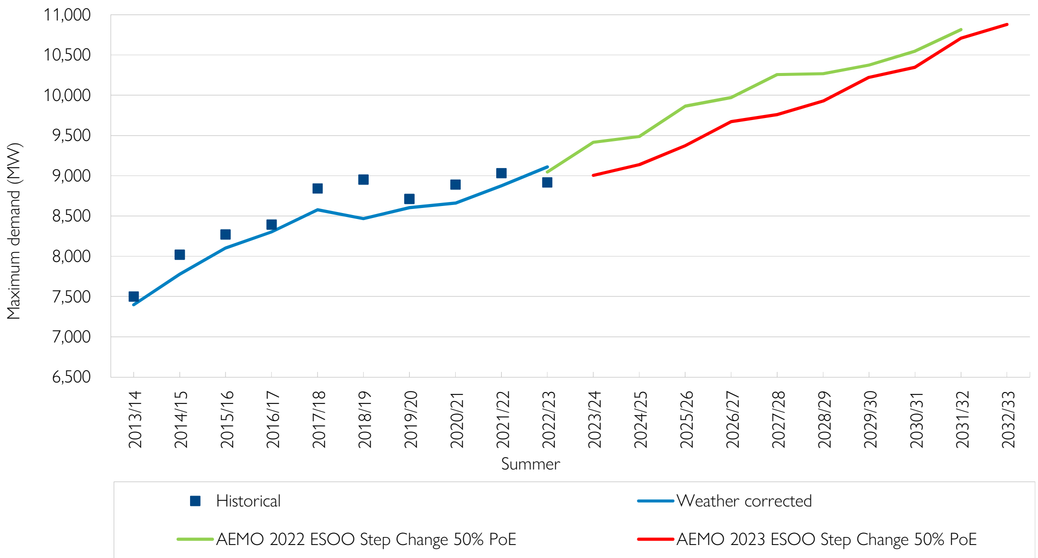
The Queensland Government's 50% renewable energy target by 2030 (QRET) and net zero by 2050 has driven renewable capacity in the form of solar PV and wind farms to connect to the Queensland transmission and distribution networks (refer to tables 7.1 and 7.2). Additional uncommitted distribution connected solar and wind farm capacity has been included into the 10-year outlook period from 2026 to model the Queensland Government's targets.

[1] AEMO, Forecasting Approach - Electricity Demand Forecasting Methodology, September 2021.

At the end of June 2023, Queensland reached 5,614MW of installed rooftop PV capacity[2]. Growth in rooftop PV capacity remains strong at around 65MW per month in 2022/23. 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 5.30pm 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.

Figure 3.2 shows a comparison of AEMO's 2022 ESOO delivered summer maximum demand forecast based on the Step Change scenario with AEMO's 2023 ESOO based on the Step Change scenario, both with 50% Probability of Exceedance (PoE). The decrease in the forecast maximum demand is due to an increase in the forecast of embedded generators within EQL network combined with a slight reduction in the pace of electrification.

Figure 3.2 Comparison of AEMO's 2022 ESOO Step Change scenario delivered demand forecast with the 2023 ESOO Step Change scenario (1) (2)



Notes:

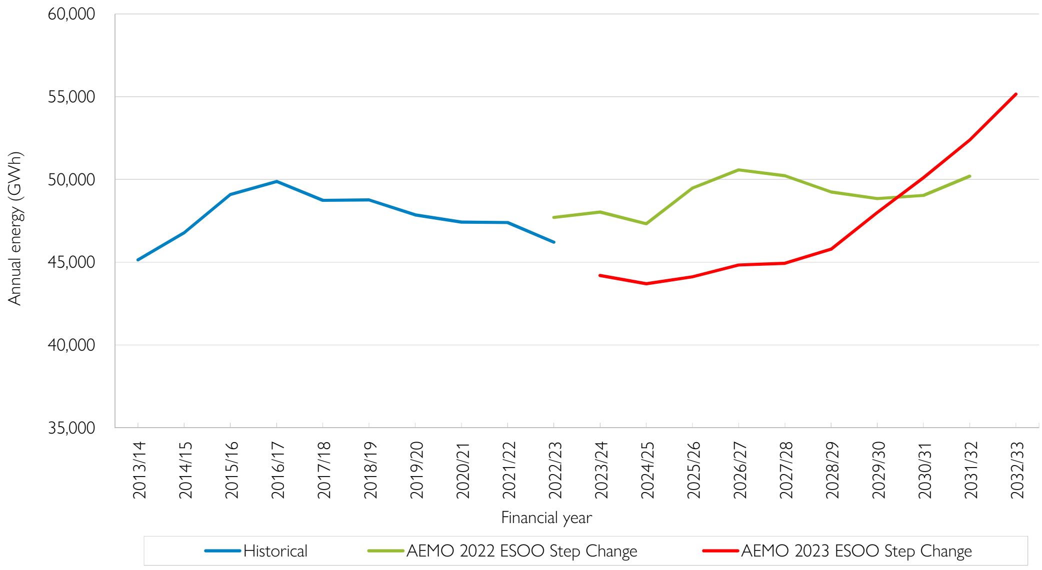
(1) AEMO's 2023 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.9 for further details.

(2) AEMO's 2023 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's renewable energy targets.

Figure 3.3 shows a comparison of AEMO's 2022 ESOO delivered energy forecast based on the Step Change scenario with AEMO's 2023 ESOO Step Change scenario. Section 3.4 discusses updates included in AEMO's 2023 ESOO forecasts. The slight drop and then uplift in delivered energy in AEMO's 2023 Step Change scenario is due to slower electrification of load and increasing embedded generation until 2024/25. From 2024/25 the increase is a combination of expected electric vehicle uptake and industries beginning to electrify their operations to meet their emission reduction targets.

[2] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/07/2023, August 2023. 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 3.3 Comparison of AEMO's 2022 ESOO Step Change scenario delivered energy forecast with the 2023 ESOO Step Change scenario (1)

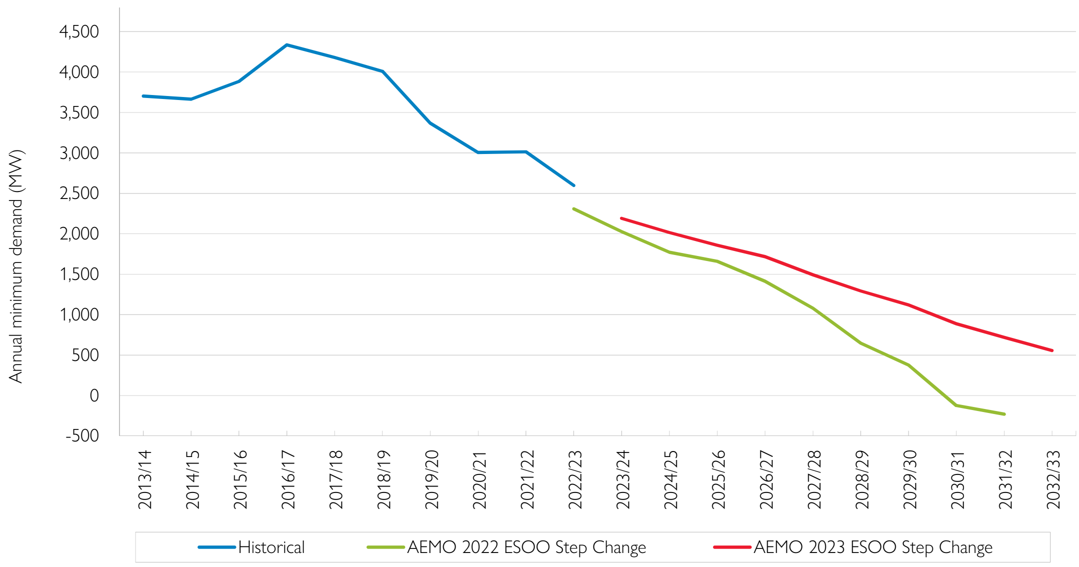


Note:

(1) AEMO's 2023 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 2022 ESOO annual delivered minimum demand forecast based on the Step Change scenario with AEMO's 2023 ESOO Step Change scenario. The rate of decline in the annual minimum demand has slowed from the previous year. This is due to the increase in electrification in the later years of the forecast.

Figure 3.4 Comparison of AEMO's 2022 ESOO Step Change scenario minimum delivered demand forecast with the 2023 ESOO Step Change scenario (1)



Note:

(1) AEMO's 2023 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.

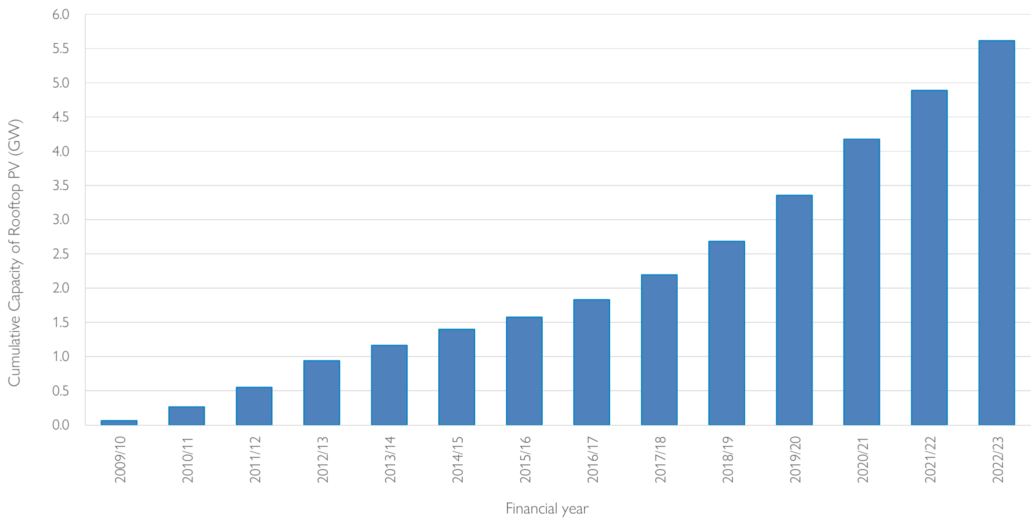
3.2 Forecasting challenges

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 782MW 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 2023 Queensland Household Energy Survey (QHES) indicating that 26% of respondents intend to purchase new or upgrade rooftop PV systems in the next three years (refer Figure 3.6). 76% of solar owners indicated a high overall importance of maximising consumption of electricity at the time when their solar system is generating. Renting (46%), followed by unaffordability (17%) are the top reasons for not having solar. Of the reasons for intending to upgrade or replace their solar PV, 52% indicated they want a larger system to reduce their electricity bill, 29% that they've purchased or are looking to purchase a household battery, and 14% have purchased or are looking to purchase an EV. Of those yet to do so, 16% of respondents intend to purchase battery storage within the next 3 years, 45% an EV and 39% have high interest in community batteries.

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

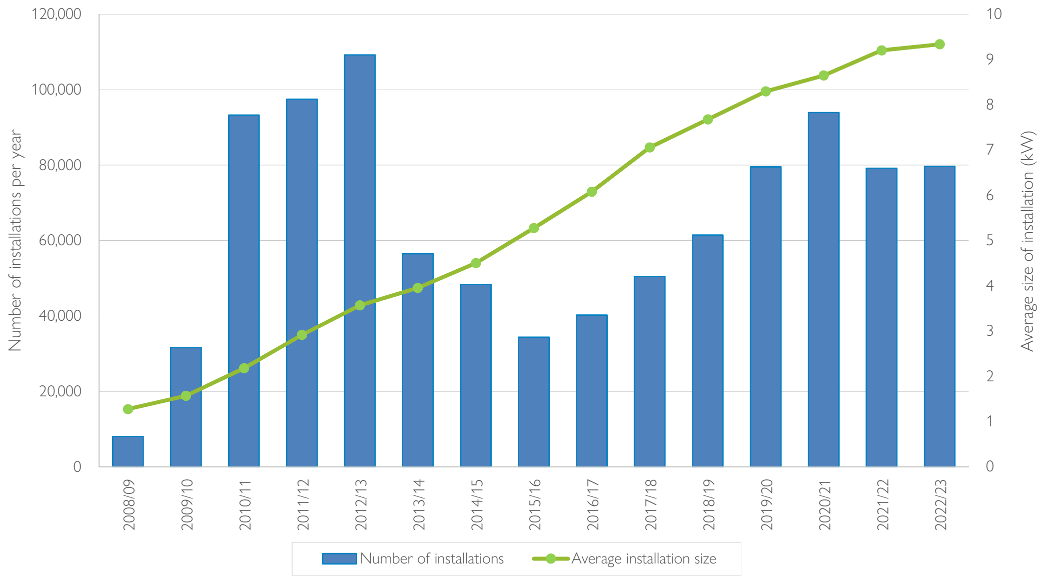


Notes:

(1) Source: Clean Energy Regulator.

(2) Registrations generally lag installations and hence data for FY2023 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.

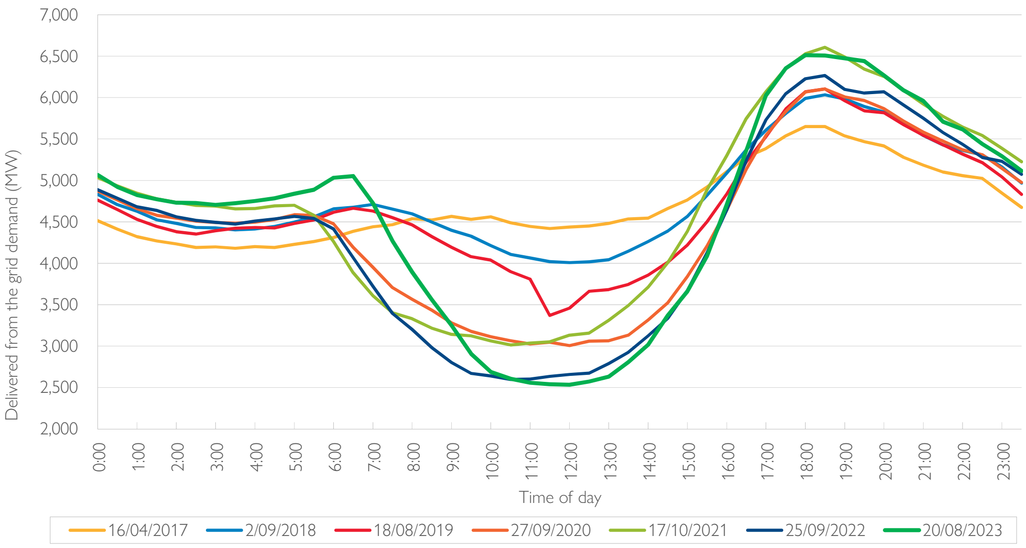
(2) Registrations generally lag installations and hence data for FY2023 may be slightly understated.

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.

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.

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



Notes:

(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.

(2) 2023 trace based on preliminary metering data up to 13 September 2023.

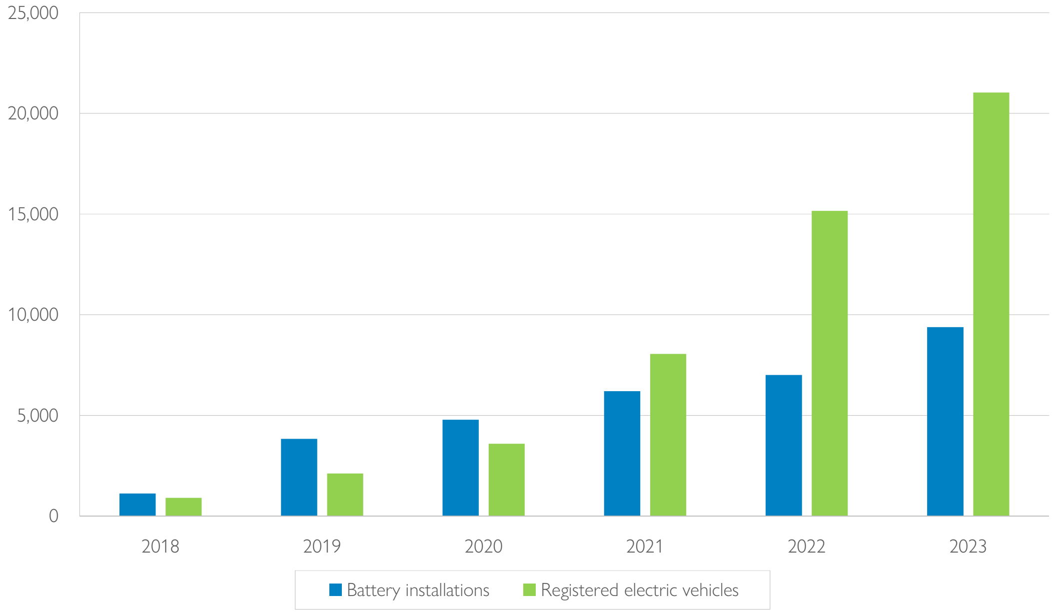
Continuation of this trend is likely to present challenges to the power system. Generators are increasingly required to ramp up and down in response to daily demand variations more steeply. Decreasing minimum demand will lead a lower number of units of synchronous generation that are able to be online 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[3].

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 9,000 battery installations currently reported within residential households and over 20,000 registered electric vehicles (refer Figure 3.8).

3 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.

3.2.2 Electrification of load and decarbonisation

Decentralisation, driven by future developments in battery storage technology coupled with rooftop PV and EVs, could see significant changes to future electricity usage patterns. This could reduce the need to develop transmission services to cover short duration peaks.

However, presently only 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.

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). These connection supply point forecasts are presented in Appendix D. 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 was committed in the past 12 months. A new manufacturing plant in the Gladstone area.

Possible new large loads

There are several proposals under development for large mining, metal processing, other industrial loads and the electrification of existing loads. These proposed new large loads total approximately 5,612MW with a high scenario of up to 12,632MW. The likely distribution of these loads are defined in Table 3.1. The majority of proposed loads have not been included in AEMO's 2023 ESOO Step Change scenario forecast. However, AEMO's Step Change scenario forecast did allow for approximately 250MW of new electrification load in the Gladstone zone (refer to sections 6.10.2 and 8.2.3). The proposed load in the Gladstone zone in Table 3.1 is inclusive of this 250MW.

Table 3.1 Possible large loads excluded from the Progressive Change, Step Change and Hydrogen Export scenario forecasts

Zone	Description	Possible load
South Queensland	Hydrogen facility Data centre	945MW
Gladstone	Electrification of existing metal processing and industrial loads Hydrogen facilities	3,543MW to 10,562MW (1)
Northern	Electrification of existing mining load New industrial New mining	1,124MW

Note

(1) This represents a base and 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 have generally occurred in winter and more recently in shoulder periods.

The annual minimum demand has moved from overnight to the day time since 2018 (as described in Section 3.2.1). The forecast for minimum delivered demand is now 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 2023 TAPR reports on the Progressive Change, Step Change and Hydrogen Export scenario forecasts provided by AEMO and aligned to its 2023 ESOO. 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 Progressive Change, Step Change and Hydrogen Export scenarios are shown in Table 3.2. These growth rates refer to transmission delivered quantities as described in Section 3.4.1. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2022/23 and 2022 respectively.

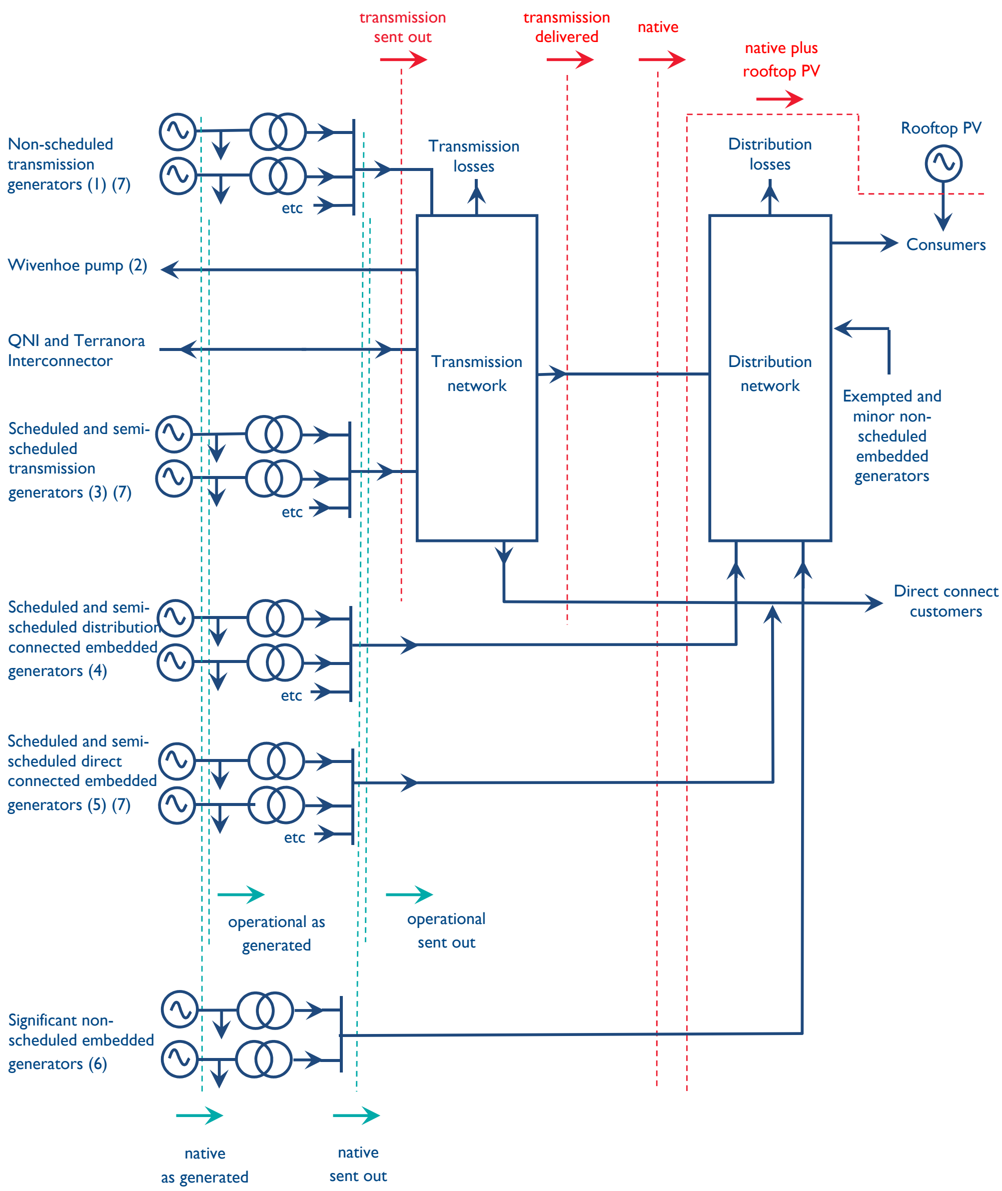
Table 3.2 Average annual growth rate over next 10 years

	AEMO future scenario outlooks		
	Progressive Change	Step Change	Hydrogen Export
Delivered energy	-0.6%	1.8%	5.3%
Delivered summer maximum demand (50% PoE)	0.2%	1.8%	2.4%
Delivered winter maximum demand (50% PoE)	0.2%	1.7%	2.4%

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 3.9.

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
2013/14	49,686	46,575	51,029	47,918	46,560	45,145	46,503	46,503
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

The transmission delivered energy forecasts are presented in Table 3.4.

Table 3.4 Forecast annual transmission delivered energy (GWh)

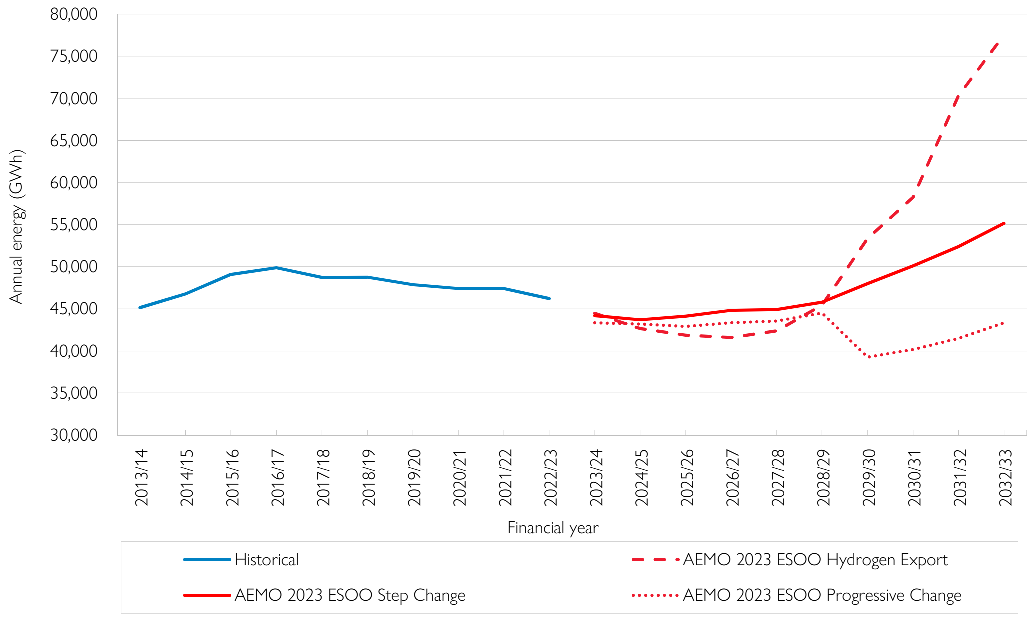
Financial year	Progressive Change	Step Change	Hydrogen Export
2023/24	43,350	44,197	44,475
2024/25	43,183	43,702	42,650
2025/26	42,905	44,123	41,863
2026/27	43,334	44,829	41,599
2027/28	43,540	44,931	42,371
2028/29	44,506	45,792	45,422
2029/30	39,260 (1)	48,008	53,352
2030/31	40,169	50,105	58,274
2031/32	41,484	52,385	70,310
2032/33	43,358	55,157	77,521

Note:

(1) AEMO assumes the shutdown of a large industrial load in the Progressive Change scenario in summer 2029/30.

The historical annual transmission delivered energy from Table 3.3 and the forecast transmission delivered energy for the Progressive Change, Step Change and Hydrogen Export scenarios from Table 3.4 are shown in Figure 3.10.

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	Progressive Change	Step Change	Hydrogen Export
2023/24	47,788	48,188	48,913
2024/25	48,557	49,573	50,162
2025/26	48,403	50,280	51,083
2026/27	49,057	51,276	51,599
2027/28	49,509	51,825	53,476
2028/29	50,699	53,314	57,175
2029/30	45,683 (1)	56,115	66,569
2030/31	46,726	58,562	73,451
2031/32	48,202	61,108	86,890
2032/33	50,052	64,275	95,395

Note:

(1) AEMO assumes the shutdown of a large industrial load in the Progressive Change scenario in summer 2029/30.

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
2013/14	8,445	7,892	8,587	8,045	7,810	7,559	7,436	7,794	8,086
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	9,201	9,413	9,395

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

Table 3.7 Forecast summer transmission delivered maximum demand (MW) (1)

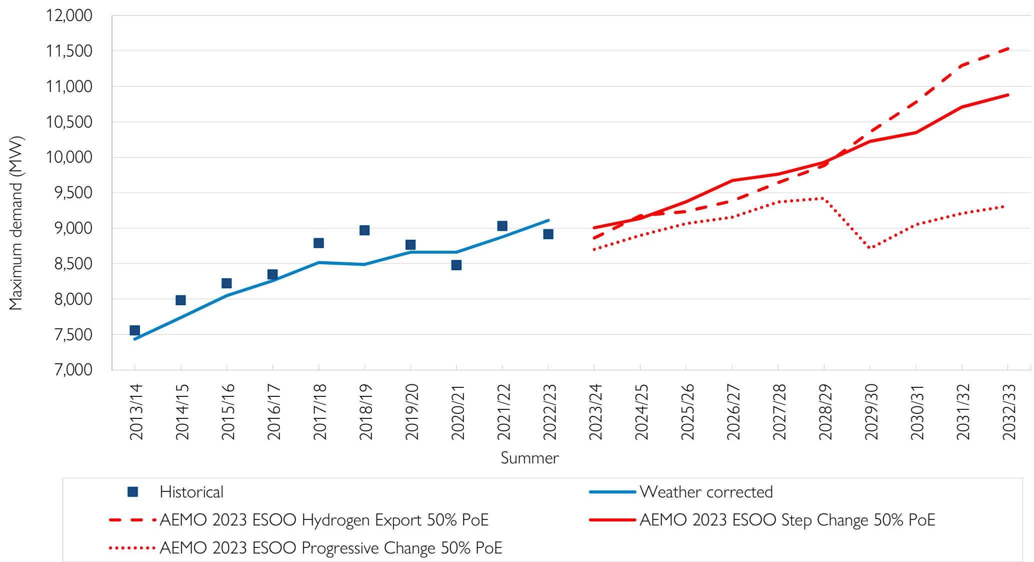
Summer	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023/24	8,245	8,700	9,136	8,536	9,005	9,435	8,388	8,862	9,295
2024/25	8,443	8,897	9,344	8,664	9,137	9,574	8,691	9,176	9,615
2025/26	8,602	9,064	9,518	8,883	9,374	9,812	8,724	9,235	9,675
2026/27	8,675	9,155	9,625	9,156	9,672	10,125	8,850	9,385	9,849
2027/28	8,883	9,370	9,851	9,238	9,761	10,219	9,102	9,643	10,113
2028/29	8,950	9,421	9,912	9,437	9,928	10,410	9,365	9,884	10,375
2029/30 (1)	8,224	8,711	9,229	9,711	10,223	10,719	9,823	10,356	10,868
2030/31	8,553	9,050	9,568	9,811	10,348	10,841	10,208	10,778	11,293
2031/32	8,688	9,208	9,720	10,149	10,709	11,194	10,695	11,293	11,803
2032/33	8,808	9,314	9,806	10,331	10,879	11,353	10,936	11,531	12,030

Notes:

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

The summer historical transmission delivered maximum demands from Table 3.11 and the forecast 50% PoE summer transmission delivered maximum demands for the Progressive Change, Step Change, and Hydrogen Export scenarios from Table 3.7 are shown in Figure 3.11.

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
2013/14	8,374	7,947	8,531	8,114	7,780	7,498	7,831	7,831	7,731
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

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

Table 3.9 Forecast summer native maximum demand (MW)

Summer	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023/24	9,097	9,556	9,988	9,200	9,673	10,099	9,240	9,718	10,147
2024/25	9,203	9,660	10,103	9,440	9,918	10,350	9,463	9,951	10,386
2025/26	9,253	9,719	10,169	9,633	10,127	10,561	9,714	10,229	10,665
2026/27	9,401	9,886	10,351	9,849	10,368	10,818	9,911	10,449	10,910
2027/28	9,513	10,004	10,481	10,027	10,554	11,008	10,163	10,707	11,174
2028/29	9,691	10,166	10,653	10,304	10,799	11,277	10,555	11,078	11,566
2029/30 (1)	9,041	9,532	10,047	10,568	11,084	11,576	11,012	11,548	12,057
2030/31	9,235	9,735	10,249	10,826	11,366	11,856	11,469	12,043	12,554
2031/32	9,369	9,893	10,402	11,045	11,608	12,090	12,035	12,637	13,144
2033/34	9,554	10,063	10,552	11,352	11,903	12,373	12,437	13,035	13,530

Note:

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

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
2014	7,288	6,895	7,448	7,091	6,853	6,642	6,761	6,879	6,879
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	(1)	7,553	7,553

Note:

(1) The winter 2023 weather corrected demand was not available at time of publication.

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

Table 3.11 Forecast winter transmission delivered maximum demand (MW) (1)

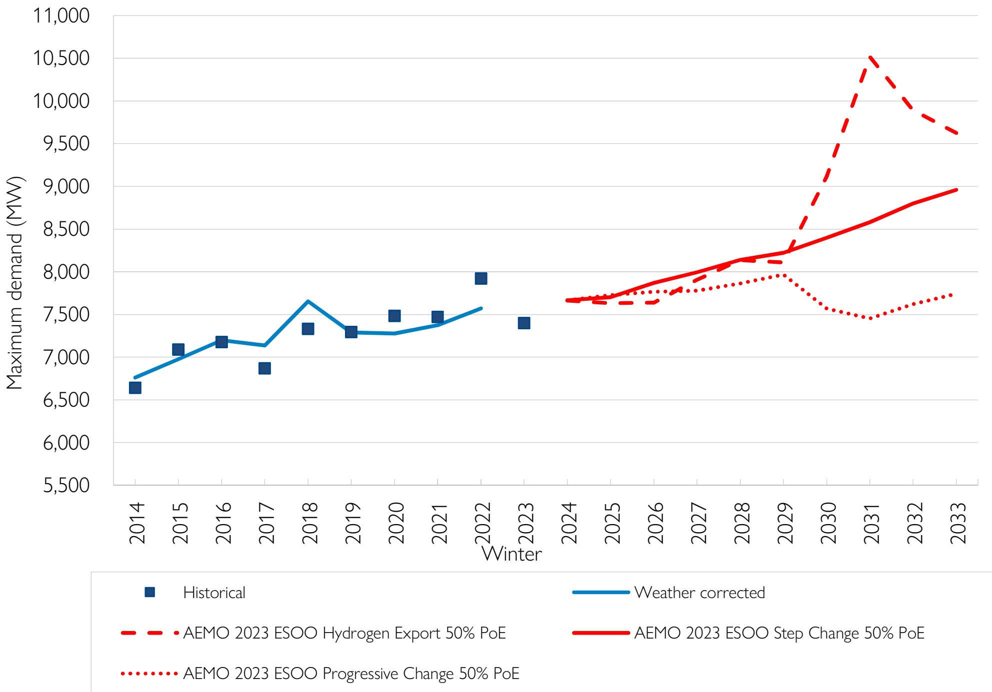
Winter	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2024	7,440	7,667	7,865	7,440	7,666	7,864	7,437	7,663	7,861
2025	7,496	7,727	7,927	7,471	7,703	7,903	7,833	7,632	7,833
2026	7,540	7,767	7,982	7,640	7,869	8,086	7,857	7,640	7,857
2027	7,549	7,777	7,995	7,762	7,995	8,215	8,129	7,905	8,129
2028	7,632	7,862	8,084	7,899	8,139	8,367	8,372	8,137	8,372
2029	7,733	7,967	8,191	7,981	8,223	8,454	8,347	8,108	8,347
2030 (1)	7,328	7,569	7,802	8,162	8,397	8,632	9,363	9,118	9,363
2031	7,207	7,453	7,690	8,341	8,580	8,820	10,769	10,517	10,769
2032	7,344	7,619	7,862	8,537	8,798	9,049	10,162	9,893	10,162
2033	7,470	7,741	7,994	8,688	8,960	9,223	9,907	9,625	9,907

Notes:

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

The winter historical transmission delivered maximum demands from Table 3.10 and the forecast 50% PoE summer transmission delivered maximum demands for the Progressive Change, Step Change, and Hydrogen Export 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
2014	7,307	6,895	7,470	7,077	6,854	6,647	6,881	6,881	6,999
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	7,754	7,754	7,830
2022	8,625	8,216	8,701	8,347	8,141	7,921	8,127	8,127	7,571
2023	8,137	7,601	8,223	7,738	7,585	7,399	7,553	7,553	(1)

Note:

(1) The winter 2023 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	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2024	7,782	8,005	8,207	7,782	8,004	8,206	7,779	8,001	8,203
2025	7,855	8,081	8,286	7,957	8,184	8,389	7,995	8,222	8,426
2026	7,902	8,125	8,344	8,154	8,379	8,600	8,206	8,435	8,657
2027	7,948	8,173	8,394	8,333	8,561	8,786	8,565	8,798	9,026
2028	8,052	8,279	8,505	8,526	8,761	8,994	8,852	9,091	9,331
2029	8,173	8,403	8,631	8,704	8,941	9,177	8,833	9,077	9,320
2030 (1)	7,784	8,021	8,258	8,939	9,169	9,409	9,925	10,160	10,409
2031	7,706	7,948	8,189	9,207	9,442	9,686	11,477	11,722	11,978
2032	7,847	8,118	8,365	9,410	9,667	9,922	10,918	11,191	11,464
2033	7,965	8,232	8,489	9,598	9,866	10,133	10,745	11,032	11,318

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
2014	4,073	3,780	4,274	4,027	3,768	3,664	3,923	3,923
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 (1)	3,490	2,973	3,655	3,277	2,634	2,538	3,181	6,232

Note:

(1) 2023 minimum based on preliminary data up to 13 September 2023.

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

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

Annual	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023/24	2,083	2,238	2,414	2,026	2,191	2,378	2,036	2,202	2,398
2024/25	2,364	2,188	2,364	2,200	2,013	2,200	2,061	1,866	2,061
2025/26	2,260	2,081	2,260	2,056	1,859	2,056	1,904	1,699	1,904
2026/27	2,232	2,046	2,232	1,923	1,715	1,923	2,010	1,754	2,010
2027/28	2,142	1,946	2,142	1,706	1,493	1,706	1,908	1,666	1,908
2028/29	2,080	1,879	2,080	1,517	1,292	1,517	1,805	1,540	1,805
2029/30 (1)	1,280	1,068	1,280	1,362	1,121	1,362	2,346	2,064	2,346
2030/31	1,247	1,024	1,247	1,143	889	1,143	1,952	1,658	1,952
2031/32	1,193	968	1,193	970	719	970	2,631	2,334	2,631
2032/33	1,184	963	1,184	817	556	817	3,011	2,720	3,011

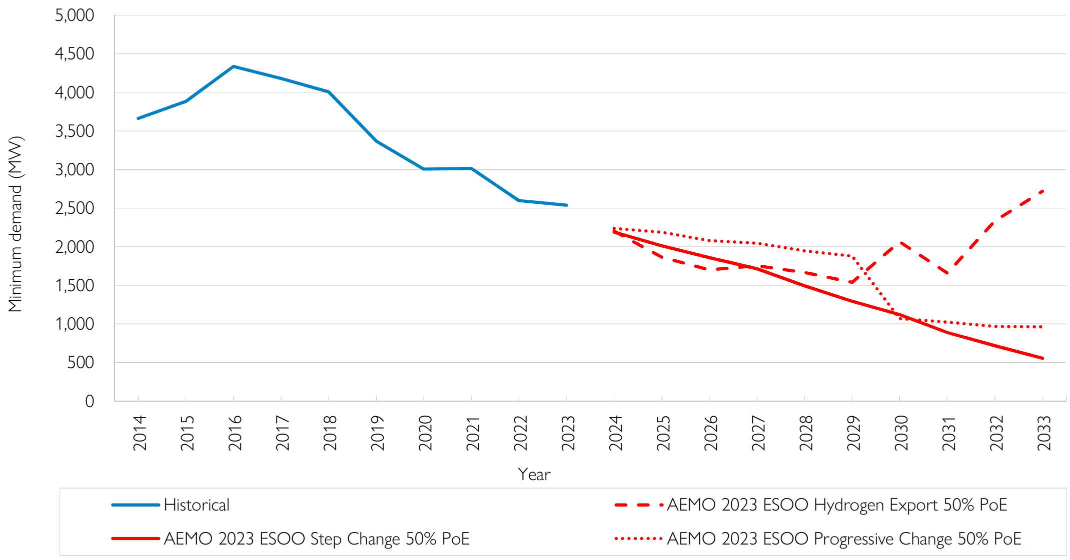
Notes:

(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.

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

The annual historical transmission delivered minimum demands from Table 3.14 and the forecast 50% PoE annual transmission delivered minimum demands for the Progressive Change, Step Change, and Hydrogen Export scenarios from Table 3.15 are shown in Figure 3.13.

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	Progressive Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023/24	2,663	2,812	2,994	2,623	2,783	2,976	2,584	2,745	2,946
2024/25	2,610	2,764	2,946	2,503	2,668	2,860	2,401	2,570	2,770
2025/26	2,508	2,667	2,850	2,355	2,525	2,727	2,297	2,473	2,682
2026/27	2,484	2,642	2,834	2,228	2,407	2,620	2,437	2,670	2,931
2027/28	2,411	2,579	2,780	2,028	2,216	2,433	2,499	2,703	2,951
2028/29	2,346	2,518	2,724	1,852	2,055	2,285	2,386	2,649	2,919
2029/30 (2)	1,533	1,715	1,931	1,684	1,904	2,150	3,059	3,292	3,580
2030/31	1,496	1,688	1,916	1,545	1,785	2,045	2,801	3,062	3,362
2031/32	1,439	1,634	1,865	1,357	1,615	1,871	3,555	3,837	4,139
2032/33	1,440	1,643	1,870	1,298	1,561	1,826	4,161	4,459	4,756

Notes:

(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.

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

3.5 Zone forecasts

AEMO's 2023 ESOO provides forecasts for Queensland as a single region. Forecasts from DNSPs and directly connected customers at each transmission connection supply point have been used to apportion the demand and energy forecasts into the 11 zones referenced throughout this TAPR. The 11 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	1.12	1.17
Ross	1.41	1.47
North	1.15	1.13
Central West	1.11	1.22
Gladstone	1.03	1.02
Wide Bay	1.02	1.08
Surat	1.17	1.20
Bulli	1.06	1.14
South West	1.05	1.13
Moreton	1.01	1.03
Gold Coast	1.03	1.10

Tables 3.18 and 3.19 show the historical and forecast of transmission delivered energy and native energy for the Step Change scenario for each of the 11 zones in the Queensland region.

Table 3.18 Annual transmission delivered energy by zone (GWh)

Financial Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2013/14	1,658	2,826	2,828	3,564	10,293	1,321	338	146	1,304	17,782	3,085	45,145
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
Forecasts												
2023/24	1,415	2,331	2,545	2,238	9,264	614	5,348	1,309	1,015	15,475	2,645	44,197
2024/25	1,366	2,259	2,586	2,260	9,314	219	4,420	1,084	1,020	16,356	2,818	43,702
2025/26	1,305	2,227	2,630	2,468	9,731	43	4,446	1,079	1,021	16,341	2,832	44,123
2026/27	1,289	2,252	2,731	2,560	10,067	59	4,346	1,047	1,065	16,545	2,869	44,829
2027/28	1,281	2,259	2,750	2,621	10,171	75	4,174	991	1,099	16,627	2,883	44,931
2028/29	1,288	2,280	2,815	2,713	10,184	117	3,990	922	1,167	17,303	3,011	45,792
2029/30	1,342	2,360	2,947	2,881	10,970	188	3,839	863	1,274	18,168	3,175	48,008
2030/31	1,411	2,466	3,087	3,056	11,472	263	3,700	817	1,385	19,093	3,353	50,105
2031/32	1,523	2,629	3,298	3,272	11,531	366	3,623	788	1,531	20,247	3,575	52,385
2032/33	1,641	2,799	3,512	3,519	11,599	482	3,547	751	1,692	21,747	3,866	55,157

Table 3.19 Annual native energy by zone (GWh)

Financial Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2013/14	1,658	3,067	3,154	3,944	10,293	1,339	402	146	1,536	17,879	3,085	46,503
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
Forecasts												
2023/24	1,447	3,017	3,078	3,082	9,264	1,188	5,988	1,309	1,639	15,532	2,645	48,188
2024/25	1,501	3,130	3,303	3,285	9,310	1,246	5,609	1,228	1,739	16,405	2,816	49,573
2025/26	1,465	3,143	3,393	3,351	9,726	1,238	5,733	1,258	1,750	16,390	2,831	50,280
2026/27	1,472	3,210	3,535	3,484	10,062	1,262	5,723	1,259	1,805	16,597	2,868	51,276
2027/28	1,500	3,283	3,618	3,608	10,167	1,294	5,684	1,252	1,861	16,677	2,882	51,825
2028/29	1,559	3,395	3,775	3,789	10,179	1,350	5,693	1,254	1,953	17,355	3,010	53,314
2029/30	1,659	3,560	3,991	4,041	10,966	1,438	5,722	1,261	2,084	18,220	3,174	56,115
2030/31	1,757	3,718	4,182	4,265	11,468	1,523	5,691	1,254	2,208	19,146	3,351	58,562
2031/32	1,890	3,919	4,430	4,517	11,526	1,634	5,697	1,254	2,366	20,299	3,574	61,108
2032/33	2,040	4,146	4,702	4,820	11,595	1,761	5,741	1,262	2,545	21,799	3,865	64,275

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 11 zones in the Queensland region. It is based on the Step Change scenario and average (50% PoE) summer weather.

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

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2013/14	296	401	427	504	1,152	248	13	17	267	3,597	637	7,559
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
Forecasts												
2023/24	302	220	479	369	1,168	191	523	182	236	4,512	760	9,005
2024/25	296	225	474	353	1,143	194	524	176	232	4,499	749	9,137
2025/26	299	239	490	388	1,217	224	528	178	257	4,668	767	9,374
2026/27	304	255	496	418	1,251	270	523	176	288	4,736	763	9,672
2027/28	311	256	503	423	1,264	261	521	176	287	4,804	768	9,761
2028/29	312	267	503	429	1,248	267	515	174	288	4,826	771	9,928
2029/30	330	278	528	463	1,379	308	530	179	318	5,048	806	10,223
2030/31	337	286	533	457	1,442	288	533	179	310	5,125	818	10,348
2031/32	356	303	558	503	1,470	356	541	183	356	5,372	858	10,709
2032/33	365	304	567	502	1,460	338	540	181	350	5,454	870	10,879

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

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2013/14	271	423	386	561	1,147	260	88	21	316	3,755	603	7,831
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
Forecasts												
2023/24	311	337	544	521	1,197	323	708	187	328	4,625	779	9,673
2024/25	312	346	550	523	1,197	329	717	185	331	4,711	785	9,918
2025/26	312	352	560	541	1,263	340	718	185	337	4,846	796	10,127
2026/27	314	352	562	547	1,291	342	709	182	343	4,887	787	10,368
2027/28	321	358	570	562	1,304	352	707	181	353	4,958	792	10,554
2028/29	329	375	580	578	1,314	362	713	183	360	5,079	811	10,799
2029/30	346	382	605	603	1,447	379	732	188	377	5,299	846	11,084
2030/31	359	402	620	618	1,534	391	744	190	389	5,450	870	11,366
2031/32	374	405	637	636	1,544	404	750	192	403	5,642	901	11,608
2032/33	387	415	654	653	1,549	416	753	192	415	5,783	923	11,903

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 11 zones in the Queensland region. It is based on the Step Change scenario and average (50% PoE) winter weather.

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

Winter	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2014	226	344	355	463	1,200	204	16	51	257	2,975	551	6,642
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
Forecasts												
2024	203	228	375	478	1,088	227	457	191	306	3,350	549	7,666
2025	197	226	365	461	1,069	220	445	183	298	3,350	539	7,703
2026	196	229	371	477	1,078	227	461	184	304	3,479	558	7,869
2027	190	227	359	470	1,089	223	431	175	296	3,408	539	7,995
2028	193	228	363	481	1,136	227	434	175	302	3,496	546	8,139
2029	194	231	363	488	1,139	231	428	174	302	3,517	548	8,223
2030	203	242	375	505	1,157	240	436	176	314	3,661	571	8,397
2031	209	249	384	516	1,268	246	441	179	323	3,777	590	8,580
2032	216	255	390	525	1,331	252	442	180	330	3,888	607	8,798
2033	221	259	394	529	1,326	255	445	179	335	3,975	616	8,960

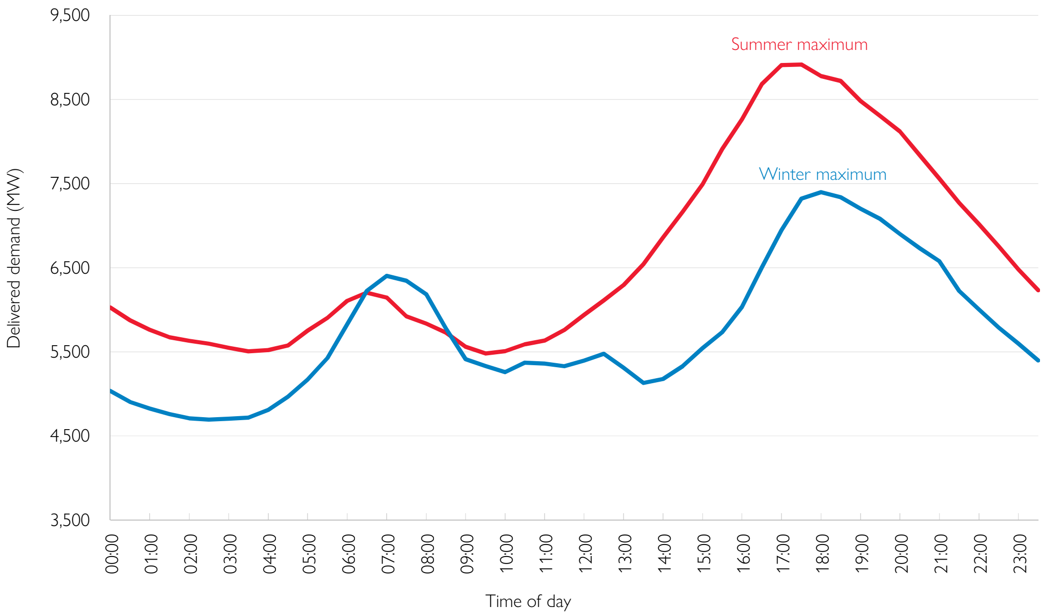
Table 3.23 State winter maximum native demand by zone (MW)

Winter	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2014	226	369	420	509	1,200	204	90	51	286	2,975	551	6,881
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
Forecasts												
2024	226	369	420	509	1,200	204	90	51	286	2,975	551	6,881
2025	192	334	404	518	1,249	203	208	137	288	3,281	597	7,411
2026	216	358	419	504	1,229	200	467	193	310	3,008	550	7,454
2027	218	367	416	415	1,070	220	554	182	276	2,913	526	7,157
2028	242	360	410	494	1,091	235	654	186	336	3,085	540	7,633
2029	230	307	408	483	1,066	241	628	207	346	3,176	532	7,624
2030	227	329	406	492	1,104	247	624	191	342	3,231	515	7,708
2031	206	255	366	459	1,079	232	691	181	357	3,373	559	7,758
2032	230	248	375	458	991	280	634	162	357	3,779	611	8,125
2033	217	223	408	441	1,069	251	697	167	318	3,224	537	7,552

3.6 Summer and winter maximum and annual minimum daily profiles

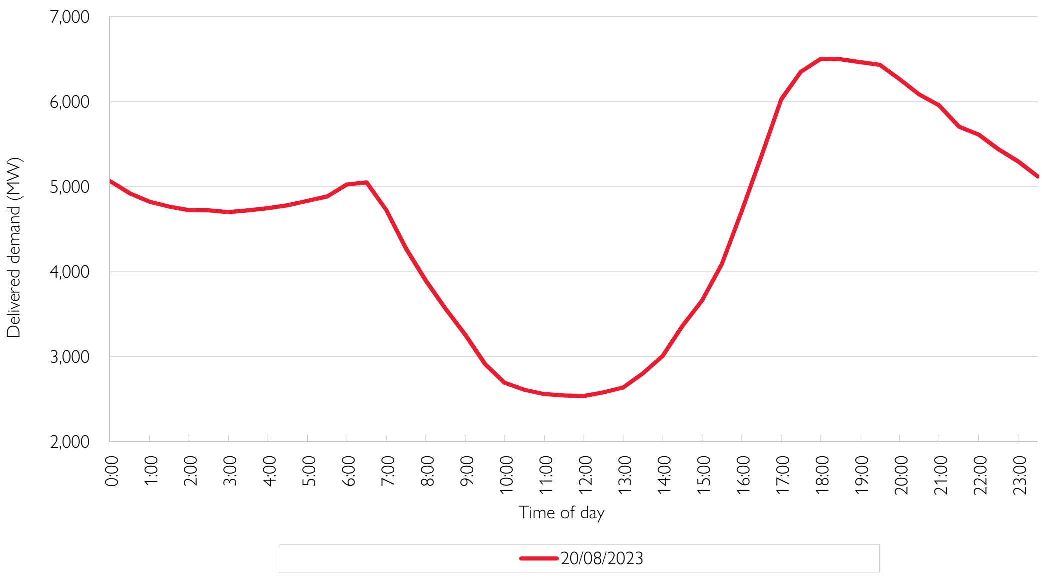
The daily load profiles (transmission delivered) for the Queensland region on the days of summer 2022/23 and winter 2023 maximum demands are shown in Figure 3.14.

Figure 3.14 Daily load profile of summer 2022/23 and winter 2023 maximum transmission delivered demand days



The 2023 annual minimum (transmission delivered) daily load profile for the Queensland region is shown in Figure 3.15.

Figure 3.15 Daily load profile of 2023 minimum transmission delivered day (1)



Note:

(1) Based on preliminary meter data up to 13 September 2023.

3.7 Annual load duration curves

The annual historical load duration curves for the Queensland region transmission delivered demand since 2018/19 is shown in Figure 3.16.

Figure 3.16 Historical transmission delivered load duration curve

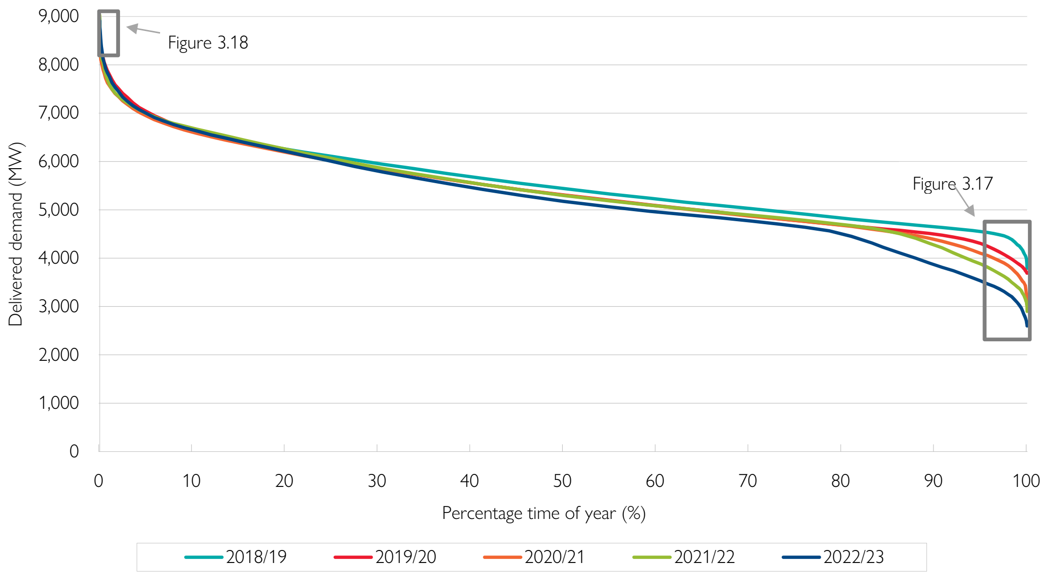


Figure 3.17 Historical transmission delivered load duration curves (95-100%)

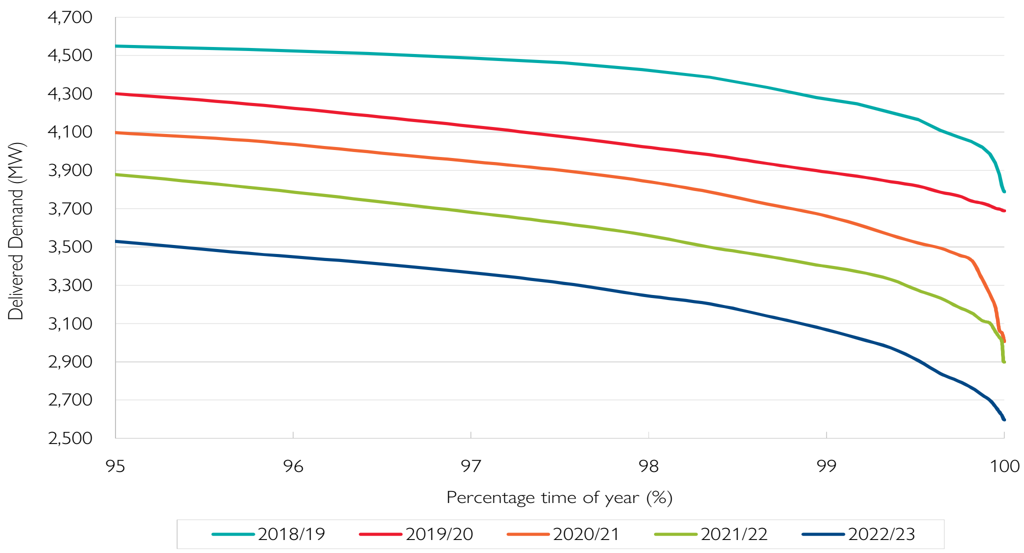
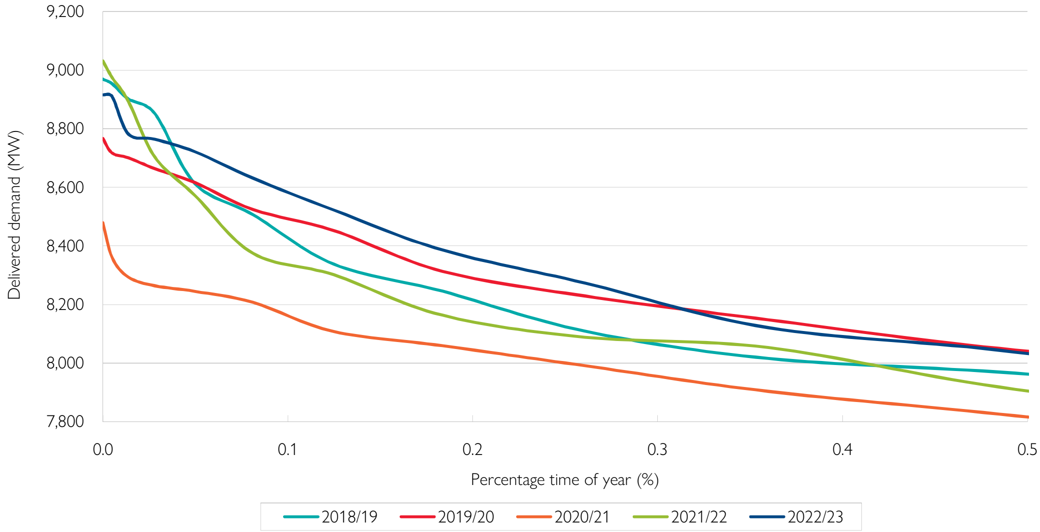


Figure 3.18 Historical transmission delivered load duration curves (0-0.5%)



04

Power system security services 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 development of system security services in Queensland.

Key highlights

- Power 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 providing system security services.
- Significant changes to power system security frameworks have been made in recent years, with further reforms under active consideration by industry and rule makers.
- Powerlink is seeking to deliver system security services for customers in a cost effective manner.

4.1 Introduction

Queensland's electricity system has historically comprised dispatchable generation such as coal-fired generators, gas turbines and hydro-electric plants[1]. These large synchronous generating units have also provided various services to keep the power system secure. The transformation of the power system to VRE generation necessitates changes to the planning of power 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 relates to the stability of the voltage waveform, and is a core electrical quality that must be maintained for the safe transfer of energy from generators to consumers[2]. System strength has traditionally been provided by 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 because the majority to date have used grid-following inverter technology to generate electricity.

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[3].

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)[4] 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
- Powerlink's forecast of the available fault level at each system strength node
- the system strength locational factor and corresponding system strength node for each connection point for which Powerlink is the Network Service Provider.

1 Queensland Government, Queensland SuperGrid Infrastructure Blueprint, September 2022, p. 9.
2 AEMC, Efficient Management of System Strength on the Power System, Final Determination, October 2021, page i.
3 AEMO, 2021 System Security Reports, December 2021, p. 18, AEMO, 2022 Inertia Report, December 2022, p. 8.
4 NER, clause 5.12.2(c)(8)(ii).

4.2 Inertia and system strength frameworks

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)[5]. 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[6].

In June 2018, AEMO published its methodology for determining minimum and secure inertia levels, and at the same time reported that it had not identified any inertia shortfalls across the NEM for 2018[7].

In March 2023, the AEMC initiated a rule change request from the Australian Energy Council (AEC) that proposed an ancillary service spot market for inertia in the NEM to address problems arising from declining system inertia and gaps in the inertia framework. The AEMC identified three options – market-based mechanisms, structured procurement, and maintenance of the existing framework – to address the issues identified by the AEC. Given the complexity of the issue, and the potential to interplay with other critical system service reforms, the AEMC extended the timeframe for a draft determination to February 2024[8].

4.2.2 System strength

In October 2021, the AEMC introduced the Efficient Management of System Strength on the Power System Rule (System Strength Rule)[9]. 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
- established a new framework for the supply, demand and coordination of system strength in the NEM.

The System Strength Rule established Powerlink as the System Strength Service Provider (SSSP) for Queensland[10]. 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. In March 2023, Powerlink published its 2023/24 system strength unit prices (SSUP) for each declared system strength node. The SSUPs for each node are based on long run average costs. The unit prices apply for a five year period and are indexed by the consumer price index in each of the four remaining years.

4.2.3 Security frameworks for the energy transition

In September 2022, the AEMC released a draft determination to establish an Operational Security Mechanism (OSM) to value, procure and schedule security services across the NEM in operational timeframes. The AEMC intended that AEMO would define the security services to be procured and accredit eligible participants, and that the OSM would commence on 1 October 2025. One of the expected advantages of the OSM was that it would address the over-reliance on directions by AEMO to bring generators online, which would otherwise be offline, to provide essential system services. In May 2023, the AEMC announced that it considered the OSM would be too costly and complex to implement.

In August 2023, the AEMC released a directions paper proposing what it described as a simpler solution to managing power system security. The AEMC suggested greater understanding of the engineering and technical capabilities of the power system were needed before complex market changes could be made. The key elements of the AEMC's proposed improvements to existing security frameworks were:

- improving inertia, network support and control ancillary services and non-market ancillary services (NMAS) frameworks to help ensure system security
- introducing a NEM-wide inertia floor, aligning procurement timeframes with the system strength framework, and removing restrictions on the procurement of synthetic inertia
- introducing an NMAS framework for 'transitional services' that would allow AEMO to procure services to meet system security needs to support the energy transition[11].

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5 AEMC, Managing the Rate of Change of Power System Frequency, September 2017.
6 AEMC, Managing the Rate of Change of Power System Frequency, Information Sheet, September 2017, p. 2.
7 AEMO, 2018 Inertia Requirements Methodology, June 2018, p. 3.
8 AEMC, Efficient Provision of Inertia, March 2023.
9 AEMC, Efficient Management of System Strength on the Power System, October 2021.
10 NER, clause 5.20C.3(a).
11 AEMC, Improving Security Frameworks for the Energy Transition, August 2023.

The AEMC considered its approach would allow for the procurement and scheduling of necessary security services, and avoid reliance on AEMO directing generators to be online to provide services. The AEMC's Final Determination is expected to be released in December 2023.

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

In December 2021, AEMO published its 2021 System Security Reports. Based on the Progressive Change scenario, AEMO identified:

- an immediate fault level shortfall at the Gin Gin system strength node of 44 to 65MVA
- an inertia shortfall of between 186 and 5,831 megawatt seconds (MWs) until 31 December 2026[12].

AEMO suggested a range of options could address system strength issues, including inverter tuning, synchronous condensers, network augmentations and contributions from existing market participants. AEMO also indicated that a variety of services would be available to meet the inertia shortfall, including inertia support activities such as fast frequency response.

In May 2022, AEMO updated its inertia assessment for the NEM to reflect the identification of the Step Change scenario as the most likely of the development scenarios for the 2022 Integrated System Plan (ISP). The update removed the previous inertia shortfall due to an improved outlook for available fast frequency control ancillary services (FCAS), but noted a potential future shortfall of 8,384 MWs remained a possibility. The update also reaffirmed the fault level shortfall, of 33 to 90MVA, at the Gin Gin system strength node[13].

Immediately following the fault level shortfall declaration, 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[14]. Powerlink received a number of responses to the EOI, with parties suggesting various combinations of new installations including pumped storage hydroelectric systems, synchronous generators, plant conversions to hybrid facilities, and batteries with grid-forming inverters. AEMO's 2022 System Security Report, released in December 2022, declared a system strength shortfall at the Gin Gin node of up to 64MVA until 1 December 2025, but did not declare shortfalls at Queensland's four other system strength nodes, being Greenbank, Lilyvale, Ross and Western Downs. AEMO also indicated that Powerlink was identifying solutions for the shortfall at Gin Gin, and that it had requested services be made available by March 2023[15]. Powerlink implemented operational measures to manage the shortfall until a longer term measure is delivered. Powerlink expect to publish the response to the shortfall by December 2023.

In March 2023 Powerlink commenced a Regulatory Investment Test for Transmission (RIT-T) to meet its system strength obligations from December 2025. The technical need for the RIT-T is discussed in Section 4.5, and a summary of the Project Specification Consultation Report (PSCR) is in Section 6.8.2.

4.4 System strength modelling

Although the declared shortfall 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 analysis.

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 allows Powerlink to quickly process generator connections and is a comprehensive model with inverter-based plant modelled at the controller level and simulation time steps in micro-seconds.

12 AEMO, 2021 System Security Reports, December 2021, pp. 42, 46.
13 AEMO, Update to 2021 System Security Reports, May 2022, pp. 7, 8, 23, 27.
14 Powerlink, Power System Security Consultations.
15 AEMO, 2022 System Strength Report, December 2022, p. 41.

Powerlink undertakes a Full Impact Assessment (FIA) or stability assessment using the system-wide 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 Methodology, assumptions and results for the fault level and stability requirements for system strength nodes

In December 2022, AEMO published the assessment of system strength requirements in the NEM for the next 10 years to be used by SSSPs for the purposes of meeting system strength standard specification under clause S5.1.14 of the NER. This includes the minimum fault level requirement at each system strength node and requirement for stable voltage waveforms with AEMO's forecast level and type of inverter-based resources (IBR) and market network service facilities (efficient level of system strength).

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 the system strength nodes, minimum fault level requirements and IBR forecasts to 2025/26 in Queensland.

Table 4.1 AEMO minimum fault level requirements and IBR forecasts, December 2022

Fault Level Node	Pre-contingent Minimum Fault Level (MVA)	Post-contingent Minimum Fault Level (MVA)	IBR Forecast to 2025/26 (MW)
Gin Gin (275kV)	2,800	2,250	1,438
Greenbank (275kV)	4,350	3,750	0
Lilyvale (275kV)	1,400	1,150	735
Ross (275kV)	1,350	1,175	1,204
Western Downs (275kV)	4,000	2,550	4,420
Total			**7,797**

Note:

(1) Forecast includes 3,747 MW of existing IBR.

Source: AEMO, 2022 System Strength Report, December 2022, pages 37 and 40.

The three phase fault level requirements at each node in Queensland in 2025/26 (the relevant year) is unchanged. At the time of 2023 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 (Section 6.8.2). It is expected that non-network solutions will materially contribute to the provision of system strength services through a range of technology solutions. To meet the minimum system strength requirements identified by AEMO the PSCR indicated the following investment would be necessary:

- 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 2022, is approximately 12.5GW by 2030 and approximately 17.5GW by 2033. Powerlink mapped its market intelligence of connection applications and enquiries against the forecast provided by AEMO. The forecast capacity for 2025 and a significant part of 2030 in each system strength node was mapped against the current applications, providing confidence in the forecast size and location of the generation plants. Existing experience in Queensland indicates that assumptions of system strength requirements based primarily on the fault level calculations can differ from the detailed assessment and therefore can be misleading. Powerlink performed detailed EMT studies to understand the required system strength support, in addition to the minimum level, to host the total 12.5GW of VRE generation.

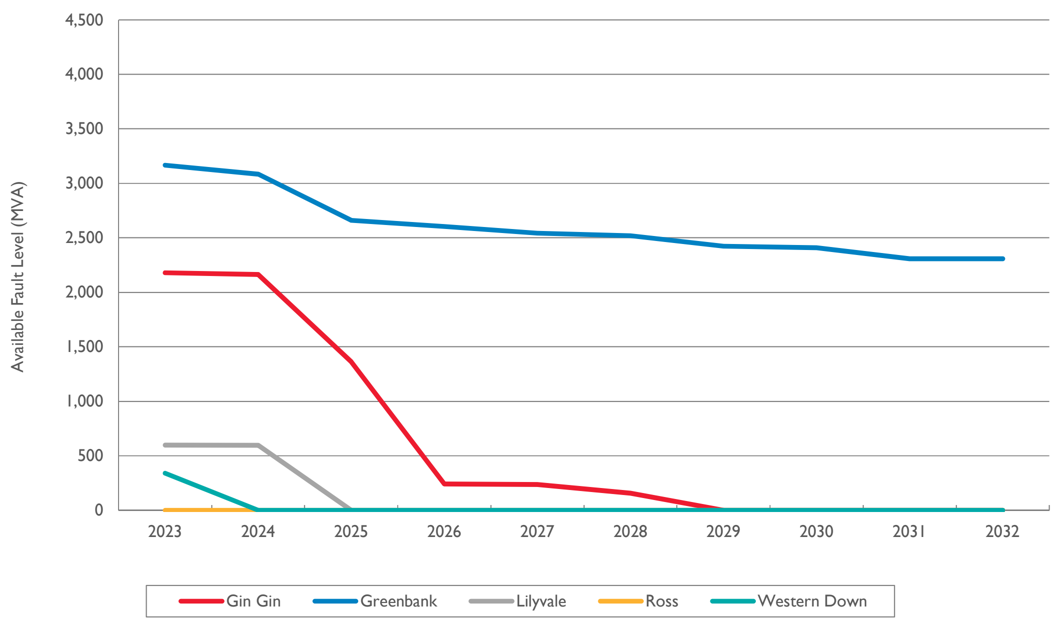
Results from studies indicated that additional system strength support equivalent of four 200MVA synchronous condensers would be required to maintain the stable voltage waveform with 12.5GW of VRE. Studies also confirmed that grid-forming BESS could provide the necessary system strength support to obtain the stable voltage waveform. Experience and studies for stable voltage waveform requirements indicate that required system strength is a function of the inverters connected and also the MW generated by the VRE.

The 2030 VRE forecast consists of more than 80% of wind farms and less than 20% of solar farms. Therefore, system strength requirements for day time and night time were assessed separately. Studies indicated night time system strength requirements were also sufficient during day time.

4.6 Available fault level at each system strength node

Figure 4.1 shows the Available Fault Level (AFL) at each system strength node.

Figure 4.1 Available Fault Level (AFL)



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[16], 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 SSUP at Western Downs is the lowest in Queensland.

16 NER, clause 5.20C.3(f)(3).

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[17]. System strength locational factors and nodes are included in Appendix H and shown in the TAPR portal.

[17] NER, clause 5.12.2(c)(13)..

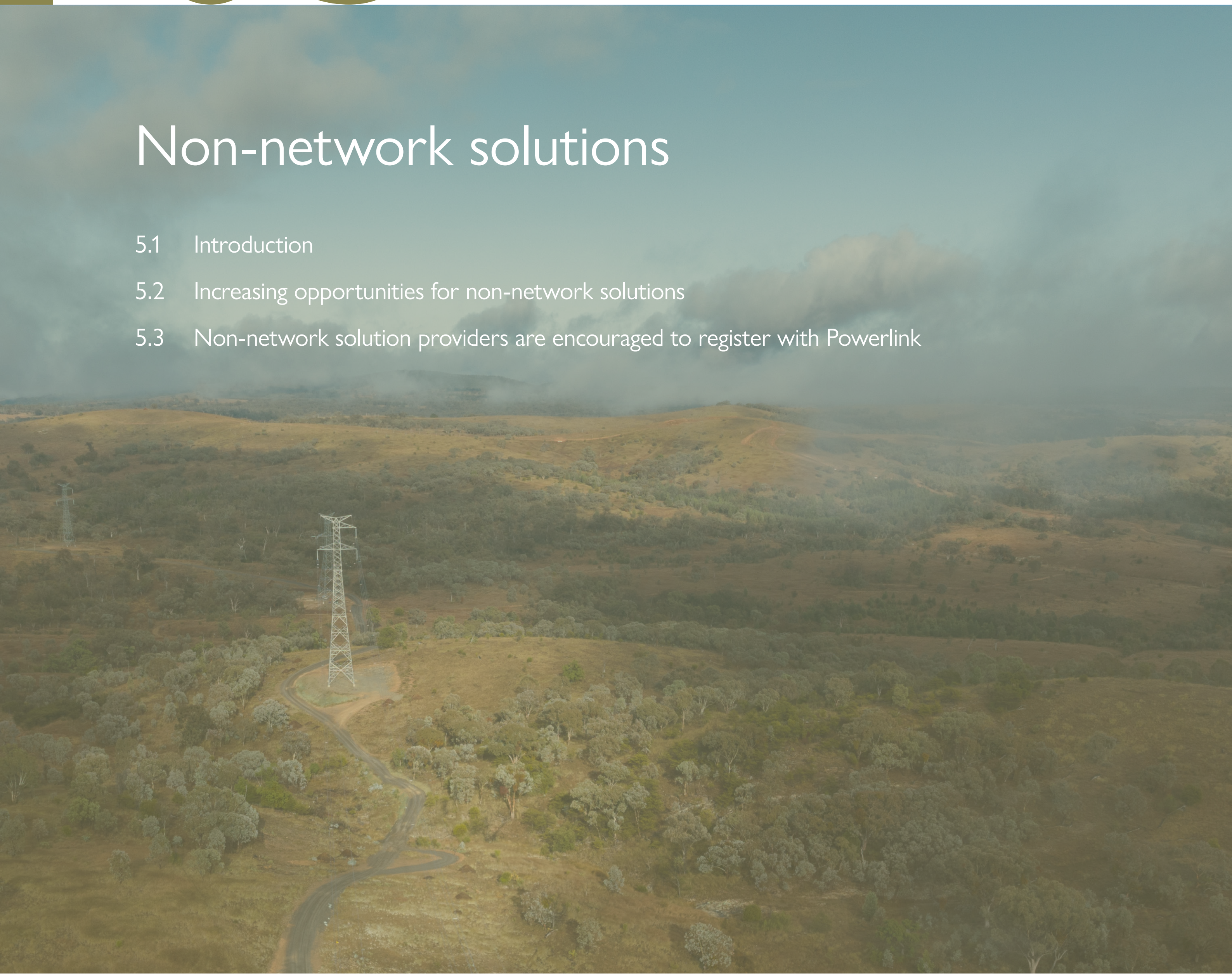
05

Non-network solutions

5.1 Introduction

5.2 Increasing opportunities for non-network solutions

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



The use of cost effective 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.
- Opportunities may become available in the future to assist 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, in early 2023, Powerlink entered into a Network Support Agreement with CleanCo Queensland (CleanCo) to assist in a short-term solution to address an NSCAS gap in Southern Queensland until such time as the longer term solution could be assessed and implemented under the Managing voltages in South East Queensland RIT-T. In September 2023 Powerlink published a Project Assessment Conclusions Report which identified the preferred option to address the identified need for reactive power absorption capability in the SEQ. This option involves the installation of a 120MVAr reactor at Belmont Substation by December 2024, and network support services from CleanCo to operate during times of reactive power absorption shortfall, while further reactive support from BESS connections and other non-network developments emerge (refer to Table 6.2 and Section 6.8.1).

Powerlink also anticipates that non-network solutions will materially contribute to meet both the forecast minimum and efficient system strength requirements in Queensland from December 2025 (refer to 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 power system. Generating stations will be required to ramp up and down in response to daily demand variations more frequently. Decreasing minimum demand may also lower the amount of synchronous generation that is on-line and this could further impact on voltage control, system strength, inertia and the ability for available generators to meet evening peak demand.

There may also be future opportunities for new technologies, including flexible loads, offering non-network solutions to assist with managing daily peaks and troughs. 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 6.9.11.

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
- 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.

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 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
Transmission lines					
Woree to Kamerunga 132kV transmission line replacement	$70m	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
Line refit works on the 275kV transmission lines between Ross and Chalumbin	$37m	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
Rebuild the 275kV transmission line between Calliope River and Larcom Creek Substation	$107m	Gladstone	Up to 160MW at peak and up to 3,200MWh per day on a continuous basis to provide supply to the 66kV and 132kV loads at Yarwun and Raglan	June 2029	Section 6.10.2
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 2026	Section 6.10.2
Rebuild of two of the three transmission lines between Calliope River and Wurdong tee as a double circuit by December 2028 Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Substation by June 2029 Targeted refit of the three single circuit transmission lines between Calliope River (Wurdong Tee) and Gin Gin substations by June 2029 Line refit works on the 275kV transmission line between Woolooga and South Pine substations by June 2029	$40m $14m $75m $16m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region.	December 2028 to June 2029	Section 6.11.1

Table 5.1 Potential non-network solution opportunities within the next five year (*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	$18m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2028	Section 6.11.4 Anticipated RIT-T
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	$30-53m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the southern Gold Coast and northern NSW area	December 2028	Section 6.11.5
Substations - primary plant and secondary systems					
Kamerunga 132kV Substation replacement	$75m	Far North	Provide supply to the 22kV network of up to a peak 60MW, and up to a peak 900MWh per day on a continuous basis would allow for the decommissioning of the Kamerunga Substation and bridging of the Woree to Kamerunga Feeders to the Kamerunga to Barron Gorge Feeders.	December 2028	Section 6.9.1
Ingham South 132kV primary plant and secondary systems replacement	$10m	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 Anticipated RIT-T
Strathmore SVC secondary systems replacement	$8m	North	Up to 260MVArs capacitive and 80MVArs inductive support at Strathmore	June 2026	Section 6.9.3 Anticipated RIT-T
Alligator Creek 132kV primary plant replacement	$7m	North	Up to a peak of 80MW and 1,400MWh per day on a continuous basis	June 2025	Section 6.9.3
Alligator Creek SVC secondary systems replacement	$7m	North	Potential non-network solutions would need to provide voltage imbalance support for the 132kV network	June 2028	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 2028	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	December 2027	Section 6.10.1

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

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Callemondah Substation primary plant and secondary systems replacement	$10m	Gladstone	Up to 180MW at peak and up to 2,500MWh per day on a continuous basis to provide supply to the 132kV network at Gladstone South and/or Aurizon load at Callemondah	June 2025	Section 6.10.2 Anticipated RIT-T
Mudgeeraba 110kV primary plant and secondary systems replacement	$33m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	June 2029	Section 6.11.5
Substations - transformers					
Nebo 132/11kV transformers replacement	$11.5m	North	Proposals would need to provide injection or demand response at Nebo Substation of up to 3MW during peak demand and up to 50MWh per day	December 2025	Section 6.9.3 Current RIT-T
Kemmis 132/66kV transformer replacement	$7m	North	Provide injection or demand response at Kemmis of up to 60MW during peak demand and up to 650MWh per day	December 2026	Section 6.9.3 Current RIT-T
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 Current RIT-T

Note:

(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).

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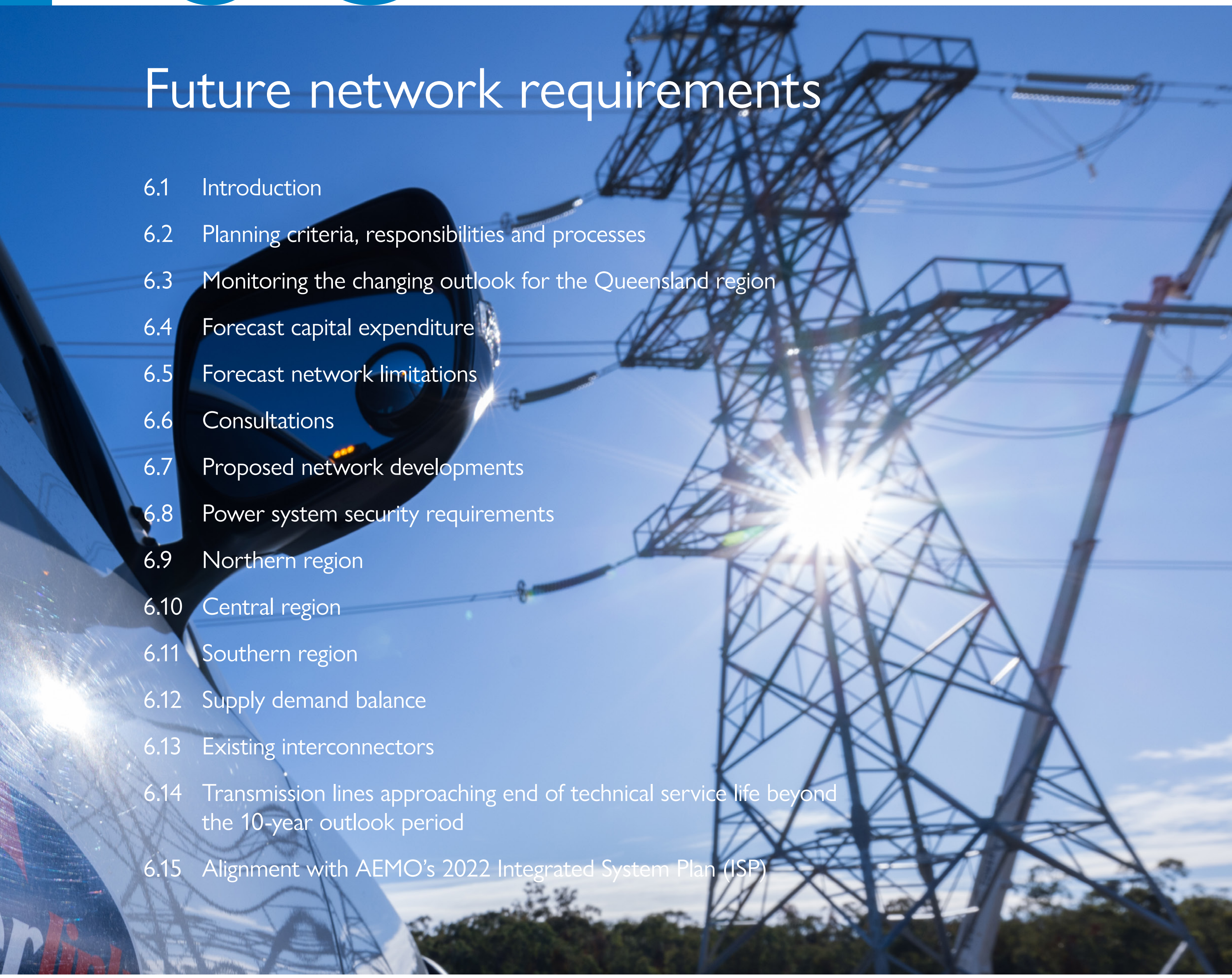


Future network requirements

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) and the most recent connection point proposals anticipated to require connection to the transmission network. This chapter also discusses major projects referenced in the 2022 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.
- To deliver positive outcomes for customers, 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 to deliver positive benefits to customers
    - actively seeking opportunities to identify and implement more cost effective solutions as demonstrated by Powerlink's Asset Reinvestment Review (ARR), and whenever possible, make 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 findings of the most recent Integrated System Plan (ISP) and the Queensland Energy and Jobs Plan (QEJP).
- Powerlink has undertaken the necessary preparatory activities that will inform the analysis for the draft 2024 ISP which will be published by the Australian Market Energy Operator (AEMO) in December 2023.

6.1 Introduction

Powerlink Queensland (Powerlink) as a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and as the appointed Jurisdictional Planning Body (JPB) by the Queensland Government is responsible for transmission network planning for the transmission system 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.

The NER (Clause 5.12.2(c)(3)) requires the TAPR to provide a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over one, three and five years. In addition, there is a requirement (Clause 5.12.2(c)(4)) 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 NER (Clause 5.12.2(c)) also requires the TAPR to be consistent with the TAPR Guidelines and include information pertinent to all proposed:

- augmentations to the network (Clause 5.12.2(c)(5))
- replacements of network assets (Clause 5.12.2(c)(5))
- network asset retirements or asset de-ratings that would result in a network constraint in the 10-year outlook period (Clause 5.12.2(c)(1A))
- inertia and system strength requirements (Clauses 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[1] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months (Clause 5.12.2(c)(4)(iii))
- 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 (Clause 5.12.2(c)(4)(iv))
- a summary of network limitations over the next five years (Clause 5.12.2.(c)(3))
- details in relation to the need to address the risks arising from ageing network assets remaining in-service and those limitations for which Powerlink intends to address or initiate consultation with market participants and interested parties
- the manner in which proposed augmentations and the replacement of network assets relate to AEMO's most recent ISP (Clause 5.12.2.(c)(6)) and 2022 System Strength, Inertia and NSCAS Reports
- a table summarising possible connection point proposals.

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.

Energex and Ergon Energy (part of the Energy Queensland Group) were issued amended Distribution Authorities from July 2014. The service levels defined in their respective Distribution Authority 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.

[1] 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.

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'[2].

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 down in clauses 5.14.1, 5.16.4, 5.16A, 5.20B, 5.20C and 5.22.14 of the NER. Planning processes require consultation with AEMO, Registered Participants and interested parties, including customers, generators, Distribution Network Service Providers (DNSP) and other 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 frequent NER consultation process undertaken by Powerlink and is discussed further in Section 6.6. Powerlink continues to publish information and consult with potential providers of non-network solutions for the provision of network support control and ancillary services (NSCAS)[3] and system strength shortfalls and inertia gaps 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.

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 and committed generation in Queensland is sourced from AEMO, unless modified following advice from relevant 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 Renewable Energy Zones (REZ)
- 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.

[2] Refer to Section 34(2) of the Act.
[3] NER Clause 5.20.3(b).

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 Clause 5.14.1 of the NER. 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 ongoing 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 are made taking into account enduring need, the role that transmission needs to play in the energy transformation and the inter-related connectivity and characteristics of the high voltage (HV) system, and 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. Each of these options is considered in the context of future capacity.

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. More broadly, this provides information to the NEM, including AEMO, Registered Participants and interested parties (including non-network providers) on Powerlink's planning processes, anticipated public consultations, and decision making relating to potential future investments and reinvestments.

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.

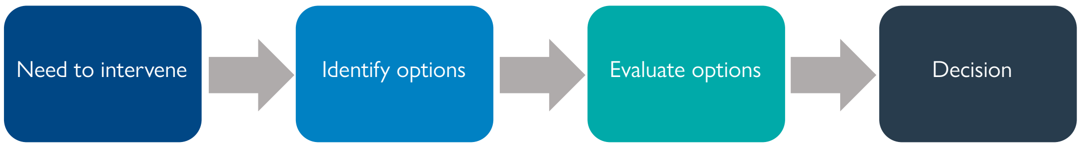
The reinvestment criteria framework

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[4]. The review considered Powerlink's risk cost modelling approach, the impact of risk on economic decisions, and the role of deterministic criteria in an economic assessment framework. The review focussed on transmission line reinvestments and provided an opportunity to identify improvements which will ultimately benefit customers as the complexities and challenges of maintaining the network continue to grow. While the focus of the review was to further improve Powerlink's approach to asset management practices for transmission line reinvestment, where appropriate Powerlink is applying improvements identified to other areas of asset reinvestment planning to ensure positive outcomes for customers.

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.

Powerlink has committed to report back to the Customer Panel on progress made in embedding the recommendations from this review into business processes, and any observed outcomes arising, one year after finalisation of the review.

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 sections 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).

[4] 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 longterm benefits as the energy system evolves, particularly in developing new transmission infrastructure in key parts of the state.

While not included in the 2023 TAPR analysis, this work is well underway and insights are provided in Powerlink's 'Actioning the Queensland Energy and Jobs Plan'.

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 to be complex. The Reserve Bank of Australia (RBA) recently reported that global inflation had remained high in 2023, despite appearing to have peaked in 2022. The RBA also noted that inflationary pressures are expected to persist for some time, particularly for services, due to labour market tightness, demand exceeding supply in some parts of the economy and rising energy costs[5].

Infrastructure Australia's Market Capacity Report (December 2022) highlighted a number of factors that are challenging infrastructure capacity in Australia, including:

- supply chain disruption caused by COVID-19, volatile demand and geopolitical impacts
- a sharp rise in construction insolvencies leaving fewer companies to deliver work
- the continued rise in complex mega-projects
- severe labour shortages[6].

While recognising these complexities, Powerlink is focussed on identifying supply risks and delivering solutions to ensure customers continue to receive cost effective and efficient services in this uncertain environment.

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.

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, the maximum demand for electricity is expected to have mild growth with an average annual increase of 1.8% 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 ISP and QEJP.

[5] Reserve Bank of Australia, Statement on Monetary Policy, August 2023.
[6] Infrastructure Australia, Infrastructure Market Capacity: 2022 Report, December 2022.

In Powerlink's Revenue Determination 2023-27[7], 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 network 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[8]. Table 6.2 summarises limitations identified in Powerlink's transmission network and noted in AEMO's December 2022 System Strength, Inertia and NSCAS Reports.

Table 6.2 Limitations in the five-year outlook period

			Time limitation may be reached			
Limitation	Zone	Reason for anticipated limitation	1-year outlook (2023/24)	3-year outlook (up to 2026/27)	5-year outlook (up to 2028/29)	Reference
System strength shortfall at Gin Gin	Central West	AEMO declared system strength shortfall December 2021	From 31 March 2023 (1)			Section 6.8.1
Reactive power absorption gap in southern Queensland	Moreton	AEMO declared gap December 2021	Immediate gap (2)			Section 6.8.1
Managing voltages in Queensland	Central West		2020/21 project in progress (3)			Table 9.3
	Moreton		2022/23 (1)(2)			Table 9.6

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 which is currently in progress to address the declared System Strength and NSCAS requirements and discussed Section 6.8.1.

(2) The short-term solution for the reactive power requirement to meet the immediate gap in southern Queensland has been assessed through the Request for System Security Services in central, southern and the broader Queensland EOI process. The immediate gap is being addressed via a Network Support Agreement with CleanCo Queensland (CleanCo) to utilise its asset in southern Queensland and in the rare event this is insufficient, the use of a range of operational measures. The longer term solution has been assessed as part of the RIT-T to manage voltages in south east Queensland which identified the installation of a 120MVAr reactor at Belmont Substation by 2024, and network support services from CleanCo to operate during times of reactive power shortfall as the preferred option.

(3) The network risk associated with this limitation is currently being managed through a range of short-term operational measures until such time as the preferred option identified in the RIT-T, installation of a 275kV bus reactor at Broadsound Substation, is commissioned in October 2024.

Based on AEMO's Step Change scenario forecast discussed in Chapter 3 there are no other network limitations forecast to occur in Queensland in the next five years[9].

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 2022 TAPR which fall into this category in 2023.

[7] Information on Powerlink's Revenue Proposal for the regulatory period is available on Powerlink's website.
[8] Refer to NER Clause 5.12.2(c)(3).
[9] Refer to NER Clause 5.12.2(c)(3).

Based on AEMO's Step Change scenario forecast there is approximately 250MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of existing customer's 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:

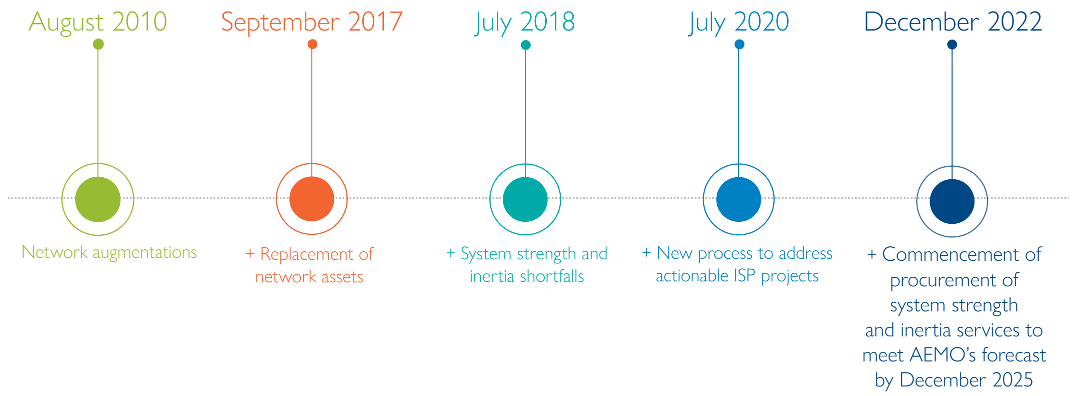
- RIT-Ts
- Expressions of Interest (EOIs) and
- Funded augmentations.

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

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 of the NER.

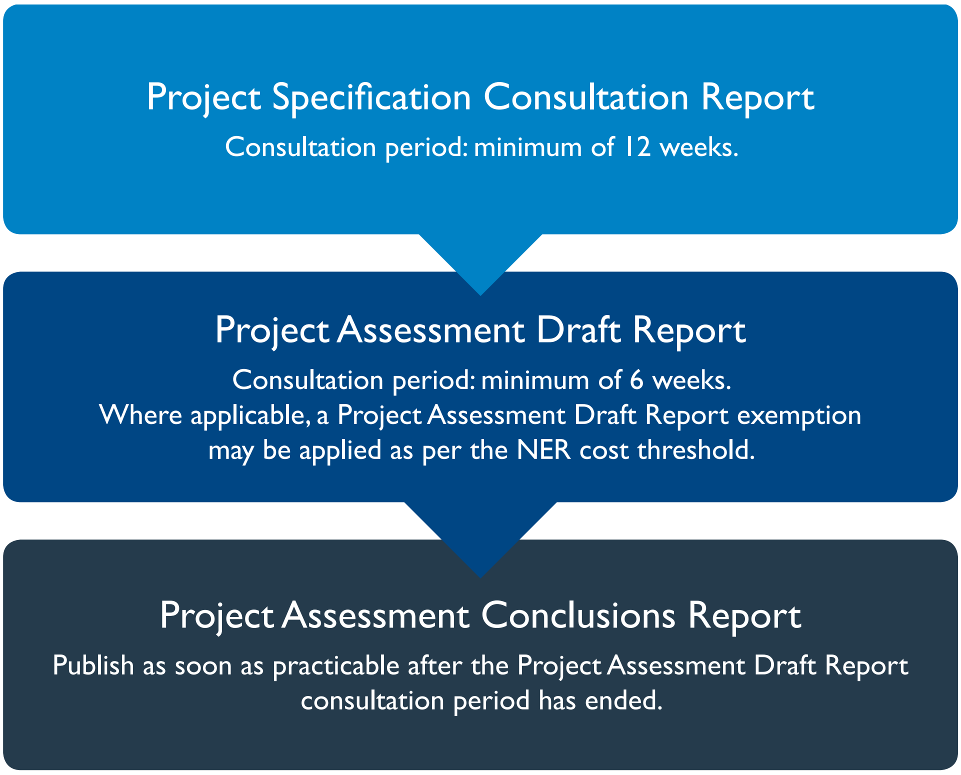
Figure 6.2 Chronological development and expansion of the RIT-T process for proposed transmission network investments



6.6.2 Current consultations – proposed transmission investments

Powerlink carries out separate consultation processes for each proposed new transmission investment 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 2022 TAPR are listed in Table 6.3 (refer to Table 9.6).

Table 6.3 RIT-T consultations completed since publication of the 2022 TAPR

Consultation
Addressing the secondary systems condition risks at Tangkam
Maintaining power transfer capability and reliability of supply at Redbank Plains
Managing voltages in South East Queensland

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 power transfer capability and reliability of supply at Kemmis	Section 6.9.3
Addressing the reliability of supply to Nebo local area	Section 6.9.3

Note:

(1) The consultations reflect the RIT-T status as at 30 September 2023.

Funded augmentation consultations completed since publication of the 2022 TAPR are listed in Table 6.5.

Table 6.5 Funded augmentation consultations completed since publication of the 2022 TAPR

Consultation	Reference
Augmenting the transmission network to enable renewable hydrogen production at Gibson Island	Gibson Island Project

Expressions of Interest currently underway since publication of the 2022 TAPR are listed in Table 6.6.

Table 6.6 Expressions of Interest currently underway since publication of the 2022 TAPR[10]

Consultation	Reference
Request for power system security services in central, southern and the broader Queensland region	Section 6.8.1

6.6.2 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 6.7 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 6.7 Anticipated consultations in the forthcoming 12 months (to October 2024)

Consultation (1)	Reference
Maintaining reliability of supply at Kamerunga	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 6.10.1
Maintaining reliability of supply at Callemondah	Section 6.10.1
Maintaining reliability of supply at Ashgrove	Section 6.11.5

Note:

(1) The anticipated consultations listed in Table 6.7 reflect the RIT-T status as at 30 September 2023.

Future ISP projects

The 2022 ISP did not identify any 'actionable' projects within Queensland. However, the 2022 ISP did identify several projects that are part of the optimal development path and may become actionable in future ISPs. Further to the three preparatory activities reports previously provided to AEMO[11], two additional projects were nominated for preparatory activities by 30 June 2023. These include:

- Darling Downs REZ Expansion
- QNI Connect (500kV option).

Preparatory activity reports for these projects were provided to AEMO by 30 June 2023 and are discussed further in Section 6.15. The commencement for consultation for these projects will be triggered by future ISPs and considered in conjunction with the QEJP[12].

6.6.3 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[13] or be initiated by generators or customers.

10 Power System Security Consultations.
11 Preparatory Activities reports for Central to Southern Queensland, Gladstone Grid Reinforcement and QNI connect were provided to AEMO by 30 June 2021.
12 Refer to Section 5.16A.3.
13 In Queensland, Energex and Ergon Energy (part of the Energy Queensland Group) and Essential Energy are the DNSPs.

Table 6.8 lists connection works that are anticipated to be required within the 10-year outlook period.

Table 6.8 Connection point commitments (1)

Connection point name (2)	Proposal	Zone
Chinchilla Battery energy storage system (BESS) (3)	New BESS	Bulli
Western Downs BESS	New BESS	Bulli
Greenbank BESS	New BESS	Moreton

Notes:

(1) AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines Version 2.1 (effective 6 June 2023) has been adopted for connection point proposals identified in the TAPR.

(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).

It should be noted that while not fully at the stage where the project can be classified as committed under the NER at the time of publication of the 2023 TAPR, Powerlink has signed an agreement for the construction of assets for the connection of the MacIntyre Wind Precinct proposed renewable development to the transmission network in south-west Queensland. More information on this project is available on Powerlink's website.

Table 6.9 summarises connection point activities[14] undertaken by Powerlink since publication of the 2022 TAPR (refer also to figures 6.4 and 6.5). 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 6.9 Connection point activities

Generator Location	Number of Applications	Number of Connection Agreements	Generator Type and Technology
North	4		Load, Wind Farm, Solar Farm and BESS
Central	8		Load, Wind Farm, Solar Farm and BESS
South	12	2	Load, Wind Farm, Solar Farm and BESS
Total	24	2	

[14] 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 2022 TAPR

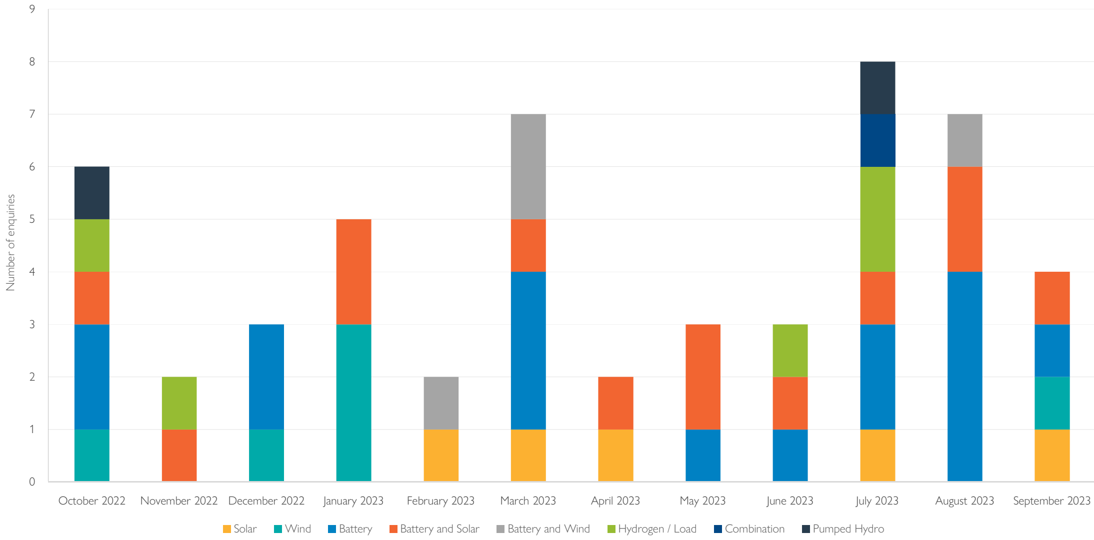
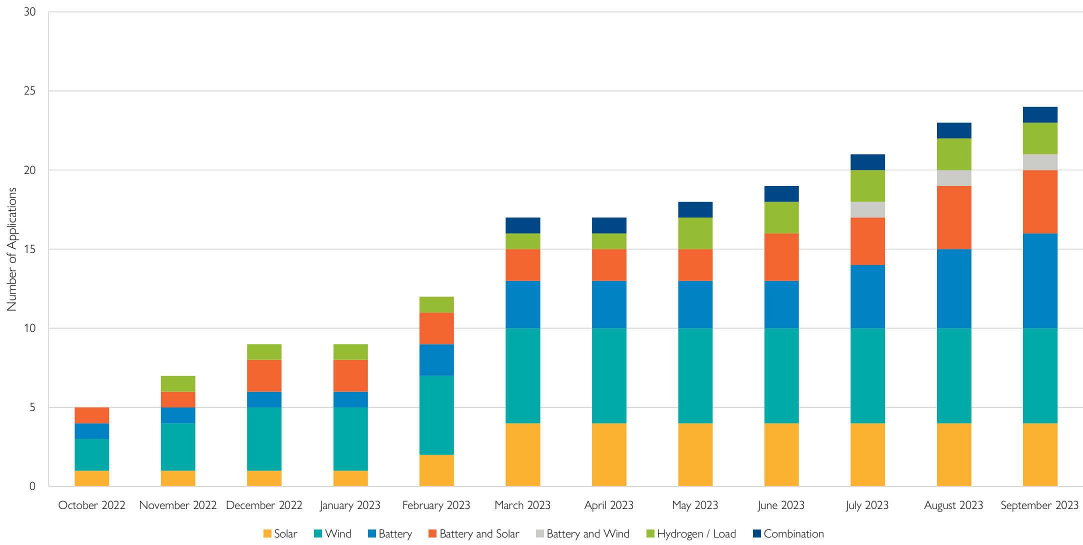


Figure 6.5 Cumulative customer applications per month since publication of the 2022 TAPR



6.7 Proposed network developments

Powerlink's 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. Proposed future network developments discussed in this chapter do not include the investments in new transmission that is needed under the energy transformation as discussed in the Queensland Energy and Jobs Plan (QEJP) and set out in the Queensland SuperGrid Infrastructure Blueprint (Infrastructure Blueprint) released by the Queensland Government in September 2022.

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.

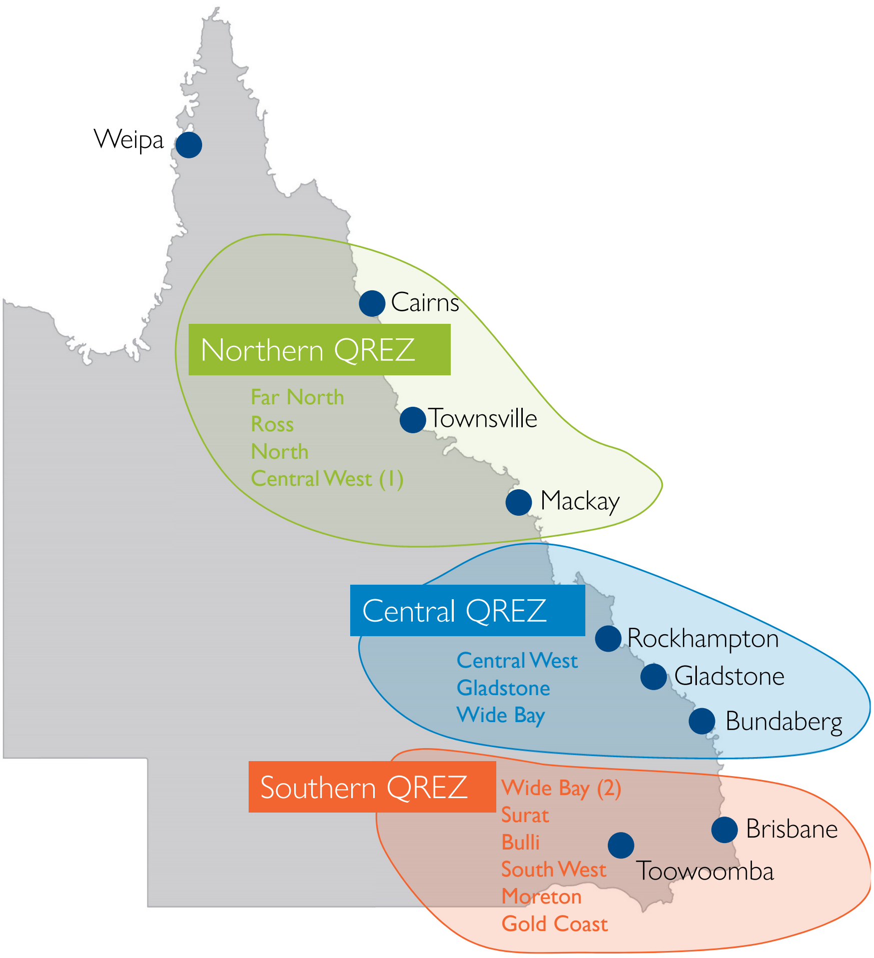
The indicative cost of potential projects identified in this chapter is updated each year to keep pace with external project cost increases that are being experienced broadly across many industries (refer to Section 6.4). Where there may be other factors materially influencing the updated indicative 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 2022 System Security and Inertia Reports (refer to Section 6.8), and based on the current information available, the possible network developments discussed in this chapter are outside of the scope of the AEMO's most recent ISP and General Power System Risk Review[15]. 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 2023 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 resource regions in Queensland, as shown in Figure 6.6.

Figure 6.6 Queensland's renewable energy resource regions



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

15 AEMO, General Power System Risk Review, July 2023. In its 2023 review, AEMO recommended Powerlink and Transgrid investigate, design and implement a Special Protection Scheme to mitigate the risk of Queensland to New South Wales Interconnector instability and synchronous separation of Queensland following a range of non-credible contingencies.

6.7.2 Investment context, timeframes and description

Against the backdrop of a rapidly changing external environment, 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 topography, 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).

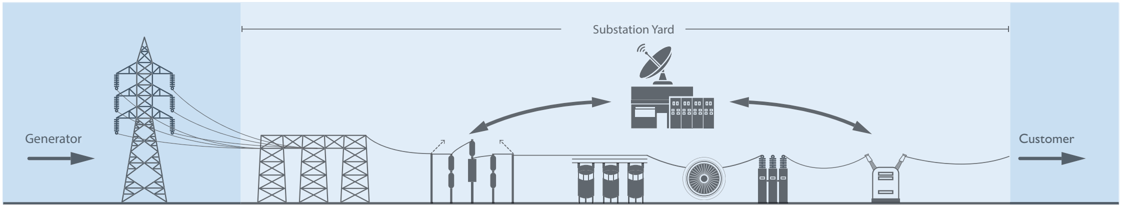
Information in relation to potential projects, alternatives and possible commissioning needs is revised annually based on the latest information available at the time of publication. Refer to Appendix D for the complete list of proposed network investments within the 10-year outlook period. Significant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

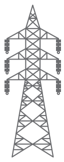
Possible network investments needs (which includes reinvestment, augmentations and/or the procurement of power system security services) likely to require RIT-T consultation within the five-year outlook period, from July 2023 to June 2029 are discussed in this Chapter.

Powerlink also 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 2022 TAPR and 2023 TAPR and TAPR Templates.

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

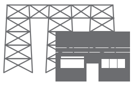
Figure 6.7 The functions of major transmission assets





Transmission line

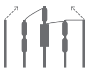
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



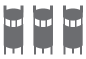
Substation

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.

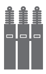


- Substation bay
  A substation bay connects and disconnects network assets during faults and also allows maintenance and repairs to occur. A typical substation bay is made up of a circuit breaker (opened to disconnect a network element), isolators and earth switches (to ensure that maintenance and repairs 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.

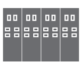
- Synchronous condenser
  A synchronous condenser is a large rotating machine connected to the transmission network with no driving force (spins freely). It is similar to a synchronous generator but does not produce energy. It helps the power system with voltage control, system strength, and inertia.



- 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.

- Bus reactor
  A bus reactor is used to control voltages on the high voltage system. Bus reactors are used especially during light load conditions to manage 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

In May 2022 Powerlink published an EOI to Request for Power System Security Services in central, southern and broader Queensland regions. The EOI requested submissions from potential solution providers to ascertain and evaluate non-network and network options to meet the power system security requirements identified in the AEMO's System Security Reports published in December 2021 and May 2022 respectively[16].

The EOI requested potential non-network solutions to address AEMO's declared shortfalls of:

- an immediate system strength shortfall of up to 90MVA at the Gin Gin 275kV fault level node, located in the Wide Bay zone, to be addressed from 31 March 2023
- an NSCAS gap of 120MVAr of reactive power absorption, more specifically a Reliability and Security Ancillary Service (RSAS) gap, in southern Queensland to be addressed immediately and rising to 250MVAr by 2026.

Submissions to the EOI closed in June 2022.

Powerlink has concluded the engagement activities and assessment in relation to the immediate NSCAS gap, and published the findings in the Final Report - Part 1 in December 2022. Since publication of the report, Powerlink has entered into a Network Support Agreement with CleanCo Queensland to address the immediate gap. Longer term NSCAS requirements have been considered in conjunction with the Managing voltages in South East Queensland RIT-T which recommended installation of a 120MVAr bus reactor at Belmont Substation in 2024 and network support services from CleanCo Queensland to operate during times of reactive power shortfall as the preferred option for implementation (refer to Powerlink's website).

Powerlink expects to publish the Final Report - Part 2 focussing on the outcome of the assessment to fill the system strength shortfall at the Gin Gin fault level node in late 2023. The findings of the EOI process will also be discussed in the 2024 TAPR.

6.8.2 Addressing system strength requirements in Queensland from December 2025

In October 2021, the Australian Energy Market Commission (AEMC) introduced the Efficient Management of System Strength on the Power System Rule (System Strength Rule)[17]. The System Strength Rule established a new framework for the supply and demand of system strength in the 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[18].

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[19]. 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), Addressing System Strength Requirements in Queensland from December 2025. 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.

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16 AEMO, System Security Planning.
17 AEMC, Efficient Management of System Strength on the Power System, October 2021.
18 Refer to Schedule 5.1.14 of the NER.
19 AEMO, 2022 System Strength Report, December 2022.

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 (but potentially as early as 2025) and four by 2033 (but potentially as early as 2030).

Given the need to meet minimum requirements from December 2025, the challenging external environment, and potential network project delivery delays in the immediate term, Powerlink did not consider there was a credible network option to install a synchronous condenser by 2025.

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[20] 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 Powerlink is progressing the technical and economic analysis for the optimal portfolio of solutions anticipated to be required. Powerlink expects publication of the Project Assessment Draft Report (PADR) in the second quarter of 2024 which will identify the proposed preferred option to provide minimum and efficient levels of system strength.

6.9 Northern region

The Northern region includes proposed network investments located within the Far North, Ross and North zones and broadly aligns with the Northern renewable energy resource region stretching between Mackay and Cairns, encompassing the northern most extent of Powerlink's transmission network (refer to Figure 6.6). The Northern region also includes a number of candidate REZ areas in north Queensland identified in the 2022 ISP optimal development pathway (refer to Figure 7.2).

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 and Woree, and a coastal 132kV network from Yabulu South to Tully 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).

20 Refer to NER rule 5.21.

Figure 6.8 Far North zone transmission network

Possible load driven limitations

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Far North zone within the next five years to meet reliability obligations.

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.

Transmission lines

Woree to Kamerunga 132kV transmission lines

Potential consultation	Maintaining reliability of supply to Cairns northern beaches area
Asset details	Constructed in 1963 Life extension in 2014 on certain components nearing end of technical service life
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2028
Proposed network solution	Maintaining 132kV network topology by replacing the existing double circuit transmission line with a new double circuit transmission line on a new easement from Woree to Kamerunga substations at an estimated cost of $70 million[21]
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

[21] This excludes easement costs yet to be determined.

The Woree to Kamerunga 132kV double circuit transmission lines, originally connected to Cairns, provide critical supply to the Cairns northern beaches region, as well as connecting the Barron Gorge Hydro Power Station to the 275kV network. A significant proportion of the transmission line traverses built-up residential, encroached development and there are a number of major and minor road crossings causing access and construction work challenges. Replacement on a new easement is a possible end of technical service life strategy and investigations for easement alternatives are currently underway.

Possible network solutions may include

- Maintaining the existing 132kV network topography by replacing the existing double circuit transmission line with a new double circuit transmission line from Woree and Kamerunga substations by December 2028
- Network reconfiguration by establishing two single circuit 132kV transmission lines between Woree and Kamerunga substations, or via Cairns North Substation, by December 2028.

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

Ross to Chalumbin to Woree 275kV transmission lines

Potential consultation	Maintaining reliability of supply in the Cairns region Stage 2 - 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 and Chalumbin substations, at an estimated cost of $37 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.

The bulk supply of electricity to the Cairns region in Far North Queensland is provided by generators in Central and Northern Queensland, via a 132kV coastal network and a 275kV inland network, as well as a 'run of the river' hydro power station north of Cairns at Barron Gorge, which is connected to the 132kV network. The majority of 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. 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, establishment of a third 275kV connection into Woree Substation is under construction and expected to be completed by April 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.

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, part of the Chalumbin to Woree section of the transmission line. The Project Assessment Conclusions Report (PACR) identified extending the life of the transmission line through the selective replacement of corroded members and components, along with painting selected towers as the preferred option (refer to Table 9.5).

The double circuit 275kV transmission line between Ross and Chalumbin 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 assessed under Stage 1 works due to its location on the western side of the Great Dividing Range.

Substations

Kamerunga 132/22kV Substation

132kV Primary plant and 132kV secondary systems replacement

Anticipated consultation	Maintaining reliability of supply at Kamerunga
Asset details	Established in 1976
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2028
Proposed network solution	Upfront replacement of all 132kV primary plant and secondary systems with GIS technology at an estimated cost of $75 million
Possible non-network solutions	Potential non-network options would need to provide supply to the 22kV network of up to a peak 60MW, and up to a peak 900MWh per day on a continuous basis. This would allow for the decommissioning of Kamerunga Substation and bridging of the Woree to Kamerunga transmission lines to the Kamerunga to Barron Gorge transmission line.

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, which was upgraded by Stanwell Corporation in 2011. The area surrounding the substation is residential and located along the flood plain of the Barron River.

In August 2019, Powerlink published a 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[22] 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. Powerlink expects to reapply the RIT-T process to address the identified need at Kamerunga within the next 12 months.

Possible network solutions

- Replacement of primary plant including additional switching functionality and secondary systems upfront with Gas Insulated Switchgear (GIS) technology 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.

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

Possible asset retirements in the 10-year outlook period[23]

Retirement of the 132kV transmission line 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 Chalumbin to Woree circuit. Should this option eventuate, there will be an opportunity to retire the existing 132kV transmission line from Chalumbin to Turkinje.

Refer to Table 9.8 for confirmed asset retirements in the Far North zone and Table 6.10 for possible asset retirements beyond the 10-year outlook period.

[22] Refer to NER clause 5.16.4(z3).

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

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 FNQ. Parts of the 132kV network are located closer to the coast in a high salt laden wind environment leading to accelerated structural corrosion (refer to figures 6.9 and 6.10).

Figure 6.9 Northern Ross zone transmission network

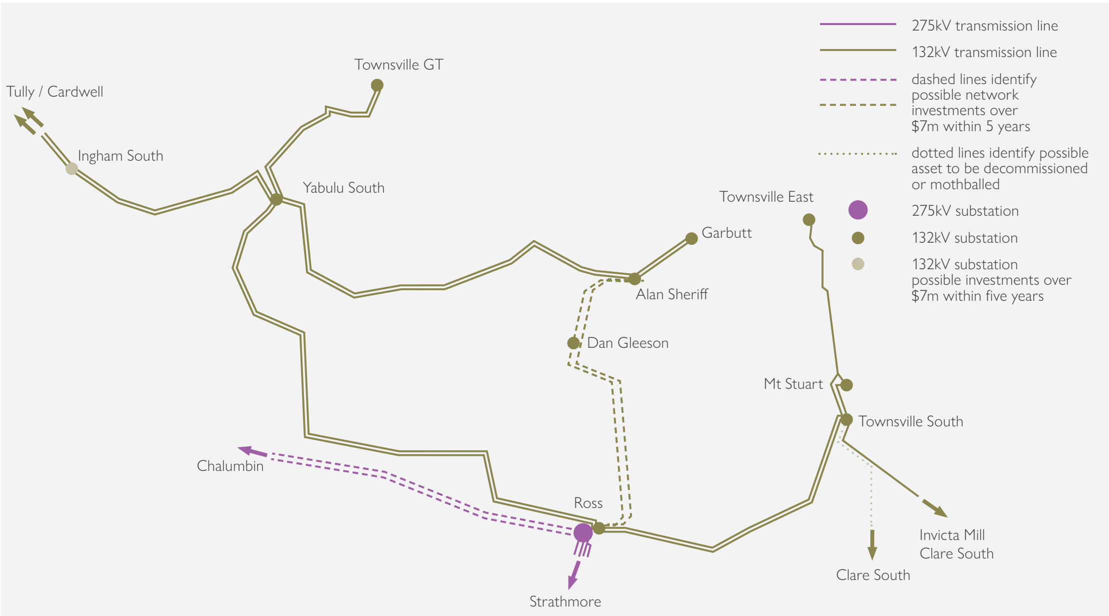


Figure 6.10 Southern Ross zone transmission network

Possible load driven limitations

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Ross 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 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.

Substations

Ingham South 132kV Substation

132kV Primary plant and 132kV secondary systems replacement

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 $10 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 the Ingham area.

Possible network solutions may include:

- 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.

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 6.10 for possible asset retirements beyond the 10-year outlook period.

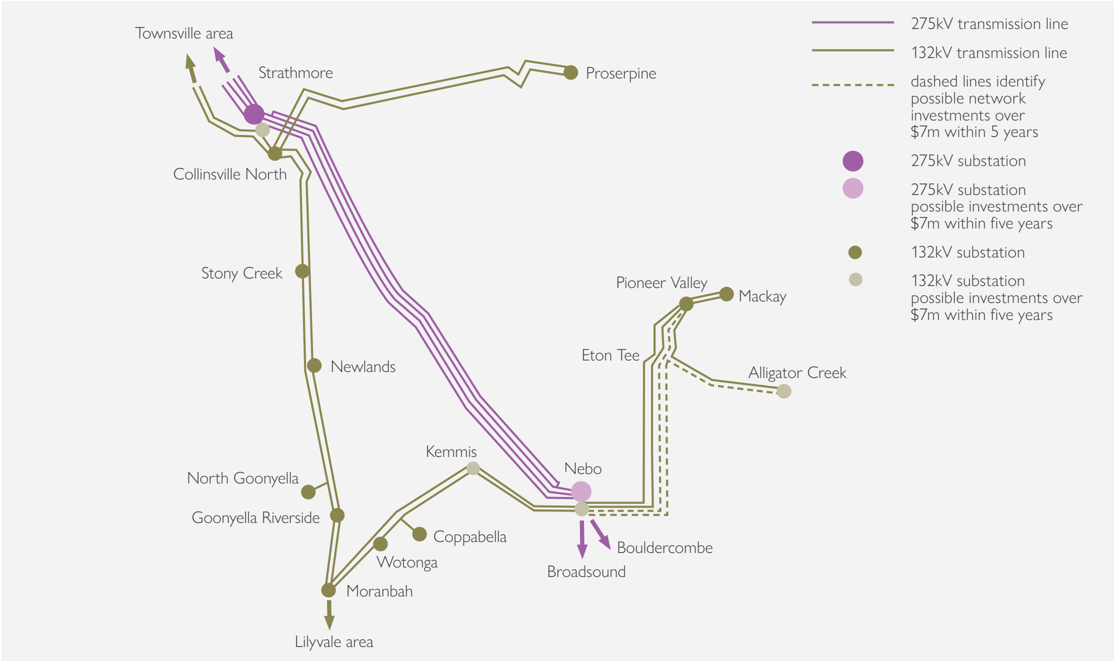
6.9.3 North zone

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

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the North zone within the next five years to meet reliability obligations.

High voltages associated with light load and low power transfer conditions are currently managed with existing reactive sources. However, midday power transfer levels are forecast to reduce as additional VRE generators are commissioned in north Queensland. As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in Section 7.6.2.

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.

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 $8 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
- Secondary systems replacement and replacing the thyristor valves including associated cooling system.

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

Nebo 275/132kV Substation

Current consultation	Addressing the reliability of supply to Nebo local area
Asset details	Established circa 1977
Project driver	Transformer condition risks at Nebo Substation
Project timing	December 2025
Proposed network solution	Replacement of transformers 3 and 4 and associated 11kV primary plant at Nebo Substation at an estimated cost of $11.5 million (2022/23 prices) by December 2025
Possible non-network solutions	A non-network option that avoids replacement of the ageing transformers and primary plant would need to provide injection or demand response at Nebo of up to 3MW during peak demand and up to 50MWh per day.

Nebo Substation was established in conjunction with the development of the interconnected 275kV network between Gladstone and North Queensland. Nebo was chosen as a location to establish a marshalling point for the 275kV network and as a transformation point to 132kV, to allow supply to local mining and domestic loads in the northern and central Queensland area.

Possible network solutions may include:

- Replacement of transformers 3 and 4 and associated 11kV primary plant by 2025.

Powerlink has identified that the options to refurbish and later replace the transformers are not credible, as it is not technically feasible due to the poor condition and age of the transformers.

Powerlink published a PSCR claiming PADR exemption, Addressing the reliability of supply to Nebo local area, in September 2023 which identified the replacement of transformers 3 and 4 and associated 11kV primary plant as the preferred network option. Submissions to the PSCR close on 22 December 2023 and Powerlink anticipates the publication of the PACR in early 2024.

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

Alligator Creek 132kV Substation

Potential consultation	Maintaining reliability of supply at Alligator Creek
Asset details	Established in 1982
Project driver	Primary plant condition risks at Alligator Creek Substation
Project timing	June 2025
Proposed network solution	Replacement of primary plant at Alligator Creek at an estimated cost of $7 million by June 2025
Possible non-network solutions	Potential non-network solutions would need to provide up to a peak 80MW, and up to a peak 1,400MWh per day on a continuous basis.

Alligator Creek Substation is a bulk supply point from mines in the Bowen Basin to the coal loading terminals of Hay Point and Dalrymple Bay and provides supply to Ergon Energy's distribution network for the surrounding communities to the south of Mackay.

Possible network solutions may include:

- Selected replacement of 132kV primary plant
- Full replacement of 132kV primary plant.

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

Potential consultation	Addressing the SVC secondary systems condition risks at Alligator Creek
Asset details	Established in 1982
Project driver	SVC Secondary systems condition risks at Alligator Creek
Project timing	June 2028
Proposed network solution	Replacement of secondary systems at Alligator Creek at an estimated cost of $7 million by June 2028
Possible non-network solutions	Potential non-network solutions would need to provide voltage imbalance support for the 132kV network.

Possible network solutions may include:

- Selected secondary systems replacement for the Alligator Creek SVC
- Full secondary systems replacement for the Alligator Creek SVC.

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

Kemmis 132kV Substation

Current consultation	Maintaining power transfer capability and reliability of supply at Kemmis
Asset details	Transformer 1 originally commissioned in 1984 and relocated to Kemmis in 2005
Project driver	Replace transformer 1 at Kemmis
Project timing	December 2026
Proposed network solution	Replacement of transformer 1 at Kemmis Substation at an estimated cost of $6.78 million (2022/23 prices) by December 2026
Possible non-network solutions	A non-network option that avoids replacement of the ageing transformer would need to provide injection or demand response at Kemmis of up to 60MW during peak demand and up to 650MWh per day.

Kemmis Substation, located approximately 32km north west of Nebo, was established to support the load growth arising from the expansion of mining in the northern Bowen Basin and to provide a bulk-supply injection point to the Ergon Energy distribution network.

Possible network solutions may include:

- Replacement of the 132kV transformer 1 at Kemmis.

Powerlink has identified that the option to refurbish and later replace the transformer is not credible, as it is not technically feasible due to the poor condition of the transformer. This is primarily due to the poor insulation strength of the transformer with condition assessments indicating significant deterioration of both oil and insulating paper condition. Based on this assessment, transformer 1 is not a candidate for refurbishment.

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

Powerlink published a PSCR claiming PADR exemption, Maintaining power transfer capability and reliability of supply at Kemmis, in September 2023 which identified the replacement of transformer 1 as the preferred network option. Submissions to the PSCR close on 22 December 2023 and Powerlink anticipates the publication of the PADR in early 2024.

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 6.10 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 renewable energy resource region (referto 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 2023 Queensland Renewable Energy Zone Roadmap (epw.qld.gov.au) (refer to Section 2.4.2).

The Central renewable energy resource region has high quality solar and wind resources and long-term industrial and hydrogen 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 8.2.3).

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 effecting the utilisation of existing transmission infrastructure. This has been most evident across the Central to North Queensland and Central to South Queensland grid sections (refer to sections 7.6.2 and 7.6.5 respectively) and the Queensland to NSW interconnector (QNI). A shift in utilisation and material change in supply demand balance within the Gladstone zone has implications for significant investment in the transmission network, including the Central to South Queensland transmission link, and the Gladstone area 275kV transmission network between the generation rich nodes of Calvale, Stanwell and Calliope River substations. Potential investments for the Central region are outlined in Section 8.2.3.

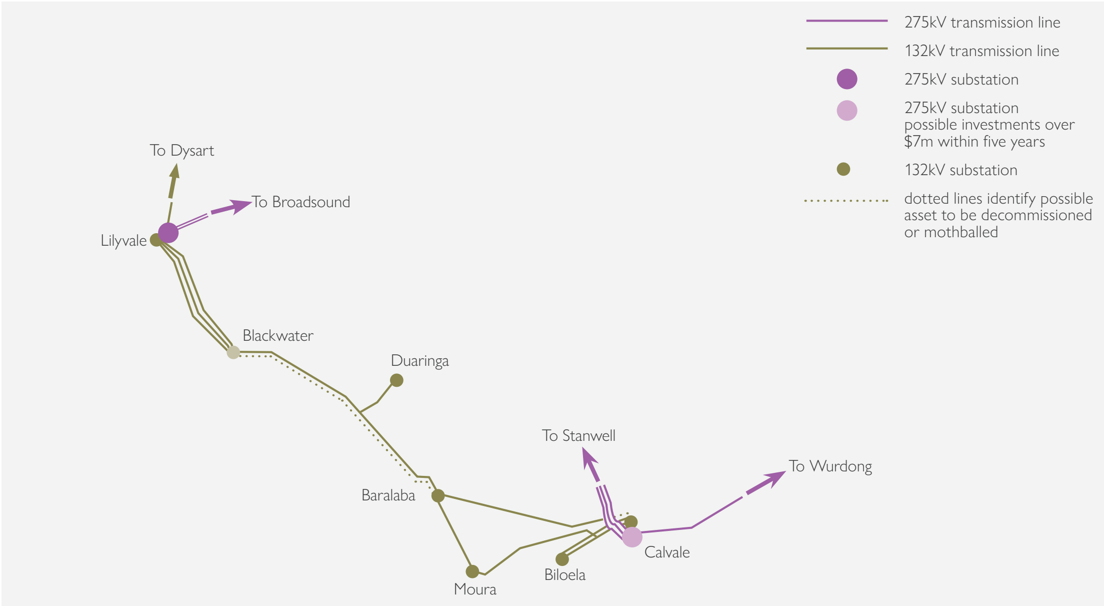
The investments outlined in Section 6.10 are based on AEMO's 2023 Electricity Statement of Opportunity (ESOO) Step Change scenario forecast in the 10-year outlook period. However, as mentioned, the Central region has the potential for significantly changed requirements in supply demand balance above this forecast. 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 6.10.1 to 6.11.1) and the Queensland SuperGrid Infrastructure Blueprint and will be updated in subsequent 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 evolving 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 AEMO's Step Change scenario forecast discussed in Chapter 3 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 reliability obligations.

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.

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 2028
Proposed network solution	Selected primary plant replacement at Calvale Substation at an estimated cost of $18 million by December 2028
Possible non-network solutions	Potential non-network solutions would need 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. Calvale Substation is also a major transmission node in Central Queensland connecting power flows between northern, central and southern Queensland. It also facilitates Callide B and Callide C generation connection, and also provides voltage support for the region.

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

Possible network solutions may include:

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

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	December 2027
Proposed network solution	Selected primary plant replacement at Broadsound Substation at an estimated cost of $19 million by December 2027
Possible non-network solutions	Potential non-network solutions would need to provide supply to Lilyvale and Blackwater loads of up to 250MW, and up to 6,000MWh per day on a continuous basis. Broadsound Substation is primarily a major transmission node connecting power flows between North and Central Queensland.

Possible network solutions may include:

- Selected primary plant replacement by December 2027
- Full primary plant replacement 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[24]

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 allows 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 6.10 for possible asset retirements beyond the 10-year outlook period.

6.10.2 Gladstone zone

Existing network

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

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

Figure 6.13 Gladstone transmission network

Possible load driven limitations

AEMO's Step Change scenario forecast discussed in Chapter 3 has approximately 250MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of a component of the existing industrial processes within the area. While Powerlink has no commitment from any direct connect customers to electrify existing industrial process, Powerlink is in discussions with corporations that have committed to decarbonisation of their existing fossil fuelled operations. Therefore, for this TAPR, any additional capacity forecast to be required to meet this increase of 250MW load will only be considered in the context of the main 275kV network supplying the Gladstone zone. Network limitations downstream of the main transmission system cannot be assessed without specific customer identification.

In addition, the new electrification loads and any other new loads have the potential to impose significant limitations impacting market outcomes as well as reliability of supply obligations. Possible network solutions to address these issues are outlined in Section 8.2.3.

Notwithstanding this additional electrification load and any future new loads and taking into account 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 reliability obligations.

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

Larcom Creek to Calliope 275kV transmission line

Potential consultation	Maintaining reliability of supply in the Gladstone region
Asset details	Constructed in 1977
Project driver	Emerging condition risks due to structural corrosion
Project timing	June 2029
Proposed network solution	Rebuild the 275kV transmission line between Calliope River and Larcom Creek substations as double circuit high capacity transmission line and turn in one or both circuits to Larcom Creek Substation at an estimated cost of $107 million, by June 2029
Possible non-network solutions	Potential non-network solutions would need to provide supply to 66kV and 132kV loads at Yarwun and Raglan of up to 160MW and up to 3,200MWh 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 line is also critical for delivering power to the Calliope River Substation, Calliope River Substation supplies the existing loads at Gladstone South, Queensland Alumina Limited (QAL) and part of Boyne Smelters Limited. Any non-network solution would also need to address this supply requirement.

The transmission line between Calliope River and Larcom Creek is located in Central Queensland immediately adjacent to the Gladstone industrial area. This built section covers the distance between Calliope River and Larcom Creek via Yarwun Substation. A proportion of the transmission line traverses tidal marine environment and due to its proximity to the large-scale industrial areas and the coast it is constantly exposed to high levels of salt laden air and industrial pollutants.

Possible network solutions may include:

- Line refit works on steel lattice structures between Mt Miller near Calliope River and Larcom Creek
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as single circuit transmission line construction
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction and turn-in one circuit to Larcom Creek substation
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction and turn-in both circuits to Larcom Creek substation.

The proposed network solution is heavily influenced by the energy transformation. There are several drivers, yet to be committed, that can have a material impact on the transmission capability required into the Gladstone zone. A number of corporations have committed to the decarbonisation of existing fossil fuelled operations and processes either through electrification or clean fuel substitution. This will have the impact of materially changing the supply and demand balance of the Gladstone zone necessitating greater transmission capability. Refitting this low capacity 275kV line or constructing a new higher capacity single circuit 275kV line is not aligned with this broader strategy (refer to Section 8.2.3).

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

Possible future development

This transmission line forms part of the existing two 275kV single transmission lines between Bouldercombe and Calliope River substations. Due to the potential for significant change in future supply demand balance within the Central Queensland region, and the potential for growing power transfer requirements from North Queensland and South Queensland, Powerlink is preserving the option to retain both 275kV transmission lines to ensure shared network needs can be met across a range of plausible development scenarios. It is expected the scale and configuration of the optimal network investment will require one single circuit transmission line to be rebuilt as a high capacity double circuit, with the other single circuit to be maintained through line refit works in the 10-year outlook period and subject to a future RIT-T consultation (refer to Appendix D, Table D.5).

The current strategy for these two 275kV single circuit lines is to construct a new high capacity 275kV double circuit transmission line between Bouldercombe and Larcom Creek Substation (refer to Section 8.2.3). This new build is adjacent (on an existing double width easement) to the existing more western single circuit 275kV line between Bouldercombe and Calliope River substations (feeder 812). This line traverses valuable wind resources in the area and will divert to Larcom Creek Substation at a suitable location where the future 500/275kV substation west of Gladstone under the QEJP will be located.

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 2026
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 2026
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 QAL.

Possible network solutions may include

- 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.

Substations

Callemondah 132kV Substation

Anticipated consultation	Maintaining reliability of supply at Callemondah
Asset details	Established in 1985 and provides supply to the Aurizon network
Project driver	Addressing the 132kV primary plant and secondary systems condition risks
Project timing	June 2025
Proposed network solution	Selected primary plant and secondary systems replacement at Callemondah Substation at an estimated cost of $10 million by June 2025
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 132kV network at Gladstone South and/or Aurizon load at Callemondah, totalling up to 180MW and up to 2,500MWh per day. The non-network solution would be required for a contingency and be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network solutions may include:

- Full primary plant and secondary systems replacement by June 2025
- Selected primary plant and secondary systems replacement by June 2025.

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

Possible asset retirements within the 10-year outlook period[25]

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 6.10 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, South West, Surat, Bulli, Moreton and Gold Coast zones. The region broadly aligns with the Southern Queensland REZ proposed development area (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 such as wind and solar to the transmission network. It is also located close to QNI. The Southern region also includes a number of candidate REZ areas in southern Queensland identified in the draft Queensland Renewable Energy Zone Roadmap and 2022 ISP (refer to Section 2.4.1).

The investments outlined in Section 6.11 are based on AEMO's 2023 ESOO Step Change 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 6.15 and 8.2.4), 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 Maryborough and Bundaberg 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

Possible load driven limitations

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

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

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, environmental conditions and demand levels. It is important to note that there is no load at risk or potential for loss of supply to customers associated with network congestion.

In its current form, the CQ-SQ transmission network offers a great deal of flexibility for possible generation dispatches, however occasionally imposes constraints to market operation. In order for power from new and existing NQ and CQ VRE 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 commissioning of the QNI Minor project (refer to Section 6.13).

The 2022 ISP identified a potential Central to Southern Queensland network project as a Future ISP project. Powerlink and AEMO (through the ISP process) will continue to investigate the impact of large-scale VRE generation investment in the Queensland region.

Possible network solutions to facilitate efficient market operation are outlined in Section 8.3.2.

Possible network investments within five years

Network reinvestments (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 or replacement with an asset of lower capacity.

Transmission Lines

CQ-SQ transmission lines

Potential consultation	Maintaining reliability of supply between central and southern Queensland
Asset details	Progressively developed during 1970s and 1980s
Project driver	Emerging condition and compliance risks related to structural corrosion
Project timing	December 2028 to June 2029
Proposed network solution	Rebuild two of the three single circuit transmission lines between Calliope River and Wurdong Tee as a double circuit at an estimated cost of $40 million by December 2028. Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Substation at an estimated cost of $14 million by June 2029. Targeted refit of the three single circuit transmission lines between Calliope River (Wurdong Tee) and Gin Gin substations at an estimated cost of $75 million by June 2030. Line refit works on the 275kV transmission single circuit transmission line between Woolooga and South Pine substations at an estimated cost of $16 million by June 2029.
Possible non-network solutions	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.

The coastal CQ-SQ transmission network between Calliope River and South Pine substations provides essential supply between the generation in central and north Queensland and the loads in 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 in these areas.

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:

- 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)
- 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:

- One 275kV single circuit transmission lines from Woolooga to Gin Gin built in 1972 (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 line form South Pine to Palmwoods built in 1976 (structural repair due to above ground corrosion).

Powerlink, through the ISP process, will continue 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 CQ-SQ grid section. Powerlink also considers the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost effective solutions are delivered for customers.

The current long-term network strategy based on existing network topology is to rebuild two of the 275kV single circuit transmission lines from Calliope River to South Pine as a double circuit at end of technical service life. 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. 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 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 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 rebuild of the coastal corridor as a new double circuit 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)
- maintaining the existing three single circuit 275kV transmission lines through a combination of staged rebuild and line refit projects
- network rationalisation (potentially three single circuits to one double circuit in sections) of the coastal corridor involving staged line refit and rebuild on the coastal corridor, and reinforcement of the CQ-SQ section via reinforcement of the western CQ-SQ transmission corridor.

Closer to the timing of the investment decision and as part of the option analysis under the RIT-T, Powerlink will consider whether the proposed preferred option will 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 6.10 for possible asset retirements beyond the 10-year outlook period.

6.11.2 Surat zone

Existing network

The Surat Basin 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 coal 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 AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Surat zone within the next five years to meet reliability obligations.

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 next five years.

Possible asset retirements within the 10-year outlook period

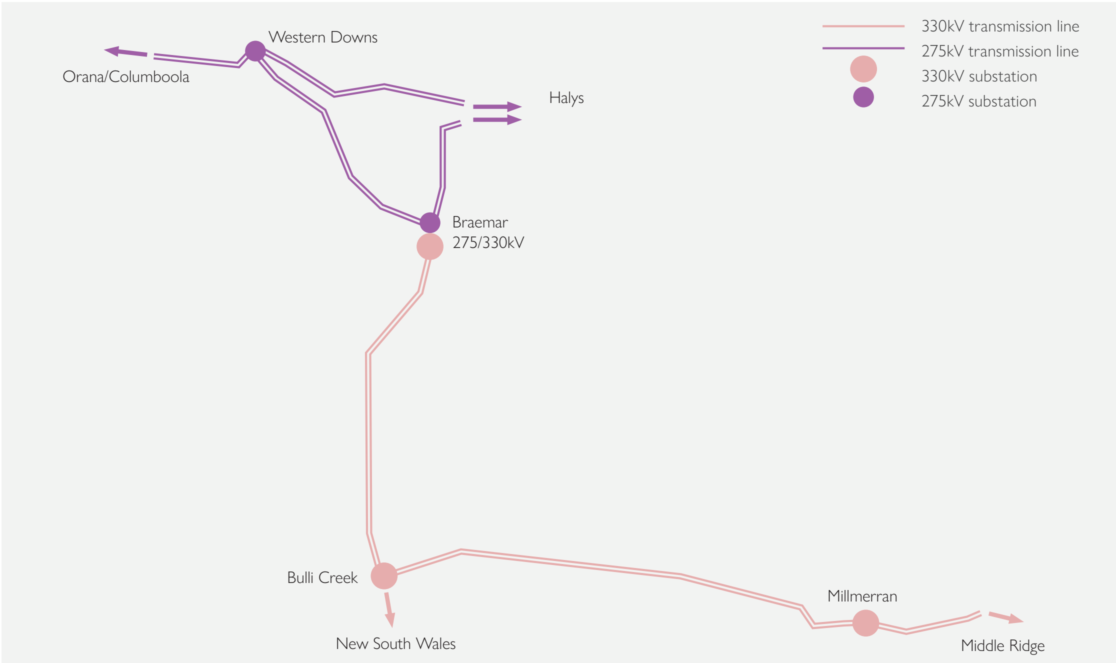
Current planning analysis has not identified any potential asset retirements in the Surat zone within the 10-year outlook period.

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 AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Bulli zone within the next five years to meet reliability obligations.

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 Surat zone within the next five years.

Possible asset retirements within the 10-year outlook period

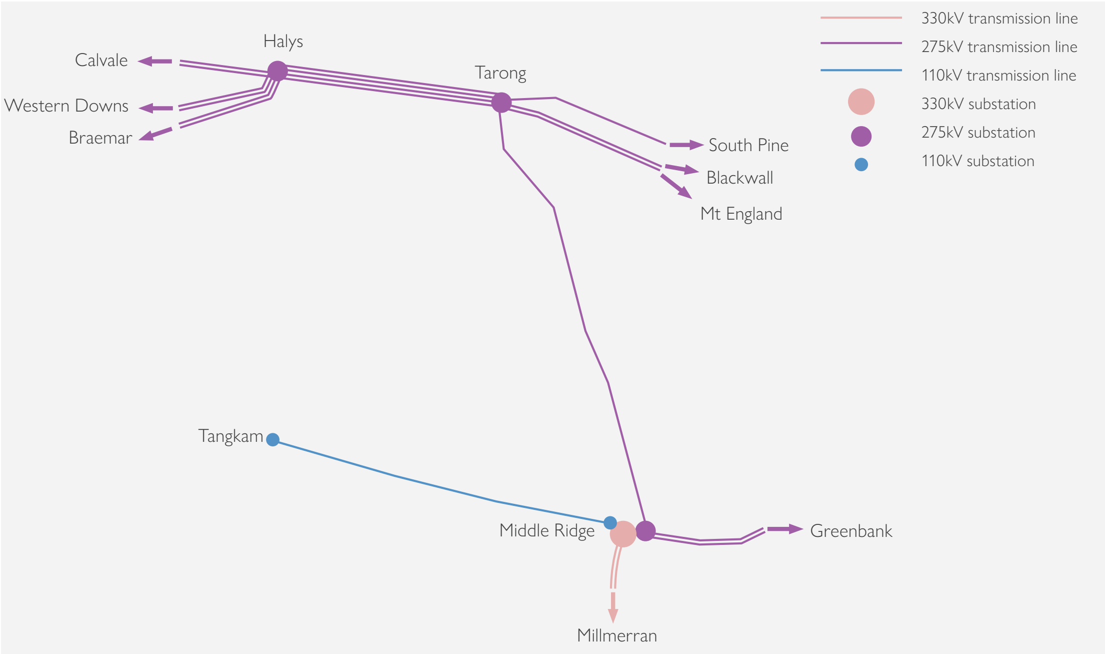
Current planning analysis has not identified any potential asset retirements in the Bulli zone within the 10-year outlook period.

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 AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional 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.

Possible network investments within the five year outlook period

Current planning analysis has not identified any assets requiring investment in the South West zone within the next five years.

Possible asset retirements within the 10-year outlook period[26]

Refer to Table 11.7 for confirmed asset retirements in the South West zone and Table 6.10 for possible asset retirements beyond the 10-year outlook period.

6.11.5 Moreton zone

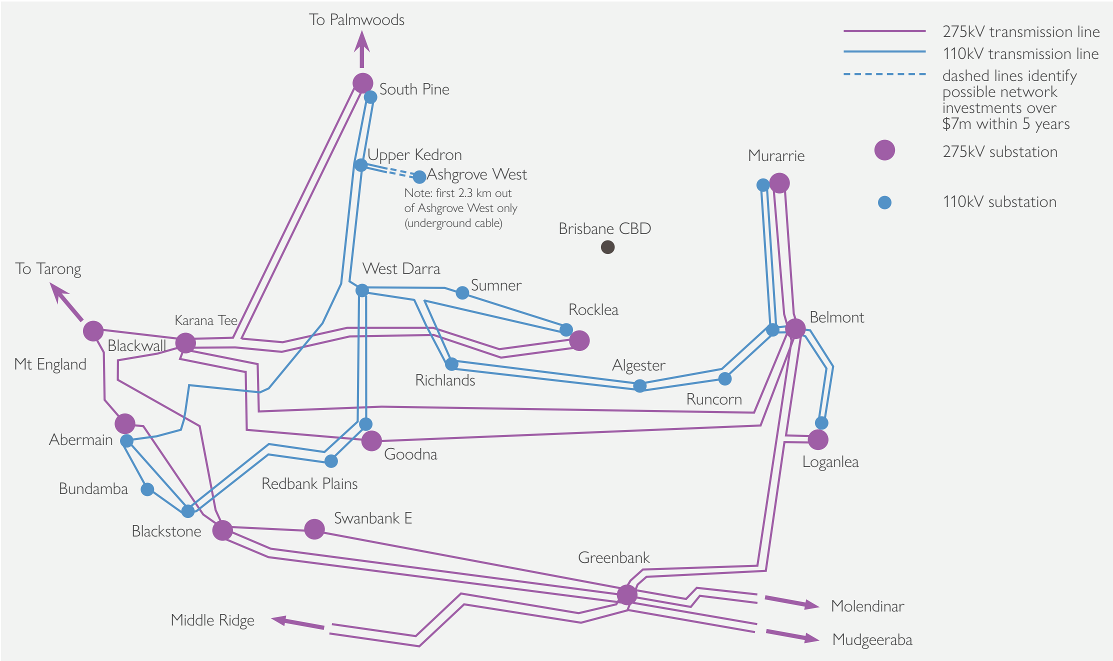
Existing network

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).

[26] 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 AEMO's Step Change scenario forecast discussed in Chapter 3 and the committed generation described in tables 7.1 and 7.2, there is no additional capacity forecast to be required in the Moreton 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 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 in-service for a reasonable period. Future decommissioning remains an option once demand growth is better understood.

Detailed analysis will be ongoing 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 ongoing review, together with further joint planning with Energex, may result in a future RIT-T in the late 2020s.

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 $18 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 may include:

- 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.

Substations

Current planning analysis has not identified any substation assets requiring investment in the Moreton zone within the next five years.

Possible asset retirements within the 10-year outlook period

Loganlea 110/33kV transformer

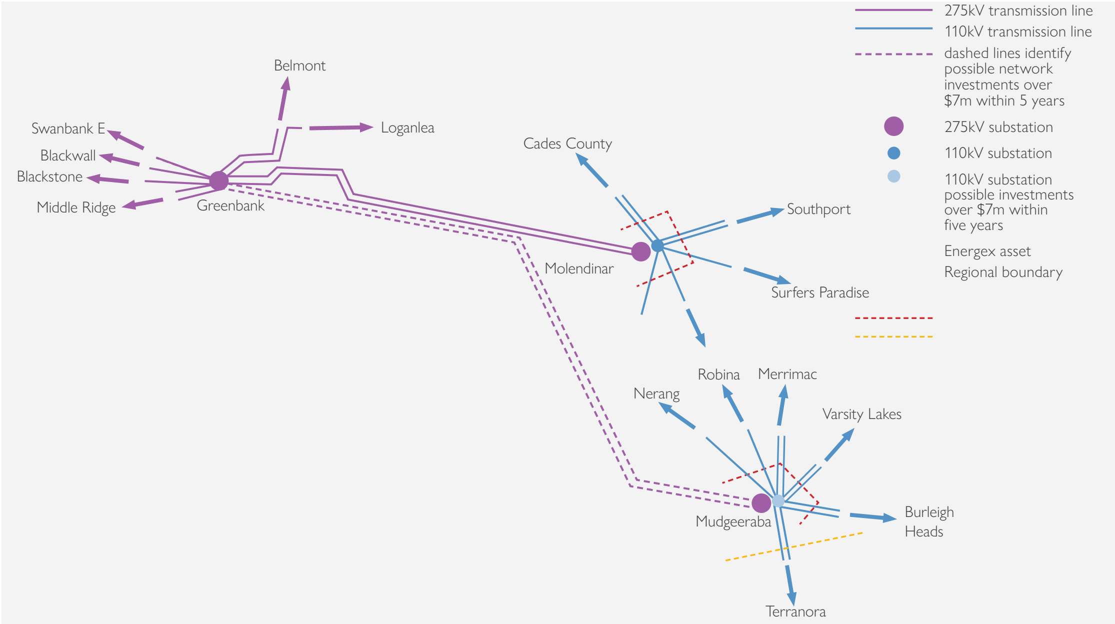
Based on the condition of one of the 110/33kV transformers at Loganlea, it is proposed to retire this transformer at the end of technical service life by June 2026. Powerlink considers that this will not impact on the ability to meet the obligations of Powerlink's reliability criteria. Since publication of the 2022 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 AEMO's Step Change scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of 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	December 2028
Proposed network solution	Maintain the existing topography by way of a targeted line refit at an estimated cost of $30 million to $53 million by December 2028
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 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 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 December 2028
- 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. Due to these challenges it has been identified that an extended delivery timeframe of at least four years would be required with the potential for works to commence within the next five years.

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

Substations

Mudgeeraba 275/110kV Substation

Mudgeeraba 275/110kV Substation, located within the southern end of the Gold Coast zone, is a major connection point for supply to the Gold Coast and northern NSW with the 110kV substation supplying distribution points including Robina, Nerang, Broadbeach, Burleigh and Terranora.

Mudgeeraba 110kV primary plant and secondary systems

Anticipated consultation	Maintaining reliability of supply at Mudgeeraba
Asset details	Established in 1972 and expanded progressively from 1980s to 2000s
Project driver	Emerging condition risks arising from the condition of the 110kV primary plant and secondary systems
Project timing	June 2029
Proposed network solution	Selected replacement of primary plant and staged replacement of secondary systems at an estimated cost of $33 million
Possible non-network solutions	Mudgeeraba 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 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.

Possible network solutions may include:

- Selected replacement of primary plant and staged replacement of the secondary systems components by June 2029
- Full replacement of all primary plant and 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

Current planning analysis has not identified any potential asset retirements in the Gold Coast zone within the 10-year outlook period.

6.12 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO ESOO[27]. Interested parties who require information regarding future supply demand balance should consult this document.

6.13 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 static capacitor banks at Tamworth, Armidale and Dumaresq substations. Transgrid completed the commissioning of these works by May 2022.

27 Published by AEMO in August 2023.

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 looking for 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 on-line 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, only a modest increase to the QNI transfer capability has been released. The northerly hold point has now been increased from 600MW to 700MW and the southerly hold point from 1,200MW to 1,300MW.

In response to this lack of available market and test conditions, the test plan was revised to remove the requirement for extended periods at a given transfer level hold-point. This will allow testing to proceed in the event of availability of favourable test conditions for shorter periods availing more testing opportunities. These tests are expected to continue until mid-2024.

6.14 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 6.10 which goes five years beyond the 10-year outlook period of the 2023 TAPR, is provided in good faith[28] and is the best information available at the time of TAPR publication. Transmission equipment 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.

28 For completeness, please refer to Powerlink's Disclaimer on **page 2**.

Table 6.10 Transmission Lines approaching end of technical service: 10-15 years (July 2034 – June 2039)

Region	Zone	Feeder	Voltage	General location
Northern	Far North	7165	132kV	Between Chalumbin and Turkinje substations
Northern	Far North	7227	132kV	Between Cairns and Woree substations
Northern	Far North	7191	132kV	Kareeya to Chalumbin substations
Northern	Ross	879	275kV	Between Strathmore and Ross Substation
Northern	Ross	7131	132kV	Between Clare South and Townsville South substations
Northern	North	7152	132kV	Between Eton and Alligator Creek substation
Northern	North	7119	132kV	Between Pioneer Valley and Alligator Creek substations
Northern	North	7238	132kV	Between Pioneer Valley and Mackay substations
Northern	North	820	275kV	Between Bouldercombe and Broadsound 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	833	275kV	Between Broadsound and Lilyvale substations
Central	Central West	7124	132kV	Between Moranbah and Dysart substations
Central	Gladstone	7145	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	275kV	Between Stanwell and Bouldercombe substations
Southern	Wide Bay	8850	275kV	Between Woolooga and Teebar Creek substations
Southern	Wide Bay	813	275kV	Between Woolooga and Gin Gin substations
Southern	Wide Bay	814	275kV	Between Woolooga and Gin Gin substations
Southern	Wide Bay	819	275kV	Between Teebar Creek and Gin Gin 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	South West	827	275kV	Between Tarong and Blackwall substations
Southern	Moreton	8819	275kV	Between Blackwall and Greenbank substations
Southern	Moreton	829	275kV	Between Loganlea and Belmont substations
Southern	Moreton	8822	275kV	Between Greenbank and Belmont substations
Southern	Moreton	825	275kV	Between Mt England and South Pine substations
Southern	Moreton	832	275kV	Between Tarong and South Pine substations

6.15 Alignment with AEMO's 2022 Integrated System Plan

The 2022 ISP published by AEMO in June 2022 provides a strategic view of the efficient development of the NEM transmission network to 2050.

The installation of large-scale VRE generation is changing the mix of generation and impacting the utilisation of existing transmission infrastructure. This has been most evident across the Central to North Queensland and Central to South Queensland grid sections (refer sections 7.6.2 and 7.6.5 respectively) and QNI. This has implications for investment in the transmission network both inter-regional and within Queensland.

These impacts have been investigated in the 2022 ISP. The 2022 ISP identified that to deliver low-cost, secure and reliable energy, investments in transmission are needed. Although no 'actionable' projects were identified for Queensland, several Queensland projects were identified as part of the optimal development path that may become 'actionable' in future ISPs. These projects will be vital to achieving lower cost solutions that meet energy security and reliability, affordability and reduced emissions.

Two projects were nominated for preparatory activities. These include:

- AEMO's Darling Downs REZ Expansion (Stage 1)
- QNI Connect (500kV option).

Powerlink completed the preparatory activities for each project as required by 30 June 2023. These reports are available on AEMO's website[29]. Each Preparatory Report provides the following information:

- Project scope and single line diagrams
- Electrical network parameters
- Ratings of network equipment
- Power transfer limits for the existing network and following the augmentation project
- High level cost estimate.

Three additional projects were identified as requiring no action as AEMO will leverage the estimated project costs from previous preparatory activities. These include:

- Central to Southern Queensland reinforcement
- Gladstone Grid reinforcement
- QNI Connect (330kV option).

For Gladstone Grid reinforcement and QNI Connect (330kV option) Powerlink has provided AEMO with updates to the project scopes to enable AEMO to reflect these changes into their updated project estimates.

This information will be used by AEMO to better inform the optimal development path for the 2024 ISP.

6.15.1 Expanding NSW-Queensland transmission transfer capacity

Increasing the capacity of interconnection between NEM regions is essential in order to take advantage of the geographic diversity of renewable resources so regions can export power when there is local generation surplus, and import power when needed to meet demand. Appropriate intra-regional transmission capacity is required to support these objectives.

The 2022 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 as early as 2029-30 in the Hydrogen Export scenario forecast and 2032/33 in the Step Change scenario forecast.

As the likely timing (2032/33) is beyond a practical delivery timing, AEMO did not declare QNI Connect as an actionable project. Rather it recommended that Powerlink and Transgrid carry out further preparatory activities to better inform options for the 2024 ISP. AEMO required preparatory activities to be undertaken for a 500kV option for both NSW and Queensland scope.

Powerlink consulted with Transgrid on a number of options to increase the capacity of QNI. These options also align with long-term development plans in both states to host more VRE generation. The preparatory activities, as outlined in this section, were completed by 30 June 2023 so that estimated costs and capacity improvements could be included in the 2024 Draft ISP.

[29] AEMO | 2023 Transmission Expansion Options Report Consultation (Reference materials) etc.

Possible network solutions

Options to upgrade QNI capacity include both 330kV and 500kV options:

- 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.

6.15.2 CQ-SQ grid section reinforcement

The utilisation of the CQ-SQ grid section is highly dependent on generation and load in Central and North Queensland. As new generation connects in Central and North Queensland, congestion along this corridor may increase and generation may be curtailed. Upgrading the capacity of QNI may also add to the congestion of this grid section. The 2022 ISP has identified a further upgrade of QNI capacity.

In the 2020 ISP, AEMO recommended Powerlink complete preparatory activities to increase transfer capability from CQ-SQ grid section. For the 2022 ISP, two options were selected. One option makes use of the existing transmission line with a mid-point switching station between Calvale and Halys substations. The other option includes a new double-circuit transmission line. For the 2024 ISP, since no changes are anticipated for this project, AEMO will escalate the estimated cost of the preparatory activities delivered for the 2022 ISP.

The 2022 ISP identified a staged approach to upgrade CQ-SQ as part of the optimal development path. The upgrade is critical for unlocking VRE resources in the North, Isaac, and Fitzroy REZs to deliver efficient market outcomes.

Under the Step Change scenario forecast an incremental upgrade was identified as economic by 2028/29. This involves establishing a mid-point switching station on the Calvale to Halys 275kV transmission line. By 2038/39 a more material upgrade has been identified as economic, involving the construction of a new 275kV double circuit transmission line between Calvale and Wandoan South substations.

Following the release of the QEJP in September 2022, Powerlink and Queensland Government have discussed the pathway for consideration for direct inclusion of elements of the Infrastructure Blueprint in the 2024 ISP. Section 2.3 outlines the components of the Queensland SuperGrid transmission backbone. AEMO will consider the Borumba PHES as an anticipated project and therefore may be selected as part of the optimal development path in all scenarios. If AEMO's ISP model selects Borumba PHES then it will be connected to the transmission system via a 500kV network between Halys, Borumba, Woolooga West and Gladstone West 500kV substations. This is described as Stages 1 and 2 in Section 2.3 and shown diagrammatically in Figure 2.3.

Stage 2, a 500kV double circuit line between Woolooga West and Gladstone West Substation, will therefore also be available as a network option to increase the power transfer capacity between Central and Southern Queensland.

Possible network solutions

Feasible network solutions to facilitate efficient market operation may differ in scale. These include:

- establishment of a mid-point switching substation on the 275kV double circuit between Calvale and Halys substations
- construction of a 275kV double circuit transmission line between Calvale and Wandoan South Substation
- construction of a 500kV double circuit transmission line between Central Queensland and Halys Substation

- a grid-scale battery system. A Virtual Transmission Line (VTL) option could comprise of grid-scale batteries on both sides of CQ-SQ, or a grid-scale battery on the south side and a braking resistor or generator tripping scheme on the northern side
- A 1,500MW high voltage direct current (HVDC) bi-pole overhead transmission line from Calvale and South West Queensland.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue 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 CQ-SQ grid section. Powerlink also considers the emerging condition based drivers (refer to Section 6.11.1) as part of the integrated planning process to ensure that overall the most cost effective solutions are delivered for customers. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered.

6.15.3 Gladstone grid section reinforcement

The 2022 ISP identified significant increases in VRE generation for the North, Isaac, and Fitzroy REZs. With this additional generation and the retirement or reduced generation from Gladstone Power Station, 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. If major industrial loads are electrified, or if large hydrogen projects progress, there is a further material shift in the supply-demand balance in the Gladstone area. These scenarios and the consequences for network development have been addressed in Section 8.2.3.

In the 2020 ISP, AEMO recommended Powerlink complete preparatory activities for reinforcement of Gladstone grid section. New 275kV transmission lines are proposed to increase the network transfer capability between Central West and Gladstone zones. For the 2024 ISP, AEMO has aligned the scope and cost of the project to match the higher capacity conductor proposed to be used (refer to Section 8.2.3).

Under the Step Change scenario forecast, the 2022 ISP identified a need to materially 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.

Possible network solutions

Feasible network solutions to facilitate efficient market operation and also deliver reliability of supply obligations in the Gladstone zone have been outlined in Section 8.2.3. In addition to these options, a new high capacity 275kV double circuit transmission line between Bouldercombe, Raglan, Larcom Creek and Calliope River substations would also increase capacity.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue to investigate the impact that investment in large-scale VRE generation and firming generation, reduced operation of the Gladstone Power Station, electrification of existing industrial processes and/or development of new industry load will have on the utilisation and economic performance of the Gladstone grid section. Powerlink will also consider the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost effective solutions are delivered for customers.

6.15.4 AEMO's Darling Downs REZ Expansion

AEMO's Darling Downs REZ extends from the border of NSW near Dumaresq to Columboola within the Surat zone of Queensland. The Darling Downs REZ has high network capacity and is near QNI and Brisbane. The area has abundant high quality solar and wind resources. A number of large-scale solar and wind projects are already connected or committed within the zone (refer to tables 7.1 and 7.2). Furthermore, the ultimate retirement of thermal generation within this REZ will also release network capacity to allow for additional VRE connections. However, given the abundant high quality solar and wind resources in this REZ and that the energy transformation will require significantly more renewable generation to connect in the REZ, expansion of the Darling Downs REZ will be required.

The Darling Downs REZ connects to South East Queensland (SEQ) across two transmission corridors; a northern corridor that consists of five 275kV transmission circuits from the Tarong Substation to SEQ and a southern corridor that consists of two 330kV transformer ended (330/275kV) circuits between Millmerran and Middle Ridge substations.

The 2022 ISP analysis found that under high demand conditions, this southern corridor can only facilitate 1,300MW into SEQ from generation connected around the Bulli Creek area. This is due to a 300/275kV transformer limitation at the Middle Ridge Substation. Therefore, VRE generation will need to connect around the Halys area to increase the overall VRE hosting capacity of the Darling Downs REZ.

Notwithstanding connection of VRE generation to the more northern regions of the REZ, the 2022 ISP identified that the Middle Ridge transformer rating is a limitation to the development of the Darling Downs REZ. It identified the earliest timing for this expansion as 2025/26 in the Hydrogen Export scenario forecast and 2028/29 in the Step Change scenario forecast. The timing of these upgrades will also be influenced by generation retirements and any QNI upgrades.

AEMO identified expansion of the Darling Downs REZ for preparatory activities. The Darling Downs REZ Expansion report was finalised for AEMO in June 2023.

Possible network solutions

Feasible network solutions to expand the capacity of the Darling Downs REZ include:

- Replacement of the existing 1,300MVA 330/275kV transformer at Middle Ridge with a 1,500MVA 330/275kV transformer
- Implementation of a Special Protection schemes (SPS), including pairing a large-scale BESS in SEQ and generation runback.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue to investigate the impact that investment in large-scale VRE generation and reduced operation of the thermal generation in the Darling Downs REZ area has on the utilisation and economic performance of the transmission between the Darling Downs REZ and SEQ. Powerlink will also consider the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost effective solutions are delivered for customers.

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 2022 Transmission Annual Planning Report (TAPR) add 399MW to Queensland's semi-scheduled variable renewable energy (VRE) generation capacity taking the total existing and committed semi-scheduled VRE generation capacity to 5,334MW.
- Storage commitments since the 2022 TPAR include the 100MW 2 hour Chinchilla Battery energy storage system (BESS).
- Record maximum and record minimum transmission delivered demands were experienced in Wide Bay, South West and Gold Coast zones during 2022/23. All three regions had a reduction in transmission delivered energy.
- Record minimum transmission delivered demands were also recorded in Far North, Ross and Moreton zones during 2022/23.
- The transmission network has performed reliably during 2022/23, 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.

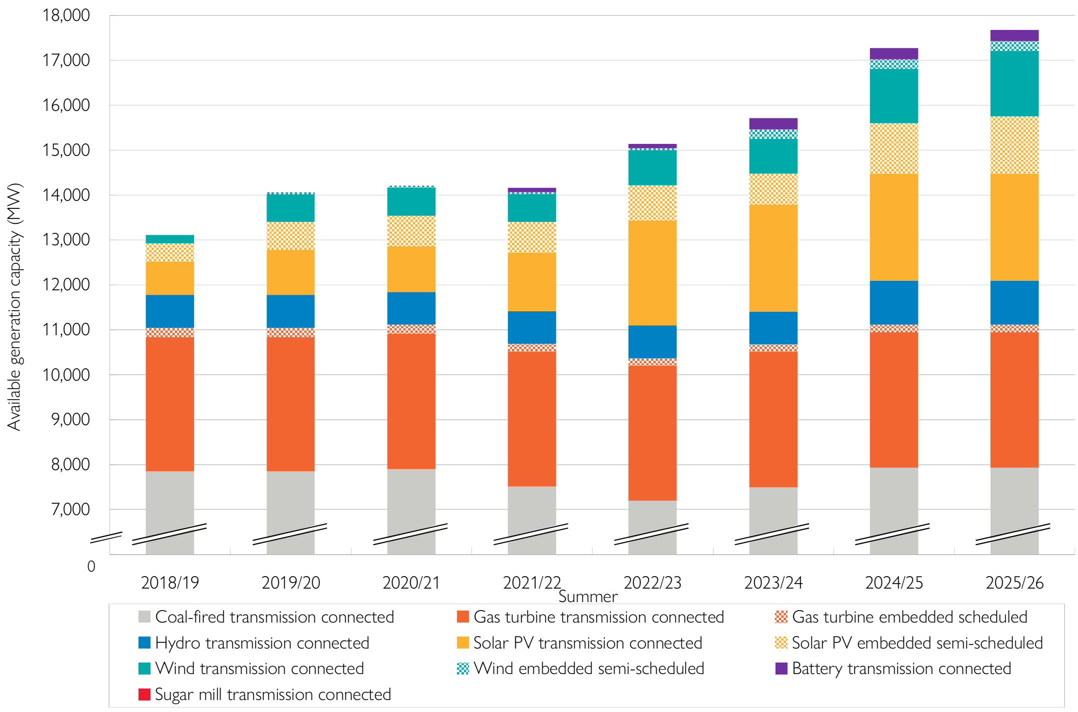
The location and pattern of generation dispatch influences power flows across the Queensland network. Future generation dispatch patterns and interconnector flows are uncertain in the deregulated electricity market and will vary substantially due to output of VRE generation and because of planned or 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 6 June 2023) has been adopted for the purposes of this year's TAPR. During 2022/23, commitments have added 399MW of semi-scheduled VRE capacity, taking Queensland's semi-scheduled VRE generation capacity to 5,334MW. Figure 7.1 illustrates the expected changes to available and committed large-scale generation capacity in Queensland from summer 2018/19 to summer 2025/26.

Figure 7.1 Summer available generation capacity by energy source



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 Wambo Wind Farm has reached committed status since the 2022 TAPR.

Scheduled transmission connected Chinchilla BESS has reached committed status since the 2022 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.

1 AEMO, System Strength Impact Assessment Guidelines, June 2023.

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 2023/24	Winter 2024	Summer 2024/25	Winter 2025	Summer 2025/26	Winter 2026
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	434	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		7,497	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
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

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 2023/24	Winter 2024	Summer 2024/25	Winter 2025	Summer 2025/26	Winter 2026
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	2,383	2,383	2,383	2,383
Wind (7)							
Mt Emerald	Walkamin	180	180	180	180	180	180
Kaban	Tumoulin	152	152	152	152	152	152
Clarke Creek	Broadsound			440	440	440	440
Wambo	Halys					245	245
Coopers Gap	Coopers Gap	440	440	440	440	440	440
Total wind		772	772	1,212	1,212	1,457	1,457
Battery (7)							
Bouldercombe 2h BESS	Bouldercombe	50	50	50	50	50	50
Wandoan 1.5h BESS	Wandoan South	100	100	100	100	100	100
Chinchilla 2h BESS	Western Downs	100	100	100	100	100	100
Total battery		250	250	250	250	250	250
Sugar mill							
Invicta (5)	Invicta Mill	0	34	0	34	0	34
Total sugar mill		0	34	0	34	0	34
Total all stations		14,649	15,652	15,773	16,342	16,018	16,587

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.

(8) Generators undergoing commissioning are shown at full capacity from the anticipated start of commissioning activities. Actual available generating capacity will vary over the course of the commissioning program.

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.

Semi-scheduled embedded Gunsynd Solar Farm and Banksia Solar Farm have reached committed status since the 2022 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.

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 (1)					
		Summer 2023/24	Winter 2024	Summer 2024/25	Winter 2025	Summer 2025/26	Winter 2026
Gas 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 gas 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
Middlemount	Lilyvale	26	26	26	26	26	26
Emerald	Emerald	72	72	72	72	72	72
Bundaberg	Gin Gin		78	78	78	78	78
Bullyard	Gin Gin				97	97	97
Banksia	Isis					60	60
Aramara	Aramara			104	104	104	104
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
Kingaroy	Kingaroy		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
Total solar PV		685	923	1,121	1,218	1,278	1,278
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		1,065	1,326	1,501	1,621	1,658	1,681

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.

7.3 Network control facilities

Powerlink participated in the 2023 General Power System Risk Review[2] (GPSRR), published by AEMO in July 2023. The GPSRR replaces and expands on the scope of the previous Power System Frequency Risk Review (PSFRR) which only focussed on power system frequency risks associated with non-credible contingency events, to now include other modes of failure.

AEMO has added the following in relation to Queensland in this review:

- 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.

Work is continuing on the following recommendations from the 2022 PSFRR including:

- Establishment of an Over Frequency Generation Shedding (OFGS) scheme to manage over frequency if QNI separates. AEMO and Powerlink are working on the design of this scheme which is planned for completion at the end of 2023.
- Identification and implementation of measures to restore Under Frequency Load Shedding (UFLS).
- Review and implementation of Wide Area Monitoring, Protection and Control (WAMPAC) for the non-credible loss of both Calvale – Halys 275kV lines and loss of both Columboola – Western Downs 275kV lines.

Associated with high penetration of rooftop photovoltaic (PV) installations, Powerlink is reviewing the transient stability limits for CQ-SQ and QNI. The review includes dynamic load models that include rooftop PV behaviour. Powerlink submitted draft reports to AEMO in March 2023.

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, 2023 General Power System Risk Review, July 2023.

7.4 Existing network configuration

Figures 7.2, 7.3, 7.4 and 7.5 illustrate Powerlink's system intact network as of July 2023.

Figure 7.2 Existing HV network July 2023 – North Queensland

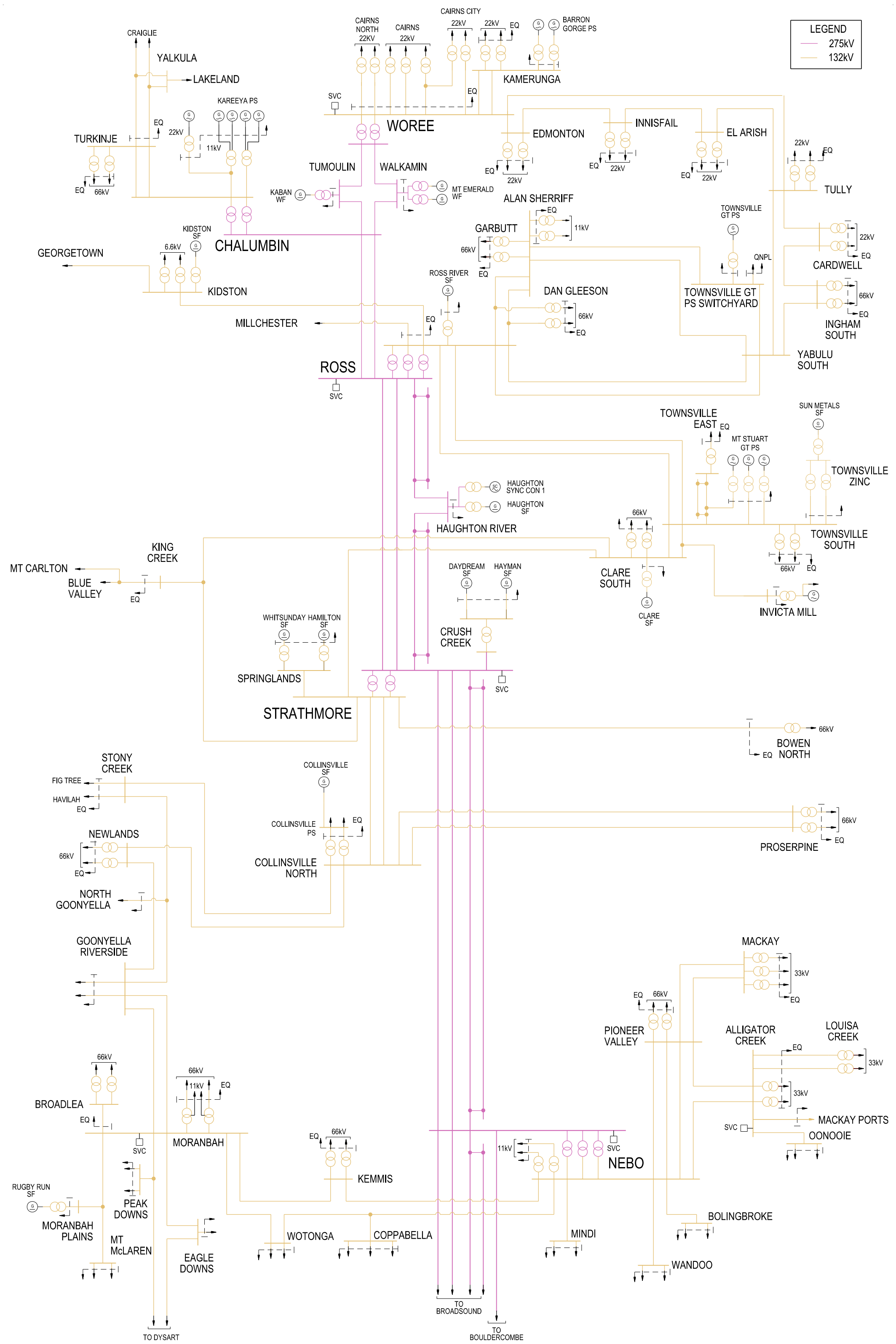


Figure 7.3 Existing HV network July 2023 – Central Queensland

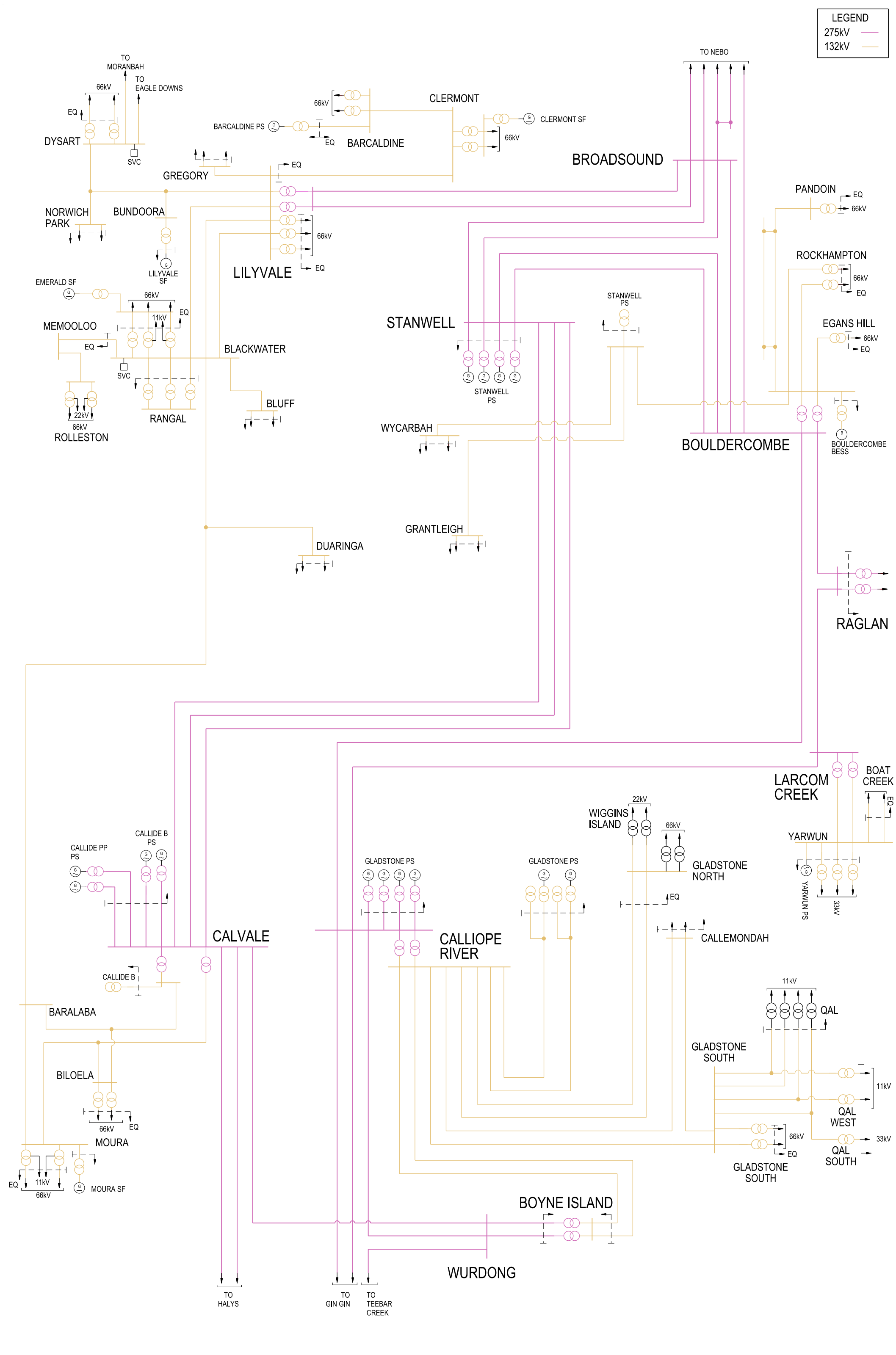


Figure 7.4 Existing HV network July 2023 - South West Queensland

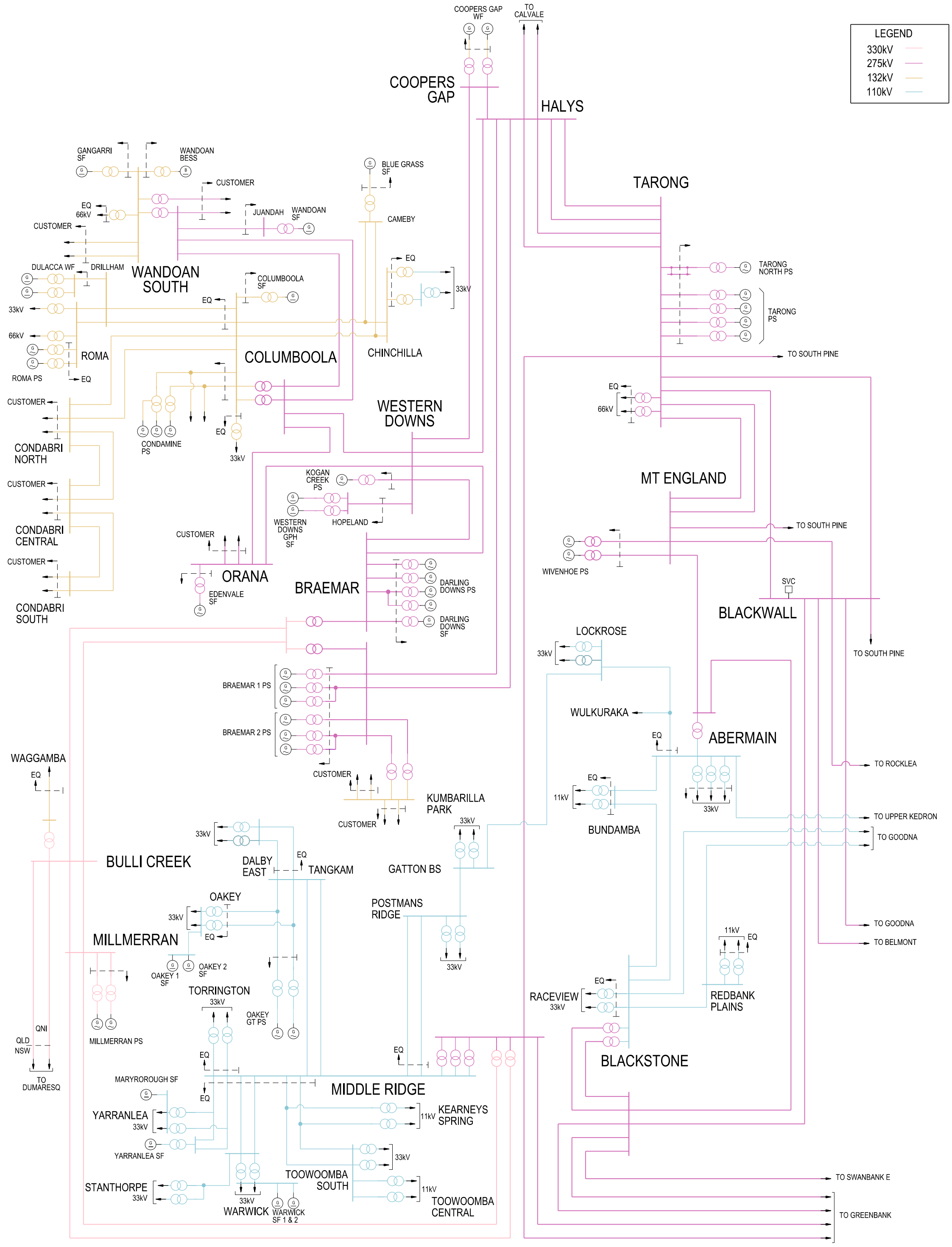
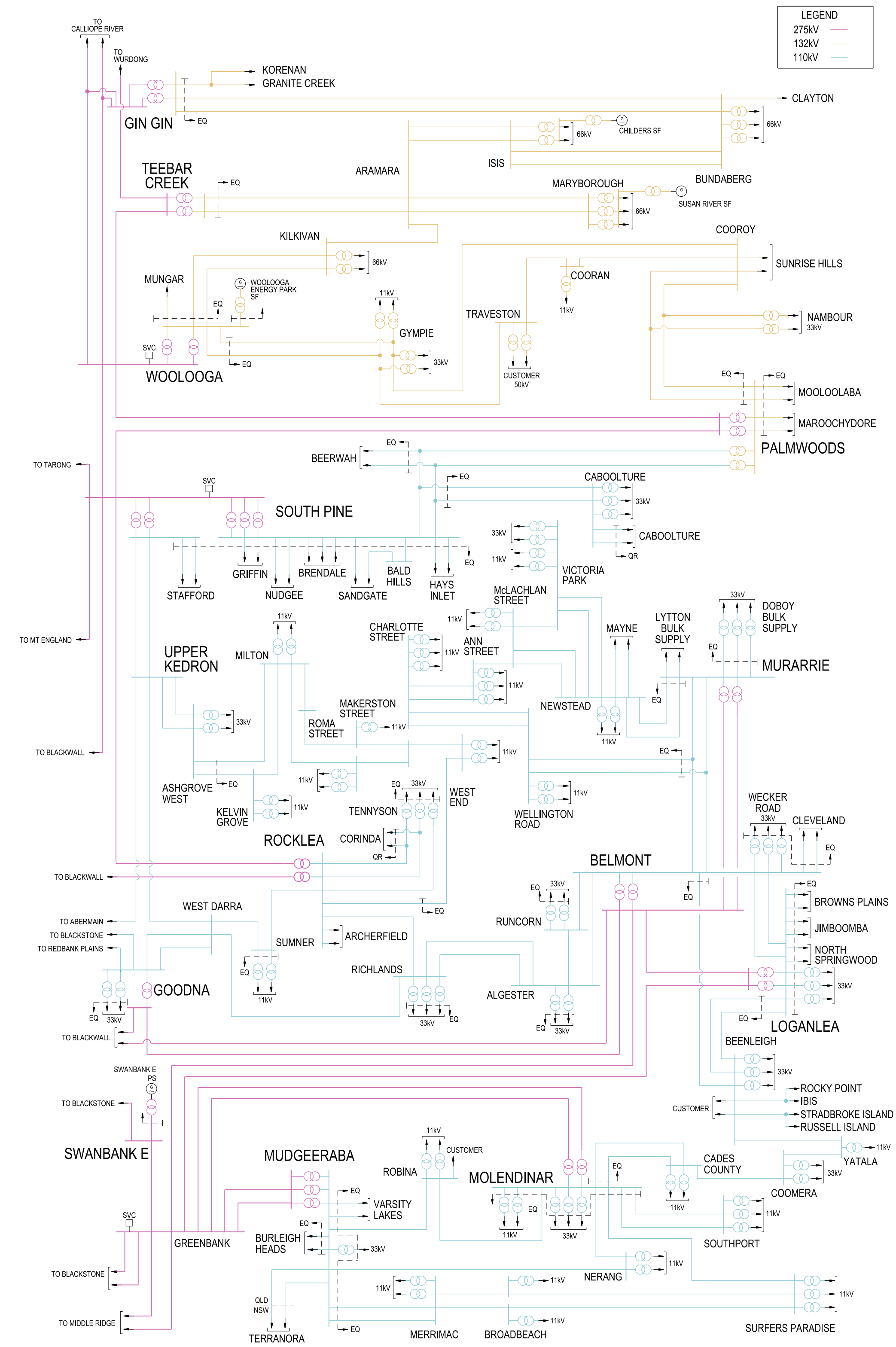


Figure 7.5 Existing HV network July 2023 - South East Queensland



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 in-service 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 later this year will trigger 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 7.6 and 7.7 provide 2021/22 and 2022/23 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 7.8 provides the changes in energy transfers from 2021/22 to 2022/23. 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 7.6 2021/22 zonal electrical energy transfers (GWh)

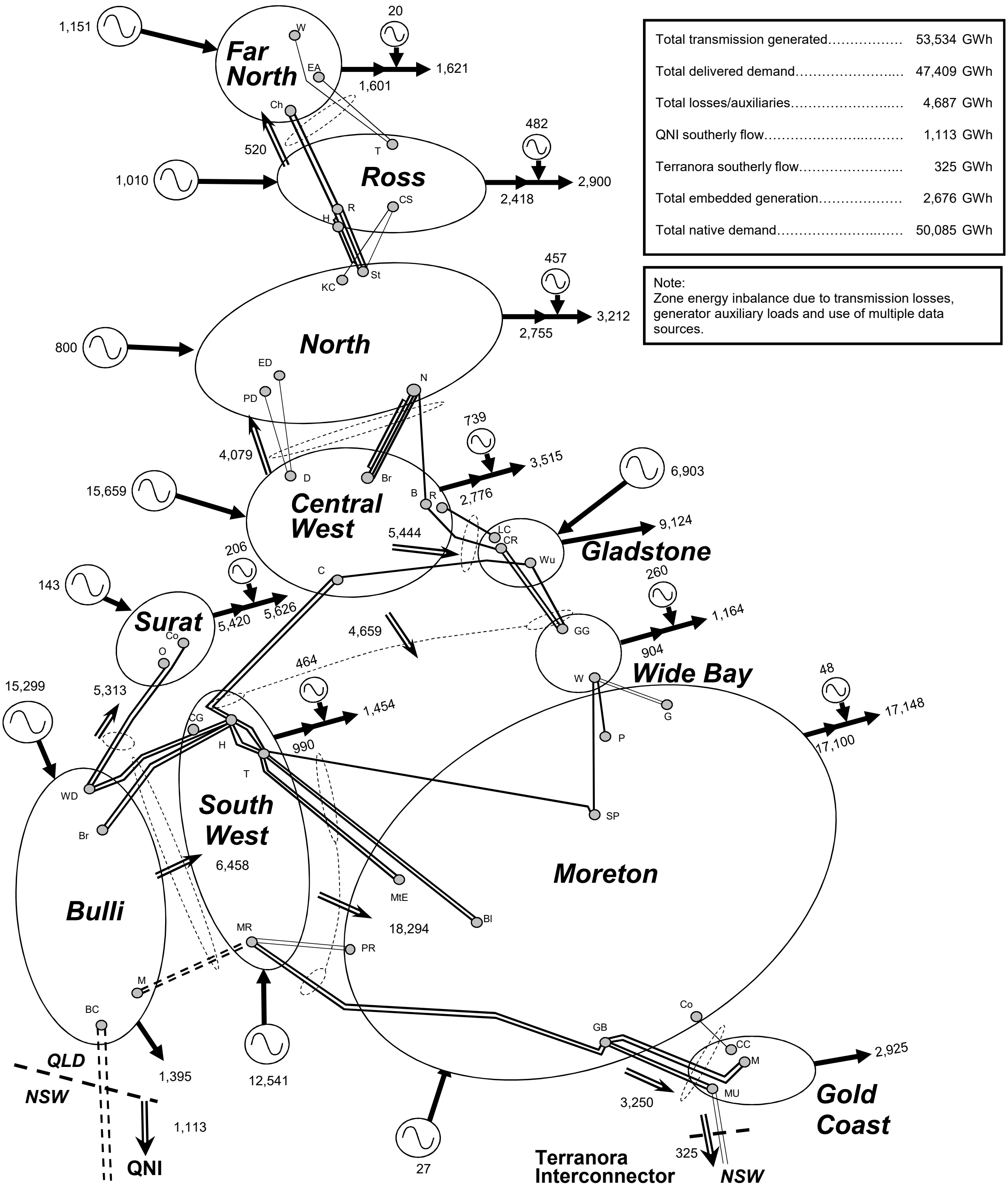


Figure 7.7 2022/23 zonal electrical energy transfers (GWh)

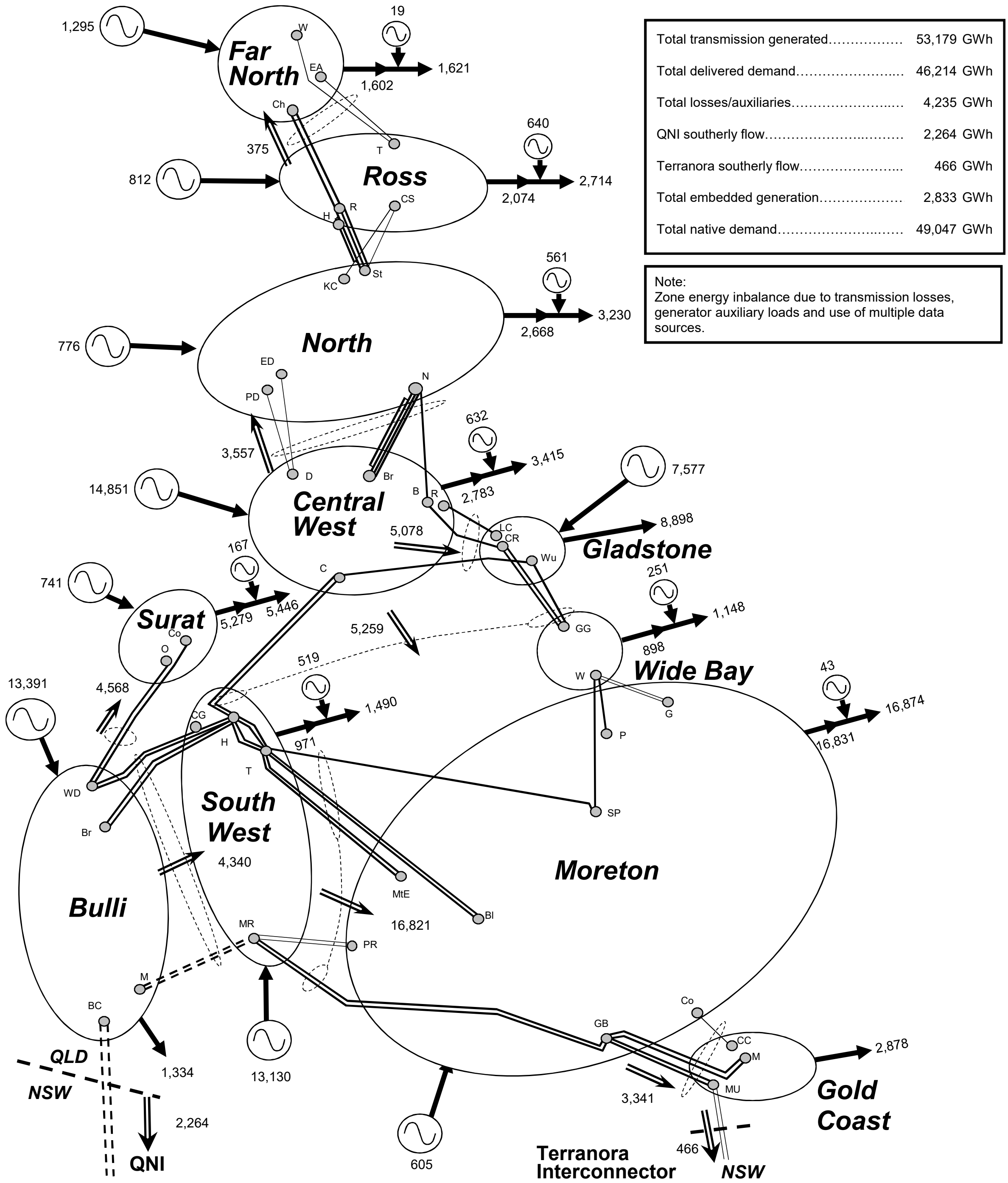
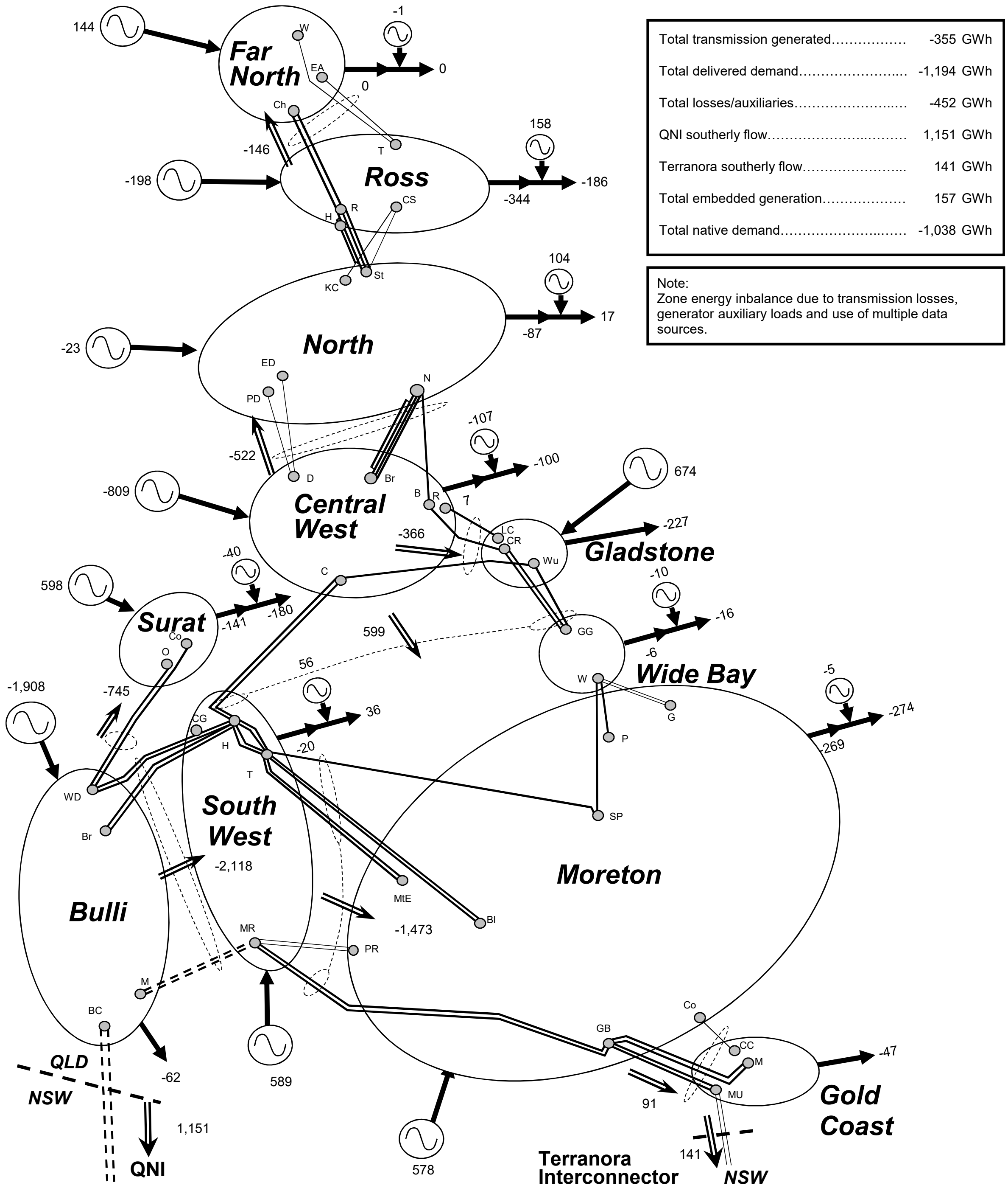


Figure 7.8 Change in zonal electrical energy transfers (GWh)



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 Woree SVC or Mt Emerald Wind Farm.

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 approximately one hour during outage conditions in 2022/23. The historical duration of constrained operation for the FNQ grid section is summarised in Figure 7.9.

Figure 7.9 Historical FNQ grid section constraint times

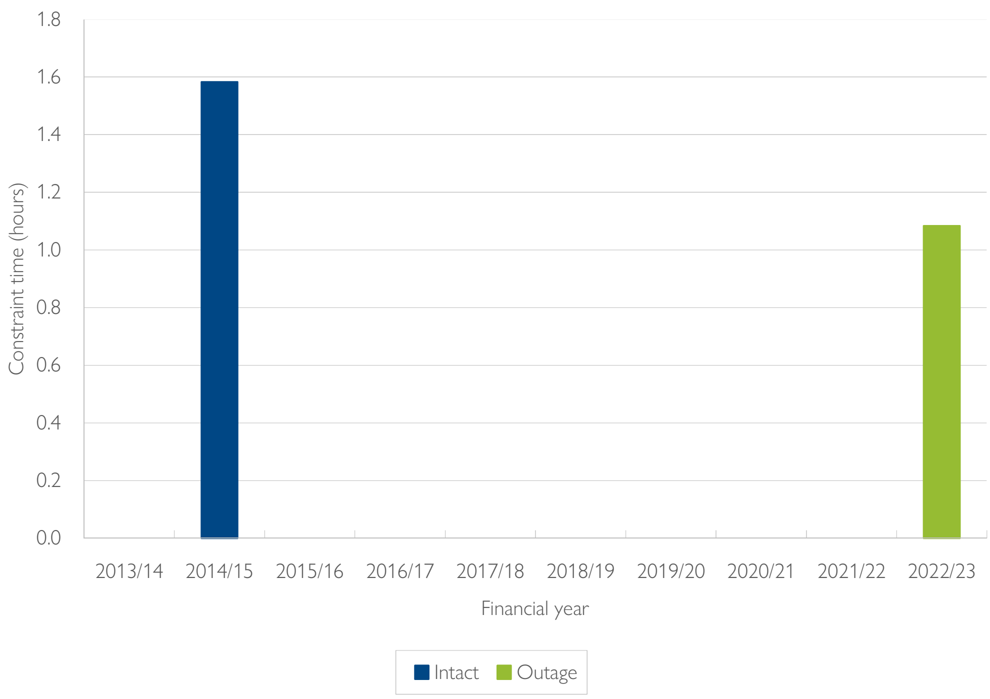
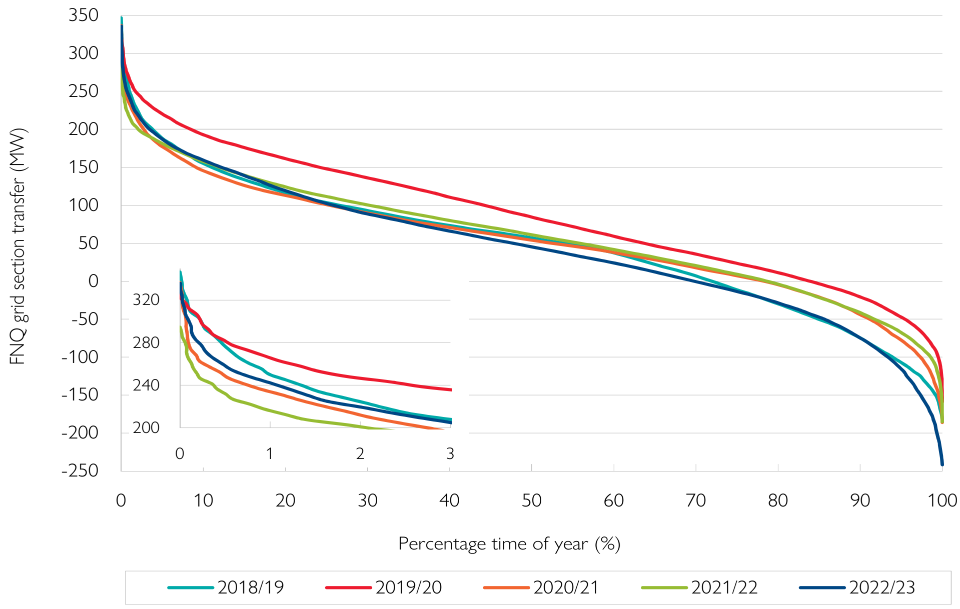


Figure 7.10 provides historical transfer duration curves showing the duration and magnitude of southerly flows have increased between 2021/22 and 2022/23. Historically, changes in peak flow and energy delivered to the Far North zone by the transmission network have been dependant on the Far North zone load and generation from the hydro generating power stations at Barron Gorge and Kareeya and Mt Emerald Wind Farm. This year the energisation of Kaban Wind Farm has further increased the available generation in the Far North zone. This has resulted in a corresponding decrease in northerly delivered energy across the Far North Queensland grid section (refer to figures 7.6, 7.7 and 7.8).

Figure 7.10 Historical FNQ grid section transfer duration curves



In May 2021 it was announced that the Queensland Government would invest transmission line infrastructure in North Queensland to establish a Queensland REZ (QREZ), with Neoen's Kaban Wind Farm identified as the foundational proponent.

The transmission augmentation works involve energising one side of the existing 132kV coastal double circuit transmission line at 275kV. This will result in the establishment of a third 275kV transmission line into Woree substation in Cairns. Work on the third 275kV transmission augmentation is expected to be completed by April 2024 (refer to Table 9.3).

7.6.2 Central Queensland to North Queensland grid section

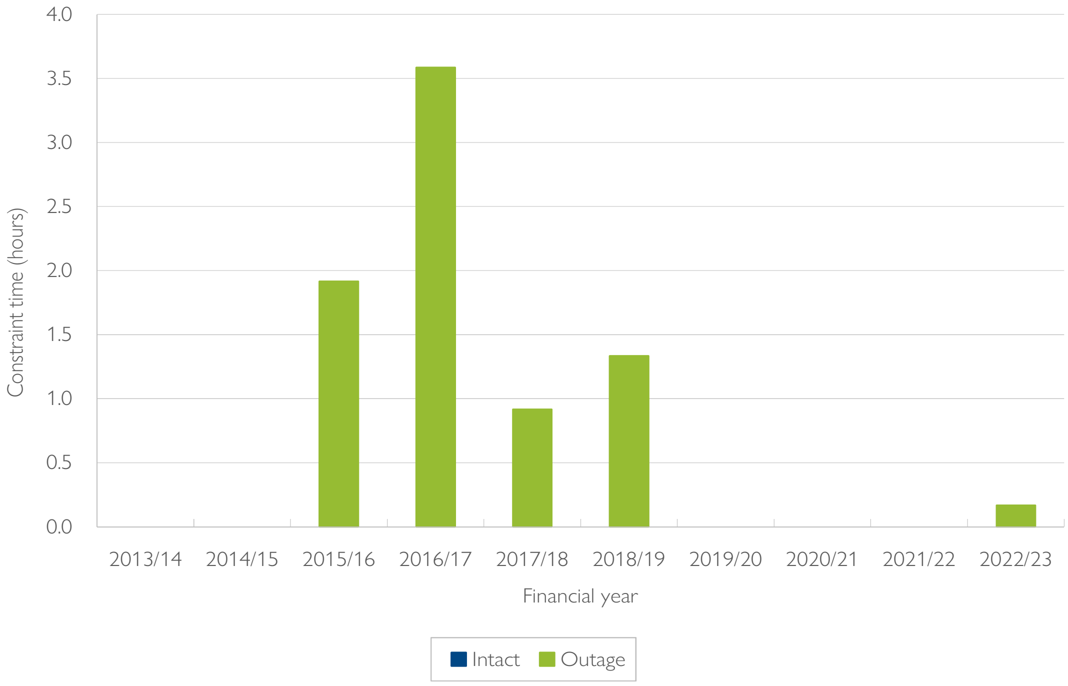
Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations 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 constrained for 10 minutes during outage conditions in 2022/23. The historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 7.11.

Figure 7.11 Historical CQ-NQ grid section constraint times



The constraint times were associated with thermal constraint equations during planned outages to ensure operation within plant thermal ratings.

Figure 7.12 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 2022/23 is similar to previous years.

Figure 7.12 Historical CQ-NQ grid section transfer duration curves

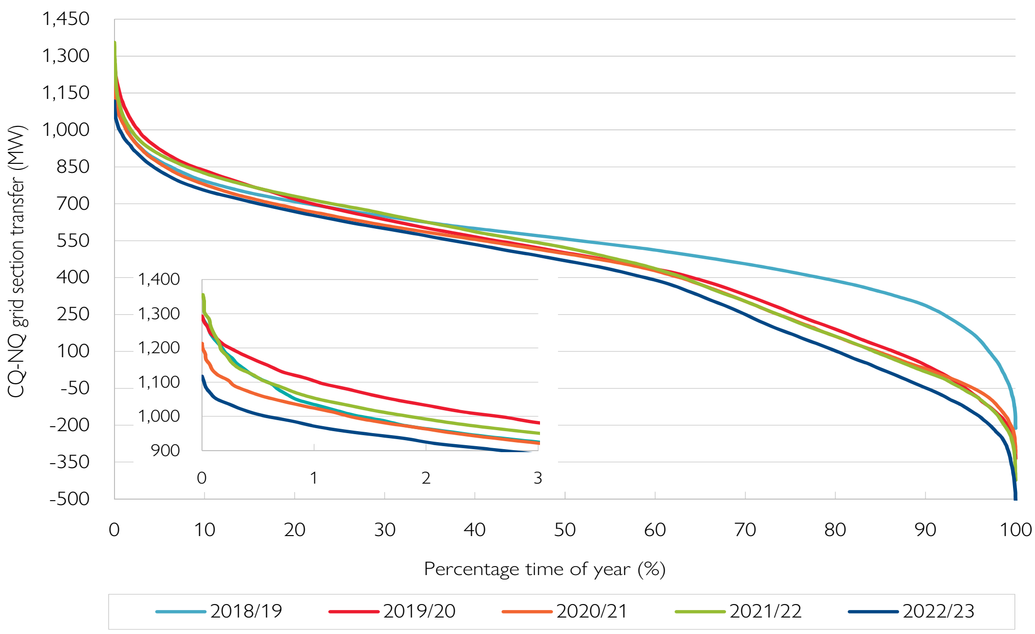
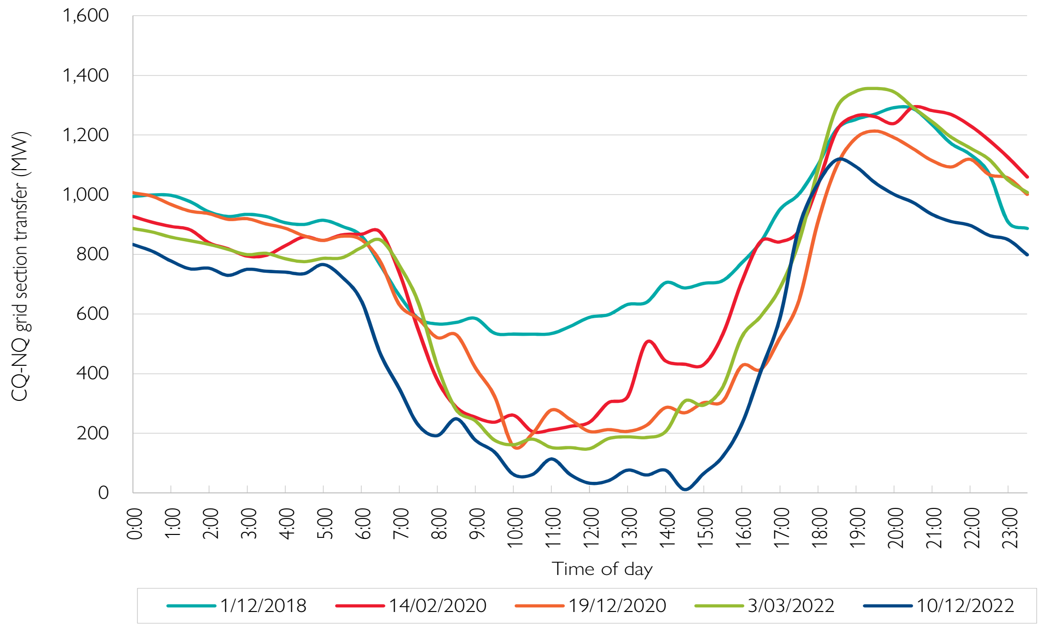


Figure 7.13 provides a different view of the altered power flows experienced over the last years for the day corresponding to the annual peak CQ-NQ transfer. This shows the impact of solar generation in creating minimum demands and network transfers during the middle of the day.

Figure 7.13 Historical CQ-NQ peak grid section transfer daily profile



These midday reductions in transfers are introducing operational challenges in voltage control. Midday transfers are forecast to continue reducing with integration of additional rooftop PV and large-scale VRE in NQ. Correspondingly, voltage control is forecast to become increasingly challenging for longer durations.

In February 2021, Powerlink completed the Project Assessment Conclusions Report (PACR)[3] recommending the establishment of a 150MVAr 300kV bus reactor at Broadsound, which is expected to be commissioned by October 2024.

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) 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:

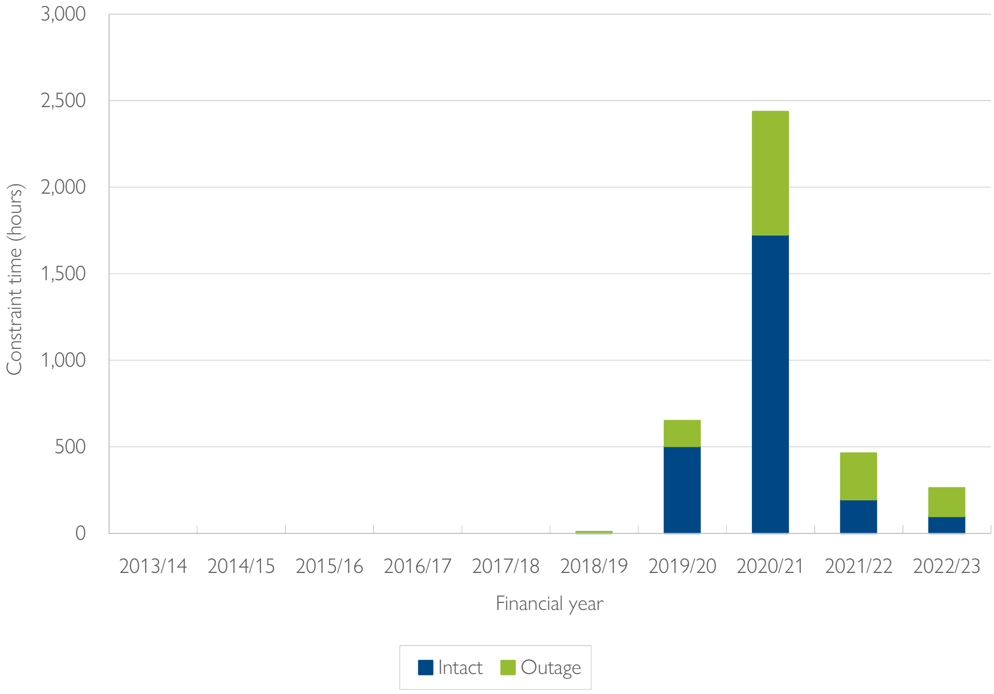
- number of synchronous units online in CQ and NQ
- NQ demand
- status of Haughton Synchronous Condenser.

[3] Powerlink, Project Assessment Conclusions Report - Managing voltage control in Central Queensland, February 2021.

The historical duration of constrained operation for inverter-based resources in NQ is summarised in Figure 7.14. During 2022/23, inverter-based resources in NQ experienced 262 hours of constrained operation, of which 98 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[4]. While the shortfall was declared in the Wide Bay zone, it may be best addressed by a solution elsewhere in the state. Progress on addressing this gap is discussed in Section 6.8.1.

Figure 7.14 Historical NQ system strength constraint times (1)



Note:

(1) AEMO's Infoserver (and therefore the 2021 TAPR) includes bound constraints applying to unavailable VRE (e.g. solar farms during the night). These constraint records are now removed from the calculation. Constraint times for 2020/21 have been revised.

7.6.4 Gladstone grid section

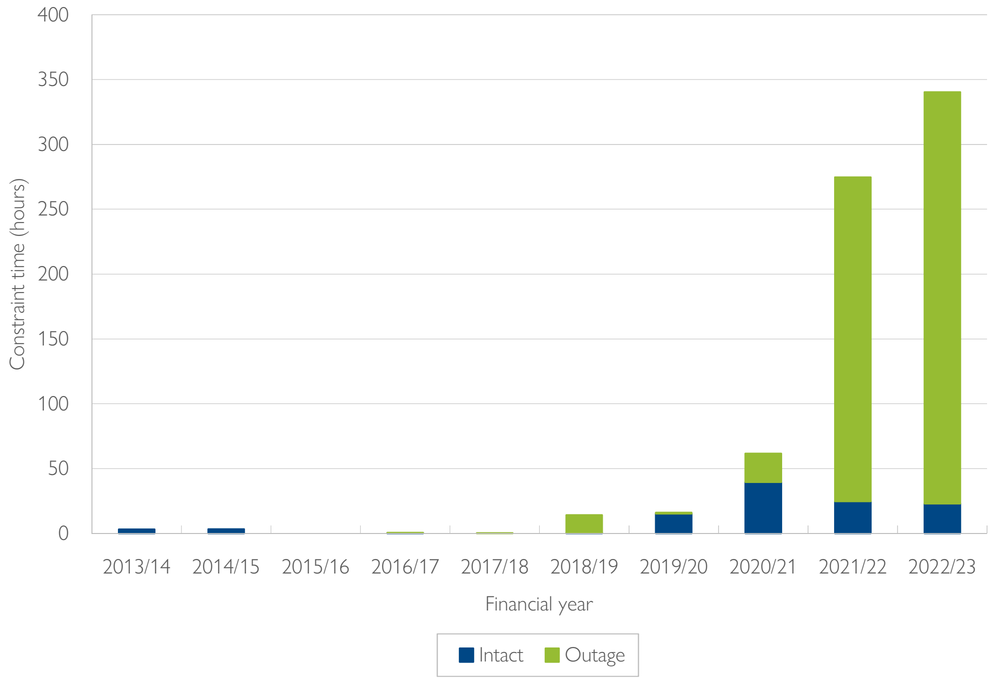
Maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits.

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 real time 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 7.15. During 2022/23, the Gladstone grid section experienced 340 hours of constrained operation, with 23 hours during intact system conditions due to lower generation in the Gladstone zone coupled with higher flows from central to southern Queensland. The majority of the constrained operation was due to outages associated with planned primary plant replacement work at Bouldercombe substation.

[4] Powerlink, Request for power system security services in central, southern and broader Queensland regions, May 2022.

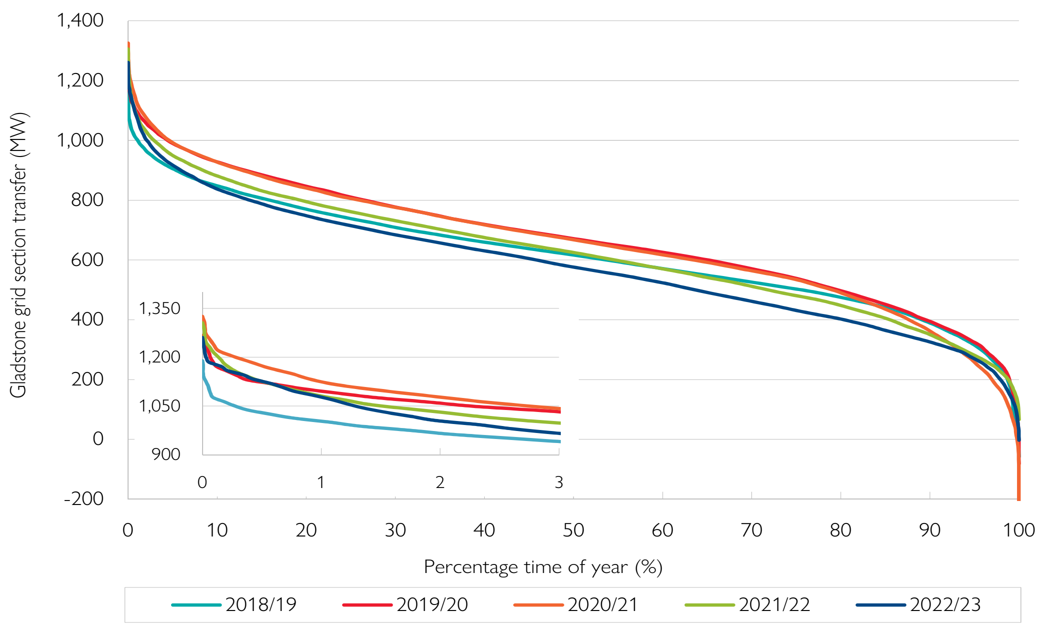
Figure 7.15 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the balance of generation and demand in Gladstone and transfers to between CQ and SQ. Figure 7.16 provides historical transfer duration curves showing decreased utilisation in 2022/23 compared to 2021/22. Reduced demand in the Gladstone zone is responsible for this change (refer to figures 7.6, 7.7 and 7.8).

Section 8.2.3 discusses the strategy to increase the capacity of the Gladstone grid section should there be a significant shift in the generation and demand balance in the Gladstone zone.

Figure 7.16 Historical Gladstone grid section transfer duration curves



7.6.5 Central Queensland - 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.

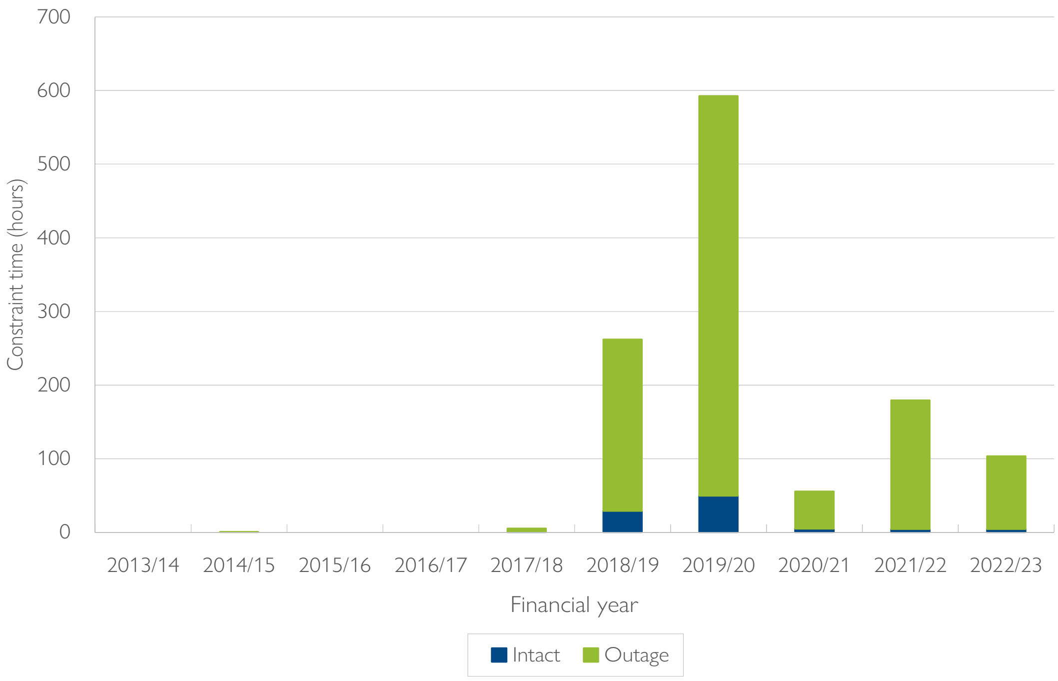
The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

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 7.17. During 2022/23, the CQ-SQ grid section experienced 103 hours of constrained operation. Constrained operation was due to outages associated with planned maintenance activities. Only five hours of constrained operation was during system normal conditions.

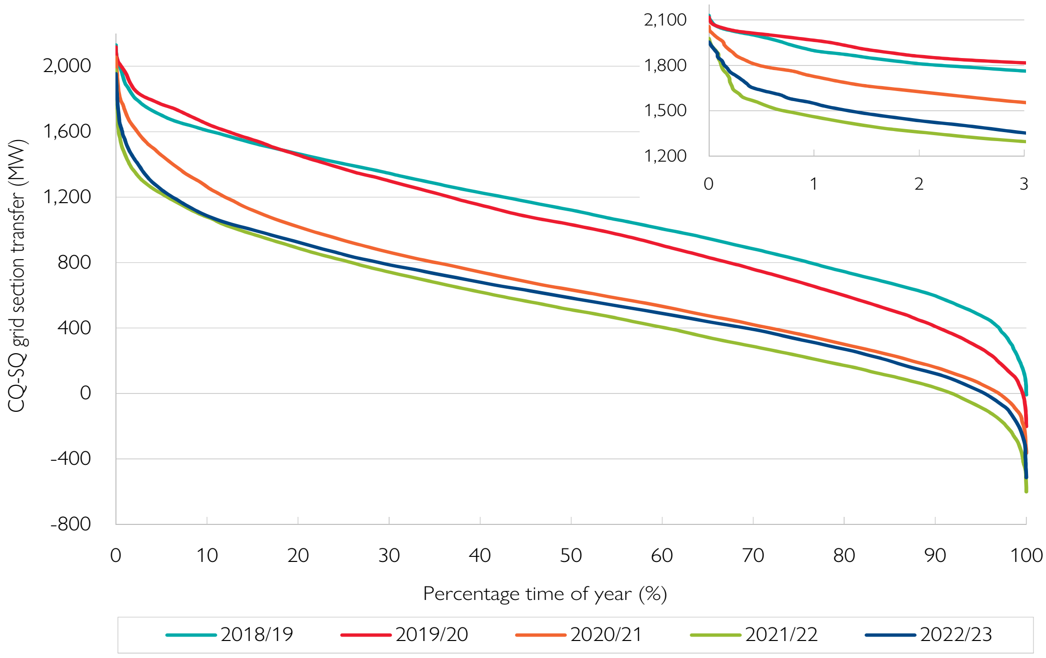
Figure 7.17 Historical CQ-SQ grid section constraint times



Associated with high penetration of rooftop PV installations in southeast Queensland, Powerlink is reviewing the transient stability limit for CQ-SQ. The review includes dynamic load models that include rooftop PV behaviour. Powerlink submitted a draft report to AEMO in March 2023.

Figure 7.18 provides historical transfer duration curves showing utilisation similar to that over the last two years. Over the 2022/23 year there was a decrease in output from generation in central Queensland but this was offset by an increase in output from generation in north Queensland (refer to figures 7.6, 7.7 and 7.8),

Figure 7.18 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.

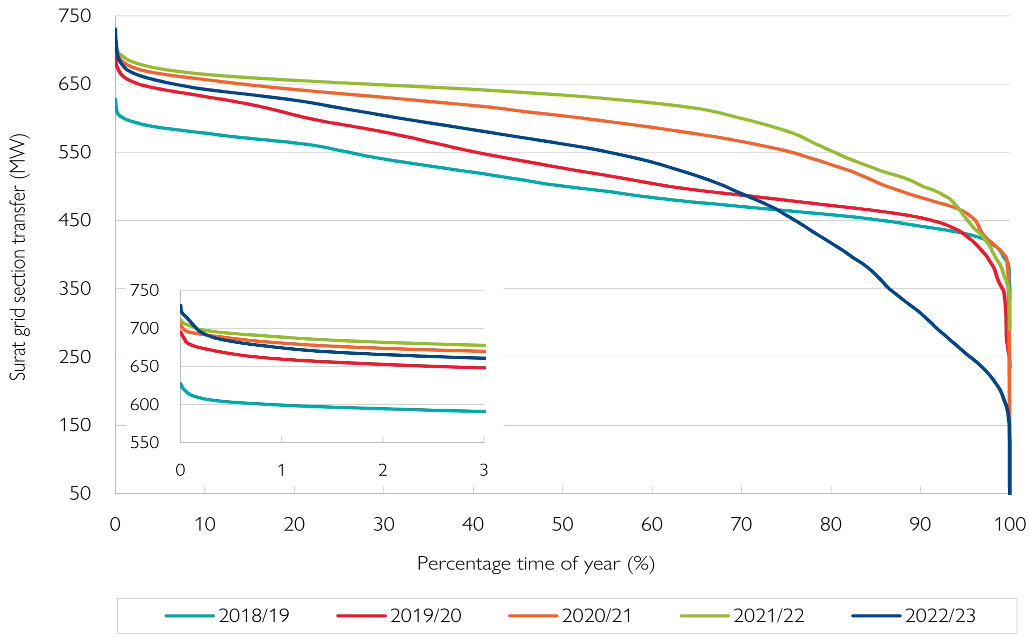
7.6.6 Surat grid section

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[5]. 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 7.19 provides the transfer duration curves for the last five years. Energy transfers have reduced in the last year due to Blue Grass, Columboola, Gangarri and Edenvale Solar Farms and Dulacca Wind Farm all coming online and at various stages of commissioning.

5 The Orana Substation is connected to one of the Western Downs to Columboola 275kV transmission lines (refer to Figure 7.4).

Figure 7.19 Historical Surat grid section transfer duration curve



In April 2023 the Tarong to Chinchilla 132kV feeders were removed from service to make way for the development of the Western Downs REZ with Wambo Wind Farm as the foundation project.

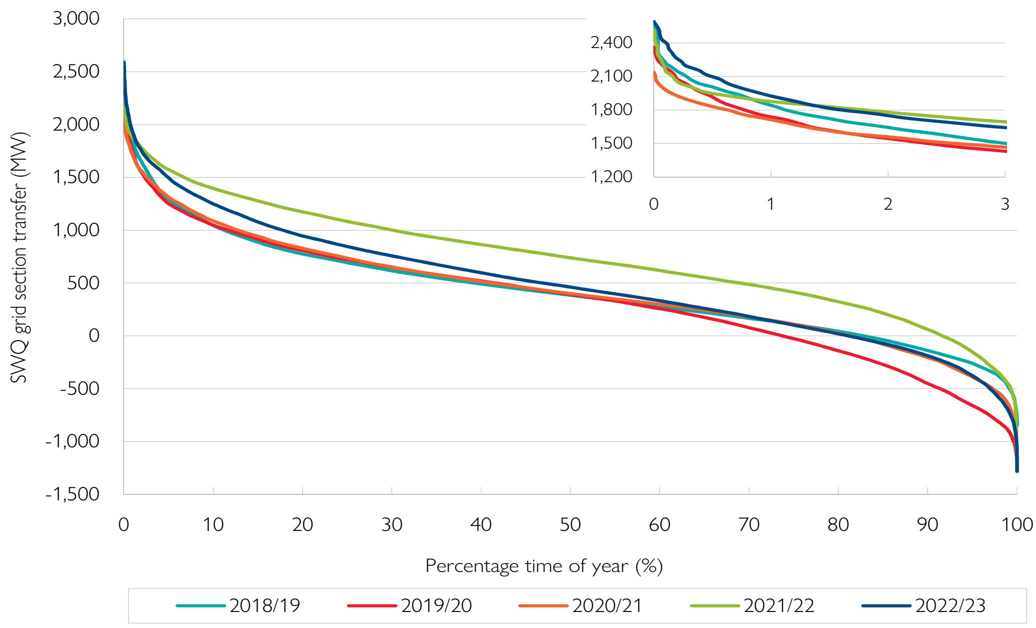
7.6.7 South West Queensland grid section

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 SWQ grid section did not constrain operation at any time during the last 10 years.

Figure 7.20 provides historical transfer duration curves showing a decrease in energy transfer between 2021/22 and 2022/23. After experiencing higher than normal flows on the SWQ grid section last year, the flows have returned to levels observed in the previous years due to higher CQ-SQ flows and more generation in the Moreton region (refer to figures 7.6, 7.7 and 7.8).

Figure 7.20 Historical SWQ grid section transfer duration curves



AEMO's 2022 Integrated System Plan[6] (ISP) identified stage 1 of the Darling Downs REZ Expansion as a future actionable ISP project. This project involves an upgrade to the transformer capacity at Middle Ridge Substation. Powerlink provided a preparatory activities report for this project to AEMO on 30 June 2023.

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. The limitation arises from insufficient reactive power reserves in southern Queensland.

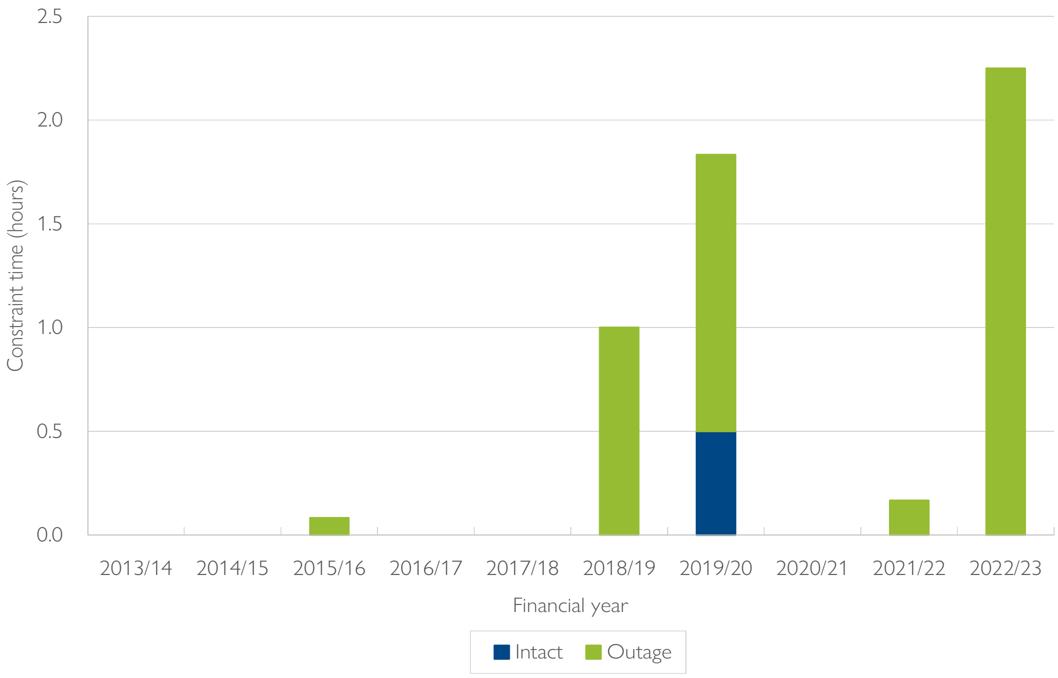
Limit equations in Table G.5 of Appendix G show that the following variables have a significant effect on transfer capability:

- 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 constrained for two hours in 2022/23. This occurred during planned maintenance work. The historical duration of constrained operation for the Tarong grid section is summarised in Figure 7.21. Constraint times have been minimal over the last 10 years.

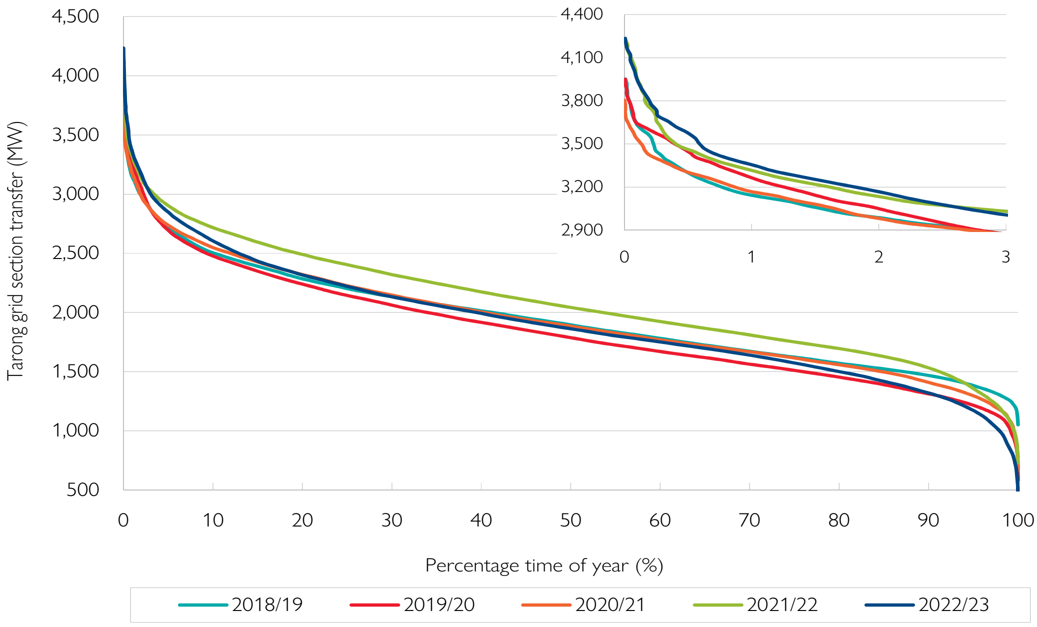
Figure 7.21 Historical Tarong grid section constraint times



[6] AEMO, 2022 Integrated System Plan (ISP), June 2022.

Figure 7.22 provides historical transfer duration curves showing a decrease in flows between 2021/22 and 2022/23. After experiencing higher than normal flows on the SWQ grid section last year, predominantly due to an unplanned outage of the Swanbank E generator between December 2021 and September 2022, the transfers have returned to levels observed in the previous years (refer to figures 7.6, 7.7 and 7.8).

Figure 7.22 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 Greenbank to Mudgeeraba 275kV circuit.

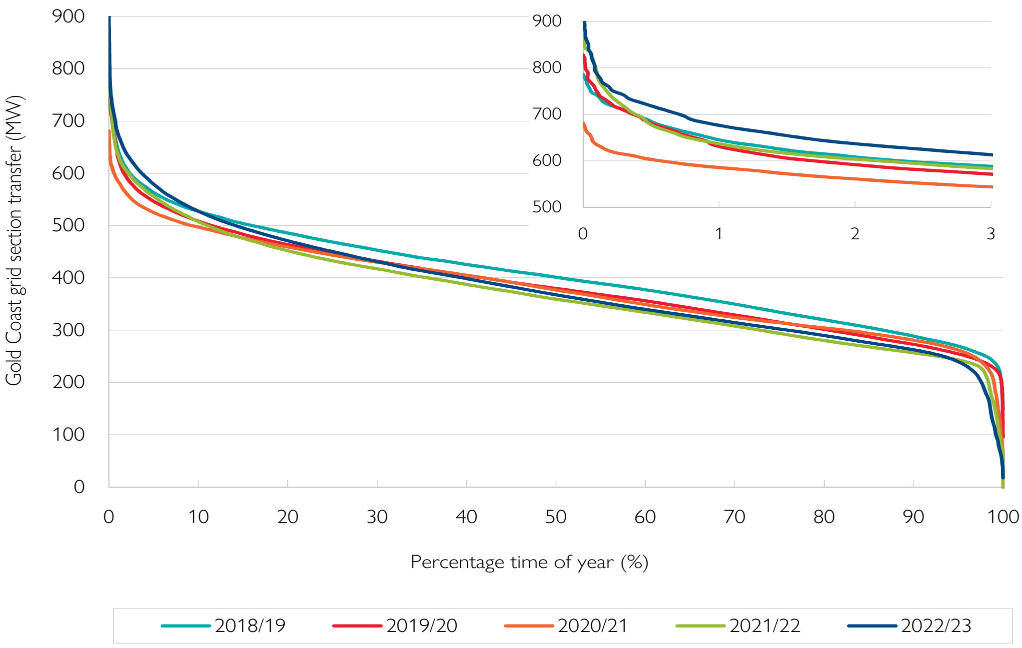
The limit equation in Table G.6 of Appendix G shows that the following variables have a significant effect on transfer capability:

- 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. There have been no constraints on the Gold Coast grid section over the last 10 years.

Figure 7.23 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 7.6, 7.7 and 7.8).

Figure 7.23 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 publish 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 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.

Associated with high penetration of rooftop PV installations, Powerlink is reviewing the transient stability limit for QNI southerly transfer. The review includes dynamic load models that include rooftop PV behaviour. Powerlink submitted a draft report to AEMO in March 2023.

AEMO's 2022 Integrated System Plan[7] (ISP) considered the QNI Connect project that would increase transfer capacity between Queensland and New South Wales. The ISP identified that QNI Connect may be required as early as 2029/30 (based on the Hydrogen Superpower scenario). Powerlink provided a preparatory activities report for this project to AEMO on 30 June 2023.

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[8]
- 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[9]) 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.

Statewide delivered energy has decreased slightly from 2021/22 to 2022/23. Most zones experienced a reduction in total delivered energy as well as the majority of zones setting new record minimum demands (refer to Figure 7.8). The Queensland region's installed rooftop PV capacity continues to increase. As at 30 June 2023 there was 5,583MW of rooftop PV generating capacity in the state[10]. This is an increase of approximately 830MW 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

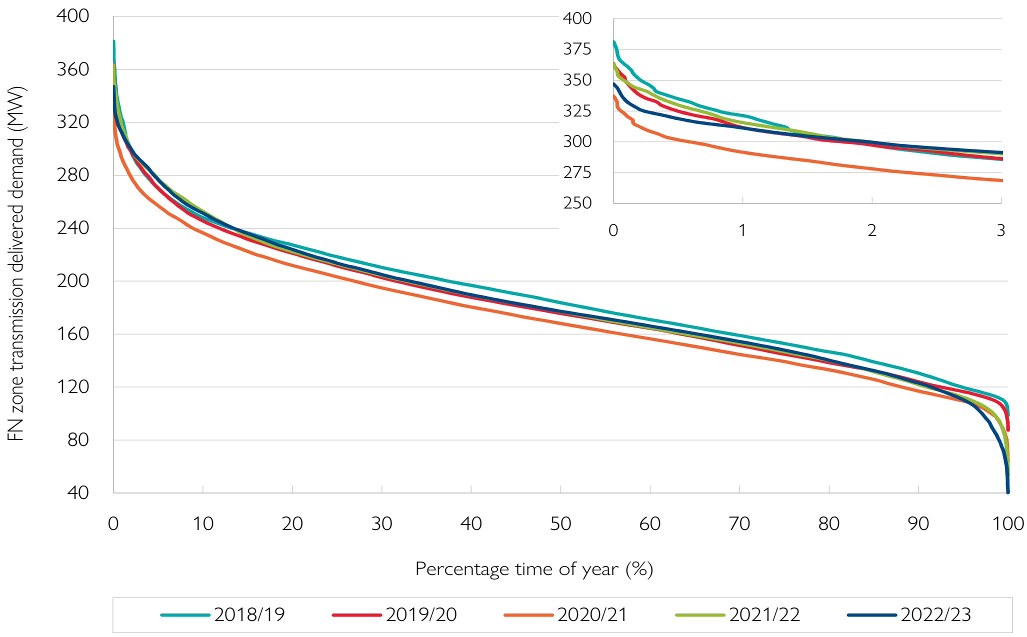
The Far North zone experienced no load loss for a single network element outage during 2022/23.

The Far North zone includes the non-scheduled embedded generator Lakeland Solar and Storage as defined in Figure 3.9. This embedded generator provided 19GWh during 2022/23.

Figure 7.24 provides historical transmission delivered load duration curves for the Far North zone. There was no material change in energy delivered from the transmission network between 2021/22 and 2022/23. The maximum transmission delivered demand in the zone was 347MW, which is below the highest maximum demand over the last five years of 381MW set in 2018/19. The minimum transmission delivered demand in the zone was 40MW, which is the lowest minimum demand on record.

7 AEMO, 2022 Integrated System Plan, June 2022.
8 AEMO, List of Vulnerable Lines, effective May 2023.
9 An Exception 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.
10 Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/07/2023, August 2023.

Figure 7.24 Historical Far North zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO includes the Chalumbin to Turkinje 132kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in November 2022.

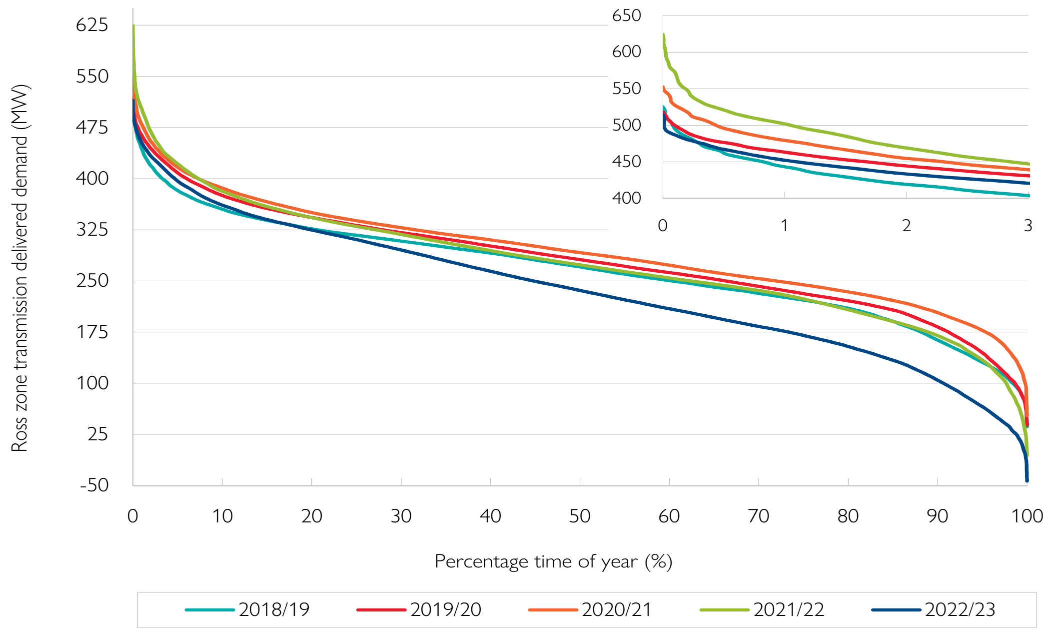
7.7.2 Ross zone

The Ross zone experienced one load loss for a single network element outage during 2022/23. The duration of the outage was approximately 15 hours and approximately 24MWh of energy was lost. The loads impacted by this outage are supplied by a single radial connection under normal system conditions.

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 640GWh during 2022/23.

Figure 7.25 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 14.2% between 2021/22 and 2022/23 to the lowest level in the last decade. The reduction in energy delivered is due to the increases in energy from the embedded generators Sun Metals Solar Farm and Kennedy Energy Park Wind Farm accompanied by a reduction in native demand. The peak transmission delivered demand in the zone was 515MW, 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 -43MW, which is the lowest demand on record.

Figure 7.25 Historical Ross zone transmission delivered load duration curves



High voltages associated with light load conditions are managed with existing reactive sources.

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.

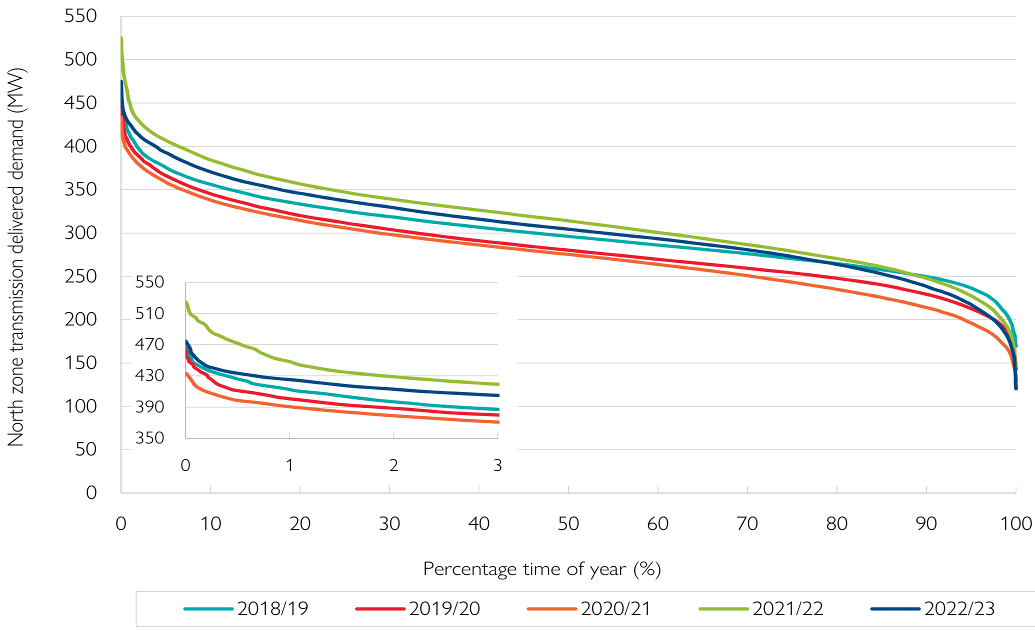
7.7.3 North zone

The North zone experienced one load loss for a single network element outage during 2022/23. The duration of the outage was less than one hour and approximately 6MWh of energy was lost. The loads impacted by this outage are supplied by a single radial connection under normal system conditions.

The North zone includes semi-scheduled embedded generator Collinsville Solar Farm and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 3.9. These embedded generators provided 561GWh during 2022/23.

Figure 7.26 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has decreased by 3.2% between 2021/22 and 2022/23. The peak transmission delivered demand in the zone was 475MW, 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 120MW, which is the lowest minimum demand in the last five years.

Figure 7.26 Historical North zone transmission delivered load duration curves



High voltages associated with light load conditions are currently managed with existing reactive sources. However, midday power transfer levels continue to reduce as additional rooftop PV is installed in NQ. As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in Section 7.6.2.

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 Stoney Creek and Collinsville North to Newlands lines, last tipped November 2022.

The following double circuit has, this year, been removed from the vulnerable list:

- Strathmore to Clare South and Strathmore to Clare South tee King Creek 132kV double circuit transmission line, last tripped January 2019.

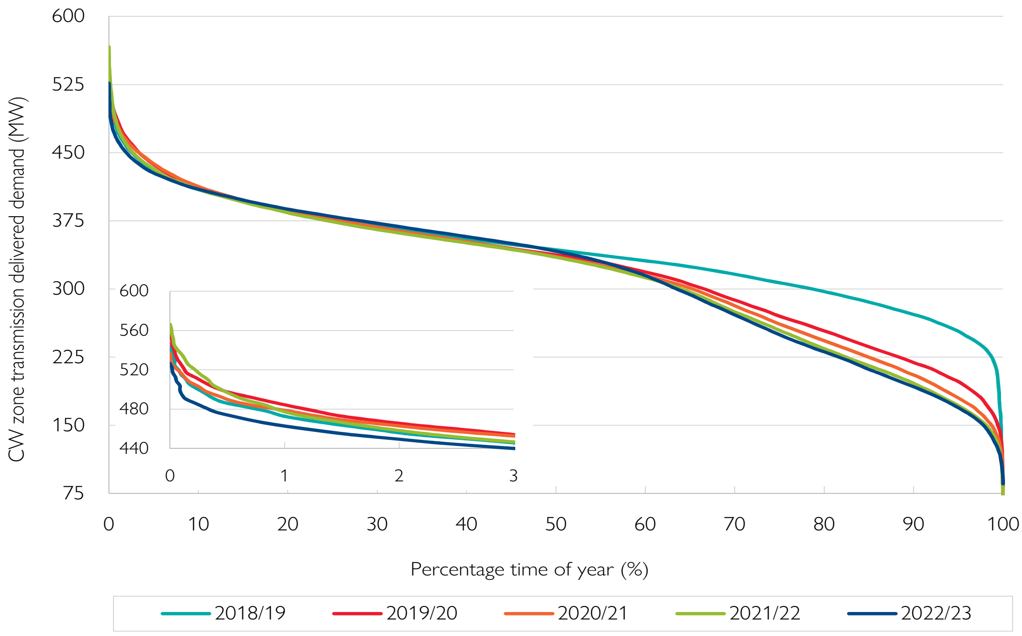
7.7.4 Central West zone

The Central West zone experienced one load loss for a single network element outage during 2022/23. The duration of the outage was less than one hour and approximately 1MWh of energy was lost. The loads impacted by this outage are supplied by a single radial connection under normal system conditions.

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 632GWh during 2022/23.

Figure 7.27 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has increased by 0.2% between 2021/22 and 2022/23, close to the historical minimum reached last year. The peak transmission delivered demand in the zone was 526MW, 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 86MW, which is higher than the lowest minimum demand over the last decade, which was 64MW recorded in 2020/21.

Figure 7.27 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.

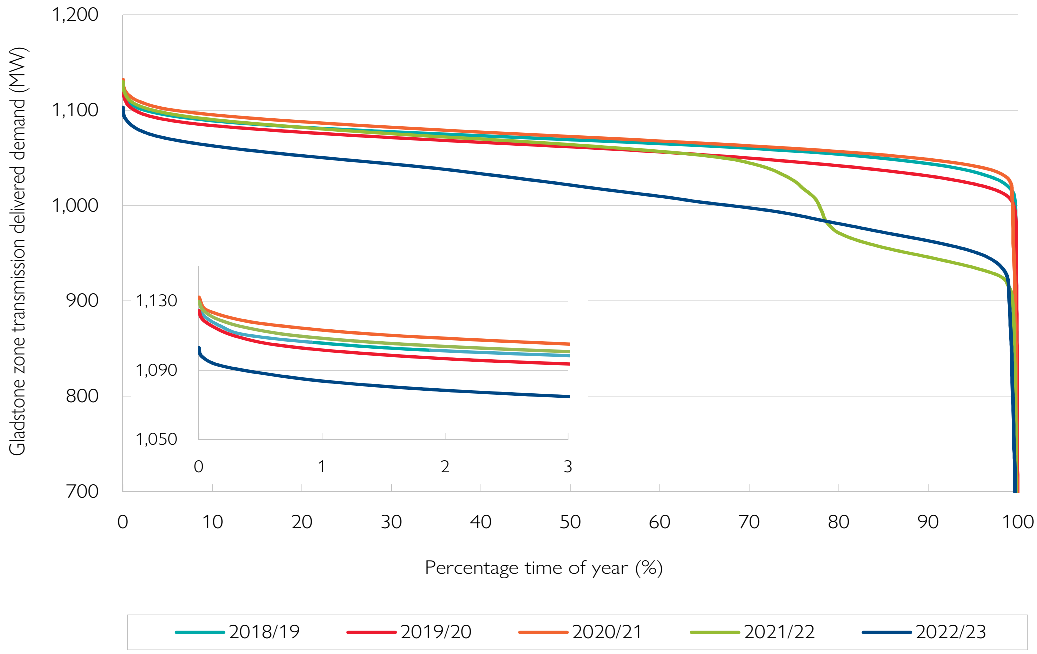
7.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2022/23.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Figure 7.28 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has reduced by 2.5% between 2021/22 and 2022/23 to the lowest level in the last decade. This decrease was due to reduced demand from Boyne Smelters Limited (BSL). The peak transmission delivered demand in the zone was 1,103MW, which is lower than the highest maximum demand over the last five years of 1,132MW set in 2020/21. 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.

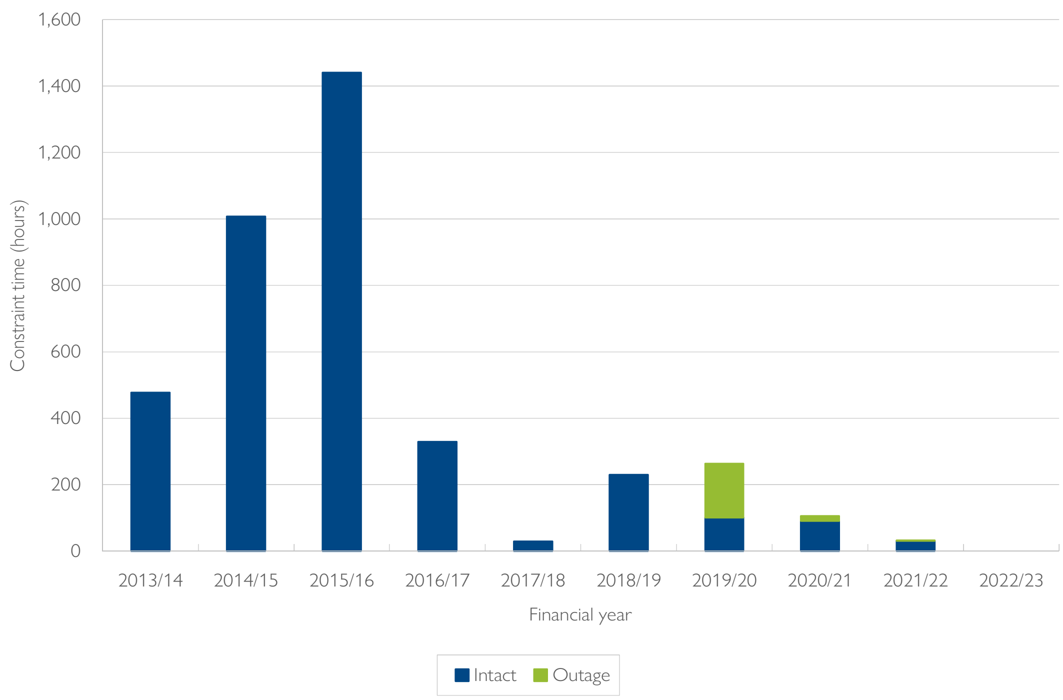
Figure 7.28 Historical Gladstone zone transmission delivered load duration curves



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 normal 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 7.29. This constraint did not constrain operation at any time during 2022/23.

Figure 7.29 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 2022/23.

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 251GWh during 2022/23.

Figure 7.30 provides historical transmission delivered load duration curves for the Wide Bay zone. Wide Bay 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. Figure 7.31 provides the daily load profile for the minimum transmission delivered days over the last five years. This Figure shows that periods of negative demand correlate with solar generation and the trend is continuing.

While energy has seen significant reductions, the peak demand, which occurs at night, remains at similar levels. Energy delivered from the transmission network reduced by 0.7% between 2021/22 and 2022/23 to the lowest level in the last decade. The peak transmission delivered demand in the zone was 325MW, which is highest maximum demand in the last decade. The minimum transmission delivered demand in the zone was -131MW, which is the lowest demand on record.

Figure 7.30 Historical Wide Bay zone transmission delivered load duration curves

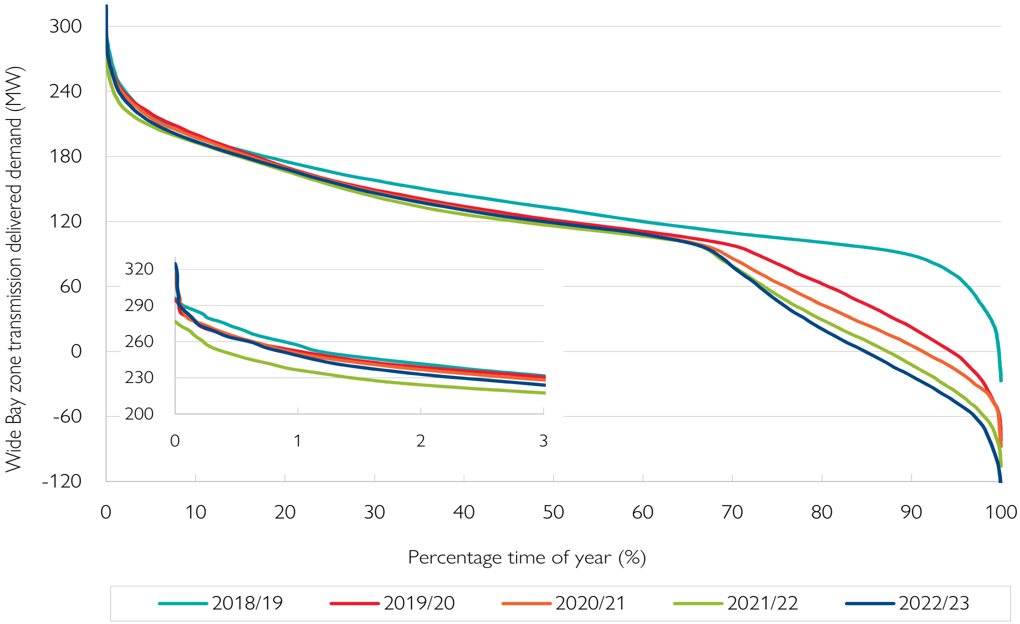
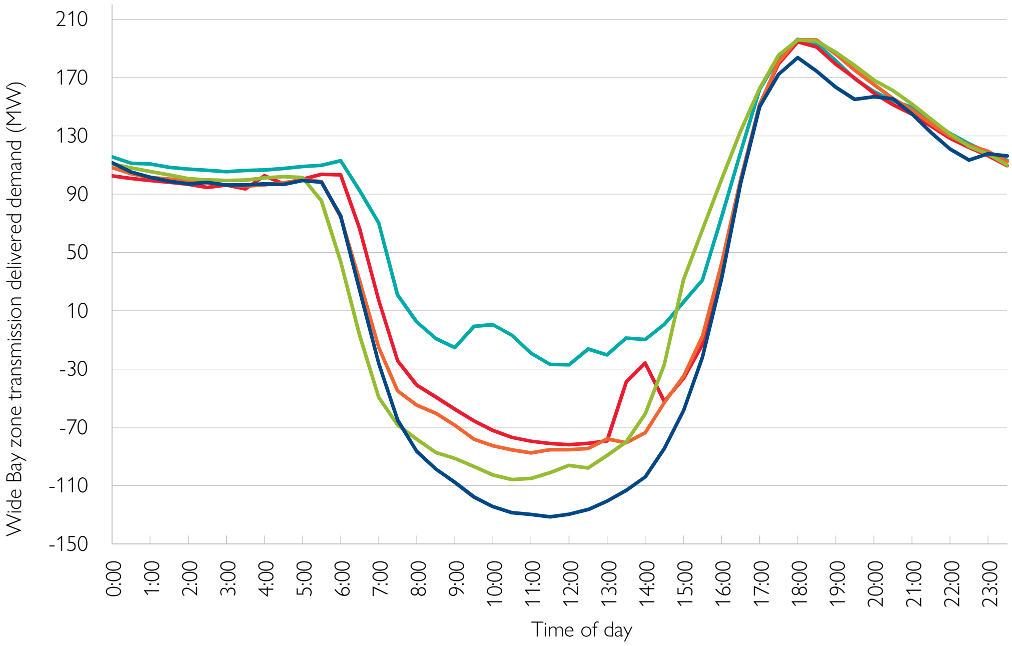


Figure 7.31 Historical Wide Bay zone minimum transmission delivered daily profile



There are currently no double circuits in the Wide Bay zone in AEMO's lightning vulnerable transmission line list.

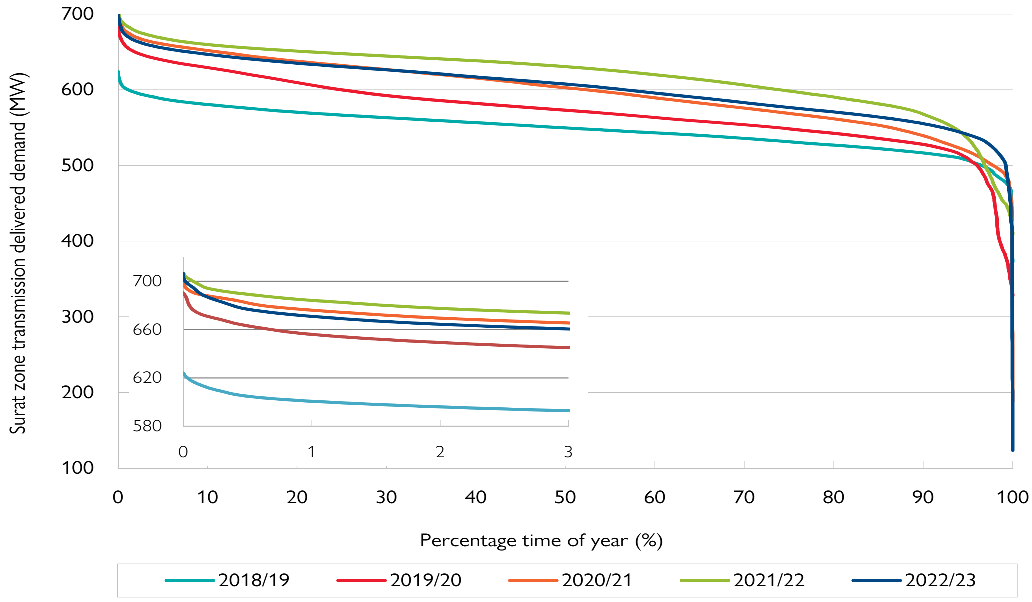
7.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2022/23.

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 167GWh during 2022/23.

Figure 7.32 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has decreased by 2.6% between 2021/22 and 2022/23. The peak transmission delivered demand in the zone was 706MW, which is just under the highest maximum demand of 707MW over the last five years set in 2021/22. The minimum transmission delivered demand in the zone was 124MW. This minimum demand coincides with a network loss of supply incident on 13 February 2023 that was the result of a multiple network element outage caused by a bushfire.

Figure 7.32 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.

The following double circuits have, this year, been removed from the vulnerable list:

- Tarong to Chinchilla 132kV double circuit transmission line, now removed from service
- Condabri North to Condabri Central 132kV double circuit transmission line, last tripped January 2020.

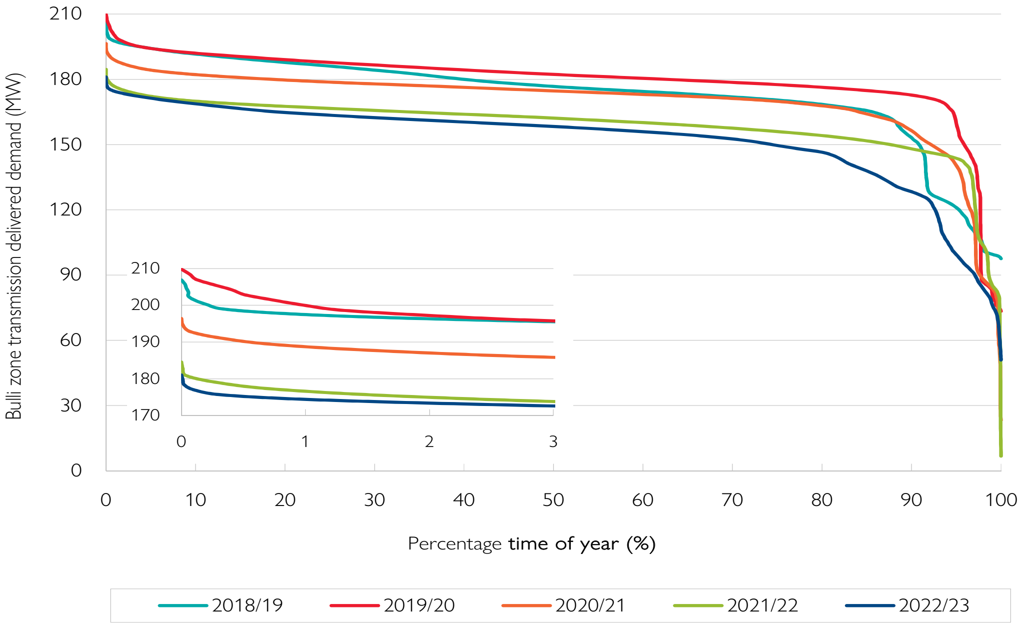
7.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2022/23.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Figure 7.33 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has reduced by 4.4% between 2021/22 and 2022/23. The peak transmission delivered demand in the zone was 181MW 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 51MW.

Figure 7.33 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

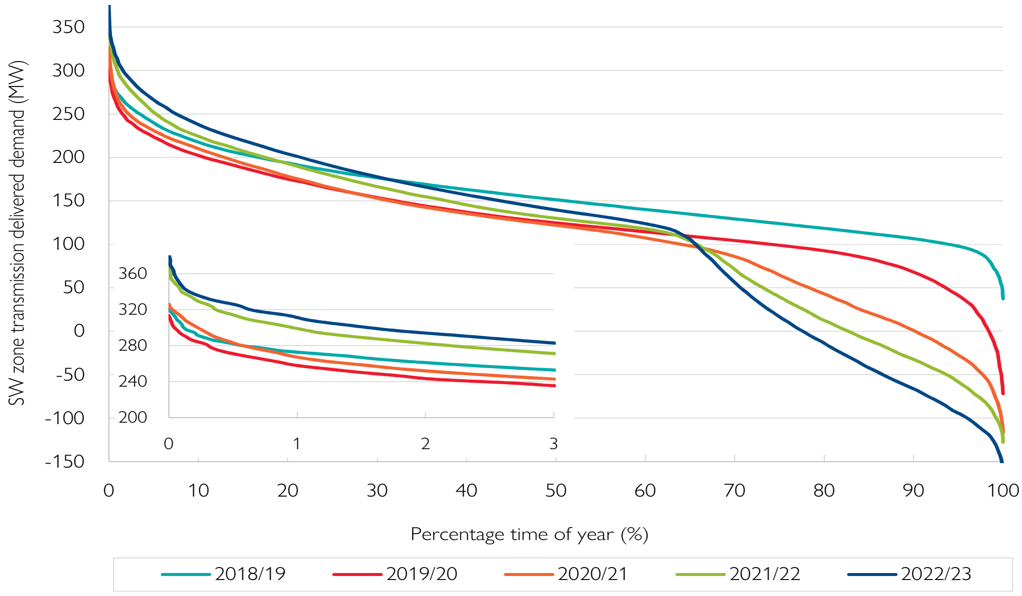
The South West zone experienced no load loss for a single network element outage during 2022/23.

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 519GWh during 2022/23.

Figure 7.34 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 2021/22 and 2022/23, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 381MW, which is the highest demand on record. The minimum transmission delivered demand in the zone was -170MW, which is the lowest demand on record.

Figure 7.34 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.

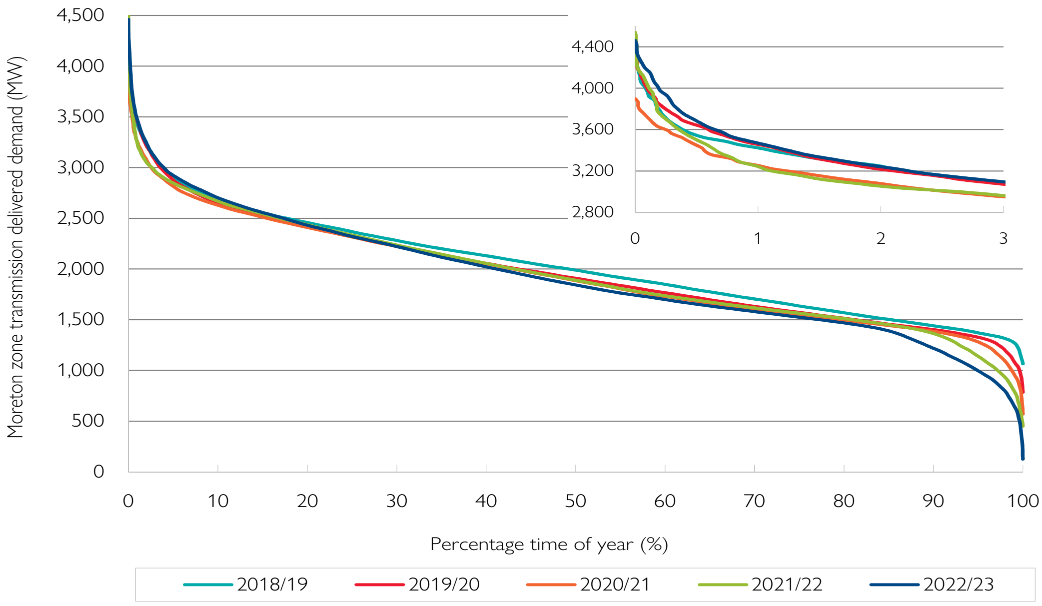
7.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2022/23.

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 43GWh during 2022/23.

Figure 7.35 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has decreased by 1.6% between 2021/22 and 2022/23 to the lowest level in the last decade. The peak transmission delivered demand in the zone was 4,460MW, which is lower than the highest maximum demand over the past five years of 4,539MW set in 2021/22. The minimum transmission delivered demand in the zone was 126MW, which is the lowest demand on record.

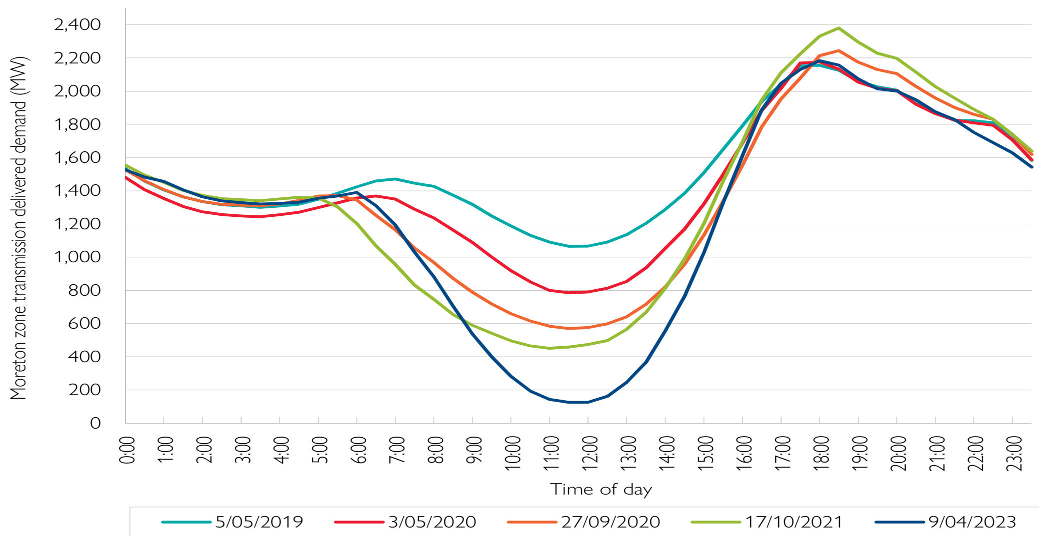
Figure 7.35 Historical Moreton zone transmission delivered load duration curves



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 NSCAS gap of up to 250 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 installed at Belmont Substation to address the long-term requirements. More detail on this process is provided in Section 6.8.1.

Figure 7.36 provides the daily load profile for the minimum transmission delivered days for the Moreton zone over the last five years. This Figure highlights the steady decrease in minimum demands but also shows the minimum demands days are shifting to shoulder periods, as the impact of greater rooftop PV yield outweighs the impact of higher native loads in the warmer weather. This is a trend observed across several zones with high levels of rooftop PV generation. The figure also highlights the increasing gap between minimum and maximum demand on these days.

Figure 7.36 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

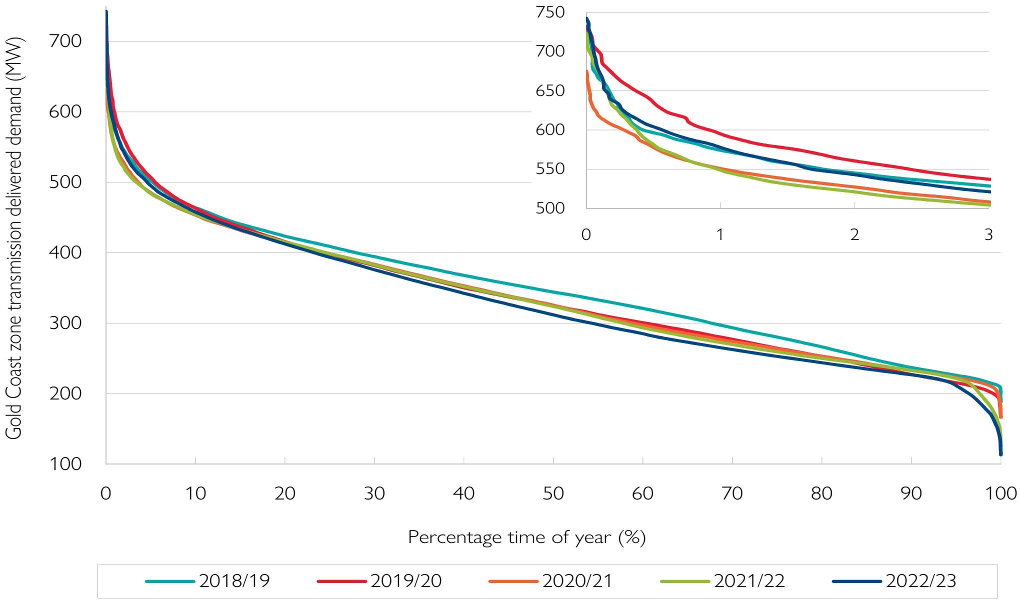
The Gold Coast zone experienced no load loss for a single network element outage during 2022/23.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.9.

Due to condition drivers, Powerlink has retired one of the 275/110kV transformers at Mudgeeraba Substation.

Figure 7.37 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has reduced by 1.6% between 2021/22 and 2022/23, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 742MW, which is the highest maximum demand over the last five. The minimum transmission delivered demand in the zone was 113MW which is the lowest demand on record.

Figure 7.37 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 planning

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 conversion of gas loads that may cause network limitations to emerge within the 10-year outlook period. It also discusses 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 and supply within South East Queensland.
- The changing generation mix (and associated peak to average production ratios of variable renewable energy (VRE) plant) also has implications for investment in the transmission network, both inter-regionally and within Queensland, across critical grid sections.
- The 2022 Integrated System Plan (ISP) and QEJP released in September 2022 identify the development of Renewable Energy Zones (REZs) that could impact the utilisation and adequacy of the Central Queensland to South Queensland (CQ-SQ) and Central West to Gladstone grid sections, Darling Downs REZ to South East Queensland and Queensland to New South Wales (NSW) Interconnector (QNI).

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 the Australian Energy Market Operator's (AEMO) Step Change 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.

In September 2022 the Queensland Government published the QEJP. The plan sets out the roadmap for the transformation of the energy system in Queensland to deliver clean, reliable and affordable energy. In November 2022, Powerlink published the Actioning the Queensland Energy and Jobs Plan document, which outlined initiatives and steps that Powerlink will undertake to support and enable the QEJP. One of the foundational investments to enable the energy transformation is the establishment of a new high voltage backbone SuperGrid capable of transporting large quantities of renewable energy and storage across the state. This new backbone system will be implemented in stages and provide one of the cornerstones for enabling energy transformation in Queensland. Powerlink worked closely with the Queensland Government in the development of the QEJP, including the establishment of new development areas for Queensland QREZs. Further detail of Powerlink's response to the QEJP is given in Chapter 2. AEMO's 2022 ISP is discussed in detail in Chapter 6.

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.

Currently there is considerable interest from customers investigating electrification in the Northern Bowen Basin. More broadly across the state, there is also the potential for conversion of existing industrial and manufacturing processes from 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 South East Queensland and the Gladstone and Townsville zones.

In March 2023, the Queensland Government announced that it will build and own the network to the North West Minerals Provence (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. This will connect the current load to the national Electricity Market (NEM) and allow the broader NWMP to access lower cost electricity sources from the NEM.

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 analyses 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 backbone 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 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 AEMO's Step Change scenario forecast discussed in Chapter 3, and the committed generation listed in tables 7.1 and 7.2, network limitations are not forecast to exceed network reliability requirements established under Powerlink's planning standard (refer to Section 6.2.1).

However, there have 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.

Combined with new and expanded mining operations, electrification of existing mining processes could see load increase by up to approximately 630MW. These loads have not reached the required development status to be included in AEMO's Step Change scenario forecast for this 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 8.2.2.

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.

Feasible network solutions to address the limitations are dependent on the magnitude, location and profile of load. The type of VRE generation interest in this area is predominately large-scale solar photovoltaic (PV). Given the coal mine load profile would be expected to be relatively flat, VRE generation is unlikely to fully address any emerging limitations.

Depending on the magnitude and location of load, possible network options may include one or more of the following:

- 132kV phase shifting transformers 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 to maintain 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 easements would need to be obtained to deliver the other network options described above.

8.2.2 CQ-NQ grid section transfer limit

Based on AEMO's Step Change 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.

However, 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 NQ. Voltage control is therefore becoming increasingly challenging and leading to high voltage violations. As outlined in Section 9.1, Powerlink has completed a RIT-T consultation recommending the installation of a 275kV shunt reactor at the Broadsound Substation. This reactor is planned to be commissioned in October 2024 (refer to Table 9.3).

As discussed in Section 8.2.1, there is the likelihood of new and expanded mines and electrification of existing mining operations in the Northern Bowen Basin. The NWMP is also anticipated to connect to the NEM in 2029 through CopperString 2032.

CopperString 2032 will connect to a new substation south of Powerlink's existing Ross Substation. 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 300MW.

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 2.3.1, CopperString 2032 will 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 designated as Flinders REZ within the draft Queensland Government REZ Roadmap (refer Section 2.4). As a result, the section of CopperString 2032 between Hughenden and 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.

The loads in Table 3.1 could result in an increase in northern Queensland demand of greater than 1,100MW. However these have not reached the required development status to be included in AEMO's Step Change scenario forecast for this TAPR.

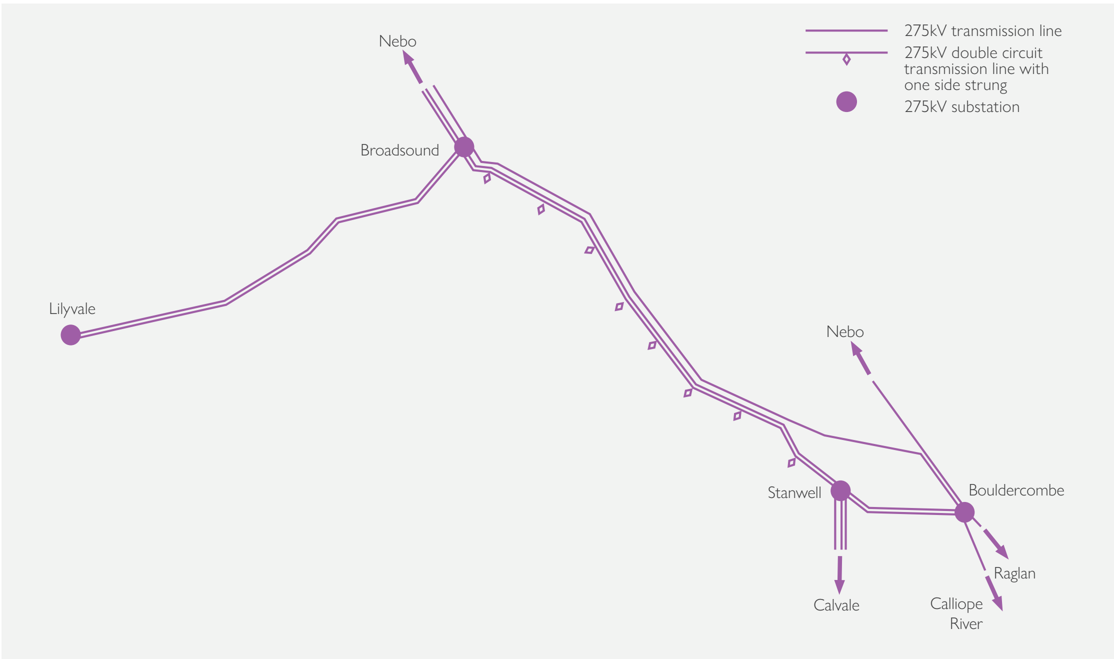
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings and voltage stability. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line following a critical contingency of a Stanwell to Broadsound 275kV transmission line. Voltage stability limitations may occur following the trip of the Townsville gas turbine or 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. The additional load in northern Queensland that could justify the network augmentation in preference to continued network support could be as low as 250MW.

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



8.2.3 Gladstone grid section transfer limit

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is approximately 250MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of a component of the existing industrial processes 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 2023 TAPR, Powerlink is engaging with customers that are committing to decarbonisation of their existing fossil fuelled operations and processes. 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 3.5GW to over 10GW (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.

As highlighted in the QEJP, Powerlink will invest in the Central Queensland REZ, reinforcing the Gladstone system to support decarbonisation of the region.

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

Feasible network solutions to facilitate efficient market operation and deliver reliability of supply obligations in the Gladstone zone may include:

- transmission line augmentation between Calvale and Calliope River substations with a high capacity 275kV double circuit transmission line. This augmentation, together with a third 275/132kV transformer at Calliope River Substation, is required to remove the reliance on the Gladstone PS for reliability of supply for the existing load in the Gladstone zone. This alone, would only support a small incremental load supplied from Larcom Creek Substation.
- rebuild of the transmission line between Larcom Creek and Calliope River substations with a high capacity 275kV double circuit transmission line.
- construction of a new high capacity 275kV double circuit transmission line between Bouldercombe and Larcom Creek Substation. This new build is adjacent (on an existing double width easement) to the existing single circuit 275kV line between Bouldercombe and Calliope River substations (feeder 812). This line traverses valuable wind resources in the area and will divert to Larcom Creek Substation at a suitable location where the future 500/275kV substation west of Gladstone under the QEJP will be located.
- construct a new high capacity 275kV double circuit transmission line between Stanwell and Bouldercombe 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. Additional network augmentations would be required within the Gladstone zone to connect this load.

Depending on the Gladstone load scenario further augmentation will be required. Feasible network solutions include:

- 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.

Powerlink has a vacant easement between Calvale and Larcom Creek substations for a 275kV double circuit line. From this corridor (adjacent to the Cedavale Tee area) a vacant easement to Calliope River also largely exists. Powerlink is in the process of acquiring the remainder of this easement. Powerlink also has projects in place to acquire necessary easements and/or corridor widening to build a new double circuit line between Larcom Creek and Calliope River substations. Powerlink will also acquire a strategic substation site west of Gladstone (and associated corridors for 500kV and 275kV transmission infrastructure).

8.2.4 Southern Queensland region

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, and the committed generation listed in tables 7.1 and 7.2, network limitations are not forecast to exceed network reliability requirements established under Powerlink's planning standard.

However, Powerlink is engaging in discussions with corporations for the development of significant new loads in southern Queensland. Fortescue Future Industries (FFI), Powerlink and Economic Development Queensland (EDQ) have signed an agreement to progress a facility at Gibson Island[1] (Southern Queensland Trade Coast Area) to produce around 50,000 tonnes of renewable hydrogen per year. Connection to Powerlink's transmission network is essential to allow electricity produced by VRE generation to power the proposed hydrogen project.

The hydrogen project will add up to 675MW in load in SEQ and connect to Powerlink's Murarrie Substation. The FFI operating strategy is to reduce load during peak periods on the network. This means that the required load can be accommodated within the existing network capability including during any critical network outage. A 675MW can be supplied, coincident with peak loads from the existing intact network. However, following a forced outage, overloads would occur without corrective action. This issue is proposed to be mitigated through implementation of a load run-back scheme.

The addition of this load does however reduce the available network capacity for future load growth in the area and advances the the timing of the identified need for when network limitations should be addressed.

Possible network solutions

Feasible network solutions to deliver reliability of supply following future load growth in the area include:

- 275kV transmission line augmentation between Blackwall, Belmont and Murarrie substations. This augmentation could involve transmission tower life extension and the application of high temperature conductor. No additional easements would be necessary under this development option.
- 275kV transmission line augmentation between Belmont and Murarrie substations. This augmentation could again involve the application of high temperature conductor. No additional easements would be necessary under this development option.
- The installation of power flow control technology to manage thermal overload between Blackwall and Belmont substations. Such devices would be installed within the existing substation boundaries.
- Establish a 275kV substation at Nudgee and 275kV cable/s between Nudgee and Murarrie substations. This option requires the acquisition of a new 275kV substation at Nudgee and the necessary easements to connect this substation to the Murarrie Substation. Underground cable would need to be deployed to connect Murarrie to the northern side of the Brisbane River.

Powerlink is also in discussions for development of a large data storage project powered by renewable energy and battery storage[2]. The project is located adjacent to Powerlink's South Pine Substation in North Brisbane. The data centre has a capacity of up to 270MW. In addition, the developer has submitted a planning application for a 750MW Battery energy storage system (BESS).

Depending on the combined operation of the load and BESS, thermal limitations may emerge on the 275kV circuits supplying the South Pine Substation.

Possible network solutions

Feasible network solutions to deliver reliability of supply to the data storage load include:

- Reconfiguration of the 275kV circuits between Blackwall, Rocklea and South Pine substations to establish two circuits between Blackwall and South Pine, with tees to Rocklea.

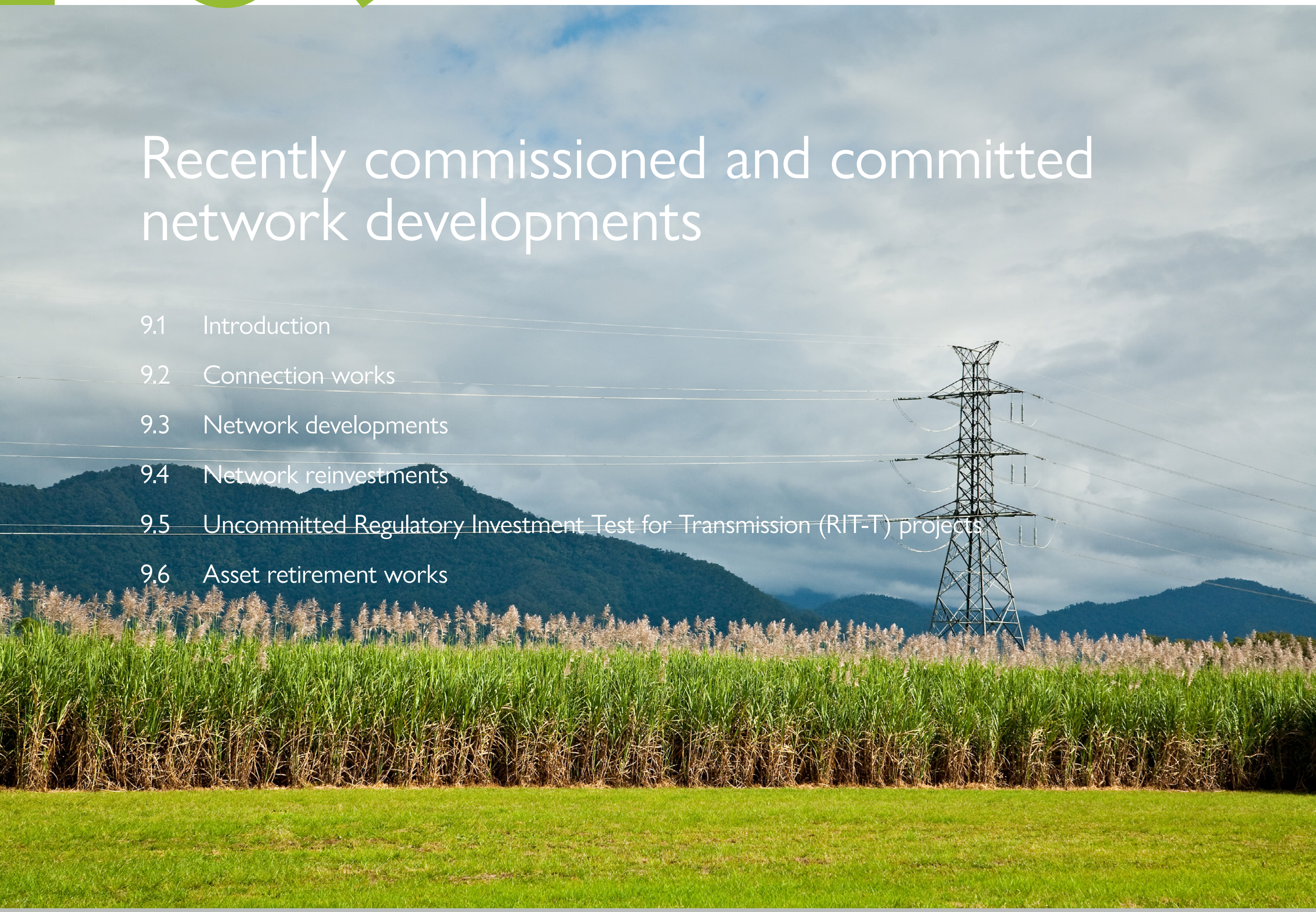
1 Refer to Powerlink's website.
2 Supernode powered by renewable energy.

- Construct 3.5km of double circuit 275kV line between Blackwall Substation and Karana Downs and rearrange existing circuits to create a double circuit 275kV line between Blackwall and South Pine substations and a double circuit 275kV line between Blackwall and Rocklea substations. The additional 3.5km double circuit line could be built (following appropriate approvals) within the existing easement corridor.
- Advance the rebuild of the 275kV network between Woolooga, Palmwoods and South Pine substations, in association with the Borumba Pumped Hydro Energy Storage (PHES) connection to the eastern backbone. Powerlink currently has a double width corridor adjacent to the existing 275kV single circuit line between Woolooga, Palmwoods and South Pine substations. The vacant corridor does not go all the way to South Pine. The last 20km single circuit lines would need to be rebuilt as double circuit lines to make the necessary connections to South Pine Substation.

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. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered, including working with the proponent to identify mutually beneficial non-network options. This may include co-ordination of the BESS to minimise the impact of the load on the network. Load flexibility and/or post-contingent interruptability may also deferred or reduce the scale of network investment required.

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 2022 Transmission Annual Planning Report (TAPR). It presents a snapshot of projects that have been commissioned, 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 2022/23, Powerlink's delivery efforts have continued to be predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's investment program is focussed 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 five reinvestment projects completed since publication of the 2022 TAPR.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland, with connection works for 1,575MW of variable renewable energy (VRE) generation developments and a Battery energy storage system (BESS) underway at the time of the 2023 TAPR publication.
- During 2022/23, Powerlink has completed two connection projects which will add 175MW of generation capacity to the grid[1].

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 2023.

9.2 Connection works

Table 9.1 lists connection works commissioned since Powerlink's 2022 TAPR was published.

Table 9.1 Commissioned connection works since October 2022

Project (1)	Purpose	Zone	Date commissioned
Bouldercombe BESS	New BESS	Gladstone	Quarter 2 2023
Wandoan Solar Farm (2)	New Solar Farm	Surat	Quarter 4 2022

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's scope of works for this project has been completed. Remaining works associated with generation connection are being coordinated with the customer.

Table 9.2 lists new transmission connection works for generating systems which are committed and under construction at October 2023. These connection projects resulted from agreements reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

[1] Refer to Table 9.1.

Table 9.2 Committed and under construction connection works at October 2023

Project (1)(2)	Purpose	Zone	Proposed commissioning date
Kidston Pumped Storage Hydro	New pumped hydro energy storage	Ross	Quarter 3 2024
Clarke Creek Wind Farm	New Wind Farm	Central West	Quarter 3 2023
Wambo Wind Farm	New Wind Farm	South West	Quarter 4 2024
Chinchilla Battery energy storage system	New BESS	Bulli	Quarter 1 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 signed an agreement for the construction of assets in south-west Queensland for the connection of the MacIntyre Wind Precinct proposed renewable development. Refer to Section 6.6.3 and Powerlink's website.

9.3 Network developments

There have been no transmission network developments (augmentation works) commissioned since Powerlink's 2022 TAPR was published.

Table 9.3 list network developments which are committed at October 2023.

Table 9.3 Committed network developments at October 2023

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	April 2024 (1)
Broadsound 275kV bus reactor	Maintain voltages in the Central West zone	Central West	October 2024

Note:

(1) Anticipated date of the completion of works at Tully and Yabulu South substations.

9.4 Network reinvestments

Table 9.4 lists network reinvestments commissioned since Powerlink's 2022 TAPR was published.

Table 9.4 Commissioned network reinvestments since October 2022

Project	Purpose	Zone	Date commissioned
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	November 2022
Bouldercombe primary plant replacement	Maintain supply reliability in the Central West zone	Central West	June 2023
Tarong secondary systems replacement	Maintain supply reliability in the South West zone (1) (2)	South West	December 2022
Palmwoods 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (2)	Moreton	March 2023
Line refit works on the 110kV transmission lines between South Pine and Upper Kedron	Maintain supply reliability in the Moreton zone	Moreton	July 2023

Notes:

(1) 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.

(2) Projects impacted by restrictions related to COVID-19.

Table 9.5 lists network reinvestments which are committed at October 2023.

Table 9.5 Committed network reinvestments at October 2023

Project	Purpose	Zone	Proposed commissioning date
Woree secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	October 2024
Woree SVC secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	July 2025
Chalumbin secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	October 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	December 2025
Cairns secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2027
Line refit works on the 132kV transmission line between Townsville South and Clare South substations	Maintain supply reliability in the Ross zone	Ross	November 2024
Garbutt configuration change	Maintain supply reliability in the Ross zone	Ross	December 2024
Townsville South 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	October 2025
Townsville South secondary systems replacement Stage 1	Maintain supply reliability in the Ross zone	Ross	October 2025
Ross 275/132kV transformers life extension	Maintain supply reliability in the Ross zone	Ross	October 2025
Ross 275kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	November 2025
Ross 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	November 2025
Strathmore 132kV secondary systems replacement	Maintain supply reliability in the North zone	North	December 2023
Strathmore 275/132kV transformer establishment	Maintain supply reliability in the North zone	North	December 2023
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone (2)	North	June 2024
Kemmis secondary systems replacement	Maintain supply reliability in the North zone	North	October 2024
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek substations	Maintain supply reliability in the North zone (1)	North	November 2024
Newlands 132kV primary plant replacement	Maintain supply reliability in the North zone	North	March 2026
Dysart 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (1)	Central West	November 2023
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (1)(2)(3)	Central West	December 2023
Blackwater 66kV CT and VT replacement	Maintain supply reliability in the Central West zone	Central West	December 2023

Table 9.5 Committed network reinvestments at October 2023 (*continued*)

Project	Purpose	Zone	Proposed commissioning date
Blackwater 132/66kV transformers replacement	Maintain supply reliability in the Central West zone	Central West	December 2024
Lilyvale 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (2)	Central West	October 2025
Lilyvale 275kV and 132kV primary plant replacement	Maintain supply reliability in the Central West zone (2)	Central West	November 2026
Wurdong secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	May 2024
Boyne Island secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	June 2024
Egans Hill secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	November 2024
Gladstone South secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	May 2026
QAL West secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	May 2026
Line refit works on 275kV transmission line between Woolooga and Palmwoods	Maintain supply reliability in the Wide Bay zone (1)	Wide Bay	November 2023
Line refit works on the 110kV transmission lines between West Darra and Sumner	Maintain supply reliability in the Moreton zone	Moreton	November 2023
Line refit works on the 110kV transmission lines between Rocklea and Sumner	Maintain supply reliability in the Moreton zone	Moreton	November 2023
Abermain 110kV secondary systems replacement	Maintain supply reliability in the Moreton zone(2)	Moreton	November 2023
Mt England 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	December 2025
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.

(3) The majority of Powerlink's staged works are anticipated for completion by summer 2023. Remaining works associated with generation connection will be coordinated with the customer.

9.5 Uncommitted Regulatory Investment Test for Transmission projects

Table 9.6 lists network investments which have undergone the RIT-T and are not fully committed at October 2023.

Table 9.6 Uncommitted network investments at October 2023

Project	Purpose	Zone	Proposed commissioning date
Innisfail 132kV secondary systems replacement	Maintain supply reliability in the Far North zone (1)	Far North	June 2028
Tangkam 110kV secondary systems replacement	Maintain supply reliability in the South West zone (1)	South West	June 2025
Chinchilla 132kV Substation replacement	Maintain supply reliability in the South West zone (1)	South West	December 2025
Tarong 275/66kV transformers and selected primary plant replacement	Maintain supply reliability in the South West zone (1)	South West	June 2027
Belmont 120MVAr bus reactor	Maintain supply reliability in the Moreton zone (2)	Moreton	December 2024
Redbank Plains 110/11kV transformers and selected primary plant replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	October 2025

Notes:

(1) Capital expenditure in relation to network asset replacement.

(2) Capital expenditure in relation to network augmentation.

9.6 Asset retirement works

Table 9.7 lists assets which have been retired since Powerlink's 2022 TAPR was published.

Table 9.7 Asset retirement works completed since October 2022

Project	Purpose	Zone	Decommissioning date
Belmont 275/110kV Transformer 2 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	December 2021 (1)
Belmont 275/110kV Transformer 3 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	December 2021 (1)

Note:

(1) Notification of decommissioning received after the publication of the 2022 TAPR.

Table 9.8 lists asset retirement works at October 2023.

Table 9.8 Asset retirement works at October 2023

Project	Purpose	Zone	Proposed retirement date
Cairns 132/22kV Transformer 4 retirement	Removal of asset at the end of technical life in the Far North zone	Far North	December 2027
Tarong 275/132kV transformers retirement	Removal of assets at the end of technical life in the South West zone	South West	June 2025
Mudgeeraba 275/110kV Transformer 3 retirement	Removal of asset at the end of technical life in the Gold Coast zone	Gold Coast	June 2026
132kV transmission line retirement between Townsville South and Clare South substations	Removal of assets at the end of technical life in the Ross zone	Ross	June 2029

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 2023

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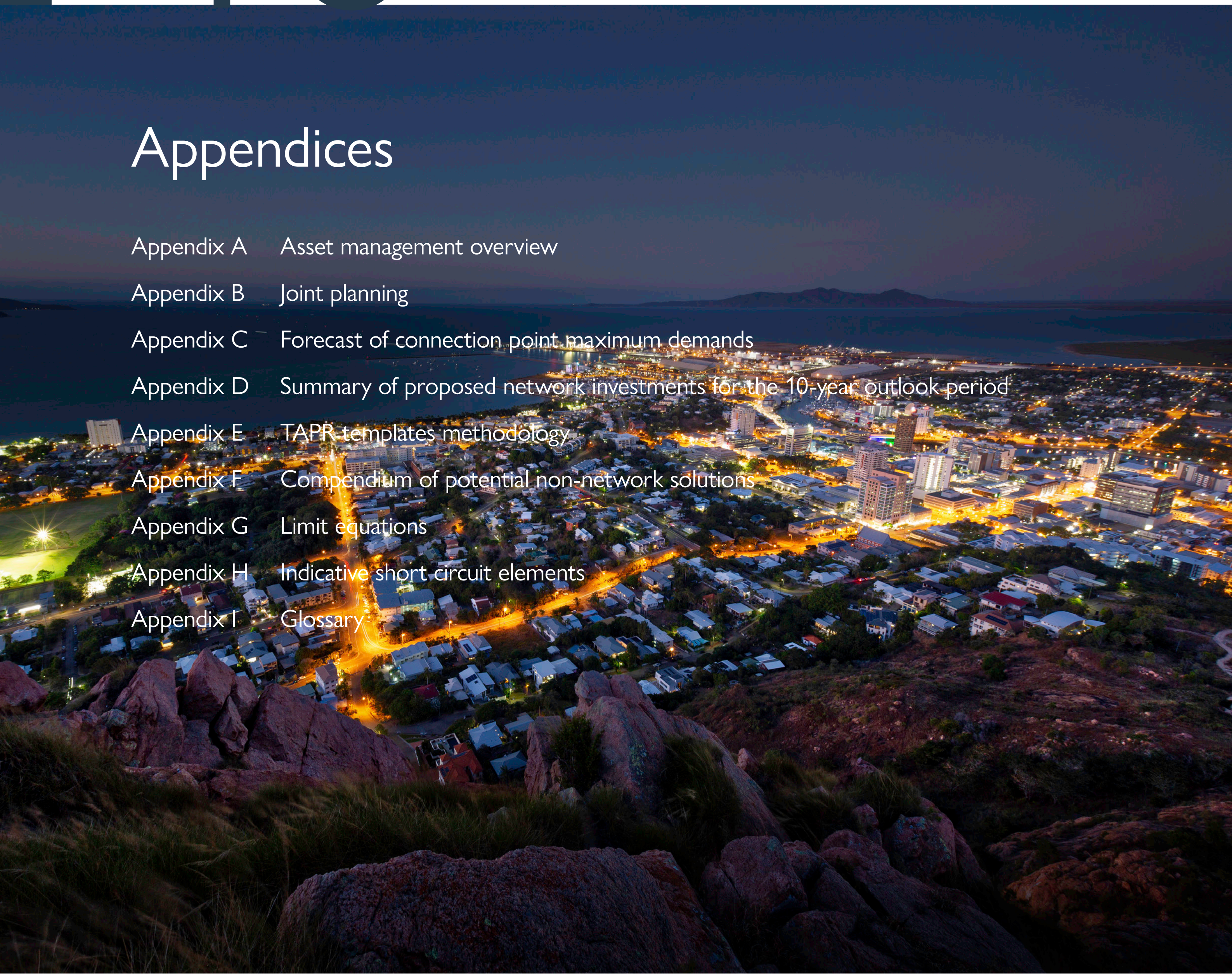


Appendices

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

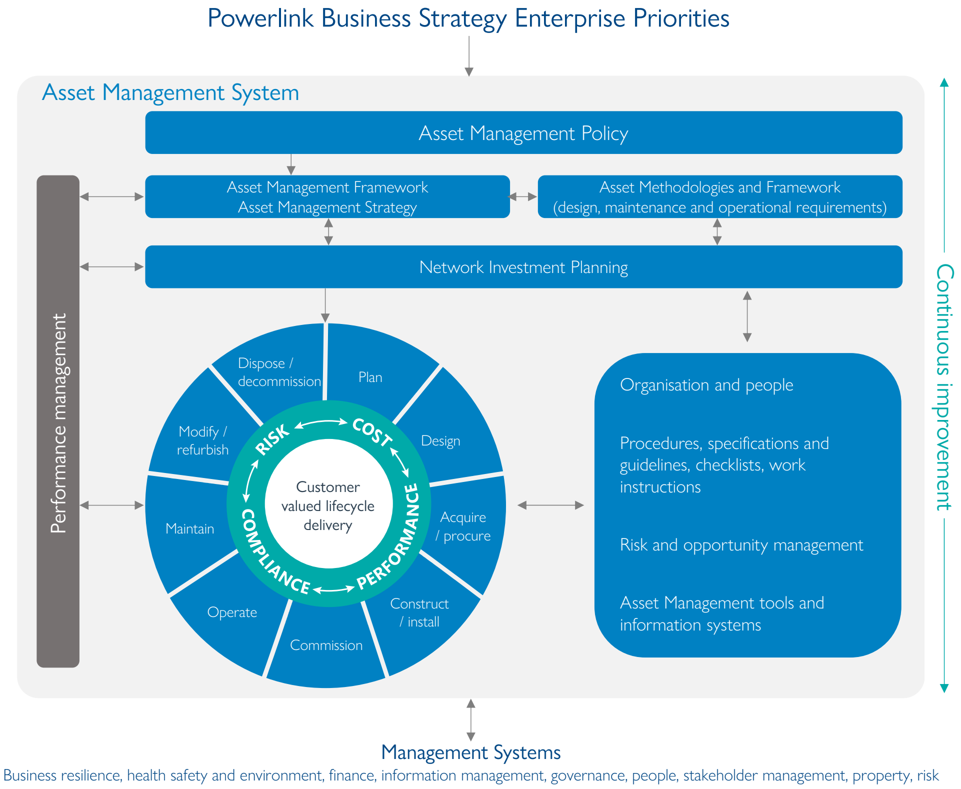
Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver safe, cost effective, reliable and sustainable services.

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 long-term 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 ongoing 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.

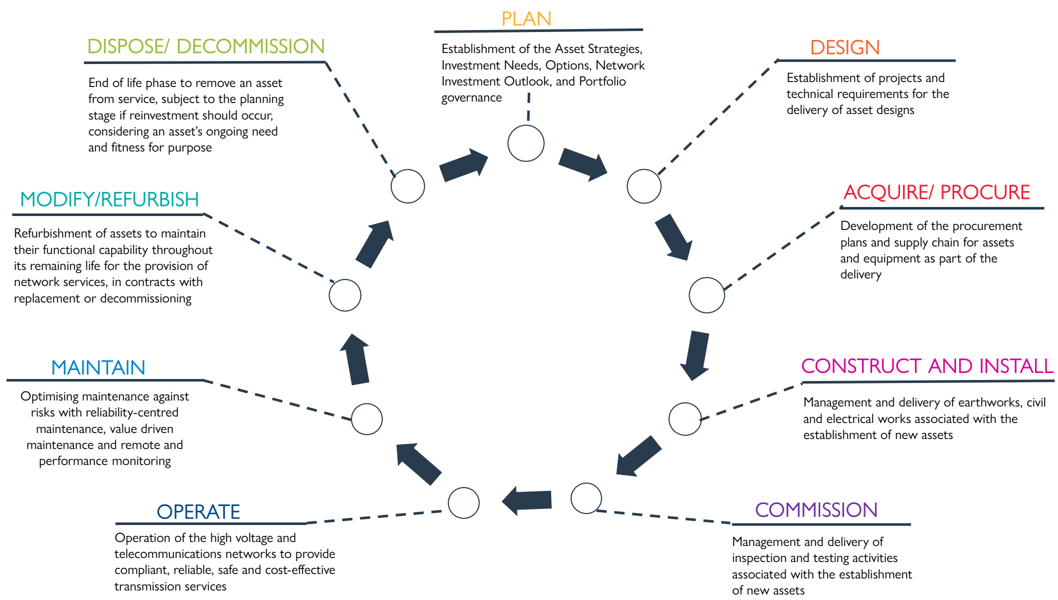
All asset management related activities are undertaken by applying relevant procedures, specifications and guidelines for delivering each stage of an asset life cycle activity.

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 ongoing 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 2022 System Security Reports
- Network Support and Control Ancillary Service (NSCAS)
- System Strength and Inertia requirements
- AEMO's 2024 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 is working closely with AEMO to support the development of the 2024 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 2022 and 2023 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. Powerlink and the Department of Energy and Public Works (DEPW) 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 has resulted in the Borumba PHES and CopperString 2032 projects being modelled as anticipated projects in the 2024 ISP.

In addition, as requested in AEMO's 2022 ISP (published in July 2022) Powerlink also prepared Preparatory Activity reports for expansion of the Darling Downs Renewable Energy Zone (REZ) expansion Stage 1 and for a further interconnector upgrade between Queensland and New South Wales (refer to Section 6.15). This involvement was critical to ensure the best possible jurisdictional inputs are provided to the ISP process in the long-term interests of customers.

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 2024 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 2022 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 for 2022. 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 2022 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 sections 4.3 and 6.8.1).

The 2022 System Security Report also 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 (refer to sections 4.5 and 6.8.2).

AEMO also published an immediate Network Support and Ancillary Service (NSCAS) gap of approximately 120MVAr reactive power absorption in Southern Queensland increasing in size to 250MVAr by 2026. Powerlink has recently published a Project Assessment Conclusions (PACR) to manage voltages in South East Queensland (SEQ) to address this NSCAS gap (refer to sections 6.5.1 and 9.5).

B.5 General Power System Risk Review and Power System Frequency Risk Review

AEMO published the General Power System Risk Review (GPSRR) in July 2023.

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.

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.

1 System Security Market Frameworks Review. System Strength Requirements Methodology - September 2002 (latest version)
2 Network Support and Control Ancillary Service Description and Quantity Procedure.

Outcomes

The Final 2023 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. If a scheme is found viable, AEMO recommends this scheme be commissioned no later than June 2025.
- Each jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risk.
- All NSPs evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.
- 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 include:

- 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 QNIto 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 commencement of 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 safe and expeditious release of additional capacity.

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 2022 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
Kamerunga 132/22kV transformer replacement	Appendix D, Table D.1
Maintaining reliability of supply to Cairns northern beaches area	Section 6.9.1
Maintaining reliability of supply and addressing condition risks at Ingham South	Section 6.9.2
Maintaining reliability of supply to Gladstone South	Section 6.10.2
Maintain reliability of supply to the Brisbane metropolitan area	Section 6.11.5
SEQ reactive power and voltage control	Section 6.5.1
Possible retirement of Loganlea 110/33kV transformer	Section 6.11.5

Note:

(1) Operational works, such as Over Load 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 Ergon Energy and Energex for maximum demand

Ergon Energy and Energex review and update the 10-year 50% probability of exceedance (PoE) and 10% PoE system summer maximum demand forecasts after each summer season. Each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency, the Ergon Energy and Energex forecast system level maximum demand is reconciled with the bottom-up substation maximum demand forecast after allowances for network losses and diversity of maximum demands.

Distribution forecasts are developed using data from Australian Bureau of Statistics (ABS), the Queensland Government, the Australian Energy Market Operator (AEMO), internally sourced rooftop photovoltaic (PV) connections and historical maximum demand data, and externally sourced Consumery Energy Resources (CER) forecast from an external consultant. The economic forecasts from Deloitte Access Economics are also utilised.

The methodology used to develop the system demand forecast, is as follows:

Ergon

- A six-region based forecast model within the Ergon network, with the aggregation of regions to provide a system peak 50% PoE. Each regional forecast uses a semi-parametric model to determine the relationship between demand and Gross State Product (GSP), population growth, temperature, lags of temperature, other weather variables and holiday periods. A Monte-Carlo process is used across the regional models to simulate a distribution of summer maximum demands using the latest 10 years of summer temperatures and an independent 10-year gross GSP and population forecast.
- Looking at *n* number of half hourly simulated demand traces a max of each of the simulated traces is used to capture a distribution of *n* max demand occurrences for each summer season going into the future. This includes calculating of the respective PoE 50 and PoE 10 for the distribution of maximum demand for each season used for the forecast values of maximum demand. A stochastic correlated term is applied to the simulated demands to capture the unexplained variance in the model fits. This process attempts to define the maximum demand rather than the regression average demand.
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for the expected impact of rooftop PV, battery storage and electric vehicles (EV) based on the maximum demand daily load profile and anticipated usage patterns.
- Further details of the methodology can be referenced in Rob J Hyndman, Shu Fan (2010) IEEE Transactions on Power Systems 25(2), 1142-1153 (latest version, with further development is 2015).

Energex

- Uses a multiple regression equation for the relationship between demand and GSP, square of weighted maximum temperature, weighted minimum temperature, coincident time relative humidity index, structural break, three continuous hot days, weekends, Fridays and the Christmas period. Three weather stations are incorporated into the model via a weighting system to capture the influence of the sea breeze on peak demand. Statistical testing is applied to the model before its application to ensure that there is minimal bias in the model. The summer regression uses data from November to March, with the temperature data excluding days where the weighted temperatures are below set levels (i.e; the weighted daily mean temperatures < 22.0°C and the weighted daily maximum temperature < 28.5°C).

[1] Where applicable, Clauses 5.12.2 (1)(c)(iii) and (iv) are discussed in Chapter 3.

- A Monte-Carlo process is used to simulate a distribution of summer maximum demands using the latest 22 years of summer weighted temperatures and an independent ten-year GSP forecast
- A stochastic term is applied to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the maximum demand rather than the regression average demand
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for rooftop PV, battery storage and the expected impact of EVs based on the maximum demand daily load profile and anticipated usage patterns.

C.2 Description of Ergon Energy's and Energex's high, medium and low growth scenarios for maximum demand

The scenarios developed for the high, medium and low case maximum demand forecasts were prepared in June 2023 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in July 2023 are based on the following assumptions.

Block Loads

There are many block loads scheduled over the next 11 years. For the majority, the block loads are incorporated at the relevant level of the network e.g. zone substation. Only a small number are considered large enough to justify accounting for them at the system level models. Ergon does not currently incorporate any block loads in the system level models. Energex has between 20MW and 70MW of block loads incorporated in the system model over the forecast horizon.

At the zone substation level, Energy Queensland is currently tracking around 220MW of block loads for Ergon, and 538MW for Energex. However, only the block loads which have a significant influence on the zone substation's peak demand are incorporated; for Ergon this is 189MW and for Energex 435MW.

Summary of the Ergon Energy model

The system demand model for regional Queensland incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Aggregation of six regional forecasts to provide a system peak 50PoE at network peak coincidence
- Demand MW = function of (weekend, public holidays, regional maximum temperature, Queensland GSP, population, structural break, demand management terms, and a constant)
- The demand management term captures historical movements of customer responses to the combination of PV uptake, tariff price changes and customer appliance efficiencies.

Ergon Energy's high growth scenario assumptions for maximum demand

- GSP – The "high" case of GSP growth (3% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Queensland regional population growth – 1.3% per annum (simple average growth for the 2024 ~ 2033 financial years).
- Weather – follow the recent trend of 10 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.1% per annum (simple average growth for the 2024 ~ 2033 financial years))
- Queensland regional population – Actual 1.6% in 2022, and 0.8% growth per annum (simple average growth for the 2024 ~ 2033 financial years)
- Weather – follow the recent 10-year trend.

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – The "low" case GSP growth (1.2% per annum (simple average growth for the 2024 ~ 2033 financial years))
- Queensland regional population growth – 0.3% per annum (simple average growth for the 2024 ~ 2033 financial years)
- Weather – follow the recent 10-year trend.

Summary of the Energex model

The latest system demand model for the South East Queensland region incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Demand MW = function of (weekend, Christmas, Friday, square of weighted maximum temperature, weighted minimum temperature, humidity index, total price, Queensland GSP, structural break, three continuous hot days, and a constant)
- In particular, the total price component incorporated into the latest model aims to capture the response of customers to the changing price of electricity. The impact of price is based on the medium scenarios for the Queensland residential price index forecast prepared by NIEIR in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – The "high" case of GSP growth (3% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a high technology penetration scenario, panel capacity may reach 10,638MW by 2033.
- Battery storage – Peak time (negative) contribution may reach 43MW by 2033 (behind the meter).
- EV – Price parity with the ICE type vehicles achieved earlier, accessible and fast charging stations, enhanced features, a variety of types, plus escalated petrol prices. The peak time contribution (without diversity ratio adjusted) may reach 411MW by 2033.
- Weather – follow the recent 10-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.1% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a medium technology penetration scenario, panel capacity may reach 9,082MW by 2033.
- Battery storage – Peak time (negative) contribution will have a slow start of around 7MW in 2024 but may reach 33MW by 2033 (behind the meter).
- EV – Stagnant in the short-term, surge in the long-term. Peak time contribution will only amount to 7MW in 2024 but will reach 233MW by 2033. Note however, EV will also have a significant impact on GWh energy sales.
- Weather – follow the recent 10-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – The "low" case GSP growth (1.2% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a slow technology penetration scenario, panel capacity may reach 7,603MW by 2033.
- Battery storage – Peak time (negative) contribution may reach a high at 24MW in 2033 (behind the meter).
- EV – Price parity with the ICE type vehicles is achieved much later, hard to find charging stations, charging time remaining long, still having basic features, less type sections, plus lower cost petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 51MW in 2033.
- Weather – follow the recent 10-year trend.

C.3 Significant changes to the connection point maximum demand forecasts

Major differences between the 2023 forecast and the 2022 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. The forecast uptake of CER has decreased for the 2023 forecast when compared to the 2022 forecast. Electric vehicle charging behaviour has been revised and includes greater day time charging in the later years of the forecast, this has resulted in a decrease in the growth rate at many substations across Ergon and Energex. 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.

C.3.1 Ergon connection points with the greatest difference in growth between the 2023 and 2022 forecasts

Connection Point	kV	Change in growth rate (per annum)
Turkinje (Craiglie and Lakeland)	132	-2%
Woolooga (Kilkivan)	132	-2%
Rockhampton	66	-2%
Pandoin	66	-2%
Egans Hill	66	-2%
Woree (Cairns North)	132	-2%
Mackay	33	-2%
Tarong	66	-2%
Chinchilla	132	-2%
Calliope River	132	-2%
Cardwell	22	-2%
Dysart	66	-1%
Moranbah (Broadlea)	132	-1%
Middle Ridge (Postmans Ridge)	110	-1%
Teebar Creek (Isis and Maryborough)	132	-1%
Lilyvale (Barcaldine & Clermont)	132	-1%
Ingham	66	-1%
Tangkam	110	-1%
Middle Ridge	110	-1%
Biloela	66	-1%
Tully	22	-1%
Cairns City	132	-1%
El Arish	22	-1%
Gladstone South	66	-1%
Gin Gin	132	-1%
Bowen North	66	-1%
Edmonton	22	-1%
Oakey	110	-1.%
Alan Sherriff	132	-1%
Alligator Creek	33	-1%
Innisfail	22	-1%
Moura	66	-1%

C.3.2 Energex connection points with the greatest difference in growth between the 2023 and 2022 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 2022/23 summer was relatively mild 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 2022 forecast values for 2022/23 and what was observed.

C.4.1 Ergon connection points with the greater than 10% absolute difference between the peak 2022/23 and corresponding base 2022 forecast for 2022/23

Connection Point	2022/23 forecast peak	2022/23 actual peak	Difference
Pioneer Valley	84	52	-61%
Clare South	82	60	-35%
Moranbah (Broadlea)	62	48	-29%
Tangkam	33	27	-219%
Collinsville North	16	14	-188%
Ingham	23	19	-16%
Blackwater	137	122	-12%
Lilyvale	141	126	-12%
Mackay	99	88	-12%
Teebar Creek (Isis and Maryborough)	160	144	-11%
Proserpine	56	50	-11%
Aligator Creek (Louisa Creek)	41	37	-10%

C.4.2 Energex connection points with the greater than 10 % absolute difference between the peak 2022/23 and corresponding base 2022 forecast for 2022/23

Connection Point	2022/23 forecast peak	2022/23 actual peak	Difference
Redbank Plains	35	27.97	-26.558%
Middle Ridge (Postmans Ridge and Gatton)	129	102.57	-26.219%
Woolooga (Gympie)	248	213.36	-16.081%
Murarrie	542	489.45	-10.699%
Wecker Road	133	120.62	-10.184%

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, medium and low growth scenarios (refer to Appendix C.2). These forecasts have been supplied by Powerlink customers.

The connection point 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
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	New 132kV double circuit transmission line	Maintain supply reliability to the Far North zone	December 2028 (1)	Two 132kV single circuit transmission lines (2)	$52m
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 December 2029	New transmission line (2)	$37m
Substations					
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2029 (1)	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 (1)	Selected replacement of 132kV secondary systems	$6m
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2031 (1)	Selected replacement of 132kV secondary systems	$4m
Turkinje 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Far North zone	December 2026	Full replacement of 132kV primary plant	$4m
Kamerunga 132kV Substation rebuild	Full replacement 132kV primary plant and secondary systems	Maintain supply reliability to Cairns northern beaches area	December 2028	Selected replacement of 132kV primary plant and secondary systems (2)	$75m
Kamerunga 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to Cairns northern beaches area	June 2029	Significant load transfers in distribution network Early replacement with higher capacity transformer by 2023 triggered by load growth	$6m
Chalumbin 275kV and 132kV primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Far North zone	June 2029	Full replacement of all 275kV and 132kV primary plant and secondary systems	$7m

Table D.1 Possible network investments in the Far North zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
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	$39m
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 (1)	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 (1)	Full replacement of 275kV and 132kV secondary systems	$5m

Notes:

(1) The change in timing of the network solution from the 2022 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.

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	December 2029	New 132kV transmission line	$5m
Line refit works on the 132kV transmission line between Townsville South and Ross substations	Targeted line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	December 2029	New 132kV transmission line Targeted line refit works on steel lattice structures with painting	$4m
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	December 2029	New 132kV transmission line	$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	$10m
Substations					
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2032 (1)	Full replacement of 132kV secondary systems Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kv network in north east Townsville	$12m
Ingham South 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	December 2027	Selected replacement of 132kV secondary systems (2)	$8m (3)
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Selected replacement of 132kV secondary systems Up to 110MW at peak and up to 800MWh per day to support the 66kV network in north east Townsville	$10m
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2033 (1)	Full replacement of secondary systems	$4m

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 South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2033 (1)	Full replacement of 132kV secondary systems Up to 150MW at peak and up to 3,000MWh per day to provide supply to Townsville East and Townsville South (including Sun Metals)	$16m
Yabulu South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Full replacement of 132kV secondary systems	$7m
Clare South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Full replacement of 132kV secondary systems	$12m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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 2029	New transmission line	\$33m
Substations					
Alligator Creek 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2024	Full replacement of 132kV primary plant	\$4m
North Goonyella 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	December 2031 (1)	Selected replacement of 132kV secondary systems	\$6m
Nebo 132/11kV transformers replacement	Replacement of 132kV transformers	Maintain supply reliability to the North zone	December 2025	(2)	\$12m
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2026	Staged replacement of secondary systems (2)	\$7m
Kemmis 132/66kV transformer replacement	Replacement of one 132/66kV transformers	Maintain supply reliability to the North zone	December 2026	Establish 66kV supply from surrounding network (2)	\$7m (3)
Pioneer Valley 132kV primary plant replacement	Selected replacement of 132kV secondary systems equipment	Maintain supply reliability to the North zone	June 2029	Full replacement of 132kV secondary systems	\$5m
Strathmore 275kV and 132kV secondary systems	Selected replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the North zone	June 2034 (1)	Selected replacement of 275kV and 132kV secondary systems in existing panels	\$15m
Alligator Creek SVC and 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2028 (1)	Staged replacement of 132kV secondary systems	\$7m
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)	\$6m

Notes:

(1) The revised timing from the 2022 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 2022 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 132kV transmission line between Calvale, Biloela and Moura	Line refit works on the 132kV transmission line and repair selected foundations	Maintain supply reliability to the Central West zone	June 2025	Rebuild the 132kV transmission lines as a double circuit from Callide A to Moura Line refit works on the 132kV transmission line and repair all foundations	$5m
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 2029	Stanwell to Broadsound second side stringing New 275kV transmission line between Bouldercombe and Broadsound substation	$31m
Substations					
Blackwater 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Central West zone	June 2025	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 (1)	Full replacement of 132kV secondary systems	$5m
Broadsound 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability to the Central West zone	June 2032 (1)	Full replacement of 275kV secondary systems	$4m
Broadsound 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2027	Full replacement of 275kV primary plant (2)	$19m (3)
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2033 (1)	Full replacement of 132kV secondary systems	$3m
Calvale 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2028	Full replacement of 275kV primary plant (2)	$18m (3)
Blackwater 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2034 (1)	Full replacement of 132kV secondary systems	$13m
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 (1)	Full replacement of 132kV and 275kV secondary systems	$10m

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
Nebo SVC secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability to the Central West zone and Northern region	June 2030	Full replacement secondary systems	$6m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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 2025	Rebuild the 275kV transmission line between Wurdong and Boyne Island	$5m (1)
Rebuild the 132kV transmission line between Callemondah and Gladstone South Substation	Rebuild the 132kV double circuit transmission line between Callemondah and Gladstone South Substation	Maintain supply reliability in the Gladstone zone	June 2026	Line refit works on steel lattice structures (2)	$53m (1)
Rebuild the 275kV transmission line between Calliope River and Larcom Creek Substation	Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction and turnin one or both circuits to Larcom Creek Substation	Maintain supply reliability in the Gladstone zone	June 2027 (4)	Line refit works on the 275kV transmission line between Larcom Creek substation and Mt Miller near Calliope River (2)	$107m (1)
Rebuild the 275kV transmission line between Bouldercombe and Calliope River substations	Rebuild the 275kV transmission line between Bouldercombe and Calliope River substation	Maintain supply reliability in the Gladstone zone	December 2029 (4)	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Bouldercombe and Larcom Creek as a double circuit transmission line, and mothball section from Cedarvale to Calliope River	$320m (3)
Line refit works on steel lattice structures on the 275kV transmission line between Raglan and Larcom Creek substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2030	Rebuild the 275kV transmission line between Raglan and Larcom Creek	$15m (3)
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 275kV transmission line between Bouldercombe and Bouldercombe Tee	$3m

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 275kV transmission line between Raglan and Bouldercombe substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2032	Rebuild the 275kV transmission line between Raglan and Bouldercombe	$20m (3)
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 2025	Full replacement of 132kV primary plant and secondary systems (1)	$10m
Rockhampton 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain reliability in Rockhampton	June 2031 (1)	Full replacement of 132kV secondary systems	$5m
Larcom Creek 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034 (1)	Full replacement of the 275kV secondary systems	$8m
Pandoin 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034 (1)	Selected replacement of 132kV secondary systems	$5m
Bouldercombe 275kV secondary systems replacement	Full replacement of the 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2032	Selected replacement of 275kV secondary systems	$25m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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.

(4) The required timing for this network investment will depend on the overall supply and demand balance in the Gladstone zone. This is impacted by the future operation of the Gladstone PS and the development of new loads associated with decarbonising existing industrial processes and new industries.

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 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 2028	Refit the two single circuit 275kV transmission lines	$40m (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 2029 (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 (2)	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$16m (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	June 2030	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$75m
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	$8m (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	December 2032 (2)	Refit the 275kV transmission line between Gin Gin and Woolooga substations	$27m (1)
Substations					
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2033 (2)	Selected replacement of 132kV and 275kV secondary systems	$19m
Woolooga 275kV and 132kV primary plant and secondary systems replacement	Selected replacement of 275kV and 132kV primary plant and full replacement of 132kV and 275kV secondary systems (including SVC)	Maintain supply to the Wide Bay zone	December 2034 (2)	Selected replacement of 275kV and 132kV secondary systems	$34m (1)

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
Palmwoods 275kV and 132kV selected primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply to the Wide Bay zone	December 2029 (2)	Full replacement of 275kV and 132kV primary plant	$15m (1)

Notes:

(1) Compared to the 2022 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 2022 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	$15m

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 (1)	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 (1)	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

Note:

(1) The change in timing of the network solution from the 2022 TAPR is based upon updated information on the condition of the assets.

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 at Middle Ridge Substation	June 2028	Full replacement of 110kV primary plant	$3m
Tangkam 110kV primary plant replacement	Selected replacement of selected 110kV primary plant	Maintain reliability of supply at Tangkam Substation	June 2030	Full replacement of 110kV primary plant	$12m
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 (1)	Full replacement of 275kV and 110kV secondary systems	$40m

Note:

(1) The change in timing of the network solution from the 2022 TAPR is based upon updated information on the condition of the assets.

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 (1)	In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (2)	$13m
Line refit works on the 110kV transmission line between Belmont and Murarrie substations	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	June 2032 (1)	Rebuild the 110kV transmission lines between Belmont and Murarrie substations	$2m
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 (1)	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	$8m
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 (3)
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 (3)
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

Table D.10 Possible network investments in the Moreton zone (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
South Pine 275/110kV transformer life extension	Life extension of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	June 2026	Retirement of a single 275kV/110kV transformer with non-network support	$3m
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2031 (1)	Staged replacement of 110kV secondary systems	$11m
Sumner 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2025	Staged replacement of 110kV secondary systems	$5m
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2031 (1)	Staged replacement of 110kV secondary systems	$17m
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2032 (1)	Staged replacement of 110kV secondary systems	$7m
Rocklea 110kV primary plant replacement	Full replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	December 2028	Staged replacement of 110kV primary plant	$5m
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of 110kV primary plant	$8m
South Pine SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of SVC secondary systems	$6m
Goodna 110/332kV transformer augmentation	Installation of a 100MVA 110/33kV transformer	Maintain supply reliability in the Moreton zone	June 2028	Installation of a smaller 110/33kV transformer and non-network support	$6m
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	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 (1)	Staged replacement of 110kV secondary systems	$11m
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2029	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 2029	Staged replacement of 275kV primary plant	$5m
Greenbank SVC and 275kV secondary systems replacement	Full replacement of 275kV SVC and secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	December 2029	Staged replacement of 275kV SVC and secondary systems	$33m
Mount England 275kV secondary systems and primary plant replacement	Full replacement of 275kV secondary systems and staged replacement of primary plant	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of 275kV secondary systems and primary plant	$11m

Table D.10 Possible network investments in the Moreton zone (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Belmont 110kV and 275kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	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 (1)	Staged replacement of 22kV and 11kV primary plant	$5m
South Pine 275kV primary plant replacement	Staged replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2030	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 2034 (1)	Staged replacement of 275kV and 110kV secondary systems	$6m (3)
South Pine secondary systems replacement	Replacement of secondary systems at South Pine 275kV	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of secondary systems	$50m
Abermain 275kV and 110kV primary plant replacement	Selected 275kV and 110kV primary plant replacement	Maintain supply reliability in the Moreton zone	June 2034	Full replacement of 275kV and 110kV primary plant	$8m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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	December 2028	Full line refit New transmission line	$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	December 2028	New double circuit 275kV transmission line (1)	$30m
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2030 (2)	Selected replacement of 275kV secondary systems	$23m (3)
Mudgeeraba 110kV primary plant and secondary systems replacement	Selected replacement of 110kV primary plant and staged replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2029	Full replacement of 110kV secondary systems (1)	$33m
Mudgeeraba 275/110kV Transformer Replacement	Replacement of the transformer	Maintain supply reliability to the Gold Coast Region	December 2030	Life extension of the existing transformer	$11m

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 2022 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2022 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 AER's 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 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 near-term 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. 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).

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 an in-house tool. These daily demand profiles are an estimate and should only be used as a guide. 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).

1 First published in December 2018.
2 Refer to the TAPR portal.
3 Separate to the publication of the TAPR document which occurs annually.

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).

Powerlink's in-house load profiling tool incorporates a base year (1 July 2020 to 1 July 2021) of historical demand and weather data (temperature and solar irradiance) for all loads supplied from the Queensland transmission network. The tool then adds at the connection point level the impacts of future forecasts of rooftop PV, distribution connected PV solar farms, battery storage, EV and load growth.

The maximum demand of every connection point within the base year has been scaled to the medium growth 50% PoE maximum demand connection point forecasts, as supplied by Powerlink's customers post-winter 2021 (the previous revision of those listed in Appendix C).

As Powerlink does not receive a minimum demand connection point forecast from its customers, the minimum demand is not scaled. The minimum demand is determined by the base year's half hour demands and the impacts of rooftop PV, distribution connected PV solar farms, battery storage and EV.

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	Forecast maximum load at risk is the raw data and does not reflect the requirements of Powerlink's jurisdictional planning standard used to calculate non-network solution requirements. Refer to chapters 5 and 6 for information.
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. Forced and faulted outages are included in the data provided. 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 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR) (as shown in figures 7.6 – 7.8).

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 is each zone.

Figure F.1 provides illustrations of the grid section definitions.

Table F.1 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of King Creek and Bowen North, excluding the Far North zone
North	North of Broadsound and Dysart, excluding the Far North 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 Millmerran
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	Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)
CQ-NQ	Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)
Gladstone	Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit)
CQ-SQ	Wurdong to Teebar Creek 275kV (1 circuit) Calliope River to Gin Gin/Woolooga 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)
Surat	Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit)
SWQ	Western Downs to Halys 275kV (1 circuit) Western Downs to Coopers Gap 275kV (1 circuit) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)
Tarong	Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)
Gold Coast	Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) 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				•			
	Clarke Creek (1)					•		
Central West	Callide B	•						
	Callide PP	•						
	Stanwell	•						
	Lilyvale				•			
	Moura				•			
	Bouldercombe						•	
Gladstone	Gladstone	•						
	Yarwun		•					
Wide Bay	Woolooga Energy Park				•			
Moreton	Swanbank E		•					
	Wivenhoe			•				

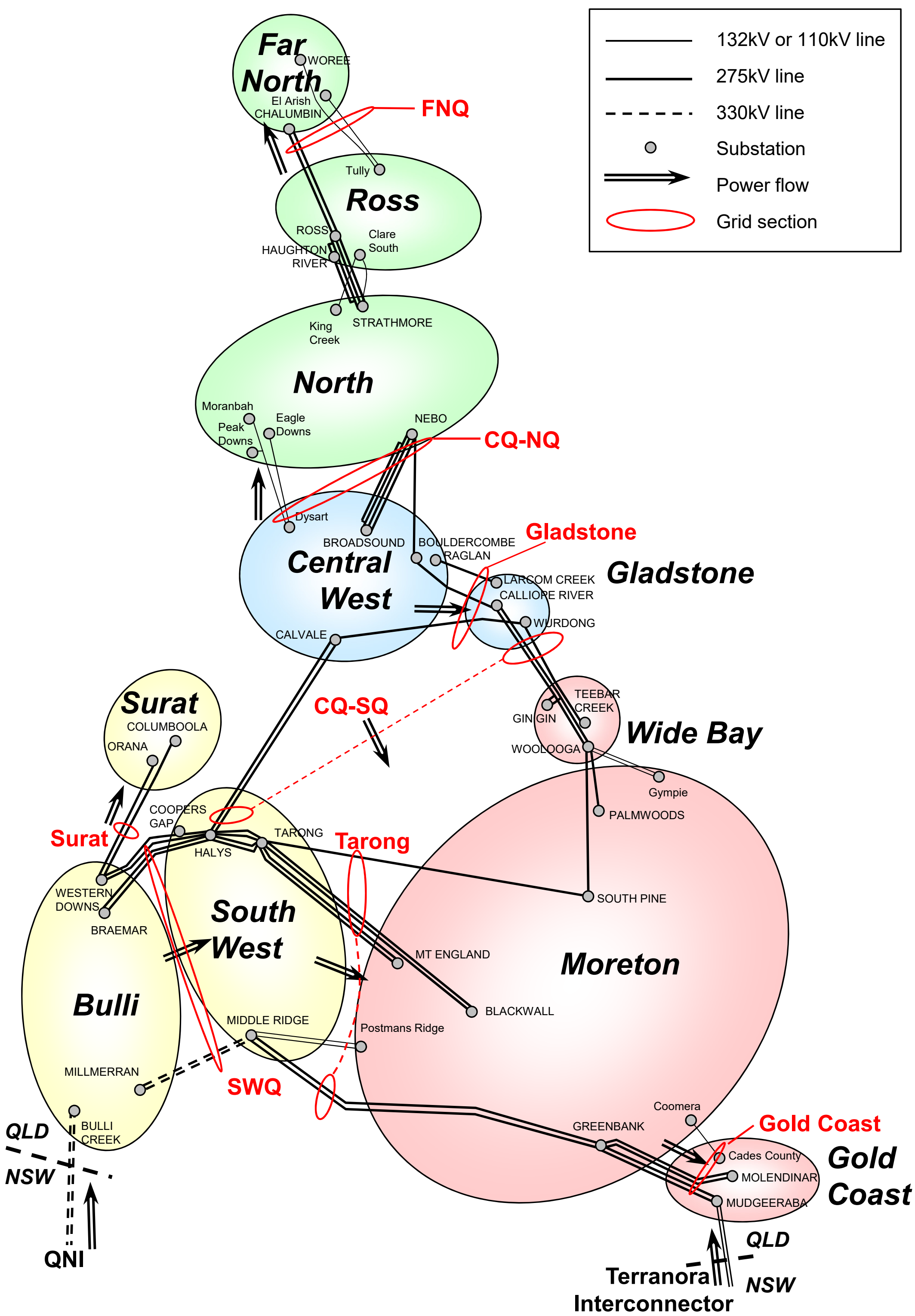
Table F.3 Zone Generation details (*continued*)

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
South West	Tarong	•						
	Tarong North	•						
	Oakey		•					
	Wambo (1)					•		
	Coopers Gap					•		
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
	Chinchilla (1)						•	
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 take into account 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	
	Equation 1	Equation 2
	Woree SVC	Mt Emerald Wind Farm
Constant term (intercept)	574	568
Number of Barron Gorge units on line [0 to 2]	21	-
Total MW generation at Barron Gorge	-0.83	-0.25
Total MW generation at Mt Emerald Wind Farm	-0.59	-0.96
Total MW generation at Kaban Wind Farm	-0.59	-0.96
Total MW generation at Kareeya Power Station	-0.51	-0.62
Total MW generation in Ross zone (1)	-	0.09
Total nominal MVAr of 132kV shunt capacitors on line within nominated Cairns area locations (2)	0.52	0.68
Total nominal MVAr of 275kV shunt reactors on line within nominated Cairns area locations (3)	-	-1.45
Total nominal MVAr of 132kV shunt reactors on line within nominated Chalumbin area locations (4)	-0.35	-0.45
Total nominal MVAr of 275kV shunt reactors on line within nominated Chalumbin area locations (5)	-0.42	-0.36
AEMO Constraint ID	Q^NIL_FNQ_MRSVC	Q^NIL_FNQ_MEWF

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	Equation 2
	Feeder contingency	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

Table G.3 North Queensland system strength equations

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.

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	Other NQ Plants
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 350	> 150	OFF	25	25	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	OFF	0	0	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	ON	100	100	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	50	50	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	ON	100	100	100
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	OFF	50	50	80
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	ON	100	50	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	N/A	100	Wind = 100 Solar = N/A
AEMO Constraint ID								Q_NIL_STRGTH_HAUSF	Q_NIL_STRGTH_KBWF	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_MEWF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_RUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

System normal equations are implemented for all other north Queensland semi-scheduled generators (Mt Emerald Wind Farm, Ross River Solar Farm, Kidston Solar Farm, Kennedy Energy Park, Clare Solar Farm, Sun Metals Solar Farm, Whitsunday Solar Farm, Hamilton Solar Farm, Daydream Solar Farm, Hayman Solar Farm, Collinsville Solar Farm and Rugby Run Solar Farm) to ensure system security is maintained during abnormally low synchronous generator dispatches. These equations allow unconstrained operation for all but one condition of Table G.3 where operation is constrained to 80%. Conditions resulting in lower synchronous unit capacity is constrained to 0.

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 Battery Energy System, 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, 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
	CalvaleHalys 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, 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 18 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 16 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 2023/24, 2024/25 and 2025/26.

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 2022 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 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.

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						SSLF	Ref Node
					2023/24		2024/25		2025/26			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Alan Sherriff	132	31.5	4.1	3.8	13.4	13.8	13.4	13.7	13.7	13.9	1.0343	Ross 275kV
Alligator Creek	132	31.5	3.1	1.8	4.4	5.9	4.4	5.8	4.4	5.8	1.1302	Ross 275kV
Aurumfield	275	40.0	1.2	1.1	-	-	-	-	3.7	4.6	1.1060	Ross 275kV
Bolingbroke	132	31.5	2.0	1.9	2.5	1.9	2.4	1.9	2.5	1.9	1.2135	Ross 275kV
Bowen North	132	31.5	2.1	0.7	3.0	3.2	2.9	3.2	3.0	3.2	1.1639	Ross 275kV
Cairns (2T)	132	31.5	3.1	0.5	6.5	8.5	6.5	8.6	6.8	8.9	1.0762	Ross 275kV
Cairns (3T)	132	31.5	3.1	0.5	6.5	8.5	6.5	8.6	6.8	8.9	1.0762	Ross 275kV
Cairns (4T)	132	31.5	3.1	0.5	6.5	8.6	6.5	8.7	6.8	9.0	1.0761	Ross 275kV
Cardwell	132	31.5	2.0	0.9	3.3	3.6	3.3	3.6	3.3	3.6	1.1447	Ross 275kV
Chalumbin	275	40.0	2.0	1.6	4.8	5.2	4.8	5.3	5.3	5.7	1.0453	Ross 275kV
Chalumbin	132	31.5	3.4	2.7	7.1	8.2	7.1	8.2	7.4	8.5	1.0790	Ross 275kV
Clare South	132	31.5	3.4	3.0	8.2	8.2	8.1	8.1	8.2	8.2	1.0696	Ross 275kV
Collinsville North	132	31.5	5.2	4.5	11.4	12.2	11.3	12.1	11.6	12.2	1.0432	Ross 275kV
Coppabella	132	31.5	2.2	1.5	3.1	3.4	3.0	3.4	3.0	3.4	1.1863	Ross 275kV
Crush Creek	275	40.0	3.5	3.0	10.4	11.6	10.3	11.5	10.7	11.8	1.0200	Ross 275kV
Dan Gleeson (1T)	132	31.5	4.1	3.8	12.8	13.2	12.8	13.1	13.0	13.3	1.0346	Ross 275kV
Dan Gleeson (2T)	132	31.5	4.1	3.8	12.8	13.3	12.8	13.2	13.0	13.4	1.0346	Ross 275kV
Edmonton	132	31.5	2.9	0.9	5.9	7.1	5.9	7.1	6.1	7.3	1.0835	Ross 275kV
Eagle Downs	132	31.5	3.0	1.5	4.6	4.5	4.6	4.4	4.6	4.4	1.1292	Lillyvale 132kV
El Arish	132	31.5	2.3	1.0	3.7	4.5	3.7	4.5	3.8	4.6	1.1219	Ross 275kV
Garbutt	132	31.5	3.8	1.7	11.0	11.0	11.0	10.9	11.2	11.0	1.0423	Ross 275kV
Greenland	132	31.5	3.5	2.1	5.6	5.0	5.5	5.0	5.5	5.0	1.1150	Ross 275kV
Goonyella Riverside	132	31.5	3.5	3.1	6.1	5.5	6.0	5.4	6.0	5.4	1.1075	Ross 275kV
Guybal Munjan	275	40.0	2.2	1.9	-	-	5.4	4.7	6.5	5.3	1.0265	Ross 275kV
Haughton River	275	40.0	2.7	2.1	8.0	8.3	8.0	8.2	8.4	8.5	1.0132	Ross 275kV
Ingham South	132	31.5	1.9	1.1	3.4	3.5	3.4	3.4	3.4	3.5	1.1543	Ross 275kV
Innisfail	132	31.5	2.1	1.3	3.2	3.9	3.2	3.8	3.3	3.9	1.1438	Ross 275kV
Invicta	132	31.5	2.6	2.4	5.3	4.8	5.3	4.8	5.3	4.8	1.1069	Ross 275kV
Kamerunga	132	31.5	2.8	2.5	5.8	7.0	5.8	7.0	6.0	7.2	1.0906	Ross 275kV
Kamerunga	132	31.5	2.8	2.5	5.8	7.0	5.8	7.0	6.0	7.2	1.0906	Ross 275kV
Kareeya	132	31.5	3.2	2.4	6.0	6.6	6.0	6.6	6.2	6.8	1.0957	Ross 275kV
Kemmis	132	31.5	4.0	1.6	6.1	6.6	6.1	6.5	6.1	6.6	1.1009	Ross 275kV
King Creek	132	31.5	3.2	1.4	5.5	4.4	5.5	4.4	5.5	4.4	1.0889	Ross 275kV
Lake Ross	132	31.5	4.7	4.2	17.7	19.8	17.7	19.6	18.3	20.1	1.0212	Ross 275kV
Mackay	132	31.5	3.4	2.9	5.0	6.1	5.0	6.0	5.0	6.0	1.1190	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Mackay Ports	132	31.5	2.6	1.6	3.4	4.1	3.4	4.0	3.4	4.1	1.1612	Ross 275kV
Mindi	132	31.5	3.5	3.3	4.9	3.7	4.8	3.7	4.9	3.7	1.1167	Ross 275kV
Moranbah	132	31.5	4.0	3.3	8.0	9.5	7.9	9.4	8.0	9.4	1.0970	Ross 275kV
Moranbah Plains	132	31.5	2.7	2.3	4.4	4.8	4.4	4.7	4.4	4.8	1.1533	Ross 275kV
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.2	5.7	5.2	1.1209	Ross 275kV
Mt Mclaren	132	31.5	1.6	1.4	2.1	2.3	2.1	2.3	2.1	2.3	1.2707	Ross 275kV
Nebo	275	40.0	4.6	4.0	11.6	11.7	11.4	12.7	11.9	13.0	1.0371	Ross 275kV
Nebo	132	31.5	7.1	6.2	14.0	16.0	13.8	16.2	14.1	16.4	1.0525	Ross 275kV
Newlands	132	31.5	2.5	1.3	3.6	4.0	3.6	4.0	3.6	4.0	1.1484	Ross 275kV
North Goonyella	132	31.5	2.9	2.5	4.5	3.7	4.5	3.7	4.5	3.7	1.1319	Ross 275kV
Oonooie	132	31.5	2.4	1.5	3.1	3.7	3.1	3.6	3.1	3.6	1.1772	Ross 275kV
Peak Downs	132	31.5	2.8	2.1	4.2	3.7	4.2	3.7	4.2	3.7	1.1360	Lillyvale 132kV
Pioneer Valley	132	31.5	4.1	3.6	6.6	7.5	6.5	7.4	6.6	7.4	1.0966	Ross 275kV
Proserpine	132	31.5	2.5	1.8	3.5	4.0	3.5	4.0	3.5	4.0	1.1375	Ross 275kV
Ross	275	40.0	2.8	2.5	9.4	10.4	9.3	10.4	10.1	11.1	1.0000	Ross 275kV
Ross	132	31.5	4.7	4.3	18.3	20.6	18.2	20.4	18.9	20.9	1.0203	Ross 275kV
Springlands	132	31.5	5.5	4.7	12.6	14.4	12.5	14.2	12.8	14.4	1.0385	Ross 275kV
Stony Creek	132	31.5	2.7	1.2	3.8	3.7	3.8	3.6	3.8	3.7	1.1341	Ross 275kV
Strathmore	275	40.0	3.5	3.0	10.5	11.7	10.4	11.6	10.8	12.0	1.0197	Ross 275kV
Strathmore	132	31.5	5.6	4.8	13.1	15.3	13.0	15.1	13.2	15.4	1.0371	Ross 275kV
Townsville East	132	31.5	3.9	1.6	13.0	12.6	13.0	12.6	13.2	12.7	1.0424	Ross 275kV
Townsville South	132	31.5	4.2	3.9	17.6	21.2	17.5	21.1	17.9	21.4	1.0326	Ross 275kV
Townsville GT PS	132	31.5	3.4	2.4	10.0	10.6	9.9	10.4	10.1	10.5	1.0557	Ross 275kV
Tully	132	31.5	2.7	1.5	4.8	5.6	4.9	5.6	5.0	5.7	1.0901	Ross 275kV
Tully South	275	40.0	1.7	0.6	3.7	3.6	3.8	3.7	3.9	3.8	1.0514	Ross 275kV
Tumoulin	275	40.0	1.8	1.3	4.2	4.9	4.2	4.6	4.5	4.9	1.0540	Ross 275kV
Turkinje	132	31.5	1.8	1.2	2.8	3.1	2.8	3.1	2.8	3.2	1.1933	Ross 275kV
Walkamin	275	40.0	1.7	1.4	4.0	4.6	4.0	4.6	4.3	4.9	1.0576	Ross 275kV
Wandoo	132	31.5	3.3	3.1	4.5	3.3	4.5	3.3	4.5	3.3	1.1241	Ross 275kV
Woree (1T)	275	40.0	1.8	1.5	4.3	5.1	4.3	5.1	4.5	5.4	1.0531	Ross 275kV
Woree (2T)	132	31.5	3.2	2.7	6.8	9.2	6.8	9.3	7.1	9.6	1.0730	Ross 275kV
Wotonga	132	31.5	3.6	1.7	6.2	7.2	6.2	7.1	6.2	7.2	1.1105	Ross 275kV
Yabulu South	132	31.5	3.8	3.2	11.1	10.8	11.1	10.2	11.3	10.4	1.0444	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Baralaba	132	31.5	3.4	2.1	4.3	3.7	4.3	3.7	4.3	3.7	1.1422	Lillyvale 132kV
Biloela	132	31.5	6.1	3.5	7.9	8.2	8.0	8.2	8.0	8.2	1.0893	Gin Gin 275kV
Blackwater	132	31.5	4.0	3.3	5.9	7.1	5.9	7.0	5.9	7.0	1.0480	Lillyvale 132kV
Bluff	132	31.5	2.6	2.3	3.5	4.3	3.4	4.2	3.4	4.3	1.1057	Lillyvale 132kV
Bouldercombe	275	40.0	10.2	8.7	20.7	20.0	21.1	19.8	21.4	19.9	1.0374	Gin Gin 275kV
Bouldercombe	132	31.5	10.3	6.3	14.4	16.7	14.4	15.8	14.5	15.8	1.0594	Gin Gin 275kV
Broadsound	275	40.0	6.0	4.9	15.1	16.0	14.7	15.3	15.3	16.9	1.0434	Lillyvale 132kV
Bundoora	132	31.5	5.2	4.4	9.4	9.1	9.3	9.0	9.3	9.0	1.0120	Lillyvale 132kV
Callemondah	132	31.5	16.9	6.9	22.0	24.6	22.1	24.7	22.2	24.7	1.0396	Gin Gin 275kV
Calliope River	275	40.0	11.8	10.2	20.9	24.0	21.2	24.1	21.3	24.2	1.0230	Gin Gin 275kV
Calliope River	132	31.5	18.7	15.3	24.7	29.8	24.8	29.9	24.9	29.9	1.0372	Gin Gin 275kV
Calvale (1T)	275	40.0	10.3	8.5	21.1	22.1	23.9	26.2	24.0	26.2	1.0379	Gin Gin 275kV
Calvale (2T)	132	31.5	6.6	2.8	8.7	9.5	8.8	9.6	8.8	9.6	1.0841	Gin Gin 275kV
Calvale	132	31.5	6.8	3.0	8.4	9.1	8.5	9.3	8.5	9.3	1.0823	Gin Gin 275kV
Duaringa	132	31.5	1.9	1.6	2.3	2.9	2.2	2.9	2.2	2.9	1.2140	Lillyvale 132kV
Dysart	132	31.5	3.2	1.9	4.8	5.4	4.8	5.3	4.8	5.3	1.1039	Lillyvale 132kV
Egans Hill	132	31.5	6.4	1.6	8.3	8.1	8.3	8.0	8.3	8.0	1.0851	Gin Gin 275kV
Gladstone PS	275	40.0	11.2	9.7	19.4	21.8	19.7	21.9	19.8	22.0	1.0241	Gin Gin 275kV
Gladstone PS	132	31.5	16.9	13.5	21.7	24.9	21.8	25.0	21.9	25.1	1.0411	Gin Gin 275kV
Gladstone South	132	31.5	12.8	10.0	16.2	17.2	16.2	17.2	16.3	17.2	1.0479	Gin Gin 275kV
Grantleigh	132	31.5	2.3	2.0	2.7	2.8	2.7	2.8	2.7	2.8	1.2083	Gin Gin 275kV
Gregory	132	31.5	5.7	4.7	10.5	11.7	10.3	11.5	10.4	11.6	1.0027	Lillyvale 132kV
Larcom Creek	275	40.0	9.2	3.3	15.5	16.4	15.6	15.7	15.7	15.8	1.0295	Gin Gin 275kV
Larcom Creek	132	31.5	8.2	4.2	12.3	13.9	12.3	13.8	12.3	13.8	1.0597	Gin Gin 275kV

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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Lilyvale	275	40.0	3.5	2.6	6.7	6.5	6.5	6.3	6.6	6.4	1.0216	Lillyvale 132kV
Lilyvale	132	31.5	5.9	4.8	11.1	12.8	10.9	12.6	11.0	12.7	1.0000	Lillyvale 132kV
Moura	132	31.5	3.2	1.5	4.3	5.3	4.2	5.2	4.3	5.2	1.1547	Gin Gin 275kV
Norwich Park	132	31.5	2.7	2.5	3.7	2.7	3.6	2.6	3.7	2.6	1.1087	Lillyvale 132kV
Pandoin	132	31.5	5.5	1.2	6.9	6.1	6.9	6.0	6.9	6.0	1.0971	Gin Gin 275kV
Raglan	275	40.0	7.7	4.3	12.0	10.7	12.1	10.5	12.1	10.5	1.0375	Gin Gin 275kV
Rockhampton (1T)	132	31.5	5.1	1.8	6.4	6.3	6.4	6.3	6.4	6.3	1.1022	Gin Gin 275kV
Rockhampton (5T)	132	31.5	5.0	1.8	6.2	6.1	6.2	6.1	6.2	6.1	1.1047	Gin Gin 275kV
Stanwell	275	40.0	10.8	9.0	23.5	24.9	24.2	25.2	24.4	25.3	1.0381	Gin Gin 275kV
Stanwell	132	31.5	4.8	3.7	5.9	6.4	5.9	6.3	5.9	6.3	1.1085	Gin Gin 275kV
Wurdong	275	40.0	10.3	6.6	16.6	16.6	16.9	16.8	17.0	16.8	1.0267	Gin Gin 275kV
Wycarbah	132	31.5	3.7	3.1	4.5	5.4	4.5	5.3	4.5	5.3	1.1346	Gin Gin 275kV
Yarwun	132	31.5	8.0	4.5	12.9	14.9	12.9	14.8	12.9	14.9	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Abermain	275	40.0	8.1	6.4	18.3	18.8	18.2	18.7	18.3	18.8	1.0054	Greenbank 275kV
Abermain	110	31.5	13.0	10.4	21.5	24.5	21.3	24.3	21.4	24.4	1.0209	Greenbank 275kV
Algester	110	31.5	12.9	11.6	21.1	20.8	20.9	20.7	21.0	20.8	1.0207	Greenbank 275kV
Ashgrove West	110	31.5	12.2	9.3	19.1	20.1	19.0	20.0	19.1	20.0	1.0258	Greenbank 275kV
Banana Bridge	275	40.0	7.6	5.2	-	-	25.8	27.4	25.9	27.5	1.0008	Western Downs 275kV
Belmont	275	40.0	7.9	7.2	17.0	17.9	16.9	17.8	17.0	19.0	1.0051	Greenbank 275kV
Belmont	110	31.5	15.4	14.4	27.8	34.4	27.6	34.2	27.8	34.6	1.0128	Greenbank 275kV
Blackstone	275	40.0	8.7	7.9	21.3	23.7	21.3	23.6	21.4	23.8	1.0017	Greenbank 275kV
Blackstone	110	31.5	14.6	13.4	25.4	28.0	25.3	27.8	25.4	27.9	1.0160	Greenbank 275kV
Blackwall	275	40.0	9.3	8.4	22.6	24.3	22.5	24.2	22.7	24.3	1.0048	Greenbank 275kV
Blythdale	132	31.5	3.2	2.3	4.3	5.3	4.3	5.3	4.3	5.4	1.1108	Western Downs 275kV
Braemar	330	50.0	7.0	5.7	24.3	26.3	24.3	26.4	24.5	26.5	1.0085	Western Downs 275kV
Braemar (East)	275	40.0	8.2	5.3	27.5	31.8	27.5	31.8	27.6	31.9	1.0117	Western Downs 275kV
Braemar (West)	275	40.0	7.9	4.7	28.8	31.7	28.9	31.7	29.0	31.9	1.0048	Western Downs 275kV
Bulli Creek	330	50.0	6.8	6.2	18.6	14.9	18.6	15.0	18.8	15.1	1.0171	Western Downs 275kV
Bulli Creek	132	31.5	3.0	3.0	3.8	4.3	3.8	4.3	4.3	4.8	1.1366	Western Downs 275kV
Bundamba	110	31.5	11.1	7.7	17.2	16.6	17.1	16.5	17.2	16.5	1.0275	Greenbank 275kV
Cameby	132	31.5	6.0	5.0	11.0	9.7	9.7	8.9	9.7	9.0	1.0516	Western Downs 275kV
Chinchilla	132	31.5	5.3	4.6	8.7	10.1	7.1	8.5	7.1	8.5	1.0623	Western Downs 275kV
Clifford Creek	132	31.5	4.1	3.3	6.0	5.4	6.0	5.4	6.0	5.4	1.0805	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Columboola	275	40.0	5.5	4.3	14.2	13.3	14.2	13.3	14.2	13.3	1.0120	Western Downs 275kV
Columboola	132	31.5	7.7	6.0	18.2	21.3	17.8	20.7	17.9	20.7	1.0325	Western Downs 275kV
Condabri Central	132	31.5	5.4	4.5	9.5	7.0	9.4	7.0	9.4	7.0	1.0566	Western Downs 275kV
Condabri North	132	31.5	6.9	5.5	14.4	13.3	14.2	13.1	14.2	13.1	1.0394	Western Downs 275kV
Condabri South	132	31.5	4.4	3.6	6.8	4.6	6.8	4.6	6.8	4.6	1.0761	Western Downs 275kV
Coopers Gap	275	40.0	8.1	3.2	18.0	17.8	17.7	17.7	17.9	17.8	1.0155	Western Downs 275kV
Diamondy	275	40.0	7.7	6.8	-	-	14.4	11.5	14.9	11.8	1.0217	Western Downs 275kV
Dinoun South	132	31.5	4.5	3.6	6.9	7.1	6.9	7.1	6.9	7.1	1.0702	Western Downs 275kV
Eurombah (1T)	275	40.0	2.8	1.2	4.7	4.9	4.7	4.9	4.7	4.9	1.0486	Western Downs 275kV
Eurombah	132	31.5	4.7	3.5	7.3	8.9	7.3	8.9	7.3	8.9	1.0667	Western Downs 275kV
Fairview	132	31.5	3.1	2.5	4.1	5.2	4.1	5.2	4.1	5.2	1.1171	Western Downs 275kV
Fairview South	132	31.5	3.8	3.0	5.4	6.8	5.4	6.8	5.5	6.9	1.0890	Western Downs 275kV
Gin Gin	275	40.0	6.4	4.4	9.3	8.7	9.5	9.0	9.6	9.1	1.0000	Gin Gin 275kV
Gin Gin	132	31.5	8.9	7.0	12.0	13.0	12.5	13.7	12.7	13.8	1.0184	Gin Gin 275kV
Goodna	275	40.0	7.8	5.6	16.3	16.0	16.2	15.9	16.3	16.0	1.0078	Greenbank 275kV
Goodna	110	31.5	14.7	12.9	25.5	27.5	25.3	27.3	25.5	27.5	1.0164	Greenbank 275kV
Greenbank	275	40.0	8.5	7.8	20.6	23.6	20.5	23.5	20.6	23.7	1.0000	Greenbank 275kV
Halys	275	40.0	11.8	10.2	33.2	28.8	32.9	29.4	33.5	29.8	1.0124	Western Downs 275kV
Kumbarilla Park	275	40.0	6.7	1.7	16.9	16.2	16.9	16.2	17.0	16.3	1.0171	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Kumbarilla Park	132	31.5	8.3	5.5	13.2	15.2	13.2	15.2	13.3	15.3	1.0383	Western Downs 275kV
Loganlea	275	40.0	7.3	6.1	15.0	15.5	14.9	15.4	15.0	15.6	1.0059	Greenbank 275kV
Loganlea	110	31.5	13.4	12.0	22.7	27.3	22.6	27.2	22.7	27.4	1.0170	Greenbank 275kV
Middle Ridge (4T)	330	50.0	5.8	3.2	12.7	12.3	12.8	12.5	12.8	12.5	1.0175	Western Downs 275kV
Middle Ridge (5T)	330	50.0	5.9	3.2	13.1	12.8	13.2	12.9	13.2	12.9	1.0169	Western Downs 275kV
Middle Ridge	275	40.0	7.6	6.7	18.3	18.4	18.3	18.5	18.4	18.6	1.0136	Western Downs 275kV
Middle Ridge	110	31.5	10.6	8.8	21.3	25.1	21.4	25.0	21.4	25.1	1.0350	Western Downs 275kV
Millmerran	330	50.0	6.3	5.9	18.6	19.9	18.6	20.5	18.7	20.6	1.0198	Western Downs 275kV
Molendinar (1T)	275	40.0	5.0	2.1	8.2	8.1	8.2	8.0	8.2	8.0	1.0175	Greenbank 275kV
Molendinar (2T)	275	40.0	5.0	2.1	8.2	8.1	8.2	8.0	8.2	8.0	1.0176	Greenbank 275kV
Molendinar	110	31.5	11.9	10.2	19.3	24.4	19.2	24.2	19.2	24.3	1.0199	Greenbank 275kV
Mt England	275	40.0	9.1	8.3	22.9	23.1	22.9	23.0	23.0	23.1	1.0072	Greenbank 275kV
Mudgeeraba	275	40.0	5.4	4.3	9.3	8.6	9.2	8.6	9.3	8.6	1.0143	Greenbank 275kV
Mudgeeraba	110	31.5	11.0	10.0	17.4	21.0	17.2	21.1	17.3	21.2	1.0233	Greenbank 275kV
Murarrie (1T)	275	40.0	6.8	2.3	13.2	13.2	13.2	13.1	14.4	16.3	1.0092	Greenbank 275kV
Murarrie (2T)	275	40.0	6.8	2.3	13.2	13.4	13.1	13.3	14.4	16.3	1.0092	Greenbank 275kV
Murarrie	110	31.5	13.9	12.7	23.8	28.9	23.7	28.7	23.8	29.3	1.0164	Greenbank 275kV
Oakey	110	31.5	4.8	3.4	11.0	12.2	11.4	12.4	11.5	12.4	1.0941	Greenbank 275kV
Oakey GT	110	31.5	4.6	1.3	9.9	9.9	10.2	10.0	10.2	10.0	1.0994	Greenbank 275kV
Orana	275	40.0	6.2	3.2	16.5	15.9	16.6	16.1	16.6	16.1	1.0072	Western Downs 275kV
Palmwoods	275	40.0	5.7	3.5	8.7	9.1	8.8	9.1	8.8	9.2	1.0299	Greenbank 275kV
Palmwoods	132	31.5	9.3	6.9	13.3	16.1	13.4	16.1	13.4	16.2	1.0402	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						SSLF	Ref Node
					2023/24		2024/25		2025/26			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
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	13.0	9.6	21.4	20.6	21.3	20.5	21.3	20.6	1.0207	Greenbank 275kV
Richlands	110	31.5	13.3	11.0	21.9	22.6	21.8	22.5	21.9	22.5	1.0202	Greenbank 275kV
Rocklea (1T)	275	40.0	7.0	2.3	13.3	12.3	13.2	12.3	13.3	12.3	1.0122	Greenbank 275kV
Rocklea (2T)	275	40.0	5.5	2.3	8.8	8.4	8.8	8.4	8.8	8.4	1.0235	Greenbank 275kV
Rocklea	110	31.5	14.7	12.9	25.0	28.8	24.9	28.6	25.0	28.7	1.0180	Greenbank 275kV
Runcorn	110	31.5	11.9	8.6	18.8	19.2	18.7	19.1	18.8	19.2	1.0237	Greenbank 275kV
South Pine	275	40.0	8.9	8.1	19.1	21.6	19.1	21.5	19.2	21.6	1.0099	Greenbank 275kV
South Pine (East)	110	31.5	13.7	11.6	21.7	27.8	21.7	27.7	21.8	27.8	1.0253	Greenbank 275kV
South Pine (West)	110	31.5	12.9	10.2	20.5	23.6	20.4	23.5	20.5	23.6	1.0249	Greenbank 275kV
Sumner	110	31.5	12.8	9.1	20.7	20.2	20.6	20.1	20.6	20.2	1.0226	Greenbank 275kV
Swanbank E	275	40.0	8.6	7.3	21.0	23.3	20.9	23.2	21.1	23.3	1.0017	Greenbank 275kV
Tangkam	110	31.5	5.6	3.8	13.0	12.1	13.8	12.4	13.8	12.4	1.0788	Greenbank 275kV
Tarong	275	40.0	12.3	10.5	34.6	37.0	34.1	36.6	34.6	37.0	1.0111	Western Downs 275kV
Tarong (1T)	132	31.5	4.5	1.1	5.8	6.1	-	-	-	-	1.0900	Western Downs 275kV
Tarong	66	31.5	12.5	7.1	15.5	16.6	15.4	16.5	15.5	16.6	1.0642	Western Downs 275kV
Teebar Creek	275	40.0	5.1	2.7	7.4	7.1	7.6	7.3	7.7	7.3	1.0317	Gin Gin 275kV
Teebar Creek	132	31.5	7.8	5.5	10.5	11.4	11.0	11.8	11.2	12.0	1.0446	Gin Gin 275kV
Tennyson	110	31.5	10.8	1.8	16.3	16.4	16.2	16.3	16.2	16.4	1.0309	Greenbank 275kV
Tummaville	330	50.0	6.2	5.8	-	-	16.5	16.6	16.6	16.7	1.0194	Western Downs 275kV
Upper Kedron	110	31.5	13.2	11.4	21.3	18.7	21.2	18.6	21.3	18.7	1.0227	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						SSLF	Ref Node
					2023/24		2024/25		2025/26			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Wandoan South	275	40.0	4.0	3.1	8.3	9.4	8.3	9.4	8.3	9.4	1.0267	Western Downs 275kV
Wandoan South	132	31.5	5.7	4.3	10.3	13.2	10.4	13.3	10.4	13.4	1.0507	Western Downs 275kV
West Darra	110	31.5	14.5	13.3	24.9	23.8	24.8	23.7	24.9	23.8	1.0173	Greenbank 275kV
Western Downs	275	40.0	7.8	5.4	27.9	30.0	28.0	30.4	28.1	30.5	1.0000	Western Downs 275kV
Woolooga	275	40.0	6.6	5.6	10.5	12.0	10.7	12.2	10.9	12.3	1.0220	Gin Gin 275kV
Woolooga	132	31.5	9.6	7.8	14.8	18.2	15.2	18.6	15.3	18.7	1.0369	Gin Gin 275kV
Yuleba North	275	40.0	3.5	2.8	6.5	7.1	6.5	7.1	6.5	7.1	1.0344	Western Downs 275kV
Yuleba North	132	31.5	5.2	4.0	8.3	10.0	8.3	10.0	8.3	10.0	1.0585	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
ARENA	Australian Renewable Energy Agency
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
DCA	Dedicated Connection Assets
DEPW	Department of Energy and Public Works
DNSP	Distribution Network Service Provider
DSM	Demand side management
EFCS	Emergency Frequency Control Schemes
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FIA	Full Impact Assessment
FNQ	Far North Queensland
GPS	Gladstone Power Station
GPSRR	General Power System Risk Review
IAM	Institute of Asset Management
IBR	Inverter-based Resources
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolts
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
NIEIR	National Institute of Economic and Industry Research
NSCAS	Nework Support and Control Ancillary Service
NSW	New South Wales
NQ	North Queensland
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

Appendix I - Glossary (continued)

PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
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
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCR	Short Circuit Ratio
SDA	State Development Area
SEQ	South East Queensland
SPS	Special Protection Scheme
SSSP	System Strength Service Provider
SSUP	System Strength Unit Prices
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condenser
TAPR	Transmission Annual Planning Report
TGCP	TAPR Guideline Connection Point
TGTL	TAPR Guideline Transmission Line
TNSP	Transmission Network Service Provider
TWh	Terawatt hour
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable renewable energy
VTL	Virtual transmission line
WAMPAC	Wide area monitoring protection and control

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