Powerlink Queensland

Transmission Annual Planning Report

2016

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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/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, the capability of the existing electricity supply system, 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 2016 TAPR outlines the key drivers impacting Powerlink's business. Excluding the positive effect of high levels of liquefied natural gas (LNG) development in the Surat Basin, forecasts for both energy and demand across the balance of Queensland over the outlook period remains relatively flat.

An amended planning standard for the transmission network also came into effect on 1 July 2014, allowing the network to be planned and developed with up to 50MW or 600MWh 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 or economic 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 Powrlink Queensland Transmission Network Forum incorporating related break-out sessions, including the revenue proposal, area planning of the network, and the impacts of new technologies on demand and energy forecasts.

Electricity energy and demand forecasts

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

- recent high levels of investment in LNG development in South West Queensland
- continued growth of solar photovoltaic (PV) installations
- continued slower Queensland economic growth
- continued consumer response to high electricity prices
- the impact of energy efficiency initiatives, battery storage technology and tariff reform.

In preparing its demand and energy forecast, Powerlink conducted a forum for industry experts to share insights and build on our knowledge relating to emerging technologies. As a result several enhancements were made to how these emerging technologies are forecast within this TAPR.

These forecasts are obtained through a reconciliation of two separate processes, namely 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.

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Powerlink has developed its own econometric model for forecasting DNSP energy and demand which has been applied since the 2013 Annual Planning Report (APR)[1]. Discussion of this methodology can be found in Appendix B. Key economic inputs to this model include population growth, retail turnover and the price of electricity. DNSP customer forecasts are reconciled to meet the totals obtained from this model.

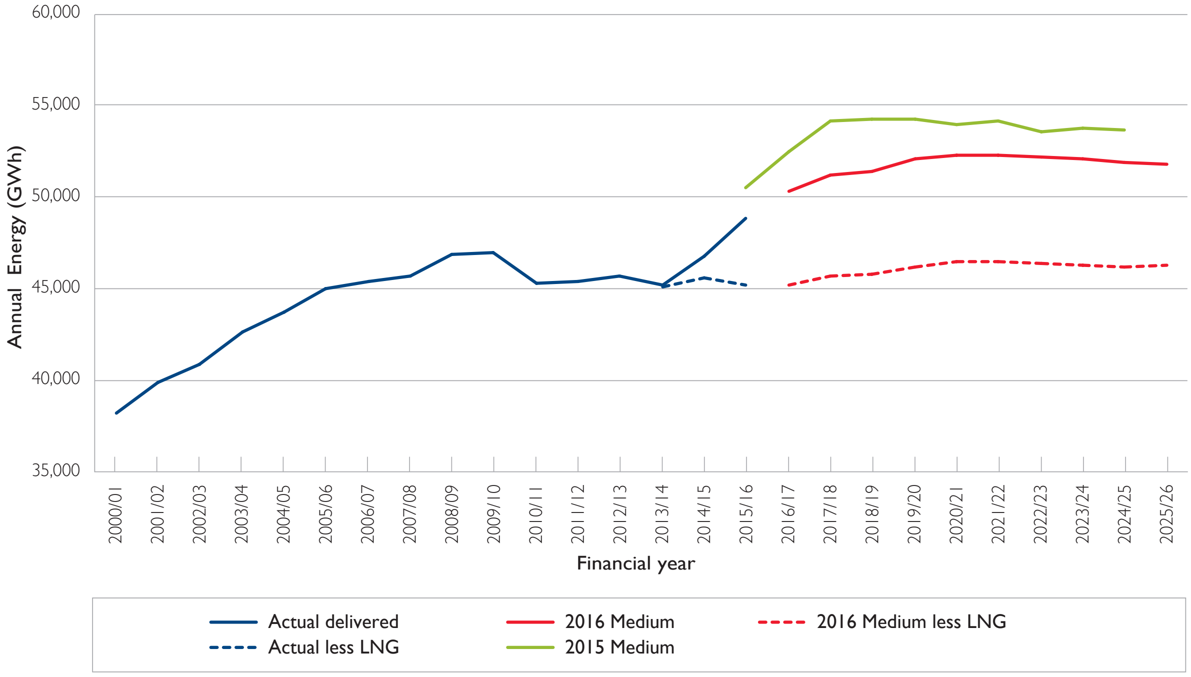
The 2015/16 summer in Queensland was hot and long lasting with a new record demand recorded at 5:30pm on 1 February, when 8,271 MW was delivered from the transmission grid. This corresponded to scheduled generation of 9,097MW, passing the previous record of 8,891MW in January 2010. This record was assisted by 439MW of new LNG load. It exceeded the 2015 Transmission Annual Planning Report forecast by around 1% and was mainly driven by load located in South East Queensland.

Electricity energy forecast

Based on the medium economic outlook, Queensland's delivered energy consumption is forecast to increase at an average of 0.6% per annum over the next 10 years from 48,965GWh in 2015/16 to 51,756GWh in 2025/26. Without the LNG sector, energy over the forecast period grows at 0.2% per annum. Continued uptake of solar PV and consumer concern regarding recent electricity price increases are expected to keep this growth rate relatively flat.

A comparison of the 2015 and 2016 TAPR forecasts for energy delivered from the transmission network is displayed in Figure 1. Energy delivered from the transmission network for 2015/16 is expected to fall short of the 2015 TAPR forecast by around 3%. This is mainly driven by slower than expected energy usage growth within the LNG sector.

Figure 1 Comparison of energy forecasts for the medium economic outlook



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[1] This Transmission Annual Planning Report was formerly called the Annual Planning Report.

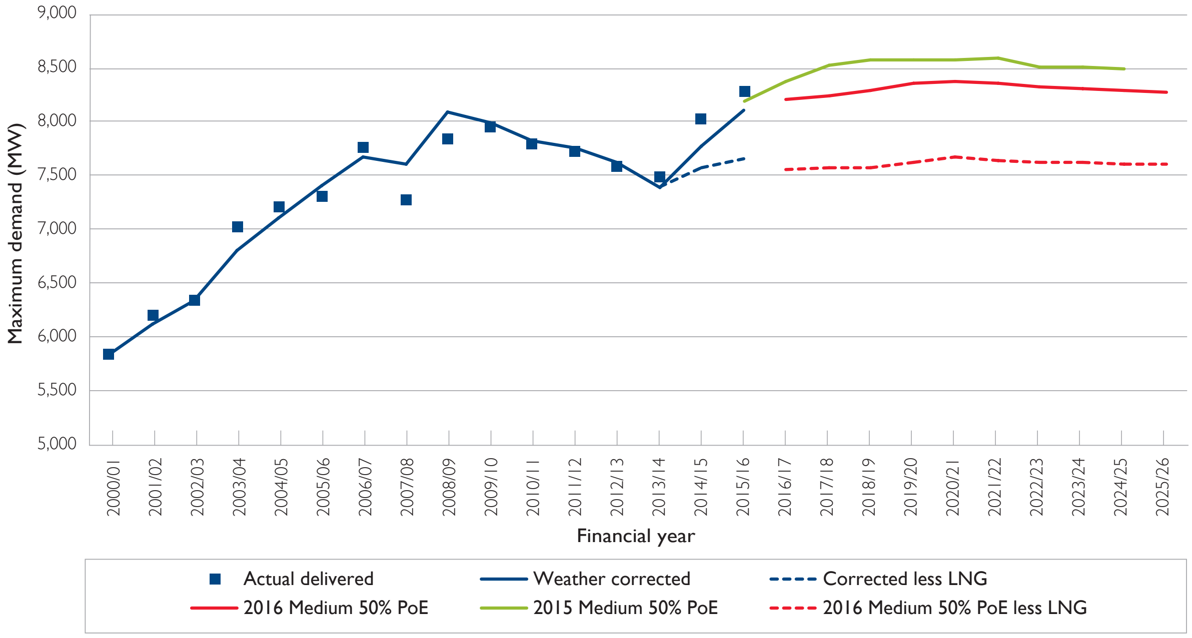
Electricity demand forecast

Based on the medium economic outlook, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.2% per annum over the next 10 years, from 8,101MW (weather corrected) in 2015/16 to 8,269MW in 2025/26. Without the LNG sector, maximum delivered summer demand is forecast to fall over the period at a rate of 0.1% per annum.

The transmission delivered maximum demand for summer 2015/16 of 8,271MW was a new record for Queensland and included 439MW of new LNG load.

A comparison of recent and current 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 latest demand forecast has been adjusted to take account of actual consumption and demands over the 2015/16 period and updated to reflect the latest economic projections for the State.

Figure 2 Comparison of summer demand forecasts for the medium economic outlook



Powerlink's asset planning criteria

There is a significant focus on striking the right balance between reliability and cost of transmission services. In response to these drivers, the Queensland Government amended Powerlink's N-1 criterion to allow for increased flexibility. This formally came into effect on 1 July 2014. The amended standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event, within limits of unsupplied demand and energy that may be at risk during 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 which is at risk of being unsupplied justifies the cost of the investment. Therefore, the amended 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 maximise reliability to consumers.

Powerlink has established policy frameworks and methodologies to support the implementation of this standard, which are being applied in various parts of the Powerlink network to inform investment decisions.

Future network development

Based on the medium economic forecast outlook, the amended planning standard and committed network and non-network solutions, network augmentations are not planned to occur as a result of network limitations within the five-year outlook period of this TAPR.

There are several proposals for large mining, metal processing and other industrial loads that have not yet 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 or economic life represents the majority of 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. With the relatively flat demand forecast outlook, Powerlink has systematically assessed the enduring need for assets at the end of their technical or economic life and considered a broad range of options including network reconfiguration, asset retirement, non-network solutions or replacement with an asset of lower capacity. An example of this is the strategy to undertake minor works from Central Queensland to Southern Queensland to align the technical end of life of the 275kV transmission lines. This incremental development approach defers large capital investment and has the benefit of maintaining the existing topology, transfer capability and operability of the transmission network.

The integrated planning approach has revealed a number of opportunities for reconfiguration of Powerlink's network within the outlook period. Powerlink has also sought to include additional information in the TAPR relating to long-term network reconfiguration strategies that in future years are likely to require further stakeholder engagement and consultation.

Committed and commissioned projects

During 2015/16, the majority of committed projects provided for reinvestment in transmission lines and substations across Powerlink's network.

In terms of network augmentation, Powerlink completed the construction of additional feeder bays at Pioneer Valley to increase voltage stability in the Mackay area.

Powerlink also has transmission augmentation projects in progress to manage localised voltage limitations in the Northern Bowen Basin and North zones, requiring the installation of 132kV capacitor banks in the Moranbah area.

Grid section and zone performance

During 2015/16, the Powerlink transmission network supported the delivery of a summer maximum demand of 8,271MW, 252MW higher than that recorded in summer 2014/15.

Most grid sections showed greater levels of utilisation during the year. Reduction in Bulli zone generation and increased Bulli zone load are the predominant reason for the lower energy transfers across the South West grid section.

The transmission network in the Queensland region performed reliably during the 2015/16 year, including during the summer maximum demand. Queensland grid sections were largely unconstrained due in part to the absence of high impact events as well as prudent scheduling of planned transmission outages.

Additional stakeholder consultation for non-network solutions

In March 2016, Powerlink initiated a Non-network Solution Feasibility Study process to further improve consultation with non-network providers and to seek potential alternate solutions for network developments outside of NER consultation requirements. This new process will help in achieving the right balance between reliability and cost by providing opportunities to exchange early information on the viability and potential of non-network solutions and how they may integrate with the transmission network. Through the recently initiated Non-network Solution Feasibility Study for Garbutt transformers, Powerlink is continuing to build upon its engagement process with non-network providers and where possible expand the use of non-network solutions to address future needs of the transmission network, particularly as an alternative option to like for like replacement or to complement an overall network reconfiguration strategy, where technically and economically feasible. Powerlink will also continue to request non-network solutions from market participants as part of the Regulatory Investment Test for Transmission (RIT-T) process.

Customer and consumer engagement

Powerlink is continuing to implement its consumer engagement strategy to support the considerable work already being undertaken to engage with stakeholders and seek their input into Powerlink's business focus and objectives.

The consumer engagement strategy focuses on education, encouraging consumer input and appropriately incorporating input into business decision making to improve planning and operational activities. A primary aim is to ensure Powerlink's service better reflects consumer values, priorities and expectations.

In early 2015, Powerlink undertook additional targeted customer and consumer research to gain a stronger understanding of stakeholder views and better respond to matters of importance.

The results from this survey represented the views from a range of stakeholders including customers, consumer organisations, government/regulators and industry associations. An additional 'health check' of key stakeholder groups in late 2015 supported this research, and highlighted that perceptions of Powerlink largely remain positive.

Powerlink has also established a Customer and Consumer Panel, which meets quarterly. This panel provides a face-to-face forum for stakeholders to provide input and feedback regarding Powerlink's decision making, processes and methodologies. It also provides Powerlink with an additional avenue to keep stakeholders better informed about operational and strategic topics of relevance.

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2016 TAPR builds upon the integrated approach to future network development introduced in the 2015 TAPR and contains detailed discussion on key areas of future expenditure.

The 2016 TAPR includes the following enhanced or additional information:

- discussion on the potential for generation developments (in particular renewable generation) including new information on available network capacity at various locations in the transmission network (refer to Chapter 7)
- incorporation of updated information explicitly relating to the future impacts of emerging technologies into Powerlink's forecasting methodology (refer to Appendix B)
- Revenue Proposal alignment – information regarding Powerlink's Revenue Proposal which was submitted to the AER in January 2016 and its relationship to the proposed capital expenditure discussed within the TAPR outlook period (refer to Section 4.1.2)
- non-network solutions – ongoing improvement of information and engagement practices for non-network solution providers (refer to Section 1.8.2 and Section 4.2)

Executive summary

Chapter 1:

Introduction

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 2015 TAPR, Powerlink has continued to proactively engage with stakeholders and seek their input to Powerlink's business processes and objectives.
- The 2016 TAPR contains detailed discussion on key areas of future expenditure and includes new information on the available network capacity at various locations in the transmission network.

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 2016 TAPR includes information on electricity energy and demand forecasts, the existing electricity supply system including committed generation and transmission network developments, and forecasts of network capability. Emerging limitations in the capability of the network and risks associated with the condition and performance of existing assets are identified and possible solutions to address these limitations are discussed. Interested parties are encouraged to provide input to facilitate identification of the most economical solution (including non-network solutions provided by others) that satisfies the required reliability standard to customers into the future. This 2016 TAPR also includes information on the capacity of the Powerlink network to connect renewable energy sources.

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

1.2 Context of the Transmission Annual Planning Report

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

Information from this process is also provided to the Australian Energy Market Operator (AEMO) to assist in the preparation of their National Electricity Forecasting Report (NEFR), Electricity Statement of Opportunities (ESOO) and National Transmission Network Development Plan (NTNDP).

The ESOO is the primary document for examining electricity supply and demand issues across all regions in the NEM. The NTNDP provides information on the strategic and long-term development of the national transmission system under a range of market development scenarios. The NEFR provides independent electricity demand and energy forecasts for each NEM region over a 10-year outlook period. The forecasts explore a range of scenarios across high, medium and low economic growth outlooks.

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 NTNDP is strategic and long-term. The NTNDP and TAPR are intended to complement each other in promoting efficient outcomes. Similarly, information from the NTNDP is considered in this TAPR, and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2016 TAPR in conjunction with AEMO's 2016 NEFR, ESOO and NTNDP, which are anticipated to be published in June 2016, August 2016 and November 2016 respectively.

1.3 Purpose of the Transmission Annual Planning Report

The purpose of Powerlink's TAPR under the NER is to provide information about the Queensland electricity transmission network to everyone interested/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 initiatives
- identify locations where major industrial loads could be connected
- identify locations where capacity for new generation developments exist (in particular renewable generation)
- understand how the electricity supply system affects their needs
- consider 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 that 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 Jurisdictional Planning Body 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 that the network is able to be operated with sufficient capability and augmented, if necessary, to provide network services to customers in accordance with Powerlink's Transmission Authority and associated reliability standard
- ensuring that the risks associated with the condition and performance of existing assets are appropriately managed
- ensuring that 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, Ergon Energy, 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 through joint planning with DNSPs and consultation with AEMO, Registered Participants and interested parties; solutions may include network upgrades or non-network options such as local generation and demand side management initiatives
- assessing whether or not a proposed transmission network augmentation has a material impact on networks owned by other TNSPs; 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 in Queensland.

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

1.5 Overview of approach to asset management

Powerlink's approach to planning of future network investment needs is in accordance with Powerlink's Asset Management Policy and Strategy. The principles and strategic objectives set out in these documents guides Powerlink's analysis of key investment drivers to form an integrated network investment plan over a 10-year outlook period.

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

Factors that influence network development, such as energy and demand forecasts, generation development and risks related to the condition and performance of the existing asset base are analysed collectively in order to form an integrated view of future network investment needs.

With reinvestment in existing assets forming such a substantial part of Powerlink's future network investment plans, the assessment of emerging risks related to the condition and performance of assets is of particular importance. Such 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 ISO31000:2009 Risk Management[1]. In order to inform risk assessments, Powerlink undertakes a periodic review of network assets to assess a range of factors including physical condition, capacity constraints, performance and functionality, statutory compliance and ongoing supportability.

1.6 Overview of planning responsibilities and processes

1.6.1 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 may be proposed to meet these legislative and NER obligations. Powerlink may also propose transmission investments that deliver a net market benefit when measured in accordance with the Regulatory Investment Test for Transmission (RIT-T).

The requirements for initiating solutions to forecast network limitations, 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. These clauses apply to different types of proposed transmission investments.

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 the network limitation and need for action which examines demand growth and its forecast exceedance of the network capability
- 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, local generation or demand side management initiatives, and classes of market benefits considered to be material which should therefore be taken into account in the comparison of options

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[1] AS/NZS ISO 31000:2009 is an international Risk Management standard.

- analysis and assessment of credible options, which include costs, market benefits and material inter-network impact
- 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.

1.6.2 Integrated planning of the shared network

Powerlink is responsible for planning the shared transmission network within Queensland. 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 and DNSPs. Section 4.4 discusses current consultations, as well as anticipated future consultations that will be conducted in line with the processes prescribed in the NER.

Significant inputs to the network planning process are:

- the forecast of customer electricity demand (including demand side management) 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 associated in allowing assets to remain in-service
- the assessment of future network capacity to meet the required planning criteria.

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 Section 5.2. Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSPs.

Powerlink examines the capability of its existing network and the future capability following any changes resulting from committed network projects. 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.

In addition to meeting the forecast demand, Powerlink must maintain its current network so that the risks associated with the condition and performance of existing assets are appropriately managed. Powerlink routinely undertakes an assessment of the condition of assets and identifies potential emerging risks related to such factors as reliability, safety and obsolescence. Further information is provided in Section 4.2.

Therefore, planning of the network optimises the network topology as assets reach the end of their technical or economic life so that the network is best configured to meet current and future capacity needs. Individual asset investment decisions are not determined in isolation. Powerlink's integrated planning process takes account of both future changes in demand and the condition based risks of related assets in the network. The integration of condition and demand based limitations delivers cost effective solutions that manage both reliability of supply obligations and the risks associated in allowing assets to remain in-service.

In response to these risks, a range of options are considered as asset reinvestments, including removing assets without replacement, non-network alternatives, line refits to extend technical life or replacing assets with assets of a different type, configuration or capacity. Each of these options is considered in the context of the future capacity needs accounting for forecast demand.

A summary of Powerlink's integrated planning approach that considers both asset condition and demand based limitations is presented in Table 1.1.

Table 1.1 Overview of Powerlink's TAPR planning process

Inputs	Integrated Planning	Solution Development	TAPR
Asset management policy and strategy Transmission Authority Generation, demand energy forecasting Asset condition and performance monitoring New customer connection need Consultation and customer/consumer engagement	• Analysis of asset condition, performance and related risks • Analysis of network capability and limitations (including Distribution Network Service Provider joint planning) • Compliance with system standards • Analysis of competition and market impacts • Analysis of operational impacts and constraints • Overall review of portfolio delivery and risks	• Integrated review of investment need and risks • Development of investment options (network reconfiguration, non-network solution, network solution) • Risk and cost benefit analysis of investment options • Project level delivery risk assessment • Market and regulatory consultation (e.g. Regulatory Investment Test for Transmission)	• Demand and energy forecast • Analysis of network capability and performance • Future network developments to address network limitations, condition and performance • Potential opportunities for non-network solutions • Committed and commissioned network projects • Strategic network development • Network technical data (e.g. connection point demand forecasts, fault levels) • Customer/consumer engagement

1.6.3 Planning of connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and DNSPs. Planning of new connections or alterations to existing connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements. The services provided can be prescribed (regulated), negotiated or non-regulated services in accordance with the definitions in the NER or the framework for provision of such services. Investments in new prescribed connections, or augmentations to existing prescribed connections costing more than the threshold specified in the NER, currently $6 million[2], may be subject to the RIT-T.

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[2] Following the Australian Energy Regulator's 2015 Cost Threshold Review, from 1st January 2016, the $5 million cost thresholds referred to in clauses 5.15.3(b)(1),(2),(3)(4) and (6) of the National Electricity Rules have increased from $5 million to $6 million.

1.6.4 Planning of interconnectors

Development and assessment of new or augmented interconnections between Queensland and New South Wales (NSW) or other States is the responsibility of the respective TNSPs. Information on potential upgrade activities is provided in Chapter 6.

1.7 Powerlink's asset planning criteria

There is a significant focus on striking the right balance between reliability and cost of transmission services. In response to these drivers, the Queensland Government amended Powerlink's N-1 criterion to allow for increased flexibility. This formally came into effect on 1 July 2014. The amended 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 which is at risk of being unsupplied justifies the cost of the investment. Therefore, the amended 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 maximise reliability to consumers.

Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations through joint planning. The objective of joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions. 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.

Energex and Ergon Energy were issued amended Distribution Authorities in 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 consistent 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 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 amended planning standard. In this instance the amended planning standard is deferring investment and delivering savings to customers and consumers.

The amended planning standard will deliver further opportunities to defer investment if new mining, metal processing or other industrial loads (discussed in Table 2.1 of Chapter 2) develop. The amended planning standard may not only affect the timing of required investment but also in some cases afford the opportunity for incremental solutions that would not have otherwise met the original N-1 criterion.

Chapter 2 provides details of possible new 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 new large loads (Table 2.1) are within the resource rich areas of Queensland or at the associated coastal port facilities. 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 6.2.

1.8 Stakeholder engagement

Powerlink aims to share effective, timely and transparent information with our 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 primarily receive electricity from the distribution networks. 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 we aim to increase understanding and awareness of some of our business practices including load forecasting and transmission network planning.

1.8.1 Customer and consumer engagement

Powerlink is proactively engaging with stakeholders and seeking their input to Powerlink's business processes and objectives. All engagement activities are undertaken in line with our Stakeholder Engagement Framework that sets out the principles, objectives and outcomes we are seeking to achieve in our interactions with stakeholders. The framework aims to achieve greater stakeholder trust and social licence to operate, better business decision making and improved management of corporate risks and reputation.

A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement performance goals, including social licence to operate and reputation measures.

Powerlink undertakes a comprehensive biennial survey, the most recent in 2014, to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. The surveys provide an evidence base to support the Stakeholder Engagement Framework and inform engagement with individual stakeholders.

In 2015, a pulse survey of stakeholders was undertaken as an interim 'health check' of stakeholder perceptions between the larger surveys. The interim pulse survey found there were no significant changes since 2014 whilst most measures had improved.

In late March we held a second Demand and Energy Forecasting Forum with a wide range of experts from across the industry. The forum examined the impact of new technologies and tariff reform on demand and energy forecasting on the Queensland transmission network. The information provided as a result of this forum has supported the development of our TAPR forecast and is detailed further in Chapter 2 and Appendix B.

Powerlink has also established a Customer and Consumer Panel that provides a face to face forum for our stakeholders to give input and feedback to Powerlink regarding our decision making, processes and methodologies. It also provides another avenue to keep our stakeholders better informed about operational and strategic topics of relevance. Members of the Customer and Consumer Panel represent a range of sectors including the resources sector, community advocacy groups, customers and research organisations. More information on the panel and other stakeholder engagement activities is available on our website.

1.8.2 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. For a given network limitation, the viability and specification of non-network solutions are first introduced in the TAPR. Further opportunities are then 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. More recently Powerlink has entered into network support services as part of the solution to address emerging limitations in the Bowen Basin area. This is outlined in Section 4.2.

Powerlink is committed to the ongoing development of its non-network engagement processes and where possible and economic expand the use of non-network solutions:

- to address future network limitations within the transmission network; or
- more broadly, in combination with network developments as part of an integrated solution to complement an overall network reconfiguration strategy.

In March 2016, Powerlink initiated a Non-network Solution Feasibility Study process to further improve consultation with non-network providers and to seek potential alternate solutions for network developments which fall outside of NER consultation requirements. In particular, where technically feasible, the process is intended to be applied to augmentations which are below the RIT-T cost threshold of $6 million and to further explore the potential to expand the use of non-network solutions in relation to network reinvestments. This new process will assist in achieving the right balance between reliability and the cost of transmission services by providing a mechanism to exchange early information on the viability and potential of non-network solutions and how they may be utilised to integrate with the transmission network to meet current and future capacity needs. Powerlink will also continue to request non-network solutions from market participants as part of the RIT-T process defined in the NER.

Since publication of the 2015 TAPR, Powerlink has continued its collaboration with the Institute for Sustainable Futures[3] and other Network Service Providers 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. This collaboration further demonstrates Powerlink's commitment to utilise a variety of platforms to raise and broaden stakeholder awareness regarding possible commercial opportunities for non-network solutions and provide technical information which historically has only been discussed in the TAPR.

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

Non-network Engagement Stakeholder Register

In 2014 Powerlink established the Non-network Engagement Stakeholder Register (NNESR) to convey non-network solution providers the details of emerging network limitations. The NNESR is made up of a variety of interested stakeholders who have the potential to offer network support through existing and/or new generation or demand side management initiatives (either as individual providers or aggregators).

The NNESR has been introduced to serve as a two-way 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;
- in relation to other augmentation network investments which may fall outside of NER consultation requirements; and
- with respect to network reinvestments which may have the potential to use non-network solutions.

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[3] Information available at http://www.uts.edu.au/research-and-teaching/our-research/institute-sustainable-futures/news/network-opportunity-mapping

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.

1.8.3 Focus on continuous improvement

As part of Powerlink's commitment to continuous improvement, the 2016 TAPR builds upon the integrated approach to future network development introduced in the 2015 TAPR 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; or
- 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 2016 TAPR includes the following enhanced or additional information:

- discussion on the potential for generation developments (in particular renewable generation), including new information on available network capacity at various locations in the transmission network (refer to Chapter 7);
- incorporation of updated information explicitly relating to the future impacts of emerging technologies into Powerlink's forecasting methodology (refer to Appendix B);
- Revenue Proposal alignment – information regarding Powerlink's Revenue Proposal which was submitted to the AER in January 2016 and its relationship to the proposed capital expenditure discussed within the TAPR outlook period (refer to section 4.1.2); and
- non-network solutions – ongoing improvement of information and engagement practices for non-network solution providers (refer to Section 4.2).

Chapter 2:

Energy and demand projections

2 Energy and demand projections

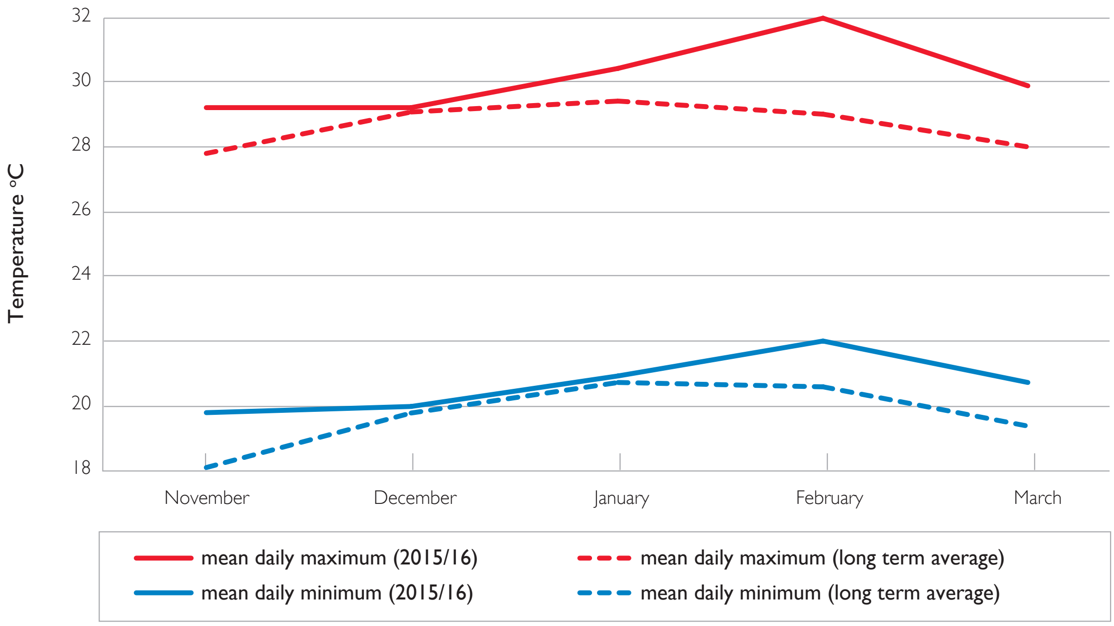
Key highlights

- This chapter sets out the historical energy and demand performance of Powerlink's transmission network and provides forecast data separated by zone.
- The 2015/16 summer in Queensland was hot and long lasting with a new record demand recorded at 5:30pm on 1 February, when 8,271MW was delivered from the transmission grid.
- Powerlink develops its energy and demand forecasts using both a top-down econometric model and bottom-up forecasts from DNSP and direct connect customers.
- Based on the medium economic outlook, Queensland's delivered energy consumption and demand is expected to remain relatively flat, with average annual increases of 0.6% and 0.2% per annum over the next 10 years.
- Powerlink is committed to understanding the future impacts of emerging technologies so that transmission network services are developed in a way most valued by customers. For example, future developments in battery storage technology coupled with small-scale solar photovoltaic (PV) could see significant changes to future electricity usage patterns including more even usage, which would reduce the need to develop transmission services to cover short duration peaks.

2.1 Overview

The 2015/16 summer in Queensland was hot and long lasting with a new record demand recorded at 5:30pm on 1 February, when 8,271 MW was delivered from the transmission grid. This corresponded to scheduled generation of 9,097MW, passing the previous record of 8,891MW in January 2010. This record was assisted by 439MW of new liquefied natural gas (LNG) load. After temperature correction, this demand fell short of the 2015 Transmission Annual Planning Report (TAPR) forecast by around 1%. The graph below shows observed temperatures for Brisbane Queensland during summer 2015/16 compared with long-term averages.

Figure 2.1 Brisbane weather over summer 2015/16



Energy delivered from the transmission network for 2015/16 is expected to fall short of the 2015 TAPR forecast by around 3%. This is mainly driven by slower than expected energy usage growth within the LNG sector.

The LNG industry continues to ramp up with observed demands close to those forecast in the 2015 TAPR. By 2018/19, LNG demand is forecast to exceed 700MW. No new loads have committed to connect to the transmission network since the 2015 TAPR was released.

During the 2015/16 summer, Queensland had around 1,500MW of installed small-scale solar PV capacity. The rate that this has been increasing has slowed to around 15MW per month. An important impact of the small-scale solar PV has been to delay the time of state peak, with state peak demand now occurring at around 5:30pm. As more small-scale solar PV is installed, future summer maximum demands are likely to occur in the early evening.

The forecasts presented in this TAPR indicate relatively flat growth for energy, summer maximum demand and winter maximum demand after the LNG industry is at full output. While there has been significant investment in the resources sector, further developments in the short-term are unlikely due to low global coal and gas prices. Queensland on the whole is still experiencing slow economic growth. However, the lower Australian dollar has improved growth prospects in areas such as tourism and foreign education while sustained low interest rates are providing a boost in the housing industry. Queensland's population growth has slowed in the aftermath of the mining boom and is expected to increase by around 15% to around 5.5 million over the 10-year forecast period.

Consumer response to high electricity prices continues to have a damping effect on electricity usage. Future developments in battery storage technology coupled with small-scale solar PV could see significant changes to future electricity usage patterns. In particular, battery storage technology has the potential to flatten electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks.

Powerlink is committed to understanding the future impacts of emerging technologies so that transmission network services are developed in a way most valued by customers. Driven by this commitment, Powerlink has again hosted a forum in March 2016 to share and build on knowledge related to emerging technologies. As a result, several enhancements were made to the forecasting methodology associated with emerging technologies in this TAPR. Details of Powerlink's forecasting process can be found in Appendix B.

Figure 2.2 presents a comparison of the delivered summer maximum demand forecast with that presented in the 2015 TAPR, based on a 50% probability of exceedance (PoE) and medium economic outlook.

Figure 2.3 presents a comparison of the delivered energy forecast with that presented in the 2015 TAPR, based on the medium economic outlook.

The 2016 TAPR forecasts for both the energy and demand represent a reduction when compared to the 2015 TAPR. The energy reduction is almost entirely due to a reduction in the energy forecast for the LNG sector. The demand reduction is due to similar demand reductions for both the LNG sector and regional Queensland.

Figure 2.2 Comparison of the medium economic outlook demand forecasts

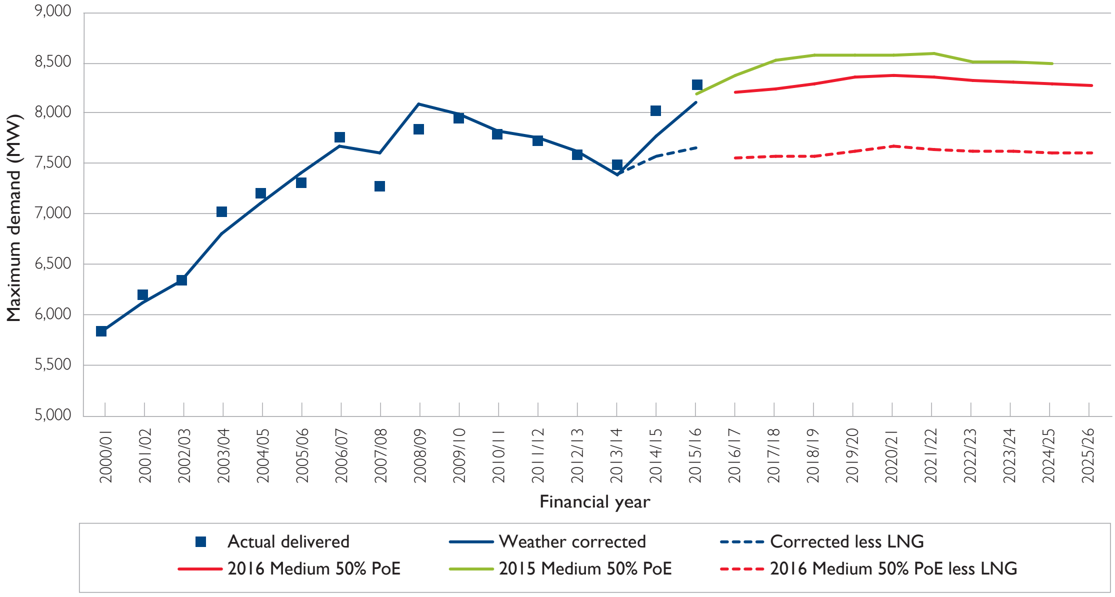
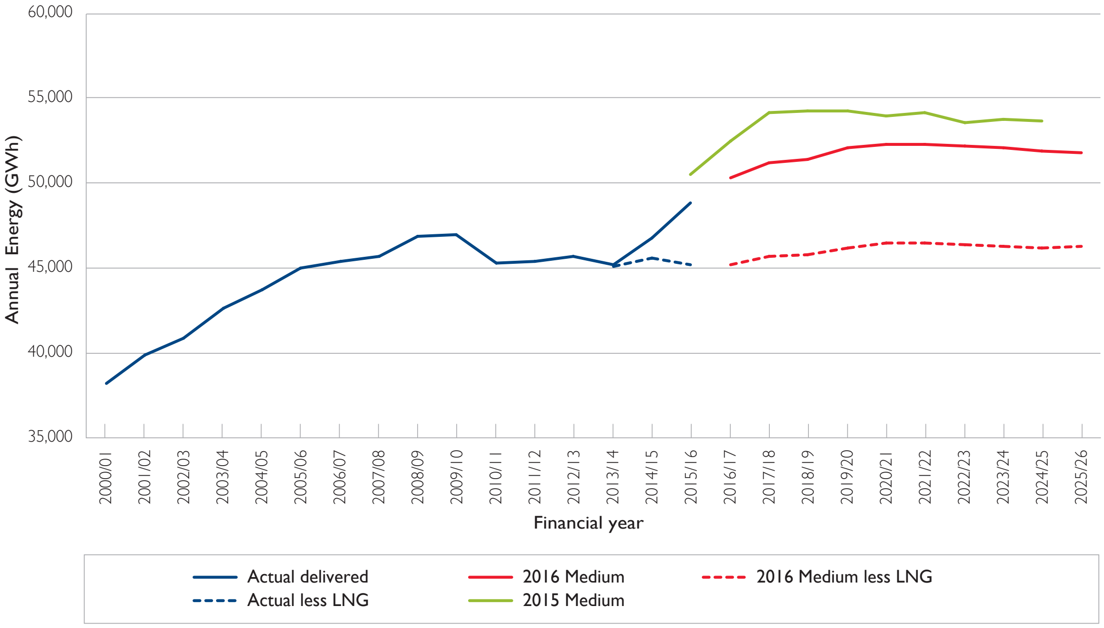


Figure 2.3 Comparison of the medium economic outlook energy forecasts



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 horizon from Queensland's Distribution Network Service Providers (DNSPs), Energex and Ergon Energy. 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 2.13 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, defined in Table 2.13.

Powerlink works with Energex, Ergon Energy, Australian Energy Market Operator (AEMO) and the wider industry to refine its forecasting process and input information. This engagement takes place through ongoing dialogue and forums such as the Demand and Energy Forecasting Forum and Powerlink Queensland Transmission Network Forum undertaken in March and July respectively.

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

Powerlink's forecasting methodology is described in Appendix B.

Transmission customer forecasts

New large loads

The medium economic outlook forecast includes the following loads that have connected recently or have committed to connect in the outlook period:

- APLNG upstream LNG processing facilities west of Wandoan South Substation
- GLNG upstream LNG processing facilities west of Wandoan South Substation
- QGC upstream LNG processing facilities at Bellevue, near Columboola Substation.

The impact of these large customer loads is shown separately in Figure 2.2 as the difference between 2016 medium 50% PoE demand forecast and 2016 medium 50% PoE less LNG demand forecast.

Possible new large loads

There are several proposals for large mining and metal processing or 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 developments, totalling nearly 1,300MW could translate to the additional loads listed in Table 2.1 being supplied by the network.

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	LNG upstream processing load (Bowen Basin area)	Up to 80MW
Central West and North	New coal mining load (Galilee Basin area)	Up to 750MW
Surat	LNG upstream processing load and coal mining projects (Surat Basin area)	Up to 350MW

2.3 Demand forecast outlook

The following sections outline the Queensland forecasts for energy, summer demand and winter 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 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 2.3.1. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2015/16. Some of this growth is driven by the emerging LNG industry in South West Queensland.

Table 2.2 **Average annual growth rate over next 10 years**

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	0.2%	0.6%	1.4%
Delivered summer maximum demand (50% PoE)	-0.2%	0.2%	1.0%
Delivered winter maximum demand (50% PoE)	0.5%	0.9%	1.7%

Table 2.3 below shows the forecast average annual growth rates for the Queensland region with the impact of LNG removed.

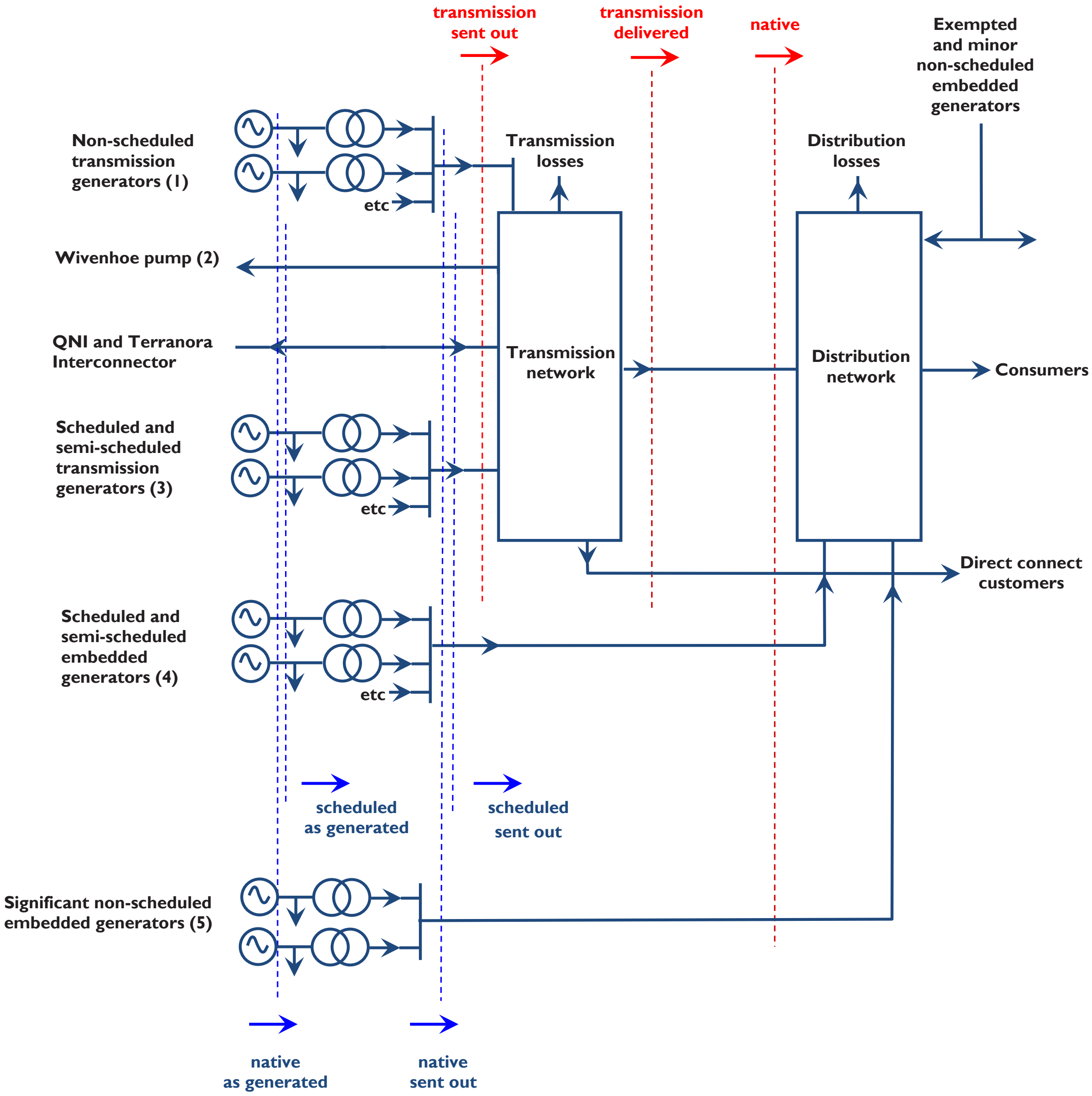
Table 2.3 **Average annual growth rate over next 10 years – without LNG**

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	-0.1%	0.2%	1.0%
Delivered summer maximum demand (50% PoE)	-0.4%	-0.1%	0.5%
Delivered winter maximum demand (50% PoE)	0.0%	0.3%	1.0%

2.3.1 Demand and energy terminology

The reported demand and energy on the network depends on where it is being measured. Different stakeholders have reasons to measure demand and energy at different points. Figure 2.4 below is presented to represent the common ways to measure demand and energy, with this terminology being 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 and Townsville Power Station 66kV component

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

2.3.2 Energy forecast

Historical Queensland energies are presented in Table 2.4. They are recorded at various levels in the network as defined in Figure 2.5.

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 2.4 Historical energy (GWh)

Year	Scheduled as generated	Scheduled sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV
2006/07	51,193	47,526	51,445	47,905	46,966	45,382	46,320	46,320
2007/08	51,337	47,660	52,268	48,711	47,177	45,653	47,188	47,188
2008/09	52,591	48,831	53,638	50,008	48,351	46,907	48,563	48,580
2009/10	53,150	49,360	54,419	50,753	48,490	46,925	49,187	49,263
2010/11	51,381	47,804	52,429	48,976	46,866	45,240	47,350	47,640
2011/12	51,147	47,724	52,206	48,920	46,980	45,394	47,334	48,018
2012/13	50,711	47,368	52,045	48,702	47,259	45,651	47,090	48,197
2013/14	49,686	46,575	51,029	47,918	46,560	45,145	46,503	47,722
2014/15	51,855	48,402	53,349	50,047	48,332	46,780	48,495	49,952
2015/16 (1)	53,589	49,990	55,158	51,708	50,034	48,965	50,639	52,460

Note:

(1) These projected end of financial year values are based on revenue and statistical metering data until February 2016.

The forecast transmission delivered energy forecasts are presented in Table 2.5 and displayed in Figure 2.5. Forecast native energy forecasts are presented in Table 2.6.

Table 2.5 Forecast annual transmission delivered energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2016/17	49,744	50,293	51,691
2017/18	50,545	51,214	53,036
2018/19	50,573	51,414	53,711
2019/20	50,864	52,034	54,521
2020/21	50,807	52,306	55,065
2021/22	50,518	52,289	55,240
2022/23	50,440	52,155	56,065
2023/24	50,228	52,066	56,083
2024/25	49,842	51,842	56,307
2025/26	49,758	51,756	56,396

Figure 2.5 Historical and forecast transmission delivered energy

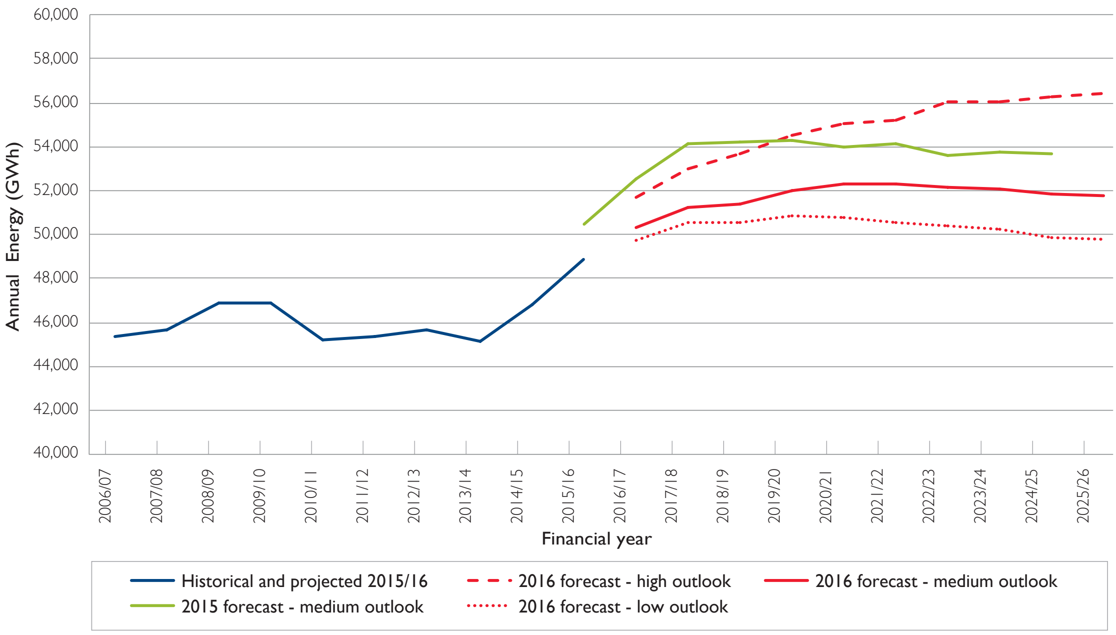


Table 2.6 Forecast annual native energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2016/17	51,015	51,564	52,962
2017/18	51,814	52,483	54,305
2018/19	51,841	52,682	54,979
2019/20	52,132	53,302	55,789
2020/21	52,074	53,573	56,332
2021/22	51,784	53,555	56,506
2022/23	51,705	53,420	57,330
2023/24	51,493	53,331	57,348
2024/25	51,106	53,106	57,571
2025/26	51,021	53,019	57,659

2.3.3 Summer maximum demand forecast

Historical Queensland summer maximum demands are presented in Table 2.7.

Table 2.7 Historical summer maximum demand (MW)

Summer	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
2006/07	8,589	8,099	8,632	8,161	7,925	7,757	7,993	7,993	7,907
2007/08	8,082	7,603	8,178	7,713	7,425	7,281	7,569	7,569	7,893
2008/09	8,677	8,135	8,767	8,239	8,017	7,849	8,070	8,078	8,318
2009/10	8,891	8,427	9,053	8,603	8,292	7,951	8,321	8,355	8,364
2010/11	8,836	8,299	8,895	8,374	8,020	7,797	8,152	8,282	8,187
2011/12	8,707	8,236	8,769	8,319	7,983	7,723	8,059	8,367	8,101
2012/13	8,453	8,008	8,691	8,245	7,920	7,588	7,913	8,410	7,952
2013/14	8,365	7,947	8,531	8,114	7,780	7,498	7,831	8,378	7,731
2014/15	8,809	8,398	9,000	8,589	8,311	8,019	8,326	8,512	8,084
2015/16	9,094	8,668	9,272	8,848	8,580	8,271	8,539	8,783	8,369

The transmission delivered summer maximum demand forecasts are presented in Table 2.8 and displayed in Figure 2.6. Forecast summer native demand is presented in Table 2.9.

Table 2.8 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
2016/17	7,747	8,134	8,659	7,817	8,206	8,732	8,030	8,428	8,970
2017/18	7,768	8,162	8,698	7,853	8,249	8,787	8,140	8,547	9,100
2018/19	7,773	8,172	8,714	7,882	8,283	8,828	8,209	8,623	9,185
2019/20	7,782	8,185	8,733	7,942	8,351	8,906	8,287	8,710	9,284
2020/21	7,743	8,151	8,704	7,955	8,371	8,936	8,336	8,767	9,352
2021/22	7,678	8,086	8,640	7,932	8,351	8,920	8,336	8,771	9,362
2022/23	7,663	8,076	8,636	7,907	8,330	8,905	8,438	8,880	9,480
2023/24	7,625	8,040	8,603	7,889	8,317	8,896	8,433	8,879	9,485
2024/25	7,566	7,984	8,551	7,857	8,289	8,875	8,457	8,910	9,524
2025/26	7,529	7,951	8,523	7,832	8,269	8,861	8,469	8,926	9,547

Figure 2.6 Historical and forecast transmission delivered summer demand

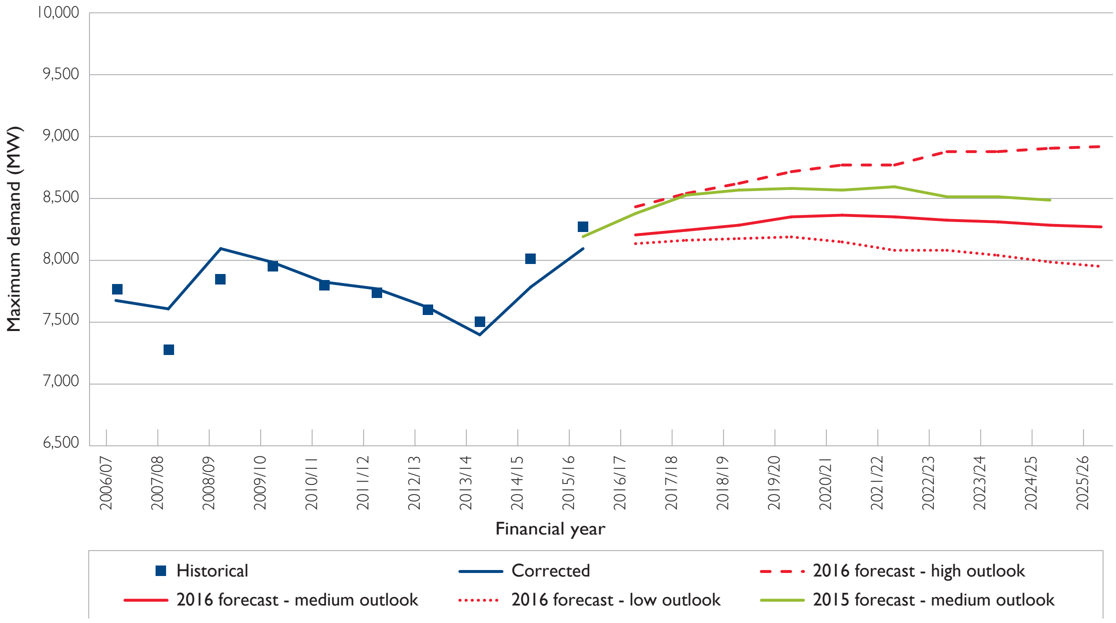


Table 2.9 Forecast summer native demand (MW)

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
2016/17	8,016	8,403	8,928	8,086	8,474	9,001	8,298	8,697	9,238
2017/18	8,036	8,431	8,967	8,122	8,518	9,056	8,409	8,816	9,369
2018/19	8,042	8,441	8,983	8,151	8,552	9,097	8,478	8,892	9,454
2019/20	8,050	8,454	9,002	8,210	8,619	9,175	8,556	8,979	9,553
2020/21	8,012	8,419	8,972	8,223	8,640	9,204	8,605	9,036	9,621
2021/22	7,946	8,355	8,909	8,200	8,619	9,189	8,605	9,040	9,631
2022/23	7,932	8,344	8,905	8,176	8,599	9,174	8,706	9,148	9,748
2023/24	7,893	8,308	8,872	8,158	8,585	9,165	8,701	9,148	9,754
2024/25	7,835	8,253	8,820	8,126	8,558	9,144	8,726	9,178	9,792
2025/26	7,798	8,219	8,792	8,101	8,537	9,129	8,738	9,195	9,816

2.3.4 Winter maximum demand forecast

Historical Queensland winter maximum demands are presented in Table 2.10. Notice that as winter normally peaks after sunset, solar PV has no impact on winter peak demand.

Table 2.10 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
2006	7,674	7,160	7,747	7,249	7,119	6,803	6,933	6,933	6,978
2007	7,837	7,416	7,893	7,481	7,298	7,166	7,350	7,350	7,026
2008	8,197	7,758	8,283	7,858	7,612	7,420	7,665	7,665	7,237
2009	7,655	7,158	7,756	7,275	7,032	6,961	7,205	7,205	7,295
2010	7,313	6,885	7,608	7,194	6,795	6,534	6,933	6,933	6,942
2011	7,640	7,207	7,816	7,400	7,093	6,878	7,185	7,185	6,998
2012	7,490	7,081	7,520	7,128	6,955	6,761	6,934	6,934	6,908
2013	7,150	6,753	7,345	6,947	6,699	6,521	6,769	6,769	6,983
2014	7,288	6,895	7,470	7,077	6,854	6,647	6,881	6,881	6,999
2015	7,816	7,369	8,027	7,620	7,334	7,126	7,411	7,412	7,301

The transmission delivered winter maximum demand forecasts are presented in Table 2.11 and displayed in Figure 2.7. Forecast winter native demand is presented in Table 2.12.

Table 2.11 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
2016	7,299	7,311	7,387	7,361	7,373	7,449	7,579	7,592	7,671
2017	7,493	7,506	7,584	7,573	7,585	7,664	7,812	7,825	7,906
2018	7,477	7,489	7,568	7,579	7,592	7,671	7,912	7,925	8,007
2019	7,530	7,542	7,622	7,684	7,697	7,778	8,040	8,054	8,137
2020	7,544	7,556	7,637	7,749	7,762	7,844	8,120	8,134	8,219
2021	7,455	7,468	7,548	7,702	7,715	7,798	8,107	8,121	8,207
2022	7,454	7,467	7,549	7,688	7,701	7,785	8,189	8,203	8,291
2023	7,418	7,431	7,513	7,671	7,684	7,768	8,226	8,240	8,328
2024	7,389	7,402	7,484	7,666	7,680	7,765	8,254	8,268	8,357
2025	7,347	7,360	7,443	7,634	7,647	7,733	8,269	8,283	8,374

Figure 2.7 Historical and forecast winter transmission delivered demand

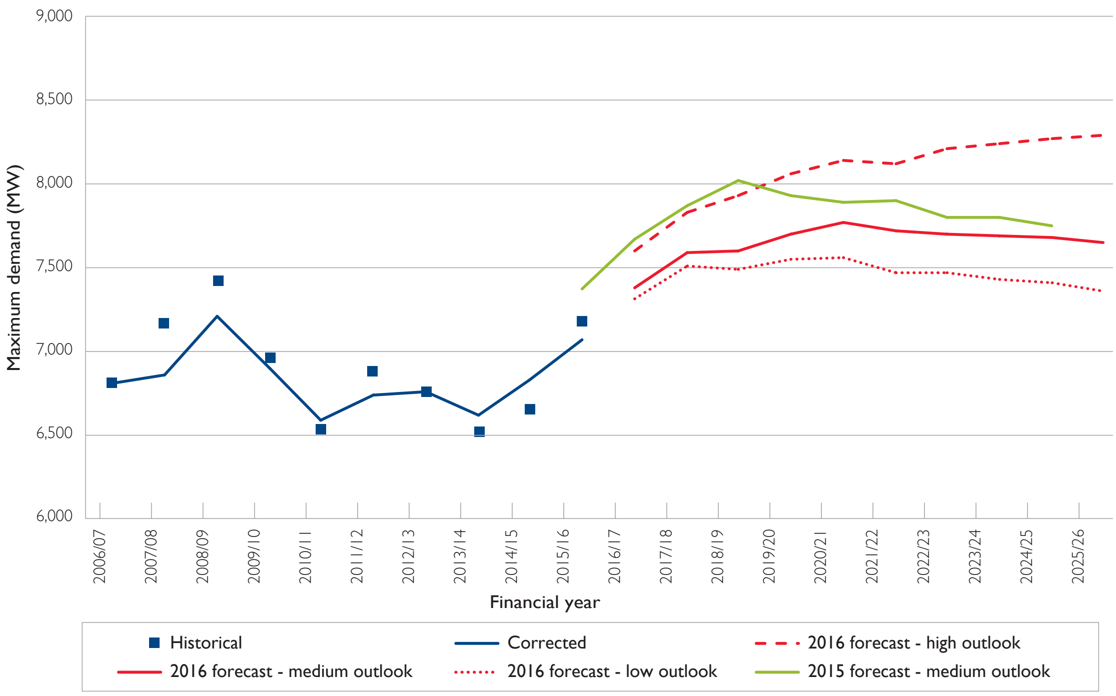


Table 2.12 Forecast winter native demand (MW)

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
2016	7,554	7,566	7,642	7,616	7,628	7,705	7,834	7,847	7,926
2017	7,749	7,761	7,839	7,828	7,841	7,919	8,067	8,080	8,161
2018	7,732	7,744	7,823	7,834	7,847	7,926	8,168	8,180	8,263
2019	7,785	7,797	7,877	7,939	7,952	8,033	8,296	8,309	8,393
2020	7,799	7,811	7,892	8,004	8,017	8,100	8,375	8,389	8,474
2021	7,710	7,723	7,803	7,957	7,970	8,053	8,362	8,376	8,462
2022	7,709	7,722	7,804	7,943	7,956	8,040	8,445	8,458	8,546
2023	7,673	7,686	7,768	7,926	7,939	8,023	8,481	8,495	8,583
2024	7,644	7,657	7,740	7,921	7,935	8,020	8,509	8,523	8,613
2025	7,602	7,615	7,698	7,889	7,903	7,989	8,524	8,539	8,629

2.4 Zone forecasts

The 11 geographical zones referred to throughout this TAPR are defined in Table 2.13 and are shown in the diagrams in Appendix C. In the 2008 Annual Planning Report (APR), Powerlink split the South West zone into Bulli and South West zones and in the 2014 TAPR, Powerlink split the South West zone into Surat and South West zones.

Table 2.13 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of Proserpine and Collinsville North, excluding the Far North zone
North	North of Broadsound and Dysart, excluding the Far North and Ross zones
Central West	South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone
Gladstone	South of Raglan, north of Gin Gin and east of Calvale
Wide Bay	Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie
Surat	West of Western Downs and south of Moura, excluding the Bulli zone
Bulli	Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Millmerran
South West	Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli and Surat zones
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 2.17 to 2.20.

Table 2.14 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 2.17 and 2.19 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 2.14 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum demand

Zone	Winter	Summer
Far North	1.15	1.16
Ross	1.53	1.36
North	1.14	1.15
Central West	1.10	1.15
Gladstone	1.03	1.05
Wide Bay	1.02	1.13
Surat (1)		
Bulli	1.16	1.28
South West	1.03	1.23
Moreton	1.01	1.01
Gold Coast	1.01	1.01

Note:

(1) As load is still ramping up in the Surat zone, ratios for this zone cannot be reliably determined.

Tables 2.15 and 2.16 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 2.15 Annual transmission delivered energy (GWh) by zone

Year	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006/07	1,770	2,563	2,733	3,169	9,945	1,461			2,047	18,469	3,225	45,382
2007/08	1,818	2,719	2,728	3,165	10,058	1,399		87	1,712	18,684	3,283	45,653
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	46,927
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	2,762	2,627	3,407	10,286	1,323		105	1,196	18,630	3,266	45,394
2012/13	1,722	2,782	2,730	3,326	10,507	1,267		103	1,746	18,233	3,235	45,651
2013/14	1,658	2,907	2,829	3,482	10,293	1,321	338	146	1,304	17,782	3,085	45,145
2014/15	1,697	3,063	2,885	3,327	10,660	1,266	821	647	1,224	18,049	3,141	46,780
2015/16	1,703	2,976	2,876	3,256	10,706	1,239	2,779	1,211	1,194	17,888	3,137	48,965
Forecasts												
2016/17	1,631	2,946	2,887	3,469	10,719	1,248	4,116	1,214	1,185	17,536	3,342	50,293
2017/18	1,634	2,951	3,033	3,528	10,657	1,268	4,508	1,232	1,196	17,804	3,403	51,214
2018/19	1,603	2,927	3,022	3,541	10,774	1,260	4,641	1,228	1,168	17,838	3,412	51,414
2019/20	1,567	2,891	3,105	3,608	10,944	1,241	4,954	1,167	1,134	17,987	3,436	52,034
2020/21	1,569	2,905	3,178	3,650	10,947	1,253	4,928	1,167	1,125	18,122	3,462	52,306
2021/22	1,550	2,899	3,178	3,659	10,945	1,251	5,011	1,166	1,102	18,075	3,453	52,289
2022/23	1,526	2,889	3,158	3,674	10,943	1,246	5,015	1,166	1,078	18,016	3,444	52,155
2023/24	1,499	2,879	3,143	3,699	10,941	1,241	5,046	1,165	1,053	17,969	3,431	52,066
2024/25	1,481	2,868	3,102	3,740	10,941	1,236	4,890	1,164	1,028	17,962	3,430	51,842
2025/26	1,462	2,857	3,062	3,800	10,941	1,229	4,832	1,164	1,003	17,974	3,432	51,756

Table 2.16 Annual native energy (GWh) by zone

Year	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006/07	1,770	3,141	2,761	3,375	9,945	1,459			2,110	18,534	3,225	46,320
2007/08	1,818	3,371	2,771	3,528	10,058	1,413		87	2,039	18,820	3,283	47,188
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	3,257	2,917	3,654	10,286	1,348		105	2,014	18,695	3,266	47,334
2012/13	1,722	3,169	3,062	3,680	10,507	1,292		103	1,988	18,333	3,235	47,090
2013/14	1,658	3,148	3,156	3,862	10,293	1,339	402	146	1,536	17,878	3,085	46,503
2014/15	1,697	3,249	3,435	3,755	10,660	1,285	1,022	647	1,468	18,136	3,141	48,495
2015/16	1,703	3,207	3,415	3,684	10,706	1,269	2,879	1,211	1,446	17,982	3,137	50,639
Forecasts												
2016/17	1,631	3,136	3,284	3,603	10,719	1,266	4,323	1,215	1,429	17,616	3,342	51,564
2017/18	1,634	3,142	3,429	3,662	10,657	1,287	4,714	1,232	1,440	17,883	3,403	52,483
2018/19	1,603	3,118	3,419	3,675	10,774	1,278	4,847	1,228	1,412	17,916	3,412	52,682
2019/20	1,567	3,082	3,501	3,743	10,944	1,260	5,160	1,167	1,378	18,064	3,436	53,302
2020/21	1,569	3,096	3,574	3,785	10,947	1,272	5,134	1,167	1,369	18,198	3,462	53,573
2021/22	1,550	3,089	3,575	3,794	10,945	1,269	5,217	1,166	1,347	18,150	3,453	53,555
2022/23	1,526	3,080	3,555	3,808	10,943	1,265	5,221	1,166	1,322	18,090	3,444	53,420
2023/24	1,499	3,069	3,540	3,833	10,941	1,260	5,253	1,165	1,297	18,043	3,431	53,331
2024/25	1,481	3,059	3,499	3,875	10,941	1,254	5,096	1,164	1,272	18,035	3,430	53,106
2025/26	1,462	3,047	3,458	3,935	10,941	1,248	5,038	1,164	1,247	18,047	3,432	53,019

Tables 2.17 and 2.18 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 2.17 State winter maximum transmission delivered demand (MW) by zone

Winter	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006	207	243	325	409	1,157	228			361	3,279	594	6,803
2007	219	309	286	442	1,165	297			410	3,451	587	7,166
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	226	326	412	1,201	215		20	346	3,207	594	6,761
2013	195	261	348	405	1,200	190	23	17	263	3,040	579	6,521
2014	226	360	359	448	1,200	204	16	51	257	2,975	551	6,647
2015	192	307	332	412	1,249	203	172	137	258	3,267	597	7,126
Forecasts												
2016	218	248	378	437	1,193	191	487	158	223	3,247	593	7,373
2017	220	240	378	465	1,191	191	620	161	224	3,298	597	7,585
2018	223	230	398	464	1,202	191	582	164	224	3,316	598	7,592
2019	225	232	417	469	1,208	192	605	158	226	3,364	601	7,697
2020	224	231	424	482	1,206	190	637	151	225	3,391	601	7,762
2021	225	228	429	484	1,204	187	612	151	220	3,379	596	7,715
2022	226	226	433	481	1,203	185	608	151	219	3,375	594	7,701
2023	227	226	431	480	1,203	185	602	151	218	3,371	590	7,684
2024	227	227	431	479	1,203	184	599	151	218	3,373	588	7,680
2025	227	227	428	479	1,203	184	572	151	218	3,370	588	7,647

Table 2.18 State winter maximum native demand (MW) by zone

Winter	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006	207	322	325	460	1,157	228			361	3,279	594	6,933
2007	219	309	292	520	1,165	297			485	3,476	587	7,350
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	302	360	446	1,201	215		20	375	3,207	594	6,934
2013	195	304	374	487	1,200	195	89	17	290	3,039	579	6,769
2014	226	384	420	495	1,200	204	90	51	286	2,974	551	6,881
2015	192	352	404	500	1,249	203	208	137	288	3,281	597	7,411
Forecasts												
2016	218	310	435	505	1,193	192	522	158	252	3,250	593	7,628
2017	220	302	436	533	1,191	192	656	161	253	3,300	597	7,841
2018	223	292	455	532	1,202	192	617	164	253	3,319	598	7,847
2019	225	294	475	537	1,208	193	640	158	255	3,366	601	7,952
2020	224	293	482	550	1,206	191	672	151	254	3,393	601	8,017
2021	225	290	486	552	1,204	188	647	151	249	3,382	596	7,970
2022	226	289	491	548	1,204	186	643	151	247	3,377	594	7,956
2023	226	289	489	547	1,203	186	637	151	247	3,374	590	7,939
2024	227	289	488	547	1,204	185	634	151	247	3,375	588	7,935
2025	227	289	486	546	1,204	185	607	151	247	3,373	588	7,903

Tables 2.19 and 2.20 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 2.19 State summer maximum transmission delivered demand (MW) by zone

Summer	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006/07	329	385	452	509	1,164	296			375	3,636	611	7,757
2007/08	292	296	386	476	1,193	243		15	314	3,466	600	7,281
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	391	405	510	1,191	249		18	217	3,788	658	7,723
2012/13	277	320	384	518	1,213	232		14	241	3,755	634	7,588
2013/14	271	330	353	481	1,147	260	30	21	291	3,711	603	7,498
2014/15	278	398	399	449	1,254	263	130	81	227	3,848	692	8,019
2015/16	308	411	412	425	1,189	214	313	155	231	3,952	661	8,271
Forecasts												
2016/17	261	326	388	505	1,185	203	522	151	203	3,799	663	8,206
2017/18	266	315	399	508	1,182	203	533	153	204	3,821	665	8,249
2018/19	265	313	403	504	1,195	201	569	153	203	3,817	660	8,283
2019/20	265	313	419	509	1,201	201	601	145	203	3,836	658	8,351
2020/21	267	312	432	517	1,201	200	583	138	202	3,861	658	8,371
2021/22	266	307	432	522	1,200	196	591	138	199	3,846	654	8,351
2022/23	267	305	433	521	1,200	195	582	138	198	3,841	650	8,330
2023/24	267	305	432	519	1,200	195	582	138	197	3,835	647	8,317
2024/25	267	305	431	519	1,201	195	558	138	197	3,832	646	8,289
2025/26	269	307	417	521	1,201	196	546	138	199	3,832	643	8,269

Table 2.20 State summer maximum native demand (MW) by zone

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2006/07	329	491	458	573	1,164	295			436	3,636	611	7,993
2007/08	292	404	390	533	1,193	243		15	387	3,512	600	7,569
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	464	434	583	1,191	249		18	378	3,788	658	8,059
2012/13	277	434	422	551	1,213	241		14	328	3,799	634	7,913
2013/14	271	435	386	549	1,147	260	88	21	316	3,755	603	7,831
2014/15	278	416	479	531	1,254	263	189	81	254	3,889	692	8,326
2015/16	308	442	491	501	1,189	214	370	155	257	3,951	661	8,539
Forecasts												
2016/17	261	391	447	551	1,185	204	578	151	228	3,815	663	8,474
2017/18	266	380	458	554	1,182	205	590	153	228	3,837	665	8,518
2018/19	265	378	462	550	1,195	203	625	153	228	3,833	660	8,552
2019/20	265	378	477	555	1,201	203	657	145	228	3,852	658	8,619
2020/21	267	376	491	564	1,201	201	640	138	227	3,877	658	8,640
2021/22	266	371	491	569	1,200	198	647	138	224	3,861	654	8,619
2022/23	267	370	492	567	1,200	197	639	138	222	3,857	650	8,599
2023/24	267	369	491	566	1,200	197	639	138	222	3,850	646	8,585
2024/25	267	370	490	565	1,200	197	615	138	222	3,848	646	8,558
2025/26	269	371	476	567	1,201	198	603	138	224	3,847	643	8,537

2.5 Daily and annual load profiles

The daily load profiles for the Queensland region on the days of 2015 winter and 2015/16 summer maximum transmission delivered 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 for the 2014/15 financial year.

Figure 2.8 Winter 2015 and summer 2015/16 maximum transmission delivered demands

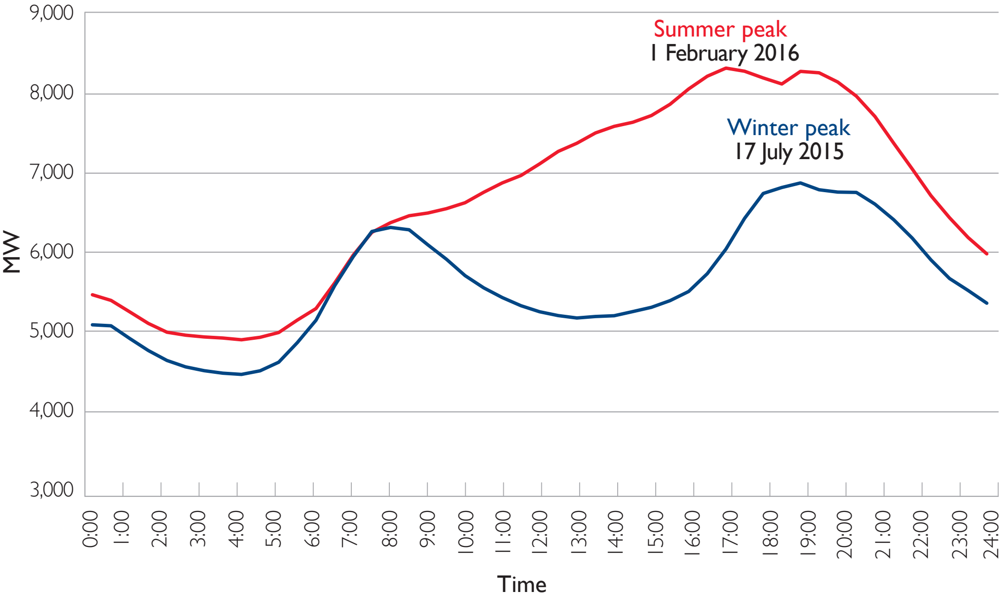
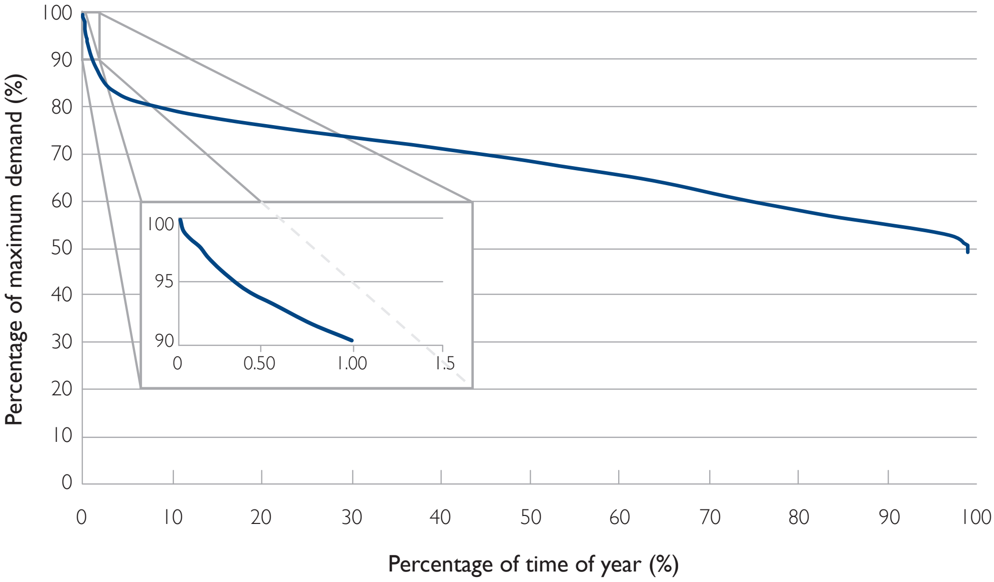


Figure 2.9 Normalised cumulative transmission delivered load duration from 1 March 2015 to 29 February 2016



Chapter 3:

Committed and commissioned network developments

3 Committed and commissioned network developments

Key highlights

- During 2015/16, the majority of Powerlink's committed projects provided for reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's reinvestment program is focused on reducing the identified risks associated with assets reaching the end of life.
- Connection works in the Surat and Bowen Basin have been completed.
- Major substation reinvestments at Collinsville North and Blackstone have been completed.

3.1 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 3.1. Single line diagrams showing network topology and connections may be made available upon request.

3.2 Committed and commissioned transmission projects

Table 3.1 lists transmission network developments commissioned since Powerlink's 2015 Transmission Annual Planning Report (TAPR) was published.

Table 3.2 lists transmission network developments which are committed and under construction at June 2016.

Table 3.3 lists transmission connection works that have been commissioned since Powerlink's 2015 TAPR was published. There are no new connection works committed or under construction at June 2016.

Table 3.4 lists network reinvestments commissioned since Powerlink's 2015 TAPR was published.

Table 3.5 lists network reinvestments which are committed and under construction at June 2016.

Table 3.6 lists network assets which are committed for retirement at June 2016.

Table 3.1 Commissioned transmission developments since June 2015

Project	Purpose	Zone location	Date commissioned
Pioneer Valley feeder bays	Increase voltage stability in Mackay	North	November 2015

Table 3.2 Committed and under construction transmission developments at June 2016

Project	Purpose	Zone location	Proposed commissioning date
Moranbah area 132kV capacitor banks (1)	Increase supply capability in the North zone	North	Progressively from winter 2013 to summer 2017/18

Note:

(1) Refer to section 4.2.3

Table 3.3 Commissioned connection works since June 2015

Project	Purpose	Zone location	Date commissioned
Aurizon 132kV rail connection (Wotonga)	New connection to supply rail load in the Bowen Basin area (1)	North	July 2015
APLNG/GLNG Wandoan South connections	New connection for CSM/LNG compression (1)	Surat	December 2015

Note:

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

Table 3.4 Commissioned network reinvestments since June 2015

Project	Purpose	Zone location	Date commissioned
Line refit works on 132kV transmission line between Woree and Kamerunga substations	Maintain supply reliability in the Far North zone	Far North	July 2015
Ross 300kV 100MVAr bus reactor	Maintain supply reliability in the Ross zone	Ross	August 2015
Collinsville Substation replacement (located at Collinsville North)	Maintain supply reliability in the North zone	North	October 2015
Swanbank B Substation replacement (located at Blackstone)	Maintain supply reliability in the Moreton zone	Moreton	November 2015
Line refit works on 110kV transmission line between Sumner Tee and Richlands substations	Maintain supply reliability in the Moreton zone	Moreton	October 2015

Table 3.5 Committed and under construction network reinvestments at June 2016[1]

Project	Purpose	Zone location	Proposed commissioning date
Turkinje secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	Summer 2018/19
Garbutt to Alan Sherriff 132kV line replacement	Maintain supply reliability in the Ross zone	Ross	June 2018
Nebo 275/132kV transformer replacements	Maintain supply reliability in the North zone (1)	North	Progressively from summer 2013/14 to summer 2017/18
Line refit works on the 132kV transmission line between Collinsville North and Proserpine substations	Maintain supply reliability to Proserpine	North	Summer 2018/19
Proserpine Substation replacement	Maintain supply reliability in the North zone	North	Winter 2016
Moranbah 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	Summer 2016/17
Mackay Substation replacement	Maintain supply reliability in the North zone	North	Summer 2017/18
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone	North	Summer 2019/20
Rockhampton Substation replacement	Maintain supply reliability in the Central West zone	Central West	Winter 2016
Blackwater Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2016/17
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2016/17
Moura Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Stanwell secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2018/19
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (2)	Central West	Winter 2021
Callide A Substation replacement	Maintain supply reliability in the Central West zone (3)	Central West	Summer 2017/18
Line refit works on 132kV transmission lines between Calliope River to Boyne Island	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Tennyson secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2017
Upper Kedron secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2016
Rocklea secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2017
Blackwall IPASS secondary systems Replacement	Maintain supply reliability in the Moreton zone	Moreton	Winter 2017

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[1] In the interests of transparency secondary systems projects have been included.

Table 3.5 Committed and under construction network reinvestments at June 2016 *(continued)*

Project	Purpose	Zone location	Proposed commissioning date
Line refit works on 110kV transmission lines between Runcorn to Algester	Maintain supply reliability in the Moreton zone	Moreton	Summer 2016/17
Line refit works on 110kV transmission lines between Belmont to Runcorn	Maintain supply reliability in the Moreton zone	Moreton	Winter 2017
Mudgeeraba 110kV Substation primary plant and secondary systems replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	Summer 2017/18
Mudgeeraba 275/110kV transformer replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	Summer 2017/18

Note:

(1) The first transformer was commissioned in August 2013.

(2) 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.

(3) Refer to Section 4.2.4.

Table 3.6 Committed asset retirement works at June 2016

Project (1)	Purpose	Zone location	Proposed retirement date
Proserpine to Glenella 132kV transmission line retirement	Removal of assets at the end of technical life in the North zone	North	Summer 2016/17

Note:

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

3 Committed and commissioned network developments

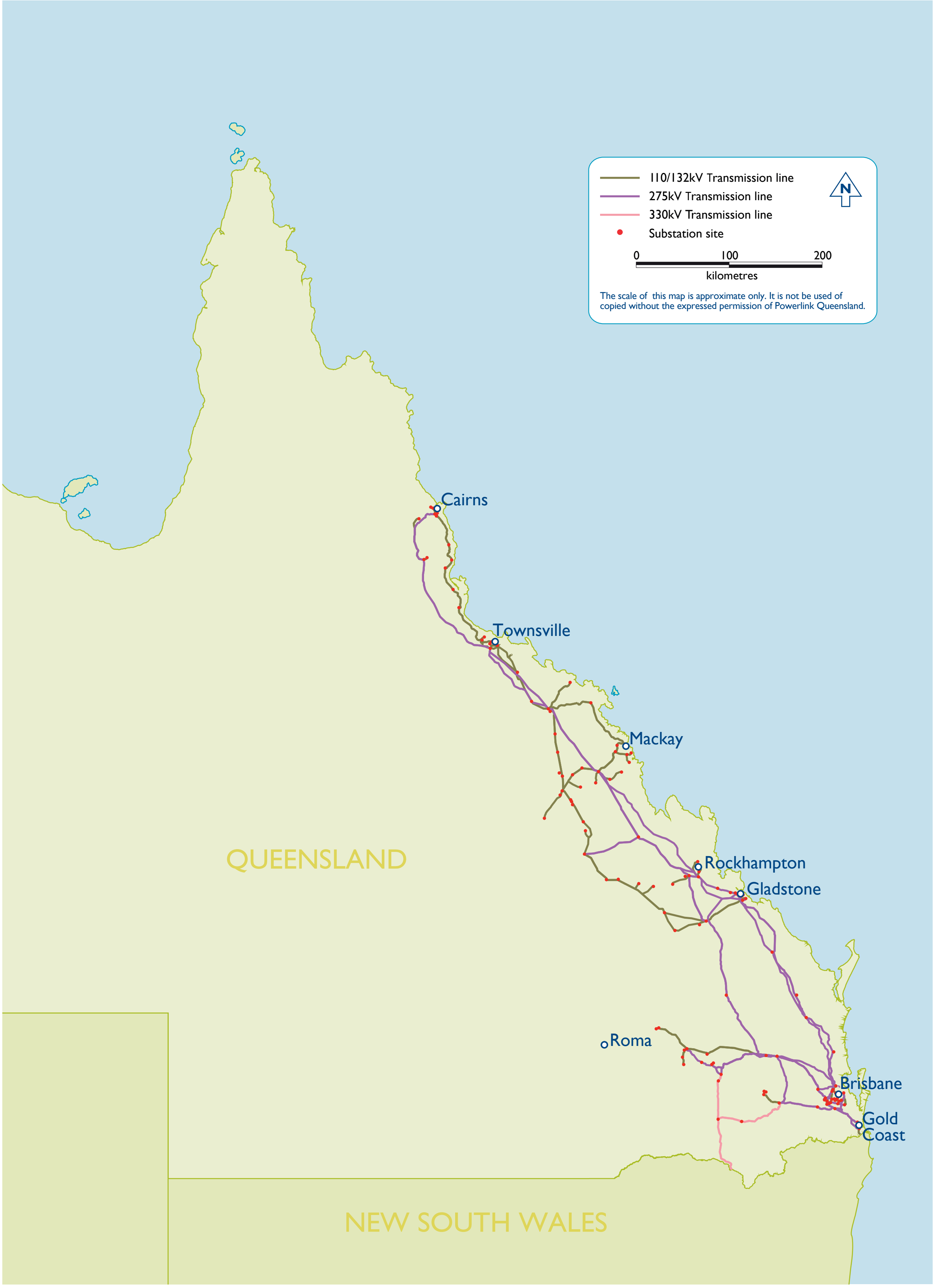

Figure 3.1 Existing Powerlink Queensland transmission network June 2016

Chapter 4:

Future network development

4 Future network development

Key highlights

- 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 reconfiguration opportunities to manage asset risks.
- The Ross, Central West, Gladstone and Moreton zones have considerable reconfiguration opportunities during the next five-year outlook period from 2016 to 2021.
- During 2015/16, Powerlink initiated a new Non-network Feasibility Study process for identifying non-network solutions. The first need being assessed through this process is the Garbutt transformers in the Townsville area.

4.1 Introduction

The National Electricity Rules (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)(7) and 5.15.3(b)(1)) requires the TAPR to include information pertinent to transmission network replacements where the capitalised expenditure is estimated to be more than $6 million[1].

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 technical or economic life and options to address identified asset risks
- 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 or non-network alternatives (NER Clause 5.12.2(c)(4)(iv))
- a table summarising the outlook for network limitations over a five-year horizon and their relationship to the Australian Energy Market Operator (AEMO) 2015 National Transmission Network Development Plan (NTNDP)
- details of 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.

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[1] In accordance with the AER's Cost Threshold Review undertaken in 2015, the revised cost threshold for the RIT-T as well as public information requirements for replacement projects was amended from $5 million to $6 million. The revised cost threshold came into effect from 1st January, 2016.

[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.

4.1.1 Integrated approach to network development

Powerlink's planning for future network development focuses on optimising the network topology based on consideration of future network needs due to:

- forecast demand
- new customer supply requirements
- 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 4.1.

Table 4.1 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 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. Powerlink also utilises a line reinvestment strategy called Line Refit to extend the technical 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.
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 retirement	May include strategies to disconnect, decommission and/or demolish an asset and is considered in cases where load driven needs have diminished or can be deferred in order to achieve long-term economic benefits.
Operational refurbishment	Operational refurbishment includes the replacement of a part of an asset which restores the asset to a serviceable level and does not significantly extend the life of the asset.
Additional maintenance	Additional maintenance is maintenance undertaken at elevated levels in order to keep assets at the end of their life in a safe and reliable condition.
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 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.

4.1.2 Forecast capital expenditure

In the five years since submitting its last Revenue Proposal, there have been 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.

As a result Powerlink's capital expenditure program of work for the outlook period is considerably less than that of previous years. The load driven capital expenditure originally forecast in the 2013-17 regulatory period will not be realised due to these fundamental shifts in Powerlink's business and operating environment which contributed to a downturn in commodity prices which significantly reduced resource sector investment, underlying economic growth and the associated demand for electricity. Similarly distribution load demand remained relatively flat driven by consumer response to high electricity prices, increased focus on energy efficiency and the uptake of distributed solar PV installations.

In this changed environment, the reduction in forecast demand growth also had an impact on Powerlink's planned reinvestment program. Powerlink has adapted its approach to reinvestment decisions, with a particular focus on assessing whether there is an enduring need for the key assets and seeking alternative investment options through network reconfiguration to manage asset condition.

Also, Powerlink has taken a cautious approach in determining where it is appropriate to refit or replace ageing transmission line assets and how to implement these works cost effectively. These changes are aimed at delivering better value to consumers. As a result, capital expenditure driven by asset condition, compliance and other non-load related factors significantly reduced in the 2013-17 regulatory period compared to the AER allowance.

For the 2018-22 regulatory period, Powerlink has increased its focus on alternative risk mitigation options (such as network reconfiguration and asset retirement) and lower cost technical solutions that deliver greater flexibility. Powerlink's forecast total capital expenditure for the 2018-22 regulatory period is $957.1m, which is an average annual expenditure of $191.4m[3]. This is a reduction of $84.8m (-31%) and $471.2m (-71%) per year compared to actual expenditure in the 2013-17 and 2008-12 regulatory periods, respectively.

The five-year outlook period discussed in the 2016 TAPR runs from 2016/17 to 2021/22 and discusses transmission network projects where the estimated cost is over $6 million. This outlook period traverses both the 2013-17 and 2018-22 regulatory periods.

4.1.3 Forecast network limitations

As outlined in Section 1.6.1, 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 amended planning standard, which came into effect 1 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 amended 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 in Chapter 3.

Assuming that the demand for electricity remains relatively flat as forecast in this TAPR, Powerlink does not anticipate undertaking any significant augmentation works within the outlook period other than those which could potentially be triggered from the commitment of mining or industrial block loads (refer to Table 4.2). In Powerlink's Revenue Proposal the projects that would be triggered by these large loads were identified as contingent projects. These proposed contingent projects and their triggers are discussed in detail in Section 6.2.

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[3] Refers to 16/17 dollars.

Table 4.2: **Proposed contingent projects**

Potential project	Indicative costs
North West Surat Basin Area	$147.2m
Central to North Queensland Reinforcement	$55.1m
Southern Galilee Basin connection shared network works	$116.9m
Northern Bowen Basin area	$55.7m
Bowen Industrial Estate	$42.9m
QNI upgrade (Queensland component)	$66.7m
Gladstone area reinforcement	$105.5m

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.

4.2 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 35 and 55 years old. It has been identified that a number of these assets are approaching the end of their technical or economic life and reinvestment in some form is required within the outlook period in order to manage emerging risks related to safety, reliability and other factors. Reinvestment in the transmission network to manage identified risks associated with these end of life 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 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; or
- consider other options from those originally identified which may deliver a greater benefit to customers and consumers.

Information regarding possible reinvestment alternatives is updated annually within the TAPR and includes discussion based on the latest information available at the time.

Proposed network developments within the five-year outlook period are discussed below. The developments are the most likely solution, but may change with ongoing analysis of asset condition and network requirements. For clarity, an analysis of this program of work has been performed across Powerlink's standard geographic zones.

4.2.1 Far North zone

Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at the Ross, 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 connection to the hydro power stations at Barron Gorge and Kareeya.

Network limitations

There are no network limitations forecast to occur in the Far North zone within the five-year outlook period.

Transmission lines

Kareeya to Chalumbin 132kV transmission line

The 132kV transmission line was constructed in the mid 1980s and provides connection to the Kareeya Power Station from the Chalumbin Substation. It operates in an environmentally sensitive world heritage area in the Wet Tropics with extremely high humidity conditions impacting on the life of its galvanised components. The extent of corrosion observed during Powerlink's condition assessment, and the inherent constraints of working within the Wet Tropics Management Authority area, requires that Powerlink consider options for line refit works by summer 2017/18 or replacement by summer 2022/23.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the Far North zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period. Planning analysis confirms these assets are required to provide an ongoing reliable supply and power station connection within the zone and the related investment needs are outlined in Table 4.3.

Table 4.3 Possible reinvestment works in the Far North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on the 132kV transmission line between Kareeya and Chalumbin substations	Line refit works on steel lattice structures	Maintain supply reliability to Kareeya	Summer 2017/18	New 132kV transmission line on new easement	$8m
Substations					
Retirement of one 132/22kV Cairns transformer	Retirement of one 132kV Cairns transformer including primary plant reconfiguration works (1)	Maintain supply reliability to the Far North zone	Summer 2019/20	Replacement of the transformer	$0.5m
Kamerunga Substation replacement	Full replacement of 132kV substation	Maintain supply reliability to the Far North zone	Summer 2019/20	Staged replacement of 132kV primary plant and secondary systems	$25m
Woree secondary systems replacement	Staged replacement of the 132kV secondary systems equipment	Maintain supply reliability to the Far North zone	Summer 2020/21	Full replacement of 132kV secondary systems	$10m

Note:

(1) There may be additional works and associated costs required by Ergon Energy that need to be economically evaluated in relation to reconfiguration of the 22kV switchyard.

4.2.2 Ross zone

Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, heavy commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville. 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 4.1 and 4.2).

Figure 4.1 Ross north zone transmission network

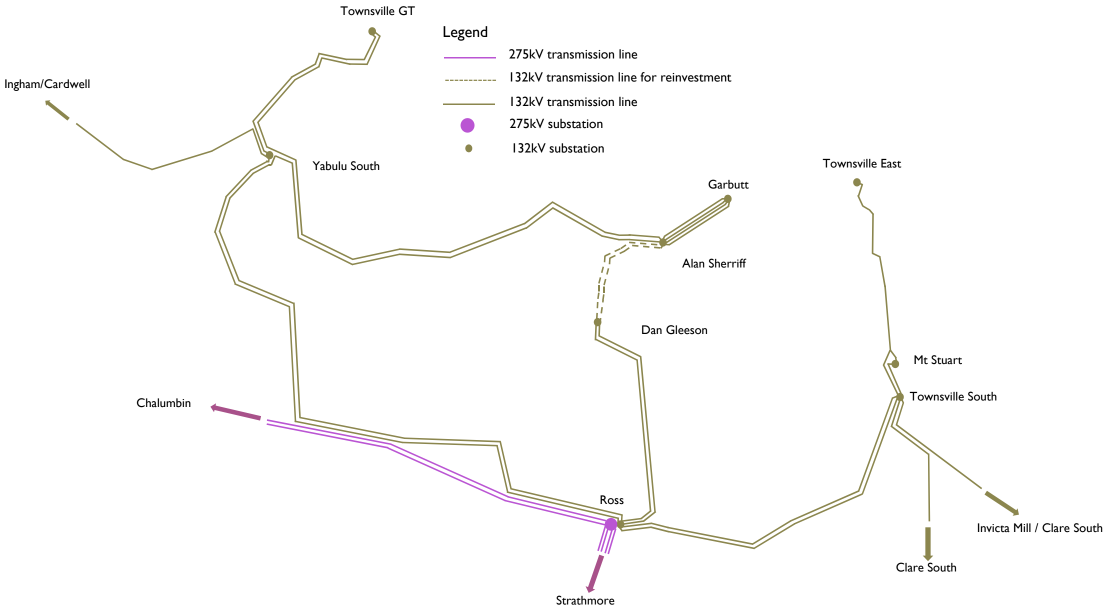
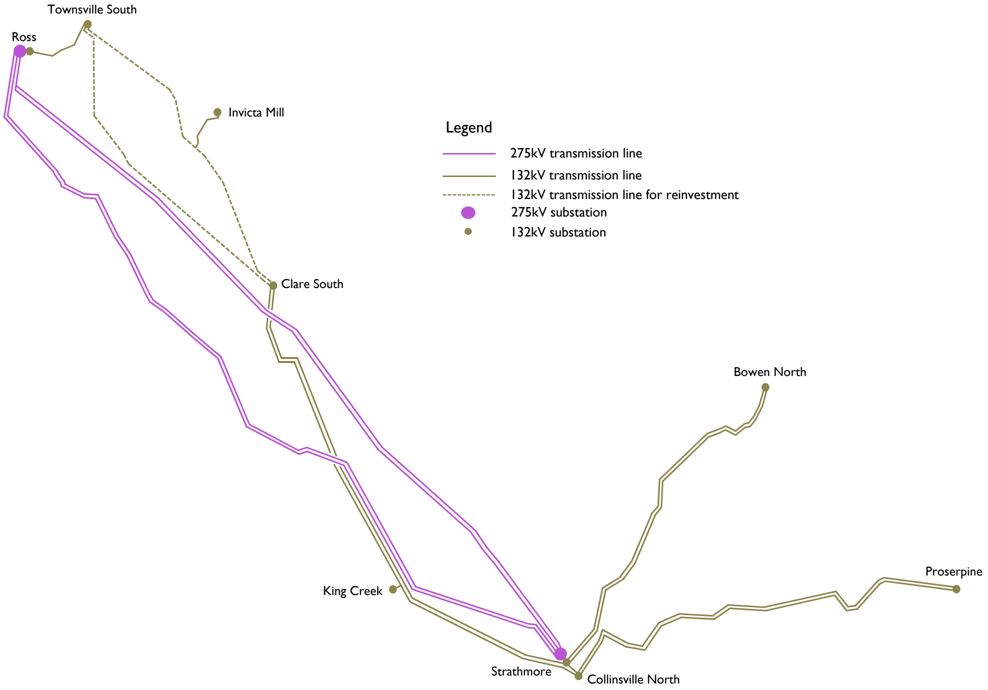


Figure 4.2 Ross south zone transmission network



Network limitations

There are no network limitations forecast to occur in the Ross zone within the five-year outlook period.

Transmission lines

Dan Gleeson – Alan Sherriff 132kV transmission line

The 132kV line between Dan Gleeson and Alan Sherriff substations was constructed in the 1960s and is located in the south-western suburbs of Townsville. The condition assessment indicates moderate levels of structural corrosion, along with the design limitations and degraded condition of the existing foundations that indicate that end of life is expected within the next five years. Detailed analysis is underway to evaluate foundation repair and line refit, replacement or possible retirement of this transmission line at the end of its technical life.

Townsville South to Clare South 132kV transmission lines

Two 132kV lines between Townsville South and Clare South substations were constructed in the 1960s on separate coastal and inland alignments. A condition assessment has confirmed that the coastal circuit has experienced higher rates of structural corrosion with end of life expected to occur within the next five to 10 years. Although the inland circuit has experienced lower rates of structural corrosion, the design limitations and degraded condition of the existing foundations indicate that end of life is expected within the next five years.

Planning studies have identified a potential network reconfiguration involving the retirement of one of the two 132kV transmission lines from Townsville South to Clare South substations. If retirement of this transmission line were to eventuate, it would result in voltage limitations in the surrounding Strathmore area. A possible solution to the voltage limitation could be the installation of a transformer at Strathmore Substation, line reconfiguration works, non-network support and/or additional voltage support in the Strathmore area (refer to Section 6.3.1).

As such, Powerlink is proposing to undertake line refit works on the coastal transmission line by around 2018/19 and further analysis is underway to evaluate the possible retirement of the inland transmission line at the end of its technical life.

Strathmore/Collinsville North to Clare South 132kV transmission lines

The 132kV line between Strathmore/Collinsville North and Clare South was constructed in the 1960s and is located in the Houghton and Burdekin catchment basins, with the northern section dominated by sugar cane and cattle grazing pastures. A recent condition assessment identified levels of structural corrosion with end of life expected to occur within the next five to 10 years.

As such, Powerlink is proposing to undertake line refit works on the transmission line by around 2021/22.

Powerlink is also considering further network reconfiguration in the Ross zone that may occur beyond the outlook period, which is discussed in Section 6.3.1.

Substations

Powerlink's routine program of condition assessments has identified transformer, primary plant and secondary systems assets within the Ross zone with emerging reliability, safety and obsolescence risks that may require reinvestment within the outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.4.

Non-network solutions

In Powerlink's 2015 TAPR a potential non-network solution was identified as an alternative option to the replacement of both of the 132/66kV transformers at Garbutt. In March 2016, Powerlink initiated a Non-network Solution Feasibility Study[4] to provide non-network service providers and interested parties with technical information regarding Powerlink's requirements for the purpose of inviting information, comment and discussion. The feasibility study is currently underway and the information received will be used for indicative cost purposes to assess the viability and potential of non-network solutions in the Townsville area. Powerlink intends to publish a statement on its website noting the conceptual findings of the study by August 2016.

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[4] Details of the Non-network Feasibility Study are available on Powerlink's website

Table 4.4 Possible reinvestment works in the Ross zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on the coastal 132kV transmission line between Townsville South and Clare South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Ross zone	Summer 2018/19	New 132kV transmission line. Line refit works on 132kV transmission line between Townsville South and Invicta, and additional reinforcement at Strathmore.	$29m
Retirement of the inland 132kV transmission line between Townsville South and Clare South substations	Retirement of the transmission line including non-network support, voltage support or network reconfiguration in the Strathmore area (1) (2)	Maintain supply reliability in the Ross zone	Summer 2019/20	New 132kV transmission line. Targeted line refit works and foundation repair on the 132kV transmission line.	$10m
Line refit works on one 132kV transmission line between Strathmore/ Collinsville North and Clare South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Ross zone	Summer 2021/22	Line refit works on 132kV transmission line Strathmore and King Creek, and additional reinforcement at Clare South. New 132kV transmission line	$55m
Substations					
Ingham South 132/66kV transformers replacement	Replacement of both 132/66kV transformers	Maintain supply reliability in the Ross zone	Summer 2019/20	Staged replacement of the two 132/66kV transformers.	$7m
Garbutt 132/66kV transformers replacement	Replacement of both 132/66kV transformers	Maintain supply reliability in the Ross zone	Summer 2018/19	Staged replacement of the two 132/66kV transformers Reconfiguration to supply through a single transformer and non-network alternatives in the Townsville area (3).	$11m
Dan Gleeson Secondary Systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	Summer 2019/20	Staged replacement of 132kV secondary systems equipment	$7m

Table 4.4 Possible reinvestment works in the Ross zone within five years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Townsville South primary plant and secondary system replacement	Staged replacement of 132kV primary plant and secondary systems	Maintain supply reliability to the Ross zone	Summer 2020/21	Full replacement of 132kV primary plant and secondary systems.	$16m

Note:

(1) Modification and installation of system integrity protection schemes may be required to manage system security during system normal and during outages. The retirement of these transmission lines may also require establishment of an alternate telecommunications network.

(2) Non-network solutions in the North zone to remain within Powerlink's amended planning standard may include up to 15MW and 2,500MWh in the Proserpine area.

(3) Non-network solutions in the Ross zone to remain within Powerlink's amended planning standard may include up to 10MW and 500MWh in the Townsville area[5].

4.2.3 North zone

Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form the 275kV transmission network supplying the Northern zone. Double circuit inland and coastal 132kV routes supply regional centres and infrastructure related to mines, coal haulage and ports associated with the Bowen Basin mines (refer to Figure 4.3).

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

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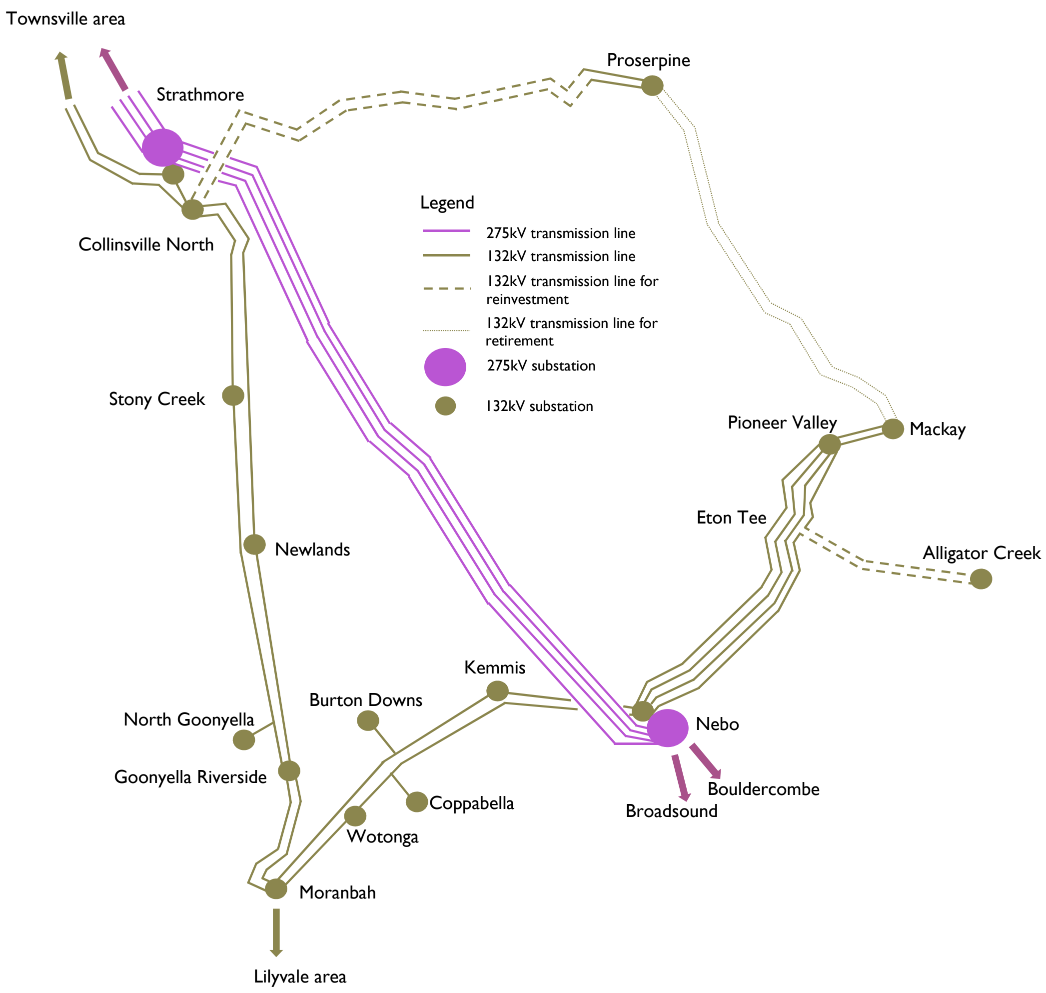
[5] The level of network support is dependent on the location and type of network support and is subject to change over time as the network and configuration changes, load forecasts are amended and operational and technical matters effect network performance. Interested parties are requested to contact Powerlink directly before considering any investment relating to the level of network support described.

Figure 4.3 North zone transmission network



Network limitations

The combination of increasing local demand in the Proserpine area, along with assets in the area reaching the end of their technical life, is expected to lead to some load at risk under Powerlink's amended planning standard within the outlook period.

The critical contingency is an outage of the 275/132kV Strathmore transformer. Based on the medium economic forecast of this TAPR, this places load at risk of 15MW and 100MWh from summer 2016/17, which is within the 50MW and 600MWh limits established under Powerlink's amended planning standard (refer to Section 1.7).

Collinsville North to Proserpine 132kV transmission line

The 132kV transmission line was constructed in the late 1960s and supplies Proserpine Substation and the Whitsunday region. Following the retirement of the Proserpine to Mackay transmission line in 2017/18, Collinsville North to Proserpine will be the only 132kV transmission line into the region. There is a committed project to address corrosion on the remaining inland structures of this transmission line by summer 2017/18.

Eton Tee to Alligator Creek 132kV transmission line

The 132kV transmission line was constructed in the early 1980s and there is an ongoing need for this asset to supply critical port and coal haulage infrastructure associated with the Mackay ports. The line is in proximity to the coast and is exposed to highly corrosive, salt laden winds. The profile of corrosion observed along the feeder is such that Powerlink is likely to refit these lines by summer 2018/19

Table 4.5 Possible reinvestment works in the North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Line refit works on the 132kV transmission line between Eton Tee and Alligator Creek Substation	Line refit works on steel lattice structures	Maintain supply reliability to Alligator Creek	Summer 2018/19	New 132kV transmission line	$10m

Supply to Bowen Basin coal mining area

Forecast limitation

The Bowen Basin area is defined as the area of 132kV supply north of Lilyvale Substation, west of Nebo Substation and south and east of Strathmore Substation.

In August 2013, Powerlink completed a RIT-T consultation to address voltage and thermal limitations[6] forecast to occur in the Bowen Basin coal mining area from summer 2013/14 due to expected demand growth. As part of this process, Powerlink identified the installation of 132kV capacitor banks at Dysart, Newlands, and Moranbah substations, and entered into a non-network arrangement as the preferred option to address the emerging network limitations.

Powerlink has completed the installation of the capacitor banks at Dysart and Newland substations. However, the installation of a capacitor bank at Moranbah substation has been deferred in order to optimise project staging with other works planned at the substation (refer to Table 3.2). The Moranbah capacitor bank is expected to be commissioned by summer 2017/18. The non-network agreement that Powerlink entered following completion of the RIT-T process will also come to an end in December 2016.

There have been several proposals for new coal mining, liquefied natural gas (LNG) and port expansion projects in the Bowen Basin area whose development status is not yet at the stage that they can be included (either wholly or in part) in the medium economic forecast of this TAPR. These loads could be up to 500MW (refer to Table 2.1) and cause voltage and thermal limitations impacting network reliability. Possible network solutions to these limitations are provided in Section 6.2.1. The timing of any emerging limitations will be subject to commitment of additional demand.

4.2.4 Central West and Gladstone zones

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 drier 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 technical life but will require replacement or rebuilding in the near future.

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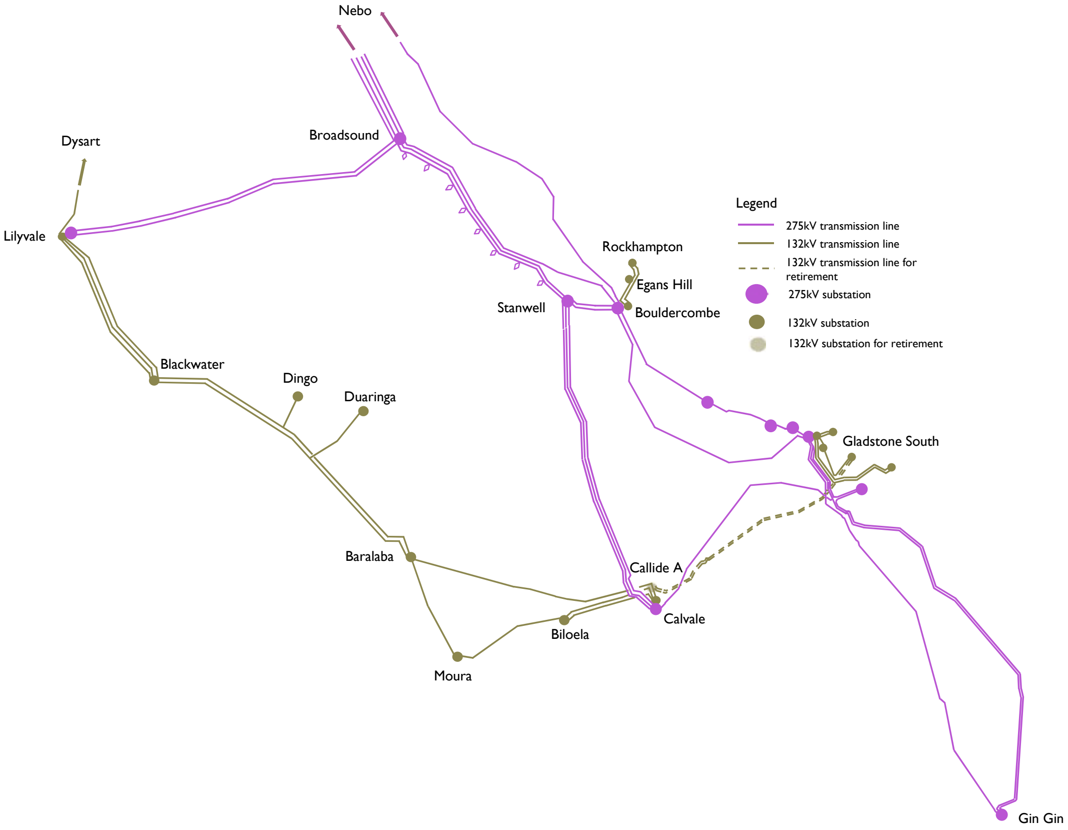
[6] Details of this consultation and the relevant technical information are available on Powerlink's website Maintaining a Reliable Electricity Supply to the Bowen Basin coal mining area

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 in the early 1990s. The 132kV injection point for Gladstone is the Calliope River Substation (refer to Figure 4.4).

Figure 4.4 Central West and Gladstone transmission network



Network limitations

There are no network limitations forecast to occur in the Central West or Gladstone zones within the five-year outlook period.

Transmission lines

Egans Hill to Rockhampton 132kV transmission line

Rockhampton is supplied via a 132kV transmission line from Bouldercombe Substation. The portion from Egans Hill to Rockhampton was constructed in the early 1960s and there is an ongoing need for this asset to supply the Rockhampton region. A recent condition assessment identified levels of structural corrosion with end of life expected to occur within the next five years.

As such, Powerlink is proposing to undertake line refit works on the transmission line by around 2018/19.

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 regions. The condition assessment indicates moderate levels of structural corrosion, along with design limitations and degraded condition of the existing foundations, end of life is expected to occur within the next five to 10 years. Detailed analysis is underway to evaluate foundation repair and line refit or a staged replacement of this transmission line progressively from 2020 to 2025.

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. A recent condition assessment identified high levels of structural corrosion with end of life expected to occur within the next five years. Planning analysis has identified the possibility of re-configuring the network in the area to achieve the lowest run cost of the 132kV substations reinvestment, and as such it is proposed this line be retired from service at the end of its technical life expected within the next five years.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets within the Central West and Gladstone zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period.

Powerlink has identified the possibility of reconfiguring the network by summer 2018/19 to provide efficiencies and cost saving by:

- Reducing the number of transformers within the zone, particularly at Lilyvale and Bouldercombe.
- Re-arrangement of the 132kV network between Gladstone South, Calvale and Blackwater substations, establishment of a second transformer at Calvale Substation, and retirement of Callide A substation and the Callide A to Gladstone South feeders.

The planning analysis also confirms the balance of substation assets are required to provide an ongoing reliable supply and the related investment needs are outlined in Table 4.6.

Table 4.6 Possible replacement works in the Central West and Gladstone zones within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit of the 132kV transmission line between Egans Hill and Rockhampton substations	Line refit works on steel lattice structures	Maintain supply reliability in the Central West zone	Summer 2018/19	New 132kV transmission line	$6m
Line replacement of the 132kV transmission line between Callide A and Moura substations	Staged replacement of 132kV transmission line between Callide A and Moura substations	Maintain supply reliability to Biloela and Moura in the Central West zone	Progressively from 2020	Foundation repair and line refit works	$68m
Retirement of the 132kV transmission line between Gladstone and Callide A	Retirement of the transmission line including network reconfiguration in Central West	Maintain supply reliability to Biloela and Moura in the Central West zone	Summer 2018/19	New 132kV transmission line	$10m
Substations					
Callide A Substation replacement	Reconfigure the network – bypass Callide A substation and establish second transformer at Calvale.	Maintain supply reliability in the Central West zone	Summer 2018/2019	Full replacement of Callide A substation	$20m
Dysart Substation replacement	Staged replacement of the 132kV primary plant and secondary systems	Maintain supply reliability in the Central West zone	Summer 2019/20	Full replacement of 132kV substation	$12m
Dysart transformer replacement	Replacement of two 132/66kV transformers	Maintain supply reliability in the Central West zone	Summer 2019/20	Staged replacement of the two transformers	$9m
Bouldercombe primary plant replacement	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Central West zone	Summer 2019/20	Full replacement of 275/132kV substation	$26m
Bouldercombe transformer replacement	Replacement of one 275/132kV transformer with a larger unit, and retirement of the other	Maintain supply reliability in the Central West zone	Summer 2019/20	Replacement of two 275/132kV transformers	$7m
Wurdong secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	Summer 2018/19	In situ staged replacement of secondary systems equipment	$10m
Lilyvale primary plant replacement	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Central West zone	Summer 2020/21	Full replacement of 275/132kV substation	$8m

Table 4.6 Possible replacement works in the Central West and Gladstone zones within five years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Lilyvale transformers replacement	Replacement of two of the three 132/66kV transformers (1)	Maintain supply reliability in the Central West zone	Winter 2020	Replacement of three 132/66kV transformers.	$9m

Note:

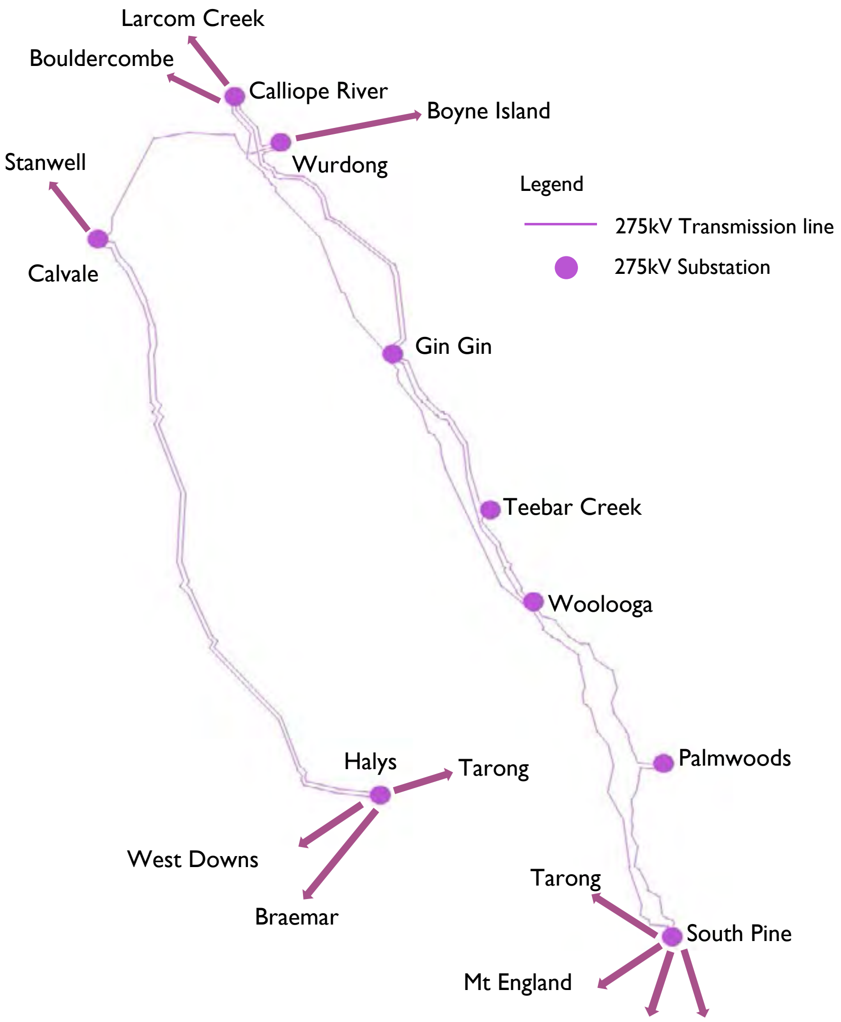
(1) Non-network solutions in the Central West and Gladstone zone:
Due to the extent of available headroom, the retirement of this transformer does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's demand forecast outlook.

4.2.5 Wide Bay zone

Existing network

The Wide Bay zone supplies loads in the Maryborough and Bundaberg region and also forms part of Powerlink's eastern Central Queensland to Southern Queensland (CQ-SQ) transmission corridor. This corridor was constructed in the 1970s and 1980s and consists of single circuit 275kV transmission lines between Calliope River and South Pine (refer to Figure 4.5). They traverse through a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 4.5 Wide Bay zone transmission network



Network limitations

There are no network limitations forecast to occur in the Wide Bay zone within the five-year outlook period.

Transmission lines

Palmwoods to Woologa 275kV transmission line

The 275kV transmission line was constructed in 1976 to support the supply of South East Queensland (SEQ) from the generation in Gladstone. A large portion of the 275kV transmission line traverses the wet hinterland micro-environment and results in higher rates of corrosion. The extent of corrosion observed during Powerlink's condition assessment required consideration of options for the line refit work around summer 2021/22.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the Wide Bay zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period. Planning analysis confirms these substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.7.

Table 4.7 Possible reinvestment works in the Wide Bay zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission Lines					
Woolooga to Palmwoods Transmission Line refit	Line refit works on steel lattice structures	Maintain supply reliability in the Wide Bay zone	Winter 2021	New 275kV transmission line	$20m
Substations					
Gin Gin Substation rebuild	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Wide Bay zone	Summer 2018/19	Full replacement of 275/132kV substation In-situ replacement of the 275/132kV substation	$27m

4.2.6 South West zone

Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge.

Network limitations

There are no network limitations forecast to occur within the South west zone within the five-year outlook period.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the South West zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period. Planning analysis confirms these substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.8.

Table 4.8 Possible reinvestment works in the South West zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Substations					
Tarong secondary systems replacement	In situ staged replacement of secondary systems equipment	Maintain supply reliability in the South West zone	Summer 2021/22	Full replacement of 275kV secondary systems	$11m

4.2.7 Moreton zone

Existing network

The Moreton zone includes a mix of 110kV and 275kV transmission network servicing a number of significant load centres in SEQ, including the Sunshine Coast, greater Brisbane, Ipswich and northern Gold Coast regions.

Future investment needs in the Moreton zone are substantially associated with 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 between the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth between the early 1970s and 2010. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane CBD.

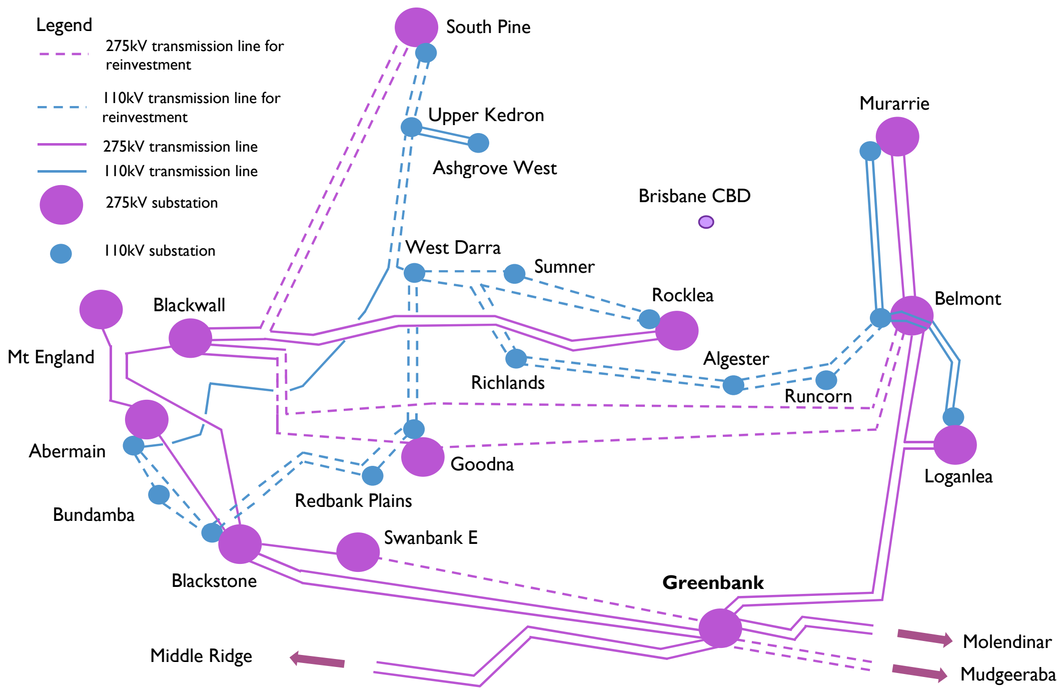
Network limitations

There are no network limitations forecast to occur in the Moreton zone within the five-year outlook period.

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. Most 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 life for most transmission line assets expected to occur between 2020 and 2025. Figure 4.6 illustrates the assets that are approaching end of life over this period.

Figure 4.6 Greater Brisbane transmission network



With the peak demand forecast relatively flat, and based on the development of the network over the last 40 years, planning studies have identified a number of 110kV and 275kV transmission line assets that could potentially be retired. Given the uncertainty in future demand growth, Powerlink proposes to implement low cost maintenance strategies to keep the transmission lines inservice for a reasonable period. Future decommissioning remains an option once demand growth is better understood. As such, detailed analysis will be ongoing to evaluate the possible retirement of the following transmission lines at the end of technical 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 investment recommendation in the 2020s and would involve further consultation with impacted parties.

For the balance of transmission line assets with an enduring need, Powerlink is progressively analysing options and is proposing a program of line refit works between winter 2016 and summer 2020/21 as the most cost effective solution to manage the safety and reliability risks associated with these assets remaining in-service.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets within the Moreton zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.9.

Table 4.9 Possible reinvestment works in the Moreton zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission Lines					
Line refit works on 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	Summer 2021/22	New 110kV transmission line/s	$7m
Line refit works on 110kV transmission lines between Sumner to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Summer 2021/22	New 110kV transmission line/s	$6m
Line refit works on 110kV transmission lines between Rocklea to Sumner	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Summer 2021/22	New 110kV transmission line/s	$9m
Line refit works on 110kV transmission lines between Blackstone to Redbank Plains to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2021/22	Reconfiguration of network and retirement of transmission line (1) New 110kV transmission line/s	$10
Line refit works on 275kV transmission lines between Karana Tee to Bergins Hill to Goodna to Belmont	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2021/22	New 275kV transmission line/s	$36m
Line refit works on 275kV transmission lines between South Pine to Karana Tee	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2021/22	New 275kV transmission line/s	$19m
Substations					
Ashgrove West Substation replacement	Full replacement of 110kV substation	Maintain supply reliability in the Moreton zone	Summer 2019	Staged replacement of 110kV primary plant and secondary systems	$13m
Abermain secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	Winter 2020	Staged replacement of 110kV secondary systems equipment	$7m
Belmont 275kV secondary system replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	Winter 2021	Staged replacement of 275kV secondary systems equipment	$9m

Table 4.9 Possible reinvestment works in the Moreton zone within five years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Palmwoods 275kV Substation primary and secondary replacement	Staged replacement of 275kV and 132kV primary plant and secondary systems panels	Maintain supply reliability in the Moreton zone	Summer 2021/22	Full replacement of 275/132kV substation	$23m

Note:

(1) Non-network solutions in the Moreton zone:

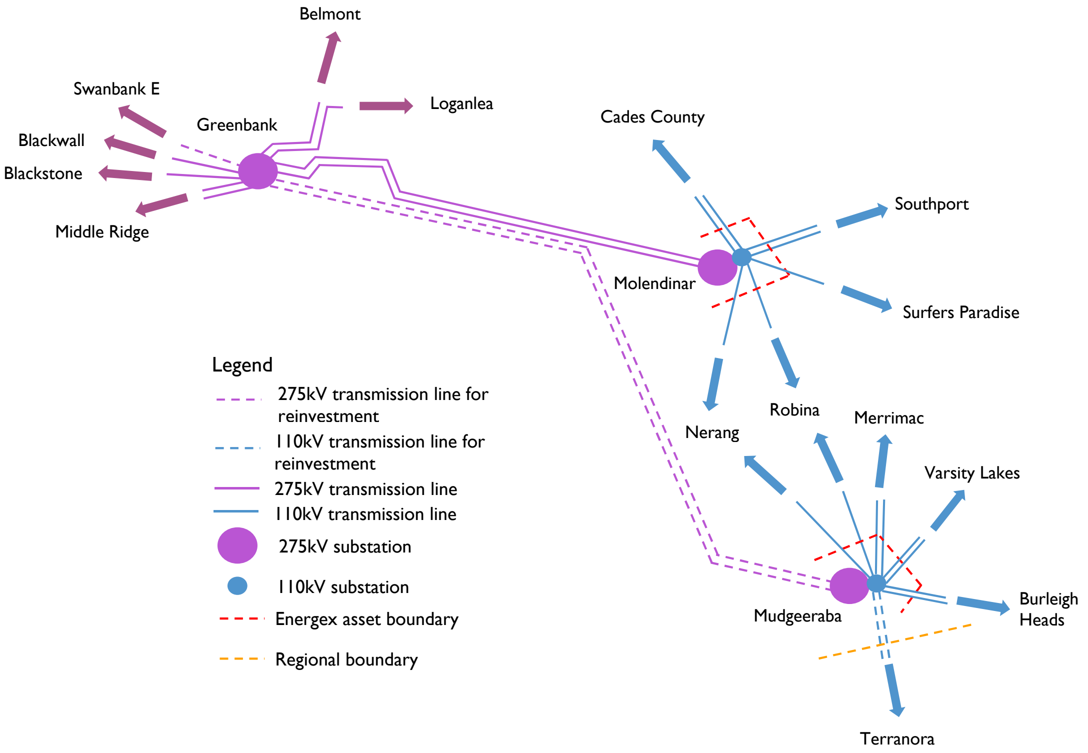
Due to the extent of available headroom, the retirement of identified 110kV transmission assets does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's demand forecast outlook.

4.2.8 Gold Coast zone

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 4.7) via a double circuit 275kV transmission line between Greenbank and Molendinar substations, and two single circuit 275kV transmission lines between Greenbank and Mudgeeraba substations.

Figure 4.7 Gold Coast transmission network



Network limitations

There are no network limitations forecast to occur in the Gold Coast zone within the five-year outlook period.

Transmission lines

Greenbank to Mudgeeraba 275kV transmission lines

The two 275kV transmission lines were constructed in the mid 1970s and are exposed to high rates of corrosion due to proximity to the coast and the prevailing salt laden coastal winds. The extent of corrosion observed during condition assessments requires that Powerlink consider options for line refit of these lines in the outlook period or the continued operation and replacement of the lines by around 2025. Network planning studies have confirmed the need to preserve 275kV injection into Mudgeeraba.

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 New South Wales (NSW), with 13km of the transmission line owned by Powerlink. The transmission line operates in a metropolitan/semi-coastal environment with moderate rates of atmospheric pollution, impacting on the life of its galvanised components and is subject to prevailing salt laden coastal winds. Based on Powerlink's condition assessment, line refit or replacement of the 13km transmission line section in the outlook period would be required by around 2025.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets at Mudgeeraba with emerging safety, reliability and obsolescence risks that may require reinvestment within the outlook period.

The condition of two of 275/110kV transformers at Mudgeeraba Substation requires action within the outlook period. Planning studies have identified the potential to replace one of the two Mudgeeraba 275/110kV transformers and subsequently retire the other transformer in summer 2019/20. This is considered feasible under the current demand forecast outlook. However, the reliability and market impacts of this option under a broader range of demand forecast scenarios need to be analysed in further detail and may require Powerlink undertake a RIT-T consultation.

Planning analysis confirms the balance of assets in this zone are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.10.

Table 4.10 **Possible replacement works in the Gold Coast zone within five years**

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on the 110kV transmission line between Mudgeeraba and Terranora substations	Line refit works on steel lattice structures	Maintain reliable interconnection to New South Wales	Summer 2019/20	New 110kV transmission line on new easement	$5m
Line refit works on the 275kV transmission lines between Greenbank and Mudgeeraba substations	Line refit works on steel lattice structures	Maintain supply reliability to the Gold Coast zone	Progressively from Summer 2020/21	New 275kV transmission line/s	$69m
Substations					
Retirement of one Mudgeeraba 275/110kV transformer	Retirement of the transformer (1)	Maintain supply reliability to the Gold Coast zone	Summer 2019/20	New 275/110kV transformer	$0.5m
Mudgeeraba 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability to the Gold Coast zone	Summer 2021/22	Staged replacement of 275kV secondary systems equipment	$11m

Note:

(1) Non-network solutions in the Gold Coast zone:

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.

4.3 Summary of forecast network limitations

Limitations discussed in Section 4.2 have been summarised in Table 4.11. This table provides an outlook (based on medium economic forecast demand, generation and committed network development assumptions contained in chapters 2, 3 and 5) for potential limitations in Powerlink's transmission network over a one, three and five-year timeframe. The table also identifies the manner in which potential limitations were analysed in the NTNDP.

Table 4.11 Summary of forecast network limitations

Anticipated limitation	Reason for limitation	Time limitation may be reached			Relationship to the 2015 NTNDP
		1-year outlook (2016/17)	3-year outlook (up to 2019/20)	5-year outlook (up to 2021/22)	
North zone					
Supply to Bowen Basin coal mining area	Due to potential mining growth by multiple proponents, thermal limitations expected to occur during a critical contingency	2013/14 to 2015/16 Committed project in progress (1)			Outside the scope of the 2015 NTNDP

Note:

(1) Refer to Table 3.2 – committed and under construction transmission developments at June 2016.

4.4 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 has been particularly evident in the Queensland region.

Proposals for transmission investments to address forecast limitations are progressed under the provisions of Clause 5.16.4 of the NER. Accordingly, and where action is considered necessary, Powerlink will:

- notify of anticipated limitations 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 to assist non-network solutions as possible genuine alternatives to transmission investments to be identified
- consult with AEMO, Registered Participants and interested parties on credible options (network or non-network) to address anticipated constraints
- carry out detailed analysis on credible options that Powerlink may propose to address identified network constraints
- 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 may be undertaken under the "funded augmentation" provisions of the NER.

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

4.4.1 Current consultations – proposed transmission investments

Proposals for transmission investments that address limitations are progressed under the provisions of Clause 5.16.4 of the NER. Powerlink carries out separate consultation processes for each proposed new transmission investment by utilising the RIT-T consultation process.

There are currently no consultations underway.

4.4.2 Future consultations – proposed transmission investments

There are currently no anticipated consultations within the next 12 months.

4.4.3 Summary of forecast network limitations beyond the five-year outlook period

The timing of forecast network limitations may be influenced by a number of factors such as load growth, industrial developments, new generation, the amended planning standard and joint planning with other network service providers. As a result of these variants, it is possible for the timing of forecast network limitations identified in a previous year's TAPR to shift beyond the five-year outlook period. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2015 TAPR which fall into this category in 2016.

4.4.4 Connection point proposals

Table 4.12 lists connection works that may be required within the five-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) or be initiated by generators or customers.

Table 4.12 Connection point proposals

Potential project	Purpose	Zone	Possible commissioning date
Mt Emerald Windfarm	New windfarm near Atherton (1)	Far North	2017/18
Clare Solar PV	New solar arm near Clare	Ross	Mid 2017
Genex Kidston Hydro/Solar PV	New Hydro generator with Solar PV	Ross	Mid 2019
Whitsunday Solar PV	New solar farm near Proserpine	North	Mid 2019
Baralaba Solar PV	New solar farm near Baralaba	Central West	Mid 2018
Multiple new coal mine 132kV connections	New industrial plant connections in the Galilee Basin area (1)	Central West	Progressively from summer 2018/19
Bulli Creek Solar PV	New solar farm neat Bulli Creek	Bulli	Mid 2019

Note:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, mine or Coal Seam Methane (CSM)/LNG 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.

4.5 NTNDP alignment

The 2015 NTNDP was published by AEMO in November 2015. The focus of the NTNDP is to provide an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission network over a 20 year planning horizon.

Modelling for the 2015 NTNDP included as its starting point the completed and committed projects defined in Section 3.2. The NTNDP transmission development analysis was based on the 2015 National Electricity Forecasting Report (NEFR) and focused on assessing the adequacy of the main transmission network to reliably support major power transfers between NEM generation and demand centres (referred to as NTNDP zones).

4 Future network development

The NEFR forecasts slowing maximum demand growth. This is broadly aligned with Powerlink's medium economic forecast in Chapter 2. The slowing forecast maximum demand growth results in fewer network limitations in all regions. In fact, the 2015 NTNDP did not identify any emerging reliability or potential economic dispatch limitations across the main transmission network linking NTNDP zones within the Queensland region. This outlook is consistent with the absence of forecast limitations identified across the main transmission network in this TAPR.

Both the NTNDP and this TAPR recognise that asset reinvestment will be the focus within the five-year outlook period and continue in the longer term. Planning for the future network will include optimising the network topology as assets reach the end of their technical and economic life so that the network is best configured to meet current and future needs.

The 2015 NTNDP modelled up to 6,700 megawatts (MW) of additional large-scale renewable generation investment across the NEM by 2020. The specific locations and capacity of this largescale renewable generation has the potential to impact the utilisation of grid sections within the Queensland region. Concentration of this generation in the same location may cause local transmission congestion due to network limitations. These outcomes will also be influenced by any subsequent withdrawal of thermal synchronous generation. This changing generation mix in the NEM may require new power system infrastructure to provide frequency control and network support services.

Powerlink will proactively monitor this 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 renewable energy in future transmission plans. These plans may include:

- reinvesting in assets to extend their end of 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 7
- replacing existing assets with assets of a different type, configuration or capacity or
- non-network solutions.

The NTNDP also presents results of analysis into the need for Network Support and Control Ancillary Services (NSCAS). NSCAS are procured to maintain power system security and reliability, and to maintain or increase the power transfer capabilities of the network. The 2015 NTNDP reported that no NSCAS gaps of any type were identified in the Queensland region over the next five years. However, both the NTNDP and this TAPR reported that operational strategies, including transmission line switching, may be required to manage high voltages under light load conditions in SEQ. AEMO and Powerlink will continue to monitor this situation.

Chapter 5:

Network capability and performance

5 Network capability and performance

Key highlights

- Tarong unit 2 (350MW) returned to service in February after being withdrawn for over 3 years. There were no commitments of new generation in Queensland during 2015/16.
- Differences in generation dispatch have resulted in greater utilisation of the FNQ, CQ-NQ, Gladstone and Tarong grid sections.
- During 2015/16, record peak transmission delivered demands were recorded in the North, Ross, Surat and Bulli zones.
- The transmission network has performed reliably during 2015/16, with Queensland grid sections largely unconstrained.

5.1 Introduction

This chapter on network capability and performance provides:

- a table of existing and committed generation capacity over the next three years
- sample power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and generation dispatch patterns
- 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 Queensland's transmission network
- historical system normal constraint times and load duration curves at key zones of Powerlink Queensland'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 summer demands generally last for many hours, whereas winter maximum demands are lower and last for short evening periods (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 2.14) and/or when embedded generation output is lower.

5.2 Existing and committed scheduled and transmission connected generation

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

There are no scheduled or semi-scheduled generation projects in Queensland that are currently classified as committed.

Due to the relatively flat outlook for load growth in the Queensland region, as outlined in Chapter 2, and more generally across the National Electricity Market (NEM), there have been a number of changes in the status of existing generating plant.

Stanwell Corporation withdrew two units at Tarong Power Station (PS) from service in October and December 2012 respectively. In December 2014, Stanwell Corporation withdrew Swanbank E PS from service for up to three years. Both Tarong PS units have now been returned to service[1].

Table 5.1 summarises the available capacity of power stations connected to Powerlink's transmission network including the non-scheduled market generators at Yarwun, Invicta and Koombooloomba. This table also includes scheduled embedded generators at Barcaldine and Roma and the Townsville PS 66kV component.

The information in this table has been provided to AEMO by the owners of the generators. Details of registration and generation capacities can be found on AEMO's website.

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[1] Tarong PS unit 4 was returned to service in July 2014 and unit 2 in February 2016.

Table 5.1 **Available generation capacity**

Existing and committed plant connected to the Powerlink transmission network and scheduled embedded generators.

Location	Available capacity MW generated (1)					
	Winter 2016	Summer 2016/17	Winter 2017	Summer 2017/18	Winter 2018	Summer 2018/19
Coalfired						
Stanwell	1,460	1,460	1,460	1,460	1,460	1,460
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Callide B	700	700	700	700	700	700
Callide Power Plant	900	900	900	900	900	900
Tarong North	443	443	443	443	443	443
Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Kogan Creek	744	730	744	730	744	730
Millmerran	852	760	852	760	852	760
Total coalfired	**8,179**	**8,073**	**8,179**	**8,073**	**8,179**	**8,073**
Combustion turbine						
Townsville (Yabulu) (2)	243	234	243	234	243	233
Mt Stuart (3)	419	379	419	379	419	379
Mackay (4)	34	34	34	-	–	–
Barcaldine (2)	37	34	37	34	37	34
Yarwun (5)	160	155	160	155	160	155
Roma (2)	68	54	68	54	68	54
Condamine	144	144	144	144	144	144
Braemar 1	504	471	504	471	504	471
Braemar 2	519	495	519	495	519	495
Darling Downs	633	580	633	580	633	580
Oakey (6)	340	282	340	282	340	282
Swanbank E (7)	–	–	385	385	385	385
Total combustion turbine	**3,101**	**2,862**	**3,486**	**3,213**	**3,452**	**3, 212**
Hydro electric						
Barron Gorge	66	66	66	66	66	66
Kareeya (including Koombooloomba) (8)	93	93	93	93	93	93
Wivenhoe (9)	500	500	500	500	500	500
Total hydro electric	**659**	**659**	**659**	**659**	**659**	**659**
Sugar mill						
Invicta (8)	34	0	34	0	34	0
Total all stations	11,973	11,594	12,358	11,945	12,324	11,944

Notes:

(1) The 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 stepup 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) Townsville 66kV component, Barcaldine and Roma power stations are embedded scheduled generators. Assumed generation is accounted in the transmission delivered forecast.

(3) Origin Energy has advised AEMO of its intention to retire Mt Stuart at the end of 2023.

(4) Stanwell Corporation has advised AEMO of its intention to retire Mackay GT at the end of financial year 2016/17.

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

(6) Oakey Power Station is an open-cycle, dual-fuel, gas-fired power station. The generated capacity quoted is based on gas fuel operation.

(7) Swanbank E has been placed into cold storage until 1 July 2017.

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

(9) Wivenhoe Power Station is shown at full capacity (500MW). However, output can be limited depending on water storage levels in the dam.

5.3 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 2016 to summer 2018/19 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 Queensland/New South Wales Interconnector (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 and committed projects (listed in tables 3.2, 3.5 and 3.6), and assume all network elements are available. In providing this information Powerlink has not attempted to predict market outcomes.

5.4 Transfer capability

5.4.1 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.

5.4.2 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, Transmission Network Service Providers (TNSPs) define the capability of their network using multiterm 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 Transmission Annual Planning Report (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 5.5 provides a qualitative description of the main system conditions that affect the capability of each grid section.

5.5 Grid section performance

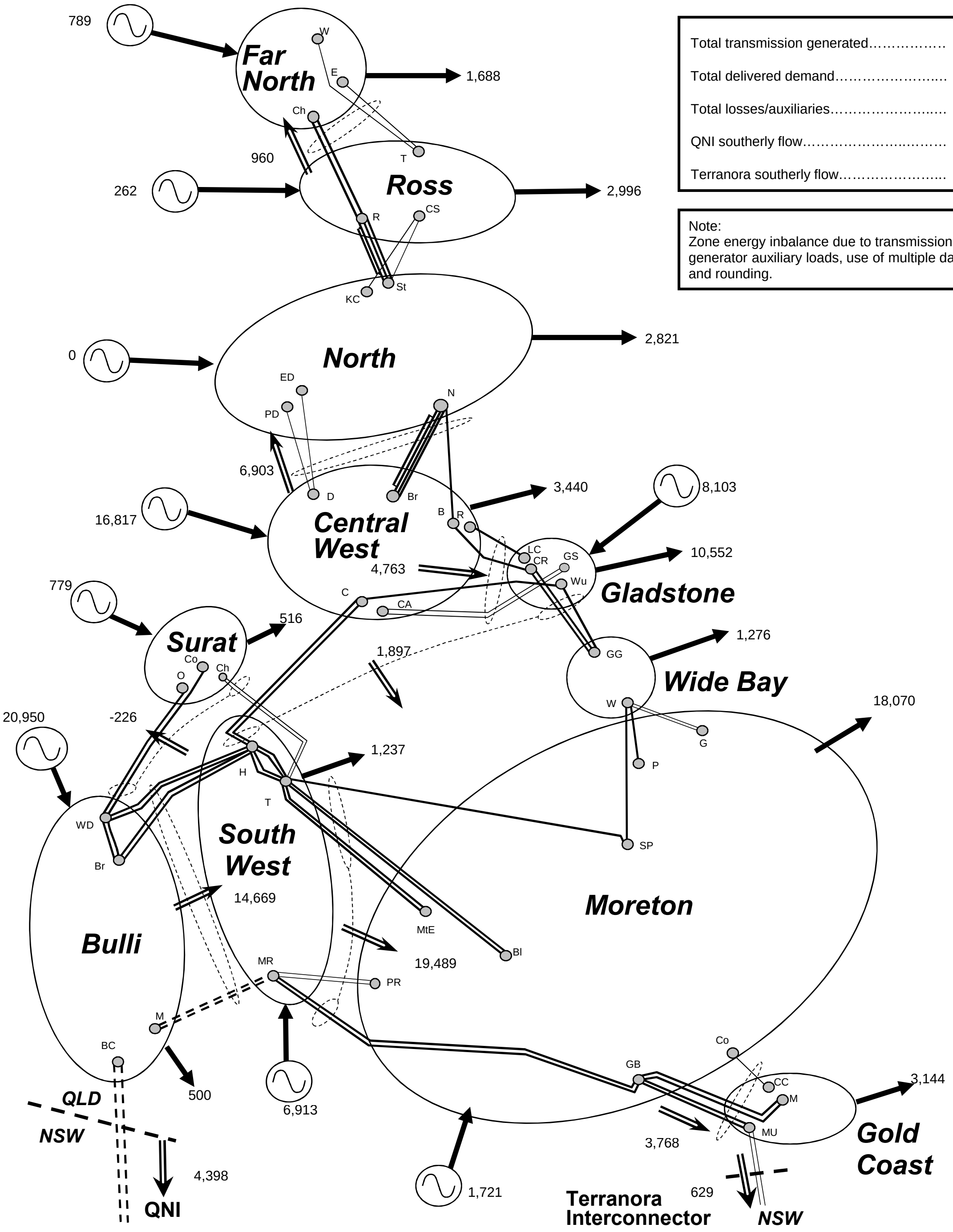
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

For each grid section, the time that the relevant constraint equations have bound is provided over the last 10 years. Years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period. 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 5.1 and 5.2 provide 2014 and 2015 zonal energy as generated into the transmission network (refer to Figure C.1 in Appendix C for generators included in each zone), transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers and grid section energy transfers. Figure 5.3 provides the changes in energy transfers from 2014 to 2015. These figures assist in the explanation of differences between 2014 and 2015 grid section transfer duration curves.

Figure 5.1 2014[2] zonal electrical energy transfers (GWh)



Total transmission generated……………..	56,334 GWh
Total delivered demand……………………..	46,240 GWh
Total losses/auxiliaries……………………..	5,067 GWh
QNI southerly flow…………………………..	4,398 GWh
Terranora southerly flow…………………...	629 GWh

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

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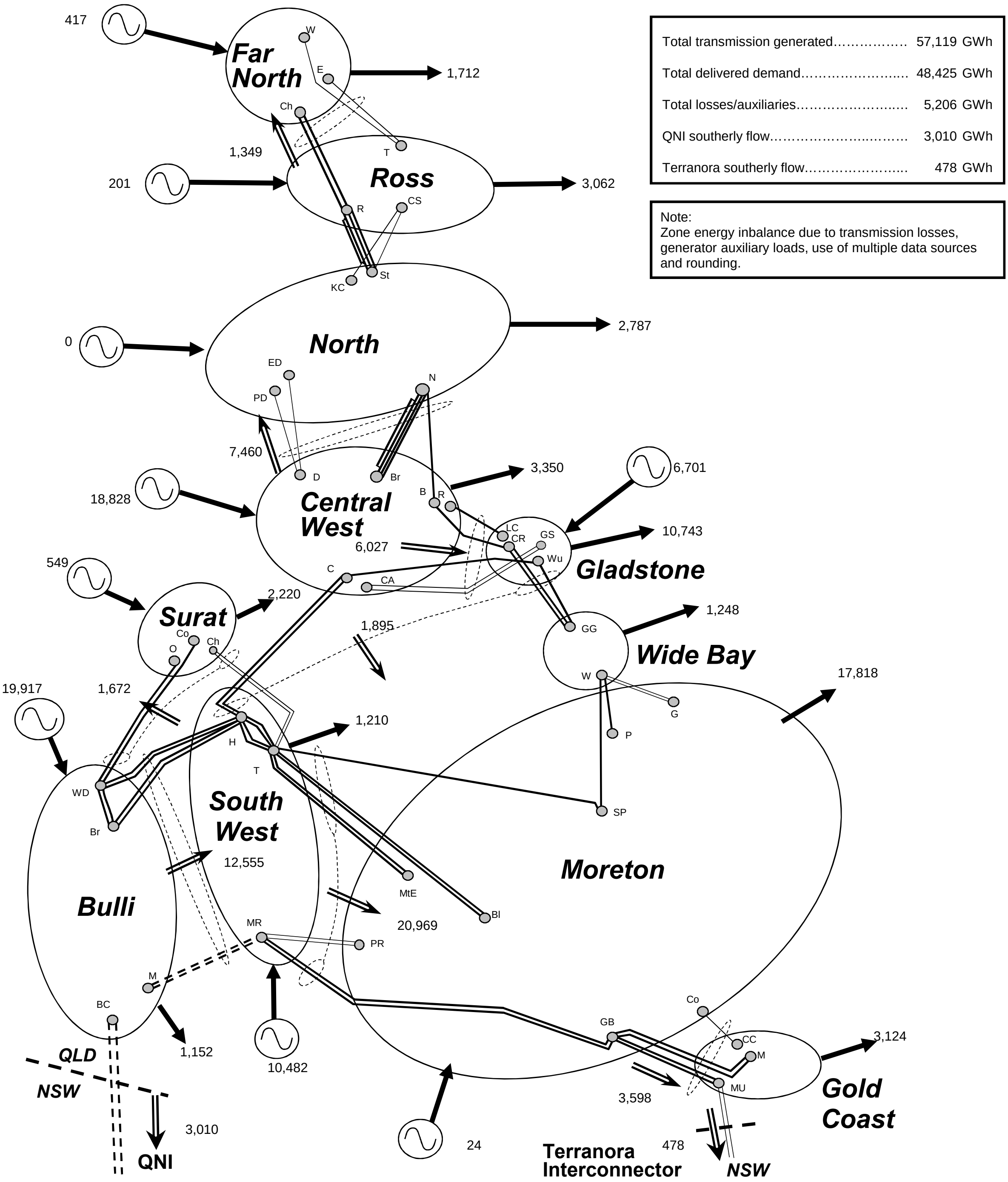
[2] Consistent with this chapter, time periods are from April 2014 to March 2015.

Figure 5.2 2015[3] zonal electrical energy transfers (GWh)



Total transmission generated.................	57,119 GWh
Total delivered demand.........................	48,425 GWh
Total losses/auxiliaries.........................	5,206 GWh
QNI southerly flow................................	3,010 GWh
Terranora southerly flow........................	478 GWh

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

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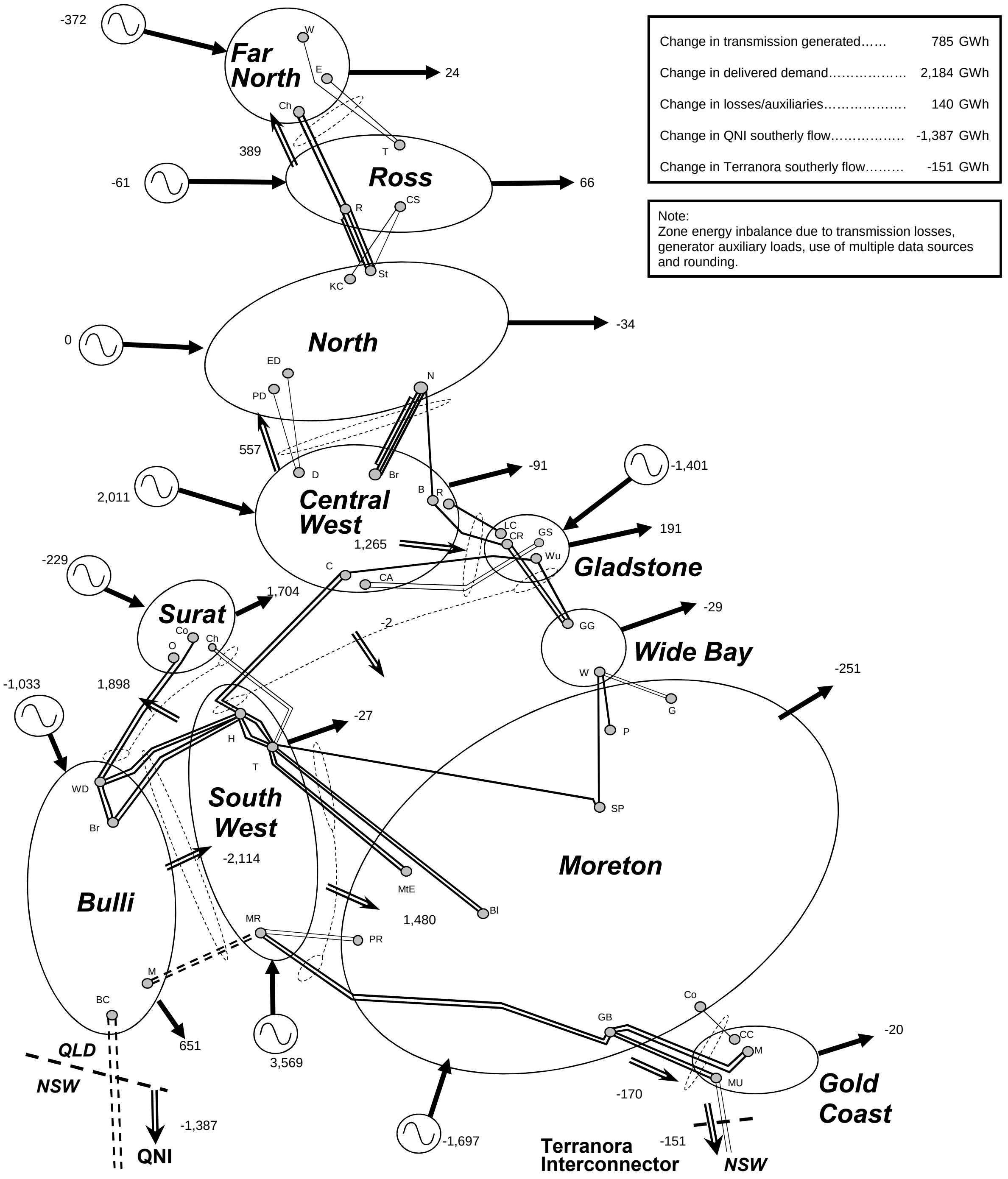
[3] Consistent with this chapter, time periods are from April 2015 to March 2016.

Figure 5.3 Change[4] in zonal electrical energy transfers (GWh)



Change in transmission generated……	785 GWh
Change in delivered demand………………	2,184 GWh
Change in losses/auxiliaries……………….	140 GWh
Change in QNI southerly flow…………….	-1,387 GWh
Change in Terranora southerly flow………	-151 GWh

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

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[4] Consistent with this chapter, time periods for the comparison are from April 2015 to March 2016 and April 2014 to March 2015.

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.

5.5.1 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.

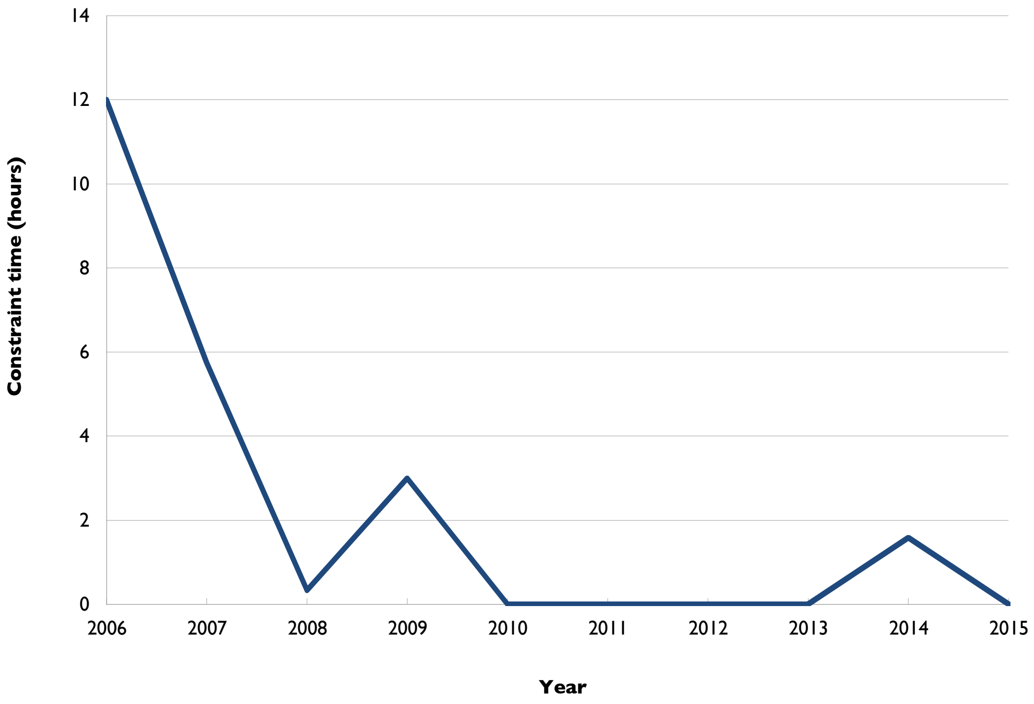
The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone to northern Queensland[5] 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 the reduction in power transfer due to increased local generation is greater than the reduction in grid section transfer capability.

The FNQ grid section did not constrain operation during April 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the FNQ grid section is summarised in Figure 5.4.

Figure 5.4 Historical FNQ grid section constraint times



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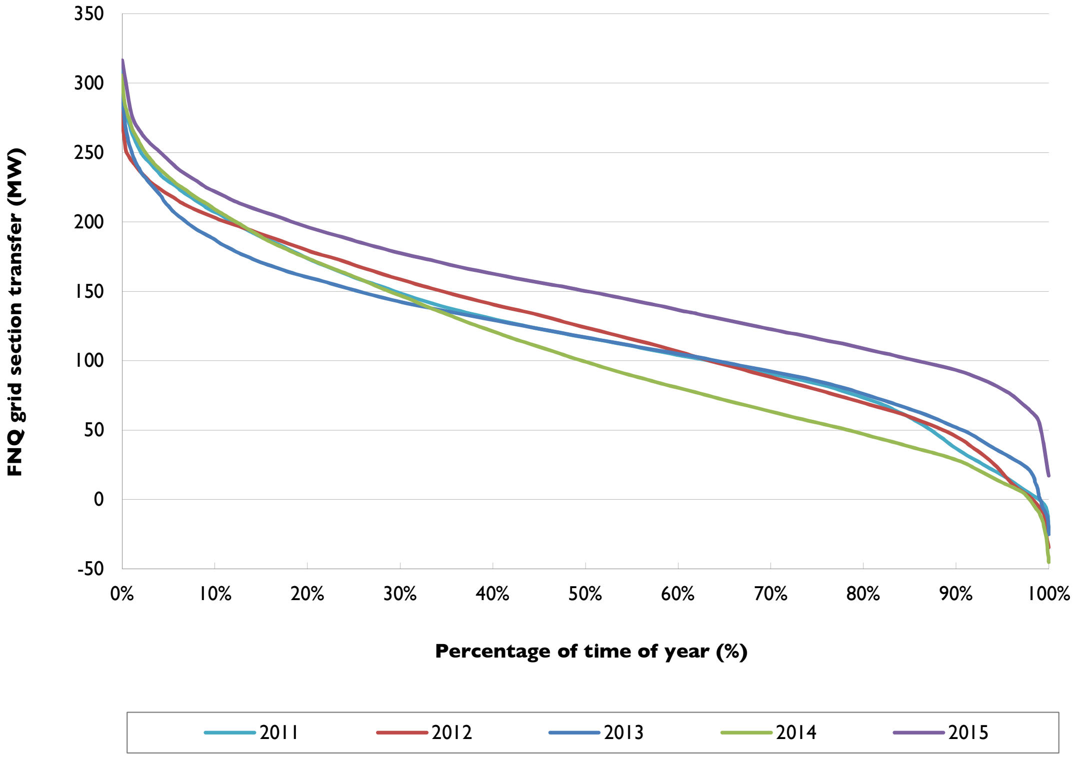
[5] Northern Queensland is defined as the combined demand of the Far North, Ross and North zones.

Constraint durations have reduced over time due to the commissioning of various transmission projects[6]. There have been minimal constraints in this grid section since 2008.

Figure 5.5 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. The peak output and annual capacity factor of the hydro generating power stations at Barron Gorge and Kareeya also impact the utilisation of this grid section. These vary depending on rainfall levels in the Far North zone. The capacity factor of the hydro generating power stations reduced from approximately 55% in 2014 to approximately 30% in 2015 (refer to figures 5.1, 5.2 and 5.3).

Figure 5.5 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.

5.5.2 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.

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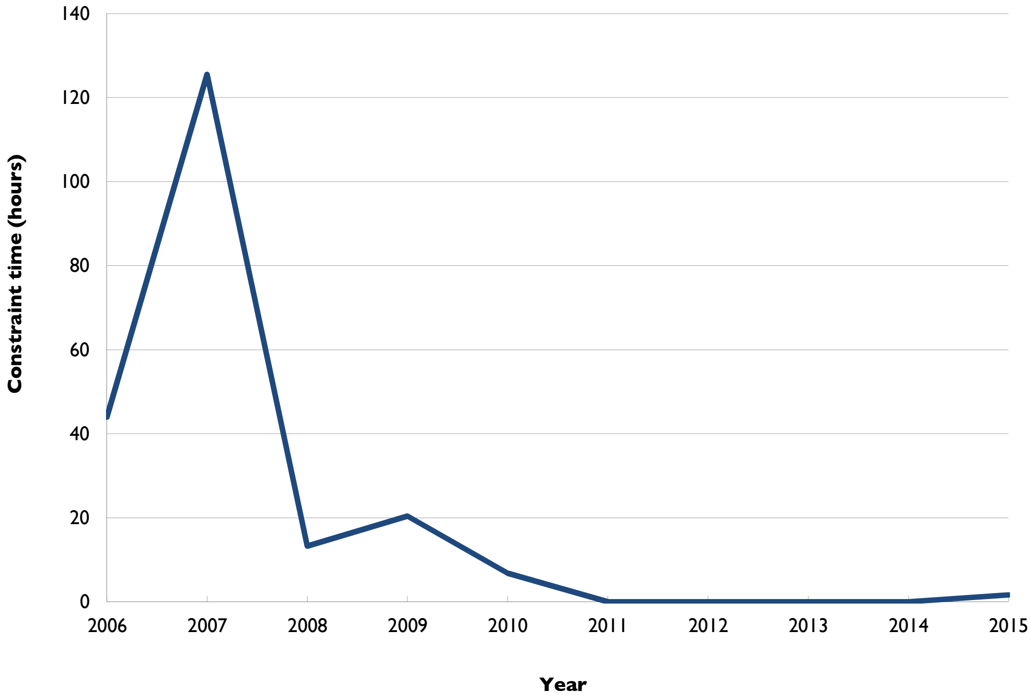
[6] The Woree static VAr compensator (SVC) and the second Woree 275/132kV transformer were commissioned in 2005/06 and 2007/08, respectively.

Information pertaining to the historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 5.6. During 2015, the CQ-NQ grid section experienced 1.67 hours of constrained operation. These constraints were associated with the reclassification of a double circuit between Strathmore and Ross as credible due to increased risk from prevailing weather conditions.

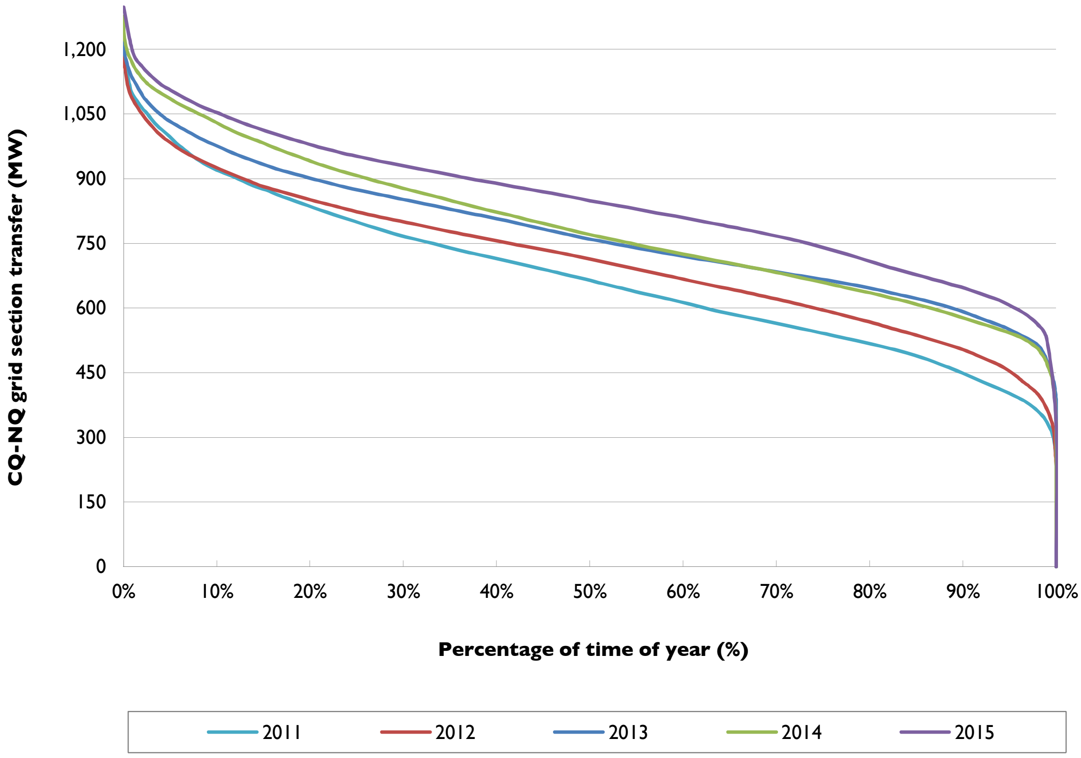
Figure 5.6 Historical CQ-NQ grid section constraint times



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 5.7 provides historical transfer duration curves showing small annual differences in grid section transfer demands and energy. Utilisation of the grid section was higher in 2015 compared to 2014 predominantly due to the lower capacity factor of the hydro generators in FNQ (refer to figures 5.1, 5.2 and 5.3).

Figure 5.7 Historical CQ-NQ 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.

The development of large loads in central or northern Queensland (additional to those included in the forecasts), without corresponding increases in central or northern Queensland generation, can significantly increase the levels of CQ-NQ transfers. This is discussed in Section 6.2.4.

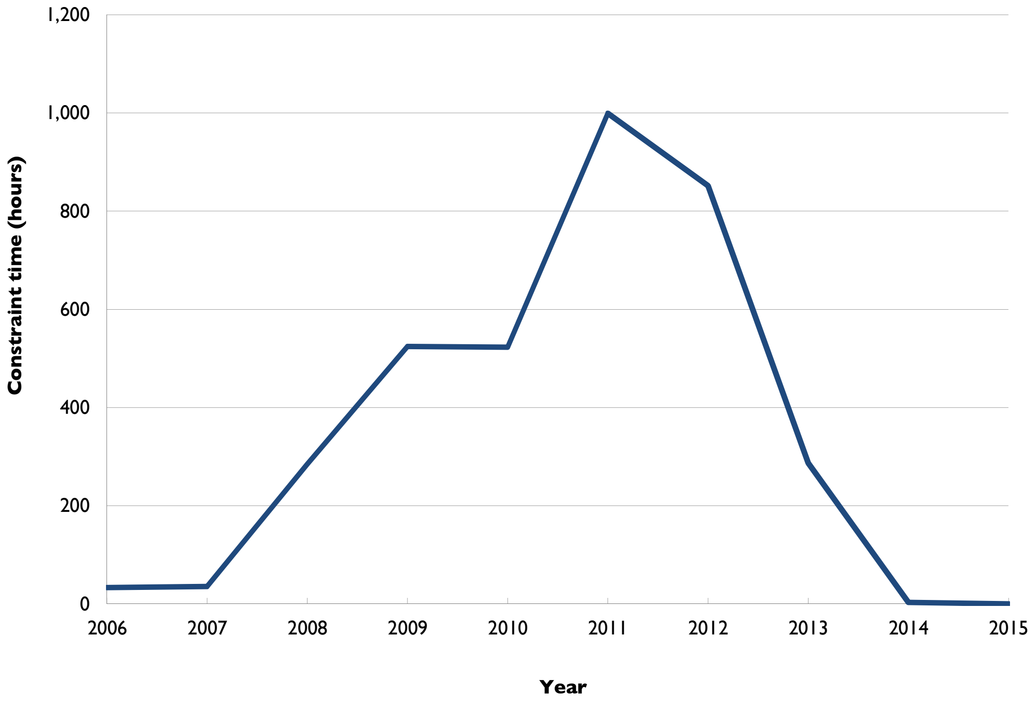
5.5.3 Gladstone grid section

Maximum power transfer across the Gladstone grid section is set by the thermal rating of the 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.

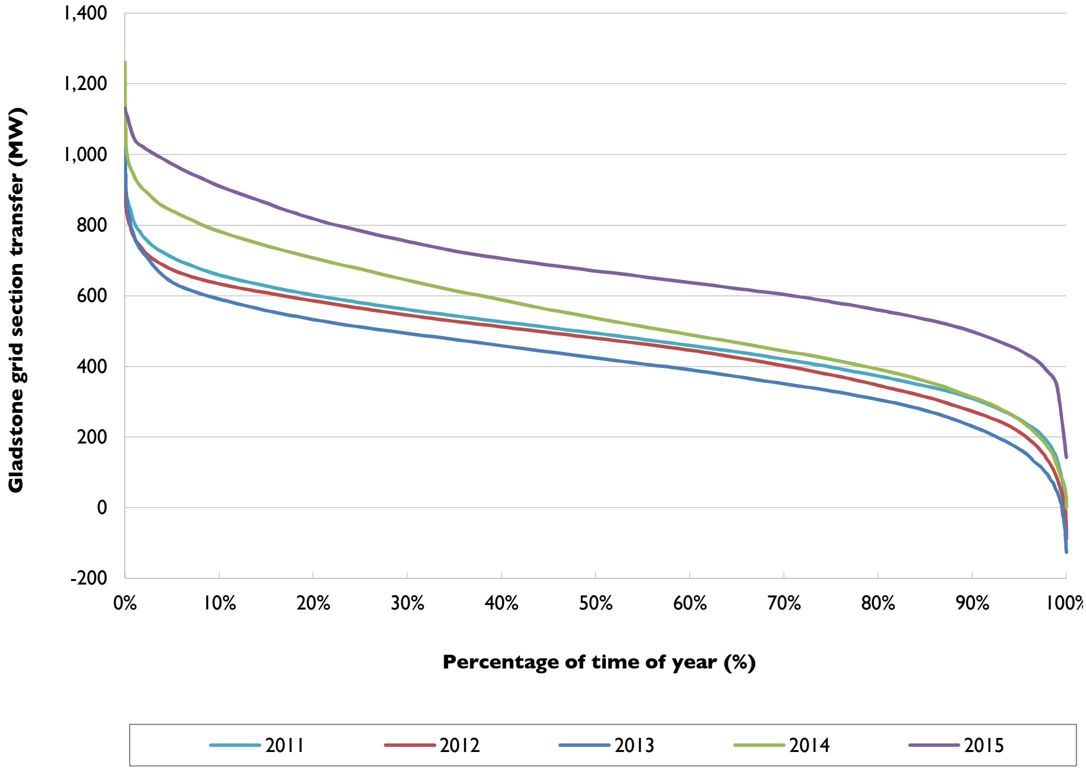
The Gladstone grid section did not constrain operation during April 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 5.8.

Figure 5.8 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 5.8 provides historical transfer duration curves showing continuing increases in utilisation. This year's higher transfers are predominantly associated with a significant increase in Central West and reduction in Gladstone zone generation (refer to figures 5.1, 5.2 and 5.3).

Figure 5.9 Historical Gladstone 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.

5.5.4 Central Queensland to South Queensland grid section

Maximum power transfer across the Central Queensland to South Queensland (CQ-SQ) grid section is set by transient or voltage stability following a Calvale to Halys 275kV circuit contingency.

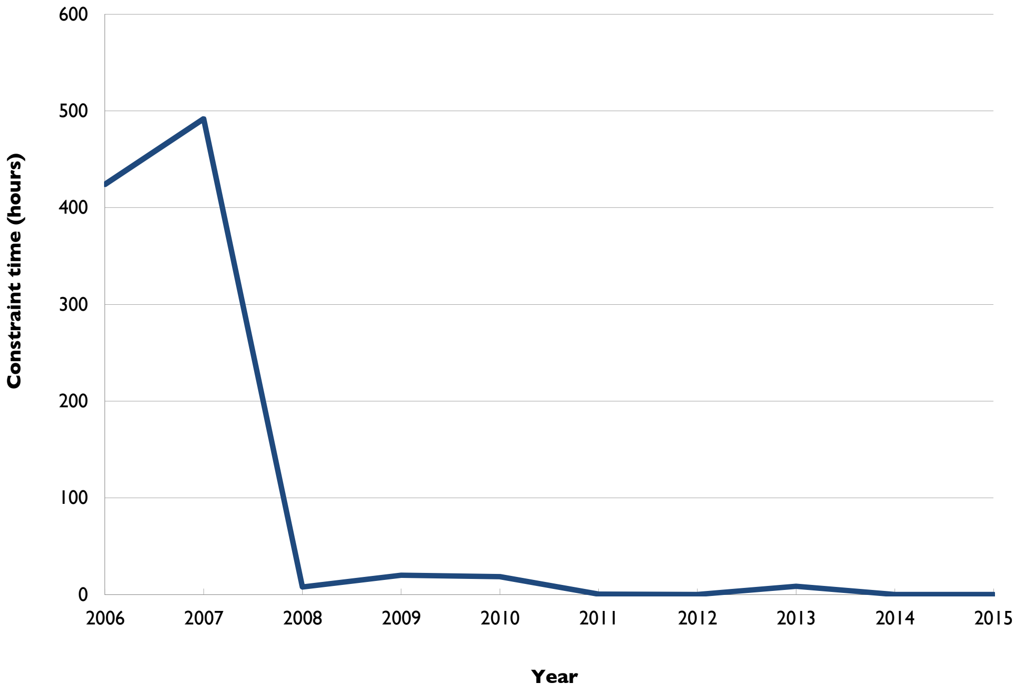
The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

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.

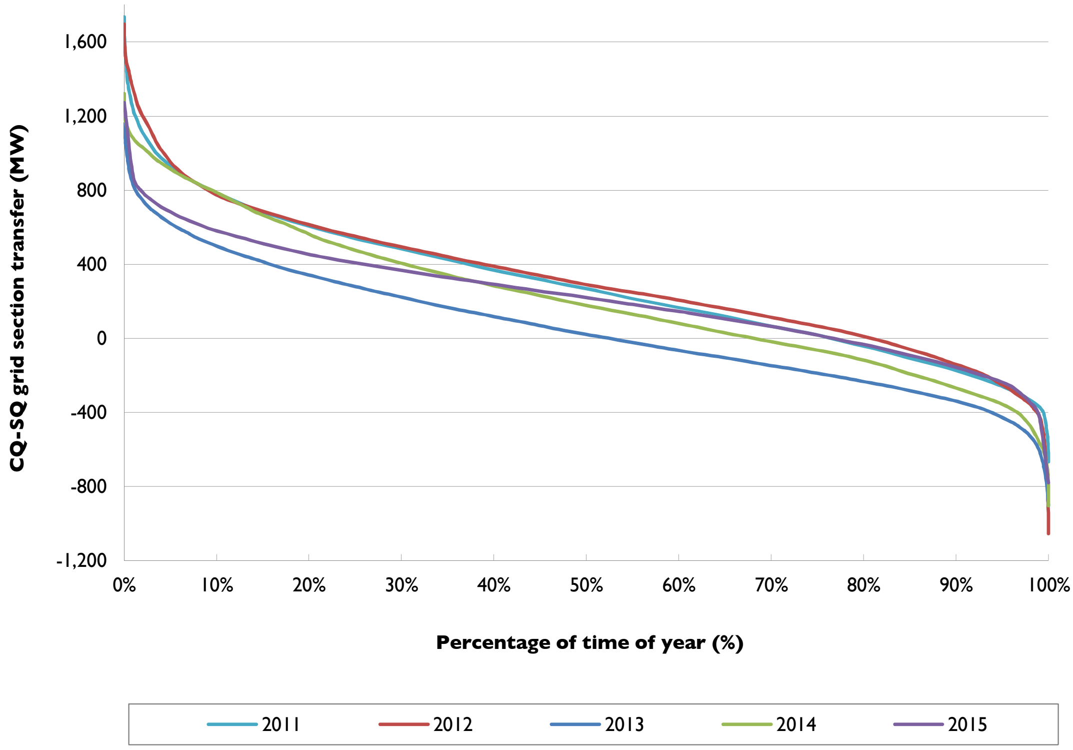
The CQ-SQ grid section did not constrain operation during April 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 5.10.

Figure 5.10 Historical CQ-SQ grid section constraint times



The reduction in constraint times since 2007 to near zero levels can be attributed to lower central to southern Queensland transfers. Central to southern Queensland energy transfers have seen a sharp decline since the commissioning of significant levels of generation in the South West Queensland (SWQ) area between 2006 and 2010. Figure 5.11 provides historical transfer duration curves.

Figure 5.11 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 life from the next five to 10 years. This is discussed in Section 6.3.3.

5.5.5 Surat grid section

The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Columboola to Western Downs 275kV transmission line[7], 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.

Following the commissioning of these projects, the maximum power transfer across the Surat grid section is expected to be set by voltage stability associated with an outage of a Western Downs to Orana 275kV circuit.

The voltage stability limit is set by insufficient reactive power reserves in the Surat zone following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability. Local generation reduces transfer capability but allows more demand to be securely supported in the Surat zone. This is because the reduction in power transfer due to increased local generation is greater than the reduction in grid section transfer capability.

There have been no constraints recorded over the brief history of the Surat grid section.

Figure 5.12 provides the transfer duration curve since the zone's creation. Grid section transfers depict the ramping of liquefied natural gas (LNG) load. The zone has transformed from a net exporter to a net importer of energy.

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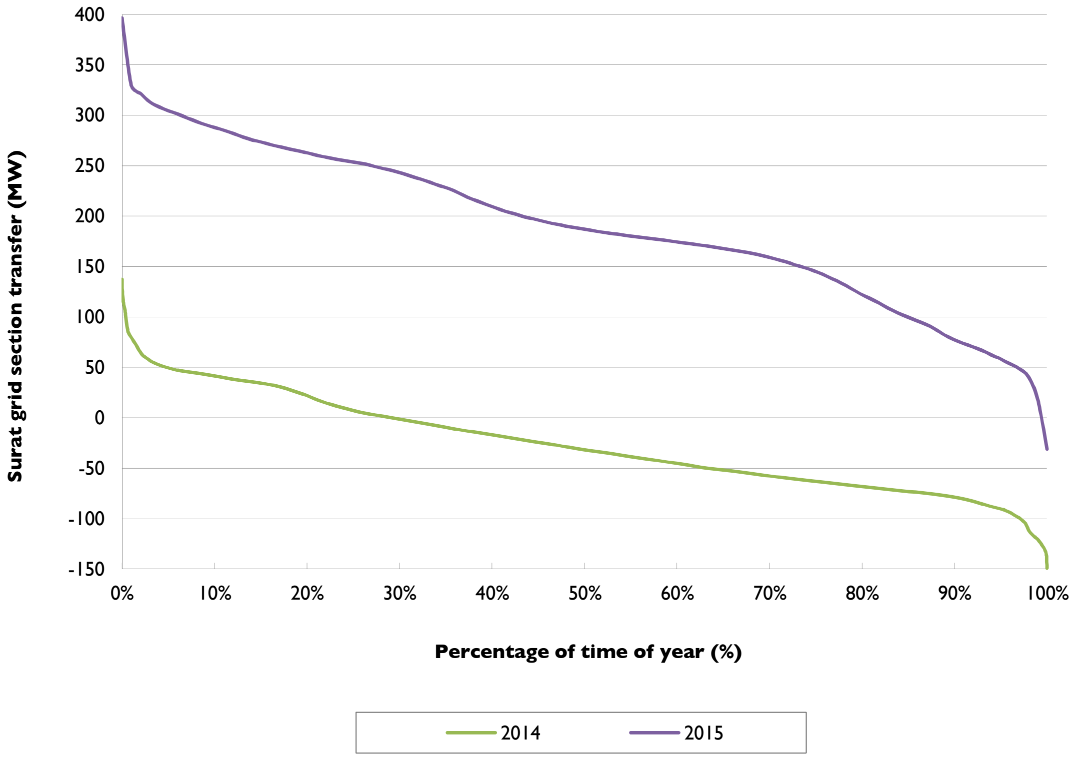
[7] The Orana Substation is connected to one of the Columboola to Western Downs 275kV transmission lines.

Figure 5.12 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.

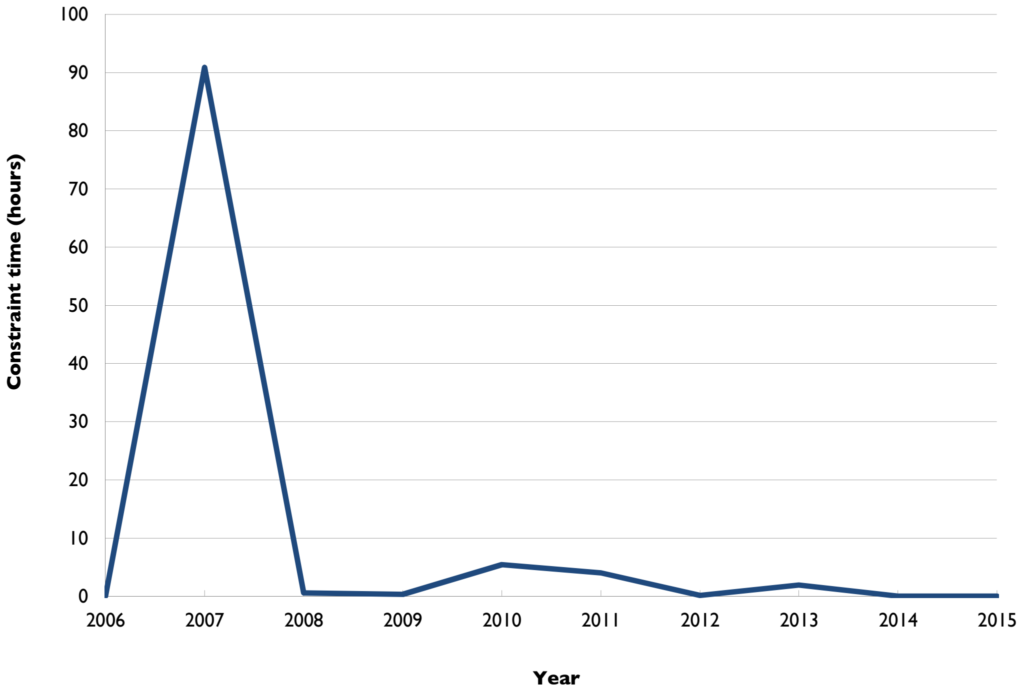
The development of large loads in Surat (additional to those included in the forecasts), without corresponding increases in generation, can significantly increase the levels of Surat grid section transfers. This is discussed in Section 6.2.4.

5.5.6 South West Queensland grid section

The 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 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 5.13.

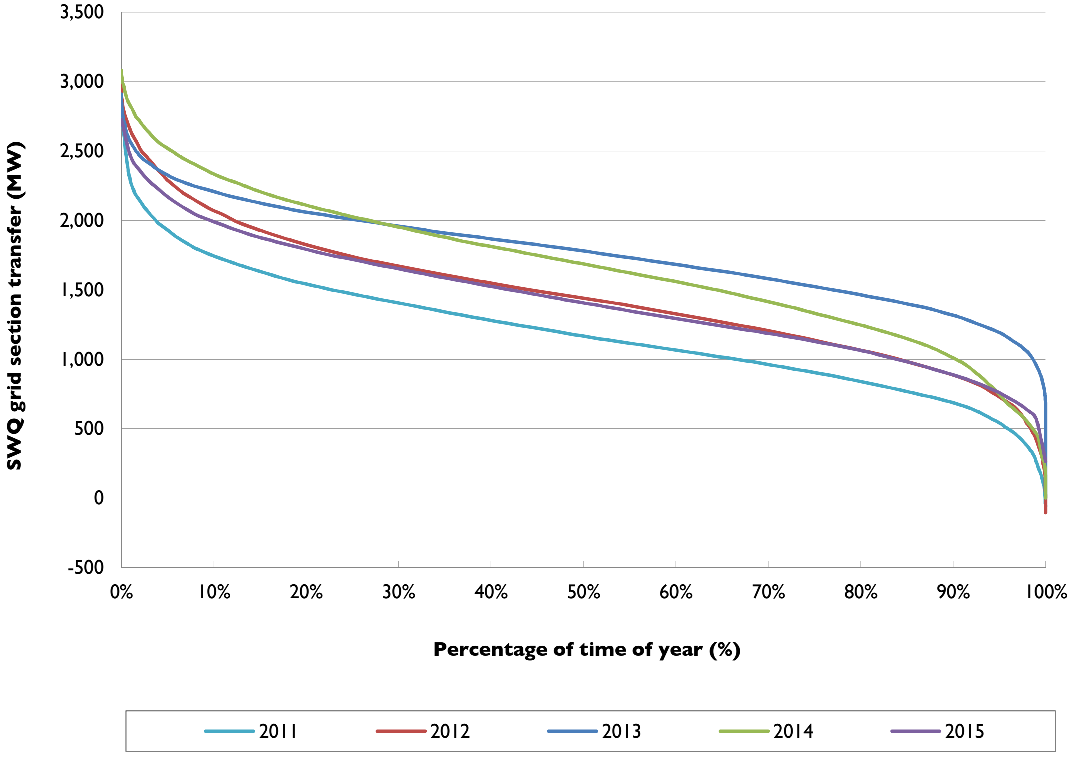
Figure 5.13 Historical SWQ grid section constraint times



The commissioning of significant levels of base load generation in the SWQ area between 2006 and 2010 increased the utilisation of this grid section. The majority of constraint times in the 2007 period were due to thermal constraint equations ensuring operation within plant thermal ratings during planned outages.

Figure 5.14 provides historical transfer duration curves showing a reduction in 2015 energy transfer to levels compared to 2014. Reductions in southerly QNI transfers were exceeded by the increase in load and reduction in generation in the Bulli zone (refer to figures 5.1, 5.2 and 5.3) resulting in reduced SWQ utilisation.

Figure 5.14 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.

5.5.7 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.

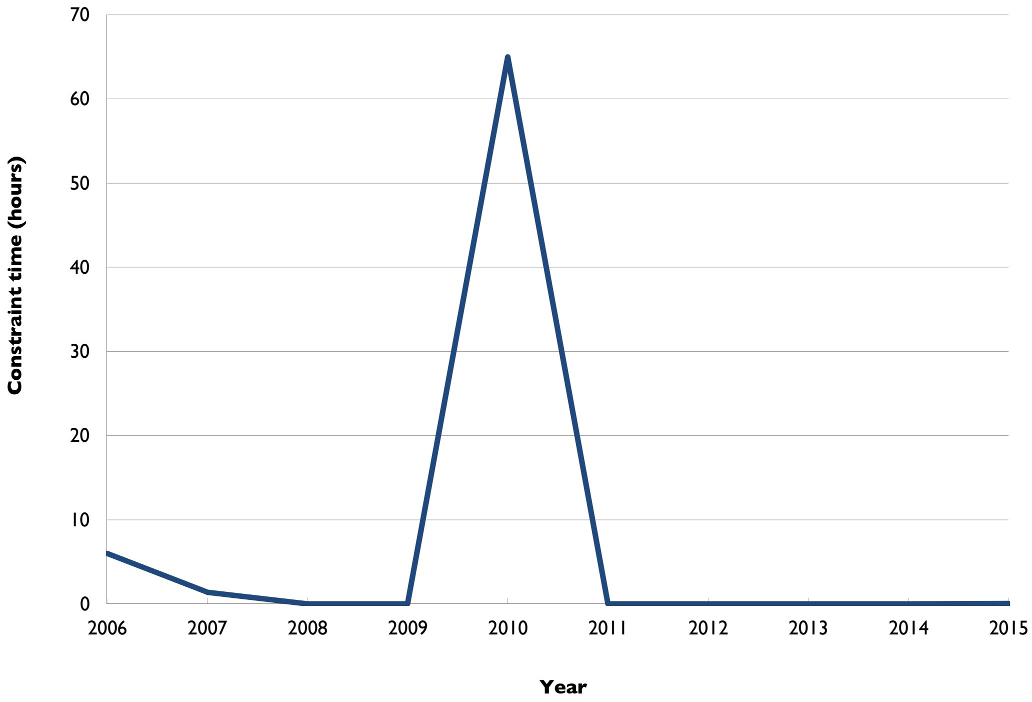
Limit equations in Table D.4 of Appendix D show that the following variables have a significant effect on transfer capability:

- 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 the reduction in power transfer due to increased generation east of this grid section is greater than the reduction in grid section transfer capability.

Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 5.15. During 2015, a single dispatch interval (5 minutes) of constrained operation occurred during planned works requiring the deloading of Calvale to Halys 275kV.

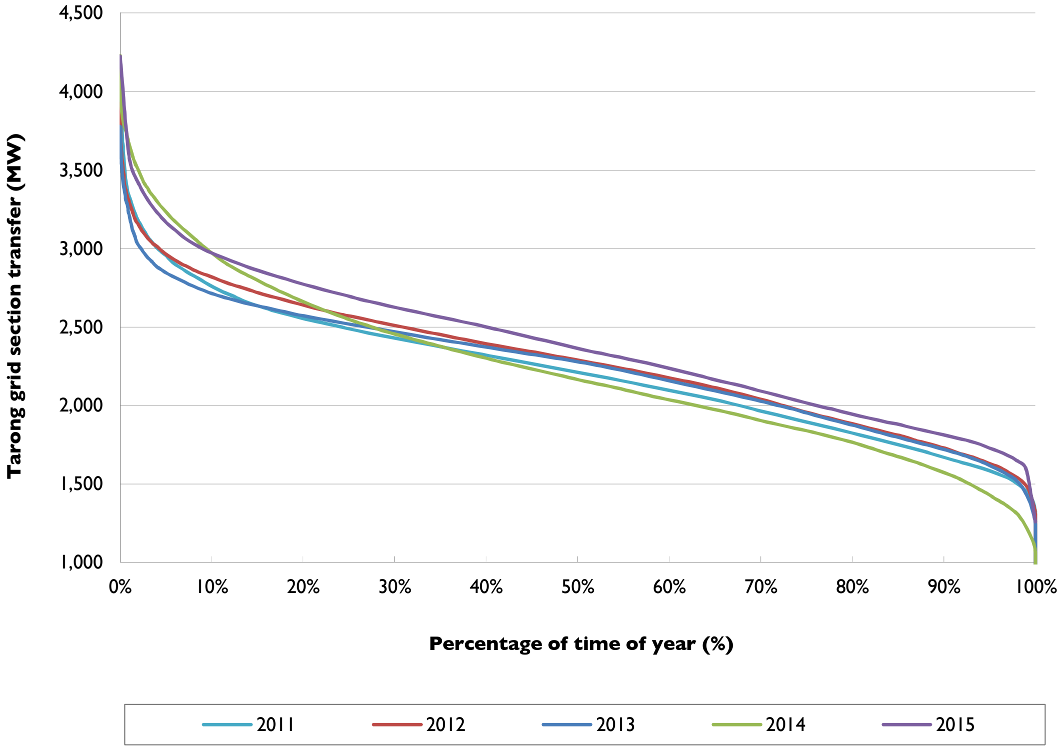
Figure 5.15 Historical Tarong grid section constraint times



Constraint times have been minimal since 2007, 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 5.16 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 placed into cold storage in December 2014 (refer to figures 5.1, 5.2 and 5.3).

Figure 5.16 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.

5.5.8 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.

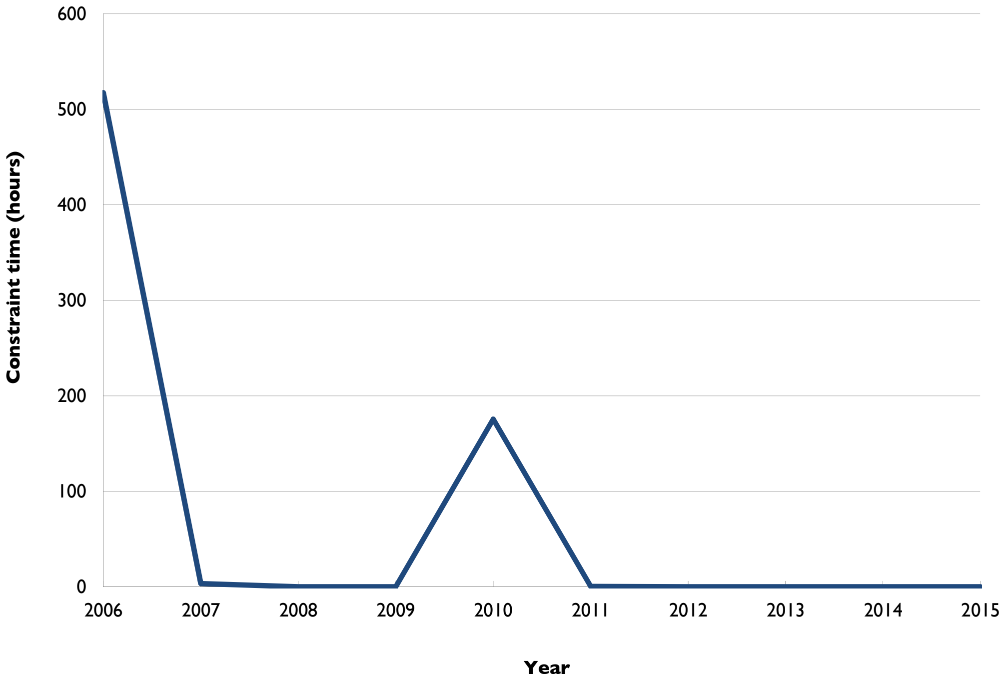
The limit equation in Table D.5 of Appendix D shows that the following variables have a significant effect on transfer capability:

- 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 reduction in power transfer due to reduced southerly flow on Terranora Interconnector is greater than the reduction in grid section transfer capability.

The Gold Coast grid section did not constrain operation during April 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 5.17.

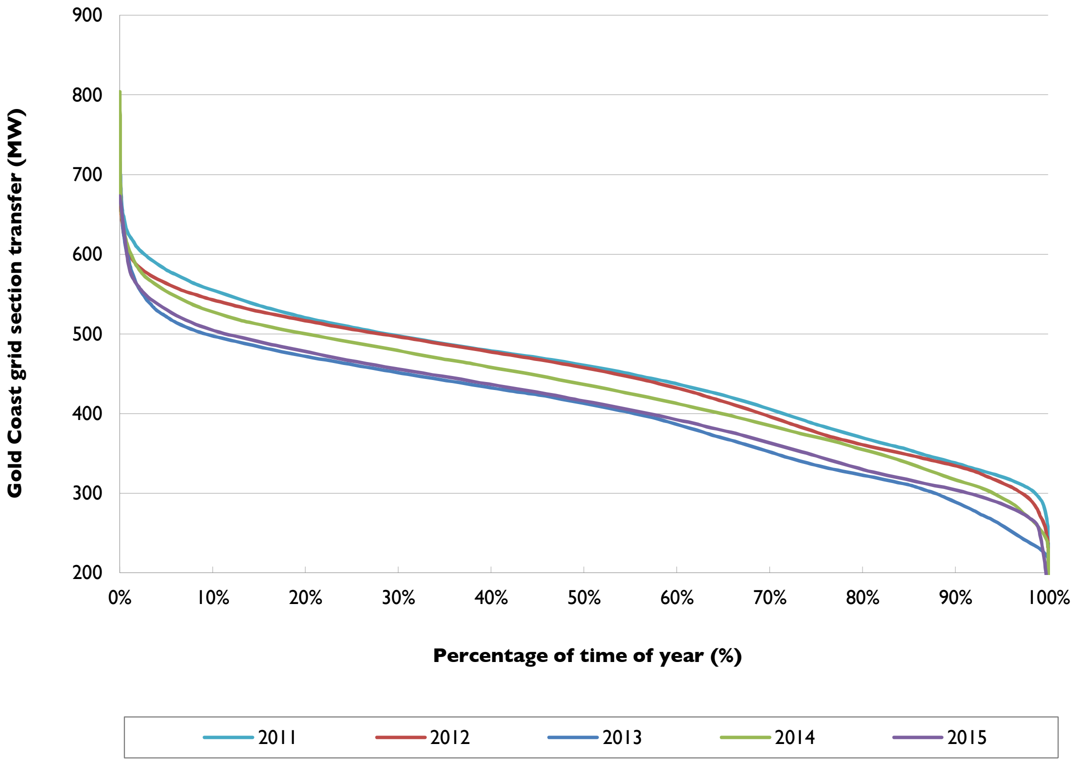
Figure 5.17 Historical Gold Coast grid section constraint times



Powerlink delivered increases to the Gold Coast grid section transfer capacity with projects including the establishment of the Greenbank Substation in 2006/07 and Greenbank SVC in 2008/09. 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 5.18 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. Terranora Interconnector southerly transfer was lower in 2015 compared to 2014 (refer to figures 5.1, 5.2 and 5.3).

Figure 5.18 Historical Gold Coast 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.

5.5.9 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 for the 2015 calendar year was published in May 2016 and can be found on AEMO's website.

In 2013, Powerlink, TransGrid and AEMO completed testing increasing the oscillatory limit to 1,200MW in the southerly direction, conditional on the availability of dynamic stability monitoring equipment.

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 in Queensland
- transient stability associated with the trip of a smelter potline load in Queensland
- transient stability associated with transmission faults in the Hunter Valley, 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.

In 2014, Powerlink and TransGrid completed a Regulatory Investment Test for Transmission (RIT-T) consultation which described the outcomes of a detailed technical and economic assessment into the upgrade of QNI. This is discussed further in Section 6.5.2.

5.6 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver 2015 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.

As described in Section 5.5, years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period.

Double circuit transmission lines that experience a lighting 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 Lighting Trip Time Window (LTTW) 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.

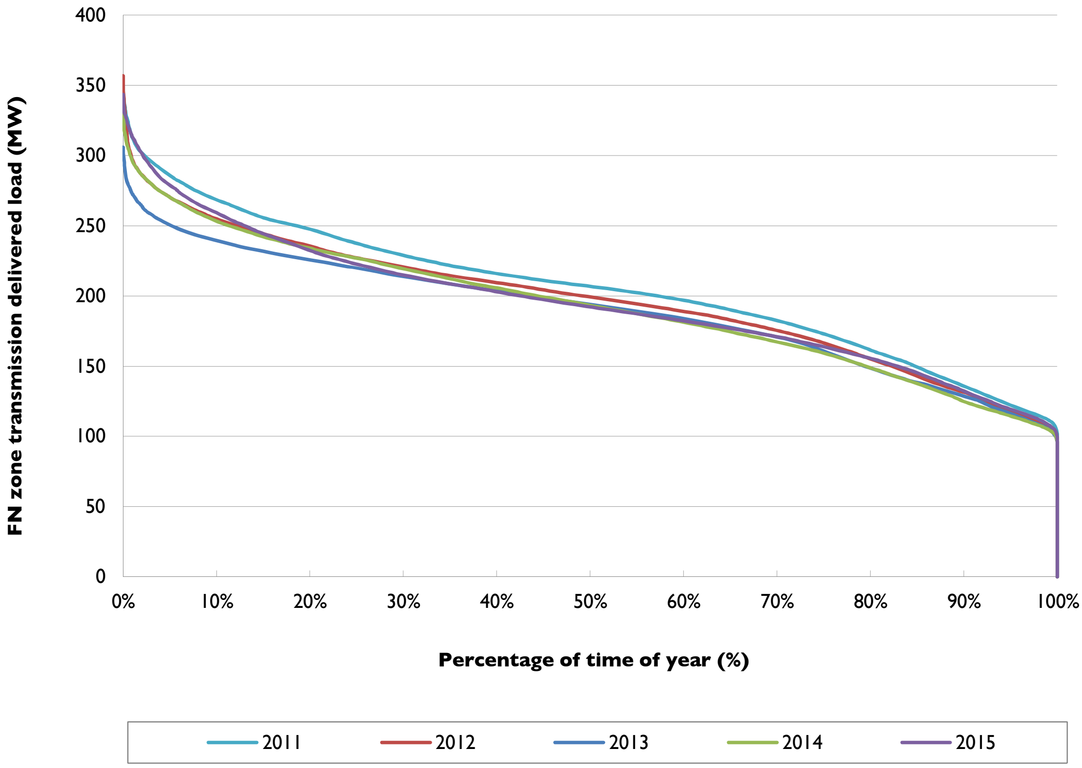
5.6.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2015.

The Far North zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 5.19 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has increased by 1.4% between 2014 and 2015. The peak transmission delivered demand in the zone was 344MW which is below the highest peak demand over the last five years of 357MW set in 2012.

Figure 5.19 Historical Far North zone transmission delivered load duration curves



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

- Chalumbin to Turkinje 132kV double circuit transmission line last tripped January 2016
- Chalumbin to Woree 275kV double circuit transmission line last tripped January 2015.

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.

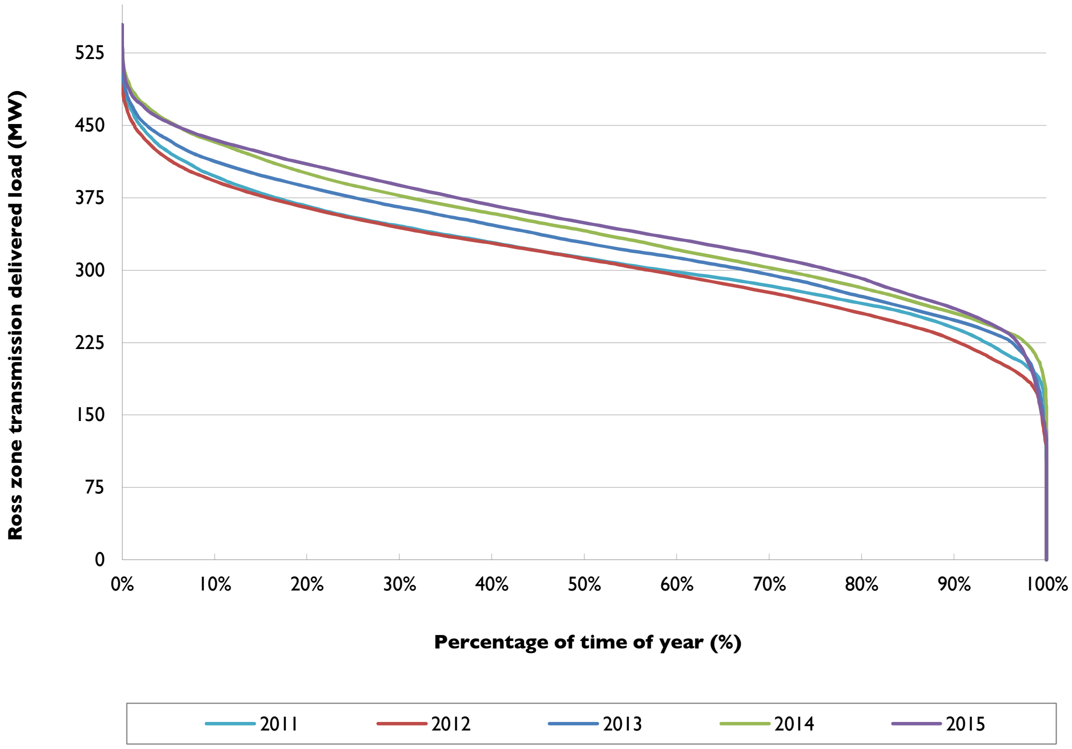
5.6.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2015.

The Ross zone includes the scheduled embedded Townsville Power Station 66kV component and the significant non-scheduled embedded generator at Pioneer Mill as defined in Figure 2.4. These embedded generators provided approximately 180GWh during 2015.

Figure 5.20 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has increased by 2.2% between 2014 and 2015. The peak transmission delivered demand in the zone was 554MW which is the highest peak demand for the zone.

Figure 5.20 Historical Ross zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO have 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 (refer to Table 3.4).

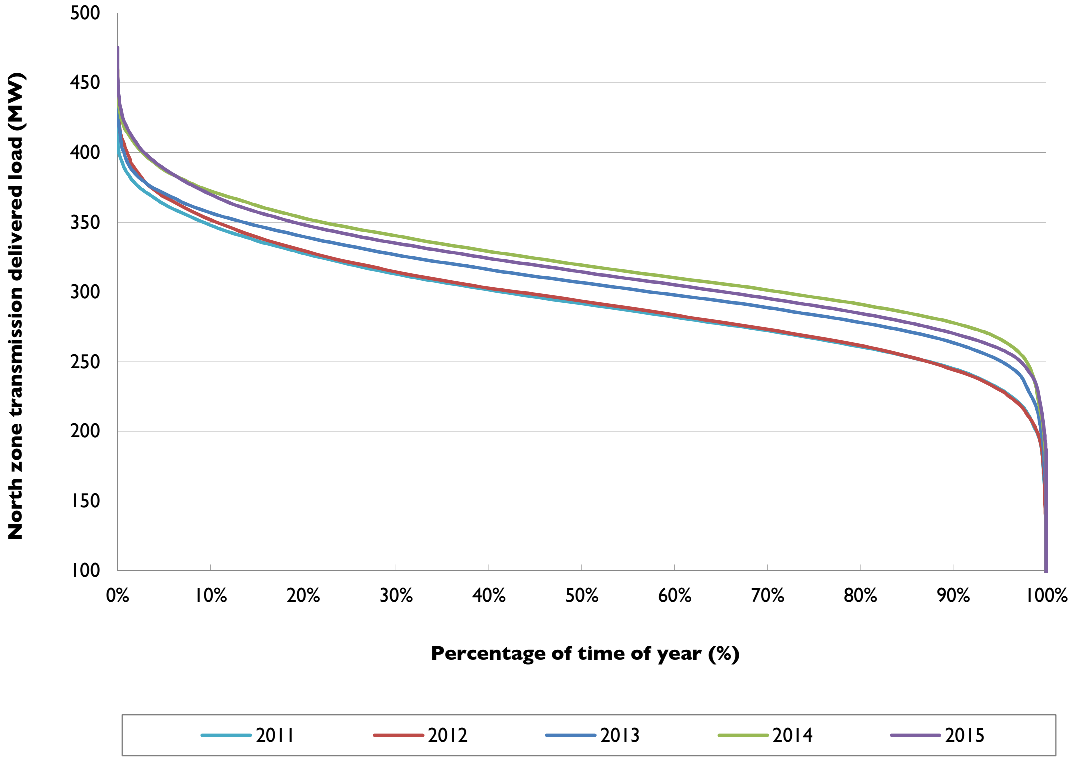
5.6.3 North zone

The North zone experienced no load loss for a single network element outage during 2015.

The North zone includes significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 2.4. These embedded generators provided approximately 554GWh during 2015.

Figure 5.21 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has reduced by 1.2% between 2014 and 2015. The peak transmission delivered demand in the zone was 475MW which is the highest peak demand for the zone.

Figure 5.21 Historical North zone transmission delivered load duration curves



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

- Collinsville to Mackay tee Proserpine 132kV double circuit transmission line last tripped February 2016
- Collinsville North to Stoney Creek and Collinsville North to Newlands 132kV double circuit transmission line last tripped February 2016
- Moranbah to Goonyella Riverside 132kV double circuit transmission line last tripped December 2014
- Kemmis to Moranbah tee Burton Downs 132kV and Nebo to Wotonga 132kV or Wotonga to Moranbah 132kV double circuit transmission line last tripped February 2012.

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.

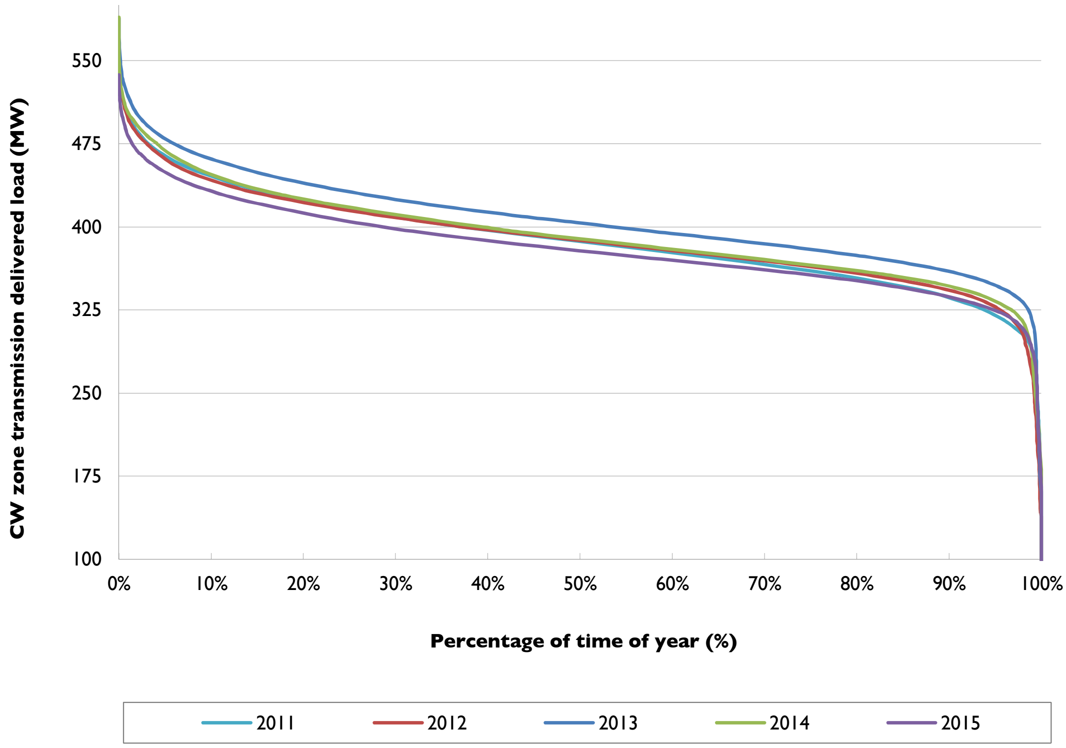
5.6.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2015.

The Central West zone includes the scheduled embedded Barcaldine generator and significant non-scheduled embedded generators at German Creek and Oaky Creek as defined in Figure 2.4. These embedded generators provided approximately 437GWh during 2015.

Figure 5.22 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 2.6% between 2014 and 2015. The peak transmission delivered demand in the zone was 537MW which is below the highest peak demand over the last five years of 589MW set in 2014.

Figure 5.22 Historical Central West zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO have this year included the Bouldercombe to Rockhampton and Bouldercombe to Egan's Hill 132kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in February 2016.

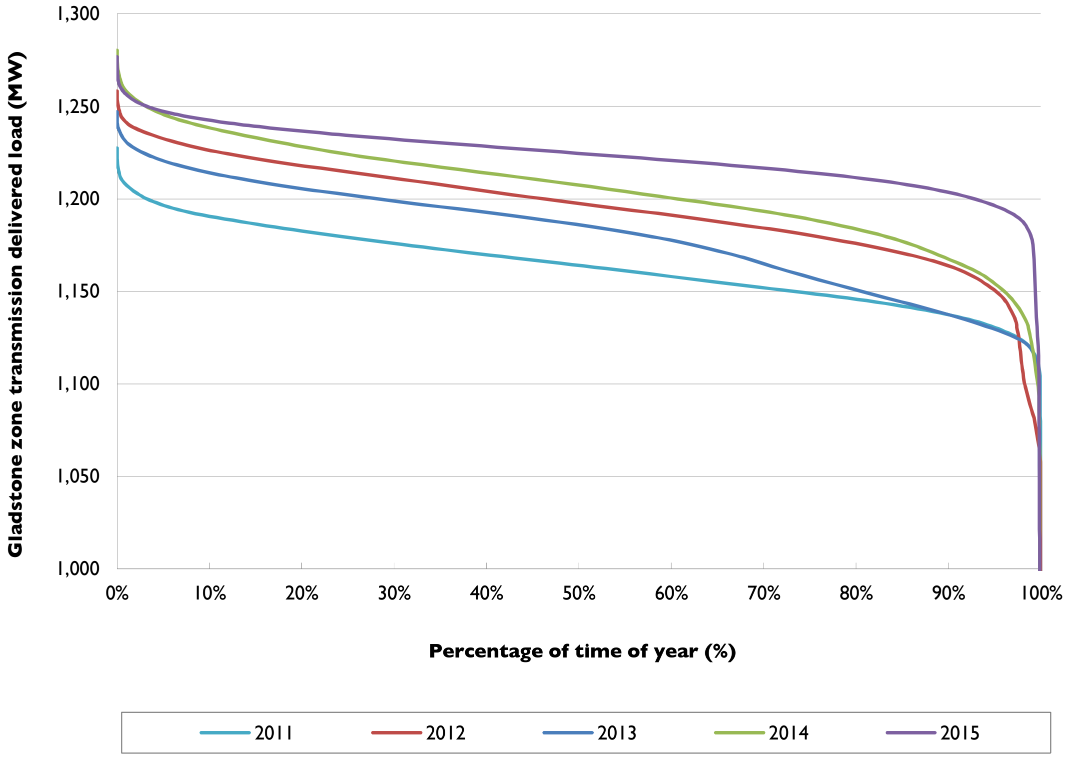
5.6.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2015.

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

Figure 5.23 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has increased by 1.8% between 2014 and 2015. The peak transmission delivered demand in the zone was 1,277MW which is below the highest peak demand over the last five years of 1,280MW set in 2014.

Figure 5.23 Historical Gladstone zone transmission delivered load duration curves

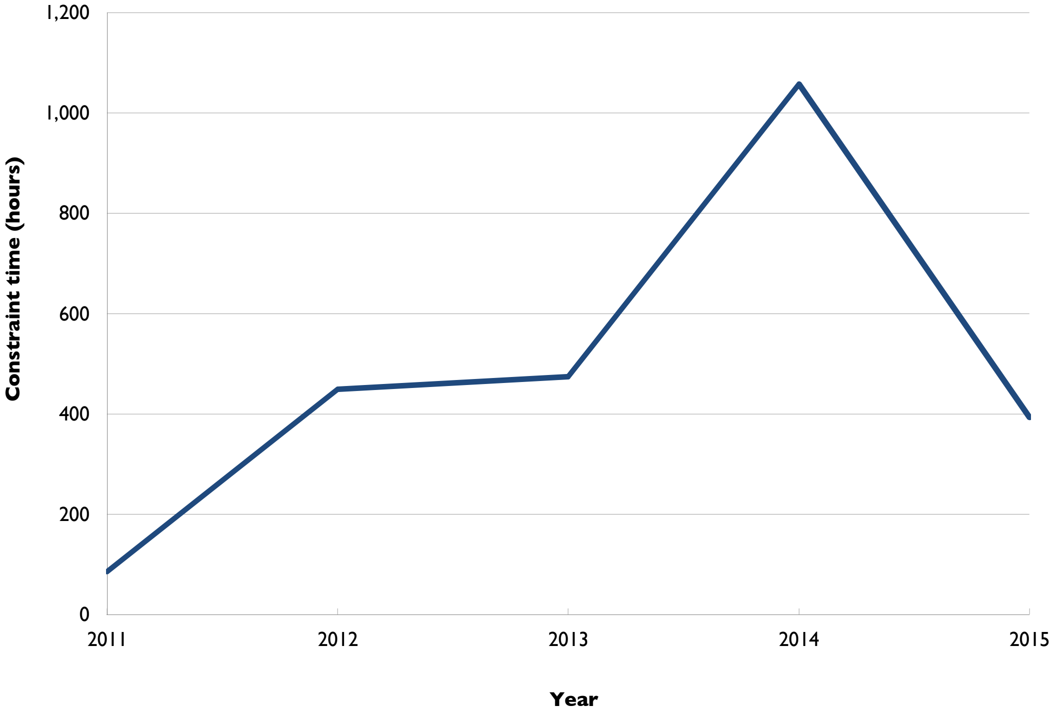


Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing within the Boyne Smelter Limited Substation. The constraint limits generation from Gladstone Power Station, mainly from the units connected at 132kV. AEMO identify this constraint by constraint identifier Q>NIL_BI_FB. This constraint was implemented in AEMO's market system from September 2011. During the 2015 period, 393.08 hours were recorded against this constraint.

A project was considered by Powerlink and AEMO under the Network Capability Incentive Parameter Action Plan (NCIPAP) to address this congestion. The project was found not to be economically feasible at this time.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 5.24. The trend is reflective of the operation of the two 132kV connected Gladstone Power Station units.

Figure 5.24 Historical Q>NIL_BI_FB constraint times



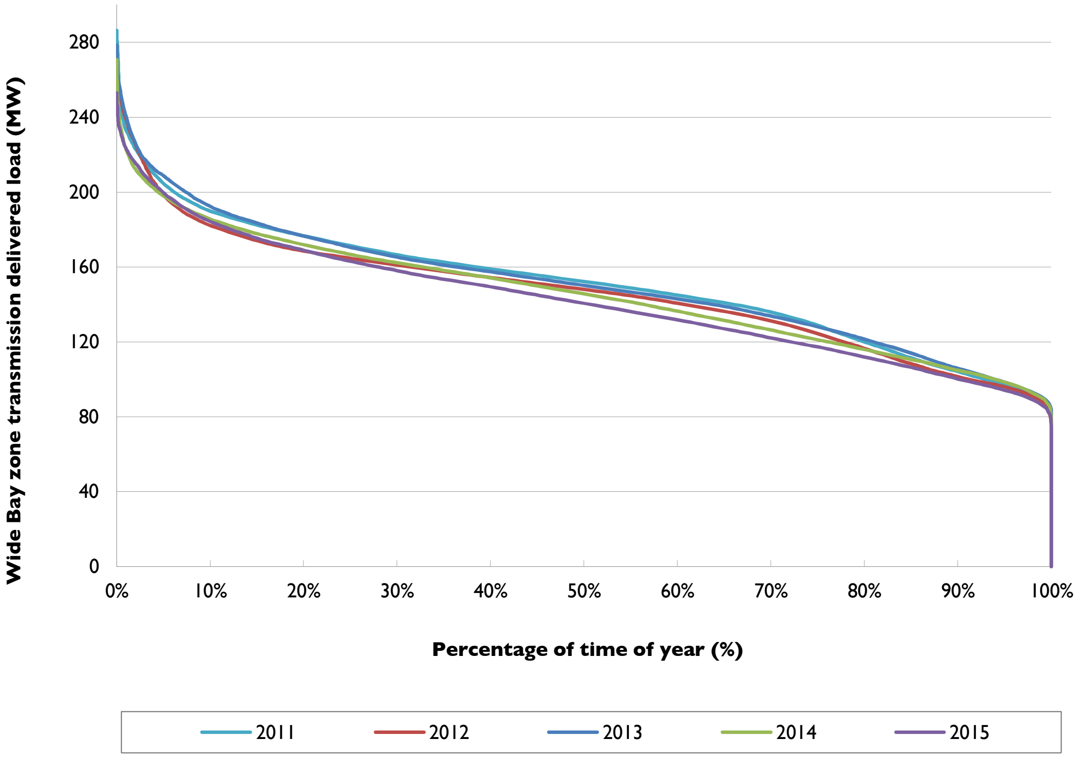
5.6.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2015.

The Wide Bay zone includes the non-scheduled embedded Isis Central Sugar Mill as defined in Figure 2.4. This embedded generator provided approximately 22GWh during 2015.

Figure 5.25 provides historical transmission delivered load duration curves for the Wide Bay zone. Energy delivered from the transmission network has reduced by 2.3% between 2014 and 2015. The peak transmission delivered demand in the zone was 253MW which is below the highest peak demand over the last five years of 286MW set in 2011.

Figure 5.25 Historical Wide Bay zone transmission delivered load duration curves



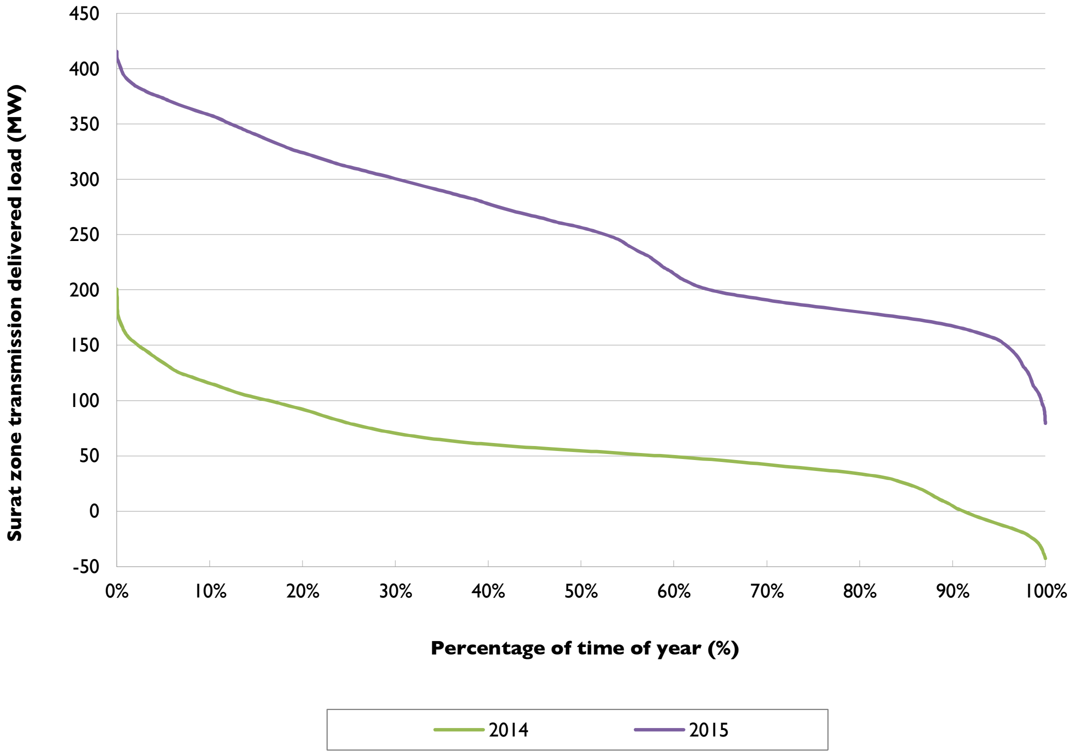
5.6.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2015.

The Surat zone includes the scheduled embedded Roma generator as defined in Figure 2.4. This embedded generator generated approximately 97GWh during 2015.

The Surat zone was introduced in the 2014 TAPR, Figure 5.26 provides transmission delivered load duration curve since its introduction. The curves reflect the ramping of LNG load in the zone.

Figure 5.26 Historical Surat zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO include 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 March 2015.

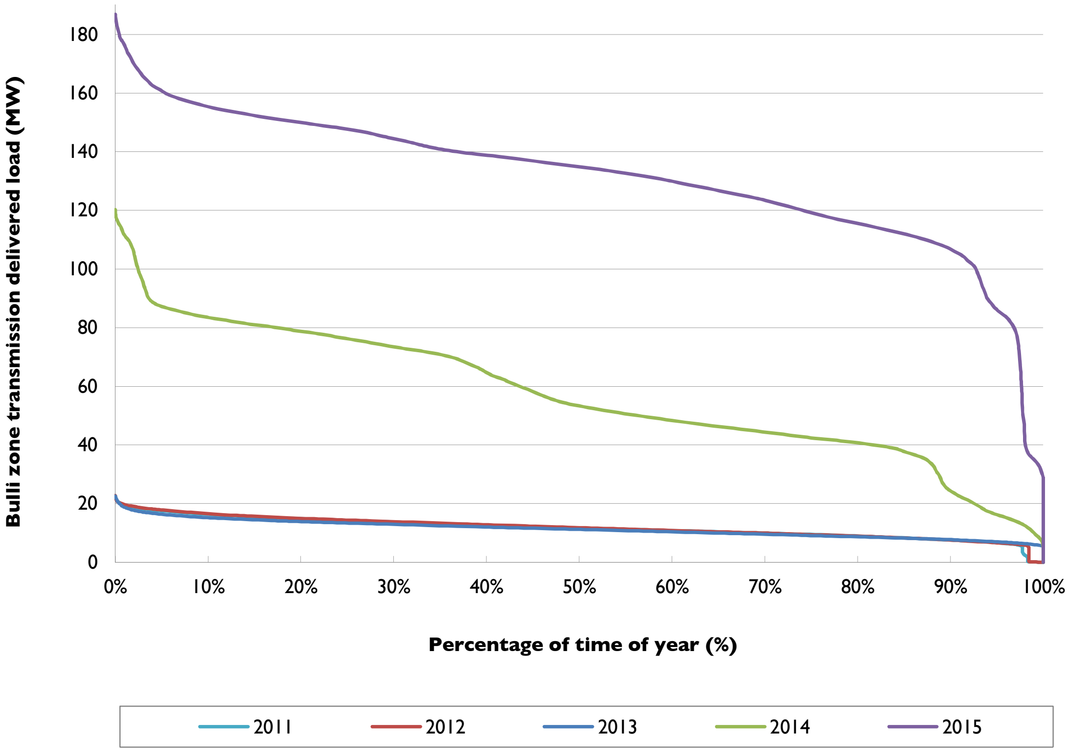
5.6.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2015.

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

Figure 5.27 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by approximately 130% between 2014 and 2015. The peak transmission delivered demand in the zone was 187MW. The significant increase is due to the ramping up of LNG load in the zone.

Figure 5.27 Historical Bulli zone transmission delivered load duration curves



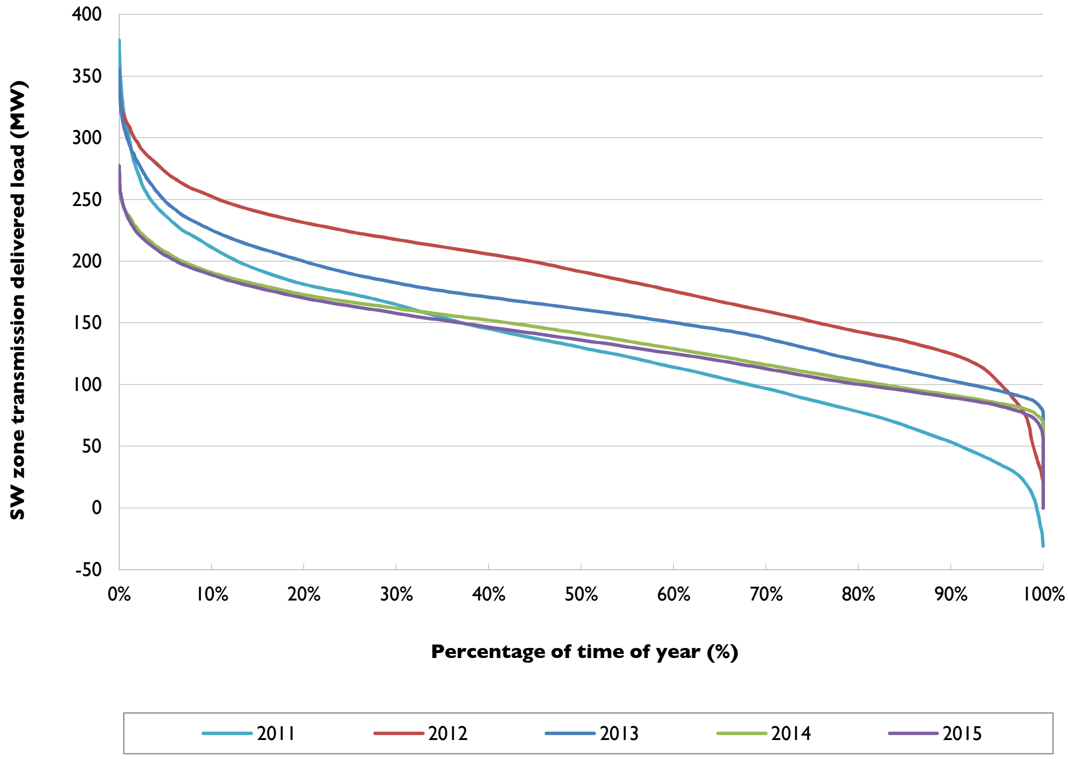
5.6.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2015.

The South West zone includes the significant non-scheduled embedded Daandine Power Station as defined in Figure 2.4. This embedded generator provided approximately 250GWh during 2015.

Figure 5.28 provides historical transmission delivered load duration curves for the South West zone. Energy delivered from the transmission network has decreased by 2.2% between 2014 and 2015. The peak transmission delivered demand in the zone was 277MW.

Figure 5.28 Historical South West zone transmission delivered load duration curves



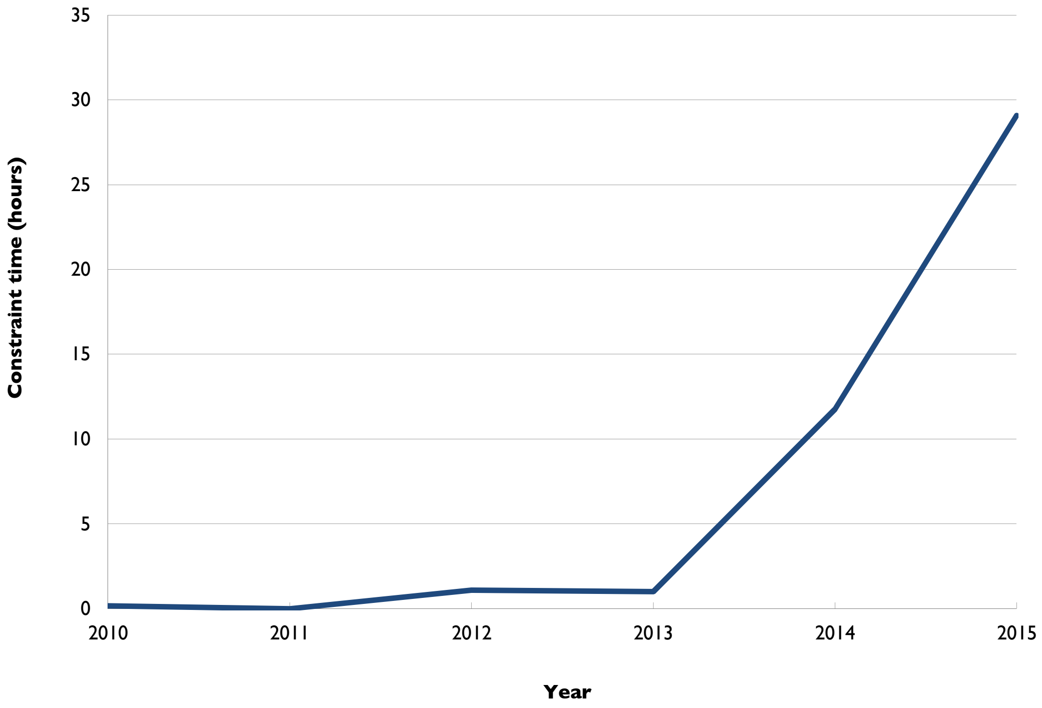
Constraints occur within the South West zone under intact network conditions. These constraints are associated with maintaining power flows of the 110kV transmission lines between Tangkam and Middle Ridge substations within the feeder's thermal ratings at times of high Oakey Power Station generation. 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 identify 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. During the 2015 period, 29.08 hours of constraints were recorded against this constraint.

Projects were considered by Powerlink and AEMO under the NCIPAP to address this congestion. These projects were found not to be economically feasible at this time.

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 5.29. The trend is reflective of the operation of the Oakey Power Station. The capacity factor of Oakey Power Station has increased from approximately 9% in 2014 to approximately 22% in 2015.

Figure 5.29 Historical Q>NIL_MRTA_A and Q>NIL_MRTA_B constraint times



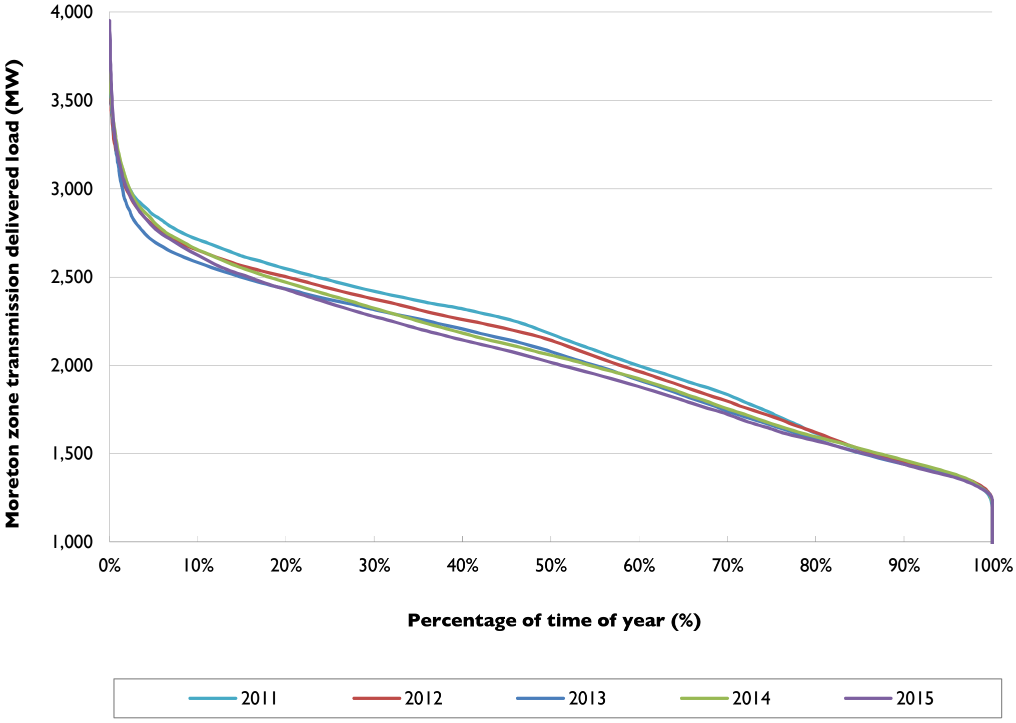
5.6.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2015.

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 73GWh during 2015.

Figure 5.30 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has reduced by 1.4% between 2014 and 2015. The peak transmission delivered demand in the zone was 3,952MW which is the highest peak demand over the last five years for the zone.

Figure 5.30 Historical Moreton zone transmission delivered load duration curves



High voltages associated with light load conditions are managed with existing reactive sources. In preparation for the withdrawal of Swanbank E, Powerlink and AEMO agreed on a 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.

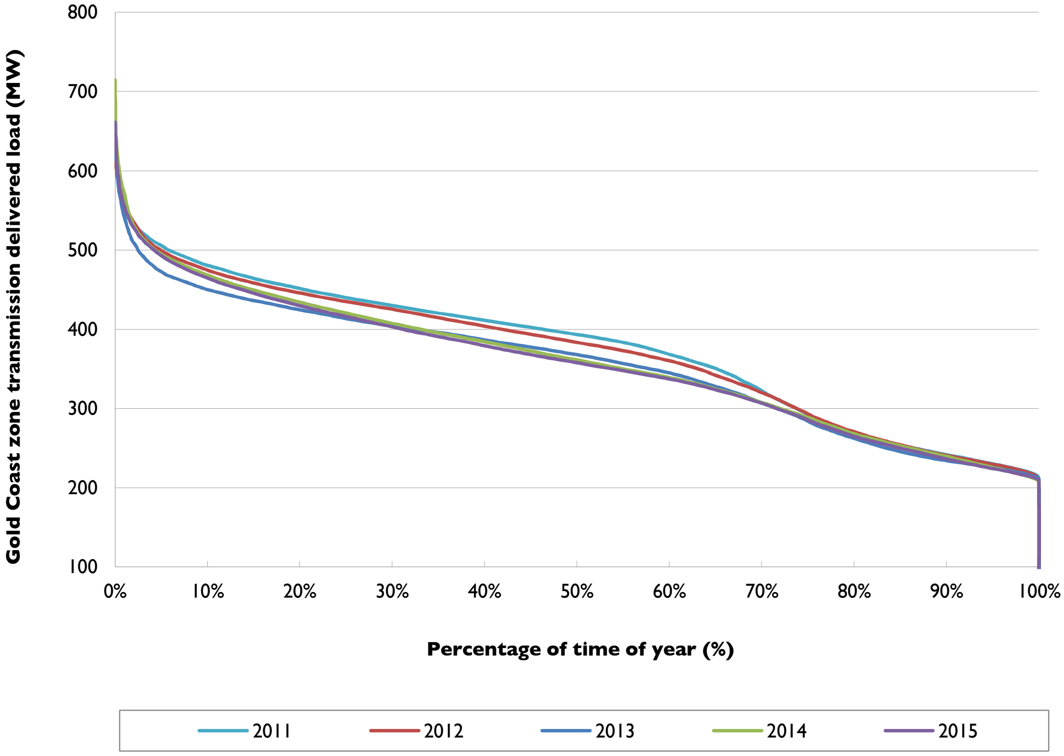
5.6.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2015.

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

Figure 5.31 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has reduced by 0.7% between 2014 and 2015. The peak transmission delivered demand in the zone was 661MW which is below the highest peak demand over the last five years of 714MW set in 2014.

Figure 5.31 Historical Gold Coast zone transmission delivered load duration curves



Chapter 6:

Strategic planning

6 Strategic planning

Key highlights

- This chapter identifies possible network limitations which may arise between the five and 10-year outlook and provides potential network solutions.
- Long-term planning takes into account 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 emerge within the 10-year outlook. These loads may cause limitations on the transmission system in excess of Powerlink's amended planning standard. Possible network options are provided for Bowen Basin coal mining area, Bowen Industrial Estate, Galilee Basin coal mining area, CQ-NQ grid section, Central West to Gladstone and the Surat Basin north west area.
- Assets where reinvestment will need to be made in the next five to 10-year period where there may be opportunities for reconfiguration include Ross, Central West and Gladstone zones and CQ-SQ grid section.

6.1 Background

Powerlink Queensland as a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and as the appointed Jurisdictional Planning Body (JPB) by the Queensland Government is responsible for transmission network planning for the national grid within Queensland. Powerlink's obligation is to plan the transmission system to reliably and economically supply load while managing risks associated with the condition and performance of existing assets in accordance with the requirements of the National Electricity Rules (NER), Queensland's Electricity Act 1994 (the Act) and its Transmission Authority.

A key step in this process is the development of long-term strategic plans for both the main transmission network and supply connections within the zones. These long-term plans take into consideration uncertainties in the future. The uncertain future can impact potential sources of generation and load growth. Uncertain load growth can occur due to different economic outlooks, emergence of new technology and the commitment or retirement of large industrial and mining loads.

The long-term plans also take into consideration the condition and performance of existing assets. As assets reach the end of technical or economic life, reinvestment decisions are required. These decisions are made in the context of the required reliability standards, load forecast and generation outlook. The reinvestment decisions also need to be cognisant of the uncertainties that exist in the generation and load growth outlooks.

As assets reach the end of technical or economic life, opportunities may emerge to retire without replacement, initiate non-network alternatives, extend technical life or replace with assets of a different type, configuration or capacity. The objective is not to automatically make like for like replacements or to make individual asset investment decisions. Rather the objective is to integrate demand based limitations and condition based risks of assets to ensure an optimised network that is best configured to meet current and a range of plausible future capacity needs.

Information in this chapter is organised in two parts. Section 6.2 discusses the possible impact uncertain load growth may have on the performance and adequacy of the transmission system. This discussion is limited to the impact of possible new large loads in Chapter 2 may have on the network. Section 6.3 provides a high-level outline of the possible network development plan for investments required to manage risks related to the condition and performance of existing assets. This high level outline is discussed for parts of the main transmission system and within regional areas where the risks based on the condition and performance of assets may initiate investment decisions in the five to 10-year horizon of this Transmission Annual Planning Report (TAPR). Information on reinvestment decisions within the current five-year outlook of this TAPR is detailed in Chapter 4.

Powerlink considers it important to identify these long-term development options so that analyses using a scenario based approach, such as the Australian Energy Market Operator's (AEMO) National Transmission Network Development Plan (NTNDP), are consistent. In this context the longer-term plans only consider possible network solutions. However, this does not exclude the possibility of non-network solutions or a combination of both. As detailed planning studies are undertaken around the future network need and possible reinvestment options, Powerlink will identify the requirements a non-network solution would need to offer in order for it to be a genuine alternative to network investment. These non-network options will be fully evaluated as part of the Regulatory Investment Test for Transmission (RIT-T) process.

6.2 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 of new or withdrawn generation to maintain the supply and demand balance for 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 (thermal and fault current ratings), voltage stability and/or transient stability. Options to address these limitations include network solutions, demand side management (DSM) and generation non-network solutions.

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 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.

Information on strategic network developments is limited to those required to address limitations that may emerge if the new large loads in Table 2.1 commit. Feasible network projects can range from incremental developments to large-scale projects capable of delivering significant increases in power transfer capability.

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 6.2.1 and 6.2.6. Consultation on the options associated with emerging limitations will be subject to commitment of additional demand.

6.2.1 Bowen Basin coal mining area

Based on the medium economic forecast defined in Chapter 2, the committed network and non-network solutions described in Section 3.2 and if the possible retirement of assets described in sections 4.2.2 and 4.2.3 is evaluated, network limitations exceeding the limits established under Powerlink's planning standard may occur. Possible solutions to the limitation could be the installation of a transformer at Strathmore Substation, line reconfiguration works and/or additional voltage support in the Strathmore area.

In addition, there has been a proposal for the development of liquefied natural gas (LNG) processing load in the Bowen Basin. The loads could be up to 80MW (refer to Table 2.1) and cause voltage and thermal limitations impacting network reliability to reoccur on the transmission system upstream of their connection points. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR.

The new load within the Bowen Basin area would result in limitations on the 132kV transmission system. Thermal and voltage limitations may emerge during an outage of the Strathmore 275/132kV transformer, a 132kV circuit between Nebo and Moranbah substations, the 132kV circuit between Strathmore and Collinsville North substations, or the 132kV circuit between Lilyvale and Dysart substations (refer to Figure 4.3).

The impact these loads may have on the Central Queensland to North Queensland (CQ-NQ) grid section and possible network solutions to address these is discussed in Section 6.2.4.

Possible network solutions

Feasible network solutions to address the limitations are dependent on the magnitude and location of load and may include one or more of the following options:

- 132kV capacitor bank at Proserpine Substation
- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV circuit 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.

Further additional load, depending on location, may require the construction of additional transmission circuits into the Bowen Basin area. Feasible solutions may involve construction of 132kV transmission lines between the Nebo, Broadlea and Peak Downs areas. An additional 132kV transmission line may also be required between Moranbah and a future substation north of Moranbah.

6.2.2 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 five-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 line from Strathmore Substation but with only a single circuit 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 circuit
- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV circuit between Collinsville North and Clare South substations.

6.2.3 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 750MW (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 approximately 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 6.2.4.

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 circuit 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 more of the following options:

- installation of capacitor bank/s at Lilyvale Substation
- third 275kV circuit between Broadsound and Lilyvale substations
- staged construction of a western 275kV transmission corridor as part of a broader development strategy.

6.2.4 Central Queensland to North Queensland grid section transfer limit

Based on the medium economic forecast outlined in Chapter 2, network limitations impacting reliability or the efficient economic operation of the NEM are not forecast to occur within the five-year outlook of this TAPR.

However, as discussed in sections 6.2.1, 6.2.2 and 6.2.3 there have been proposals for large coal mine developments in the Galilee Basin, and development of LNG processing load in the Bowen Basin and associated port expansions. The loads could be up to 900MW (refer to Table 2.1) but have not reached the required development status to be included in the medium economic forecast of this TAPR.

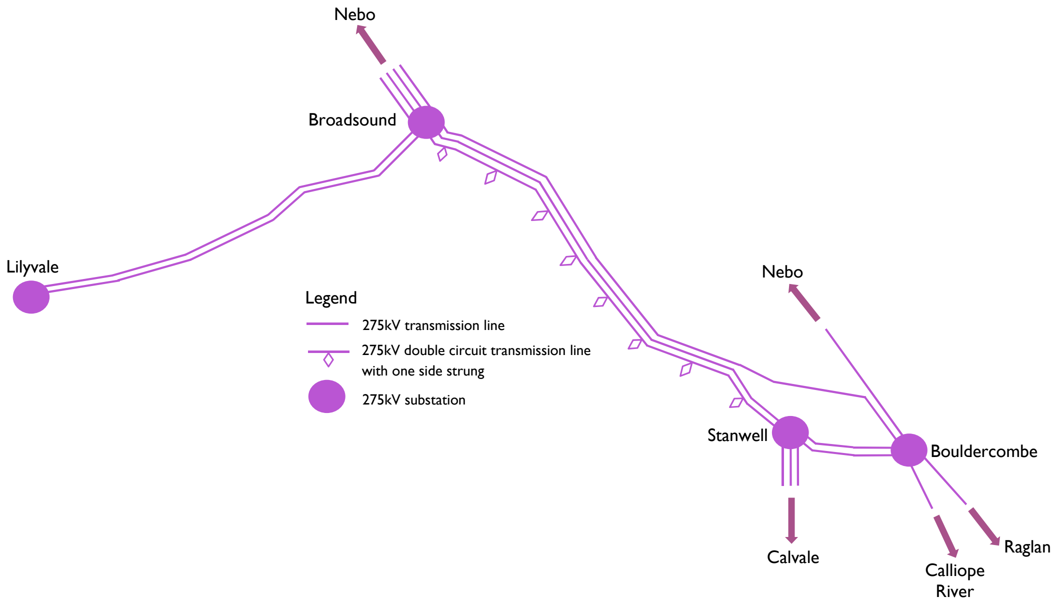
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line during a critical contingency of a Stanwell to Broadsound 275kV circuit. Voltage stability limitations may occur during the trip of the Townsville gas turbine or 275kV circuit supplying northern Queensland.

As generation costs are higher in northern Queensland due to reliance on liquid fuels, there may be positive net market benefits in augmenting the transmission network.

Possible network solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with one circuit strung (refer to Figure 6.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second circuit.

Figure 6.1 Stanwell/Broadsound area transmission network



Following this augmentation, voltage and thermal limitations may emerge depending on new mining or industrial load developments. Feasible solutions to address the emerging limitations could vary depending on the size and location of load that commits and the size, location and type of generation that may be required to maintain an appropriate supply and demand balance in the Queensland region.

Feasible network solutions to emerging voltage limitations may involve the installation of capacitor banks and/or a static VAr compensator (SVC) at existing central and northern Queensland substations. Depending on the location of the additional loads, capacitor banks may be required at Broadsound, Lilyvale and Nebo substations. If the voltage stability limitations require dynamic reactive compensation, then an SVC may be installed at Broadsound Substation.

For higher levels of load, feasible network solutions may include installation of series capacitors and/or the construction of new transmission lines. The construction of new transmission lines between Stanwell and Broadsound substations and between Broadsound and Nebo substations would also increase the thermal, voltage and transient limits.

An alternative to augmenting the existing transmission corridor north of Stanwell is to establish a western 275kV corridor connecting Calvale and Lilyvale substations, via Blackwater Substation.

6.2.5 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 Smelter (BSL) 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, network limitations impacting reliability or efficient market outcomes are not forecast to occur within the five-year outlook of this TAPR. This assessment also takes into consideration the possible retirement of the Callide A to Gladstone South 132kV double circuit transmission line within the next five years (refer to Section 4.2.4).

However, 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 may lead to limitations within this 275kV triangle. Network limitations would need to be addressed by dispatching out-of-merit generation and the technical and economic viability of uprating 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 uprate its power transfer capacity to alleviate constraints. A feasible network solution to facilitate efficient market operation may include transmission line augmentation between:

- Calvale and Larcom Creek substations and
- Larcom Creek and Calliope River substations.

6.2.6 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 five-year outlook of this TAPR.

However, there have been several proposals for additional LNG 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 350MW (refer to Table 2.1) and cause voltage and/or thermal limitations impacting network reliability on the transmission system upstream of their connection points.

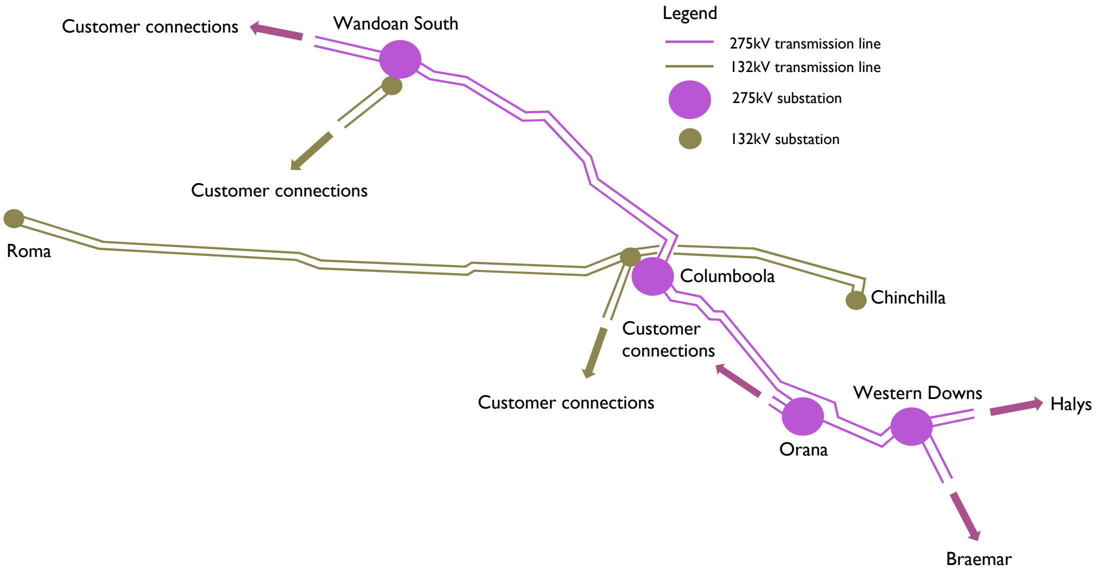
Depending on the location and size of additional load, voltage stability limitations may emerge prior to thermal limitations being reached on the 275kV network supplying the Surat Basin north west area. For voltage stability limitations the critical contingencies are outages of the 275kV circuits between Western Downs and Columboola, and between Columboola and Wandoan South substations. For thermal limitations the critical contingency is an outage between Columboola and Wandoan South substations.

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 will not be possible to address this issue by installing a single SVC at a single location. To address the voltage stability limitation the following network options are viable:

- SVCs at both Columboola and Wandoan South substations
- additional circuits between Western Downs, Columboola and Wandoan South substations to increase fault level and transmission strength or
- a combination of the above options.

Figure 6.2 Surat Basin north west area transmission network



6.3 Possible reinvestment options initiated within the five to 10-year outlook

In addition to meeting the forecast demand, Powerlink must maintain existing assets to ensure the risks associated with condition and performance are appropriately managed. To achieve this Powerlink routinely undertakes an assessment of the condition of assets and identifies potential emerging risks related to such factors as reliability, physical condition, safety, performance and functionality, statutory compliance and obsolescence.

Based on these assessments a number of assets have been identified as approaching the end of technical or economic life. This section focuses on those assets where reinvestment will need to be made in the next five to 10-year period of this TAPR and where there may be opportunities for network reconfiguration. Information on reinvestment decisions within the current five-year outlook is detailed in Chapter 4.

The parts of the main transmission system and regional areas for which Powerlink has identified opportunities for reconfiguration in the five to 10-year period of this TAPR include:

- Ross zone
- Central West and Gladstone zones
- Central Queensland to South Queensland grid section.

Powerlink will also continue to investigate opportunities for reconfiguration in other parts of the network where assets are approaching the end of technical or economic life and demand and generation developments evolve.

Reinvestment decisions in these areas aim to optimise the network topology to ensure the network is best configured to meet current and a range of plausible future capacity needs. As assets reach the end of technical life, consideration is given to a range of options to manage these associated risks. These include asset retirement, network reconfiguration, partial or full replacement (possibly with assets of a different type, configuration or capacity), extend technical life, and/or non-network alternatives. Individual asset investment decisions are not determined in isolation. An integrated planning process is applied to take account of both future load and the condition based risks of related assets in the network. The integration of condition and demand based limitations delivers cost effective solutions that manage both reliability of supply obligations and the risks associated in allowing assets to remain inservice.

A high-level outline of the possible network development plan for these identified areas that manage risks related to the condition and performance of the existing assets is given in sections 6.3.1, 6.3.2 and 6.3.3.

6.3.1 Ross zone

The network between Collinsville and Townsville has developed over many years. It comprises a 132kV network and a 275kV network which operate in parallel. The 132kV lines are approaching end of technical life within the next five to 10 years, while the earliest end of life trigger for the 275kV lines is beyond the 10-year outlook of this TAPR.

Powerlink is investigating options to ensure that the condition based risks associated with these 132kV lines are managed. There are a number of technically feasible options for the retirement of certain 132kV transmission line assets within this area. Options include ongoing maintenance, asset retirement, line refit, rebuild and network reconfiguration.

Planning studies have indicated that there is the potential to reconfigure the network by retiring one of the two 132kV transmission lines from Townsville South to Clare South substations. If this retirement were to eventuate, and based on the medium economic forecast defined in Chapter 2, network limitations exceeding the limits under Powerlink's planning standard are forecast to occur. Possible solutions to the limitation are described in Section 4.2.2.

Further condition based risks emerge on the double circuit 132kV lines between Clare South and Collinsville North substations within the five to 10-year period of this TAPR. Powerlink is investigating options to ensure that the associated condition based risks are managed appropriately. The current options being considered include line refit or network reconfiguration.

Reinvestment in the double circuit transmission line may involve structural refit of the towers and tower painting. This line refit is likely to be required within the five to 10-year outlook of this TAPR. However, the reconfiguration options allow the majority of the double circuit transmission line to remain in-service to the predicted end of technical life. Reconfiguration options therefore defer the reinvestment need compared to the line refit option[1].

A potential reconfiguration option consists of:

- a line refit of Collinsville to King Creek circuit section only
- decommission King Creek to Clare South
- install second 275/132kV transformer at Strathmore[2]
- establish 275kV injection into Clare South[3].

As discussed in Section 6.2.1 voltage and thermal limitations may emerge within the 132kV network supplying the Bowen Basin area if additional load commits within the area. Depending on the magnitude and location of this additional load a feasible network solution may involve the installation of a second 275/132kV transformer at Strathmore Substation. Reinvestment decisions will be made cognisant of this potential outcome.

6.3.2 Central West and Gladstone zones

Within the five to 10-year outlook of this TAPR further condition based risks emerge on the double circuit 132kV line between Callide and Gladstone South substations. Powerlink is investigating options to ensure that these condition based risks are managed. The current options consist of refitting these circuits or retirement of this double circuit line with possible network reconfiguration. Section 4.2.4 discusses the condition based risks for the 132kV lines between Callide, Bioela and Moura substations which need to be addressed within the five-year outlook period.

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[1] Refit options are performed approximately five years prior to the end of technical life.

[2] Required to deliver reliability of supply to the Proserpine and Bowen Basin areas with the loss of voltage support when the 132kV connection to Townsville South is removed.

[3] Required to deliver reliability of supply to Clare South Substation following the decommissioning of inland single circuit transmission line.

6.3.3 Central Queensland to South Queensland grid section

Three single circuit 275kV transmission lines operate between Calliope River and South Pine substations and form the coastal corridor of the Central Queensland to South Queensland (CQ-SQ) grid section. These transmission lines were constructed in the 1970s and 1980s. The lines traverse a variety of environmental conditions that have resulted in different rates of corrosion. The risk levels therefore vary across the transmission lines. Updated condition assessments have been completed since the 2015 TAPR, for those sections of the lines where the environmental conditions are more onerous.

Based on these detailed assessments the 275kV single circuit lines in the most northern and southern end will reach end of technical and economic life in the five to 10-year outlook of this TAPR. The remainder of the circuits will be at end of technical and economic life from the next 10 to 30 years.

The 275kV lines at the northern end of this coastal corridor are currently experiencing to a higher rate of corrosion. It is expected that the risks, primarily driven by the 275kV single circuit transmission lines between Calliope River and Wurdong substations, will exceed acceptable corrosion levels by approximately 2021. The higher rate of corrosion is due to the proximity to the coast and exposure to salt laden coastal winds. The Calliope River to Wurdong line also traverses two tidal crossings and operates in a heavy industrial area.

Risks on the section between Calliope River and Wurdong may be managed through maintenance works, with minimal work required over the next five years. This strategy is economic and will allow the technical end of life of the 275kV single circuits between Calliope River to Wurdong to be aligned with those from Wurdong to Gin Gin.

The 275kV transmission lines between South Pine to Woolooga and Palmwoods to South Pine substations are also experiencing a higher rate of corrosion and will exceed acceptable risk levels in the next five years. The higher rate of corrosion is due to a localised wet weather environment in the hinterland regions of Mapleton and Maleny.

Similar to the strategy in the northern section, it is considered economic to align the technical and economic end of life of the South Pine to Woolooga and Palmwoods to Woolooga transmission lines. This will require a moderate amount of maintenance or refurbishment on the South Pine to Woolooga 275kV transmission line in the next five to 10 years. A transmission line refit project will also be required within the next five years to manage the risks of the 275kV single circuit transmission line between Palmwoods and Woolooga substations.

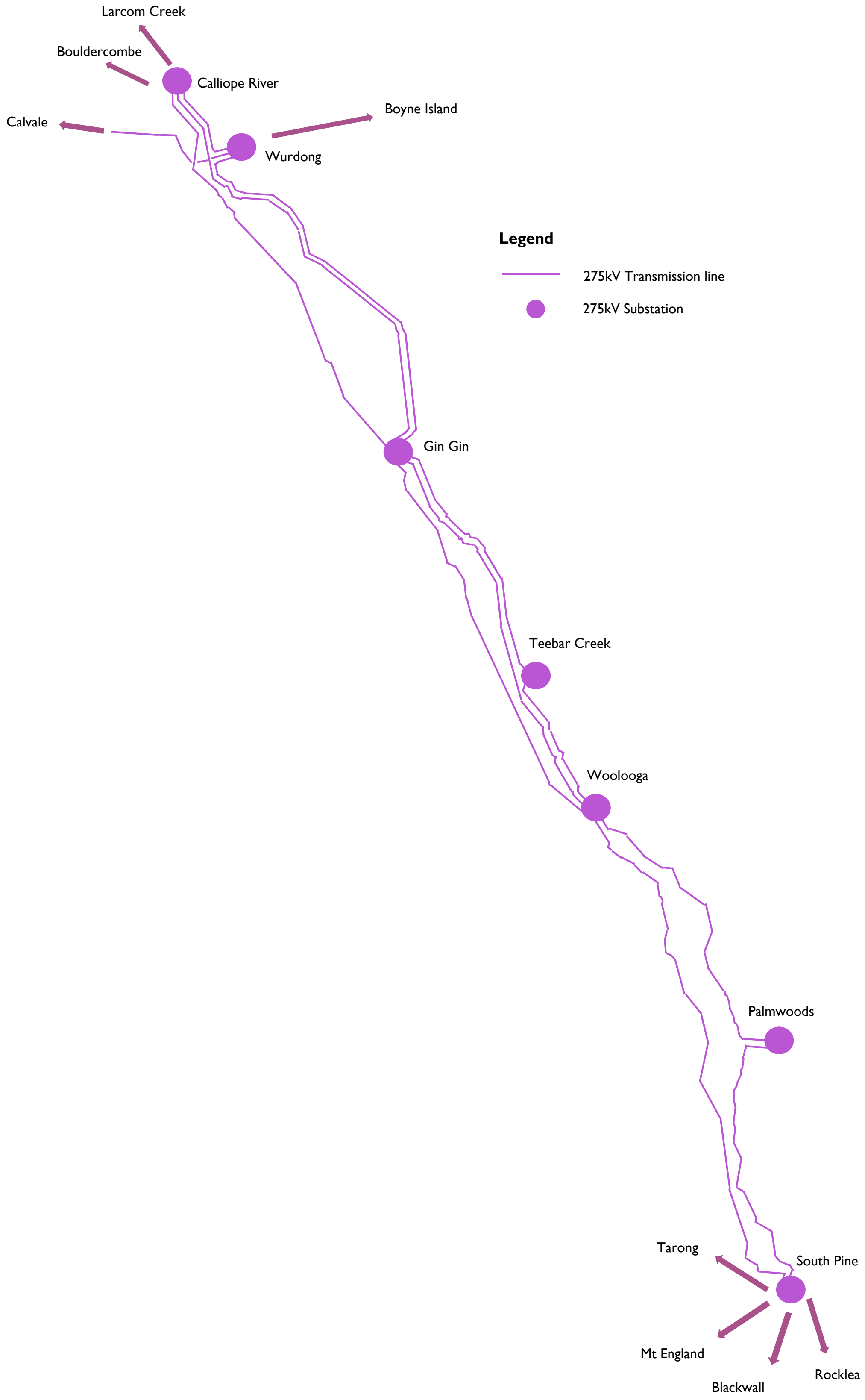
These strategies have the benefit of maintaining the existing topology, transfer capability and operability of the network. The strategies provide for an incremental development approach and defer large capital investment.

The incremental approach to reinvesting in the existing assets is both economic over the 10-year outlook of this TAPR and is fully aligned with providing time to better understand the impact that a lower carbon (higher renewable) generation future may have on the required transfer capability of this grid section.

The CQ-SQ grid section is an important intra-connector for the efficient operation of the NEM. Based on the medium economic forecast defined in Chapter 2 and the existing and committed generation defined in Table 5.1 there may be an opportunity to consolidate assets on the CQ-SQ grid section beyond the 10-year outlook of this TAPR without materially impacting the efficient operation of the NEM. However, potential investment in renewable generation in central and north Queensland, coupled with the possible displacement and/or retirement of existing thermal plant may significantly increase the utilisation of the grid section.

Powerlink will take these developments into account when formulating the strategies to meet the future emerging market requirements.

Figure 6.3 Central Queensland to South Queensland area transmission network



6.4 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2015 Electricity Statement of Opportunities (ESOO)[4]. Interested parties who require information regarding future supply demand balance should consult this document.

6.5 Interconnectors

6.5.1 Existing interconnectors

The Queensland transmission network is interconnected to the New South Wales (NSW) transmission system through the Queensland/New South Wales Interconnector (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 5.5.9).

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 5.5.9).

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 the market or transmission projects are commissioned in either region.

6.5.2 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 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 continue to monitor market developments to determine if any material changes could warrant reassessment of an upgrade to QNI. Relevant changes may include:

- changes in generation and large-scale load developments in Queensland and the NEM (including LNG, coal developments, renewable generation, retirement of generation); and
- NEM-wide reductions in forecast load and energy consumption.

There is considerable uncertainty in both load and generation development/retirement in the Queensland region. This uncertainty also extends to the southern states; perhaps not to the same extent for new large-scale load developments, but certainly for new generation development and or retirements. The impact this may have on the congestion and incidence of constraints on QNI is complex and varied. Depending on the emergence of these changes, QNI congestion may increase in the northerly or southerly direction. The different investments in load and investments and de-investments in generation across the NEM may also impact on the location and scope of viable network upgrade options.

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[4] Published by AEMO in August 2015.

Possible network solutions

Due to the nature of the voltage, transient and oscillatory stability limitations (as detailed in Section 5.5.9) a technically viable network option that would increase the QNI power transfer capability would be to establish controllable series compensation. All or part of this series compensation could be installed in the Queensland region.

Depending on the emergence of network limitations across QNI it may become economically viable to uprate its power transfer capacity to alleviate constraints. A feasible network solution to facilitate efficient market operation may include controllable series compensation. To manage the voltage profile a part of this series compensation could be installed in the Queensland region. While there is no current regulatory consultation process underway, Powerlink and TransGrid still encourage expressions of interest for potential non-network solutions which may be capable of increasing the transfer capability across the interconnector and hence deliver market benefits[5]. This is part of a broader strategy Powerlink is implementing to further develop, expand and capture economically and technically feasible non-network solutions. This strategy is based on enhanced collaboration with stakeholders (refer to Section 1.8.2).

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[5] Information on non-network solutions maybe found at QNI Upgrade consultation.

6 Strategic planning

Chapter 7:

Renewable energy

7 Renewable energy

Key highlights

- This chapter explores the potential for the development and connection of renewable energy generation to Powerlink's transmission network.
- The generation connection capacity of Powerlink's 132kV and 110kV substations for the existing transmission network is identified to facilitate high level decision making for interested parties.
- Compared to most other States in the NEM, Queensland's network presently has a much lower proportion of intermittent renewables (to total generation capacity) and is capable of accommodating a considerable number of additional renewable connections without immediate concern for overall system stability.
- Where economies of scale can be achieved through project cluster, Powerlink may consider the development of Renewable Energy Zones (REZs), subject to regulatory approvals and the conditions of its Transmission Licence.

7.1 Introduction

Queensland is rich in a diverse range of renewable energy resources – geothermal, biomass, wind and hydro – however the focus to date has been on solar, with Queensland displaying amongst the highest levels of solar concentration in the world. This makes Queensland an attractive location for large-scale solar powered generation development projects. There is significant potential for energy supply from renewable resources in Queensland. The rapid uptake of renewable energy systems is stimulating the development of supporting technologies, which in turn is improving the affordability of these systems.

The uptake of over 1,500MW of small-scale solar in Queensland to date provides strong indication that Queensland consumers are no longer meeting their energy requirements entirely through conventional means. New technologies such as solar PV, smart appliances, and energy storage technologies are changing the way customers consume and produce energy. Revised policy frameworks, State based incentive schemes, Federal Government support programs, and climate change concerns are influencing developments in the energy sector, and will continue to have an impact. Powerlink is continually adapting to align with changes in its operating environment.

Due to the recent volume of interest in solar development projects in Queensland, this newly-developed chapter of Powerlink's 2016 Transmission Annual Planning Report (TAPR) focuses on solar energy project development opportunities. Powerlink is committed to supporting the development of all types of energy projects, however for the reasons outlined above, solar is a key focus area going forward. It should be noted that the network capacity information presented in this chapter is applicable to all forms of generation[1].

The Australian Government Department of Geoscience has published an assessment of Australia's energy resource across the continent. The report acknowledges that Australia's potential for renewable energy generation is very large and widely distributed across the continent. The annual average solar radiation map in Figure 7.1 indicates Queensland's solar energy potential, and in particular the proximity of Powerlink's high voltage transmission infrastructure to this energy resource.

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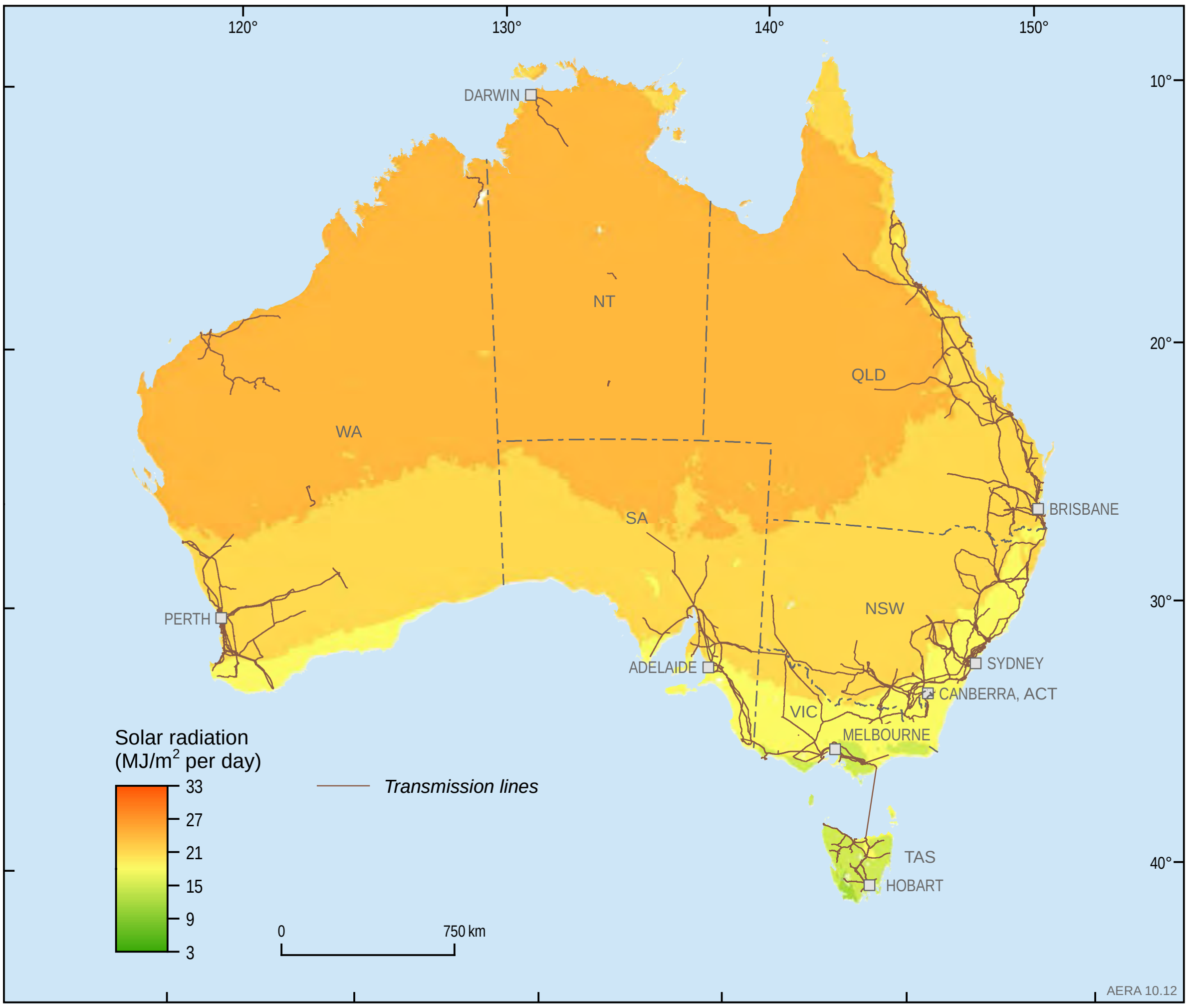
[1] The impact of new synchronous generator connections on existing fault levels has not been considered in the assessments conducted in this chapter. For further information on existing fault levels and equipment rating, please refer to Appendix E.

Figure 7.1 Australian annual average solar radiation



Source: Geoscience Australia and Bureau of Meteorology[2]

7.2 Network capacity for new generation

Powerlink has assessed the ability of various locations across the existing transmission network to connect additional generation capacity without significant network congestion emerging. This section provides a broad overview of the results of this assessment. Interested parties are invited to use this data as a first pass to facilitate high level decision making. The data presented here is not exhaustive, and is not intended to replace the existing procedures and processes that must be followed to access Powerlink's transmission network.

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[2] © Commonwealth of Australia (Geoscience Australia and Bureau of Meteorology) 2016. This product is released under the Creative Commons Attribution 4.0 International Licence. http://creativecommons.org/licenses/by/4.0/legalcode

7 Renewable energy

Locations assessed for generation connection capacity were selected based broadly on their distance from metropolitan load centres. Locations close to major cities were considered unlikely to host a large renewable energy connection, and were excluded from the assessment. In addition, plant operating at 275kV (and higher) were excluded from this study as they can generally accommodate significant levels of generation. The approach used to establish the available capacity at the selected sites was as follows:

- A notional generator was placed sequentially at each of the selected locations and its output was gradually increased. The capacity of the location was established when either:
  - the loss of a network element caused an overload of one or more adjacent elements or
  - the size of the notional generator connection exceeded the network strength[3].

The results of the assessment are shown in Table 7.1.

Table 7.1 Indicative connection point capacity limits in the existing transmission network[4]

132kV and 110kV Substation Connection Nodes Assessed			Indicative Connection Point Capacity Limit
Baralaba	Egans Hill	Norwich Park	up to 50MW
Biloela	Grantleigh	Oonooie	
Cardwell	Ingham South	Peak Downs	
Coppabella	Innisfail	Proserpine	
Dingo	Kamerunga	Turkinje	
Edmonton	Moura		
Alligator Creek	Collinsville North	Pandoin	between 50MW and 150MW
Bluff	Dan Gleeson	Rocklands	
Bowen North	Dysart	Strathmore	
Bulli Creek	Kemmis	Tangkam	
Burton Downs	Mackay	Tully	
Chalumbin	Moranbah South	Wandoo	
Chinchilla	Mt. McLaren	Woree	
Clare South	Newlands		
Alan Sheriff	Larcom Creek	Pioneer Valley	between 150MW and 400MW
Blackwater	Lilyvale	Ross	
Bouldercombe	Middle Ridge	Teebar Creek	
Callemondah	Moranbah	Townsville Sth	
Columboola	Nebo	Woolooga	
Gin Gin	Palmwoods	Yabulu South	
Blackstone	Calliope River	Gladstone South	potentially greater than 400MW

This information will be revised as new information related to available network capacity becomes available. Please refer to the TAPR 2016 Addendum for the updated network capacities.

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[3] Network strength is measured through the fault level and short circuit ratio in an area.

[4] 275kV and 330kV connections were excluded from this assessment on the basis that they can generally accommodate significantly higher levels of generation.

The findings indicate that the Queensland transmission network is sufficiently strong, and well positioned to accommodate sizeable quantities of new generation without encroaching stability limits. These results are encouraging, particularly given the volume of interest shown in renewable energy projects in Queensland. The results are also presented graphically in Figure 7.2, together with an overlay of the Queensland solar radiation depicted in Figure 7.1.

Key points to note:

- Generation opportunities presented in this section are not cumulative. If a new generator connects to the network, it will likely impact the capacity of other areas in the network. Similarly, changes to the existing network arrangement will impact transfer limits and consequently, available capacity. Network capacity must be reassessed each time the network topology changes or a prospective generator commits.
- The capacity limits are based primarily on thermal limits and network strength[5], with the assumption that the proposed generation facility will comply with the NER's automatic access standard for reactive power dispatch. A formal connection enquiry could trigger an assessment of other stability limits, including the potential for network congestion.
- While some areas may appear to have restricted capacity, there may be low cost solutions available to accommodate much larger capacities. Fast run-back schemes are often used to curtail generation to avoid breaching thermal limits. The capacities stated in Table 7.1 are therefore not absolute. They are presented as a guideline, and starting point for further discussions.

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[5] Network strength is measured through the fault level and short circuit ratio in an area. Fault level is the maximum current expected to flow in response to a short circuit at a given point in the power system. A project-specific measure of system strength for a generator connection is the Short Circuit Ratio (SCR), which is the ratio of the power system fault level at the proposed connection point to the rated generator connection. Both the minimum fault level and the minimum SCR are important values in establishing the limit of an asynchronous generator connection (such as wind or solar).

Figure 7.2: Transmission network capacity for new generation with solar radiation overlay

7.3 Supporting renewable energy infrastructure development

7.3.1 Renewable Energy Zone (REZ)

Powerlink is committed to supporting the development of renewable energy projects in Queensland. While the majority of recent interest has focussed on solar related activity, Powerlink recognises that considerable opportunity exists for wind, biomass, geothermal and hydroelectric projects in Queensland. Where economies of scale can be achieved through project clusters, Powerlink may consider the development of Renewable Energy Zones (REZs), subject to regulatory approvals and the conditions of its Transmission Licence.

The implementation of a REZ would require that consideration be given to a range of criteria, including economic benefit to customers, energy resource potential, infrastructure availability and access, stakeholder and local authority support, environmental suitability, and where possible, opportunity for deferral or replacement of planned network investment projects.

A REZ may be viewed as an expansion of the existing network into the zone of interest, as a high capacity transmission line or a connection hub, either of which would be aimed at supporting clusters of renewable energy projects. These arrangements are generally more cost effective than the creation of multiple connection paths to the grid as infrastructure sharing reduces the need for asset duplication. Although this concept is aimed at identifying priority areas for development, it is not intended to preclude the development of renewable energy projects outside the targeted zones.

Figure 7.3: REZ with high capacity transmission line

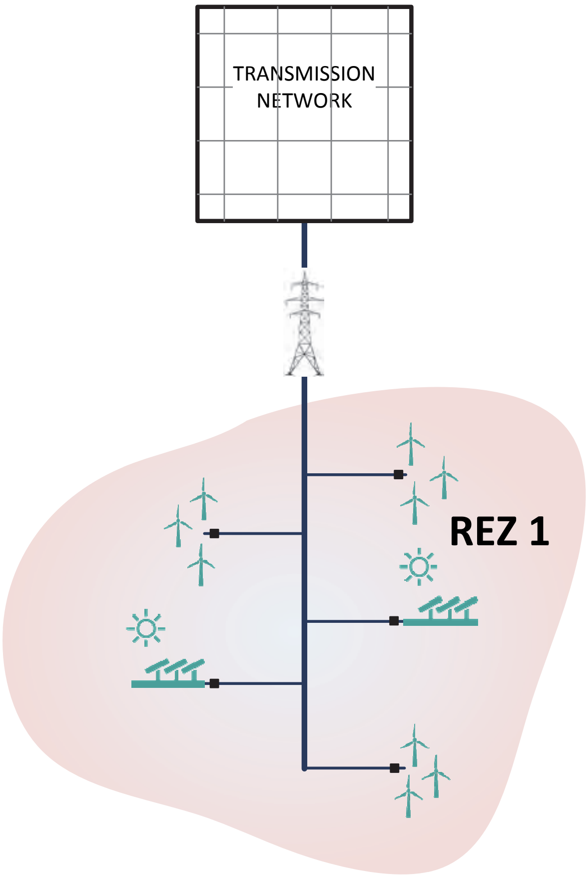
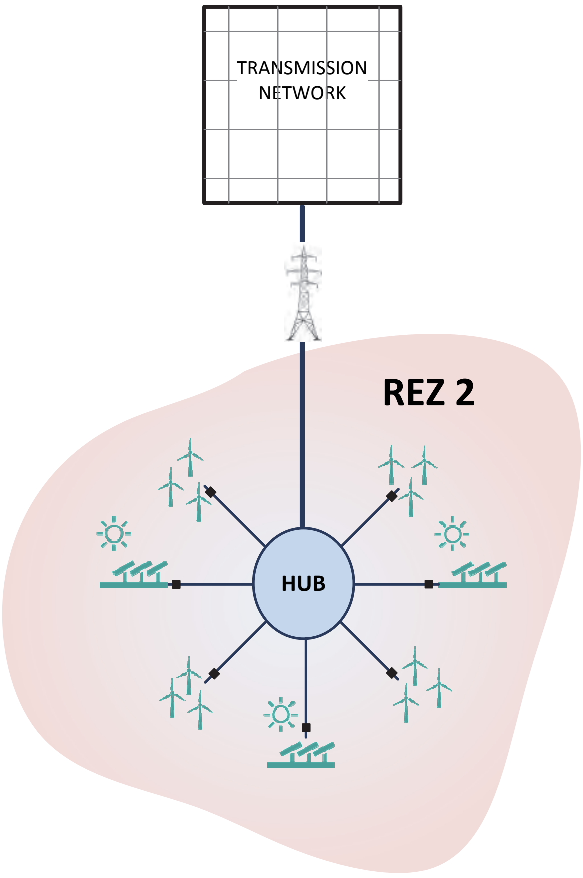


Figure 7.4: REZ with dedicated connection hub



Powerlink will continue to engage broadly with developers and interested parties to understand the needs and expectations of its stakeholders. Powerlink expects to work with the relevant government agencies to further explore efficient connection arrangements for renewable energy development schemes in Queensland.

7.3.2 Technical considerations

Due to the high level of growth in renewable energy systems in Queensland, Powerlink, in conjunction with Ergon Energy, considered the potential impact of large-scale renewable energy penetration on grid stability. The high level findings were:

- There are presently no anticipated network stability issues arising from projects under consideration that require solutions outside of normal customer connection planning processes.
- Compared to most other States in the NEM, Queensland's network presently has a much lower proportion of intermittent renewables to total generation capacity.
- Powerlink's transmission network is sufficiently strong, with capability to accommodate a considerable number of additional renewable energy connections without immediate concern for overall system stability.
- Monitoring the network for potential stability impacts will need to continue as intermittent renewable connections increase.

These findings will be reassessed for each new generator commitment.

7.3.3 Proposed renewable connections in Queensland

There has been significant interest in renewable energy projects in Queensland. The Queensland Government Department of Energy and Water Supply (DEWS) maintains mapping information on proposed (future) renewable energy projects that have been publicly announced, together with existing generation facilities (and other information) on its website. The data used to populate the *Proposed Renewable Energy Projects in Queensland* map shown in Figure 7.5 has been sourced from DEWS and is included in this chapter for completeness. For further information on proposed renewable energy projects in Queensland, please refer to www.dews.qld.gov.au.

Figure 7.5: Proposed renewable energy development projects in Queensland

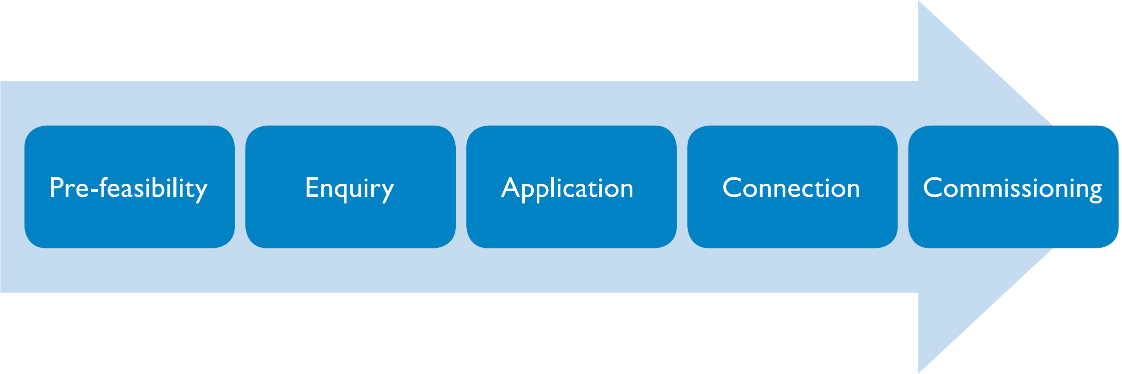
NAME	Capacity (MW)
Baralaba Solar Farm	50
Barcaldine Remote Community Solar Farm	25
Bulli Creek	2,000
Clare Solar Farm	150
Cloncurry Solar Farm	6
Collinsville Solar Power Station	42
Coopers Gap Wind Farm	350
Darling Downs Solar Farm	107
Etheridge Integrated Agricultural Project	90
Forsayth Wind Farm	75
High Road Wind Farm	34
Hughenden Sun Farm	14.2
Ingham	115
Kennedy Energy Park	19.2
Kennedy Energy Park	1,300
Kidston Project	330
Kidston Solar Project	50
Lakeland Solar Farm	26
Lilyvale solar farm	150
Longreach Solar Farm	15
Mt Cotton Biomass Cogeneration Power Station	8
Mt Emerald Wind Farm	180
Normanton Solar Farm	5
North Queensland Solar Farm	50
Oakey Solar Farm	25
Valdora Solar Farm	15
Weipa Solar Farm	5
Whitsunday Solar Farm	52.8
Winton Geothermal plant	0.3

Data Source: Queensland Government Department of Energy and Water Supply (DEWS)

7.4 Further information

Powerlink will continue to work with market participants and interested parties across the renewables sector to better understand the potential for renewable energy, and to identify opportunities and emerging limitations as they occur. The National Electricity Rules (Clause 5.3) prescribes procedures and processes that Network Service Providers must apply when dealing with connection enquiries. Powerlink uses a five-stage approach as illustrated in Figure 7.6 below to facilitate this process.

Figure 7.6: **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[6] www.powerlink.com.au.

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[6] Refer to Connecting to Powerlink's Network on the Powerlink website.

Appendices

Appendices

Appendix A – Forecast of connection point maximum demands

Tables A.1 to A.6 show 10-year forecasts of native summer and winter demand at connection point peak. 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.6 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

Table A.1 Ergon Energy connection point forecast of summer native peak demand

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	27	14	27	14	28	14	27	14	28	14	28	14	29	14	28	14	29	14	29	15
Aligator Creek (Louisa Creek)	132	N	57	17	56	17	56	17	54	16	54	16	54	16	54	16	53	16	52	16	52	16
Alligator Creek	33	N	44	16	43	16	43	16	43	16	43	16	42	16	43	16	42	16	42	16	42	16
Biloela	66	CW	35	7	35	7	35	7	35	6	35	7	36	7	36	7	36	7	36	7	35	7
Blackwater	132	CW	30	19	32	20	32	20	31	20	31	20	31	19	31	19	30	19	30	19	30	19
Blackwater	66	CW	120	14	120	14	118	14	116	13	126	14	138	16	140	16	137	16	136	16	135	15
Bowen North	66	R	22	8	23	9	23	9	24	9	24	9	24	9	24	9	23	9	24	9	24	9
Bulli Creek (Waggamba)	132	B	18	3	18	3	18	3	17	3	17	3	17	3	17	3	17	3	17	3	17	3
Cairns	22	FN	49	0	49	0	48	0	47	0	47	0	47	0	47	0	46	0	45	0	45	0
Cairns City	132	FN	61	32	61	32	60	32	59	31	58	31	58	30	58	30	56	30	56	29	56	29
Calliope River	132	G	38	20	38	20	43	23	41	21	41	21	40	21	40	21	40	20	39	20	39	20
Cardwell	22	R	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4
Chinchilla	132	SW	22	11	22	11	22	11	22	11	22	11	23	11	23	11	23	11	23	11	23	11
Clare South	66	R	73	23	73	23	72	23	71	23	71	23	70	22	70	23	69	22	69	22	68	22
Collinsville	33	N	18	9	18	9	18	10	22	11	22	12	22	12	23	12	23	12	23	12	23	12
Columboola	132	SW	68	9	68	9	71	9	70	9	71	10	73	10	73	10	72	10	72	10	72	10
Dan Gleeson	66	R	112	46	107	43	107	43	105	42	105	42	105	44	106	44	104	43	104	43	104	43
Dysart	66	CW	75	13	74	13	74	12	72	12	72	12	72	12	72	12	70	12	70	12	69	12
Edmonton	22	FN	45	10	45	10	46	10	45	10	46	10	46	10	47	10	46	10	47	10	47	10
Egans Hill	66	CW	55	9	55	9	55	9	55	9	55	9	55	9	55	9	55	8	55	8	55	8
El Arish	22	FN	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1
Garbutt	66	R	116	47	111	45	110	45	109	44	109	44	109	45	109	45	108	45	108	45	108	44

Table A.1 Ergon Energy connection point forecast of summer native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	154	19	153	19	152	19	149	19	148	19	147	18	147	18	145	18	144	18	143	18
Gladstone South	66	G	76	28	76	29	77	29	78	29	79	30	80	30	81	31	81	30	82	31	82	31
Ingham	66	R	19	5	18	5	18	5	18	5	18	5	18	4	18	4	17	4	17	4	17	4
Innisfail	22	FN	27	14	27	14	27	14	26	13	26	13	26	13	26	13	25	13	25	13	25	13
Kamerunga	22	FN	64	22	64	22	65	22	64	22	64	22	69	24	73	26	73	25	73	25	73	26
Lilyvale (Barcaldine & Clermont)	132	CW	44	7	44	7	44	7	43	7	43	7	43	7	43	7	43	7	43	7	43	7
Lilyvale	66	CW	155	67	155	67	154	67	158	68	158	68	157	68	157	68	155	67	154	67	153	66
Mackay	33	N	95	71	94	71	94	70	92	69	92	69	91	68	92	68	90	67	89	67	89	67
Middle Ridge	110	SW	197	28	197	28	196	28	192	27	192	27	191	27	192	27	189	27	189	27	188	27
Middle Ridge (Postmans Ridge)	110	M	23	10	23	10	23	10	23	10	23	10	23	10	23	10	22	10	22	10	22	10
Moranbah (Broadlea)	132	N	48	18	48	18	48	18	47	17	54	20	57	21	58	21	57	21	57	21	56	21
Moranbah	66 and 11	N	112	34	130	39	129	39	126	38	126	38	135	41	146	44	143	43	142	43	141	43
Moura	66	CW	62	20	62	20	61	20	61	20	61	20	61	20	61	20	60	20	60	20	60	19
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	37	12	36	12	41	14	40	13	40	13	40	13	40	13	39	13	39	13	38	13
Oakey	110	SW	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6
Pandoin	66	CW	45	7	45	7	45	7	44	7	45	7	45	7	45	7	44	7	44	7	44	7
Pioneer Valley	66	N	59	27	59	27	58	27	57	26	57	26	57	26	57	26	55	26	55	25	55	25
Proserpine	66	N	57	20	57	20	57	20	56	19	61	21	65	23	65	23	64	22	64	22	63	22

Table A.1 Ergon Energy connection point forecast of summer native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	99	16	100	16	99	16	98	15	98	16	98	15	99	16	98	15	98	15	98	15
Ross (Kidston, Milchester and Georgetown)	132	R	40	15	40	15	40	15	40	14	40	15	40	15	40	15	40	14	40	14	40	14
Stoney Creek	132	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	2	1	2	1	2	1
Tangkam	110	SW	31	9	31	9	32	10	32	10	32	10	32	10	33	10	32	10	33	10	33	10
Tarong	66	SW	42	17	42	17	41	17	41	17	41	17	41	16	41	17	40	16	40	16	40	16
Teebar Creek (Isis and Maryborough)	132	WB	121	39	121	39	121	39	119	38	119	39	119	38	120	39	118	38	118	38	118	38
Townsville East	66	R	41	17	39	16	39	16	39	16	39	16	39	16	39	16	38	16	38	16	38	16
Townsville South	66	R	110	45	105	42	105	42	103	41	103	41	103	43	104	43	102	42	102	42	102	42
Tully	22	R	15	7	15	7	15	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7
Turkinje (Craiglie and Lakeland)	132	FN	23	7	23	7	23	7	22	7	22	7	22	7	22	7	22	7	22	7	22	7
Turkinje	66	FN	59	16	63	17	62	17	61	16	64	17	63	17	63	17	62	17	62	17	61	16
Woolooga (Kilkivan)	132	WB	32	4	32	4	31	4	31	4	31	4	30	4	30	4	30	4	30	4	30	4
Woree (Cairns North)	132	FN	46	22	48	22	49	23	49	23	51	24	52	24	53	25	54	25	55	26	56	26
Yarwun (Boat Creek)	132	G	43	27	43	27	42	26	41	26	41	26	41	25	40	25	40	25	39	25	39	24
Hail Creek and King Creek	Various	N	47	11	47	11	47	11	46	11	45	11	45	10	45	10	44	10	44	10	43	10

Note:

(1) Connection point loads for summer 2025/26 have been extrapolated.

Table A.2 Ergon Energy connection point forecast of winter native peak demand

Connection point	Voltage (kV)	Zone	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	18	9	18	9	18	9	18	9	17	9	17	9	17	9	18	9	18	9	17	9
Alligator Creek (Louisa Creek)	132	N	51	17	51	17	51	17	51	17	49	16	49	16	49	16	49	16	48	16	48	16
Alligator Creek	33	N	20	8	20	8	20	8	20	8	20	7	20	7	20	7	20	7	19	7	19	7
Biloela	66	CW	29	4	29	4	29	4	29	4	29	4	30	4	30	4	30	4	30	4	30	4
Blackwater	132	CW	29	21	32	23	31	23	31	23	30	22	30	22	30	22	30	22	30	22	30	21
Blackwater	66	CW	99	14	99	14	98	14	98	14	104	15	115	16	116	16	117	17	115	16	114	16
Bowen North	66	R	26	10	26	11	27	11	27	11	30	12	30	12	30	12	30	12	29	12	30	12
Bulli Creek (Waggamba)	132	B	21	11	21	11	21	11	21	11	21	11	21	11	21	11	22	11	21	11	21	11
Cairns	22	FN	39	5	39	5	39	5	38	5	37	5	37	5	37	5	37	5	37	5	36	5
Cairns City	132	FN	42	23	42	23	42	23	41	23	40	22	40	22	40	22	40	22	39	22	39	22
Calliope River	132	G	32	16	32	16	38	19	38	19	35	18	35	18	35	18	35	18	34	18	34	17
Cardwell	22	R	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3
Chinchilla	132	SW	19	5	19	5	18	5	18	5	18	5	18	4	18	4	18	4	17	4	17	4
Clare South	66	R	51	13	44	12	44	12	44	12	43	11	43	11	42	11	43	11	42	11	42	11
Collinsville	33	N	15	6	15	6	15	6	18	8	18	8	18	8	18	8	18	8	18	8	17	8
Columboola	132	SW	75	16	76	16	76	16	79	16	79	16	80	17	80	17	81	17	80	17	79	16
Dan Gleeson	66	R	91	32	92	32	85	28	85	28	83	27	83	27	84	27	85	28	84	28	84	28
Dysart	66	CW	40	7	60	10	60	10	59	10	58	10	58	10	57	10	58	10	57	10	56	10
Edmonton	22	FN	31	6	31	6	31	6	31	6	30	6	30	6	30	6	30	6	29	6	29	6
Egans Hill	66	CW	43	11	44	11	44	11	44	11	43	10	43	10	43	10	44	11	43	10	43	10
El Arish	22	FN	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0
Garbutt	66	R	87	30	88	31	81	27	82	27	80	26	80	26	80	26	81	27	81	26	81	26

Table A.2 Ergon Energy connection point forecast of winter native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	116	14	116	14	115	14	115	14	112	14	112	14	111	14	112	14	111	14	110	14
Gladstone South	66	G	63	21	63	21	63	21	63	21	63	21	63	21	64	21	64	22	64	22	64	22
Ingham	66	R	21	4	21	4	21	4	21	4	20	4	20	4	20	4	20	4	20	4	20	3
Innisfail	22	FN	25	13	25	13	25	13	25	13	24	12	24	12	24	12	24	12	24	12	24	12
Kamerunga	22	FN	43	13	43	13	42	13	42	13	41	12	44	13	47	14	47	14	47	14	46	14
Lilyvale Barcaldine and Clermont)	132	CW	37	2	37	2	37	2	37	2	36	2	36	2	36	2	36	2	36	2	35	2
Lilyvale	66	CW	133	56	139	58	138	57	138	58	140	58	139	58	139	58	139	58	137	57	136	57
Mackay	33	N	72	58	72	58	72	57	71	57	70	56	69	56	69	55	69	56	69	55	68	54
Middle Ridge	110	SW	198	17	198	17	197	17	197	17	192	17	192	17	192	17	193	17	190	17	189	17
Middle Ridge (Postmans Ridge)	110	M	51	16	51	16	51	16	51	16	50	16	50	16	50	16	51	16	50	16	50	16
Moranbah (Broadlea)	132	N	37	14	38	14	38	14	38	14	42	15	44	16	46	17	46	17	45	17	45	17
Moranbah	66 and 11	N	94	27	94	27	108	31	108	31	105	30	115	33	124	36	125	36	123	35	122	35
Moura	66	CW	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	36	12	36	12	41	13	40	13	39	13	39	13	39	13	39	13	39	13	38	13
Oakey	110	SW	21	3	21	3	21	3	21	3	20	3	20	3	20	3	20	3	20	3	20	3
Pandoin	66	CW	33	8	33	8	33	8	33	8	32	8	32	8	33	8	33	8	33	8	33	8
Pioneer Valley	66	N	50	21	50	21	50	21	50	21	49	21	49	21	49	21	49	21	49	21	49	20
Proserpine	66	N	35	13	35	13	35	13	35	13	39	14	43	16	43	16	43	16	43	16	43	16

Table A.2 Ergon Energy connection point forecast of winter native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	69	17	70	17	70	17	70	17	68	17	69	17	69	17	70	17	69	17	69	17
Ross (Kidston, Milchester and Georgetown)	132	R	30	10	30	10	30	10	30	10	30	10	30	10	30	10	31	10	30	10	30	10
Stoney Creek	132	N	3	1	3	1	3	1	3	1	2	1	2	1	2	1	2	1	2	1	2	1
Tangkam	110	SW	30	8	30	8	30	8	30	8	30	8	30	8	30	8	31	8	30	8	30	8
Tarong	66	SW	39	12	39	12	38	12	38	12	37	12	37	12	37	12	37	12	37	12	37	12
Teebar Creek (Isis and Maryborough)	132	WB	111	15	111	15	110	15	110	15	107	14	107	14	106	14	107	14	106	14	105	14
Townsville East	66	R	41	14	41	14	38	12	38	12	37	12	37	12	37	12	38	12	37	12	38	12
Townsville South	66	R	83	29	84	29	78	26	78	26	76	25	76	25	76	25	77	25	77	25	77	25
Tully	22	R	11	5	11	5	11	5	11	5	11	5	11	5	11	5	11	5	11	4	11	4
Turkinje (Craiglie and Lakeland)	132	FN	19	6	19	6	19	6	19	6	19	6	19	6	18	6	19	6	18	6	18	6
Turkinje	66	FN	55	13	55	13	59	14	59	14	57	13	60	14	60	14	60	14	59	14	59	14
Woolooga (Kilkivan)	132	WB	29	5	29	5	28	5	28	5	28	5	27	5	27	5	27	5	27	5	27	5
Woree (Cairns North)	132	FN	35	6	36	7	38	7	39	7	39	7	40	7	41	7	43	8	43	8	44	8
Yarwun (Boat Creek)	132	G	41	22	41	22	41	22	40	22	39	21	39	21	39	21	39	21	38	21	38	21
Hail Creek and King Creek	Various	N	46	9	46	9	45	9	45	9	44	9	44	9	43	9	44	9	43	9	42	9

Table A.3 Energex connection point forecast of summer native peak demand

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	54	18	55	19	55	19	55	19	56	19	57	19	57	19	58	19	58	20	59	20
Abermain	33	M	88	15	90	15	91	15	94	16	94	16	95	16	96	16	98	16	99	16	100	17
Algester	33	M	66	17	67	17	67	17	67	17	67	17	67	17	68	17	68	17	68	17	68	17
Ashgrove West	110	M	113	10	116	11	118	11	119	11	121	11	123	11	125	12	127	12	129	12	131	12
Ashgrove West	33	M	73	6	73	6	73	6	73	6	73	6	73	6	74	6	74	6	74	6	74	6
Belmont	110	M	414	264	426	272	431	275	434	277	435	278	438	280	444	284	451	288	457	292	462	295
Blackstone (Raceview)	110	M	89	14	91	14	93	14	93	14	94	14	95	14	95	15	96	15	82	12	82	13
Bundamba	110	M	35	23	36	23	36	23	36	23	36	23	36	23	36	23	37	24	37	24	37	24
Goodna	33	M	108	13	113	14	116	14	117	14	120	15	110	14	112	14	115	14	117	14	119	15
Loganlea	110	M	308	128	313	131	315	131	315	131	322	134	326	136	329	137	332	138	335	139	337	141
Loganlea	33	M	106	19	107	20	107	19	106	19	107	19	107	20	108	20	108	20	109	20	109	20
Middle Ridge (Postmans Ridge and Gatton)	110	M	140	19	142	19	143	20	143	20	144	20	144	20	145	20	146	20	146	20	147	20
Molendinar	110	GC	464	64	473	66	478	67	476	66	480	67	482	67	486	68	491	68	494	69	497	69
Mudgeeraba	110	GC	334	92	339	93	337	93	336	92	339	93	339	93	341	94	343	94	344	94	345	95
Mudgeeraba	33	GC	20	8	21	8	21	8	20	8	21	8	21	8	21	8	21	8	21	8	21	8
Murarrie	110	M	406	90	415	92	418	93	421	93	427	94	431	95	438	97	447	99	455	101	463	102
Palmwoods	110 & 132	M	365	166	374	170	375	171	378	172	386	176	393	179	403	184	411	187	413	188	415	189
Redbank Plains	11	M	20	7	21	7	21	7	22	7	22	8	23	8	23	8	24	8	24	8	25	9
Richlands	33	M	114	31	116	32	116	31	115	31	116	32	116	32	117	32	118	32	118	32	118	32
Rocklea	110	M	165	68	165	68	165	68	166	68	179	73	180	74	181	75	183	75	184	76	185	76

Table A.3 Energex connection point forecast of summer native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	61	8	64	9	65	9	65	9	65	9	65	9	66	9	66	9	66	9	67	9
South Pine	110	M	896	191	911	194	910	194	911	194	921	196	926	197	933	199	942	201	948	202	954	203
Sumner	110	M	36	17	36	17	36	17	36	17	36	17	36	17	36	17	36	17	36	17	37	17
Tennyson	33	M	172	26	175	26	174	26	174	26	175	26	176	26	177	26	178	26	179	27	180	27
Wecker Road	33	M	128	20	130	20	132	20	132	21	134	21	134	21	135	21	136	21	136	21	137	21
Woolooga (Gympie)	132	M	171	16	173	16	172	16	172	16	174	16	174	17	175	17	176	17	177	17	178	17

Table A.4 Energex connection point forecast of winter native peak demand

Connection point	Voltage (kV)	Zone	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	31	12	31	12	32	12	32	12	32	12	33	13	33	13	33	13	33	13	34	13
Abermain	33	M	64	5	65	5	67	6	67	6	69	6	70	6	71	6	72	6	73	6	74	6
Algester	33	M	54	30	54	30	55	30	55	30	54	30	55	30	55	30	55	30	55	30	56	31
Ashgrove West	110	M	81	11	86	11	89	12	90	12	91	12	93	12	94	12	95	12	97	13	99	13
Ashgrove West	33	M	70	8	70	8	71	8	71	8	70	8	71	8	71	8	71	8	71	8	72	8
Belmont	110	M	282	49	285	49	296	51	299	52	300	52	301	52	301	52	303	52	307	53	313	54
Blackstone (Raceview)	110	M	62	13	62	13	64	13	66	14	66	14	67	14	67	14	67	14	68	14	55	11
Bundamba	110	M	29	16	29	16	30	17	30	17	29	16	30	17	30	17	30	17	30	17	30	17
Goodna	33	M	82	7	87	8	92	8	94	9	95	9	98	9	90	8	91	8	94	9	96	9
Loganlea	110	M	213	65	213	65	220	67	221	67	222	68	228	69	229	70	230	70	232	71	235	72
Loganlea	33	M	74	11	74	11	75	11	75	11	74	11	75	11	75	11	75	11	75	11	76	12
Middle Ridge (Postmans Ridge and Gatton)	110	M	111	13	112	13	114	13	114	13	114	13	115	13	115	13	115	13	116	13	117	14
Molendinar	110	GC	344	26	347	27	357	27	359	28	356	27	362	28	362	28	363	28	366	28	371	28
Mudgeeraba	110	GC	267	74	267	74	273	75	271	75	269	74	273	75	272	75	272	75	273	75	276	76
Mudgeeraba	33	GC	18	6	18	6	19	6	18	6	18	6	19	6	19	6	19	6	19	7	19	7
Murarrie	110	M	345	73	347	74	356	76	358	76	359	76	364	77	368	78	374	79	381	81	389	83
Palmwoods	110 & 132	M	300	122	311	126	322	130	322	131	324	131	334	135	340	138	347	141	355	144	359	145
Redbank Plains	11	M	15	3	15	4	16	4	16	4	16	4	16	4	17	4	17	4	17	4	18	4
Richlands	33	M	87	15	88	15	90	16	90	15	89	15	90	16	90	15	90	15	91	16	92	16
Rocklea	110	M	113	29	115	29	115	30	115	30	115	30	125	32	126	32	126	32	127	33	128	33

Table A.4 Energex connection point forecast of winter native peak demand *(continued)*

Connection point	Voltage (kV)	Zone	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	41	8	41	8	44	8	45	9	45	9	45	9	45	9	45	9	46	9	46	9
South Pine	110	M	686	95	697	97	715	99	713	99	710	98	722	100	723	100	724	100	730	101	739	102
Sumner	110	M	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8
Tennyson	33	M	128	12	129	12	132	12	131	12	130	12	132	12	132	12	132	12	133	13	134	13
Wecker Road	33	M	95	9	95	9	98	9	99	9	100	9	101	9	101	9	101	9	102	10	103	10
Woolooga (Gympie)	132	M	157	9	157	9	161	9	160	9	159	9	161	9	161	9	161	9	162	9	164	9

Table A.5 Sum of individual summer native peak forecast demands for the transmission connected loads

Connection point (1)	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,261	444	1,258	442	1,268	448	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452
Transmission connected mining loads (3)	77	31	74	29	78	30	93	36	103	39	106	41	107	41	108	41	108	41	103	39
Transmission connected LNG loads (4)	727	239	742	244	779	256	806	265	777	256	785	258	776	255	776	255	749	246	735	242
Transmission connected rail supply substations (5)(6)	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new LNG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kV and 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) LNG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Table A.6 Sum of individual winter native peak forecast demands for the transmission connected loads

Connection point (1)	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,269	451	1,262	446	1,269	450	1,274	453	1,272	452	1,272	452	1,272	452	1,272	452	1,272	452	1,272	452
Transmission connected mining loads (3)	71	26	68	24	74	26	95	33	96	33	101	36	101	36	101	36	101	36	96	33
Transmission connected LNG loads (4)	662	218	814	267	775	255	788	259	817	268	789	259	785	258	779	256	775	255	745	245
Transmission connected rail supply substations (5)(6)	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new LNG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kVand 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) LNG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Appendix B – Powerlink's forecasting methodology

A discussion of Powerlink's forecasting methodology is presented below. Powerlink is publishing its forecasting model with the 2016 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

Customers other than Energex and Ergon that connect directly to Powerlink's transmission network are assessed based on their forecast, recent history and 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 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 small-scale solar PV, battery storage, electric vehicles, energy efficiency improvements, smart meters are factored into the forecast for Energex and Ergon.

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

Econometric regressions

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

To prepare these forecasts, regression analysis is carried out using native demand and energy plus small-scale solar PV 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.

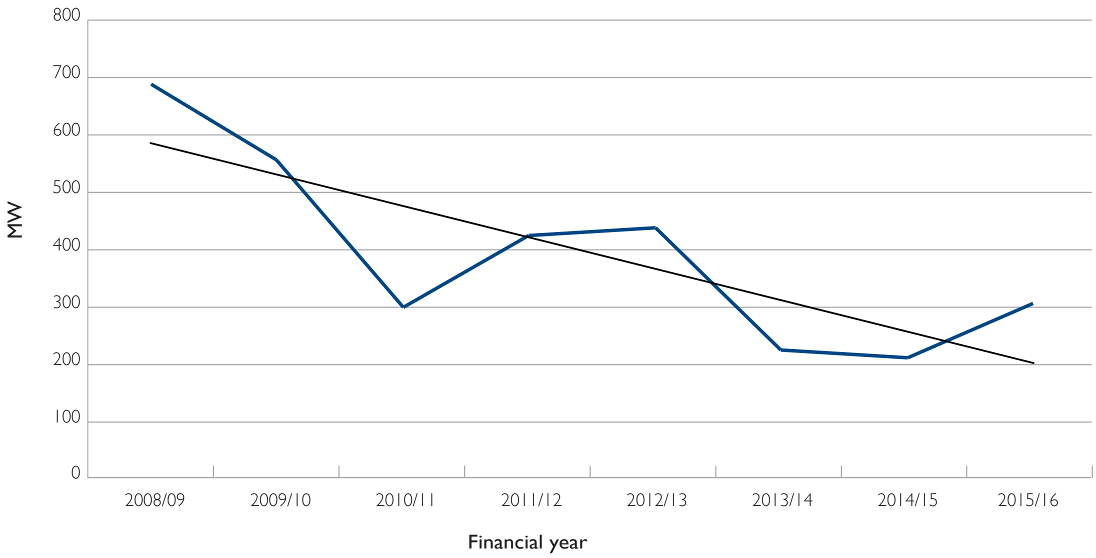
The first step in the regression analysis is to assemble historical native energy and maximum demand values as follows:

a) Energy. Determine DNSP native energy for each year from 2000/01. As this work is done in March, an estimation is prepared for the current financial year which will be updated with actuals 12 months later when preparing the next TAPR.

b) Winter maximum demand. The DNSP native demand at the time of winter state peak is collated from winter 2000. These demands are then corrected to average weather conditions. Powerlink has enhanced its method for weather correction as described later in this appendix.

c) Summer maximum demand. The DNSP native demand at the time of summer state peak is collated from summer 2000/01. These demands are then corrected to average weather conditions. DNSP native demand at the time of summer state evening peak (after 6pm) is also collated 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 network due to the increasing impact of small-scale solar PV. This move to an evening peak by 2019/20, 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 corrected maximum demand



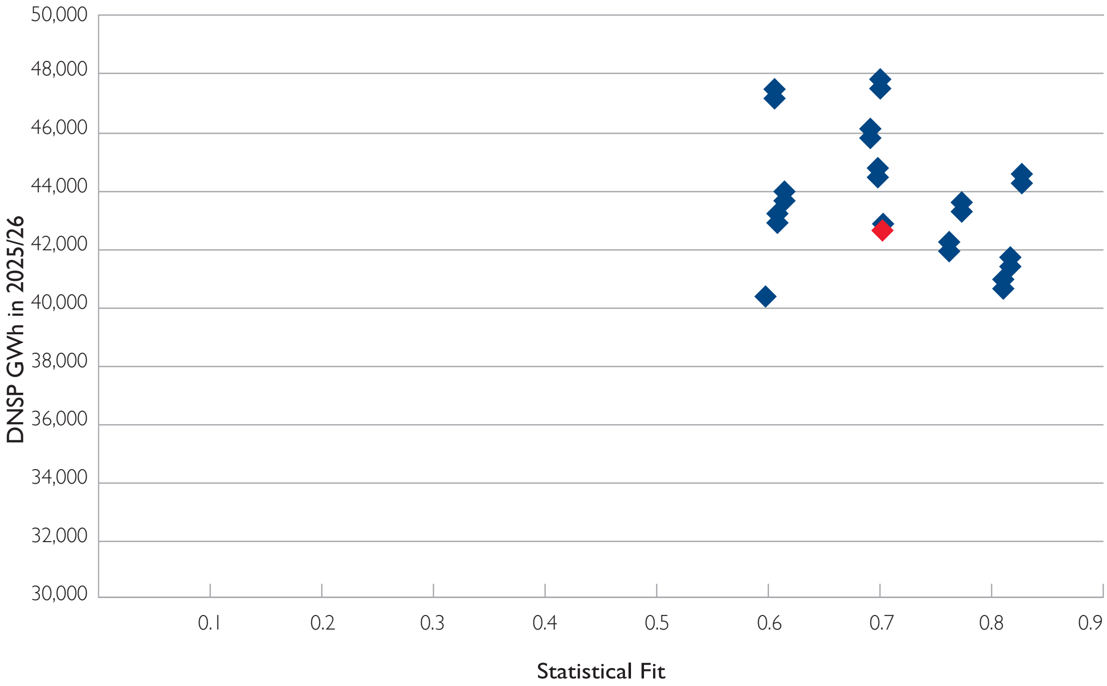
Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for small-scale solar PV. This ensures that the full underlying DNSP load is being regressed. As forecast summer maximum demand is now based on an evening regression and winter maximum demand occurs in the evening, only an adjustment for energy is needed. This energy adjustment assumes that small-scale solar PV output averages 15% of capacity. The 15% figure is based on observations through the Australian PV Institute. Following the regression for energy, the forecast is then adjusted down to take into account future small-scale solar PV contributions based on forecast small-scale solar PV capacity.

Energy regression

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

Input variables are selected from two price variables (supplied by AEMO) and 16 economic variables (supplied by Deloitte Access Economics). This provides 32 combinations. For each of these 32 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 128 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 retail turnover and total electricity price with a one year delay. The regression selected reflects a central outcome at the end of the regression period and uses broad based input variables.

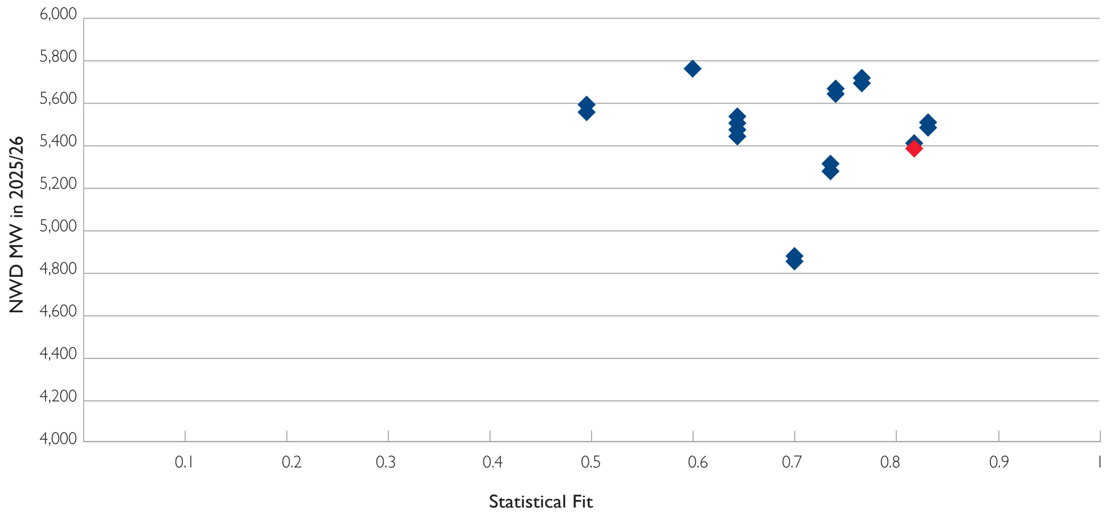
Economic data was supplied for the medium economic outlook with variations derived for low and high economic outlooks. The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The corrected 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 maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected 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.

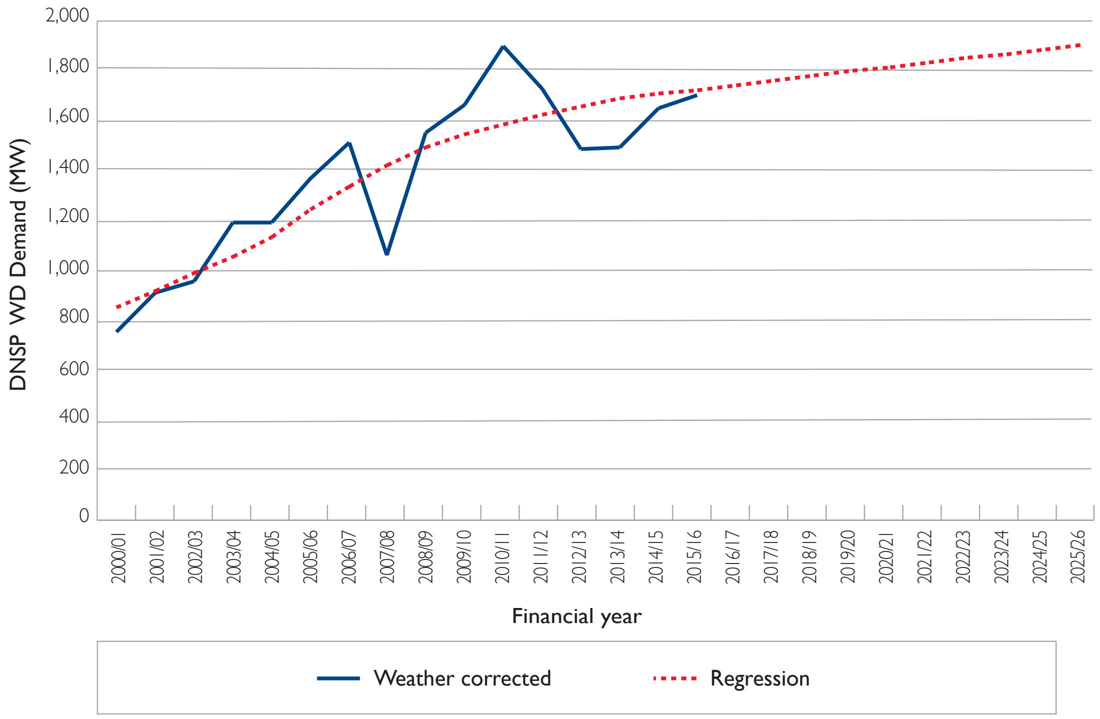
Figure B.3 Non-weather dependent demand regression results



The selected regression shown above in red uses Queensland retail turnover and total electricity price both with a one year delay.

The WD demand is mainly a reflection of air conditioning usage. These regressions have been based on one input variable – population multiplied by Queensland air conditioning penetration. This variable is a measure of the air conditioning capacity in Queensland and demonstrates a good statistical fit as illustrated in Figure B.4 by the summer regression below. Historical and forecast air conditioning penetration rates are provided annually in the Queensland Household Energy Survey.

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 (probability of exceedance), 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. WD analysis described above is applied to historical demands temperature corrected to 50% PoE conditions. It therefore leads to the 50% PoE forecast. The analysis is repeated using historical demands corrected to 10% PoE and 90% PoE conditions to deliver the other forecasts.

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 for change.

Driven by this commitment, Powerlink again conducted a forum of industry experts to learn more about new technologies and the impacts that they may have on future electrical demand and energy. Based on the information shared for the 2016 Transmission Annual Planning Report, Powerlink adopted technology and other inputs as summarised in Table B.1.

Table B.1 **Difference in summer day and summer evening corrected maximum demand**

	Solar PV	Battery Storage	Energy Efficiency Beyond Trend	Electric Vehicles	Tariff Reform / DSM	Customer Momentum
Energy (GWh)[1]	3,969	0	0	0	0	1,747
Maximum demand (MW)[2]	0	240	0	0	120	307
Installed capacity MW in 2025/26	4,300					
First year of impact	now	2017/18			2018/19	2016/17

Notes:

(1) This is the energy reduction in financial year 2025/26 compared to 2015/16.

(2) This is the maximum demand reduction in summer 2025/26 compared to summer 2015/16.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Further, Powerlink recognises a range of other outcomes could have been adopted. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow other levels to be factored into the demand forecasts if desired.

Small-scale solar PV

The installed capacity of small-scale solar PV in Queensland as at the end of 2015 was 1,500MW. After a rapid uptake in the years 2011 to 2013, installations have now moderated to a rate of around 15MW[1] per month, predominately residential.

Of the 1,500MW installed capacity, around 100MW is non-residential. Despite moderation in residential installations, growth in commercial and industrial installations are expected to make up the shortfall, maintaining 20MW per month of installations over the 10-year forecast period. Furthermore, as battery storage systems fall in price it is expected that an additional 200MW worth of small-scale solar PV will connect by 2025/26. In total, this will increase capacity of small-scale solar PV in Queensland to 4,300MW by 2025/26. This is around 600MW above the forecast in the 2015 TAPR.

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[1] Based on information from the Clean Energy Website

Analysis has revealed that Queensland will move to a summer evening peak by 2019/20 and so further small-scale solar 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 15%[2] capacity.

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

Future impacts of small-scale solar 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 small-scale solar PV installation levels could increase beyond this forecast.

Battery storage

Battery storage technology has the potential to significantly change the electricity supply industry. 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 small-scale solar PV, consumers may have the option to go "off grid". A number of factors will drive the uptake of this technology, namely:

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

The 2015 Queensland Household Energy Survey (QHES) indicates around 9% of Queensland households are considering to purchase a battery storage system. However this same feedback indicates that most people underestimate the current price of installing a storage solution. Assuming half of those households who have expressed an interest proceed to installation as prices drop there will be 100,000 household systems installed by 2025/26. If 80% of these households have someone home at the time of state peak (7pm) and assuming an average of 3kW load per household, a reduction in state peak demand of 240MW is estimated.

Energy Efficiency

Future energy efficiency improvements are now expected to continue broadly in line with historical trends. Over the last six months a report commissioned by Energex relating to household efficiency in South East Queensland (SEQ) and the QHES both support future energy efficiency improvements in line with historical trends. The QHES notes that Queensland consumers have now become less frugal and are more inclined to use air conditioning during warm weather. The forecasting reference group[3] recently noted that above historical trend improvements such as pink batts and low cost LEDs are not expected to be repeated. As such additional energy efficiency gains beyond these historic levels are forecast to be hard to achieve. As a result in this updated forecast energy efficiency improvements have been brought into line with historical trends.

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[2] Based on information obtained from the Australian PV Institute

[3] This is a national electricity forecasting group convened by AEMO

Electric vehicles

Compared to world leading countries in electric vehicle uptake such as Norway and the Netherlands, the uptake of electric vehicles in Australia is quite low. Without significant government policy changes to actively encourage their purchase this is not expected to change in the short-term. Ultimately, the efforts by manufacturers such as Tesla to lower battery costs and improve performance will drive up sales. Powerlink has continued not to include a specific allowance in its demand and energy forecast for electric vehicles but will continue to monitor progress in this area. In the event that there is a significant update in electric vehicles it is expected that most owners will be incentivised to charge their cars at off peak times resulting in minimal increase in peak demand. Similarly it is estimated a 1% penetration of electric vehicles on the road would result in approximately 0.3% increase in total energy usage.

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 the batteries during peak demand / high price times. The extent to which this occurs will depend on how quickly new tariffs are offered 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 per cent of trials internationally have resulted in peak reductions of 10 per cent or more."[4]

A big challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies will meet resistance from those currently benefitting from them.

Some of this peak reduction will already be captured through the battery storage allowance above. An additional 120MW has been assumed within this forecast and represents a further 1.5% of the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy is expected to be low.

Customer momentum factor

Over the last 10 years, the price of electricity in Queensland has nearly doubled. This has led many customers to adopt frugal behaviours in an effort to minimise the financial impact. The price used in the regression model now forecasts an increase of 4% over the next 10 years. The logic hardwired in the regression model suggests that customers will lessen their frugal behaviour in response to moderating electricity prices. Powerlink's view is that people may not be so quick to change behaviour. Observed behaviour during a history of rising electricity prices may not be the ideal predictor of behaviour during a period of relatively flat prices.

To allow for this effect, a new 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 that energy and demand will not bounce back with the moderation of electricity prices.

In future years when additional information on customers' actual behaviour during moderating electricity prices is captured in the data series, this factor will be removed.

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

Weather correction methodology

Peak 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. 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% Probability of Exceedance (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).

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.

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 amount 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 peak demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are filtered out of the dataset.
- Calculate a regression model for each year: A regression model is calculated for each year, 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.
- Determine the 10% and 50% PoE thresholds using 20 years of weather data: The model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the peak demand would have been on each day if the relationship between peak 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 twenty 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 2015/16 summer was hotter than average. Therefore, the 50% PoE demand is 170MW lower than the observed peak demand. The 2015 winter was cooler than average, resulting in an downwards adjustment of 110MW to the observed winter peak 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 2016 to summer 2018/19. 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 2016 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2016 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2016 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2017 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2017 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2017 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2016/17 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2017/18 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at 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

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[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 – possible 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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	
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 132 kV (1 circuit)	177/177/177	178/178/178	182/182/182	220/220/220	225/225/225	224/224/224	V
CQ-NQ Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)	660/660/660	655/655/655	668/668/668	799/799/799	805/805/805	805/805/805	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)	714/724/732	661/710/717	674/590/718	608/609/613	589/590/594	593/595/599	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) Calliope River into Gin Gin 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)	1,706/1,675/1,675	1,499/1,655/1,655	1,487/1,789/1,631	1,733/1,733/1,733	1,726/1,726/1726	1,718/1,718/1,718	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	490/490/490/	627/627/627	589/589/589	527/527/527	539/539/539	576/576/576	V
SWQ Western Downs to Halys 275kV (2 circuits) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,141/1,168/1,234	1,018/868/934	1,040/752/968	1,761/1,759/1,788	1,395/1,395/1,427	1,393/1,394/1,426	(5)
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)	3,241/3,259/3,319	3,010/2,939/2,999	3,033/2,881/3,029	3,843/3,843/3,872	3,495/3,494/3,524	3,492/3,491/3,520	V

Table C.1: Summary of figures C.3 to C.20 – possible 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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	
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	
Gold Coast Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	709/709/771	712/712/775	715/715/777	777//777/808	780/780/811	776/776/807	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 5.5.6, SWQ grid section is not expected to impose limitations to power transfer under intact system conditions with the existing levels of generating capacity.

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

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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	38	48	48	34	48	48	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	122	124	122	159	159	159	Barron Gorge generation	Kareeya, Townsville and Mt Stuart generation
Ross 275/132kV (3x250)	R	125	123	114	196	187	178	Mt Stuart, Townsville and Invicta generation	
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	271	278	286	293	297	298	Mackay generation	
Strathmore 275/132kV (1x375MVA)	N	110	111	116	126	128	129	Invicta generation	Townsville and Mt Stuart generation
Bouldercombe 275/132kV (2x200MVA and 1x375MVA)	CW	148	148	149	187	188	188		
Calvale 275/132kV (1x250MVA)	CW	129	135	140	129	136	124	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	203	217	217	221	219	228	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132 kV (2x375MVA)	G	67	67	67	56	55	56	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	127	137	141	151	151	150		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	74	78	74	76	76	76		CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	212	214	223	217	215	213		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	162	186	111	188	111	113	Roma and Condamine generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	264	266	265	260	260	260	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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	26	43	37	14	19	22	Roma and Condamine generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	37	37	37	29	29	29		
Abermain 275/110kV (1x375MVA)	M	140	146	147	171	174	175	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250 and 2x375 MVA)	M	507	512	516	600	611	605	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250 and 1x240MVA)	M	153	172	173	195	210	211		
Goodna 275/110kV (1x375MVA)	M	130	128	129	163	161	161	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	348	353	355	401	413	405	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	339	341	344	365	369	370		
Palmwoods 275/132kV (2x375MVA)	M	312	321	323	304	310	305		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	312	307	308	389	384	383	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	593	605	607	664	670	666		
South Pine West 275/110kV (1x375, 1x250MVA)	M	239	231	232	299	291	290		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	423	428	428	456	458	455	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector
Mudgeeraba 275/110kV (3x250MVA)	GC	375	377	378	391	393	426	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea

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

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 sub-transmission network or operational switching strategies.

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

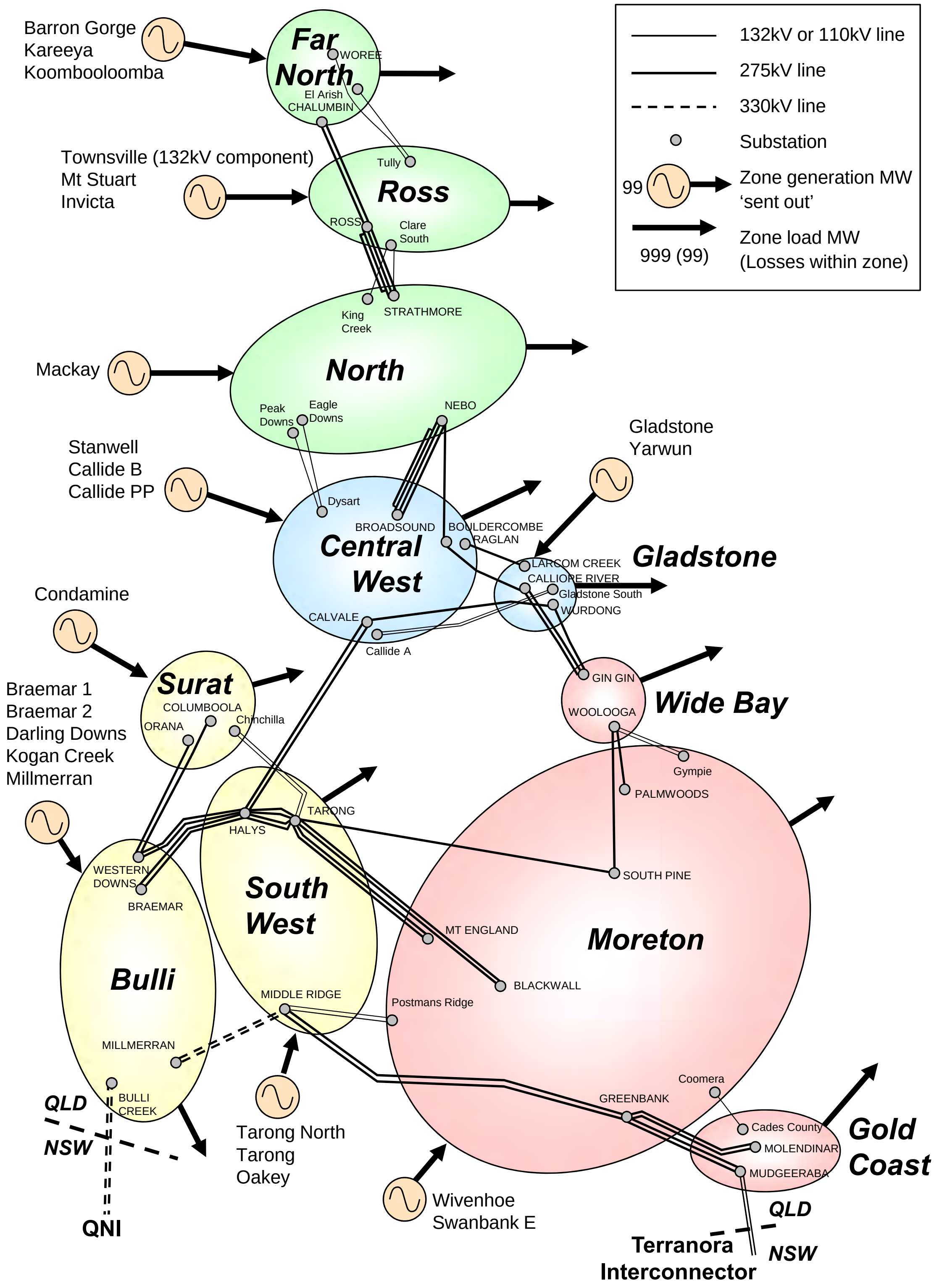


Figure C.2 Grid section legend for figures C.3 to C.20

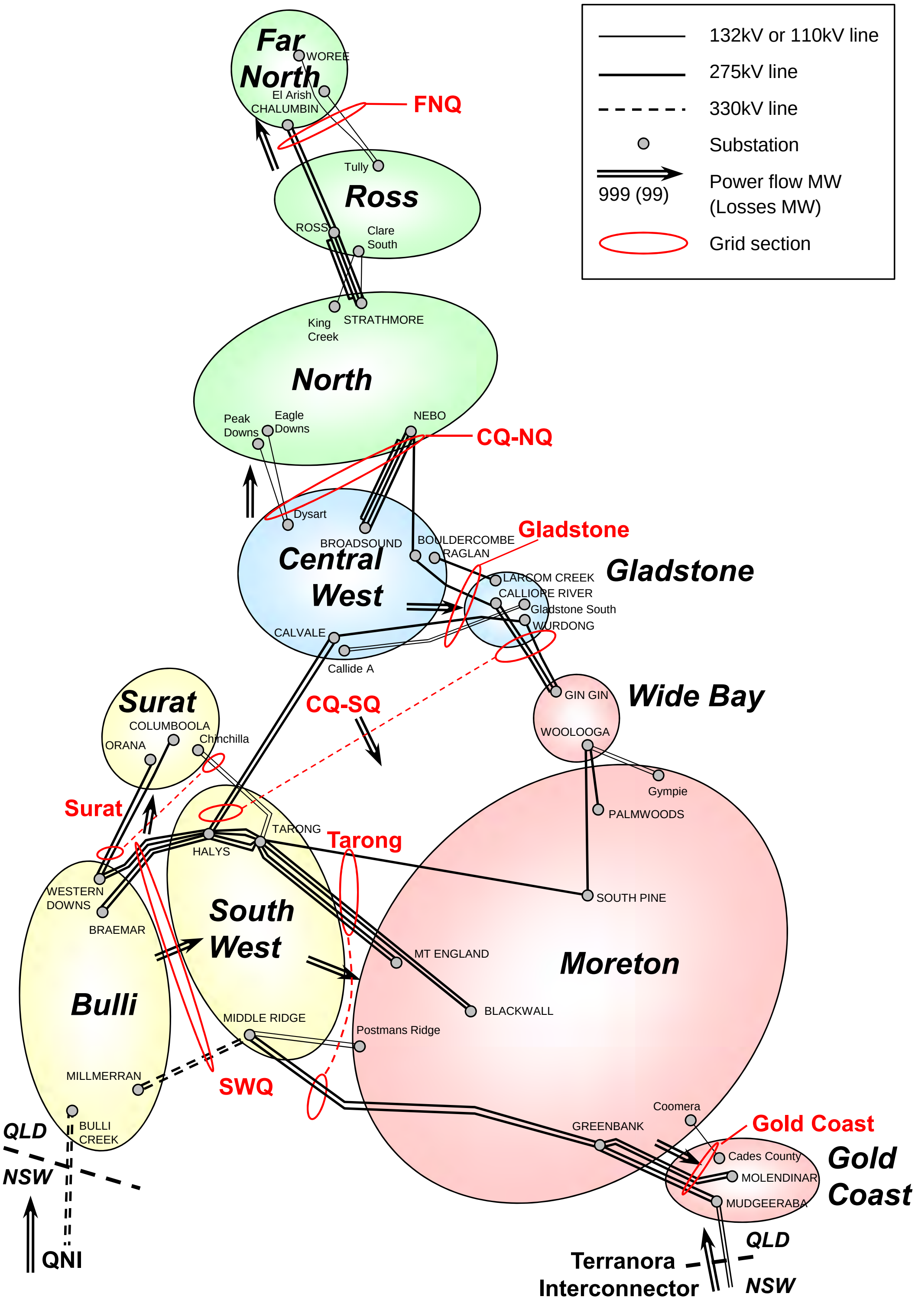
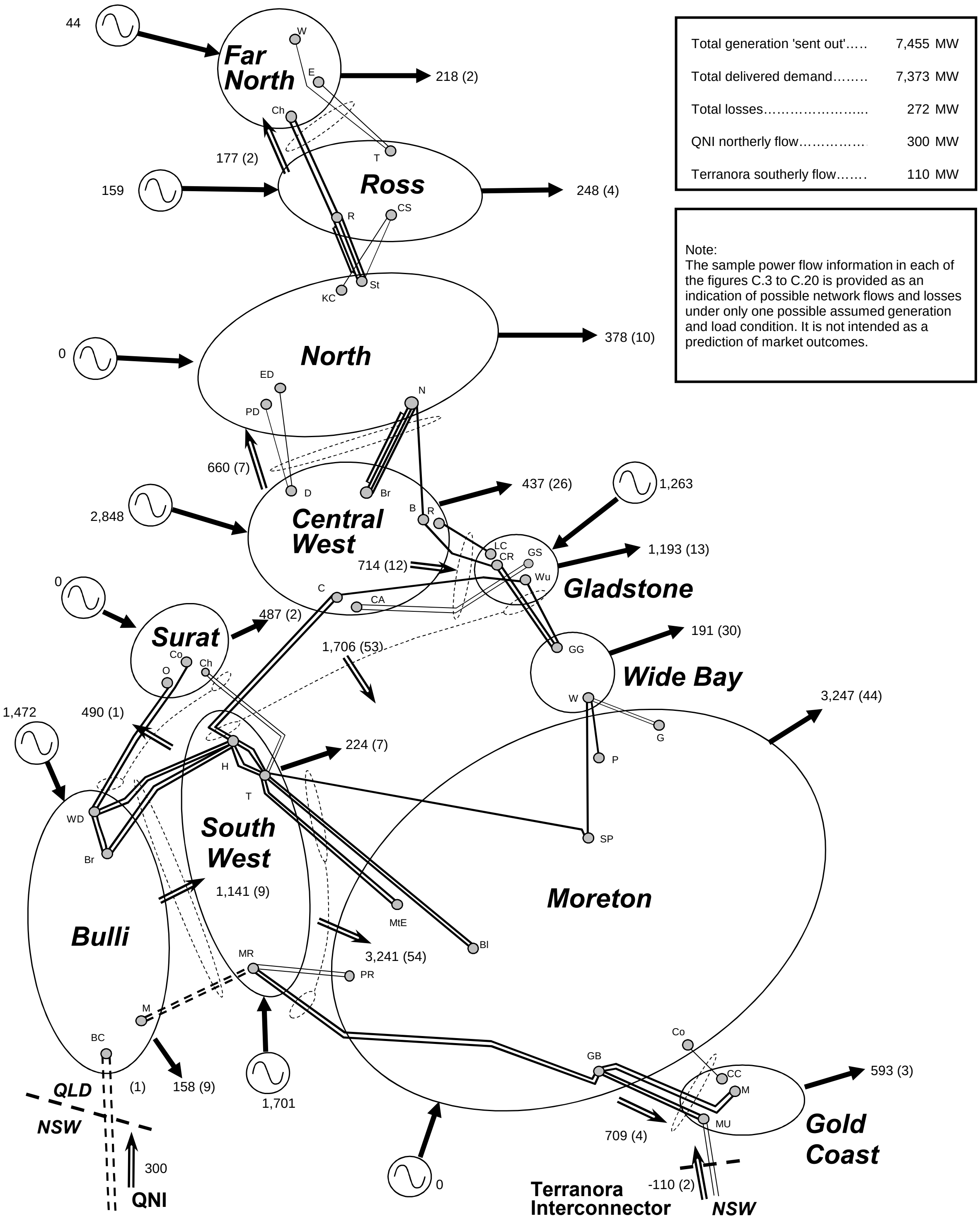


Figure C.3 Winter 2016 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,455 MW
Total delivered demand……..	7,373 MW
Total losses…………………...	272 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 2016 Queensland maximum demand 0MW QNI flow

Total generation 'sent out'…..	7,751 MW
Total delivered demand……..	7,373 MW
Total losses…………………...	268 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.

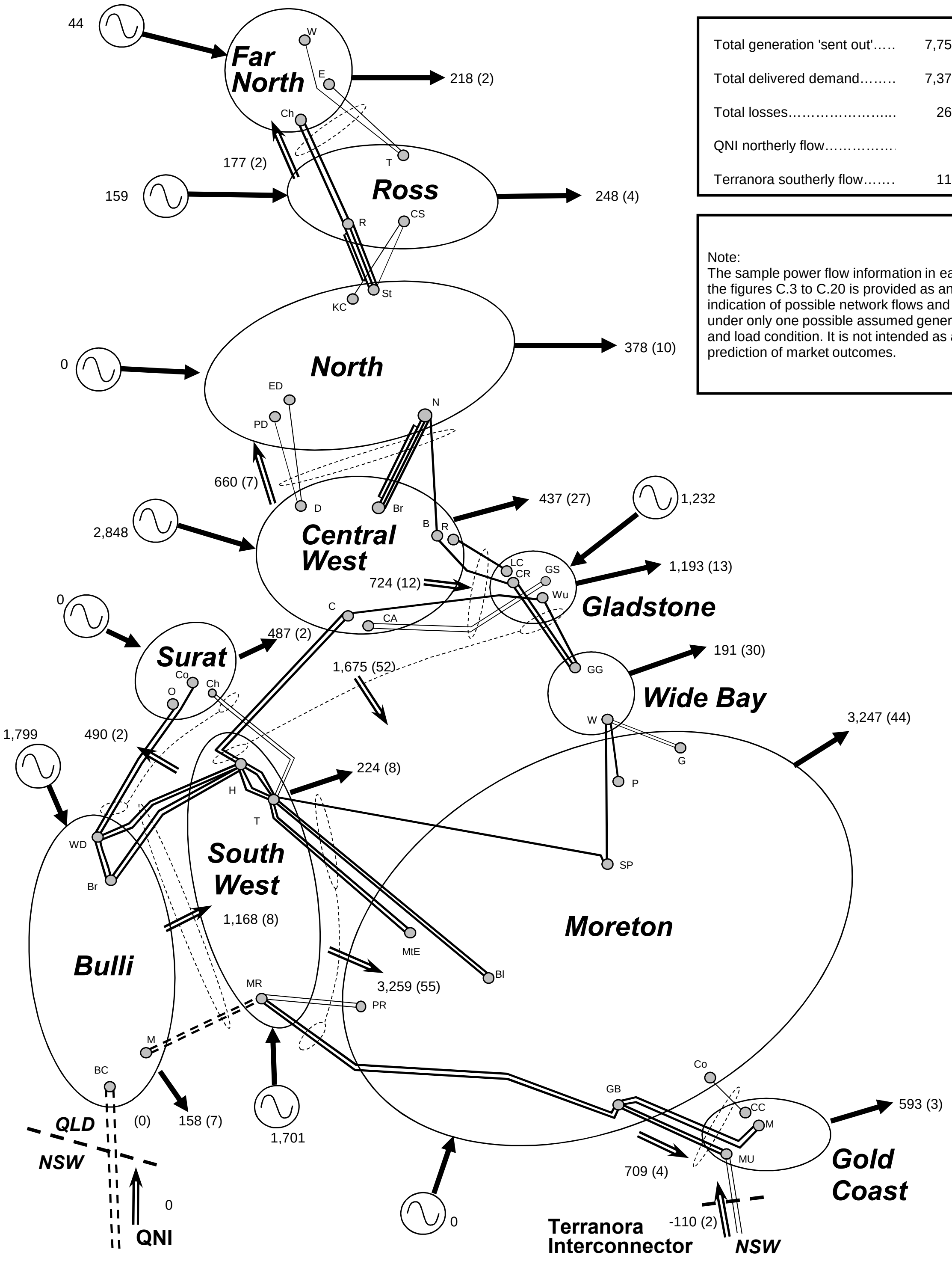
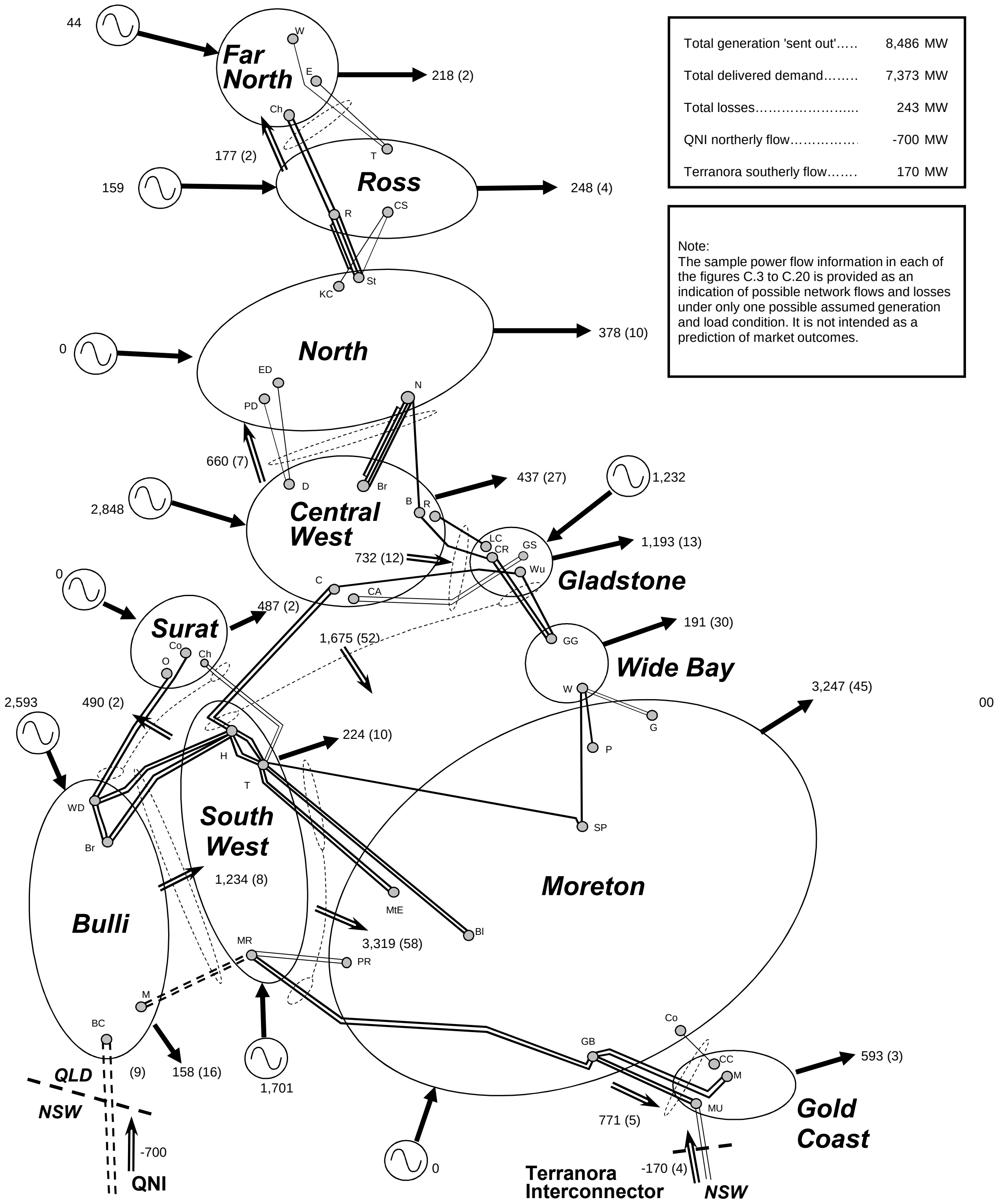


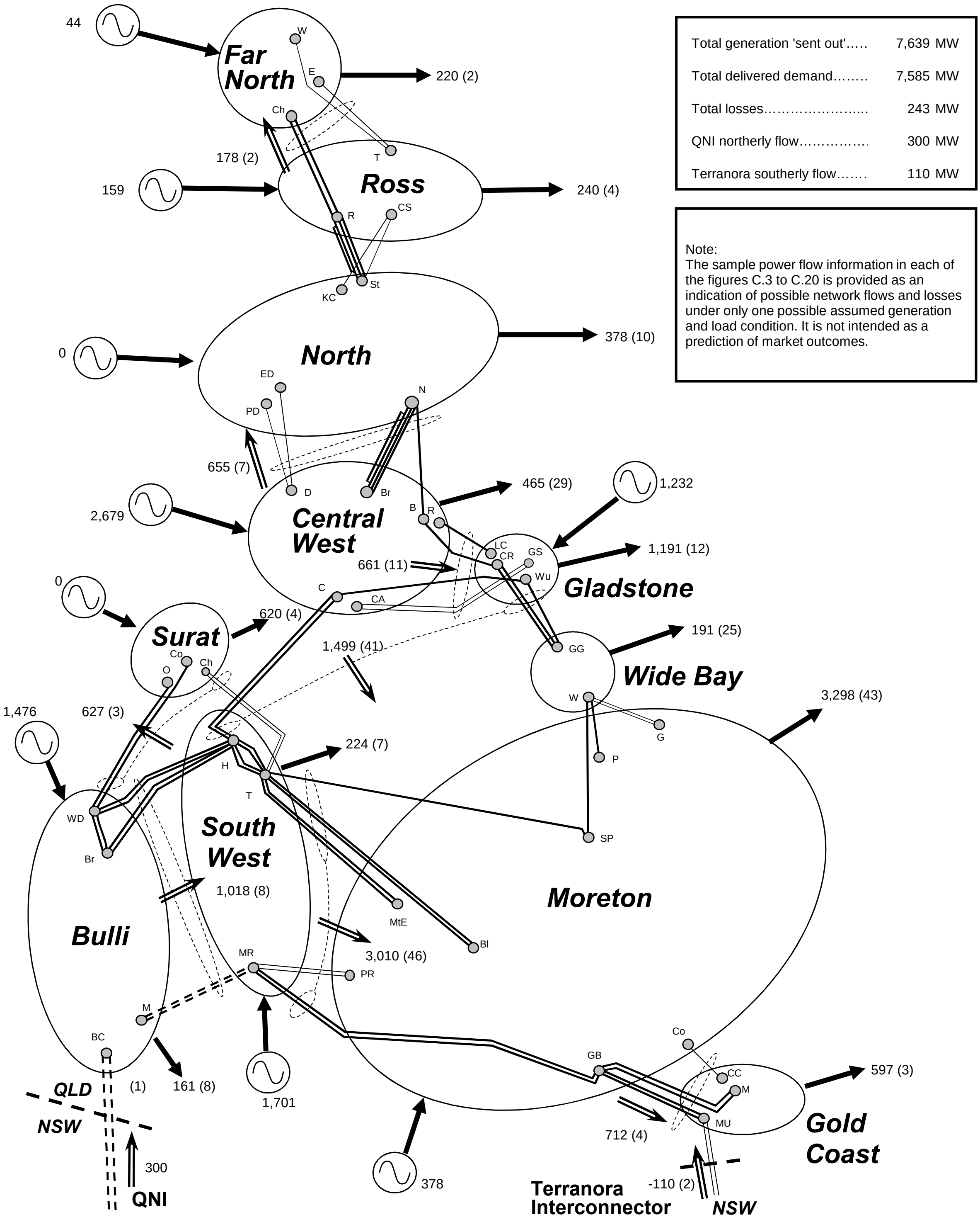
Figure C.5 Winter 2016 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,486 MW
Total delivered demand……..	7,373 MW
Total losses……………………	243 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.

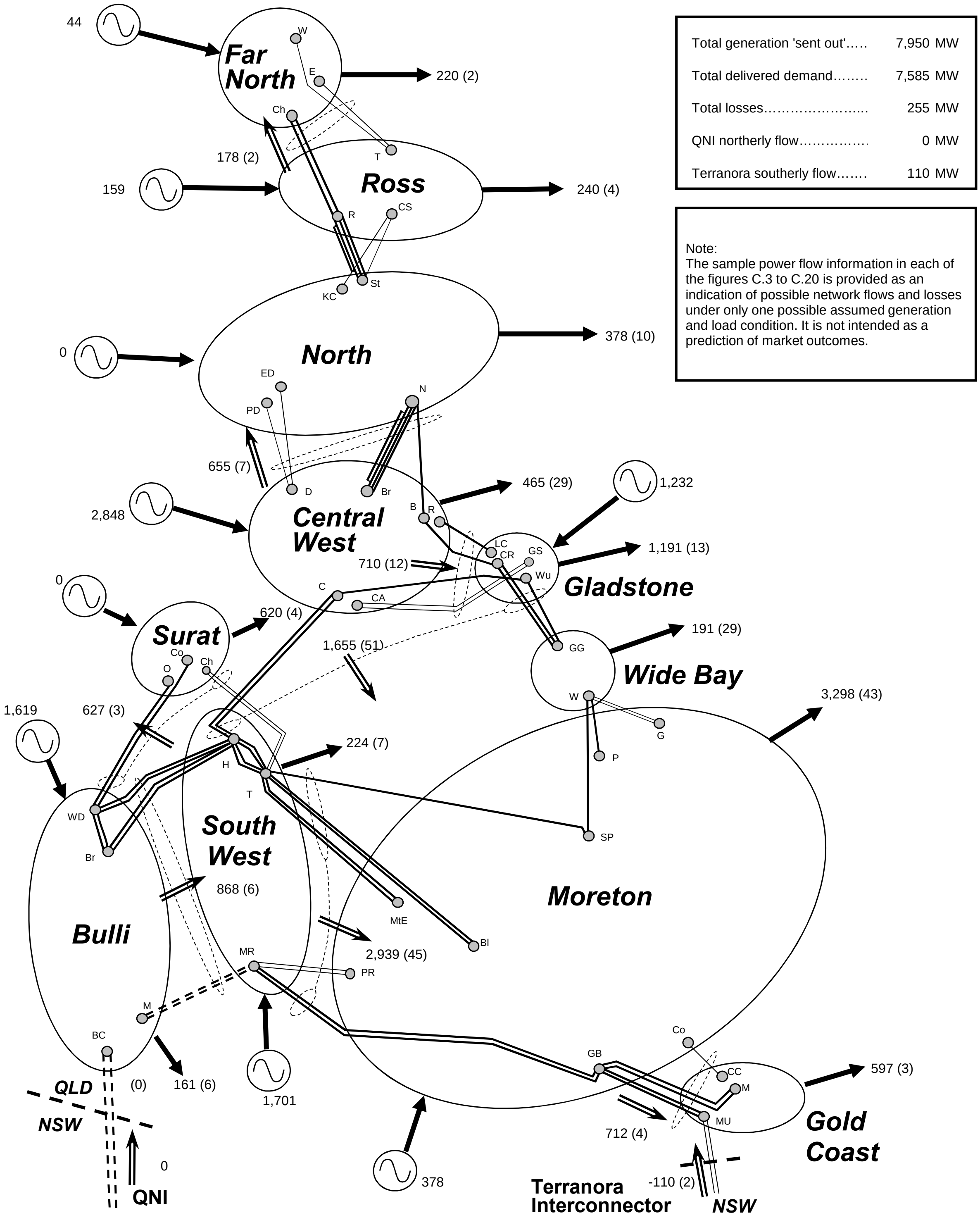
Figure C.6 Winter 2017 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,639 MW
Total delivered demand……..	7,585 MW
Total losses……………………...	243 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.

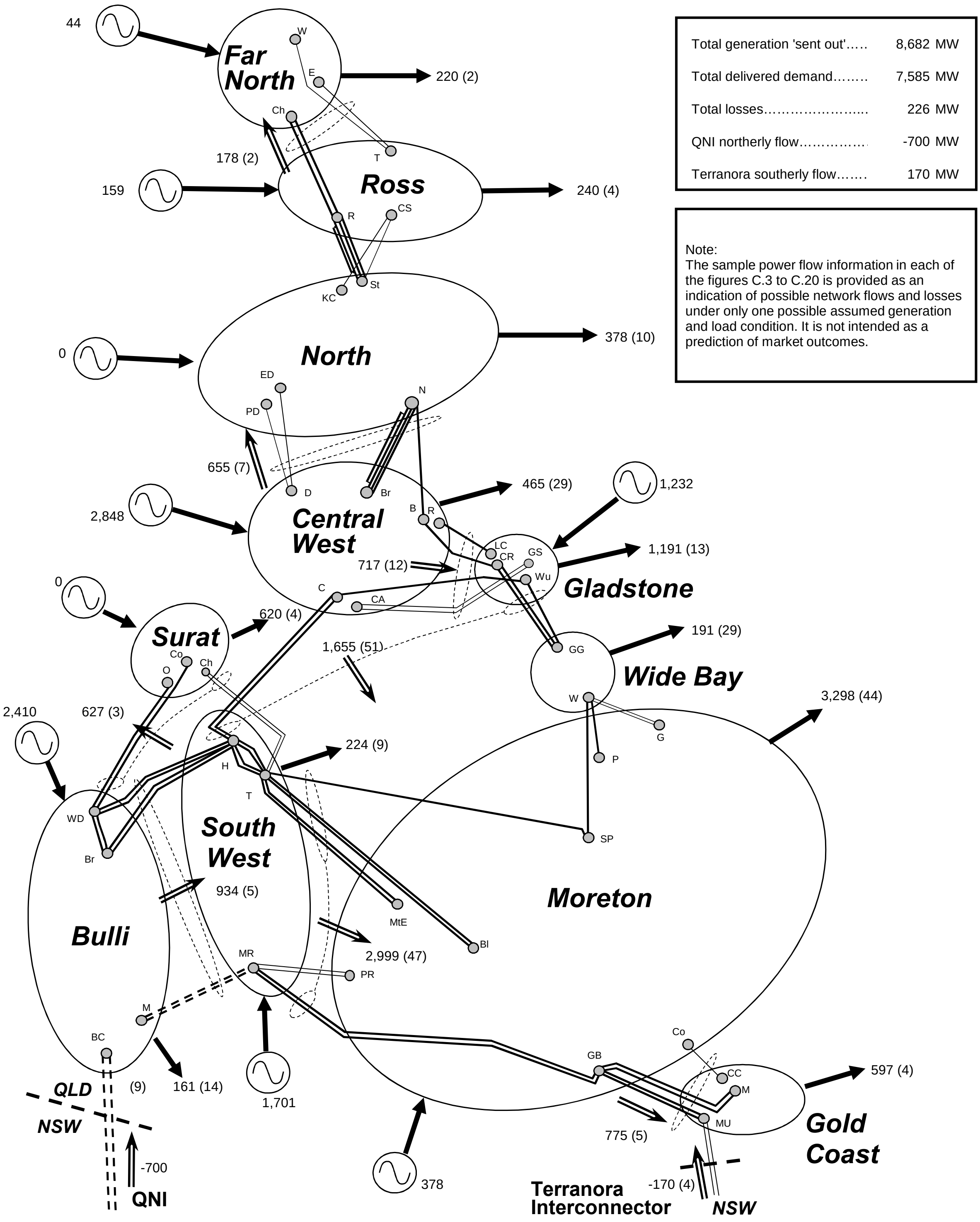
Figure C.7 Winter 2017 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,950 MW
Total delivered demand……..	7,585 MW
Total losses…………………...	255 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.

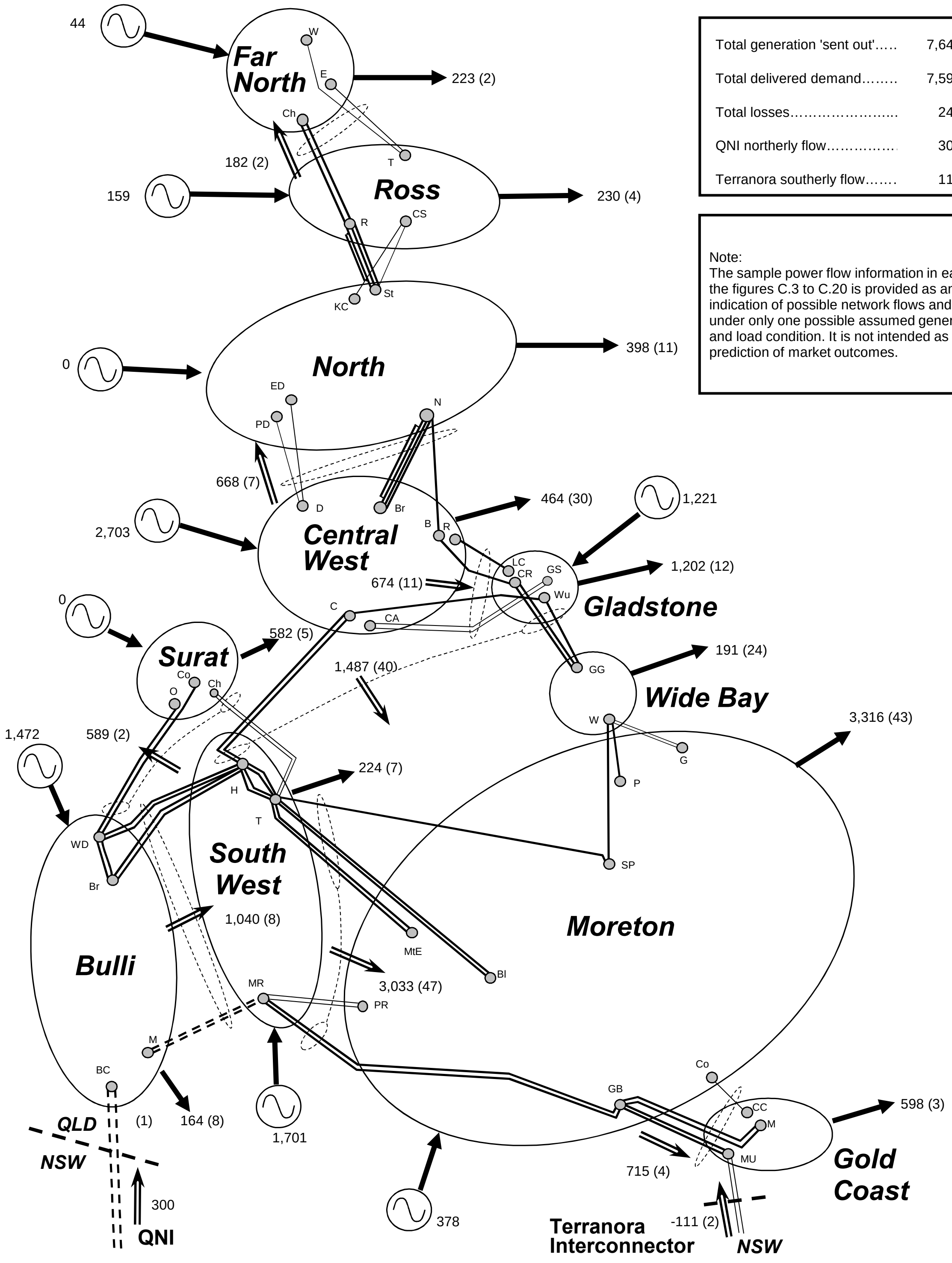
Figure C.8 Winter 2017 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'.....	8,682 MW
Total delivered demand........	7,585 MW
Total losses........................	226 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.

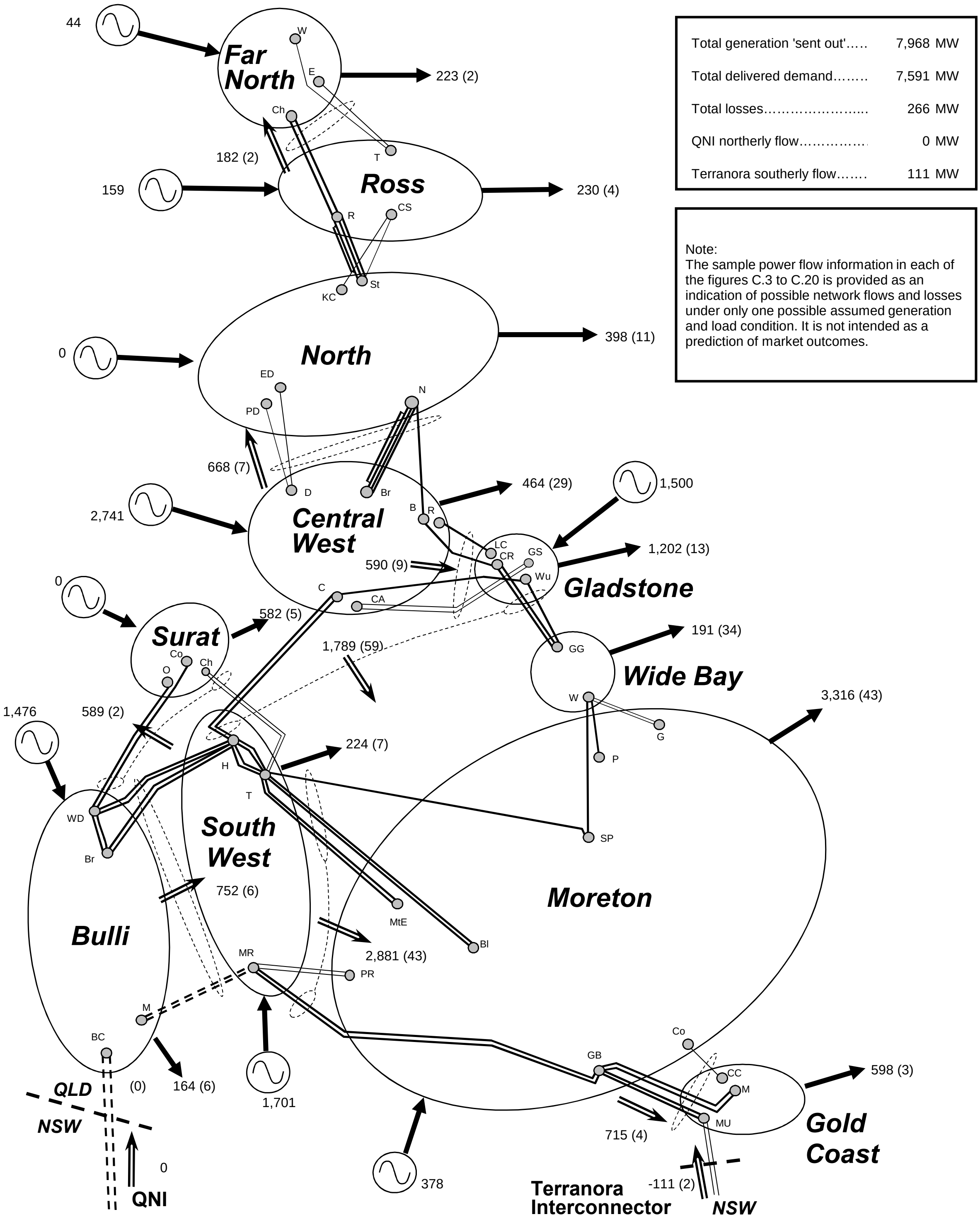
Figure C.9 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,648 MW
Total delivered demand……..	7,591 MW
Total losses…………………..	246 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.

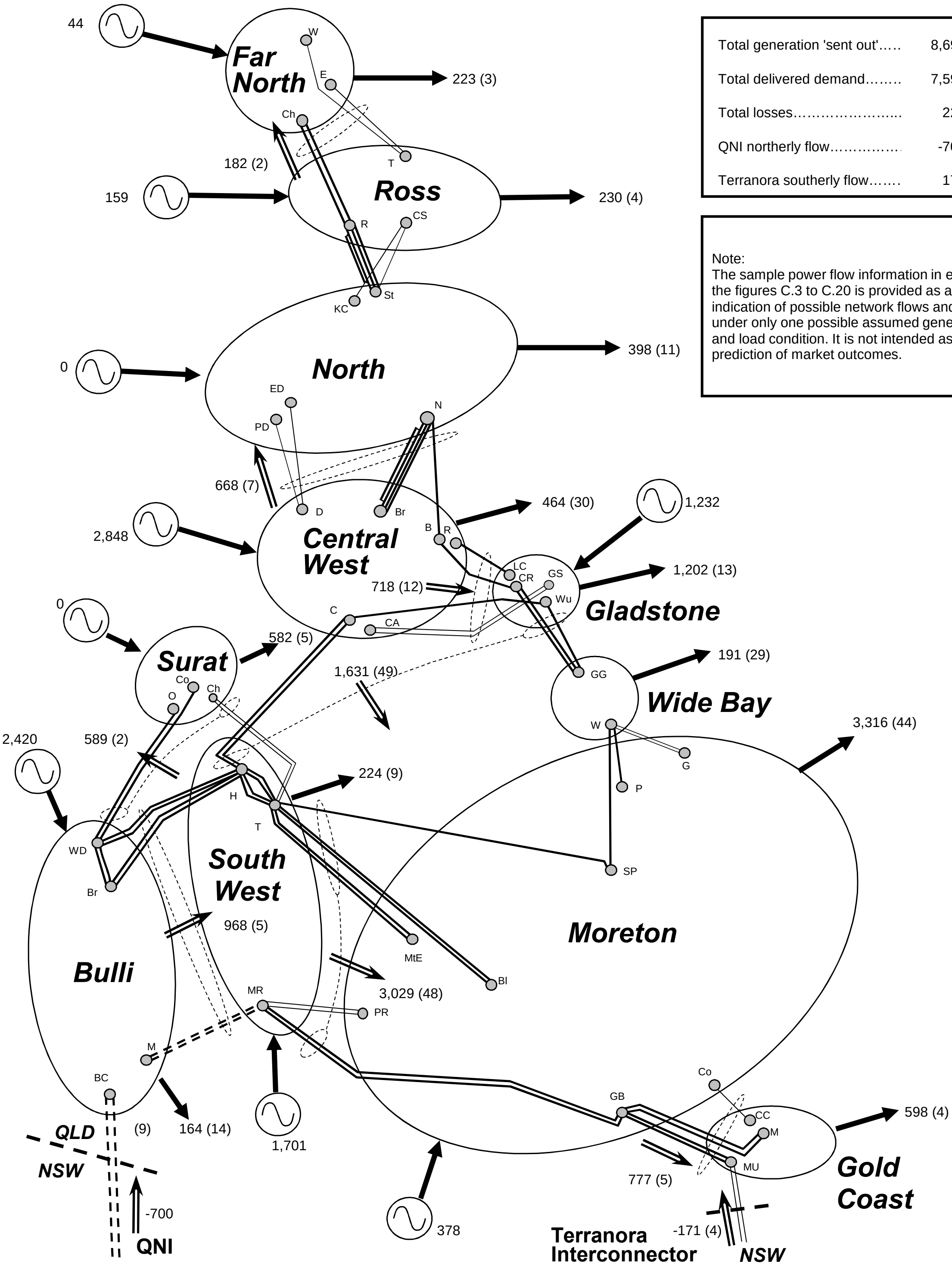
Figure C.10 Winter 2018 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,968 MW
Total delivered demand……..	7,591 MW
Total losses……………………...	266 MW
QNI northerly flow…………….	0 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.

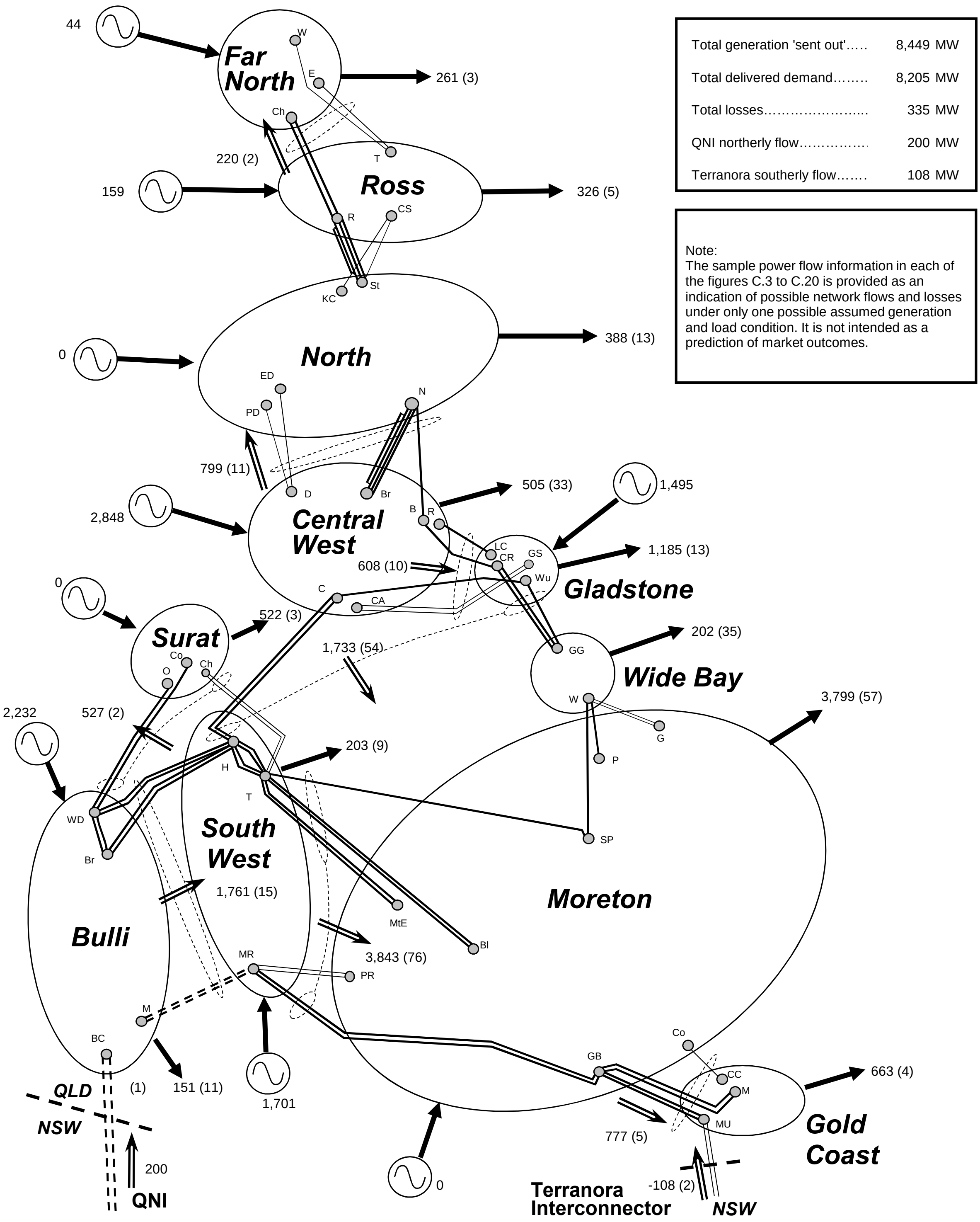
Figure C.11 Winter 2018 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,691 MW
Total delivered demand……..	7,591 MW
Total losses…………………..	228 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.

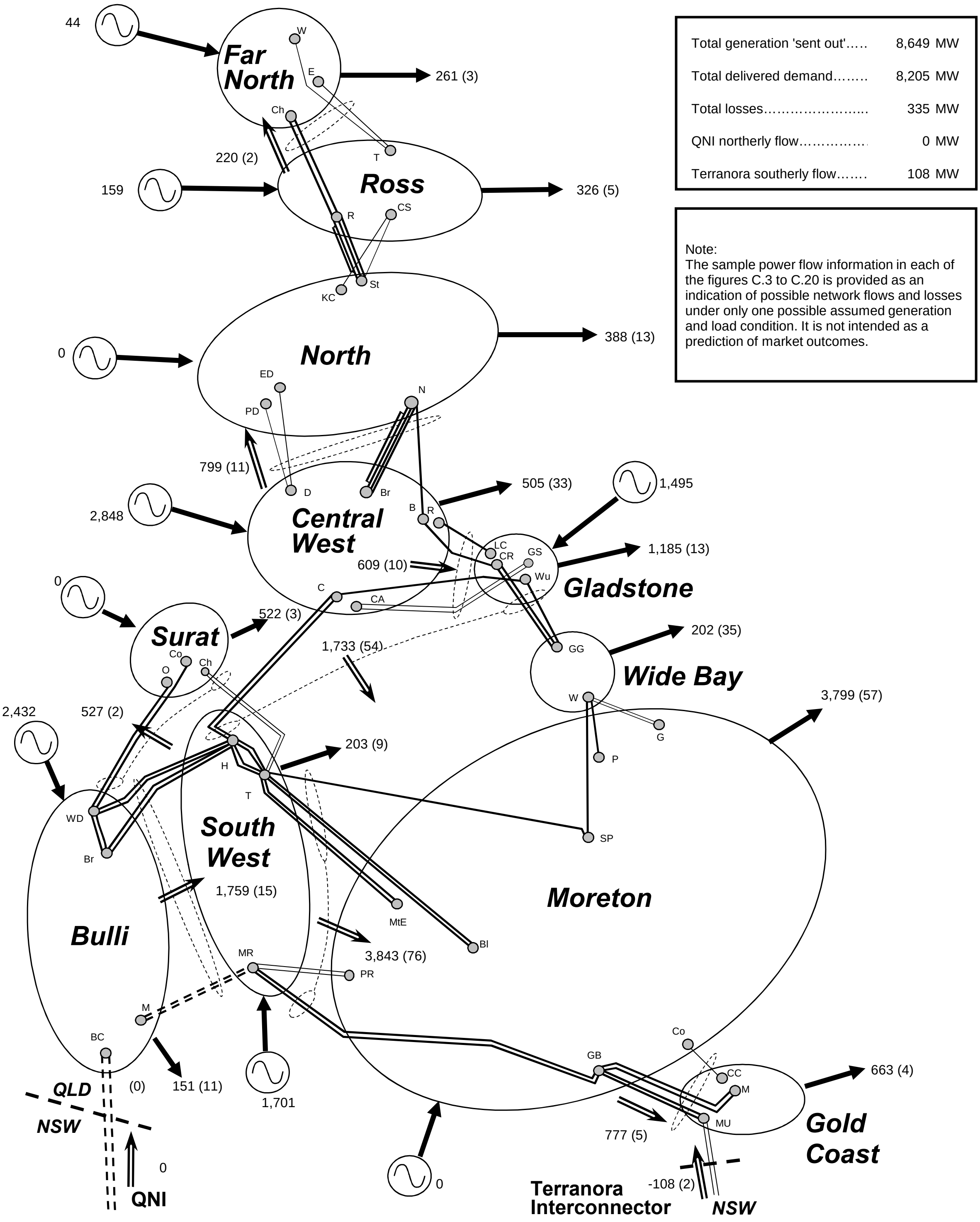
Figure C.12 Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,449 MW
Total delivered demand……..	8,205 MW
Total losses…………………...	335 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.

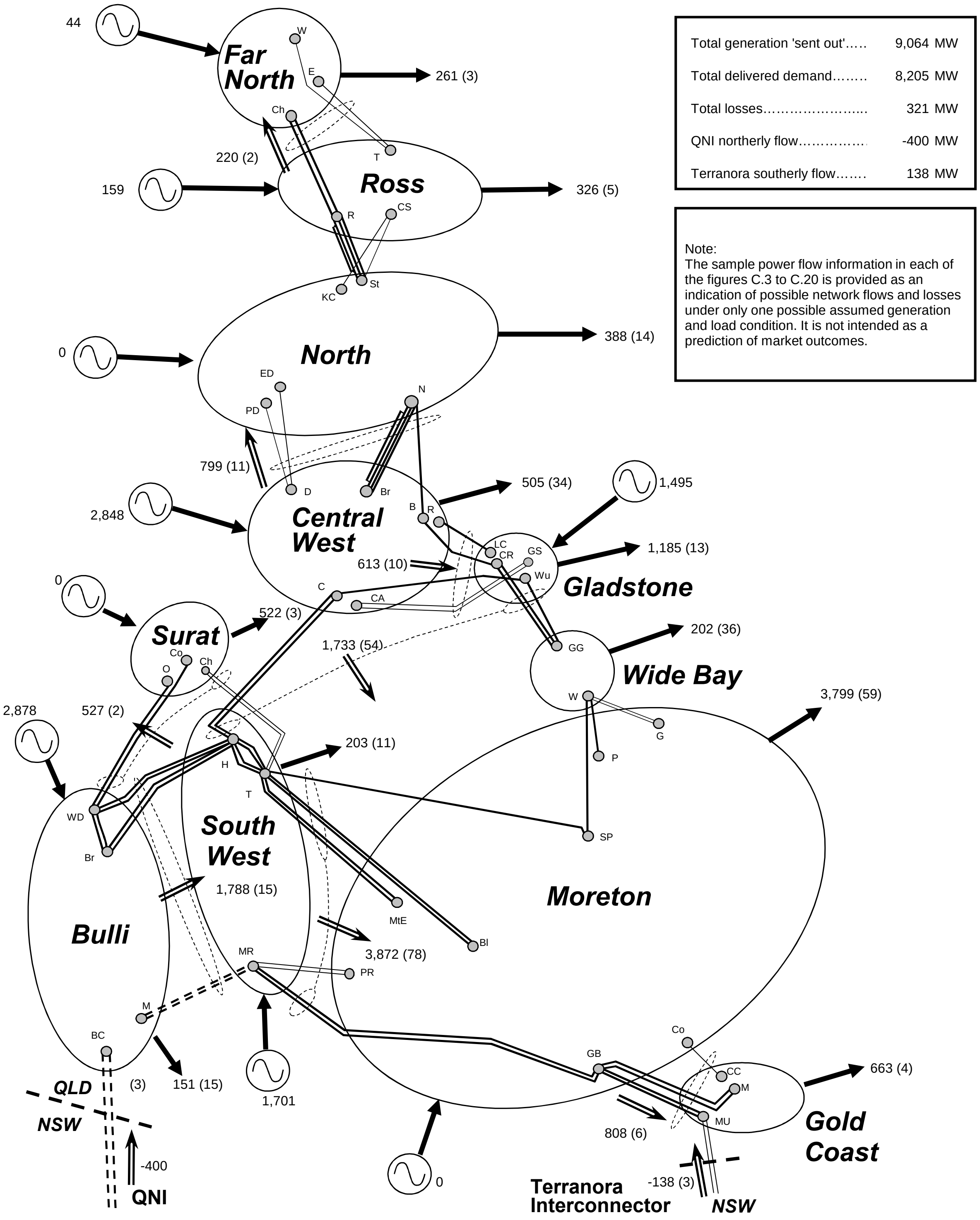
Figure C.13 Summer 2016/17 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,649 MW
Total delivered demand……..	8,205 MW
Total losses……………………..	335 MW
QNI northerly flow……………	0 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.

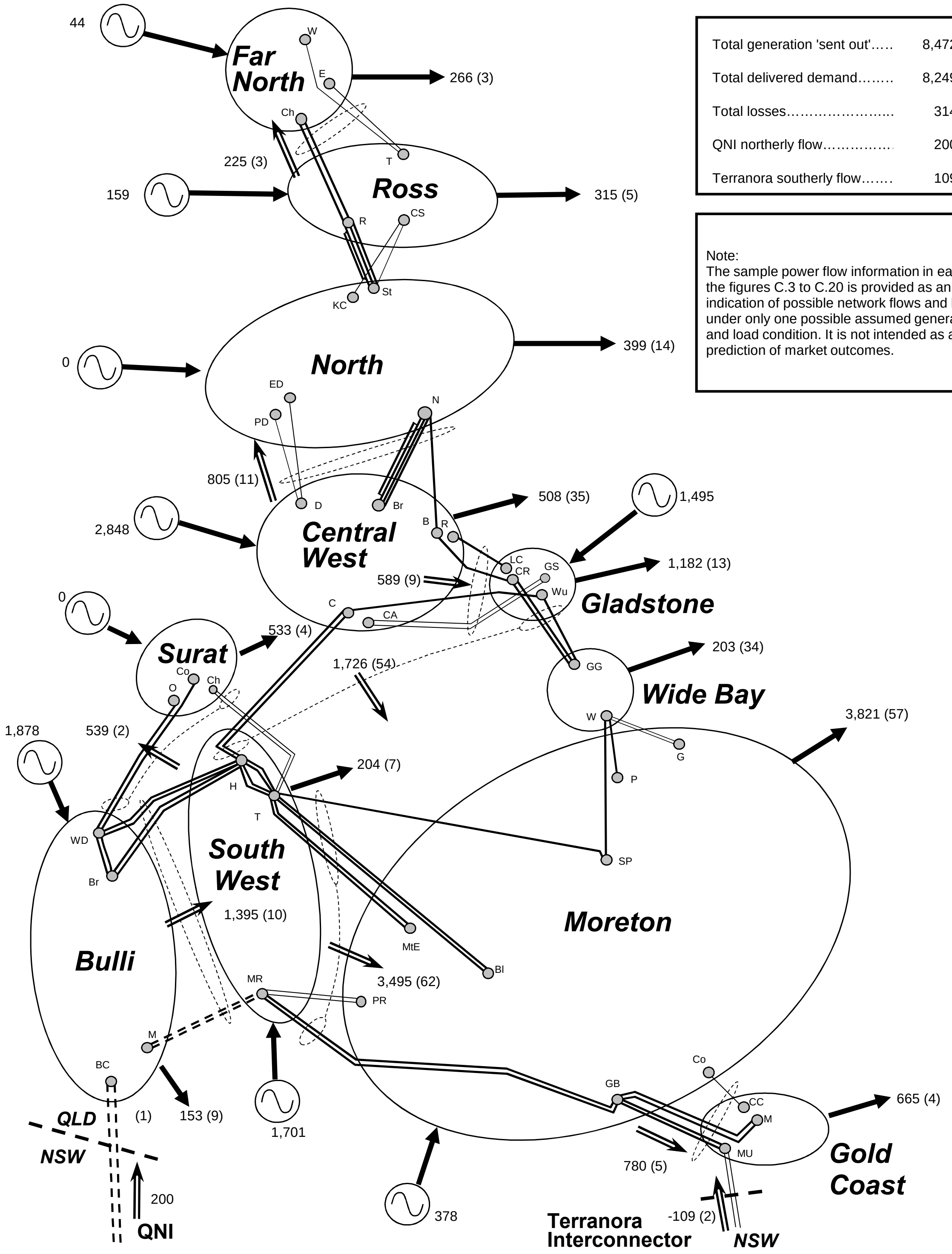
Figure C.14 Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,064 MW
Total delivered demand……..	8,205 MW
Total losses…………………...	321 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.

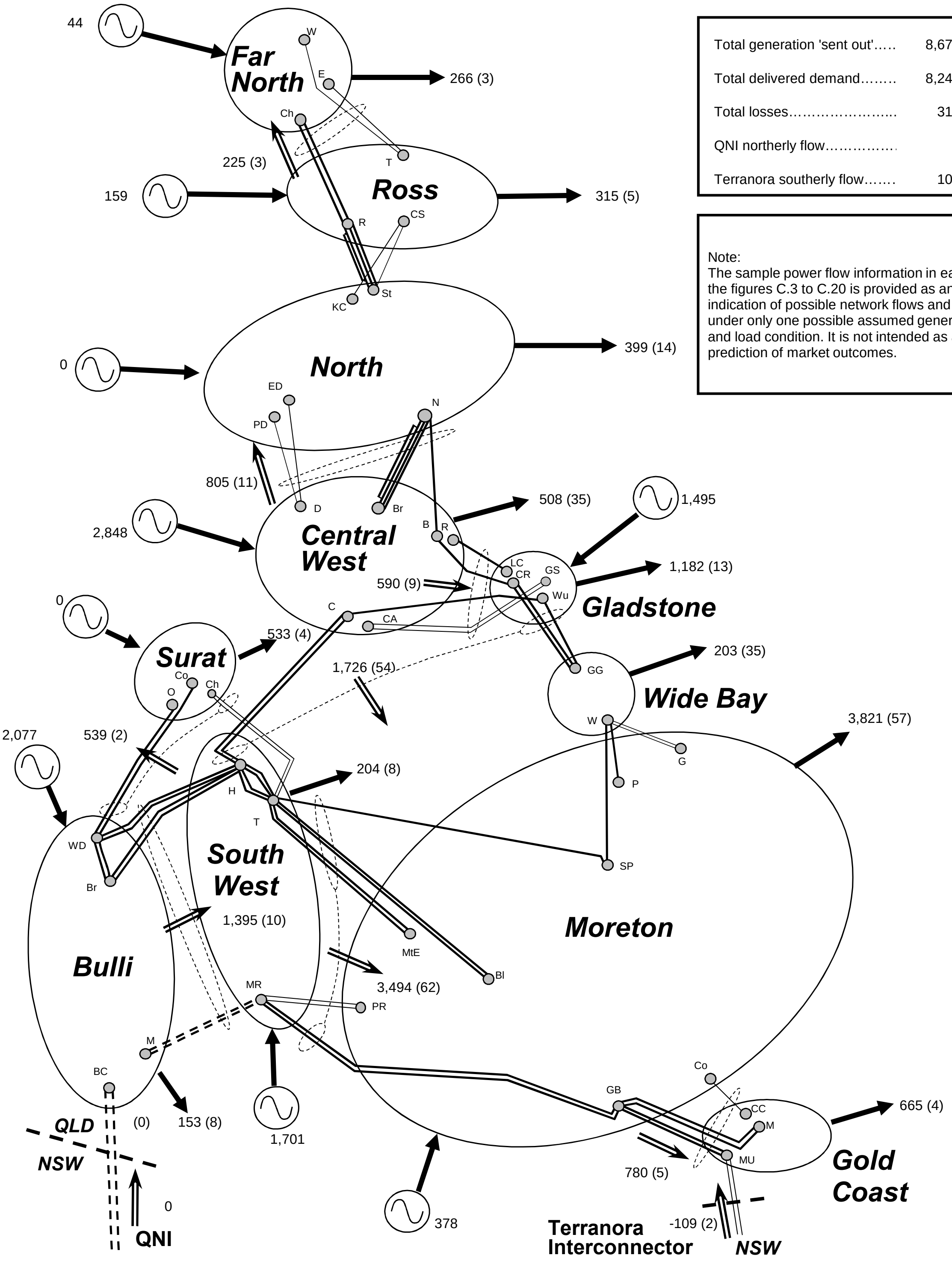
Figure C.15 Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,472 MW
Total delivered demand……..	8,249 MW
Total losses…………………...	314 MW
QNI northerly flow……………	200 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.

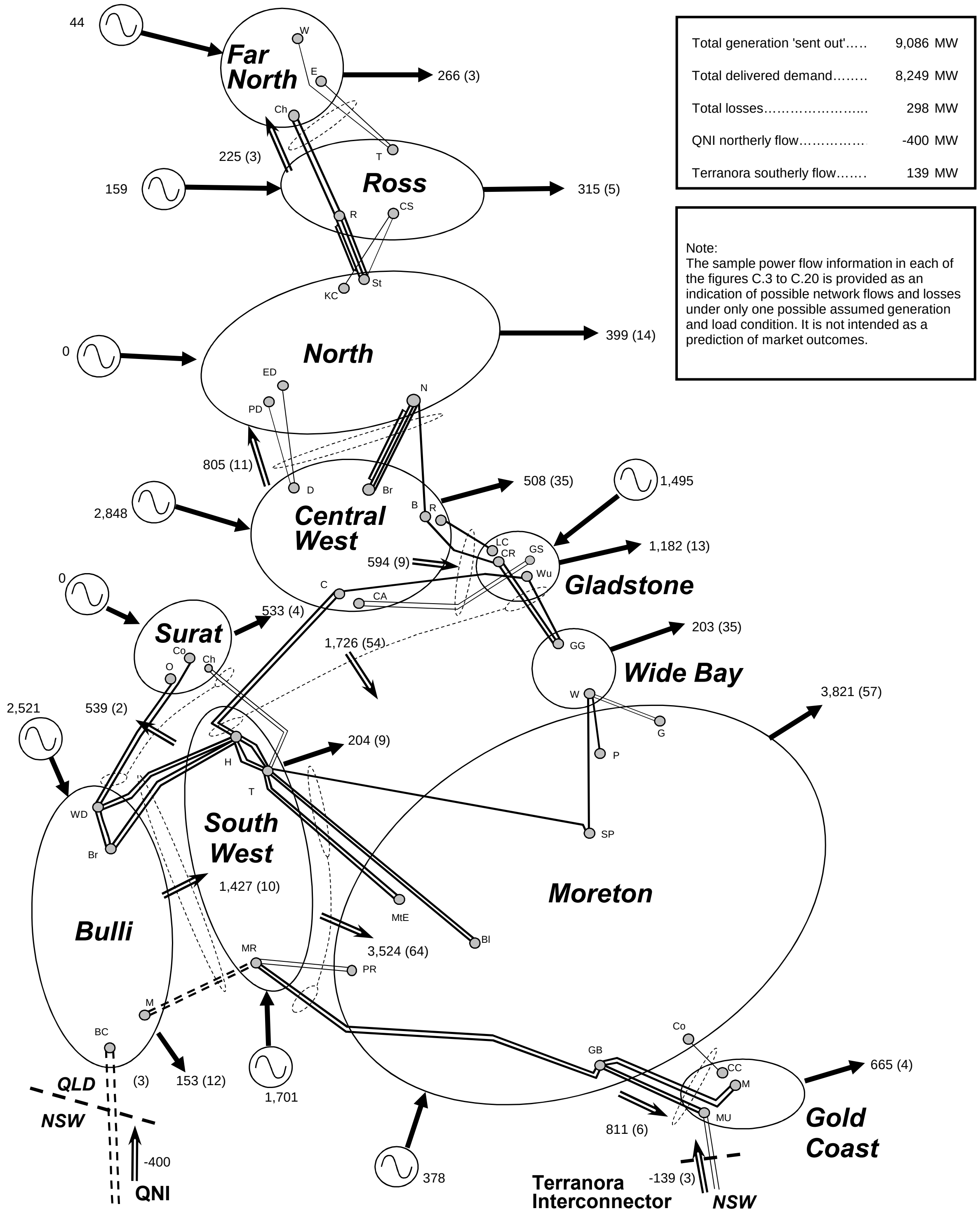
Figure C.16 Summer 2017/18 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,672 MW
Total delivered demand……..	8,249 MW
Total losses…………………...	314 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.

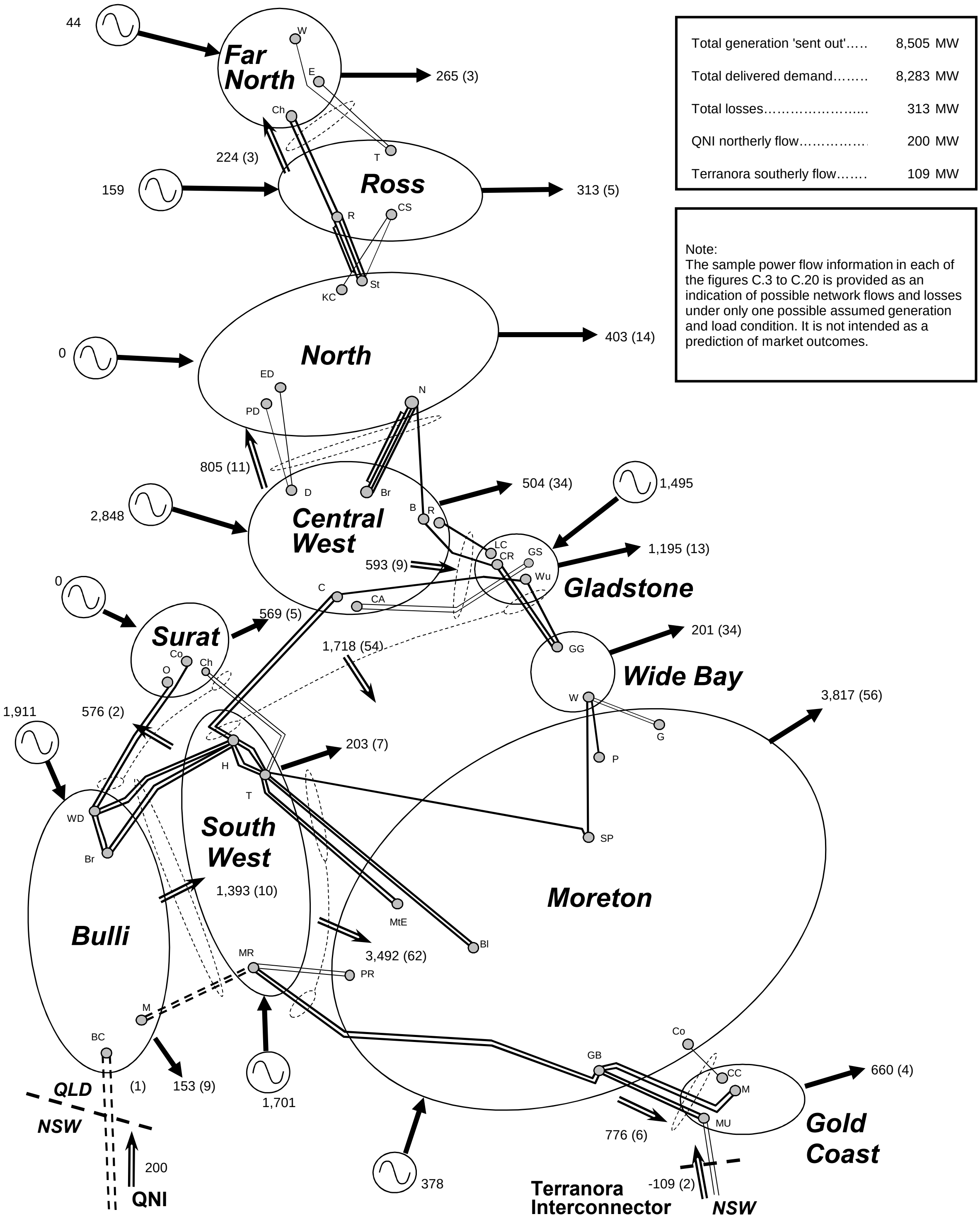
Figure C.17 Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'.....	9,086 MW
Total delivered demand........	8,249 MW
Total losses........................	298 MW
QNI northerly flow...............	-400 MW
Terranora southerly flow.......	139 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.

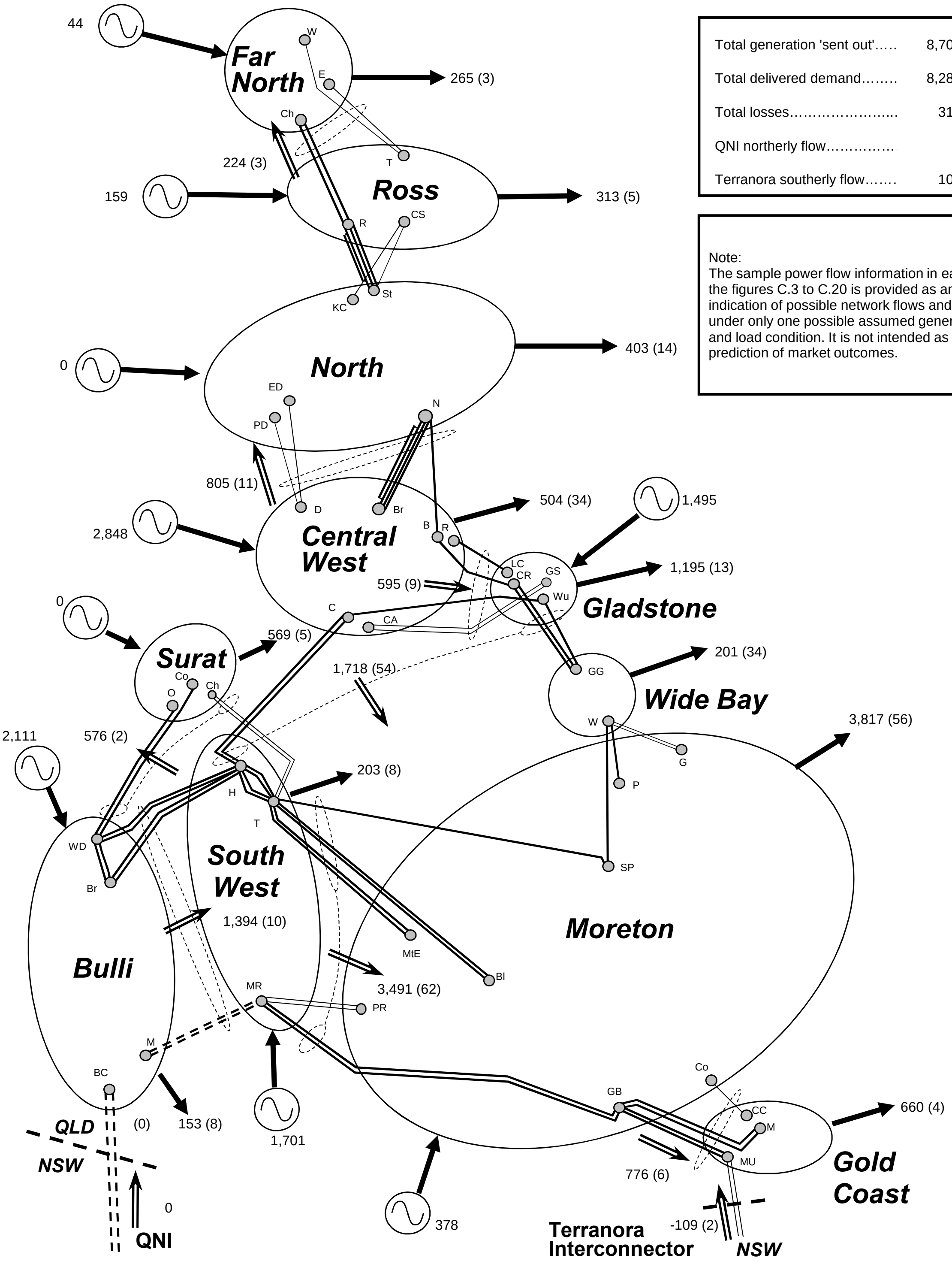
Figure C.18 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,505 MW
Total delivered demand……..	8,283 MW
Total losses…………………….	313 MW
QNI northerly flow…………….	200 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.

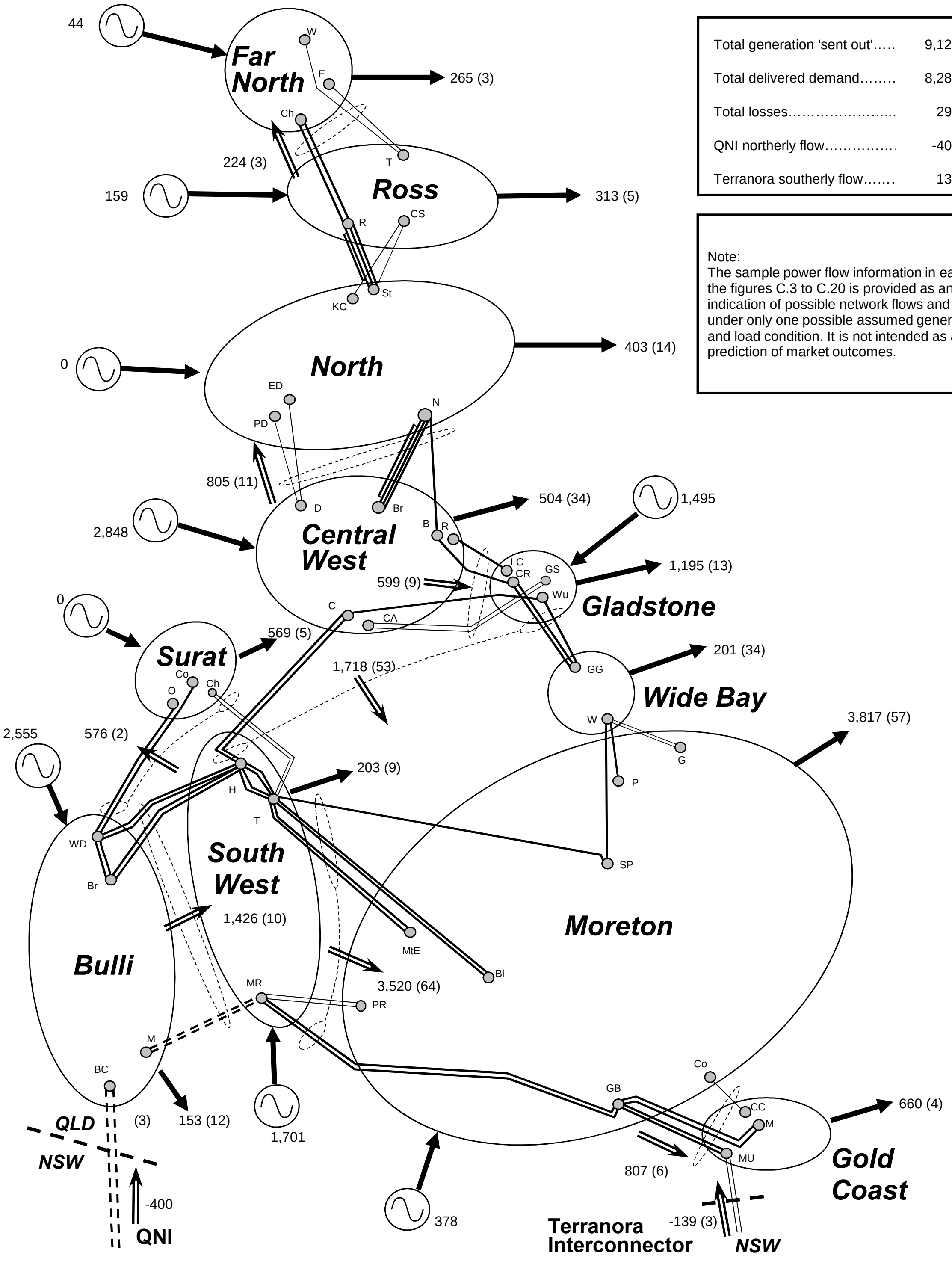
Figure C.19 Summer 2018/19 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,705 MW
Total delivered demand……..	8,283 MW
Total losses…………………...	313 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 2018/19 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,120 MW
Total delivered demand……..	8,283 MW
Total losses…………………...	297 MW
QNI northerly flow…………….	-400 MW
Terranora southerly flow…….	139 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.

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 + Invicta + 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:

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	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW 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 40 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage $= \frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector.

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table D.5 Gold Coast grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	-137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	-20.0000
Active power transfer (MW) across Terranora Interconnector (3)	-0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	**Q^NIL_GC**

Notes:

(1) Moreton to Gold Coast demand ratio $= \frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 16 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 36 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 short circuit currents at Powerlink Queensland's substations. The tables also show indicative minimum short circuit currents.

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 2016/17, 2017/18 and 2018/19.

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 5.1[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

The connection of fluctuating load and reactive plant should consider the minimum short circuit current at the prospective point of connection to ensure that there is no adverse impact on power quality.

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 from a typical winter light load system condition and associated generation dispatch. The single network element that makes the greatest contribution to the symmetrical three phase short circuit fault current for each bus considered was also removed from service.

These minimum short circuit currents are indicative only. Fault currents can be lower for different generation dispatches and/or network elements out of service.

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[1] Swanbank E is out of service for Summer 16/17 consistent with Table 5.1. However, for the short circuit currents calculated for 2017/18 and 2018/19 Swanbank E is in-service. This was chosen on the basis of; conservative for short circuit current assessment, Stanwell maintains a Connection and Access Agreement with Powerlink, Stanwell advise that a lead-time of six to nine months is required to restart Swanbank E.

Table E.1 Indicative short circuit currents – northern Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Alan Sherriff	132	40.0	4.0	12.0	12.7	12.0	12.7	12.0	12.7
Alligator Creek	132	25.0	1.9	4.5	5.9	4.5	5.9	4.5	5.9
Bollingbroke	132	40.0	2.0	2.4	1.9	2.4	1.9	2.4	1.9
Bowen North	132	40.0	1.3	2.1	2.4	2.1	2.4	2.1	2.4
Burton Downs	132	19.3	3.6	5.1	4.9	5.1	4.9	5.1	4.9
Cairns (2T)	132	25.0	0.6	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (3T)	132	25.0	0.6	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (4T)	132	25.0	0.6	5.4	7.3	5.4	7.3	5.4	7.3
Cardwell	132	19.3	1.0	2.8	3.0	2.8	3.0	2.8	3.0
Chalumbin	275	31.5	1.3	3.7	4.0	3.7	3.9	3.7	3.9
Chalumbin	132	31.5	2.6	6.1	7.1	6.1	7.1	6.1	7.1
Clare South	132	40.0	3.0	7.1	7.4	7.1	7.4	7.1	7.4
Collinsville North	132	31.5	2.1	7.4	8.4	7.4	8.4	7.4	8.4
Coppabella	132	31.5	2.3	2.9	3.3	2.9	3.3	2.9	3.3
Dan Gleeson (1T)	132	31.5	3.6	11.4	12.1	11.3	12.1	11.3	12.1
Dan Gleeson (2T)	132	40.0	3.6	11.3	12.0	11.3	12.0	11.3	12.0
Edmonton	132	40.0	0.8	5.0	6.1	4.9	6.1	4.9	6.1
Eagle Downs	132	40.0	1.6	4.2	4.2	4.2	4.2	4.2	4.2
El Arish	132	40.0	1.0	3.1	3.8	3.1	3.8	3.1	3.8
Garbutt	132	40.0	1.8	10.0	10.2	10.2	10.5	10.2	10.5
Goonyella Riverside	132	40.0	3.2	5.3	5.0	5.3	5.0	5.3	5.0
Ingham South	132	31.5	1.0	2.8	2.8	2.8	2.8	2.8	2.8
Innisfail	132	40.0	1.2	2.7	3.3	2.7	3.3	2.7	3.3
Invicta	132	19.3	2.5	5.1	4.6	5.1	4.6	5.1	4.6
Kamerunga	132	15.3	0.6	4.3	5.1	4.3	5.1	4.3	5.1
Kareeya	132	40.0	2.8	5.3	6.0	5.3	6.0	5.3	6.0
Kemmis	132	31.5	1.7	5.8	6.4	5.7	6.4	5.7	6.4
King Creek	132	40.0	2.1	4.4	3.8	4.4	3.8	4.4	3.8
Mackay (2T)	132	10.9	1.2	4.7	5.4	4.7	5.4	4.7	5.4
Mackay (1T & 3T)	132	10.9	1.2	4.8	5.3	4.8	5.4	4.8	5.4
Mackay Ports	132	40.0	1.7	3.5	4.1	3.5	4.1	3.5	4.1
Mindi	132	40.0	3.3	4.4	3.6	4.4	3.6	4.4	3.6
Moranbah	132	10.9	3.4	6.6	8.0	6.6	8.0	6.6	8.0

Table E.1 Indicative short circuit currents – northern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Moranbah South	132	31.5	3.4	5.0	4.8	5.0	4.8	5.0	4.8
Mt McLaren	132	31.5	1.6	2.0	2.1	2.0	2.1	2.0	2.1
Nebo	275	31.5	3.9	9.4	9.9	9.3	9.9	9.3	9.8
Nebo	132	15.3	6.2	12.7	14.8	12.7	14.8	12.7	14.7
Newlands	132	25.0	1.3	3.3	3.8	3.3	3.8	3.3	3.8
North Goonyella	132	20.0	3.0	4.1	3.5	4.1	3.5	4.1	3.5
Oonooie	132	31.5	1.5	3.1	3.7	3.1	3.7	3.1	3.7
Peak Downs	132	31.5	1.7	3.9	3.5	3.9	3.5	3.9	3.5
Pioneer Valley	132	31.5	3.6	7.0	7.7	6.9	7.8	6.9	7.8
Proserpine	132	40.0	1.4	2.6	3.2	2.6	3.2	2.6	3.2
Ross	275	31.5	2.5	7.1	8.1	7.1	8.2	7.1	8.1
Ross	132	31.5	4.4	15.2	17.6	15.2	17.9	15.1	17.6
Stony Creek	132	40.0	1.2	3.4	3.4	3.4	3.4	3.4	3.4
Strathmore	275	31.5	3.0	7.8	8.3	7.7	8.3	7.7	8.3
Strathmore	132	40.0	2.3	8.2	9.6	8.2	9.6	8.2	9.6
Townsville East	132	40.0	1.5	11.6	11.6	11.6	11.7	11.6	11.6
Townsville South	132	20.0	4.0	15.1	18.6	15.1	18.8	15.0	18.6
Townsville PS Switchyard	132	31.5	2.5	9.8	10.5	9.8	10.5	9.8	10.5
Tully	132	31.5	1.9	3.7	4.0	3.7	4.0	3.7	4.0
Turkinje	132	20.0	1.2	2.6	3.0	2.6	3.0	2.6	3.0
Wandoo	132	31.5	3.4	4.5	3.1	4.4	3.3	4.4	3.3
Woree (1T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree (2T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree	132	40.0	2.4	5.6	7.7	5.6	7.7	5.6	7.7
Wotonga	132	40.0	1.7	5.5	6.5	5.5	6.5	5.5	6.5
Yabulu South	132	40.0	3.8	11.3	11.2	11.3	11.2	11.3	11.2

Table E.2 Indicative short circuit currents – central Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Baralaba	132	15.3	1.5	4.2	3.7	4.7	4.0	4.1	3.5
Biloela	132	20.0	1.1	7.3	7.6	7.4	7.7	7.8	8.1
Blackwater	132	10.9	3.4	5.5	6.8	5.7	6.9	5.2	6.5
Bluff	132	40.0	2.3	3.4	4.2	3.4	4.2	3.2	4.1
Bouldercombe	275	31.5	9.0	19.7	19.5	19.7	19.5	19.7	19.5
Bouldercombe	132	21.8	4.7	14.5	16.8	14.5	16.8	14.5	16.8
Broadsound	275	31.5	4.8	11.2	8.6	11.2	8.8	11.2	8.7
Callemondah	132	31.5	6.9	24.1	26.3	23.8	26.1	22.0	24.6
Callide A	132	11.0	1.1	10.1	10.8	10.2	10.9	10.2	10.9
Calliope River	275	40.0	9.7	21.0	23.8	20.9	23.7	20.6	23.5
Calliope River	132	40.0	17.1	26.9	31.9	26.6	31.6	24.7	29.7
Calvale	275	31.5	10.0	23.7	26.0	23.7	26.0	23.2	25.7
Calvale	132	31.5	1.1	10.2	10.9	10.2	11.0	8.4	9.2
Dingo	132	31.5	1.6	2.6	2.8	2.7	2.9	2.7	2.9
Duaringa	132	40.0	1.3	2.1	2.7	2.1	2.8	1.3	1.8
Dysart	132	10.9	1.9	4.4	5.1	4.4	5.1	4.4	5.0
Egans Hill	132	25.0	1.6	8.3	8.2	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	10.2	19.5	21.7	19.5	21.6	19.2	21.4
Gladstone PS	132	40.0	17.0	23.3	26.3	23.1	26.1	21.7	24.9
Gladstone South	132	40.0	9.9	18.7	19.1	18.2	18.8	15.9	16.9
Grantleigh	132	31.5	2.3	2.7	2.8	2.7	2.8	2.7	2.8
Gregory	132	31.5	6.2	8.7	10.0	8.7	10.1	8.5	9.8
Larcom Creek	275	40.0	3.4	15.4	15.3	15.4	15.3	15.3	15.2
Larcom Creek	132	40.0	4.5	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	2.8	5.6	5.6	5.6	5.6	5.5	5.5
Lilyvale	132	25.0	5.5	9.1	10.8	9.2	10.9	8.8	10.6
Moura	132	12.3	1.2	2.9	3.0	4.0	4.3	3.9	4.2
Norwich Park	132	31.5	1.4	3.5	2.6	3.5	2.6	3.5	2.6
Pandoin	132	40.0	1.4	7.0	6.2	7.0	6.3	7.0	6.3
Raglan	275	40.0	4.4	11.9	10.4	11.8	10.4	11.8	10.4
Rockhampton (1T)	132	10.9	4.6	6.5	6.4	6.3	6.4	6.3	6.4
Rockhampton (5T)	132	10.9	4.7	6.3	6.2	6.5	6.2	6.5	6.2
Rocklands	132	31.5	5.6	7.7	6.6	7.7	6.6	7.7	6.6

Table E.2 Indicative short circuit currents – central Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Stanwell	275	31.5	10.1	22.3	24.1	22.3	24.1	22.3	24
Stanwell	132	31.5	4.5	6.0	6.4	6.0	6.5	6.0	6.5
Wurdong	275	31.5	7.2	16.9	16.8	16.9	16.7	16.7	16.6
Wycarbah	132	40.0	3.6	4.5	5.4	4.5	5.4	4.5	5.4
Yarwun	132	40.0	5.3	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Abermain	275	40.0	7.0	18.0	18.6	18.0	18.6	18.0	18.6
Abermain	110	31.5	10.9	21.4	25.2	21.3	25.2	21.3	25.2
Algester	110	40.0	13.0	21.5	21.2	21.5	21.2	21.5	21.2
Ashgrove West	110	26.3	12.5	19.1	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	8.5	16.8	18.5	16.8	18.5	16.8	18.5
Belmont	110	37.4	17.7	29.7	37.0	29.7	37.0	29.7	37.0
Blackwall	275	37.0	9.8	22.0	23.9	22.0	23.9	22.0	23.9
Blackstone	275	40.0	9.1	20.9	23.2	20.9	23.2	20.9	23.2
Blackstone	110	40.0	14.9	25.4	29.1	25.2	28.9	25.2	28.9
Blythdale	132	40.0	2.6	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	7.9	23.0	25.2	23.0	25.1	23.0	25.1
Braemar (East)	275	40.0	8.5	33.4	38.9	26.4	30.8	26.4	30.8
Braemar (West)	275	40.0	6.8	-	-	26.3	29.3	26.3	29.3
Bulli Creek	330	50.0	8.9	18.1	14.3	18.1	14.3	18.1	14.3
Bulli Creek	132	40.0	3.5	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	8.4	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	4.8	8.0	7.8	7.9	7.8	7.9	7.8
Clifford Creek	132	40.0	3.9	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.6	12.8	11.9	12.2	11.6	12.2	11.6
Columboola	132	25.0	7.0	16.3	18.4	16.1	18.2	16.1	18.2
Condabri Central	132	40.0	5.2	9.0	6.7	8.9	6.6	8.9	6.6
Condabri North	132	40.0	7.4	13.2	12.1	13.1	12.1	13.1	12.1
Condabri South	132	40.0	4.2	6.6	4.4	6.5	4.4	6.5	4.4
Dinoun South	132	40.0	4.7	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	1.3	4.3	4.6	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	1.3	4.3	4.6	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.3	6.9	8.5	6.8	8.4	6.8	8.4
Fairview	132	40.0	2.9	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	3.7	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.5	10.9	10.4	10.9	10.1	10.9	10.0
Gin Gin	132	20.0	6.8	12.6	13.0	12.8	13.9	12.8	13.9
Goodna	275	40.0	6.2	16.0	16.0	16.0	16.0	16.0	16.0
Goodna	110	40.0	14.4	25.3	27.5	25.3	27.5	25.3	27.5

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Greenbank	275	40.0	9.1	20.2	22.4	20.2	22.4	20.2	22.4
Halys	275	50.0	13.1	31.4	26.0	31.3	26.0	31.3	26.0
Kumbarilla Park (1T)	275	40.0	1.7	19.0	17.7	16.5	15.9	16.5	15.9
Kumbarilla Park (2T)	275	40.0	1.7	19.0	17.7	16.5	15.9	16.5	15.9
Kumbarilla Park	132	40.0	6.2	13.8	15.8	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.8	14.8	15.4	14.8	15.4	14.8	15.4
Loganlea	110	25.0	13.7	22.8	27.4	22.8	27.4	22.8	27.4
Middle Ridge (4T)	330	50.0	4.1	12.5	12.2	12.5	12.3	12.5	12.3
Middle Ridge (5T)	330	50.0	4.1	12.9	12.6	12.9	12.7	12.9	12.7
Middle Ridge	275	31.5	8.6	17.9	18.1	17.9	18.3	17.9	18.3
Middle Ridge	110	18.3	9.7	20.3	24.2	20.3	24.8	20.3	24.9
Millmerran Switchyard	330	40.0	9.1	18.3	19.6	18.3	19.6	18.3	19.6
Molendinar (1T)	275	40.0	2.4	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	2.4	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	12.1	20.0	25.3	20.0	25.2	20.0	25.2
Mt England	275	31.5	9.5	22.4	22.7	22.4	22.7	22.4	22.7
Mudgeeraba	275	31.5	5.0	9.4	9.5	9.4	9.4	9.4	9.4
Mudgeeraba	110	25.0	12.7	18.7	22.8	18.7	23.0	18.7	23.0
Murarrie (2T)	275	40.0	2.6	13.0	13.4	13.0	13.4	13.0	13.4
Murarrie (3T)	275	40.0	2.6	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie	110	40.0	15.0	24.2	29.2	24.2	29.2	24.2	29.2
Oakey GT PS	110	31.5	5.3	10.8	12.0	10.8	12.0	10.8	12.0
Oakey	110	40.0	1.2	10.1	10.0	10.1	10.0	10.1	10.0
Orana	275	40.0	4.0	15.5	14.1	14.6	13.6	14.6	13.6
Palmwoods	275	31.5	3.7	8.4	8.8	8.4	8.9	8.4	8.9
Palmwoods	132	21.9	8.9	13.0	15.5	13.0	15.7	13.0	15.7
Palmwoods (7T)	110	40.0	2.8	7.2	7.5	7.2	7.6	7.2	7.6
Palmwoods (8T)	110	40.0	2.8	7.2	7.5	7.2	7.6	7.2	7.6
Redbank Plains	110	31.5	10.5	21.3	20.8	21.3	20.8	21.3	20.8
Richlands	110	40.0	12.4	22.0	22.7	22.0	22.7	22.0	22.7
Rocklea (1T)	275	31.5	2.6	13.1	12.3	13.1	12.3	13.1	12.3
Rocklea (2T)	275	31.5	2.6	8.7	8.4	8.7	8.4	8.7	8.4

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Rocklea	110	31.5	14.5	24.9	28.7	24.8	28.7	24.8	28.7
Runcorn	110	40.0	9.5	19.3	19.6	19.3	19.6	19.3	19.6
South Pine	275	31.5	8.9	18.5	21.1	18.5	21.1	18.5	21.1
South Pine (West)	110	40.0	11.3	20.4	23.5	20.4	23.5	20.4	23.5
South Pine (East)	110	40.0	13.2	21.4	27.5	21.4	27.5	21.4	27.5
Sumner	110	40.0	10.1	20.6	20.2	20.6	20.2	20.6	20.2
Swanbank E	275	40.0	9.8	20.6	22.7	20.6	22.7	20.6	22.7
Tangkam	110	31.5	4.2	12.8	12.0	12.8	12.1	12.8	12.1
Tarong (1)	275	31.5	13.5	32.9	34.6	32.9	34.6	32.9	34.6
Tarong (1T)	132	25.0	1.2	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	1.2	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	7.0	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	3.4	7.3	7.2	7.3	7.2	7.3	7.2
Teebar Creek	132	40.0	6.3	10.1	11.2	10.1	11.2	10.1	11.2
Tennyson	110	40.0	1.9	16.2	16.4	16.2	16.4	16.2	16.4
Upper Kedron	110	40.0	13.3	21.2	18.7	21.1	18.7	21.1	18.7
Wandoan South	275	40.0	3.8	7.2	7.9	7.0	7.7	7.0	7.7
Wandoan South	132	40.0	4.9	8.7	11.1	8.6	11.0	8.6	11.0
West Darra	110	40.0	14.9	24.8	23.8	24.8	23.8	24.8	23.8
Western Downs	275	40.0	12.0	26.8	26.2	24.1	24.2	24.1	24.2
Woolooga	275	31.5	5.7	9.6	10.8	9.6	10.8	9.6	10.8
Woolooga	132	20.0	8.0	13.0	15.5	13.1	15.5	13.0	15.5
Yuleba North	275	40.0	3.8	5.8	6.4	5.7	6.3	5.7	6.3
Yuleba North	132	40.0	4.7	7.8	9.4	7.7	9.3	7.7	9.3

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 – Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APLNG	Australia Pacific Liquefied Natural Gas
APR	Annual Planning Report
BSL	Boyne Smelters Limited
CQ	Central Queensland
CSM	Coal Seam Methane
DNSP	Distribution Network Service Provider
ESOO	Electricity Statement of Opportunity
FNQ	Far North Queensland
GLNG	Gladstone Liquefied Natural Gas
GT	Gas Turbine
GWh	Gigawatt hour
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
LNG	Liquefied natural gas
MJ	Megajoules
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
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
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
NWD	Non-weather dependent

PoE	Probability of exceedance
PS	Power Station
PV	Photovoltaic
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QGC	Queensland Gas Company
QNI	Queensland/New South Wales Interconnector transmission line
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SCR	Short Circuit Ratio
SEQ	South East Queensland
SQ	South Queensland
SVC	Static VAr Compensator
SWQ	South West Queensland
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
WD	Weather dependent

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