2019

Transmission Annual Planning Report

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Contents

Contents

Executive summary

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 National Electricity Market (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 TAPR includes information on electricity energy and demand forecasts, committed generation and network developments. It also provides estimates of transmission grid capability and potential network and non-network developments required in the future to continue to meet electricity demand in a timely manner and provide a valued service to our customers.

Overview

The 2019 TAPR outlines the key factors impacting Powerlink's transmission network development and operations and discusses how Powerlink continues to adapt and respond to dynamic changes in the external environment.

The forecasts presented in this TAPR indicate low growth for summer and winter maximum demand and a decline in delivered energy for the transmission network over the 10-year outlook period.

The Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure required to manage emerging risks related to assets now reaching the end of technical service life represents the majority of Powerlink's program of work over the outlook period. In line with customer and stakeholder expectations, emphasis will be placed on ensuring that asset reinvestment considers the enduring need and most cost effective option. Network planning studies have focussed on evaluating the enduring need for existing assets in the context of increasing diversity of generation, a relatively flat demand growth outlook and the potential for network reconfiguration, coupled with alternative non-network solutions.

Powerlink's focus on customer and stakeholder engagement has continued over the last year, with a range of activities undertaken to seek feedback and input into our network investment decision making and planning. This included holding the Powerlink Queensland Transmission Network Forum, incorporating related interactive feedback sessions on managing peaks and hollows to improve network utilisation and customer outcomes, navigating the renewable connection process and creating a Transmission Network Vision.

Since the 2018 TAPR, Powerlink as a founding participant, has committed to the industry-led and world-first whole-of-sector initiative, the Energy Charter. The Charter is focussed on driving customer-centric culture and conduct in energy businesses to create price and service delivery improvements for the benefit of customers.

Electricity energy and demand forecasts

The 2018/19 summer in Queensland set a new record demand at 6:00pm on 13 February, when 8,969MW was delivered from the transmission grid. Operational 'as generated' and native demand records were recorded at 5:30pm on 13 February, with operational 'as generated' reaching 10,044MW, passing the previous record of 9,796MW set last summer. After temperature correction, the 2018/19 summer demand aligned with the 2018 TAPR forecast.

Powerlink has incorporated AEMO forecasts into its demand and energy forecasts and planning processes. This will avoid duplication of effort and deliver better value to our customers. It also presents an opportunity for Powerlink to work even closer with AEMO and bring specific jurisdictional knowledge to the development of these load forecasts.

Executive Summary

Electricity energy forecast

Based on the medium economic outlook, Queensland's delivered energy consumption is forecast to decrease at an average of 0.7% per annum over the next 10 years from 48,886GWh in 2018/19 to 45,421GWh in 2028/29. The reduction is due to anticipated increases in the capacity of distribution connected renewable generation.

Electricity demand forecast

Based on the medium economic outlook, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.5% per annum over the next 10 years, from 8,467MW (weather corrected) in 2018/19 to 8,874MW in 2028/29.

The transmission delivered maximum demand for summer 2018/19 of 8,969MW was a new record for Queensland. Operational 'as generated' and native demand in summer 2018/19 were also new records, with operational 'as generated' reaching 10,044MW, passing the previous record of 9,796MW set last summer.

Future network development

Shifts in customer expectation and dynamic changes in the external environment including the upturn in variable renewable energy (VRE) developments in Queensland, are reshaping the operating environment in which Powerlink delivers its transmission services. In addition, market initiatives such as the Integrated System Plan (ISP) have the potential to influence the future development of the power system and the associated network topography of the transmission network in Queensland and the NEM over the 10-year outlook period.

Powerlink continues to adopt and respond to these changes by:

- committing to the industry-led and world first whole-of-sector initiative – The Energy Charter
- ongoing active customer and stakeholder engagement for informed decision making and planning
- implementing and adopting the recommendations of various reviews
- adapting to changes in electricity customer behaviour and economic outlook
- continuing to adapt its approach to investment decisions
- placing considerable emphasis on an integrated and flexible analysis of future reinvestment needs
- supporting diverse generation connection
- continuing to focus on developing options that deliver a secure, safe, reliable and cost effective transmission network.

Based on the medium economic forecast outlook, the planning standard and committed network solutions, significant network augmentations to meet load growth are not forecast to occur within the 10-year outlook period of this TAPR.

There are proposals for large mining, metal processing and other industrial loads that have not reached a committed development status. These new large loads are within the resource rich areas of Queensland and associated coastal port facilities. These loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. Within this TAPR, Powerlink has outlined the potential network investment required in response to these loads emerging in line with the high economic outlook forecast.

Since January 2016, Queensland has seen an unprecedented level of renewable energy investment activity in north and central Queensland. These investments in VRE generation are expected to increase the utilisation of the Central West to Gladstone and Central Queensland to Southern Queensland (CQ-SQ) grid sections. Depending on the emergence of network limitations it may become economically viable to increase the power transfer capacity to alleviate constraints across these grid sections. Feasible network solutions are outlined within the TAPR.

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

Considerable emphasis has been given to an 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 network reconfiguration, asset retirement, non-network solutions or replacement with an asset of lower capacity. This incremental development approach potentially defers large capital investment and has the benefit of maintaining the existing topography, transfer capability and operability of the transmission network.

Renewable energy and generation capacity

To date Powerlink has completed connection of 11 large-scale solar and wind farm projects in Queensland, adding 1,423MW of generation capacity to the grid. An additional two projects are fully operational, and 40 connection applications, totalling about 8,000MW of new generation capacity, have been received and are at varying stages of progress[1].

To ensure that any adverse system strength impact is adequately addressed, Powerlink is working with proponents, suppliers and AEMO enhance its integrated system strength model for the Queensland network. This work has provided important insights into the extreme complexity of system strength and how it impacts on managing asynchronous connections and the network in general.

Powerlink will apply this integrated system strength model to existing and new connection applications and engage with renewables sector customers to better understand the potential for additional VRE generation in Queensland.

Grid section and zone performance

During 2018/19, the Powerlink transmission network supported the delivery of a record summer maximum demand of 8,969MW, 127MW higher than that recorded in summer 2017/18. Record transmission delivered demand was recorded for Far North, South West, Moreton and Gold Coast zones.

The CQ-SQ grid section showed greater levels of utilisation during 2018/19, reflecting higher generation levels in North Queensland as a result of recently commissioned VRE generators.

The transmission network in the Queensland region performed reliably during the 2018/19 year, including during the record summer maximum demand.

Consultation on network reinvestments

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.

Following the Replacement Expenditure Planning Arrangements Rule, which commenced in September 2017, Powerlink has made considerable progress in its Regulatory Investment Test for Transmission (RIT-T) program in relation to the replacement of network assets, finalising 13 RIT-Ts since the publication of the 2018 TAPR (refer to Chapter 9).

In addition, during 2018/19, Powerlink also commenced a further four RIT-Ts to consider opportunities for non-network solutions to resolve the following network reinvestment requirements, where technically and economically feasible:

- maintaining reliability of supply at Kamerunga Substation
- maintaining reliability of supply between Clare South and Townsville South
- maintaining power transfer capability and reliability of supply at Lilyvale
- maintaining reliability of supply in the Blackwater area.

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[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.

The TAPR also highlights anticipated upcoming 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 5.6.2). 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.

Expanding New South Wales to Queensland transmission transfer capacity

Preliminary assessment of the impact of dynamic changes in the external environment, including the upturn in VRE developments, has indicated that it could be technically and economically justified to expand the New South Wales (NSW) to Queensland transmission transfer capacity. TransGrid and Powerlink are undertaking joint planning relating to existing and forecast network congestion between Queensland and NSW. A RIT-T process to consider investment options on the Queensland/New South Wales Interconnector (QNI) has now commenced. This process includes consideration of the ISP recommended Group 1 and Group 2 investments.

In November 2018, Powerlink and TransGrid released a Project Specification Consultation Report (PSCR) on 'Expanding NSW-Queensland transmission transfer capacity', as the first step in the RIT-T. This RIT-T is investigating options to increase overall net market benefits in the NEM through relieving congestion on the transmission network between NSW and Queensland. The PSCR outlines a range of credible options to meet the identified network need.

Powerlink and TransGrid are currently performing power system analysis and market modelling to assess various network and non-network options. Findings will be published in the Project Assessment Draft Report (PADR) anticipated later in 2019.

Committed and commissioned projects

During 2018/19, having finalised the necessary regulatory processes for the proposed replacement of network assets, the committed projects for reinvestment across Powerlink's network include:

- Woree secondary systems and Static VAr Compensator (SVC) secondary systems replacement
- Ingham South transformers replacement
- Ross 275/132kV primary plant replacement
- Dan Gleeson secondary systems replacement
- Townsville South primary plant replacement
- Egan's Hill to Rockhampton transmission line refit
- Bouldercombe primary plant and transformer replacement
- Baralaba secondary systems replacement
- Palmwoods secondary systems replacement
- Tarong secondary systems replacement
- Belmont secondary systems replacement
- Abermain secondary systems replacement
- Line refit works in the Brisbane metropolitan area between South Pine and Upper Kedron, West Darra to Sumner and Rocklea to Sumner.

Projects completed in 2018/19 include reinvestment works at:

- Turkinje Substation
- Ross Substation
- Nebo Substation
- Stanwell Substation
- Broadsound Substation
- Tennyson Substation
- Line refit works on the 132kV transmission lines between Calliope River and Boyne Island.

Stakeholder consultation for non-network solutions

Powerlink engages with non-network providers to expand the potential use of non-network solutions, addressing the future needs of the transmission network, where technically and economically feasible. These may be in the form of an alternative option to like-for-like replacements, as a partial solution in conjunction with a network solution, or to complement an overall network reconfiguration strategy. Non-network solutions such as demand side management (DSM) will be essential in future years to avoid or delay the need to augment the transmission network in response to any increase in maximum demand.

Since the publication of the 2018 TAPR, Powerlink has continued to hold webinars with non-network providers, customers and other stakeholders. The webinars inform and discuss relevant and topical matters impacting potential future non-network opportunities and more broadly, the future regulated development of the transmission network. Webinars during 2018/19 focussed on:

- the content of the 2018 TAPR
- Expanding NSW-Queensland transmission transfer capacity RIT-T (in conjunction with TransGrid)
- Maintaining reliability of supply between Clare South and Townsville South RIT-T.

Sharing information and seeking customer input through activities such as the Transmission Network Forum and webinars assists in broadening customer and stakeholder understanding of our business and provides additional opportunities to seek input on potential non-network solutions.

Customer and stakeholder engagement

Powerlink has embedded its Stakeholder Engagement Framework, which focuses on engaging with customers and stakeholders and seeking their input into Powerlink's business focus and objectives.

The framework aims to promote more effective stakeholder engagement, better inform customers and encourage feedback, and appropriately incorporate that input into Powerlink's business decision making to improve our planning. A primary aim is to ensure Powerlink's services better reflect customer values, priorities and expectations.

Powerlink surveys its key stakeholder groups, including customers, consumer advocates, government, regulators and industry, to gain a stronger understanding of stakeholder perceptions of performance. The survey completed in 2018 sought views from almost 100 key stakeholders and highlighted improvements in reputation and social licence to operate for Powerlink. The latest survey also sought specific insights from existing directly-connected customers and renewable proponents on aspects of customer service and delivery, and Powerlink's responsiveness.

Powerlink's Customer Panel met throughout the year, with panel members providing input and feedback on Powerlink's decision making processes and methodologies. This has included discussions on the active RIT-T consultations. Composed of members from a range of sectors including energy industry, resources, community advocacy groups, consumers and research organisations, the panel provides an important channel to keep our stakeholders better informed about operational activities and strategic topics of interest to them.

Since 2018, Powerlink has engaged with key stakeholders in a number of ways, including its Transmission Network Forum, and various webinars – all proving to be valuable avenues to exchange information and receive stakeholder input on a range of investment and forecasting considerations.

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2019 TAPR continues to focus on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

The 2019 TAPR:

- provides information in relation to joint planning and Powerlink's approach to asset management (refer to chapters 3 and 4)
- discusses possible future network asset reinvestments for the 10-year outlook period (refer to Chapter 5)
- includes the most recent information for the proposed replacement of network assets which are anticipated to be subject to the RIT-T in the next five years (refer to Chapter 5)
- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 8)
- contains a quick reference guide on where to locate information on potential non-network opportunities in the TAPR, grouped by investment type (refer to Appendix F) and discusses Powerlink's approach to assisting the development of non-network solutions – specifically, through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to 1.9.2 and 5.7)
- introduces the TAPR templates and discusses the context, methodology and principles applied for the development of the Queensland transmission network data (refer to Appendix B).

CHAPTER 1

Introduction

1 Introduction

Key highlights

- The purpose of Powerlink's Transmission Annual Planning Report (TAPR) under the National Electricity Rules (NER) is to provide information about the Queensland electricity transmission network.
- Powerlink is responsible for planning the shared transmission network within Queensland.
- Since publication of the 2018 TAPR, Powerlink has continued to proactively engage with stakeholders and seek their input into Powerlink's network development objectives, network operations and investment decisions.
- The 2019 TAPR identifies key areas of the transmission network in Queensland forecast to require expenditure in the 10-year outlook period.
- Based on Powerlink's most recent planning review and information currently available, the 2019 TAPR also provides substantial detailed technical data (TAPR templates), available on Powerlink's website, to further inform stakeholders on potential transmission network developments.

1.1 Introduction

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) electricity transmission network. It has also been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB) responsible for transmission network planning for the national grid within the State.

As part of its planning responsibilities, Powerlink undertakes an annual planning review in accordance with the requirements of the NER and publishes the findings of this review in its TAPR and TAPR templates.

This 2019 TAPR includes information on electricity energy and demand forecasts, the existing electricity supply system, including committed generation and transmission network reinvestments and developments, and forecasts of network capability. Risks arising from the condition and performance of existing assets, as well as emerging limitations in the capability of the network are identified and possible solutions to address these are discussed. Interested parties are encouraged to provide input to identify the most economical solution (including non-network solutions provided by others) that satisfies the required reliability standard to customers into the future. The 2019 TAPR builds upon work undertaken by Powerlink since 2016, embedding the approach for the connection of variable renewable energy (VRE) generation to Powerlink's transmission network.

Powerlink's annual planning review and TAPR play an important part in planning Queensland's transmission network and helping to ensure it continues to meet the needs of Queensland electricity consumers and participants in the NEM.

1.2 Context of the TAPR

All bodies with jurisdictional planning responsibilities in the NEM are required to undertake the annual planning review and reporting process prescribed in the NER[1].

Information from this process is also provided to the Australian Energy Market Operator (AEMO) to assist in the preparation of its Electricity Forecast Insights (EFI – previously the National Electricity Forecasting Report), Electricity Statement of Opportunities (ESOO), National Transmission Network Development Plan (NTNDP) and Integrated System Plan (ISP).

The ESOO is the primary document for examining electricity supply and demand issues across all regions in the NEM. The NTNDP and ISP provide information on the strategic and long-term development of the national transmission system under a range of market development scenarios. AEMO's EFI provides independent electricity demand and energy forecasts for each NEM region over a 20-year outlook period. The forecasts explore a range of scenarios across high, medium and low economic growth outlooks. The inaugural ISP which integrated generation and grid development outlooks was released in July 2018.

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[1] For the purposes of Powerlink's 2019 TAPR, Version 122 of the NER in place from 30 May 2019.

The primary purpose of the TAPR is to provide information on the short-term to medium-term planning activities of TNSPs, whereas the focus of the ISP and NTNDP is strategic and long-term. The ISP, NTNDP and TAPR are intended to complement each other in informing stakeholders and promoting efficient investment decisions. In supporting this complementary approach, information from both the 2018 ISP and NTNDP, as the most recent versions published, are considered in this TAPR and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2019 TAPR in conjunction with AEMO's 2018 EFI and the 2019 ESOO and NTNDP, which are anticipated to be published in September and December 2019 respectively. The next ISP is currently anticipated for release in mid-2020.

1.3 Purpose of the TAPR

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

It aims to provide information that assists to:

- identify locations that would benefit from significant electricity supply capability or demand side management (DSM) initiatives
- identify locations where major industrial loads could be connected
- identify locations where capacity for new generation developments exist (in particular VRE generation)
- understand how the electricity supply system affects their needs
- 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 are not intended to be relied upon explicitly for the evaluation of participants' investment decisions.

1.4 Role of Powerlink Queensland

Powerlink has been nominated by the Queensland Government as the entity with transmission network planning responsibility for the national grid in Queensland, known as the JPB as outlined in Clause 5.20.5 of the NER.

As the owner and operator of the electricity 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
- 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
- advising AEMO, Registered Participants and interested parties of emerging network limitations 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 and DSM initiatives
- examining options and developing recommendations to address transmission constraints and economic limitations across interconnectors through joint planning with other TNSPs and Network Service Providers (NSP), and consultation with AEMO, Registered Participants and interested parties, with potential solutions including network upgrades, development of new interconnectors or non-network options
- assessing whether or not 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 transmission augmentations and the replacement of transmission network assets in Queensland.

In addition, Powerlink participates in inter-regional system tests associated with new or augmented interconnections.

1.5 Meeting the challenges of a changing external environment

Powerlink continues to adapt and respond by:

- committing to the industry-led and world-first whole-of-sector initiative – The Energy Charter
- ongoing active customer and stakeholder engagement for informed decision making and planning
- implementing and adopting the recommendations of various reviews
- adapting to changes in electricity customer behaviour and economic outlook
- continuing to adapt its approach to investment decisions
- placing considerable emphasis on an integrated and flexible analysis of future reinvestment needs
- supporting diverse generation connection
- continuing to focus on developing options that deliver a secure, safe, reliable and cost effective transmission network.

1.6 Overview of approach to asset management

Powerlink's asset management system captures significant internal and external drivers on the business and sets out initiatives to be adopted. The Asset Management Policy forms the foundation of the Asset Management Strategy. Information on the principles and approach set out in these documents which guide Powerlink's analysis of future network investment needs and key investment drivers is provided in Chapter 4.

1.7 Overview of planning responsibilities and processes

1.7.1 Planning criteria and processes

Powerlink has obligations that govern how it should address forecast network limitations. These obligations are prescribed by *Queensland's Electricity Act 1994* (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'.

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.

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Powerlink may also propose transmission investments that deliver a net market benefit when assessed in accordance with the Regulatory Investment Test for Transmission (RIT-T). The requirements for initiating solutions to meet forecast network limitations 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 and 5.20.5 of the NER.

While each of these clauses prescribes a slightly different process, at a higher level the main steps in network planning for transmission investments subject to the RIT-T can be summarised as follows:

- Publication of information regarding the nature of network limitations, the risks related to ageing network assets remaining in-service and the need for action which includes an examination of demand growth and its forecast exceedance of the network capability (where relevant).
- Consideration of generation and network capability to determine when additional capability is required.
- Consultation on assumptions made and credible options, which may include:
    - network augmentation
    - asset replacement
    - asset retirement
    - network reconfiguration and/or
    - local generation or DSM initiatives

  together with classes of market benefits considered to be material which should be taken into account in the comparison of options.
- Analysis and assessment of credible options, which include costs, market benefits, material inter-network impact and material impact on network users[2] (where relevant).
- Identification of the preferred option that satisfies the RIT-T, which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.
- Consultation and publication of a recommended course of action to address the identified future network limitation or the risks arising from ageing network assets remaining in-service.

1.7.2 Integrated planning of the shared network

Powerlink is responsible for planning the shared transmission network within Queensland, and inter-regionally. The NER sets out the planning process and requires Powerlink to apply the RIT-T to transmission investment proposals for augmentations to the transmission network and the replacements of network assets over $6 million. The planning process requires consultation with AEMO, Registered Participants and interested parties, including customers, generators, DNSPs and other TNSPs. Section 5.6 discusses current consultations, as well as anticipated future consultations, that will be conducted in line with the processes prescribed in the NER.

Significant inputs to the network planning process are the:

- forecast of customer electricity demand (including DSM) and its location
- location, capacity and arrangement of new and existing generation (including embedded generation)
- condition and performance of assets and an assessment of the risks arising from ageing network assets remaining in-service
- assessment of future network capacity to meet the required planning criteria and efficient market outcomes.

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[2] NER Clause 5.16.3 (a) (5).

1 Introduction

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 and is provided in tables 6.1 and 6.2. 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). This involves consultation with the relevant DNSP in situations where the performance of the transmission network may be affected 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 (refer to Chapter 3).

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. Consideration is given to optimising the topography and capacity of the network, taking into account current and future network needs, including future renewable generation. 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 inter-related connectivity 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 integrated planning approach.

The integration of condition and demand based limitations 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. These strategies include:

- retiring or decommissioning assets where there is unlikely to be an ongoing future need
- refurbishing to extend the service life of assets
- replacing assets of different capacity or type
- changing the topography of the network
- implementing non-network solutions.

Each of these options is considered in the context of future capacity needs.

Furthermore, 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 reinvestments. Further information is provided in Section 5.7 and Appendix B.

A summary of Powerlink's integrated planning approach that takes into account both network capacity needs and end of technical service life related issues is presented in Figure 1.1.

Figure 1.1 Overview of Powerlink's TAPR planning process

Inputs	Integrated Planning	Solution Development	TAPR
Asset management policy and strategy Transmission Authority Generation, demand and energy forecasting Asset condition and performance monitoring New customer connection need Consultation and customer/consumer engagement	• Analysis of asset condition, performance and related risks • Analysis of network capability and limitations (including Distribution Network Service Provider joint planning) • Compliance with system standards • Analysis of competition and market impacts • Analysis of operational impacts and constraints • Overall review of portfolio delivery and risks	• 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)	• 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 • Customer and stakeholder engagement

1.7.3 Joint planning

Powerlink undertakes joint planning with other NSPs to collaboratively identify network and non-network solutions, which best serve the long-term interests of customers and consumers irrespective of the asset boundaries. This process provides a mechanism for providers to discuss and identify technically feasible network and non-network options that provide lowest cost solutions across the network as a whole, regardless of asset ownership or jurisdictional boundaries.

Powerlink's joint planning, while traditionally focussed on the DNSPs (Energex, Ergon Energy and Essential Energy) and TransGrid, can also include consultation with AEMO, other Registered Participants, load aggregators and other interested parties.

Information on Powerlink's joint planning framework, and the joint planning activities that Powerlink has undertaken with other NSPs since publication of the 2018 TAPR is provided in Chapter 3.

1.7.4 Connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and other NSPs. New connections or alterations to existing connections involves consultation between Powerlink and the connecting party to negotiate a 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 agreeing 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 1 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 IUSAs above $10 million must enter into a Network Operating Agreement to provide operations and maintenance services. Further information in relation to the connection process is available on Powerlink's website (refer to Chapter 8).

1.7.5 Interconnectors

Development and assessment of new or augmented interconnections between Queensland and other States is the responsibility of the respective TNSPs. Information on the analysis of potential interconnector upgrades and new interconnectors, including the current RIT-T being undertaken by TransGrid and Powerlink to consider expanding NSW-Queensland transmission transfer capacity, is provided in Chapter 5.

1.8 Powerlink's asset planning criteria

There is a significant focus on striking the right balance between reliability and the cost of providing transmission services. In response to these drivers, 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 (QER).

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits set out above are exceeded or when the economic cost of load at risk of being unsupplied 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.

As mentioned, 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 (refer to Section 1.7.3).

Energex and Ergon Energy 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.

Powerlink has established policy frameworks and methodologies to support the implementation of this standard. These are being applied in various parts of the Powerlink network where possible emerging limitations are being monitored. For example, based on the medium economic load forecast in Chapter 2, voltage stability limitations occur in the Proserpine area within the outlook period. However, the load at risk of not being supplied during a contingency event does not exceed the risk limits of the planning standard. In this instance the planning standard is deferring investment and delivering savings to customers and consumers.

The planning standard will deliver further opportunities to defer investment if new mining, metal processing or other industrial loads develop (discussed in Table 2.1 of Chapter 2). These new loads are within the resource rich areas of Queensland or at the associated coastal port facilities but have not yet reached the development status necessary to be included (either wholly or in part) in the medium economic forecast. The loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. The possible impact of these loads is discussed in Section 7.2. The planning standard may not only affect the timing of required investment but also in some cases affords the opportunity for incremental solutions that would not have otherwise met the original N-1 criterion.

1.9 Stakeholder engagement

Powerlink shares effective, timely and transparent information with its customers and stakeholders using a range of engagement methods. Customers are defined as those who are directly connected to Powerlink's network and electricity end-users, such as households and businesses, who receive electricity from the distribution network. There are also stakeholders who can provide Powerlink with non-network solutions. These stakeholders may either connect directly to Powerlink's network, or connect to the distribution networks. The TAPR is just one avenue that Powerlink uses to communicate information about transmission planning in the NEM. Through the TAPR, Powerlink aims to increase stakeholder and customer understanding and awareness of our business practices, including load forecasting and transmission network planning.

1.9.1 Customer and stakeholder engagement

Powerlink is committed to proactively engaging with stakeholders and customers and seeking their input into Powerlink's business processes and objectives. All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework that sets out the principles, objectives and outcomes Powerlink seeks to achieve in our interactions with stakeholders. A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement performance goals. In particular, Powerlink undertakes a bi-annual stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed in November 2018, the survey provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders. The latest survey also sought specific insights from existing directly-connected customers and renewable proponents on aspects of customer service and delivery, and Powerlink's responsiveness.

2018/19 Stakeholder engagement activities

Since the publication of the 2018 TAPR, Powerlink has engaged with stakeholders and customers in various ways through a range of forums as outlined below.

Transmission Network Forum

In September 2018, more than 100 customer, community advocacy group, government and industry representatives attended Powerlink's annual Transmission Network Forum. The forum provided an update on the state of the network, followed by interactive breakout sessions on managing demand peaks and hollows to improve network utilisation and customer outcomes, navigating the renewable connection process, and the development of Powerlink's Transmission Network Vision.

Customer Panel

Powerlink hosts a Customer Panel that provides an interactive forum for our stakeholders and customers to give input and feedback to Powerlink regarding our decision making, processes and methodologies. Composed of members from a range of sectors including the energy industry, resources, community advocacy groups, customers and research organisations, the panel provides an important avenue to keep our stakeholders better informed about operational and strategic topics of relevance. The panel met in December 2018 and March 2019 to discuss and explore topics including the RIT-T for replacement projects and process for expanding the NSW-Queensland transmission transfer capacity, development of Powerlink's 30 year Transmission Network Vision, updates on the regulatory environment, asset management strategies, AEMO's next ISP, and planning for Powerlink's next Revenue Determination process.

2018 TAPR webinar

Powerlink held a webinar on 31 July 2018 to share the key findings of the 2018 TAPR and to provide an opportunity for stakeholders to ask questions. The webinar focussed on:

- the energy, demand and generation outlook for the 10-year outlook period
- the publication of the inaugural ISP and identification of potential Renewable Energy Zones (REZ) in Queensland
- Powerlink's approach to asset management and integrated planning approach
- possible future network developments and the RIT-T consultation process.

Stakeholder engagement for RIT-Ts

Powerlink recognises the importance of transparency for stakeholders and customers, particularly when undertaking transmission network planning and engaging in public consultation under the RIT-T process.

In relation to engagement activities for RIT-Ts, Powerlink is committed to a balanced approach in the public consultation process as determined with its Customer Panel. In addition, Powerlink will utilise and be guided by the AER's Stakeholder Engagement Framework and Consumer Engagement Guideline for Network Service Providers as the benchmarks when consulting as part of the RIT-T process.

Taking this into account, the appropriate level of engagement for RIT-Ts may most easily be identified through feedback received from stakeholders on proposed investments identified in the TAPR, discussion and consideration of the context of the proposed investment. Engagement activities for RIT-Ts are assessed on a case-by-case basis. This includes consideration of the:

- potential impacts on stakeholders
- opportunities for network reconfiguration or asset retirement
- estimated capital cost
- type of RIT-T process being undertaken (refer to Figure 5.1).

Detailed information on proposed engagement activities for RIT-Ts can be found on Powerlink's website.

Major stakeholder activities undertaken for RIT-Ts since the publication of the 2018 TAPR include:

- Expanding NSW – Queensland transmission transfer capacity RIT-T stakeholder webinar

  Powerlink and TransGrid held a joint webinar in February 2019 to share key information contained in the Project Specification Consultation Report (PSCR), Expanding NSW-Queensland Transmission Transfer Capacity, as the first stage of the RIT-T process. The webinar provided an opportunity outside of the formal consultation process to engage with and respond to questions from a wide range of stakeholders including consumer advocates, customer representatives, and market participants.

- North Queensland RIT-T stakeholder webinar

  Powerlink initially planned to host a forum in Townsville in February/March 2019 to share key information contained in the PSCR for Maintaining reliability of supply between Strathmore and Townsville, which was published at the end of November 2018. Due to the unprecedented floods experienced by the Townsville region's community and customers, and impact on stakeholder availability, Powerlink conducted a webinar for interested stakeholders in March 2019. Powerlink will continue to maximise engagement opportunities to ensure interested parties in the North Queensland region are proactively engaged with throughout the RIT-T consultation process.

It is anticipated that the provision and exchange of early information through engagement activities such as these will generate more opportunities for interactions with our customers and stakeholders, during formal or informal consultation processes.

More information on Powerlink's engagement activities is available on our website.

1.9.2 Non-network solutions

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the NER. These engagement processes centre on publishing relevant information on the need and scope of viable non-network solutions to emerging network limitations and more recently, in relation to the replacement of network assets. For a given network limitation or potential asset replacement, the viability and an indicative specification of non-network solutions are first introduced in the TAPR and more recently, in TAPR templates. As the identified need date approaches and a detailed planning analysis is undertaken, further opportunities are explored in the consultation and stakeholder engagement processes undertaken as part of any subsequent RIT-T.

In the past, these processes have been successful in delivering non-network solutions to emerging network limitations. As early as 2002, Powerlink engaged generation units in North Queensland to maintain reliability of supply and defer transmission projects between central and northern Queensland. Powerlink also entered into network support services as part of the solution to address emerging limitations in the Bowen Basin area, ending these in 2016.

Non-network solutions such as DSM will be essential in future years to avoid or delay the need to augment the transmission network in response to any increase in maximum demand.

Powerlink is committed to the ongoing development of its non-network engagement processes to facilitate the identification of optimal non-network solutions:

- to 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
- to provide demand management and load balancing.

Powerlink's 2019 TAPR includes a compendium for non-network providers that highlights possible future non-network opportunities where there is more certainty around key areas of the transmission network in Queensland forecast to require expenditure in the next five years (refer to Appendix F). In addition, the TAPR templates published in conjunction with the 2019 TAPR provide detailed technical data on Powerlink's transmission connection points and line segments. This data may be of value to non-network providers when considering opportunities for the development of potential non-network solutions (refer to Appendix B). Powerlink will continue to engage and work collaboratively with non-network providers during the RIT-T process to arrive at the optimal solution for customers.

As discussed in Section 1.9.1, Powerlink has held various webinars to further assist non-network providers, particularly in relation to significant RIT-T consultations currently in progress. In addition to enabling the delivery of information and providing a discussion platform, other benefits provided through informal activities, such as webinars, include a broadening of communication channels to reach a wider audience and as an aid to fostering positive relationships with non-network providers. Powerlink will continue to hold webinars on an ongoing basis as relevant and topical issues arise that are likely to be of interest to non-network providers and other interested stakeholders.

Since publication of the 2018 TAPR, Powerlink has continued its collaboration with the Institute for Sustainable Futures[3] and other NSPs regarding the Network Opportunity Mapping project. This project aims to provide enhanced information to market participants on network constraints and the opportunities for demand side solutions. These collaborations further demonstrate Powerlink's commitment to using a variety of platforms to broaden stakeholder awareness regarding possible commercial opportunities for non-network solutions.

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[3] Information available at Network Opportunity Mapping.

Non-network Engagement Stakeholder Register

Powerlink has a Non-Network Engagement Stakeholder Register (NNESR) to inform non-network providers of the details of emerging network limitations and other future transmission network needs, such as the replacement of network assets, which may have the potential for non-network solutions. The NNESR is comprised of a variety of interested stakeholders who have the potential to offer network support through advancement in technologies, existing and/or new generation or DSM initiatives (either as individual providers or aggregators).

Potential non-network providers are encouraged to register their interest in writing to networkassessments@powerlink.com.au to become a member of Powerlink's NNESR.

1.9.3 Focus on continuous improvement

As part of Powerlink's commitment to continuous improvement, the 2019 TAPR focuses on an integrated approach to future network development and contains detailed discussion on key areas of the transmission network forecast to require expenditure.

In conjunction with condition assessments and risk identification, as assets approach their anticipated replacement dates, possible reinvestment alternatives undergo detailed planning studies to confirm alignment with future reinvestment, optimisation and delivery strategies. These studies have the potential to deliver new information and may provide Powerlink with an opportunity to:

- improve and further refine options under consideration
- consider other options from those originally identified, delivering better outcomes for customers.

Information regarding possible reinvestment alternatives is updated annually within the TAPR and includes discussion on the latest information available as planning studies mature.

The 2019 TAPR:

- provides information in relation to joint planning and Powerlink's approach to asset management (refer to chapters 3 and 4)
- discusses possible future network asset reinvestments for the 10-year outlook period (refer to Chapter 5)
- includes the most recent information for the proposed replacement of network assets which are anticipated to be subject to the RIT-T in the next five years (refer to Chapter 5)
- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 8)
- contains a quick reference guide on where to locate information on potential non-network opportunities in the TAPR, grouped by investment type (refer to Appendix F) and discusses Powerlink's approach to assisting the development of non-network solutions – specifically, through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to sections 1.9.2 and 5.7)
- introduces the TAPR templates and discusses the context, methodology and principles applied for the development of the Queensland transmission network data (refer to Appendix B).

CHAPTER 2

Energy and demand projections

2 Energy and demand projections

Key highlights

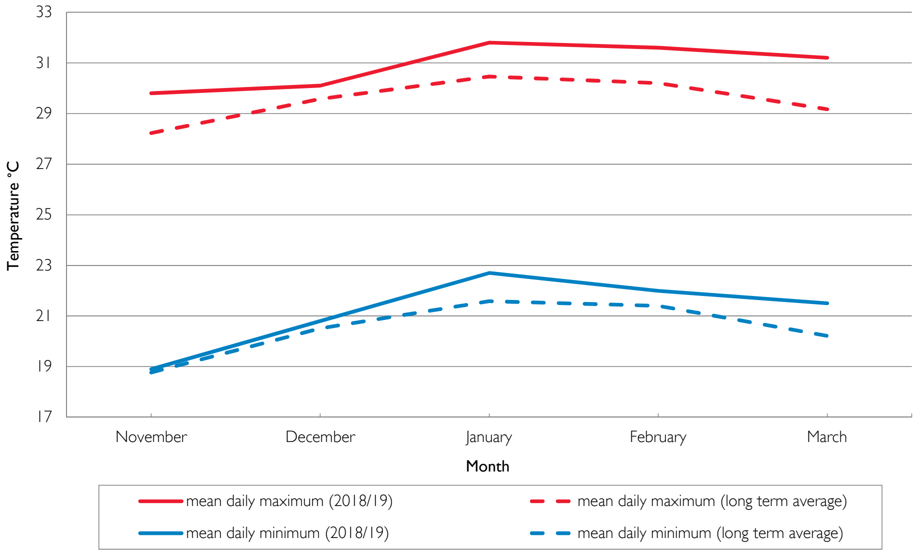
- This chapter describes the historical energy and demand performance of Powerlink's transmission network and provides forecast data separated by zone.
- The 2018/19 summer in Queensland set a new maximum delivered demand record at 6:00pm on 13 February, when 8,969MW was delivered from the transmission network.
- Based on the medium economic outlook, Queensland's delivered maximum demand is expected to maintain low growth, with an average annual increase of 0.5% per annum over the next 10 years.
- Queensland's transmission delivered energy is expected to decline over the next 10 years due to the committed and uncommitted solar farms and wind farms connecting to the distribution networks. Based on the medium economic outlook, transmission delivered energy consumption is expected to decline at an average annual rate of 0.7% per annum over the next 10 years.
- Powerlink has sought to incorporate Australian Energy Market Operator's (AEMO) forecasts in its planning analysis. Powerlink is focussed on working with AEMO to understand the potential future impacts of emerging technologies so transmission network services are developed in ways that are valued by customers.
- Following a review of the high demand over summer 2018/19, AEMO has enhanced its maximum demand forecasting methodology and advised that the 2019 Electricity Statement of Opportunities (ESOO) forecasts are broadly aligned with Powerlink's 2018 Transmission Annual Planning Report (TAPR) forecast. Powerlink has adopted its 2018 TAPR forecasts for the planning analysis of the 2019 TAPR.

2.1 Overview

The 2018/19 summer in Queensland set a new record demand at 6:00pm on 13 February, when 8,969MW was delivered from the transmission grid. Operational 'as generated' and native demand records were recorded at 5:30pm on 13 February, with operational 'as generated' reaching 10,044MW, passing the previous record of 9,796MW set last summer. After temperature correction, the 2018/19 summer demand is aligned with the 2018 TAPR forecast.

Figure 2.1 shows observed temperatures for Brisbane during summer 2018/19 compared with long-term averages, demonstrating a slightly warmer year than average.

Figure 2.1 Brisbane temperature ranges over summer 2018/19 (1)



Note:

(1) Long-term average based on years 2000 to 2019.

Energy delivered from the transmission network for 2018/19 is expected to be within 1% of the 2018 TAPR forecast.

In previous TAPRs, Powerlink developed its own demand and energy forecasts as an input for planning studies. Powerlink has decided for future TAPR publications and planning analysis to incorporate AEMO's forecasts, instead of developing its own. This will avoid duplication of effort and deliver better value to our customers. It also presents an opportunity for Powerlink to work even closer with AEMO and bring specific jurisdictional knowledge to the development of these load forecasts.

The only currently available forecast from AEMO is from the 2018 ESOO. Following a review of the high demand over summer 2018/19, AEMO has enhanced its maximum demand forecasting methodology and advised that the 2019 ESOO forecasts are broadly aligned with Powerlink's 2018 TAPR forecast. Given Powerlink's 2018 TAPR forecasts are better aligned with 2018/19 demand, the planning analysis for the 2019 TAPR is based on the forecasts from the 2018 TAPR. Planning analysis for the 2020 TAPR is expected to be based on AEMO's 2019 ESOO forecasts for Queensland.

Information on the development of the 2018 forecast is available on Powerlink's website.

Powerlink is committed to understanding the future impacts of emerging technologies and to work with AEMO so that these are accounted for within the forecasts. This will allow transmission network services to be developed in ways that are valued by customers. For example, future developments in battery storage technology coupled with small-scale photovoltaic (PV) could see significant changes to future electricity usage patterns. This could reduce the need to develop transmission services to cover short duration peaks.

The electrical load for the coal seam gas (CSG) industry experienced observed demands close to those forecast in the 2018 TAPR. The CSG demand reached 770MW in 2018/19. No new CSG loads have committed to connect to the transmission network since the publication of 2018 TAPR.

The Federal Government's large-scale renewable energy target of 33,000GWh per annum by 2020 has driven renewable capacity in the form of solar PV and wind farms to connect to the Queensland transmission and distribution networks (refer to Table 6.1 and Table 6.2).

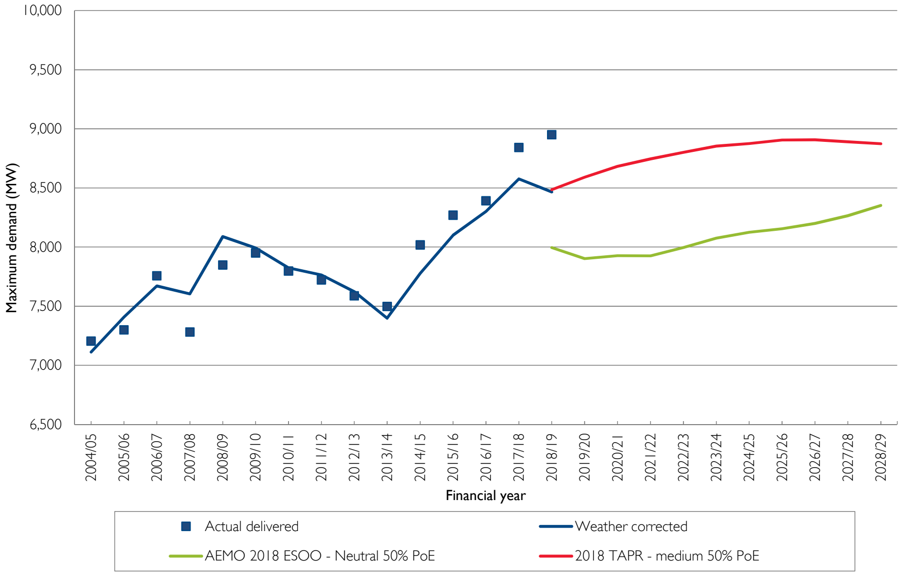
Additional uncommitted distribution connected solar farm capacity has been included into the 10-year outlook period from 2023 to model the Queensland Government's target of 50% renewable energy by 2030.

During the 2018/19 summer, Queensland reached 2,440MW of installed rooftop PV capacity. Growth in rooftop PV capacity has increased from around 25MW per month in 2017/18 to 35MW per month in 2018/19. An impact of rooftop PV, has been the time shift of the state's maximum demand, which now occurs around 5:30pm. As more rooftop PV is installed, future summer maximum demands are likely to occur in the early evening.

Figure 2.2 shows a comparison of Powerlink's 2018 TAPR delivered summer maximum demand forecast with AEMO's 2018 ESOO, based on a 50% probability of exceedance (PoE) and medium economic outlook.

Figure 2.3 shows a comparison of Powerlink's 2018 TAPR delivered energy forecast with AEMO's 2018 ESOO, based on the medium economic outlook.

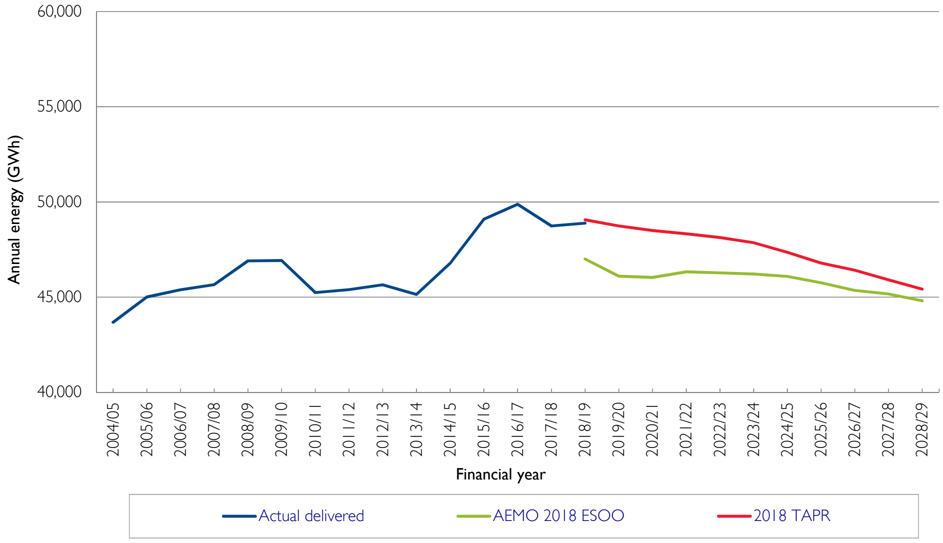
Figure 2.2 Comparison of the medium economic outlook demand forecasts (1)



Notes:

(1) AEMO's 2018 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 2.4 for further details.

Figure 2.3 Comparison of the medium economic outlook energy forecasts (1) (2)



Notes:

(1) AEMO's 2018 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 2.4 for further details.

(2) AEMO's 2018 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030. Powerlink applied the same adjustment to AEMO's 2018 ESOO forecast that was applied to Powerlink's 2018 TAPR forecast.

2.2 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 Distribution Network Service Providers (DNSPs), Energex and Ergon Energy (part of the Energy Queensland group). These connection supply point forecasts are presented in Appendix A. Also in accordance with the NER, Powerlink has obtained summer and winter maximum demand forecasts from other customers that connect directly to the 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.

Transmission customer forecasts

New large loads

No new large loads have connected or have committed to connect in the outlook period.

Possible new large loads

There are several proposals under development for large mining, metal processing and other industrial loads. These are not yet at a stage that they can be included (either wholly or in part) in the medium economic forecast. These developments totalling nearly 900MW, are listed in Table 2.1.

Table 2.1 Possible large loads excluded from the medium economic outlook forecast

Zone	Description	Possible load
North	Further port expansion at Abbot Point	Up to 100MW
North	CSG load (Bowen Basin area)	Up to 80MW
North and Central West	New coal mining load (Galilee Basin area)	Up to 400MW
Surat	CSG load and coal mining projects (Surat Basin area)	Up to 300MW

2.3 Demand forecast outlook

The following sections outline the Queensland forecasts for energy, summer maximum demand and winter maximum demand.

The 2018 TAPR forecasts were prepared for three economic outlooks, high, medium and low. 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 conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

The forecast average annual growth rates for the Queensland region over the next 10 years under low, medium and high economic growth outlooks are shown in Table 2.2. These growth rates refer to transmission delivered quantities as described in Section 2.3.2. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2018/19.

Table 2.2 Average annual growth rate over next 10 years

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	-1.4%	-0.7%	0.4%
Delivered summer peak demand (50% PoE)	-0.1%	0.5%	1.4%
Delivered winter peak demand (50% PoE)	-0.6%	-0.1%	0.7%

2.3.1 Future management of maximum demand

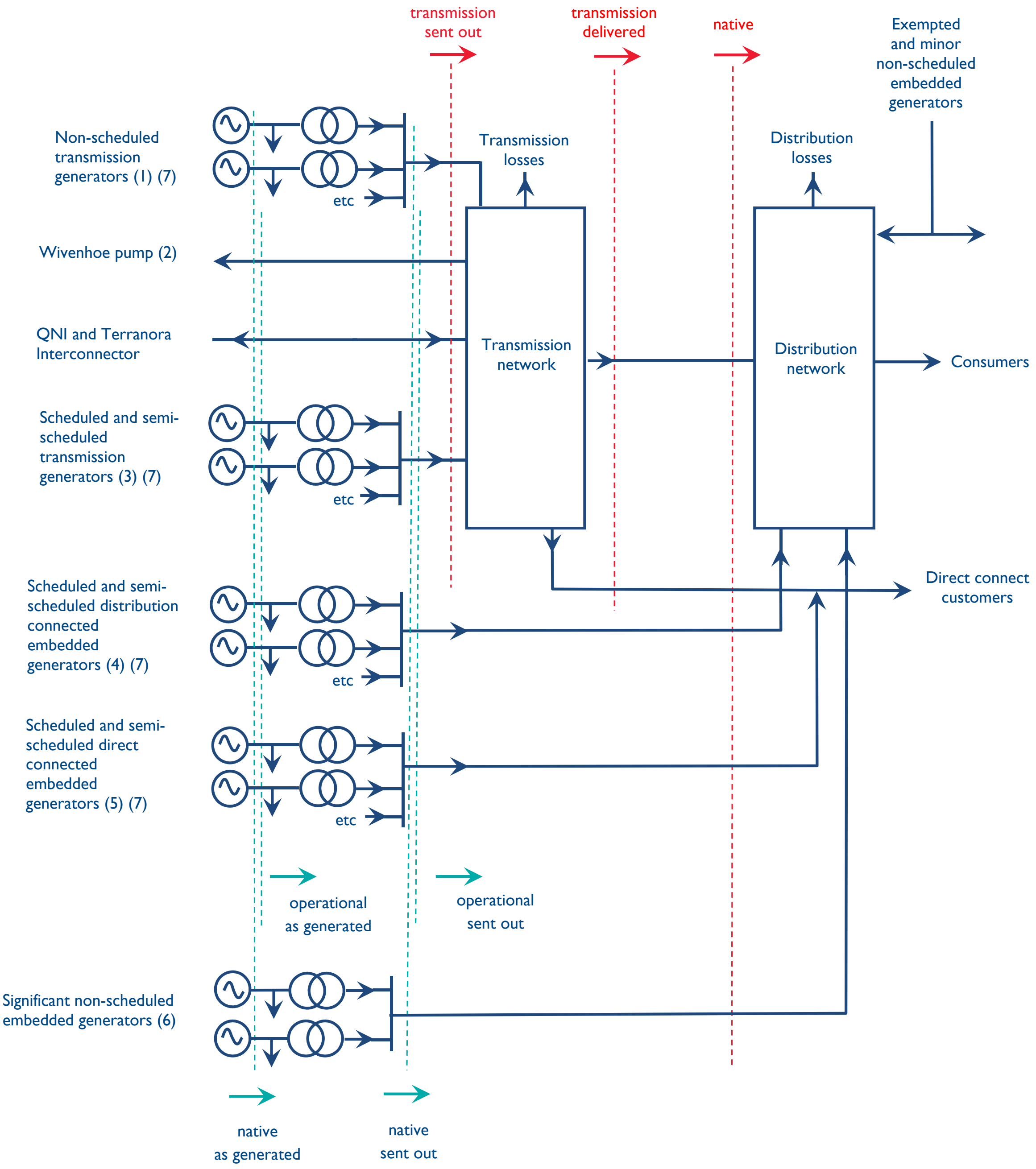
The installation of additional rooftop PV systems and distribution connected solar farms is expected to delay the current time of the maximum demand from around 5:30pm to an evening peak and reduce the delivered demand and energy during daylight hours. The 10-year demand forecast shows low growth in the maximum demand (refer to Figure 2.2). If the trend continues, Powerlink will need to consider the approach to meet these evening peaks. However, there is an opportunity for new technology and non-network solutions to assist in managing evening demand, which could deliver cost efficiencies and negate the need to build new transmission assets. The successful integration of non-network solutions has the potential to shift and reduce maximum demand back into the period where demand levels are reduced due to embedded solar generation. This can also have the benefit of impacting the scope of Powerlink's reinvestment decisions when assets approach end of technical service life.

Powerlink seeks input on new technology and non-network solutions through ongoing engagement activities such as the annual Transmission Network Forum, Powerlink's Customer Panel, various webinars (refer to Section 1.9.1) and Non-network Engagement Stakeholder Register (NNESR) (refer to Section 1.9.2). Early advice on the potential for non-network solutions is provided each year in the TAPR (refer to Chapter 5, Appendix B and Appendix F) and submissions for non-network solutions are invited as part of the TAPR process. Powerlink will also continue to request non-network solutions from market participants for individual asset reinvestments as part of the Regulatory Investment Test for Transmission (RIT-T) process defined in the NER.

2.3.2 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 2.4 shows the common ways to measure demand and energy, with this terminology used consistently throughout the TAPR.

Figure 2.4 Load forecast definitions



Notes:

(1) Includes Invicta and Koombooloomba.

(2) Depends on Wivenhoe generation.

(3) Includes Yarwun which is non-scheduled.

(4) Kidston Solar Farm, Collinsville Solar Farm, Mackay, Barcaldine, Clermont Solar Farm, Emerald Solar Farm, Susan River Solar Farm, Childers Solar Farm, Roma, Oakey 1 Solar Farm and Townsville Power Station 66kV component.

(5) Sun Metals Solar Farm and Condamine.

(6) Lakeland Solar and Storage, Pioneer Mill, Hughenden Solar Farm, Racecourse Mill, Moranbah North, Moranbah, Barcaldine Solar Farm, Longreach Solar Farm, German Creek, Oaky Creek, Isis Central Sugar Mill, Daandine, Sunshine Coast Solar Farm, Bromelton and Rocky Point.

(7) For a full list of transmission network connected generators and scheduled and semi-scheduled distribution connected embedded and direct connected embedded generators refer to Table 6.1 and Table 6.2.

2.3.3 Energy forecast

Historical Queensland energy is presented in Table 2.3. They are recorded at various levels in the network as defined in Figure 2.4.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled power station auxiliaries are the difference between scheduled as generated and scheduled sent out energy.

Table 2.3 Historical energy (GWh)

Year	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV
2009/10	53,150	49,360	54,419	50,753	48,490	46,925	49,187	49,187
2010/11	51,381	47,804	52,429	48,976	46,866	45,240	47,350	47,350
2011/12	51,147	47,724	52,206	48,920	46,980	45,394	47,334	47,334
2012/13	50,711	47,368	52,045	48,702	47,259	45,651	47,090	47,090
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 (1)	55,090	50,383	56,557	51,979	50,083	48,886	51,270	54,251

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2019.

The forecast transmission delivered energy forecasts are presented in Table 2.4 and in Figure 2.5. Forecast native energy forecasts are presented in Table 2.5.

Table 2.4 Forecast annual transmission delivered energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2019/20	48,179	48,736	49,771
2020/21	47,542	48,494	49,718
2021/22	47,018	48,331	49,896
2022/23	46,504	48,126	50,036
2023/24	45,924	47,862	50,196
2024/25	45,137	47,356	50,417
2025/26	44,314	46,792	50,375
2026/27	43,675	46,410	50,612
2027/28	42,962	45,913	50,720
2028/29	42,261	45,421	50,828

Figure 2.5 Historical and forecast transmission delivered energy

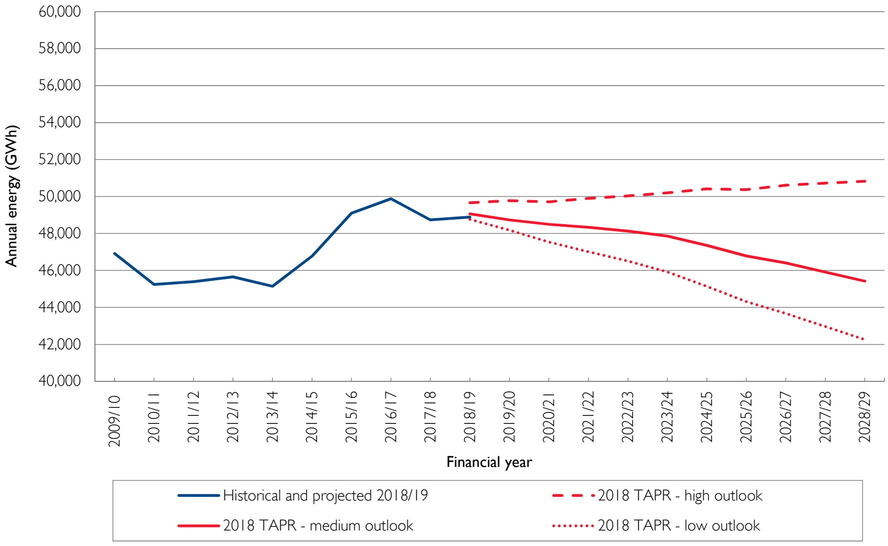


Table 2.5 Forecast annual native energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2019/20	50,774	51,331	52,366
2020/21	51,082	52,034	53,258
2021/22	51,066	52,379	53,945
2022/23	50,893	52,516	54,425
2023/24	50,651	52,589	54,924
2024/25	50,192	52,410	55,472
2025/26	49,684	52,163	55,746
2026/27	49,361	52,096	56,298
2027/28	48,949	51,899	56,707
2028/29	48,540	51,703	57,119

2.3.4 Summer maximum demand forecast

Historical Queensland summer maximum demands at time of native peak are presented in Table 2.6.

Table 2.6 Historical summer maximum demand (MW)

Summer	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV	Native corrected to 50% PoE
2009/10	8,897	8,427	9,053	8,603	8,292	7,951	8,321	8,321	8,364
2010/11	8,826	8,299	8,895	8,374	8,020	7,797	8,152	8,152	8,187
2011/12	8,714	8,236	8,769	8,319	7,983	7,723	8,059	8,059	8,101
2012/13	8,479	8,008	8,691	8,245	7,920	7,588	7,913	7,913	7,952
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	9,541	9,062	8,698	8,392	8,756	8,899	8,666
2017/18	9,796	9,262	10,054	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

The transmission delivered summer maximum demand forecasts are presented in Table 2.7 and in Figure 2.6. Forecast summer native demand is presented in Table 2.8.

Table 2.7 Forecast summer transmission delivered demand (MW)

Summer	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2019/20	8,014	8,500	9,100	8,100	8,591	9,197	8,220	8,717	9,330
2020/21	8,039	8,533	9,144	8,181	8,682	9,302	8,352	8,862	9,493
2021/22	8,040	8,542	9,162	8,233	8,745	9,378	8,449	8,973	9,620
2022/23	8,040	8,548	9,176	8,279	8,800	9,444	8,552	9,089	9,752
2023/24	8,040	8,553	9,186	8,326	8,854	9,507	8,669	9,216	9,892
2024/25	8,014	8,529	9,166	8,342	8,876	9,536	8,788	9,344	10,031
2025/26	7,996	8,514	9,155	8,365	8,905	9,572	8,882	9,447	10,146
2026/27	7,953	8,474	9,118	8,363	8,908	9,580	8,972	9,547	10,257
2027/28	7,896	8,419	9,065	8,342	8,891	9,569	9,041	9,625	10,345
2028/29	7,839	8,364	9,013	8,321	8,874	9,558	9,111	9,704	10,435

Figure 2.6 Historical and forecast transmission delivered summer demand

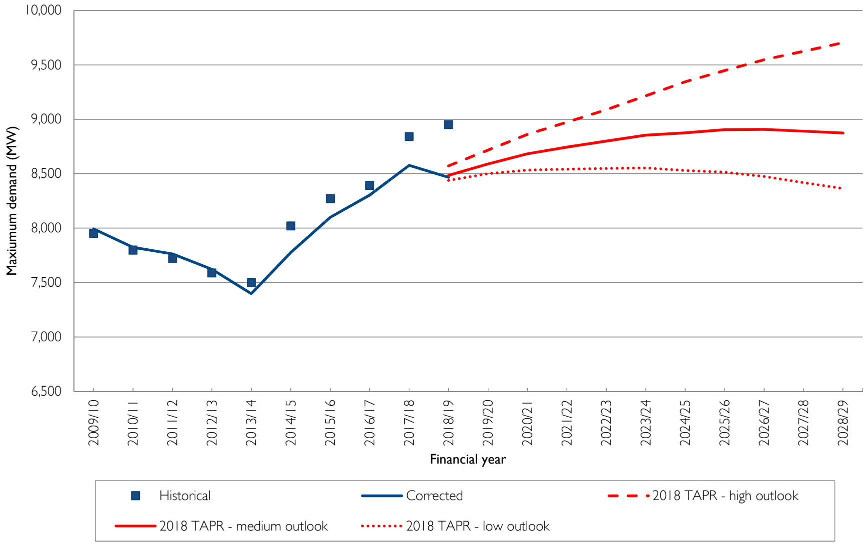


Table 2.8 Forecast summer native demand (MW)

Summer	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2019/20	8,425	8,911	9,512	8,511	9,002	9,608	8,631	9,128	9,742
2020/21	8,443	8,937	9,548	8,585	9,087	9,706	8,756	9,267	9,898
2021/22	8,432	8,934	9,554	8,625	9,137	9,770	8,841	9,365	10,012
2022/23	8,425	8,933	9,561	8,664	9,185	9,829	8,937	9,474	10,137
2023/24	8,422	8,934	9,568	8,707	9,236	9,889	9,050	9,598	10,274
2024/25	8,392	8,908	9,545	8,721	9,255	9,915	9,167	9,723	10,410
2025/26	8,371	8,889	9,530	8,740	9,280	9,947	9,256	9,822	10,521
2026/27	8,324	8,845	9,489	8,734	9,279	9,951	9,343	9,918	10,628
2027/28	8,263	8,786	9,432	8,709	9,258	9,936	9,409	9,992	10,713
2028/29	8,202	8,728	9,376	8,684	9,238	9,921	9,475	10,067	10,798

2.3.5 Winter maximum demand forecast

Historical Queensland winter maximum demands at time of native peak are presented in Table 2.9. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 2.9 Historical winter maximum demand (MW)

Winter	Scheduled as generated	Scheduled sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV	Native corrected to 50% PoE
2009	7,694	7,158	7,756	7,275	7,032	6,961	7,205	7,205	7,295
2010	7,335	6,885	7,608	7,194	6,795	6,534	6,933	6,933	6,942
2011	7,632	7,207	7,816	7,400	7,093	6,878	7,185	7,185	6,998
2012	7,469	7,081	7,520	7,128	6,955	6,761	6,934	6,934	6,908
2013	7,173	6,753	7,345	6,947	6,699	6,521	6,769	6,769	6,983
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	8,191	7,686	7,439	7,207	7,454	7,454	7,479
2017	7,723	7,221	7,879	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

The transmission delivered winter maximum demand forecasts are presented in Table 2.10 and displayed in Figure 2.7. Forecast winter native demand is presented in Table 2.11.

Table 2.10 Forecast winter transmission delivered demand (MW)

Winter	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2019	7,261	7,453	7,741	7,326	7,519	7,809	7,413	7,608	7,901
2020	7,278	7,473	7,766	7,386	7,583	7,880	7,505	7,705	8,005
2021	7,310	7,507	7,805	7,459	7,660	7,962	7,628	7,832	8,140
2022	7,308	7,508	7,808	7,492	7,695	8,002	7,694	7,902	8,215
2023	7,281	7,482	7,784	7,499	7,705	8,015	7,752	7,963	8,282
2024	7,241	7,442	7,745	7,491	7,698	8,010	7,811	8,025	8,347
2025	7,191	7,393	7,698	7,471	7,679	7,993	7,863	8,079	8,405
2026	7,132	7,335	7,640	7,439	7,649	7,965	7,901	8,120	8,449
2027	7,075	7,278	7,584	7,407	7,618	7,936	7,936	8,157	8,490
2028	7,018	7,222	7,529	7,374	7,587	7,906	7,971	8,195	8,532

Figure 2.7 Historical and forecast winter transmission delivered demand

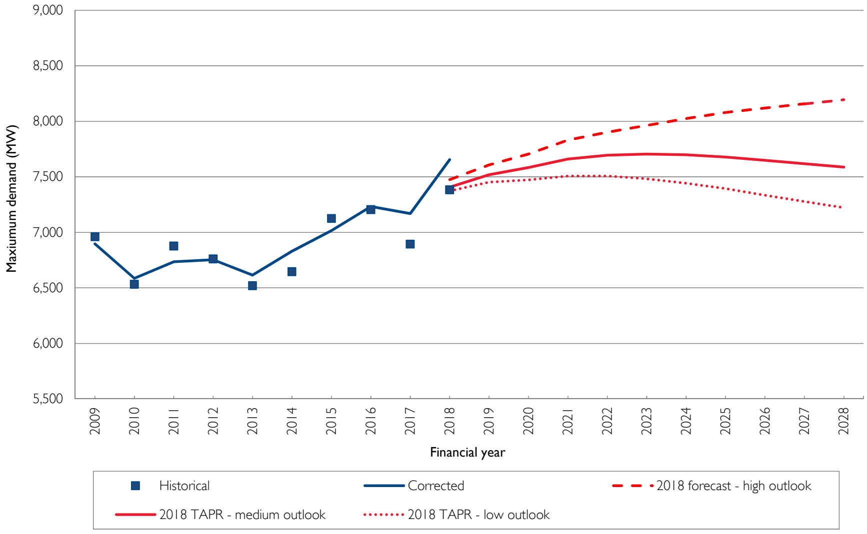


Table 2.11 Forecast winter native demand (MW)

Winter	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2019	7,574	7,765	8,054	7,638	7,831	8,122	7,725	7,920	8,214
2020	7,591	7,786	8,079	7,699	7,896	8,192	7,817	8,017	8,318
2021	7,621	7,819	8,116	7,771	7,971	8,273	7,939	8,144	8,451
2022	7,619	7,819	8,120	7,803	8,007	8,313	8,005	8,213	8,527
2023	7,592	7,793	8,095	7,810	8,016	8,326	8,063	8,274	8,593
2024	7,547	7,748	8,051	7,797	8,004	8,316	8,117	8,331	8,653
2025	7,495	7,697	8,001	7,774	7,982	8,296	8,166	8,382	8,708
2026	7,429	7,631	7,937	7,736	7,946	8,262	8,197	8,416	8,746
2027	7,369	7,572	7,878	7,700	7,912	8,229	8,229	8,451	8,784
2028	7,309	7,513	7,820	7,665	7,878	8,197	8,262	8,486	8,823

2.4 Zone forecasts

The 11 geographical zones referenced throughout this TAPR are defined in Table 2.12 and are shown in the diagrams in Appendix C. In the 2008 Annual Planning Report (APR) Powerlink split the South West zone into Bulli and South West zones, and in the 2014 TAPR Powerlink split the South West zone into Surat and South West zones.

Table 2.12 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of Proserpine and Collinsville, 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

Each zone normally experiences its own maximum demand, which is usually greater than that shown in tables 2.16 to 2.19.

Table 2.13 shows the average ratios of forecast zone maximum transmission delivered demand to zone transmission delivered demand at the time of forecast Queensland region maximum demand. These values can be used to multiply demands in tables 2.16 and 2.18 to estimate each zone's individual maximum transmission delivered demand, the time of which is not necessarily coincident with the time of Queensland region maximum transmission delivered demand. The ratios are based on historical trends.

Table 2.13 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum demand

Zone	Winter	Summer
Far North	1.18	1.18
Ross	1.36	1.61
North	1.15	1.16
Central West	1.10	1.20
Gladstone	1.03	1.04
Wide Bay	1.03	1.09
Surat	1.15	1.23
Bulli	1.13	1.16
South West	1.05	1.10
Moreton	1.02	1.00
Gold Coast	1.03	1.01

Tables 2.14 and 2.15 show the forecast of transmission delivered energy and native energy for the medium economic outlook for each of the 11 zones in the Queensland region.

Table 2.14 Annual transmission delivered energy (GWh) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009/10	1,836	2,849	2,719	3,300	10,173	1,427		84	1,442	19,619	3,476	46,925
2010/11	1,810	2,791	2,590	3,152	10,118	1,308		95	1,082	18,886	3,408	45,240
2011/12	1,792	2,723	2,611	3,463	10,286	1,323		105	1,196	18,629	3,266	45,394
2012/13	1,722	2,693	2,732	3,414	10,507	1,267		103	1,746	18,232	3,235	45,651
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)	1,651	2,379	2,648	2,996	9,357	1,227	4,759	1,526	1,413	17,867	3,063	48,886
Forecasts												
2019/20	1,693	2,188	2,710	3,084	9,476	1,204	4,609	1,490	1,087	17,816	3,384	48,736
2020/21	1,616	2,216	2,733	2,770	9,456	864	4,892	1,594	944	17,994	3,417	48,494
2021/22	1,349	2,243	2,753	2,572	9,493	875	4,903	1,570	955	18,168	3,450	48,331
2022/23	1,363	2,268	2,744	2,528	9,523	834	4,721	1,482	914	18,270	3,479	48,126
2023/24	1,371	2,287	2,727	2,474	9,529	788	4,562	1,448	868	18,312	3,497	47,862
2024/25	1,372	2,300	2,705	2,413	9,532	740	4,307	1,354	820	18,308	3,505	47,356
2025/26	1,375	2,313	2,685	2,356	9,535	694	4,024	1,208	774	18,313	3,515	46,792
2026/27	1,379	2,328	2,667	2,300	9,540	649	3,895	1,070	729	18,327	3,526	46,410
2027/28	1,381	2,341	2,647	2,245	9,543	605	3,696	904	686	18,330	3,535	45,913
2028/29	1,382	2,352	2,626	2,189	9,538	564	3,507	763	644	18,316	3,540	45,421

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2019.

Table 2.15 Annual native energy (GWh) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009/10	1,836	3,507	3,070	3,635	10,173	1,447		84	2,193	19,766	3,476	49,187
2010/11	1,810	3,220	2,879	3,500	10,118	1,328		95	2,013	18,979	3,408	47,350
2011/12	1,792	3,217	2,901	3,710	10,286	1,348		105	2,014	18,695	3,266	47,334
2012/13	1,722	3,080	3,064	3,767	10,507	1,292		103	1,988	18,332	3,235	47,090
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)	1,672	2,925	3,224	3,605	9,357	1,302	5,072	1,526	1,558	17,966	3,063	51,270
Forecasts												
2019/20	1,730	2,698	3,440	3,639	9,474	1,339	4,726	1,490	1,540	17,873	3,384	51,331
2020/21	1,746	2,726	3,464	3,669	9,457	1,352	5,008	1,594	1,552	18,050	3,417	52,034
2021/22	1,762	2,754	3,483	3,697	9,493	1,363	5,020	1,570	1,563	18,224	3,450	52,379
2022/23	1,776	2,779	3,508	3,722	9,523	1,373	4,923	1,482	1,573	18,378	3,479	52,516
2023/24	1,783	2,797	3,525	3,735	9,529	1,378	4,848	1,448	1,578	18,471	3,497	52,589
2024/25	1,785	2,810	3,536	3,740	9,532	1,379	4,675	1,354	1,579	18,516	3,505	52,410
2025/26	1,788	2,824	3,547	3,745	9,536	1,381	4,471	1,208	1,581	18,568	3,514	52,163
2026/27	1,792	2,838	3,560	3,753	9,540	1,383	4,421	1,070	1,583	18,630	3,526	52,096
2027/28	1,794	2,852	3,571	3,758	9,543	1,384	4,297	904	1,585	18,677	3,535	51,899
2028/29	1,796	2,863	3,581	3,761	9,538	1,384	4,177	763	1,586	18,714	3,540	51,703

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2019.

Tables 2.16 and 2.17 show the 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 medium economic outlook and average summer weather.

Table 2.16 State summer maximum transmission delivered demand (MW) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009/10	317	394	415	505	1,176	268		11	211	3,919	735	7,951
2010/11	306	339	371	469	1,172	274		18	175	3,990	683	7,797
2011/12	296	376	405	525	1,191	249		18	217	3,788	658	7,723
2012/13	277	303	384	536	1,213	232		14	241	3,754	634	7,588
2013/14	271	318	353	493	1,147	260	30	21	291	3,711	603	7,498
2014/15	278	381	399	466	1,254	263	130	81	227	3,848	692	8,019
2015/16	308	392	412	443	1,189	214	313	155	231	3,953	661	8,271
2016/17	269	291	392	476	1,088	276	447	175	309	3,957	712	8,392
2017/18	304	376	414	464	1,102	278	557	183	301	4,145	718	8,842
2018/19	338	319	389	445	1,104	289	518	191	313	4,314	731	8,951
Forecasts												
2019/20	329	399	410	475	1,063	214	484	181	277	4,023	736	8,591
2020/21	337	408	409	481	1,062	213	511	184	276	4,062	739	8,682
2021/22	340	413	414	484	1,063	214	518	183	278	4,098	740	8,745
2022/23	347	411	415	501	1,066	214	504	171	279	4,144	748	8,800
2023/24	344	406	432	509	1,068	215	497	166	281	4,186	750	8,854
2024/25	347	409	446	507	1,069	214	477	157	280	4,218	752	8,876
2025/26	353	416	447	509	1,070	215	461	151	280	4,250	753	8,905
2026/27	357	421	453	509	1,070	214	458	125	280	4,268	753	8,908
2027/28	360	424	452	509	1,071	214	447	103	280	4,279	752	8,891
2028/29	363	426	451	509	1,071	214	436	85	280	4,288	751	8,874

Table 2.17 State summer maximum native demand (MW) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009/10	317	500	453	539	1,176	268		11	361	3,961	735	8,321
2010/11	306	412	408	551	1,172	274		18	337	3,991	683	8,152
2011/12	296	449	434	598	1,191	249		18	378	3,788	658	8,059
2012/13	277	417	422	568	1,213	241		14	328	3,799	634	7,913
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	4,337	731	9,415
Forecasts												
2019/20	329	494	494	545	1,063	215	595	181	303	4,047	736	9,002
2020/21	337	494	493	552	1,062	213	626	184	302	4,085	739	9,087
2021/22	340	488	497	555	1,063	214	629	183	305	4,122	741	9,137
2022/23	347	480	499	571	1,066	214	616	171	305	4,168	748	9,185
2023/24	344	475	516	579	1,069	215	605	166	307	4,210	750	9,236
2024/25	347	478	530	578	1,069	214	582	157	306	4,242	752	9,255
2025/26	353	486	531	578	1,069	215	563	151	307	4,274	753	9,280
2026/27	357	490	537	579	1,070	214	555	125	307	4,292	753	9,279
2027/28	360	494	536	579	1,070	214	541	103	306	4,303	752	9,258
2028/29	363	497	535	579	1,070	214	527	85	305	4,312	751	9,238

Tables 2.18 and 2.19 show the 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 medium economic outlook and average winter weather.

Table 2.18 State winter maximum transmission delivered demand (MW) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009	210	342	328	416	1,125	218		19	341	3,361	601	6,961
2010	227	192	325	393	1,174	179		18	269	3,173	584	6,534
2011	230	216	317	432	1,155	222		22	376	3,303	605	6,878
2012	214	212	326	426	1,201	215		20	346	3,207	594	6,761
2013	195	249	348	418	1,200	190	23	17	263	3,039	579	6,521
2014	226	346	359	463	1,200	204	16	51	257	2,974	551	6,647
2015	192	289	332	429	1,249	203	172	137	258	3,268	597	7,126
2016	216	278	341	451	1,229	193	467	193	280	3,009	550	7,207
2017	218	290	343	366	1,070	220	520	182	247	2,912	526	6,894
2018	242	366	336	440	1,091	235	527	186	336	3,084	540	7,383
Forecasts												
2019	210	299	367	416	1,075	209	527	202	281	3,345	588	7,519
2020	212	303	371	418	1,072	210	529	208	286	3,380	594	7,583
2021	214	305	372	426	1,073	211	548	209	290	3,417	595	7,660
2022	215	307	375	433	1,074	213	548	194	292	3,445	599	7,695
2023	217	297	380	437	1,075	215	533	192	296	3,464	599	7,705
2024	218	297	380	438	1,076	215	524	183	297	3,474	596	7,698
2025	218	298	381	438	1,076	216	504	172	298	3,482	596	7,679
2026	218	298	387	438	1,076	216	491	148	298	3,485	594	7,649
2027	218	298	387	438	1,075	216	484	131	298	3,482	591	7,618
2028	218	298	387	438	1,074	216	477	116	298	3,477	588	7,587

Table 2.19 State winter maximum native demand (MW) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2009	210	425	372	466	1,125	218		19	407	3,362	601	7,205
2010	227	319	363	484	1,174	186		18	380	3,198	584	6,933
2011	230	339	360	520	1,155	222		22	428	3,304	605	7,185
2012	214	289	360	460	1,201	215		20	375	3,206	594	6,934
2013	195	291	374	499	1,200	195	89	17	290	3,040	579	6,769
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
Forecasts												
2019	210	353	432	479	1,076	211	623	202	309	3,348	588	7,831
2020	212	356	437	482	1,072	213	625	208	314	3,383	594	7,896
2021	214	359	438	490	1,073	214	642	209	318	3,419	595	7,971
2022	215	360	441	497	1,075	215	643	194	320	3,448	599	8,007
2023	217	350	446	501	1,075	217	627	192	325	3,467	599	8,016
2024	218	351	446	501	1,076	218	613	183	326	3,476	596	8,004
2025	218	351	447	502	1,076	218	591	172	326	3,485	596	7,982
2026	218	352	453	502	1,076	218	572	148	327	3,487	593	7,946
2027	218	351	453	501	1,076	218	561	131	327	3,484	592	7,912
2028	218	350	453	500	1,076	218	550	116	327	3,479	591	7,878

2.5 Daily and annual load profiles

The daily load profiles (transmission delivered) for the Queensland region on the days of 2018 winter and 2018/19 summer maximum native demands are shown in Figure 2.8.

The annual cumulative load duration characteristic for the Queensland region transmission delivered demand is shown in Figure 2.9.

Figure 2.8 Daily load profile of winter 2018 and summer 2018/19 maximum native demand days

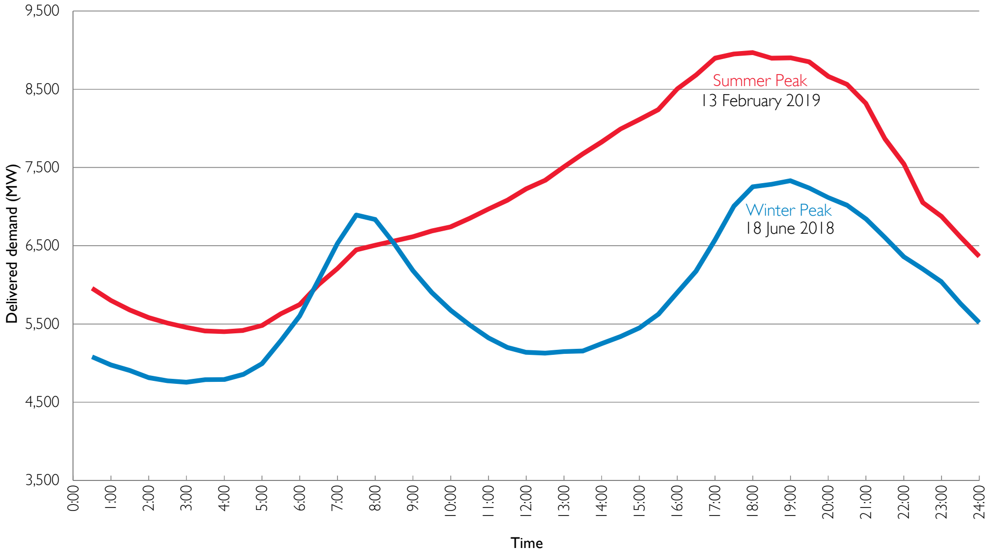
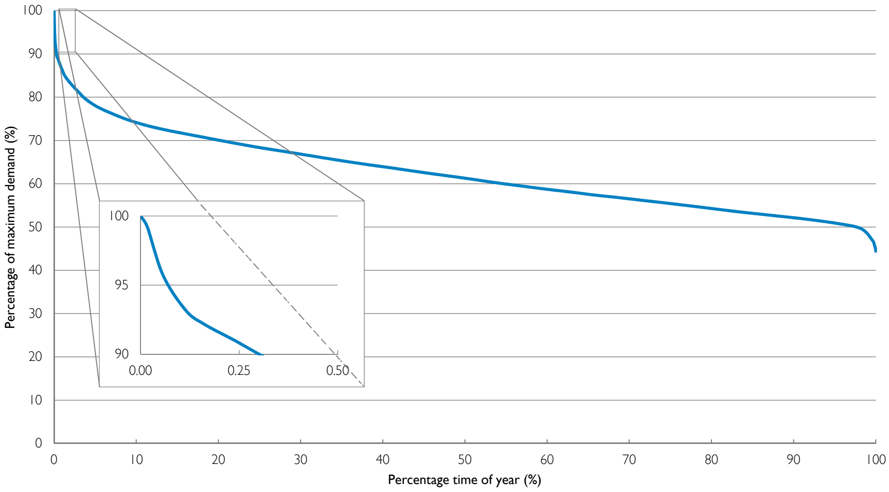


Figure 2.9 Normalised cumulative transmission delivered load duration from 1 April 2018 to 31 March 2019



2 Energy and demand projections

CHAPTER 3

Joint planning

3 Joint planning

Key highlights

- Joint planning provides a mechanism for Network Service Providers (NSPs) to discuss and identify technically feasible, cost effective network or non-network options that address identified network needs regardless of asset ownership or jurisdictional boundaries.
- Key joint planning focus areas since the publication of the 2018 Transmission Annual Planning Report (TAPR) include:
  - the Integrated System Plan (ISP) and Power System Frequency Risk Review (PSFRR) with the Australian Energy Market Operator (AEMO)
  - publication of a Project Specification Consultation Report (PSCR) as well as ongoing power system and market modelling analysis associated with expanding the transmission transfer capacity between New South Wales (NSW) and Queensland with TransGrid
  - the analysis of options to address condition driven reinvestments with Energex and Ergon Energy (part of the Energy Queensland Group).

3.1 Introduction

Powerlink's joint planning framework with AEMO and other NSPs is in accordance with the requirements set out in Clause 5.14.3 of National Electricity Rules (NER).

Joint planning begins many years in advance of an investment decision. The nature and timing of future investment needs are reviewed at least on an annual basis utilising an interactive joint planning approach.

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).

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.

The joint planning process is intrinsically iterative, and the extent to which this occurs will depend upon the nature of the limitation or asset condition driver to be addressed and the complexity of the proposed corrective action. In general, joint planning seeks to:

- understand the issues collectively faced by the different network owners and operators
- understand existing and forecast congestion on power transfers between neighbouring regions
- help identify the most efficient options to address these issues, irrespective of the asset boundaries (including those between jurisdictions)
- influence how networks are managed, and what network changes are required.

Projects where a feasible network option exists which is greater than $6 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 as the regulatory instrument 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.

3.2 Working groups and regular engagement

Powerlink collaborates with the other National Electricity Market (NEM) jurisdictional planners through a range of committees and groups.

3.2.1 Regular joint planning meetings

For the purpose of effective network planning, Powerlink has collaborated in regular joint planning meetings with:

- AEMO on the 2018 PSFRR (refer to Section 6.3)
- AEMO National Planning and other jurisdictional planners in the development of the 2019-20 ISP anticipated to be released in mid-2020
- TransGrid for the assessment of the economic benefits of expanding the transmission transfer capability between Queensland and NSW (refer to Section 5.7.14)
- Energex and Ergon Energy for the purposes of efficiently planning developments and project delivery in the transmission and sub-transmission network.

3.3 AEMO national planning – ISP

Powerlink worked closely with AEMO to support the development of the inaugural ISP, published in July 2018 and continues to work with AEMO to deliver the next iteration, due in mid-2020. The ISP signals priority development paths in the near to short-term, along with an over arching long-term strategy. The ISP reflects the dynamic nature of the power system and the need to continually innovate and evolve analysis methodologies and development strategies for the future transmission network.

Process

Powerlink reviewed the long-term network development strategy and findings of the 2018 ISP. Aligned with the findings from the ISP, Powerlink and TransGrid have published a PSCR associated with expanding the transmission transfer capacity between NSW and Queensland. Powerlink continues to provide a range of network planning inputs to AEMO's 2019-20 ISP consultation and modelling processes, through regular engagement and workshops.

Methodology

More information on the 2019-20 ISP including methodology and assumptions is available on AEMO's website.

Outcomes

The ISP sets out 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.

3.4 Power System Frequency Risk Review

The PSFRR is an integrated, periodic review of power system frequency risks associated with non-credible contingency events in the NEM.

Process

Powerlink participated in the inaugural PSFRR in 2018 to identify non-credible contingencies and emergency control schemes that could be within the scope of the PSFRR. From a preliminary list of events for the Queensland region, AEMO, in consultation with Powerlink, ruled out some events and prioritised two non-credible contingency events for assessment based on criteria consistent with the NER. AEMO shared and discussed initial findings with Powerlink and preliminary versions of the PSFRR and incorporated feedback from Powerlink into the PSFRR. The PSFRR Final Report was published in June 2018.

Methodology

With support from Powerlink, AEMO assessed the performance of existing Emergency Frequency Control Schemes (EFCS). AEMO also assessed high priority non-credible contingency events identified in consultation with Powerlink.

From these assessments AEMO determined whether further action may be justified to manage frequency risks. Powerlink has reviewed AEMO's work and supports the outcomes of the PSFRR.

Outcomes

The 2018 PSFRR Final Report recommended two outcomes:

- the expansion of Powerlink's Central Queensland to Southern Queensland (CQ-SQ) Special Protection Scheme (SPS) to improve its effectiveness for the increased southerly flows that are projected as variable renewable energy (VRE) generation connects in central and north Queensland. Powerlink is reviewing the scope of this scheme to ensure that it is able to provide the intended CQ-SQ power transfer coverage and considers any subsequent system strength issues following the potential non-credible loss of both Calvale to Halys 275kV feeders (refer to Section 6.3); and
- the potential need to establish a coordinated Over Frequency Generation Shedding (OFGS) scheme. AEMO and Powerlink have completed the joint study which considered the risk of major supply disruptions which could lead to an over frequency event. The study concluded that the measures recommended in AEMO's Final Report on the 25 August 2018 Islanding Event, which are due to be completed by mid-2020, will mitigate the risk of over-frequency[1].

3.5 Joint planning with TransGrid – Expanding the transmission transfer capacity between New South Wales and Queensland

On November 2018, Powerlink and TransGrid released a PSCR on 'Expanding NSW-Queensland transmission capacity', as the first step in the RIT-T process. This RIT-T is investigating options to increase overall net market benefits in the NEM through increasing transfer capacity on the transmission network between NSW and Queensland. Powerlink and TransGrid are currently working through public submissions on the PSCR and the power system and market modelling to assess various network and non-network options. Findings will be published in the Project Assessment Draft Report (PADR) anticipated later in 2019. This is discussed further in Section 5.7.14.

3.6 Joint planning with Energex and Ergon Energy

Queensland's Distribution Network Service Providers (DNSPs) Energex and Ergon Energy 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[2]. 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 3.1 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.

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[1] AEMO, Final Report – Queensland and South Australia system separation on 25 August 2018, January 2019.

[2] Where applicable to inform and in conjunction with the appropriate RIT-T consultation process.

Table 3.1 Joint planning activities

Activity	Frequency		
	Week-to-week	Monthly	Annual
Sharing and validating information covering specific issues	Y	Y	
Sharing updates to network data and models	Y	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	Y	
Sharing information for respective works plans			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

3.6.1 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 2018 TAPR. 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 5 (refer to Table 3.2).

Table 3.2 Joint planning project references

Project	Reference
Cairns 132/22kV transformer replacement/retirement and cable replacement	Section 5.7.1
Townsville South – Clare South – Collinsville North 132kV transmission lines	Section 5.7.2
Lilyvale 132/66kV transformer replacement	Section 5.7.4
Blackwater 132/66kV transformer replacement and voltage regulator replacement	Section 5.7.4
Redbank Plains transformer and primary plant replacement	Section 5.7.10
Mudgeeraba 275/110kV transformer replacement/retirement	Section 5.7.11

3 Joint planning

CHAPTER 4

Asset management overview

4 Asset management overview

Key highlights

- Powerlink is committed to sustainable asset management practices that consider and recognise our customer and stakeholder requirements.
- Powerlink's asset management practices provide safe, reliable and environmentally conscious services that are cost effective while supporting a sustainable energy market.
- Powerlink's approach to asset management:
  - delivers value to our customers by managing risk, optimising performance and expenditure on assets through whole of asset life cycle management
  - is underpinned by Powerlink's corporate risk management framework and good practice international risk assessment methodologies.

4.1 Introduction

Powerlink's asset management system captures significant internal and external drivers on the business and sets out initiatives to be adopted.

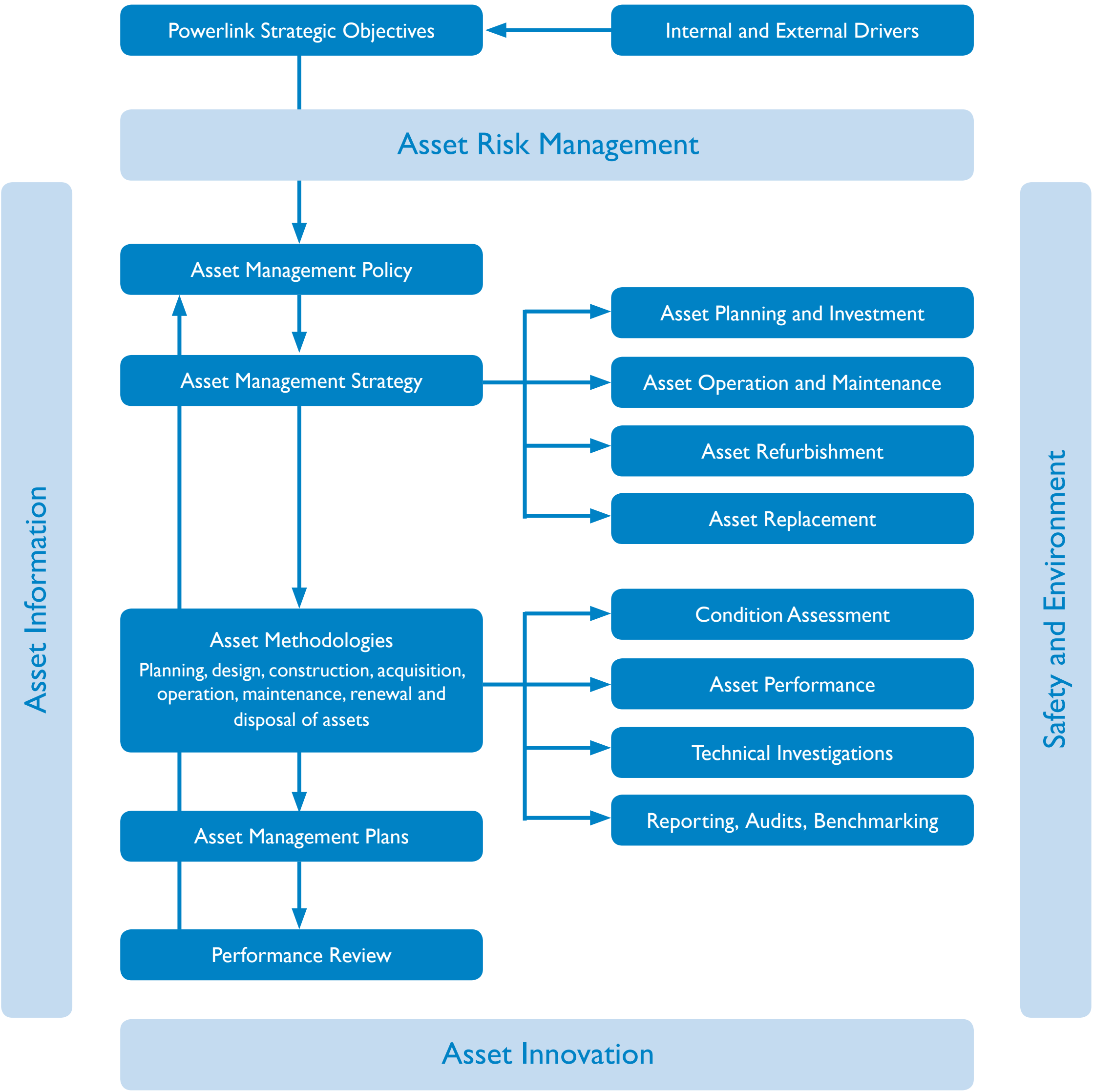
Other factors that influence network development, such as energy and demand forecasts, generation development (including potential generation withdrawal), and risks arising from the condition and performance of the existing asset base are also analysed collectively in order to form an integrated network investment plan over a 10-year outlook period.

4.2 Overview of approach to asset management

Powerlink's Asset Management System ensures assets are managed in a manner consistent with the Asset Management Policy and overall corporate objectives to deliver cost effective and efficient services. The principles set out in the Asset Management System (refer to Figure 4.1) and Asset Management Policy guides Powerlink's analysis of future network investment needs and key investment drivers.

Powerlink's asset management and joint planning approaches ensure asset reinvestment needs are not just considered on a like-for-like basis, rather the enduring need and most cost effect option are considered. A detailed analysis of both asset condition and network capability is performed prior to 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.

Figure 4.1 Asset Management System



4.3 Asset Management Policy

Powerlink's Asset Management Policy sets out a commitment to sustainable asset management practices that ensure Powerlink provides a valued transmission service to its customers by managing risk, optimising performance and managing expenditure on assets through the whole of asset life cycle. The policy includes principles that are applied to manage Powerlink's entire transmission network, including telecommunications and business infrastructure assets.

4.4 Asset Management Strategy

Powerlink's Asset Management Strategy identifies the principles and the approach that guide the development of investment plans for the network, including such factors as expected service levels, investment policy and risk management.

Powerlink's Asset Management Strategy is based on two parallel aspects:

- Asset Life Cycle, which considers assets on a 'whole of life' basis
- Asset Management Cycle, which considers the broader business environment including continuous improvement from the review of evolving factors.

Together, these complementary systems:

- enable a process of continuous improvement which focuses on providing valued services to customers by taking into account evolving internal and external factors
- provide a framework to ensure Powerlink's obligations are able to be effectively and efficiently delivered.

4.4.1 Asset life cycle

A critical element of asset management is to consider the life cycle of assets. There are three primary timeframes in the life of an asset. These timeframes and the interaction between them over the life cycle of assets are shown in Figure 4.2.

Figure 4.2 Asset life cycle

4.4.2 Asset management cycle

Powerlink's asset management practices also consider the broader business environment. This includes operating and overarching business requirements such as safety and environment, risk and information management.

Powerlink manages these aspects by considering the asset management cycle and applying the four phases (refer to Figure 4.3).

Phase 1 – Strategic alignment

Assessing Powerlink's obligations across a wide range of legislation and market requirements and determining the expectations of relevant stakeholders.

This assessment enables Powerlink to responsibly deliver electricity transmission services that are valued by stakeholders, customers and the market.

Phase 2 – Asset management strategies

Considering the obligations and expectations identified under the strategic alignment phase and determining how Powerlink responds in meeting or managing those obligations and expectations.

By managing these obligations and expectations, Powerlink is aligning asset management processes and practices with AS ISO55000:2014[1] to ensure a consistent approach is applied throughout the life cycle of assets.

Phase 3 – Resource alignment

Ensuring resources are made available to achieve strategies which are to be implemented and that resourcing needs are taken into account in the development of asset management strategies.

Powerlink uses a range of tools to develop resource plans over medium to long-term forward planning horizons.

Phase 4 – Continuous review

Monitoring and reviewing network, asset and business performance outcomes continuously.

Powerlink focuses on:

- reviewing the implementation of strategies to identify and adopt improvements
- checking strategies deliver to Powerlink's obligations and the expectations of customers.

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[1] AS ISO 55000:2014 is an international Asset Management standard.

Figure 4.3 Asset management cycle

4.5 Asset management methodologies

Powerlink's asset management methodologies are fundamental in supporting the appraisal of future reinvestment needs, particularly in relation to:

- the monitoring and analysis of asset health, condition and performance
- risk assessment methodology
- whole of life cycle planning.

The systematic appraisal of strategic value and business utility is also required to support investment decisions.

Powerlink employs a structured approach to risk management, applying contemporary and good industry asset risk management practices.

As reinvestment in assets approaching end of technical service life forms a substantial part of Powerlink's future network investment plans in the 10-year outlook period, the assessment of emerging risks arising from the condition and performance of these assets is of particular importance. In order to inform such risk assessments, Powerlink undertakes a periodic review of network assets which considers a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and ongoing supportability.

Risk assessments are underpinned by Powerlink's corporate risk management framework and the application of a range of risk assessment methodologies set out in AS/NZS ISO31000:2018 Risk Management Guidelines[2].

4.6 Integrated network investment planning

A fundamental element of the Asset Management System involves the adoption of processes to manage the life cycle of assets, from planning and investment to operation, maintenance and refurbishment, to end of technical service life.

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[2] AS/NZS ISO 31000:2018 is an international Risk Management standard.

A range of options are considered as part of integrated network investment planning, which includes asset retirement, non-network alternatives, life extension, network reconfiguration and asset reinvestment, which may include replacement.

The purpose of integrated network investment planning is to:

- apply the principles set out in Powerlink's Asset Management Policy, Asset Management Strategy and related processes to guide the development of proposals for future investment and reinvestment in the transmission network
- provide an overview and analysis of factors that impact network development, including energy and demand forecasts, generation developments, network performance and the condition and performance of the existing asset base
- provide an overview of asset condition and health, life cycle plans and emerging risks related to factors such as safety, network reliability and obsolescence and
- identify potential opportunities for optimisation of the transmission network.

4.7 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, program 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 and
- reduce the requirement for 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.

4.8 Further information

Further information on Powerlink's Asset Management System may be obtained by emailing networkassessments@powerlink.com.au.

4 Asset management overview

CHAPTER 5

Future network development

5 Future network development

Key highlights

- Powerlink continues to adapt and respond to shifts in its operating environment by adapting its approach to investment decisions to deliver better outcomes for customers. In particular:
  - assessing whether an enduring need exists for key assets and investigating alternate network configuration opportunities and/or non-network solutions, where feasible, to manage asset risks
  - implementing cost effective solutions, such as transmission line refits, that avoid or delay the need to establish new transmission network infrastructure.
- The changing generation mix may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints holistically with the emerging condition based drivers as part of the planning process.
- Powerlink and TransGrid have responded to the recommendations of the 2018 Integrated System Plan (ISP) and commenced a Regulatory Investment Test for Transmission (RIT-T) to assess the market benefits of expanding the New South Wales (NSW)-Queensland transmission transfer capacity to support more efficient generation sharing between NSW and Queensland and improve the overall reliability of the transmission system.
- Since the publication of the 2018 Transmission Annual Planning Report (TAPR), Powerlink has progressed through a RIT-T program targeting key areas of the transmission network in Queensland requiring capital expenditure.

5.1 Introduction

Powerlink Queensland 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 national grid 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)) of the NER 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 (Clauses 5.12.2(c)(1) and (1A)).

This chapter on proposed future network developments contains:

- discussion on Powerlink's integrated planning approach to network development
- information regarding assets reaching the end of their service life and options to address the risks arising from ageing assets remaining in-service, including asset replacement, 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))

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[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 grows as forecast in this TAPR. Powerlink regularly reviews the need and timing of its projects, primarily based on forecast electricity demand, to ensure solutions are not delivered too early or too late to meet the required network reliability.

- 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 and their relationship to the Australian Energy Market Operator (AEMO) 2018 National Transmission Network Development Plan (NTNDP)
- 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 and
- a table summarising possible connection point proposals.

Where appropriate all transmission network, distribution network or non-network (either demand management or local generation) alternatives are considered as options for investment or reinvestment. Submissions for non-network alternatives are invited by contacting networkassessments@powerlink.com.au.

5.2 NTNDP alignment

In June 2018, the AEMO published the first ISP, which met the requirements of the NTNDP and provided an independent, strategic view of the efficient development of the NEM transmission network over a 20-year planning horizon. The 2018 NTNDP published in December 2018 builds on the ISP, assesses the short-term system adequacy of the national transmission grid over the next five years and reports on the implementation of the ISP.

Powerlink will proactively monitor the changing outlook for the Queensland region and take into consideration the impact of emerging technologies, withdrawal of gas and coal-fired generation and the integration of variable renewable energy (VRE) generation in future transmission plans. These plans may include:

- 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 detail in Chapter 8
- replacing existing assets with assets of a different type, configuration or capacity
- investing in assets to maintain planning standards, including Powerlink's obligations for system strength
- non-network solutions.

5.3 Integrated approach to network development

Powerlink's planning for future network development will continue to focus on optimising the network topography based on the analysis of future network needs due to:

- forecast demand
- new customer access requirements (including possible Renewable Energy Zones (REZ))
- potential power system development pathways signalled in the ISP
- existing network configuration
- safety, condition and compliance based risks related to existing assets.

This planning process includes consideration of a broad range of options to address identified needs described in Table 5.1. Irrespective of the option or range of options used to address an identified need, where Powerlink identifies that there is a credible option greater than $6 million, Powerlink is required to undertake a RIT-T. The RIT-T demonstrates the need, the credible options identified and provides the requirements for non-network alternatives.

Table 5.1 Examples of planning options

Option	Description
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 and in some cases to ensure system strength is maintained.
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.
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.
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 and the abrasive blasting of tower steelwork followed by painting.
Non-network alternatives	Non-network solutions are not limited to, but may include network support from existing and/or new generation or demand side management (DSM) initiatives (either from individual providers or aggregators) which may reduce, negate or defer the need for network investment solutions.
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.

5.4 Forecast capital expenditure

The energy industry is going through a period of transformation driven by shifts in economic outlook, electricity customer behaviour, government policy and regulation and emerging technologies that have reshaped the environment in which Powerlink delivers its transmission services.

In this changed environment, Powerlink is focussing on assessing the enduring need for key ageing assets that are approaching the end of their service life. Powerlink is also seeking alternative investment options through network reconfiguration to manage asset condition and/or non-network solutions where economic and technically feasible. As a result, Powerlink's ongoing capital expenditure program of work is considerably less than undertaken in previous regulatory periods.

Powerlink has a focussed and strategic approach in determining when it is appropriate to refit or replace ageing transmission assets and how to implement these works cost effectively, such as targeted asset replacement or staged works that avoid or delay the need to establish new transmission network infrastructure. This approach is aimed at delivering better value to customers.

The 10-year outlook period discussed in the 2019 TAPR runs from 2019/20 to 2029/30.

5.5 Forecast network limitations

As outlined in Section 1.7.1, under its Transmission Authority, Powerlink must plan and develop its network so that it can supply the forecast maximum demand with the system intact. The planning standard, which came into effect from July 2014, permits Powerlink to plan and develop the network on the basis that some load may be interrupted during a single network contingency event. 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.

Emerging limitations may be triggered by thermal plant ratings (including fault current ratings), protection relay load limits, voltage stability and/or transient stability. Appendix E 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 6.

Assuming that the demand for electricity remains relatively flat in the next five years and taking into consideration the new peak demand discussed in Chapter 2, Powerlink does not anticipate undertaking any significant augmentation works during this period based on load growth. However, the changing generation mix may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints holistically with the emerging condition based drivers as part of the planning process.

In Powerlink's Revenue Determination 2017-2022, projects that could be triggered by the commitment of large mining or industrial block loads were identified as contingent projects (refer to Table 5.2). These contingent projects and their triggers are discussed in detail in sections 7.2 and 7.3.

Table 5.2: Potential contingent projects

Potential project	Indicative cost
Northern Bowen Basin area	$56m
Bowen Industrial Estate	$43m
Central to North Queensland reinforcement	$55m
Central West to Gladstone area reinforcement	$105m
QNI upgrade (Queensland component)	$67m
Queensland to South Australia interconnection (Queensland component)	$120m

In accordance with the NER, Powerlink undertakes consultations with AEMO, Registered Participants and interested parties on feasible solutions to address forecast network limitations through the RIT-T process. Solutions may include provision of network support from existing and/or new generators, advancement in technologies, DSM initiatives (either from individual providers or aggregators) and network augmentations.

5.5.1 Summary of forecast network limitations within the next five years

Powerlink has identified that due to declining minimum demand and increasing penetration of VRE generation, particularly in NQ, there is an emerging need for additional reactive plant in central Queensland to manage potential overvoltages:

Project	Indicative Timing	Reference
Managing voltages in central and north Queensland	2021	Section 5.7.4

Based on the medium economic load forecast in Chapter 2 there are no additional network limitations forecast to occur in Queensland in the next five years[2].

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[2] Refer to NER Clause 5.12.2(3).

5.5.2 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, 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 shift beyond the previously identified timing. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2018 TAPR which fall into this category in 2019.

5.6 Consultations

Network development to meet forecast demand is dependent on the location and capacity of generation developments and the pattern of generation dispatch in the competitive electricity market. Uncertainty about the generation pattern creates uncertainty about the power flows on the network and subsequently, which parts of the network will experience limitations. This uncertainty is a feature of the competitive electricity market and historically has been particularly evident in the Queensland region. Notwithstanding the discussion in sections 5.7.6 and 7.2, Powerlink has not anticipated any material changes to network power flows which may require any major augmentation driven network development. This is due to a combination of several factors including a relatively flat energy and demand forecast in the 10-year outlook period and Powerlink's planning criteria (refer to chapters 1 and 2).

Proposals for transmission investments and reinvestments over $6 million are progressed under the provisions of Clause 5.16.4 of the NER. In accordance with these provisions, and where action is considered necessary, Powerlink will:

- notify of anticipated limitations or risks arising from ageing network assets remaining in-service within the timeframe required for action
- seek input, initially via the TAPR, on potential solutions to network limitations which may result in transmission network or non-network investments in the 10-year outlook period
- issue detailed information outlining emerging network limitations or the risks arising from ageing network assets remaining in-service to assist non-network solutions as possible genuine alternatives to network investments to be identified
- consult with AEMO, Registered Participants and interested parties on credible options (network or non-network) to address emerging limitations or the risks arising from ageing network assets remaining in-service
- carry out detailed analysis on credible options that Powerlink may propose to address identified network limitations or the risks arising from ageing network assets remaining in-service
- consult with AEMO, Registered Participants and interested parties on all credible options (network and non-network) and the preferred option
- implement the preferred option in the event an investment (network and/or non-network) is found to satisfy the RIT-T

Alternatively, transmission investments maybe undertaken under the 'funded augmentation' provisions of the NER.

It should be noted that the information provided regarding Powerlink's network development plans may change and should be confirmed with Powerlink before any action is taken based on the information contained in this TAPR or the accompanying TAPR templates[3].

5.6.1 Current consultations – proposed transmission investments

Commencing August 2010 proposals for transmission investments over $6 million addressing network limitations (augmentation works) are progressed under the provisions of Clause 5.16.4 of the NER. In September 2017 this NER requirement, i.e. to undertake a RIT-T, was extended[4] to include the proposed replacement of network assets.

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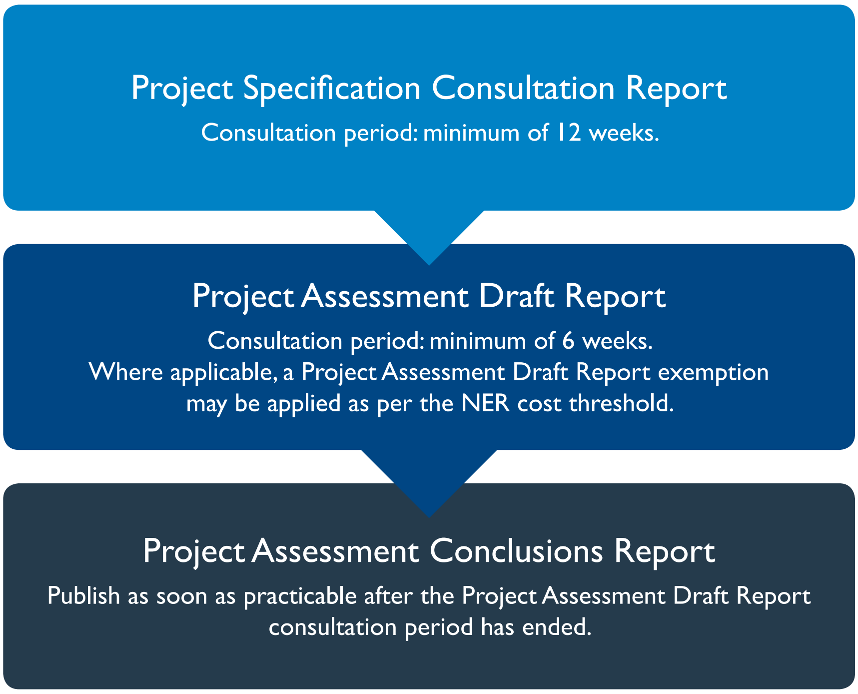
[3] In accordance with the AER's Transmission Annual Planning Report Guidelines published in December 2018.

[4] Replacement expenditure planning arrangements Rule 2017 No. 5.

During 2018/19, Powerlink has made considerable progress through a significant RIT-T program to address the risks arising from ageing network assets remaining in-service, finalising 13 RIT-Ts since the publication of the 2018 TAPR.

This initial 'heavier' program was due to the inclusion of public consultation into the planning timetable for proposed reinvestments in the nearer term (refer to Figure 5.1) which is now expected to moderate in coming years.

Figure 5.1 Overview of the RIT-T consultation process



Project Specification Consultation Report

Consultation period: minimum of 12 weeks.

Project Assessment Draft Report

Consultation period: minimum of 6 weeks.
Where applicable, a Project Assessment Draft Report exemption may be applied as per the NER cost threshold.

Project Assessment Conclusions Report

Publish as soon as practicable after the Project Assessment Draft Report consultation period has ended.

Powerlink carries out separate consultation processes for each proposed new transmission investment or reinvestment over $6 million by utilising the RIT-T consultation process.

The consultations completed since publication of the 2018 TAPR are listed in Table 5.3 (refer to Chapter 9).

Table 5.3: Consultations completed since publication of the 2018 TAPR

Consultation
Addressing the secondary systems condition risks at Woree Substation
Maintaining reliability of supply to Ingham
Addressing the secondary systems condition risks at Dan Gleeson Substation
Maintaining reliability of supply at Townsville South Substation
Maintaining power transfer capability and reliability of supply at Ross Substation
Maintaining reliability of supply to the Rockhampton area
Maintaining power transfer capability and reliability of supply at Bouldercombe Substation
Addressing the secondary systems condition risks at Baralaba Substation
Addressing the secondary systems condition risks at Palmwoods Substation
Addressing the secondary systems condition risks at Tarong Substation
Addressing the secondary systems condition risks at Abermain Substation
Maintaining reliability of supply to the Brisbane metropolitan area
Addressing the secondary systems condition risks at Belmont Substation

The consultations currently under way are listed in Table 5.4.

Table 5.4: Consultations currently under way

Consultation	Reference
Maintaining reliability of supply at Kamerunga Substation	Section 5.7.1
Maintaining reliability of supply between Clare South and Townsville South	Section 5.7.2
Maintaining reliability of supply in the Blackwater area	Section 5.7.4
Maintaining power transfer capability and reliability of supply at Lilyvale	Section 5.7.4
Expanding Transmission Transfer Capacity Between New South Wales and Queensland	Section 5.7.14

Registered Participants and interested parties are referred to the consultation documents which are published and made available on Powerlink's website for further information.

5.6.2 Future consultations – proposed transmission investments

Anticipated consultations

Reinvestment in the transmission network to manage the risks arising from ageing assets remaining in-service will form the majority of Powerlink's capital expenditure program of work moving forward. These emerging risks over the 10-year outlook period are discussed in Section 5.7.

Table 5.5 summarises consultations Powerlink anticipates undertaking within the next 12 months under the Australian Energy Regulator's (AER) RIT-T to address either the proposed reinvestment in a network asset or limitation.

Table 5.5: Anticipated consultations in the forthcoming 12 months (to June 2020)

Consultation	Reference
Addressing the secondary systems condition risks at Cairns	Section 5.7.1
Maintaining reliability of supply in the Cairns area	Section 5.7.1
Addressing the secondary systems condition risks at Innisfail	Section 5.7.1
Addressing the secondary systems condition risks at Kemmis	Section 5.7.3
Maintaining reliability of supply to Gladstone South	Section 5.7.5
Addressing the secondary systems condition risks at Gladstone South	Section 5.7.5
Addressing the secondary systems condition risks at Murarrie	Section 5.7.10
Addressing the secondary systems condition risks at Mudgeeraba	Section 5.7.11

5.6.3 Connection point proposals

Table 5.6 lists possible connection works that may be required within the 10-year outlook period.

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 Distribution Network Service Provider (DNSP)[5] or be initiated by generators or customers. There are no new transmission connection works to supply loads resulting from agreements reached with relevant connected customers, generators or DNSPs since publication of the 2018 TAPR (refer to Chapter 9). Additional details on potential new generation connections are available in the relevant TAPR template located on Powerlink's website as noted in Appendix B.

Table 5.6 Connection point proposals

Generator Location (1)	Number of Applications	Generator Type and Technology
North	5	Solar, Pumped Hydro & Solar
Central	22	Solar, Wind, Gas
South	16	Solar, Wind, Combined (Solar & Wind)
Total	**43**	

Note:

(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.

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[5] In Queensland, Energex and Ergon Energy (part of the Energy Queensland Group) are the DNSPs.

5.7 Proposed network developments

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are now many transmission assets between 40 and 60 years old. It has been identified that a number of these assets are approaching the end of their technical service life and reinvestment in some form is required within the 10-year outlook period in order to manage emerging risks related to safety, reliability and other factors. Moving forward, Powerlink's capital expenditure program of work focusses on reinvestment in the transmission network to manage the identified risks arising from the condition of these ageing assets[6].

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

- improve and further refine options under consideration
- consider other options from those originally identified which may deliver a greater benefit to customers.

Information regarding possible reinvestment alternatives and anticipated timing is updated annually within the TAPR and includes discussion on significant changes which have occurred since publication of the previous year's TAPR together with the latest information available at the time.

Where applicable, in relation to proposed expenditure for the replacement of network assets or network augmentations, Powerlink will consult with AEMO, Registered Participants and interested parties on feasible solutions identified through the RIT-T. The latest information on RIT-T publications can be found on Powerlink's website.

Proposed network developments discussed within this chapter identify the most likely network solution, although as mentioned this has the potential to change with ongoing detailed analysis of asset condition and risks, network requirements or as a result of RIT-T consultations.

Other than the 'Expanding NSW-Queensland transmission transfer capacity' RIT-T as identified in the 2018 ISP, based on the current information available, Powerlink considers all of the possible network developments discussed in this chapter are outside of the scope of the most recent NTNDP and Power System Frequency Risk Review[7].

Powerlink also reviews the rating of assets throughout the transmission network periodically and has not identified the need to permanently de-rate assets as part of the 2019 annual planning review[8].

For clarity, an analysis of this program of work has been performed across Powerlink's standard geographic zones (refer to sections 5.7.1 to 5.7.11) and separated into two periods.

Possible network reinvestments within five years

This includes the financial period from 2019/20 to 2024/25 for possible near term reinvestments when:

- confirmation of the enduring network need and timing occurs
- detailed planning studies are under way or have recently been finalised.

The results of detailed planning analysis and condition assessment are used in the development and consideration of network and non-network options to meet future reinvestment needs and to inform RIT-T consultations.

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[6] Generally these risks fall into four categories – safety, network, environmental and financial. Refer to Powerlink's website for more information.

[7] NER Clauses 5.12.2(6) and (6A).

[8] NER Clause 5.12.2(c)(1A).

Possible network reinvestments within six to 10 years

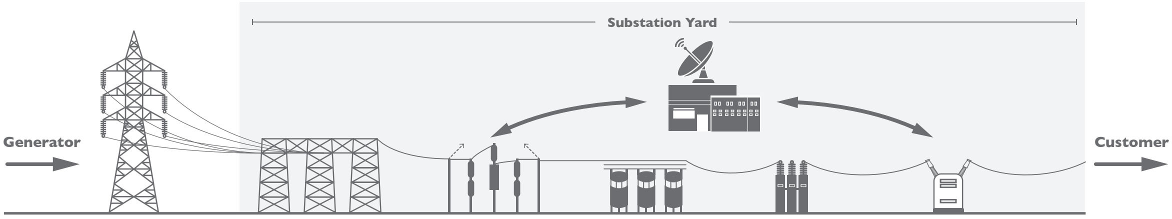
This includes the financial period from 2025/26 to 2029/30, for possible medium to long-term reinvestments. Powerlink takes a balanced, prudent and proportionate approach to the consideration of reinvestment needs to address the risks arising from network assets in the medium to long-term and undertakes detailed planning analysis and condition assessment closer to the possible reinvestment date, typically within five years.

In addition, due to the current dynamic operating environment, there is less certainty regarding the needs or drivers for reinvestments in these later years of the annual planning review period. As a result, considerations in this period have a greater potential to change when compared to near term investments. Possible reinvestment considerations within six to 10 years will need to be flexible in order to adapt to externally driven changes as the NEM evolves and customer behaviours change. Any significant adjustments which may occur as a result of changes will be updated and discussed in subsequent TAPRs.

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 consumers. 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 2018 TAPR and 2019 TAPR. Significant timing differences are noted in the analysis of the program of work within this chapter (refer to sections 5.7.1 to 5.7.11).

The functions performed by the major transmission network assets discussed in this chapter and which form the majority of Powerlink's capital expenditure in the 10-year outlook period are illustrated in Figure 5.2.

Figure 5.2 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.
- **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.

Secondary systems

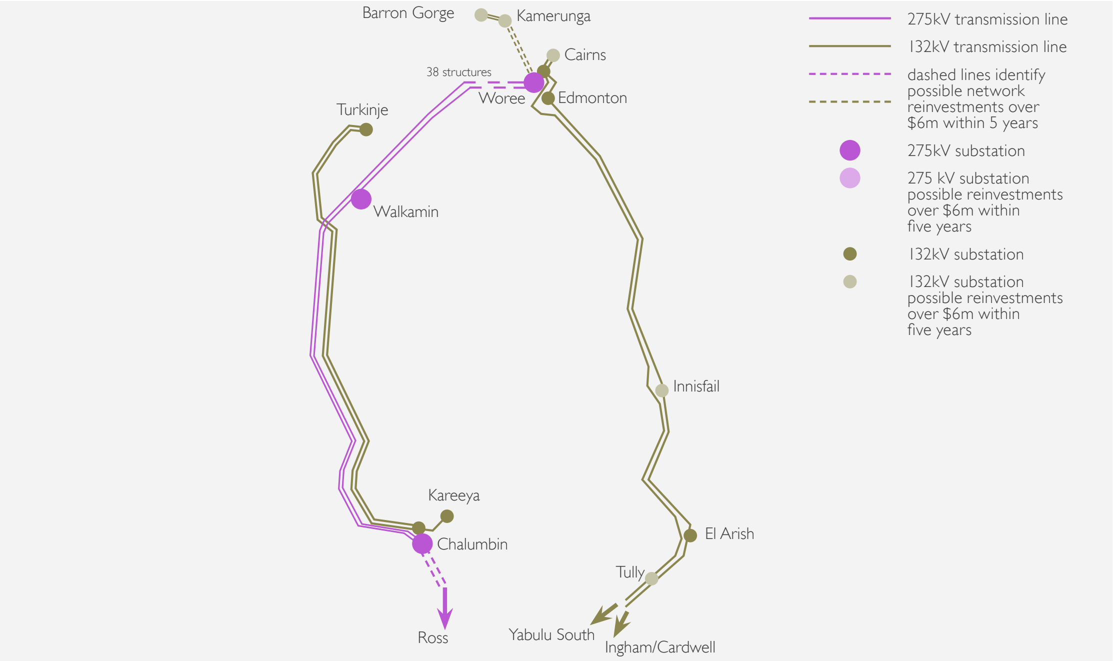
Secondary systems equipment assists in the control, protection and safe operation of transmission assets that transfer electricity in the transmission network.

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.

5.7.1 Far North zone

Figure 5.3 Far North zone transmission network



Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at the Chalumbin and Woree substations into the 132kV transmission network. This 132kV network supplies the Ergon Energy distribution network in the surrounding areas of Tully, Innisfail, Turkinje and Cairns, and connects the hydro power stations at Barron Gorge and Kareeya (refer to Figure 5.3).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments within five years

Network reinvestments in Far 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 Rules' 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 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

The Woree to Kamerunga 132kV double circuit transmission lines were constructed in 1963. Originally connected to Cairns, it provides critical supply to the Cairns northern beaches region, as well as connecting the Barron Gorge Hydro Power Station to the backbone 275kV network.

Project driver

Emerging conditions risks due to structural corrosion.

In 2014 life extension works were performed on certain components of this transmission line that were nearing the end of their operational life. However, it is anticipated that reinvestment will be required by 2024. The location of the existing structures poses access and construction work challenges. Possible end of technical service life strategies for this transmission line may include replacement on a new easement. Investigations for easement alternatives are currently underway.

Project timing: June 2024

Possible network solutions

- Maintaining the existing 132kV network topography through a new double circuit transmission line from Woree and Kamerunga substations by June 2024.
- Network reconfiguration by establishing two single circuit 132kV transmission lines between Woree to Kamerunga substations, or via Cairns North substation, by June 2024.

Proposed network solution: Maintaining 132kV network topology through a new double circuit transmission line on a new easement from Woree to Kamerunga substations at an estimated cost of $30 million[9], by June 2024

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

Possible non-network solutions

Potential non-network solutions 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. It should be noted that this transmission line also facilitates generation connection in the area.

Ross to Chalumbin to Woree 275kV transmission lines

Anticipated consultation: Maintaining reliability of supply in the Cairns region

The majority of electricity used in the Cairns region is transported from central and north Queensland on Powerlink's 275kV system to Ross, near Townsville. From Ross it is transferred via a double circuit 275kV transmission line to Chalumbin, then via a double circuit transmission line, between Chalumbin and the Woree Substation on the outskirts of Cairns. These 275kV transmission lines also provide supply to Turkinje, and connection to the Mt Emerald Wind Farm and Kareeya Hydro Power Station. Additional connections are made through the parallel 132kV transmission network that provides supply to the coastal communities between Townsville and Cairns.

The double circuit 275kV transmission line between Ross and Chalumbin substations is 244km in length and comprises of 528 steel lattice towers. The line was commissioned in 1989 and traverses the rugged terrain of the North Queensland tropical rain forest, passing through environmentally sensitive, protected areas and crossing numerous regional roads and rivers. Recent inspections have indicated these transmission lines display extensive corrosion and a major refit will be required at end of technical service life around 2026.

The Chalumbin to Woree section of line was built in 1998 and is approximately 140km in length. While the condition of a large majority of the line is consistent with its age, this is not the case for the final 16km into Cairns. This final section contains 32 towers that traverse the environmentally sensitive World Heritage Wet Tropics area and terminates near Trinity Inlet Marine Park. These towers have been designed to allow over spanning to minimise corridor clearing. However the extended height has increased exposure to coastal winds. It is subject to a comprehensive maintenance program. Recent inspections have indicated that it displays extensive corrosion to the extent that major member and bolt replacement needs to be undertaken in the near term on five towers, followed by an extensive refit including painting on all 32 towers by 2022.

Due to the environmentally sensitive and geographic conditions in this region, and to ensure reliability of supply to customers, the required renewal works will be complex and need to be completed in stages outside of summer peak load and wet seasons. As a result it has been identified that an extended delivery timeframe of at least six years will be required with consultation anticipated to commence within the next 12 months.

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

Project driver

Emerging conditions risks due to structural corrosion.

Project timing: staged to December 2026

Taking into account the most recent information received, subsequent analysis and understanding of the risks arising from

- the condition and network connectivity of both of the 275kV transmission lines
- ongoing network supply needs in the Far North and Ross zones
- the complexity of undertaking works in environmentally sensitive areas and
- the associated delivery of any potential network solutions in the required timeframe including consideration of the impact of outages

There is an opportunity for Powerlink to consider an integrated approach to optimise any potential reinvestment required, delivering better outcomes for customers. Given the size of the proposed investment and the associated technical requirements, undertaking an integrated, staged approach may also increase the potential to utilise non-network solutions.

Possible network solutions

Maintaining the existing 275kV network topography and capacity through staged line refits or selective rebuild on:

- Chalumbin to Woree 275kV transmission line by 2022, and Ross to Chalumbin 275kV transmission line to achieve 20 to 25 year life extension by 2026
- Chalumbin to Woree 275kV transmission lines to achieve 20 to 25 year life extension by 2022, and line refit on Ross to Chalumbin to achieve seven to 10-year life extension followed by 275kV line rebuild on Ross to Chalumbin by 2026
- potential network reconfiguration through a combination of staged line refits or replacement of the existing 275kV transmission lines as per options above, and uprating one circuit of the 132kV coastal transmission line to 275kV by 2026.

Proposed network solution: Maintaining 275kV network topology through staged line refit projects of the Chalumbin to Woree 275kV transmission line at an estimated cost of $10 to $15 million by October 2023, and the Ross to Chalumbin 275kV transmission line at an estimated cost of $85 to $165 million by 2026.

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

Possible non-network solutions

The Ross to Chalumbin transmission lines provide injection to the Far North area of over 300MW at peak.

The Chalumbin to Woree transmission lines provide injection to the Cairns area of over 250MW at peak. Voltage stability governs the maximum supportable power transfer that can be injected into the Cairns area.

It should be noted that the network configuration facilitates the provision of voltage control and system strength from local synchronous generation. This would need to be taken into consideration for all non-network solutions.

Substations

Kamerunga 132/22kV Substation

Current consultation: Maintaining reliability of supply at Kamerunga Substation

Kamerunga Substation was established in 1976 to supply the rapidly growing area north of Cairns. 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.

Project driver

Addressing emerging condition, obsolescence and compliance risks on selected primary plant and all secondary systems and risks related to a potential future flood event.

Project timing: October 2022

Possible network solutions

- Replacement of selected primary equipment and full replacement of 132kV secondary systems by June 2021, followed by the remainder of the primary plant by 2028.
- Replacement of primary plant and secondary systems upfront with Air Insulated Switchgear (AIS) technology by October 2022.
- Replacement of primary plant including additional switching functionality and secondary systems upfront with Gas Insulated Switchgear (GIS) technology by October 2022
- Replacement of primary plant including additional switching functionality and secondary systems upfront with AIS technology by October 2022.

In accordance with the requirements of the RIT-T, Powerlink published a Project Assessment Draft Report (PADR) in April 2019 which identified upfront replacement with AIS technology by October 2022 as the proposed preferred option.

Submissions to the PADR close in June 2019 and Powerlink anticipates publication of the Project Assessment Conclusions Report (PACR) in July 2019.

Proposed network solution: Upfront replacement of all 132kV primary plant and secondary systems with AIS technology at an estimated cost of $24 million by October 2022

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

Possible non-network solutions

Potential non-network solutions 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.

Cairns 132kV Substation

Anticipated consultation: Addressing the secondary systems condition risks at Cairns Substation

Cairns Substation was established in the mid to late 1950s and was the principal connection point for all 132kV circuits in the Cairns area. In 2002 Woree Substation was established and included switching capability which allowed the Cairns Substation to be rebuilt with a reduced configuration.

One of the three 132/22kV transformers at Cairns Substation is approaching end of technical service life due to increasing risks arising from failure. Based on the medium economic load forecast in Chapter 2, this transformer is no longer required to maintain reliability of supply, and is being considered for retirement including the associated secondary systems.

Project driver:

Condition driven replacement to address emerging obsolescence and compliance risks on the 132kV secondary systems.

Project timing: December 2022

Possible network solutions:

- Staged replacement of the majority of secondary systems components by December 2022.
- Complete replacement of all secondary systems and associated panels by December 2022.

Proposed network solution: Complete replacement of 132kV secondary systems at Cairns Substation in the existing or prefabricated building at an estimated cost of $6 million by December 2022

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

Possible non-network solutions

To maintain the required reliability standards the non-network solution would need to inject at Cairns up to 65MW and up to 1000MWh per day based on steady demand in the future. Non-network solutions may include, but are not limited to, local generation or DSM initiatives.

Innisfail 132kV Substation

Anticipated consultation: Addressing the secondary systems condition risks at Innisfail Substation

Innisfail Substation is a 132/22kV bulk supply point for Ergon Energy in Far North Queensland (FNQ). The 132kV assets were built as part of the Kareeya Power Station hydro-electricity project during the late 1950s, which established the 132kV transmission system to provide electricity to expanding coastal communities in the region. Innisfail Substation was rebuilt in 2003 and the secondary systems installed as part of this rebuild are anticipated to reach end of technical service life around 2023.

Project driver:

Condition driven replacement to address emerging obsolescence and compliance risks on 32kV secondary systems.

Project timing: December 2023

Possible network solutions

- In-situ replacement of the secondary systems components by December 2023.
- Replacement of all secondary systems and associated panels in a new building by December 2023.

Proposed network solution: Complete replacement of all secondary systems and associated panels in a new building at an estimated cost of $7 million by December 2023.

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

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 22kV network at Innisfail of up to a peak of 27MW, and up to a 550MWh per day on a continuous basis. This would facilitate the removal of Innisfail Substation and connection of the Innisfail to Tully transmission line to the Innisfail to El Arish transmission line.

Tully 132/22kV Substation

Potential consultation: Maintaining reliability of supply at Tully

Tully Substation, established in 1976, is an essential 132kV switching station and bulk supply point for Ergon Energy to supply the Tully township and surrounding area in FNQ. One of the transformers has now been in operation for 43 years and is anticipated to reach end of technical service life around 2024.

Project driver:

Emerging condition risks arising from the condition of the 132kV transformer.

Possible network solutions

- Refurbish the transformer by June 2024.
- Replace the transformer by June 2024.

Proposed network solution: Replace the transformer at an estimated cost of $5m by June 2024.

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

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 22kV network at Tully of up to 15MW at peak and up to 270MWh per day. The non-network solution would be required to be operational within 48 hours of a contingency occurring and from that point operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network reinvestments in the Far North zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Far North zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.7 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.7. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.7 Possible network reinvestments in the Far North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Woree to Kamerunga 132kV transmission line replacement	New 132kV double circuit transmission line	Maintain supply reliability to the Far North zone	June 2024	Two 132kV single circuit transmission lines (1)	$30m
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations	Staged line refit works on steel lattice structures	Maintain supply reliability to the Far North and Ross zones	Staged works by October 2023	New transmission line (1)	$10 to $15m
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 2026	New transmission line (1)	$85m to $165m (2)

Table 5.7 Possible network reinvestments in the Far North zone within five years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Kamerunga 132kV Substation replacement	Full replacement of 132kV substation	Maintain supply reliability to the Far North zone	October 2022	Staged replacement of 132kV primary plant and secondary systems (1)	$24m
Retirement of one 132/22kV Cairns transformer	Retirement of one 132kV Cairns transformer including primary plant reconfiguration works (3)	Maintain supply reliability to the Far North zone	December 2021	Replacement of the transformer	$0.5m (4)
Cairns 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2022	Staged replacement of the 132kV secondary systems equipment (1)	$6m
Innisfail 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2023	Replacement of selected secondary systems equipment (1)	$7m
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2024	Refurbishment of the existing transformer (1)	$5m
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2025	Selected replacement of 132kV secondary systems	$4m

Note:

(1) The envelope for non-network solutions is defined in Section 5.7.1.

(2) The project cost will be dependent upon assessment of technical feasibility and commercial analysis of first intervention options to maintain network topography before second intervention is required.

(3) Due to the extent of available headroom, the retirement of this transformer does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's medium economic load forecast outlook of the TAPR.

(4) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget. However material operational costs, which are required to meet the scope of a network option, are included in the overall cost of that network option as part of the RIT-T cost-benefit analysis. Therefore, in the RIT-T analysis, the total cost of the proposed option will include additional costs to account for operational works for the retirement of the transformer.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Far North zone from around 2025/26 to 2029/30 (refer to Table 5.8).

Table 5.8 Possible network reinvestments in the Far North zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Substations					
Edmonton 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2026	Selected replacement of 132kV secondary systems	$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 2026	Full replacement of all 275kV and 132kV primary plant and 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	$6m
Woree 275kV and 132kV secondary systems replacement	Selected replacement of 275kV and 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2028	Full replacement of 275kV and 132kV secondary systems	$16m

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

Retirement of one of the 132/22kV transformers at Cairns Substation

Planning analysis has shown that, based on the medium economic load forecast in Chapter 2, there is no enduring need for one of the three transformers at Cairns Substation, which is approaching end of technical service life within the next five years. Retirement of the transformer provides cost savings through the avoidance of capital expenditure to address the condition and compliance risks arising from the asset remaining in-service. Some primary plant reconfiguration may be required to realise the benefits of these cost savings at an indicative cost of $0.5 million. There may also be additional works and associated costs on Ergon Energy's network which requires joint planning closer to the proposed retirement in December 2021 (refer to table 5.7).

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

5.7.2 Ross zone

Figure 5.4 Northern Ross zone transmission network

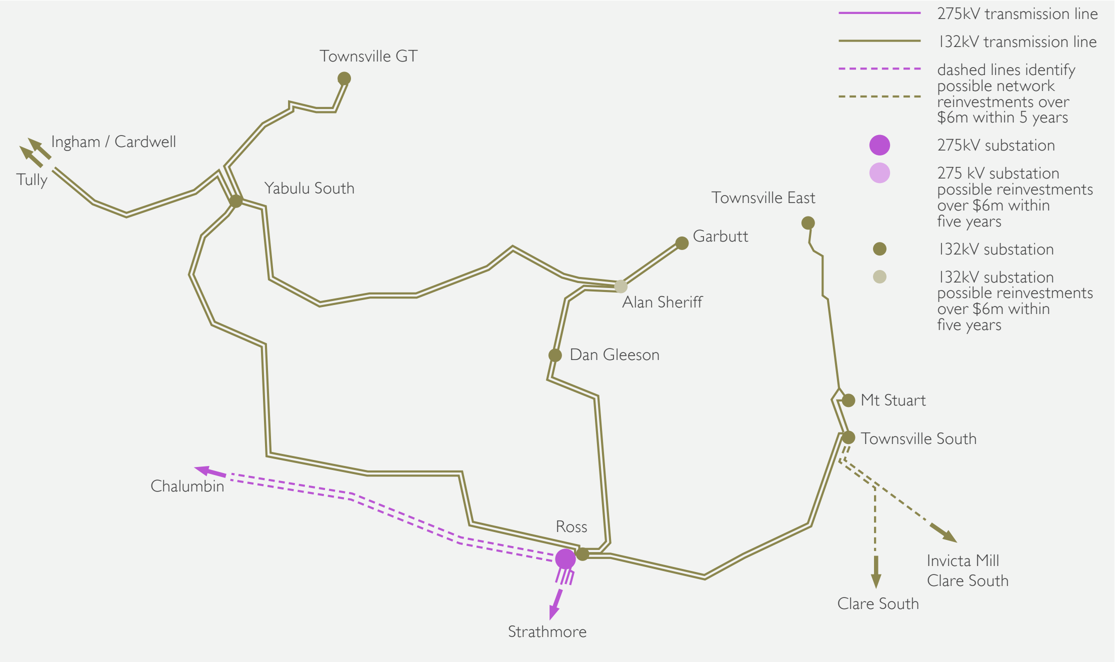

Figure 5.5 Southern Ross zone transmission network

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 5.4 and 5.5).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments within five years

Network reinvestments in 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 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 Ross zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission lines

Clare South to Townsville South 132kV transmission lines

Current consultation: Maintaining reliability of supply between Clare South and Townsville South

The 275kV and 132kV network, which operates in parallel between Collinsville and Townsville, has developed over many years. The 132kV lines are reaching end of technical service life within the 10-year outlook of this TAPR, while the earliest end of technical service life trigger for the 275kV lines is beyond the 10-year outlook of this TAPR.

The 275kV transmission infrastructure is adequate for load requirements with minimal reliance on the 132kV transmission lines for intra-regional transfers. The main function of the current 132kV infrastructure is to provide connections to King Creek, Invicta Mill and Clare South substations, and to support power transfers in the area, including from renewable generation.

Project driver

Emerging condition and compliance risks on the following assets.

Within the next five years:

- Clare South to Townsville South 132kV inland single circuit transmission line built in 1963 (repair of majority of foundations).
- Clare South to Townsville South 132kV coastal single circuit transmission line built in 1967 (structural repair due to above ground corrosion).

Within the next six to 10 years:

- Clare South to Townsville South 132kV inland single circuit transmission line (structural repair due to above ground corrosion separate to the foundation repair described above).
- Strathmore/Collinsville to Clare South 132kV double circuit transmission line (structural repair due to above ground corrosion).

Project timing: December 2022

The inland Townsville South to Clare South transmission line has 156 structures with older style grillage foundations that have emerging condition-based risks that will need to be addressed in the next five years. As a precautionary measure to reduce the risk of tower failure during an extreme weather event, eight towers were repaired by micro piles in 2017 and a further 23 towers have been repaired by micro piles in 2018.

Possible network solutions

Powerlink's future investment strategy aims to focus on maximising value for customers to make the best use of Powerlink's existing assets, and to ensure that investment in the network provides the most value and flexibility for our customers moving forward. Given the nature of the proposed future investment strategies which have been developed, Powerlink has placed considerable emphasis on engaging with and obtaining feedback from customers in the area (refer to Section 1.9.2).

In accordance with the requirements of the RIT-T, Powerlink published a Project Specification Consultation Report (PSCR) In November 2018 which identified the proposed network options based on two themes:

- Maintaining the existing 132kV network topography and capacity through staged line refit projects, and foundation repair of the inland Townsville South to Clare South transmission line by December 2022 with proposed network options ranging from approximately $41 million to $55 million in 2018/19 prices.
- Potential network reconfiguration through a combination of staged line refit projects and decommissioning of parts of the 132kV transmission lines by December 2022 with proposed network options ranging from approximately $28 to $42 million in 2018/19 prices[11].

Submissions to the PSCR closed in April 2019 and Powerlink anticipates publication of the PADR in July 2019.

Proposed network solution: Subject to the RIT-T currently in progress, network reconfiguration through staged line refits of the coastal 132kV transmission line between Clare South and Townsville South, transformer installation at Strathmore Substation and decommissioning the inland 132kV transmission line between Clare South and Townsville South at an estimated cost of $28 million

Powerlink is analysing all possible solutions, as part the current RIT-T consultation.

Possible non-network solutions

Non-network solutions to enable the removal of the inland Townsville South to Clare South transmission line, and remain within Powerlink's planning standard, may include up to 10MW in the Proserpine, Clare or Collinsville area. Non-network solutions may include, but are not limited to local generation, dynamic voltage support or DSM. It should be noted that the network configuration facilitates the provision of voltage control and system strength from local synchronous generation. This would need to be taken into consideration for non-network solutions.

Strathmore to Ross 275kV transmission line

Potential consultation: Maintain reliability of supply between Strathmore and Ross

The two Strathmore to Ross 275kV single circuit transmission lines are 160km in length and were commissioned in 1978 and 1985. They are currently operated paralleled. The last 8km section of the line from Ross Substation was constructed as a double circuit transmission line. Currently one side is operated at 275kV and the other side of the double circuit provides supply to Milchester through an Ergon Energy 132kV feeder. Based on maintenance records and modelling of corrosion it is expected that the 8km section from Ross Substation may require some refit or additional refurbishment to align with the expected end of technical service life for the remainder of the line. A detailed assessment of condition is scheduled for 2020 to inform the required scope of works.

Project driver

Emerging conditions risks due to structural corrosion.

Project timing: June 2024

Possible network solutions

- Refit the section of transmission line.
- Replace the section transmission line with a new double circuit transmission line.

Proposed network solution: Line refit works on the 275kV transmission lines between Strathmore and Ross substations at an estimated cost of $6 million by June 2024

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

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[11] This excludes the cost of operational works, such as asset retirements, which do not form part of Powerlink's capital expenditure budget. However material operational costs, which are required to meet the scope of a network option, are included in the overall cost of that network option as part of the RIT-T cost-benefit analysis.

Possible non-network solutions

Potential non-network solutions to facilitate the removal of the 8km section from Ross Substation would need to provide injection to the 132kV or 66kV network at or near Milchester of up to 40MW at peak and up to 800MWh per day on a continuous basis while maintaining the CQ-NQ transfer limit.

Substations

Townsville South 132kV Substation

Townsville South Substation was established in 1978 to replace the 132kV switchyard at Mt Stuart Substation. It is a major substation supplying the city of Townsville and large industrial loads in the area and is a connection point for the Mt Stuart Power Station.

The 2017 and 2018 TAPR's identified a possible future requirement to address emerging condition, obsolescence and compliance risks arising from the condition of some of the 132kV secondary systems at Townsville South Substation by December 2021. Taking into account the most recent analysis, Powerlink has deferred any potential near term capital reinvestment to address the condition of one regulated bay. It is anticipated the risks arising from the condition of this bay will be considered in conjunction with other secondary systems condition risks, towards the end of the 10-year outlook period.

Alan Sherriff 132kV Substation

Potential consultation: Addressing the secondary systems condition risks at Alan Sherriff

Alan Sherriff Substation was established in 2002 as a two transformer 132/11kV substation, and replaced the 132kV switching functions at Garbutt in 2004. The substation is a major injection point into Ergon Energy's 66kV distribution network providing supply to the Townsville area.

Project driver

Addressing the secondary systems condition risks at Alan Sherriff Substation.

Project timing: June 2025

Possible network solutions

Full replacement of all secondary systems.

Selected replacement of secondary systems, with decommissioning or extended maintenance of the two bays associated with the Dan Gleeson to Alan Sheriff transmission line.

Proposed network solution: Selected replacement of secondary systems at estimated cost of $9 million by June 2025

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

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 11kV network in north east Townsville of up to 25MW at peak and up to 450MWh per day. Reconfiguration of the 132kV network at Alan Sherriff, and of the Townsville 66kV network around Townsville, would be required to facilitate removal of Alan Sherriff Substation.

Possible network reinvestments in the Ross zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Ross zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.9 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.9. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.9 Possible network reinvestments in the Ross zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the coastal 132kV transmission line between Clare South and Townsville South substations with network reconfigurations	Repair or replace selected components on coastal line, and install new transformer at Strathmore Decommission inland line (1)	Maintain supply reliability in the Ross zone	December 2022	Line refit works on steel lattice structures and foundation repair of the inland 132kV transmission line New 132kV transmission line (2)	$28m (3) (4)
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 in the Ross zone	June 2023	New 132kV transmission line Targeted line refit works on steel lattice structures with painting	$2m
Line refit works on the 275kV transmission lines between Strathmore and Ross substations	Targeted line refit works on the 275kV steel lattice towers	Maintain reliability of supply between Strathmore and Ross	June 2024	New transmission line (2)	$6m
Substations					
Strathmore 275kV and 132kV partial secondary systems replacement	Selective replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the Ross zone	December 2022	Selected replacement of 275 and 132kV secondary systems in existing panels	$5m
Ingham South 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2025	Selected replacement of 132kV secondary systems	$4m
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2025	Full replacement of 132kV secondary systems (2)	$9m

Note:

(1) The scope of works, or the need to undertake this potential project, will rely upon the outcome of the RIT-T currently underway.

(2) The envelope for non-network solutions is defined in Section 5.7.2.

(3) The revised project estimate from the 2018 TAPR is based upon the change of scope in the potential network option that is considered likely in the RIT-T underway.

(4) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget. However material operational costs, which are required to meet the scope of a network option, are included in the overall cost of that network option as part of the RIT-T cost-benefit analysis. Therefore, in the RIT-T analysis, the total cost of the proposed option will include an additional $10 million to account for operational works for the retirement of the transmission line.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Ross zone from around 2025/26 to 2029/50 (refer to Table 5.10).

Table 5.10 Possible network reinvestments in the Ross zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Ross and Dan Gleeson substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028	New 132kV transmission line	$8m
Line refit works on the 132kV transmission lines between Collinsville, Strathmore and Clare substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028	New 132kV transmission line Line refit works on steel lattice structures with painting	$20m
Substations					
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2026	Selected replacement of 132kV secondary systems	$3m
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2026	Staged replacement of secondary systems	$5m
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2028	Full replacement of secondary systems	$3m
King Creek 132kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2028	Staged replacement of secondary systems	$2m
Townsville South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2029	Full replacement of 132kV secondary systems	$12m

Possible asset retirements in the 10-year outlook period

Townsville South to Clare South inland transmission line

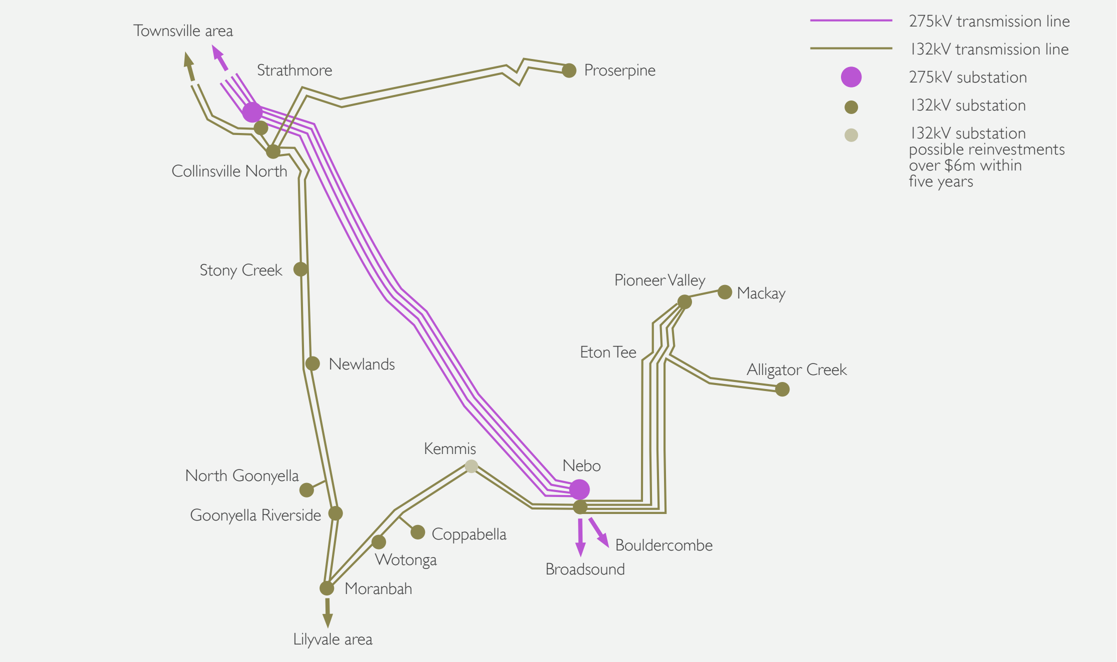
Subject to the outcome of further analysis and RIT-T consultation, Powerlink may retire the inland transmission line at the end of its service life anticipated around 2021.

Dan Gleeson to Alan Sherriff 132kV transmission line

The 132kV transmission line between Dan Gleeson and Alan Sherriff substations was constructed in the 1960s and is located in the south-western suburbs of Townsville. Foundation repair on this transmission line was completed in 2016 to allow the continued safe operation in the medium term. Planning studies are currently underway to assess the viability of potentially retiring this transmission line.

5.7.3 North zone

Figure 5.6 North zone transmission network



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 5.6).

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

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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.

Increasing local demand in the Proserpine area is expected to lead to some load at risk. The critical contingency is an outage of the 275/132kV Strathmore transformer. Based on the medium economic load forecast of this TAPR, this places load at risk of 10MW from summer 2020/21, which is within the 50MW and 600MWh limits established under Powerlink's planning standard (refer to Section 1.8).

High voltages associated with light load 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 (NQ). As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in sections 5.7.4 and 6.6.2.

Possible network reinvestments within five years

Network reinvestments 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 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 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

Pioneer Valley to Eton tee 132kV transmission lines

Potential consultation: Maintaining reliability of supply to the Mackay area

The 132kV line between Pioneer Valley Substation and Eton tee was constructed in 1977 as part of the transmission line between Nebo and Mackay substations to meet the growing load in the Mackay region. A second transmission line was constructed on the original towers in 1981. The establishment of Alligator Creek Substation resulted in one transmission line in and out at the Eton tee point in 1982, followed by a reconfiguration in 1998 when Pioneer Valley Substation was established. The transmission line is located in a harsh saline and corrosive environment.

Taking into account the most recent analysis, Powerlink has deferred any potential near term capital reinvestment to address the condition of the Pioneer Valley to Eton tee transmission line. It is anticipated the risks arising from the condition of this transmission line will be considered in conjunction with the risks arising from the condition of the Nebo to Eton tee 132kV transmission line, within the next seven years.

Substations

Kemmis 132kV Substation

Potential consultation: Addressing the secondary systems risk at Kemmis

Kemmis Substation was established in 2002 to support the load growth arising from the expansion of mining in the Northern Bowen Basin. Two 40MVA 132/66kV transformers are installed, with Transformer 1 relocated from Proserpine and Transformer 2 relocated from Townsville South substations.

Project driver

Addressing the secondary systems condition risks at Kemmis Substation.

Project timing: June 2023

Possible network solutions

- Staged replacement of the majority of secondary systems components by June 2023.
- Complete replacement of all secondary systems and associated panels by June 2023.

Proposed network solution: Complete replacement of all secondary systems at Kemmis Substation at an estimated cost of $7 million by June 2023

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

Possible non-network solutions

Kemmis provides supply to local mining and town loads as well as switching of 132kV circuits that provide essential supply to the Northern Bowen Basin. Network support for the local load would need to provide injection or demand response of up to 32MW on a continuous basis, and up to 760MWh per day, alongside reconfiguration of the 132kV network at Kemmis and surrounding substations. Due to the nature of the load at Kemmis, short duration peaks of up to 70MVA must also be able to be supported.

Possible network reinvestments in the North zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the North zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.11 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.11. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.11 Possible network reinvestments in the North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
North Goonyella 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	December 2020	Selective replacement of 132kV secondary systems	$2m
Nebo 132/11kV transformer replacements	Replacement of two 132/11kV transformers at Nebo Substation	Maintain supply reliability to the North zone	June 2022 (2)	Establish 11kV supply from surrounding network	$3m
Newlands 132kV primary plant replacement	Staged replacement of 132kV primary plant	Maintain supply reliability in the North zone	June 2022	Replacement of all 132kV primary plant	$4m
Kemmis 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2023	Staged replacement of 132kV secondary systems equipment (1)	$7m
Alligator Creek 132kV primary plant replacement	Selective replacement of132kV primary plant	Maintain supply reliability in the North zone	June 2024	Full replacement of 132kV primary plant	$4m

Note:

(1) The envelope for non-network solutions is defined in Section 5.7.3.

(2) The revised timing from the 2018 TAPR is based upon the latest condition assessment.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 North zone from around 2025/26 to 2029/30 (refer to Table 5.12).

Table 5.12 Possible network reinvestments in the North zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Nebo Substation, Eton tee and Pioneer Valley Substation	Line refit works on steel lattice structures	Maintain supply reliability to the North zone	December 2026	New transmission line	$31m
Substations					
Pioneer Valley 132kV primary plant replacement	Staged replacement of 132kV secondary systems equipment	Maintain supply reliability to the North zone	December 2028	Full replacement of 132kV secondary systems	$6m

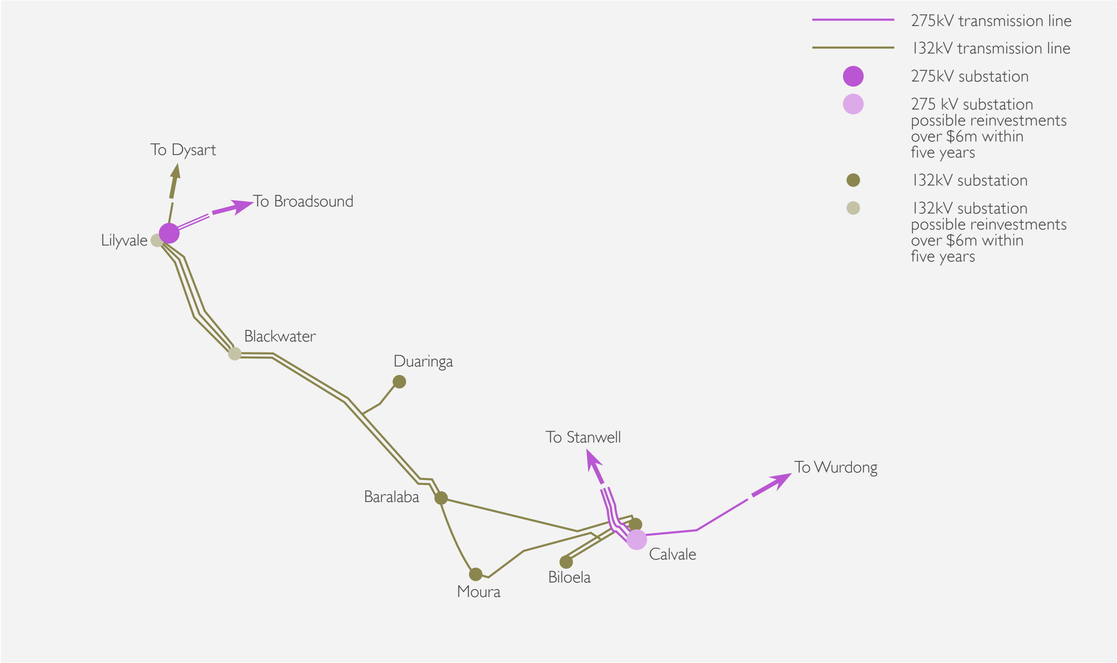
Possible asset retirements within the 10-year outlook period

Pioneer Valley to Eton tee transmission line

Subject to the outcome of further analysis, Powerlink may retire the inland transmission line at the end of its service life anticipated around 2026.

5.7.4 Central West zone

Figure 5.7 Central West transmission network



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. 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 require replacement or rebuilding in the near future (refer to Figure 5.7).

Possible load driven limitations

Based on the medium economic forecast outlined in Chapter 2 and the committed generation described in tables 6.1 and 6.2, there is no additional capacity forecast to be required in the Central West zone within the next five years to meet reliability obligations.

High voltages associated with light load conditions are currently managed with existing reactive sources. However, midday power transfer levels are forecast to reduce as additional VRE generators are commissioned in NQ, leading to greater utilisation of voltage control plant in the Central Queensland (CQ) and NQ zones. As a result, voltage control is forecast to become increasingly challenging for longer durations and potentially lead to high voltage (HV) violations (that is, voltages exceed defined safe operating limits).

Powerlink has in the past used operational line switching to reduce voltages to within safe operating limits. Line switching can lead to reduced reliability arising from non-credible events, and can lead to reduced system strength.

The lines required to be switched to mitigate higher operational voltages in NQ and CQ, are the lines that have the largest impact on the system strength in NQ. The reduction in system strength from line switching may breach Powerlink's obligations under clauses 11.101.2 and 4.6.6 of the NER, as amended by the National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10 (Fault Levels Rule) and this may result in VRE generators in NQ being constrained to ensure system strength is maintained.

Powerlink has identified a need for additional reactive support, to:

- Maintain voltages within operational and design limits during minimum demand periods, and to maintain the power system in a secure operating state
- Reduce reliability impact from the de-energisation of 275kV transmission lines, and
- Reduce market constraints to meet system strength requirements

Project timing: December 2020

Possible network solutions

- Installation of an 84MVAr bus reactor at Broadsound
- Installation of an 84MVAr bus reactor at Nebo.

Proposed network solution: Installation of an 84MVAr bus reactor at Broadsound at an estimated cost of $5 million by 2021.

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

Possible non-network solutions

To address the requirement, Powerlink would be seeking additional voltage control in the northern CQ or southern NQ zone, being south of Strathmore and north of Stanwell, which is able to provide sufficient voltage control to Nebo or Broadsound. The nature of this limitation is that the voltage control would be required to operate on a continuous basis.

Possible network reinvestments within five years

Network reinvestments in 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

Powerlink has identified opportunities to reconfigure the network in the Central West zone providing efficiencies and cost savings by:

- reducing the number of transformers at Bouldercombe Substation, where as an outcome of a recently completed RIT-T, two of the existing transformers will be retired and replaced by a single transformer by December 2021 and
- re-arrangement of the 132kV network around Callide A Substation by the establishment of a second transformer at Calvale Substation and retirement of Callide A Substation and the Callide A to Gladstone South transmission line. A committed project is underway to establish a second transformer at Calvale Substation (refer to Table 9.5).

Lilyvale 275/132kV Substation

Current consultation: Maintaining power transfer capability and reliability of supply at Lilyvale Substation

Lilyvale Substation was established in 1980 to supply the mining load in the Bowen Basin and Blackwater regions of central Queensland. Lilyvale Substation connects the generation points at Gladstone, Stanwell and Callide to the central Queensland mining area. The substation also supplies the central Queensland region owned and operated by Ergon Energy.

275kV and 132kV primary plant

Project driver

Emerging condition risks arising from selective 275kV and 132kV primary plant.

Project timing: October 2022

Possible network solutions

- Selected replacement of 132/275kV primary plant by October 2022.
- Full 132/275kV primary plant replacement by October 2022.

132/66kV transformers

Project driver

Emerging condition risks arising from the three original transformers at Lilyvale Substation.

Project timing: October 2022

Taking into consideration the most recent analysis and understanding of the risks arising from the condition of the primary plant and transformers at Lilyvale Substation, the proposed network solution has been deferred by approximately 15 months from the possible commissioning date of June 2021 as advised in the 2018 TAPR to October 2022.

Possible network solutions

- Replacement of two 80MVA transformers with two 100MVA transformers and full replacement of 132kV and 275kV primary plant in selected bays by October 2022 combined with replacement of the third transformer in 2027
- Replacement of two 80MVA transformers with two 160MVA transformers and full replacement of 132kV and 275kV primary plant in selected bays by October 2022.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in May 2019 which identified replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and the full bay replacement of primary plant in selected bays by October 2022 as the preferred option.

Submissions to the PSCR close on 21 August 2019 and Powerlink anticipates publication of the PACR in October 2019.

Proposed network solution: Replacement of two 80MVA transformers with two 160MVA transformers and full replacement of 132kV and 275kV primary plant in selected bays with an estimated capital cost of $26 million by October 2022

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

Possible non-network solutions

Non-network solutions may include, but are not limited to local generation or DSM initiatives in the Lilyvale areas.

A full non-network option that avoids replacement of ageing primary plant and all three 132/66kV transformers would need to provide injection or demand response at Lilyvale of over 200MW at peak, as well as providing switching for a number of connections in the region from October 2022.

A partial non-network solution could provide support from as early as June 2021 by the replacement of one of the two at risk transformers. More detailed information on the technical requirements of possible non-network solutions is available in the PSCR.

Blackwater 132kV Substation

Current consultation: Maintaining reliability of supply to Blackwater

Blackwater Substation is an essential 132kV switching and load substation in the central Queensland network, originally established in 1969 to supply the mining load in the Blackwater area. The substation was further expanded in 1987 to meet the demand of the rail system to support local mining development in the southern Bowen Basin and to enable the transport of coal to port. Ergon Energy also operates a 66kV and 22kV distribution network from within the site.

132/66kV transformers

Project driver

Emerging condition risks arising from the original transformers at Blackwater Substation.

Project timing: June 2022

Possible network solutions

- Replace both transformers with one transformer by June 2022.
- Replace both transformers with two transformers by June 2022.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in May 2019 which identified replacing the two 132/66/11kV 80MVA transformers with one 132/66/11kV 160MVA transformer by June 2022 by as the preferred option.

Submissions to the PSCR close on 27 August 2019 and Powerlink anticipates publication of the PACR in October 2019.

Proposed network solution: Replace two transformers at Blackwater Substation with one transformer at an estimated cost of $6 million by June 2022

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

Possible non-network solutions

Non-network solutions may include, but are not limited to, local generation or DSM initiatives on the 66kV network in the Blackwater area. Any non-network solution would need to provide support to the 66kV network of up to 150MW and up to 2650MWh per day.

Calvale 275/132kV Substation

Potential consultation: Maintaining reliability of supply at Calvale

Calvale 275/132kV Substation, located in central Queensland, was established in 1988 and is a key switching station for the region with power flowing to the north and east of the state as well as to southern Queensland. Originally the substation was established to connect to Callide A and B power stations. Calvale Substation was extended to connect to Callide Power Plant and Tarong Substation in 1998 and further expanded in 2013 as part of the Calvale to Stanwell augmentation to meet increased demand in the region.

Project driver

Addressing the 275kV primary plant condition risks.

Project timing: June 2025

Possible network solutions

- Selected replacement of 275kV primary plant by June 2025.
- Full 275kV primary plant replacement by June 2025.

Proposed network solution: Selected replacement of 275kV primary plant at an estimated cost of $13 million by June 2025

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

Possible non-network solutions

Calvale Substation provides an essential switching function on the Central Queensland to South Queensland (CQ-SQ) grid section, including marshalling 275kV circuits from Halys, Wurdong and Stanwell and providing connection to Callide B Power Station and Callide Power Plant.

Removal of the Calvale Substation would have a very material impact on the performance, capability and operability[12] of critical grid sections (CQ-SQ and Gladstone grid section) and on the reliability of the generator connections. As such, removal of the substation in its entirety this is not a technically viable option.

However, Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the scope of the replacement project, 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 generation or DSM initiatives that may facilitate reconfiguration of the network.

Additionally, Calvale Substation provides 132kV supply to the central west mining area. A viable non-network solution would be required to provide network support in the Biloela or Moura area of up to 85MW at peak and up to 1800MWh per day on a continuous basis.

Possible network investments in the Central West zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Central West zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.13 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.13. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

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[12] Outages would require multiple network elements to be taken out of service.

Table 5.13 Possible network investments in the Central West zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
84MVAr bus reactor at Broadsound	Installation of an 84MVAr bus reactor at Broadsound Substation	Voltage control in CQ	December 2021	84MVAr bus reactor at Nebo	$5m
Lilyvale primary plant and transformers replacement	Selective replacement of 132kV and 275kV primary plant and replacement of two of the three 132/66kV transformers (1)	Maintain supply reliability in the Central West zone	October 2022	Full replacement of 132kV and 275kV primary plant and replacement of three 132/66kV transformers (2)	$26m
Blackwater 132/66/11kV transformers replacement	Replacement of two 132/66/11kV transformers with one transformer	Maintain supply reliability in the Central West zone	June 2022	Replace both 132/66/11kV transformers with two transformers	$6m
Calvale 275kV primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability in the Central West zone	June 2025	Full replacement of 275kV primary plant (2)	$13m

Note:

(1) The scope of works, or the need to undertake this potential project, will rely upon the outcome of a RIT-T.

(2) The envelope for non-network solutions is defined in Section 5.7.4.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Central West zone from around 2025/26 to 2029/30 (refer to Table 5.14).

Table 5.14 Possible network reinvestments in the Central West zones within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Bouldercombe to Egans Hill substations	Line refit works on a section of the 132kV transmission line	Maintain supply reliability in the Central West and CQ-SQ transmission corridor	June 2027	Rebuild the section with a new 132kV transmission line	$4m
Line refit works on the 132kV transmission line between Bouldercombe and Stanwell substations	Line refit works on the 132kV transmission line	Maintain supply reliability in the Central West zone	June 2028	Rebuild the section with a new 132kV transmission line	$2m
Rebuild the 132kV transmission lines from Callide A to Biloela and Moura	Rebuild the 132kV transmission lines as a double circuit from Callide A to Moura, and retire the single circuit transmission lines between Callide A and Baralaba, and Baralaba to Moura	Maintain supply reliability in the Central West zone	June 2028	Maintain existing topology through line refits of the existing single circuit transmission lines and repair to all foundations	$60m
Substations					
Broadsound 275kV primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability in the Central West Zone	June 2026	Full replacement of 275kV primary plant	$10m
Lilyvale 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2026	Full replacement of 132kV secondary systems	$3m
Biloela 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2026	Full replacement of 132kV secondary systems	$7m
Rockhampton 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2027	Full replacement of 132kV secondary systems	$5m
Broadsound 275kV secondary systems replacement	Selective replacement of 275kV secondary systems	Maintain supply reliability in the Central West zone	June 2027	Full replacement of 275kV secondary systems	$4m

Note:

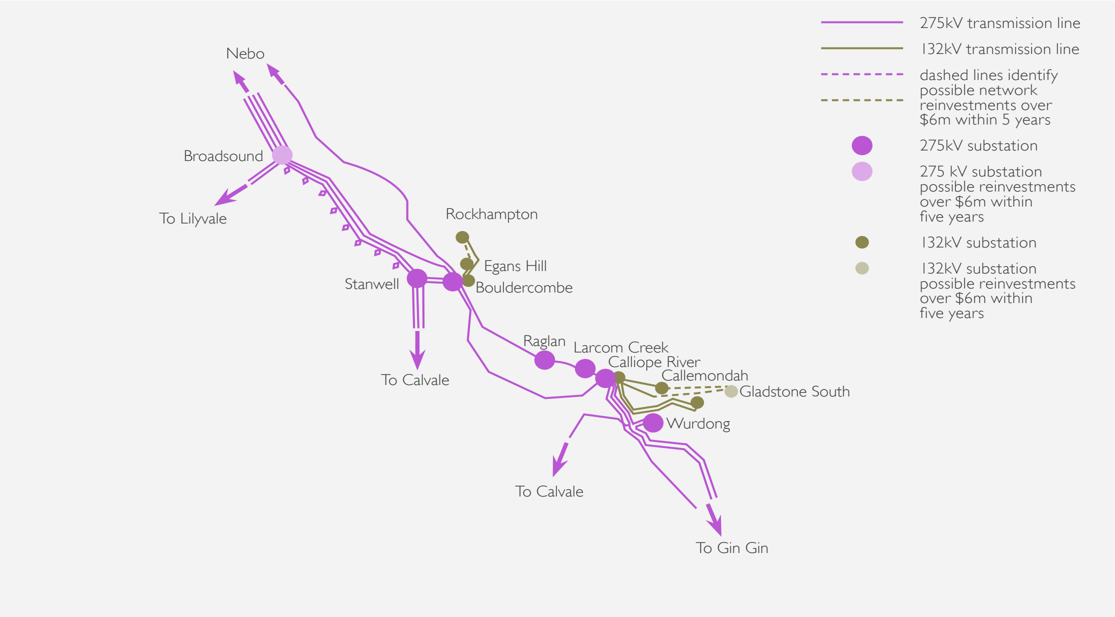
(1) The scope of works of the potential option excludes associated easement costs.

Possible asset retirements within the 10-year outlook period[13]

Subject to the outcome of further analysis and RIT-T consultation, Powerlink may retire the single circuit transmission lines between Callide and Baralaba, and Baralaba and Moura at the end of its technical service life anticipated around 2028.

5.7.5 Gladstone zone

Figure 5.8 Gladstone transmission network



Existing network

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station and has evolved over time with the addition of the Wurdong Substation and supply into Boyne Smelter Limited (BSL) in the early 1990s (refer to Figure 5.8).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, there is no additional capacity forecast to be required in the Gladstone zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments 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 being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations – resulting in poor customer, safety and environmental outcomes.

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

Callemondah to Gladstone South 132kV transmission lines

Potential consultation: Maintaining reliability of supply to Gladstone South

The Callemondah to Gladstone South 132kV double circuit transmission line was constructed in 1977. The transmission line facilitates supply to Gladstone South Substation which is an Ergon Energy bulk supply point and the connection point for Queensland Alumina Limited (QAL).

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

Project driver

Emerging conditions risks due to structural corrosion.

Project timing: December 2021

Possible network solutions

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

Proposed network solution: Refit the double circuit transmission line between Callemondah and Gladstone South substations, at an estimated cost of $10 million, by December 2021

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

Possible non-network solutions

Potential non-network solutions would need to provide supply up to 180MW/3,200MWh daily.

Substations

Gladstone South Substation

Potential consultation: Maintaining reliability of supply at Gladstone South 132kV Substation

The Gladstone South site consists of two substations. The original Gladstone South Substation was built in the early 1960s as a 132kV supply point for transformation to the distribution network and as a major connection to QAL. In 2002, a substation was constructed on an adjacent site to manage the rising fault level and condition risks of the original substation. The transformers, metering and harmonic filter bank are retained at the old substation site.

Project driver

Addressing the secondary systems condition risks at Gladstone South Substation.

Project timing: December 2023

Possible network solutions

- Selective secondary systems replacement by December 2023.
- Full secondary systems replacement by December 2023.

Proposed network solution: Selective secondary systems replacement at Gladstone South Substation at an estimated cost of $17 million by December 2023

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

Possible non-network solutions

Gladstone South Substation supplies the Ergon Energy and customer loads at Gladstone South of over 200MW at peak. 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 reinvestments in the Gladstone zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Gladstone zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.15 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.15. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.15 Possible network reinvestments in the Gladstone zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission line between Larcom Creek Substation and Mt Miller	Line refit works on steel lattice structures (1)	Maintain supply reliability in the Gladstone zone	June 2024	Rebuild the 275kV transmission line between Calliope River and Larcom Creek Substation (3)	$4m
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2021	Rebuild the 132kV transmission line between Callemondah and Gladstone South Substation (2)	$10m
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	June 2022	Rebuild the 275kV transmission line between Wurdong and Boyne Island	$5m
Substations					
QAL West 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Gladstone zone	December 2022	Full replacement of the 132kV secondary systems	$5m
Gladstone South 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Gladstone zone	December 2023	Full replacement of 132kV secondary systems (3)	$17m

Note:

(1) More detailed option analysis and consideration of the associated scope of works to address emerging condition risks on this transmission line has been undertaken since the publication of the 2018 TAPR. This new analysis has supported the development of new strategies and options providing an opportunity to deliver a more cost effective solution than previously identified, delivering better outcomes for customers.

(2) Powerlink would exceed reliability criteria (N-1-50) if network support was not available pre-contingent.

(3) The envelope for non-network solutions is defined in Section 5.7.5.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Gladstone zone from around 2025/26 to 2029/30 (refer to Table 5.16).

Table 5.16 Possible network reinvestments in the Gladstone zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission line between Calliope River and Bouldercombe Substation (from Mt Miller)	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2026	Rebuild 275kV transmission line between Mt Miller and Bouldercombe Substation	$15m
Line refit works 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 2025	Rebuild the 275kV transmission line between Raglan and Larcom Creek	$15m
Substations					
Stanwell 275kV primary plant replacement	Selective replacement primary plant	Maintain supply reliability in the Gladstone zone	June 2027	Full replacement of primary plant	$12m
QAL South 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2028	Full replacement of the 132kV secondary systems	$2m

Possible asset retirements within the 10-year outlook period[14]

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.

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

5.7.6 Wide Bay zone

Figure 5.9 CQ-SQ transmission network

Existing network

The Wide Bay zone supplies loads in the Maryborough and Bundaberg region and also forms part of Powerlink's eastern 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 5.8). These transmission lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, there is no additional capacity forecast to be required in the Wide Bay zone within the next five years to meet reliability obligations.

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 bidding behaviour, 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, seldom imposing constraints to market operation. Over time the utilisation of the CQ-SQ grid sections is expected to increase as new NQ and CQ VRE generating systems connect to the transmission network (refer to Section 5.7.5, Section 6.6.4 and Section 7.3.2). Powerlink's modelling shows that congestion across the CQ-SQ grid section will occur with maximum transfer levels reached. At these times, generators in central and northern Queensland will be constrained to reduced levels in accordance with the outcomes of security constrained dispatch and market arrangements.

In addition, the incidence of congestion will increase if additional southerly transfer capacity on Queensland/New South Wales Interconnector (QNI) is shown to be economically justified. If material emerging market constraints are forecast, Powerlink must demonstrate that the economic benefit to the market exceeds the cost of addressing the constraint. In the case of emerging constraints across CQ-SQ, the potential investments to address these constraints are likely to be significant. Powerlink will consider these constraints holistically with the emerging condition based drivers as part of the planning process.

Possible network reinvestments within five years

Network reinvestments in 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 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 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

Potential consultation: Maintain reliability of supply on the coastal CQ-SQ 275kV transmission corridor

The coastal CQ-SQ transmission network between Calliope River and South Pine substations was progressively developed in the 1970s and 1980s to support loads in the Gladstone area and facilitate power transfer between central and southern Queensland. This corridor provides the major injection points at Gin Gin, Teebar Creek, Woolooga and Palmwoods 275/132kV for the Wide Bay and Sunshine Coast areas. The Ergon Energy 132kV and Energex 132/110kV sub-transmission systems supply bulk supply points 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.

Project driver

Emerging condition and compliance risks related to structural corrosion on the Calliope River to South Pine 275kV single circuit transmission lines.

With varying distance from the ocean, and localised industrial pollution, these 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 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:

- Two 275kV single circuit transmission lines from Woolooga to Gin Gin built in 1972 and 1976 (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)

Project timing: December 2024 to December 2029

Possible network solutions

The current long-term network solution strategy based on existing network topology and requirements, is to rebuild the 275kV single circuit transmission lines from Calliope River to South Pine as a double circuit and to supply Wurdong from Calliope River via a dedicated 275kV double circuit. This strategy will be commercially assessed and adjusted to align with future generation and network developments, in particular if further planning analysis identify triggers to increase capacity or alternative network configuration options.

Strategies to address the transmission line sections with advanced corrosion in the five-year outlook will be commercially assessed in consideration of long-term options for reconfiguring the 275kV transmission lines. The longer term network solution options 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 stage rebuild and line refit projects; or
- 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.

Proposed network solution within the next five years:

- Partial rebuild of the transmission line between Calliope River and Gin Gin substations (up to Wurdong Tee) at an estimated cost of $18 million by December 2024.
- Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Tee at an estimated cost of $6 million by December 2024.
- Line refit works on the 275kV transmission line between Woolooga and South Pine substations at an estimated cost of $20 million by June 2024.

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

Possible non-network solutions

The coastal CQ-SQ transmission network provides essential supply between the generation in central and north Queensland and the loads in southern Queensland. 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.

Powerlink considers that a non-network solution may have material intra-regional and other impacts.

Possible network reinvestments in the Wide Bay zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Wide Bay zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.17 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.17. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.17 Possible network reinvestments in the Wide Bay zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Partial rebuild of the transmission line between Calliope River and Gin Gin substations (up to Wurdong Tee)	New double circuit transmission line for the first 15km out of Calliope River substation	Maintain supply to the Moreton zone	December 2024	Refit the two single circuit 275kV transmission lines (1)	$18m
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Tee	Refit the 275kV transmission line between Calliope River Substation and Wurdong Tee	Maintain supply reliability in the CQ-SQ transmission corridor (and Gladstone zone)	December 2024	Rebuild the 275kV transmission line as a double circuit (1)	$6m
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 to the Moreton zone	June 2024	Rebuild the 275kV transmission line between Woolooga and South Pine substations (1)	$20m

Note:

(1) The envelope for non-network solutions is defined in Section 5.7.6.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Wide Bay zone from around 2025/26 to 2029/30 (refer to Table 5.18).

Table 5.18 Possible network reinvestments in the Wide Bay zone within six to 10 years

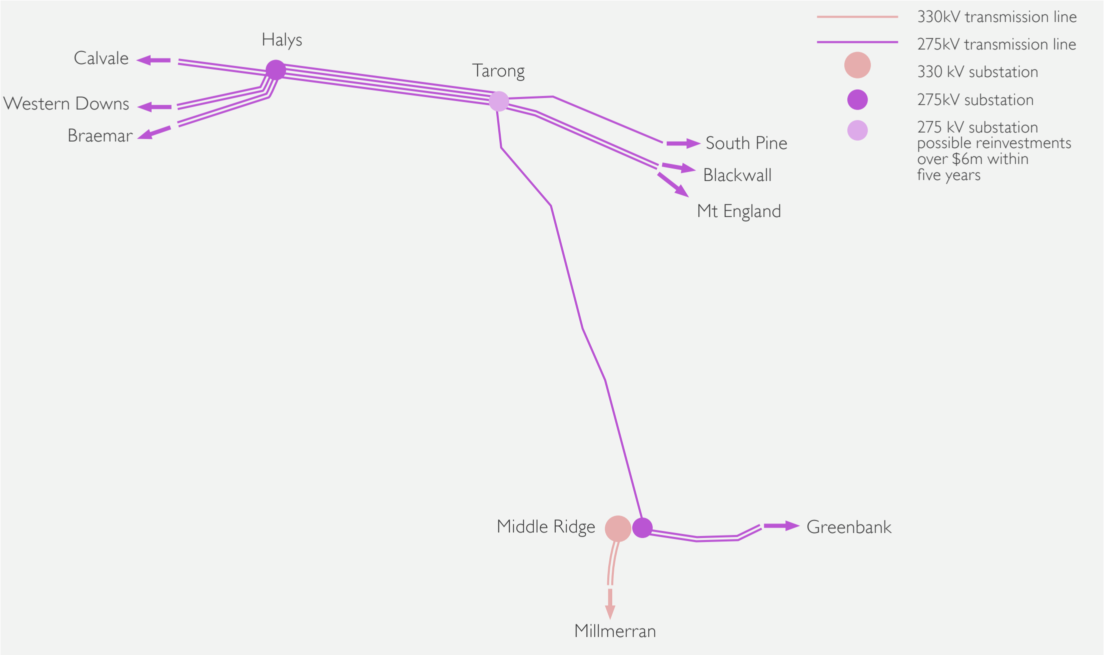
Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission line between Gin Gin and Woolooga substations	Refit the 275kV transmission line between Gin Gin and Woolooga substations	Maintain supply to the Wide Bay zone	June 2027	Rebuild the 275kV transmission line between Gin Gin and Woolooga substations	$40m
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	December 2027	Rebuild 275kV transmission line between South Pine and Palmwoods substations	$12m
Rebuild the 275kV transmission lines between Wurdong Tee and Gin Gin Substation	Double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation	Maintain supply to the Wide Bay zone	June 2029	Refit the 275kV transmission line between Wurdong Tee and Gin Gin Substation	$130m
Substations					
Woolooga SVC secondary systems replacement	Replacement of secondary systems of the SVC	Maintain supply to the Moreton zone	June 2026	Staged replacement of secondary systems of the SVC	$6m
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Moreton zone	June 2027	Selective replacement of 132kV and 275kV secondary systems	$14m
Woolooga 275kV and 132kV secondary systems replacement	Full replacement of 132kV and 275kV secondary systems (including SVC)	Maintain supply to the Moreton zone	June 2029	Selective replacement of 132kV and 275kV secondary systems	$25m

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 five years

5.7.7 South West zone

Figure 5.10 South West area network



Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge (refer to Figure 5.10).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments within five years

Network reinvestments in South 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 South 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

Tarong 275kV Substation

Tarong Substation is located in the South West Queensland transmission network and is a critical part of the 275kV network supplying South East Queensland. Located approximately 130km north-west of Brisbane, Tarong Substation is a major part of the 275kV transmission backbone connecting generators to the major load centres in the south-east of the State. It also provides the major injection point for local, rural and bulk mining loads in south-west Queensland.

The Tarong Substation was established in conjunction with the Tarong Power Station in 1982. The substation consists of one switchyard of 275kV operating voltage and one switchyard of 132kV and 66kV operating voltages. Powerlink owns the 275kV, 132kV and 66kV assets on site.

Potential consultation: Maintain supply reliability in the South West zone and Tarong 66kV load

Project driver

Emerging condition risks arising from the condition of the existing 275/66kV and 275/132kV transformers.

Project timing: June 2024

Possible network solutions

- Maintain network topology by replacement of the two 275/66kV and two 275/132kV transformers
- Network reconfiguration by replacement of the two 275/66kV and decommissioning the two 275/132kV transformers
- Network reconfiguration by replacement of the two 275/66kV and one 275/132kV transformers (while decommissioning the other)
- Network reconfiguration by replacement of one 275/132kV and decommissioning the two 275/66kV transformers and replacing with two 132/66kV transformers

Proposed network solution: Network reconfiguration by replacement of the two 275/66kV transformers at an estimated cost of $16 million by June 2024. The two 275/132kV transformers are to be decommissioned.

Compared to the 2018 TAPR, the increase in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

Possible non-network solutions

To replace the functionality of both of the existing transformers, a non-network solution would be required to provide up to 40MW and up to 850MWh per day on an ongoing basis to meet the requirements of Powerlink's planning criteria.

To replace the functionality of one of the existing transformers, a non-network solution would be required to provide up to 40MW and up to 850MWh per day on a continuous basis following an outage of the transformer, and to be in-service within six hours following a contingency to meet the requirements of Powerlink's reliability criteria. The network support would also be required to provide supply for planned outages.

The non-network solution must also be able to provide auxiliary supply to Tarong Power Station, which can be up to 38MVA.

Possible network reinvestments in the South West zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the South West zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.19 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.19. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.19 Possible network reinvestments in the South West zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Chinchilla 132kV primary plant replacement (3)	Reduced scope replacement and transformer ending from Columboola	Maintain supply reliability in the South West zone	June 2024	Replacement of the entire 132kV switchyard	$5m
Tarong 275/66kV transformers replacement	Replacement of 275/66kV transformers and decommissioning the 275/132kV transformers at Tarong Substation (2)	Maintain supply reliability in the South West zone	December 2024	Refurbishment of existing transformers (1)	$16m
Tarong 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability in the South West zone	June 2025	Full replacement of 275kV primary plant	$2m

Note:

(1) The envelope for non-network solutions is defined in Section 5.7.7.

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

(3) Based on the most recent analysis and understanding of the risks arising from the condition of the primary plant at Chinchilla Substation, the proposed network solution has been advanced from the possible commissioning date of December 2026 as advised in the 2018 TAPR.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 South West zone from around 2025/26 to 2029/30 (refer to Table 5.20).

Table 5.20 Possible network reinvestments in the South West zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Chinchilla 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability in the South West zone	December 2026	Staged replacement of 132kV secondary system	$4m
Oakey 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the South West zone	June 2028	Staged replacement of 110kV secondary system	$3m

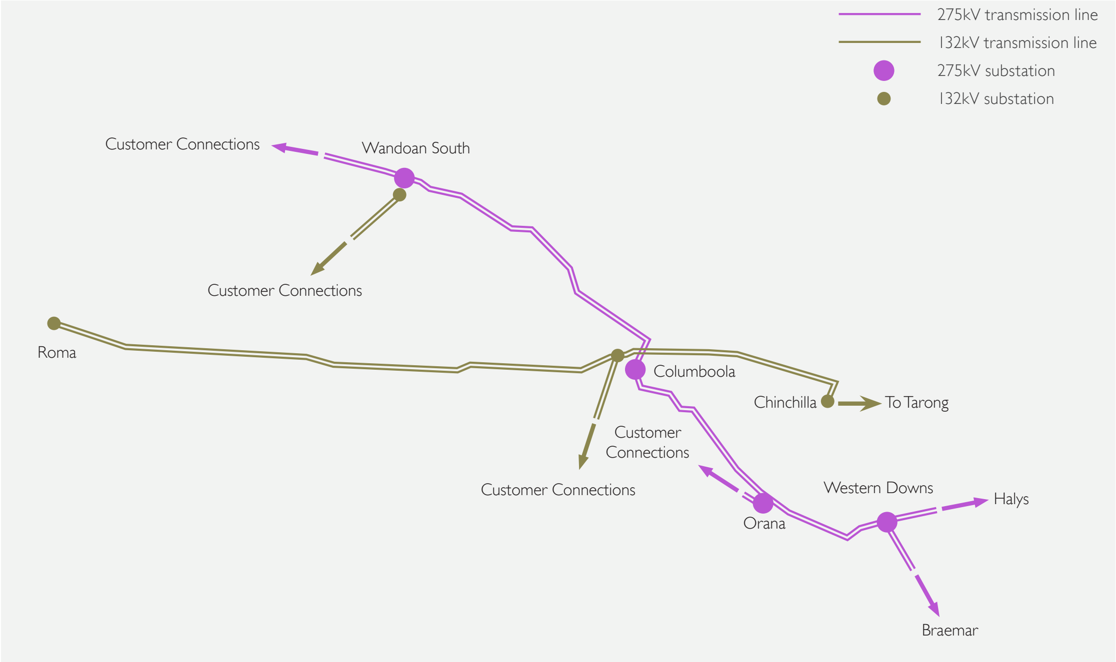
Possible asset retirements within the 10-year outlook period[15]

Condition assessment has identified emerging condition risks arising from the condition of two 275/132kV transformers at Tarong Substation by 2024. Planning studies have confirmed the potential to subsequently retire both transformers based on the medium economic load forecast in Chapter 2. On this basis, it is considered likely the 275/132kV transformers at Tarong Substation will be retired at end of technical service life.

Condition assessment has identified emerging condition risks arising from the condition of 132kV primary plant at Chinchilla Substation by 2024. At this time, an option would be a reduced scope replacement that would involve transformer ending from Columboola 132kV Substation, and retirement of the 132kV primary plant arising from the connection to Tarong Substation.

5.7.8 Surat zone

Figure 5.11 Surat Basin North West area transmission network



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. Electricity demand in the area is forecast to continue to grow due to new developments of VRE projects, CSG upstream processing facilities by multiple proponents, together with the supporting infrastructure and services (refer to Figure 5.11).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments within the 10-year outlook period

There are no reinvestment requirements within the 10-year outlook period.

Possible asset retirements within the 10-year outlook period

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

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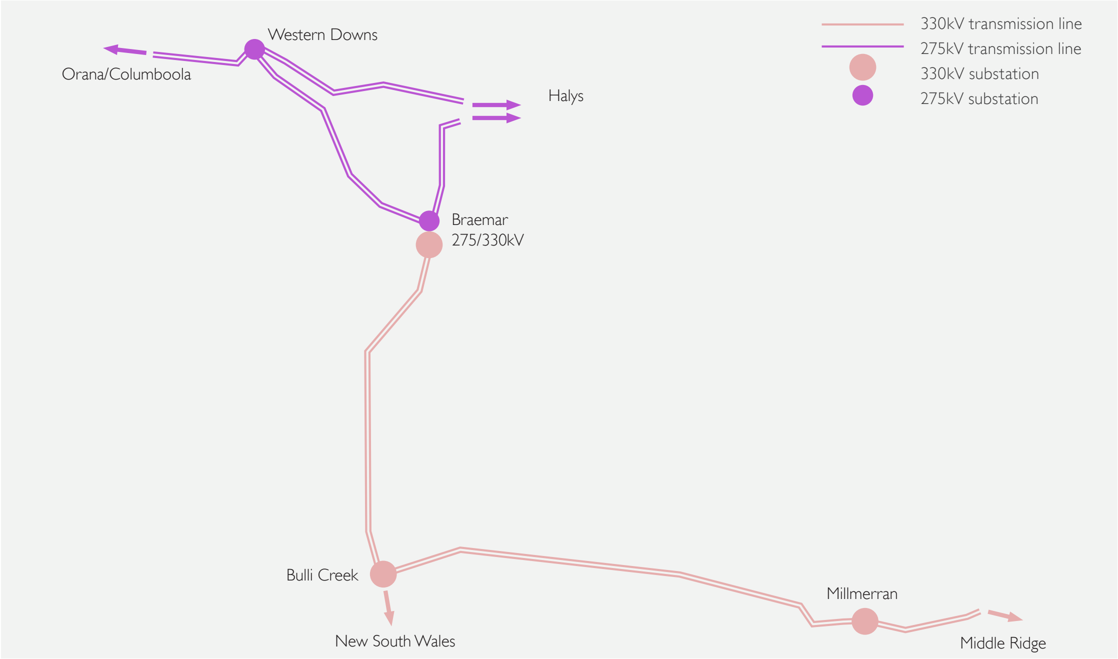
[15] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

5.7.9 Bulli zone

Figure 5.12 Bulli area transmission network



Existing network

The Bulli zone is defined as the area surrounding Goondiwindi and the 275/330kV network south of Kogan Creek and west of Millmerran (refer to Figure 5.12).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments in the Bulli zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Bulli zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.21 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.21. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.21 Possible network reinvestments in the Bulli zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Bulli Creek 132kV secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability in the Bulli zone	June 2025	Full replacement of secondary systems	$2m

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Bulli zone from around 2025/26 to 2029/30 (refer to Table 5.22).

Table 5.22 Possible network reinvestments in the Bulli zone within six to 10 years

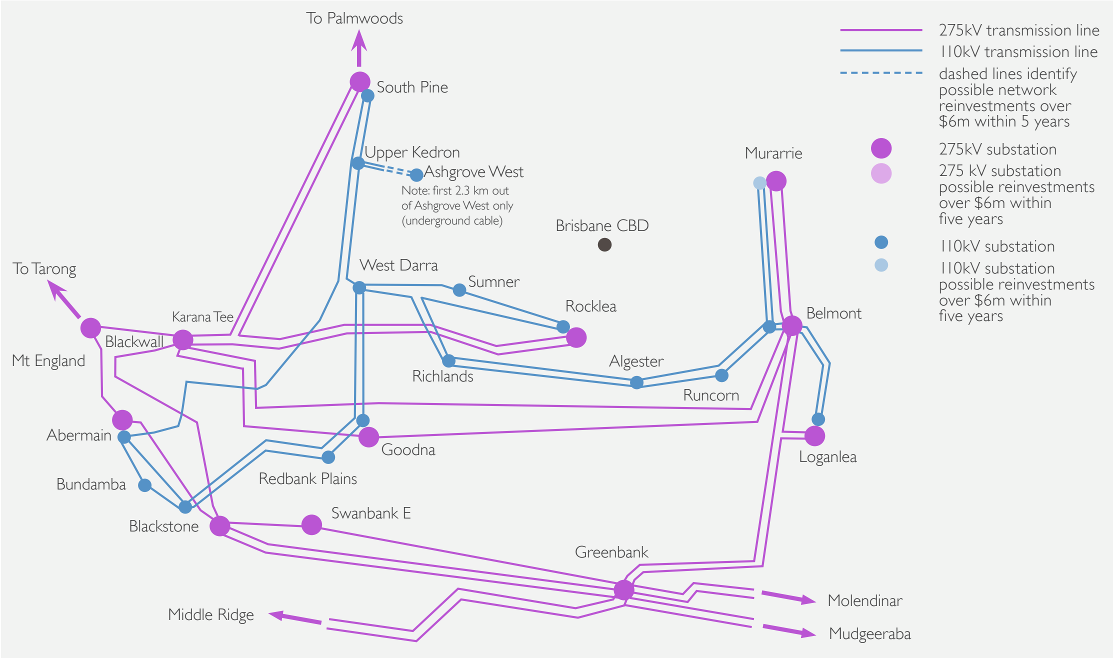
Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Middle Ridge 275kV and 110kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Bulli zone	December 2025	Selected replacement of secondary systems	$41m
Middle Ridge 110kV primary plant replacement	Replacement of primary plant in transformer bays	Maintain supply reliability in the Bulli zone	June 2026	Refurbishment of primary plant in transformer bays	$3m
Millmerran 330kV AIS secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability in the Bulli zone	June 2027	Full replacement of secondary systems	$5m
Bulli Creek transformer replacement	Replace one 330/132kV transformer at Bulli Creek Substation	Maintain supply reliability in the Bulli zone	December 2028	Retirement of 330/132kV transformers with non-network support	$7m

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.

5.7.10 Moreton zone

Figure 5.13 Greater Brisbane transmission network



Existing network

The Moreton zone includes a mix of 110kV and 275kV 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 5.13).

Future investment needs in the Moreton zone are substantially arising from the condition and performance of 110kV and 275kV 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).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, there is no additional capacity forecast to be required as a result of network limitations in the Moreton zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in 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 between 2020 and 2025.

With the maximum demand forecast relatively flat in the next five 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 2020s.

Underground 110kV cable between Upper Kedron and Ashgrove West

Potential consultation: Maintain reliability of supply to the Brisbane metropolitan area

The 110kV transmission line between Upper Kedron and Ashgrove West substations was established in 1978, as one of the principle sources of supply to the north-west Brisbane area. Predominantly an overhead transmission line, with the final 2.3km long section to Ashgrove West Substation being an underground cable.

Project driver

Emerging condition, end of technical service life and compliance risks for the Upper Kedron to Ashgrove West oil-filled cables.

Project timing: June 2024

Possible network solutions

- Replacement of the existing cables with new cables in a new easement by June 2024. Replacement of the existing cables with new cables from Rocklea
- Replacement of existing cables with new cables in the existing easement by June 2024.

Proposed network solution: Replacement of the oil-filled cables with new cables in a new easement at an estimated cost of $13 million by June 2024

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

Possible non-network solutions

The Upper Kedron to Ashgrove West cables provide supply of up to 220MVA 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.

Substations

Redbank Plains 110kV Substation

Potential consultation: Maintaining power transfer capability and reliability of supply at Redbank Plains Substation

Redbank Plains Substation was established to provide electricity to the expanding communities west of Brisbane in 1986 and serves as a bulk supply injection point to the Energex distribution network.

Project driver

Addressing the 110kV primary plant condition risks.

Project timing: June 2024

Possible network solutions

- Replacement of selected 110kV primary plant by June 2024.
- Full replacement of 110kV primary plant by June 2024.

Project driver

Emerging condition driven risks arising from the condition of the existing 110/11kV transformers.

Redbank Plains 110/11kV 25MVA transformers 1 and 2 were installed onsite in 1985 and 1984 respectively. The transformers exhibit aged paper insulation and increased moisture levels in oil, possibly due to the numerous oil leaks from the main tanks. The high voltage bushings are the original porcelain housed oil insulated paper bushings, which have been in service well past their 25 year technical service life. The paint on the main tank is also compromised and does not provide adequate protection.

Project timing: June 2024

Possible network solutions

- Replace both 110/11kV transformer by June 2024.
- Replace one 110/11kV transformer and engage non-network support by June 2024.

Proposed network solution: Replacement of selected 110kV primary plant and both 110/11kV transformers at Redbank Plains Substation at an estimated cost of $10 million by June 2024.

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

Possible non-network solutions

Non-network solutions may include, but are not limited to, local generation or demand side management initiatives on the 11kV network in the area. Any non-network solution would need to be available on a firm basis and provide support to the 11kV network of up to 25MW and up to 400MWh per day.

Murarrie 275/110kV Substation secondary systems replacements

Anticipated consultation: Addressing the secondary systems condition risks at Murarrie

Murarrie Substation was established in 2003 as a bulk supply point to service the industrial load around the Brisbane River and port areas. Murarrie secondary systems were commissioned between 2003 and 2006.

Project driver

Emerging condition and compliance risks arising from the 110kV secondary systems at Murarrie Substation.

Project timing: December 2023

Possible network solutions

- Full replacement of all of the 110kV secondary systems upfront by December 2023.
- Staged replacement on 110kV secondary systems by December 2023.

Proposed network solution: Full replacement of the 110kV secondary systems at Murarrie Substation at an estimated cost of $21 million by December 2023

Compared to the 2018 TAPR, the decrease in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

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

Possible non-network solutions

Murarrie Substation provides injection and switching to the CBD and south-eastern suburbs of Brisbane of over 300MW at peak. 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 reinvestments in the Moreton zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Moreton zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.23 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.23. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.23 Possible network reinvestments in the Moreton zone within five years

Potential project	High level scope	Purpose	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 2024	Replace the 110kV underground cable between Upper Kedron and Ashgrove West substations using the existing easement (1)	$13m
Line refit works on the 275kV transmission line between Belmont and Murarrie substations	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	June 2025	New 275kV transmission line/s	$2m
Substations					
Redbank Plains 110kV primary plant and 110/11kV transformers replacement	Selective replacement of 110kV primary plant and replacement of two 110/11kV transformers	Maintain reliability of supply at Redbank Plains Substation	June 2024	Full replacement of 110kV primary plant, replace one 110/11kV transformer and engage non-network support (1)	$10m
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	December 2023	Staged replacement of 110kV secondary systems (1)	$21m
Mt England 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton zone	December 2022	Selective replacement of 275kV secondary systems	$5m

Note:

(1) The envelope for non-network solutions is defined in Section 5.7.10.

Possible network reinvestments in the Moreton zone within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Moreton zone from around 2025/26to 2029/30 (refer to Table 5.24).

Table 5.24 Possible network reinvestments in the Moreton zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
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	December 2025	Rebuild the 275kV transmission line between Karana Downs and South Pine substations	$8m
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 (2)	Maintain supply reliability in the Moreton zone	December 2026	Potential retirement of the transmission line between West Darra and Upper Kedron substations	$5m
Line refit works on the 110kV transmission lines between Swanbank, Redbank Plains and West Darra	Refit the 110kV transmission lines between Swanbank, Redbank Plains and West Darra	Maintain supply reliability in the Moreton zone	December 2026	Rebuild the 110kV transmission lines between Swanbank, Redbank Plains and West Darra	$6m
Line refit works on the 110kV transmission line between South Pine and Upper Kedron substations	Refit the 110kV transmission line between South Pine and Upper Kedron substations	Maintain supply reliability in the Moreton zone	June 2028	Replacement of the transmission line between South Pine and Upper Kedron substations	$4m
Line refit works on the 110kV transmission line between Richlands and Algester substations	Refit the 110kV transmission line between Richlands and Algester substations (2)	Maintain supply reliability in the Moreton zone	June 2026	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 (2)	Maintain supply reliability in the Moreton zone	December 2026	Rebuild the 110kV transmission line between Blackstone and Abermain substations	$6m
Line refit works on the 110kV transmission line between Rocklea to Sumner to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton Zone	June 2028	New 110kV transmission line/s (1)	$5m

Table 5.24 Possible network reinvestments in the Moreton zone within six to 10 years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
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 2026	Replacement of the transmission line between Bergins Hill and Karana Downs substations	$4m
Substations					
South Pine 275/110kV transformer replacement	Replacement of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	December 2025	Retirement of a single 275kV/110kV transformers with non-network support	$6m
South Pine primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2026	Full replacement of primary plant	$12m
South Pine SVC secondary systems replacement	Replacement of the South Pine 275kV SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2027	Staged replacement of 275kV SVC secondary systems	$6m
Ashgrove West 110kV secondary systems replacement	Staged replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2026	Full replacement of 110kV secondary systems	$6m
Sumner 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2026	Staged replacement of 110kV secondary systems	$4m
Algester 110kV secondary systems replacements	Full replacement of 110kV Algester secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 110kV secondary systems	$10m
West Darra 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2027	Staged replacement of 110kV secondary systems	$10m
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2029	Refurbishment of Rocklea transformer	$5m
Rocklea 110kV primary plant replacement	Full replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	June 2029	Selective replacement of 110kV primary plant	$13m
Loganlea 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2029	Selective replacement of 275kV primary plant	$9m

Table 5.24 Possible network reinvestments in the Moreton zone within six to 10 years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Goodna 110kV and 275kV secondary systems replacement	Full replacement of 110kV and 275kV secondary systems	Maintain supply reliability in the Moreton zone	June 2026	Staged replacement of 110kV and 275kV secondary systems	$16m
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Selective replacement of 110kV primary plant	$6m
Greenbank 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	June 2027	Staged replacement of 275kV secondary systems (including SVC)	$25m
Greenbank SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	December 2027		$6m

Note:

(1) Compared to the 2018 TAPR, the decrease 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) More detailed option analysis and consideration of the associated scope of works to address emerging condition risks on this transmission line has been undertaken since the publication of the 2018 TAPR. This new analysis has supported the development of new strategies and options providing an opportunity to deliver a more cost effective solution than previously identified, delivering better outcomes for customers.

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 December 2021. Powerlink considers that this will not impact on the ability to meet the obligations of Powerlink's reliability criteria. Further joint planning will be undertaken prior to a final decision being made.

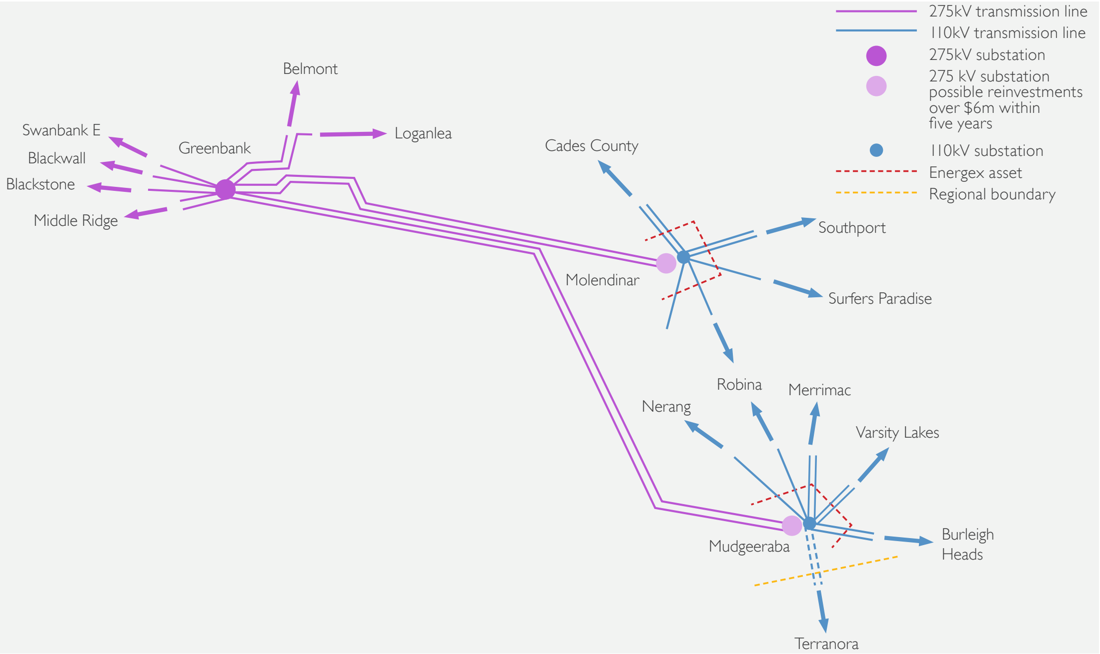
Belmont 275/110kV transformers

Based on the condition of the two transformers at Belmont Substation, Powerlink proposes to retire two of the four 275/110kV transformers by December 2020.

Since publication of the 2018 TAPR, it has been confirmed that retirement of these transformers will not result in load at risk in the Brisbane area. Powerlink considers the retirement of these two transformers will not have a material inter-network impact or a material impact to network users.

5.7.11 Gold Coast zone

Figure 5.14 Gold Coast transmission network



Existing network

The Powerlink transmission system in the Gold Coast was originally constructed in the 1970s and 1980s. The Molendinar and Mudgeeraba substations are the two major injection points into the area (refer to Figure 5.13) 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 5.14).

Possible load driven limitations

Based on the medium economic load forecast defined in Chapter 2, 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 reinvestments within five years

Network reinvestments in 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: Maintain reliability of supply to the southern Gold Coast area

The two 275kV single circuit transmission lines were constructed in the mid-1970s and support the supply to Gold Coast and northern NSW.

Project driver

Emerging condition driven risks related to an unacceptable level of corrosion.

Project timing: December 2026

Possible network solutions

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 2026.
- 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.
- Decrease in transfer capacity into the Gold Coast and rationalisation of the transmission lines supplying the Gold Coast through a combination of line refit projects and decommissioning of some assets.

Proposed network solution: Maintain the existing topography by way of a targeted line refit at an estimated cost of $36 million by December 2026

The increase in the estimated cost of the proposed network solution since 2018 TAPR is based upon more detailed option analysis and consideration of the associated scope of work to address the emerging condition risks. However, to ensure reliability of supply to customers, the required renewal works will be 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. Due to these challenges it has been identified that an extended delivery timeframe of at least four years would be required.

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

Possible non-network solutions

The Greenbank to Mudgeeraba 275kV transmission lines provide injection to the southern Gold Coast and northern NSW area of over 250MW at peak. 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.

Substations

Mudgeeraba 275/110kV Substation

Network requirement: Maintaining reliability of supply to the southern Gold Coast area

Mudgeeraba 110kV Substation was established in 1972 and extended from the 1980s to 2000s due to load growth and is located within the southern end of zone of the Gold Coast. Further extensions included the establishment of a 275kV switchyard and associated secondary systems in 1992, which was further expanded in 2002. Mudgeeraba 275/110kV Substation is one of two 275kV injection points on the Gold Coast and 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.

275/110kV Transformers

Project driver

Emerging condition risks arising from the condition of one of the existing 275/110kV transformers.

Project timing: June 2020

Possible network solutions

- Decommission the transformer and uprate No.1 transformer bay and install high speed protection schemes by June 2020.
- Refurbish the transformer by June 2020, and decommission by 2022 as above.
- Replace the transformer by June 2020.

Proposed network solution: Decommission the transformer at an estimated cost of $3 million by June 2020

One of the original transformers was replaced in 2017, and the remaining existing transformer requires renewal or decommissioning by 2020. Powerlink has analysed possible network solutions through joint planning with Energex, Transgrid and Essential Energy. Planning studies have confirmed the potential to subsequently retire the remaining transformer given the current flat demand forecast. Powerlink proposes to retire the transformer by 2020 and considers the proposed network solution will not have a material inter-network impact or a material impact to network users.

275kV secondary systems

Mudgeeraba 275/110kV Substation

Anticipated consultation: Addressing the secondary systems condition risks at Mudgeeraba

Project driver

- Emerging condition risks arising from the condition of the 275kV secondary systems.
- The 275kV secondary systems at Mudgeeraba were commissioned between 2001 and 2004.

Project timing: December 2021

Possible network solutions

- Staged replacement of the secondary systems components by December 2021.
- Full replacement of all secondary systems by December 2021.

Proposed network solution: Full replacement of secondary systems at an estimated cost of $9 million by December 2021

Compared to the 2018 TAPR, the decrease in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

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

Possible non-network solutions

Mudgeeraba Substation provides injection and switching to the southern Gold Coast and northern NSW area of over 250MW at peak. 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.

Molendinar 275/110kV Substation

Potential consultation: Maintaining reliability of supply at Molendinar substation

Project driver

- Emerging condition risks arising from the condition of the 275kV secondary systems.
- The 275kV secondary systems at Molendinar was originally established in 2003 and 2007, and is expected to reach the end of technical service life within the 10-year outlook.

Project timing: June 2024

Possible network solutions

- Staged replacement of all secondary systems components.
- Full replacement of all secondary systems.

Proposed network solution: Full replacement of all secondary systems at an estimated cost of $13 million by June 2024

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

Possible non-network solutions

Molendinar Substation provides injection and switching to the northern Gold Coast area of over 250MW at peak. 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 reinvestments in the Gold Coast zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Gold Coast zone. As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 5.25 will be subject to detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works and deliver greater benefits to customers. This will be achieved through improving and further refining options or considering other options, including the associated delivery strategies, from those described in Table 5.25. Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 5.25 Possible network reinvestments in the Gold Coast zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Mudgeeraba 275kV secondary systems replacement	Full replacement of 275kV secondary systems (1)	Maintain supply reliability in the Gold Coast zone	December 2021	Staged replacement of 275kV secondary systems equipment	$9m
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2024	Selected replacement of 275kV secondary systems (2)	$13m

Note:

(1) The scope of works, or the need to undertake this potential project, will rely upon the outcome of a RIT-T undertaken in the next one to two years.

(2) The envelope for non-network solutions is defined in Section 5.7.11.

Possible network reinvestments in the Gold Coast zone within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments 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 Gold Coast zone from around 2025/26 to 2029/30 (refer to Table 5.26).

Table 5.26 Possible network reinvestments in the Gold Coast zone within six to 10 years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 110kV transmission line between Mudgeeraba Substation and Terranora	Full line refit	Maintain supply reliability from Queensland to NSW Interconnector	December 2025	Targeted line refit New transmission line	$5m
Targeted line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	Targeted line refit works on steel lattice structures (1)	Maintain supply reliability in the Gold Coast zone	December 2026	New double circuit 275kV transmission line (2)	$36m
Substations					
Mudgeeraba 110kV secondary systems replacement	Partial replacement of 110kV secondary systems (3)	Maintain supply reliability in the Gold Coast zone	December 2025	Full replacement of 110kV secondary systems	$9m
Mudgeeraba 275kV and 110kV primary plant replacement	Full replacement of 110kV primary plant and selected 275kV equipment	Maintain supply reliability in the Gold Coast zone	December 2025	Staged replacement of 110kV primary plant in existing bays and selected 275kV equipment	$20m

Note:

(1) Compared to the 2018 TAPR, the increase in the estimated cost of the proposed network solution is based upon updated information in relation to required scope of works.

(2) The envelope for non-network solutions is defined in Section 5.7.11.

(3) The 2018 TAPR reported project cost of $2 million was a typographical error.

Possible asset retirements within the 10-year outlook period

Mudgeeraba 275/110kV Transformer

Recent investigations have highlighted emerging issues related to the condition of 275/110kV Transformer 3 at Mudgeeraba Substation which is reaching its end of technical service life in 2020.

Joint Planning studies have confirmed the potential to subsequently retire the transformer given the current flat demand forecast. Powerlink considers the proposed network solution will not have a material inter-network impact or a material impact to network users. Powerlink proposes to retire the third Mudgeeraba 275/110kV transformer at the end of technical service life anticipated around 2020. Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

5.7.12 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2018 Electricity Statement of Opportunities (ESOO)[16]. Interested parties who require information regarding future supply demand balance should consult this document.

5.7.13 Existing interconnectors

The Queensland transmission network is interconnected to the NSW transmission system through the QNI transmission line and Terranora Interconnector transmission line.

The QNI maximum southerly capability is limited by voltage stability, transient stability, oscillatory stability, and line thermal rating considerations (as detailed in Section 6.6.9).

The combined QNI plus Terranora Interconnector maximum northerly capability is limited by thermal ratings, voltage stability, transient stability and oscillatory stability (as detailed in Section 6.6.9).

The capability of these interconnectors can vary significantly depending on the status of plant, network conditions, weather and load levels in both Queensland and NSW. It is for these reasons that interconnector capability is regularly reviewed, particularly when new generation enters or leaves the market or transmission projects are commissioned in either region.

5.7.14 Expanding NSW-Queensland transmission transfer capacity

Preliminary assessment of the impact of dynamic changes in the external environment, including the upturn in VRE developments, has indicated that it could be technically and economically justified to expand the NSW to Queensland transmission capacity. TransGrid and Powerlink are undertaking joint planning relating to existing and forecast network congestion between Queensland and NSW. A RIT-T process to consider investment options on the QNI has now commenced. This process includes consideration of the ISP recommended Group 1 and Group 2 investments.

In November 2018, Powerlink and TransGrid released a PSCR on 'Expanding NSW-Queensland transmission transfer capacity', as the first step in the RIT-T process. This RIT-T is investigating options to increase overall net market benefits in the NEM through relieving congestion on the transmission network between NSW and Queensland. The PSCR outlines a range of credible options to meet the identified network need.

In addition, a variety of public submissions were received on network, non-network options or combinations of both following the PSCR. Powerlink and TransGrid are currently working through these submissions. Plausible options identified in submissions may supplement existing network or non-network options identified (including Group 1 and 2 projects). Due to the complexity of submissions, it is likely more modelling and analysis will be required.

Powerlink and TransGrid are currently performing power system analysis and market modelling to assess various network and non-network options. Findings will be published in the Project Assessment Draft Report (PADR) anticipated later in 2019.

The TAPR template for Expanding NSW-Queensland transmission transfer capacity is available on TransGrid's website.

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[16] Updated by AEMO in September 2017.

5 Future network development

CHAPTER 6

Network capability and performance

6 Network capability and performance

Key highlights

- During 2018/19, Powerlink has completed the connection of 11 large-scale solar and wind farm projects, adding 1,423MW of semi-scheduled variable renewable energy (VRE) generation capacity to the grid.
- Generation commitments since the 2018 Transmission Annual Planning Report (TAPR) add 64MW to Queensland's semi-scheduled VRE generation capacity taking the total existing and committed VRE generation capacity to 2,457MW.
- The Central Queensland to Southern Queensland (CQ-SQ) grid section was highly utilised during 2018/19, reflecting higher generation levels in North Queensland (NQ) as a result of recently commissioned VRE generators.
- Committed generation is expected to continue to alter power transfers, particularly during daylight hours, increasing the likelihood of congestion across the Gladstone, CQ-SQ and Queensland/New South Wales (NSW) Interconnector (QNI) grid sections.
- Record peak transmission delivered demands were recorded in the Far North, South West, Moreton and Gold Coast zones, during 2018/19.
- The transmission network has performed reliably during 2018/19, with Queensland grid sections largely unconstrained.

6.1 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 system normal 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)
- a summary of the management of high voltages associated with light load conditions.

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, reactive power requirements are greater and transmission plant has lower power carrying capability. Also, higher demands occur in summer as shown in Figure 2.8.

The location and pattern of generation dispatch influences power flows across most of 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 due to the effect 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 2.13) and/or when embedded generation output is lower.

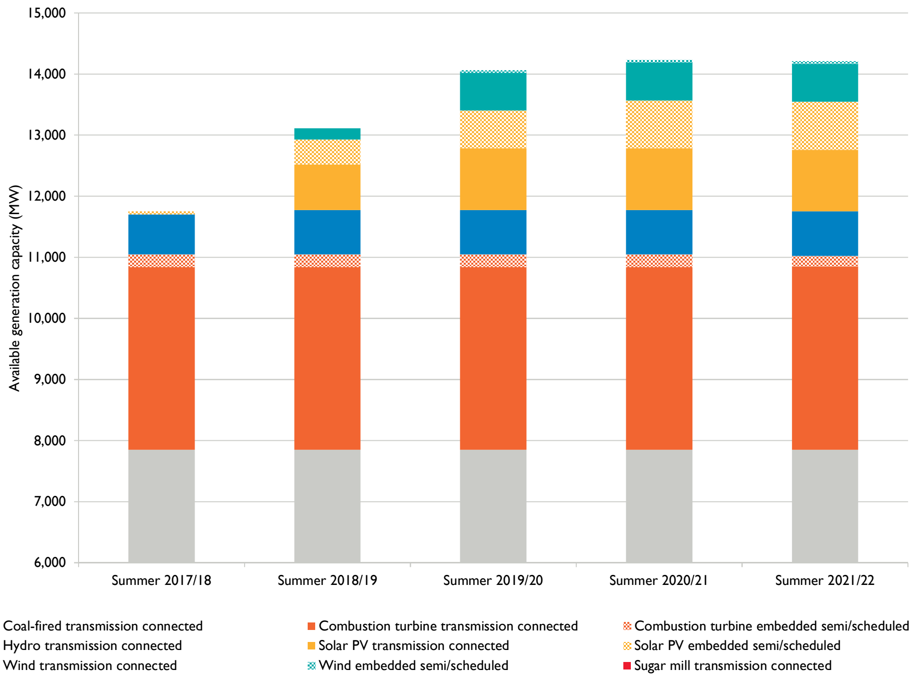
The years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period.

6.2 Available generation capacity

Scheduled generation in Queensland is predominantly a combination of coal-fired, gas turbine and hydro-electric generators. In addition during 2018/19, Powerlink has completed connection of 11 large-scale solar and wind farm projects, adding 1,423MW of semi-scheduled VRE generation capacity to the grid.

AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines[1] (effective 1 July 2018) has been adopted for the purposes of this year's TAPR. During 2018/19, commitments have added 64MW of capacity, taking Queensland's semi-scheduled VRE generation capacity to 2,457MW. Figure 6.1 illustrates the expected changes to available and committed generation capacity in Queensland from summer 2017/18 to summer 2021/22.

Figure 6.1 Summer available generation capacity by energy source



6.2.1 Existing and committed transmission connected and direct connect embedded generation

Table 6.1 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 connected to direct connect customers.

Semi-scheduled transmission connected solar farms Ross River, Haughton, Whitsunday, Hamilton, Daydream, Hayman, Rugby Run, Lilyvale and Darling Downs in addition to Coopers Gap and Mt Emerald wind farms have been connected since the 2018 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 NER, Powerlink's Register of Large Generator Connections with information on generators connected to Powerlink's network can be found on Powerlink's website.

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[1] AEMO, System Strength Impact Assessment Guidelines, June 2018.

Table 6.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network

Generator	Location	Available generation capacity (MW) (1)					
		Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21	Winter 2021	Summer 2021/22
Coal-fired							
Stanwell	Stanwell Switchyard	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 Switchyard	700	700	700	700	700	700
Callide Power Plant	Calvale Switchyard	840	840	840	840	840	840
Tarong North	Tarong Switchyard	443	443	443	443	443	443
Tarong	Tarong Switchyard	1,400	1,400	1,400	1,400	1,400	1,400
Kogan Creek	Kogan Creek PS Switchyard	750	713	750	713	750	713
Millmerran	Millmerran PS Switchyard	852	612	852	6120	852	612
Total coal-fired		**8,125**	**7,848**	**8,125**	**7,848**	**8,125**	**7,848**
Combustion turbine							
Townsville 132kV	Townsville GT PS	161	149	159	149	159	149
Mt Stuart	Townsville South	428	400	428	400	428	400
Yarwun (2)	Yarwun	160	155	160	155	160	155
Condamine (3)	Columboola	100	90	100	90	100	90
Braemar 1	Braemar	530	491	530	491	530	501
Braemar 2	Braemar	519	495	519	495	519	495
Darling Downs	Braemar	633	580	633	580	633	580
Oakey (4)	Tangkam	346	282	346	282	346	282
Swanbank E	Swanbank E PS Switchyard	365	350	365	350	365	350
Total combustion turbine		**3,242**	**2,992**	**3,240**	**2,992**	**3,240**	**3,002**
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
Total hydro-electric		**729**	**729**	**729**	**729**	**729**	**729**

Table 6.1 Available generation capacity - existing and committed generators connected to the Powerlink transmission network *(continued)*

Generator	Location	Available generation capacity (MW) (1)					
		Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21	Winter 2021	Summer 2021/22
Total solar PV (7)							
Ross River	Ross	116	116	116	116	116	116
Sun Metals (3)	Townsville Zinc	107	107	107	107	107	107
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
Lilyvale	Lilyvale	100	100	100	100	100	100
Darling Downs	Braemar	108	108	108	108	108	108
Total solar		**1,010**	**1,010**	**1,010**	**1,010**	**1,010**	**1,010**
Wind (7)							
Mt Emerald	Walkamin	180	180	180	180	180	180
Coopers Gap	Coopers Gap	440	440	440	440	440	440
Total wind		**620**	**620**	**620**	**620**	**620**	**620**
Sugar mill							
Invicta (5)	Invicta Mill	34	0	34	0	34	0
Total all stations		**13,760**	**13,199**	**13,758**	**13,199**	**13,758**	**13,209**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than power station 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 Power Station is an open-cycle, dual-fuel, gas-fired power station. The generated capacity quoted is based on gas fuel operation.

(5) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(6) Wivenhoe Power Station is shown at full capacity (570MW). However, output can be limited depending on water storage levels in the dam.

(7) VRE generators shown at maximum capacity at the point of connection. Sun Metals and Clare solar farms are fully operational. Other VRE generators may not be at full capacity at the time of publication of the 2019 TAPR.

6.2.2 Existing and committed scheduled and semi-scheduled distribution connected embedded generation

Table 6.2 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 solar farms Collinsville, Clermont, Emerald, Susan River, Childers and Oakey 1 have been connected since the 2018 TAPR.

Semi-scheduled embedded solar farm Warwick has reached committed status since the 2018 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 6.2 Available generation capacity – existing and committed scheduled or semi-scheduled generators connected to the Energex and Ergon Energy (part of the Energy Queensland Group) distribution networks.

Generator	Location	Available generation capacity (MW)					
		Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21	Winter 2021	Summer 2021/22
Combustion turbine (1)							
Townsville 66kV	Townsville GT PS	84	84	84	84	84	84
Mackay (2)	Mackay	34	34	34	34	34	
Barcaldine	Barcaldine	37	34	37	34	37	34
Roma	Roma	68	54	68	54	68	54
Total combustion turbine		**223**	**206**	**223**	**206**	**223**	**172**
Total solar PV (3)							
Cape York	Cape York switching station		48	48	48	48	48
Kidston	Kidston	50	50	50	50	50	50
Kennedy Energy Park	Hughenden	15	15	15	15	15	15
Collinsville	Collinsville North	42	42	42	42	42	42
Clermont	Clermont	75	75	75	75	75	75
Emerald	Emerald	72	72	72	72	72	72
Aramara	Aramara			104	104	104	104
Susan River	Maryborough	75	75	75	75	75	75
Childers	Isis	56	56	56	56	56	56
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			32	64	64	64
Total solar		**568**	**616**	**720**	**784**	**784**	**784**
Wind (3)							
Kennedy Energy Park	Hughenden	43	43	43	43	43	43
Total all stations		**834**	**865**	**986**	**1,033**	**1,050**	**999**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than power station 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) Stanwell Corporation has advised AEMO of its intention to retire Mackay GT at the end of financial year 2020/21.

(3) VRE generators shown at maximum capacity at the point of connection.

6.3 Network control facilities

Powerlink participated in the inaugural Power System Frequency Risk Review[2] (PSFRR) in 2018. The PSFRR, as part of the Emergency Frequency Control Schemes rule change[3], placed an obligation on AEMO to undertake, in collaboration with Transmission Network Service Providers (TNSPs), an integrated, periodic review of power system frequency risks associated with non-credible contingency events.

AEMO published the 2018 PSFRR Final Report in June 2018. For Queensland, the recommendation involved the expansion of Powerlink's CQ-SQ Special Protection Scheme (SPS). The existing scheme disconnects one or two highest generating Callide units, depending on CQ-SQ transfer, for the unplanned loss of both Calvale to Halys 275kV feeders. The existing scheme is limited to transfers lower than 1,700MW and relies on the ability to disconnect high output generating units.

The CQ-SQ SPS was commissioned in 2012. CQ-SQ transfers have subsequently increased and are expected to continue increasing with the integration of the committed VRE generation in north and central Queensland. The CQ-SQ SPS expansion involves extending the scheme to other sites in addition to Callide to access additional large units to disconnect if necessary.

Powerlink has initiated discussions with AEMO to modify the scope of the scheme. During expected periods of high VRE generation in north and central Queensland, the disconnection of large synchronous generators would be a destabilising action. Powerlink has commenced a project to investigate an alternative SPS that provides the intended CQ-SQ power transfer coverage and considers subsequent system strength issues following the potential non-credible loss of both Calvale to Halys 275kV feeders. Scope and timeframes will be discussed with AEMO to ensure the delivery of an appropriate scheme.

The 2018 PSFRR also identifies a potential need to establish a coordinated Over Frequency Generation Shedding (OFGS) scheme. AEMO and Powerlink have completed the joint study which considered the risk of major supply disruptions which could lead to an over frequency event. The study concluded that the measures recommended in AEMO's Final Report on the 25 August 2018 Islanding Event[4], which are proposed to be completed by mid-2020, would mitigate the current risk of over-frequency, if implemented. The need for an OFGS will also need to be reviewed as part of the QNI upgrade.

Powerlink owns other network control facilities which 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 6.3.

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[2] AEMO, 2018 Power System Frequency Risk Review, June 2018.

[3] AEMC, Rule Determination National Electricity Amendment (Emergency frequency control schemes) Rule 2017, 30 March 2017.

[4] AEMO, Final Report – Queensland and South Australia system separation on 25 August 2018, January 2019.

Table 6.3 Powerlink owned network control facilities configured to disconnect load as a consequence of non-credible events during system normal conditions

Scheme	Purpose
Far North Queensland Under Voltage Load Shed (UVLS) scheme	Minimise risk of voltage collapse in Far North Queensland
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
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

6.4 Existing network configuration

Figures 6.2, 6.3, 6.4 and 6.5 illustrate Powerlink's network as of June 2019.

Figure 6.2 Existing HV network June 2019 - North Queensland

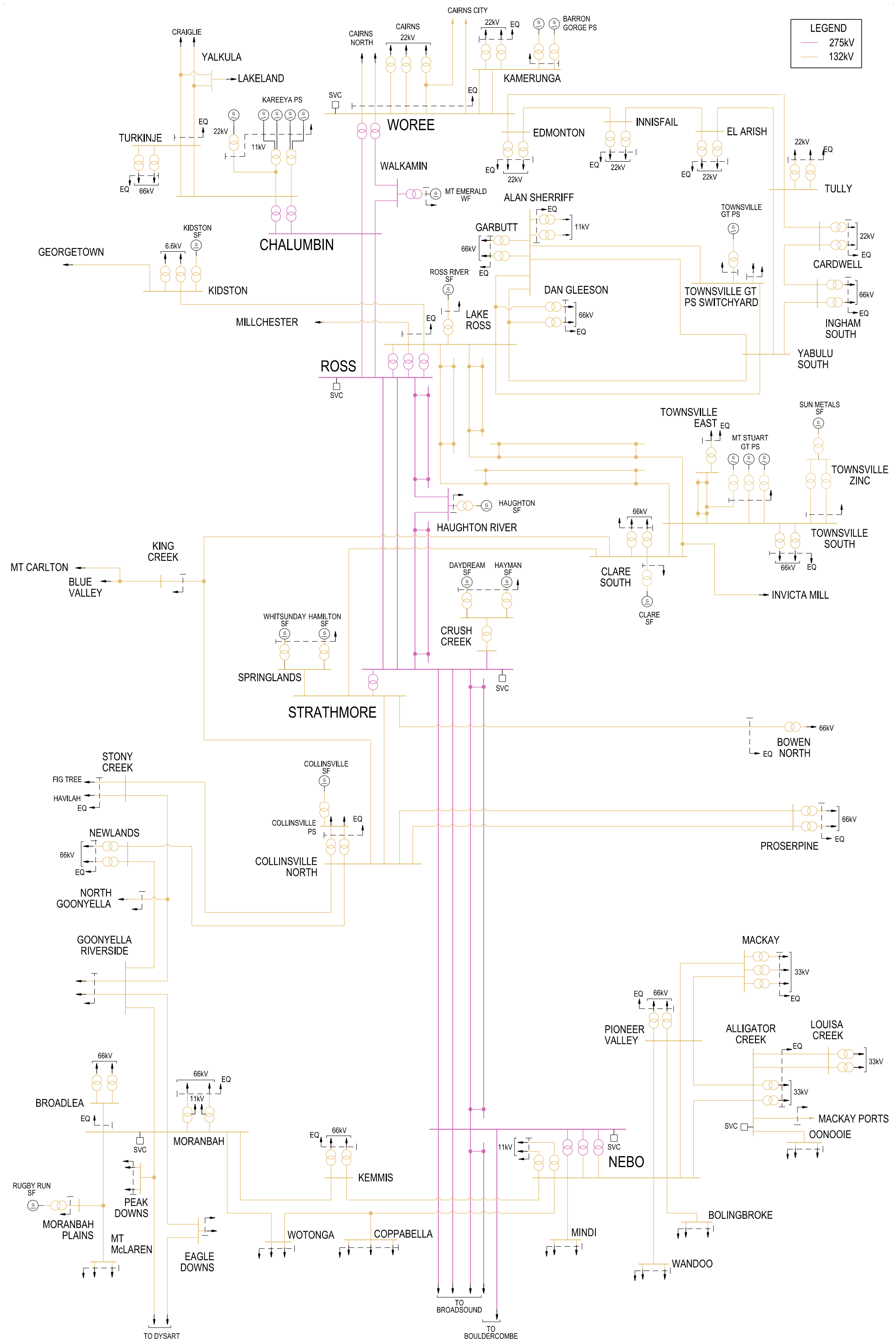


Figure 6.3 Existing HV network June 2019 - Central Queensland

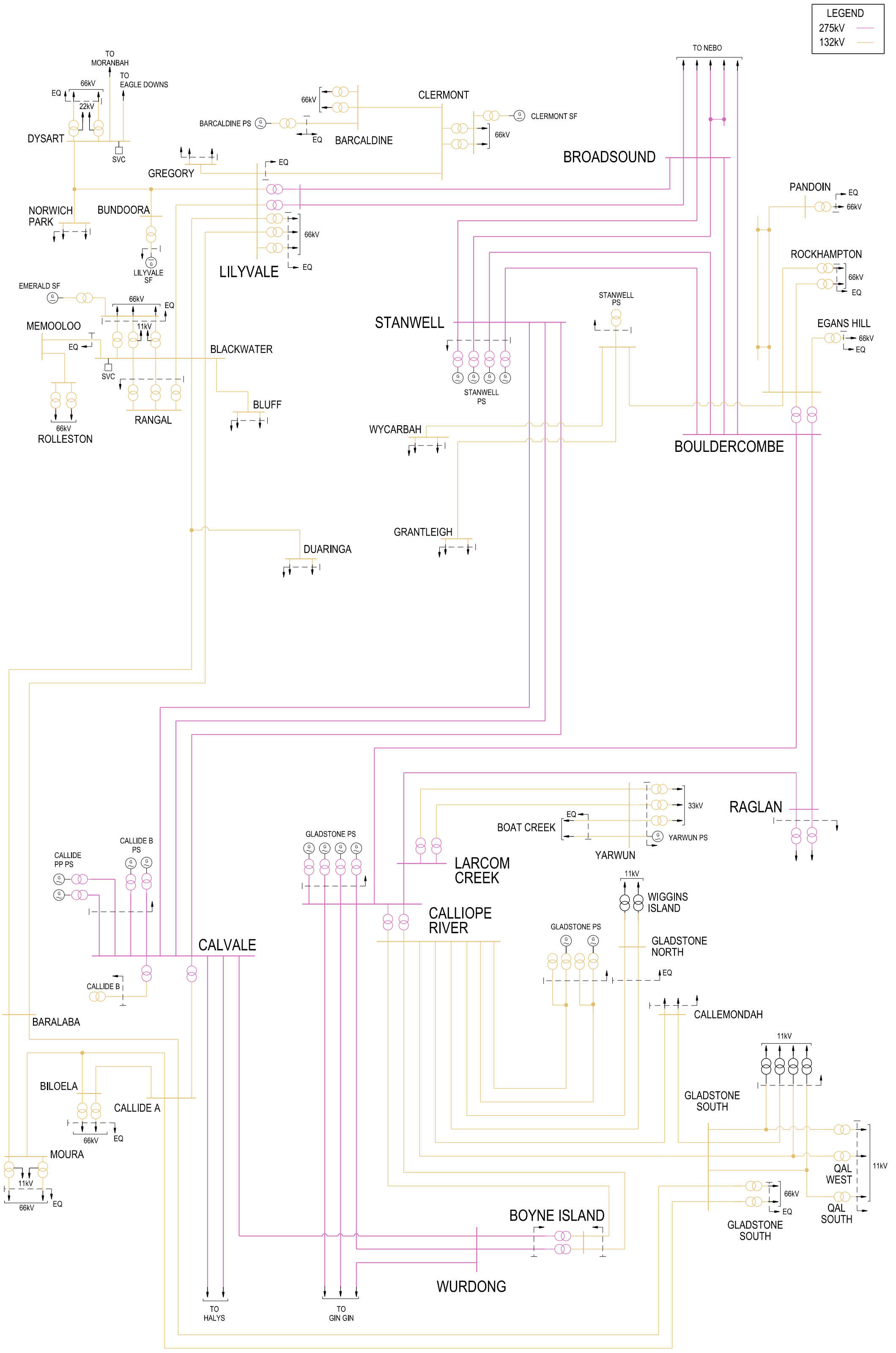


Figure 6.4 Existing HV network June 2019 - South West Queensland

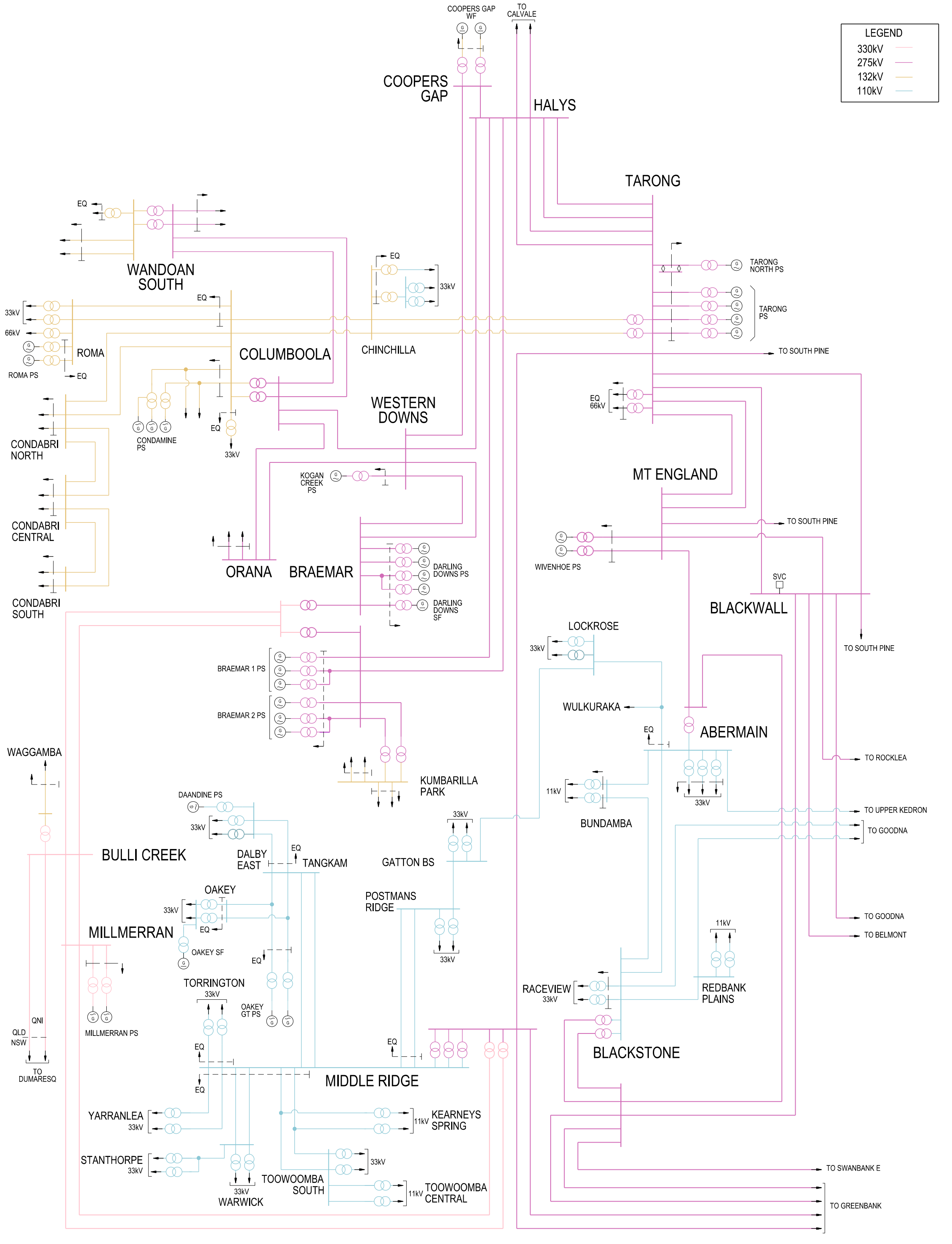
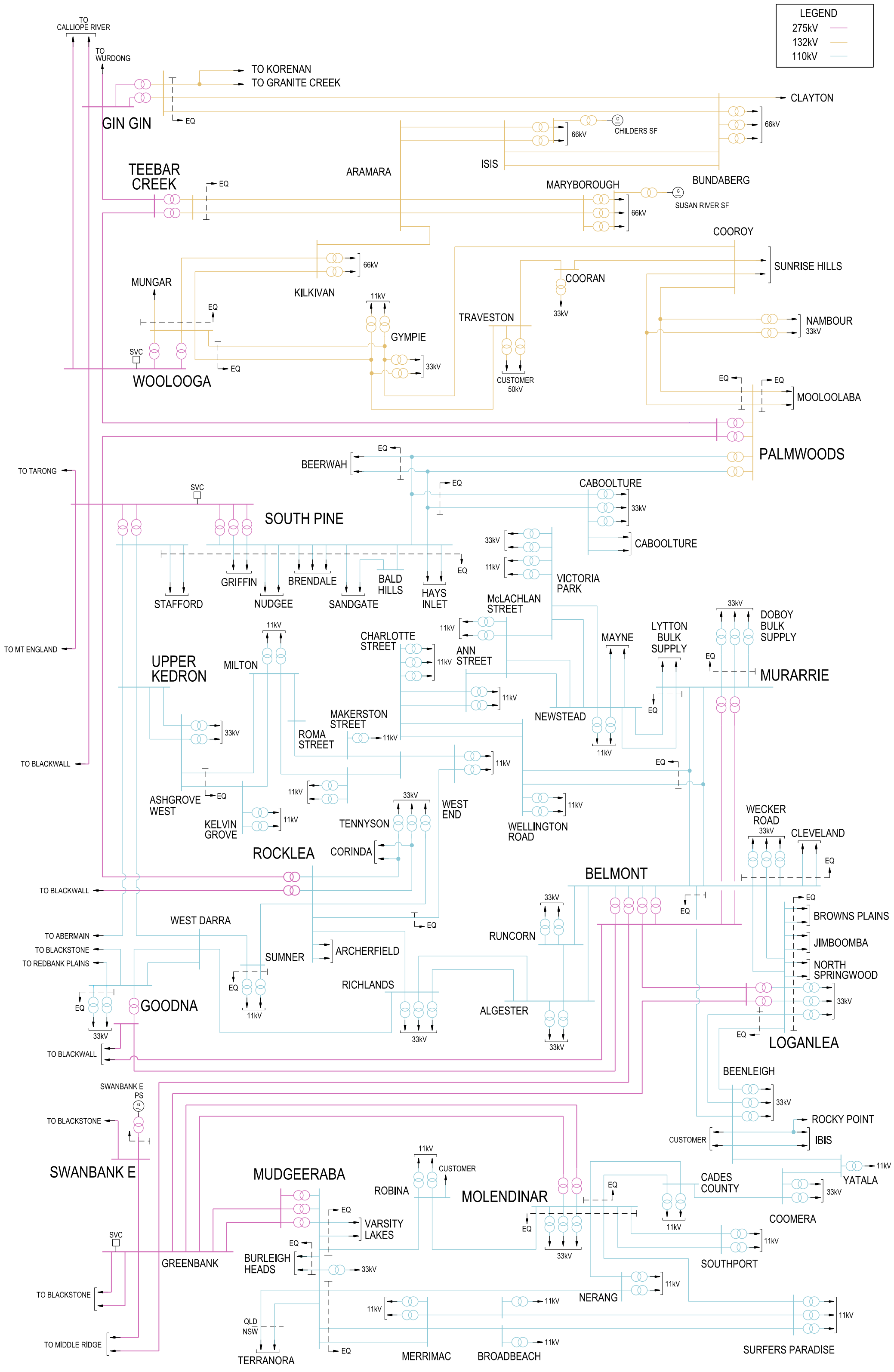


Figure 6.5 Existing HV network June 2019 - South East Queensland



6.5 Transfer capability

6.5.1 Location of grid sections

Powerlink has identified a number of grid sections that allow network capability and forecast limitations to be assessed in a structured manner. Limit equations have been derived for these grid sections to quantify maximum secure power transfer. Maximum power transfer capability may be set by transient stability, voltage stability, thermal plant ratings or protection relay load limits. AEMO has incorporated these limit equations into constraint equations within the National Electricity Market Dispatch Engine (NEMDE), Table C.2 provides definitions and Figure C.2 in Appendix C shows the location of relevant grid sections on the Queensland network.

6.5.2 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 which are current at the time of publication of this TAPR are provided in Appendix D. Limit equations will change over time with demand, generation and network development and/or network reconfiguration. Such detailed and extensive analysis on limit equations has not been carried out for future network and generation developments for this TAPR. However, expected limit improvements for committed works are incorporated in all future planning. Section 6.6 provides a qualitative description of the main system conditions that affect the capability of each grid section.

6.6 Grid section performance

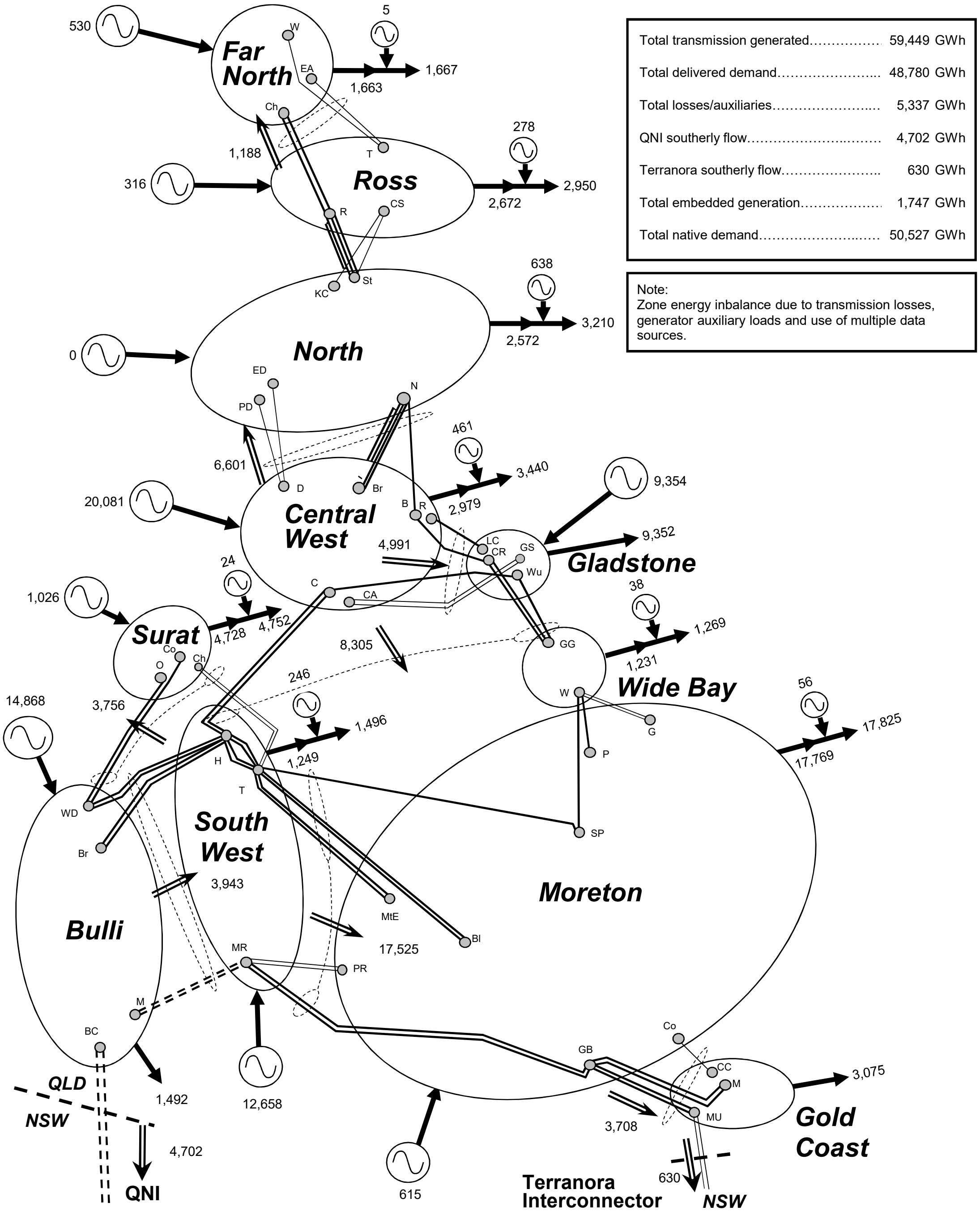
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

For each grid section, the time that the relevant constraint equations have bound over the last 10 years is provided. 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.

Historical transfer duration curves for the last five years are included for each grid section. Grid section transfers are predominantly affected by load, generation and transfers to neighbouring zones. Figures 6.6 and 6.7 provide 2017 and 2018 zonal energy as generated into the transmission network (refer to Figure C.1 in Appendix C for generators included in each zone) and by major embedded generators, transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers and grid section energy transfers. Figure 6.8 provides the changes in energy transfers from 2017 to 2018. These figures assist in the explanation of differences between 2017 and 2018 grid section transfer duration curves.

Figure 6.6 2017[5] zonal electrical energy transfers (GWh)



Total transmission generated................	59,449 GWh
Total delivered demand........................	48,780 GWh
Total losses/auxiliaries........................	5,337 GWh
QNI southerly flow..................................	4,702 GWh
Terranora southerly flow.......................	630 GWh
Total embedded generation..................	1,747 GWh
Total native demand............................	50,527 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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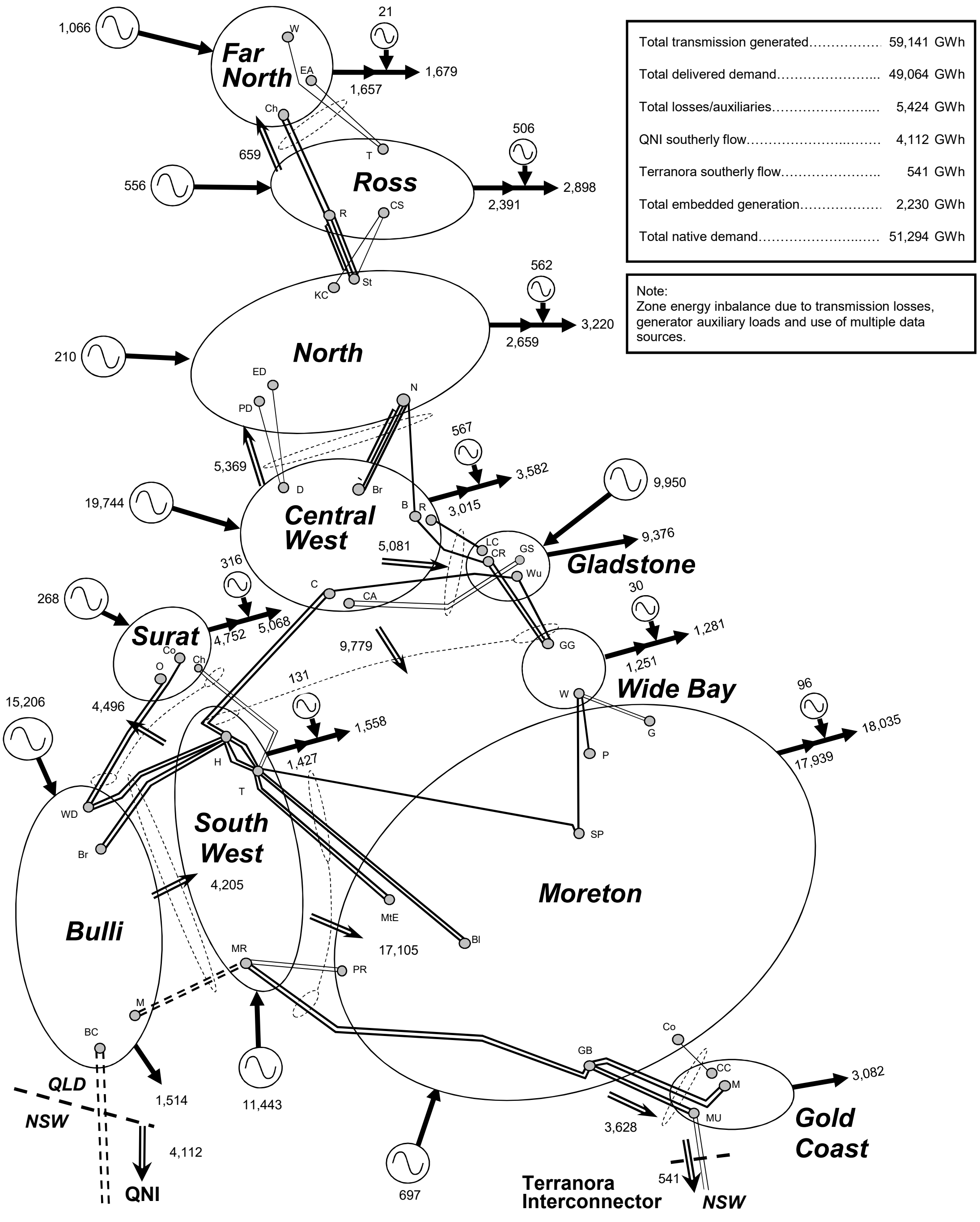
[5] Consistent with this chapter, time periods are from April 2017 to March 2018.

Figure 6.7 2018[6] zonal electrical energy transfers (GWh)



Total transmission generated	59,141 GWh
Total delivered demand	49,064 GWh
Total losses/auxiliaries	5,424 GWh
QNI southerly flow	4,112 GWh
Terranora southerly flow	541 GWh
Total embedded generation	2,230 GWh
Total native demand	51,294 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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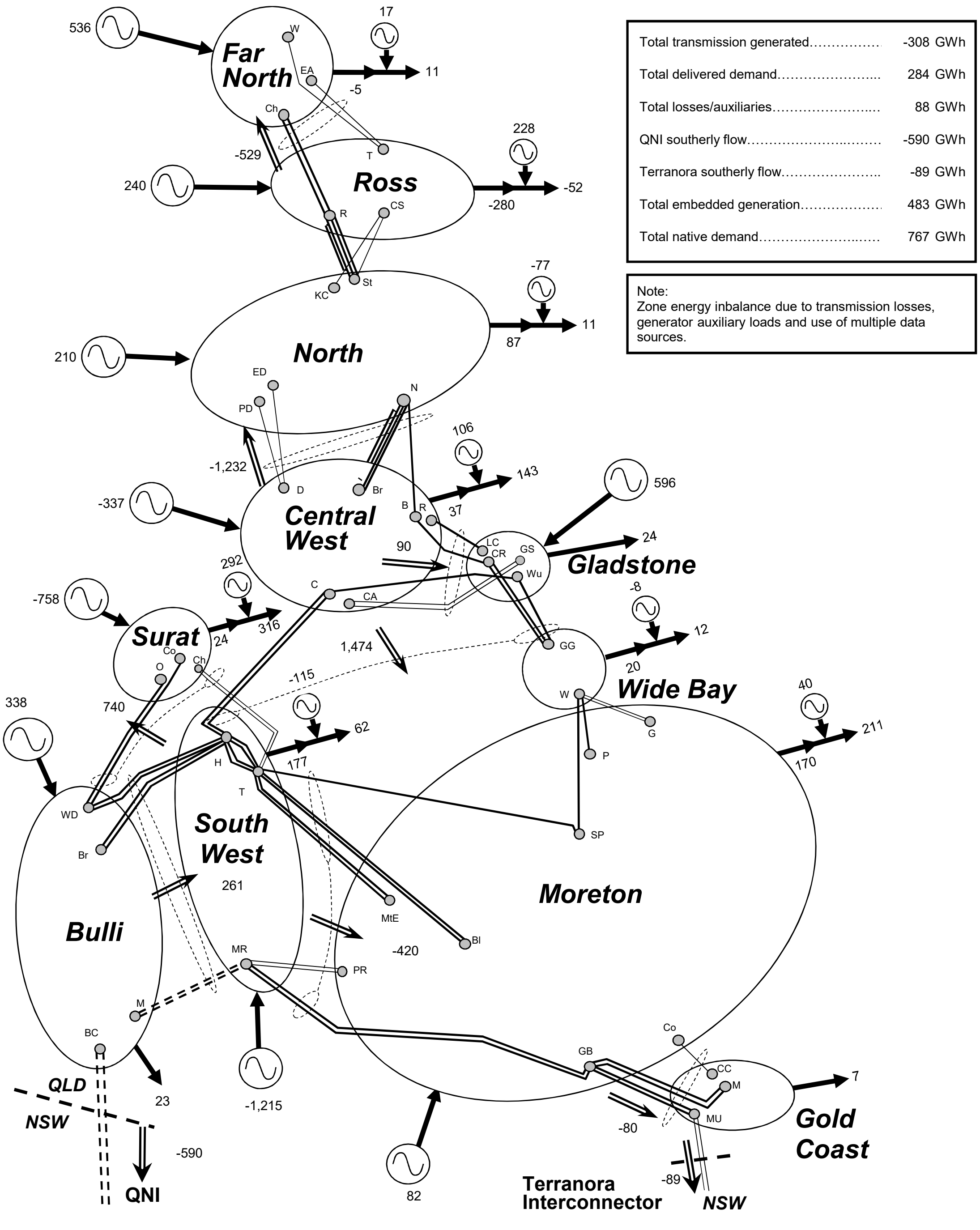
[6] Consistent with this chapter, time periods are from April 2018 to March 2019.

Figure 6.8 Change[7] in zonal electrical energy transfers (GWh)



Total transmission generated................	-308 GWh
Total delivered demand........................	284 GWh
Total losses/auxiliaries.........................	88 GWh
QNI southerly flow..................................	-590 GWh
Terranora southerly flow.......................	-89 GWh
Total embedded generation...................	483 GWh
Total native demand.............................	767 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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[7] Consistent with this chapter, time periods for the comparison are from April 2018 to March 2019 and April 2017 to March 2018.

6.6.1 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 a Ross to Chalumbin 275kV circuit.

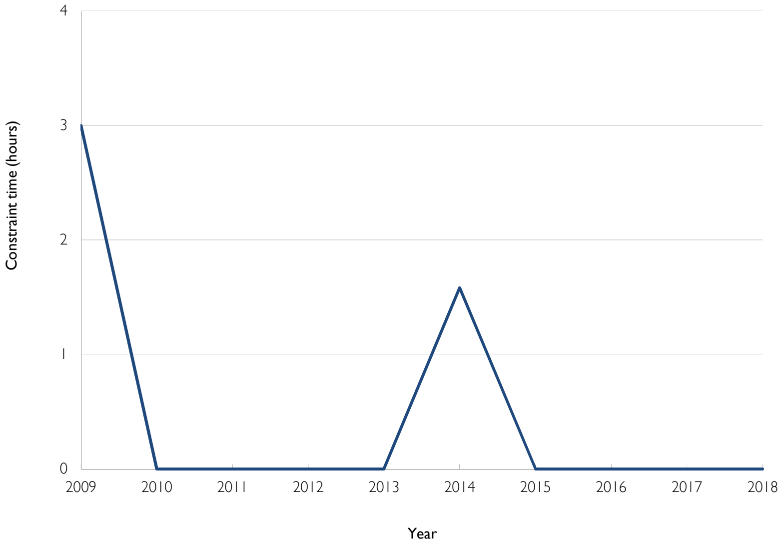
The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone to northern Queensland area[8] demand ratio
- Far North and Ross zones generation.

Local hydro 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 did not constrain operation during April 2018 to March 2019. Information pertaining to the historical duration of constrained operation for the FNQ grid section is summarised in Figure 6.9.

Figure 6.9 Historical FNQ grid section constraint times



Constraint durations have reduced over time due to the commissioning of various transmission projects[9]. There have been minimal constraints in this grid section since 2008.

Figure 6.10 provides historical transfer duration curves showing a large decrease in energy transfer but similar peak transfers over 2018. This is predominantly attributed to the recently commissioned Mount Emerald wind farm located between Chalumbin and Woree substations. Given production only started in August 2018, annual energy transfers are expected to decrease further over the coming year. 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. These vary depending on rainfall levels in the Far North zone. The hydro generating power stations have also increased capacity factors between 2017 and 2018 adding to the reduction in energy transfers (refer to figures 6.6, 6.7 and 6.8).

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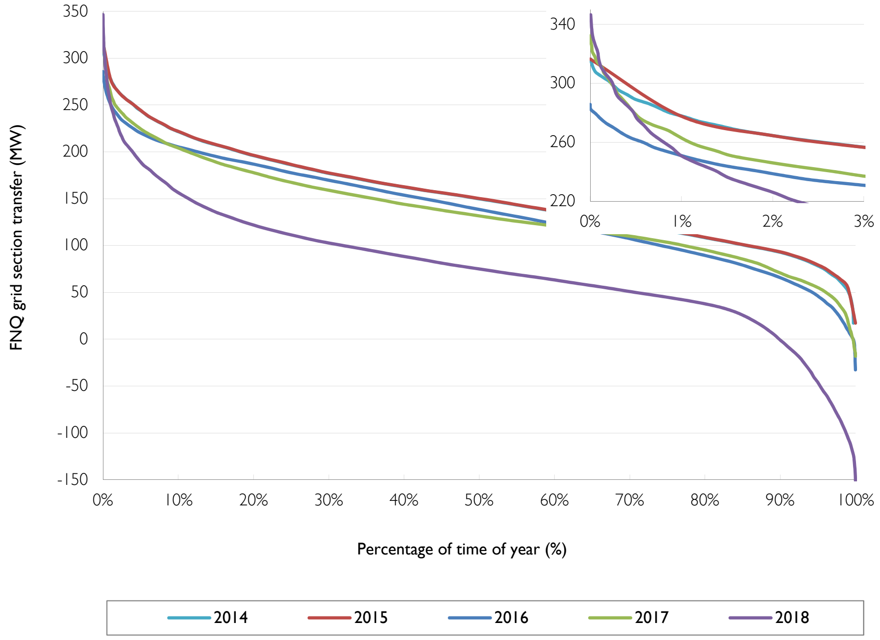
[8] Northern Queensland area is defined as the combined demand of the Far North, Ross and North zones.
[9] For example, the second Woree 275/132kV transformer commissioned in 2007/08.

Figure 6.10 Historical FNQ grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

6.6.2 Central Queensland to North Queensland grid section

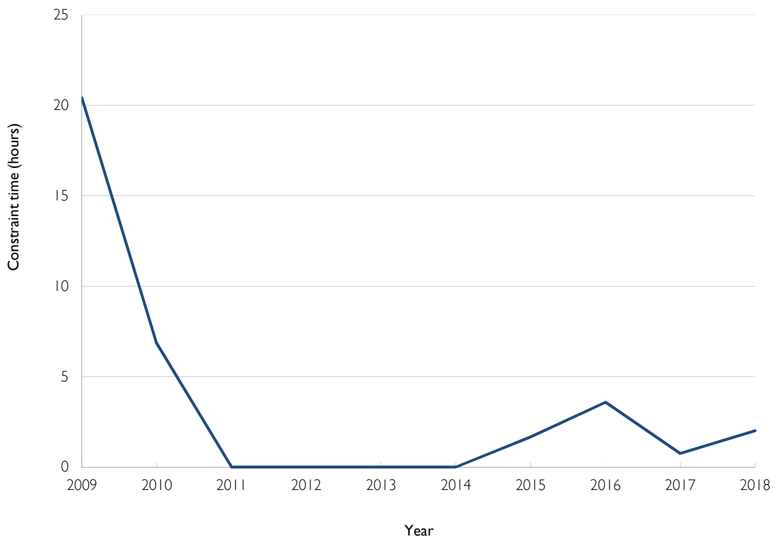
Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations associated with the contingency of the Townsville gas turbine or a Stanwell to Broadsound 275kV circuit.

The limit equations in Table D.2 of Appendix D 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.

Information pertaining to the historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 6.11. During 2018, the CQ-NQ grid section experienced 2.0 hours of constrained operation. These constraints were associated with planned and unplanned outages.

Figure 6.11 Historical CQ-NQ grid section constraint times



Historically, the majority of the constraint times were associated with thermal constraint equations ensuring operation within plant thermal ratings during planned outages. The staged commissioning of double circuit lines from Broadsound to Ross completed in 2010/11 provided increased capacity to this grid section. There have been minimal constraints in this grid section since 2008.

Figure 6.12 provides historical transfer duration curves showing a large decrease in energy transfer but similar peak transfers over the 2018 year. This is predominantly attributed to the recently commissioned solar farms Ross River, Sun Metals, Clare, Collinsville, Whitsunday, Hamilton, Daydream, Hayman and the Mt Emerald wind farm. Given production only commenced through the year, and ramp ups with commissioning activities, annual energy transfers from Central Queensland are expected to decrease further over the coming year. Notably, peak transfers continue to be maintained at similar levels, as high net loading conditions continue to coincide (refer to figures 6.6, 6.7 and 6.8).

Figure 6.12 Historical CQ-NQ grid section transfer duration curves

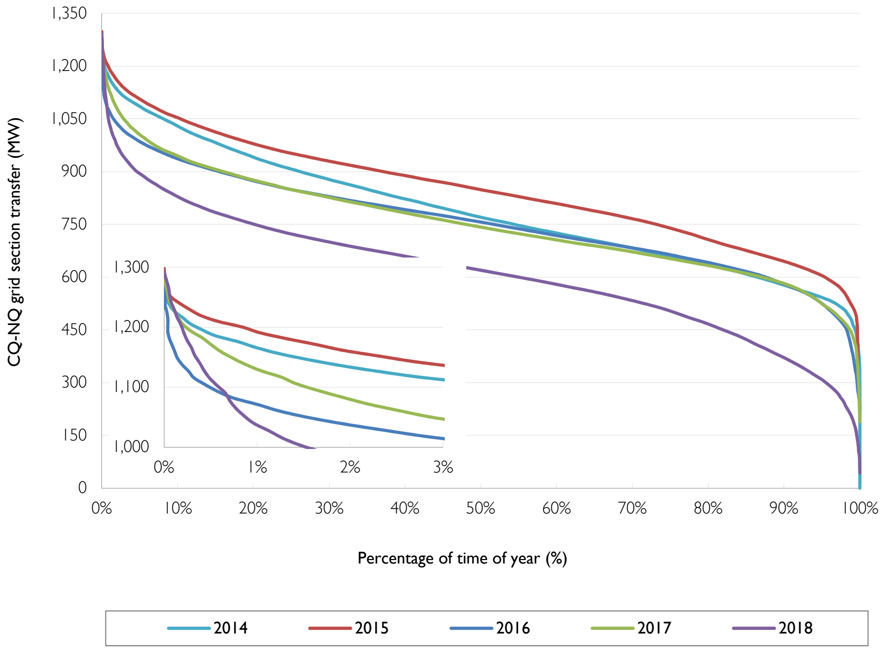
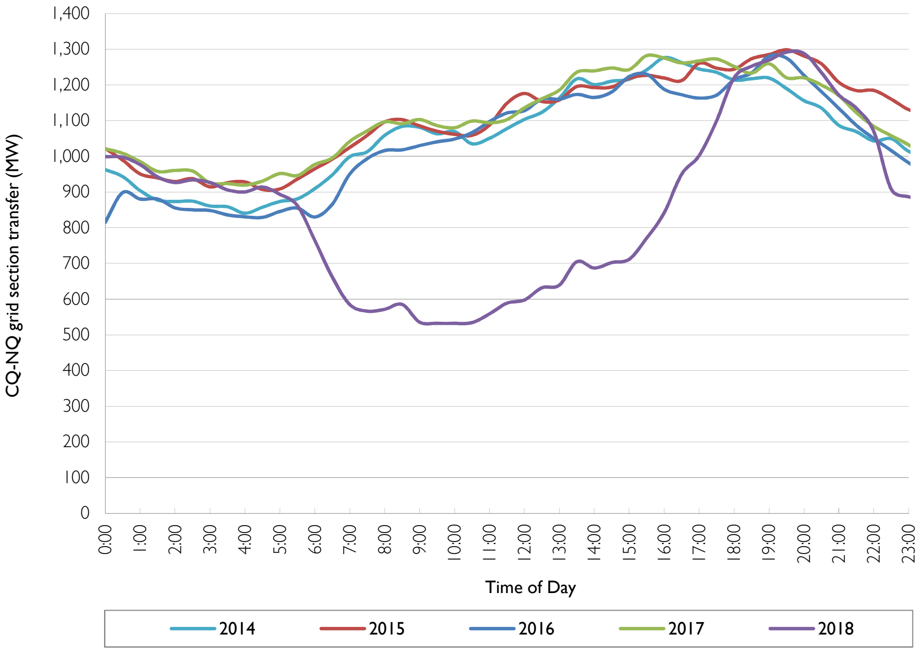


Figure 6.13 provides a different view of the altered power flows experienced over the last year.

Figure 6.13 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 additional commissioning of VRE generators in North Queensland. Correspondingly, voltage control is forecast to become increasingly challenging for longer durations. Section 5.7.4 recommends the installation of a bus reactor to mitigate the risk of over voltages.

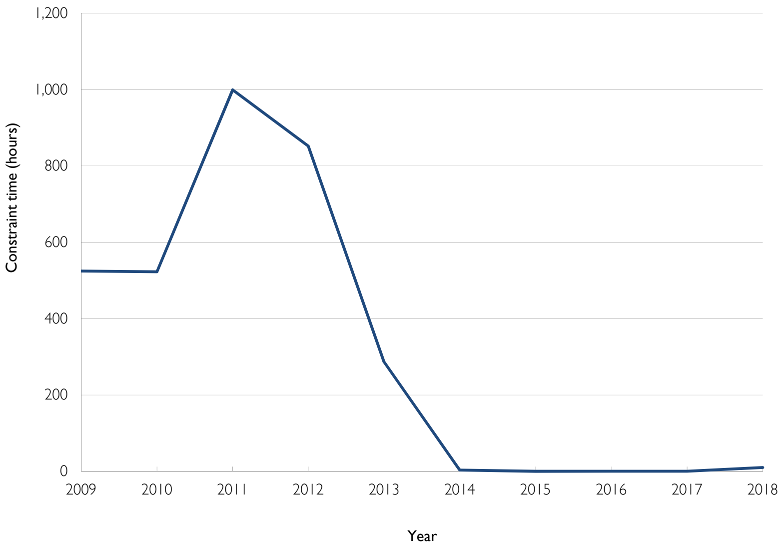
6.6.3 Gladstone grid section

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, or the Calvale 275/132kV transformer.

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 NEMDE.

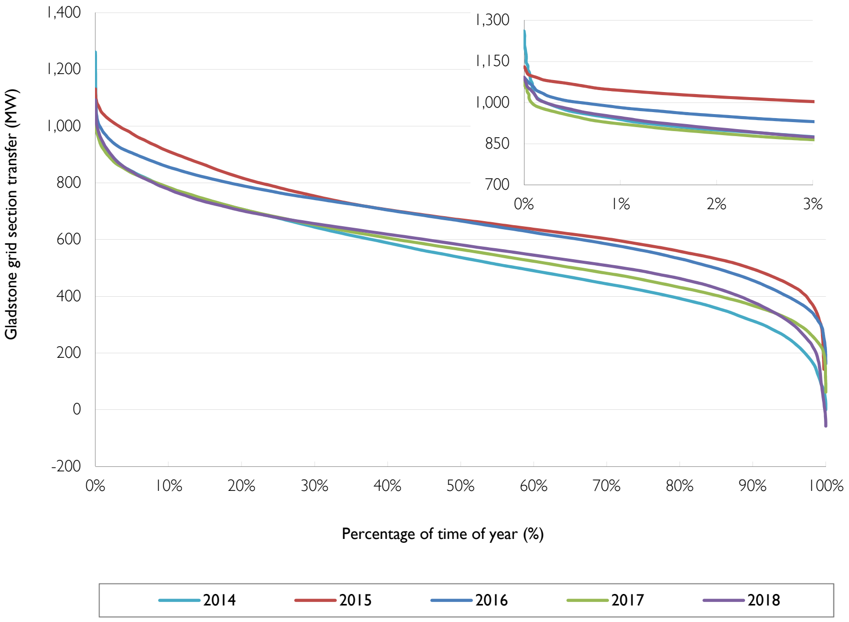
Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 6.14. During 2018, the Gladstone grid section experienced 10.1 hours of constrained operation.

Figure 6.14 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the dispatch of generation in Central Queensland and transfers to northern and southern Queensland. Figure 6.15 provides historical transfer duration curves showing largely similar utilisation in 2018 compared to 2017. Increased capacity factor from Gladstone Power Station has maintained the transfer through this grid section although more energy is being transferred from north Queensland (refer to figures 6.6, 6.7 and 6.8).

Figure 6.15 Historical Gladstone grid section transfer duration curves



The utilisation of the Gladstone grid section is expected to increase if the recently committed generators in the north displace Gladstone zone or southern generators as this incremental power makes its way to the load in the Gladstone and/or southern Queensland zones. In 2018, Powerlink commissioned a project which has increased the design temperature of Bouldercombe to Raglan and Larcom Creek to Calliope River 275kV transmission lines. This project was approved by the AER under the Network Capability Incentive Parameter Action Plan (NCIPAP) to assist in relieving congestion.

6.6.4 Central Queensland to South 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 D.3 of Appendix D 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 Power Station generation.

Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 6.16. During 2018, the CQ-SQ grid section experienced 57.2 hours of constrained operation. Constrained operation was mainly associated with planned maintenance outages, with only 29.4 hours or about half of the time, constrained in a system normal state.

Figure 6.16 Historical CQ-SQ grid section constraint times

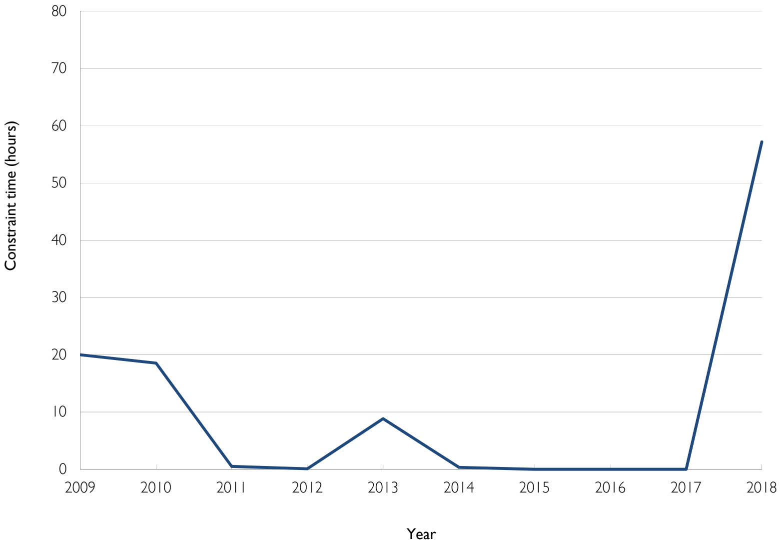
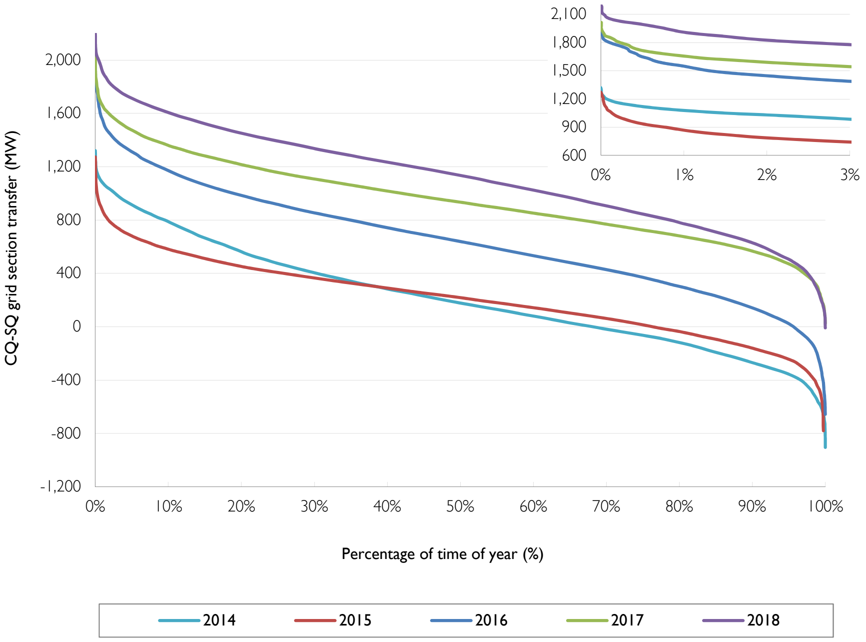


Figure 6.17 provides historical transfer duration curves showing continued increase in utilisation since 2015. This increase in transfer has been predominantly due to a significant reduction in generation from the gas fuelled generators in the Bulli zone and higher interconnector transfers sourced predominantly by generation in central and north Queensland (refer to figures 6.6, 6.7 and 6.8). The utilisation of the CQ-SQ grid section is expected to further increase over time if the newly committed generators in the north displace southern generators.

Figure 6.17 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. This is discussed in Section 5.7.6.

6.6.5 Surat grid section

The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Western Downs to Columboola 275kV transmission line[10], Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed in September 2014 and significantly increased the supply capacity to the Surat Basin north west area.

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. 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 brief history of the Surat grid section.

Figure 6.18 provides the transfer duration curve since the zone's creation. Grid section transfers depict the ramping of coal seam gas (CSG) load. The zone has transformed from a net exporter to a significant net importer of energy.

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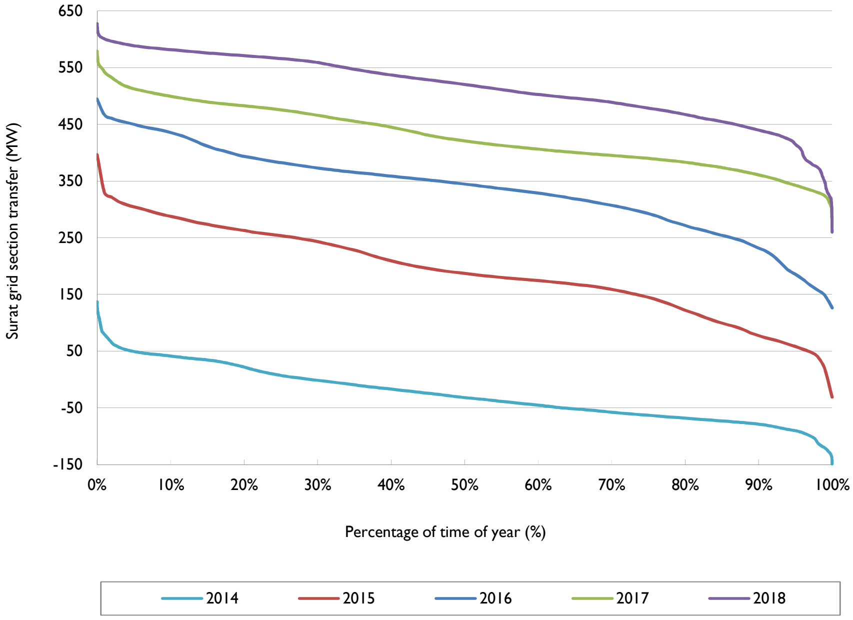
[10] The Orana Substation is connected to one of the Western Downs to Columboola 275kV transmission lines.

Figure 6.18 Historical Surat grid section transfer duration curve



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

The development of large loads in Surat (additional to those included in the forecasts), without corresponding increases in generation, can significantly increase the levels of Surat grid section transfers. This is discussed in Section 7.2.6.

6.6.6 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 grid section is not expected to impose limitations to power transfer under intact system conditions with existing levels of generating capacity.

The SWQ grid section did not constrain operation during April 2018 to March 2019. Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 6.19.

Figure 6.19 Historical SWQ grid section constraint times

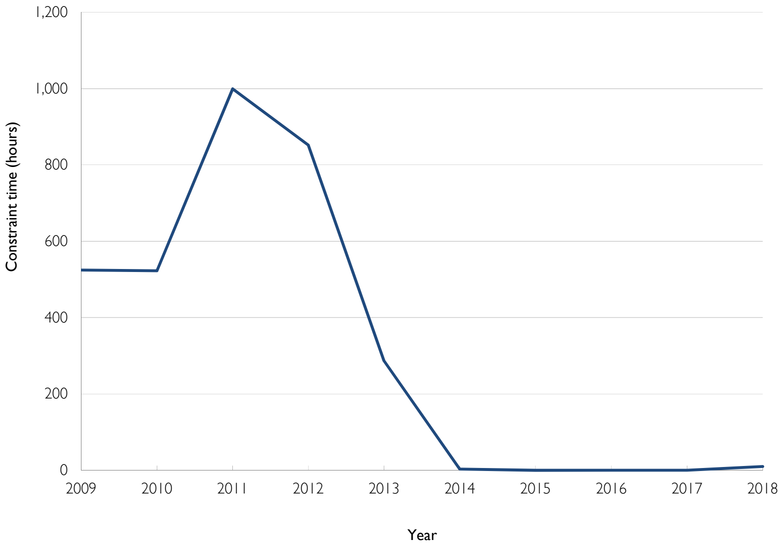
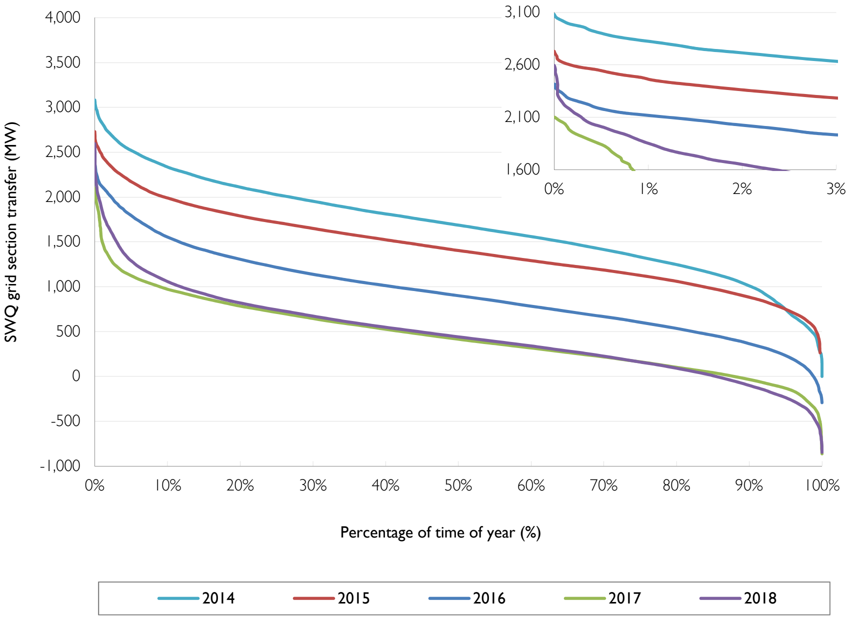


Figure 6.20 provides historical transfer duration curves showing reductions in energy transfer since 2014. Increases in QNI southerly flows, reductions in gas fuelled generation in the Bulli zone, increases in SW zone generation and CQ-SQ transfers (refer to figures 6.6, 6.7 and 6.8) are predominantly responsible for the reduction in SWQ utilisation.

Figure 6.20 Historical SWQ grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

6.6.7 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.

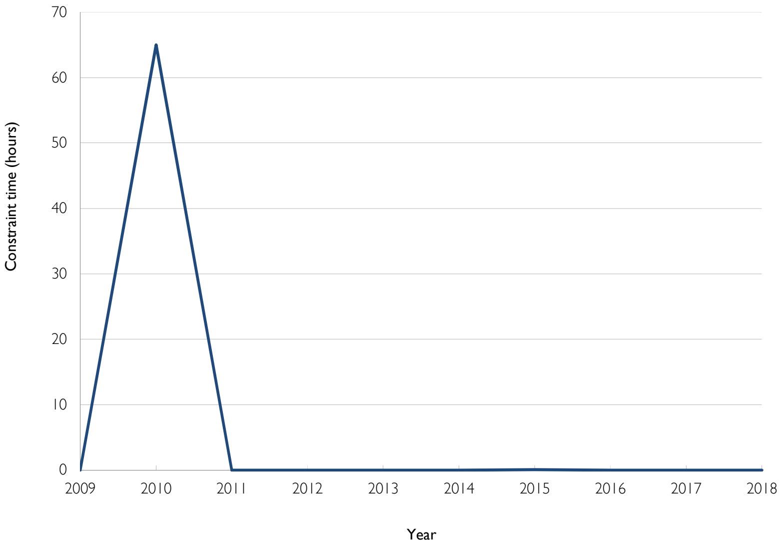
Limit equations in Table D.4 of Appendix D show that the following variables have a significant effect on transfer capability:

- 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 did not constrain during April 2018 to March 2019. Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 6.21.

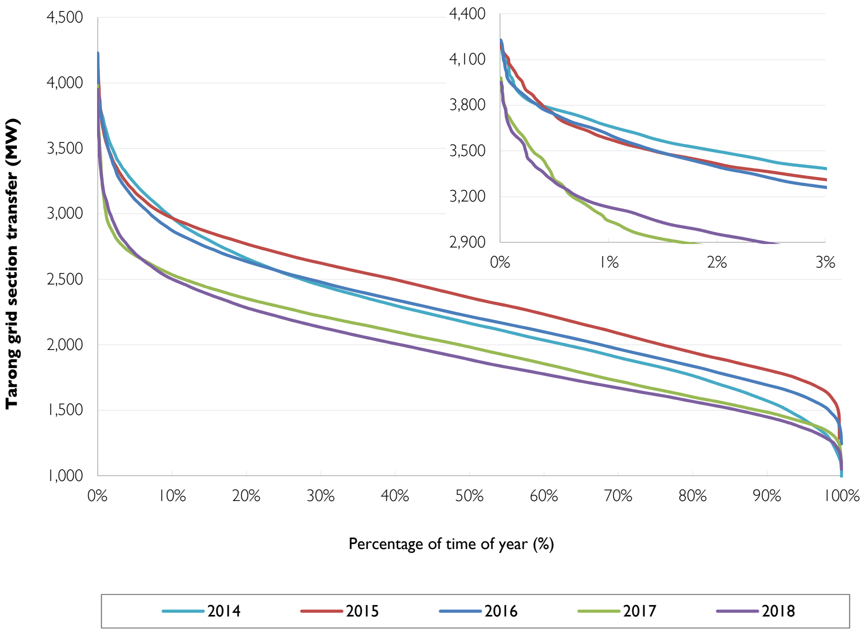
Figure 6.21 Historical Tarong grid section constraint times



Constraint times have been minimal over the last 10 years, with the exception of 2010/11, where constraint times are associated with line outages as a result of severe weather events in January 2011.

Figure 6.22 provides historical transfer duration curves showing small annual differences in grid section transfer demands. The increase in transfer between 2014 and 2015 is predominantly attributed to Swanbank E being removed from service in December 2014. Swanbank E was brought back into service in December 2017. The 2018 trace reflects lower energy transfers into SEQ as a result of Wivenhoe and Swanbank E generation and greater transfers from CQ and NQ generators (refer to figures 6.6, 6.7 and 6.8).

Figure 6.22 Historical Tarong grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

6.6.8 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.

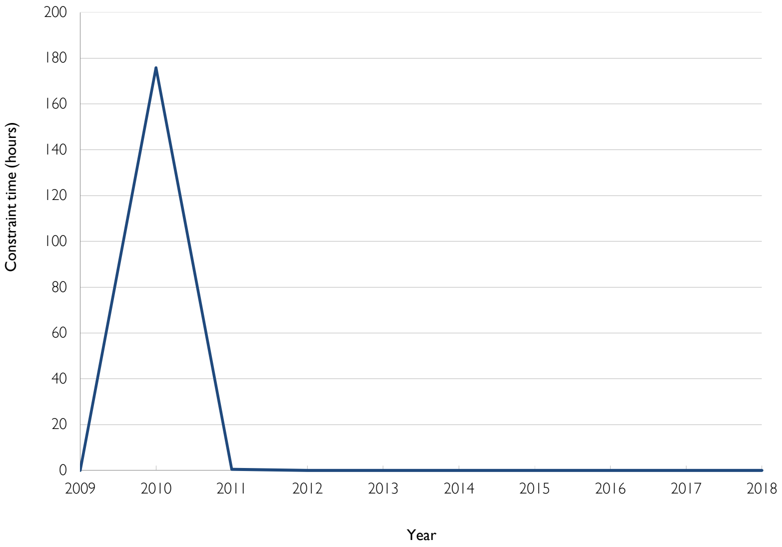
The limit equation in Table D.5 of Appendix D shows that the following variables have a significant effect on transfer capability:

- number of generating units online in Moreton zone
- level of Terranora Interconnector transmission line transfer
- Moreton and Gold Coast zones capacitive compensation levels
- Moreton zone to the Gold Coast zone demand ratio.

Reducing southerly flow on Terranora Interconnector reduces transfer capability, but increases the overall amount of supportable Gold Coast demand. This is because reactive margins increase with reductions in southerly Terranora Interconnector flow, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the reduction in Terranora Interconnector southerly transfer. Limiting power transfers are thereby lower with reduced Terranora Interconnector southerly transfer but a greater load can be delivered.

The Gold Coast grid section did not constrain operation during April 2018 to March 2019. Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 6.23.

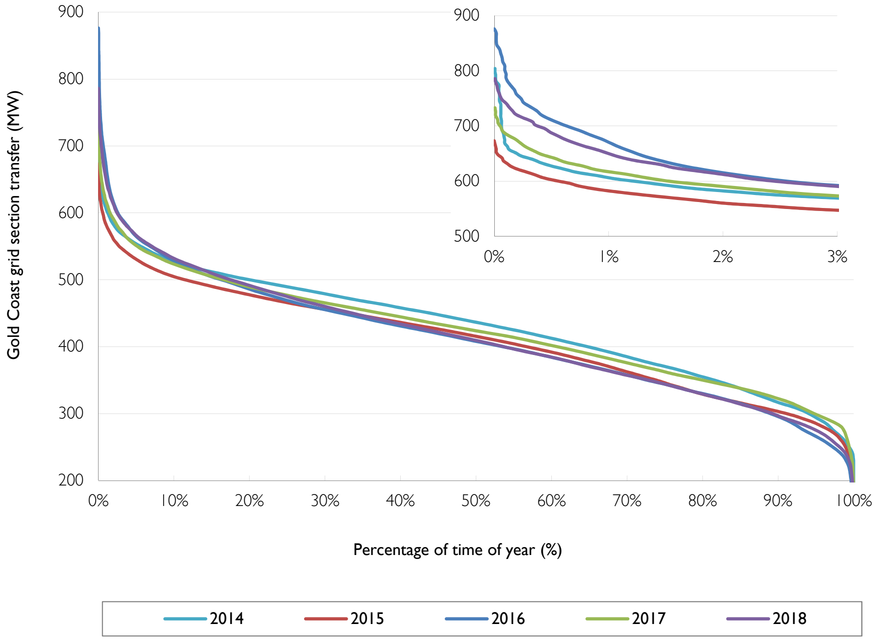
Figure 6.23 Historical Gold Coast grid section constraint times



Constraint times have been minimal since 2007, with the exception of 2010 where constraint times are associated with the planned outage of one of the 275kV Greenbank to Mudgeeraba feeders.

Figure 6.24 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. Gold Coast zone demand was higher in 2018 compared to 2017 (refer to Section 6.7.11).

Figure 6.24 Historical Gold Coast grid section transfer duration curves



Due to condition drivers, Powerlink is proposing to retire one of the aging 275/110kV transformers at Mudgeeraba Substation by 2020. This is discussed further in Section 5.7.11.

6.6.9 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 an annual NEM Constraint Report which includes a chapter 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 Annual NEM Constraint Reports. The NEM 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
- transient stability associated with transmission faults near the Queensland border
- transient stability associated with the trip of a smelter potline load in Queensland
- transient stability associated with transmission faults in the Hunter Valley in NSW
- transient stability associated with a fault on the Hazelwood to South Morang 500kV transmission line in Victoria
- thermal capacity of the 330kV transmission network between Armidale and Liddell in NSW
- oscillatory stability upper limit of 1,200MW.

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 stability 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
- oscillatory stability upper limit of 700MW.

On November 2018, Powerlink and TransGrid released a Project Specification Consultation Report (PSCR) on 'Expanding NSW-Queensland transmission capacity', as the first step in the Regulatory Investment Test for Transmission (RIT-T) process. This RIT-T is investigating options to increase overall net market benefits in the NEM through relieving congestion on the transmission network between NSW and Queensland. Powerlink and TransGrid are currently working through public submissions on the PSCR and the power system and market modelling to assess various network and non-network options. Findings will be published in the Project Assessment Draft Report (PADR) anticipated later in 2019. This is discussed further in Section 5.7.14.

6.7 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver 2018 loads
- historical zonal transmission delivered loads
- intra-zonal system normal constraints
- double circuit transmission lines categorised as vulnerable by AEMO
- 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 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.

Zonal transmission delivered energy, in general, has remained steady in 2018, compared to 2017 (refer to Figure 6.8), despite significant increases in embedded VRE generation and Queensland's installed rooftop photovoltaic (PV) reaching 2,440MW in February 2019.

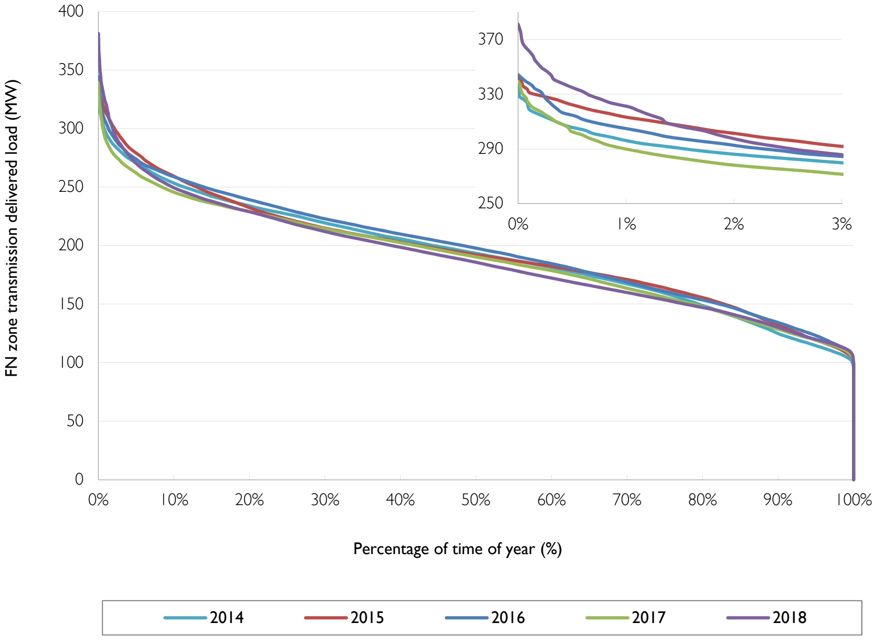
6.7.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2018.

The Far North zone includes the scheduled embedded generator Lakeland Solar and Storage as defined in Figure 2.4. This embedded generator provided approximately 21GWh during 2018.

Figure 6.25 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has reduced by 0.3% between 2017 and 2018. The maximum transmission delivered demand in the zone was 381MW, which is the highest maximum demand over the last five years.

Figure 6.25 Historical Far North zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO has included Chalumbin to Turkinje 132kV in the vulnerable list. This double circuit tripped due to lightning in January 2016.

High voltages associated with light load conditions are managed with existing reactive sources. The need for voltage control devices increased with the reinforcements of the Strathmore to Ross 275kV double circuit transmission line and the replacement of the coastal 132kV transmission lines between Yabulu South and Woree substations. Powerlink relocated a 275kV reactor from Braemar to Chalumbin Substation in April 2013. Generation developments in the Braemar area resulted in underutilisation of the reactor, making it possible to redeploy. Additional reactive sources are not required in the Far North zone within the five-year outlook period for the control of high voltages.

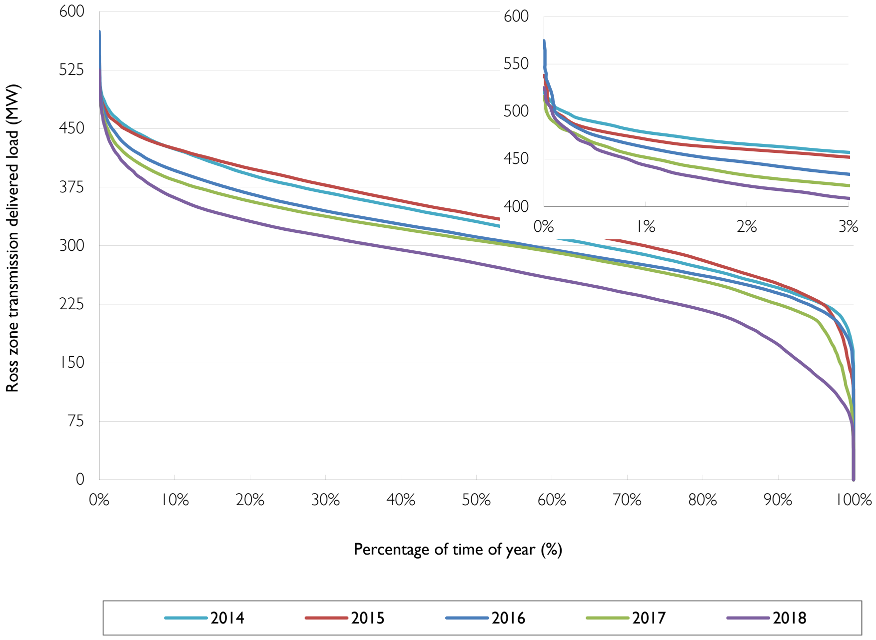
6.7.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2018.

The Ross zone includes the scheduled embedded Townsville Power Station 66kV component, semi-scheduled distribution connected embedded Kidston Solar Farm and direct connected embedded Sun Metal Solar Farm, and the significant non-scheduled embedded generator at Pioneer Mill as defined in Figure 2.4. These embedded generators provided approximately 506GWh during 2018.

Figure 6.26 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 10.5% between 2017 and 2018. The reduction in energy delivered is predominantly due to the increase in embedded generation. The peak transmission delivered demand in the zone was 525MW which is below the highest maximum demand over the last five years of 574MW set in 2016.

Figure 6.26 Historical Ross zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO has included the Ross to Chalumbin 275kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in January 2015.

High voltages associated with light load conditions are managed with existing reactive sources. Two tertiary connected reactors at Ross Substation were replaced by a bus reactor in August 2015.

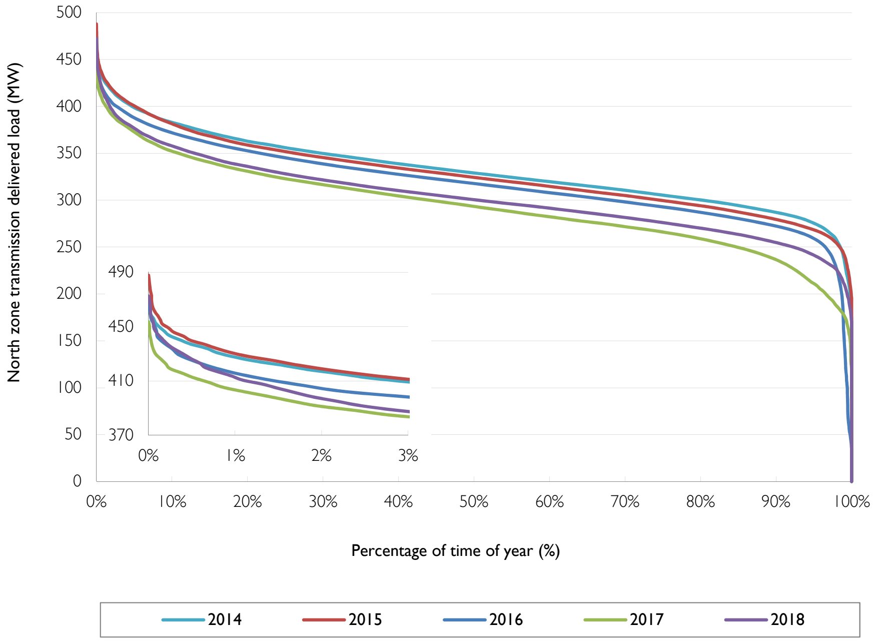
6.7.3 North zone

The North zone experienced no load loss for a single network element outage during 2018.

The North zone includes the scheduled embedded Mackay generator, semi-scheduled embedded generator Collinsville Solar Farm and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 2.4. These embedded generators provided approximately 562GWh during 2018.

Figure 6.27 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has increased by 3.4% between 2017 and 2018. The peak transmission delivered demand in the zone was 473MW, which is below the highest maximum demand over the last five years of 488MW set in 2015.

Figure 6.27 Historical North zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the North zone in the vulnerable list:

- Strathmore to Clare South and Collinsville North to King Creek to Clare South 132kV double circuit transmission line, last tripped January 2019
- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 2018
- Collinsville North to Stony Creek and Collinsville North to Newlands 132kV double circuit transmission line, last tripped February 2016
- Goonyella to North Goonyella and Goonyella to Newlands 132kV double circuit transmission line, last tripped February 2018
- Moranbah to Goonyella Riverside 132kV double circuit transmission line, last tripped December 2014.

High voltages associated with light load 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 sections 6.6.2 and 5.7.4.

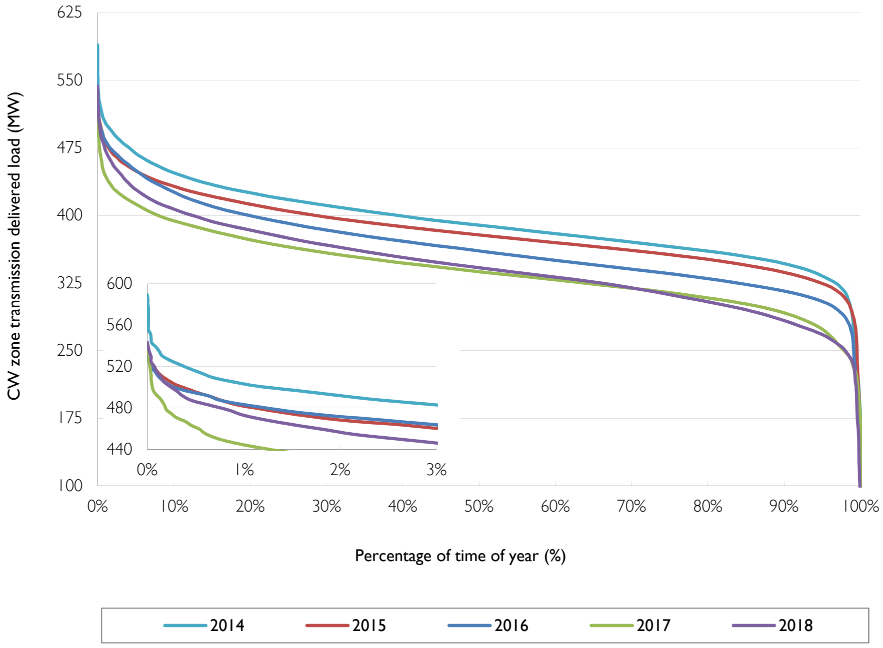
6.7.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2018.

The Central West zone includes the scheduled embedded Barcaldine generator, semi-scheduled embedded generators Clermont Solar Farm and Emerald Solar Farm and significant non-scheduled embedded generators Barcaldine Solar Farm, Longreach Solar Farm, German Creek and Oaky Creek as defined in Figure 2.4. These embedded generators provided approximately 567GWh during 2018.

Figure 6.28 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has increased by 1.2% between 2017 and 2018. The peak transmission delivered demand in the zone was 543MW, which is below the highest maximum demand over the last five years of 589MW set in 2014.

Figure 6.28 Historical Central West zone transmission delivered load duration curves



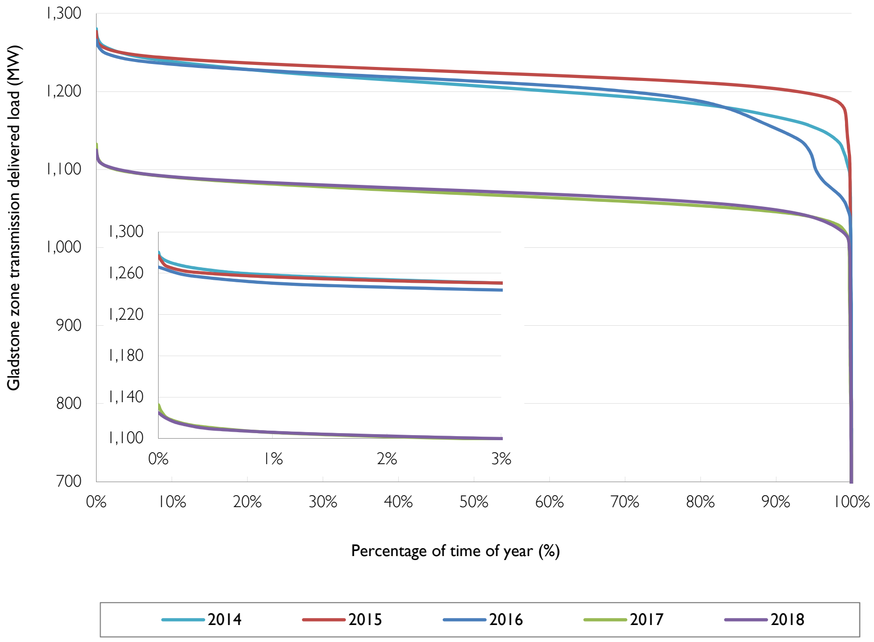
6.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2018.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.29 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has increased by 0.3% between 2017 and 2018. The peak transmission delivered demand in the zone was 1,125MW, which is below the highest maximum demand over the last five years of 1,280MW set in 2014.

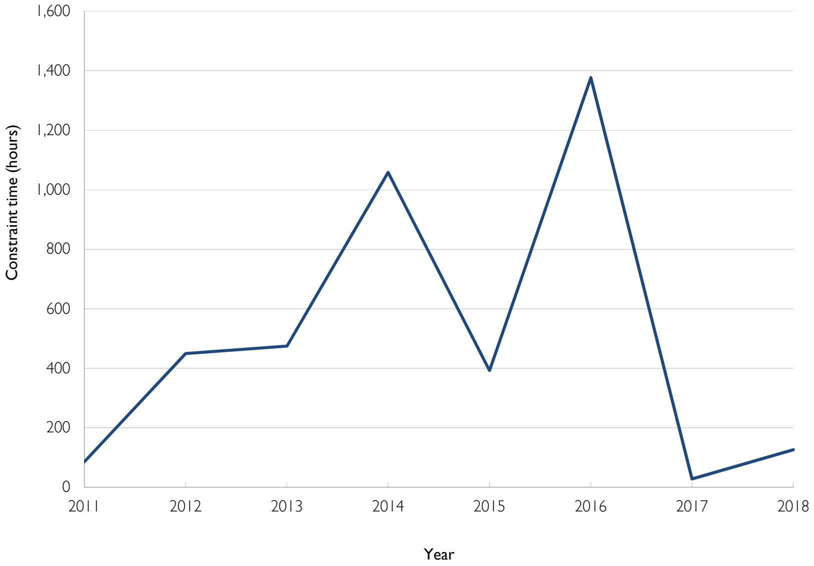
Figure 6.29 Historical Gladstone zone transmission delivered load duration curves



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 Boyne Smelter Limited's (BSL) substation. The constraint limits generation from Gladstone Power Station, mainly from the units connected at 132kV. AEMO identifies this 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 6.30. The trend prior to 2017 was reflective of the operation of the two 132kV connected Gladstone Power Station units. Although, Gladstone 132kV units ran at highest capacity factors in this decade during 2018, due to the BSL's reduced production the constraint only bound 126.3 hours.

Figure 6.30 Historical Q>NIL_BI_FB constraint times



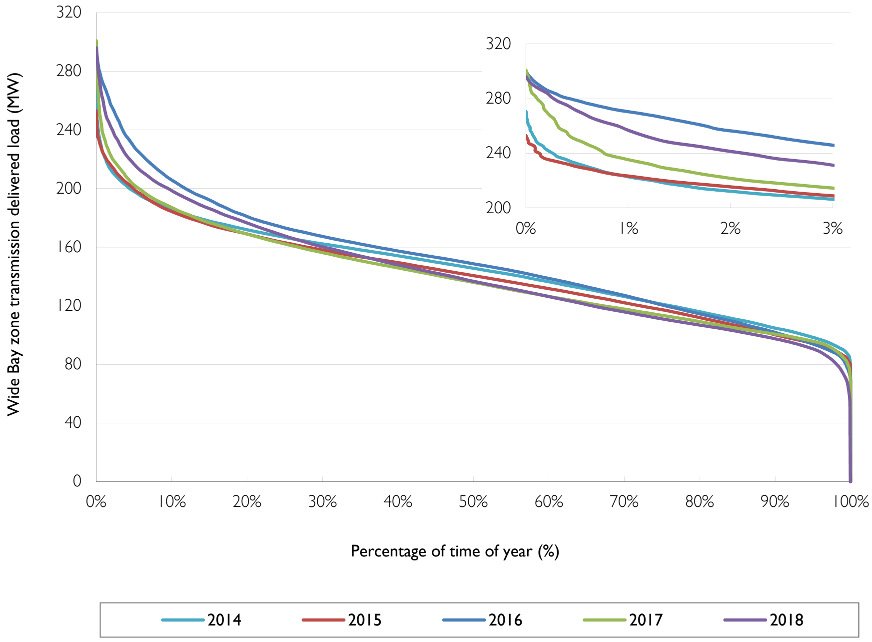
6.7.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2018.

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 2.4. These embedded generators provided approximately 30GWh during 2018.

Figure 6.31 provides historical transmission delivered load duration curves for the Wide Bay zone. Energy delivered from the transmission network increased by 1.6% between 2017 and 2018. The peak transmission delivered demand in the zone was 296MW, which is below the highest maximum demand over the last five years of 301MW set in 2017.

Figure 6.31 Historical Wide Bay zone transmission delivered load duration curves



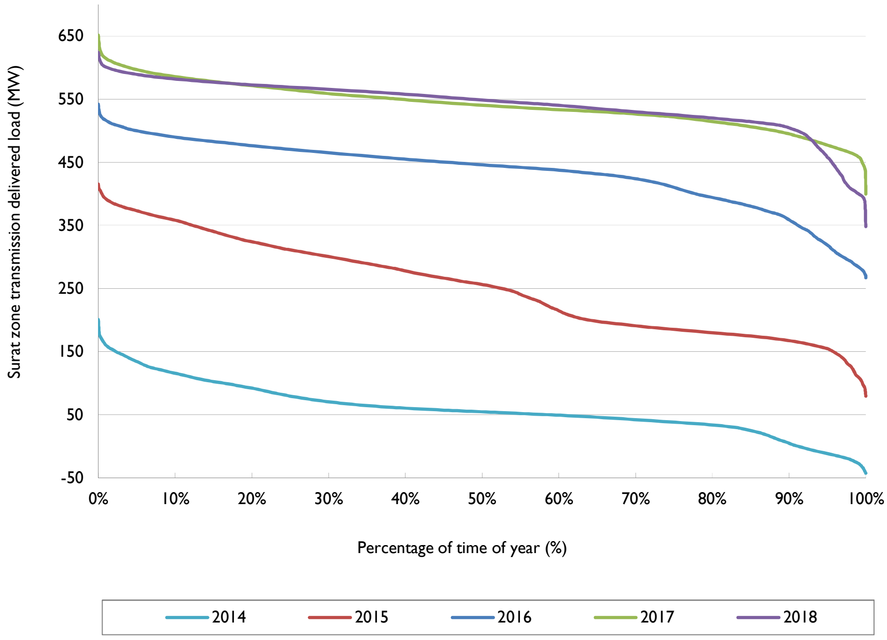
6.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2018.

The Surat zone includes the scheduled embedded Roma and Condamine generators as defined in Figure 2.4. This embedded generator provided approximately 316GWh during 2018.

Figure 6.32 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has increased by approximately 0.2% between 2017 and 2018. The peak transmission delivered demand in the zone was 624MW, which is below the highest maximum demand over the last five years of 651MW set in 2017. The CSG load in the zone has now reached expected demand levels.

Figure 6.32 Historical Surat zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO includes the Tarong to Chinchilla 132kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in February 2018.

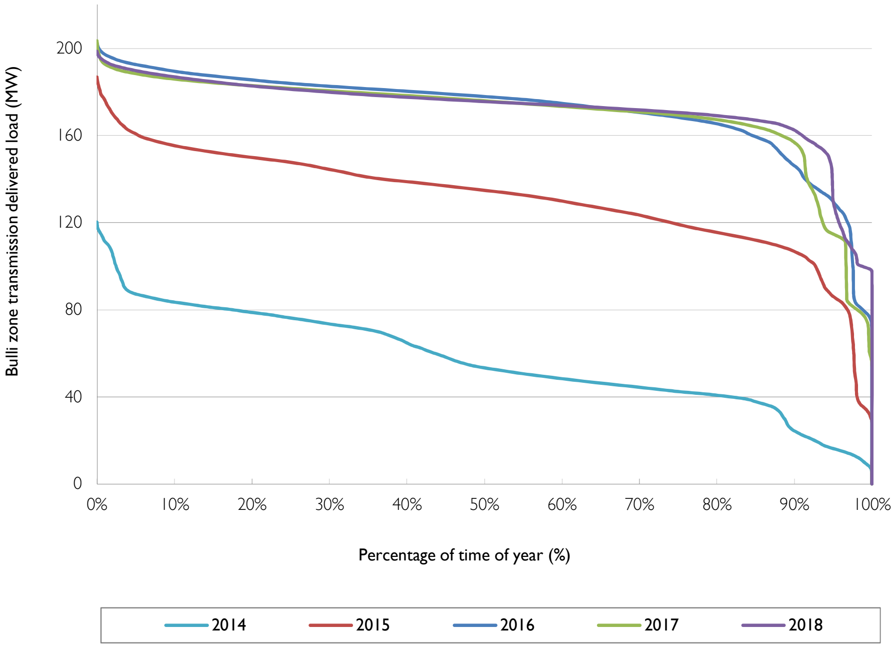
6.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2018.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.33 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by approximately 1.5% between 2017 and 2018. The peak transmission delivered demand in the zone was 199MW, which is below the highest maximum demand over the last five years of 204MW set in 2017. The CSG load in the zone has now reached expected demand levels.

Figure 6.33 Historical Bulli zone transmission delivered load duration curves



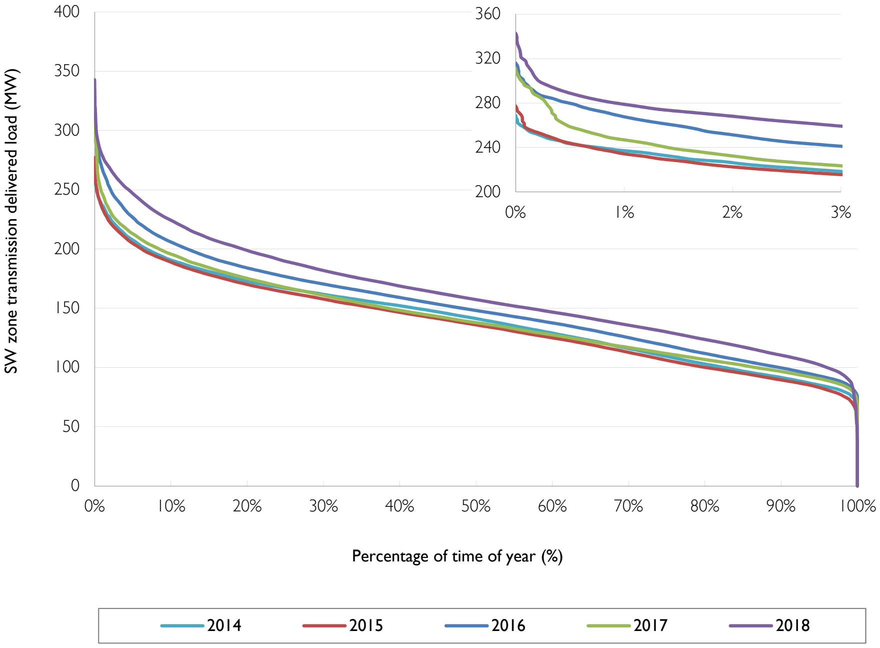
6.7.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2018.

The South West zone includes the semi-scheduled embedded generator Oakey 1 Solar Farm and significant non-scheduled embedded generator Daandine Power Station as defined in Figure 2.4. These embedded generators provided approximately 131GWh during 2018.

Figure 6.34 provides historical transmission delivered load duration curves for the South West zone. Energy delivered from the transmission network has increased by 14.2% between 2017 and 2018. The peak transmission delivered demand in the zone was 343MW, which is the highest maximum demand over the past five years.

Figure 6.34 Historical South West zone transmission delivered load duration curves

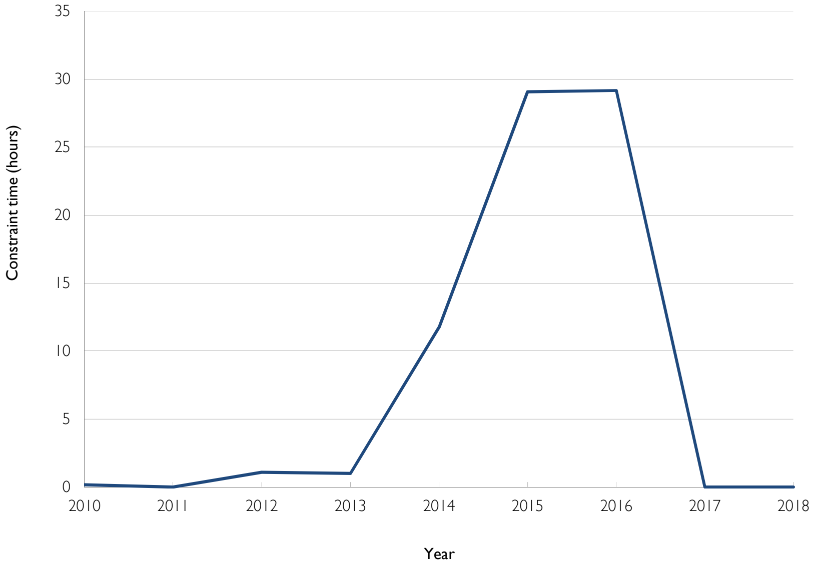


Constraints occur within the South West zone under intact network conditions. These constraints are associated with maintaining power flows of the 110kV transmission lines between Tangkam and Middle Ridge substations within the feeder's thermal ratings at times of high Oakey Power Station generation. Powerlink maximises the allowable generation from Oakey Power Station by applying dynamic line ratings to take account of real time prevailing ambient weather conditions. AEMO identifies these constraints with identifiers Q>NIL_MRTA_A and Q>NIL_MRTA_B. These constraints were implemented in AEMO's market system from April 2010. There were no constraints recorded against this constraint equations in 2018. Oakey's production reduced significantly since 2017, in line with other gas fired generators in South West Queensland.

Energy Infrastructure Investments (EII) has advised AEMO of its intention to retire Daandine Power Station in June 2022.

Information pertaining to the historical duration of constrained operation due to these constraints is summarised in Figure 6.35.

Figure 6.35 Historical Q>NIL_MRTA_A and Q>NIL_MRTA_B constraint times



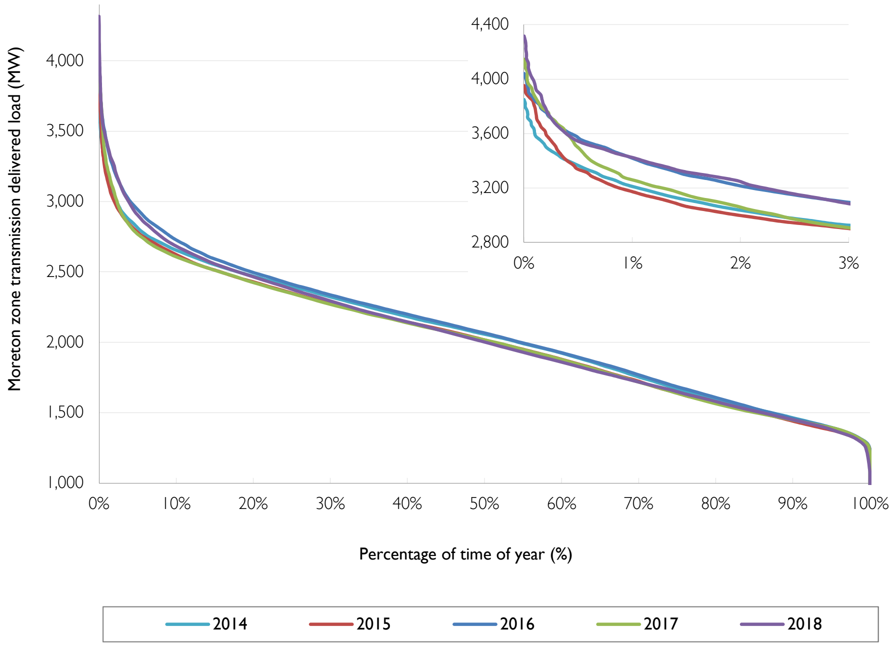
6.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2018.

The Moreton zone includes the significant non-scheduled embedded generators Sunshine Coast Solar Farm, Bromelton and Rocky Point as defined in Figure 2.4. These embedded generators provided approximately 96GWh during 2018.

Figure 6.36 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has increased by 1.0% between 2017 and 2018. The peak transmission delivered demand in the zone was 4,316W, which is the highest ever maximum demand for the zone.

Figure 6.36 Historical Moreton zone transmission delivered load duration curves



High voltages associated with light load conditions are managed with existing reactive sources. Powerlink and AEMO have an agreed procedure to manage voltage controlling equipment in SEQ. The agreed procedure uses voltage control of dynamic reactive plant in conjunction with Energy Management System (EMS) online tools prior to resorting to network switching operations. There are no additional reactive sources forecast in the Moreton zone within the five-year outlook period for the control of high voltages.

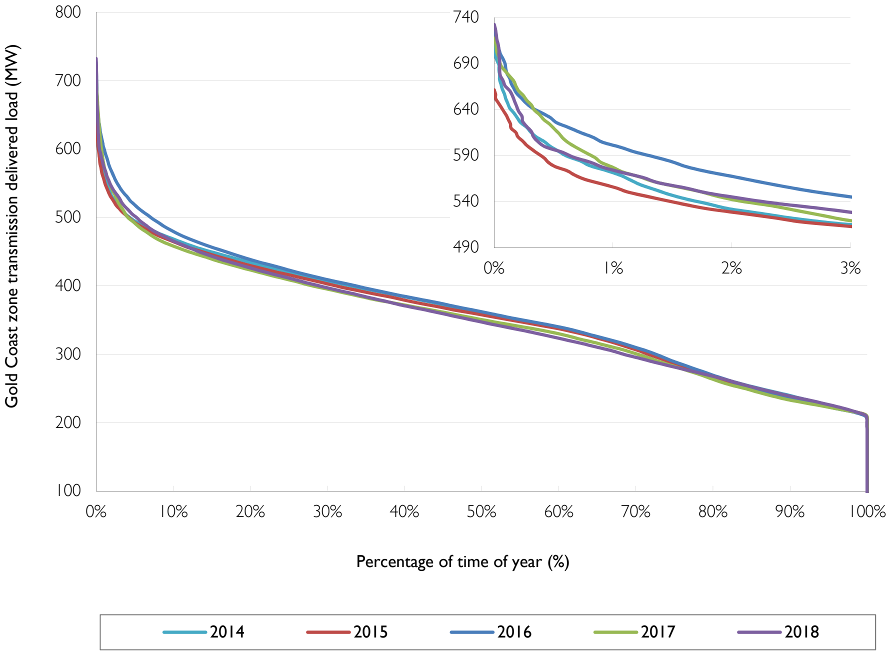
6.7.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2018.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.37 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has increased by 0.2% between 2017 and 2018. The peak transmission delivered demand in the zone was 732MW, which is the highest maximum demand over the last five years.

Figure 6.37 Historical Gold Coast zone transmission delivered load duration curves



CHAPTER 7

Strategic planning

7 Strategic planning

Key highlights

- Long-term planning takes into account:
  - the role the transmission network is to play in enabling the transition to a lower carbon future while continuing to deliver a secure, safe, reliable and cost effective service
  - dynamic changes in the external environment, including load growth, the upturn in variable renewable energy (VRE) developments in Queensland, and the condition and performance of existing assets to optimise the network that is best configured to meet current and a range of plausible future capacity needs.
- Plausible new loads within the resource rich areas of Queensland or at the associated coastal port facilities may cause network limitations to emerge within the 10-year outlook period. Possible network options are provided for Bowen Basin coal mining area, Bowen Industrial Estate, Galilee Basin coal mining area, Central Queensland to North Queensland (CQ-NQ) grid section and the Surat Basin north west area.
- The changing generation mix also has implications for investment in the transmission network, both inter-regional and within Queensland across critical grid sections. These impacts and possible network augmentation options for the Central West to Gladstone and Central Queensland to Southern Queensland (CQ-SQ) grid sections are discussed.
- Powerlink is actively participating in energy market reform initiatives, in particular the coordination of investment in renewable generation and transmission infrastructure.

7.1 Introduction

Australia is in the midst of an energy transformation driven by advances in renewable energy technologies, displacement/retirement of existing fossil fuelled generation, changing customer expectations and Government emission policies.

The future customer load will be supplied by a mix of large-scale generation and distributed energy resources (DER). Queensland is experiencing a high level of growth in VRE generation, in particular solar photovoltaic (PV) and wind farm generation. Section 6.2 outlines that 2,457MW of large-scale VRE generation is connected, or committed to connect, to the Queensland transmission and distribution networks.

Customer behaviour is central to the energy transformation. Customers are demanding choice and the ability to exercise greater control over their energy needs, while still demanding reliability and greater affordability. The future load is also uncertain due to different economic outlooks, emergence of new technology, orchestration of significant DER, and the commitment and/or retirement of large industrial and mining loads.

These changes are creating opportunities and challenges for the power system. The changing generation mix and uncertain load levels will impact the utilisation of existing transmission infrastructure. Optimising the utilisation of existing assets and any new development requirements will be vital to achieving lower cost solutions that meet energy security and reliability, affordability and reduced emissions.

To achieve these objectives the network must support the integration of large-scale VRE generation. The network must also enable the transition to a lower carbon future by supporting the sharing of generation between areas and National Electricity Market (NEM) regions. However, all developments must continue to be economic and efficient to support sustainable affordability.

Powerlink is investigating the future network needs by assessing the impact of uncertain load growth and the connection of VRE generation to meet Government emissions reduction targets on the utilisation of grid sections and interconnectors.

Chapter 2 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 can be included (either wholly or in part) in the medium economic forecast. These load developments are listed in Table 2.1. Section 7.2 discusses the possible impact these uncertain loads may have on the performance and adequacy of the transmission system.

The changing generation mix also has implications for investment in the transmission network, both inter-regional and within Queensland across critical grid sections. Section 7.3 discusses these impacts and possible network augmentation options for the Central West to Gladstone and CQ-SQ grid sections.

Increasing the capacity of interconnection between NEM regions could be pivotal to meeting Australia's long-term energy targets, providing the advantage of the geographic diversity of renewable resources so regions could export power when there is local generation surplus, and import power when needed to meet demand. Appropriate intra-regional transmission capacity could also be required to support these objectives. Investigations underway to inform the efficient development of the network include joint planning with:

- Australian Energy Market Operator (AEMO) and other Transmission Network Service Providers (TNSPs) to develop the Integrated System Plan (ISP)[1].
- TransGrid to investigate the economic benefits of increasing the transmission transfer capacity between Queensland and New South Wales (NSW). Powerlink and TransGrid have commenced the formal Regulatory Investment Test for Transmission (RIT-T) consultation process (refer to Section 5.7.14).

Against this backdrop of the rapidly changing electricity sector, the AEMC completed its initial review of the Coordination of Generation and Transmission Investment (CoGaTI). This review made a series of recommendations for how investment in generation and transmission should be better coordinated into the future. The most significant of these recommendations relates to reforms to the management of congestion and access on the transmission network. These recommendations are being progressed by the AEMC through 2019 and Powerlink is actively participating in energy market reform initiatives including participating in technical working groups established to assist the AEMC in their work. Section 7.4 summarises the scope of these reviews and the various linkages.

7.2 Possible network options to meet reliability obligations for potential new loads

Chapter 2 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 can be included (either wholly or in part) in the medium economic forecast.

The new large loads, listed in Table 2.1, are within the resource rich areas of Queensland or at the associated coastal port facilities. The relevant resource rich areas include the Bowen Basin, Galilee Basin and Surat Basin. These loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. The degree of impact is also dependent on the location and capacity of new or withdrawn generation in the Queensland region.

The commitment of some or all of these loads may cause limitations to emerge on the transmission network. These limitations could be due to plant ratings, voltage stability and/or transient stability. Options to address these limitations include network solutions, demand side management (DSM) and generation non-network solutions. Feasible network projects can range from incremental developments to large-scale projects capable of delivering significant increases in power transfer capability.

As the strategic outlook for non-network options is not able to be clearly determined, this section focuses on strategic network developments only. This should not be interpreted as predicting the preferred outcome of the RIT-T process. The recommended option for development, in the RIT-T, is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

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[1] AEMO will publish the second ISP in mid-2020.

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 6.1 and 6.2 have been taken into account when discussing the possible network limitations and options. However, where current interest in connecting further 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.

Details of feasible network options are provided in sections 7.2.1 to 7.2.5, for the transmission grid sections potentially impacted by the possible new large loads in Table 2.1. Formal consultation via the RIT-T process on the network and non-network options associated with emerging limitations will be subject to commitment of additional demand.

7.2.1 Bowen Basin coal mining area

Based on the medium economic forecast defined in Chapter 2, the committed network described in Chapter 9, and the committed generation described in tables 6.1 and 6.2 network limitations exceeding the limits established under Powerlink's planning standard occur following the retirement of assets. A possible solution to the voltage limitation could be the installation of a transformer at Strathmore Substation, network reconfiguration works, or a non-network solution as described in Section 5.7.2.

In addition, there has been a proposal for the development of coal seam gas (CSG) processing load of up to 80MW (refer to Table 2.1) in the Bowen Basin. These loads have not reached the required development status to be included in the medium economic forecast for this Transmission Annual Planning Report (TAPR).

The new loads within the 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 the Strathmore 275/132kV transformer, a 132kV transmission line between Nebo and Moranbah substations, the 132kV transmission line between Strathmore and Collinsville North substations, or the 132kV transmission line between Lilyvale and Dysart substations (refer to Figure 5.6).

The impact these loads may have on the CQ-NQ grid section and possible network solutions to address these is discussed in Section 7.2.4.

Possible network solutions

Feasible network solutions to address the limitations are dependent on the magnitude and location of load. The location, type and capacity of future VRE generation connections in North Queensland may also impact on the emergence and severity of network limitations. The type of VRE generation interest in this area is predominately large-scale solar PV. Given that the Bowen Basin coal mining area has a predominately flat load profile, it is unlikely that the daytime PV generation profile will be able to successfully address all emerging voltage limitations. However, voltage limitations may be ameliorated by these renewable plants, particularly if they are designed to provide voltage support 24 hours a day.

Possible network options may include one or more of the following:

- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV transmission line between Collinsville North and Clare South substations
- 132kV phase shifting transformers to improve the sharing of power flow in the Bowen Basin within the capability of the existing transmission assets.

7.2.2 Bowen Industrial Estate

Based on the medium economic forecast defined in Chapter 2, no additional capacity is forecast to be required as a result of network limitations within the 10-year outlook period of this TAPR.

However, electricity demand in the Abbot Point State Development Area (SDA) is associated with infrastructure for new and expanded mining export and value adding facilities. Located approximately 20km west of Bowen, Abbot Point forms a key part of the infrastructure that will be necessary to support the development of coal exports from the northern part of the Galilee Basin. The loads in the SDA could be up to 100MW (refer to Table 2.1) but have not reached the required development status to be included in the medium economic forecast for this TAPR.

The Abbot Point area is supplied at 66kV from Bowen North Substation. Bowen North Substation was established in 2010 with a single 132/66kV transformer and supplied from a double circuit 132kV transmission line from Strathmore Substation but with only a single transmission line connected. During outages of the single supply to Bowen North the load is supplied via the Ergon Energy 66kV network from Proserpine, some 60km to the south. An outage of this single connection will cause voltage and thermal limitations impacting network reliability.

Possible network solutions

A feasible network solution to address the limitations comprises:

- installation of a second 132/66kV transformer at Bowen North Substation
- connection of the second Strathmore to Bowen North 132kV transmission line
- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV transmission line between Collinsville North and Clare South substations.

7.2.3 Galilee Basin coal mining area

There have been proposals for new coal mining projects in the Galilee Basin. Although these loads could be up to 400MW (refer to Table 2.1) none have reached the required development status to be included in the medium economic forecast for this TAPR. If new coal mining projects eventuate, voltage and thermal limitations on the transmission system upstream of their connection points may occur.

Depending on the number, location and size of coal mines that develop in the Galilee Basin it may not be technically or economically feasible to supply this entire load from a single point of connection to the Powerlink network. New coal mines that develop in the southern part of the Galilee Basin may connect to Lilyvale Substation via an approximate 200km transmission line. Whereas coal mines that develop in the northern part of the Galilee Basin may connect via a similar length transmission line to the Strathmore Substation.

Whether these new coal mines connect at Lilyvale and/or Strathmore Substation, the new load will impact the performance and adequacy of the CQ-NQ grid section. Possible network solutions to the resultant CQ-NQ limitations are discussed in Section 7.2.4.

In addition to these limitations on the CQ-NQ transmission system, new coal mine loads that connect to the Lilyvale Substation may cause thermal and voltage limitations to emerge during an outage of a 275kV transmission line between Broadsound and Lilyvale substations.

Possible network solutions

For supply to the Galilee Basin from Lilyvale Substation, feasible network solutions to address the limitations are dependent on the magnitude of load and may include one or both of the following options:

- installation of capacitor bank/s at Lilyvale Substation
- third 275kV transmission line between Broadsound and Lilyvale substations.

The location, type and capacity of future VRE generation connections in Lilyvale, Blackwater and Bowen Basin areas may also impact on the emergence and severity of this network limitation. The type of VRE generation interest in this area is predominately large-scale solar PV. Given that the coal mining load in the area has a predominately flat profile it is unlikely that the daytime PV generation profile will be able to successfully address all emerging limitations.

7.2.4 CQ-NQ grid section transfer limit

Based on the medium economic forecast outlined in Chapter 2 and the committed generation described in tables 6.1 and 6.2, network limitations impacting reliability are not forecast to occur within the 10-year outlook of this TAPR. However, midday power transfer levels are forecast to reduce as additional VRE generators are commissioned in North Queensland (NQ) and consequentially voltage control is forecast to become increasingly challenging and potentially lead to high voltage (HV) violations. As outlined in Section 5.7.4 a possible network solution includes the installation of shunt bus reactor.

However, as discussed in sections 7.2.1, 7.2.2 and 7.2.3 there have been proposals for large coal mine developments in the Galilee Basin, and development of CSG processing load in the Bowen Basin and associated port expansions. The loads could be up to 580MW (refer to Table 2.1) but have not reached the required development status to be included in the medium economic forecast of this TAPR.

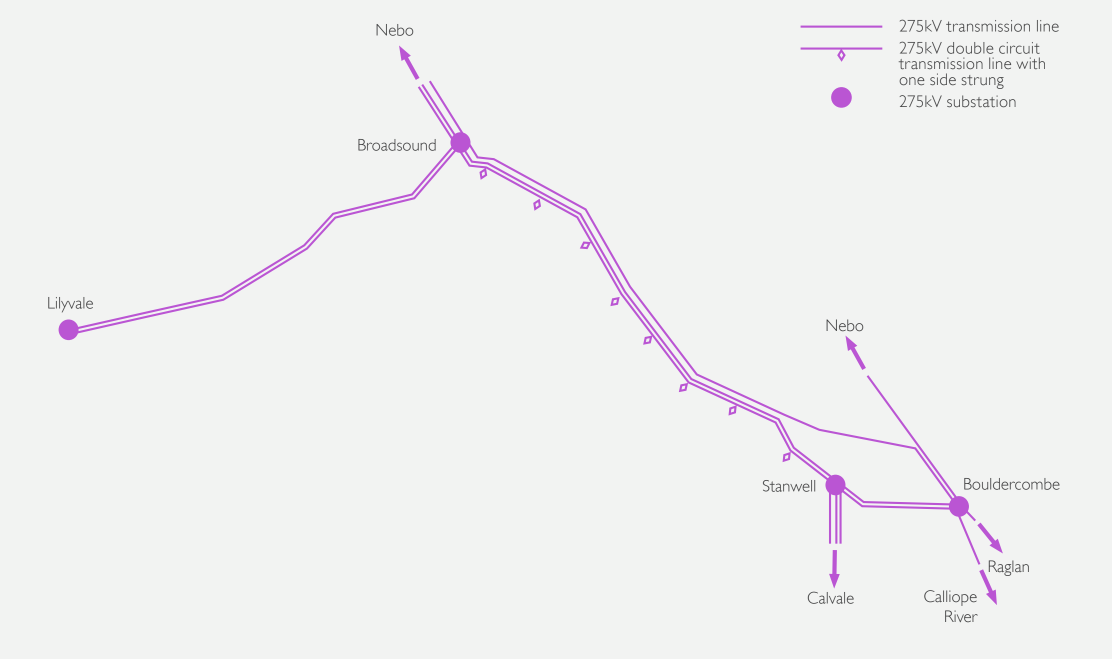
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line during a critical contingency of a Stanwell to Broadsound 275kV transmission line. Voltage stability limitations may occur during the trip of the Townsville gas turbine or 275kV transmission line supplying northern Queensland.

Currently generation costs are higher in northern Queensland due to reliance on liquid fuels, and there may be positive net market benefits in augmenting the transmission network. The current commitment of VRE generation in North Queensland and any future uptake of VRE generation would be taken into account in any market benefit assessment, including consideration of the location, type and capacity of these future connections.

Possible network solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with one circuit strung (refer to Figure 7.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second side of this transmission line.

Figure 7.1 Stanwell/Broadsound area transmission network



7.2.5 Surat Basin north west area

Based on the medium economic forecast defined in Chapter 2, network limitations impacting reliability are not forecast to occur within the next five years of this TAPR.

However, there have been several proposals for additional CSG upstream processing facilities and new coal mining load in the Surat Basin north west area. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR. The loads could be up to 300MW (refer to Table 2.1) and cause voltage limitations impacting network reliability on the transmission system upstream of their connection points.

Depending on the location and size of additional load, voltage stability limitations may occur following outages of the 275kV transmission lines between Western Downs and Columboola, and between Columboola and Wandoan South substations (refer to Figure 7.2).

Possible network solutions

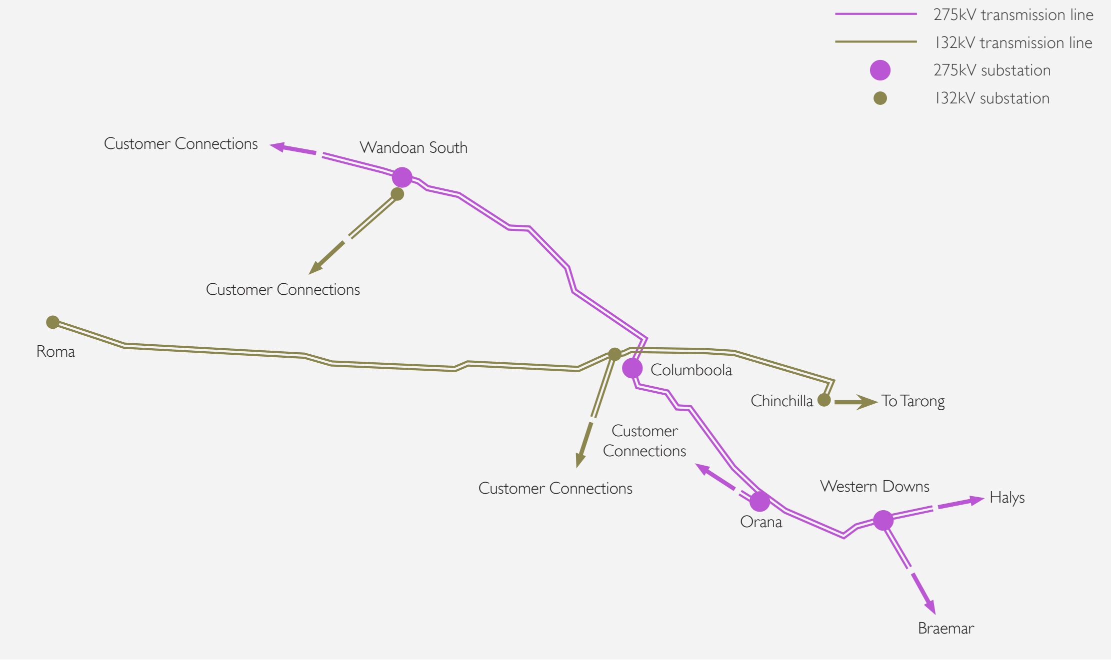
Due to the nature of the voltage stability limitation, the size and location of load and the range of contingencies over which the instability may occur, it may not be possible to address this issue by installing a single Static VAr Compensator (SVC) at one location.

The location, type and capacity of future VRE generation connections in the Surat Basin north west area may also impact on the emergence and severity of these voltage limitations. The type of VRE generation interest in this area is large-scale solar PV. Given that the CSG upstream processing facilities and new coal mining load has a predominately flat load profile it is unlikely that the daytime PV generation profile will be able to successfully address all emerging voltage limitations. However, voltage limitations may be ameliorated by these renewable plants, particularly if they are designed to provide voltage support 24 hours a day.

To address the voltage stability limitation the following network options are viable:

- SVCs, Static Synchronous Compensators (STATCOM) or Synchronous Condensors (SynCon) at both Columboola and Wandoan South substations
- additional transmission lines between Western Downs, Columboola and Wandoan South substations to increase fault level and transmission strength, or
- a combination of the above options.

Figure 7.2 Surat Basin north west area transmission network



7.3 Possible impact of the changing generation mix on critical grid sections

Since January 2016, Powerlink has seen an unprecedented level of renewable energy investment activity with over 2,450MW of large scale renewable energy projects commencing construction or finalising commercial arrangements (refer to tables 6.1 and 6.2). This will continue as Queensland moves towards its Queensland Renewable Energy Target (QRET) target of 50% renewable generation by 2030. Powerlink continues to process numerous connection applications many of which are in central and north Queensland.

The existing, committed and expected investments in VRE generation are expected to increase the utilisation of the Central West to Gladstone and CQ-SQ grid sections. While not impacting reliability of supply, this investment has the potential to cause congestion depending on how the thermal generating units in central Queensland bid to meet the NEM demand.

7.3.1 Central West to Gladstone area reinforcement

The 275kV network forms a triangle between the generation rich nodes of Calvale, Stanwell and Calliope River substations. This triangle delivers power to the major 275/132kV injection points of Calvale, Bouldercombe (Rockhampton), Calliope River (Gladstone) and Boyne Island substations.

Since there is a surplus of generation within this area, this network is also pivotal to supply power to northern and southern Queensland. As such, the utilisation of this 275kV network depends not only on the generation dispatch and supply and demand balance within the Central West and Gladstone zones, but also in northern and southern Queensland.

Based on the medium economic forecast defined in Chapter 2 and the existing and committed generation in tables 6.1 and 6.2, network limitations impacting reliability are not forecast to occur within the 10-year outlook period of this TAPR. This assessment also takes into consideration the retirement of the Callide A to Gladstone South 132kV double circuit transmission line (refer to Section 5.7.4).

However, the committed VRE generation in tables 6.1 and 6.2 in North Queensland is expected to increase the utilisation of this grid as generation in the Gladstone zone or southern generators is displaced. Whilst not impacting reliability of supply, the committed VRE generation in North Queensland has the potential to cause congestion depending on how the thermal generating units in central Queensland bid to meet the NEM demand.

Powerlink recognised the vulnerability of this grid section to congestion and proposed a network project under the Network Capability Incentive Parameter Action Plan (NCIPAP) for the 2018-22 Revenue Reset period. This project involves increasing the ground clearance of 11 spans on Bouldercombe to Raglan 275kV and three on Larcom Creek to Calliope River 275kV transmission lines to increase the thermal rating of these lines. This project was accepted by the Australian Energy Regulator (AER). Powerlink has now implemented these improvements.

In addition, there are several developments in the Queensland region that would change not only the power transfer requirements between the Central West and Gladstone zones but also on the intra-connectors to northern and southern Queensland. These developments include new loads in the resource rich areas of the Bowen Basin, Galilee Basin and Surat Basin and also the connection of VRE generation, in particular large-scale solar PV and wind farm generation. Such generation, together with what it displaces, has the potential to further significantly increase the utilisation of this grid section. This may lead to significant limitations within this 275kV triangle impacting efficient market outcomes despite the uprating from the NCIPAP project. Network limitations would need to be addressed by dispatching out-of-merit generation and the technical and economic viability of increasing the power transfer capacity would need to be assessed under the requirements of the RIT-T.

Possible network solutions

Depending on the emergence of network limitations within the 275kV network it may become economically viable to increase its power transfer capacity to alleviate constraints. Feasible network solutions to facilitate efficient market operation may include:

- transmission line augmentation between Calvale and Larcom Creek substations and rebuild between Larcom Creek and Calliope River substations with a high capacity 275kV double circuit transmission line
- rebuild between Larcom Creek, Raglan, Bouldercombe and Calliope River substations with a high capacity 275kV double circuit transmission line.

7.3.2 CQ-SQ grid section transfer limit

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 of the CQ-SQ grid sections is therefore expected to increase (refer to Section 5.7.6 and Section 6.6.4) and may lead to levels of congestion depending on the response of the central and northern Queensland generators to the energy market. In addition, the incidence of congestion may increase if additional southerly transfer capacity on the Queensland/New South Wales Interconnector (QNI) is shown to be economically justified (refer to Section 5.7.14).

As outlined in Section 5.7.6 there are emerging condition and compliance risks related to structural corrosion on significant sections of the coastal CQ-SQ 275kV network between Calliope River and South Pine substations. Strategies to address the transmission line sections with advanced corrosion in the five year outlook are described in Section 5.7.6.

In parallel, Powerlink continues to investigate the impact of large scale VRE generation investment in the Queensland region on the utilisation and economic performance of intra-regional grid sections, and in particular the CQ-SQ grid section. The CQ-SQ reinvestment strategies in 5.7.6 will be adjusted to align with future generation and network developments if this planning analysis identifies economic triggers to increase the CQ-SQ capacity.

If material emerging constraints are forecast, Powerlink must demonstrate that the economic benefit to the market exceeds the cost of addressing the constraint. In the case of emerging constraints across the CQ-SQ, the potential investments to address these constraints are likely to be significant. Powerlink will consider these constraints holistically with the emerging condition based drivers as part of the planning process. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered.

Possible network solutions

Depending on the emergence of network limitations between CQ and SQ it may become economically viable to increase its power transfer capacity to alleviate constraints. Feasible network solutions to facilitate efficient market operation may differ in scale and include:

- establishing a mid-point switching substation on the 275kV double circuit between Calvale and Halys substations
- reduce the series impedance of the 275kV double circuit between Calvale and Halys substations via a variety of technologies
- a grid-connected storage system
- a new western single or double circuit 275kV line connecting CQ to SWQ/Surat zones and
- adoption of other technologies, including high voltage direct current (HVDC) between zones.

7.4 Coordination of generation and transmission investment

In August 2018, the Council of Australian Governments (COAG) Energy Council requested the Energy Security Board (ESB) to deliver a work program to 'convert the ISP' into an 'actionable strategic plan', including 'how the Group 1 projects identified in the inaugural ISP can be implemented and delivered as soon as practicable and with efficient outcomes for customers, and how the Group 2 projects will be reviewed and progressed.'

This culminated with the AEMC finalising a rule change (4 April 2019) that streamlines the RIT-T processes. The rule change allows the three AER post RIT-T assessments (any dispute lodged, the preferred option assessment, and the contingent project revenue determination) to be run concurrently. This anticipates reducing the RIT-T timeframe by approximately six to eight months, for three projects[2].

Further, the progression of subsequent projects identified in ISPs are to occur through an 'actioned' ISP. To allow this, and following the release of the Coordination of Generation and Transmission Investment Review (CoGaTI) Final Report in December 2018, the AEMC, ESB and the Senior Committee of Officials (SCO) are consulting on the necessary reforms and rule changes required to embed the ISP in the regulatory framework. It is proposed that the draft ISP will identify credible network options, developed in consultation with TNSPs, which address the system wide needs. The inclusion of credible options analysis in the draft ISP will potentially allow the Project Specification Consultation Report (PSCR) to be removed from the RIT-T for ISP projects, streamlining the regulatory process.

The AEMC propose to pair the 'actioned' ISP with mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion. The AEMC is of the view that change is needed now to better coordinate investment in renewable generation and transmission infrastructure, so that regulatory frameworks evolve to match this transition in the NEM. The AEMC has made a series of recommendations for how investment in generation and transmission should be better coordinated into the future. Recommendations are made across five key aspects; planning, access, charging, connection and economic regulation. The recommendations complement each other to transform the way generation and transmission is planned, invested in and operated in the NEM.

Key recommendations include:

- Phased implementation of dynamic regional pricing
  Dynamic regional pricing will put a price on network congestion by creating pricing regions through existing dispatch processes. This will introduce a signal to generators that reflects the short-run costs of using the network, providing better locational information to generators.
- Generators to fund transmission network augmentation in return for financial firm access
  Generators will have the choice to compel TNSPs to provide transmission services consistent with the level of firm access (that is, guaranteed access to the wholesale market) paid for by generators.
- Review of inter-regional Transmission Use of System (TUOS) and the broader TUOS framework
  The AEMC considers that there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment.

The detailed design of these reforms including better managing network congestion and access is being progressed by the AEMC throughout 2019.

Powerlink is actively participating energy market reform initiatives and technical working groups established to assist the AEMC with these initiatives.

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[2] Upgrades to QNI and VNI, and the proposed interconnector between South Australia and NSW – Project EnergConnect.

CHAPTER 8

Renewable energy

8 Renewable energy

Key highlights

- This chapter explores the potential for the connection of variable renewable energy (VRE) generation to Powerlink's transmission network.
- Powerlink has a key role in enabling the connection of VRE infrastructure in Queensland.
- System strength has been a focus for VRE generators and Powerlink, including development of the Electromagnetic Transient (EMT-type) model for Queensland.
- Powerlink has actively engaged in a Rule change proposal through Energy Networks Australia (ENA) to enhance information availability, focussing on improving outcomes for connecting parties.

8.1 Introduction

Queensland is rich in a diverse range of renewable resources – solar, wind, geothermal, biomass and hydro. This makes Queensland an attractive location for large-scale VRE generation development projects. In response, Powerlink introduced this chapter of the TAPR in 2016 to facilitate exploration of Queensland VRE opportunities.

Rooftop solar in Queensland exceeded 2,400MW in February 2019, with existing and committed utility scale connections of VRE generation totalling to 2,457MW. Large scale wind and solar connections to Powerlink's transmission network make up 1,630MW of this capacity. Further information on these connections can be found in Section 6.2.

Utility scale connections of VRE generation, both in Queensland and the rest of the National Electricity Market (NEM), has brought with it a number of challenges to which Powerlink is responding. The distributed nature of VRE generation is changing the way the transmission network is operated, including managing system strength, changes to flow patterns and utilisation.

A number of changes to the regulatory environment have been introduced through the National Electricity Rules (NER). These Rule changes, which impact how generation can connect to Powerlink's network, have been put in place to ensure that system stability and security are able to be maintained now and into the future. The Rule changes most relevant to the information provided in this chapter are:

- Managing Power System Fault Level
- Transmission Connection and Planning Arrangements
- Generator Performance Standards.

This chapter also provides information on:

- Renewable Energy Zones (REZs)
- emerging constraints on the transmission system
- Marginal Loss Factors (MLFs)
- Powerlink's role.

8.2 Managing power system fault level

In September 2017, the Australian Energy Market Commission (AEMC) finalised the 'Managing Power System Fault Levels' rule. The Rule provides for a holistic, flexible and technology neutral solution to issues arising from the forecast reduction in system strength.

The Rule, which came into effect on 1 July 2018, requires AEMO to develop a system strength requirements methodology from which it can determine the minimum required fault level at key 'fault level nodes' and then assess whether a fault level shortfall exists or is likely to exist in the future.

Powerlink has worked with AEMO to develop a probable assessment of the minimum fault level in Queensland. This assessment has considered the displacement[1] of existing synchronous plant in Queensland. The minimum fault level is used to assess that the system can be operated safely and reliably now and into the future.

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[1] Displacement may occur for periods when it is not economic for a synchronous generator to operate, and is distinct from retirement which is permanent removal from the market.

The required minimum fault level will be subject to an annual review in accordance with the guidelines. This may require that the minimum fault level is amended at one or more key nodes to ensure safe and reliable operation of the system.

Where AEMO identifies an emerging shortfall, Powerlink will consider how best to address this gap. Solutions include, but are not limited to:

- network reconfiguration
- contracting with existing synchronous generation (network support) and
- installation of synchronous condensers.

TNSPs have a holistic perspective of their network and will be able to address system strength in a manner that considers the best options for the entire network, including consideration of other key services such as inertia. These synergies should result in more efficient outcomes for consumers in the long-term.

In accordance with the Rule, AEMO also published the System Strength Impact Assessment Guidelines (the guidelines) on 29 June 2018. The guidelines require Powerlink to consider the impact of VRE generating systems operating in areas of low system strength, as well as the interaction of multiple VRE generating systems with each other and system voltage control devices. Powerlink is required to undertake a Preliminary Assessment at the connection enquiry phase to assess this impact. If Preliminary Assessment criterion are breached, then a Full Assessment is required.

The Rule introduces a requirement on new connecting generators to 'do no harm' to the security of the power system, in relation to any adverse impact on the ability of the power system to maintain system stability or on a nearby generating system to maintain stable operation.

8.2.1 Preliminary Assessment

The Preliminary Assessment uses steady state power system analysis tools to assess the likelihood of an adverse system strength impact. At the enquiry stage, detailed information on the characteristics of the connection are unlikely to be available, and as such the Preliminary Assessment balances the need for meaningful insight against the time and cost of undertaking more rigorous analysis.

A Full Assessment is required if the screening criteria are breached.

8.2.2 Full Assessment

The Full Assessment requires EMT-type studies, and is carried out as part of the connection process as per the System Strength Impact Assessment Guidelines. This is to ensure that any adverse system strength impact is adequately identified and addressed as part of the connection application either via a system strength remediation scheme or through system strength connection works.

Generation must meet the NER Generator Performance Standards (GPS), and generation proponents are required to demonstrate that their proposed generation technology is able to meet these standards during the connection process. Powerlink is obligated to undertake due diligence on projects, including EMT-type studies even where Full Assessment is not indicated by the Preliminary Assessment.

8.2.3 Development of integrated system strength model

Powerlink is working with committed proponents, equipment manufacturers' and AEMO to enhance the EMT-type model for the Queensland network.

Work on the integrated system strength model has been very challenging due to complex interactions between plants and the sensitivity to plant model updates. The model development involved numerous iterations to inform not only the models of the plant seeking connection, but also for existing synchronous plant and dynamic voltage control devices[2].

The integrated system strength model also identified issues with generator models and plant performance that were not previously visible. This has led to delays in assessing a number of applications.

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[2] Transmission connected Static VAr Compensators (SVC), load balancing SVCs and Static Synchronous Compensators (STATCOM).

This work has provided an important insight into the complexity of system strength and how it impacts on managing non-synchronous connections and the network in general. This understanding is now being applied to future assessments.

8.2.4 System strength during network outages

Throughout the year, it is necessary to remove plant in the transmission network from service. In the majority of circumstances planned outages are necessary to maintain or replace equipment. It may also be necessary to remove plant from service unexpectedly. During these planned and unplanned outages, Powerlink and AEMO must ensure that the system continues to be operated in a secure state.

Network outages may lead to reductions in system strength. This may be a localised issue, however for outages on key 275kV corridors, as well as some 275/132kV transformers, the reduction in system strength may impact on a number of VRE generators. To address this, Powerlink is working with AEMO to develop constraint equations to be implemented in the National Energy Market Dispatch Engine (NEMDE). The purpose of these equations is to maximise the dispatch of VRE generators in the Queensland system within the available system strength.

8.3 Transmission connection and planning arrangements

In May 2017, the AEMC published the Final Determination on the Transmission Connections and Planning Arrangements Rule change request. The Rule sets out significant changes to the arrangements by which parties connect to the transmission network, as well as changes to enhance how transmission network businesses plan their networks.

Since the implementation of the Rule from July 2018, Powerlink has continued to refine the documentation available and processes used to meet Powerlink's obligations under the NER. Documents updated include the 'Network Configuration Document – Selection for New Substations'. Parties seeking connection to Powerlink's network should ensure that they are referencing the most up to date documentation.

During 2018/19, connection activity at both the enquiry and application stages decreased. Powerlink considers that this is not a result of the new connection arrangements, but rather the market reaching a point where the developments already under consideration are focussing on the impact of the Rule changes and the obligations under the GPS on their pending investment decisions.

Powerlink is focussed on delivering a timely and transparent connection process to connecting generators including coordination of the physical connection works, GPS and system strength.

8.4 Indicative available network capacity – Generation Capacity Guide

Powerlink provides a significant amount of information for parties seeking connection to the transmission network in Queensland, including the Generation Capacity Guide (GCG) and the Network Limitations Advice. Proponents are encouraged to utilise this information to make informed proposals, however we encourage early engagement with Powerlink's Business Development team.

The GCG is published on Powerlink's website separate to the TAPR to facilitate updates to the GCG as required making available the most up to date data for VRE developers.

The GCG includes capacity and congestion information for customers seeking to connect to Powerlink's transmission network. The calculation methodology is based upon the existing configuration of the transmission network and the technical standards that currently apply to transmission network design and power system operation. Only generation that has an executed Connection and Access Agreement (CAA), an agreed GPS, and acceptance by AEMO of any requirements under NER 5.3.4A and 5.3.4B, is included in the calculation. The analysis also assumes that the proposed generation facility will comply with the NER's automatic access standard for reactive power capability (NER S5.2.5.1). Changes to the network configuration and the technical standards that apply to new connections have the potential to change the network capacity available to new generators.

Under the NEM's open access regime, it is possible for generation to be connected to a connection point in excess of the network's capacity, or for the aggregate generation within a zone to exceed the capacity of the main transmission system. Where this occurs, the dispatch of generation may need to be constrained. This 'congestion' is managed by AEMO in accordance with the procedures and mechanisms of the NEM. It is the responsibility of each generator proponent to assess and consider the consequences of potential congestion, both immediate and into the future.

Powerlink also provides more detailed information on its website in the form of the Network Limitations Advice. These maps provide indicative available capacity for non-synchronous generation at substations throughout each region. It is important to note that the capacities provided are not cumulative. Information is also available in the 'New generator connections data' TAPR template.

It is important to note that the indicative capacity for non-synchronous generation is based on simple 'screening metrics' consistent with the Preliminary Assessment methodology. Detailed EMT-type analysis will be required to confirm the capacity (refer to the calculation methodology section of the Powerlink Generation Capacity Guide for further description and additional assumptions).

More detail on the methodology for assessment of capacity for the transmission network is provided in the Generation Capacity Guide.

8.5 Transmission congestion and Marginal Loss Factors

As part of normal planning processes, Powerlink proactively monitors the potential for congestion to occur, and will assess the potential network investments to maximise market benefits using the Australian Energy Regulator's (AER) Regulatory Investment Test for Transmission (RIT-T)[3]. Where found to be economic, Powerlink may augment the network to ensure that the electricity market operates efficiently and at the lowest overall long run cost to consumers. Generator proponents are encouraged to refer to Chapter 5 and Chapter 7, which provides more detail on potential future network development as well as emerging constraints.

Where Powerlink is aware of emerging constraints, Powerlink must demonstrate that the economic benefit to the market must exceed the cost of addressing the constraint. In the case of emerging constraints across the CQ-SQ and Gladstone grid sections (refer to Chapter 7), the potential investments to address these constraints are likely to be significant. Powerlink is considering these constraints holistically with emerging condition based drivers as part of its normal planning processes. Potential development decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered.

The development, displacement or retirement of generating plant, changes to generation dispatch and/or load patterns, and/or changes to the underlying transmission network may alter transmission losses within the high voltage (HV) system. This will result in changes to the Marginal Loss Factors (MLFs) used within the NEM dispatch and financial settlement processes. AEMO is responsible for the calculation of MLFs, and interested parties seeking further information on this are encouraged to contact AEMO, or refer to the AEMO website.

As a TNSP, the scheduling of generation is not part of Powerlink's role and the indicative connection point generation capacity limits are not related to the MLF or scheduling and dispatch of generation in the NEM.

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[3] Details of the RIT-T, including the market benefits which can be considered, are available on the AER's website.

8.6 Supporting new generation development in Queensland

Powerlink supports a number of initiatives associated with the establishment of new generation in Queensland. Further information on these is provided in the following sections.

8.6.1 Renewable Energy Zones (REZs)

REZs can be used to deliver an effective, lower cost connection to a number of parties. Powerlink is working to enhance the concept of the REZs based on recent experience around the connection of VRE projects. However this is not without challenges such as system strength, constraints and regulatory obligations.

Significant opportunities exist for new VRE generation in Queensland that is not adjacent to existing infrastructure. Powerlink is committed to providing as much information as it can to developers to assist, with an example of this being the Rule change submitted by Energy Networks Australia (ENA) to provide information about current enquiries and applications discussed in Section 8.7.2. This proposed rule change will increase transparency of information, and provide information to VRE developers that may assist in the development of REZs in the NEM.

The 2018 Integrated System Plan (ISP) provides an overview of REZs. A range of REZs were assessed across the NEM, with information on a select number of these published. In assessing REZs, AEMO has considered the following:

- resource quality, diversity and demand requirements
- existing transmission network capacity and access to the main transmission network
- system strength and
- network losses, including MLFs.

In the broader context of supporting VRE generation connections, the concept of a REZ may involve:

- a high-capacity radial transmission line, with renewable projects connecting along the length of this line
- the establishment of a centralised hub, from which radial connections to individual renewable projects emanate
- a hybrid of these two options, with hub substations placed along the length of a new high-capacity transmission line.

Further to the concepts discussed above, providing system firming services to facilitate the connection of new VRE generation may provide benefit, particularly in areas where the interest in VRE generation exceeds the available system strength. Powerlink considers that new VRE generation may be able to utilise one, or a combination of the following methods to mitigate system strength issues:

- installation of a synchronous condenser to improve system strength
- contracting with existing synchronous generation to access system strength
- modifying the scope of the connection works
- the use of non-synchronous plant based on grid forming converter technologies and
- establishing intertrip schemes to mitigate against critical contingencies[4].

As with the establishment of a central hub and the high capacity line concept, system firming services may be utilised as a standalone solution or in combination with the other methods to deliver a REZ.

8.6.2 Changes impacting on REZs

Currently, TNSPs cannot disclose information about connecting parties seeking to connect to the transmission network in the same area. As a result, information that may assist Powerlink and connecting parties to optimise connection outcomes is often not available in a timely or coordinated manner.

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[4] Powerlink considers that these schemes are used to mitigate against single credible contingencies that result in a significantly lower plant capacity that is compliant compared to the next most critical contingency, and where the resultant loss of generation does not introduce any further constraint on the system.

Energy Networks Australia (ENA), of which Powerlink is a member, has proposed a rule change to the AEMC relating to confidentiality of information in the NEM. Similar requests have also been received from AEMO and the Australian Energy Council. This rule change has been sought to assist connecting parties and Powerlink optimise connection investment decisions and outcomes.

Further information is available on the AEMC website.

8.6.3 Other sources of renewable energy

There is value in securing energy from diverse sources of renewable energy in Queensland. The developments over the last few years have centred on solar photovoltaic (PV) and wind generation sources. These are not the only source of renewable energy in Queensland, with the Department of Natural Resources, Mines and Energy (DNRME) website also considering biomass, hydro-electric and geothermal energy as potential sources of renewable energy.

Depending on the nature and type of connection, not all of the information relating to the assessments highlighted may apply. For example, a new synchronous generator would not require a Full Assessment even if seeking connection in a weak network. It remains the case that generation must meet the NER Generator Performance Standards, and generation proponents are required to demonstrate that their proposed generation technology is able to meet these standards during the connection process.

8.6.4 Energy storage

Currently, the level of VRE development in Queensland may lead to constraints during periods of high VRE output. The pathway to a low emissions future indicates that for VRE to be able to reliably supply energy, storage will play a key role in shifting this energy.

Energy storage can take a number of forms, for example:

- hydro-electric, in particular pumped storage
- thermal storage, such as molten salts
- battery energy systems, similar to those used in South Australia
- compressed air storage and
- hydrogen.

A number of the technologies listed above are based on synchronous machines, however battery energy storage and other inverter connected plants (e.g. Variable Speed Drive coupled hydro-electric machines) would require the system strength assessment highlighted in Section 8.2 be carried out as part of the connection process.

8.6.5 Proposed renewable connections in Queensland

DNRME provide 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, please refer to DNRME website.

8.6.6 Further information

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 Network Service Providers (NSP) must apply when dealing with connection enquiries. Powerlink will continue to engage with interested parties who have lodged connection enquiries under the previous Rules framework for connection of generation. Should an interested party wish to utilise the connection framework referred to in Section 8.4, it will be necessary to submit a new connection enquiry.

Figure 8.1 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.

CHAPTER 9

Committed, current and recently commissioned network developments

9 Committed, current and recently commissioned network developments

Key highlights

- During 2018/19, Powerlink's efforts have continued to be predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's reinvestment program is focussed on reducing the identified risks arising from assets reaching the end of technical service life while continuing to deliver safe, reliable and cost efficient transmission services to our customers.
- A major project for Powerlink has been the completion of a secondary systems upgrade at Broadsound Substation which is critical to transporting power generated in central Queensland to communities in northern and western Queensland.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland, with numerous connection works enabling variable renewable energy (VRE) generation completed during 2018/19.
- During 2018/19, Powerlink has completed its scope of works for 11 large-scale VRE developments in Queensland, adding 1,423 MW of generation capacity to the grid.[1]

9.1 Transmission network

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 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.

There have been no transmission network developments commissioned or network assets retired[2] since Powerlink's 2018 TAPR was published.

Table 9.1 lists connection works commissioned since Powerlink's 2018 TAPR was published.

Table 9.2 lists new transmission connection works for supplying loads which are committed and under construction at June 2019. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 9.3 lists network reinvestments commissioned since Powerlink's 2018 TAPR was published.

Table 9.4 lists network reinvestments which are committed at June 2019.

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[1] Refer to tables 9.1 and 9.2

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

Table 9.1 Commissioned connection works since June 2018

Project (1)	Purpose	Zone location	Date commissioned
Mount Emerald Wind Farm	New wind farm	Far North	Quarter 3 2018
Ross River Solar Farm	New solar farm	Ross	Quarter 3 2018
Haughton Solar Farm	New solar farm	Ross	Quarter 4 2018
Hamilton Solar Farm	New solar farm	North	Quarter 2 2018 (2)
Whitsunday Solar Farm	New solar farm	North	Quarter 2 2018 (2)
Rugby Run Solar Farm	New solar farm	North	Quarter 4 2018
Daydream Solar Farm	New solar farm	North	Quarter 4 2018
Hayman Solar Farm	New solar farm	North	Quarter 4 2018
Lilyvale Solar Farm	New solar farm	Central West	Quarter 1 2019
Darling Downs Solar Farm	New solar farm	Bulli	Quarter 1 2018 (2)

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 by the company making the connection request.

(2) Powerlink's scope of works for this project were completed as noted in Table 9.1. Remaining works associated with generation connection have been coordinated with the customer since publication of the 2018 TAPR.

Table 9.2 Committed and under construction connection works at June 2019

Project (1)	Purpose	Zone location	Proposed commissioning date
Coopers Gap Wind Farm	New wind farm	South West	Quarter 4 2019 (2)

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 9.3 Commissioned network reinvestments since June 2018

Project	Purpose	Zone location	Date commissioned
Turkinje secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	November 2018
Tully secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	November 2018
Ross secondary systems replacement	Maintain supply reliability in the Ross zone	Ross	December 2018
Moranbah 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	October 2018
Nebo 275/132kV transformer replacements	Maintain supply reliability in the North zone	North	December 2018
Broadsound secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	January 2019
Stanwell secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	November 2018
Line refit works on 132kV transmission lines between Calliope River and Boyne Island	Maintain supply reliability in the Gladstone zone	Gladstone	November 2018
Tarong 66kV cable replacement	Maintain supply reliability in the South West zone	South West	December 2018
Tennyson secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	December 2018

Table 9.4 Committed network reinvestments at June 2019

Project	Purpose	Zone location	Proposed commissioning date
Woree secondary systems replacement	Maintain supply reliability in the Cairns area (1)	Far North	December 2022
Woree SVC secondary systems replacement	Maintain supply reliability in the Cairns area (1)	Far North	December 2022
Garbutt transformers replacement	Maintain supply reliability in the Ross zone (2)	Ross	August 2019
Ingham South 132/66kV transformers replacement	Maintain supply reliability in the Ross zone (1)	Ross	October 2019
Townsville South 132kV primary plant replacement	Maintain supply reliability in the Ross zone (1)	Ross	December 2022
Ross 132kV primary plant replacement	Maintain supply reliability in the Ross zone (1)	Ross	October 2024
Ross 275kV primary plant replacement	Maintain supply reliability in the Ross zone (1)	Ross	October 2024
Line refit works on the 132kV transmission line between Collinsville North and Proserpine substations	Maintain supply reliability to Proserpine	North	January 2020
Mackay Substation replacement	Maintain supply reliability in the North zone	North	February 2020
Kemmis 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	July 2020
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek Substation	Maintain supply reliability in the North zone (2)	North	October 2020
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone	North	August 2022
Moura Substation replacement	Maintain supply reliability in the Central West zone (3)	Central West	December 2019
Blackwater 66kV CT & VT replacement	Maintain supply reliability in the Central West zone	Central West	September 2019
Dysart Substation replacement	Maintain supply reliability in the Central West zone (2)	Central West	October 2019
Dysart transformer replacement	Maintain supply reliability in the Central West zone (2)	Central West	October 2019
Calvale 275/132kV transformer reinvestment	Maintain supply reliability in the Central West zone (2)(4)	Central West	June 2020
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone (1)	Central West	December 2020
Line refit works on the 132kV transmission line between Egans Hill and Rockhampton Substation	Maintain supply reliability in the Central West zone (1)	Central West	December 2020
Bouldercombe primary plant replacement	Maintain supply reliability in the Central West zone (1)	Central West	December 2021

Table 9.4 Committed network reinvestments at June 2019 *(continued)*

Project	Purpose	Zone location	Proposed commissioning date
Bouldercombe transformer replacement	Maintain supply reliability in the Central West zone (1)	Central West	June 2021
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (2) (5)	Central West	December 2021
Wurdong secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	September 2019
Boyne Island secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	September 2019
Line refit works on 275kV transmission line between Woolooga and Palmwoods	Maintain supply reliability in the Wide Bay zone (2)	Wide Bay	October 2020
Gin Gin Substation rebuild	Maintain supply reliability in the Wide Bay zone (2)	Wide Bay	October 2020
Tarong secondary systems replacement	Maintain supply reliability in the South West zone (1)	South West	June 2022
Rocklea secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	November 2019
Ashgrove West Substation replacement	Maintain supply reliability in the Moreton zone (2)	Moreton	October 2020
Line refit works on the 110kV transmission lines between South Pine and Upper Kedron	Maintain supply reliability in the Moreton zone (1)	Moreton	December 2020
Line refit works on the 110kV transmission lines between West Darra and Sumner	Maintain supply reliability in the Moreton zone (1)	Moreton	December 2020
Line refit works on the 110kV transmission lines between Rocklea and Sumner	Maintain supply reliability in the Moreton zone (1)	Moreton	December 2020
Belmont 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	December 2020
Abermain 110kV secondary systems replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	June 2021
Palmwoods 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	July 2021

Notes:

(1) RIT-T project undertaken after the commencement of the Replacement expenditure planning arrangements Rule 2017 No.5.

(2) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

(3) Major works were completed in October 2017. Minor works scheduling is being coordinated with Ergon Energy (Energex and Ergon Energy are part of the Energy Queensland Group).

(4) Approved works were rescoped as part of the Callide A/Calvale 132kV transmission reinvestment, previously named Callide A Substation replacement. Refer to Section 5.7.5.

(5) The majority of Powerlink's staged works are anticipated for completion by summer 2020/21. Remaining works associated with generation connection will be coordinated with the customer.

Figure 9.1 Existing Powerlink Queensland transmission network June 2019

9 Committed, current and recently commissioned network developments

Appendices

Appendices

Appendix A – Forecast of connection point maximum demands

Appendix A 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 A.1)
- a description of high, most likely and low growth scenarios (refer to Section A.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 A.3).

A.1 Forecasting methodology used by Energex and Ergon Energy (part of the Energy Queensland Group) for maximum demand

Energex and Ergon Energy review and update the 10-year 50% probability of exceedence (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 Energex and Ergon Energy's 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 Australian Bureau of Statistics (ABS) data, Queensland Government data, the Australian Energy Market Operator (AEMO) data, the National Institute of Economic and Industry Research (NIEIR), Deloitte Access Economics, an independently produced Queensland air conditioning forecast, rooftop photovoltaic (PV) connection data and historical maximum demand data.

The methodology used to develop the system demand forecast as recommended by consultants ACIL Tasman, is as follows:

- Develop a multiple regression equation for the relationship between demand and Gross State Product (GSP), maximum temperature, minimum temperature, total electricity price, structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from December to February (with the exception for the South East Queensland (SEQ) in the 2014/15 year, as the peak day occurred on 5 March 2015). For the SEQ case, three weather stations were incorporated into the model through a weighting system with the two associated temperature thresholds. Firstly, those summer days are dropped if the weighted average temperature is below 22.0°C. Secondly, those summer days are also dropped if the weighted maximum temperature is below 28.5°C. These two thresholds are introduced for the purpose of capturing the impacts of hot days as well as the influence of the sea breeze on maximum demand. Statistical testing is applied to the model before its application to ensure that there is minimum bias in the model. For regional Queensland, up to five weather stations are chosen depending upon the significance tests undertaken each year.
- A Monte-Carlo process is used across the SEQ and regional models to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures and an independent 10-year gross GSP forecast and an independent air conditioning load forecast.
- Use the 30 top summer maximum demands to produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.
- 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.

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[1] Where applicable, Clauses 5.12.2(c)(iii) and (iv) are discussed in Chapter 2.

- 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 electric vehicles (EV) based on the maximum demand daily load profile and expected equipment usage patterns.

A.2 Description of Energex's and Ergon Energy'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 2018 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in November 2018 are based on these assumptions. In the forecasting methodology high, medium and low scenarios refer to maximum demand rather than the underlying drivers or independent variables. This avoids the ambiguity on both high and low meaning, as there are negative relationships between the maximum demand and some of the drivers e.g. high demand normally corresponds to low battery installations.

Block Loads

There are some block loads scheduled over the next 11 years. It is expected that Queensland Rail will undertake some projects which will either permanently or temporarily impact on the Energex system maximum demand, and around 38MW is expected in SEQ for the year to 2022. In regional Queensland, in excess of 50MW is expected in mining load over the next four years.

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:

- Daily Maximum Demand = Function of (weighted maximum temperature, weighted minimum temperature, three continuous hot days, total price, Queensland GSP, Friday, weekend, Sunday, Christmas period, Christmas day, structural break, 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 November 2017 System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – the medium case of GSP growth (2.2% per annum over the next 11 years).
- Total real electricity price – the low case of annual price change of -0. 5% (compounded and consumer price index (CPI) adjusted).
- Queensland population – a relatively high growth of 1.95% in 2019 (driven by improved net immigration), slowing to 1.78% in 2024 before reaching marginally higher to 1.80% by 2029
- Rooftop PV – lack of incentives for customers who lost the feed-in tariff (FIT), plus slow falls in battery prices which discourage PV installations. Capacity may reach 2,363MW by 2029.
- Battery storage – prices fall slowly, battery safety remains an issue, and kW demand based network tariff is not introduced. Capacity gradually increase to 258MW by 2029.
- EV – significant fall in EV prices, accessible and fast charging stations, enhanced features, a variety of types, plus escalated petrol prices. The peak time contribution (without diversity ratio adjusted) may exceed 993MW by 2029.
- Weather – follow the recent 30-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – the low case of GSP growth (1.2% per annum over the next 11 years).
- Total real electricity price – the medium case of annual price change of 0.5%.
- Queensland population – growth of 1.61% in 2019, slowing to 1.52% in 2024 and decelerating further to 1.48% by 2029.
- Rooftop PV – invertor capacity increasing from 1,391MW in 2018 to 3,224MW by 2029.

- Battery storage – capacity will have a slow start of around 16.5MW in 2019, but will gradually accelerate to 385MW by 2029.
- EV – Stagnant in the short-term, boom in the long-term. Peak time contribution (without diversity ratio adjusted) will only amount to 6.9MW in 2019, but will reach 547MW by 2029. Note however, EV will impact gigawatt hour (GWh) energy sales more than the maximum demand, and up to 80% diversity ratios will be used in the charging period.
- Weather – follow the recent 30-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – the long-term variation adjusted low case GSP growth (0.3% per annum over the next 11 years).
- Total real electricity price – the high case of annual price change of 1.5%.
- Queensland population – low growth of 1.37% in 2019 (due to adverse immigration policies), then weak GDP growth plus loss in productivity may slow growth to 1.33% in 2024 and weaken further to 1.26% by 2029.
- Rooftop PV – strong incentives for customers who lost the FIT tariffs, plus fast falls in battery prices which encourage more PV installations. Capacity may hit 4,215MW by 2029.
- Battery storage – prices fall quickly, no battery safety issues, and a demand based network tariff is introduced. Capacity may reach 530MW by 2029.
- EV – slow fall in EV prices, hard to find charging stations, charging time remaining long, still having basic features, plus cheap petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 394MW by 2029.
- Weather – follow the recent 30-year trend.

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:

- Demand MW = function of (weekend, public holidays, weighted maximum temperature, weighted minimum temperature, Queensland GSP, structural break, air conditioning, 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 (adjusted to 2.6% per annum over the next 11 years).Queensland population – growth of 0.5% pa to 2021, progressively increasing to 1.42% in 2017 before slowing down to 1.0% by 2030.
- Rooftop PV – numbers and capacity monitored and estimated.
- Battery storage – not used in the forecast baseline but inclusion as part of ongoing PV installations are closely monitored and reviewed.
- EV – not used in the forecast baseline but uptake within regional Queensland closely reviewed.
- Weather – follow the recent trend of at least 30 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – the 'medium' case of GSP growth (adjusted to 2.0% per annum over the next 11 years).
- Ergon Energy's low growth scenario assumptions for maximum demand
- GSP – the 'low' growth case of GSP growth (adjusted to 0.7% per annum over the next 11 years).

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

The general trend in connection point maximum demand growth is relatively flat. The main exceptions to this trend for SEQ are in Table A.1.

Connection Point	2017/18 Forecast
Abermain 33kV	3.3% pa
Ashgrove West 110kV	1.9% pa
Goodna 33kV	1.7% pa
Redbank Plains 11kV	1.7% pa

The key reason for the changes is the underlying growth rates at the zone substations supplied from each connection point.

Ergon connection points are forecast over the next 10 years to be flat or slightly declining with the exception of load coming on from earlier mining activity.

A.4 Customer forecasts of connection point maximum demands

Tables A.1 to A.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 A.2). These forecasts have been supplied by Powerlink customers.

The connection point reactive power (MVAr) forecast includes the customer's downstream capacitive compensation.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

In tables A.1 to A.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 B – TAPR templates

In accordance with Clause 5.14B.1(a) of the National Electricity Rules (NER), the Australian Energy Regulator's (AER) Transmission Annual Planning Report (TAPR) Guidelines[1] set out the required format of TAPRs, in particular the provision of TAPR templates to complement the TAPR document. The purpose of the TAPR templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are encouraged to contact Powerlink in the first instance.

The TAPR templates may be directly accessed on Powerlink's website[2] (other than the Expanding NSW-Queensland transmission transfer capacity line segment data which is available on Transgrid's website). Alternatively please contact NetworkAssessments@powerlink.com.au for assistance.

For consistency with the TAPR document, the TAPR templates are able to filtered by Powerlink's geographical zones and outlook period, as well as the AER TAPR Guidelines template type (transmission connection point / line segment / new generator connection).

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 economically assessed under the 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.

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).

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[1] First published in December 2018.

[2] Refer to the Data tab on the TAPR website page.

[3] Separate to the publication of the TAPR document which occurs annually.

Development of daily demand profiles

Forecasts of the daily demand profiles for the 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)

  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 March 2018 to 28 February 2019) 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 roof-top photovoltaic (PV), distribution connected PV solar farms, battery storage, electric vehicles (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 (refer to Appendix A).

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 roof-top PV, distribution connected PV solar farms, battery storage and EV.

The maximum demand forecast on the minimum demand day (TGCP009) and the minimum demand forecast on the minimum demand day (TGCP011) were determined from the minimum (annual) daily demand profiles.

Table B.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. Please refer to Chapter 5 and/or Appendix F 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 5.4.
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 Historic 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 2016 to December 2018.
TGPC028 and TGTL019 Annual economic cost of constraint	The annual economic cost of the constraint is the direct product of the 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 C – Zone and grid section definitions

This appendix provides definitions of illustrations of the 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR).

Tables C.1 and C.2 provide detailed definitions of zone and grid sections.

Figures C.1 and C.2 provide illustrations of the generation, load and grid section definitions.

Table C.1 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of Proserpine and Collinsville, 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 C.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 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) Callide A into Gladstone South 132kV (2 circuits)
CQ-SQ	Wurdong into Gin Gin 275kV (1 circuit) (2) Calliope River into Gin Gin 275kV (2 circuits) (2) Calvale into Halys 275kV (2 circuits)
Surat	Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)
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)

Notes:

(1) The grid sections defined are as illustrated in Figure C.2. 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.

(2) CQ-SQ cutset redefined following Gin Gin Substation rebuild in summer 2020/21. Wurdong into Gin Gin 275kV becomes Wurdong to Teebar Creek 275kV. Calliope River into Gin Gin 275kV becomes Calliope River to Gin Gin/Woolooga 275kV.

Figure C.1 Generation and load legend

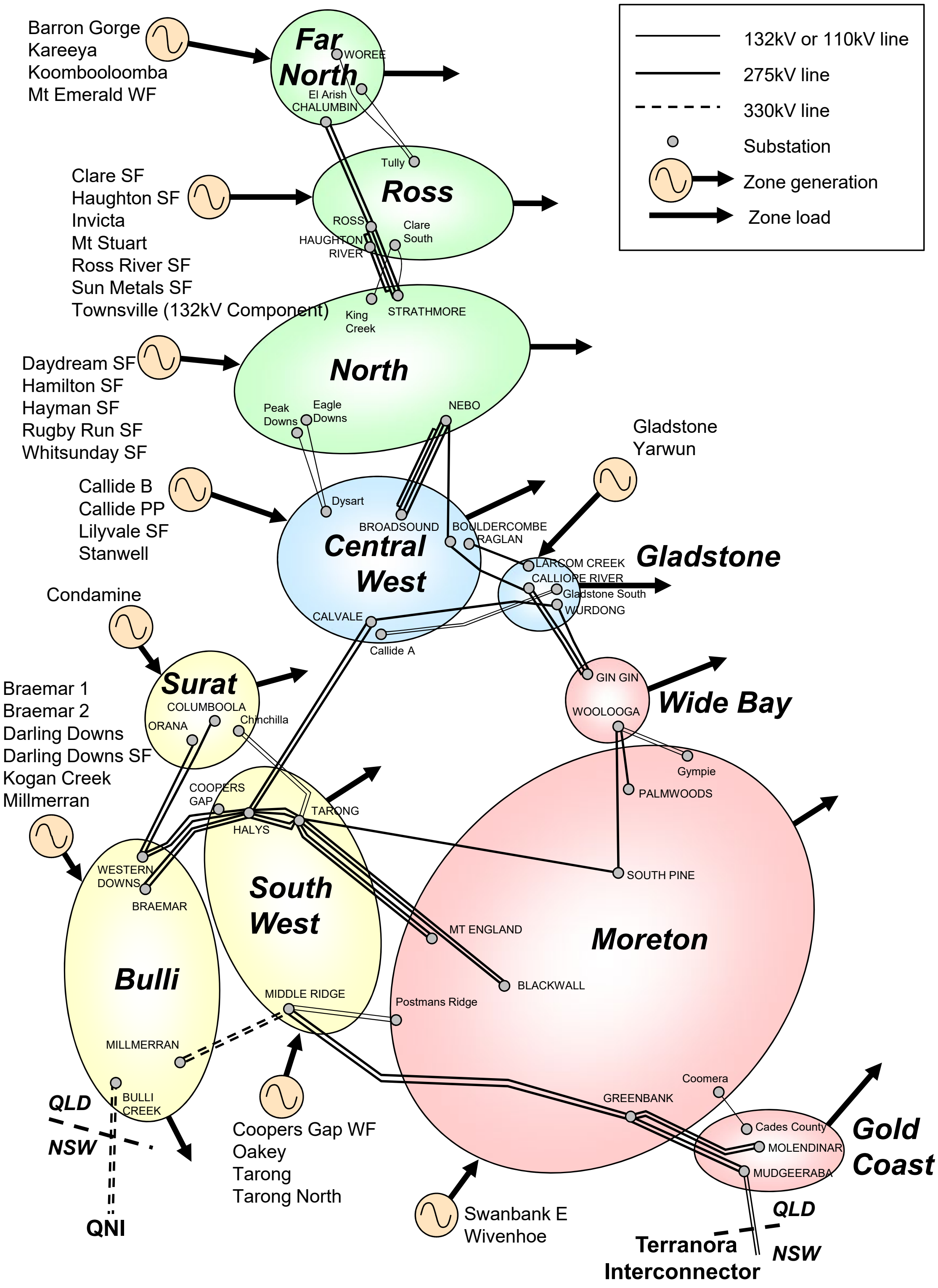
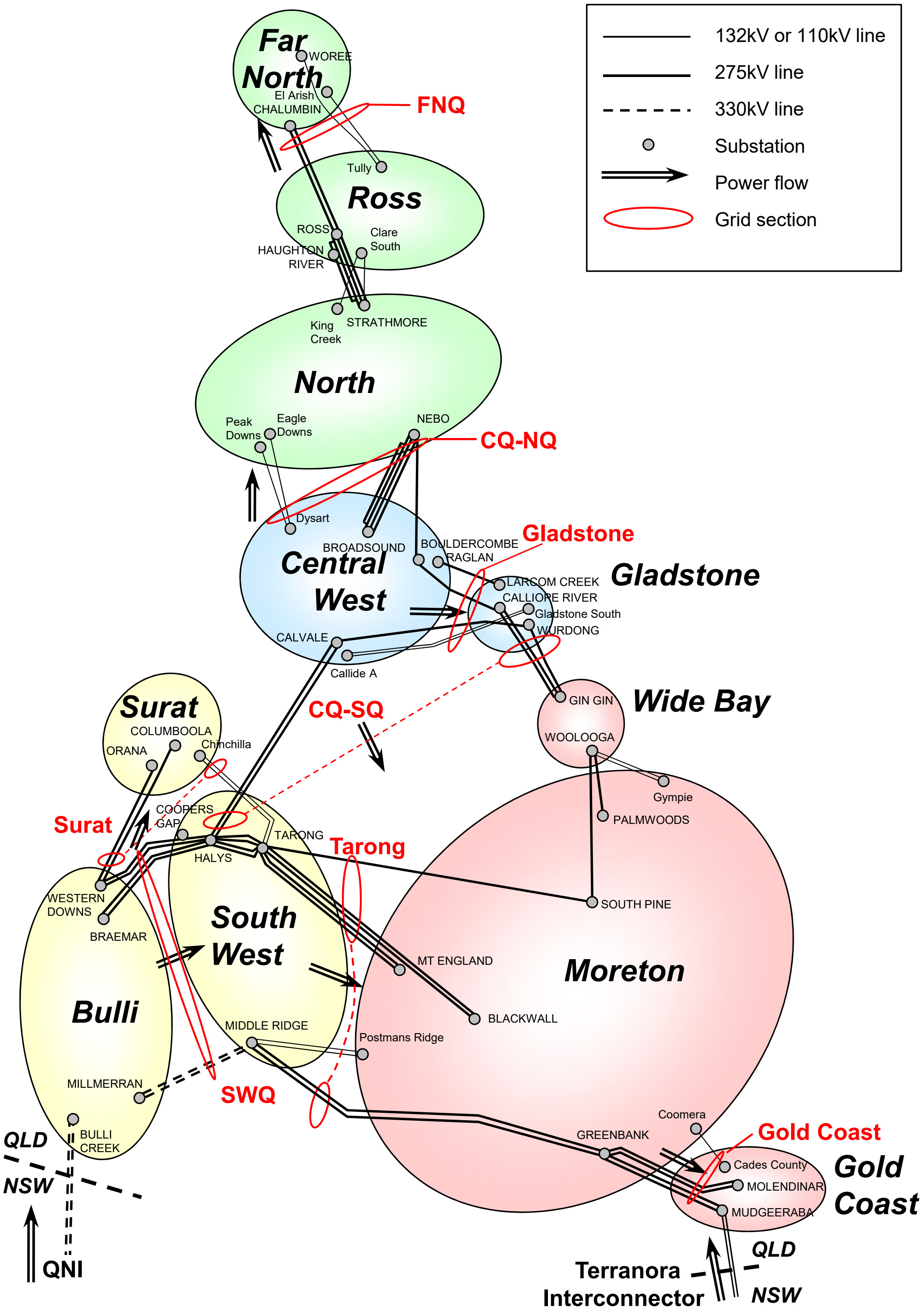


Figure C.2 Grid section legend



Appendix D – 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.

It should be noted that 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 D.1 Far North Queensland (FNQ) grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	-19.00
FNQ demand percentage (1) (2)	17.00
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	-0.46
Total MW generation at Mt Stuart and Townsville	0.13
Total MW generation at Mt Emerald	-1.00
AEMO Constraint ID	Q^NIL_FNQ

Notes:

(1) FNQ demand percentage = $\dfrac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Mt Emerald Wind Farm + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Mt Emerald Wind Farm + Townsville + Ross River Solar Farm + Haughton Solar Farm + Pioneer Mill + Mt Stuart + Sun Metals Solar Farm + Kidston Solar Farm + Invicta Mill + Clare Solar Farm + Collinsville Solar Farm + Whitsunday Solar Farm + Hamilton Solar Farm + Hayman Solar Farm + Daydream Solar Farm + Moranbah North + Mackay + Racecourse Mill + Moranbah + Moranbah North) generation

(2) The FNQ demand percentage is bound between 22 and 31.

Table D.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 generation at Mackay	-0.700	-0.478
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

Table D.2 Central to North Queensland grid section voltage stability equations *(continued)*

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) Northern VRE include:

Mt Emerald 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 D.3 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 120MVAr capacitor banks available at Gin Gin [0 to 1]	63.5367
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, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Coopers Gap Wind Farm, Oakey, Millmerran 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 D.4 Tarong grid section voltage stability equations

Measured variable	Coefficient Equation 1 Calvale-Halys contingency	 Equation 2 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 generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Coopers Gap Wind Farm, Oakey, Oakey 1 Solar Farm, Millmerran 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 (2)	-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) Positive transfer denotes northerly flow.

(3) There are currently 4 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 38 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 D.5 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 4 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 34 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix E – Indicative short circuit currents

Tables E.1 to E.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations.

Indicative maximum short circuit currents

Tables E.1 to E.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2019/20, 2020/21 and 2021/22.

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 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 E.1 to E.3 are based on generation shown in tables 6.1 and 6.2 (together with any of the more significant embedded non-scheduled generators) and on the committed network development as at the end of each calendar year. The tables also show the rating of the lowest rated Powerlink owned plant at each location. No assessment has been made 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 system quality and stability and for ensuring the proper operation of protection systems.

Additional to this information, Powerlink provides information in the Generation Capacity Guide on the capacity available to connect new non-synchronous generators.

Tables E.1 to E.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by analysing half hourly system normal snapshots over the period 1 April 2018 and 31 March 2019. The minimum of subtransient, transient and synchronous short circuit currents over the year were compiled for each substation, both for system normal and with the individual outage of each significant network element.

These minimum short circuit currents are indicative only, and as they are based on history are distinct from the minimum fault level published in the System Strength Requirements Methodology, System Strenth Requirements and Fault Level Shortfalls published by AEMO in July 2018.

Table E.1 Indicative short circuit currents – northern Queensland – 2019/20 to 2021/22

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.2	3.9	13.5	13.8	13.6	13.8	13.6	13.8
Alligator Creek	132	25.0	3.0	1.7	4.6	6.1	4.6	6.1	4.6	6.1
Bolingbroke	132	40.0	2.0	1.8	2.5	1.9	2.5	1.9	2.5	1.9
Bowen North	132	40.0	3.1	1.8	2.8	3.0	2.8	3.0	2.8	3.0
Cairns (2T)	132	25.0	2.9	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.9	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.9	0.7	5.9	7.9	5.9	7.9	-	-
Cardwell	132	19.3	1.9	1.0	3.0	3.3	3.0	3.3	3.0	3.3
Chalumbin	275	31.5	1.7	1.3	4.2	4.4	4.2	4.4	4.2	4.4
Chalumbin	132	31.5	3.1	2.5	6.7	7.7	6.7	7.7	6.7	7.7
Clare South	132	40.0	3.4	2.9	8.0	8.1	7.9	8.0	7.9	8.0
Collinsville North	132	31.5	4.4	2.3	8.7	9.6	8.7	9.6	8.7	9.5
Coppabella	132	31.5	2.2	1.4	3.1	3.4	3.1	3.4	3.1	3.4
Crush Creek	275	40.0	1.9	1.8	9.5	9.7	9.5	9.7	9.5	9.7
Dan Gleeson (1T)	132	31.5	4.2	3.6	12.8	13.2	12.8	13.2	12.8	13.2
Dan Gleeson (2T)	132	40.0	4.2	3.6	12.8	13.1	12.8	13.3	12.8	13.3
Edmonton	132	40.0	1.3	0.4	5.4	6.6	5.3	6.6	5.3	6.6
Eagle Downs	132	40.0	2.8	1.5	4.6	4.4	4.6	4.4	4.6	4.4
El Arish	132	40.0	2.1	1.0	3.2	4.0	3.2	4.0	3.2	4.0
Garbutt	132	40.0	3.9	1.8	11.1	11.0	11.1	11.0	11.1	11.0
Goonyella Riverside	132	40.0	3.4	2.9	5.9	5.4	5.9	5.4	5.9	5.4
Haughton River	275	40.0	2.9	2.1	7.2	7.1	7.2	7.1	7.2	7.1
Ingham South	132	31.5	1.9	1.0	3.3	3.3	3.3	3.3	3.3	3.3
Innisfail	132	40.0	1.9	1.2	2.9	3.5	2.9	3.5	2.9	3.5
Invicta	132	19.3	2.6	1.7	5.3	4.8	5.3	4.7	5.3	4.7
Kamerunga	132	15.3	2.5	0.8	4.5	5.4	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.8	2.3	5.7	6.4	5.7	6.4	5.7	6.4
Kemmis	132	31.5	3.8	1.6	6.1	6.5	6.1	6.5	6.1	6.5
King Creek	132	40.0	2.9	1.5	4.7	4.0	4.7	3.9	4.7	3.9
Lake Ross	132	31.5	4.8	4.4	17.7	19.7	17.8	19.8	17.8	19.8
Mackay	132	10.9	2.9	1.0	5.8	6.8	5.8	6.8	5.8	6.8
Mackay Ports	132	40.0	2.5	1.5	3.5	4.2	3.5	4.2	3.5	4.2

Table E.1 Indicative short circuit currents – northern Queensland – 2019/20 to 2021/22 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Mindi	132	40.0	3.2	3.0	4.5	3.7	4.5	3.7	4.5	3.7
Moranbah	132	10.9	3.8	3.1	7.9	9.3	7.9	9.2	7.9	9.2
Moranbah Plains	132	31.5	2.2	1.9	4.4	4.0	4.4	4.0	4.4	4.0
Moranbah South	132	31.5	3.2	2.6	5.7	5.2	5.7	5.2	5.7	5.2
Mt Mclaren	132	31.5	1.5	1.4	2.1	2.3	2.1	2.3	2.1	2.3
Nebo	275	31.5	3.8	3.4	10.8	11.0	10.8	11.0	10.8	11.0
Nebo	132	15.3	6.5	5.8	14.0	16.0	14.0	16.0	14.0	16.0
Newlands	132	25.0	2.4	1.3	3.5	3.9	3.5	3.9	3.5	3.9
North Goonyella	132	20.0	2.8	1.0	4.4	3.7	4.4	3.7	4.4	3.7
Oonooie	132	31.5	2.2	1.4	3.2	3.7	3.2	3.7	3.2	3.7
Peak Downs	132	31.5	2.7	1.5	4.2	3.7	4.2	3.7	4.2	3.7
Pioneer Valley	132	31.5	3.9	3.4	7.2	8.0	7.2	8.0	7.2	8.0
Proserpine	132	40.0	2.2	1.5	3.2	3.8	3.2	3.8	3.2	3.8
Ross	275	31.5	2.6	2.3	8.6	9.6	8.6	9.6	8.6	9.6
Ross	132	31.5	4.8	4.4	18.3	20.5	18.4	20.6	18.4	20.6
Springlands	132	40.0	4.4	2.2	9.6	10.6	9.6	10.6	9.6	10.6
Stony Creek	132	40.0	2.5	1.2	3.6	3.5	3.6	3.5	3.6	3.5
Strathmore	275	31.5	3.1	2.7	9.6	9.8	9.6	9.8	9.6	9.8
Strathmore	132	40.0	4.7	2.3	9.8	11.1	9.8	11.0	9.8	11.0
Townsville East	132	40.0	4.0	1.6	13.2	12.7	13.2	12.6	13.2	12.6
Townsville South	132	21.9	4.4	4.0	17.9	21.5	17.9	21.5	17.9	21.5
Townsville PS	132	31.5	3.7	2.5	10.7	11.2	10.7	11.2	10.7	11.2
Tully	132	31.5	2.4	1.9	4.0	4.2	4.0	4.2	4.0	4.2
Turkinje	132	20.0	1.8	1.2	2.9	3.3	2.9	3.3	2.9	3.3
Walkamin	275	40.0	1.6	0.9	3.2	3.7	3.2	3.7	3.2	3.7
Wandoo	132	31.5	3.2	2.9	4.6	3.3	4.5	3.3	4.5	3.3
Woree (1T)	275	40.0	1.4	0.9	2.8	3.3	2.8	3.3	2.8	3.3
Woree (2T)	275	40.0	1.4	0.9	2.9	3.4	2.9	3.4	2.9	3.4
Woree	132	40.0	3.0	2.5	6.1	8.4	6.1	8.4	6.1	8.4
Wotonga	132	40.0	3.5	1.6	6.2	7.2	6.2	7.2	6.2	7.2
Yabulu South	132	40.0	4.1	3.8	12.8	12.2	12.8	12.1	12.8	12.1

Table E.2 Indicative short circuit currents – central Queensland – 2019/20 to 2021/22

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Baralaba	132	15.3	3.3	1.4	4.2	3.6	4.2	3.6	4.2	3.6
Biloela	132	20.0	3.7	1.0	7.9	8.1	7.9	8.1	7.9	8.1
Blackwater	132	10.9	4.0	3.1	6.7	7.9	6.7	7.9	6.7	7.9
Bluff	132	40.0	2.6	2.2	3.7	4.6	3.7	4.6	3.7	4.6
Bouldercombe	275	31.5	7.1	6.4	20.4	19.7	20.4	19.6	20.4	20.1
Bouldercombe	132	21.8	8.1	4.5	11.6	13.6	11.5	13.6	15.0	17.8
Broadsound	275	31.5	4.9	4.1	12.5	9.4	12.5	9.4	12.5	9.4
Bundoora	132	31.5	3.5	1.2	8.7	8.7	8.7	8.7	8.7	8.7
Callemondah	132	31.5	11.0	5.6	22.1	24.7	22.1	24.7	22.1	24.7
Calliope River	275	40.0	7.6	6.6	20.9	23.8	20.9	23.8	20.9	23.8
Calliope River	132	40.0	11.7	9.5	24.8	29.9	24.8	29.9	24.8	29.9
Calvale	275	31.5	7.6	6.8	23.6	26.0	23.6	26.1	23.6	26.0
Calvale (1T)	132	31.5	5.3	1.0	8.8	9.6	8.8	9.6	8.8	9.6
Calvale (2T)	132	31.5	5.3	1.0	8.4	9.3	8.4	9.3	8.4	9.3
Duaringa	132	40.0	1.7	1.1	2.3	3.0	2.3	3.0	2.3	3.0
Dysart	132	10.9	3.0	1.8	4.8	5.4	4.8	5.4	4.8	5.4
Egans Hill	132	25.0	5.5	1.5	7.3	7.4	7.2	7.4	8.5	8.3
Gladstone PS	275	40.0	7.4	6.4	19.5	21.7	19.5	21.7	19.5	21.7
Gladstone PS	132	40.0	7.4	6.5	21.8	25.0	21.8	25.0	21.8	25.0
Gladstone South	132	40.0	9.1	7.5	16.2	17.3	16.2	17.3	16.2	17.3
Grantleigh	132	31.5	2.1	1.7	2.6	2.8	2.6	2.7	2.7	2.9
Gregory	132	31.5	5.5	4.6	10.6	11.7	10.6	11.7	10.6	11.7
Larcom Creek	275	40.0	6.6	3.0	15.5	15.4	15.5	15.3	15.5	15.4
Larcom Creek	132	40.0	6.8	3.7	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.2	2.5	6.4	6.2	6.4	6.2	6.4	6.2
Lilyvale	132	25.0	5.7	4.8	11.3	12.8	11.3	12.8	11.3	12.8
Moura	132	40.0	2.8	1.1	3.9	4.2	3.9	4.2	3.9	4.2
Norwich Park	132	31.5	2.4	1.1	3.6	2.7	3.6	2.7	3.6	2.7
Pandoin	132	40.0	4.8	1.2	6.2	5.6	6.2	5.6	7.0	6.1
Raglan	275	40.0	6.0	3.7	12.0	10.5	12.0	10.4	12.0	10.5
Rockhampton (1T)	132	40.0	4.5	1.7	5.8	5.9	5.8	5.9	6.6	6.4
Rockhampton (5T)	132	40.0	4.4	1.7	5.7	5.7	5.6	5.7	6.3	6.2

Table E.2 Indicative short circuit currents – central Queensland – 2019/20 to 2021/22 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklands	132	31.5	5.2	3.5	6.8	6.1	6.8	6.1	7.9	6.7
Stanwell	275	31.5	7.3	6.6	23.2	24.6	23.2	24.6	23.2	24.8
Stanwell	132	31.5	4.2	3.0	5.4	6.0	5.4	6.0	6.0	6.5
Wurdong	275	31.5	7.1	5.5	16.7	16.6	16.7	16.6	16.7	16.6
Wycarbah	132	40.0	3.4	2.5	4.2	5.1	4.2	5.1	4.6	5.4
Yarwun	132	40.0	6.6	4.2	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2019/20 to 2021/22

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	6.6	5.6	18.2	18.8	18.3	18.8	18.2	18.8
Abermain	110	31.5	12.1	9.9	21.5	25.4	21.5	25.4	21.5	25.4
Algester	110	40.0	12.1	10.7	21.1	20.9	21.1	20.9	21.1	20.9
Ashgrove West	110	26.3	11.4	9.0	19.2	20.1	19.2	20.1	19.2	20.1
Belmont	275	31.5	6.5	5.7	17.0	17.8	17.0	17.8	17.0	17.8
Belmont	110	37.4	14.4	12.7	27.8	34.4	27.8	34.5	27.8	34.4
Blackstone	275	40.0	6.9	6.0	21.3	23.4	21.3	23.5	21.3	23.4
Blackstone	110	40.0	13.4	11.9	25.5	29.1	25.5	29.1	25.5	29.1
Blackwall	275	37.0	7.2	6.2	22.5	24.2	22.5	24.2	22.5	24.2
Blythdale	132	40.0	3.3	2.4	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	6.1	5.2	23.7	25.7	23.7	25.7	23.7	25.7
Braemar (East)	275	40.0	7.0	4.7	27.0	31.3	27.1	31.3	27.1	31.3
Braemar (West)	275	40.0	7.0	4.7	27.5	30.3	27.5	30.3	27.5	30.3
Bulli Creek	330	50.0	6.2	5.5	18.5	14.5	18.5	14.6	18.5	14.6
Bulli Creek	132	40.0	3.1	2.9	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	10.5	7.6	17.3	16.7	17.3	16.7	17.3	16.7
Chinchilla	132	25.0	5.3	4.2	8.6	8.2	8.6	8.2	8.6	8.2
Clifford Creek	132	40.0	4.2	3.5	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.3	3.8	12.6	11.8	12.6	11.8	12.6	11.8
Columboola	132	25.0	7.9	6.2	16.5	18.6	16.5	18.6	16.5	18.6
Condabri North	132	40.0	7.1	5.7	13.4	12.2	13.4	12.2	13.4	12.2
Condabri Central	132	40.0	5.6	4.6	9.0	6.7	9.0	6.7	9.0	6.7
Condabri South	132	40.0	4.5	3.7	6.6	4.4	6.6	4.4	6.6	4.4
Coopers Gap	275	40.0	3.3	2.6	17.7	17.4	17.8	17.4	17.7	17.4
Dinoun South	132	40.0	4.6	3.8	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	2.9	1.2	4.3	4.6	4.3	4.6	4.3	4.6
Eurombah (2T)	275	40.0	2.9	1.2	4.3	4.6	4.3	4.6	4.3	4.6
Eurombah	132	40.0	4.6	3.5	6.9	8.5	6.9	8.5	6.9	8.5
Fairview	132	40.0	3.2	2.6	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	3.9	3.0	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	5.9	5.3	9.2	8.6	9.2	8.6	9.2	8.6
Gin Gin	132	20.0	8.1	6.1	12.1	13.0	12.1	13.0	12.1	13.0

Table E.3 Indicative short circuit currents – southern Queensland – 2019/20 to 2021/22 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Goodna	275	40.0	6.4	5.1	16.3	16.0	16.3	16.1	16.3	16.0
Goodna	110	40.0	13.4	11.9	25.5	27.6	25.5	27.6	25.5	27.6
Greenbank	275	40.0	6.9	6.0	20.5	22.7	20.5	22.7	20.5	22.7
Halys	275	50.0	8.1	6.9	32.7	28.2	32.8	28.3	32.7	28.2
Kumbarilla Park (1T)	275	40.0	6.1	1.7	16.8	16.2	16.8	16.2	16.8	16.2
Kumbarilla Park (2T)	275	40.0	6.1	1.7	16.8	16.2	16.8	16.2	16.8	16.2
Kumbarilla Park	132	40.0	8.3	5.6	13.3	15.3	13.3	15.3	13.3	15.3
Loganlea	275	40.0	6.2	5.5	15.0	15.4	15.0	15.4	15.0	15.4
Loganlea	110	31.5	13.0	11.6	22.7	27.3	22.7	27.3	22.7	27.2
Middle Ridge (4T)	330	50.0	5.3	3.2	12.8	12.4	12.8	12.4	12.8	12.4
Middle Ridge (5T)	330	50.0	5.2	3.2	13.1	12.8	13.2	12.8	13.1	12.8
Middle Ridge	275	31.5	6.7	5.9	18.3	18.4	18.3	18.4	18.3	18.4
Middle Ridge	110	18.3	10.8	9.1	21.4	25.3	21.4	25.3	21.4	25.3
Millmerran	330	40.0	5.9	5.2	18.6	19.9	18.6	19.9	18.6	19.9
Molendinar (1T)	275	40.0	4.7	2.1	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar (2T)	275	40.0	4.7	2.1	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar	110	40.0	11.5	10.0	20.1	25.4	20.1	25.4	20.1	25.4
Mt England	275	31.5	7.1	6.2	22.8	23.0	22.8	23.0	22.8	23.0
Mudgeeraba	275	31.5	5.0	4.2	9.5	9.4	9.5	9.4	9.5	9.4
Mudgeeraba	110	25.0	10.6	9.6	18.8	22.9	18.8	23.0	18.8	22.9
Murarrie (1T)	275	40.0	5.9	2.5	13.2	13.2	13.2	13.2	13.2	13.2
Murarrie (2T)	275	40.0	5.9	2.4	13.2	13.3	13.2	13.3	13.2	13.3
Murarrie	110	40.0	13.4	11.9	23.8	28.8	23.8	28.8	23.8	28.8
Oakey PS	110	31.5	5.1	1.2	11.4	12.5	11.4	12.5	11.4	12.5
Oakey	110	40.0	4.9	1.2	10.2	10.1	10.2	10.1	10.2	10.1
Orana	275	40.0	5.8	3.3	15.1	13.8	15.1	13.8	15.1	13.8
Palmwoods	275	31.5	5.1	3.3	8.6	8.9	8.6	9.0	8.6	9.0
Palmwoods	132	21.9	6.9	5.5	13.1	15.7	13.1	15.9	13.1	15.9
Palmwoods (7T)	110	40.0	8.9	6.7	7.3	7.6	7.3	7.6	7.3	7.6
Palmwoods (8T)	110	40.0	8.9	6.7	7.3	7.6	7.3	7.6	7.3	7.6

Table E.3 Indicative short circuit currents – southern Queensland – 2019/20 to 2021/22 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2019/20		2020/21		2021/22	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Redbank Plains	110	31.5	12.1	9.2	21.4	20.9	21.4	20.9	21.4	20.9
Richlands	110	40.0	12.3	10.5	21.9	22.7	21.9	22.7	21.9	22.7
Rocklea (1T)	275	31.5	6.0	2.4	13.3	12.3	13.3	12.4	13.3	12.3
Rocklea (2T)	275	31.5	5.0	2.4	8.8	8.5	8.8	8.5	8.8	8.5
Rocklea	110	31.5	13.3	11.8	25.0	28.8	25.0	28.8	25.0	28.8
Runcorn	110	40.0	11.3	8.4	18.8	19.3	18.9	19.3	18.8	19.3
South Pine	275	31.5	7.0	6.1	18.9	21.4	18.9	21.4	18.9	21.4
South Pine (West)	110	40.0	12.8	11.2	20.5	23.6	20.5	23.6	20.5	23.6
South Pine (East)	110	40.0	12.1	9.9	21.6	27.7	21.7	27.7	21.6	27.7
Sumner	110	40.0	11.9	8.8	20.7	20.3	20.7	20.3	20.7	20.3
Swanbank E	275	40.0	6.9	6.0	20.9	23.0	21.0	23.0	20.9	23.0
Tangkam	110	31.5	5.9	4.0	13.5	12.5	13.5	12.5	13.5	12.5
Tarong	275	31.5	8.1	6.9	34.1	35.9	34.2	35.9	34.1	35.9
Tarong (1T)	132	25.0	4.5	1.1	5.8	6.1	5.8	6.1	5.8	6.1
Tarong (4T)	132	31.5	4.5	1.1	5.8	6.1	5.8	6.1	5.8	6.1
Tarong	66	40.0	11.4	6.5	15.1	16.3	15.1	16.3	15.1	16.3
Teebar Creek	275	40.0	4.7	3.2	7.4	7.1	7.4	7.1	7.4	7.1
Teebar Creek	132	40.0	7.5	5.9	10.8	11.6	10.8	11.6	10.8	11.6
Tennyson	110	40.0	10.3	1.7	16.3	16.5	16.3	16.5	16.3	16.5
Upper Kedron	110	40.0	12.1	10.8	21.3	18.8	21.3	18.8	21.3	18.8
Wandoan South	275	40.0	4.0	3.1	7.1	7.8	7.1	7.8	7.1	7.8
Wandoan South	132	40.0	5.9	4.6	8.7	11.0	8.7	11.1	8.7	11.0
West Darra	110	40.0	13.2	11.7	24.9	23.9	25.0	23.9	24.9	23.9
Western Downs	275	40.0	6.9	4.3	25.6	24.9	25.6	24.9	25.6	24.9
Woolooga	275	31.5	5.6	4.8	10.0	11.2	10.0	11.2	10.0	11.2
Woolooga	132	20.0	9.0	7.6	13.4	15.7	13.4	15.7	13.4	15.7
Yuleba North	275	40.0	3.5	2.8	5.8	6.4	5.8	6.4	5.8	6.4
Yuleba North	132	40.0	5.3	4.2	7.7	9.4	7.7	9.4	7.7	9.4

Appendix F – Compendium of potential non-network solutions opportunities within the next five years

Table F.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	$30m	Far North	Up to 60MW at peak and up to 900MWh per day on a continuous basis to provide supply to the 22kV network	June 2024	Section 5.7.1
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations	$10 to $15m	Far North	Over 250MW at peak to provide supply to the Cairns area, facilitating the provision of system strength and voltage control	October 2023	Section 5.7.1
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations	$85 to $165m	Far North	Over 300MW at peak to provide supply to the Far North area, facilitating the provision of system strength and voltage control	December 2026	Section 5.7.1
Line refit works on the coastal 132kV transmission line between Clare South and Townsville South substations with network reconfiguration	$28m	Ross	Up to 10MW in the Proserpine, Clare or Collinsville area facilitating the provision of system strength and voltage control (1)	December 2022	Section 5.7.2 RIT-T in progress
Line refit works on the 275kV transmission lines between Strathmore and Ross substations	$6m	Ross	Up to 40MW at peak and up to 800MWh per day on a continuous basis near Milchester while maintaining the CQ-NQ transfer limit	June 2024	Section 5.7.2
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	$10m	Gladstone	Up to 180MW and approximately 3,200MWh per day	December 2021	Section 5.7.5
Partial rebuild of the transmission line between Calliope River and Gin Gin substations	$18m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional impacts and impacts on network users requiring consideration.	December 2024	Section 5.7.6

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Tee	$6m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional impacts and impacts on network users requiring consideration.	December 2024	Section 5.7.6
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	$20m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional impacts and impacts on network users requiring consideration.	June 2024	Section 5.7.6
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	$13m	Moreton	Up to 220MVA at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2024	Section 5.7.10
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	$46m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area of over 250MW	December 2026	Section 5.7.11
Substations - primary plant and secondary systems					
Kamerunga 132kV Substation replacement	$24m	Far North	Up to 60MW and 900MWh per day on a continuous basis to provide supply to the 22kV network	October 2022	Section 5.7.1 RIT-T in progress
Cairns 132kV secondary systems replacement	$6m	Far North	Up to 65MW and 550MWh per day in the Cairns area	December 2022	Section 5.7.1
Innisfail 132kV secondary systems replacement	$7m	Far North	Up to 27MW at peak and 550MWh per day on a continuous basis to provide supply to the 22kV network at Innisfail	December 2023	Section 5.7.1

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Alan Sherriff 132kV secondary systems replacement	$9m	Ross	Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kV neetwork in north-east Townsville	June 2025	Section 5.7.2
Kemmis 132kV secondary systems replacement	$7m	North	Injection or demand response of up to 32MW on a continuous basis, and up to 760MWh per day as well as short duration peaks of up to 70MVA	June 2023	Section 5.7.3
Calvale 275kV primary plant replacement	$13m	Central West	Powerlink would consider proposals from non-network providers, predominantly generation, to reduce the load requirements in this region. However, this would result in material intra-and other impacts requiring consideration.	June 2025	Section 5.7.4
Gladstone South 132kV secondary systems replacement	$17m	Gladstone	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Gladstone area of up to 200MW	December 2023	Section 5.7.5
Murarrie 110kV secondary systems replacement	$21m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into the CBD and south-eastern suburbs of Brisbane of over 300MW	December 2023	Section 5.7.10
Mudgeeraba 275kV secondary systems replacement	$9m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area of over 250MW	December 2021	Section 5.7.11
Molendinar 275kV secondary systems replacement	$13m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the norther Gold Coast area of over 250MW	June 2024	Section 5.7.11

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Substations - transformers					
Tully 132/22kV transformer replacement	$5m	Far North	Up to 15MW at peak and up to 270MWh per day to provide supply to the 22kV network at Tully	June 2024	Section 5.7.1
Lilyvale 275/132kV primary plant replacement and transformers replacement	$9m	Central West	Full network support – over 200MW at peak at Lilyvale and switching functionality	October 2022	Section 5.7.4 RIT-T in progress
			Partial network support – replace the functionality of one of the two at risk transformers	As early as June 2021	
Blackwater 132/66/11kV transformers replacement	$5m	Central West	Provide support to the Ergon Energy 66kV network of up to 150MW and 2,6500MWh per day in the Blackwater area	June 2022	Section 5.7.4 RIT-T in progress
Tarong 275/66kV transformers replacement	$16m	South West	Full network support – up to 40MW and up to 850MWh per day on a continuous basis	December 2024	Section 5.7.7
			Partial network support – replace the functionality of one of the existing transformers on a continuous basis		
Redbank Plains 110kV primary plant and 110/11kV transformers replacement	$10m	Moreton	Provide support to the 11kV network of up to 25MW and up to 400MWh per day	June 2024	Section 5.7.10

Notes:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget. However material operational costs, which are required to meet the scope of a network option, are included in the overall cost of that network option as part of the RIT-T cost-benefit analysis. Therefore, in the RIT-T analysis, the total cost of the proposed option will include an additional $10 million to account for operational works for the retirement of the transmission line.

(2) Please refer to Powerlink and TransGrids' joint Project Specification Consultation Report for the non-network requirements in relation to the Expanding NSW-Queensland transmission transfer capacity RIT-T currently in progress which has been excluded from this Appendix.

(3) More generally, TAPR template data associated with emerging constraints which may require future capital expenditure, including potential projects which fall below the RIT-T cost threshold, is available on Powerlink's website (refer to Appendix B, in particular transmission connection points and transmission line segments data templates).

Appendix G – Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
AIS	Air Insulated Switchgear
BSL	Boyne Smelter Limited
CAA	Connection and Access Agreement
CBD	Central Business District
COAG	Council of Australian Governments
CoGaTI	Coordination of Generation and Transmission Investment
CPI	Consumer Price Index
CQ	Central Queensland
CQ-SQ	Central Queensland to South Queensland
CQ-NQ	Central Queensland to North Queensland
CSG	Coal Seam Gas
DCA	Dedicated Connection Assets
DER	Disbributed Energy Resources
DNRME	Deparment of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DSM	Demand side management
EFCS	Emergency Frequency Control Systems
EFI	AEMO's Electricity Forecast Insights
EII	Energy Infrastructure Investments
EMS	Energy Management System
ENA	Energy Networks Australia
ESB	Energy Security Board
EMT-type	Eletromagnetic Transient-type
ESOO	Electricity Statement of Opportunity
EV	Electric vehicles
FIT	Feed-in tariff
FNQ	Far North Queensland
GCG	Generation Capacity Guide
GIS	Gas Insulated Switchgear
GPS	Generator Performance Standards
GSP	Gross State Product
GWh	Gigawatt hour
HV	High Voltage
HVDC	High voltage direct current
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovoltage
LTTW	Lightning Trip Time Window
MLF	Marginal Loss Factors
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecasting Report
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
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
NSW	New South Wales

Appendix G - Glossary *(continued)*

NQ	North Queensland
OFGS	Over Frequency Generation Shedding
PADR	Project Assessment Draft Report
PoE	Probability of Exceedance
PS	Power Station
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QHES	Queensland Household Energy Survey
QNI	Queensland/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
SQ	South Queensland
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TGP	TAPR Guideline Connection Point
TGTL	TAPR Guideline Transmission Line
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable renewable energy

Contact us

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