Transmission Annual Planning Report

2018

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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. It provides information about the Queensland electricity transmission network to 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 broader 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.

Overview

The 2018 TAPR outlines the key factors impacting Powerlink's transmission network development and operations and discusses how Powerlink is responding 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 amended planning standard has been in effect from July 2014. It allows the network to be planned and developed with up to 50MW or 600MWh load at risk of being interrupted during a single network contingency. This provides more flexibility in the cost-effective development of network and non-network solutions to meet future demand.

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. Considerable emphasis is placed on ensuring that asset reinvestment is not just on a like-for-like basis. Network planning studies have focused on evaluating the enduring need for existing assets in the context of a subdued demand growth outlook and the potential for network reconfiguration, coupled with alternative non-network solutions.

Powerlink's focus on stakeholder engagement has continued over the last year, with a range of engagement activities undertaken to seek stakeholder feedback and input into our network investment decision making. This included the Powerlink Queensland Transmission Network Forum, incorporating related break-out sessions on delivering clean energy hubs in Queensland, how transmission can deliver secure, affordable and sustainable electricity in the future, and transmission network connections under the Transmission Connection and Planning Arrangements Rule change.

Electricity energy and demand forecasts

The energy and demand forecasts presented in this TAPR consider the following factors:

- consumer response to forecast reductions in retail electricity prices
- continued growth of solar photovoltaic (PV) installations, including solar PV farms connecting to the distribution network
- forecast improvement in Queensland economic growth conditions over the outlook period
- the impact of energy efficiency initiatives, battery storage technology and tariff reform.

Powerlink's forecasts are obtained through a reconciliation of top-down econometric forecasts derived from externally provided forecasts of economic indicators, and bottom-up forecasts from Distribution Network Service Providers (DNSPs) and directly connected customers at each transmission connection supply point.

Key economic inputs to Powerlink's econometric model include population growth, employment and the price of electricity. DNSP customer forecasts are reconciled to meet the totals obtained from this model.

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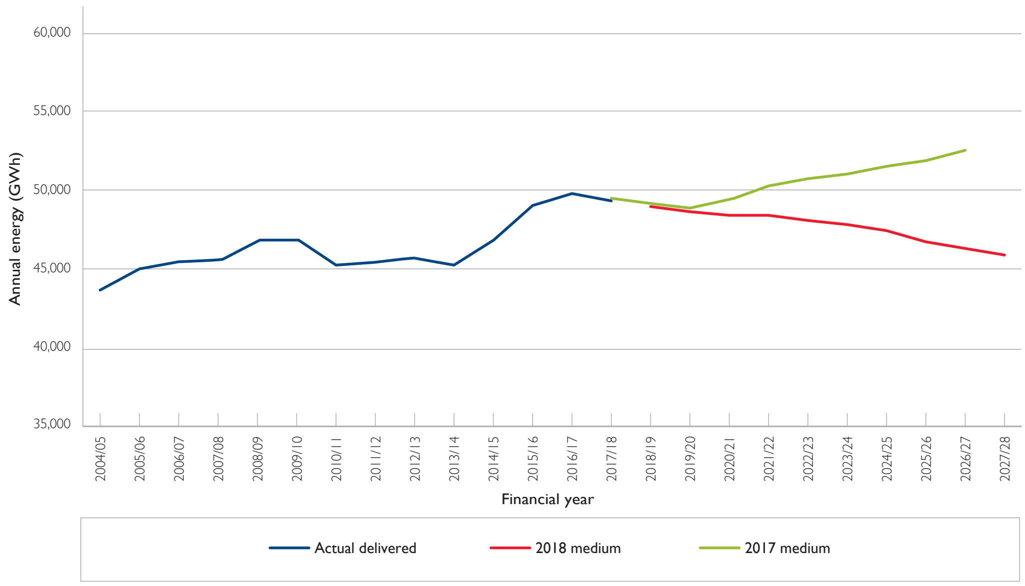
The 2017/18 summer in Queensland set a new record demand at 5:00pm on 14 February, when 8,842MW was delivered from the transmission grid. This corresponded to an operational 'as generated' demand of 9,796MW, passing the previous record of 9,412MW set last summer. After temperature correction, the 2017/18 summer demand exceeded the 2017 TAPR forecast by around 3%.

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 49,374GWh in 2017/18 to 45,913GWh in 2027/28. The delivered energy forecast in the 2018 TAPR shows a significant reduction compared to the 2017 TAPR. The reduction is due to forecast increases in the capacity of distribution connected renewable generation. The additional generation capacity is in response to the federal government's large-scale renewable energy target of 33,000GWh per annum by 2020 and the Queensland government's target of 50% renewable energy by 2030.

A comparison of the 2017 and 2018 TAPR forecasts for energy delivered from the transmission network is displayed in Figure 1. Energy delivered from the transmission network for 2017/18 is expected to be within 1% of the 2017 TAPR forecast.

Figure 1 Comparison of the medium economic outlook energy forecasts



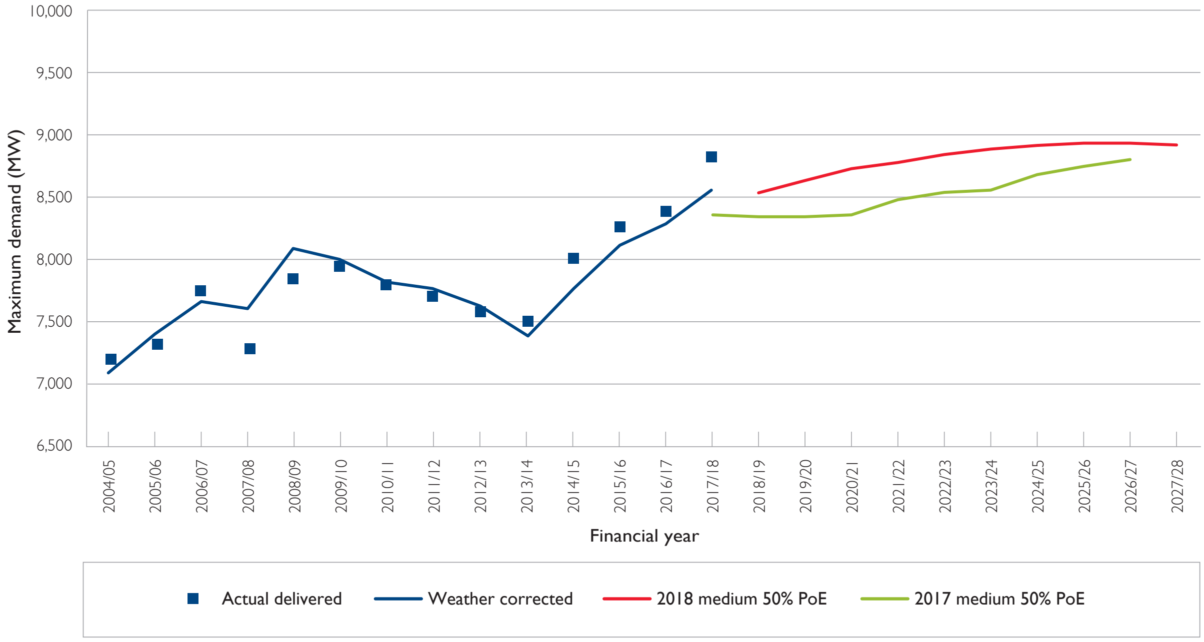
Electricity demand forecast

Based on the medium economic outlook, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.4% per annum over the next 10 years, from 8,577MW (weather corrected) in 2017/18 to 8,925 MW in 2027/28.

The transmission delivered maximum demand for summer 2017/18 of 8,842MW was a new record for Queensland.

A comparison of 2017 and 2018 summer maximum demand forecasts for the medium economic outlook, based on a 50% probability of exceedance (PoE) is displayed in Figure 2. As with the energy forecasts, the 2018 demand forecast has been adjusted to take account of actual consumption over the 2017/18 period and updated to reflect the latest economic projections for the State. The increase is largely due to an expectation that electricity prices will reduce and that the Queensland state economy will return to solid growth.

Figure 2 Comparison of the medium economic outlook demand forecasts



Powerlink's asset planning criteria

There is a continued strong focus on delivering the right balance between reliability and cost of transmission services. The amended planning standard (introduced from 1 July 2014) allows for increased flexibility by permitting Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event. The planning standard sets limits of unsupplied demand and energy that may be at risk for the contingency event.

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits of 50MW or 600MWh are exceeded, or when the economic cost of load at risk of being unsupplied justifies the cost of the investment. Therefore, the application of the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required in response to demand growth. Powerlink will continue to maintain and operate its transmission network to deliver safe, reliable and cost effective supply to customers.

Future network development

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 and network topography of the transmission network in Queensland and the NEM over the 10-year outlook period.

Powerlink is responding to these changes by:

- implementing and adopting the recommendations of the Finkel and other reviews
- adapting to changes in electricity consumer 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, 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.

As previously mentioned, the Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure needed to manage the emerging risks related to this asset base, which is now reaching end of technical service life, represents Powerlink's program of work within the outlook period. The reinvestment program is particularly focused on transmission lines where condition assessment has identified emerging risks requiring action 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 and considered a broad range of options including network reconfiguration, asset retirement, non-network solutions or replacement with an asset of lower capacity. This strategy was used to undertake minor works from Central Queensland to Southern Queensland to align the end of technical service life of the 275kV transmission lines. 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.

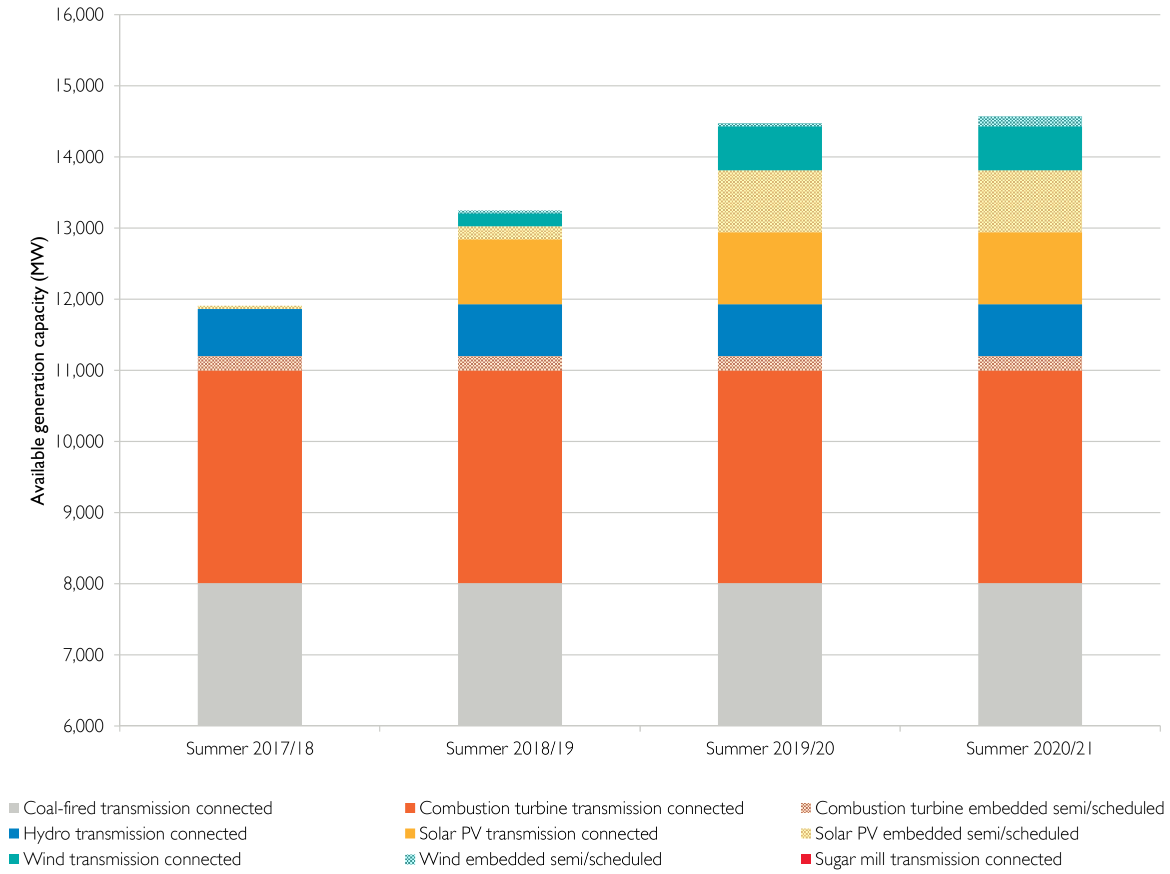
The integrated planning approach has identified a number of potential reconfiguration opportunities in the Ross, Central West, Gladstone and Moreton zones within the outlook period. Powerlink has also included additional information in this TAPR relating to long-term network reconfiguration strategies that in future years will include further stakeholder engagement and consultation.

Renewable energy and generation capacity

Over the past year, Powerlink has supported a high level of connection activity, responding to more than 120 connection enquiries comprising over 25,000MW of potential VRE generation. In 2017/18, Powerlink finalised seven VRE generator Connection and Access Agreements (CAAs) totalling 1,012MW.

The aggregate of executed CAAs across Network Service Providers (NSP) in Queensland during 2017/18 has added 1,912MW of capacity, taking Queensland's semi-scheduled VRE generation capacity to 2,645MW. Figure 3 illustrates the expected changes to available generation capacity in Queensland from summer 2017/18 to summer 2020/21.

Figure 3 Summer available generation capacity by energy source



Powerlink is also working with the Queensland Government on two initiatives:

- Economic Development Queensland on the Aldoga Renewable Energy Zone project and
- the Powering North Queensland Plan.

Powerlink will continue to engage with market participants and interested parties across the renewables sector to better understand the potential for VRE generation in Queensland.

Committed and commissioned projects

During 2017/18, major committed projects providing for reinvestment in substations and transmission lines across Powerlink's network include:

- Callide A/Calvale 132kV transmission reinvestment
- Garbutt 132/66kV transformers replacement
- Dysart 132kV primary plant and transformers replacement
- Calvale and Callide B 275/132k secondary systems replacement
- Gin Gin Substation replacement
- Ashgrove West Substation replacement
- line refit works on the 132kV transmission line between Eton tee and Alligator Creek Substation
- line refit works on the 275kV transmission line between Woolooga and Palmwoods substations.

Reinvestment projects completed in 2017/18 include replacement works at:

- Proserpine Substation
- Blackwater Substation
- Mudgeeraba Substation
- 132kV transmission line between Garbutt and Alan Sherriff substations.

Powerlink also finalised the last of its minor transmission augmentation projects to manage localised voltage limitations in the Northern Bowen Basin, with the installation of a 132kV capacitor bank at Moranbah Substation.

Grid section and zone performance

During 2017/18, the Powerlink transmission network supported the delivery of a record summer maximum demand of 8,842MW, 441MW higher than that recorded in summer 2016/17. Record transmission delivered demand was recorded for Wide Bay, Surat and Moreton zones.

The Central Queensland to Southern Queensland grid section showed greater levels of utilisation during 2017/18, mainly due to lower gas fired generation in the Bulli Zone and higher interconnector transfers sourced predominantly by generation in central and north Queensland.

The transmission network in the Queensland region performed reliably during the 2017/18 year, including during the record summer maximum demand. Queensland grid sections were largely unconstrained due in part to the absence of high impact events on the transmission network, effective emergency response, and prudent scheduling of planned transmission outages. Towers damaged by Tropical Cyclone Debbie were rectified in 2017.

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 anticipates a significant Regulatory Investment Test for Transmission (RIT-T) program in relation to the replacement of network assets, particularly over the next two years.

During 2017/18, Powerlink commenced regulatory processes associated with proposed future network reinvestments, in particular, where technically and economically feasible, to consider opportunities for non-network solutions to resolve the following network requirements:

- addressing the secondary systems condition risks at Baralaba Substation
- addressing the secondary systems condition risks at Dan Gleeson Substation
- maintaining reliability of supply to Ingham.

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.

Queensland/New South Wales Interconnector (QNI) transmission line

Preliminary market modelling studies undertaken in 2017 by TransGrid and Powerlink indicate that there may be net market benefits arising from upgrading the interconnector capability on QNI. These preliminary findings are consistent with the 2016 NTNDP. In accordance with the requirements of the RIT-T, TransGrid and Powerlink aim to publish a joint Project Specification Consultation Report (PSCR) in the third quarter of 2018 relating to the potential upgrade of the interconnection between Queensland and New South Wales.

Additional stakeholder consultation for non-network solutions

Powerlink is continuing to build its engagement processes with non-network providers and expand the use of non-network solutions to address the future needs of the transmission network, as an alternative option to like-for-like replacements or to complement an overall network reconfiguration strategy, where technically and economically feasible.

As the opportunity arises, Non-network Solution Feasibility Studies will be undertaken to seek potential alternate solutions for future network developments resulting from augmentation and reinvestments needs which fall outside of NER consultation requirements. Powerlink will continue to request non-network solutions from market participants as part of the RIT-T process.

In March and May 2018, Powerlink held Future Transmission Network webinars, to inform and discuss with non-network providers and other stakeholders relevant and topical matters impacting potential future non-network opportunities and more broadly, the future regulated development of the transmission network in Queensland. The webinars included discussion on recent regulatory changes in relation to transmission network planning and an informative session on Powerlink's approach to assessing risk on an ageing transmission network.

Sharing information and building relationships through activities such as the Transmission Network Forum and Future Transmission Network webinar series will assist in broadening communication channels and provide additional opportunities to exchange information on the viability and potential of non-network solutions.

Customer and consumer engagement

Powerlink has embedded its Stakeholder Engagement Framework, which focuses on engaging with 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 2017 sought views from over 100 key stakeholders and highlighted year-on-year improvements in reputation and social licence to operate for Powerlink.

Powerlink's Customer Panel met throughout the year, with panel members providing input and feedback on Powerlink's decision making processes and methodologies. 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 2017, Powerlink has engaged with key stakeholders in a number of ways, including its Transmission Network Forum, and Future Transmission Network webinars – all proving to be valuable avenues to exchange information and receive stakeholder input on a range of investment and forecasting considerations.

Executive Summary

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2018 TAPR continues to focus on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

The 2018 TAPR:

- provides additional information in relation to joint planning and Powerlink's approach to asset management (refer to Chapters 3 and 4)
- includes additional information for the proposed replacement of network assets and potential non-network solutions which are anticipated to be subject to the RIT-T in the next five years (refer to Chapter 5)
- summarises possible network reinvestments in the next six to 10 years (refer to Chapter 5)
- discusses possible future network asset retirements for the 10-year outlook period (refer to Chapter 5)
- includes information on network control facilities and the outcome of the inaugural Power System Frequency Risk Review (refer to Chapter 6)
- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 8)
- includes enhanced information with respect to forecasting data, sources of input and assumptions (refer to Appendices A and B)
- to assist non-network providers, includes a compendium on where to locate information within the TAPR on potential non-network opportunities, grouped by investment type (Appendix F)
- includes updated information on Powerlink's approach to assisting the development of non-network solutions – specifically through the ongoing improvement of engagement practices for non-network solution providers (refer to Section 1.8.1).

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 2017 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 2018 TAPR contains enhanced information with respect to forecasting data and identifies key areas of the transmission network in Queensland requiring expenditure in the 10-year outlook period.

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 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.

This 2018 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 2018 TAPR builds upon work undertaken by Powerlink since 2016, maturing 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 (NEFR)), Electricity Statement of Opportunities (ESOO), National Transmission Network Development Plan (NTNDP)[2] and/or Integrated System Plan (ISP)[3].

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. During 2018 AEMO will deliver the first ISP which will integrate generation and grid development outlooks.

1 For the purposes of Powerlink's 2018 TAPR, Version 108 of the NER in place from 31 May 2018.

2 The release of the 2017 NTNDP was deferred by the Australian Energy Regulator and will form part of the 2018 Integrated System Plan to be published in July 2018.

3 The introduction of the ISP was a recommendation of the Independent Review into the Future Security of the National Electricity Market (Finkel Review) released in June.

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 the 2016 NTNDP, as the most recent version published, is considered in this TAPR and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2018 TAPR in conjunction with AEMO's 2018 EFI, 2018 ISP and ESOO, which are anticipated to be published in June, July and August 2018 respectively.

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 everyone interested or involved in the NEM including AEMO, Registered Participants and interested parties. The TAPR also provides broader 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 is 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, 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 is responding to dynamic changes in the external environment by:

- implementing and adopting the recommendations of the Finkel and other reviews
- adapting to changes in electricity consumer behaviour and economic outlook.

Powerlink is responding to these changes by:

- 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 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 (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 promulgated by the Australian Energy Regulator (AER) to transmission investment proposals. 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.

1 Introduction

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.

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).

In addition to meeting the forecast demand, Powerlink must maintain its current network so that the risks arising from the condition and performance of existing assets are appropriately managed. Powerlink routinely undertakes an assessment of asset condition to identify emerging asset 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. 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 assets are not necessarily replaced on a like-for-like basis. Rather, asset reinvestment strategies and decisions are made taking into account the inter-related connectivity of the high voltage 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:

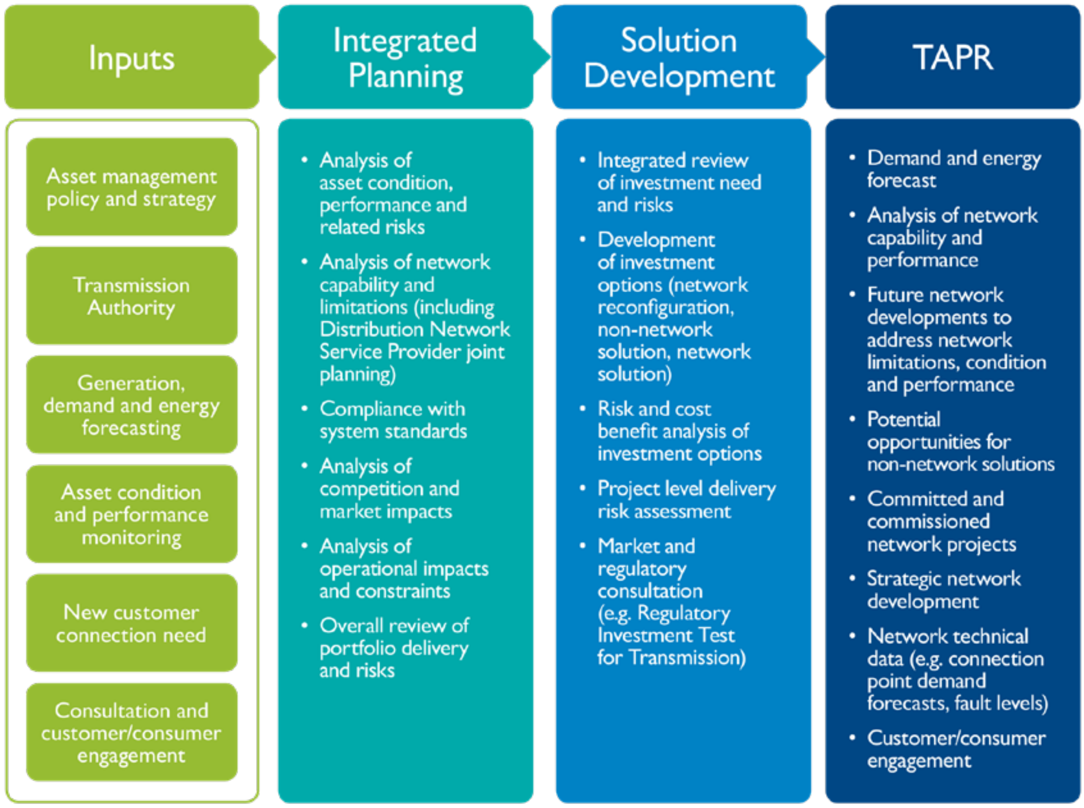
- retiring or decommissioning assets where there is unlikely to be an ongoing future need
- refurbishing to extend the service life of assets
- replacing assets of different capacity or type
- changing the topography of the network
- implementing non-network solutions.

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. 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.

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



1.7.3 Joint planning

Powerlink undertakes joint planning with other Network Service Providers (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 focused 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 2017 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 are 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 anticipated regulatory consultations, 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 to allow for increased flexibility from July 2014. 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 consumers.

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 stakeholders using a range of engagement methods. Two key stakeholder groups for Powerlink are customers and consumers. Customers are defined as those who are directly connected to Powerlink's network, while consumers are 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 understanding and awareness of our business practices, including load forecasting and transmission network planning.

1.9.1 Customer and consumer engagement

Powerlink is committed to proactively engaging with stakeholders 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 2017, the survey provides comparisons between baseline research undertaken in 2012 and year on year trends to inform engagement strategies with individual stakeholders.

2017/18 Stakeholder engagement activities

Since the publication of the 2017 TAPR, Powerlink has engaged with stakeholders in various ways through a range of forums as outlined below.

Transmission Network Forum

In August 2017, more than 100 customer, consumer, government and industry representatives attended Powerlink's annual Transmission Network Forum. The forum provided an overview of Powerlink's 2017 TAPR, followed by interactive breakout sessions on delivering clean energy hubs in Queensland, how transmission can deliver secure, affordable and sustainable electricity in the future, and transmission network connections under the Transmission Connection and Planning Arrangements Rule change effective 1 July 2018.

Customer Panel

Powerlink hosts a Customer Panel that provides an interactive forum for our stakeholders to give input and feedback to Powerlink regarding our decision making, processes and methodologies. Composed of members from a range of sectors including energy industry, resources, community advocacy groups, consumers 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 2017 and April 2018 to discuss and explore topics including the RIT-T for replacement projects, AER's Rate of Return Guideline Review, asset management strategies, transmission pricing arrangements and Powerlink's new Customer Service Charter. The panel also conducted a site visit to the Belmont Substation in September 2017 to view Powerlink's infrastructure first-hand and raise awareness of how the transmission network operates.

Future Transmission Network webinars

Powerlink's first Future Transmission Network webinar for 2018 was held in March and tailored specifically for non-network providers. The webinar focused on:

- providing an update on recent regulatory changes to the TAPR and RIT-T, which increase transparency on transmission network planning and investment decision making
- discussing opportunities and proposed communication activities to broaden and extend engagement with non-network providers.

It is anticipated that the provision and exchange of early information through engagement activities such as this will generate more opportunities for interactions with non-network providers during formal or informal consultation processes.

Powerlink's second Future Transmission Network webinar for 2018 was held in May. The webinar provided an opportunity to:

- engage with a wide range of stakeholder groups as Powerlink develops and refines an approach to assessing and quantifying risk, particularly in relation to an ageing transmission network
- discuss how this approach to risk may be used to optimise future investment decision making and to assist in lowering the long run cost to consumers.

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

Stakeholder engagement activities for RIT-Ts

Powerlink recognises the importance of enhancing transparency to customers and consumers, particularly when undertaking transmission network planning and making investment decisions. In relation to stakeholder engagement activities for RIT-Ts, Powerlink is committed to a balanced approach in the public consultation process as suggested by the Customer Panel. In addition, Powerlink will leverage off and be guided by the AER's Stakeholder Engagement Framework as the benchmark when consulting with stakeholders as part of the RIT-T process. Taking this into account, the appropriate level of engagement for RIT-Ts may be most easily identified through discussion and consideration of the context of the proposed investment. Engagement activities for RIT-Ts will be considered 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.

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. 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, only ending these in 2016.

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
- through the use of Powerlink's Non-network Solution Feasibility Study process to actively seek non-network solutions for proposed network reinvestments which fall below the RIT-T cost threshold of $6 million.

Informal feedback received from non-network providers since the publication of the 2017 TAPR continues to indicate the importance of early advice of possible non-network opportunities outside of a defined process and ensuring that any engagement process implemented is iterative in nature.

Powerlink's 2018 TAPR includes a compendium for non-network providers that indicates possible future non-network opportunities, for the next five years (Appendix F). It is anticipated that the majority of these opportunities will require a RIT-T to identify the preferred option. Powerlink will continue to engage and work collaboratively with non-network providers during the RIT-T process to ensure an optimal solution is reached.

As discussed in Section 1.9.1, a Future Transmission Network webinar was held in March 2018 for non-network providers. 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 build upon the Future Transmission Network webinar series 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 2017 TAPR, Powerlink has continued its collaboration with the Institute for Sustainable Futures[4] 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 and provide additional technical information which historically has only been discussed at a high-level in the TAPR.

[4] Information available at Network Opportunity Mapping.

The Non-network Solution Feasibility Study process, in conjunction with the publicly available data provided via the Network Opportunities Mapping project and informal information sessions such as the Future Transmission Network webinar, responds to previous feedback Powerlink has received from a number of stakeholders about the need to provide enhanced and earlier information on the potential value and timing of non-network solutions.

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 existing and/or new generation or DSM initiatives (either as individual providers or aggregators).

The NNESR was introduced to serve as a communication tool to achieve the following outcomes:

- leveraging off the knowledge of participants to seek input on process enhancements that Powerlink can adopt to increase the potential uptake of non-network solutions
- to provide interested parties with information prior to the commencement of formal public consultation as part of the RIT-T
- provide information on potential opportunities in relation to other network reinvestments or augmentation network investments which may fall outside of NER consultation requirements.

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 2018 TAPR focuses on an integrated approach to future network development and contains detailed discussion on key areas of future 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 and optimisation 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 which may deliver a greater benefit to stakeholders.

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

The 2018 TAPR:

- provides additional information in relation to joint planning and Powerlink's approach to asset management (refer to Chapters 3 and 4)
- discusses possible future network asset retirements for the 10-year outlook period (refer to Chapter 5)
- includes additional 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)
- summarises possible network reinvestments in the next six to 10 years (refer to Chapter 5)
- includes information on network control facilities and the outcome of the inaugural Power System Frequency Risk Review (refer to Chapter 6)
- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 8)
- includes commentary on recent changes to the network connection process (refer to Chapter 8)

- includes enhanced information with respect to forecasting data, sources of input and assumptions (refer to Appendices A and B)
- includes a quick reference guide on where to locate information on potential non-network opportunities in the TAPR, grouped by investment type (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).

1 Introduction

CHAPTER 2

Energy and demand projections

2 Energy and demand projections

Key highlights

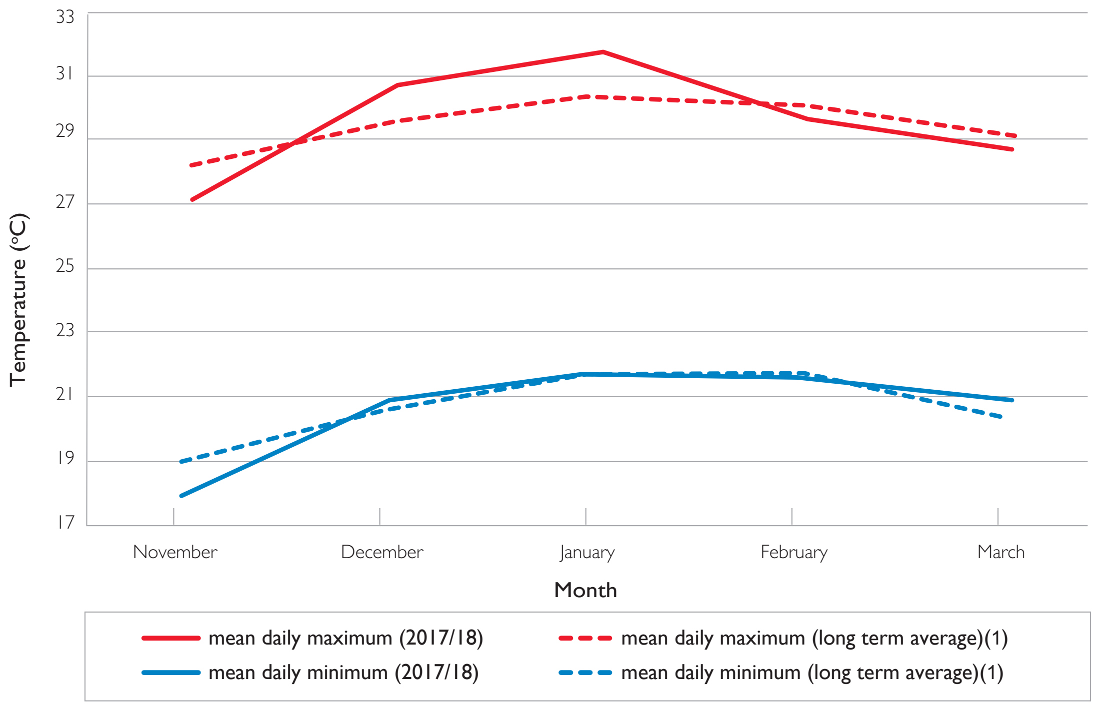
- This chapter describes the historical energy and demand performance of Powerlink's transmission network and provides forecast data separated by zone.
- The 2017/18 summer in Queensland set a new maximum delivered demand record at 5:00pm on 14 February, when 8,842MW was delivered from the transmission network.
- Powerlink develops its energy and demand forecasts using both a top-down econometric model and bottom-up forecasts from the distribution businesses and direct connect customers.
- Queensland's delivered energy consumption 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 in response to market and policy incentives. Based on the medium economic outlook, delivered energy consumption is expected to decline at an average annual rate of 0.7% per annum over the next 10 years.
- Based on the medium economic outlook, Queensland's delivered maximum demand is expected to maintain low growth, with an average annual increase of 0.4% per annum over the next 10 years.
- Powerlink is focused on understanding the potential future impacts of emerging technologies so transmission network services are developed in ways that are valued by customers.

2.1 Overview

The 2017/18 summer in Queensland set a new record demand at 5:00pm on 14 February, when 8,842MW was delivered from the transmission grid. This corresponded to an operational 'as generated' demand of 9,796MW, passing the previous record of 9,412MW set last summer. After temperature correction, the 2017/18 summer demand exceeded the 2017 Transmission Annual Planning Report (TAPR) forecast by around 3%.

Figure 2.1 shows observed temperatures for Brisbane during summer 2017/18 compared with long-term averages.

Figure 2.1 Brisbane weather over summer 2017/18



Note:

(1) Based on years 2000 to 2018.

Energy delivered from the transmission network for 2017/18 is expected to be within 1% of the 2017 TAPR forecast.

The electrical load for the coal seam gas (CSG) industry has nearly reached its forecast peak with observed demands close to those forecast in the 2017 TAPR. The CSG demand reached 725MW in 2017/18. No new CSG loads have committed to connect to the transmission network since the publication of 2017 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 photovoltaic (PV) and wind farms to connect to the Queensland transmission and distribution networks over the next two to three years (refer to Table 6.1 and Table 6.2).

The energy forecast includes 654MW of semi-scheduled solar farms and 107MW of semi-scheduled wind farms to connect to the distribution networks. This is 75% of the renewable generation connecting to the distribution networks within Table 6.2. The energy forecast also includes 98MW of non-scheduled solar farms connecting to the distribution networks over the next two years. Solar PV and wind farms connecting directly to the distribution network will reduce the amount of energy being delivered through the transmission network.

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.

Powerlink engaged independent consultants to develop the Queensland retail electricity price projections for the 10-year forecast period of the 2018 TAPR. The price projection forecast includes a significant reduction over the next five years, which is much lower than the price projections assumed within the 2017 TAPR. The reduction in forecast retail price is attributed to the high quantities of renewable generation that have committed over the previous 12 months within Queensland. The additional generation is expected to make the wholesale generation market within Queensland more competitive.

Based on the historical impact of electricity prices on electricity demand, a reduction in electricity prices would result in higher electricity demand. However, the consumer response to falling electricity prices is expected to be weaker on increasing electricity usage than rising electricity prices had on dampening electricity usage. It is expected that electricity consumers will generally maintain their energy efficiency behaviours with falling electricity prices and this has been reflected in the demand and energy forecast. The Queensland Government is supporting continued energy efficiency behaviours by encouraging households to purchase four-star and higher energy efficient appliances through their energy efficient appliance rebate.

During the 2017/18 summer, Queensland reached 2,000MW of installed rooftop PV capacity. Growth in rooftop PV capacity has increased from around 15MW per month in 2016/17 to 25MW per month in 2017/18. However, the forecast of reducing electricity prices will extend the payback period of new rooftop PV and this is expected to decrease the rate of new capacity over the forecasting period. New rooftop PV capacity is forecast to remain at 25MW per month in 2018/19 before reducing and remaining at 15MW per month from 2020/21. An impact of rooftop PV has been the delay of the time of state 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.

The summer maximum demand and winter maximum demand forecasts presented in this TAPR indicate low growth over the 10-year outlook period. Independent economic outlook is that Queensland, on the whole, has been experiencing slow economic growth. However, this is expected to return to solid growth for the forecasting period. The lower Australian dollar has improved growth prospects in areas such as tourism and foreign education while there is moderate growth in the engineering construction industry. Queensland's population growth has slowed following the resources boom and is expected to increase by around 16% to around 5.8 million over the 10-year forecast period.

2 Energy and demand projections

Powerlink is committed to understanding the future impacts of emerging technologies so that transmission network services are developed in ways that are valued by customers. For example, future developments in battery storage technology coupled with small-scale PV could see significant changes to future electricity usage patterns. This could reduce the need to develop transmission services to cover short duration peaks. Details of Powerlink's forecasting methodology can be found in Appendix B.

The delivered maximum demand forecast in the 2018 TAPR shows a slight increase compared to the 2017 TAPR. The increase is due to a higher than expected maximum demand for 2017/18 and to an expectation that electricity prices will fall. Figure 2.2 shows a comparison of the delivered summer maximum demand forecast with the 2017 TAPR, based on a 50% probability of exceedance (PoE) and medium economic outlook.

The delivered energy forecast in the 2018 TAPR shows a reduction compared to the 2017 TAPR. The reduction is largely due to the high quantity of distribution connected solar PV farms that were committed over the last 12 months. Also, additional uncommitted distribution connected solar PV farm capacity has been included to meet a proportion of the Queensland Government's target of 50% renewable energy by 2030. Figure 2.3 shows a comparison of the delivered energy forecast with the 2017 TAPR, based on the medium economic outlook.

Figure 2.2 Comparison of the medium economic outlook demand forecasts

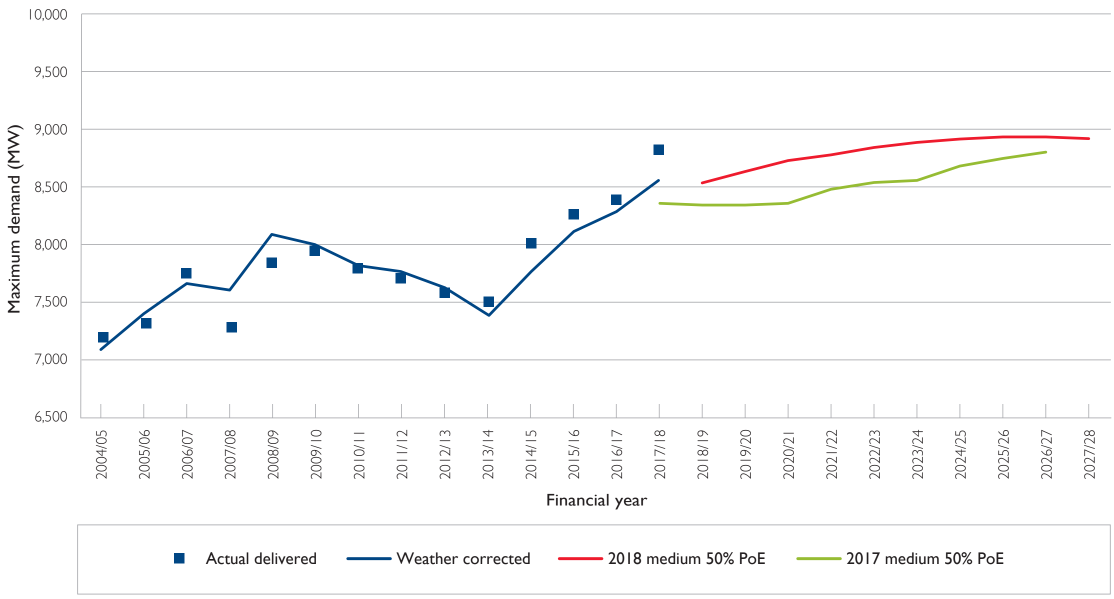
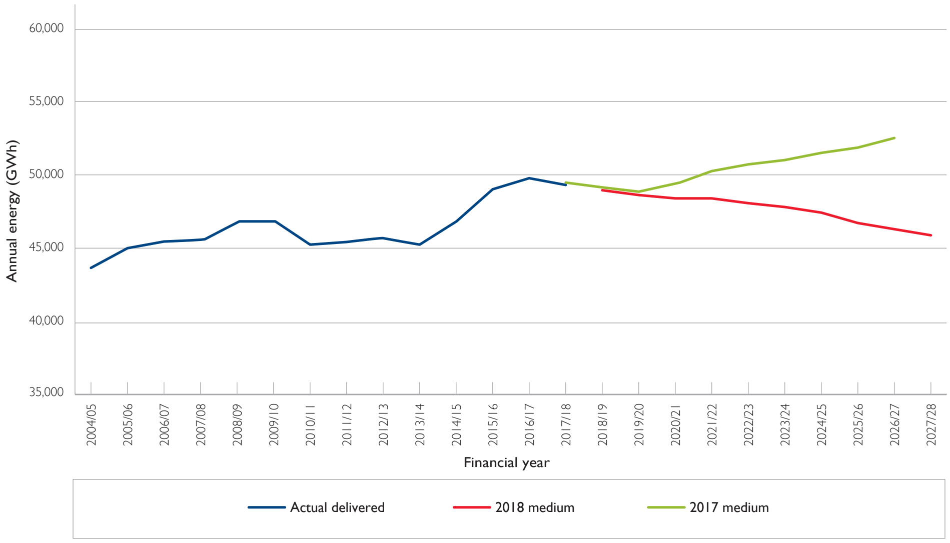


Figure 2.3 Comparison of the medium economic outlook energy forecasts



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. These forecasts have been aggregated into demand forecasts for the Queensland region and for 11 geographical zones, defined in Table 2.12 in Section 2.4, using diversity factors observed from historical trends.

Energy forecasts for each connection supply point were obtained from Energex, Ergon Energy and other transmission connected customers. These have also been aggregated for the Queensland region and for each of the 11 geographical zones in Queensland.

Powerlink works with Energex, Ergon Energy, Australian Energy Market Operator (AEMO), customer and consumer representatives, and the wider industry to refine its forecasting process and input information.

Powerlink, Energex and Ergon Energy jointly conduct the Queensland Household Energy Survey to improve understanding of consumer behaviours and intentions. This survey provides air conditioning penetration forecasts that feed directly into the demand forecasting process, plus comprehensive insights on consumer intentions on electricity usage.

Powerlink's forecasting methodology is described in Appendix B.

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.

All forecasts are 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 'as generated' and 'sent out' maximum demands within the summer and winter maximum demand tables 2.6 and 2.9, have been changed from scheduled to operational within the 2018 TAPR. Scheduled demands are a short-term forecast used for the dispatch of scheduled and semi-scheduled generators, whereas operational demand is the actual demand that occurred. There is minimal difference between scheduled and operational demands. The change will bring the 2018 TAPR into alignment with other market participants that are using operational demand.

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 2017/18.

Table 2.2 Average annual growth rate over next 10 years

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	-1.4%	-0.7%	0.3%
Delivered summer peak demand (50% PoE)	-0.1%	0.4%	1.2%
Delivered winter peak demand (50% PoE)	0.2%	0.7%	1.3%

2.3.1 Future management of maximum demand

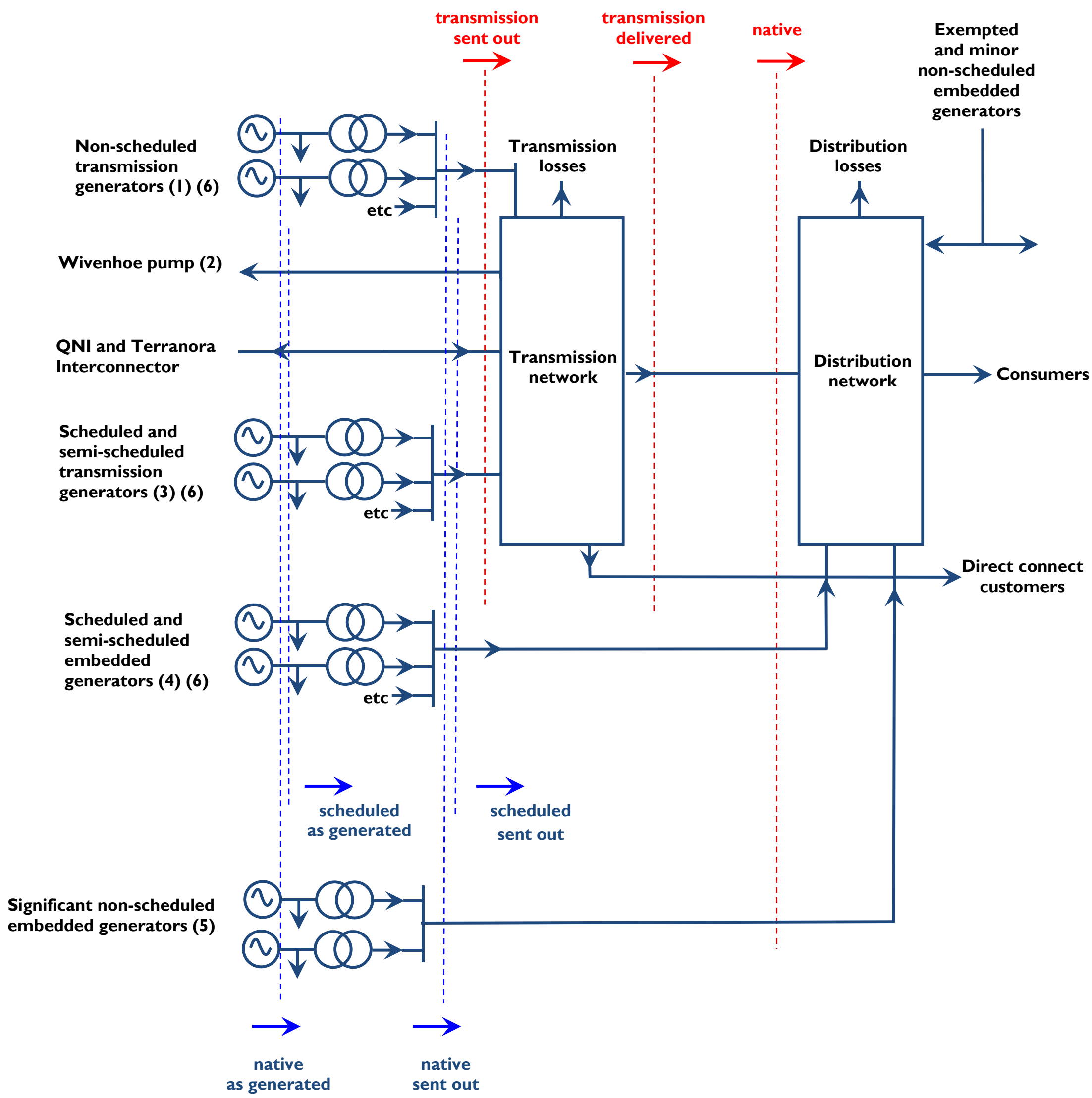
The installation of additional rooftop PV systems and distribution connected solar farms is expected to delay the current time of the maximum demand from around 5:30pm to an evening peak and reduce the delivered demand and energy during daylight hours. The 10-year demand forecast shows low growth in 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, Future Transmission Network webinars (refer to Section 1.9.1) and Non-network Engagement Stakeholder Register (NESR) (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 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) Barcaldine, Roma, Mackay, Kidston Solar Farm and Townsville Power Station 66kV component.

(5) Pioneer Mill, Racecourse Mill, Moranbah North, Moranbah, Barcaldine Solar Farm, German Creek, Oaky Creek, Isis Central Sugar Mill, Daandine, Bromelton and Rocky Point.

(6) For a full list of transmission network connected generators and scheduled and semi-scheduled 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
2008/09	52,591	48,831	53,638	50,008	48,351	46,907	48,563	48,563
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 (1)	54,619	50,8867	56,228	52,6156	50,8723	49,374	51,117	53,663

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2018.

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
2018/19	48,765	49,061	49,664
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

Figure 2.5 Historical and forecast transmission delivered energy

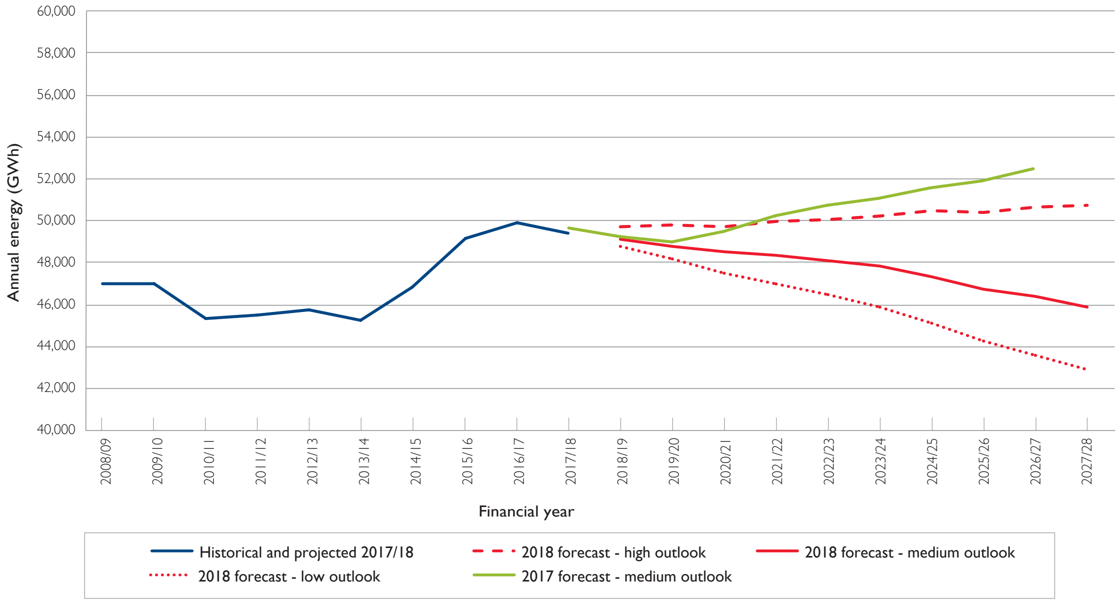


Table 2.5 Forecast annual native energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2018/19	50,788	51,084	51,686
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

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
2008/09	8,707	8,135	8,767	8,239	8,017	7,849	8,070	8,070	8,318
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

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
2018/19	8,015	8,491	9,080	8,059	8,538	9,130	8,144	8,626	9,221
2019/20	8,065	8,551	9,152	8,151	8,642	9,248	8,271	8,768	9,382
2020/21	8,093	8,588	9,198	8,235	8,737	9,356	8,406	8,917	9,548
2021/22	8,092	8,594	9,214	8,285	8,797	9,430	8,501	9,025	9,672
2022/23	8,092	8,600	9,228	8,330	8,852	9,496	8,604	9,141	9,804
2023/24	8,088	8,601	9,234	8,373	8,902	9,555	8,717	9,264	9,940
2024/25	8,059	8,575	9,211	8,387	8,921	9,581	8,833	9,390	10,077
2025/26	8,037	8,556	9,196	8,407	8,947	9,614	8,923	9,489	10,188
2026/27	7,991	8,512	9,155	8,401	8,945	9,618	9,010	9,584	10,294
2027/28	7,930	8,453	9,099	8,376	8,925	9,603	9,075	9,659	10,379

Figure 2.6 Historical and forecast transmission delivered summer demand

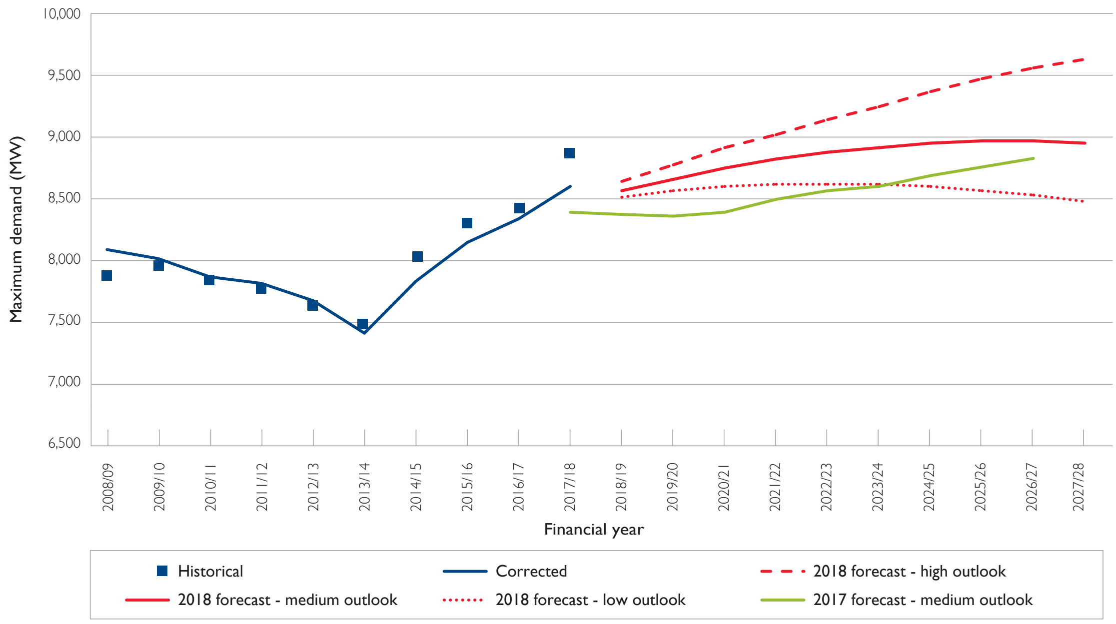


Table 2.8 Forecast summer native demand (MW)

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
2018/19	8,348	8,825	9,413	8,392	8,872	9,464	8,477	8,959	9,554
2019/20	8,399	8,885	9,485	8,485	8,976	9,582	8,605	9,102	9,715
2020/21	8,426	8,921	9,531	8,568	9,070	9,690	8,739	9,250	9,881
2021/22	8,426	8,927	9,547	8,619	9,131	9,763	8,834	9,358	10,006
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

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
2008	8,212	7,758	8,283	7,858	7612	7,420	7,665	7,665	7,237
2009	7,694	7,158	7,756	7,275	7032	6,961	7,205	7,205	7,295
2010	7,335	6,885	7,608	7,194	6795	6,534	6,933	6,933	6,942
2011	7,632	7,207	7,816	7,400	7093	6,878	7,185	7,185	6,998
2012	7,469	7,081	7,520	7,128	6955	6,761	6,934	6,934	6,908
2013	7,173	6,753	7,345	6,947	6699	6,521	6,769	6,769	6,983
2014	7,307	6,895	7,470	7,077	6854	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

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
2018	7,239	7,427	7,710	7,272	7,461	7,745	7,339	7,529	7,815
2019	7,315	7,507	7,795	7,379	7,572	7,863	7,466	7,661	7,955
2020	7,332	7,527	7,820	7,440	7,637	7,933	7,559	7,758	8,059
2021	7,362	7,560	7,857	7,512	7,712	8,014	7,680	7,885	8,192
2022	7,360	7,560	7,861	7,544	7,748	8,055	7,746	7,954	8,268
2023	7,333	7,534	7,836	7,551	7,757	8,067	7,804	8,016	8,334
2024	7,288	7,489	7,792	7,538	7,745	8,057	7,858	8,072	8,394
2025	7,236	7,438	7,742	7,515	7,724	8,037	7,907	8,123	8,449
2026	7,170	7,372	7,678	7,477	7,687	8,003	7,938	8,157	8,487
2027	7,110	7,313	7,619	7,442	7,653	7,970	7,970	8,192	8,525

Figure 2.7 Historical and forecast winter transmission delivered demand

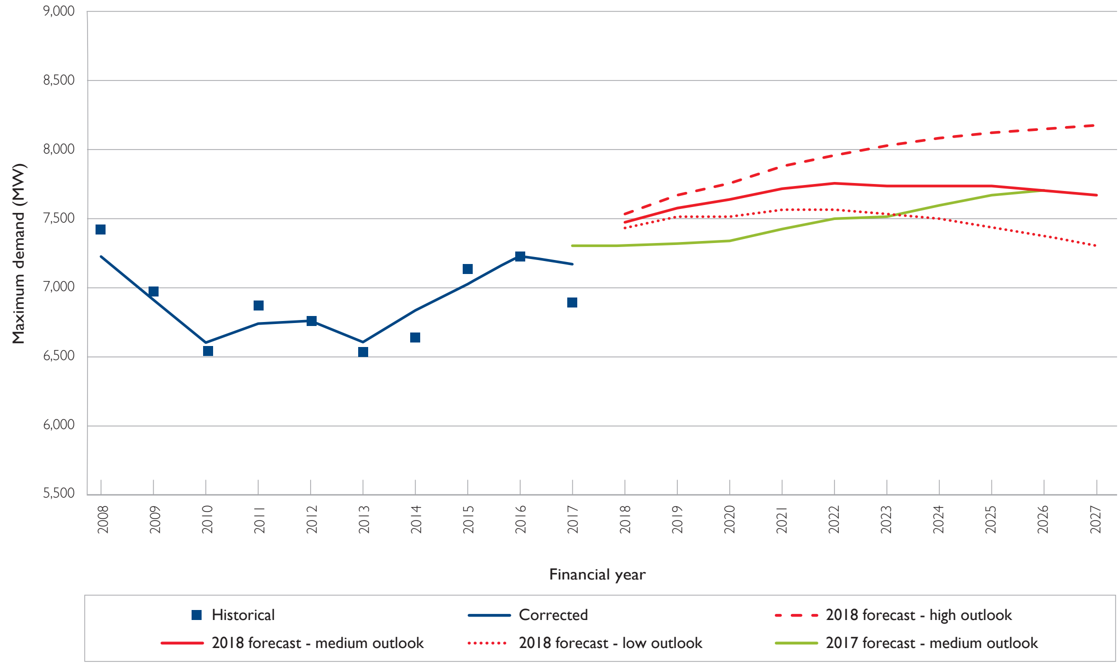


Table 2.11 Forecast winter native demand (MW)

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
2018	7,498	7,686	7,969	7,531	7,720	8,004	7,598	7,788	8,074
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

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 APR 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	1.19	1.16
Ross	1.38	1.55
North	1.13	1.15
Central West	1.12	1.21
Gladstone	1.03	1.05
Wide Bay	1.04	1.11
Surat	1.07	1.14
Bulli	1.14	1.22
South West	1.05	1.13
Moreton	1.02	1.01
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												
2008/09	1,851	2,772	2,779	3,191	10,076	1,430		94	1,774	19,532	3,408	46,907
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)	1,689	2,676	2,662	3,043	9,374	1,245	4,805	1,484	1,259	18,013	3,124	49,374
Forecasts												
2018/19	1,683	2,276	2,795	3,154	9,471	1,312	4,628	1,436	1,252	17,699	3,355	49,061
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

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2018.

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												
2008/09	1,851	3,336	2,950	3,481	10,076	1,437		94	2,265	19,665	3,408	48,563
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)	1,697	2,954	3,310	3,504	9,374	1,264	4,838	1,484	1,499	18,070	3,124	51,117
Forecasts												
2018/19	1,719	2,676	3,464	3,620	9,472	1,332	4,723	1,436	1,532	17,756	3,355	51,084
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

Note:

(1) These projected end of financial year values are based on revenue metering and statistical data up until April 2018.

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												
2008/09	280	350	317	459	1,178	278		19	367	3,934	667	7,849
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
Forecasts												
2018/19	327	396	412	468	1,062	212	522	164	273	3,973	729	8,538
2019/20	329	399	410	475	1,063	214	535	181	277	4,023	736	8,642
2020/21	337	408	409	481	1,062	213	566	184	276	4,062	739	8,737
2021/22	340	413	414	484	1,063	214	570	183	278	4,098	740	8,797
2022/23	347	411	415	501	1,066	214	556	171	279	4,144	748	8,852
2023/24	344	406	432	509	1,068	215	545	166	281	4,186	750	8,902
2024/25	347	409	446	507	1,069	214	522	157	280	4,218	752	8,921
2025/26	353	416	447	509	1,070	215	503	151	280	4,250	753	8,947
2026/27	357	421	453	509	1,070	214	495	125	280	4,268	753	8,945
2027/28	360	424	452	509	1,071	214	481	103	280	4,279	752	8,925

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												
2008/09	280	423	331	510	1,178	278		19	421	3,963	667	8,070
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
Forecasts												
2018/19	327	465	496	538	1,062	212	582	164	299	3,998	729	8,872
2019/20	329	468	494	545	1,063	215	595	181	303	4,047	736	8,976
2020/21	337	477	493	552	1,062	213	626	184	302	4,085	739	9,070
2021/22	340	482	497	555	1,063	214	629	183	305	4,122	741	9,131
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

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												
2008	216	285	361	432	1,161	253		17	374	3,655	666	7,420
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
Forecasts												
2018	208	295	368	412	1,075	206	559	185	274	3,296	583	7,461
2019	210	299	367	416	1,075	209	580	202	281	3,345	588	7,572
2020	212	303	371	418	1,072	210	583	208	286	3,380	594	7,637
2021	214	305	372	426	1,073	211	600	209	290	3,417	595	7,712
2022	215	307	375	433	1,074	213	601	194	292	3,445	599	7,748
2023	217	297	380	437	1,075	215	585	192	296	3,464	599	7,757
2024	218	297	380	438	1,076	215	571	183	297	3,474	596	7,745
2025	218	298	381	438	1,076	216	549	172	298	3,482	596	7,724
2026	218	298	387	438	1,076	216	529	148	298	3,485	594	7,687
2027	218	298	387	438	1,075	216	519	131	298	3,482	591	7,653

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												
2008	216	362	365	470	1,161	253		17	479	3,676	666	7,665
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
Forecasts												
2018	208	348	434	476	1,075	209	601	185	302	3,299	583	7,720
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

2.5 Daily and annual load profiles

The daily load profiles (transmission delivered) for the Queensland region on the days of 2017 winter and 2017/18 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 2017 and summer 2017/18 maximum native demand days

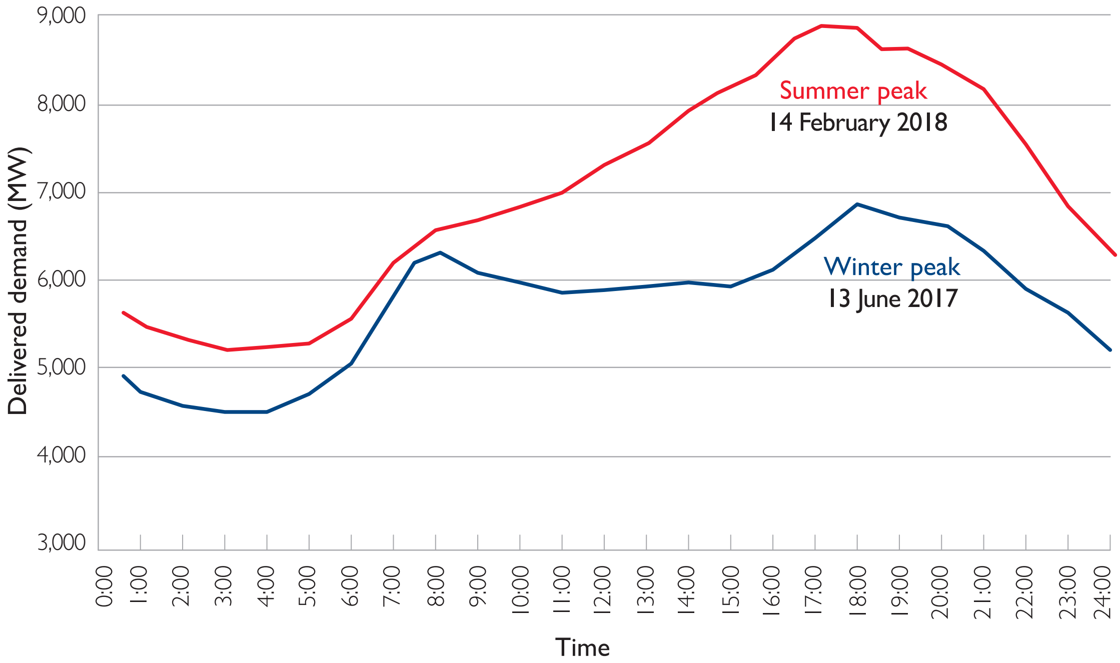
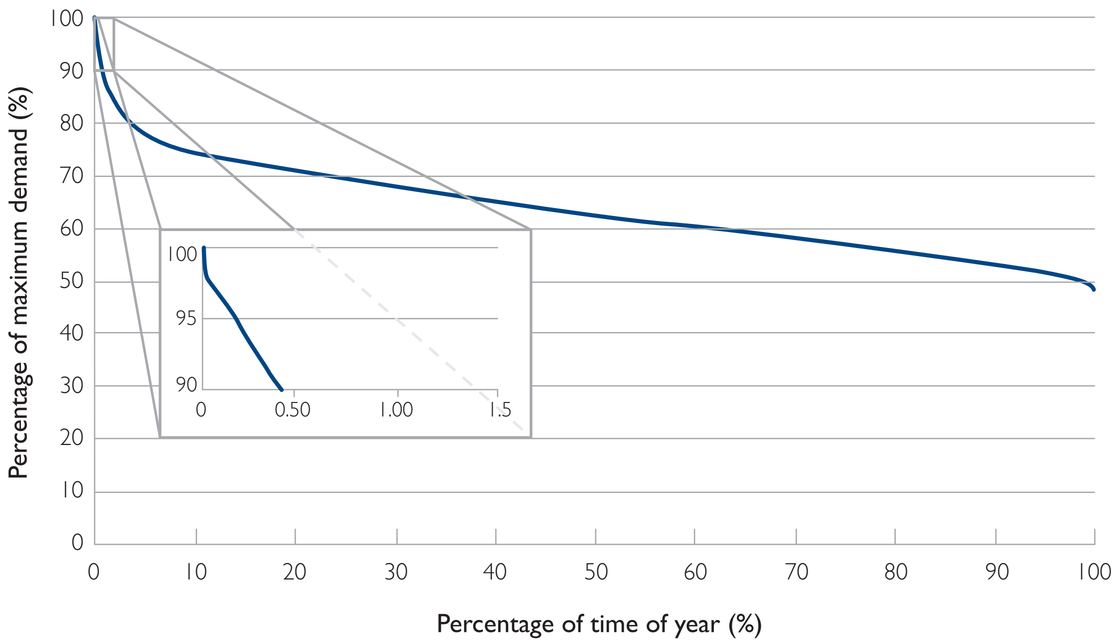


Figure 2.9 Normalised cumulative transmission delivered load duration from 1 April 2017 to 31 March 2018



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 2017 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)
  - consideration of the economic benefits associated with a potential QNI upgrade 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 and consumers, 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 Power System Frequency Risk Review (refer to Section 6.3)
- AEMO National Planning and other jurisdictional planners in the development of the 2018 ISP

- TransGrid for the assessment of the economic benefits of upgrading the inter-connector capability between Queensland and New South Wales (NSW) (refer to Section 5.7.12)
- ElectraNet, for the purposes of contributing to the South Australian Energy Transformation project (SAET)
- Energex and Ergon Energy.

3.3 AEMO national planning – Integrated System Plan (ISP)

The Independent Review into the Future Security of the National Electricity Market (Finkel Review) recommended[1]:

> *By mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.*

Powerlink has worked closely with AEMO to support the development of the 2018 ISP. The ISP signals priority development paths in the near to short-term, along with an over-arching long-term strategy.

The 2018 ISP is not the end of the process, but rather the first of many steps, with updates in future years to reflect the dynamically changing nature of the power system and the need to continually innovate and evolve strategies for the future.

Process

Powerlink provided a range of network planning inputs to AEMO's ISP modelling process, supported the development of the ISP through regular engagement, and reviewed the long-term network development strategy and findings. Throughout its development, AEMO conducted workshops and regular coordination meetings to incorporate input from industry. AEMO's public consultation received 68 formal submissions, which are available on AEMO's website.

Methodology

The ISP methodology is outlined 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. This plan will be available on AEMO's website.

3.4 Power System Frequency Risk Review (PSFRR)

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

Process

Powerlink supported AEMO in identifying 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 others for assessment based on criteria consistent with the NER. AEMO shared and discussed initial findings with Powerlink and preliminary versions of the PSFRR. AEMO incorporated feedback from Powerlink into the PSFRR.

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.

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1 Finkel et al., 2017. Independent Review into the future security of the National Electricity Market – recommendation 5.1, available at http://www.environment.gov.au/energy/national-electricity-market-review.

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 existing mainland NEM Under-Frequency Load Shedding (UFLS) schemes are currently sufficient to contain frequency within the Frequency Operating Standard (FOS) for large under-frequency events. AEMO is currently reviewing the need to modify the mainland NEM UFLS schemes to account for potential over correction.

AEMO, in consultation with Powerlink, identified a need to modify the central Queensland to southern Queensland Special Protection Scheme (SPS) to improve its effectiveness for the increased southerly flows that are projected as variable renewable energy (VRE) generation connects in North Queensland. Additionally, AEMO recommends that a joint study between Powerlink and AEMO be commenced in 2018 to establish the risk of major supply disruption due to Queensland becoming islanded during high export to NSW.

3.5 Joint planning with TransGrid – QNI upgrade

Section 5.7.12 outlines the joint planning being undertaken by Powerlink and TransGrid to assess the economic benefits in upgrading the interconnector capability between Queensland and NSW.

TransGrid and Powerlink are undertaking preparatory work to progress a RIT-T to investigate the net market benefits of options for increasing the transfer capacity between NSW and Queensland. The first stage of this RIT-T consultation is anticipated to commence in the third quarter of 2018.

3.6 Joint planning with ElectraNet – SAET RIT-T

In November 2016 ElectraNet commenced the SAET RIT-T consultation. A feasible option in the RIT-T includes a High Voltage Direct Current (HVDC) Voltage Source Converter (VSC) interconnector between South Australia and South West Queensland.

Powerlink has been working collaboratively with ElectraNet to:

- define the scope and cost of this option
- assess the impact that this option has on the existing power transfer limits of the interconnected NEM
- review the technical assumptions for assessing the market benefits.

3.7 Joint planning with Energex and Ergon Energy

Queensland's Distribution Network Service Provider (DNSP) Energex and Ergon Energy participate in regular joint planning and coordination meetings with Powerlink to ensure that interface works are communicated. These meetings identify, 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 DNSP will then initiate detailed discussions around the need and timing of emerging limitations or asset condition drivers to ensure the recommended solution is optimised for efficient expenditure outcomes[2].

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 updates to demand forecasts			Y
Joint planning workshops			Y

3.7.1 Matters requiring joint planning

The following is a summary of projects where detailed joint planning with Energex and Ergon Energy has occurred since the publication of the 2017 TAPR. There are a number of projects where Powerlink and Energex and Ergon Energy interface on delivery, changes to secondary systems or metering, and other relevant matters which are not covered here. 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	Section 5.7.1
Townsville South – Clare South – Collinsville North 132kV transmission lines	Section 5.7.2
Dan Gleeson secondary systems replacement	Section 5.7.2
Ingham South 132/66kV transformer replacement	Section 5.7.2
Lilyvale 132/66kV transformer replacement	Section 5.7.4
South Pine – Upper Kedron 110kV transmission lines	Section 5.7.9
Rocklea – Sumner – West Darra 110kV transmission lines	Section 5.7.9
Mudgeeraba 275/110kV transformer replacement/retirement	Section 5.7.10

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.

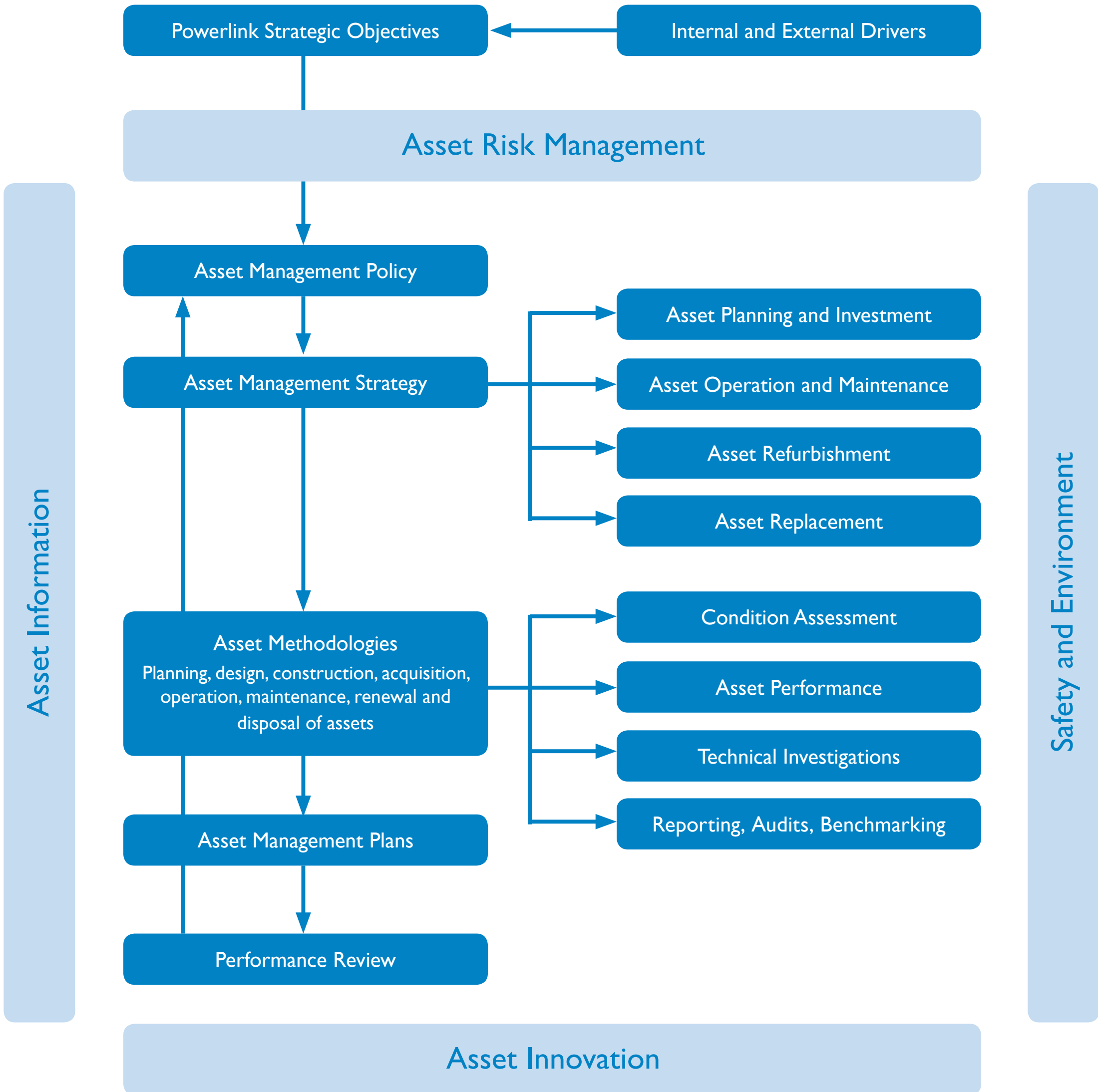
Other factors that influence network development, such as energy and demand forecasts, generation development (including potential generation withdrawal), and risks arising from the condition and performance of the existing asset base are also analysed collectively in order to form an integrated network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

4.2 Overview of approach to asset management

Powerlink's Asset Management System ensure 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 ensures asset reinvestment needs are not just considered on a 'like-for-like' basis. 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 guides the development of investment plans for the network, including such factors as expected service levels, investment policy and risk management.

4 Asset management overview

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

1. Asset Life Cycle, which considers assets on a 'whole of life' basis
2. 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 and the interaction of these phases on each other. 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 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 consumers.

Figure 4.3 Asset management cycle

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

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's approach to risk management requires a structured approach, 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-life.

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.

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

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:

- contacting Kevin Kehl on 07 3860 2801 or
- emailing networkassessments@powerlink.com.au.

4 Asset management overview

CHAPTER 5

Future network development

5 Future network development

Key highlights

- Market initiatives, such as the Integrated System Plan (ISP), have the potential to influence the future development and network topography of the transmission network in Queensland and the National Electricity Market (NEM) in the 10-year outlook period.
- Powerlink is responding to fundamental shifts in its operating environment by adapting its approach to investment decisions. 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.
- The Ross, Central West, Gladstone and Moreton zones have potential reconfiguration opportunities within the next five years.
- Powerlink anticipates a significant Regulatory Investment Test for Transmission (RIT-T) program for the replacement of network assets, particularly over the next two years.

Preface

AEMO will publish the inaugural ISP on 4 July 2018. The 2018 ISP is not the end of the process, but rather the first of many steps. Updates in successive years will improve analysis methodologies and take account of the dynamically changing nature of the power system and the need to continually innovate and evolve strategies.

As outlined in Section 3.3, Powerlink has worked closely with AEMO to support the development of the 2018 ISP. Modelling for the 2018 ISP included as its starting point the completed and committed projects defined in Section 9.2.

The objective of the ISP is to signal pathways for an integrated strategic plan. The plan must consider how the transmission system will continue to deliver reliability and security at the lowest long-term cost for consumers, in an environment of rapid technological transformation at both ends of the supply chain. The 2018 ISP signals these pathways under a range of scenarios. The objective is to determine a power system development pathway which is most robust to these different futures[1]. Common to all scenarios is the Queensland's commitment to a renewable energy target of 50% by 2030 (Queensland Renewable Energy Target (QRET)).

The ISP also considers the merits of different Renewable Energy Zones (REZ) and the role these may play in delivering long-term lowest costs for consumers. For these REZ the ISP explores what storage and transmission investment would be needed to support these developments.

The objective is to determine the optimal balance between a more interconnected NEM, which can reduce the need for local reserves and take advantage of regional diversity, thereby more efficiently sharing resources and services between regions, and a more regionally independent NEM with each region self-sufficient in system security and reliability.

As a Transmission Network Service Provider (TNSP) with jurisdictional planning responsibilities, Powerlink appreciates the national perspective that AEMO brings to the ISP analysis. Powerlink will build on this work taking into account regional considerations and joint planning with Distribution Network Service Providers (DNSP). Whilst generators will make investment decisions independently, the enhanced provision of information in the ISP will support their long-term decision making. This will contribute to achieving a coordinated approach to investment decisions, benefitting electricity consumers, while meeting emissions reduction targets.

5.1 Introduction

Powerlink Queensland as a TNSP in the 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.

[1] The ISP scenarios are outlined on AEMO's website.

The NER (Clause 5.12.2(c)(3)) requires the Transmission Annual Planning Report (TAPR) to provide "a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 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 or non-network alternatives. The NER (Clauses 5.12.2(c)(5)) also requires the TAPR to include information pertinent to all proposed:

- augmentations to the network
- replacements of network assets
- network asset retirements or asset-deratings that would result in a network constraint in the 10-year outlook period (NER 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[2] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months (NER Clause 5.12.2(c)(4)(iii))
- a statement of intent to issue request for proposals for augmentation, the proposed replacement of ageing network assets or non-network alternatives identified as part of the annual planning review (NER 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) 2016 National Transmission Network Development Plan (NTNDP)[3]
- details in relation to the need to address the risks arising from ageing network assets remaining in-service and those limitations for which Powerlink Queensland intends to address or initiate consultation with market participants and interested parties
- 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

The most recent NTNDP was published by AEMO in December 2016. The focus of the NTNDP is to provide an independent, strategic view of the efficient development of the NEM transmission network over a 20-year planning horizon. The release of the 2017 NTNDP was deferred by the Australian Energy Regulator and will form part of the 2018 ISP to be published by AEMO in July 2018.

Due to the timing of the release of the ISP and subsequent overlap with the publication of the 2018 TAPR, where applicable Powerlink's 2019 TAPR will consider the expected outcomes of the ISP including:

- the demand and energy forecast
- discussion on Regulatory Investment Tests for Transmission (RIT-Ts) which may be required, either independently or jointly with other Network Service Providers (NSP).

2 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.

3 The release of the 2017 NTNDP was deferred by the Australian Energy Regulator (AER) and will form part of the Integrated System Plan to be published by mid-2018. Powerlink has referred to the 2016 NTNDP as the most recent publication for the purpose of compliance with NER Clause 5.12.2(c)(6).

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 Electricity (VRE) 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
- 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)
- existing network configuration
- condition 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.

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.
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 also 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 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 fundamental shifts in economic outlook, electricity consumer 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 taken a cautious approach in determining when it is appropriate to refit or replace ageing transmission assets and how to implement these works cost effectively. This approach is aimed at delivering better value to consumers.

The 10-year outlook period discussed in the 2018 TAPR runs from 2018/19 to 2028/29.

5.5 Forecast network limitations

As outlined in Section 1.7.1, under its Transmission Authority, Powerlink Queensland 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, Powerlink does not anticipate undertaking any significant augmentation works during this period other than those which could be triggered from economic drivers and/or the commitment of mining or industrial block loads (refer to Table 5.2). In Powerlink's Revenue Determination 2017-2022, the projects that would be triggered by these large loads were identified as contingent projects. These contingent projects and their triggers are discussed in detail in Section 7.2.

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 Regulatory Investment Test for Transmission (RIT-T) process. Solutions may include provision of network support from existing and/or new generators, demand side management initiatives (either from individual providers or aggregators) and network augmentations.

5.5.1 Summary of forecast network limitations within the next five years

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in Queensland in the next five years[4].

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 2017 TAPR which fall into this category in 2018.

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 Section 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, generally via the TAPR, on potential solutions to network limitations which may result in transmission network or non-network investments
- 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 non-network) is found to satisfy the RIT-T
- Alternatively, transmission investments maybe undertaken under the 'funded augmentation' provisions of the NER.

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

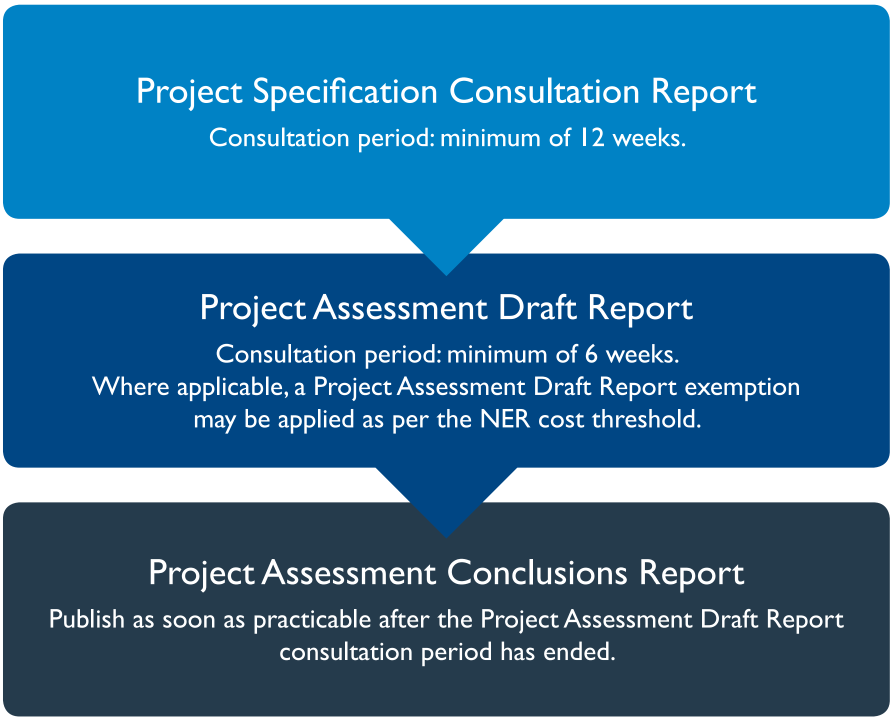
It should be noted that the information provided regarding Powerlink's network development plans may change and should therefore be confirmed with Powerlink before any action is taken based on the information contained in this TAPR.

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[5] to include the proposed replacement of network assets.

As a result, Powerlink anticipates a significant RIT-T program to address the risks arising from ageing network assets remaining in-service, particularly over the next two years. This initial 'heavier' program is due to the inclusion of public consultation into the planning timetable for proposed reinvestments in the nearer term (refer to Figure 5.1).

Figure 5.1 Overview of the RIT-T consultation process



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

The consultations currently under way are listed in Table 5.3. Registered Participants and interested parties are referred to consultation documents published on Powerlink's website for further information.

Table 5.3: Consultations currently under way

Consultation	Reference
Addressing the secondary systems condition risks at Dan Gleeson Substation	S5.7.2
Addressing the secondary systems condition risks at Baralaba Substation	S5.7.4
Maintaining reliability of supply to Ingham	S5.7.2

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

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 5.4 summarises consultations Powerlink anticipates undertaking within the next 12 months under the AER RIT-T to address either the proposed replacement of a network asset or limitation.

Table 5.4: Potential consultations in the forthcoming 12 months

Consultation	Reference
Maintaining reliability of supply at Kamerunga Substation	S5.7.1
Maintaining power transfer capability and reliability of supply at Ross Substation	S5.7.2
Maintaining reliability of supply between Strathmore and Townsville	S5.7.2
Maintaining reliability of supply at Townsville South Substation	S5.7.2
Addressing the secondary systems condition risks at Kemmis Substation	S5.7.3
Maintaining reliability of supply to the Rockhampton area	S5.7.4
Maintaining power transfer capability and reliability of supply at Lilyvale Substation	S5.7.4
Maintaining power transfer capability and reliability of supply at Bouldercombe Substation	S5.7.4
Addressing the secondary systems condition risks at Tarong Substation	S5.7.6
Addressing the secondary systems condition risks at Palmwoods Substation	S5.7.9
Maintaining reliability of supply to the Brisbane metropolitan area	S5.7.9
Addressing the secondary systems condition risks at Belmont Substation	S5.7.9
Addressing the secondary systems condition risks at Abermain Substation	S5.7.9
Maintaining reliability of supply to the southern Gold Coast area	S5.7.10
Expanding NSW-Queensland transmission transfer capacity	S5.7.12

5.6.3 Connection point proposals

Table 5.5 lists 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)[6] or be initiated by generators or customers.

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

Table 5.5 Connection point proposals

Potential project (1) (2)	Purpose	Zone
Kaban Wind farm	New wind farm	Far North
Kidston Hydro/Solar PV	New hydro generator with solar PV	Ross
Rollingstone Solar Farm	New solar farm	Ross
Majors Creek Solar Farm	New solar farm	Ross
Brampton Solar Farm	New solar farm	North
Rugby Run Solar Farm	New solar farm	North
Collinsville North Solar Farm	New solar farm	North
Burton Downs Mine	New mine	North
Ironbark Mine	New mine	North
Bouldercombe Solar Farm	New solar farm	Central West
Broadsound Solar Farm	New solar farm	Central West
Dingo Solar Farm	New solar farm	Central West
Dysart Solar Farm (RED)	New solar farm	Central West
Dysart Solar Farm (Dysart)	New solar farm	Central West
Rodds Bay Solar Farm	New solar farm	Gladstone
Lower Wonga Solar PV	New solar farm	Wide Bay
Dooroo Solar Farm	New solar farm	Surat
Columboola Solar Farm	New solar farm	Surat
Chinchilla Solar Farm	New solar farm	Surat
Beelbee Solar Farm	New solar farm	Bulli
Bulli Creek Solar PV	New solar farm	Bulli
Western Downs Solar Farm (Yellow)	New solar farm	Bulli
Western Downs Solar Farm (Neoen)	New solar farm	Bulli

Note:

(1) Table 5.5 lists the projects that are in the public domain, either as approved or through publication by the proponents. Powerlink does not include projects that are not public.

(2) 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.

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. Reinvestment in the transmission network to manage identified risks arising from these assets will form the majority of Powerlink's capital expenditure program of work moving forward.

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 and optimisation 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 and consumers.

Information regarding possible reinvestment alternatives and anticipated timing is updated annually within the TAPR and includes discussion on 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.

In addition, where technically feasible, Powerlink's Non-network Solution Feasibility Study process (refer to Section 1.9.2) will be applied to potential augmentations or network asset replacements which fall below the RIT-T cost threshold.

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.

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 temporarily or permanently de-rate some assets as part of the 2018 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 5.7.10) and separated into two periods:

- *Possible network reinvestments within five years*

  This includes the financial period from 2018/19 to 2023/24 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.

7 Refer to NER Clauses 5.12.2(6) and (6A).
8 NER Clause 5.12.2(c)(1A).

- *Possible network reinvestments within six to 10 years*

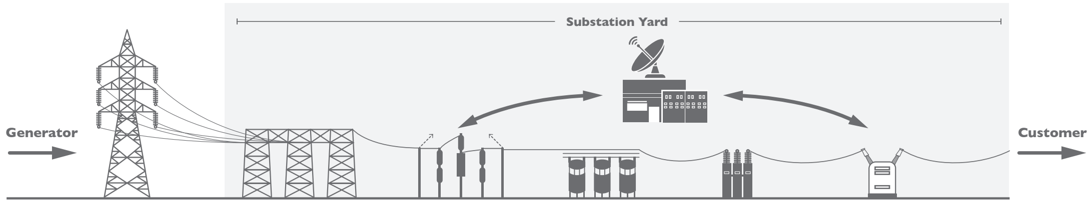
  This includes the financial period from 2024/25 to 2028/29, for possible medium to long-term reinvestments. Powerlink takes a balanced, prudent and proportionate approach to the consideration of reinvestment needs to address the risks arising from network assets in the medium to long-term and undertakes detailed planning analysis and condition assessment closer to the possible reinvestment date, typically within five years.

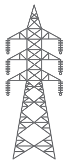
  In addition, due to the current dynamic operating environment, there is less certainty regarding the needs or drivers for reinvestments in these later years of the annual planning review period. As a result, considerations in this period have a greater potential to change when compared to near term investments. 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 necessary 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 2017 TAPR and 2018 TAPR. These timing differences are noted in the analysis of the program of work within this Chapter (refer to sections 5.7.1 to 5.7.10).

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.

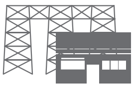
Figure 5.2 The functions of major transmission assets





Transmission line

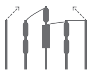
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



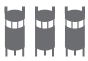
Substation

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.

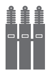
A substation that connects to transmission lines, but does not include a transformer, is known as a switching station.



- **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.

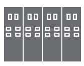


- **Static VAR Compensator (SVC)**
  A SVC is used where needed, to smooth voltage fluctuations, which may occur from time-to-time on the transmission network. This enables more power to be transferred on the transmission network and also assists in the control of voltage.



- **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.

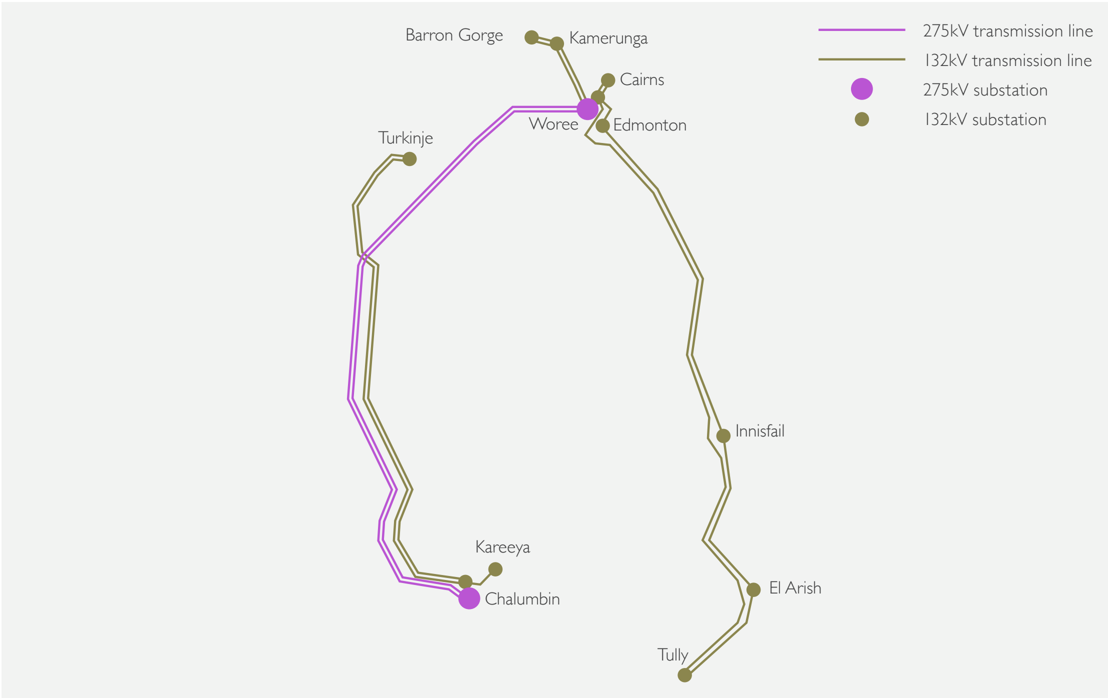
Telecommunication systems

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

Existing network

Figure 5.3 Far North zone transmission 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 in Chapter 2 there are no network limitations forecast to occur in the Far North zone within the next five years.

Possible network reinvestments within five years

Substations

Kamerunga 132/22kV Substation

Network requirement: 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: June 2021

Based on more recent analysis and assessment of the risks arising from the assets remaining in-service, the proposed network solution has been deferred by approximately 18 months to June 2021 compared to the possible commissioning date of summer 2019/20 as advised in the 2017 TAPR.

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 over the 10-year outlook period.
- Replacement of primary plant and secondary systems upfront by June 2021.
- Establishment of a new 132kV substation on an alternate site by June 2021.

Proposed network solution: Upfront replacement of all 132kV primary plant and secondary systems at an estimated cost of $21 million by June 2021

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 in the northern Cairns region. Any non-network solution would be required to be available on a firm basis to replace the network functionality provided by Kamerunga Substation. The substation provides supply to the 22kV network of up to 60MW, and up to 900MWh per day, on a continuous basis.

Woree 275/132kV Substation

Network requirement: Maintain power transfer capability and reliability of supply in Cairns

Woree Substation was established in 2002, initially with one 275/132kV transformer and 132kV switchyard, and was part of a major transmission network reinforcement to meet growing demand in the Cairns area.

Project driver:

Emerging condition, obsolescence and compliance risks for all of the 132kV secondary systems, and 275kV secondary systems associated with the establishment of the first 275/132kV transformer. The SVC secondary systems have also entered the discontinuation phase with only limited support and spares available.

Project timing: June 2022

Possible network solutions

- Replacement of selected 132kV, SVC and 275kV secondary systems by June 2022.
- Complete replacement of all secondary systems and associated panels by June 2022.

Proposed network solution: Replacement of selected secondary systems at an estimated cost of $19 million by June 2022

The change to the indicative costs of the proposed network solution from those identified in the 2017 TAPR is a result of the extension of the scope of works to address the risks arising from the SVC and selected 275kV secondary systems.

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

Possible non-network solutions

Woree Substation provides injection and switching 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, as such, the Woree SVC is considered vital to provide voltage support to this region.

Powerlink is not aware of any non-network proposals in the Cairns area that can address these requirements in their entirety and welcomes proposals from non-network providers that can significantly contribute to reducing the requirement in this region. Such proposals may present opportunities to reconfigure the network that could otherwise not be considered due to Powerlink's planning standard and obligations. Non-network solutions may include, but are not limited to, local generation or demand side management initiatives, and would be required to be available on a firm basis.

Cairns 132kV Substation

Network requirement: Maintain reliability of supply 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.

Project driver:

- One of the three 132/22kV transformers at Cairns Substation is approaching end of 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.
- Condition driven replacement to address emerging obsolescence and compliance risks on selected secondary systems.

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 132kV secondary systems at Cairns Substation in the existing or prefabricated building at an estimated cost of $8 million by June 2023

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 demand side management initiatives, and would be required to be available on a firm basis.

Table 5.6 Possible network reinvestments in the Far North zone within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Kamerunga Substation replacement	Full replacement of 132kV substation	Maintain supply reliability to the Far North zone	June 2021	Staged replacement of 132kV primary plant and secondary systems Non-network (1)	$21m
Woree 275kv and 132kV and SVC secondary systems replacement	Replacement of selected secondary systems equipment	Maintain supply reliability to the Far North zone	June 2022	Full replacement of all secondary systems Non-network (1)	$19m
Retirement of one 132/22kV Cairns transformer	Retirement of one 132kV Cairns transformer including primary plant reconfiguration works (2)	Maintain supply reliability to the Far North zone	December 2021	Replacement of the transformer	$0.5m (3)
Cairns secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2023	Staged replacement of the 132kV secondary systems equipment Non-network (1)	$8m

Note:

(1) The envelope for non-network solutions is defined above in S5.7.1.

(2) 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.

(3) 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 2024/25 to 2028/29 (refer to Table 5.7).

Table 5.7 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
Transmission Lines					
Line refit works on the 275kV transmission lines between Chalumbin to Woree	Line refit works on 38 steel lattice structures	Maintain supply reliability to the Far North zone	December 2024	New transmission line	$13m
Woree to Kamerunga 132kV transmission line replacement	New 132kV double circuit transmission line	Maintain supply reliability to the Far North zone	December 2025	Two 132kV single circuit transmission lines	$30m
Substations					
Innisfail secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2024	Replacement of selected secondary systems equipment	$8m
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2025	Refurbishment of the existing transformer	$4m
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
Chalumbin 275kV and 132kV primary plant and secondary systems replacement	Selected replacement of 275kV and 132kV primary plant and secondary systems	Maintain supply reliability to the Far North zone	June 2025	Full replacement of all 275kV and 132kV primary plant and secondary systems	$10m
Edmonton 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2026	Selected replacement of 132kV secondary systems	$8m
Turkinje 132kV primary plant replacement	Selected replacement of primary plant	Maintain supply reliability to the Far North zone	December 2027	Full replacement of primary plant	$6m

Possible asset retirements in the 10-year outlook period[9]

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 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.

[9] 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

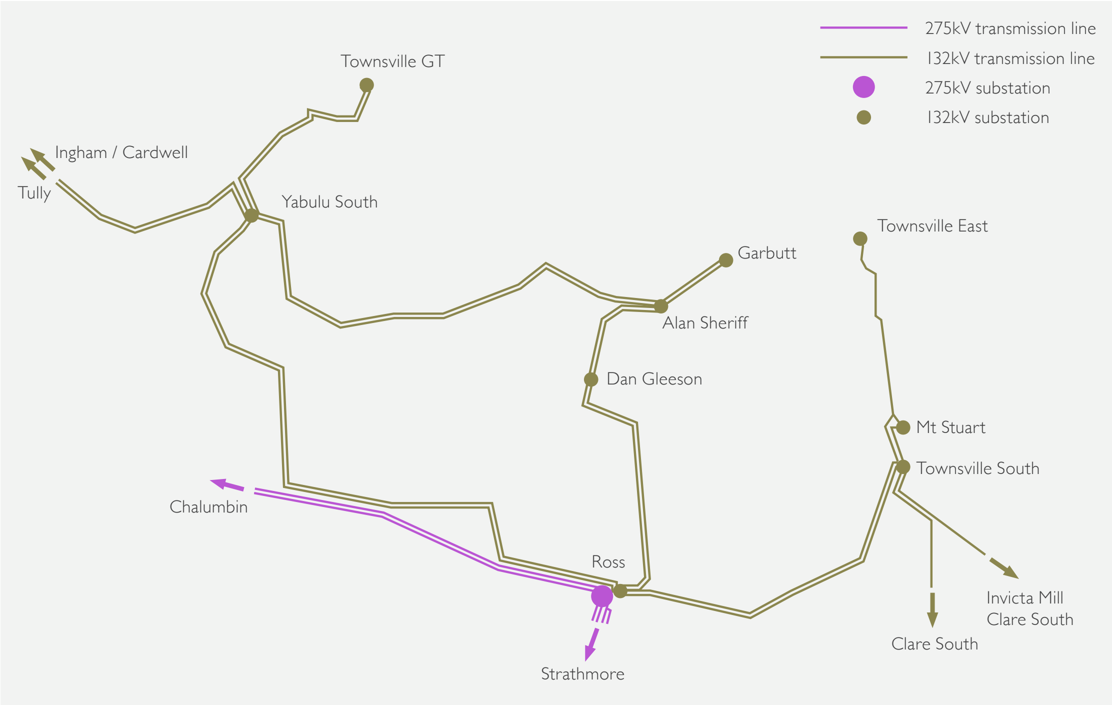


Figure 5.5 Southern Ross zone transmission network

5 Future network development

Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville and far north Queensland. Parts of the 132kV network are located closer to the coast in a high salt laden wind environment leading to accelerated structural corrosion (refer to figures 5.4 and 5.5).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in the Ross zone within the next five years.

Possible network reinvestments within five years

Transmission lines

Clare South to Townsville South 132kV transmission lines

Network requirement: Maintain reliability of supply between Strathmore and Townsville

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 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: June 2021

Taking into account the most recent analysis and understanding of the risks arising from 132kV transmission lines and network supply, the proposed network solution has been deferred by approximately 18 months to June 2021 compared to the possible commissioning date of summer 2019/20 as advised in the 2017 TAPR. 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 programmed for repair by micro piles in 2018.

Possible network solutions

Powerlink is considering a number of end of life strategies for the 275kV and 132kV transmission corridor and will holistically consider reliability of supply obligations and future network requirements as part of a RIT-T consultation. It has been identified that removal of one of the 132kV transmission lines between Townsville South and Clare South substations would require a substitute network or non-network solution to meet reliability obligations. A possible network solution to the resulting voltage limitation could include the installation of an additional transformer at Strathmore Substation.

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.

The RIT-T consultation is targeted to commence within the next 12 months and will assess a number of end of life strategies for the 132kV transmission lines between Townsville South and Clare South substations.

Feasible network solutions to address the risks arising from maintaining a reliable supply in the Townsville area include:

- 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 June 2021.
- Potential network reconfiguration through a combination of staged line refit projects and decommissioning of parts of the 132kV transmission lines by June 2021.

Proposed network solution: Reconfiguration through staged line refits and decommissioning of some assets at an estimated cost of $40 million, that may include:

- Structural refit of the coastal 132kV transmission line between Townsville South to Clare South substations by June 2021 at an estimated cost of $25 million.
- Decommission the inland 132kV transmission line between Townsville South to Clare South substations by June 2021 at an estimated cost of $10 million[10], as well as the installation of a transformer at Strathmore or Clare South substations by June 2021 at an estimated cost of $15 million.

Powerlink is currently analysing all possible network solutions, as part of an upcoming 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 and 1,000MWh in the Proserpine or Collinsville area. Non-network solutions may include, but are not limited to local generation, dynamic voltage support or demand side management.

Substations

Townsville South 132kV Substation

Network requirement: Maintaining reliability of supply at Townsville South 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.

132kV secondary systems

Project driver

Emerging condition, obsolescence and compliance risks arising from the 132kV secondary systems.

10 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.

Project timing: December 2021

Taking into account the most recent analysis and understanding of the risks arising from 132kV transmission lines and network supply, the proposed network solution has been deferred by approximately 18 months to December 2021 compared to the possible commissioning date of summer 2019/20 as advised in the 2017 TAPR.

Possible network solutions

- Complete replacement of all secondary systems and associated panels by December 2021.
- Staged replacement of all secondary systems and associated panels. The first stage would be completed by December 2021, followed by completion of a second stage in 2028.

Proposed network solution: Staged replacement of all secondary systems at Townsville South Substation at an estimated cost of $3 million by December 2021

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

132kV primary plant

Project driver

Emerging condition and compliance risks arising from the 132kV primary plant.

Project timing: December 2021

Possible network solutions

- Replacement of selected equipment in the existing bays by December 2021.
- Adjacent greenfield replacement of the entire switchyard by December 2021.

Proposed network solution: replacement of selected equipment of the 132kV primary plant at an estimated cost of $9 million at Townsville South Substation by December 2021

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

Possible non-network solutions

Townsville South Substation provides injection and switching to the central business district and south-eastern suburbs of Townsville of over 200MW at peak, as well as providing connection for over 450MW of generation.

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Dan Gleeson 132kV Substation

Network requirement: maintaining reliability of supply at Dan Gleeson Substation

Located in south-west Townsville, Dan Gleeson Substation is a major injection point into the Ergon Energy distribution network.

Project driver

Addressing the secondary systems condition risks at Dan Gleeson Substation.

Project timing: December 2020

Taking into account the most recent analysis and understanding of the risks arising from secondary systems at Dan Gleeson, the proposed network solution has been deferred by approximately 12 months to December 2020 compared to the possible commissioning date of summer 2019/20 as advised in the 2017 TAPR.

Possible network solutions

- Staged in-situ replacement of only those secondary systems components that are obsolete, using the existing building and secondary systems panels by December 2020.
- Complete replacement of all secondary systems and associated panels, using a prefabricated building with new secondary systems equipment and wiring preinstalled by December 2020.
- Staged replacement of all secondary systems and associated panels using a prefabricated building with new secondary systems equipment and wiring preinstalled. The first stage would occur by December 2020, followed by completion of a second stage in 2025.

Proposed network solution: complete replacement of all secondary systems at an estimated cost of $5.4 million by December 2020

In May 2018 Powerlink published a Project Specification Consultation Report (with Project Assessment Draft Report exemption) (PSCR) which identified complete replacement of all secondary systems by December 2020 at an estimated cost of $5.4 million as the proposed preferred option. Submissions to the PSCR close on 3 August 2018 and Powerlink anticipates publication of the Project Assessment Conclusions Report in September 2018.

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

Possible non-network solutions

Non-network solutions identified in the PSCR include the requirement to provide injection or demand response at Dan Gleeson, or into the meshed Townsville network in the vicinity of Dan Gleeson, of up to 50MW and up to approximately 850MWh per day. This requirement is based on the power transferred through the Dan Gleeson transformers through previous years, and accounting for steady demand in the future.

Ingham South 132/66kV Substation

Network requirement: Maintaining reliability of supply to Ingham

Ingham South Substation was established in 2005 to replace the original Ingham Substation and is critical to supply Ergon Energy's 66kV distribution network in the Ingham area. As a measure to minimise costs when the substation was established, two 132/66kV transformers from the Gladstone South Substation rebuild project were recovered and installed at Ingham South Substation.

Project driver

Emerging condition risks arising from the 132/66kV transformers.

Project timing: December 2019

Possible network solutions

- Life extension of both transformers by December 2019 followed by replacement with new transformers in 2032.
- Replacement of one transformer by December 2019 and life extension of the other transformer in December 2019, followed by its replacement in 2032.
- Replacement of both transformers with new transformers by December 2019.

Proposed network solution: Replacement of both transformers at Ingham South Substation at an estimated cost of $5.7 million by December 2019

In June 2018 Powerlink published a Project Specification Consultation Report (with Project Assessment Draft Report exemption) (PSCR) which identified replacement of both transformers by December 2019 at an estimated cost of $5.7 million as the proposed preferred option. Submissions to the PSCR close on 12 September 2018 and Powerlink anticipates publication of the Project Assessment Conclusions Report in November 2018.

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

Possible non-network solutions

Network support to supply the entire load at Ingham South would require injection to the 66kV network at Ingham of up to 20MW at peak and up to 300MWh per day on a continuous basis.

Alternative non-network options may include installation of a single 132/66kV transformer at Ingham South and:

- network support of up to 20MW and 300MWh per day
- dynamic voltage support of up to 15MVAr, and network support of up to 10MW and 110MWh per day.

Ross 275/132kV Substation

Network requirement: Maintaining power transfer capability and reliability of supply at Ross Substation

Ross Substation was established in the mid-1980s and is an essential switching station for 275kV power transfer into North and Far North Queensland, providing switching for five 275kV transmission lines from Strathmore and Chalumbin substations. Three 275/132kV bulk supply transformers provide connection to the 132kV switchyard. The 132kV switchyard provides supply to Townsville and surrounding areas through eight 132kV feeders connected from the Townsville South, Millchester, Alan Sherriff, Kidston and Yabulu South substations.

Project driver

Emerging condition risks arising from selective 275kV equipment and the majority of 132kV primary plant.

Project timing: December 2022

Possible network solutions

- Complete replacement of all 132kV bays and selective replacement of 275kV primary plant equipment bays by December 2022.
- Complete replacement of all 132kV and 275kV primary plant bays that have been identified to have equipment at risk of failure by December 2022.
- Complete replacement of the 132kV and 275kV switchyards at an adjacent site by December 2022.

Proposed network solution: Complete replacement of the 132kV bays and replacement of selective 275kV equipment in existing bays at an estimated cost of $24 million by December 2022

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

Possible non-network solutions

The Ross Substation provides an essential switching station for 275kV power transfer into North and Far north Queensland, with the 132kV switch yard providing supply to Townsville and the surrounding areas. The maximum demand at Ross Substation is forecast to approach 400MW.

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Table 5.8 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	Line refit works on steel lattice structures (1)	Maintain supply reliability in the Ross zone	June 2021	Line refit works on 132kV transmission line between Townsville South and Invicta, and additional reinforcement at Strathmore. New 132kV transmission line. Non-network (2)	$25m
Retirement of the inland 132kV transmission line between Clare South and Townsville South substations and network reconfiguration	Retirement of the transmission line and installation of a transformer at Strathmore Substation (2)	Maintain supply reliability in the Ross zone	June 2021	Targeted foundation repair on the 132kV transmission line, followed by line refit or decommissioning. New 132kV transmission line. Non-network (2)	$15m (4)
Substations					
Dan Gleeson 132kV secondary systems replacement	Full replacement of 132kV secondary systems (3)	Maintain supply reliability to the Ross zone	December 2020	Staged replacement of 132kV secondary systems equipment Non-network (2)	$5m
Townsville South 132kV primary and secondary systems replacement	Replacement of selective 132kV primary plant and staged replacement of 132kV secondary systems (1)	Maintain supply reliability to the Ross zone	December 2021	Full replacement of 132kV primary plant and secondary systems Non-network (2)	$12m
Ingham South 132/66kV transformers	Replacement of both transformers (3)	Maintain supply reliability to the Ross zone	December 2019	Refurbishment of both transformers Non-network (2)	$6m
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	June 2022	Selected replacement of 275 and 132kV secondary systems in existing panels	$5m
Ross 275kV and 132kV primary plant replacement	Full replacement of 132kV primary plant and selective replacement of 275kV primary plant	Maintain supply reliability in the Ross zone	December 2022	Full replacement of 275 and 132kV primary plant Non-network (2)	$24m

Table 5.8 Possible network reinvestments in the Ross zone within five years *(continued)*

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 above in S5.7.2.

(3) The scope of works, or the need to undertake this potential project, will rely upon the outcome of a RIT-T that is currently under way.

(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 service life and to maintain reliability of supply in the Ross zone from around 2024/25 to 2028/29 (refer to Table 5.9).

Table 5.9 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 2027	New 132kV transmission line	$7m
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 2026	New 132kV transmission line	$58m
Substations					
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	$3m
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	$4m
Townsville South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems (1)	Maintain supply reliability to the Ross zone	June 2028	Full replacement of 132kV secondary systems	$15m
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	$11m
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2026	Staged replacement of secondary systems	$6m

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.

Possible asset retirements in the 10-year outlook period

Townsville South to Clare South inland transmission line

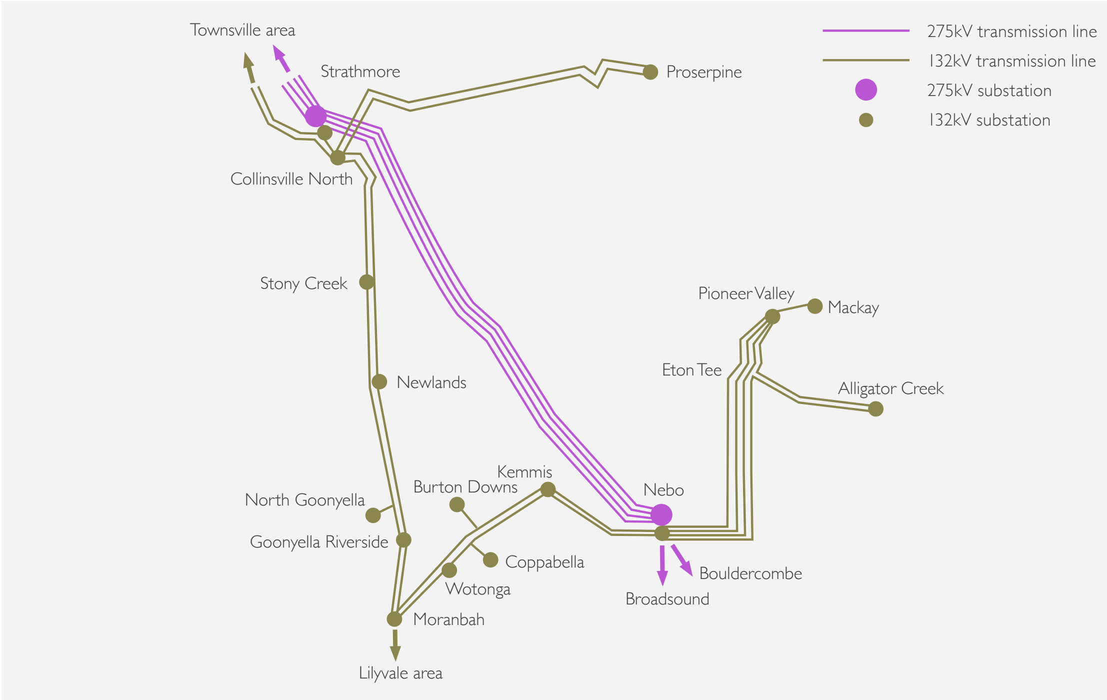
Subject to the outcome of further analysis and RIT-T consultation, Powerlink may retire the inland transmission line at the end of its service life anticipated around 2021.

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. Condition assessment has identified moderate levels of structural corrosion and end of technical service life is expected within the next six to 10 years. Possible end of service life strategies for this transmission line may include replacement on a new easement or retirement.

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 in Chapter 2 there are no network limitations forecast to occur in the North zone within the next five years.

Increasing local demand in the Proserpine area is expected to lead to some load at risk under Powerlink's planning standard. 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 1.7).

Possible network reinvestments within five years

Transmission lines

Pioneer Valley to Eton tee transmission lines

Network requirement: 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.

Project driver

Emerging conditions risks due to structural corrosion.

Project timing: June 2023

Possible network solutions

- Refit the existing transmission line by June 2023.
- Rebuild the transmission line by June 2023.

Proposed network solution: Refit of the transmission line at an estimated cost of $8 million by June 2023

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 in the Pioneer Valley or Mackay area, along with reconfiguration of the 132kV network at Eton tee. Any non-network solutions to remain within Powerlink's planning standard may include up to 10MW and 50MWh per day in the Mackay or Pioneer Valley area.

Substations

Kemmis 132kV Substation

Network requirement: Maintaining reliability of supply at Kemmis Substation

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 T1 relocated from Proserpine and T2 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 $8 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.

Table 5.10 Possible network reinvestments in the North zone within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Eton tee and Pioneer Valley Substation	Line refit works on steel lattice structures	Maintain supply reliability to the North zone	June 2023	Line rebuild or reconfiguration of the 132kV network and network support. Non-network (1)	$8m
Substations					
Kemmis 132/66kV transformer replacement	Replacement of 132/66kV transformer	Maintain supply reliability to the North zone	December 2020	Refurbishment of 132/66kV transformer Up to 32MW and approximately 760MWh per day	$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 Non-network (1)	$8m
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 Up to 21MW and approximately 415MWh per day	$2m
Newlands 132kV primary plant replacement	Staged replacement of 132kV primary plant	Maintain supply reliability in the North zone	June 2023	Replacement of all 132kV primary plant Up to 23MW and approximately 460MWh per day	$4m

Note:

(1) The envelope for non-network solutions is defined above in S5.7.3.

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 2024/25 to 2028/29 (refer to Table 5.11).

Table 5.11 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 and Eton tee	Line refit works on steel lattice structures	Maintain supply reliability to the North zone	June 2026	New transmission line	\$10m
Substations					
Nebo 132/11kV transformer replacements	Replacement of two 132/11kV transformers at Nebo Substation	Maintain supply reliability to the North zone	June 2025	Establish 11kV supply from surrounding network	\$4m
Newlands 132/66kV transformer replacement	Replace one 132/66kV transformer	Maintain supply reliability in the North zone	June 2026	Establish 66kV supply from surrounding network	\$4m

Possible asset retirements within the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the North zone within the next 10 years.

5.7.4 Central West and Gladstone zones

Figure 5.7 Central West and Gladstone transmission network

Existing network

The Central West 132kV network was developed between the mid 1960s to 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.

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 the Boyne Island Smelter (BSL) in the early 1990s (refer to Figure 5.7).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in the Central West and Gladstone zones within the next five years.

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 constraint durations and levels are sensitive to highly uncertain variables including changes in bidding behaviour, environmental conditions, demand levels, etc.

Powerlink engaged market modelling specialists to inform the market implications of additional renewable energy projects in North Queensland (NQ). Key conclusions included:

- high levels of NQ renewable generation resources will play a major role in the overall market changes
- flows between NQ and Central Queensland (CQ) are expected to reverse during the day to southerly flows
- most of the displaced thermal generation resulting from NQ renewables is within CQ

- additional NQ renewables could create additional congestion in CQ
- results are sensitive to bidding behaviour of CQ generators.

Possible network reinvestments within five years

Transmission lines

Egans Hill to Rockhampton 132kV transmission line

Network requirement: Maintaining reliability of supply to the Rockhampton area

Rockhampton Substation is supplied via these 132kV transmission lines from Bouldercombe Substation. The section from Egans Hill to Rockhampton was constructed in the early 1960s.

Project driver

Emerging condition driven risks related to degraded foundations in the near term and corrosion issues to structures in the medium term.

Project timing: December 2020

Possible network solutions

- Life extension strategy for the entire transmission line by December 2020.
- Partial rebuild strategy that involves a new transmission line along the section from Egans Hill Substation to the Fitzroy river in 2020, with life extension works for the section of line from the Fitzroy river to the Rockhampton Substation by December 2020 that will require regular follow-up paint applications at 15 year intervals.

Proposed network solution: Life extension strategy for the entire transmission line at an estimated cost of $14 million by December 2020

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

Possible non-network solutions

The Bouldercombe to Rockhampton 132kV transmission lines, which includes the section of transmission line between Egan's Hill to Rockhampton, provides supply of up to 100MW at peak, injecting into the 66kV network at Rockhampton Substation. Rockhampton Substation is supported via Pandoin Substation to the north and Egans Hill Substation to the south through Ergon's 66kV network.

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

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

Callide A to Moura 132kV transmission line

The 132kV transmission line was constructed in the early 1960s and there is an ongoing need for this asset to supply the Biloela and Moura substations. While the above-ground structures are in generally good condition, the transmission line was constructed with grillage foundations that require more detailed and ongoing condition assessment. Based on Powerlink's current understanding of the grillage foundations' condition, reinvestment in this transmission line will be required towards the end of the 10-year outlook period of this TAPR (refer to Table 5.13).

Calliope River to Wurdong tee 275kV transmission lines

Network requirement: Maintaining a reliable supply to the Gladstone, Wide Bay and Moreton zones

Project driver:

Emerging condition driven risks related to structural corrosion on the single circuit 275kV transmission lines from Calliope River to Wurdong tee.

Project timing: December 2023

Possible network solutions

- Refit the transmission lines by December 2023.
- Replace two single circuit transmission lines with a double circuit line by December 2023.

Proposed network solution: Replace the transmission lines at an estimated cost of $15 million by December 2023

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

Possible non-network solutions

The 275kV transmission lines between Calliope River and Wurdong tee facilitate power transfer from generation in Central and North Queensland, as well as the Gladstone Power Station, to BSL at Wurdong and on into South-East Queensland. Any removal or reconfiguration of these lines is expected to significantly reduce the transfer capability on these grid sections and as such, Powerlink is not aware of any non-network proposals in this area that can address this requirement in its entirety.

Substations

In the 2017 TAPR, Powerlink identified opportunities to reconfigure the network by summer 2018/19 to provide efficiencies and cost savings by:

- reducing the number of transformers within the zone, particularly at Lilyvale and Bouldercombe. These possible reinvestments are now subject to public consultation and are discussed within this section 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

Network requirement: 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: June 2021

Possible network solutions

- Selected replacement of 132/275kV primary plant by June 2021.
- Full 132/275kV primary plant replacement by June 2021.

Proposed network solution: selective primary plant replacement at an estimated cost of $9 million by June 2021

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

Possible non-network solutions

Lilyvale Substation is a major injection point to the Central West and Northern Bowen Basin regions, supplying over 370MW at peak, as well as providing switching for a number of connections in the region.

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

132/66kV transformers

Project driver

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

Project timing: June 2021

Taking into consideration the most recent analysis and understanding of the risks arising from the transformers at Lilyvale Substation, the proposed network solution has been deferred by approximately 12 months from the possible commissioning date of winter 2020 as advised in the 2017 TAPR to June 2021.

Possible network solutions

- Replacement of three transformers with two larger transformers by June 2021.
- Replacement of three transformers with two smaller units (relative to option 1) by June 2021 (this option would require Powerlink to engage non-network support).
- Replacement of the transformers with three new transformers by June 2021.

Proposed network solution: Replacement of three transformers with two larger transformers at an estimated cost of $10 million by June 2021

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 in the Lilyvale areas. Any non-network solution would be required to be available on a firm basis to replace the network functionality provided by Lilyvale Substation which supports a load of up to 120MW at peak, and approximately 1,700MWh per day.

Network support, in conjunction with the installation of a single transformer at Lilyvale, would be required to support the full load of the substation of up to 120MW at peak, and over 1,700MWh per day and be available to operate within four hours of a contingency occurring.

Network support, in conjunction with the installation of two smaller transformers (relative to option 1) at Lilyvale would require injection of up to 25MW and 300MWh per day.

Blackwater 132kV Substation

Network requirement: 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.

Powerlink is considering a number of end of life strategies for the transformers, selected secondary systems within five years, and selected primary plant in the five to 10-year outlook, and will holistically consider reliability of supply obligations and future network requirements as part of a RIT-T consultation.

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.

Proposed network solution: Replace two transformers at Blackwater Substation with one transformer at an estimated cost of $5 million by June 2022

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

132kV secondary systems

Project driver

Emerging condition, obsolescence and compliance risks arising from the 132kV secondary systems.

Project timing: June 2023

Possible network solutions

- Complete replacement of all secondary systems and associated panels by June 2023.
- Staged replacement of all secondary systems and associated panels. The first stage would be completed by June 2023, followed by completion of a second stage in 2029.

Proposed network solution: Staged replacement of all secondary systems at Blackwater Substation at an estimated cost of $5 million by June 2023

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 66kV network in the Blackwater area. Any non-network solution would need to be available on a firm basis and provide support to the 66kV network of up to 260MW and up to 2,650MWh per day. Powerlink considers the proposed network solution will not have a material inter-network impact.

Bouldercombe 275/132kV Substation

Network requirement: Maintaining power transfer capability and reliability of supply at Bouldercombe Substation

Bouldercombe 132kV switchyard was established in 1975, with the subsequent establishment of a 275kV switchyard and installation of two transformers in 1977. A third transformer was installed in 2012 due to load growth experienced at that time. Bouldercombe Substation is a critical part of the 275kV transmission network, connecting the 275kV transmission lines north to Broadsound and Nebo, south to Raglan and Calliope River and west to Stanwell.

275kV and 132kV primary plant

Project driver

Emerging condition risks arising from 275kV and 132kV primary plant at Bouldercombe Substation.

Project timing: December 2022

Taking into consideration the most recent analysis and understanding of the risks arising from the primary plant at Bouldercombe Substation, the proposed network solution has been deferred from the possible commissioning date of summer 2020 as advised in the 2017 TAPR to December 2022.

Possible network solutions

- Replace selected primary plant by December 2022, followed by a second stage of replacement of selected plant in 2029 in the existing bays.
- Selective primary plant replacement by establishing new bays by December 2022.

Proposed network solution: Selective primary plant replacement by establishing new bays at an estimated cost of $26 million by December 2022

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

275/132kV transformers

Project driver

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

Project timing: June 2021

Taking into consideration the most recent analysis and understanding of the risks arising from the primary plant at Bouldercombe Substation, the proposed network solution has been deferred from the possible commissioning date of summer 2020 as advised in the 2017 TAPR to June 2021.

Possible network solutions

- Replace two transformers with one transformer by June 2021.
- Replace two transformers with two transformers by June 2021.

Proposed network solution: Replace two transformers at Bouldercombe Substation with a single transformer at an estimated cost of $7 million by June 2021

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

Possible non-network solutions

Bouldercombe Substation solely supplies load of approximately 275MW at peak to the Ergon Energy 66kV network at Rockhampton, Pandoin and Egans Hill, and to customer loads at Stanwell, Wycarbah and Grantleigh. A non-network solution for Bouldercombe would need to provide an additional 132kV injection to ensure supply to these loads, specifically by considering the transformer size, configuration and consolidation of the transformers. Any non-network solution would require injection at either Bouldercombe, or closer to the loads on the Ergon Energy 66kV network, of up to 275MW and 3,500MWh per day.

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Gladstone South 132kV Substation

Network requirement: 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 major connection to Queensland Alumina Limited (QAL). In 2002, a substation was constructed on an adjacent site to manage the rising fault level and general condition 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: June 2023

Possible network solutions

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

Proposed network solution: Selective secondary systems replacement at Gladstone South Substation at an estimated cost of $15 million by June 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 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Baralaba 132kV Substation

Project driver

Addressing the secondary systems condition risks at Baralaba Substation.

Baralaba Substation is located approximately six kilometres south east of the Baralaba township in central Queensland. It was established as a switchyard in 1976 in conjunction with the development of the 132kV network between Callide A Power Station and Blackwater Substation to facilitate supply to increasing mining loads in the Blackwater area.

Network requirement: Maintaining reliability of supply at Baralaba Substation

Project timing: December 2020

Possible network solutions

- Full in-situ replacement – to replace all secondary systems panels and associated wiring for three bays within the existing secondary systems building by December 2020.
- Full replacement with prefabricated building – to replace all secondary systems for three bays using a modular prefabricated building with new secondary systems installed by December 2020.

Proposed network solution: full replacement with a prefabricated building at an estimated cost of $8 million by December 2020

In March 2018 Powerlink published a Project Specification Consultation Report (with Project Assessment Draft Report exemption) (PSCR) which identified full replacement with prefabricated building by December 2020 at an estimated cost of $8 million as the proposed preferred option.

Submissions to the PSCR closed in June 2018 and Powerlink anticipates publication of the Project Assessment Conclusions Report in August 2018.

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

Possible non-network solutions

Non-network solutions identified in the PSCR include network reconfiguration to bypass Baralaba Substation, coupled with a non-network option to provide support at Moura. Potential non-network options that could provide this support include:

- Local generation: injection at Moura to reduce the peak loads at Biloela and Moura by up to 36MW. This injection would need to be available on a continuous basis as required.
- DSM: bulk 66kV customers at Moura may be incentivised to reduce their demand. This could result in a peak combined reduction of 36MW or 34MWH (daily)[11] at Moura and Biloela.

11 The estimated daily MWH has been derived from the 2017 historical load data.

Table 5.12 Possible network reinvestments in the Central West and Gladstone zones within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Egans Hill and Rockhampton substations	Line refit works on steel lattice structures (1)	Maintain supply reliability in the Central West zone	December 2020	New 132kV transmission line Non-network (2)	$14m
Rebuild the 275kV transmission lines between Wurdong and Calliope River Substation	Rebuild the two single circuit 275kV transmission lines between Calliope River and Wurdong with one double circuit.	Maintain supply reliability in the Gladstone zone and CQ-SQ transmission corridor	December 2023	Refit the 275kV transmission lines between Calliope River and Wurdong Non-network (2)	$15m
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	June 2019	Rebuild the 132kV transmission line between Callemondah and Gladstone South substations Up to 180MW and approximately 3,200MWh (4)	$5m
Substations					
Lilyvale transformers replacement	Replacement of two of the three 132/66kV transformers (1)	Maintain supply reliability in the Central West zone	June 2021	Replacement of three 132/66kV transformers. Retire one of three 132/66kV transformers and implement non-network solution (2)	$10m
Lilyvale primary plant replacement	Selective replacement of 132kV and 275kV primary plant (1)	Maintain supply reliability in the Central West zone	June 2021	Full replacement of 132kV and 275kV primary plant Non-network (2)	$9m
Bouldercombe primary plant replacement	Selective replacement of 132kV and 275kV primary plant (1)	Maintain supply reliability in the Central West zone	December 2022	Full replacement of 132kV and 275kV primary plant Non-network (2)	$26m
Bouldercombe transformer replacement	Replacement of one 132/275kV transformer with a larger unit, and retirement of the other (1)	Maintain supply reliability in the Central West zone	June 2021	Replacement of two 132/275kV transformers Non-network (2)	$7m (4) (5)

Table 5.12 Possible network reinvestments in the Central West and Gladstone zones within five years *(continued)*

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Baralaba secondary systems replacement	Full replacement with prefabricated building (3)	Maintain supply reliability in the Central West zone	December 2020	Full in-situ replacement Non-network (2)	$8m
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 Up 160MW and approximately 2,000MWh per day	$5m
Blackwater 132kV secondary systems replacement	Staged replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2023	Full replacement of the 132kV secondary systems Up to 260MW and approximately 2,650MWh per day	$5m
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 Up to 40MW and approximately 800MWhr per day (N-1-600 within 24 hours to ensure reliability criteria)	$5m
Gladstone South 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2023	Full replacement of 132kV secondary systems Non-network (2)	$15m

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 above in S5.7.4.

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

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

(5) 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.

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 and Gladstone zones from around 2024/25 to 2028/29 (refer to Table 5.13).

Table 5.13 Possible network reinvestments in the Central West and Gladstone 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 275kV transmission line between Calliope 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 Calliope River and Larcom Creek substations	$14m
Rebuild the 275kV transmission lines between Wurdong and Gin Gin substations	Rebuild the single circuit 275kV transmission lines between Wurdong and Gin Gin with a double circuit transmission line	Maintain supply reliability in the Central West and transfer capacity between Central and Southern Queensland	December 2028	Refit the 275kV transmission lines between Wurdong and Gin Gin	$130m
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	$2m
Rebuild the 132kV transmission lines from Callide A to Biloela and Moura.	Rebuild the 132kV transmission lines from Callide A to Biloela and Moura as a double tee	Maintain supply reliability in the Central West and CQ-SQ transmission corridor	June 2029	Refit the 132kV transmission lines from Callide A to Biloela and Moura	$68m
Substations					
Blackwater 132kV primary plant replacement	Selective replacement of 132kV primary plant	Maintain supply reliability in the Central West	December 2024	Full replacement of 132kV primary plant	$4m
Alligator Creek 132kV primary plant replacement	Selective replacement of132kV primary plant	Maintain supply reliability in the Central West	June 2025	Full replacement of 132kV primary plant	$3m
Lilyvale 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Central West	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	December 2026	Full replacement of 132kV secondary systems	$8m
Rockhampton 132kV secondary systems replacement	Selective replacement of 132kV secondary systems	Maintain supply reliability in the Central West	June 2027	Full replacement of 132kV secondary systems	$6m

Table 5.13 Possible network reinvestments in the Central West and Gladstone zones within six to 10 years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Broadsound 275kV secondary systems replacement	Selective replacement of 275kV secondary systems	Maintain supply reliability in the Central West	June 2027	Full replacement of 275kV secondary systems	$3m
Calvale 275kV primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability in the Central West	December 2026	Full replacement of 275kV primary plant	$13.5m

Possible asset retirements within the 10-year outlook period[12]

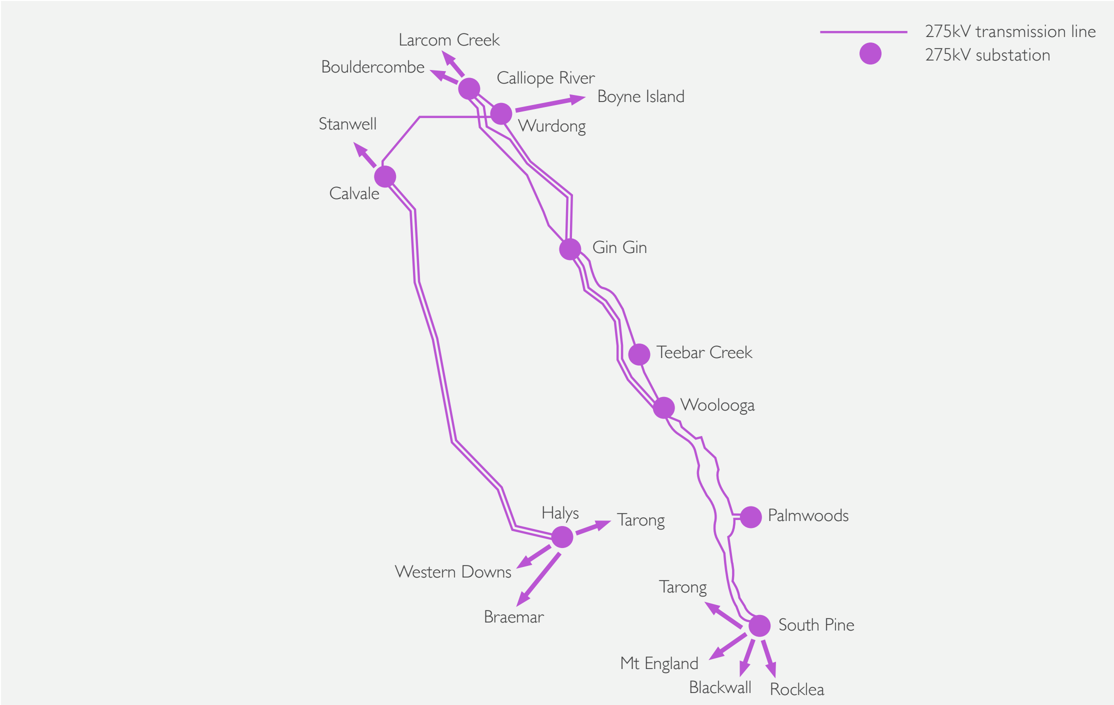
Callide A to Gladstone South 132kV transmission double circuit line

The 132kV transmission line was constructed in the mid 1960s to support the loads in the Gladstone area. Due to reconfiguration in the area, it is likely this transmission line will be retired from service at the end of technical service life, expected within the next six to 10 years.

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

5.7.5 Wide Bay zone

Figure 5.8 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 in Chapter 2 there are no network limitations forecast to impact reliability of supply in the Wide Bay zone within the next five years.

Possible network reinvestments within five years

Substations

Powerlink's routine program of condition assessments has not identified any reinvestment requirements in the Wide Bay zone within the next five years.

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 2024/25 to 2028/29 (refer to Table 5.14).

Table 5.14 Possible network reinvestments in the Wide Bay zone within six to 10 years

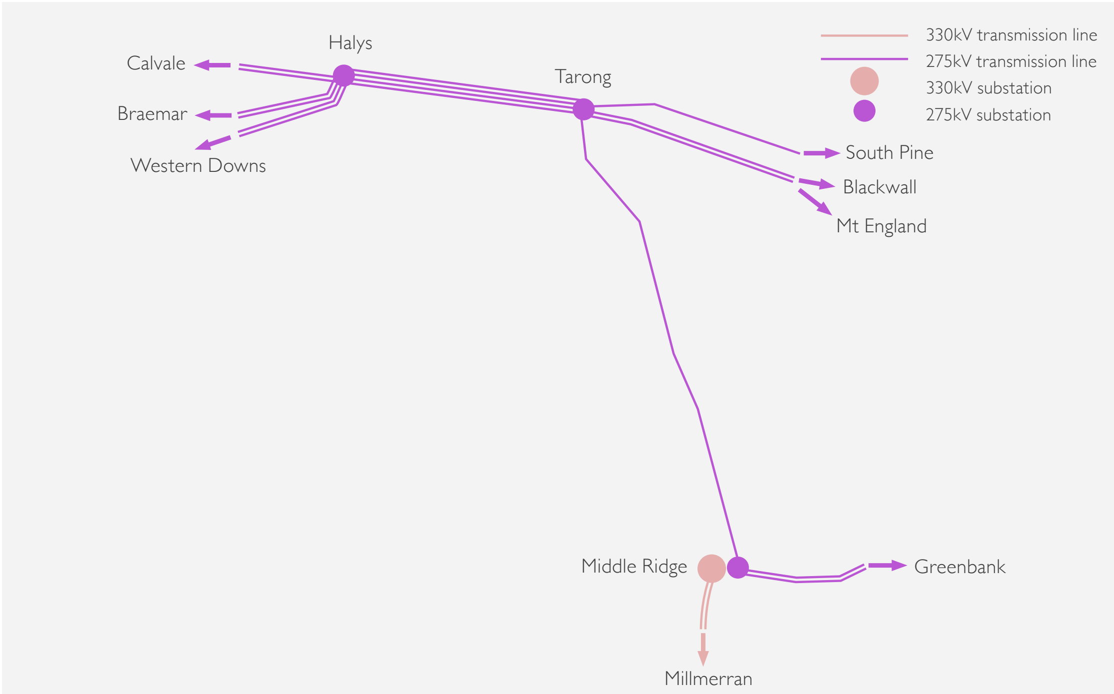
Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the transmission lines between Gin Gin and Woolooga substations	Refit the 275kV transmission lines between Gin Gin and Woolooga substations	Maintain supply to the Wide Bay zone	June 2027	Rebuild the 275kV transmission lines between Gin Gin and Woolooga substations	$17m
Substations					
Woolooga 275kV and 132kV secondary systems replacement	Full replacement of 132kV and 275kV secondary systems (including SVC)	Maintain supply to the Moreton zone	December 2027	Selective replacement of 132kV and 275kV secondary systems (including SVC)	$30m
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Moreton zone	December 2027	Selective replacement of 132kV and 275kV secondary systems	$14m

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

5.7.6 South West zone

Figure 5.9 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 5.9).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in the South West zone within the next five years.

Possible network reinvestments within five years

Substations

Tarong 275/132kV/66kV substation

Project driver

Addressing the secondary systems condition risks at Tarong Substation.

Tarong Substation was established in conjunction with the Tarong Power Station in 1982 and connects the 275kV transmission circuits from the central and south west parts of Queensland into the South East Queensland load centre. The Tarong Substation is also the connection point for the Tarong and Tarong North base load coal fired power stations and provides supply to local, rural and bulk mining loads.

Network requirement: Maintaining reliability of supply at Tarong Substation

Project timing: December 2021

Possible network solutions

- Replace all selected secondary systems panels and associated wiring for selected equipment within the existing secondary systems building by December 2021.
- Replace all selected secondary systems panels using a modular prefabricated building with new secondary systems installed by December 2021.

Proposed network solution: selected replacement within the existing building at an estimated cost of $11 million by December 2021

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

Possible non-network solutions

Tarong Substation provides connection for generation of approximately 1,850MW, supplies local loads of over 55MW and power transfer capacity of over 3,600MW to meet the SEQ load. Switching at Tarong Substation facilitates power transfer from the CQ-SQ, Tarong and SWQ cut sets into SEQ. A non-network solution for Tarong would need to maintain adequate transfer capability and switching capability in the area.

Powerlink is not aware of any non-network proposals in this area that can address this requirement in its entirety. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or demand side management initiatives in the area, and would be required to be available on a firm basis.

Table 5.15 Possible network reinvestments in the South West zone within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Tarong secondary systems replacement	In situ staged replacement of secondary systems equipment (1)	Maintain supply reliability in the South West zone	December 2021	Full replacement of 275kV secondary systems Non-network (2)	$11m
Tarong 66kV cable replacement	Overhead transmission line	Maintain supply reliability in the South West zone	June 2019	Replacement of underground cable Up to 24MW and approximately 200MWh per day	$3m

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 above in S5.7.6.

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 South West zone from around 2024/25 to 2028/29 (refer to Table 5.16).

Table 5.16 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					
Tarong 275/66/11kV transformers replacement	Replacement of 275/66/11kV transformers at Tarong Substation	Maintain supply reliability in the South West zone	December 2024	Refurbishment of existing transformers	$8m
Tarong 275/132kV transformers replacement	Decommissioning of 275/132kV transformers (1)	Maintain supply reliability in the South West zone	December 2024	Replacement of one or both the 275/132kV transformers	$1m
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	$10m
Chinchilla 132kV primary plant and secondary replacement	Reduced scope replacement and transformer ending from Columboola	Maintain supply reliability in the South West zone	December 2026	Replacement of the entire 132kV switchyard	$10m

Note:

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

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

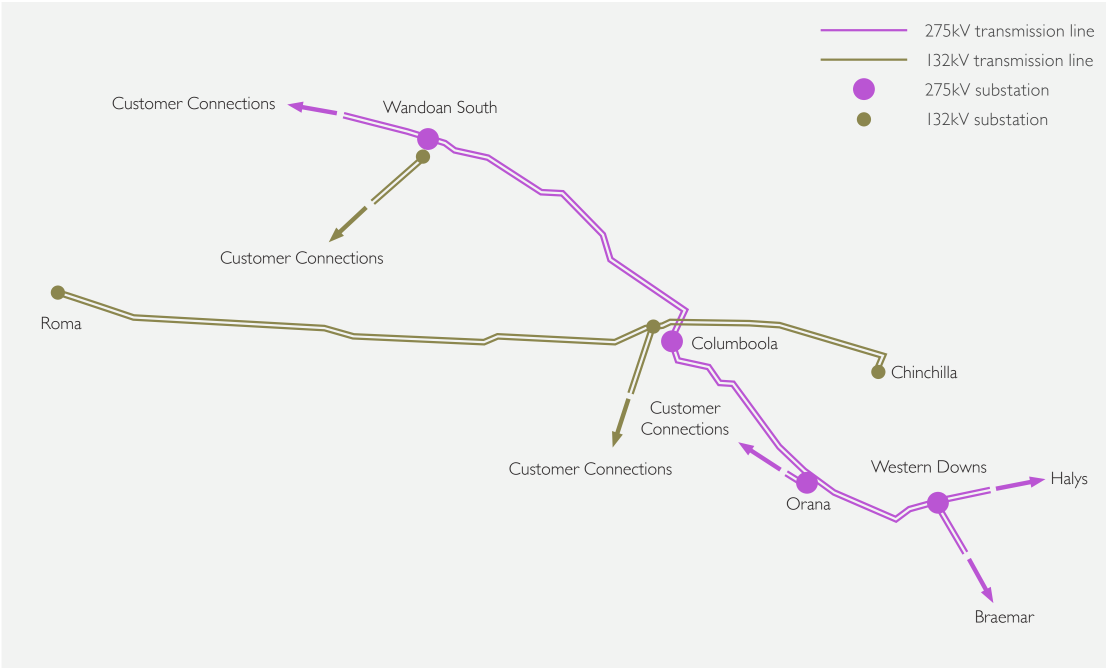
Condition assessment has identified emerging condition risks arising from the condition of two 275/132kV transformers at Tarong Substation by 2024. Planning studies have confirmed the potential to subsequently retire both transformers based on the medium economic load forecast in Chapter 2. On this basis, 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 and secondary systems at Chinchilla Substation by 2026. At this time, an option would be a reduced scope replacement that would involve transformer ending from Coolumboola 132kV Substation, and retire the 132kV primary plant and secondary systems arising from the connection to Tarong Substation.

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

5.7.7 Surat zone

Figure 5.10 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 5.10).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in the Surat zone within the next five years.

Possible network reinvestments within the 10-year outlook period

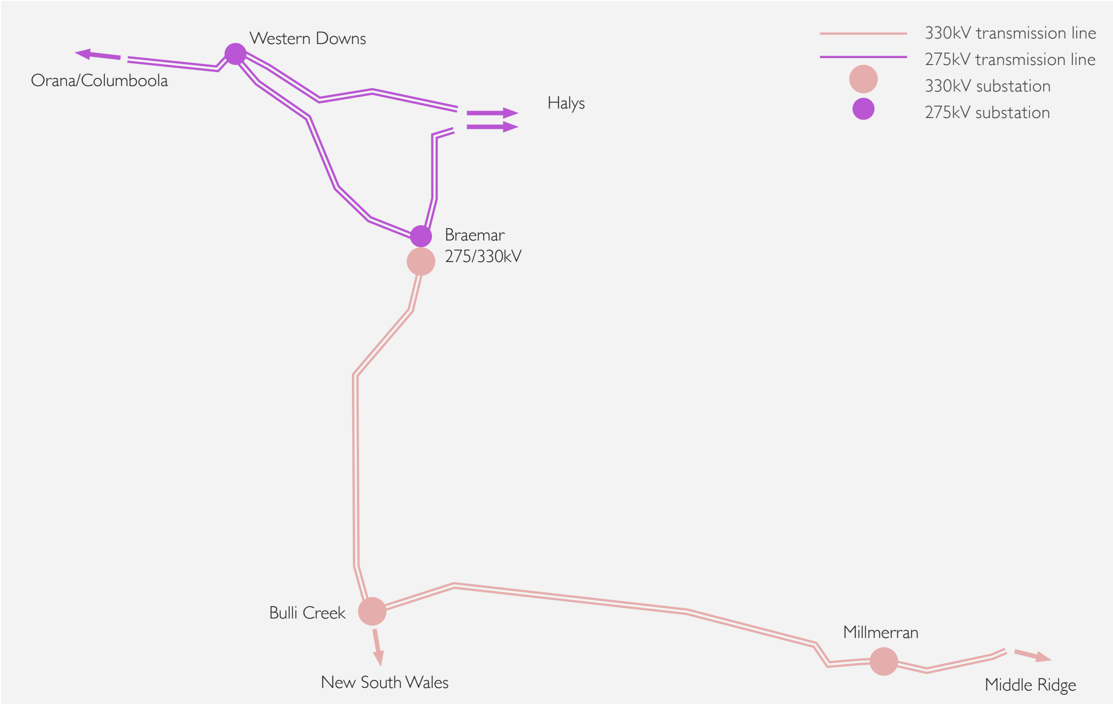
There are no reinvestment requirements within the 10-year outlook period.

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.

5.7.8 Bulli zone

Figure 5.11 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 5.11).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to impact reliability of supply in the Bulli zone within the next five years.

Possible network reinvestments within five years

There are no reinvestment requirements within the next five years.

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 2024/25 to 2028/29 (refer to Table 5.17).

Table 5.17 Possible network reinvestments in the Bulli zone within six to 10 years

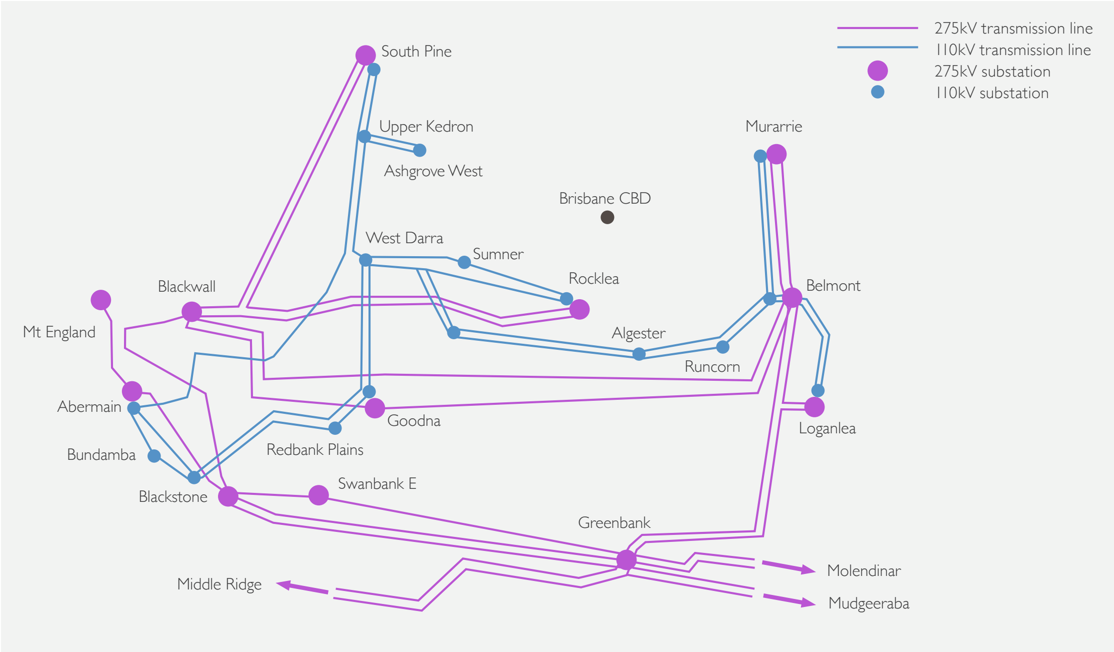
Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Bulli Creek 132kV secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability in the Bulli zone	December 2024	Full replacement of secondary systems	$2m
Middle Ridge 275kV and 110kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Bulli zone	December 2024	Selected replacement of secondary systems	$41m
Middle Ridge 110kV primary plant replacement	Selected replacement of primary plant bays and transformer refurbishment	Maintain supply reliability in the Bulli zone	December 2025	Selected replacement of equipment in bay and transformer refurbishment	$4m
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	$8m

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.

5.7.9 Moreton zone

Figure 5.12 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 5.12).

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 in Chapter 2 there are no network limitations forecast to occur in the Moreton zone within the next five years.

Possible network reinvestments within five years

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.

As such, 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 and would involve consultation with potentially impacted parties.

South Pine to Upper Kedron and West Darra to Rocklea transmission lines

Network requirement: Maintaining reliability of supply to the Brisbane metropolitan area

South Pine to Upper Kedron 110kV transmission line

The South Pine to Upper Kedron 110kV transmission line was constructed in 1963 and is approximately 13km in length. The transmission line is within 20km of the coast and is moderately protected from any prevailing coastal winds by virtue of its alignment through undulating forestry, semi-rural and residential areas.

Project driver

Emerging condition driven risks related to specific components of the transmission line are exhibiting an unacceptable level of corrosion.

Project timing: April 2022

Rocklea to Sumner to West Darra 110kV transmission line

The Rocklea to Sumner to West Darra 110kV transmission line was constructed in 1963 and is approximately 10km in length. The line is within 20kms of the coast and subject to the conditions of both a highly industrial and dense urban environment in which it operates.

Project driver

Emerging condition driven risks related to specific components of the transmission line, in particular some of the overhead earth wire and associated equipment are exhibiting an unacceptable level of corrosion.

Project timing: June 2021

Possible network solutions

Due to the connectivity of both the above 110kV transmission lines, Powerlink will undertake a RIT-T consultation to collectively assess feasible network and non-network solutions to address the risks arising from maintaining a reliable supply in greater Brisbane area include:

- Staged refit of the transmission lines.
- Refitting both of the transmission lines by June 2021.
- Selective retirement of one or both of the transmission lines by June 2021.

Proposed network solution: Refit both transmission lines at an estimated cost of $24 million by June 2021

Powerlink anticipates the commencement of a RIT-T within the next 12 months. The Brisbane Metropolitan area RIT-T will holistically address the risks arising from these 110kV transmission lines to analyse potential synergies which may be gained and to arrive at an optimal solution.

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

Possible non-network solutions

The 110kV lines between Rocklea, Sumner and West Darra provide supply to the south western suburbs of Brisbane through Sumner and Richlands substations of over 150MW at peak. The 110kV lines between South Pine and Upper Kedron provide supply to part of the Brisbane CBD and the inner western suburbs of Brisbane of over 150MW at peak.

Powerlink is not aware of any non-network proposals in this area that can address these 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

South Pine to Karana Downs 275kV transmission line

The 275kV transmission line between Karana Downs and South Pine was constructed in 1970 and is approximately 32km in length. The transmission line is between 10kms and 40kms from the coast and is, for the most part, geographically located in forest reserve with continual changes in elevation. At its lowest point, which is the South Pine Substation, the transmission line is only 20 metres above sea level. However it rises to 250 metres above sea level behind the Enoggera Reservoir.

Condition assessment previously indicated that specific components of the transmission line are exhibiting corrosion and the associated emerging risks need to be addressed within the next five years. Based on the most recent analysis and understanding of the risks arising from this transmission line, the likely proposed network solution has been deferred from the possible commissioning date of summer 2022 as advised in the 2017 TAPR to December 2025 (refer to Table 5.19).

Substations

Abermain 110/33kV Substation

Network requirement: Maintaining reliability of supply at Abermain Substation

Abermain Substation was established in 1994 to meet demand in the expanding Ipswich area. Further extensions at the substation due to ongoing load growth have resulted in a mixture of secondary systems from the early 1990s through to 2009.

Project driver

Addressing the secondary systems condition risks at Abermain Substation.

Project timing: June 2021

Taking into consideration the most recent analysis and understanding of the risks arising from the 110kV secondary systems requiring replacement at Abermain Substation, the likely proposed network solution has been deferred by approximately 12 months from the possible commissioning date of winter 2020 as advised in the 2017 TAPR to June 2021.

Possible network solutions

- Full replacement of the 110kV secondary systems by June 2021.
- Staged replacement of the 110kV secondary systems by 2021.

Proposed network solution: Full replacement of the 110kV secondary systems at Abermain Substation at an estimated cost of $7 million by June 2021

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

Possible non-network solutions

Abermain Substation provides injection and switching to Ipswich, Lockrose, Gatton areas and into the south-western suburbs of Brisbane of over 200MW 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

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

Palmwoods 275/132/110kV Substation secondary systems replacement

Project driver

Addressing the secondary systems condition risks at Palmwoods Substation.

Palmwoods Substation was established in 1978, initially operating at 132/110kV to supply the increasing demand in the Sunshine Coast and surrounding areas. The 275kV switchyard was built in 1993 with subsequent extensions to both switchyards in the 2000s.

Network requirement: Maintaining reliability of supply at Palmwoods Substation

Project timing: December 2020

Possible network solutions

- Staged replacement of all of the 275kV secondary systems in new protection panels in the existing control building, with the first stage of works being completed by December 2020 and the second stage of works completed by June 2024.
- Replacement of all of the 275kV secondary systems by June 2021.

Proposed network solution: Replacement of all of the 275kV secondary systems at Palmwoods Substation at an estimated cost of $7 million by June 2021

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

Possible non-network solutions

Palmwoods Substation is a major node in the wider interconnected network supplying power into South-East Queensland, as well as providing injection to Energex for the Sunshine Coast and Caboolture areas of over 400MW 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Murarrie 275/110kV Substation secondary systems replacements

Project driver

Addressing the secondary systems condition risks at Murarrie Substation.

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.

Network requirement: Maintaining reliability of supply at Murarrie Substation

Project timing: June 2023

Possible network solutions

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

Proposed network solution: Replace the 110kV secondary systems at Murarrie Substation at an estimated cost of $25 million by June 2023

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 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Belmont 275/110kV Substation

Project driver

Addressing the secondary systems condition risks at Belmont Substation.

Belmont Substation is a major substation in the Brisbane transmission network and was established in the early 1970s. Extensions as a result of load growth and equipment replacements have resulted in a mixture of primary and secondary plant ranging from the 1970s, early 1980s through to the 1990s.

Network requirement: Maintaining reliability of supply at Belmont Substation

Project timing: December 2020

Possible network solutions

- Staged replacement of the 275kV secondary systems by December 2020.
- Full replacement of all of the 275kV secondary systems upfront by December 2020.

Proposed network solution: Selective replacement of 275kV secondary systems at Belmont Substation at an estimated cost of $9 million by December 2020

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

Possible non-network solutions

Belmont Substation provides injection and switching to the CBD and south-eastern suburbs of Brisbane of over 700MW 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Table 5.18 Possible network reinvestments in the Moreton zone within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Line refit works on the 110kV transmission lines between South Pine to Upper Kedron	Line refit works on steel lattice structures	Maintain supply reliability in the CBD and Moreton zone	June 2021	New 110kV transmission line/s Non-network (1)	$9m
Line refit works on the 110kV transmission lines between Rocklea, to Sumner to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	June 2021	New 110kV transmission line/s Non-network (1)	$15m
Line refit works on the 275kV transmission lines between Belmont and Murarrie	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	June 2022	New 275kV transmission line/s	$2m
Substations					
Abermain 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2021	Staged replacement of 110kV secondary systems Non-network (1)	$7m
Palmwoods 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton zone	June 2021	Staged replacement of 275kV secondary systems	$7m
Belmont 275kV secondary systems replacement	Staged replacement of 275kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	December 2020	Full replacement of 275kV secondary systems Non-network (1)	$9m
Swanbank E 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	June 2021	Selective replacement of 275kV secondary systems	$4m
Redbank Plains 110kV primary plant replacement	Selective replacement of 110kV primary plant	Maintain supply reliability in the CBD and Moreton zone	June 2022	Full replacement of 110kV primary plant Up to 25MW and approximately 350MWh per day	$3m
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	June 2023	Selective replacement of 110kV secondary systems Non-network (1)	$25m

Table 5.18 Possible network reinvestments in the Moreton zone within five years *(continued)*

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Redbank Plains 110/11kV transformers replacement	Replace two 110/11kV transformers	Maintain supply reliability in the Moreton zone	June 2024	Replace one 110/11kV transformer and engage non-network support Up to 25MW and approximately 350MWh per day	$5m
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 above in S5.7.9.

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 2024/25 to 2028/29 (refer to Table 5.19).

Table 5.19 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 lines between Woolooga and South Pine	Refit the 275kV transmission lines between Woolooga and South Pine substations	Maintain supply reliability in the Moreton zone	December 2024	Rebuild the 275kV transmission lines between Woolooga and South Pine substations	$4m
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	June 2025	Rebuild the 110kV transmission lines between Swanbank, Redbank Plains and West Darra	$11m
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	$21m
Line refit works on the 110kV transmission line between West Darra and Upper Kedron	Refit the 110kV transmission line between West Darra and Upper Kedron substations	Maintain supply reliability in the Moreton zone	June 2027	Potential retirement of the transmission line between West Darra and Upper Kedron	$21m
Line refit works on the 110kV transmission line between Richlands and Algester	Refit the 110kV transmission line between Richlands and Algester substations	Maintain supply reliability in the Moreton zone	June 2025	Potential retirement of the transmission line between Richlands and Algester	$5m
Replacement of the underground 110kV transmission line between Upper Kedron and Ashgrove West	Replace the 110kV underground transmission line between Upper Kedron and Ashgrove West substations using an alternate easement	Maintain supply reliability in the Moreton zone	December 2025	Replace the 110kV underground transmission line between Upper Kedron and Ashgrove West substations using the existing easement	$15m
Line refit works on the 110kV transmission line between Blackstone and Abermain	Refit the 110kV transmission line between Blackstone and Abermain substations	Maintain supply reliability in the Moreton zone	June 2026	Rebuild the 110kV transmission line between Blackstone and Abermain substations	$9m

Table 5.19 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
Substations					
Palmwoods 275kV primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability to the Wide Bay zone	December 2026	Full replacement of 275kV primary plant	$10m
South Pine 275/110kV transformer replacement	Replacement of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	June 2025	Retirement of a single 275kV/110kV transformers with non-network support	$7m
Ashgrove West 110kV secondary systems replacement	Staged replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2026	Full replacement of 110kV secondary systems	$8m
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	$5m
South Pine SVC secondary systems replacement	Replacement of the South Pine 275kV SVC secondary systems	Maintain supply reliability in the Moreton zone	December 2027	Staged replacement of 275kV SVC secondary systems	$7m
Belmont selected 275kV primary plant replacement	Selective replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	December 2028	Full replacement of 275kV primary plant	$22m
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	$14m
Goodna 110kV and 275kV secondary systems replacement	Full replacement of 110kV and 275kV secondary systems	Maintain supply reliability in the Moreton zone	December 2026	Staged replacement of 110kV and 275kV secondary systems	$19m
Greenbank 275kV secondary systems replacement	Full replacement of 275kV secondary systems (including SVC)	Maintain supply reliability in the Moreton zone	December 2027	Stage replacement of 275kV secondary systems (including SVC)	$20m

Possible asset retirements within the 10-year outlook period

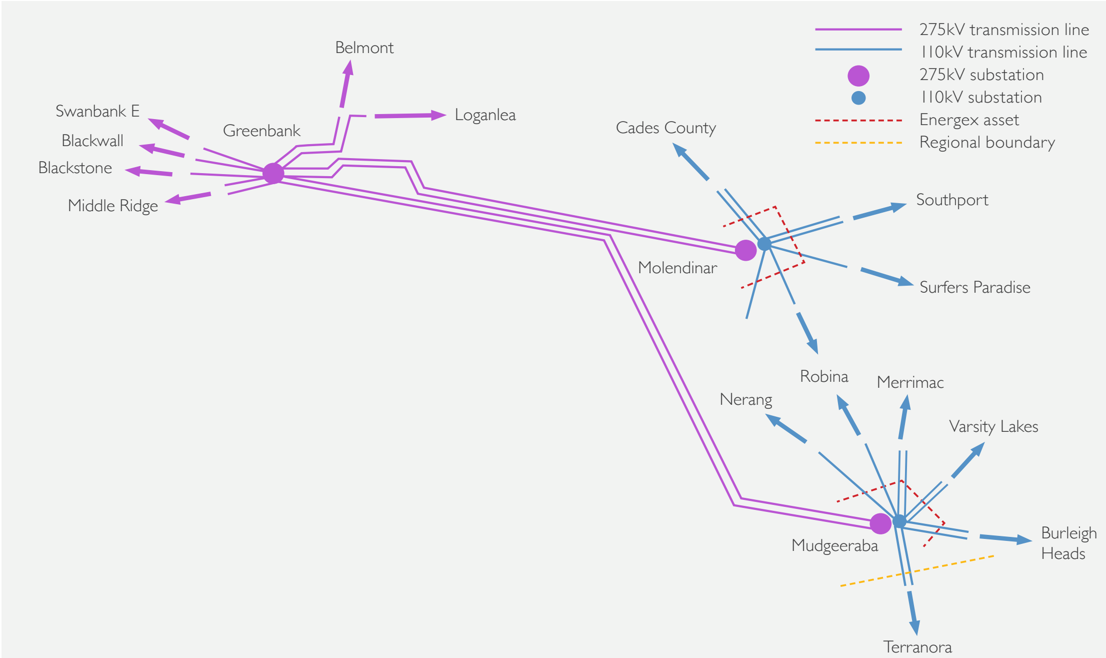
Belmont 275/110kV transformers

Within the forecast period, two 275/110kV transformers will be sufficient to meet the network need at Belmont substation. Within the next five years, the opportunity to retire two of the four 275/110kV transformers, based on condition, has been identified.

Planning analysis has confirmed that retirement of these transformers will not result in load at risk in the Brisbane area, and that there is adequate headroom to accommodate moderate growth above the medium economic load forecast in Chapter 2.

5.7.10 Gold Coast zone

Figure 5.13 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 5.13).

Possible load driven limitations

Based on the medium economic load forecast in Chapter 2 there are no network limitations forecast to occur in Moreton zone within the next five years.

Possible network reinvestments within five years

Transmission lines

Greenbank to Mudgeeraba 275kV transmission lines

Network requirement: 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 New South Wales.

Project driver

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

Project timing: December 2025

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 2025.
- 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 $20 million by December 2025

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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Mudgeeraba to Terranora 110kV transmission lines

The 110kV line was constructed in the mid-1970s and forms an essential part of the interconnection between Powerlink and Essential Energy's network in northern NSW, with 13km of the transmission line owned by Powerlink. The transmission line operates in a metropolitan/semicoastal environment with moderate rates of atmospheric pollution impacting on the life of its galvanised components and is subject to prevailing salt laden coastal winds. Condition assessment has identified that, line refit or replacement of the 13km transmission line section will be required in the latter part of the 10-year outlook period (refer to Table 5.21).

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. Planning studies have confirmed the potential to subsequently retire the other transformer given the current flat demand forecast. However, the reliability and market impacts of retiring a transformer across a broader range of demand forecast scenarios may potentially have a material inter-network impact and will require consultation.

Powerlink is currently analysing all possible network solutions, including if there is the potential for material inter-network impact, as part of an upcoming RIT-T consultation.

275kV secondary systems

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 majority of secondary systems components by December 2021.
- Complete replacement of all secondary systems by December 2021.

Proposed network solution: Complete replacement of all secondary systems at an estimated cost of $16 million by December 2021

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 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 demand side management initiatives in the area, and would be required to be available on a firm basis.

Table 5.20 Possible network reinvestments in the Gold Coast zone within five years

Potential project	High-level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Retirement of one Mudgeeraba 275/110kV transformer and associated works	Retirement of the transformer (1) including protection schemes and bay rating upgrade (2)	Maintain supply reliability in the Gold Coast zone	June 2020	New 275/110kV transformer	$3m (3)
Mudgeeraba 275kV secondary systems replacement	Full replacement of 275kV secondary systems (2)	Maintain supply reliability in the Gold Coast zone	December 2021	Staged replacement of 275kV secondary systems equipment	$16m

Note:

(1) 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 demand forecast outlook of the TAPR.

(2) 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.

(3) 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.

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 2024/25 to 2028/29 (refer to Table 5.21).

Table 5.21 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					
Targeted line refit works on sections of the 275kV transmission lines between Greenbank and Mudgeeraba substations	Targeted line refit works on steel lattice structures	Maintain supply reliability in the Gold Coast zone	December 2025	New double circuit 275kV transmission line Full line refit on one or both existing 275kV single circuit transmission lines Non-network (1)	$20m
Line refit works on the 110kV transmission line between Mudgeeraba and Terranora	Full line refit	Maintain supply reliability from Queensland to NSW Interconnector	June 2025	Targeted line refit New transmission line	$4m
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2024	Selected replacement of 275kV secondary systems	$16m
Mudgeeraba 110kV secondary systems replacement	Partial replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2025	Full replacement of 110kV secondary systems	$2m
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 2026	Staged replacement of 110kV primary plant in existing bays and selected 275kV equipment	$20m
Greenbank SVC secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2027	Staged replacement of secondary systems	$7m

Note:

(1) The envelope for non-network solutions is defined above in S5.7.10.

Possible asset retirements within the 10-year outlook period

Mudgeeraba 275/110kV Transformer

Subject to the outcome of further analysis and RIT-T consultation, Powerlink may retire the third Mudgeeraba 275/110kV transformer at the end of technical service life anticipated around 2020.

5.7.11 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2017 Electricity Statement of Opportunities (ESOO)[14]. Interested parties who require information regarding future supply demand balance should consult this document.

5.7.12 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 thermal ratings, transient stability and oscillatory stability (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.

Interconnector upgrades

Powerlink and TransGrid have assessed whether an upgrade of QNI could be technically and economically justified on several occasions since the interconnector was commissioned in 2001. Each assessment and consultation was carried out in accordance with the relevant version of the AER's Regulatory Investment Test in place at the time.

The most recent assessment was carried out as part of the joint Powerlink and TransGrid regulatory consultation process which concluded in December 2014. At that time, in light of uncertainties, Powerlink and TransGrid considered it prudent not to recommend a preferred upgrade option, however would continue to monitor market developments to determine if any material changes could warrant reassessment of an upgrade to QNI.

Since the conclusion of the 2014 consultation the NEM has, and continues to, undergo rapid change as the sector transitions to a world with lower carbon emissions and greater uptake of emerging technologies.

The Independent Review into the Future Security of the National Electricity Market[15], Electricity Network Transformation Roadmap[16] and AEMO's 2016 NTNDP suggest that transmission interconnections will play a stronger role in the future. Greater levels of interconnection allows the diversity of VRE generation, particularly wind generation, across regions during summer and winter peaking conditions, to deliver fuel cost savings by improving utilisation of renewable generation and reducing reliance on higher-cost generation.

VRE is making up an increasing proportion of the national energy mix. Going forward, even more of Australia's existing electricity generation is likely to be replaced by lower emission alternatives to meet policy commitments, including the nation's COP21 pledge to reduce carbon emissions by 26-28% below 2005 levels by 2030[17].

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14 Updated by AEMO in September 2017.

15 Independent Review into the Future Security of the National Electricity Market, Dr Alan Finkel et al, June 2017 (page 127).

16 Electricity Network Transformation Roadmap – Final Report, April 2017 (page 99).

17 The 2015 United Nations Climate Change Conference (also known as 'COP 21' or 'CMP 11') was held in Paris, France, from 30 November to 12 December 2015.

The Council of Australian Governments (COAG) Energy Council also noted that interconnectors provide a range of benefits that facilitate this energy transition, in particular:

- enabling the lowest cost generation in the NEM to reach more consumers
- mitigating the risk of supply shortfall through imports from other regions
- sharing system stability support services, such as frequency and voltage control
- improving system resilience to high impact, low probability events (such as interconnector failures) through a further interconnected NEM.

Since Powerlink and TransGrid completed the 2014 RIT-T there have been specific changes that may impact the forecast utilisation and congestion on QNI. These changes include:

- gas prices increasing markedly in Queensland (and the east coast) on account of liquefied natural gas (LNG) exports
- retirement of Redbank, Munmorah and Wallerawang power stations
- committed retirement of Liddell Power Station in March 2022[18]
- commitment of wind farms in northern NSW
- commitment of approximately 2,700MW of VRE generation in the Queensland region.

As a result of these developments, preliminary market modelling studies undertaken in 2017 indicate that there may be net market benefits arising from upgrading the interconnector capability on QNI. These preliminary findings are consistent with the 2016 NTNDP. AEMO's modelling indicated that bi-directionally increasing the capability of QNI may deliver net positive market benefits from 2026–27 depending on the scenario.

As a result of this and previous analysis, both TransGrid and Powerlink sought to have an upgrade of QNI classified as a contingent project in their Revenue Proposals for the 2018-2023 and 2017-2022 periods, respectively. Both applications were successful due to uncertainties regarding the preferred option to practicably achieve the lowest sustainable cost of delivering the prescribed transmission services. Successful application of this RIT-T is one of the triggers proposed for these contingent projects.

Accordingly, TransGrid and Powerlink are currently undertaking preparatory work to progress a RIT-T to investigate the net market benefits of options for increasing the transfer capacity between NSW and Queensland. The first stage of this RIT-T (PSCR) is anticipated to commence in the third quarter of 2018.

As required by the NER the net market benefits of options for increasing the transfer capacity between NSW and Queensland are being assessed for a range of plausible scenarios. These will be broadly consistent with the scenarios developed for the ISP which will be released in July 2018. All scenarios will model a 50% Queensland Renewable Energy Target (QRET) by 2030.

18 In 2017, AGL notified AEMO that it will close the 2,000 MW Liddell Power Station in NSW in March 2022.

CHAPTER 6

Network capability and performance

6 Network capability and performance

Key highlights

- Generation commitments since the 2017 Transmission Annual Planning Report (TAPR) will add 1,912MW to Queensland's semi-scheduled variable renewable energy (VRE) generation capacity taking the total VRE generation capacity to 2,645MW.
- During 2017/18, the Central Queensland to Southern Queensland (CQ-SQ) grid section was highly utilised reflecting higher CQ generator scheduling. The utilisation of this grid section is expected to increase with the connection of further VRE generators in North Queensland (NQ) and Central Queensland (CQ).
- Committed generation is expected to alter power transfers, particularly during daylight hours, increasing the likelihood of congestion across the Gladstone, CQ-SQ and Queensland/New South Wales Interconnector (QNI) grid sections.
- Record peak transmission delivered demands were recorded in the Wide Bay, Surat and Moreton zones, during 2017/18.
- The transmission network has performed reliably during 2017/18, 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
- sample power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and generation dispatch patterns
- 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 also vary substantially 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.

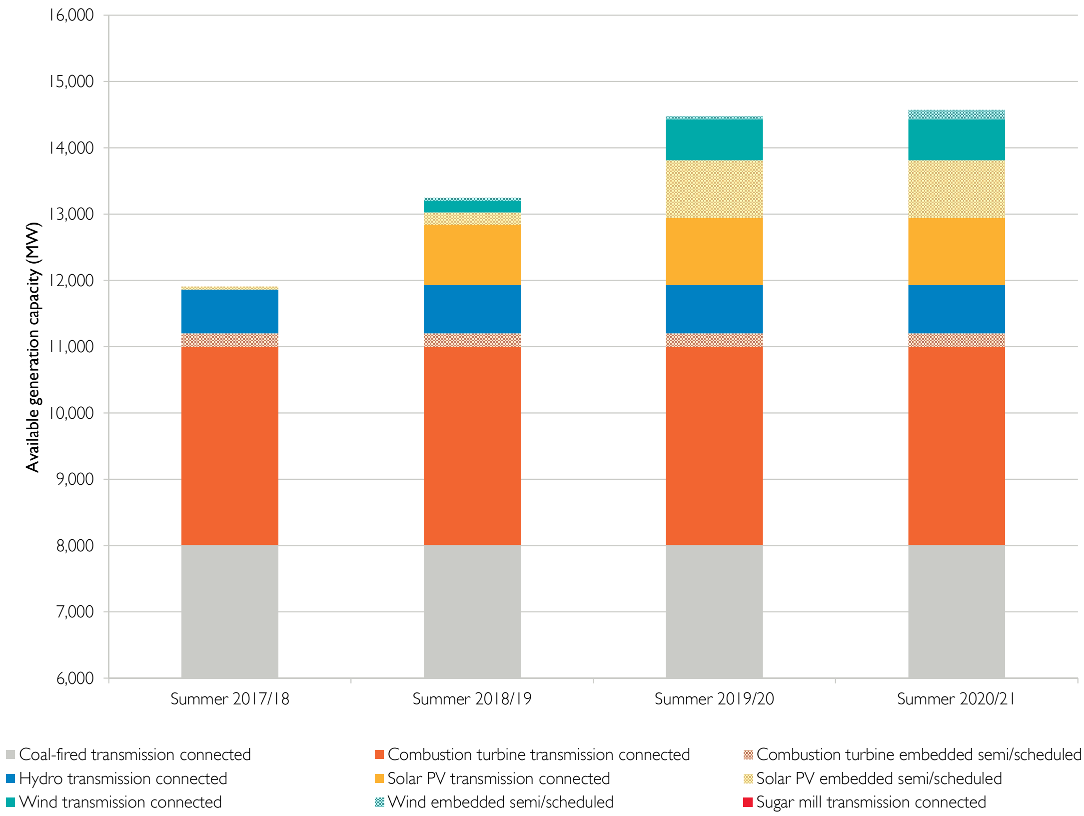
The years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period.

6.2 Available generation capacity

Scheduled generation in Queensland is currently a combination of coal-fired, gas turbine and hydro electric generators.

For the purposes of this TAPR, new generators are regarded as reaching committed status (incorporated into future studies) when a Connection and Access Agreement (CAA) has been executed. During 2017/18, commitments have added 1,912MW of capacity, taking Queensland's semi-scheduled VRE generation capacity to 2,645MW. Figure 6.1 illustrates the expected changes to available generation capacity in Queensland from summer 2017/18 to summer 2020/21.

Figure 6.1 Summer available generation capacity by energy source



6.2.1 Existing and committed transmission connected 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.

The semi-scheduled transmission connected solar farms namely, Sun Metals, Haughton, Daydream, Hayman and Lilyvale in addition to the Coopers Gap wind farm have reached committed status since the 2017 TAPR.

In December 2014, Stanwell Corporation withdrew Swanbank E Power Station (PS) from service. Swanbank E was brought back to service in December 2017.

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.

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

Generator	Location	Available generation capacity (MW) (1) Winter 2018	Summer 2018/19	Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21
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	744	730	744	730	744	730
Millmerran	Millmerran PS Switchyard	852	760	852	760	852	760
Total coal-fired		**8,119**	**8,013**	**8,119**	**8,013**	**8,119**	**8,013**
Combustion turbine							
Townsville 132kV	Townsville GT PS	159	149	159	149	159	148
Mt Stuart (2)	Townsville South	423	398	423	398	423	398
Yarwun (3)	Yarwun	160	155	160	155	160	155
Condamine	Columboola	100	90	100	90	100	90
Braemar 1	Braemar	504	471	504	471	504	471
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	365	365	365	365	365
Total combustion turbine		**3,209**	**2,985**	**3,209**	**2,985**	**3,209**	**2,984**
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 2018	Summer 2018/19	Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21
Solar PV (7)							
Ross River	Ross		116	116	116	116	116
Sun Metals	Townsville Zinc	107	107	107	107	107	107
Haughton	Haughton River			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
Hayman	Strathmore		50	50	50	50	50
Rugby Run	Moranbah		65	65	65	65	65
Lilyvale	Lilyvale		100	100	100	100	100
Darling Downs	Braemar	108	108	108	108	108	108
Total solar		**429**	**910**	**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
Total wind		**180**	**180**	**620**	**620**	**620**	**620**
Sugar mill							
Invicta (5)	Invicta Mill	34	0	34	0	34	0
Total all stations		**12,700**	**12,817**	**13,721**	**13,357**	**13,721**	**13,356**

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) Origin Energy has advised AEMO of its intention to no longer retire Mt Stuart in 2023.

(3) Yarwun is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator.

(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.

6.2.2 Existing and committed scheduled and semi-scheduled 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.

The semi-scheduled solar farms namely, Cape York, Clermont, Blackwater, Emerald, Aramara, Susan River, Childers, Yarranlea, and Oakey 2 in addition to the Lakeland wind farm and Kennedy Energy Park have reached committed status since the 2017 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 2018	Summer 2018/19	Winter 2019	Summer 2019/20	Winter 2020	Summer 2020/21
Combustion turbine (1)							
Townsville 66kV	Townsville GT PS	84	84	84	84	84	84
Mackay (2)	Mackay	34	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**	**206**
Solar PV (3)							
Cape York	Cape York switching station					53	53
Kidston	Kidston	49	49	49	49	49	49
Kennedy Energy Park	Hughenden		15	15	15	15	15
Collinsville	Collinsville North		41	41	41	41	41
Clermont	Clermont			75	75	75	75
Blackwater	Blackwater				150	150	150
Emerald	Emerald			73	73	73	73
Aramara	Aramara			101	101	101	101
Susan River	Maryborough			76	76	76	76
Childers	Isis			56	56	56	56
Yarranlea	Yarranlea			103	103	103	103
Oakey 1	Oakey		25	25	25	25	25
Oakey 2	Oakey		55	55	55	55	55
Total solar		**49**	**185**	**669**	**872**	**872**	**872**
Wind (3)							
Lakeland	Lakeland					100	100
Kennedy Energy Park	Hughenden		43	43	43	43	43
Total wind		**0**	**43**	**43**	**43**	**143**	**143**
Total all stations		**272**	**434**	**935**	**1,121**	**1,238**	**1,221**

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[1] (PSFRR) during 2017/18. The PSFRR is part of the Emergency Frequency Control Schemes rule change[2] which 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 results of the PSFRR in April 2018. For Queensland, the recommendation involved the expansion of Powerlink's CQ-SQ Special Protection Scheme (SPS). The 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. 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.

The 2018 PSFRR also identifies a potential need to establish a coordinated Over Frequency Generation Shedding (OFGS) scheme. AEMO and Powerlink will undertake a joint study to consider the risk of major supply disruptions which could lead to an over frequency event.

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.

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

1 AEMO, 2018 Power System Frequency Risk Review, April 2018.
2 AEMC, Rule Determination National Electricity Amendment (Emergency frequency control schemes) Rule 2017, 30 March 2017.

6.4 Sample winter and summer power flows

Powerlink has selected 18 sample scenarios to illustrate possible power flows for forecast Queensland region summer and winter maximum demands. These sample scenarios are for the period winter 2018 to summer 2020/21 and are based on the 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2. These sample scenarios, included in Appendix C, show possible power flows under a range of import and export conditions on the QNI transmission line. The dispatch assumed is broadly based on historical observed dispatch of generators.

Power flows in Appendix C are based on existing network configuration (illustrated in figures 6.2, 6.3, 6.4 and 6.5) and committed projects (listed in tables 9.1, 9.3 and 9.4), and assume all network elements are available. In providing this information Powerlink has not attempted to predict market outcomes.

Figure 6.2 Existing HV network June 2018 - North Queensland

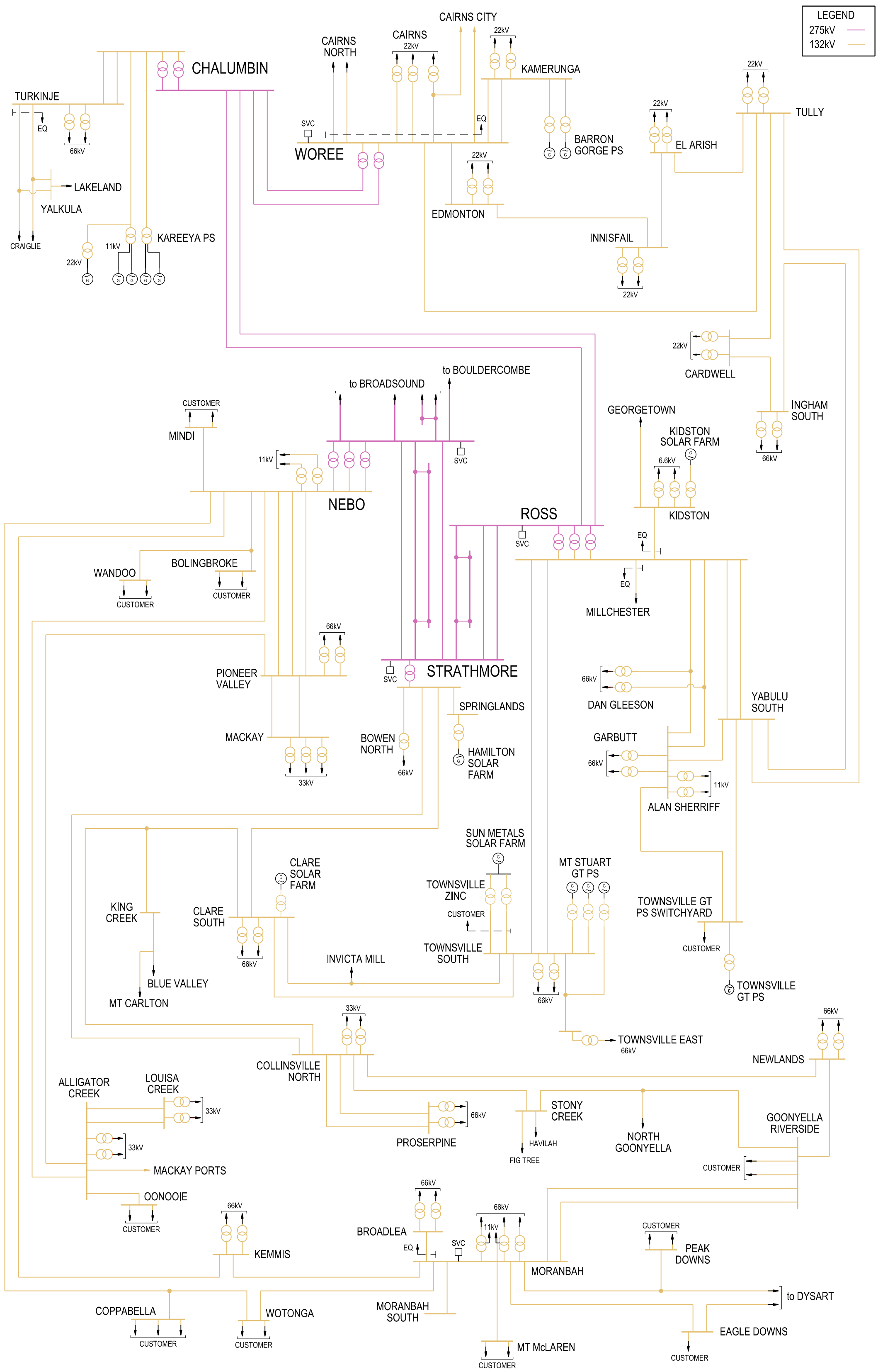
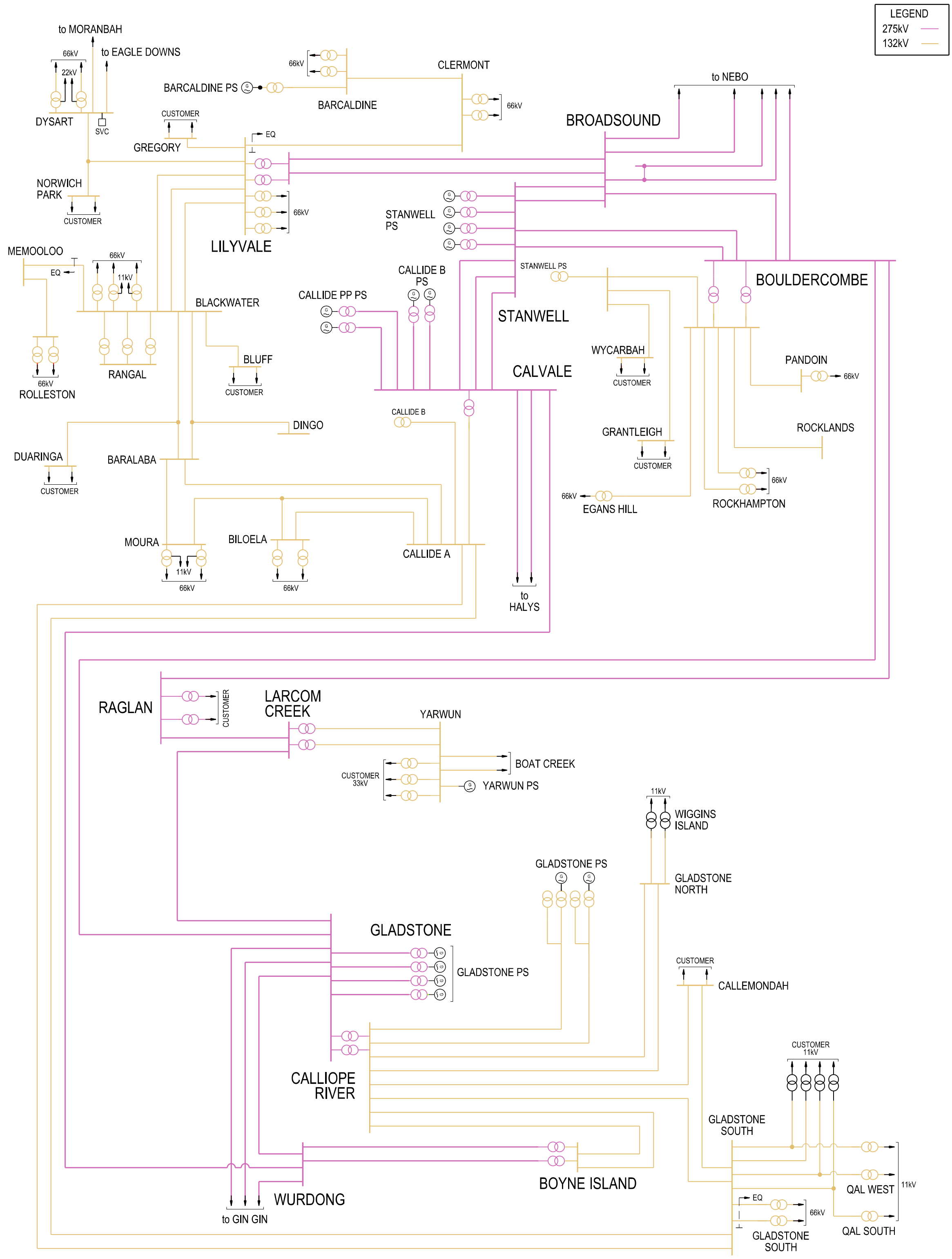


Figure 6.3 Existing HV network June 2018 - Central Queensland



6 Network capability and performance

Figure 6.4 Existing HV network June 2018 - South West Queensland

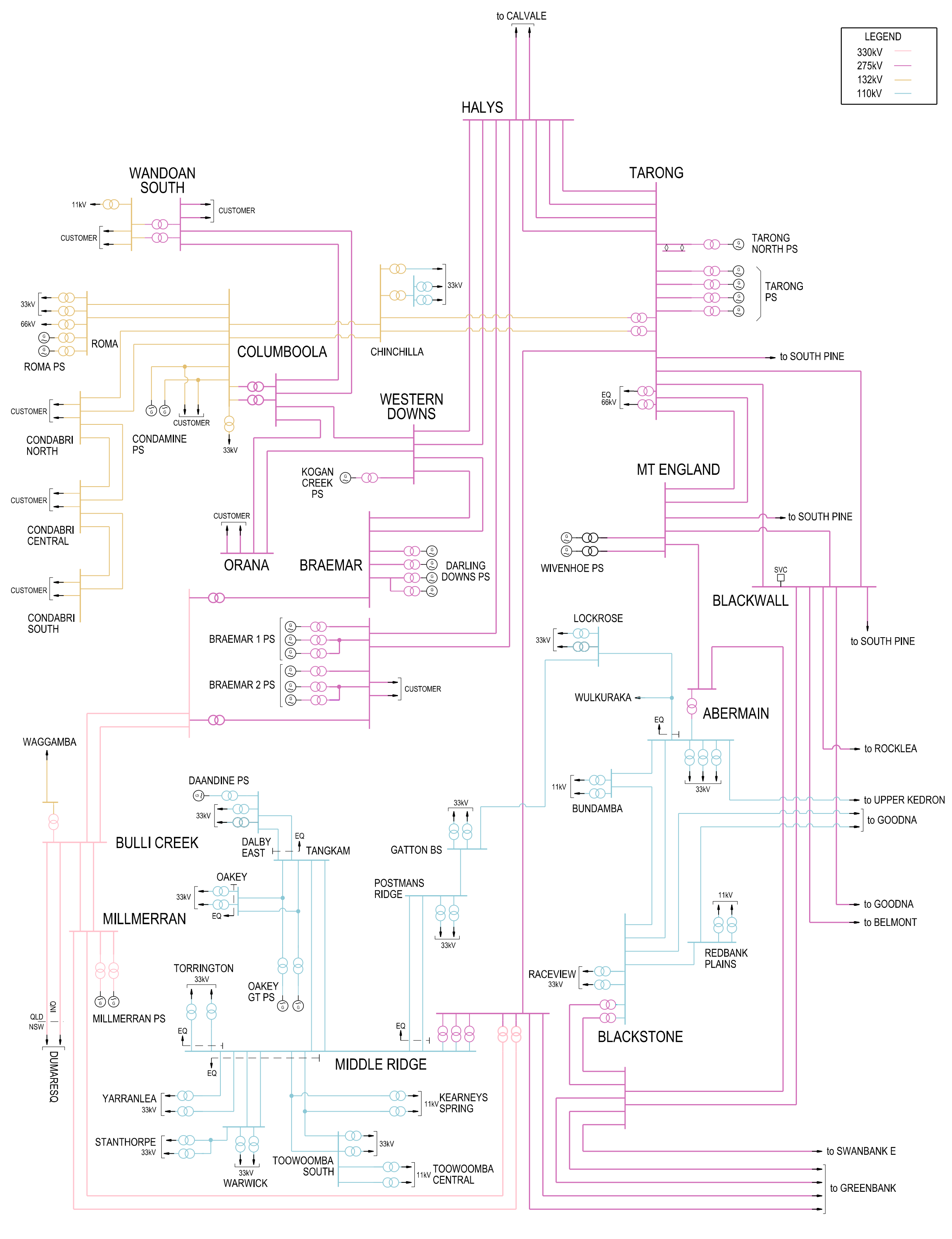
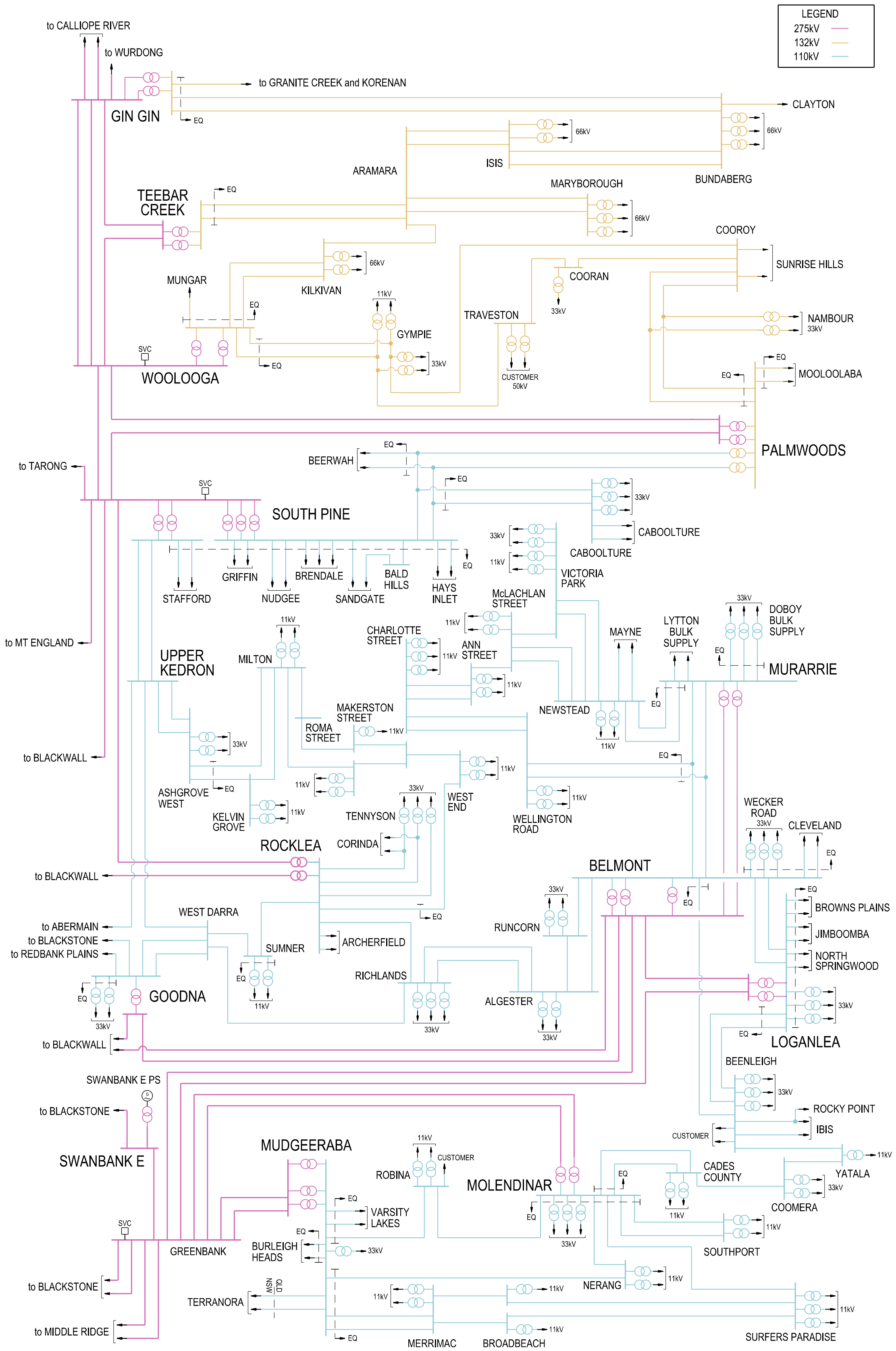


Figure 6.5 Existing HV network June 2018 - South East Queensland



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). 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 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

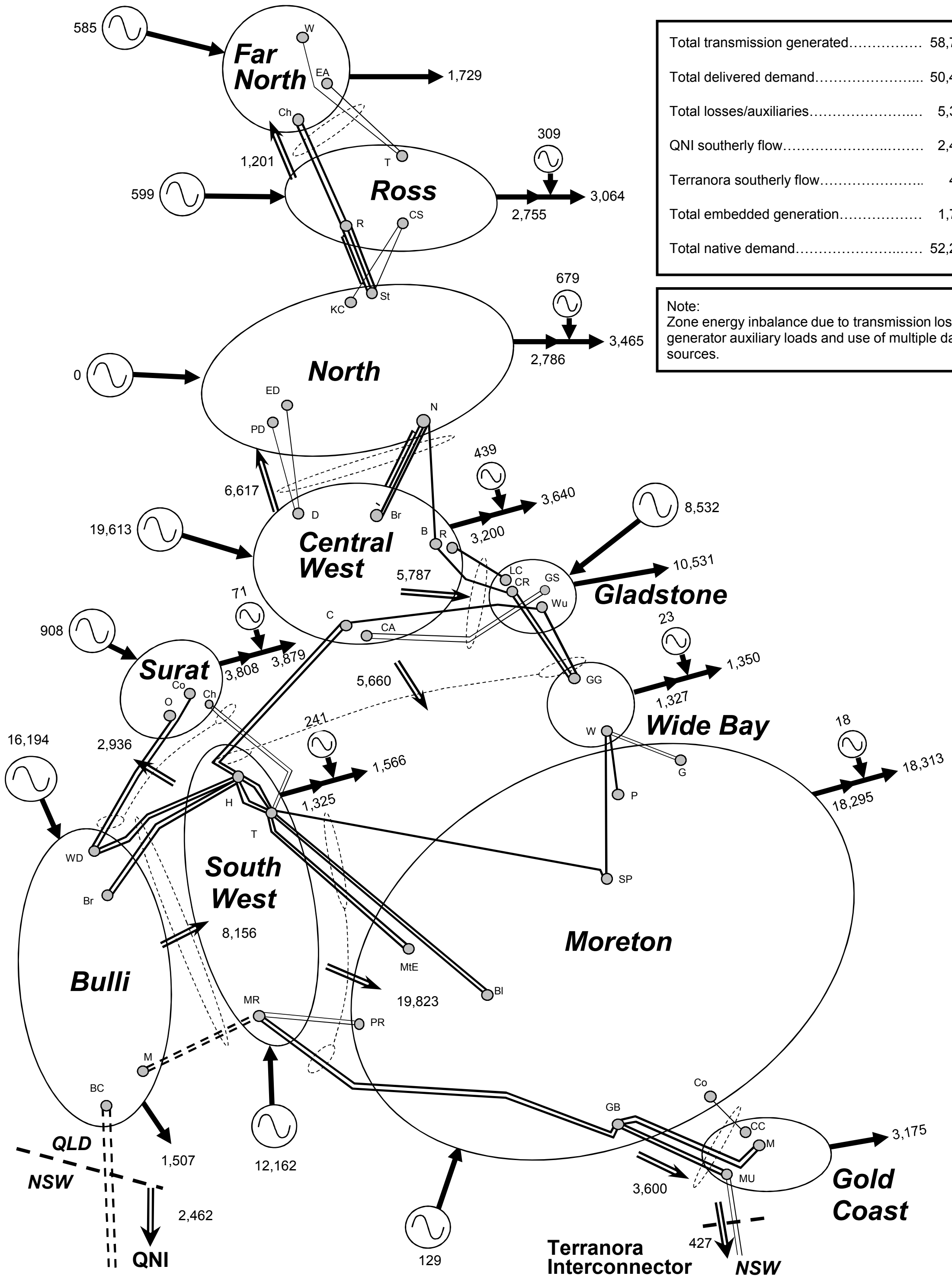
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

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 2016 and 2017 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 2016 to 2017. These figures assist in the explanation of differences between 2016 and 2017 grid section transfer duration curves.

Figure 6.6 2016[3] zonal electrical energy transfers (GWh)

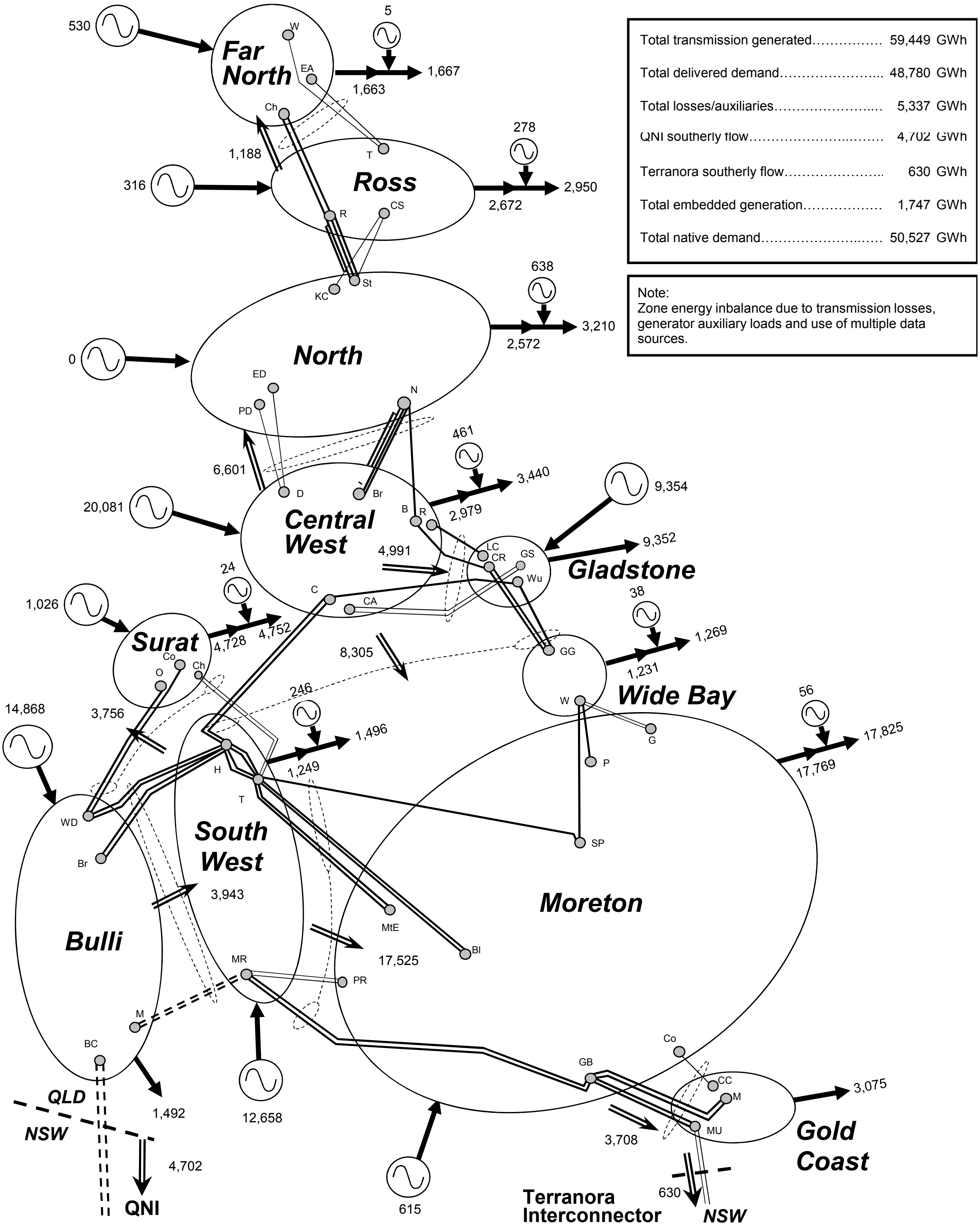


Total transmission generated	58,723 GWh
Total delivered demand	50,438 GWh
Total losses/auxiliaries	5,396 GWh
QNI southerly flow	2,462 GWh
Terranora southerly flow	427 GWh
Total embedded generation	1,780 GWh
Total native demand	52,218 GWh

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

[3] Consistent with this chapter, time periods are from April 2016 to March 2017.

Figure 6.7 2017[4] zonal electrical energy transfers (GWh)

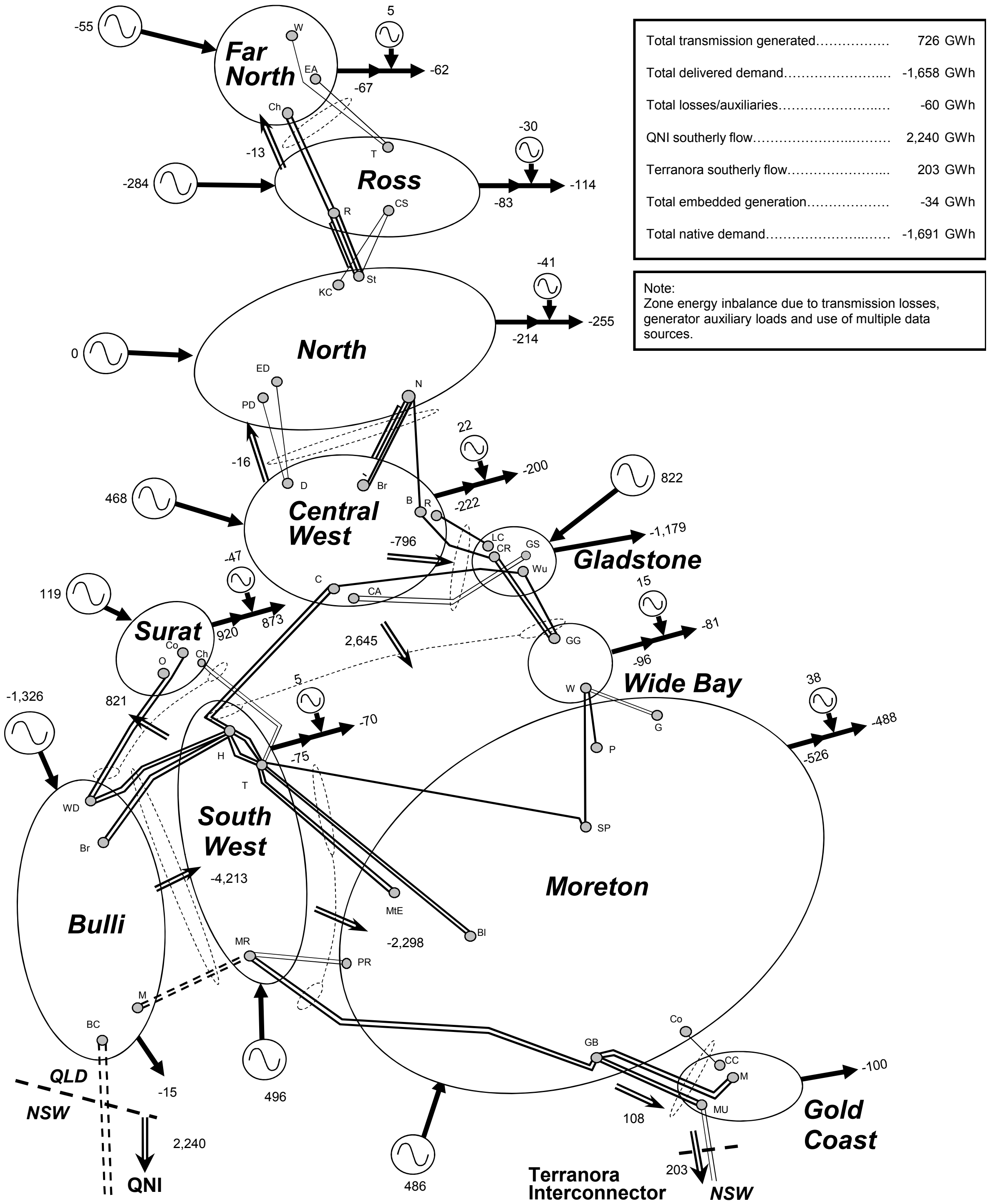


Total transmission generated	59,449 GWh
Total delivered demand	48,780 GWh
Total losses/auxiliaries	5,337 GWh
QNI southerly flow	4,702 GWh
Terranora southerly flow	630 GWh
Total embedded generation	1,747 GWh
Total native demand	50,527 GWh

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

4 Consistent with this chapter, time periods are from April 2017 to March 2018.

Figure 6.8 Change[5] in zonal electrical energy transfers (GWh)



5 Consistent with this chapter, time periods for the comparison are from April 2017 to March 2018 and April 2016 to March 2017.

Table C.1 in Appendix C shows power flows across each grid section at time of forecast Queensland region maximum demand, corresponding to the sample generation dispatch shown in figures C.3 to C.20. It also identifies whether the maximum power transfer across each grid section is limited by thermal plant ratings, voltage stability and/or transient stability. Power transfers across all grid sections are forecast to be within transfer capability of the network for these sample generation scenarios. This outlook is based on 50% PoE medium economic outlook demand forecast conditions.

Power flows across grid sections can be higher than shown in figures C.3 to C.20 in Appendix C at times of local area or zone maximum demands. However, transmission capability may also be higher under such conditions depending on how generation or interconnector flow varies to meet higher local demand levels.

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.

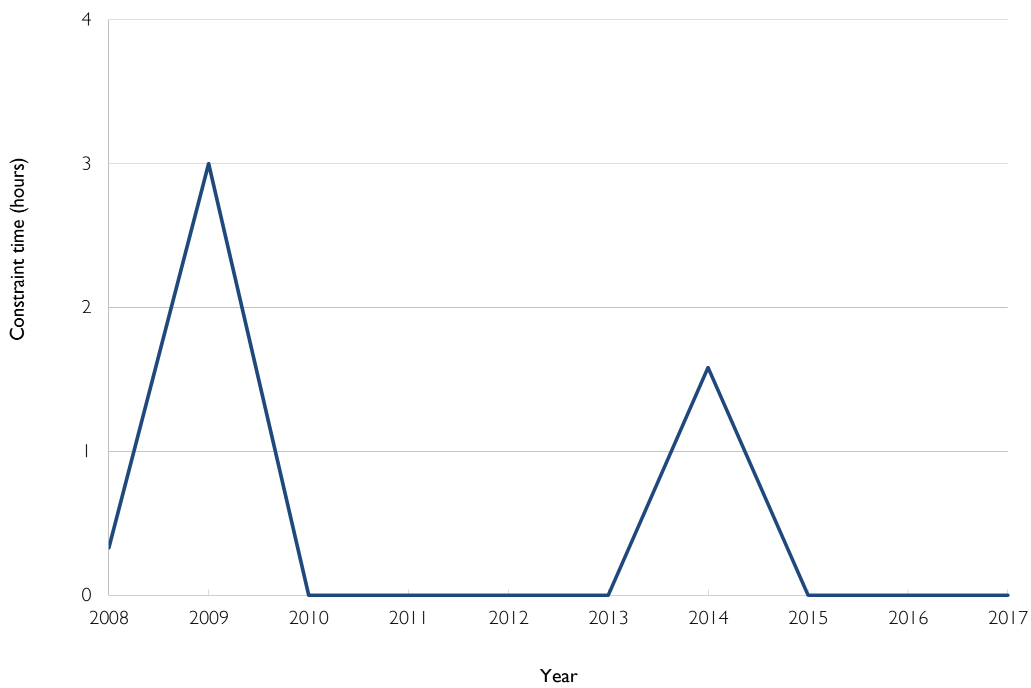
The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone to northern Queensland area[6] 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 2017 to March 2018. 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

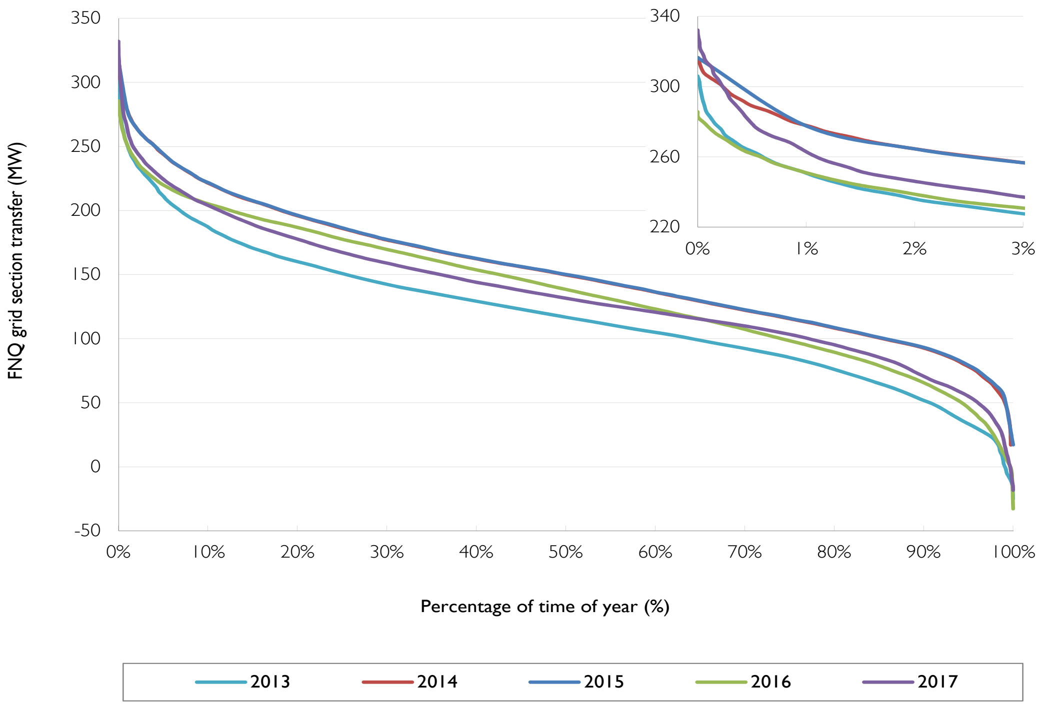


[6] Northern Queensland area is defined as the combined demand of the Far North, Ross and North zones.

Constraint durations have reduced over time due to the commissioning of various transmission projects[7]. There have been minimal constraints in this grid section since 2008.

Figure 6.10 provides historical transfer duration curves showing small annual differences in grid section transfer demands and energy. The peak flow and energy delivered to the Far North zone by the transmission network is not only dependant on the Far North zone load, but also 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 generated at lower levels during peak load conditions in 2017 compared to 2016. Over the full year, the capacity factor of these power stations decreased nearly on par with reductions in delivered energy in the Far North zone resulting in near equal energy transfers between 2016 and 2017 (refer to figures 6.6, 6.7 and 6.8).

Figure 6.10 Historical FNQ grid section transfer duration curves



No network augmentations are 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.

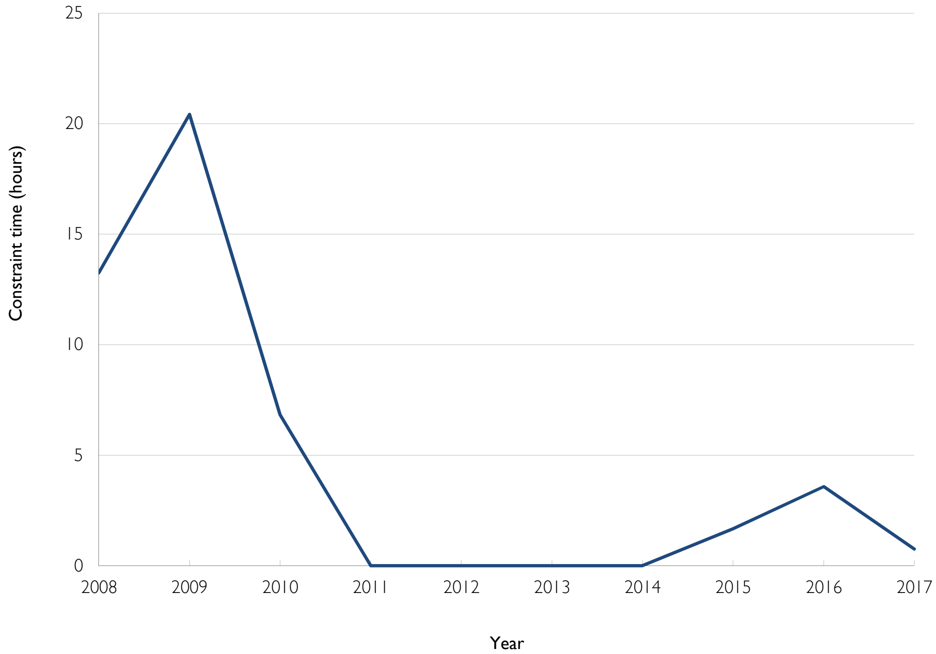
The limit equations in Table D.2 of Appendix D show that the following variables have a significant effect on transfer capability:

- 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 2017, the CQ-NQ grid section experienced 0.75 hours of constrained operation. These constraints were associated with planned outages.

[7] For example, the second Woree 275/132kV transformer commissioned in 2007/08.

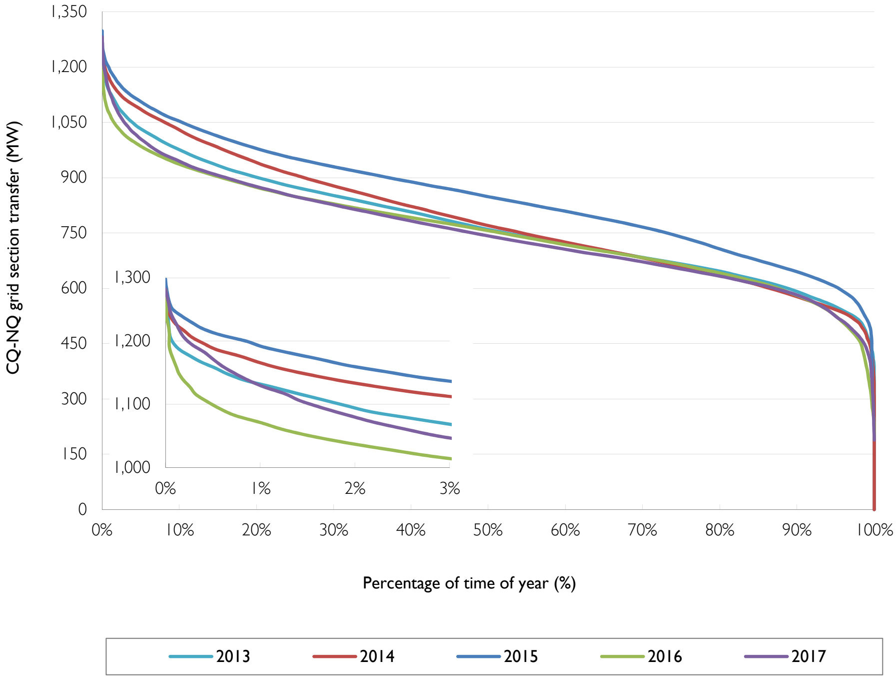
Figure 6.11 Historical CQ-NQ grid section constraint times



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 small annual differences in grid section transfer demands and energy. Utilisation of the grid section was approximately equivalent, albeit higher during periods of higher loadings, in 2017 compared to 2016 predominantly due to the lower capacity factor of the generators in Far North and Ross zones balancing the lower delivered energy in the Northern Queensland area (refer to figures 6.6, 6.7 and 6.8).

Figure 6.12 Historical CQ-NQ grid section transfer duration curves



Flooding associated with Tropical Cyclone Debbie caused collapse and damage to 19 towers on one of the paralleled 275kV single circuit lines between Broadsound and Nebo. The transmission line was subsequently returned to service with a large section unparalleled. The system normal capacity of the grid section is not impacted. The damaged towers were rectified in 2017.

The recent commitment of VRE generators (refer to tables 6.1 and 6.2) in north Queensland are expected to reduce CQ-NQ transfers, especially during daylight hours. CQ-NQ transfer duration curves in future years are expected to reflect these new transfer patterns with a downward trend as more energy is supplied locally. The development of large loads in central or northern Queensland (additional to those included in the forecasts), on the other hand, can significantly increase the levels of CQ-NQ transfers. This is discussed in Section 7.2.4.

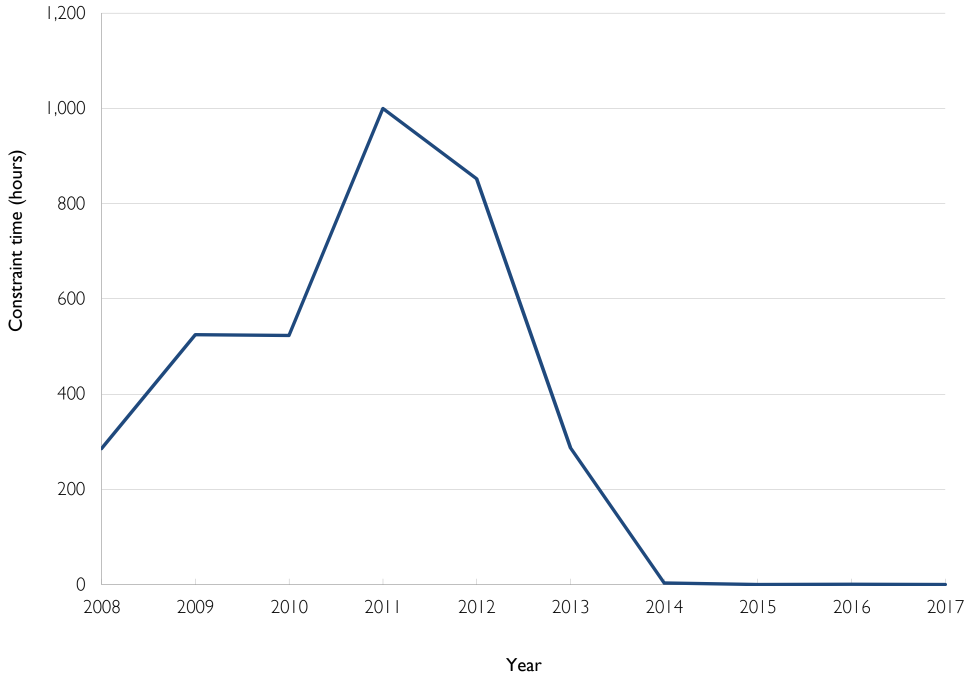
6.6.3 Gladstone grid section

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.

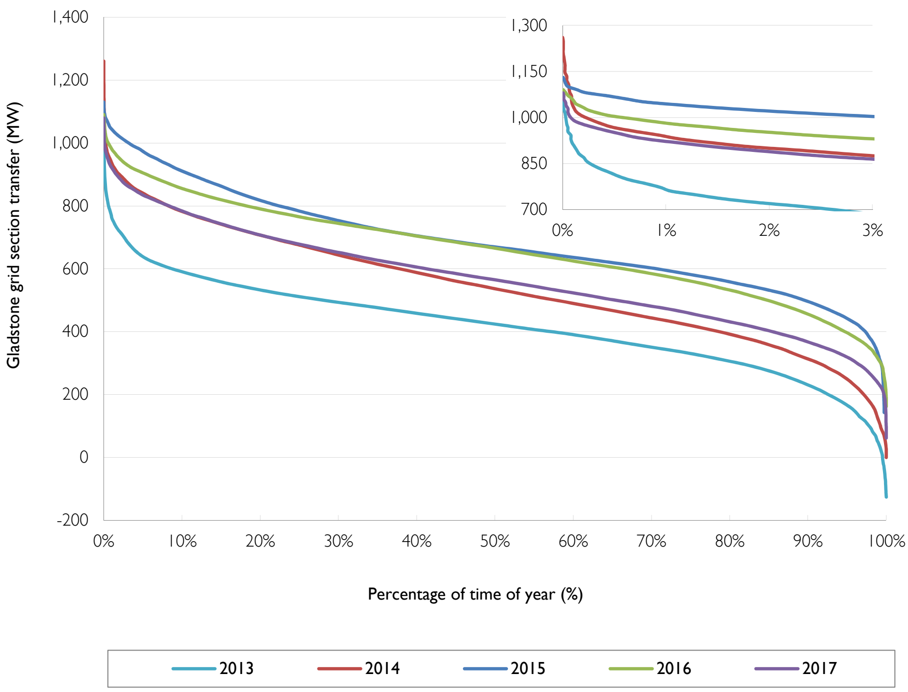
Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 6.13. During 2017, the Gladstone grid section experienced 0.25 hours of constrained operation.

Figure 6.13 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 6.14 provides historical transfer duration curves showing a significant decrease in utilisation in 2017 compared to 2016. This reduction in transfer is predominantly associated with a significant increase in net Gladstone zone generation (refer to figures 6.6, 6.7 and 6.8).

Figure 6.14 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. A project to increase the design temperature of Bouldercombe to Raglan and Larcom Creek to Calliope River 275kV transmission lines, approved by the AER under the Network Capability Incentive Parameter Action Plan (NCIPAP), will assist in relieving this 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.

The CQ-SQ grid section did not constrain operation during April 2017 to March 2018. Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 6.15.

Figure 6.15 Historical CQ-SQ grid section constraint times

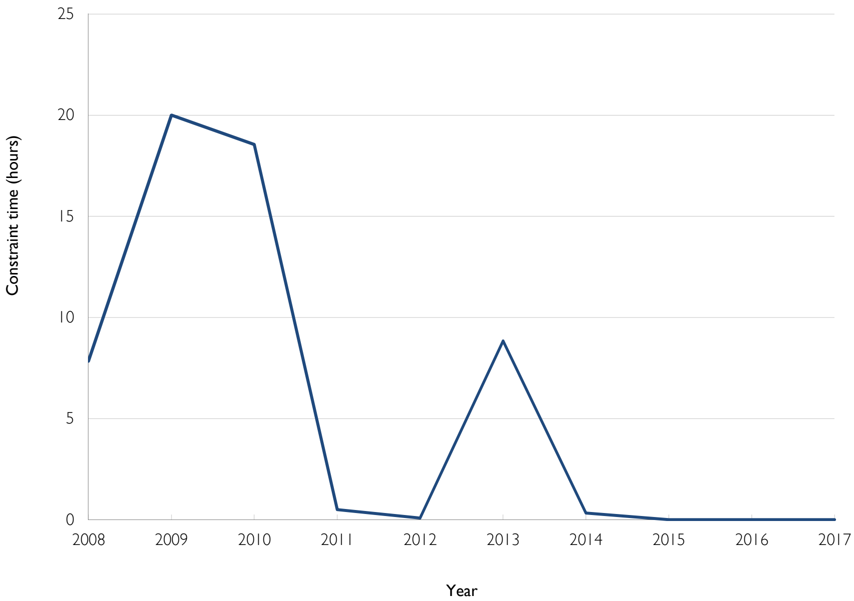
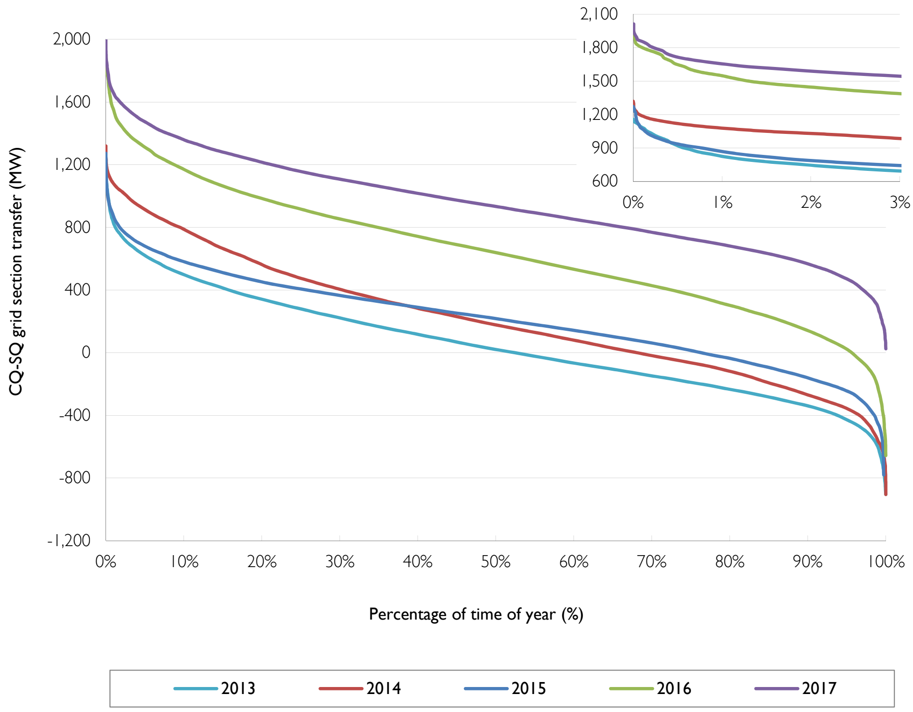


Figure 6.16 provides historical transfer duration curves showing continued increase in utilisation since 2015. This increase in transfer is predominantly due to a significant reduction in generation from the gas fuelled generators in the Bulli zone and higher interconnector transfers sourced predominantly 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 (refer to Section 5.7.5).

Figure 6.16 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 resulted in 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

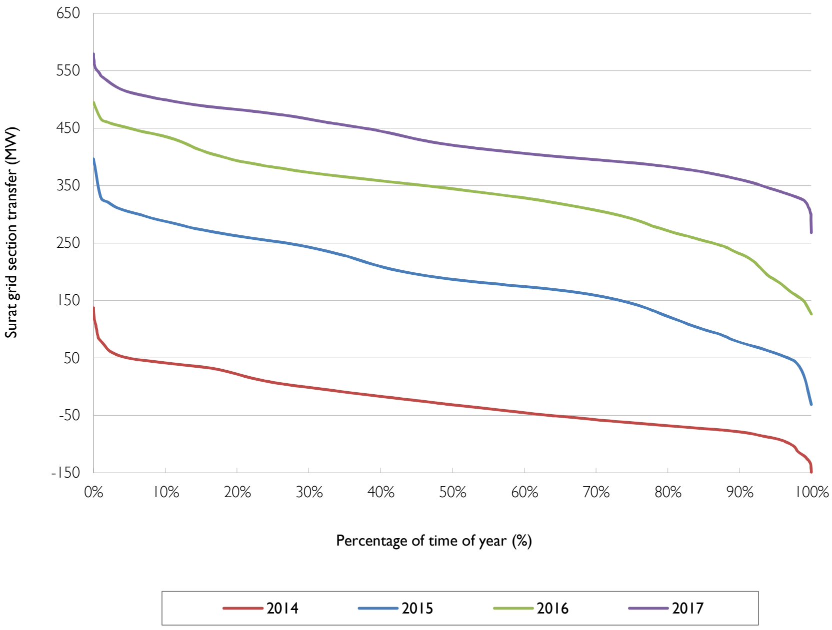
The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Western Downs to Columboola 275kV transmission line[8], Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed 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 6.17 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.

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

Figure 6.17 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 2017 to March 2018. Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 6.18.

Figure 6.18 Historical SWQ grid section constraint times

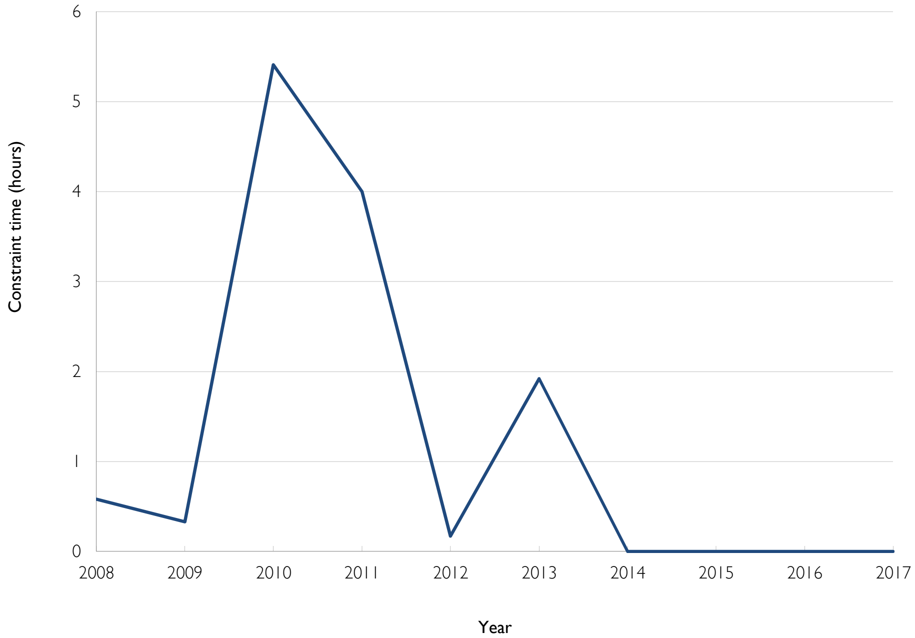
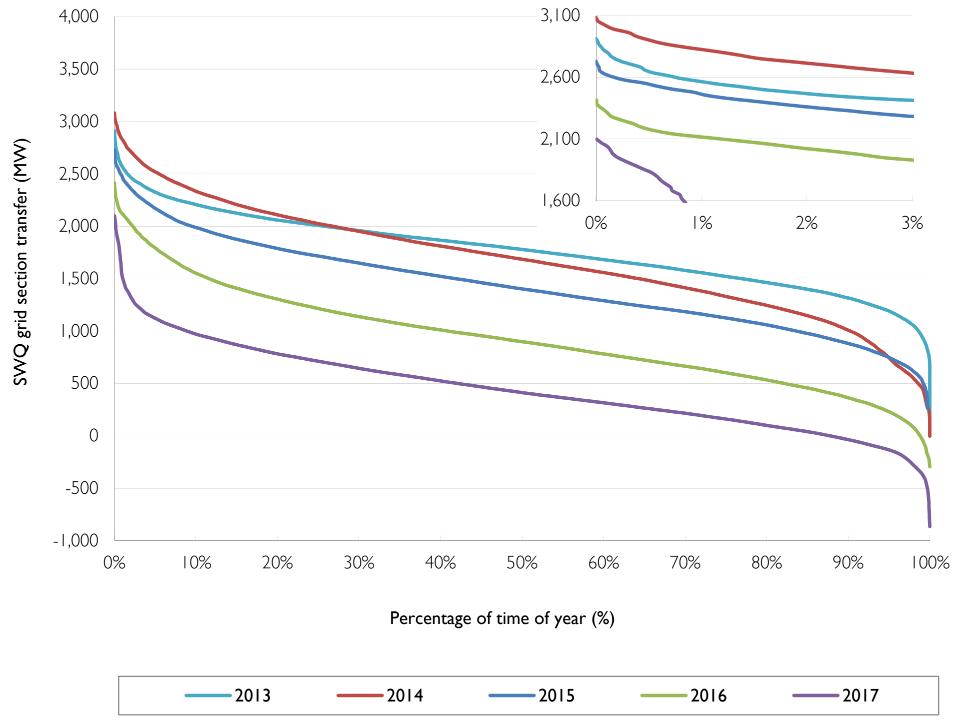


Figure 6.19 provides historical transfer duration curves showing a continued reduction in energy transfer since 2015. Increases in QNI southerly flows, reductions in gas fuelled generation in the Bulli zone, increases in SW zone generation and CQ-SQ transfers (refer to figures 6.6, 6.7 and 6.8) are predominantly responsible for the reduction in SWQ utilisation.

Figure 6.19 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.

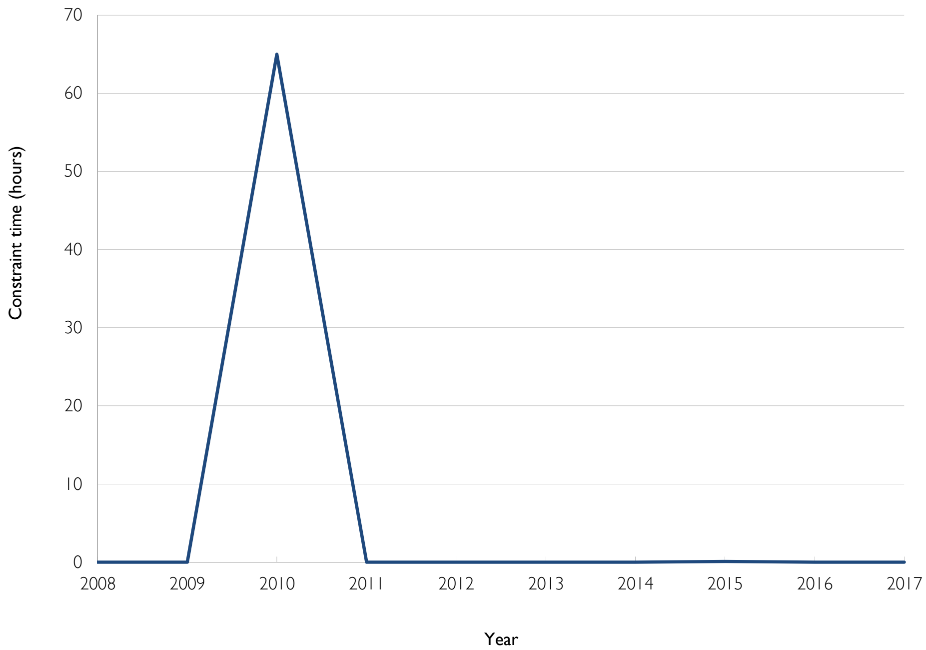
Limit equations in Table D.4 of Appendix D show that the following variables have a significant effect on transfer capability:

- 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 2017 to March 2018. Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 6.20.

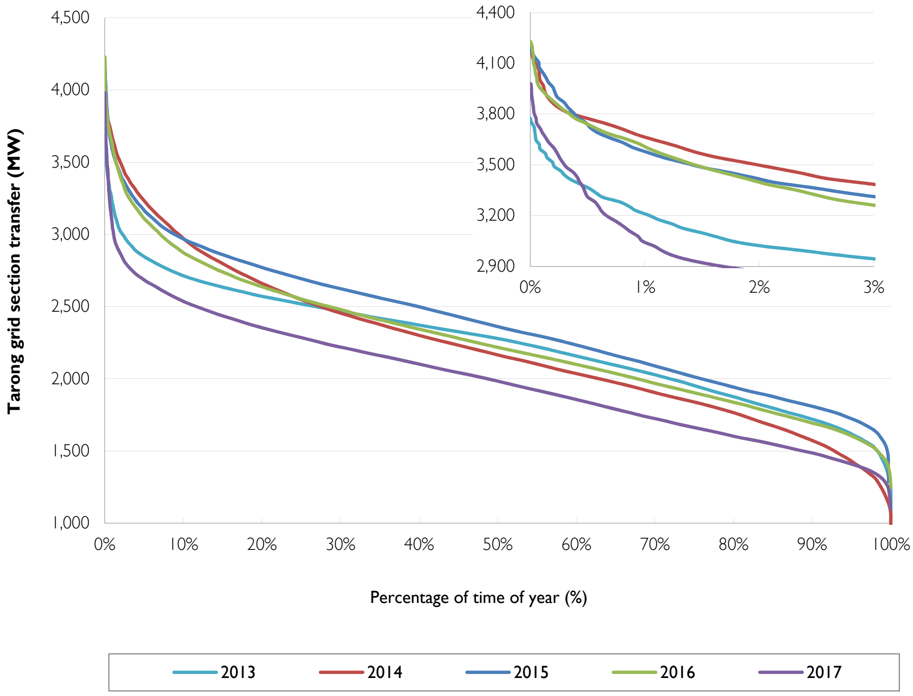
Figure 6.20 Historical Tarong grid section constraint times



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 6.21 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 2017 trace reflects lower delivered south east Queensland demands as a result of overall mild conditions, Swanbank E generation and greater transfers from CQ generators (refer to figures 6.6, 6.7 and 6.8).

Figure 6.21 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.

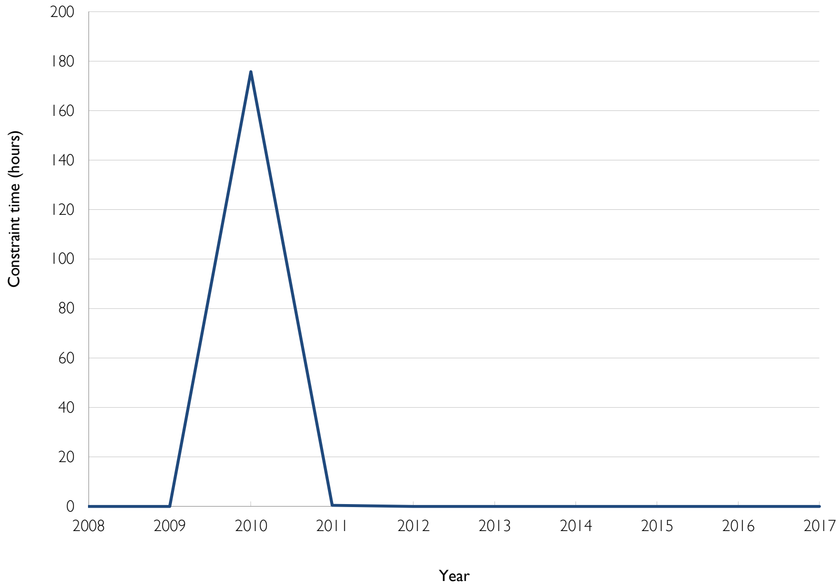
The limit equation in Table D.5 of Appendix D shows that the following variables have a significant effect on transfer capability:

- 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 2017 to March 2018. Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 6.22.

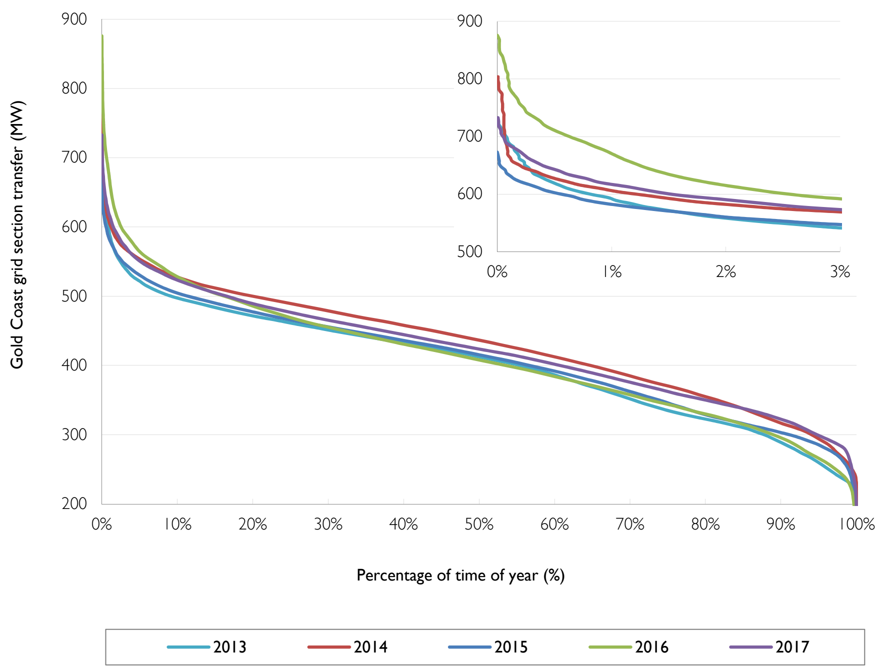
Figure 6.22 Historical Gold Coast grid section constraint times



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 6.23 provides historical transfer duration curves showing changes in grid section transfer demands and energy in line with changes in transfer to northern New South Wales (NSW) and changes in Gold Coast loads. Gold Coast zone demand was lower in 2017 compared to 2016 (refer to figures 6.6, 6.7 and 6.8).

Figure 6.23 Historical Gold Coast grid section transfer duration curves



The condition of two 275/110kV transformers at Mudgeeraba Substation requires action within the five-year outlook. One of the transformers was replaced in 2017. This is discussed in Section 5.7.10.

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:

- 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.

AEMO's 2016 National Transmission Network Development Plan (NTNDP) indicated net positive market benefits in increasing the capability of QNI from 2026/27. The ISP Consultation Paper[9] recommended that Powerlink and TransGrid initiate a RIT-T to increase interconnector capacity between and reduce the likelihood of reserve deficit in either region. Powerlink and TransGrid are currently in preparation to undertake this RIT-T. This is discussed further in Section 5.7.12.

6.7 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver 2017 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.

[9] AEMO, Integrated System Plan Consultation, December 2017.

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 been lower in 2017 compared to 2016. This is predominantly due to mild winter conditions in 2017 (refer to Section 2.4). Additionally, Queensland continues to lead Australia in the capacity of installed rooftop photovoltaic (PV), reaching 2,000MW in February 2018.

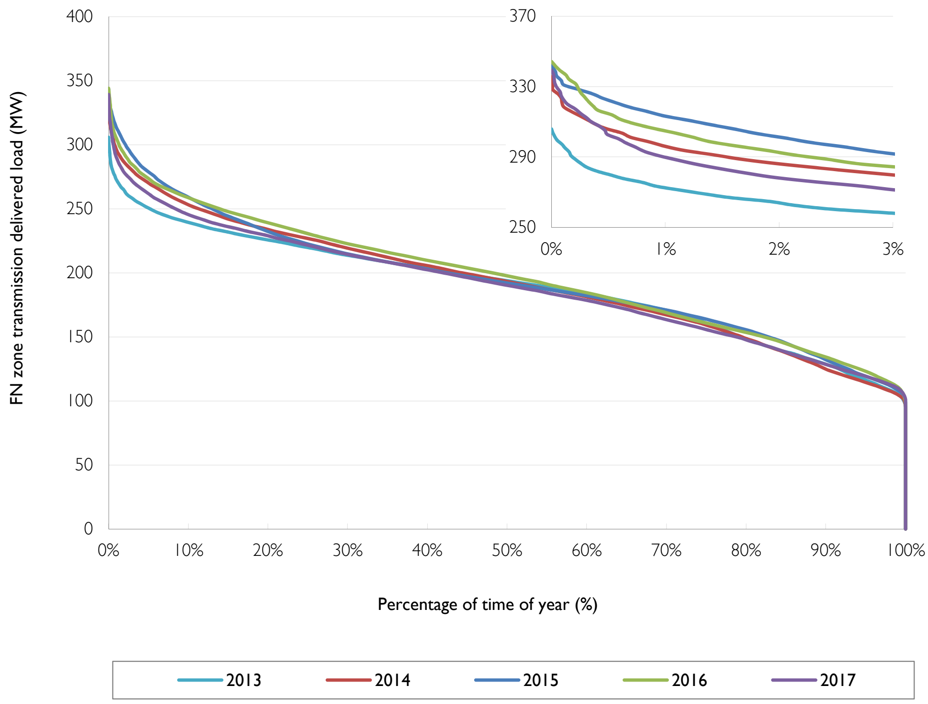
6.7.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2017.

The Far North zone includes the-scheduled embedded generator Lakeland Solar and Storage as defined in Figure 2.4. This embedded generator provided approximately 5GWh during 2017.

Figure 6.24 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has reduced by 3.9% between 2016 and 2017. The maximum transmission delivered demand in the zone was 339MW, which is below the highest maximum demand over the last five years of 344MW set in 2016.

Figure 6.24 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. No additional reactive sources are required in the Far North zone within the five-year outlook period for the control of high voltages.

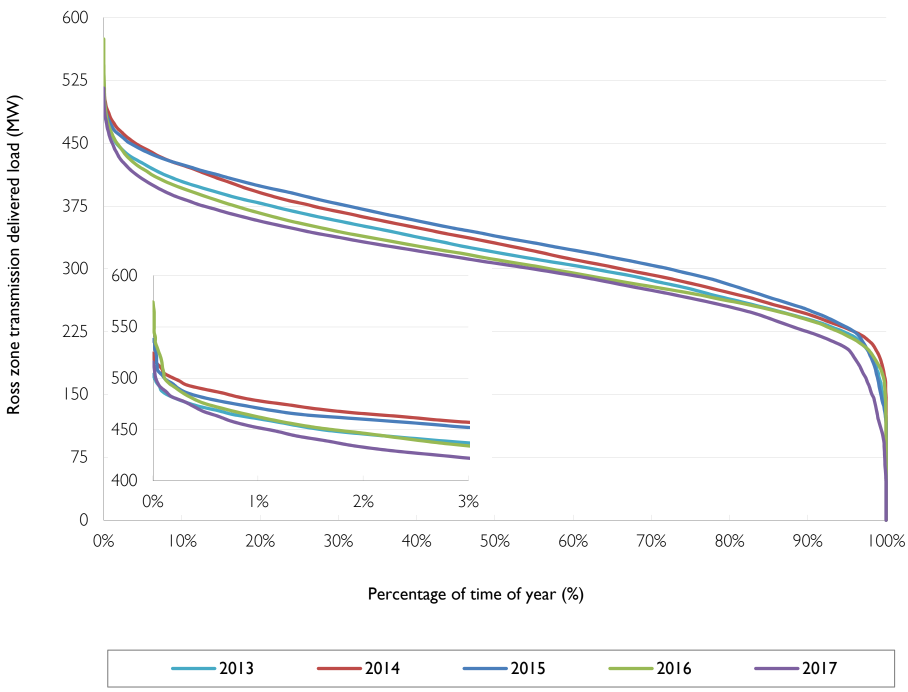
6.7.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2017.

The Ross zone includes the scheduled embedded Townsville Power Station 66kV component, semi-scheduled embedded Kidston Solar Farm and the significant non-scheduled embedded generator at Pioneer Mill as defined in Figure 2.4. These embedded generators provided approximately 278GWh during 2017.

Figure 6.25 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 3.0% between 2016 and 2017. The peak transmission delivered demand in the zone was 516MW which is below the highest maximum demand over the last five years of 574MW set in 2016.

Figure 6.25 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.

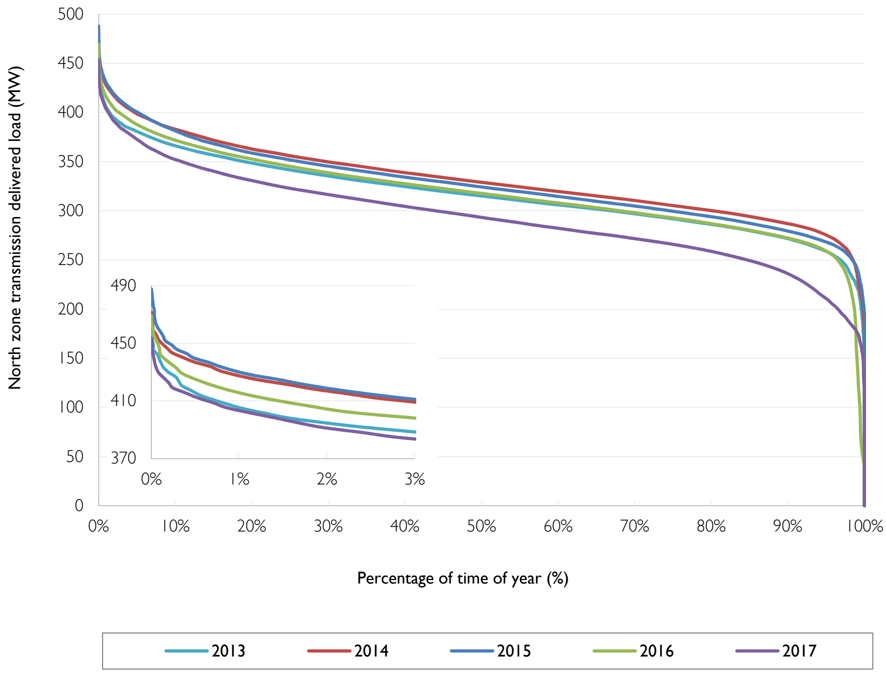
6.7.3 North zone

The North zone experienced no load loss for a single network element outage during 2017.

The North zone includes the scheduled embedded Mackay generator and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 2.4. These embedded generators provided approximately 638GWh during 2017.

Figure 6.26 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has reduced by 7.7% between 2016 and 2017. The peak transmission delivered demand in the zone was 454MW, which is below the highest maximum demand over the last five years of 488MW set in 2015.

Figure 6.26 Historical North zone transmission delivered load duration curves



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

- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 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 managed with existing reactive sources. A Braemar 275kV reactor was relocated to replace two transformer tertiary connected reactors decommissioned due to condition at Nebo Substation in August 2013. Generation developments in the Braemar area resulted in underutilisation of the reactor, making it possible to redeploy. No additional reactive sources are required in the North zone within the five-year outlook period for the control of high voltages.

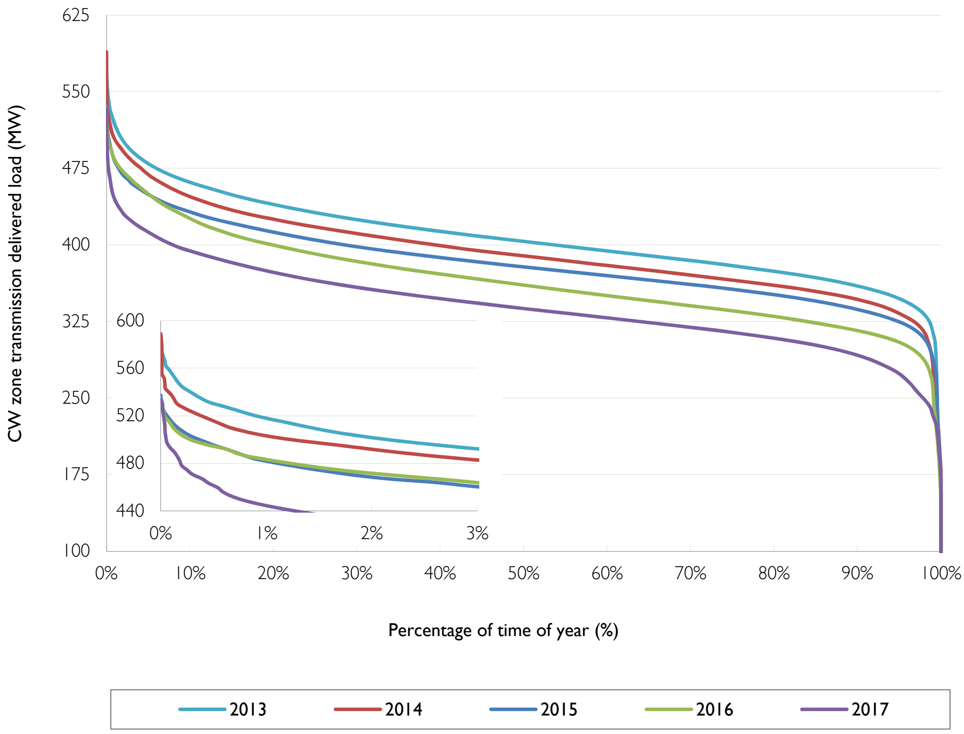
6.7.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2017.

The Central West zone includes the scheduled embedded Barcaldine generator and significant non-scheduled embedded generators Barcaldine Solar Farm, German Creek and Oaky Creek as defined in Figure 2.4. These embedded generators provided approximately 461GWh during 2017.

Figure 6.27 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 6.9% between 2016 and 2017. The peak transmission delivered demand in the zone was 534MW, which is below the highest maximum demand over the last five years of 589MW set in 2014.

Figure 6.27 Historical Central West zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO includes the Bouldercombe to Rockhampton and Bouldercombe to Egans Hill 132kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in February 2016.

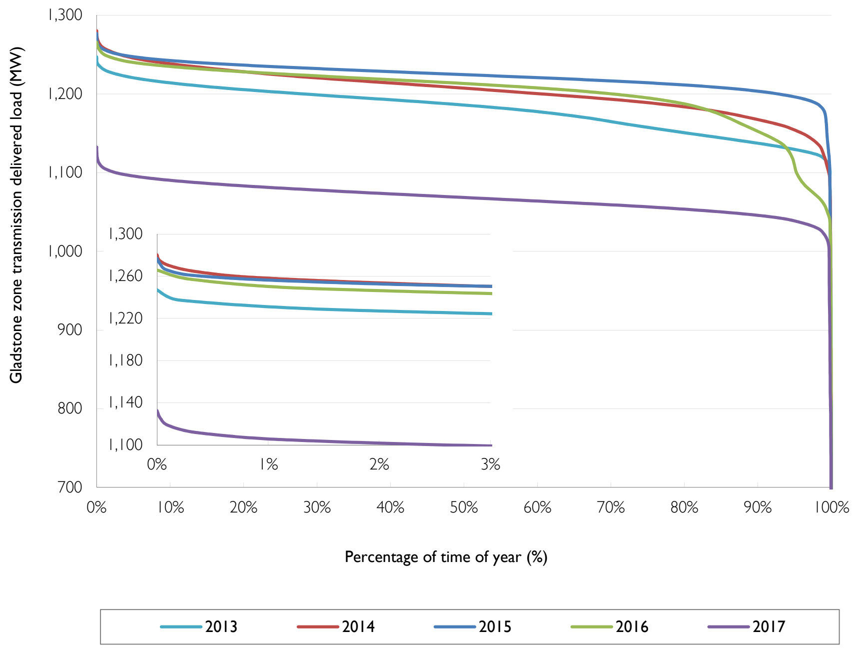
6.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2017.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.28 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has reduced by 11.2% between 2016 and 2017 predominantly due reductions to production of aluminium by BSL. The peak transmission delivered demand in the zone was 1,133MW, which is below the highest maximum demand over the last five years of 1,280MW set in 2014.

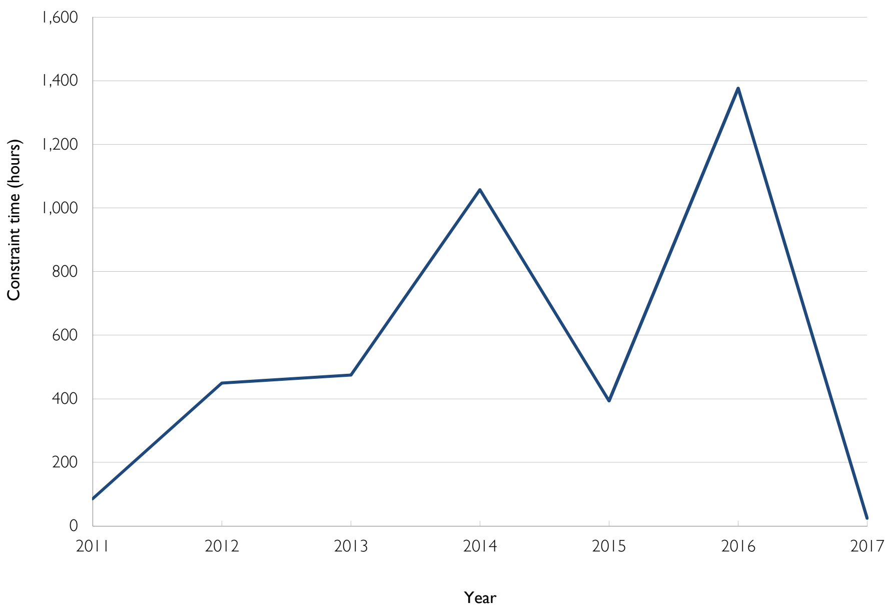
Figure 6.28 Historical Gladstone zone transmission delivered load duration curves



Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing within BSL's substation. The constraint limits generation from Gladstone 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 6.29. 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 the last decade, due to the BSL's reduced production the constraint only bound 25 hours during 2017.

Figure 6.29 Historical Q>NIL_BI_FB constraint times



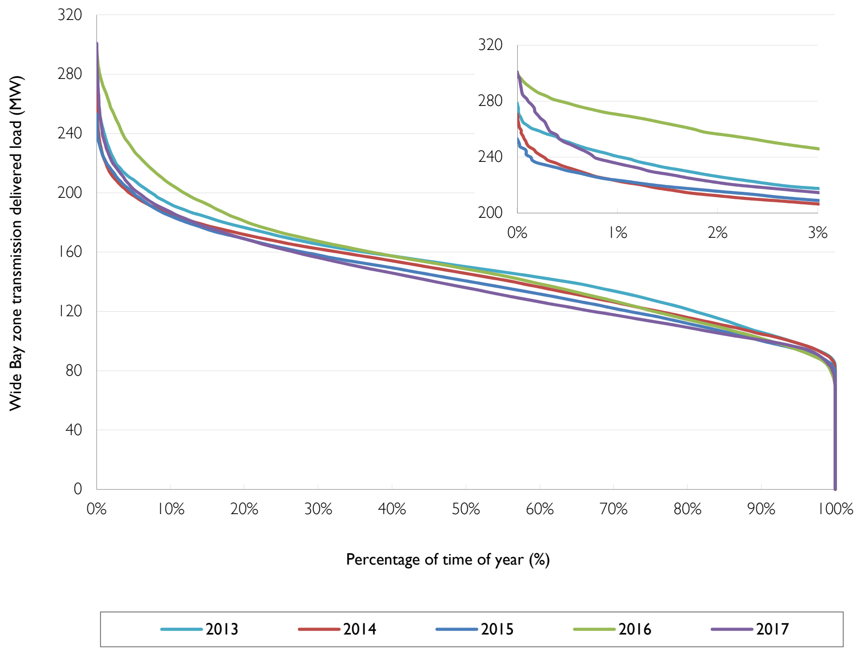
6.7.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2017.

The Wide Bay zone includes the non-scheduled embedded Isis Central Sugar Mill and Sunshine Coast Solar Farm as defined in Figure 2.4. These embedded generators provided approximately 38GWh during 2017.

Figure 6.30 provides historical transmission delivered load duration curves for the Wide Bay zone. Energy delivered from the transmission network reduced by 7.2% between 2016 and 2017 predominantly due to summer 2016/17 being hot and long lasting (refer to Section 2.1). The peak transmission delivered demand in the zone was 301MW, which is the highest maximum demand over the last five years.

Figure 6.30 Historical Wide Bay zone transmission delivered load duration curves



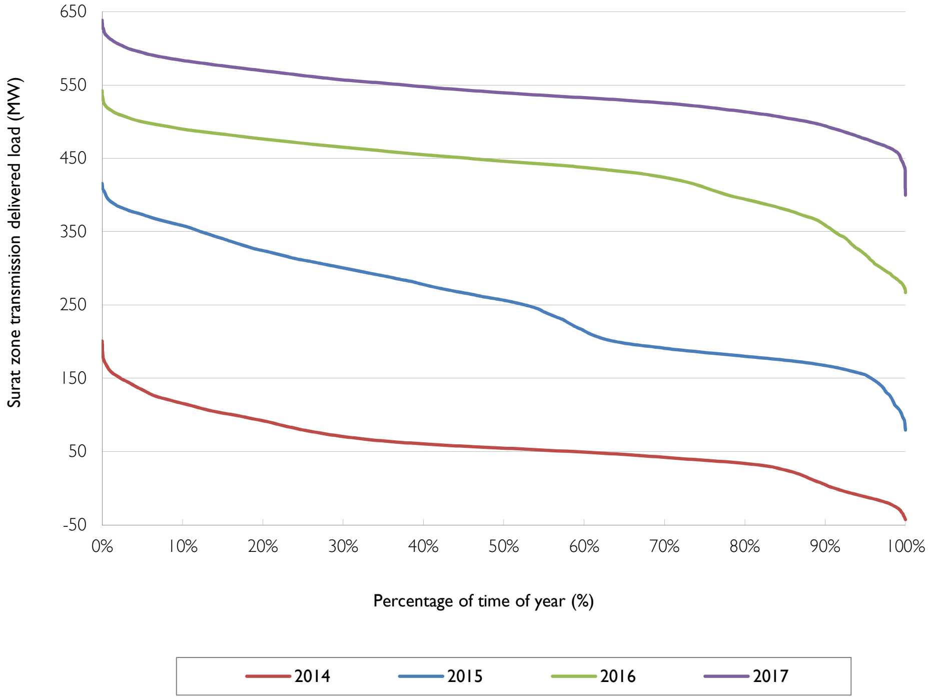
6.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2017.

The Surat zone includes the scheduled embedded Roma generator as defined in Figure 2.4. This embedded generator provided approximately 24GWh during 2017.

The Surat zone was introduced in the 2014 TAPR, Figure 6.31 provides transmission delivered load duration curve since its introduction. The curves reflect the ramping of CSG load in the zone.

Figure 6.31 Historical Surat 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 Surat zone in the vulnerable list:

- Chinchilla to Columboola 132kV double circuit transmission line, last tripped October 2015
- Tarong to Chinchilla 132kV double circuit transmission line, last tripped February 2018.

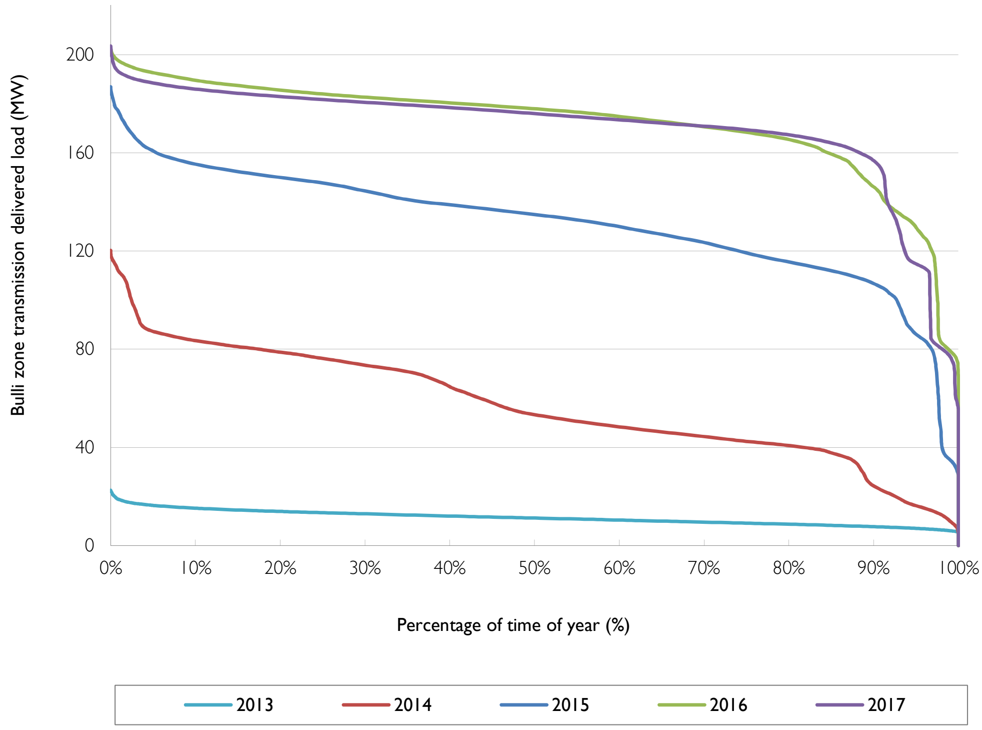
6.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2017.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.32 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has reduced by approximately 1.0% between 2016 and 2017. The peak transmission delivered demand in the zone was 204MW. The CSG load in the zone has now reached expected demand levels.

Figure 6.32 Historical Bulli zone transmission delivered load duration curves



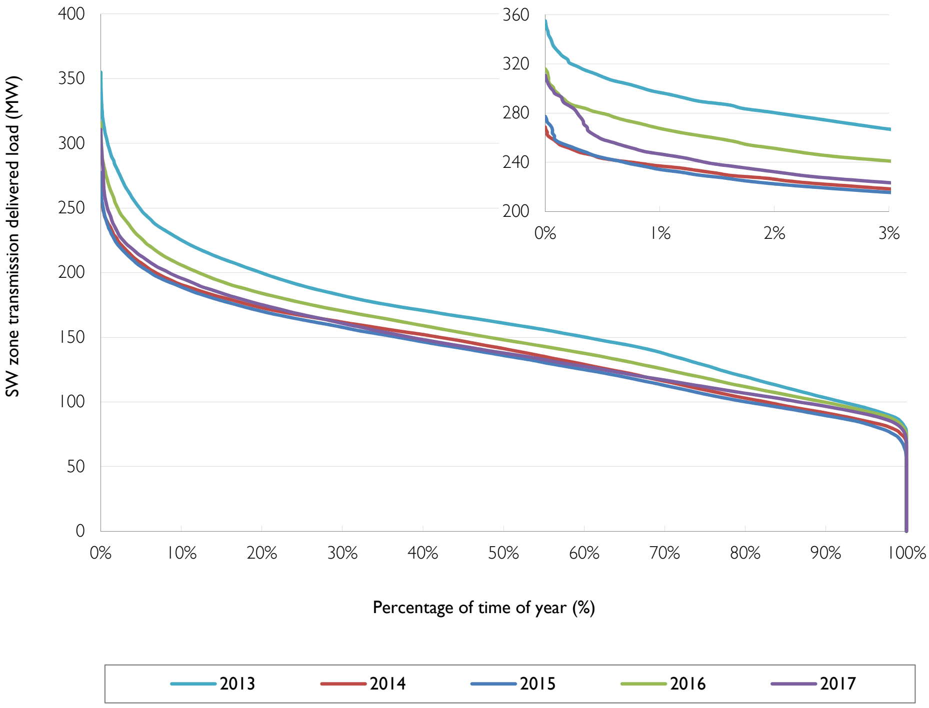
6.7.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2017.

The South West zone includes the significant non-scheduled embedded Daandine Power Station as defined in Figure 2.4. This embedded generator provided approximately 246GWh during 2017.

Figure 6.33 provides historical transmission delivered load duration curves for the South West zone. Energy delivered from the transmission network has reduced by 5.7% between 2016 and 2017. The peak transmission delivered demand in the zone was 311MW.

Figure 6.33 Historical South West zone transmission delivered load duration curves

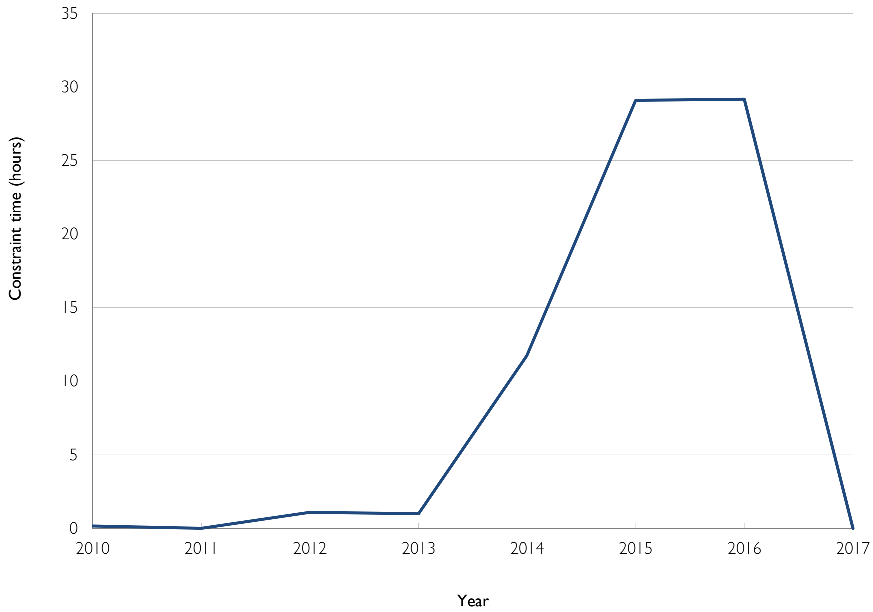


Constraints occur within the South West zone under intact network conditions. These constraints are associated with maintaining power flows of the 110kV transmission lines between Tangkam and Middle Ridge substations within the feeder's thermal ratings at times of high Oakey Power Station generation. 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. No constraints were recorded against this constraint in 2017. Oakey's production reduced significantly over 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 6.34.

Figure 6.34 Historical Q>NIL_MRTA_A and Q>NIL_MRTA_B constraint times



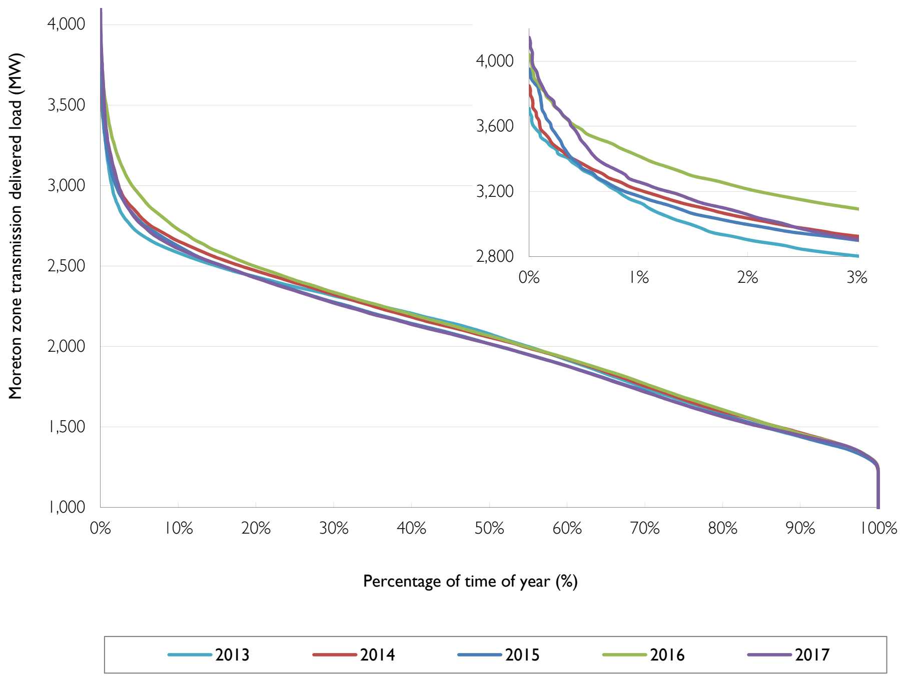
6.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2017.

The Moreton zone includes the significant non-scheduled embedded generators Bromelton and Rocky Point as defined in Figure 2.4. These embedded generators provided approximately 56GWh during 2017.

Figure 6.35 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has reduced by 2.9% between 2016 and 2017. The peak transmission delivered demand in the zone was 4,145MW, which is the highest ever maximum demand for the zone.

Figure 6.35 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. No additional reactive sources are forecast in the Moreton zone within the five-year outlook period for the control of high voltages.

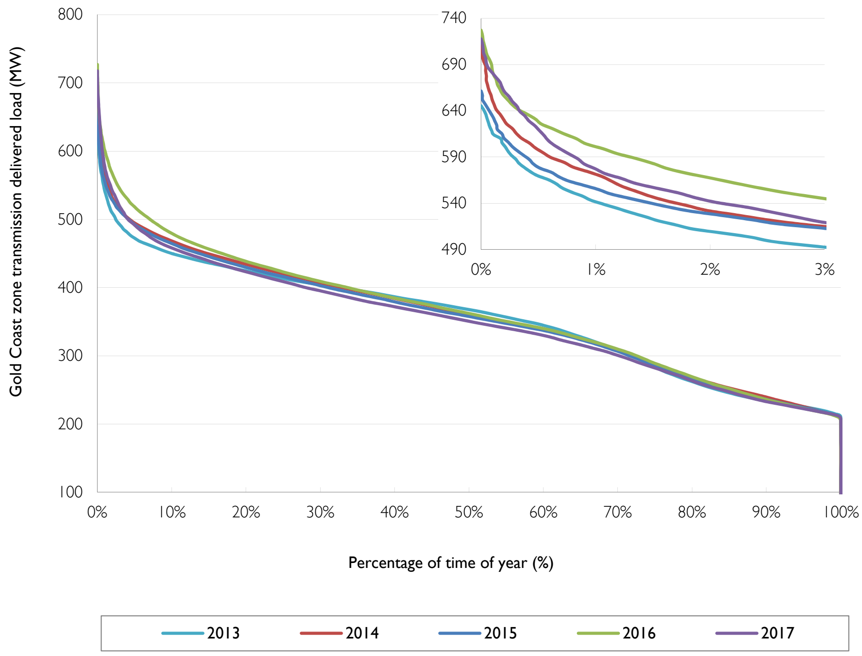
6.7.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2017.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 6.36 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has reduced by 3.2% between 2016 and 2017. The peak transmission delivered demand in the zone was 718MW which is below the highest maximum demand over the last five years of 727MW, set in 2016.

Figure 6.36 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 network is to play in enabling the transition to a lower carbon future while continuing to balance the economic and efficient development of the network
  - uncertainties in load growth and sources of generation, 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, Central West to Gladstone and the Surat Basin north west area.

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, community expectations and Government emission policies.

The future customer and consumer 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 variable renewable energy (VRE) generation, in particular solar photovoltaic (PV) and wind farm generation. Section 6.2 outlines that approximately 2,700MW of large-scale VRE generation is, or committed, to connect to the Queensland transmission and distribution networks by 2020.

Consumer behaviour is central to the energy transformation. Consumers 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 and 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 and the connection of diverse sources of VRE generation. 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.

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. 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.]
- ElectraNet for the South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T). The options being considered include a high voltage direct current (HVDC) interconnector between South West Queensland and South Australia.
- TransGrid to investigate the economic benefits of increasing the capacity between Queensland and New South Wales (NSW) (refer to Section 5.7.12). Powerlink and TransGrid propose to commence the formal RIT-T consultation process and publish the Project Specification Consultation Report (PSCR) in the third quarter of 2018.

The changing generation mix will also impact the stability and security of the power system. System security deals with the technical parameters of the power system such as voltage, frequency, the rate at which these might change and the ability of the system to withstand faults.

New investment in VRE generation will put pressure on the NEM's fossil fuelled power stations as the competition to supply load erodes the production base of these power stations. These synchronous generators, by nature or their technology and design, provide security and stability services to the NEM not inherent in the VRE generators. These generators, through their electro-mechanical interface to the system provide frequency stability and significant voltage support or system strength. However, VRE generators, such as wind and solar, use measurement, communications and control techniques to synchronise to the network which cannot provide instantaneous response and are reliant on system strength.

Therefore, displacing synchronous generation will reduce these services giving rise to increasing challenges for:

- AEMO to maintain the power system in a secure operating state
- Network Service Providers (NSP) to maintain power system standards for power quality, voltage control and protection system operation.

The power system must therefore facilitate mechanisms that provide the necessary stability, security and ancillary services at the lowest possible cost.

These technical challenges have been recognised and are being addressed through various reviews and working groups, including:

- AEMO's Future Power Systems Security taskforce and Power System Issues Technology Advisory Group (PSITAG)
- Independent Review into the Future Security of the National Electricity Market (Chief Scientist)
- Australian Energy Market Commission's (AEMC's) System Security Market Frameworks Review.

Section 7.3 provides a high-level summary of the technical challenges and the role TNSP's will play in providing directly or facilitating the connection and/or sharing of these services.

1 During 2018 AEMO will deliver the first ISP, a strategic infrastructure development plan that will present a framework to facilitate the connection of renewable energy in the NEM.

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. These load developments are listed in Table 2.1.

The new large loads 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 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.

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.

For the transmission grid sections potentially impacted by the possible new large loads in Table 2.1, details of feasible network options are provided in sections 7.2.1 to 7.2.6. 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 may occur following the possible retirement of assets described in Section 5.7.2. 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.

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 or the efficient economic operation of the CQ-NQ grid section are not forecast to occur within the 10-year outlook of this TAPR.

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 coal seam gas (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.

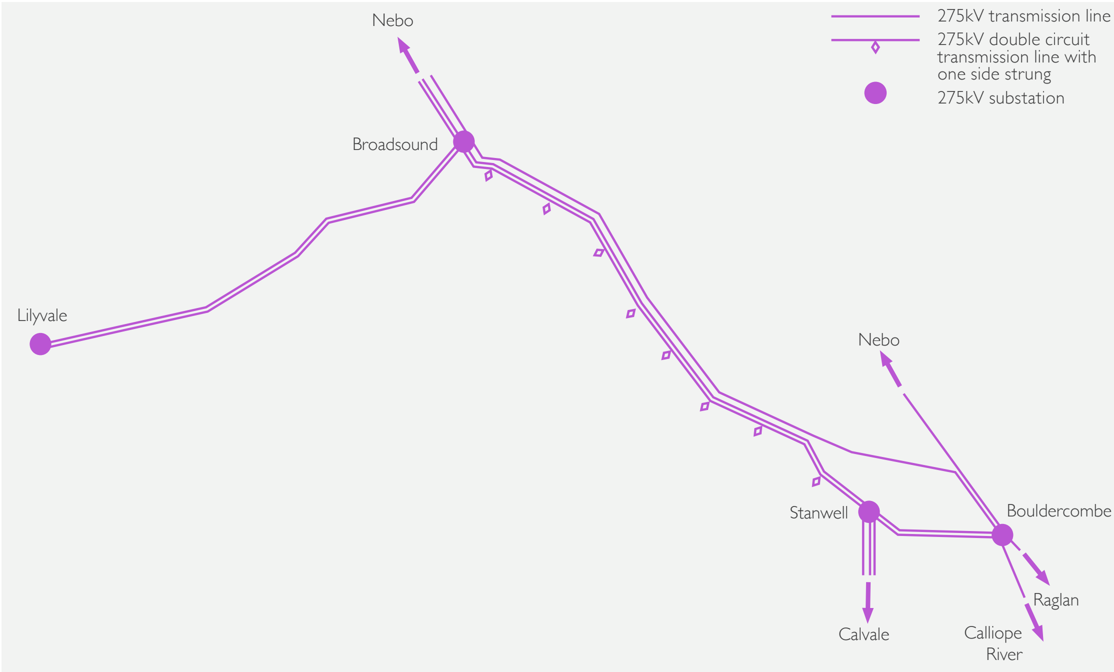
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line during a critical 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 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 likely retirement of the Callide A to Gladstone South 132kV double circuit transmission line within the next 10 year (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 Central West and Gladstone zones 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 now has final approval, as per the National Electricity Rules (NER), and plans to implement these improvements by June 2019.

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 energy 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.

7.2.6 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

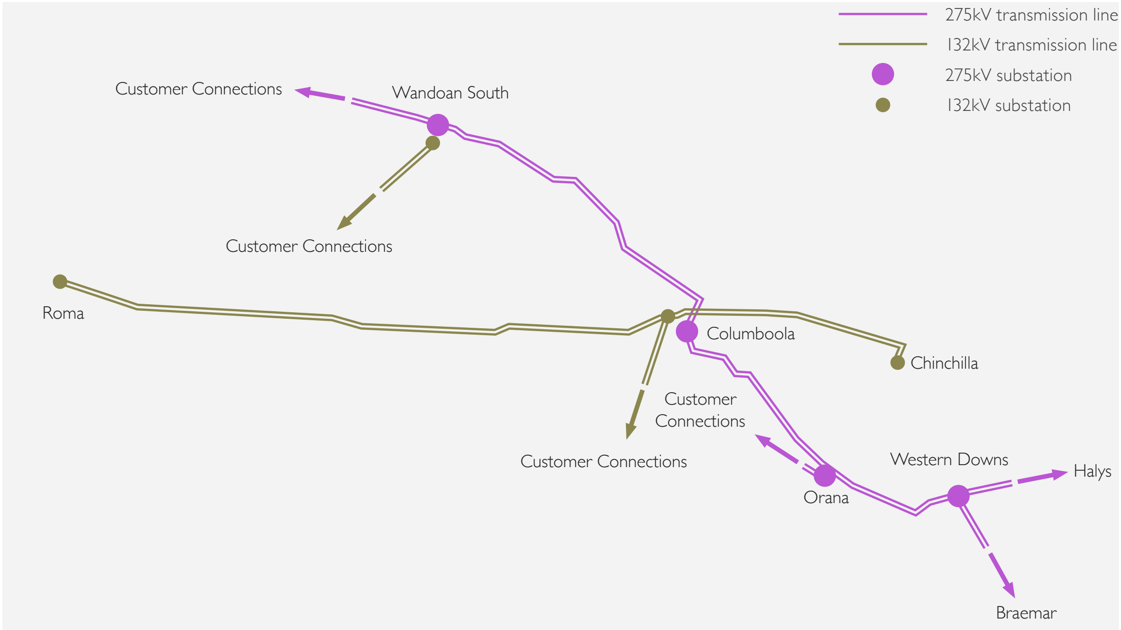
Due to the nature of the voltage stability limitation, the size and location of load and the range of contingencies over which the instability may occur, it may not be possible to address this issue by installing a single Static VAr Compensator (SVC) at one location.

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 (STATCOMs) or Synchronous Condensors (SynCons) 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
- a combination of the above options.

Figure 7.2 Surat Basin north west area transmission network



7.3 Technical challenges from the changing generation mix

Industry collaboration and consultation with stakeholders and regulatory and rule making bodies is essential to identify the most cost-effective solutions to the future power system security challenges. These technical challenges have been recognised and are being addressed through various reviews and working groups. This section focuses on two challenges where the AEMC has placed clear obligations on TNSPs: managing the rate of change of power system frequency, and fault levels.

7.3.1 Managing the rate of change of power system frequency

In order to maintain the power system in a secure operating state, a number of physical parameters must be controlled. Rapid changes in frequency or large deviations from normal operating frequency can lead to instability and wide-spread loss of load. Rotating inertia (provided historically from synchronous generators) controls the rate of change of frequency for a given disturbance. As the generation mix shifts to smaller and more non-synchronous VRE generation, inertia is not provided as a matter of course giving rise to increasing challenges to arrest the frequency change and restore the frequency to normal operating levels.

The AEMC have established new Rules to address these emerging problems. The Final Determination (September 2017) placed an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services such that the rate of change of frequency is controlled for prescribed extreme events (e.g. loss of interconnection and islanding of regions) and such that the inertia sub-network can be returned to a secure state.

The AEMC considered that TNSPs were best incentivised under the Regulatory framework to deliver this service at the least cost possible to consumers. TNSPs are best placed to provide the required levels of inertia within each sub-network and to coordinate the location of inertia with other network support services, including obligations related to minimum system strength (refer to Section 7.3.2). This co-optimisation of services will assist in minimising the overall costs to consumers.

The final rule requires AEMO to assess the levels of inertia being provided in each inertia sub-network, assess whether there is likely to be an inertia shortfall and forecast of the period over which that shortfall will exist. The assessment should be across a planning horizon of at least five years. AEMO is required to publish its projections and whether a shortfall is likely to exist.

Where an inertia shortfall is identified there is an obligation on the relevant TNSP to make continuously available minimum required levels of inertia. The TNSP can provide the inertia itself or procure inertia services from third parties such as generators. There is also ability for TNSPs to invest in or contract with third-party providers of alternative frequency control services ('inertia support activities'), including fast frequency response (FFR) services, as a means of reducing the minimum required levels of inertia, with approval from AEMO. AEMO will publish the first periodic review for the Queensland region as part of the ISP in July 2018. It is expected that AEMO will not identify any sub-networks within the Queensland region that are required to be able to operate independently as an island. It is also expected that AEMO will not identify any shortfall in inertia exists, or is likely to exist over the five-year forecast in the Queensland region.

7.3.2 Managing power system fault levels

System strength is a characteristic of a power system that relates to the size of the change in voltage following a fault or disturbance. System strength is correlated with the availability of fault current at a given location (should a fault occur). High levels of fault current are found in a strong power system while low fault levels are representative of a weak power system. When the system strength is high, the voltage changes very little for a change in the loading (i.e. a change in load or generation). However, when the system strength is lower the voltage varies more with the same change in loading.

Synchronous machines are the primary source of fault current and system strength. As the penetration of VRE generation increases and synchronous generators are displaced/retired, the system strength will decrease. This can mean that the system strength is not sufficiently high to keep the remaining generators stable and connected to the power system following a major disturbance, which introduces the risk of a cascading outage and a major supply disruption (or widespread blackouts).

On 19 September 2017, the AEMC published a final rule concluding that TNSPs are best positioned to maintain system strength such that the power system can be kept in a secure operating state. The existing incentive based economic regulatory framework will provide an incentive for the TNSP to meet this obligation at the lowest long-term costs for consumers.

The AEMC considers that TNSPs are able to consider a range of issues associated with low system strength and are well placed to develop solutions that best address multiple system strength issues. Indeed, the existing rules make NSPs responsible for the functioning of protection systems and the management of network voltages and power quality, all of which become more difficult as system strength reduces. TNSPs will be able to co-optimise the sources of system strength services with the provision of other necessary system security services such as inertia.

The final rule places an obligation on AEMO to develop a methodology ('system strength requirements methodology') that sets out the process for how it will determine the system strength needed in each region ('system strength requirements'). This methodology has been developed collaboratively with TNSPs. AEMO must then undertake an assessment of any fault level shortfall. If AEMO assesses that there is likely to be a shortfall AEMO must specify the extent of the fault level shortfall and the date by which the TNSP must provide services to address the shortfall. When procuring these services, the TNSP is required to identify and implement the least cost option or combination of options.

AEMO will publish the first periodic review for the Queensland region as part of the ISP in July 2018. It is expected that AEMO will not identify system strength requirements within the Queensland region. It is also expected that AEMO will not identify any shortfall in system strength, or is likely to exist over the five-year forecast in the Queensland region.

The final rule also places an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system.

When a new generator is negotiating its connection with the relevant NSP, a system strength impact assessment is required to be undertaken by the NSP to assess the impact of the connection of the generating system on the ability of the power system to maintain stability in accordance with the NER, and for other generating systems to maintain stable operation including following any credible contingency event or protected event (this is discussed in detail in Section 8.3.1).

TNSPs must also consider the impacts on the level of system strength to maintain the security of the power system when making investment and reinvestment decisions (eg. network consolidation, network rearrangement or retirement).

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.
- A number of Rule changes have been finalised since the publication of the 2017 Transmission Annual Planning Report (TAPR) impacting how customers may connect to Powerlink's network.
- Over the past year, Powerlink has supported a high level of connection activity, responding to more than 120 connection enquiries comprising over 25,000MW of potential VRE generation.
- In 2017/18, Powerlink finalised a further seven VRE generator Connection and Access Agreements (CAA) totalling 1,012MW.

8.1 Introduction

Queensland is rich in a diverse range of VRE resources – solar, wind, geothermal, biomass and hydro. This makes Queensland an attractive location for large-scale VRE generation development projects.

In January 2018, the level of roof top solar installations in Queensland exceeded 2,000MW and is presently increasing at approximately 25MW each month (refer to Section 2.1). This uptake provides a strong indication that Queensland consumers are seeking alternatives to meet their energy requirements. The development of complementary technologies, such as distributed energy storage, smart appliances, and electric vehicles will change the way customers consume and produce energy.

During the past year there has been a significant increase in the development of large-scale solar and wind generation farms. Fundamental external shifts such as these are shaping the operating environment in which Powerlink delivers its transmission services. Powerlink is responding to this changing operating environment by:

- implementing and adopting the recommendations of the Finkel and other reviews
- adapting to changes in electricity consumer behaviour and economic outlook.

Powerlink is committed to supporting the development of all types of energy projects requiring connection to the transmission network. Powerlink also has a key role in enabling the connection of VRE infrastructure developments, which aim to provide a sustainable, low-carbon future for electricity producers and users in Queensland.

The network capacity information presented in this chapter is applicable to all forms of generation including energy storage[1].

Since the publication of the 2017 TAPR, there have been a number of Rule changes. The Rule changes most relevant to the information provided in this chapter are:

- Managing Power System Fault Level
- Transmission Connection and Planning Arrangements.

Further information on managing power system fault levels, as it applies to the connection of new VRE generators, is available in Section 8.3.

Further information on the transmission connection and planning arrangements is available in Section 8.4.

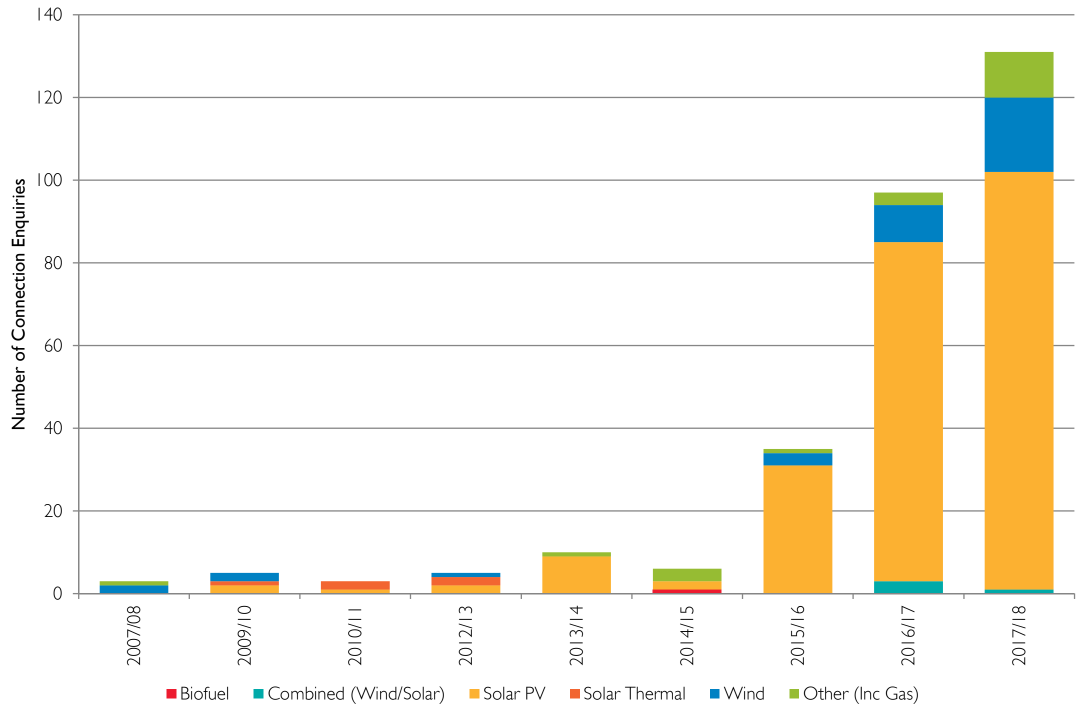
1 The impact of new synchronous generator connections on existing fault levels has not been considered in the assessments conducted in this chapter. For further information on existing fault levels and equipment rating, please refer to Appendix E.

8.2 Connection activity during 2017/18

Powerlink continues to manage a high level of interest in transmission connections for VRE projects. In 2017/18, Powerlink received more than 120 new connection enquiries totalling in excess of 25,000MW[2].

Figure 8.1 illustrates the historical number of generation connection enquiries and the record levels that have been received over the last year.

Figure 8.1 Historical number of generation connection enquiries



During 2017/18, Powerlink finalised seven CAAs for new semi-scheduled VRE generation, totalling 1,012MW (refer to Table 8.1).

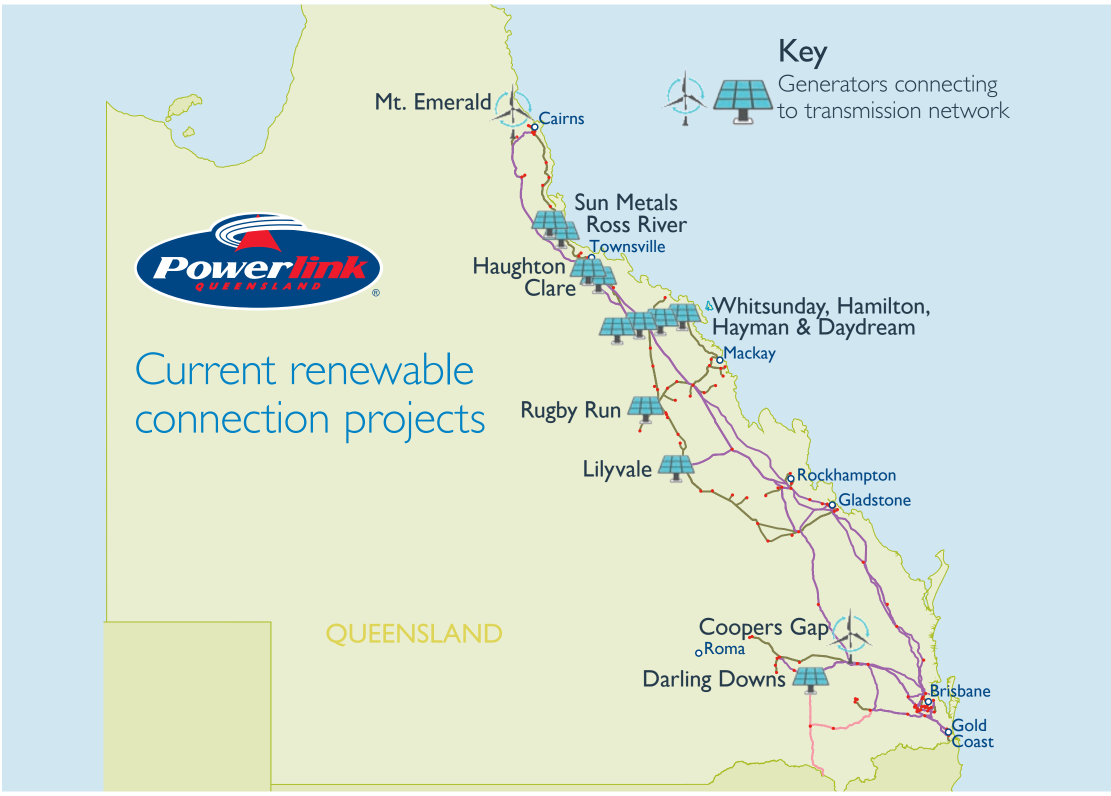
Table 8.1 Transmission connected VRE generation projects committed during 2017/18

Zone	Project	Registered capacity (MW)	Connection location
Ross	Sun Metals Solar Farm	107	Townsville South 132kV Substation
Ross	Haughton Solar Farm	100	New 275kV substation between Ross and Strathmore
North	Daydream Solar Farm	150	Strathmore 275kV Substation
North	Hayman Solar Farm	50	Strathmore 275kV Substation
North	Rugby Run Solar Farm	65	New 132kV substation near Moranbah
Central West	Lilyvale Solar Farm	100	New 132kV substation near Lilyvale
South West	Coopers Gap Wind Farm	440	New 275kV substation near Halys

Additionally, Powerlink has been advised of over 1,015MW of committed semi-scheduled renewable projects connecting within the distribution networks.

2 Connection activity details as at 1 June 2018.

Figure 8.2 Committed projects connecting to the Powerlink network



8.3 Network capacity for new generation

Powerlink has assessed the potential generation capacity which could be accommodated at various locations across the transmission network. This information is available on Powerlink's website. The data presented is not comprehensive, and is not intended to replace the existing processes that must be followed to seek connection to Powerlink's transmission network.

8.3.1 Calculation methodology

Powerlink has assessed the available generation connection capacity at a number of locations across the network predominantly at the 275kV and 132kV level. Locations close to major urban areas were considered less likely to host a large VRE project and were excluded from the assessment.

Thermally Supportable Generation

A connection point's thermal capacity relates to the highest level of generation that can be injected into a connection point without exceeding the rating of a transmission circuit following the loss of a network element. It may be possible for generation to be installed in excess of this level if a fast generation runback scheme is implemented to limit generation output following the relevant network contingency events.

Each connection point's thermal capacity was calculated by applying generation of increasing levels to a connection point, displacing Queensland/New South Wales Interconnector (QNI) transmission line transfer, and performing contingency analysis. The thermal limit of a connection point was assessed as being reached when a rating breach was identified on the network surrounding the connection point. Powerlink has assessed each connection point individually, and has not assessed whether multiple generators in a region are likely to result in congestion on the main transmission network.

The capacity available for thermally supportable generation is based on summer daytime peak loadings, and does not take account of varying load, generation and market conditions that may drive other constraints at a local or system level.

System Strength Supportable Generation

Section 8.1 outlines that energy transformation underway, driven by advances in renewable energy technologies and displacement/retirement of existing synchronous generation. These changes are creating opportunities and challenges for the power system. One of these challenges is the impact that the displacement/retirement of synchronous generators has on the system fault levels. Section 8.3.2 describes the impact of this reducing system strength on the stability and security of the power system.

In response to these challenges, the Australian Energy Market Commission (AEMC) finalised Rule 2017 No.10 (Managing Power System Fault Levels). This Rule created a framework in the National Electricity Rules (NER) for the management of system strength in the NEM. As required under the Rule, the Australian Energy Market Operator (AEMO) published the System Strength Impact Assessment Guidelines for consultation on 5 March 2018, with an update on 14 May 2018. The final guidelines are to be published on 29 June 2018. As such, it is not possible for Powerlink to fully consider these in this TAPR.

Further detail on Powerlink's methodology on assessment of capacity for the Transmission Network is provided in the Generation Capacity Guide.

Overall VRE Supportable Generation

The overall VRE supportable generation is the lower of the thermally supportable generation and the system strength supportable generation at each location.

8.3.2 Network capacity results

As outlined in Section 8.1, Powerlink has received more than 120 connection enquiries and finalised seven connection agreements for new VRE generation since publication of the 2017 TAPR. As a consequence, the capacity results calculated via the methodology described in Section 8.3.1 are continually changing. On this basis, the detailed calculation results will be published on Powerlink's website in order to more efficiently address the dynamics of this evolving environment and best serve the needs of customers (refer to Powerlink's Generation Capacity Guide). Powerlink expects to maintain this data as required and encourages proponents to make informed investment decisions through the established connection enquiry process. This process includes the provision of detailed capacity and congestion information for customers seeking to connect to Powerlink's transmission network. To join Powerlink's Non-network Engagement Stakeholder Register (NNESR) and be notified of any updates to this data, please email networkassessments@powerlink.com.au.

The calculation methodology assumes 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 CAA, an agreed Generator Performance Standard, and acceptance by AEMO of any requirements under National Electricity Rules (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 5.2.5.1). 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 open access regime which applies in the NEM, 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 proactively monitors the potential for congestion to occur, and will assess the potential network augmentations to maximise market benefits using the Australian Energy Regulator's (AER) Regulatory Investment Test for Transmission (RIT-T)[3]. Where augmentations are 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, which provides more detail.

It is possible that 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 system, and hence Marginal Loss Factors (MLFs) used within the NEM dispatch and financial settlement processes. AEMO is responsible for the calculation of Marginal Loss Factors, and interested parties seeking further information on this are encouraged to contact AEMO, or refer to the AEMO website.

As a Transmission Network Service Provider, the scheduling of generation does not form part of Powerlink's role and as such, the indicative connection point generation capacity limits are not related to the scheduling and dispatch of generation in the NEM.

8.4 Transmission connection and planning arrangements

Powerlink, as part of the 2017 Transmission Network Forum, ran an engagement session on the upcoming rule change, seeking input from stakeholders on:

- What other information can Powerlink provide that would benefit connection applicants?
- How detailed should the functional specification be?
- How detailed should the Network Operation Agreement be, particularly with respect to operations and maintenance?

In May 2017 the AEMC published the final determination on the Transmission Connections and Planning Arrangements Rule change request. The final 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.

In response to the Rule change and to further assist customers during the connection process, Powerlink has developed the following information and material:

- typical operations and maintenance scheduling
- standard suite of contracts (including the new network operating agreement)
- terms and conditions and fees for making a connection enquiry and a connection application
- design standards for substations and transmission lines, including current rating and configurations and land related policies
- equipment strategies for key plant, such as current transformers, circuit breakers, earth switches, surge arrestors, and voltage transformers
- standard layouts for Powerlink substations, overhead lines, underground cables and secondary systems.

A summary of the feedback from the 2017 Transmission Network Forum, and the information and material referred to above is available on Powerlink's website.

[3] Details of the RIT-T, including the market benefits which can be considered, are available on the AER's website: Regulatory investment test for transmission (RIT-T) and application guidelines 2010.

8.5 Supporting VRE development in Queensland

Powerlink is supporting a number of initiatives associated with the establishment of new generation in Queensland. Further information on these is provided in the following sections.

8.5.1 Shared network connections

In the broader context of supporting VRE generation connections, the concept of 'Renewable Energy Zones' (REZ) can be used to deliver lower cost connections to a number of parties. Powerlink is working to enhance the concept of the REZ based on recent experience around the connection of VRE, particularly in North Queensland.

As illustrated in figures 8.3 and 8.4, the existing 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.

Figure 8.3: REZ with high capacity transmission line

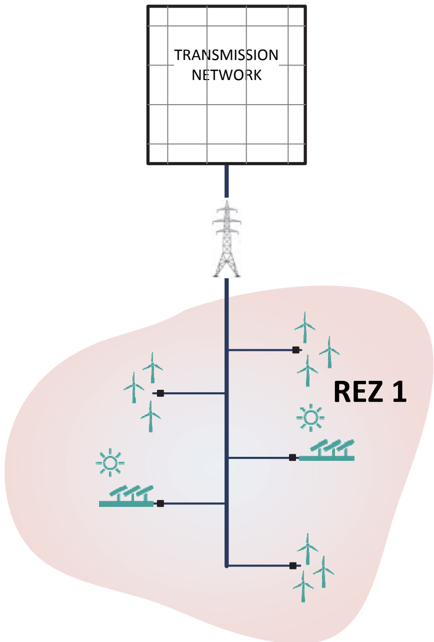
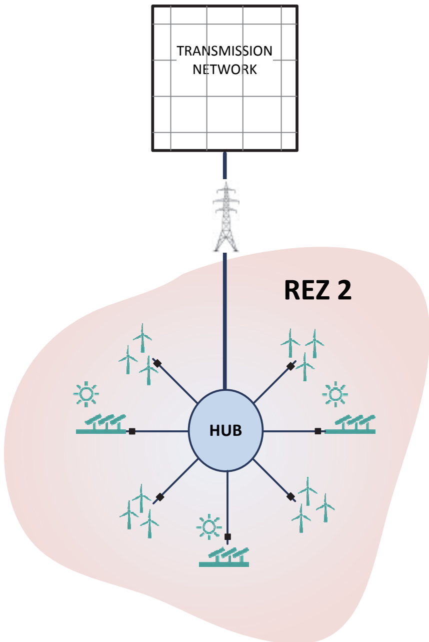


Figure 8.4: REZ with dedicated connection hub



Further to the concepts 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.

Where new VRE generation is seeking to connect in areas of low system strength, there are a number of mitigation measures available to maintain adequate fault levels in the network. 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 improve system strength
- modifying the scope of the connection works
- 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.

8.5.2 Delivering Clean Energy Hubs in Queensland

Powerlink, as part of the 2017 Transmission Network Forum, hosted an engagement session that provided an introduction into the potential development of a Clean Energy Hub (CEH) – a key action of the Powering Queensland Plan.

As part of the feasibility study into the CEH, discussions focused on connection options, technical and environmental considerations and operating models. Discussions also considered how the model could be replicated across Queensland.

Expression of Interest (EOI) in the CEH closed on 8 September 2017, with more than 30 submissions received from interested parties.

Powerlink, in collaboration with the Queensland Energy Security Taskforce and the Queensland Government, assessed these EOI responses including technical, economic, environmental, social and regional considerations. These assessments informed the CEH feasibility study.

The feasibility study is currently being considered within the context of broader Government energy policy.

8.5.3 Aldoga Renewable Energy Project

In April 2018, Energy Development Queensland announced Acciona as the successful tenderer for the Aldoga Renewable Energy Project. This project involves utilising a 1,250 hectare site adjacent to Powerlink's Larcom Creek Substation. Whilst the original concept for the site identified the potential to support more than 450MW of generation, detailed investigation has identified that the site capacity is limited to less than 300MW.

As a flagship project, it is envisaged that the Aldoga development will act as a catalyst for further opportunities. More information about this project is available on the website of the Queensland Department of Infrastructure, Local Government and Planning (DILGP).

8.5.4 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.

8.5.5 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 current Rules framework for connection of generation. Should an interested party wish to utilise the new connection framework referred to in Section 8.4, it will be necessary to submit a connection enquiry pursuant to the new Rule.

4 Powerlink considers that these schemes are used to mitigate against single credible contingencies that result in a significantly lower available fault level (AFL).

Figure 8.5 Overview of Powerlink's existing network connection process

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

8 Renewable energy

CHAPTER 9

Committed, current and recently commissioned network developments

9 Committed, current and recently commissioned network developments

Key highlights

- During 2017/18, Powerlink's efforts have been predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's reinvestment program is focused on reducing the identified risks arising from assets reaching the end of technical service life.
- A major project for Powerlink has been the works completed at Mudgeeraba Substation to maintain the reliability of supply of Powerlink's transmission network in the Gold Coast zone ensuring a safe, reliable and secure electricity supply for the region into the future.

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.

- Table 9.1 lists transmission network developments commissioned since Powerlink's 2017 Transmission Annual Planning Report (TAPR) was published.
- Table 9.2 lists connection works commissioned since Powerlink's 2017 TAPR was published.
- Table 9.3 lists new transmission connection works for supplying loads which are committed and under construction at June 2018. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.
- Table 9.4 lists network reinvestments commissioned since Powerlink's 2017 TAPR was published.
- Table 9.5 lists network reinvestments which are committed at June 2018.
- Table 9.6 lists network assets retired since Powerlink's 2017 TAPR was published.

Table 9.1 Commissioned transmission developments since June 2017

Project	Purpose	Zone location	Date commissioned
Moranbah area 132kV capacitor banks	Increase supply capability in the North zone	North	July 2017

Table 9.2 Commissioned connection works since June 2017

Project (1)	Purpose	Zone location	Date commissioned
Clare Solar Farm	New solar farm	Ross	Quarter 1 2018
Sun Metals Solar Farm	New solar farm	Ross	Quarter 1 2018

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 by the company making the connection request.

Table 9.3 Committed and under construction connection works at June 2018

Project (1)	Purpose	Zone location	Proposed commissioning date
Ross River Solar Farm	New solar farm	Ross	Quarter 2 2018
Coopers Gap Wind Farm	New wind farm	Bulli	Quarter 2 2018
Darling Downs Solar Farm	New solar farm	Bulli	Quarter 2 2018 (2)
Mount Emerald Wind Farm	New wind farm	Far North	Quarter 3 2018
Whitsunday Solar Farm	New solar farm	North	Quarter 3 2018 (2)
Hamilton Solar Farm	New solar farm	North	Quarter 3 2018 (2)
Haughton Solar Farm	New solar farm	Ross	Quarter 4 2018
Daydream Solar Farm	New solar farm	North	Quarter 4 2018
Hayman Solar Farm	New solar farm	North	Quarter 4 2018

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 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 9.4 Commissioned network reinvestments since June 2017

Project	Purpose	Zone location	Date commissioned
Mudgeeraba 275/110kV transformer replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	May 2017 (1)
Blackwater Substation replacement	Maintain supply reliability in the Central West zone	Central West	September 2017
Garbutt to Alan Sherriff 132kV line replacement	Maintain supply reliability in the Ross zone	Ross	October 2017
Proserpine Substation replacement	Maintain supply reliability in the North zone	North	December 2017
Mudgeeraba 110kV Substation primary plant and secondary systems replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	February 2018

Note:

(1) Formal notification of project commissioning was not issued until after the publication of the 2017 TAPR.

Table 9.5 Committed network reinvestments at June 2018

Project	Purpose	Zone location	Proposed commissioning date
Turkinje secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2018
Garbutt transformers replacement	Maintain supply reliability in the Ross zone	Ross	June 2019
Moranbah 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	July 2018
Nebo 275/132kV transformer replacements	Maintain supply reliability in the North zone (1)	North	November 2018
Mackay Substation replacement	Maintain supply reliability in the North zone	North	May 2019
Line refit works on the 132kV transmission line between Collinsville North and Proserpine substations	Maintain supply reliability to Proserpine	North	June 2019
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek Substation	Maintain supply reliability in the North zone	North	October 2020
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone	North	August 2022
Calvale 275/132kV transformer reinvestment	Maintain supply reliability in the Central West zone (2)	Central West	May 2019
Moura Substation replacement	Maintain supply reliability in the Central West zone	Central West	May 2019 (1)
Stanwell secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	November 2018
Dysart Substation replacement	Maintain supply reliability in the Central West zone	Central West	October 2019
Dysart transformer replacement	Maintain supply reliability in the Central West zone	Central West	October 2019
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (3)	Central West	June 2021
Line refit works on 132kV transmission lines between Calliope River and Boyne Island	Maintain supply reliability in the Central West and Gladstone zones	Gladstone	May 2019
Wurdong 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	Wide Bay	December 2019
Gin Gin Substation rebuild	Maintain supply reliability in the Wide Bay zone	Wide Bay	October 2020
Tennyson secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	December 2018
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	Moreton	October 2020

Table 9.5 Committed network reinvestments at June 2018 *(continued)*

Note:

(1) Major works completed in October 2017. Minor works scheduling is being coordinated with Ergon Energy (Energex and Ergon Energy are part of the Energy Queensland Group).

(2) 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.

(3) The majority of Powerlink's staged works are anticipated for completion by summer 2018/19. Remaining works associated with generation connection will be coordinated with the customer.

Table 9.6 Completed asset retirement works since June 2017

Project (1)	Purpose	Zone location	Proposed retirement date
Proserpine to Glenella 132kV transmission line retirement	Removal of assets at the end of service life in the North zone	North	June 2017

Note:

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

Figure 9.1 Existing Powerlink Queensland transmission network June 2017

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 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 photo voltaic (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 but excludes days where the average temperature at Amberley is <24.5°C. Other parameters such as customer behaviour patterns and demand management responses are also included. For the South East Queensland (SEQ) system model, three weather stations were incorporated into the model through a weighting system to capture 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.
- 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 (EVs) based on the maximum demand daily load profile and expected equipment usage patterns.

1 Where applicable, Clauses 5.12.2(c)(iii) and (iv) are discussed in Chapter 2.

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 March 2017 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink at the end of 2017 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 correspond 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. 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:

In particular, the total price component incorporated into the latest model aims to capture the response of customers to the changing price of electricity. The impact of price is based on the medium scenarios for the Queensland residential price index forecast prepared by NIEIR in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – the medium case of GSP growth (2.7% per annum over the next 11 years).
- Total real electricity price – the low case of annual price change of -0.2% (compounded and consumer price index (CPI) adjusted).
- Queensland population – a relatively high growth of 1.68% in 2018 (driven by improved net immigration), slowing to 1.50% in 2024 before climbing back to 1.65% by 2028.
- Roof top PV – lack of incentives for customers who lost the feed-in tarriff (FIT) tariffs, plus slow falls in battery prices which discourage PV installations. Capacity may reach 2,246MW by 2028.
- Battery storage – prices fall slowly, battery safety remains an issue, and kW demand based network tariff is not introduced. Capacity gradually increase to 583MW by 2028.
- 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 350MW by 2028.
- Weather – follow the recent 30-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – the low case of GSP growth (1.6% per annum over the next 11 years).
- Total real electricity price – the medium case of annual price change of 0.1%.
- Queensland population – growth of 1.35% in 2016, increasing to 1.42% in 2017 before slowing down to 1.27% by 2028.
- Roof top PV – invertor capacity increasing from 1,184MW in 2017 to 2,974MW by 2028.
- Battery storage – capacity will have a slow start of around 2.6MW in 2017, but will gradually accelerate to 892MW by 2028.
- EV – Stagnant in the short term, boom in the long term. Peak time contribution (without diversity ratio adjusted) will only amount to 2.2MW in 2018, but will reach 232MW by 2028. Note however, EV will impact 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 (0.6% per annum over the next 11 years)
- Total real electricity price – the high case of annual price change of 1.4%
- Queensland population – low growth of 1.2% in 2018 (due to adverse immigration policies), then weak gross domestic product (GDP) growth plus loss in productivity may slow growth to 0.9% by 2028
- Roof top PV – strong incentives for customers who lost the FIT tariffs, plus fast falls in battery prices which encourage more PV installations. Capacity may hit 3,927MW by 2028
- Battery storage – prices fall quickly, no battery safety issues, and a demand based network tariff is introduced. Capacity may reach a high at 1,252MW by 2028
- 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 175MW by 2028
- Weather – follow the recent 30-year trend.

Summary of the Ergon model

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

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 – high growth average (3.4% per annum consistent with NIEIR's high growth average).
- Queensland population – growth of 1.35% in 2016, increasing to 1.42% in 2017 before slowing down to 1.27% by 2028.
- Roof top 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 – medium growth average (2.6% per annum consistent with NIEIR's medium growth agerage).

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – low growth average (1.5% per annum consisistent with NIEIR's low growth average).

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

The general trend in connection point maximum demand growth is flat or slightly declining. The main exceptions to this trend for SEQ are:

Connection Point	2016/17 Forecast	2015/16 Forecast
Abermain 33 CP	2.3% pa	0.9% pa
Belmont 110 CP	1.2% pa	0.7% pa
Goodna 33 CP	3.1% pa	2.9% pa
Redbank Plains 11 CP	2.0% pa	3.1% 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 – Powerlink's forecasting methodology

This appendix describes Powerlink's demand and energy forecasting methodology. Powerlink is publishing its forecasting model with the 2018 Transmission Annual Planning Report (TAPR), which should be reviewed in conjunction with this description.

Powerlink's forecasting methodology for energy, summer maximum demand and winter maximum demand comprises the following three steps:

1. Transmission customer forecasts

   The loads of customers other than Energex and Ergon Energy that connect directly to Powerlink's transmission network are assessed based on their forecasts, recent history and through direct consultation. Only committed load is included in the medium economic outlook forecast, while some speculative load is included in the high economic outlook forecast.

2. Econometric regressions

   Forecasts are developed for Energex and Ergon Energy based on relationships between past usage patterns and economic variables where reliable forecasts for these variables exist.

3. New technologies

   The impact of new technologies such as rooftop photo voltaic (PV), distribution connected solar and wind farms, battery storage, electric vehicles (EV) and demand side management (DSM) are factored into the forecasts for Energex and Ergon Energy.

The discussion below provides further insight to steps 2 and 3, where Distribution Network Service Provider (DNSP) forecasts are developed.

Econometric regressions

DNSP forecasts are prepared for summer maximum demand, winter maximum demand and annual energy.

To prepare these forecasts, regression analysis is carried out using native demand and energy plus distribution connected solar PV which includes rooftop PV and distribution connected solar and wind farms as this represents the total underlying Queensland DNSP load. This approach is necessary as the regression process needs to describe all electrical demand in Queensland, irrespective of the type or location of generation that supplies it.

Data preparation

To undertake weather correction and regression analysis the following historical native energy and maximum demand values need to be assembled. as follows:

- *Energy*

  Determine DNSP native energy for each year from 2000/01. As this work is performed in April, an estimation is prepared for the current financial year which will be updated with actual totals 12 months later when preparing the next TAPR.

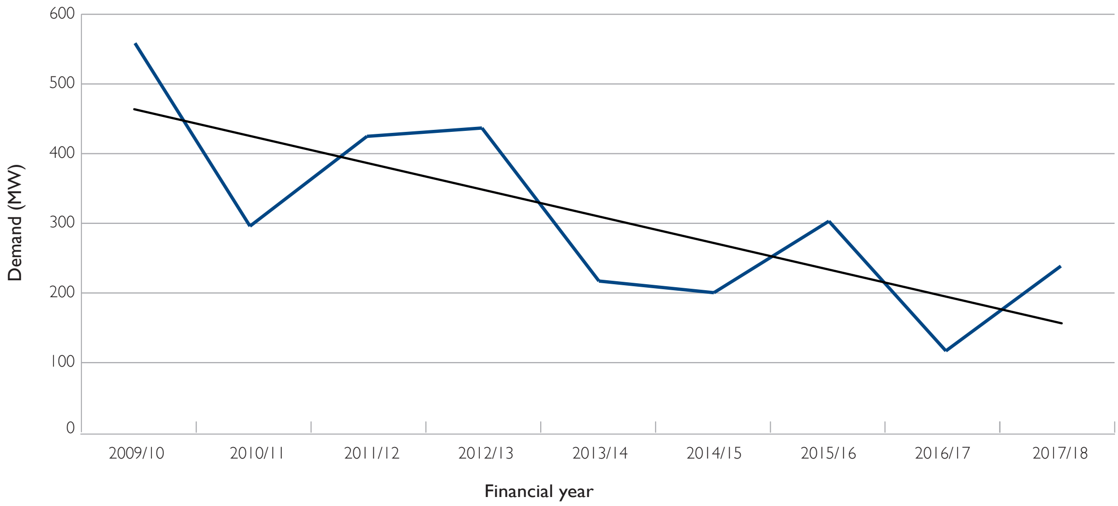
- *Winter maximum demand*

  The DNSP native demand at the time of winter state peak is collated for each year from winter 2000. Each of these demands are then normalised to average weather conditions (50% probability of exceedance (PoE)). Powerlink's method for weather correction is described later in this appendix.

- *Summer maximum demand*

  The DNSP native demand at the time of summer state peak is collated for each year from summer 2000/01. Each of these demands are then normalised to average weather conditions (50% PoE). DNSP native demand at the time of summer state evening peak (after 6pm) is also collated for each year from summer 2000/01. These demands are also corrected to average weather conditions. This evening series is used as the basis for regressing as evidence supports Queensland moving to a summer evening peak due to the increasing impact of rooftop PV and distribution connected solar farms. This move to an evening peak by 2022/23 is supported through analysis of day and evening trends for corrected maximum demand as illustrated in Figure B.1.

Figure B.1 Difference in summer day and summer evening normalised maximum demand



Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for existing rooftop PV and distribution connected solar farms. This ensures that the full underlying DNSP load is being regressed. This energy adjustment assumes that rooftop PV, on average, has a 14% capacity factor. This capacity factor is based on observations through the use of data sourced from the Australian PV Institute.

Following the regression for energy, the forecast is then adjusted to take into account future rooftop PV and distribution connected solar and wind farm contributions based on forecast capacity. Forecast summer maximum demand is now based on an evening regression adjusted for the transition to an evening peak. Winter maximum demand has historically occurred in the evening, so no adjustment needs to be applied.

Retail electricity price projections

Powerlink engaged an independent consultant to develop the Queensland retail electricity price projections for the 10-year forecast period for the 2018 TAPR. The price projection forecast includes a significant reduction over the next five years, which is much lower than the price projections assumed within the 2017 TAPR. The reduction in forecast retail price is attributed to the high quantities of renewable generation that have committed over the previous 12 months. The additional generation is expected to make the wholesale generation market within Queensland more competitive.

The demand and energy regression models have been modelled on flat retail electricity prices (2004/05 to 2006/07 and 2014/15 to 2017/18) and with rising retail electricity prices (2006/07 to 2014/15). The 14 years of historical data that defines the forecasting regression models, do not include any years where the retail electricity prices are falling. As a result there is no quantitative data on how the demand and energy will respond to falling electricity prices. Without intervention the impact on the regression models to falling prices will be the reverse of the damping effect that rising electricity prices have had on the demand and energy forecast in the past. However, it is expected that electricity consumers will generally maintain their energy efficiency behaviours, implying that there is an asymmetrical effect of rising and falling electricity prices on the demand and energy forecast.

Powerlink has explored the asymmetrical concept of electricity pricing with AEMO and some members of Powerlink's Customer Panel. Feedback from members of Powerlink's Customer Panel includes:

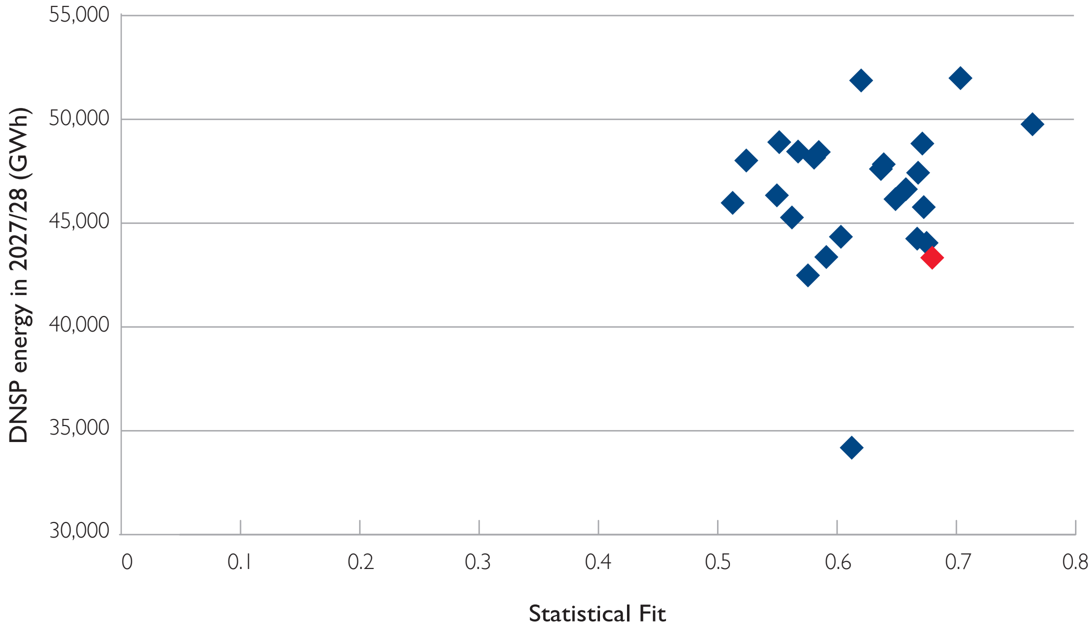
- Customers are conditioned to rising electricity prices and generally consumption is not expected to increase.
- Older consumers will continue with their current consumption patterns and won't change their behaviour, even if there is a significant reduction in prices. Reference was made to water saving programs in several jurisdictions e.g. Victoria, Queensland and Australian Capital Territory where consumers changed their consumption patterns permanently even after water restrictions were lifted.
- People on low incomes will not increase consumption and any savings will be used elsewhere.
- Consumers don't have confidence in energy companies. They won't trust that prices will stay down, and will be suspicious that there will be extraordinary price rises in subsequent years to make up for an initial price reduction. They will not feel sufficiently confident to change behaviour.
- Many consumers have put in place measures to reduce energy consumption, and these tend to be permanent in nature.
- Majority of people find it difficult to compare retail offers and 'crunch the numbers'.
- There is a lack of education on electricity billing and pricing.
- Business will react to electricity price changes before residential households.
- Both AEMO and Powerlink acknowledge the asymmetrical effects that rising and reducing retail electricity prices have on the demand and energy forecast. With falling electricity prices, lower income households (seniors, disadvantaged and vulnerable) are not expected to materially change their consumption behaviours, however more affluent households may slightly increase their consumption.

Energy regression

An energy regression is developed using historical energy data (described above) as the output variable and total retail electricity price and an economic variable for inputs. A logarithmic relationship between the input and output variables is used in keeping with statistical good practice in energy forecasting.

Input variables are the total retail electricity price and an economic variable selected from 16 economic variables (supplied by consultants). For each of these 16 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 64 regressions being assessed. Of these, the top 25 are selected and placed on a scatter plot as shown in Figure B.2 where the statistical fit and energy forecast at the end of the forecast period are assessed. The statistical fit combines several measures including R-squared, Durbin-Watson test for autocorrelation, mean absolute percentage error and mean bias percentage. All top 25 regressions shown in Figure B.2 qualify as statistically good regressions.

Figure B.2 Energy regression results



The selected regression shown above in red uses Queensland employment with no delay and total electricity price with a one year delay. The selected regression was chosen as it uses broad based input variables and reflects the expected outcome of asymmetrical pricing effects with reducing electricity prices. The 2017 TAPR energy regression used Queensland retail turn-over with no delay and total electricity price with a one year delay.

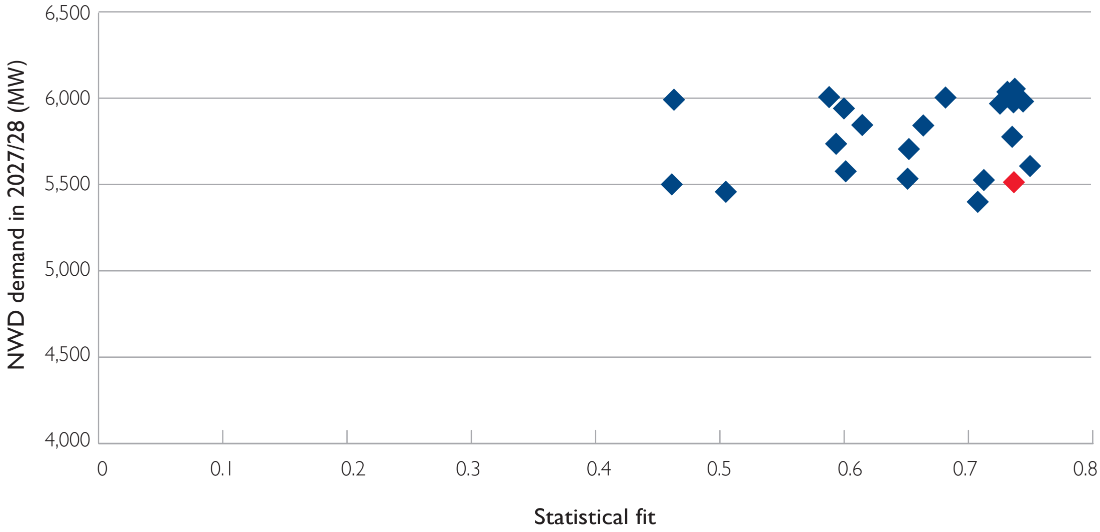
The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The temperature-normalised historical demands are split into two components: non-weather dependent (NWD) demand and weather dependent (WD) demand. NWD demand is determined as the median weekday maximum demand in the month of September. This reflects the low point in cooling and heating requirements for Queensland. The balance is the WD demand. For summer, this is the difference between the corrected summer maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected winter maximum demand and the NWD demand based on the following September.

The forecast NWD demand is therefore used for both the summer and winter maximum demand forecasts. The regression process used to determine the NWD demand is the same as used for energy with the results illustrated in Figure B.3.

Figure B.3 Non-weather dependent demand regression results

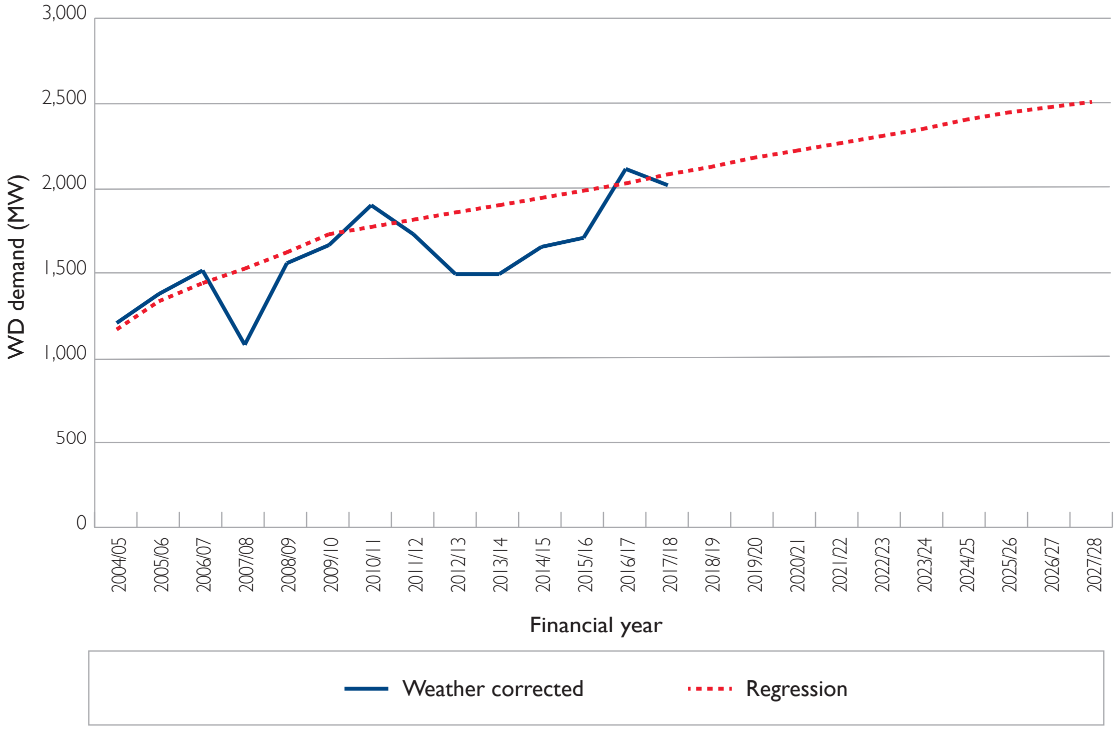


The selected regression shown above in red uses Queensland employment with no delay and total electricity price with a one year delay. The 2017 TAPR NWD regression used Queensland retail turnover and total electricity price both with a one year delay.

The summer and winter WD demand is mainly related to air conditioning usage. These regressions have been based on one input variable, the population multiplied by Queensland air conditioning penetration. Historical air conditioning penetration rates and consumer intensions to purchase air conditioners are provided annually in the Queensland Household Energy Survey (QHES).

The 2016/17 and 2017/18 summer WD demand was substantially higher than the previous four summers. A number of troughs for the summer WD demand have been recorded, these include summer 2007/08 and the period from 2011/12 to 2015/16. Summer 2007/08 aligns with the initial shock of the Global Financial Crisis (GFC) and the period from 2011/12 to 2015/16 aligns with high electricity price increases from about 2009. The QHES results indicate that households were more frugal in their electricity behaviours from 2011 to 2015 and that this behaviour has been tempered from 2016. The summer WD demand regression is illustrated in Figure B.4, with the years impacted by the GFC and high price increases removed from the regression.

Figure B.4 Weather dependent demand regression – summer



Similar to the energy analysis, low, medium and high economic outlook forecasts are produced for maximum demands by applying the appropriate economic forecasts as inputs. For maximum demand it is also necessary to provide three seasonal variation forecasts for each of these economic outlooks leading to nine forecasts in total. 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.

New technologies

Understanding the future impacts of new technologies is crucial to developing robust and meaningful demand and energy forecasts. Recognising the importance that these technologies will play in shaping future demand and energy, Powerlink is committed to furthering its understanding of these drivers. The new technologies discussed in this section are not incorporated within the energy regression and the summer and winter maximum demand regressions. To include these new technologies, post regression adjustments are made to the DNSP demand and energy forecasts. The new technology adjustments that Powerlink has adopted within the forecasts are summarised in Table B.1.

Table B.1 New technology assumptions

	Rooftop PV	Distribution connected solar and wind farms	Battery storage	Electric vehicles	Tariff reform/ DSM	Customer momentum
Energy (GWh) (1)	2,589	4,244	0	-311	0	1,804
Maximum demand (MW) (2)	0	0	16	0	180	215
Installed capacity in 2027/28 (MW)	4,175	1,583				
Installed capacity in 2027/28 (MWh)			74			
First year of impact	now	now	now	now	2020/21	2018/19

Notes:

(1) This is the energy reduction in financial year 2027/28 compared to 2017/18.

(2) This is the maximum demand reduction in summer 2027/28 compared to summer 2017/18.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow readers to substitute alternative assumptions into the forecast if desired.

Rooftop PV

The installed capacity of rooftop PV in Queensland as at the end of 2017 was in the order of 2,000MW. Growth in rooftop PV capacity has increased from around 15MW per month in 2016/17 to 25MW per month in 2017/18. However the forecast of reducing electricity prices will extend the payback period of new rooftop PV and this is expected to decrease the rate of new capacity over the forecasting period. New rooftop PV capacity is forecast to remain at 25MW per month in 2018/19 before reducing and remaining at 15MW per month from 2020/21.

Analysis has revealed that Queensland will move to a summer evening peak by 2022/23 and so further rooftop PV, which is predominantly installed facing north, is expected to have little impact on maximum demand after this time. Energy impacts have been based on an average output of 14% capacity.

Powerlink is a member of the Australian PV Institute which supplies real time data for rooftop PV. This information allows Powerlink to analyse a range of effects and in particular its impact on maximum demand.

Future impacts of rooftop PV will need to be monitored carefully. As older systems fail, they may be replaced with larger systems or not replaced at all. Furthermore, if enabling factors such as government incentives or rapid uptake of battery storage were to occur, then future rooftop PV installation levels could increase beyond this forecast.

Distribution connected solar farms

The federal government's large-scale renewable energy target (LRET) of 33,000GWh per annum by 2020 and the Queensland government's target of 50% renewable energy by 2030 are driving forecast increases of renewable generation connecting directly to the distribution networks. Previous TAPRs did not model the Queensland government's target of 50% renewable energy by 2030.

The energy forecast includes 654MW of committed semi-scheduled solar farms and 107MW of committed semi-scheduled wind farms to connect to the distribution networks. This is 75% of the committed renewable generation connecting to the distribution networks within Table 6.2. The energy forecast also includes 98MW of committed non-scheduled solar farms connecting to the distribution networks over the next two years.

Solar farms connecting directly to the distribution network will accelerate the delay of the state maximum demand from around 5:30pm to an evening peak.

Battery storage

Battery storage technology has the potential to significantly change electricity consumption patterns. In particular, this technology could 'flatten' electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks. By coupling this technology with rooftop PV, consumers may have the option to go 'off grid'. A number of factors will drive the uptake of this technology, namely:

- affordability
- retail electricity prices
- introduction of time of use tariffs
- continued uptake of rooftop PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

The 2017 QHES indicates that around 8% of Queensland households are considering the purchase of a battery storage system. However the same survey indicates that most people underestimate the current price of installing a storage solution.

The forecast of reducing electricity prices will extend the payback period of battery storage systems and delay the uptake of new systems. As a consequence, the forecast capacity of battery storage systems at the end of the 10-year forecasting period has been significantly reduced within the 2018 TAPR. Powerlink's methodology to estimate the uptake of battery storage and the impact on summer maximum demand involves the following steps:

1. Estimate the maximum population of residential battery storage systems, based on dwelling type, home ownership, and household income factors. This is estimated to be 400,000 households.
2. Bell curved the uptake of battery storage systems based on the financial payback period, with a mean of five years and a standard deviation of 1.75 years.
3. Calculate the pay-back period for a market leading battery storage system for each year in the 10-year outlook period. The installation price of future battery storage systems was estimated using CSIRO's battery cost path from their electricity network transformation roadmap interim program report.
4. From the bell curve of battery uptake (based on the financial payback period) and the calculated yearly payback period of a battery system, calculate the uptake of battery storage systems. Multiply the yearly uptake by the predicted average size of a battery storage system (10kWh), to calculate a predicted yearly uptake in MWh.
5. Calculate the yearly maximum demand reduction by taking into account the maximum discharge rate of the fleet of battery storage systems (a MW figure equivalent to 37% of the energy storage capacity) and the proportion of systems that are expected to be discharging at the time of summer maximum demand (assumed to be 60%).

Electric vehicles

The uptake of EVs in Australia is low compared to world leading countries such as Norway and the Netherlands. Without government policy support for the adoption of EVs, uptake is expected to be limited in the short-term. The availability of affordable EVs assisted by the expected reduction in battery costs will likely lift EV sales in the medium to longterm.

Powerlink has adopted the neutral uptake scenario from the Electric Vehicle Insights paper[1] prepared in September 2017 by Energeia for Australian Energy Market Operator (AEMO).

It is estimated that a 1% penetration of electric vehicles on the road would result in approximately 0.2% increase in total energy usage.

[1] Available on AEMO's website

It is expected that most owners will charge their electric vehicles during off peak periods, resulting in minimal increase in maximum demand. Therefore, Powerlink has not included a specific adjustment for electric vehicles in its maximum demand forecast.

Tariff reform and demand side management

Network tariff reforms could influence consumer behaviour, shifting energy usage away from peak times. In addition to this maximum demand reduction, it is anticipated that network tariff reforms could also influence future use of battery storage technology, encouraging consumers to draw from batteries during maximum demand or high price times. The extent to which this occurs will depend on how quickly new tariffs are offered, the tariff structure and the adoption rate.

> *'In Australia and internationally there is evidence that customers will significantly reduce their demand in response to well-designed price signals that reward off-peak use and peak demand management. Sixty percent of trials internationally have resulted in peak reductions of 10 per cent or more.'*[2]

A challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies could meet with resistance. Some of this peak reduction is already captured through the battery storage allowance described above. An additional 180MW has been assumed within this forecast and represents a further 2% reduction in the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy consumption is expected to be negligible.

Customer momentum factor

Over the last 10 years, many customers have been purchasing appliances with higher energy efficiency ratings and adopting more energy efficient behaviours in an effort to minimise financial impacts. The electricity price metric used in the regression model is forecast to decrease by 34% over the next five years and then low growth is forecast for the last five years of the forecasting horizon. The logic hardwired within the regression model suggests that customers will change their behaviour in response to falling electricity prices.

To allow for this effect, a customer momentum factor has been developed and is explicitly incorporated within the energy and non-weather dependent demand regressions. The impact of price on electricity usage is determined for the last 10 years. Rather than simply accepting the regression model's prediction for the next 10 years, a weighting of two thirds has been applied. This results in a dampening effect, limiting the 'bounce-back' in energy and demand with the forecast reduction of electricity prices.

It is expected that this factor will be reduced or removed in future years as additional information on customers' actual behaviour during falling and moderating electricity prices is captured in the data series.

Weather correction methodology

Maximum demand is strongly related to the temperature. To account for the natural variation in the weather from year to year, temperature correction is carried out to normalise raw demand observations. Three conditions are calculated:

- 10% PoE demand, corresponding to a one in 10-year season (i.e. a particularly hot summer or cold winter)
- 50% PoE demand, which indicates what the demand would have been if it was an 'average' season
- 90% PoE demand, corresponding to a nine in 10-year season (particularly mild weather).

Within each year, separate temperature corrections are calculated for extended summer and extended winter seasons. For the purposes of weather correction, summer is defined as November to March and winter is taken as May to August.

Temperature correction is applied to historical metered load supplied to connection points with Ergon and Energex. Powerlink's other direct-connect customers are largely insensitive to temperature.

[2] Towards a National Approach to Electricity Network Tariff Reform (page 6) – ENA Position Paper December 2014.

Powerlink's temperature correction process is described below:

Develop composite temperature

The temperature from multiple weather stations is combined to produce a composite temperature for all of Queensland. The weighting of each weather station is based on the proportion of Energex and Ergon-supplied load in the vicinity of that weather station.

Exclude mild days and holidays

To ensure that the fitted model accurately describes the relationship between temperature and maximum demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are excluded from the dataset.

Calculate a regression model for each season since 2000

A regression model is calculated for each summer since 2000/01 and winter since 2000, expressing the daily maximum demand as a function of: daily maximum temperature, daily minimum temperature, daily 6pm temperature, and whether the day is a weekday.

For each season, determine the 10% and 50% PoE thresholds using 23 years of weather data

The regression model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the maximum demand would have been on each day if the relationship between maximum demand and temperature described by the model had existed at the time. A Monte-Carlo approach is used to incorporate the standard error from each season's regression model. The maximum demand calculated for each of the 23 years is recorded in a list, and the 10th, 50th and 90th percentile of the list is calculated to determine the 10% PoE, 50% PoE and 90% PoE thresholds.

Final Scaling to avoid bias

To ensure that temperature correction process does not introduce any upward or downward bias, for each summer since 2000/01 and winter since 2000, the ratio of the calculated 50% PoE threshold to the actual maximum demand is calculated. The calculated PoE thresholds are divided by the average of these ratios.

Applying this methodology, the 2017/18 summer peak day was hotter than average. Therefore, the 50% PoE demand is 265MW lower than the observed maximum demand on 14 February. The 2017 winter peak day was warmer than average, resulting in an upwards adjustment of 276MW to the observed winter maximum demand.

Appendix C – Estimated network power flows

This appendix illustrates 18 sample power flows for the Queensland region for each summer and winter over three years from winter 2018 to summer 2020/21. Each sample shows possible power flows at the time of winter or summer region 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2, with a range of import and export conditions on the Queensland/New South Wales Interconnector (QNI) transmission line.

The dispatch assumed is broadly based on historical observed dispatch of generators.

Sample conditions[1] include:

Figure C.3	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2019 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2019 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2019 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2020 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2020 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2020 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2019/20 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2020/21 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2020/21 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2021/21 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at the Gladstone South end of Callide A to Gladstone South 132kV double circuit. These open points can be closed depending on system conditions.

Table C.1 provides a summary of the grid section flows for these sample power flows and the limiting conditions capable of setting the maximum transfer.

Table C.2 lists the 275kV transformer nameplate capacity and the maximum loading of the sample power flows.

Figures C.1 and C.2 provide the generation, load and grid section legends for the subsequent figures C.3 to C.20. The reported generation and load is the transmission sent out and transmission delivered defined in Figure 2.4.

[1] The transmission network diagrams shown in this appendix are high level representations only, used to indicate zones and grid sections.

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
FNQ Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)	166/166/166	124/124/124	127/127/127	243/243/243	246/246/246	254/254/254	V
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)	695/695/695	655/654/654	664/665/665	931/931/931	933/933/933	952/952/952	Th V
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)	505/429/390	519/446/397	415/395/399	379/380/382	389/390/393	387/388/391	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) (6) Calliope River into Gin Gin 275kV (2 circuits) (6) Calvale into Halys 275kV (2 circuits)	1,539/1,845/2,032	1,537/1,843/2,067	1,961/2,060/2,059	1,753/1,753/1,753	1,747/1,747/1,747	1,754/1,754/1,754	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	564/564/564	586/586/586	589/589/589	527/527/527	540/540/540	571/571/571	V
SWQ Western Downs to Halys 275kV (2 circuits) (7) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,051/760/651	1,021/725/579	1,009/915/987	1,718/1,717/1,747	1,706/1,707/1,746	1,775/1,778/1,817	(5)

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions *(continued)*

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
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)	3,034/2,876/2,843	3,091/2,933/2,880	2,919/2,865/2,927	3,749/3,747/3,777	3,805/3,803/3,833	3,858/3,858/3,887	V
Gold Coast Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	697/697/760	703/703/766	710/710/773	844/844/875	852/852/883	855/855/886	V

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) Grid power flows are derived from the assumed generation dispatch cases shown in figures C.3 to C.20. The flows estimated for system normal operation are based on the existing network configurations and committed projects. Power flow across each grid section can be higher at times of local zone peak.

(3) All grid section power flows shown are within network capability.

(4) Tr = Transient stability limit, V = Voltage stability limit and Th = Thermal plant rating.

(5) As stated in Section 6.6.6, SWQ grid section is not expected to impose limitations to power transfer under intact system conditions with the existing levels of generating capacity.

(6) Applies by summer 20/21 after the Gin Gin Substation rebuild. CQSQ cutset redefined following Gin Gin Substation rebuild in summer 2020/21. Wurdong into GinGin 275kV becomes Wurdong to Teebar Creek 275kV. Calliope River into Gin Gin 275kV becomes Calliope River to Gin Gin/Woolooga 275kV.

(7) Coopers Gap connects to a Western Downs to Halys circuit from winter 2019.

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers

275kV substation (1)(2)(3)(4)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
(Number of transformers x MVA nameplate rating)		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	15	27	17	25	26	29	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	119	147	133	229	229	234	Barron Gorge generation	Kareeya and Ross zone generation
Ross 275/132kV (3x250MVA)	R	236	160	160	238	243	252	Ross zone generation	North zone generation
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	270	266	269	315	316	316	Mackay GT generation	North zone generation
Strathmore 275/132kV (1x375MVA)	N	123	123	122	155	150	153	Invicta and North zone generation	Ross zone generation
Bouldercombe 275/132kV (1x200MVA and 1x375MVA)	CW	144	146	147	168	169	168		
Calvale 275/132kV (1x250MVA)	CW	131	138	120	167	146	148	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	188	184	198	195	212	217	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132 kV (2x375MVA)	G	49	47	43	50	49	47	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	151	163	165	151	161	150		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	89	87	85	75	78	83	Wide Bay zone embedded generation	CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	231	235	236	232	233	236		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	165	162	147	176	150	141	Surat zone generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	310	319	328	292	296	296	Oakey generation	

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

275kV substation (1)(2)(3)(4) (Number of transformers x MVA nameplate rating)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	42	45	41	20	33	33	Surat zone generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	35	36	36	41	42	41		
Abermain 275/110kV (1x375MVA)	M	153	155	150	188	190	192	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250MVA and 2x375MVA)	M	442	434	450	538	541	553	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250MVA and 1x240MVA)	M	176	178	177	219	220	225		
Goodna 275/110kV (1x375MVA)	M	145	147	151	186	187	189	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	379	382	385	464	469	473	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	354	357	361	431	437	442		
Palmwoods 275/132kV (2x375MVA)	M	308	321	311	354	358	370		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	336	340	345	418	424	415	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Blackstone and Swanbank E generation
South Pine East 275/110kV (3x375 MVA)	M	573	590	580	679	689	690		
South Pine West 275/110kV (1x375MVA and 1x250MVA)	M	255	262	260	305	310	307		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	466	474	479	547	554	559	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector

275kV substation (1)(2)(3)(4)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
(Number of transformers x MVA nameplate rating)		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Mudgeeraba 275/110kV (3x250MVA)	GC	325	329	331	374	378	381	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea

Notes:

(1) Not included are 275/132kV tie transformers within the Calliope River Substation. Loading on these transformers varies considerably with local generation.

(2) Not included are 330/275kV transformers located at Braemar and Middle Ridge substations. Loading on these transformers is dependent on QNI transfer and south west Queensland generation.

(3) To protect the confidentiality of specific customer loads, transformers supplying a single customer are not included.

(4) Nameplate based on present ratings. Cyclic overload capacities above nameplate ratings are assigned to transformers based on ambient temperature, load cycle patterns and transformer design.

(5) Zone abbreviations are defined in Appendix A.

(6) Substation loadings are derived from the assumed generation dispatch cases shown within figures C.3 to C.20. The loadings are estimated for system normal operation and are based on the existing network configuration and committed projects. MVA loadings for transformers depend on power factor and may be different under other generation patterns, outage conditions, local or zone maximum demand times or different availability of local and dowstream capacitor banks.

(7) Substation loadings are the maximum of each of the northerly/zero/southerly QNI scenarios for each year/season shown within the assumed generation dispatch cases in figures C.3 to C.20.

(8) Under outage conditions the MVA transformer loadings at substations may be lower due to the interconnected nature of the subtransmission network or operational switching strategies.

Figure C.1 Generation and load legend for figures C.3 to C.20

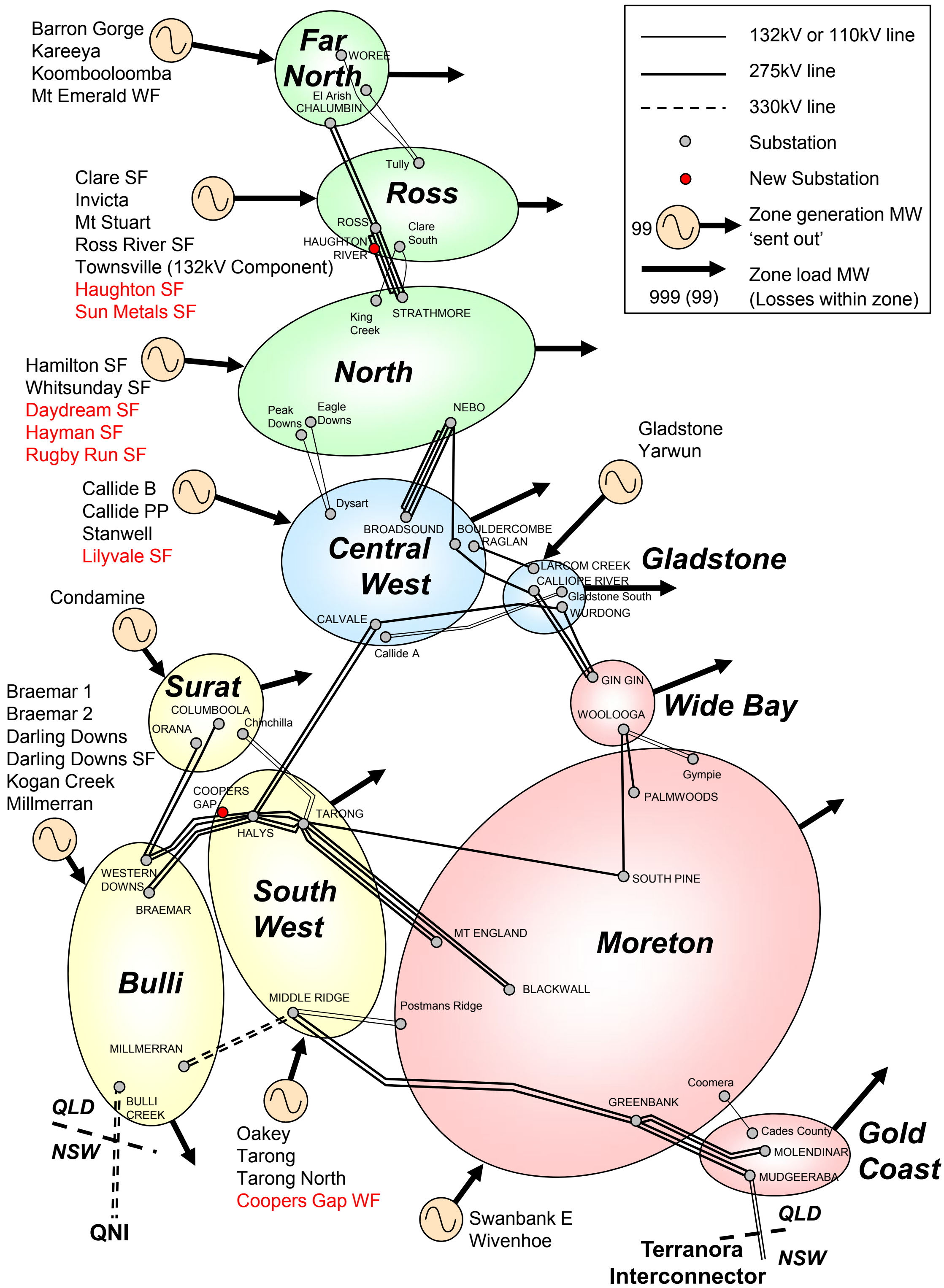


Figure C.2 Generation and load legend for figures C.3 to C.20

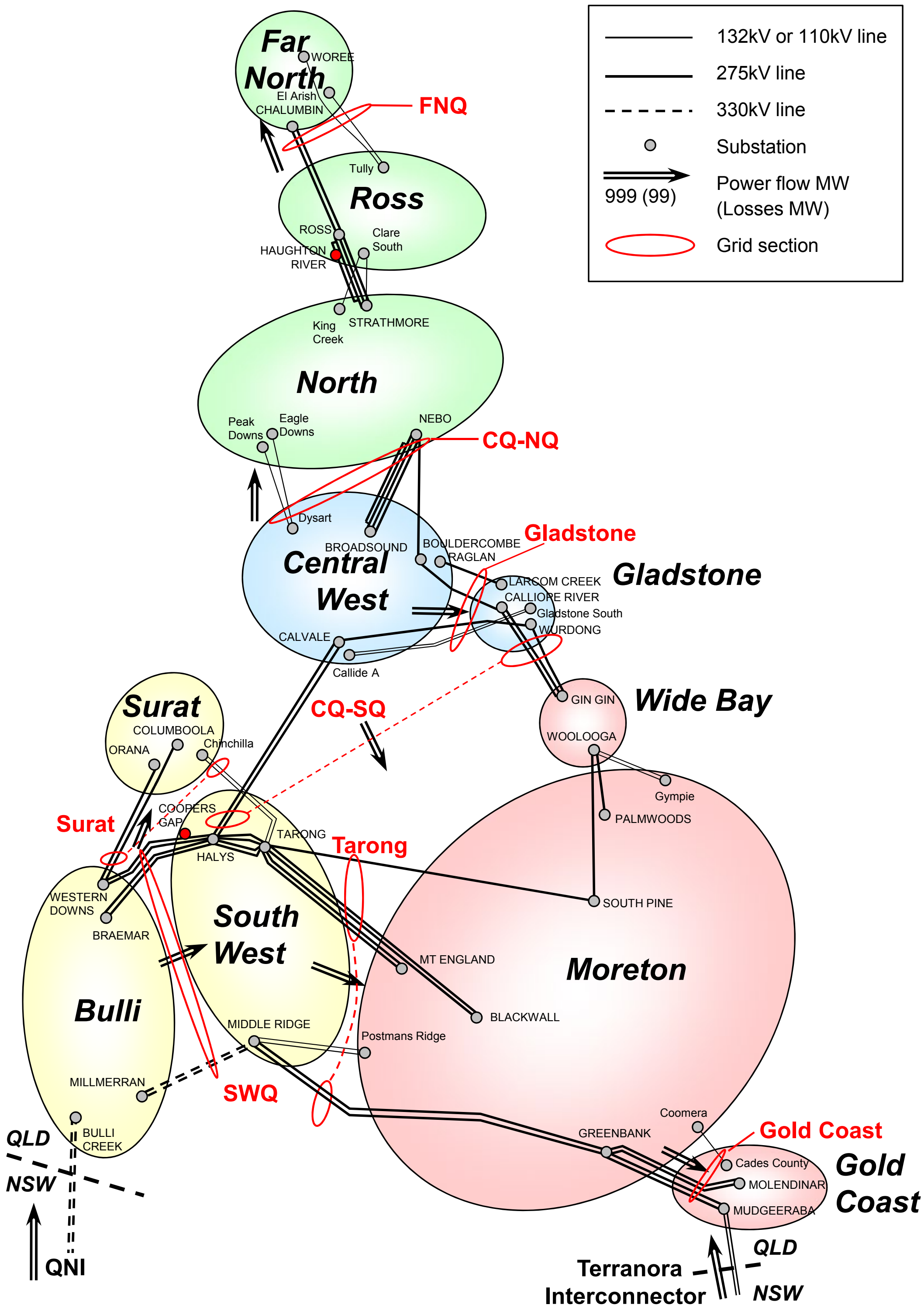
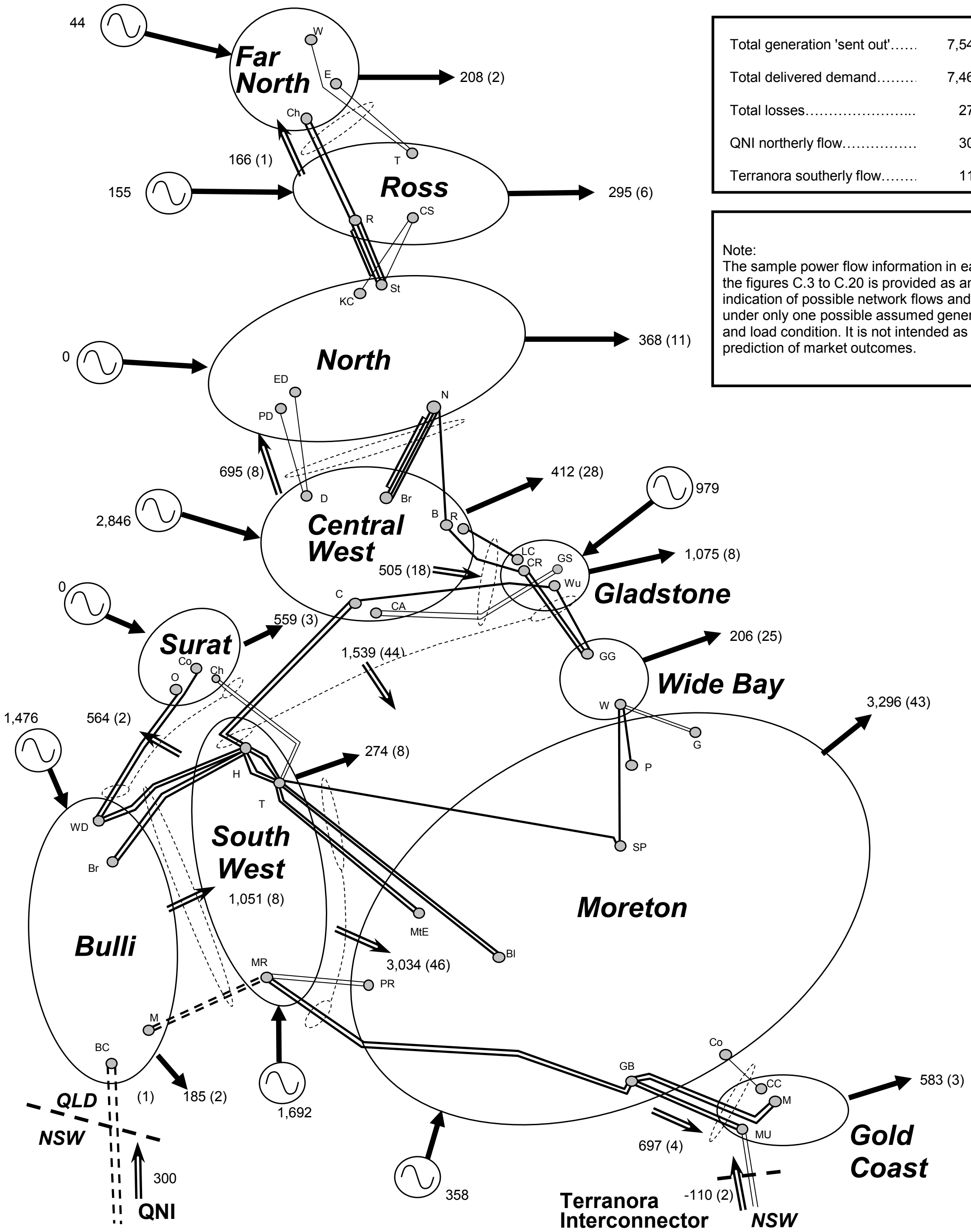


Figure C.3 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'......	7,549 MW
Total delivered demand.........	7,461 MW
Total losses........................	278 MW
QNI northerly flow................	300 MW
Terranora southerly flow........	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.4 Winter 2018 Queensland maximum demand 0MW QNI flow

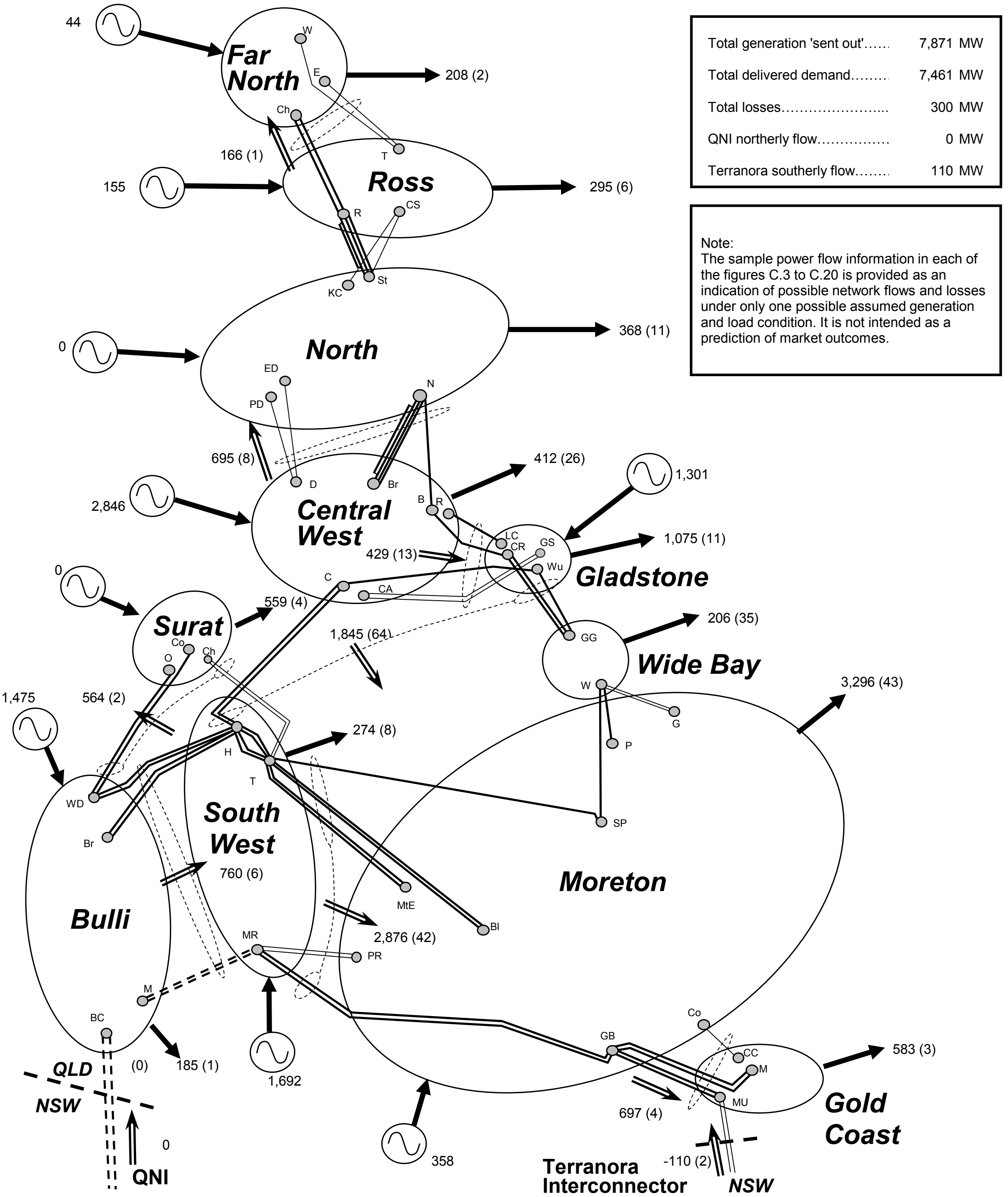


Figure C.5 Winter 2018 Queensland maximum demand 700MW southerly QNI flow

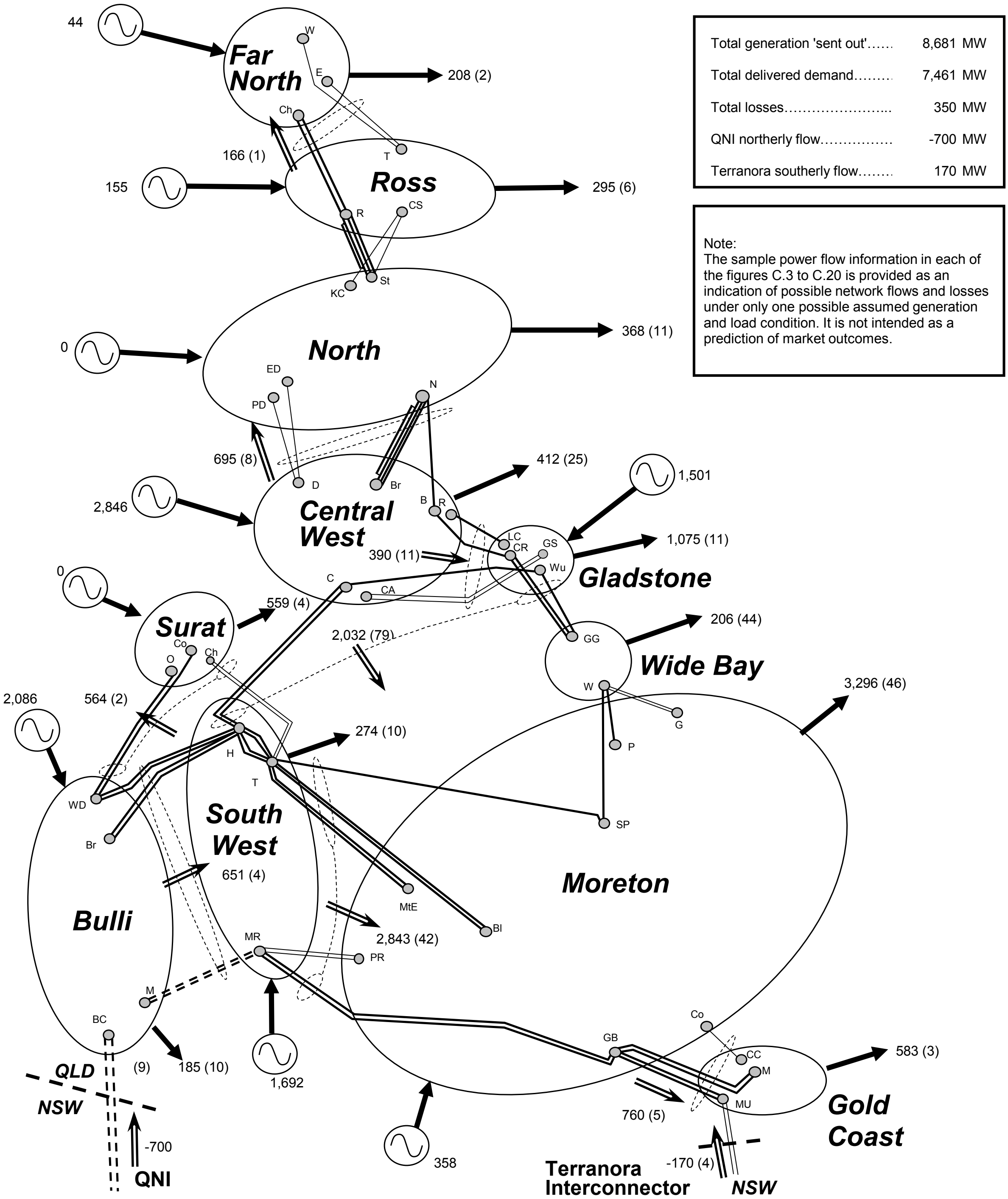


Figure C.6 Winter 2019 Queensland maximum demand 300MW northerly QNI flow

Total generation 'sent out'......	7,667 MW
Total delivered demand........	7,572 MW
Total losses........................	284 MW
QNI northerly flow................	300 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

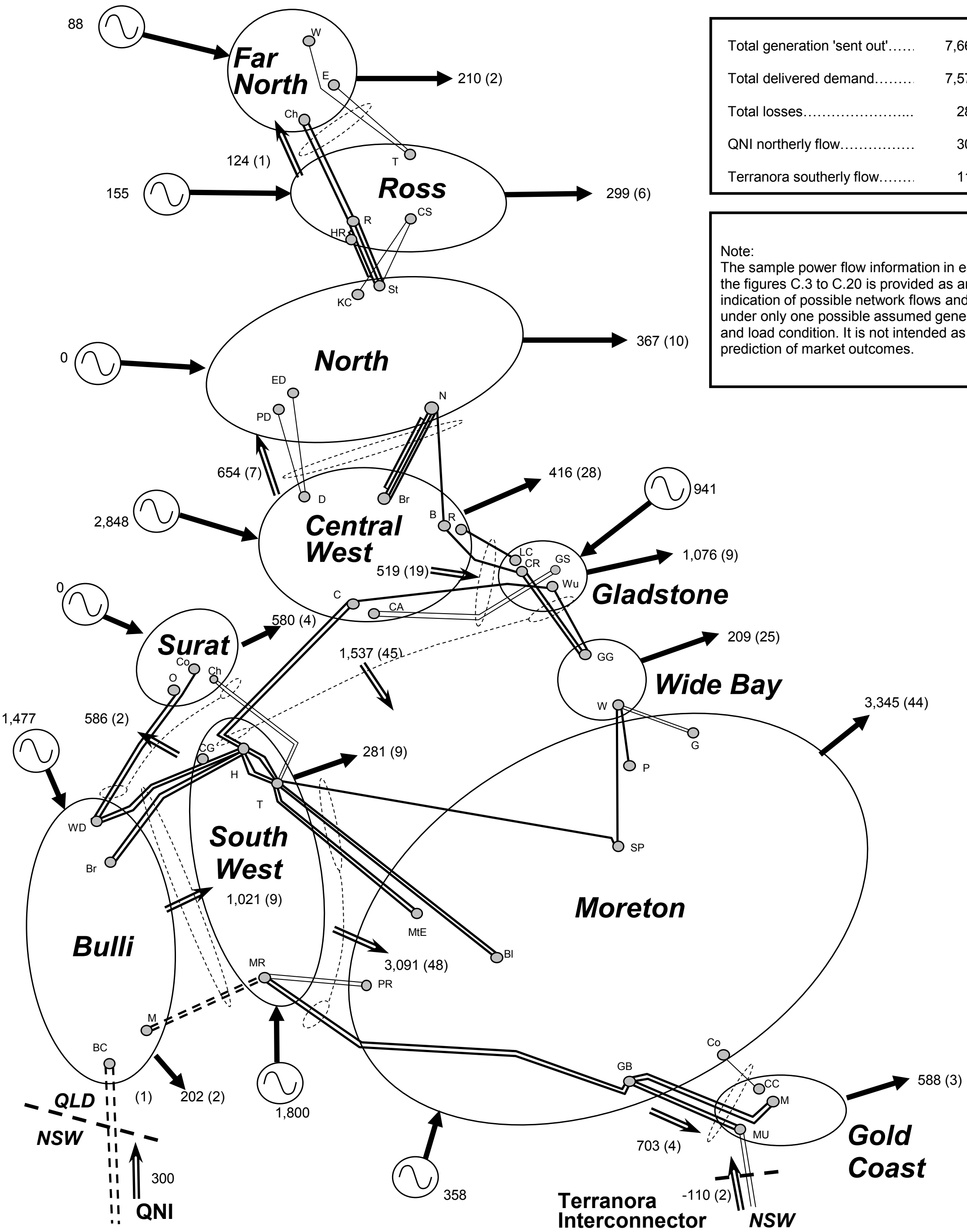


Figure C.7 Winter 2019 Queensland maximum demand 0MW QNI flow

Total generation 'sent out'……	7,985 MW
Total delivered demand………	7,572 MW
Total losses…………………….	303 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

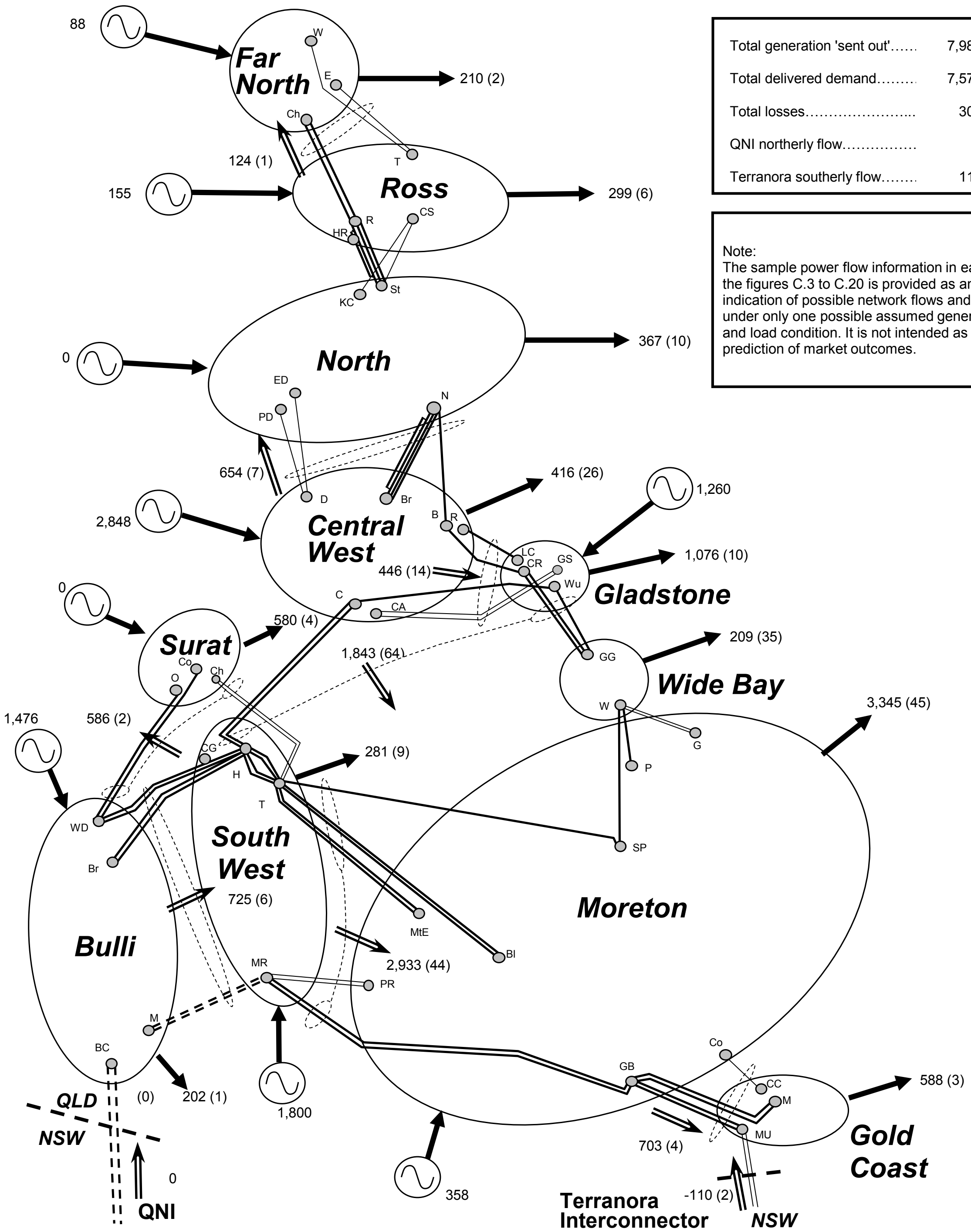
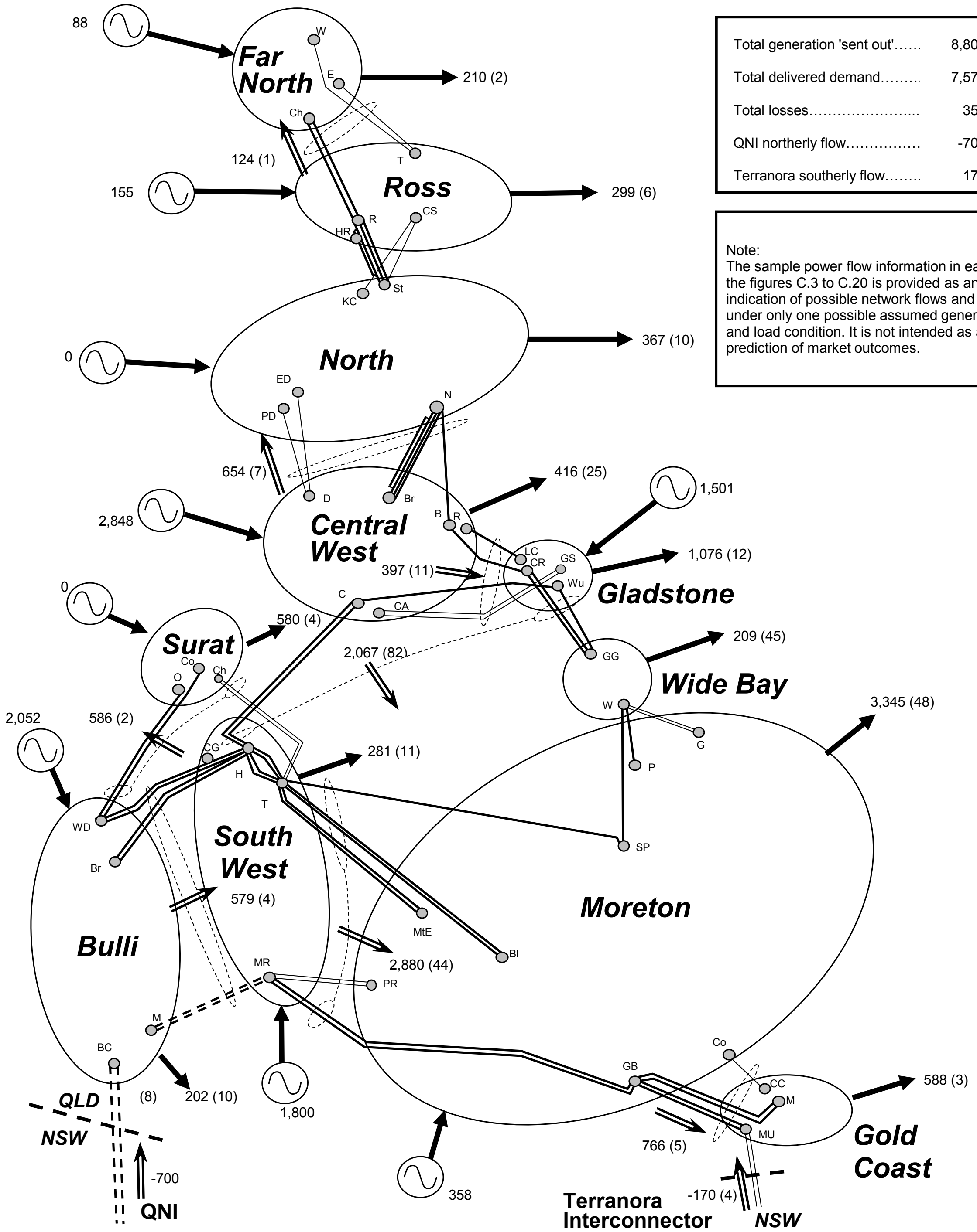


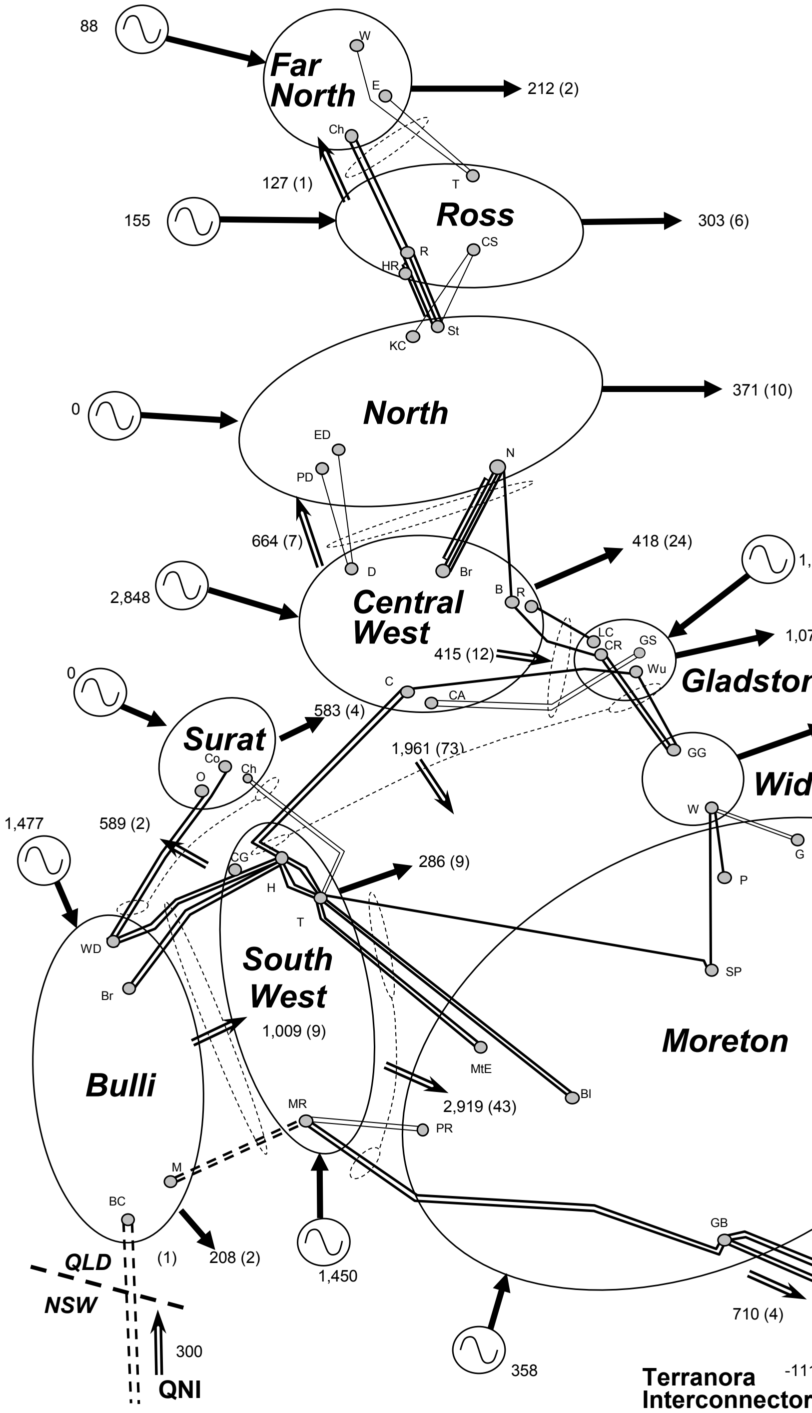
Figure C.8 Winter 2019 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,801 MW
Total delivered demand……..	7,572 MW
Total losses…………………….	358 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow…….	170 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.9 Winter 2020 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'……	7,770 MW
Total delivered demand………	7,637 MW
Total losses…………………….	322 MW
QNI northerly flow…………….	300 MW
Terranora southerly flow……..	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.10 Winter 2020 Queensland maximum demand 0MW QNI flow

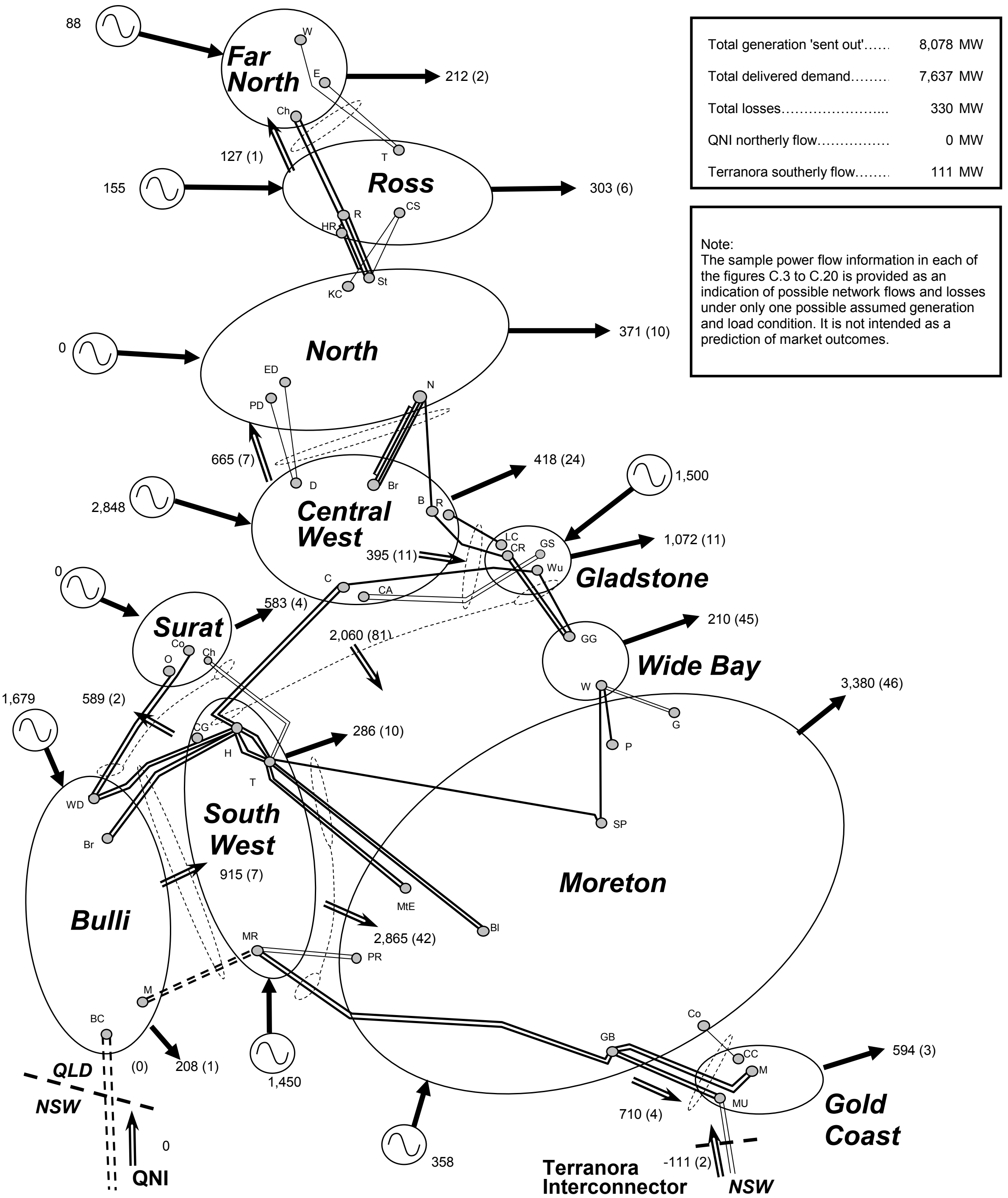
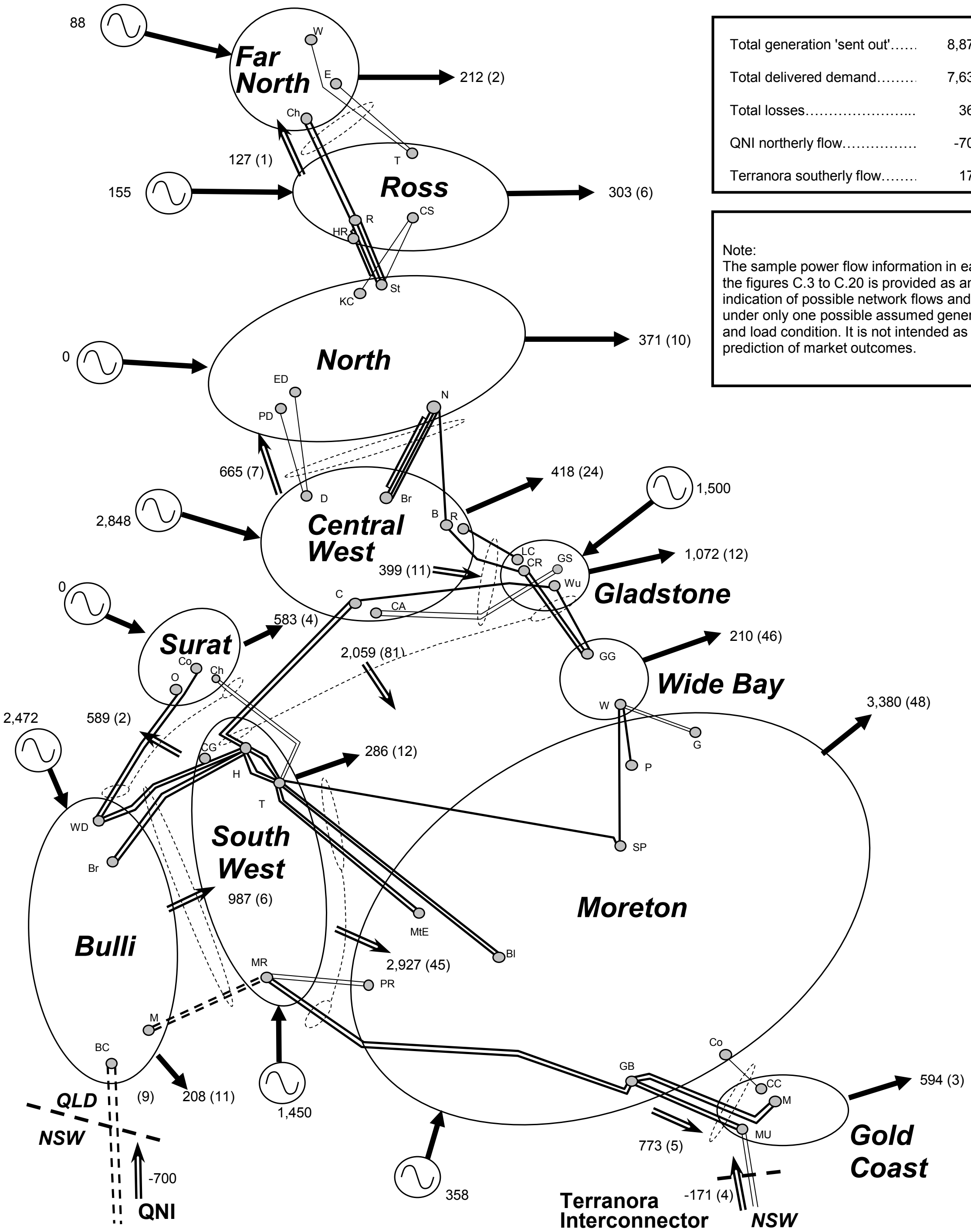


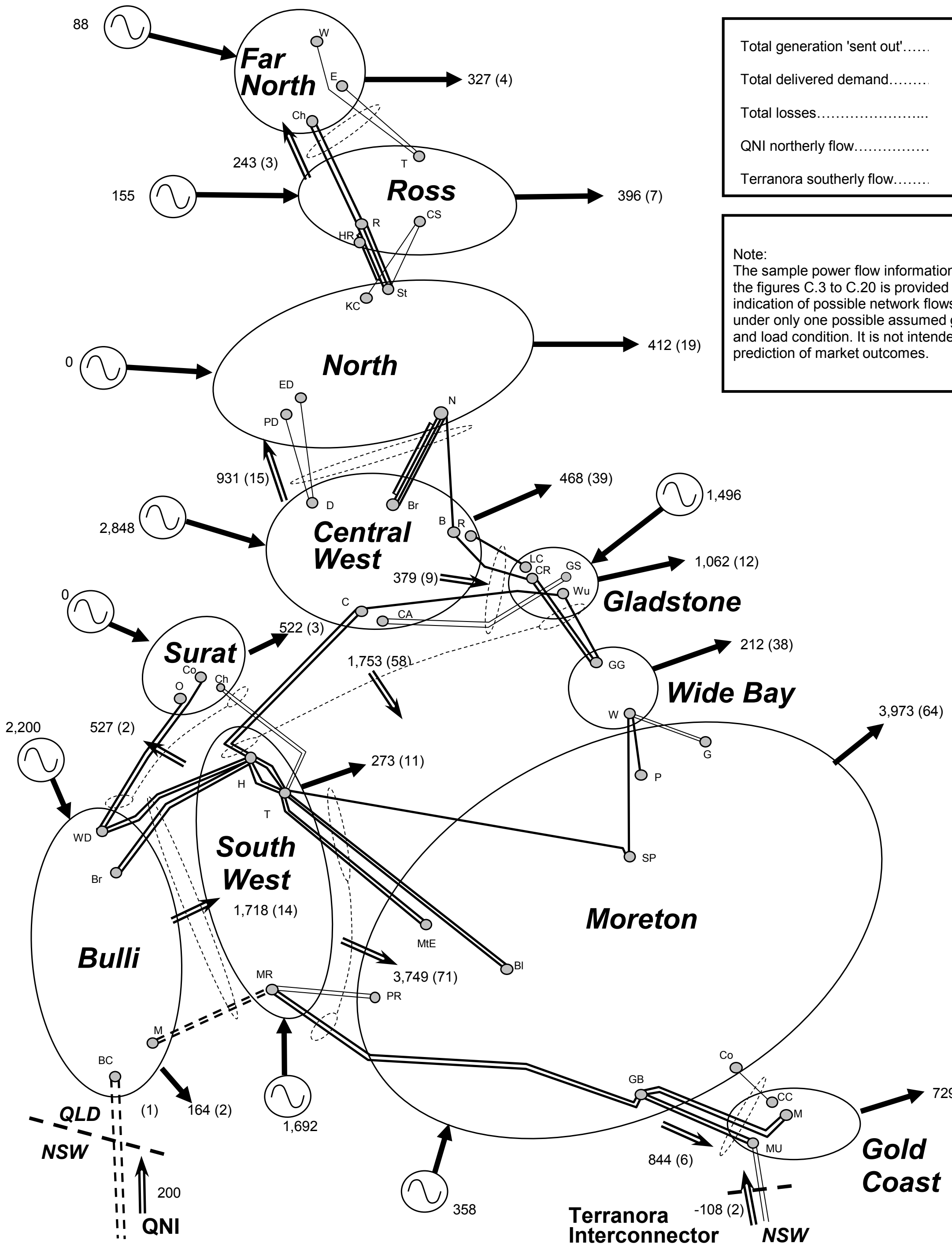
Figure C.11 Winter 2020 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,872 MW
Total delivered demand………	7,637 MW
Total losses…………………….	364 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow……..	171 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.12 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'……	8,835 MW
Total delivered demand……..	8,538 MW
Total losses…………………..	389 MW
QNI northerly flow…………….	200 MW
Terranora southerly flow…….	108 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.13 Summer 2018/19 Queensland maximum demand 0MW QNI flow

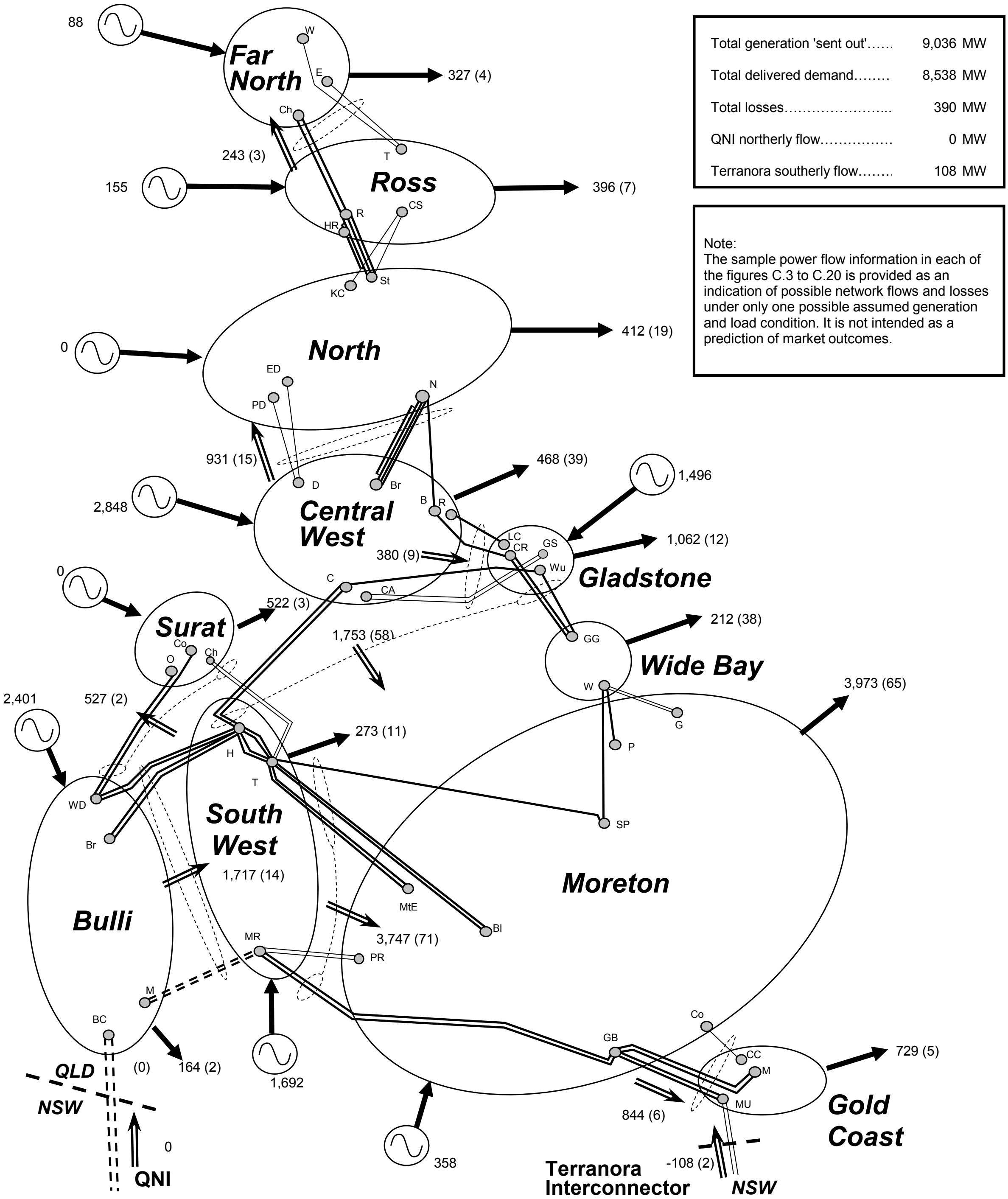
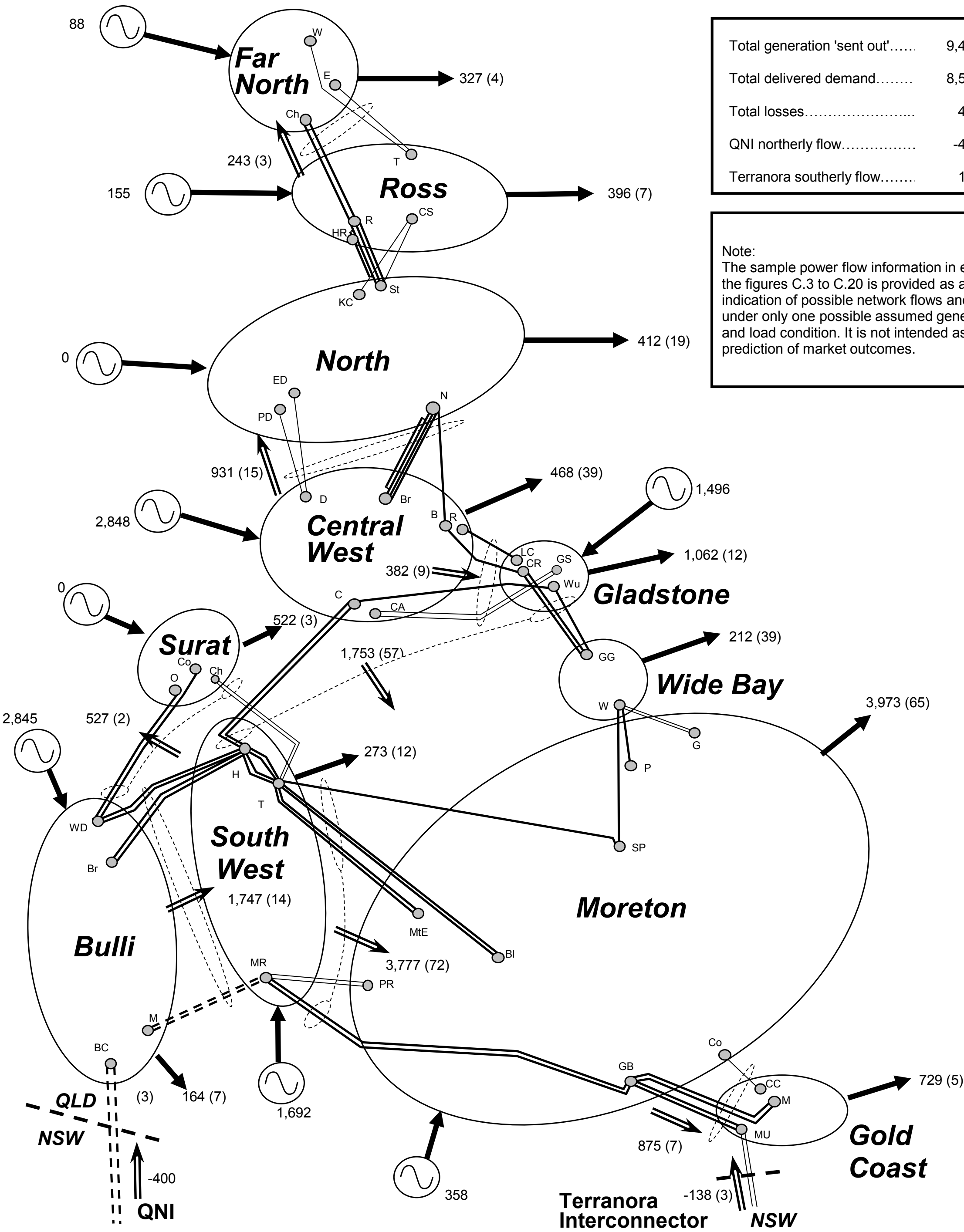


Figure C.14 Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'……	9,480 MW
Total delivered demand……..	8,538 MW
Total losses…………………..	404 MW
QNI northerly flow…………….	-400 MW
Terranora southerly flow…….	138 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.15 Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow

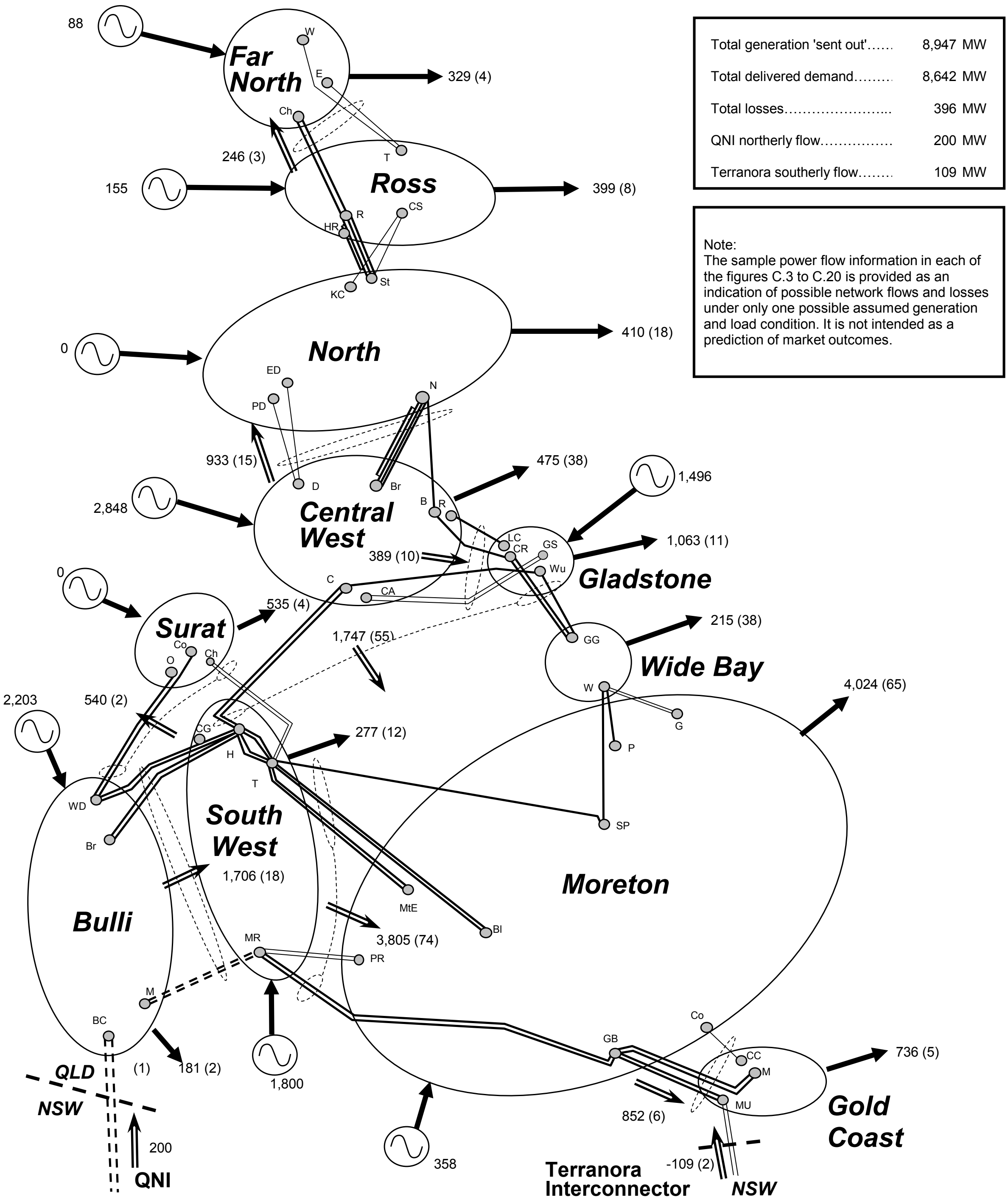
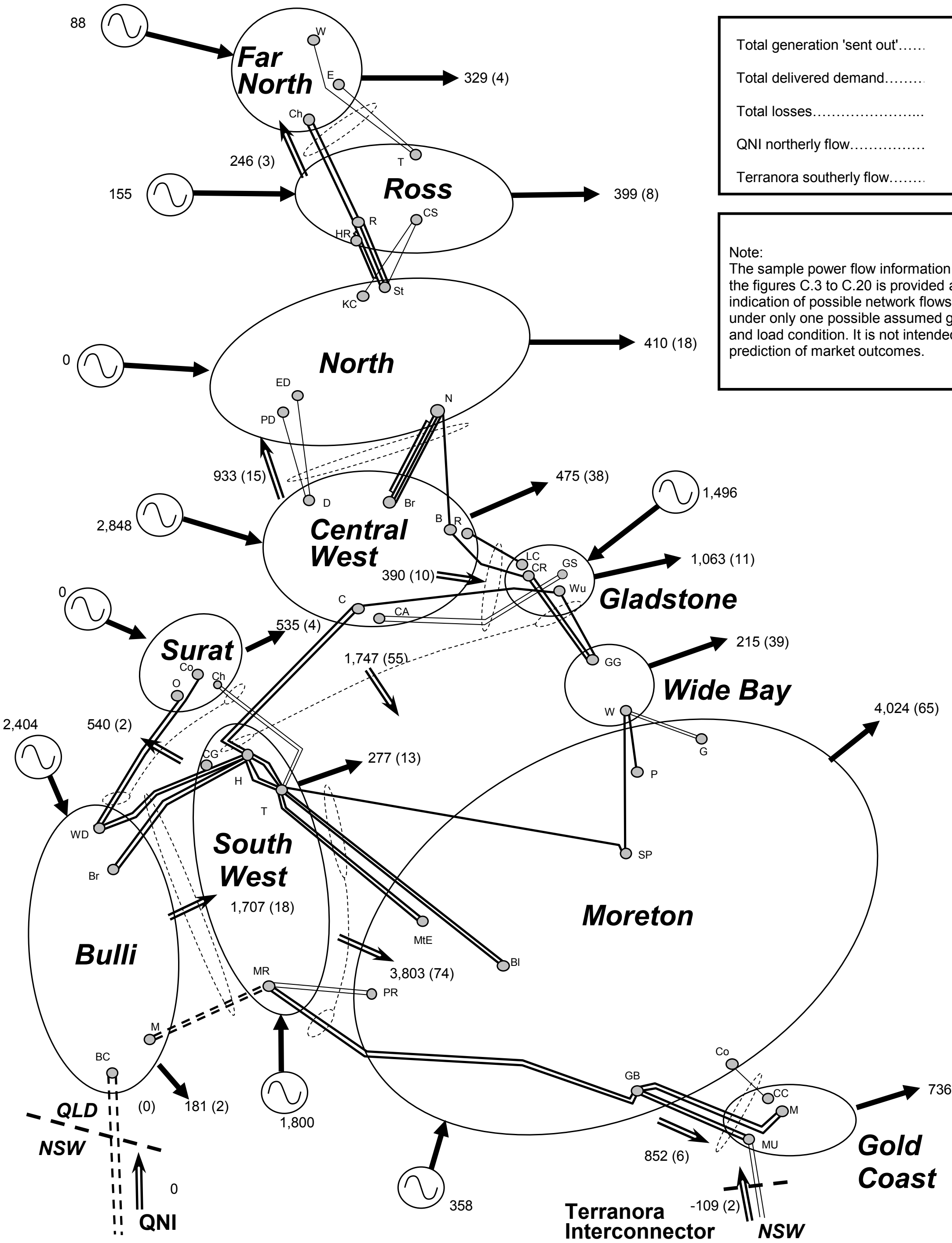


Figure C.16 Summer 2019/20 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	9,148 MW
Total delivered demand……..	8,642 MW
Total losses…………………….	397 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.17 Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow

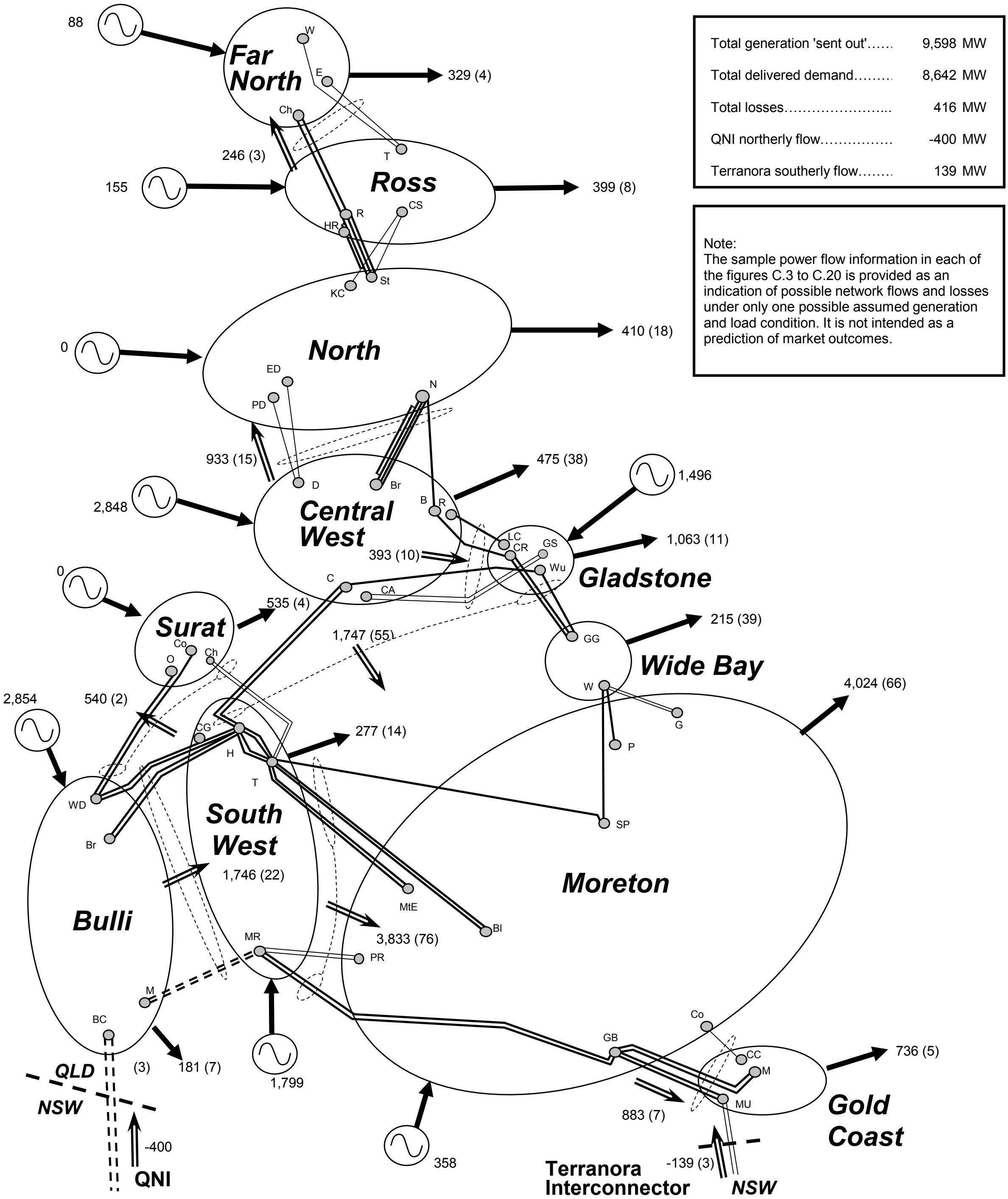


Figure C.18 Summer 2020/21 Queensland maximum demand 200MW northerly QNI flow

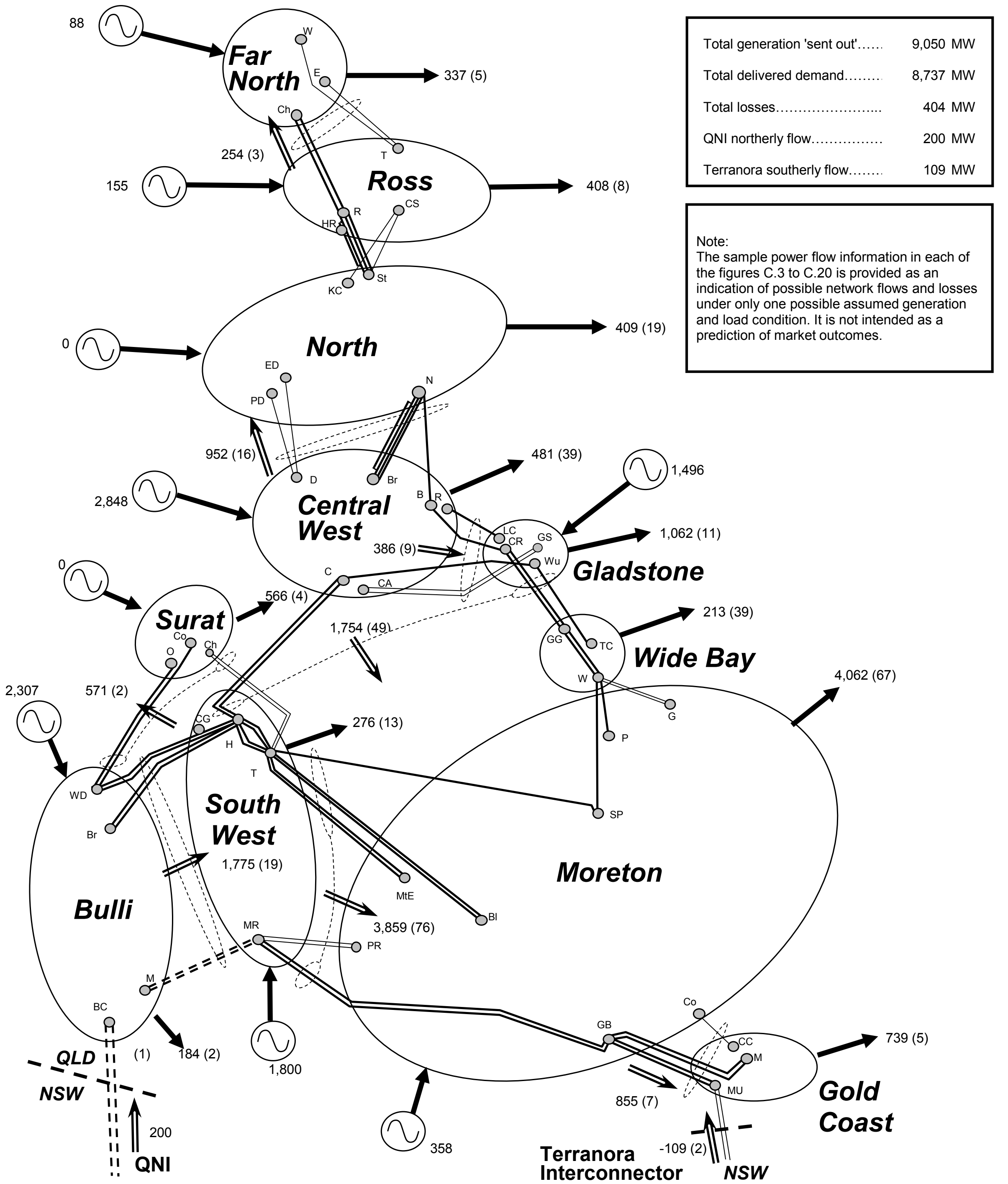
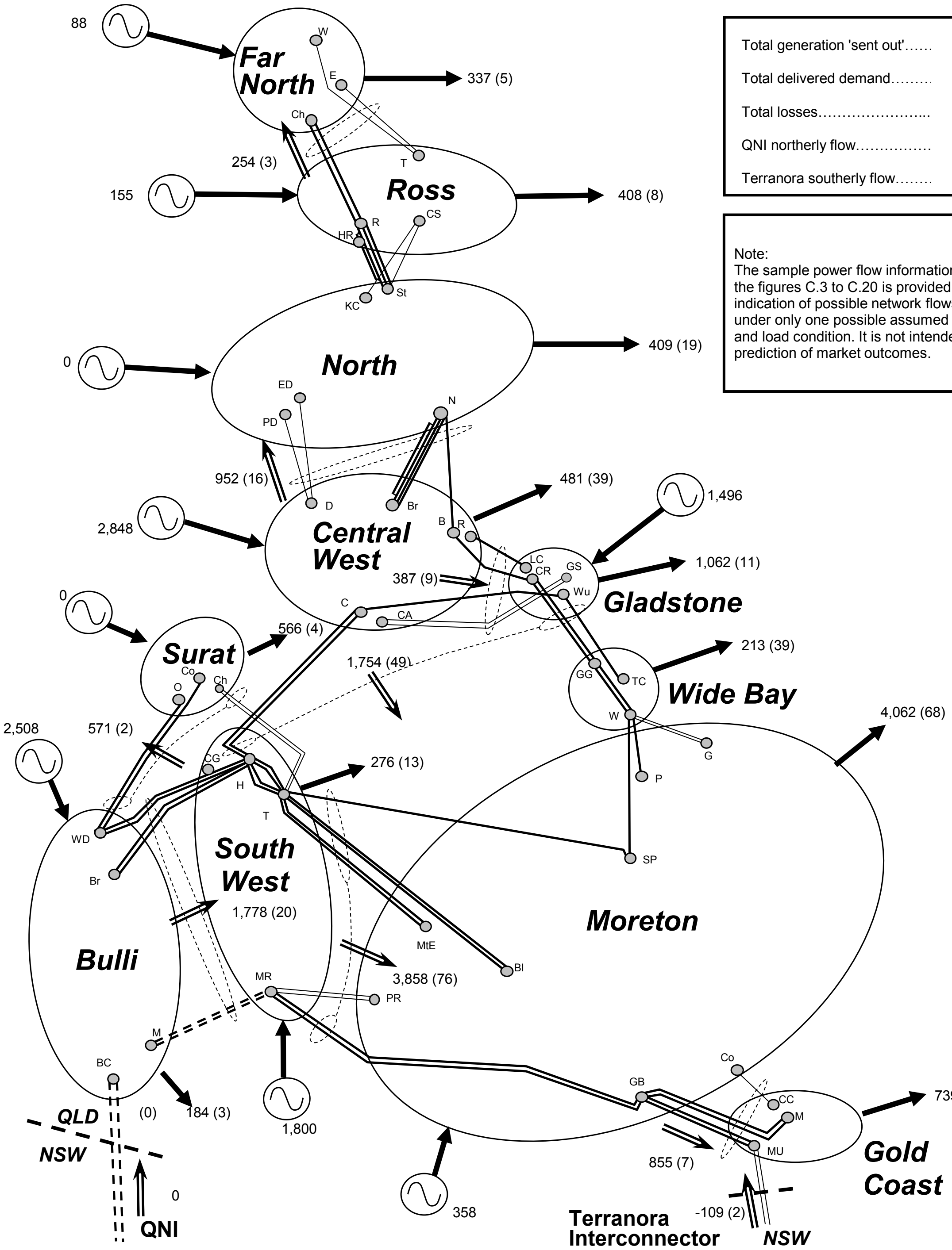


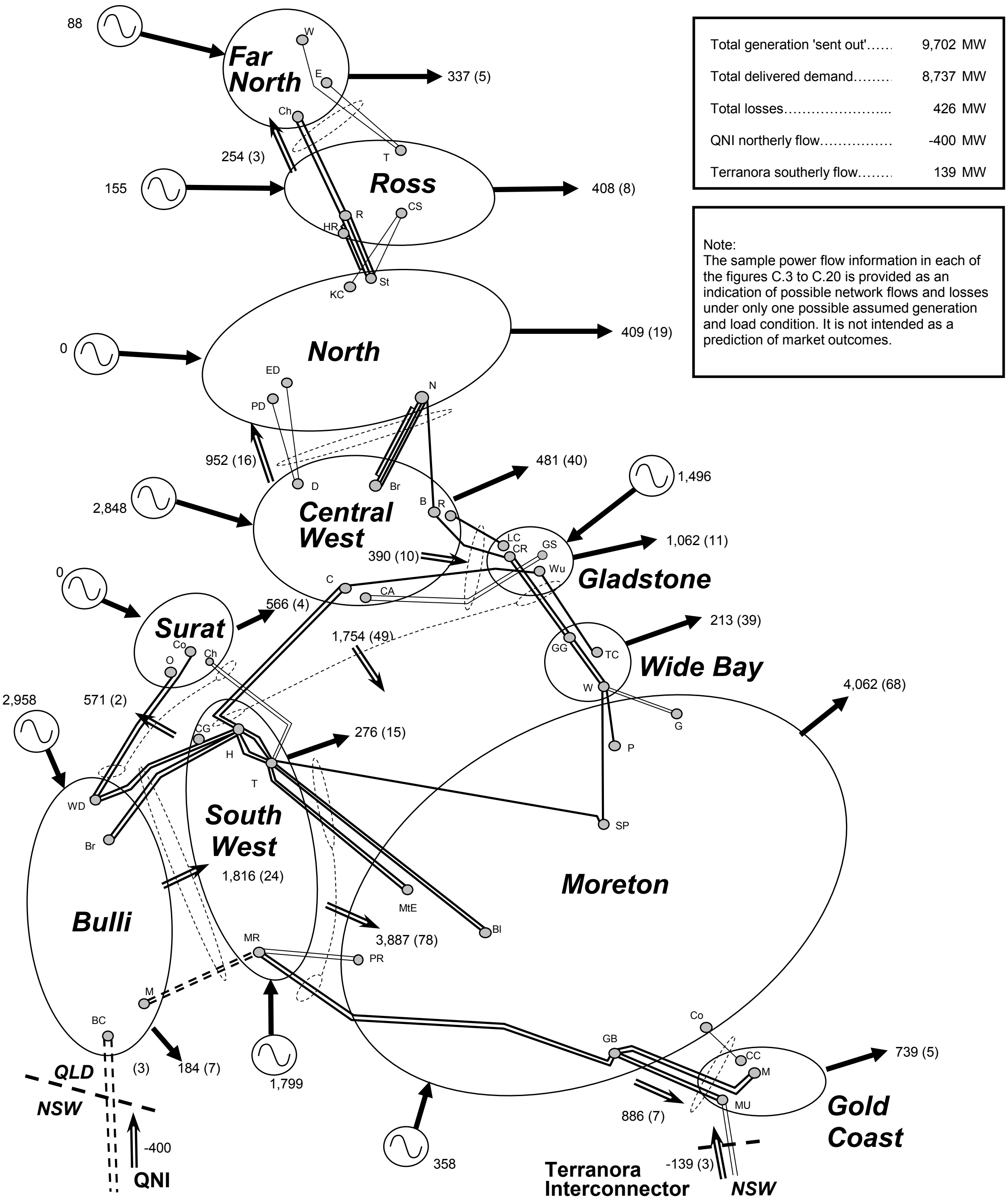
Figure C.19 Summer 2020/21 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	9,252 MW
Total delivered demand………	8,737 MW
Total losses…………………...	406 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.20 Summer 2021/21 Queensland maximum demand 400MW southerly QNI flow



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
AEMO Constraint ID	**Q^NIL_FNQ**

Notes:

(1) FNQ demand percentage = $\frac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + Sun Metals Solar Farm + Kidston + Invicta + Clare Solar Farm + Mackay) 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 nominal MVAr shunt capacitors on line within nominated Ross area locations (2)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (3)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (4)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (5)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (6)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (7)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (8)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (8)	0.296	0.470
AEMO Constraint ID	Q^NIL_CN_FDR	Q^NIL_CN_GT

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) 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

(3) 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

(4) 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

(5) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Strathmore 275kV	1 x 84MVAr

(6) 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

(7) 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

(8) 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, Oakey, Millmerran and Terranora Interconnector and 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	Coefficient: 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, Oakey, 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 $= \dfrac{\text{Zone reactive demand}}{\text{active demand}} \times 100$

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 $= \dfrac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(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 2018/19, 2019/20 and 2020/21.

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 Table 6.1 (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). 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 symmetrical three phase short circuit currents at Powerlink's substations. These indicative minimum short circuit currents were calculated by analysing half hourly system normal snapshots over the period 1 April 2017 and 31 March 2018. The minimum of subtransient, transient and synchronous short circuit currents over the year were compiled for each substation, with the individual outage of each significant network element.

Minimum system normal short circuit currents are also included, based on the same methodology, instead with all network elements in-service. These short circuit currents could be used to calculate connection capacity for proponents who would be willing to reduce capacity for specific network outages.

These minimum short circuit currents are indicative only, and are based on history. Short circuit currents can be lower for different generation dispatches and/or network elements out of service.

Table E.1 Indicative short circuit currents – northern Queensland –2018/19 to 2020/21

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 2018/19 3 phase (kA)	2018/19 L – G (kA)	2019/20 3 phase (kA)	2019/20 L – G (kA)	2020/21 3 phase (kA)	2020/21 L – G (kA)
Alan Sherriff	132	40.0	4.2	3.8	13.2	13.6	13.3	13.7	13.3	13.7
Alligator Creek	132	25.0	3.0	1.7	4.6	6.0	4.6	6.0	4.6	6.0
Bolingbroke	132	40.0	2.0	1.9	2.5	1.9	2.5	1.9	2.5	1.9
Bowen North	132	40.0	2.0	0.5	2.2	2.5	2.2	2.5	2.2	2.5
Cairns (2T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.9	5.9	7.9
Cardwell	132	19.3	1.6	0.9	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	3.0	2.3	6.6	7.6	6.7	7.7	6.7	7.7
Clare South	132	40.0	3.4	2.9	7.9	8.1	7.9	8.1	7.9	8.1
Collinsville North	132	31.5	4.4	2.3	8.6	9.5	8.7	9.6	8.7	9.6
Coppabella	132	31.5	2.2	1.4	3.0	3.4	3.1	3.4	3.1	3.4
Crush Creek	275	40.0	-	-	9.1	10.4	9.4	10.7	9.4	10.7
Dan Gleeson (1T)	132	31.5	4.2	3.6	12.5	13.0	12.6	13.1	12.6	13.1
Dan Gleeson (2T)	132	40.0	4.2	3.6	12.5	12.9	12.6	13.0	12.6	13.0
Edmonton	132	40.0	2.5	0.8	5.3	6.5	5.4	6.6	5.4	6.6
Eagle Downs	132	40.0	2.9	1.5	4.4	4.3	4.5	4.4	4.5	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	1.9	10.9	10.8	10.9	10.9	10.9	10.9
Goonyella Riverside	132	40.0	3.4	2.9	5.7	5.3	5.9	5.4	5.9	5.4
Haughton	275	40.0	-	-	-	-	7.1	7.0	7.1	7.0
Ingham South	132	31.5	1.8	0.7	3.2	3.1	3.2	3.1	3.2	3.1
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	4.7	5.3	4.7	5.3	4.7
Kamerunga	132	15.3	2.3	0.8	4.5	5.4	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.7	2.1	5.7	6.3	5.7	6.4	5.7	6.4
Kemmis	132	31.5	3.9	1.7	6.0	6.6	6.1	6.7	6.1	6.7
King Creek	132	40.0	2.9	1.4	4.7	3.9	4.7	4.0	4.7	4.0
Lake Ross	132	31.5	-	-	17.1	19.1	17.4	19.4	17.4	19.4
Mackay (2T)	132	10.9	3.4	2.9	4.9	5.7	4.8	5.5	4.8	5.5
Mackay (1T & 3T)	132	10.9	3.4	2.9	4.7	5.1	4.3	4.1	4.3	4.1

Table E.1 Indicative short circuit currents – northern Queensland –2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Mackay Ports	132	40.0	2.5	1.5	3.5	4.2	3.5	4.2	3.5	4.2
Mindi	132	40.0	3.2	3.0	4.5	3.6	4.5	3.7	4.5	3.7
Moranbah	132	10.9	3.9	3.1	7.4	8.8	7.9	9.3	7.9	9.3
Moranbah South	132	31.5	3.2	2.6	5.4	5.0	5.7	5.2	5.7	5.2
Mt McLaren	132	31.5	1.5	1.4	2.0	2.2	2.1	2.2	2.1	2.2
Nebo	275	31.5	4.0	3.5	10.3	10.6	10.6	10.9	10.6	10.9
Nebo	132	15.3	6.7	5.9	13.5	15.6	13.9	15.9	13.9	15.9
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	4.3	3.7	4.4	3.7	4.4	3.7
Oonooie	132	31.5	2.3	1.4	3.2	3.7	3.2	3.7	3.2	3.7
Peak Downs	132	31.5	2.7	1.6	4.0	3.6	4.1	3.7	4.1	3.7
Pioneer Valley	132	31.5	4.0	3.5	7.1	7.9	7.1	7.8	7.1	7.8
Proserpine	132	40.0	2.2	1.5	2.8	3.3	2.8	3.4	2.8	3.4
Ross	275	31.5	2.7	2.3	8.2	9.1	8.5	9.5	8.5	9.5
Ross	132	31.5	4.8	4.3	17.6	19.9	17.9	20.2	17.9	20.2
Springlands	132	40.0	-	-	9.4	10.6	9.5	10.7	9.5	10.7
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	3.2	2.8	9.2	10.5	9.5	10.9	9.5	10.9
Strathmore	132	40.0	4.8	2.2	9.6	11.1	9.8	11.2	9.8	11.2
Townsville East	132	40.0	4.0	1.6	12.8	12.4	12.8	12.5	12.8	12.5
Townsville South	132	21.9	4.4	3.9	17.1	20.7	17.3	20.9	17.3	20.9
Townsville PS	132	31.5	3.6	2.5	10.5	11.1	10.6	11.2	10.6	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	1.7	1.1	2.9	3.2	2.9	3.3	2.9	3.3
Walkamin	275	40.0	-	-	3.2	3.6	3.2	3.6	3.2	3.6
Wandoo	132	31.5	3.2	3.0	4.5	3.3	4.5	3.3	4.5	3.3
Woree (1T)	275	40.0	1.3	0.9	2.8	3.2	2.8	3.3	2.8	3.3
Woree (2T)	275	40.0	1.3	0.9	2.9	3.3	2.9	3.3	2.9	3.3
Wotonga	132	40.0	3.5	1.7	5.9	6.9	6.2	7.1	6.2	7.1
Yabulu South	132	40.0	4.1	3.7	12.5	12.0	12.7	12.0	12.7	12.0

Table E.2 Indicative short circuit currents – central Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					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	3.5	0.9	7.8	8.1	7.9	8.1	7.9	8.1
Blackwater	132	10.9	4.0	3.0	5.3	6.5	6.3	7.5	6.3	7.5
Bluff	132	40.0	2.5	2.1	3.3	4.1	3.6	4.5	3.6	4.5
Bouldercombe	275	31.5	7.2	6.4	20.0	19.4	20.3	19.6	20.3	19.6
Bouldercombe	132	21.8	8.1	4.7	11.5	13.6	11.6	13.6	11.6	13.6
Broadsound	275	31.5	5.1	4.3	11.7	9.1	12.2	9.3	12.2	9.3
Callemondah	132	31.5	11.0	5.6	22.4	25.0	22.5	25.0	22.5	25.0
Calliope River	275	40.0	7.6	6.8	20.8	23.7	21.0	23.9	21.0	23.9
Calliope River	132	40.0	11.7	9.7	25.1	30.2	25.2	30.3	25.2	30.3
Calvale	275	31.5	7.5	6.7	23.4	25.8	23.5	26.0	23.5	26.0
Calvale (1T)	132	31.5	5.3	1.0	8.7	9.6	8.8	9.6	8.8	9.6
Calvale (2T)	132	31.5	-	-	8.4	9.2	8.4	9.3	8.4	9.3
Dingo	132	31.5	2.1	1.2	2.7	3.0	2.8	3.1	2.8	3.1
Duaringa	132	40.0	1.7	1.1	2.2	2.9	2.3	3.0	2.3	3.0
Dysart	132	10.9	3.1	1.8	4.4	5.1	4.6	5.4	4.6	5.4
Egans Hill	132	25.0	5.5	1.6	7.3	7.4	7.3	7.5	7.3	7.5
Gladstone PS	275	40.0	7.3	6.5	19.4	21.6	19.6	21.7	19.6	21.7
Gladstone PS	132	40.0	10.7	9.0	22.1	25.2	22.1	25.3	22.1	25.3
Gladstone South	132	40.0	9.1	7.5	16.4	17.3	16.4	17.3	16.4	17.3
Grantleigh	132	31.5	2.1	1.8	2.6	2.8	2.6	2.7	2.6	2.7
Gregory	132	31.5	5.6	4.7	8.6	10.0	9.8	11.0	9.8	11.0
Larcom Creek	275	40.0	6.6	3.0	15.4	15.3	15.5	15.4	15.5	15.4
Larcom Creek	132	40.0	6.9	3.8	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.3	2.6	5.6	5.6	6.1	6.0	6.1	6.0
Lilyvale	132	25.0	5.8	4.8	9.0	10.7	10.3	11.9	10.3	11.9
Moura	132	12.3	2.8	1.1	3.9	4.2	3.9	4.2	3.9	4.2
Norwich Park	132	31.5	2.7	1.1	3.3	2.5	3.4	2.5	3.4	2.5
Pandoin	132	40.0	4.9	1.2	6.2	5.8	6.2	5.8	6.2	5.8
Raglan	275	40.0	5.9	3.7	11.9	10.4	12.0	10.4	12.0	10.4
Rockhampton (1T)	132	10.9	4.5	1.7	5.8	6.0	5.8	6.0	5.8	6.0
Rockhampton (5T)	132	10.9	4.4	1.7	5.6	5.8	5.7	5.8	5.7	5.8

Table E.2 Indicative short circuit currents – central Queensland – 2018/19 to 2020/21 *(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					
					2018/19		2019/20		2020/21	
					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	6.8	6.1
Stanwell	275	31.5	7.3	6.7	22.7	24.2	23.0	24.5	23.0	24.5
Stanwell	132	31.5	4.2	3.1	5.4	6.0	5.4	6.0	5.4	6.0
Wurdong	275	31.5	7.1	5.6	16.8	16.7	16.8	16.6	16.8	16.6
Wycarbah	132	40.0	3.4	2.6	4.2	5.1	4.2	5.1	4.2	5.1
Yarwun	132	40.0	6.8	4.2	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	6.7	5.6	18.1	18.6	18.2	18.7	18.2	18.7
Abermain	110	31.5	12.2	10.0	21.4	25.2	21.4	25.3	21.4	25.3
Algester	110	40.0	12.2	11.0	21.5	21.2	21.6	21.2	21.6	21.2
Ashgrove West	110	26.3	11.5	9.1	19.1	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	6.6	5.9	16.8	18.5	16.9	18.6	16.9	18.6
Belmont	110	37.4	14.7	13.2	29.8	37.0	29.9	37.1	29.9	37.1
Blackstone	275	40.0	6.9	6.2	21.0	23.3	21.2	23.4	21.2	23.4
Blackstone	110	40.0	13.4	12.1	25.3	29.0	25.4	29.0	25.4	29.0
Blackwall	275	37.0	7.2	6.4	22.2	24.0	22.4	24.1	22.4	24.1
Blythdale	132	40.0	3.3	2.4	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	6.0	5.3	23.4	25.4	23.6	25.6	23.6	25.6
Braemar (East)	275	40.0	6.9	4.7	26.8	31.0	26.9	31.1	26.9	31.1
Braemar (West)	275	40.0	6.8	4.4	27.2	29.9	27.3	30.0	27.3	30.0
Bulli Creek	330	50.0	6.2	3.6	18.3	14.5	18.4	14.5	18.4	14.5
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	10.6	7.6	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	5.3	4.3	8.0	7.8	7.9	7.8	7.9	7.8
Clifford Creek	132	40.0	4.3	3.5	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.2	4.2	12.4	11.7	12.5	11.7	12.5	11.7
Columboola	132	25.0	7.9	6.3	16.1	18.2	16.1	18.2	16.1	18.2
Condabri North	132	40.0	7.1	5.8	13.1	12.1	13.1	12.1	13.1	12.1
Condabri Central	132	40.0	5.7	4.7	8.9	6.6	8.9	6.6	8.9	6.6
Condabri South	132	40.0	4.5	3.8	6.5	4.4	6.5	4.4	6.5	4.4
Coopers Gap	275	40.0	-	-	-	-	17.5	15.8	17.5	15.8
Dinoun South	132	40.0	4.8	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	4.5	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.9	3.6	6.9	8.4	6.9	8.4	6.9	8.4
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	4.0	3.1	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.1	5.5	10.9	10.1	9.2	8.6	9.2	8.6
Gin Gin	132	20.0	8.1	6.2	12.8	13.9	12.0	13.0	12.0	13.0

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Goodna	275	40.0	6.5	5.2	16.1	16.0	16.2	16.0	16.2	16.0
Goodna	110	40.0	13.5	12.1	25.4	27.5	25.4	27.5	25.4	27.5
Greenbank	275	40.0	6.9	6.2	20.3	22.5	20.5	22.6	20.5	22.6
Halys	275	50.0	8.0	7.1	31.8	25.9	32.5	27.6	32.5	27.6
Kumbarilla Park (1T)	275	40.0	6.0	1.7	16.7	16.1	16.7	16.1	16.7	16.1
Kumbarilla Park (2T)	275	40.0	6.0	1.7	16.7	16.1	16.7	16.1	16.7	16.1
Kumbarilla Park	132	40.0	8.4	5.7	13.2	15.2	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.3	5.5	14.9	15.4	14.9	15.5	14.9	15.5
Loganlea	110	31.5	13.1	11.8	22.8	27.4	22.9	27.5	22.9	27.5
Middle Ridge (4T)	330	50.0	5.2	3.2	12.6	12.3	12.7	12.3	12.7	12.3
Middle Ridge (5T)	330	50.0	5.3	3.2	13.0	12.7	13.1	12.7	13.1	12.7
Middle Ridge	275	31.5	6.7	6.0	18.1	18.3	18.3	18.4	18.3	18.4
Middle Ridge	110	18.3	10.7	9.0	21.0	24.8	21.3	25.2	21.3	25.2
Millmerran	330	40.0	5.8	5.2	18.4	19.8	18.5	19.8	18.5	19.8
Molendinar (1T)	275	40.0	4.7	2.1	8.3	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	4.7	2.1	8.3	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	11.7	10.2	20.0	25.3	19.3	24.5	19.3	24.5
Mt England	275	31.5	7.1	6.3	22.5	22.8	22.7	22.9	22.7	22.9
Mudgeeraba	275	31.5	5.0	4.2	9.4	9.4	9.3	8.6	9.3	8.6
Mudgeeraba	110	25.0	10.9	10.0	18.7	22.8	17.4	21.0	17.4	21.0
Murarrie (1T)	275	40.0	6.0	2.5	13.1	13.5	13.2	13.5	13.2	13.5
Murarrie (2T)	275	40.0	6.0	2.5	13.1	13.6	13.2	13.7	13.2	13.7
Murarrie	110	40.0	13.5	12.2	24.4	29.4	24.4	29.5	24.4	29.5
Oakey Gt Ps	110	31.5	5.1	1.2	11.3	12.4	11.3	12.4	11.3	12.4
Oakey	110	40.0	4.9	1.3	10.1	10.1	10.1	10.0	10.1	10.0
Orana	275	40.0	5.7	3.4	14.9	13.7	15.0	13.7	15.0	13.7
Palmwoods	275	31.5	5.2	3.4	8.4	8.8	8.5	9.0	8.5	9.0
Palmwoods	132	21.9	9.1	6.8	13.0	15.5	13.1	15.8	13.1	15.8
Palmwoods (7T)	110	40.0	5.9	2.8	7.2	7.5	7.3	7.6	7.3	7.6
Palmwoods (8T)	110	40.0	5.9	2.8	7.2	7.5	7.3	7.6	7.3	7.6
Redbank Plains	110	31.5	12.2	9.2	21.3	20.8	21.4	20.8	21.4	20.8
Richlands	110	40.0	12.4	10.7	22.1	22.7	22.1	22.8	22.1	22.8

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21 *(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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (1T)	275	31.5	6.0	2.4	13.2	12.3	13.2	12.3	13.2	12.3
Rocklea (2T)	275	31.5	5.0	2.4	8.7	8.4	8.8	8.4	8.8	8.4
Rocklea	110	31.5	13.5	12.1	24.9	28.7	25.0	28.7	25.0	28.7
Runcorn	110	40.0	11.5	8.5	19.4	19.6	19.4	19.7	19.4	19.7
South Pine	275	31.5	7.0	6.3	18.6	21.1	18.8	21.3	18.8	21.3
South Pine (East)	110	40.0	12.9	11.4	21.5	27.5	21.6	27.6	21.6	27.6
South Pine (West)	110	40.0	12.3	10.0	20.4	23.5	20.5	23.5	20.5	23.5
Sumner	110	40.0	12.0	8.9	20.6	20.3	20.7	20.3	20.7	20.3
Swanbank E	275	40.0	6.9	6.2	20.7	22.8	20.9	22.9	20.9	22.9
Tangkam	110	31.5	5.9	4.0	13.3	12.4	13.4	12.4	13.4	12.4
Tarong (1)	275	31.5	8.1	7.1	33.3	34.7	33.9	35.6	33.9	35.6
Tarong (1T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	11.7	7.1	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	4.8	3.2	7.3	7.2	7.4	7.1	7.4	7.1
Teebar Creek	132	40.0	7.6	6.0	10.1	11.2	10.8	11.6	10.8	11.6
Tennyson	110	40.0	10.4	1.7	16.2	16.4	16.3	16.4	16.3	16.4
Upper Kedron	110	40.0	12.3	10.9	21.2	18.7	21.2	18.7	21.2	18.7
Wandoan South	275	40.0	4.0	3.2	7.1	7.7	7.1	7.7	7.1	7.7
Wandoan South	132	40.0	5.4	4.0	8.6	11.0	8.6	11.0	8.6	11.0
West Darra	110	40.0	13.3	12.0	24.9	23.8	24.9	23.9	24.9	23.9
Western Downs	275	40.0	6.6	4.9	25.2	24.5	25.4	24.7	25.4	24.7
Woolooga	275	31.5	5.7	4.9	9.6	10.9	10.0	11.2	10.0	11.2
Woolooga	132	20.0	9.2	7.8	13.0	15.3	13.4	15.7	13.4	15.7
Yuleba North	275	40.0	3.5	2.9	5.8	6.4	5.8	6.4	5.8	6.4
Yuleba North	132	40.0	5.5	4.3	7.7	9.4	7.7	9.4	7.7	9.4

Note:

(1) The lowest rated plant at this location is required to withstand and/or interrupt a short circuit current which is less than the maximum short circuit current and below the plant rating.

Appendix F – Compendium of potential non-network solution 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
Transmissmion line					
Line refit works on the coastal 132kV transmission line between Clare South and Townsville South substations	$25m	Ross	Up to 10MW and 1,000MWh in the Proserpine or Collinsville area	June 2021	S5.7.2
Retirement of the inland 132kV transmission line between Clare South and Townsville South substations and installation of a transformer at Strathmore Substation	$15m (1)	Ross			
Line refit works on the 132kV transmission line between Eton tee and Pioneer Valley Substation	$8m	North	Up to 10MW and 50MWh per day in the Mackay or Pioneer Valley area	June 2023	S5.7.3
Line refit works on the 132kV transmission line between Egans Hill and Rockhampton substations	$14m	Central West	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Rockhampton area of up to 100MW	December 2020	S5.7.4
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	$5m	Gladstone	Up to 180MW and approximately 3,200MWh per day	June 2019	S5.7.4
Line refit works on the 110kV transmission lines between South Pine to Upper Kedron	$24m	Moreton	In excess of 150MW in the CBD and inner west suburbs of Brisbane	June 2021	S5.7.9
Line refit works on the 110kV transmission lines between Rocklea, Sumner and West Darra			In excess of 150MW in the south west suburbs of Brisbane		

Note:

(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.

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
Targeted line refit works on sections of the 275kV transmission lines between Greenbank and Mudgeeraba substations	$20m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission network into to the southern Gold Coast and northern NSW area of over 250MW	December 2025	5.7.10
Substations - primary plant and secondary systems					
Kamerunga 132kV Substation replacement	$21m	Far North	Up to 60MW and 900MWh per day on a continuous basis in the northern Cairns region	June 2021	S5.7.1
Woree 275/132kV and SVC secondary systems replacement	$19m	Far North	Proposals which may significantly contribute to reducing the requirements in the Far North region. Currently over 250MW at peak is injected via Woree Substation	June 2022	S5.7.1
Cairns 132kV secondary systems replacement	$8m	Far North	Up to 65MW and 1,000MWh per day in the Cairns area	June 2023	S5.7.1
Dan Gleeson 132kV secondary systems replacement	$5m	Ross	Up to 50MW and 850MWh per day in the vicinity of Dan Gleeson	December 2020	S5.7.2 RIT-T in progress
Townsville South 132kV primary plant and secondary systems replacement	$12m	Ross	Proposals which may significantly contribute to reducing the requirements in the Townsville area of over 200MW at peak, as well as providing connection for over 450MW of generation	December 2021	S5.7.2
Ross 275/132kV primary plant replacement	$24m	Ross	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Townsville area of up to 400MW	December 2022	S5.7.2
North Goonyella 132kV secondary systems replacement	$2m	North	Up to 21MW and approximatley 415MWh	December 2020	S5.7.3
Kemmis 132kV secondary systems replacement	$8m	North	Injection or demand response of up to 32MW on a continuous basis, and up to 760MWh per day	June 2023	S5.7.3
Newlands 132kV primary plant replacement	$4m	North	Up to 23MW and approximately 460MWh	June 2023	S5.7.4

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
Baralaba secondary systems replacement	$8m	Central West	Injection at Moura of up to 36MW or a reduction of 36MW or 34MWH per day at Moura and Biloela	December 2020	S5.7.4 RIT-T in progress
Lilyvale 275/132kV primary plant replacement	$9m	Central West	Proposals which may significantly contribute to reducing the requirements in the transmission network into the central west and northern Bowen Basin area of up to 370MW	June 2021	S5.7.4
Bouldercombe 275/132kV primary plant replacement	$26m	Central West	Injection at either Bouldercombe, or closer to the loads on the Energy Queensland 66kV network, of up to 275MW	December 2022	S5.7.4
Blackwater 132kV secondary systems replacement	$5m	Central West	Up to 260MW and approximately 2,650MWh per day	June 2023	S5.7.4
QAL West 132kV secondary systems replacement	$5m	Gladstone	Up to 40MW and approximately 800MWh	December 2022	S5.7.4
Gladstone South 132kV secondary systems replacement	$15m	Gladstone	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Gladstone area of up to 200MW	June 2023	S5.7.4
Tarong 66kV Cable Replacement	$3m	South West	Up to 24MW and approximately 200MWh per day	June 2019	S5.7.6
Tarong 275kV secondary systems replacement	$11m	South West	Proposals which may significantly contribute to reducing the requirements in the transmission network into the South West zone of over 55MW at peak as well as providing connection for over 2,000MW of generation and power transfer capacity of over 3,600MW	December 2021	S5.7.6

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
Palmwoods 275kV secondary systems replacement	$7m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into South-East Queensland, as well as providing injection to Energex for the Sunshine Coast and Caboolture areas of over 400MW	June 2021	S5.7.9
Belmont 275kV secondary systems replacement	$9m	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 700MW	December 2020	S5.7.9
Abermain 110kV secondary systems replacement	$7m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Ipswich, Lockrose, Gatton areas and into the south-western suburbs of Brisbane of over 200MW	June 2021	S5.7.9
Redbank Plains 110kV primary plant replacement	$3m	Moreton	Up to 25MW and approximately 350MWh per day	June 2022	S5.7.9
Murarrie 110kV secondary systems replacement	$25m	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	June 2023	S5.7.9
Mudgeeraba 275kV secondary systems replacement	$16m	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	S5.7.10

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					
Ingham South 132/66kV transformers replacement	$6m	Ross	Up to 20MW and 300MWh per day on a continuous basis: Installation of one transformer only and either: (i) non-network of up to 20MW and 300MWh per day (ii) dynamic voltage support of up to 15MVAr, and network support of up to 10MW and 110MWh per day	December 2019	5.7.2 RIT-T in progress
Kemmis 132/66kV transformer replacement	$4m	North	Up to 32MW and approximately 760MWh per day	December 2020	S5.7.3
Lilyvale 132/66kV transformers replacement	$10m	Central West	Up to 120MW and approximately 1,700MWh per day, or up to 25MW and 300MWh per day (to support two smaller transformers)	June 2021	S5.7.4
Bouldercombe 275/132kV transformers replacement	$7m	Central West	Injection at either Bouldercombe, or closer to the loads on the Ergon Energy 66kV network, of up to 275MW and 3,500MWh per day	June 2021	S5.7.4
Blackwater 132/66/11kV transformers replacement	$5m	Central West	Provide support to the Ergon Energy 66kV network of up to 160MW and 2,000MWh per day in the Blackwater area	June 2022	S5.7.4
Redbank Plains 110/11kV transformers replacement	$5m	Moreton	Up to 25MW and approximately 350MWh per day	June 2024	S5.7.9

Appendix G — Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
BSL	Boyne Smelter Limited
CAA	Connection and Access Agreement
CBD	Central Business District
CEH	Clean Energy Hub
COAG	Council of Australian Governments
CPI	Consumer Price Index
CQ	Central Queensland
CQ-SQ	Central Queensland to Southern Queensland
CQ-NQ	Central Queensland to North Queensland
CSG	Coal Seam Gas
DCA	Dedicated Connection Assets
DER	Disbributed Energy Resources
DILGP	Department of Infrastructure, Local Government and Planning
DNRME	Deparment of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DSM	Demand Side Management
EDQ	Economic Development Queensland
EFI	AEMO's Electricity Forecast Insights
EII	Energy Infrastructure Investments
EMS	Energy Management System
EOI	Expression of Interest
ESOO	Electricity Statement of Opportunity
EV	Electric vehicles
EY	Ernst & Young
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FIT	Feed-in tariff
FNQ	Far North Queensland
GFC	Global Financial Crisis
GIS	Geospatial Information Systems
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
LNG	Liquified Natural Gas
LTTW	Lightning Trip Time Window
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
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
NWD	Non-weather dependent

Appendix G - Glossary *(continued)*

OFGS	Over Frequency Generation Shedding
PoE	Probability of Exceedance
PSITAG	Power System Issues Technology Advisory Group
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
	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rates of change of frequency
RTA	Rio Tino Aluminium
SCR	Short Circuit Ratio
SDA	State Development Area
SEQ	South East Queensland
SAET	South Australian Energy Transformation
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
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VRE	Variable renewable energy
VSC	Voltage Source Converter
WD	Weather dependent

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