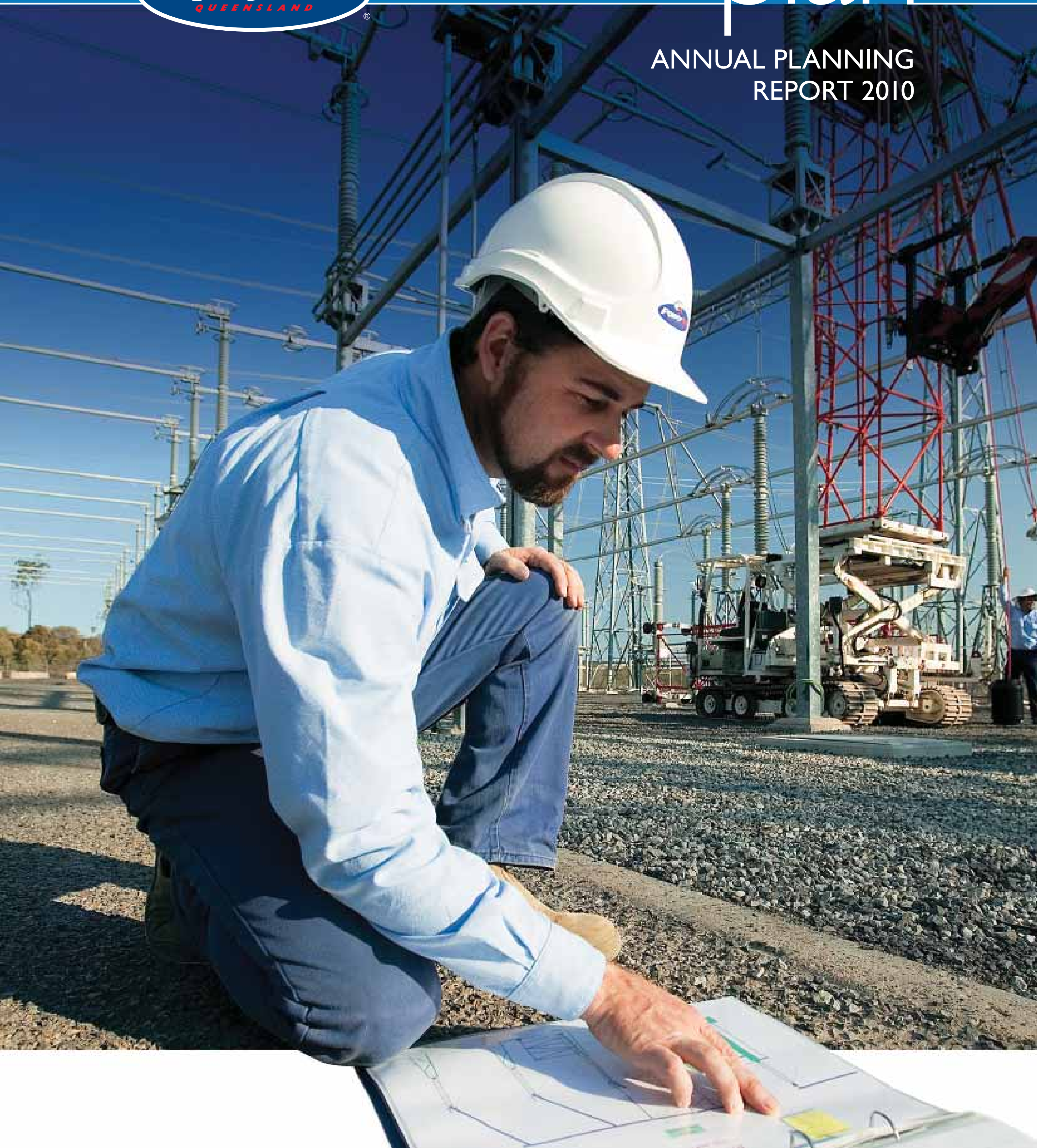
# the power to plan

## ANNUAL PLANNING REPORT 2010



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## Executive summary

Planning and development of the transmission network are integral to Powerlink Queensland meeting its obligations under the National Electricity Rules (NER), *Electricity Act 1994 (Queensland)* and its Transmission Licence. This Annual Planning Report (APR) is a key part of this process. It provides information about the Queensland electricity transmission network to Registered Participants and interested parties. It includes information on electricity demand forecasts, the existing electricity supply system including committed generation and network developments, as well as estimates of grid capability and potential network and non-network developments required in the future to meet growing customer demand for electricity in a timely manner.

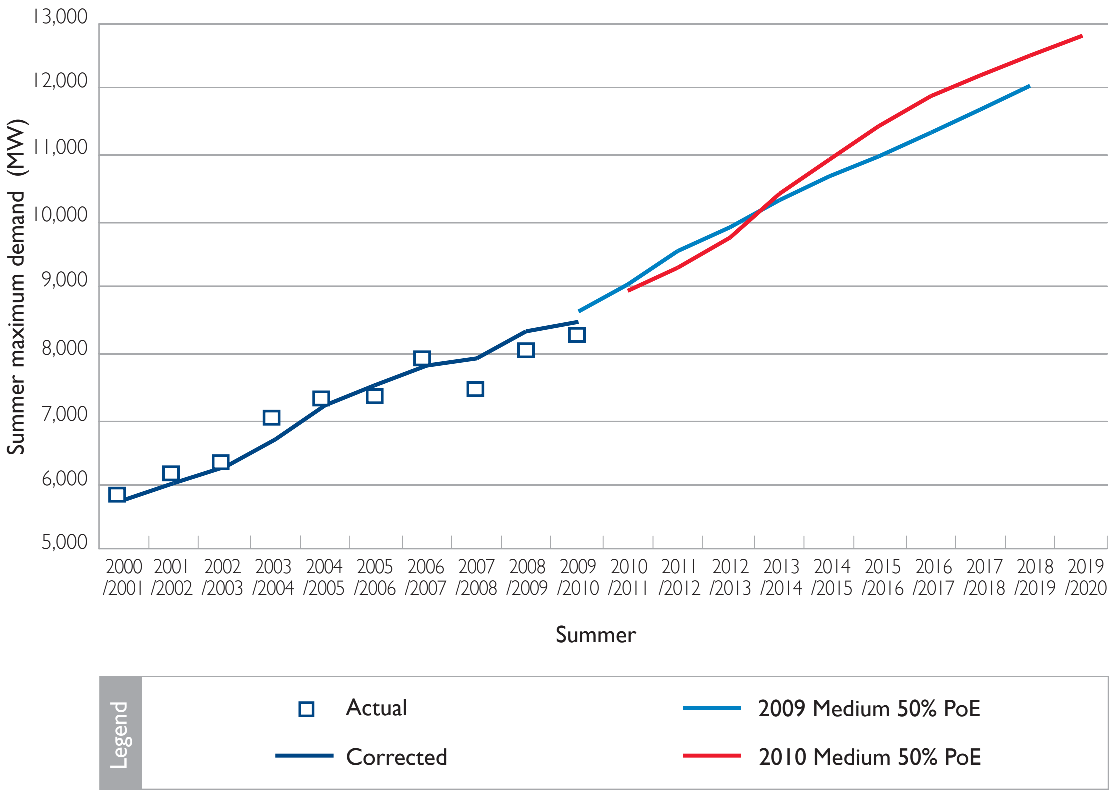
### Electricity demand forecast

The forecast presented in this APR indicates sustained long-term growth in electricity demand in Queensland over the next 10 years. On average, summer maximum electricity demand is forecast to increase at a rate of 4.2% per annum from 8,489MW in 2009/10 to 12,821MW in 2019/20, based on the medium economic forecast.

Economic and population growth will continue to underpin increases to electricity demand over the 10-year forecast period. The outlook reflects the emerging trends in the Queensland economy – a return to trend growth following the recent short period of economic slowdown, and a strong resurgence in the resources sector. The forecast has also recognised the emerging electricity requirements in the Surat Basin area arising from the upstream processing facilities of liquefied natural gas (LNG) projects, coal mining and related load growth in the service towns. The medium growth forecast allows for a proportion of the total demand from the proposed LNG projects to arise from the commencement of "ramp up" production from around 2012/13.

The weather and diversity corrected, summer maximum native demand for Queensland has increased by 2.2% from 8,310MW in 2008/09 to 8,489MW in 2009/10.

A comparison of the medium economic outlooks of the 2009 APR and 2010 APR summer peak demand, based on 50% probability of exceedance (PoE), is displayed below.



### Electricity energy forecast

Annual native energy consumption within Queensland is forecast to increase at an average rate of 4.0% per annum over the next 10 years for the medium economic outlook. This continues the trend of energy consumption growing at a marginally slower rate than peak demand. As with the demand forecast, the energy forecast reflects the resurgence of the Queensland economy following the recent short period of economic slowdown. The introduction and increased uptake of energy efficiency initiatives have also been factored into this energy forecast. The energy efficiency initiatives, by their nature, tend to impact energy consumption much more than the forecast peak demands. As with the demand forecast, the energy forecast also includes a proportion of the total energy consumption for the upstream processing facilities of the proposed LNG projects.

### Transmission projects completed

Significant projects completed since the 2009 APR include:

- Nebo to Strathmore 275kV transmission reinforcement, which has augmented transmission capability between Central and North Queensland (Stage 2 of the three stage project)
- Ross (Townsville) to Yabulu South 275kV transmission reinforcement (including the new Yabulu South Substation), which has augmented transmission capability within the greater Townsville area
- South Pine to Sandgate 275kV transmission reinforcement, which has augmented transmission capability into north east Brisbane
- Bouldercombe to Pandoin 132kV transmission reinforcement (including the new Pandoin Substation), which has augmented transmission capability into Rockhampton and surrounding areas
- establishment of the Larcom Creek 275/132kV Substation which has augmented transmission capability to the Gladstone area
- installation of 275kV shunt capacitor banks at Greenbank, Mt England and South Pine, which have augmented capacitive compensation in South East Queensland to meet increasing reactive demand
- installation of a 275kV shunt capacitor bank at Tarong, which has augmented capacitive compensation in South West Queensland to meet increasing reactive demand
- installation of a 132/110kV transformer at Palmwoods, which has augmented transmission capability into the Caboolture and Beerwah areas
- installation of a 275/110kV transformer at South Pine, which has augmented transmission capability into north east Brisbane.

In addition, network support contracts were maintained with power stations in North Queensland to assist in meeting peak electricity demand requirements in the region.

### Transmission projects in progress

Powerlink is currently implementing the following major augmentation projects.

Three 275kV transmission lines:

- between Strathmore and Ross, to increase transfer capability between Central and North Queensland (Stage 3 of the three stage project)
- between Western Downs (near Kogan) and Halys (near Tarong), including new 275kV substations at Western Downs and Halys, to increase transfer capability between Bulli and South West Queensland zones
- between Halys and Blackwall (near Ipswich), to increase transfer capability into the South East Queensland area. This transmission line will be constructed as a 500kV line but initially operated at 275kV.

One 132kV transmission line:

- between Strathmore and Bowen North, including the new Bowen North Substation, to augment supply to the Bowen area.

Smaller augmentations, comprising the installation of capacitor banks to maintain network reliability and quality of supply standards, are also under way.

### Generation capacity

The following generation has been commissioned in the Queensland Region since the 2009 APR:

- Mt Stuart Power Station third unit (liquid fuel)
- Braemar 2 Power Station (open cycle gas)
- Darling Downs Power Station (combined cycle gas)
- Condamine Power Station (combined cycle gas), which is connected to the Ergon network.

The commissioning of Rio Tinto Aluminium (RTA) Yarwun Power Station (gas) is well advanced.

One new power station, ERM's 600MW Braemar 3, has reached an advanced stage of commitment since the 2009 APR.

### Queensland/New South Wales Interconnector

Powerlink and TransGrid published a Final Report in October 2008 relating to the potential upgrade of the interconnection between Queensland and New South Wales. The Final Report detailed the outcomes of comprehensive technical and economic studies into feasible upgrade options, each delivering different increments in Queensland/New South Wales interconnection transfer capability, in accordance with the Australian Energy Regulator's (AER's) Regulatory Test.

The Final Report also responded to submissions from market participants to the Interim Report for Public Consultation published earlier that year.

The Final Report indicated that the installation of series compensation, with an estimated cost of around $120 million, provided the highest net market benefits in the majority of scenarios considered. The optimum timing under the most plausible scenario is 2015/16.

Based on that timing, TransGrid and Powerlink considered it premature at that time to recommend an upgrade.

In light of a number of market developments, including mooted generation investments, the expanded renewable energy target, and the recent revision of the Regulatory Test, the two organisations have agreed to undertake the further investigations to evaluate the economic viability (and optimal timing) of potential upgrades to Queensland/New South Wales Interconnector (QNI), based on the principles and methodology of the Regulatory Investment Test for Transmission (RIT-T). Depending on the results which emerge from this economic analysis, the organisations may decide to formally progress an upgrade through the National Electricity Rules process.

### Major flow paths

A record peak demand was set in the 2009/10 summer, with the actual peak being 3.4% higher than that recorded in the 2008/09 summer. The transmission network in the Queensland Region performed reliably during the 2009/10 year, including during the period of record summer peak demand.

The Central Queensland to South Queensland (CQ-SQ) intraconnector experienced minor incidences of binding over the 2009/10 year (0.23% of time). The incidence of binding is marginally higher than the previous year, attributable to Central Queensland generating plant operating at high outputs to take advantage of market opportunities to export into southern regions via the QNI.

No binding occurred on the Tarong limit during 2009/10. The ongoing installation of additional shunt compensation equipment has enabled the capability of this grid section to keep pace with demand growth.

The Central Queensland to North Queensland (CQ-NQ) limit is managed by network support arrangements between Powerlink and North Queensland generators, which have been approved under the AER Regulatory Test process. The three-stage CQ-NQ transmission project, with the first two stages already completed and the final stage due for completion in 2010, will improve transfer capability to meet forecast electricity demand in North Queensland and reduce transmission losses. Minor binding (0.24% of time) was experienced on this grid section during 2009/10.

The Gladstone limit bound for a total of 6.0% during 2009/10. Binding events are currently managed by operational strategies and redispatch of generation. These operational strategies include network rearrangement and re-rating critical transmission lines to take account of prevailing ambient weather conditions. Due to ongoing demand growth, this thermal limitation will require a reliability augmentation by the summer of 2013/14.

### Future augmentations

The predominant driver for augmentations to network capability will continue to be the need to maintain mandated reliability standards as peak demand continues to grow. Powerlink is committed to continually reviewing and expanding its transmission network in a timely manner to meet this growth.

The NER requires the APR to identify emerging network limitations which are expected to arise some years into the future, based on the forecast growth in demand for electricity. This allows Powerlink to identify and implement appropriate augmentations to maintain a reliable power supply to customers including, where technically and economically appropriate, non-network solutions.

The APR highlights those potential future limitations for which Powerlink intends to implement augmentations and/or initiate consultation with Registered Participants and interested parties in the near future.

### Consultation on network augmentations

During 2009/10, Powerlink finalised regulatory processes associated with the new network investments to address forecast emerging limitations in the South West to South East Queensland area.

Powerlink is currently undertaking several consultations with Registered Participants and interested parties about expected future network limitations. These consultations include:

- Supply to the Surat Basin north west area
- Supply within the Central Queensland area.

Within the next 12 months, Powerlink also expects to initiate the consultation processes in relation to the expected future network limitations to supply within the northern Bowen Basin area.

### Proposed network replacements

In addition to developing its network to meet forecast electricity demand, Powerlink is also required to maintain the capability of its existing network. Powerlink undertakes asset replacement projects when assets are deemed to reach the end of their life. Powerlink has included in this report a list of potential replacement works over the value of $5 million that are envisaged to occur in the next five years.

chapter

# Introduction

# Chapter 1

## 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 of the capability of its transmission network to meet the forecast electricity demands. Pursuant to the National Electricity Rules (NER), Powerlink is required to publish the findings of this review in its Annual Planning Report (APR).

This 2010 APR provides details of Powerlink's latest planning review. The report 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 are identified, and possible solutions to address these limitations are discussed. Interested parties are encouraged to provide input to facilitate identification of the most economic solution (including non-network solutions) to ensure supply reliability can be maintained to customers in the face of continued growth in electricity demand.

Powerlink's annual planning review and report are an important part of the process of planning the Queensland transmission network so that it can continue to meet the needs of participants in the NEM and consumers of electricity in Queensland.

## 1.2 Context of the 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 the 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 will provide information on the strategic and long-term development of the national transmission system under a range of market development scenarios.

The APR provides information on the short-term to medium-term planning activities of TNSPs, whereas the focus of the NTNDP is strategic and longer term. The NTNDP and APR are intended to complement each other in promoting efficient outcomes. Accordingly, information from the annual planning review process has been provided to AEMO in the preparation of the ESOO and NTNDP. Similarly, information from the NTNDP will be considered in future annual review processes undertaken by TNSPs.

Interested parties may benefit from reviewing Powerlink's 2010 APR in conjunction with AEMO's 2010 ESOO and NTNDP, which are anticipated to be published in August 2010 and December 2010 respectively.

## 1.3 Purpose of the Annual Planning Report

The purpose of Powerlink's APR is to provide information about the Queensland electricity transmission network to Registered Participants and interested parties.

It aims to provide information that assists interested parties 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
- 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 or used for other purposes, such as for the evaluation of participants' investment decisions.

## 1.4 Role of Powerlink Queensland

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 APR, Powerlink's transmission network planning and development responsibilities include:

- ensuring that its network is operated with sufficient capability, and augmented if necessary, to provide network services to customers
- ensuring that its 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, Country Energy and TransGrid
- advising 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 Registered Participants and interested parties. Solutions may include network upgrades or non-network options, such as local generation and demand side management initiatives
- undertaking the role of the proponent for regulated transmission augmentations in Queensland.

Powerlink has also been nominated by the Queensland Government as the entity having transmission network planning responsibility for the National Grid in Queensland, known as the Jurisdictional Planning Body (JPB) as outlined in Clause 5.6A.5 of the NER.

In addition, Powerlink provides advice on network developments which may have material inter-network effects, and participates in inter-regional system tests associated with new or augmented interconnections.

## 1.5 Overview of planning responsibilities

The development of the Queensland transmission network encompasses the following:

- connection of new participants, or alteration of existing connections
- augmentation of the shared network within Queensland
- augmentation to existing interconnectors, or development of new interconnectors between Powerlink's network and networks owned by other TNSPs.

### 1.5.1 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.

### 1.5.2 Planning of the shared network within Queensland

Powerlink is responsible for planning the shared transmission network within Queensland. The NER sets out the planning process and requires Powerlink to apply the Regulatory Test promulgated by the Australian Energy Regulator (AER) to new regulated network augmentation proposals. The planning process requires consultation with Registered Participants and interested parties, including customers, generators and DNSPs. Section 4.7 discusses Regulatory Test consultations currently under way, as well as anticipated future consultations that will be conducted under the new Regulatory Investment Test for Transmission (RIT-T) prescribed by the NER. The RIT-T replaces the Regulatory Test for consultations initiated from 1 August 2010.

The significant inputs into the network planning process within Queensland are:

- the forecast of customer electricity demand (including demand side management) and its location
- location, capacity and expected operation of generation
- planning criteria for the network
- the assessment of future network capability
- prediction of future loadings on the transmission network.

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

Powerlink examines the capability of its existing network, and the future capability following any changes resulting from committed augmentations. 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 is required to notify market participants of these forecast emerging network limitations. If augmentation is considered necessary, joint planning investigations are carried out with DNSPs (or other TNSPs if relevant) in accordance with Clause 5.6.2 of the NER. The objective of this joint planning is to identify the most cost effective network solution.

In addition to the requirement for joint planning, Powerlink has other obligations that govern how it should address forecast network limitations. These obligations are prescribed by the *Electricity Act 1994 (Queensland)*, the NER and Powerlink's Transmission Authority.

The Electricity 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. Under its Transmission Authority, Powerlink must plan and develop its network to be capable of supplying the forecast peak demand, even if the most critical network element is out of service (known as the N-1 criterion).

In addition, other obligations are contained in Schedule 5.1 of the NER. 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 network augmentations that deliver a net market benefit when measured in accordance with the AER Regulatory Test.

The requirements for initiating new regulated network developments are set down in Clauses 5.6.2, 5.6.6 and 5.6.6A of the NER. These clauses apply to different types of proposed augmentations.

While each of these clauses involves a slightly different process, the main steps in network planning can be summarised as follows:

- publication of information regarding the need for augmentation, which examines demand growth and its impact on network capability
- consideration of generation and network capability to determine the time when additional capability is required
- consultation on assumptions made and potential solutions, which may include transmission or distribution network augmentation, local generation or demand side management initiatives
- where a network development has a material inter-network impact, either the agreement of the entities responsible for those affected networks must be obtained, or the development must be examined by AEMO
- analysis of feasible options to determine the one that satisfies the AER Regulatory Test. In the case of an augmentation required to meet reliability and quality standards, this involves cost effectiveness analysis to determine the option that minimises present value of costs. In all other cases, the Regulatory Test requires that the proposed development maximises the net market benefit as defined in the Regulatory Test (noting that the new RIT-T will combine these two "limbs" into a single analysis)
- consultation and publication of a recommended course of action to address the identified future network limitation.

### 1.5.3 Planning of interconnectors

Development and assessment of new or augmented interconnections between Queensland and New South Wales (or other States) is the responsibility of the respective TNSPs. Information on interconnection upgrade activities between Powerlink and TransGrid is provided in Chapter 5.

# chapter 2 Intra-regional energy and demand projections

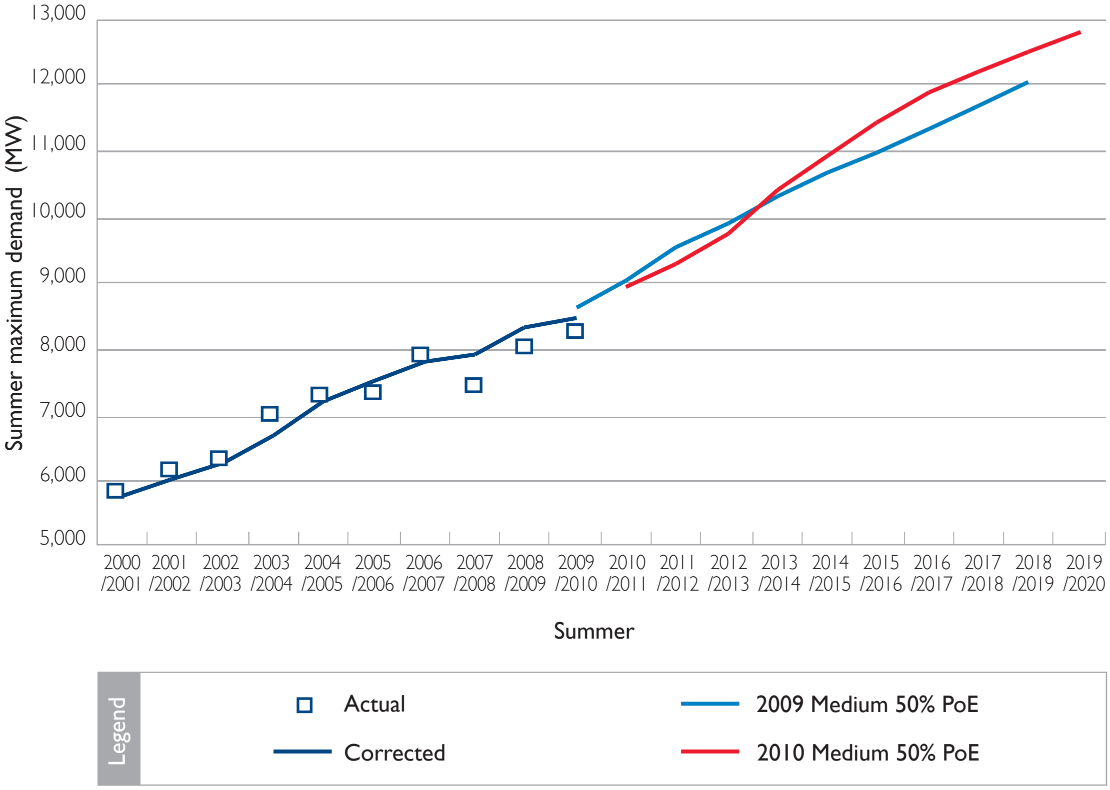
## 2.1 Summary of findings

The forecast presented in this Annual Planning Report (APR) indicates sustained growth in electricity demand in Queensland over the next 10 years. On average, summer maximum electricity demand is forecast to increase at 4.2% per annum from 8,489MW in 2009/10 to 12,821MW in 2019/20. Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 4.0% per annum over the next 10 years for the medium economic outlook.

Economic and population growth will continue to underpin increases to electricity demand over the 10-year forecast period. Strong growth is predicted for Queensland from 2010/11, reflecting the return to trend growth in the Queensland economy following the recent short period of economic slowdown and a strong resurgence in the resources sector. In particular, there are significant new loads emerging in the Surat Basin from the upstream processing facilities of the multiple proposed liquefied natural gas (LNG) projects, coal mining and related load growth in the service towns. In addition, while other possible coal mining loads (up to 800MW) in the Galilee and Bowen Basins have been identified, these have not yet been incorporated into the forecast, given the status of the projects at the time of compilation of this APR.

A comparison of the medium economic outlooks of the 2009 APR and this 2010 APR summer peak native demand, based on 50% probability of exceedance (PoE), is displayed in Figure 2.1.

**Figure 2.1 Queensland Region summer peak native demand – comparison with 2009**



### 2.1.1 Sources of load forecasts

In accordance with the National Electricity Rules (NER), Powerlink Queensland has obtained summer and winter peak demand forecasts over a 10-year horizon from Distribution Network Service Providers (DNSPs) and from directly connected customers at each transmission connection supply point. These individual connection supply point forecasts are aggregated into demand forecasts for the Queensland Region and for 10 geographical zones, defined in Table 2.12 in Section 2.5, using temperature corrections and diversity factors observed from historical trends.

Energy forecasts for each connection supply point were also obtained from the DNSPs and directly connected customers. These have also been aggregated for the Queensland Region, and for each of the 10 geographical zones in Queensland.

Forecasts were also sought from potential direct connect customers who were well advanced with plans for connection to the grid.

In addition to these 'bottom-up' forecasts, Powerlink engaged the National Institute of Economic and Industrial Research (NIEIR) to provide an independent assessment of energy and demand forecasts for Queensland. These forecasts were based on a 'top-down' econometric model. Inputs to this model include economic data, specific customer forecast information, energy efficiency measures and the anticipated impact of climate change policies. NIEIR also takes into account population growth trends which are sourced from the Australian Bureau of Statistics and population data from other Federal, State and Local Government sources. This information was used to develop low, medium and high economic outlooks.

The NIEIR medium outlook forecasts are consistent with the Queensland economic forecast undertaken by KPMG for the Australian Energy Market Operator's (AEMO's) 2010 National Transmission Network Development Plan (NTNDP).

### 2.1.2 Basis of load forecasts

#### Population growth

Queensland's electricity demand growth continues to be underpinned by sustained levels of population growth.

Average population growth rates for the low, medium and high economic outlooks developed by NIEIR over the period 2009/10 to 2019/20 are included in Table 2.1.

**Table 2.1 Average population growth rates**

| | Low | Medium | High |
|---|---|---|---|
| South East Queensland (average growth p.a.) | 2.1% | 2.4% | 2.7% |
| Queensland (average growth p.a.) | 1.9% | 2.2% | 2.5% |

#### Economic outlook

Three economic outlooks for Queensland, which have been reviewed by NIEIR, are characterised as:

- low growth economic outlook
- medium growth economic outlook
- high growth economic outlook.

Average growth indicators for the low, medium and high economic outlooks developed by NIEIR over the period 2009/10 to 2019/20 are included in Table 2.2.

Table 2.2 Economic growth indicators

| | Low | Medium | High |
|---|---|---|---|
| Queensland Gross State Product (average growth p.a.) | 2.6% | 3.6% | 4.6% |
| Australian Gross Domestic Product (average growth p.a.) | 2.0% | 2.8% | 3.8% |

Compared with the 2009 APR, the updated Queensland Gross State Product growth rate predictions are unchanged for the low economic outlook and slightly lower for the medium and high economic outlooks.

The updated Australian Gross Domestic Product growth rates are marginally higher for the low economic outlook and slightly lower for the medium and high economic outlooks.

### Weather conditions

Within each of these three economic outlooks, NIEIR also prepared three forecasts to incorporate sensitivity of peak summer and winter demands to prevailing ambient temperature weather conditions across Queensland, namely:

- a 10% PoE forecast region peak, corresponding to conditions that would be exceeded one year in 10
- a 50% PoE forecast region peak, corresponding to conditions that would be exceeded one year in two
- a 90% PoE forecast region peak, corresponding to conditions that would be exceeded nine years in 10.

### Energy efficiency

The Council of Australian Government's (COAG's) paper, National Strategy on Energy Efficiency 2009-2020 – Memorandum of Understanding, outlines the following key elements in strategy to increase energy efficiency:

- assisting households and businesses to transition to a low-carbon future
- reducing impediments to the uptake of energy efficiency
- making buildings more energy efficient
- government working in partnership and leading the way.

A number of initiatives relating to the above strategies are built into the DNSP forecasts and are therefore accounted for in the forecasts presented in this chapter. The initiatives that are expected to have the most impact in the 10-year forecast period are the ongoing transition to energy efficient lighting and the replacement of electric hot water systems with solar or gas. These impact the growth rate for energy consumption much more than peak demand.

Changes to building codes is expected to have more impact in the longer term, given that the number of new buildings constructed annually is quite small compared with the number of existing buildings.

### Wivenhoe Power Station pumping load

Energy delivered to the Wivenhoe Power Station during pumping operation is excluded from both the demand and energy forecasts.

### Native demand

Native demand refers to the demand delivered to DNSPs and to direct connected customers, and includes the output of embedded exempted and non-scheduled generators which do not export to the grid. Effectively, it is a measure of delivered demand (energy) which would occur if the embedded non-scheduled and exempt generation was offline. In the case of Queensland, this non-scheduled embedded generation includes a small number of sugar mill cogenerators, wind, thermal landfill and biomass generators. This higher underlying native demand is a better indicator of customer demand for the purpose of projecting future growth.

This APR reports forecasts for both delivered and native demand, with particular emphasis on native demand to reflect underlying growth rates. Historical data in this report has also been corrected to native values as far back as 2006/07, before which the differences between native and delivered demand are not considered material.

### Interconnector loads

Energy flows across the Queensland/New South Wales Interconnector (QNI) and the Terranora Interconnector are not included in the forecast loads in this chapter as they are not part of the Queensland customer load. These flows will increase or decrease the dispatch of generation within Queensland and loading on parts of the transmission network.

### New large loads

The forecast now includes:

- the first two stages of port handling facility upgrades at Abbot Point (Bowen)
- rail traffic electrification projects in the Blackwater area
- Goonyella Riverside mine connection
- QGC upstream processing facilities at Kumbarilla Park, near Braemar
- a proportion of new load in the Surat Basin arising from the multiple, dispersed upstream processing facilities of multiple LNG projects, coal mining and the related load growth in the service towns
- a proportion of new load arising from new and expanded coal mines in the Bowen Basin.

### Possible new large loads

There have been 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 include:

- coal mining load in the Galilee Basin
- additional coal mining load in the Bowen Basin
- major expansions of an existing zinc smelter plant (Townsville)
- Stage Three port handling facility upgrade at Abbot Point (Bowen)
- major expansions of an existing aluminium smelter plant (Gladstone)
- development and electrification of the Goonyella to Abbot Point railway line
- load at Gladstone for LNG projects.

Expansion of the zinc and aluminium plants has been included in the high economic outlook in accordance with data provided by customers. These developments could translate to the following additional load to be supplied by the network.

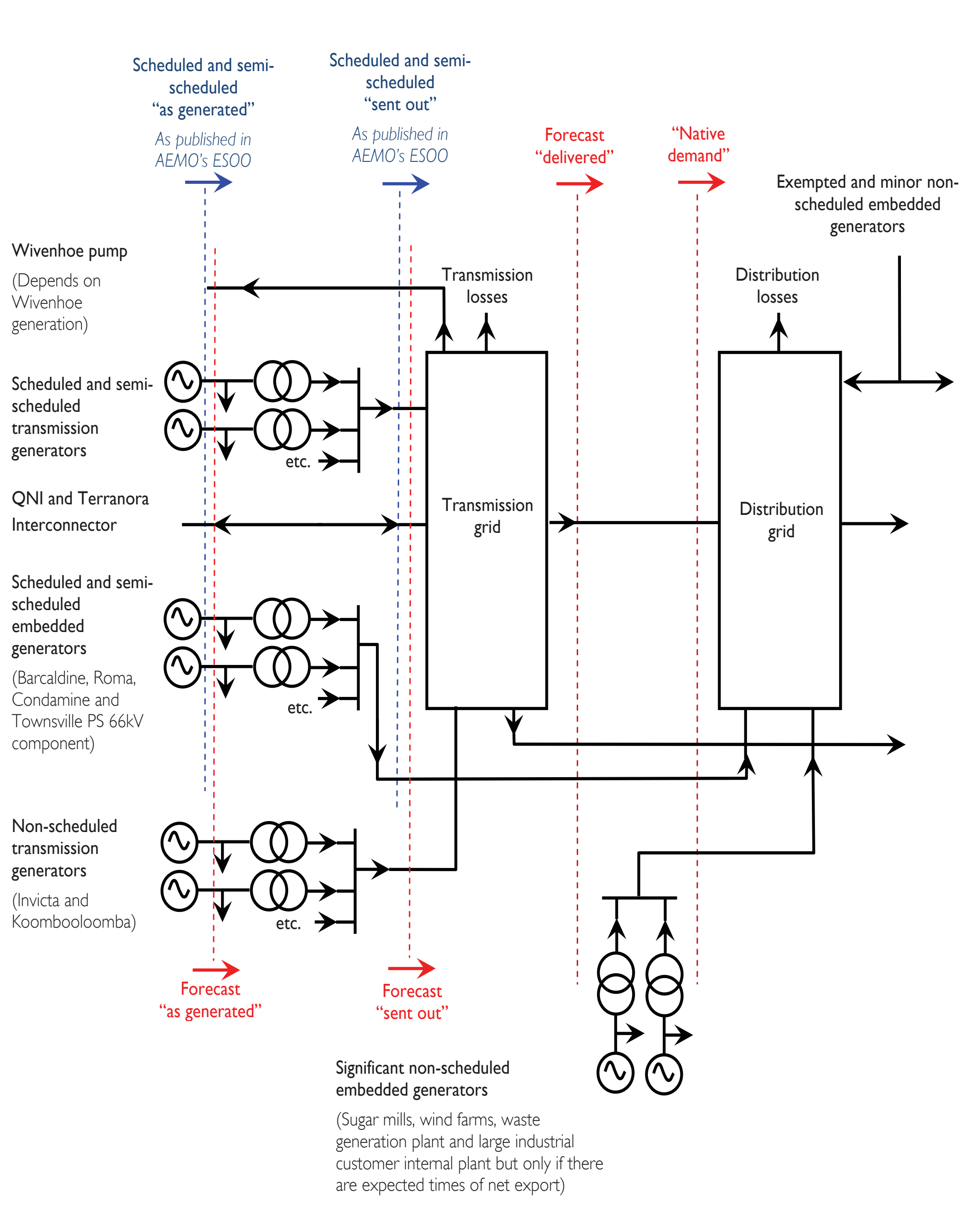
**Table 2.3 Possible large loads excluded from the forecast**

| Zone | Type of plant | Possible load |
|---|---|---|
| Central West (Galilee Basin) | Coal mining load | Up to 600MW |
| Central West and North | Greater than forecast increase in coal mining and railway load | Up to 200MW |
| Gladstone | Aluminium | Up to 800MW |
| Gladstone | LNG load | Up to 250MW |
| Ross | Zinc | Up to 120MW |

### 2.1.3 Load forecast definitions

The relationship between the classes of generation and the forecast quantities in this report is shown in Figure 2.2.

Figure 2.2 Load forecast definitions



## 2.2 Recent energy and demands

### 2.2.1 Recent summers

A summary of recent summer electricity demands, seasonal energy and prevailing weather conditions for South East Queensland is shown in Table 2.4.

Summer 2009/10 in South East Queensland was average in temperature terms. There was no significant period of above average temperatures, which normally result in increased air conditioner use. Summer temperatures in North Queensland were slightly below average, with no significant period of above average temperatures.

The weather and diversity corrected, summer maximum native demand for Queensland has increased by 2.2% from 8,310MW in 2008/09 to 8,489MW in 2009/10.

At the time of Queensland actual peak demand for summer 2009/10, the weather pattern diversity across the State was 95.5% coincidence compared with the previous 10-year average of 95.3% coincidence. The trend of low coincidence at the time of state peak is continuing.

The actual delivered summer energy for Queensland in 2009/10 was 1.7% higher than in summer 2008/09, on a native basis. In South East Queensland, the growth in 2009/10 summer native energy was 2.8% over summer 2008/09.

Recent surveys have shown that air conditioning penetration in South East Queensland will continue to increase over the next five years. Further detail is provided in Appendix A.

**Table 2.4 Comparison of recent South East Queensland summer native demand**

| Summer (1) | Native summer energy GWh (2) | Maximum native demand MW (2) | Prevailing South East Queensland weather summer conditions | Brisbane temperature (3) | | |
|---|---|---|---|---|---|---|
| | | | | Summer average °C | Peak demand day °C | No days > 30.0°C (4) |
| 1999/00 | 4,085 | 2,946 | Mild | 23.1 | 31.9 | 2+1 |
| 2000/01 | 4,352 | 2,977 | Average, dry | 24.9 | 29.9 | 0+2 |
| 2001/02 | 4,694 | 3,120 | Very hot over Christmas holiday period only, dry | 25.9 | 30.4 | 1+6 |
| 2002/03 | 4,746 | 3,383 | Mild | 24.7 | 32.4 | 3 |
| 2003/04 | 5,282 | 3,846 | Sustained very hot and humid in February | 26.1 | 30.3 | 7+1 |
| 2004/05 | 5,373 | 4,024 | Average | 24.9 | 29.4 | 0+2 |
| 2005/06 | 5,917 | 4,141 | Overall a very hot summer, high energy consumption, but a lack of very hot working weekdays | 26.5 | 28.0 | 1 (5) |
| 2006/07 | 5,572 | 4,300 | Mild – a lack of very hot days | 24.2 | 28.3 | 1 |
| 2007/08 | 5,741 | 4,114 | Mild and generally overcast with lower daytime temperatures – no very hot days | 24.1 | 29.7 | 0 |
| 2008/09 | 6,074 | 4,635 | Average and wet – no very hot days | 24.9 | 27.4 | 0 |
| 2009/10 | 6,227 | 4,740 | Average – no very hot days | 25.4 | 29.0 | 0 |

Notes:

(1) In this table, summer includes all the days of December, January and February.

(2) Demands and energy are native from 2006/07, but are 'delivered' for prior years.

(3) Brisbane summer temperature is measured at Amberley. Day temperatures refer to average of daily minimum and maximum to represent the driver for cooling load. Where the previous day is hotter, 25% of this day's average temperature is combined with 75% of the average temperature of the current day. For Amberley 30.0°C is the 50% PoE summer reference temperature.

(4) First or single figure is the number of working days. A second figure is the number of non-working days (that is, weekends, public holidays or the Christmas to New Year holiday period).

(5) The one isolated very hot working day was in early December when general air conditioning demand is not as high as later in summer.

### 2.2.2 Recent winters

A summary of recent winter electricity demands, seasonal energy and prevailing weather conditions for South East Queensland is shown in Table 2.5.

The South East Queensland winter of 2009 was mild. It contained no days cooler than the 50% PoE reference temperature. Peak native demand in South East Queensland for winter 2009 was below that recorded in 2008.

The weather and diversity corrected, winter 2009 maximum native demand for Queensland was 7,219MW which was a reduction from the previous year.

The native winter energy in 2009 fell 1.0% for Queensland, while in South East Queensland it rose marginally. This reduction is attributable to a combination of mild weather conditions and the short period of economic slowdown.

**Table 2.5** Comparison of recent South East Queensland winter native demand

| Winter (1) | Native winter energy GWh (2) | Maximum native demand MW (2) | Prevailing South East Queensland weather winter conditions | Brisbane temperature (3) | | |
|---|---|---|---|---|---|---|
| | | | | Winter average °C | Peak demand day °C | No days <11.0°C (4) |
| 1998 | 3,982 | 2,617 | Mild to warm | 16.5 | 11.9 | 0 |
| 1999 | 4,227 | 2,769 | Mild | 15.3 | 15.5 | 0 |
| 2000 | 4,456 | 2,992 | Cooler than average | 14.3 | 8.8 | 2 |
| 2001 | 4,543 | 2,975 | Mild | 15.0 | 10.1 | 1+2 |
| 2002 | 4,775 | 2,999 | Average | 14.6 | 12.9 | 0+1 |
| 2003 | 4,921 | 3,325 | Mild but one eight day cold snap | 15.0 | 11.0 | 4+1 |
| 2004 | 5,094 | 3,504 | Mild | 15.4 | 11.8 | 0 |
| 2005 | 5,252 | 3,731 | Mild | 15.7 | 10.5 | 2 |
| 2006 | 5,420 | 3,882 | Mild | 15.6 | 13.9 | 0 |
| 2007 | 5,610 | 4,118 | Average to Mild | 15.1 | 10.1 | 3+1 |
| 2008 | 5,734 | 4,341 | Mild | 15.2 | 11.6 | 1 |
| 2009 | 5,743 | 3,981 | Mild | 15.7 | 11.1 | 0 |

Notes:

(1) In this table, winter includes all the days of June, July and August.

(2) Demands and energy are 'native' from 2007, but are 'delivered' for prior years.

(3) Brisbane winter temperature is measured at Archerfield. Day temperatures refer to average of daily minimum and maximum to represent the driver for heating load. Where the previous day is cooler, 25% of this day's average temperature is combined with 75% of the average temperature of the current day. For Archerfield 11.0°C is the 50% PoE winter reference temperature.

(4) First or single figure is the number of working days. A second figure is the number of non-working days (that is, weekends or public holidays).

### 2.2.3 Seasonal growth patterns

Energy delivered to DNSPs for recent summers and winters is shown in Figure 2.3. Figure 2.3 excludes the energy delivered to major industrial customers connected directly to the transmission network, making it indicative of the underlying trend of electricity consumption growth in Queensland.

### 2.2.4 Temperature and diversity correction of demands

Queensland is too large geographically to be accurately described as having a demand that is dependent on a single location's weather. Powerlink and the DNSPs analyse the temperature dependence of demands for all major areas across Queensland. Details of this analysis are outlined in Appendix A.

Queensland Region corrected demands for all winters and summers from 2001 are shown on Figure 2.4. Figure 2.5 shows the same information for South East Queensland alone.

Figure 2.3 Historic native energy to DNSPs in Queensland

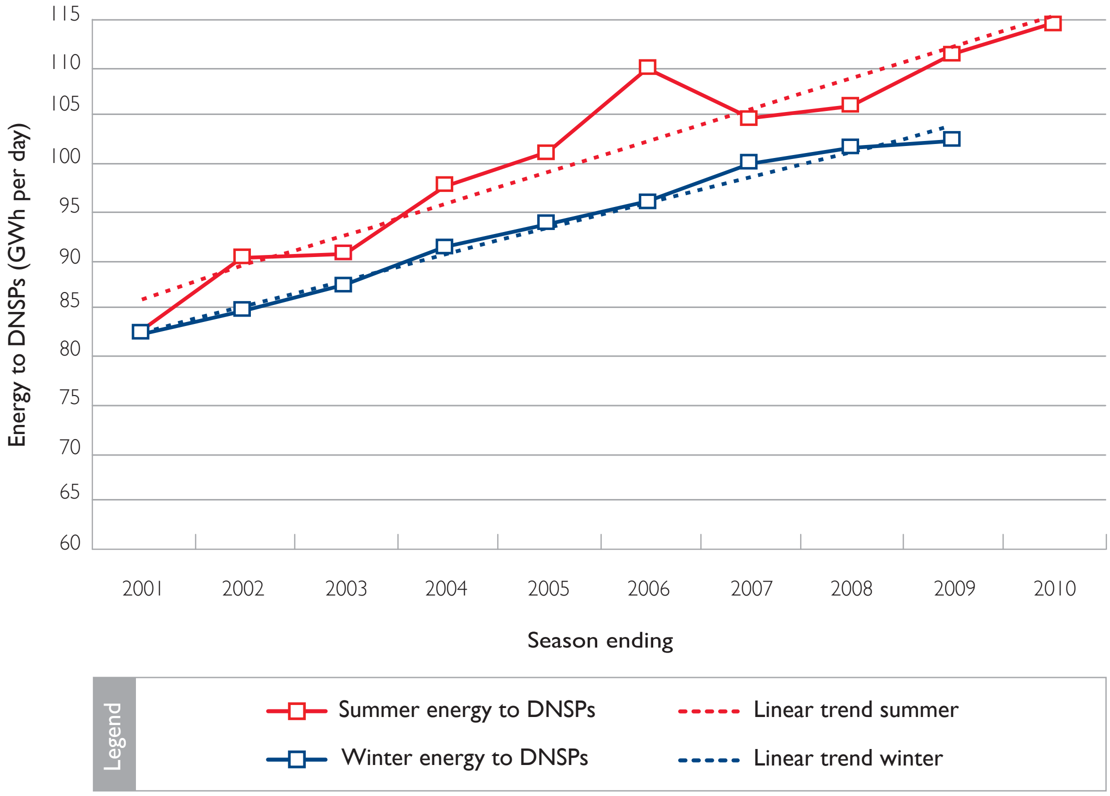



Figure 2.4 Historic native demand for Queensland (including temperature and diversity correction)

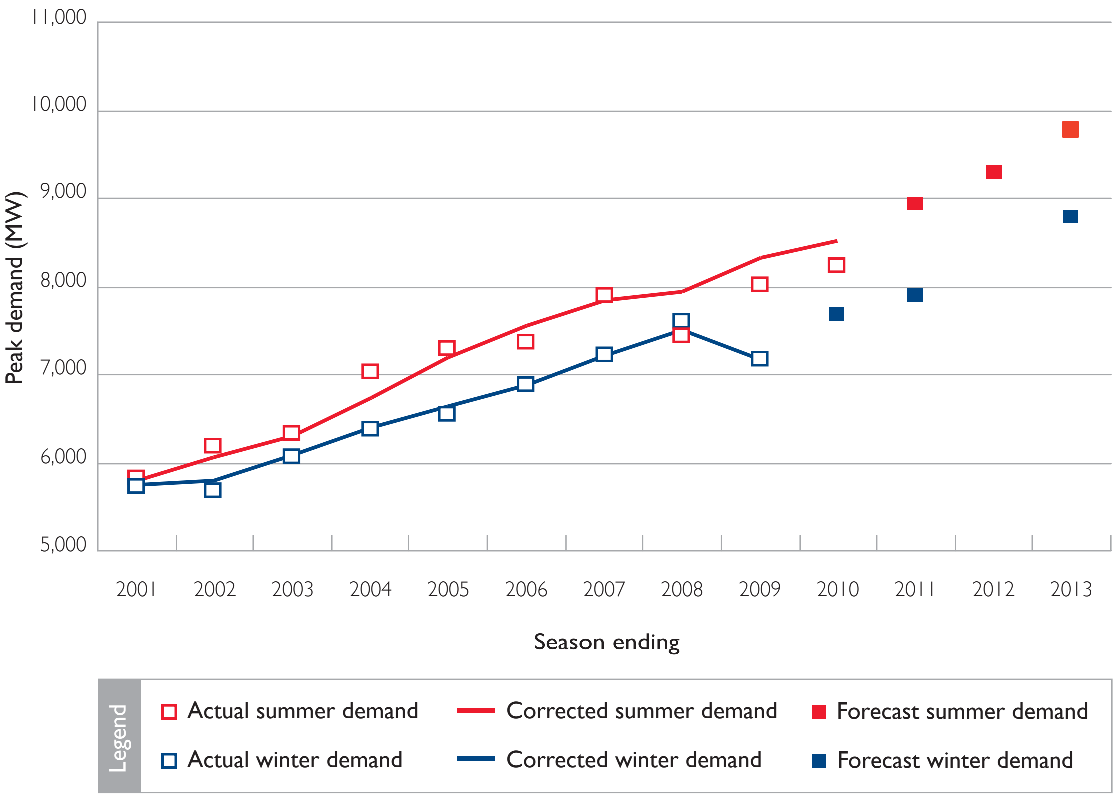
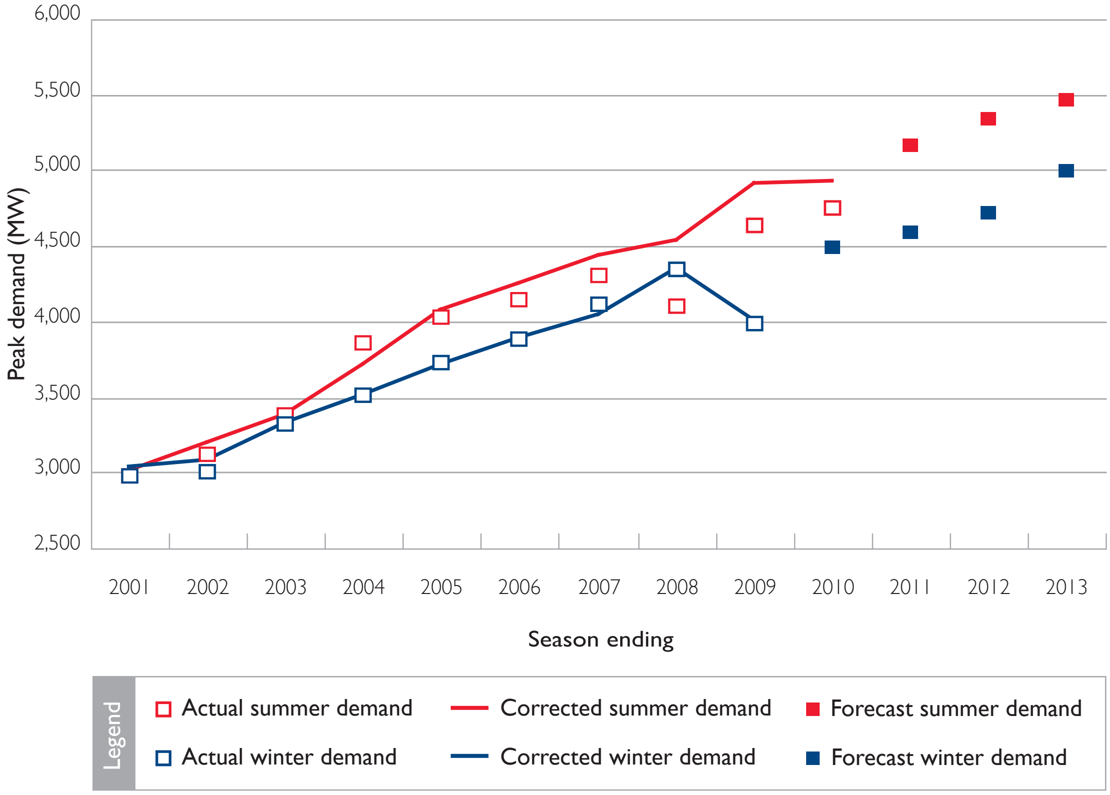


Figure 2.5 Historic native demand for South East Queensland (including temperature correction)



## 2.3 Comparison with the 2009 Annual Planning Report

The major difference in forecasts in this APR compared with the 2009 APR is the emergence of new resource-based loads in the Surat Basin. This load is forecast to increase from 2012/13, having a significant effect on Queensland demand and an even greater effect on energy due to the continuous profile of this load. The compressed timeframe to connect this load means that planning has begun, with a request for information issued in April 2010 and an Application Notice issued recently. This load comprises multiple, dispersed upstream processing facilities, proposed coal mine and related load growth in the service towns. Aside from the impacts arising from the Surat basin LNG forecast, the 2010 demand forecast is slightly lower than the 2009 forecast for the same period, mainly resulting from a slower assumed rate of growth for new coal mine expansion in the Bowen Basin area.

## 2.4 Forecast data

The information pertaining to the forecasts is shown in tables and figures as follows.

### 2.4.1 Energy forecast

Table 2.7, Figure 2.6 and Figure 2.7 show the historical and 10-year forecast of native energy from the transmission network. It also shows native energy for 2008/09 and projected 2009/10, with an adjustment to add to the various outlook forecasts of delivered energy.

### 2.4.2 Summer demand forecast

Table 2.8 and Figure 2.8 show the historical and 10-year Queensland Region summer native demand forecast for each of the three economic outlooks and also for 10%, 50% and 90% PoE weather conditions.

### 2.4.3 Winter demand forecast

Table 2.9 and Figure 2.9 show the historical and 10-year Queensland Region winter native demand forecast for each of the three economic outlooks and also for 10%, 50% and 90% PoE weather conditions.

### 2.4.4 Transmission losses and auxiliaries

Table 2.10 shows the medium growth outlook forecast of average weather winter and summer maximum coincident region electricity delivered demand including estimates of transmission network losses, power station 'sent out' and 'as generated' demands.

Table 2.11 shows the medium growth forecast of one in 10-year or 10% PoE weather winter and summer maximum coincident region electricity delivered demand including estimates of transmission network losses, power station 'sent out' and 'as generated' demands.

### 2.4.5 Load profiles

Figure 2.10 shows the daily load profile on the days of the recent 2009 winter and 2009/10 summer Queensland Region peak demand delivered from the transmission network and from embedded scheduled generators. Figure 2.11 shows the cumulative annual load duration curve for the completed 2008/09 financial year.

### 2.4.6 Connection point forecasts

The forecast loading at connection points to Powerlink's network for summer and winter are shown in Appendix B.

The 'projected actual' forecast for 2009/10 accounts for actual energy delivery in the first eight months of the financial year, that is, up to the end of February 2010, plus forecast energy from March 2010 to the end of June 2010 which is based on statistical "as generated" data, and a nominal growth rate applied to equivalent months in 2009.

In summary, 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 2.6.

**Table 2.6** Average annual growth rate over next 10 years

| | Economic growth outlooks | | |
|---|---|---|---|
| | Low | Medium | High |
| Queensland Gross State Product | 2.6% | 3.6% | 4.6% |
| Native energy (1) | 1.7% | 4.0% | 6.8% |
| Native summer peak demand (50% PoE) (2) | 2.4% | 4.2% | 6.6% |
| Native winter peak demand (50% PoE) (2) | 1.7% | 4.3% | 7.2% |

Notes:

(1) This is energy delivered from the transmission network, embedded scheduled generators, and significant embedded non-scheduled generators. It does not include the output from any exempted generators, nor from embedded non-scheduled generators which never, or rarely, expect to have times of net export into the grid.

(2) This is the half hour average power delivered from the transmission network, embedded scheduled generators, and significant embedded non-scheduled generators. It does not include the output from any exempted generators, nor from embedded non-scheduled generators which never, or rarely, expect to have times of net export into the grid.

**Table 2.7** Annual native energy GWh – actual and forecast

| Year | Sent out (1) | | | Transmission losses (2) | | | Native energy | | | Delivered energy adjustment (3) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2000/01 | | 39,820 | | | 1,642 | | | 38,179 | | 0 |
| 2001/02 | | 41,889 | | | 1,994 | | | 39,895 | | 0 |
| 2002/03 | | 42,705 | | | 1,856 | | | 40,850 | | 0 |
| 2003/04 | | 44,593 | | | 1,943 | | | 42,650 | | 0 |
| 2004/05 | | 45,714 | | | 1,825 | | | 43,890 | | 0 |
| 2005/06 | | 47,384 | | | 1,823 | | | 45,561 | | 0 |
| 2006/07 | | 47,751 | | | 1,844 | | | 46,186 | | -280 |
| 2007/08 | | 47,910 | | | 1,785 | | | 47,046 | | -921 |
| 2008/09 | | 49,104 | | | 1,801 | | | 48,336 | | -1,033 |
| 2009/10 (4) | | 49,581 | | | 1,834 | | | 49,183 | | -1,436 |
| Forecast | Low | Med | High | Low | Med | High | Low | Med | High | |
| 2010/11 | 50,368 | 52,184 | 54,172 | 1,835 | 1,931 | 2,037 | 49,837 | 51,557 | 53,438 | -1,303 |
| 2011/12 | 51,074 | 54,297 | 58,096 | 1,840 | 2,009 | 2,214 | 50,538 | 53,592 | 57,185 | -1,303 |
| 2012/13 | 52,395 | 57,430 | 62,551 | 1,862 | 2,125 | 2,403 | 51,836 | 56,608 | 61,451 | -1,303 |
| 2013/14 | 54,070 | 60,879 | 67,722 | 1,899 | 2,253 | 2,627 | 53,475 | 59,930 | 66,399 | -1,303 |
| 2014/15 | 55,062 | 64,207 | 72,740 | 1,903 | 2,376 | 2,845 | 54,462 | 63,135 | 71,198 | -1,303 |
| 2015/16 | 55,946 | 67,354 | 78,207 | 1,906 | 2,492 | 3,093 | 55,343 | 66,165 | 76,417 | -1,303 |
| 2016/17 | 56,416 | 69,122 | 82,049 | 1,907 | 2,558 | 3,278 | 55,812 | 67,868 | 80,075 | -1,303 |
| 2017/18 | 57,628 | 70,548 | 85,636 | 1,949 | 2,610 | 3,456 | 56,983 | 69,241 | 83,484 | -1,303 |
| 2018/19 | 58,270 | 72,425 | 93,915 | 1,957 | 2,680 | 3,904 | 57,616 | 71,049 | 91,314 | -1,303 |
| 2019/20 | 58,974 | 74,302 | 98,086 | 1,968 | 2,749 | 4,111 | 58,309 | 72,857 | 95,278 | -1,303 |

Notes:

(1) This is the input energy that is sent into the Queensland network from Queensland scheduled generators, Invicta Mill and Koombooloomba (transmission connected but non-scheduled), and net imports to Queensland. The energy to Wivenhoe Power Station pumps is not included in this table.

(2) The table assumes reduction in losses due to future transmission works.

(3) The difference between native and delivered demand before summer 2006/07 is negligible. Accordingly, native energy is assumed to be equal to delivered energy prior to the 2006/07 year.

(4) These projected end of financial year values are based on revenue and statistical metering data until February 2010.

Figure 2.6 History and forecasts of annual native energy for medium economic outlooks

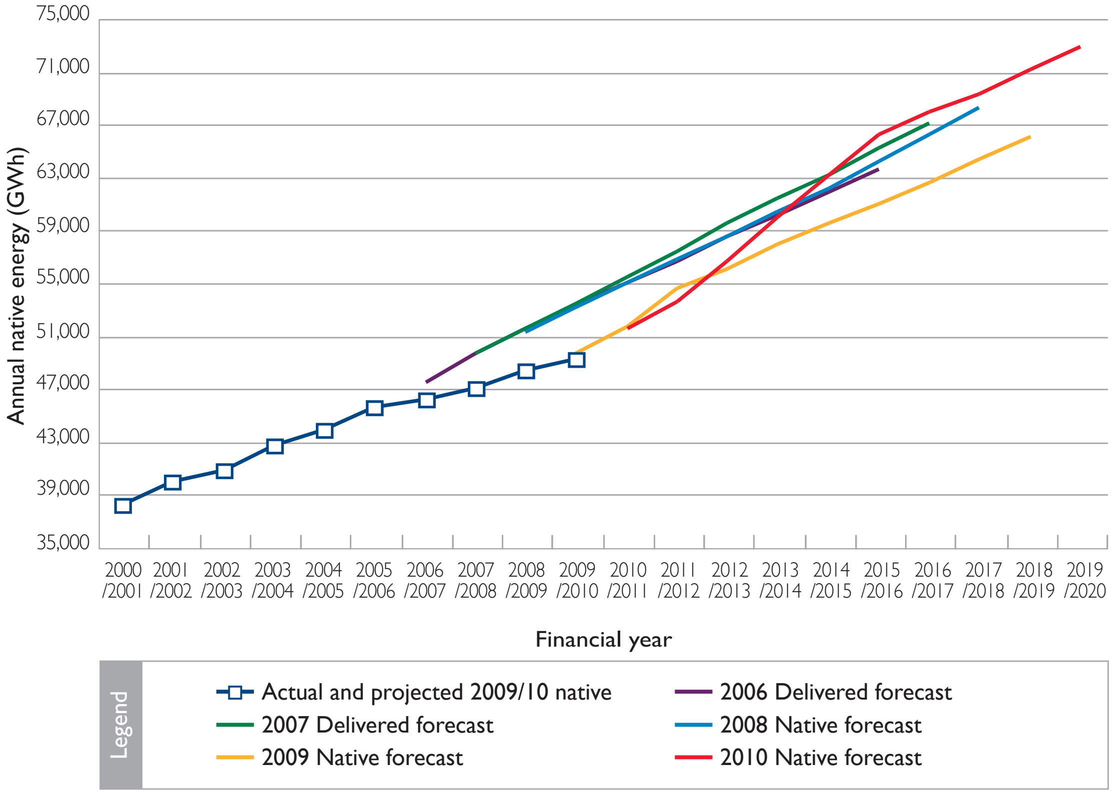



Figure 2.7 History and Forecast of native energy for low, medium and high economic outlooks

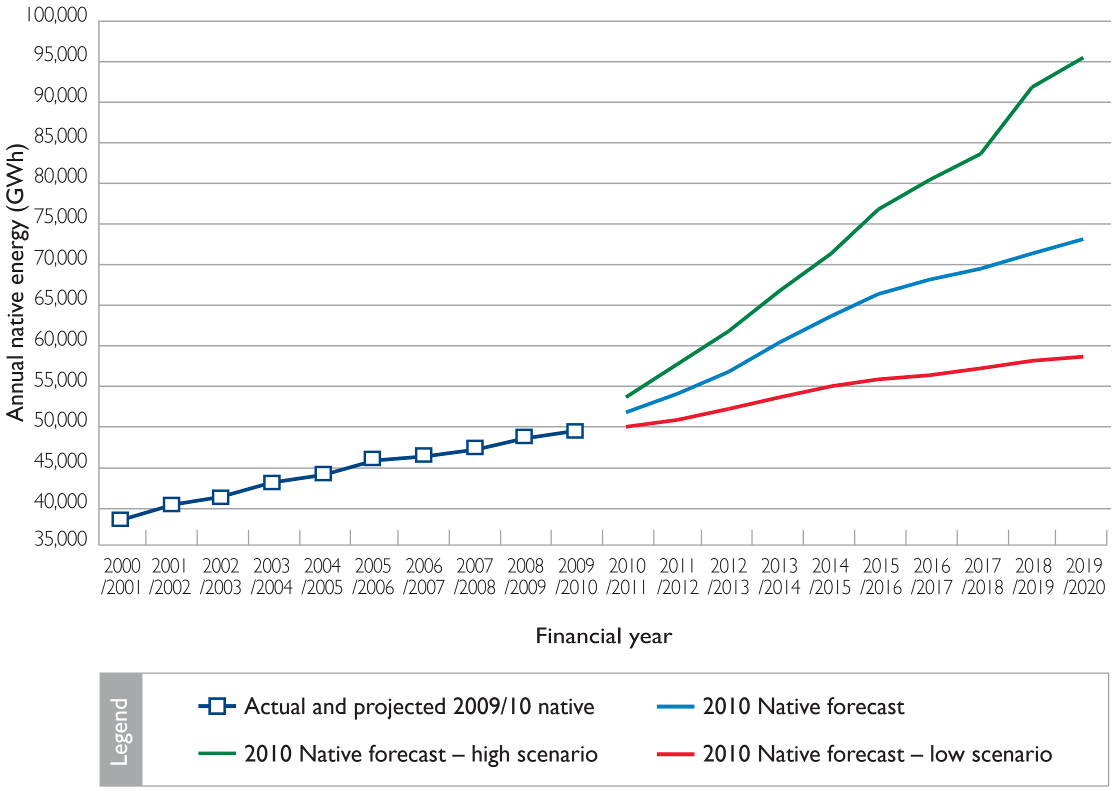


Table 2.8 Peak summer native demand (MW) with delivered demand adjustment

| Summer | Actual native | Actual delivered (1) | Weather and diversity corrected native demand | Delivered demand adjustment |
|---|---|---|---|---|
| 2000/01 | 5,830 | 5,830 | 5,772 | 0 |
| 2001/02 | 6,183 | 6,183 | 6,046 | 0 |
| 2002/03 | 6,336 | 6,336 | 6,275 | 0 |
| 2003/04 | 7,020 | 7,020 | 6,718 | 0 |
| 2004/05 | 7,282 | 7,282 | 7,188 | 0 |
| 2005/06 | 7,373 | 7,373 | 7,533 | 0 |
| 2006/07 | 7,889 | 7,832 | 7,830 | -57 |
| 2007/08 | 7,464 | 7,357 | 7,910 | -107 |
| 2008/09 | 8,021 | 7,922 | 8,310 | -99 |
| 2009/10 | 8,293 | 8,117 | 8,489 | -176 |

| Summer native demand forecasts | Low growth outlook | | | Medium growth outlook | | | High growth outlook | | | Delivered demand adjustment |
|---|---|---|---|---|---|---|---|---|---|---|
| | 10% PoE | 50% PoE | 90% PoE | 10% PoE | 50% PoE | 90% PoE | 10% PoE | 50% PoE | 90% PoE | |
| 2010/11 | 9,179 | 8,735 | 8,465 | 9,379 | 8,924 | 8,647 | 9,609 | 9,142 | 8,858 | -176 |
| 2011/12 | 9,341 | 8,890 | 8,615 | 9,753 | 9,280 | 8,992 | 10,233 | 9,738 | 9,435 | -176 |
| 2012/13 | 9,587 | 9,129 | 8,850 | 10,252 | 9,765 | 9,467 | 10,901 | 10,384 | 10,067 | -176 |
| 2013/14 | 9,987 | 9,516 | 9,229 | 10,907 | 10,400 | 10,090 | 11,790 | 11,245 | 10,910 | -176 |
| 2014/15 | 10,190 | 9,714 | 9,425 | 11,450 | 10,930 | 10,613 | 12,559 | 11,992 | 11,644 | -176 |
| 2015/16 | 10,395 | 9,909 | 9,614 | 11,984 | 11,447 | 11,120 | 13,308 | 12,714 | 12,351 | -176 |
| 2016/17 | 10,648 | 10,148 | 9,846 | 12,437 | 11,877 | 11,537 | 14,030 | 13,404 | 13,020 | -176 |
| 2017/18 | 10,982 | 10,468 | 10,157 | 12,799 | 12,219 | 11,868 | 14,668 | 14,011 | 13,609 | -176 |
| 2018/19 | 11,127 | 10,606 | 10,292 | 13,113 | 12,520 | 12,160 | 15,706 | 15,024 | 14,607 | -176 |
| 2019/20 | 11,271 | 10,744 | 10,426 | 13,427 | 12,821 | 12,453 | 16,743 | 16,037 | 15,605 | -176 |

Note:

(1) The difference between native and delivered demand before summer 2006/07 is negligible. Accordingly temperature and diversity corrections have been calculated on delivered demand prior to summer 2006/07.

Figure 2.8 Queensland Region summer peak native demand

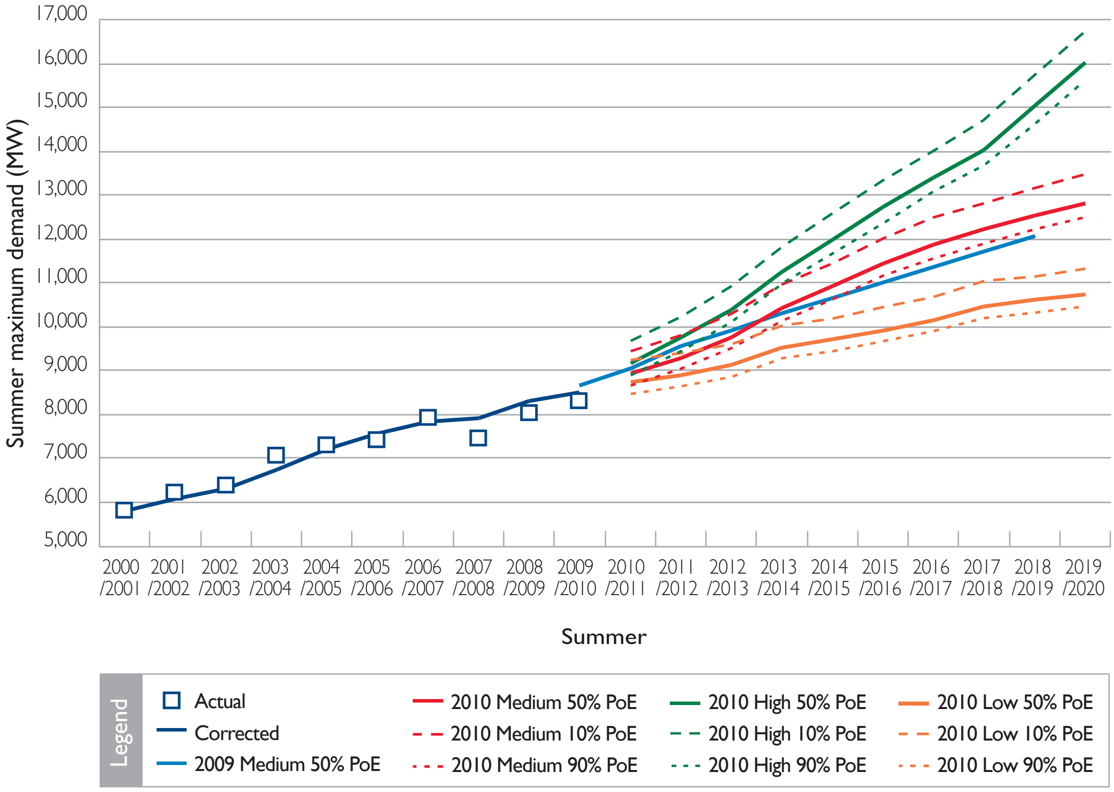


**Table 2.9** Peak winter native demand (MW) with delivered demand adjustment

| Winter | Actual native | | | Actual delivered (1) | | | Weather and diversity corrected native demand | | | Delivered demand adjustment |
|---|---|---|---|---|---|---|---|---|---|---|
| 2001 | 5,731 | | | 5,731 | | | 5,742 | | | 0 |
| 2002 | 5,671 | | | 5,671 | | | 5,795 | | | 0 |
| 2003 | 6,066 | | | 6,066 | | | 6,082 | | | 0 |
| 2004 | 6,366 | | | 6,366 | | | 6,389 | | | 0 |
| 2005 | 6,553 | | | 6,553 | | | 6,646 | | | 0 |
| 2006 | 6,882 | | | 6,882 | | | 6,873 | | | 0 |
| 2007 | 7,224 | | | 7,166 | | | 7,238 | | | -58 |
| 2008 | 7,593 | | | 7,497 | | | 7,544 | | | -96 |
| 2009 | 7,165 | | | 7,049 | | | 7,219 | | | -116 |
| Winter native demand forecasts | Low growth outlook | | | Medium growth outlook | | | High growth outlook | | | |
| | 10% PoE | 50% PoE | 90% PoE | 10% PoE | 50% PoE | 90% PoE | 10% PoE | 50% PoE | 90% PoE | |
| 2010 | 7,996 | 7,889 | 7,734 | 7,788 | 7,683 | 7,533 | 7,626 | 7,524 | 7,377 | -141 |
| 2011 | 8,507 | 8,392 | 8,228 | 8,007 | 7,900 | 7,745 | 7,618 | 7,517 | 7,370 | -141 |
| 2012 | 9,099 | 8,975 | 8,801 | 8,363 | 8,251 | 8,091 | 7,739 | 7,636 | 7,488 | -141 |
| 2013 | 9,920 | 9,787 | 9,599 | 8,905 | 8,788 | 8,618 | 8,034 | 7,928 | 7,775 | -141 |
| 2014 | 10,860 | 10,719 | 10,515 | 9,505 | 9,383 | 9,205 | 8,297 | 8,190 | 8,033 | -141 |
| 2015 | 11,665 | 11,517 | 11,302 | 10,006 | 9,880 | 9,696 | 8,420 | 8,313 | 8,156 | -141 |
| 2016 | 12,391 | 12,236 | 12,010 | 10,410 | 10,282 | 10,092 | 8,460 | 8,353 | 8,196 | -141 |
| 2017 | 13,108 | 12,943 | 12,705 | 10,753 | 10,621 | 10,425 | 8,632 | 8,523 | 8,363 | -141 |
| 2018 | 13,775 | 13,602 | 13,352 | 11,017 | 10,881 | 10,681 | 8,775 | 8,665 | 8,503 | -141 |
| 2019 | 14,925 | 14,743 | 14,475 | 11,332 | 11,193 | 10,987 | 8,865 | 8,755 | 8,592 | -141 |

Note:

(1) The difference between native and delivered demand before winter 2007 is negligible. Accordingly, temperature and diversity corrections have been calculated on delivered demand prior to winter 2007.

Figure 2.9 Queensland Region winter peak native demand

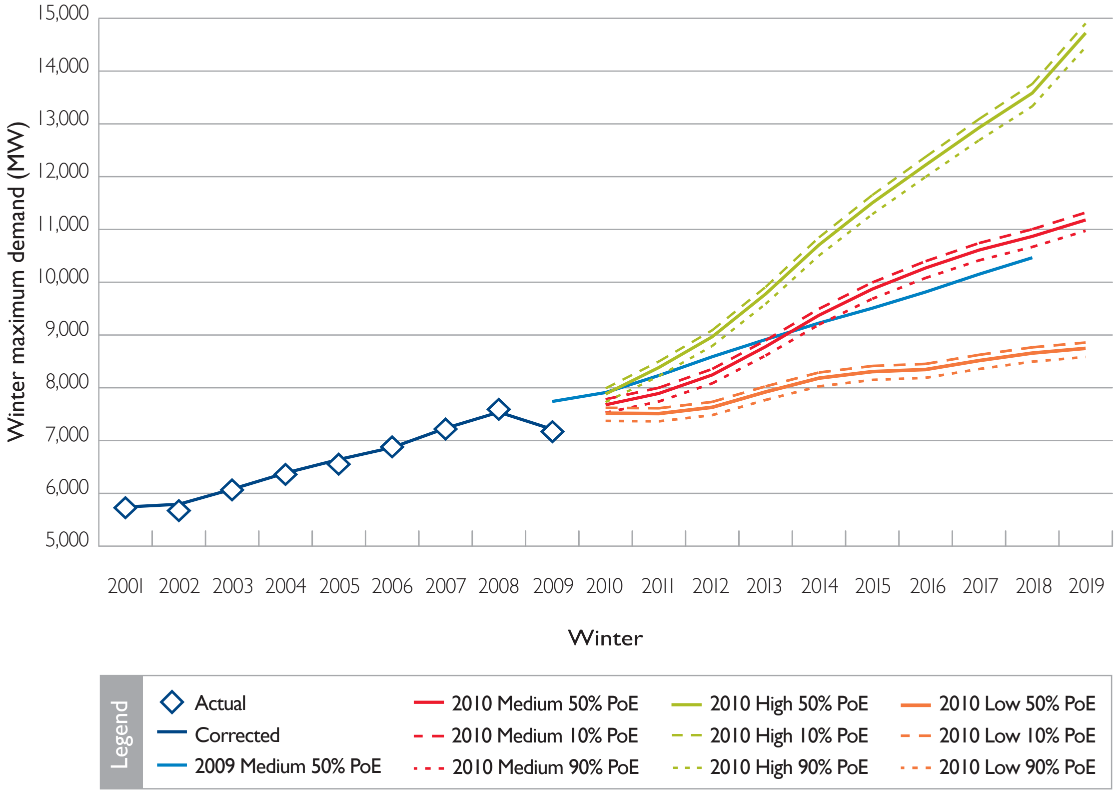


**Table 2.10** Maximum delivered, 'sent out' and 'as generated' Queensland Region demand (MW) – 50% PoE delivered forecast

| | Station 'as generated' demand | Station auxilliaries and losses | Station 'sent out' demand | Transmission losses | Delivered from network demand (1) |
|---|---|---|---|---|---|
| Winter state peak | | | | | |
| 2010 | 8,471 | 604 | 7,868 | 325 | 7,543 |
| 2011 | 8,725 | 622 | 8,103 | 344 | 7,759 |
| 2012 | 9,133 | 651 | 8,482 | 372 | 8,110 |
| 2013 | 9,737 | 694 | 9,043 | 397 | 8,647 |
| 2014 | 10,408 | 742 | 9,666 | 424 | 9,242 |
| 2015 | 10,968 | 782 | 10,186 | 447 | 9,740 |
| 2016 | 11,420 | 814 | 10,606 | 465 | 10,141 |
| 2017 | 11,802 | 841 | 10,961 | 481 | 10,480 |
| 2018 | 12,095 | 862 | 11,233 | 493 | 10,740 |
| 2019 | 12,447 | 887 | 11,559 | 507 | 11,052 |
| Summer state peak | | | | | |
| 2010/11 | 9,837 | 626 | 9,211 | 463 | 8,748 |
| 2011/12 | 10,241 | 651 | 9,589 | 485 | 9,104 |
| 2012/13 | 10,748 | 684 | 10,064 | 475 | 9,589 |
| 2013/14 | 11,460 | 729 | 10,731 | 506 | 10,224 |
| 2014/15 | 12,054 | 767 | 11,287 | 533 | 10,754 |
| 2015/16 | 12,633 | 804 | 11,830 | 558 | 11,271 |
| 2016/17 | 13,116 | 834 | 12,281 | 580 | 11,702 |
| 2017/18 | 13,499 | 859 | 12,640 | 597 | 12,044 |
| 2018/19 | 13,836 | 880 | 12,956 | 612 | 12,344 |
| 2019/20 | 14,173 | 902 | 13,272 | 626 | 12,645 |

Note:

(1) 'Delivered from network demand' includes the demand taken directly from the transmission network as well as net power output from embedded scheduled generators (currently Condamine, Barcaldine, Roma and the 66kV output component of Townsville power stations).

**Table 2.11** Maximum delivered, 'sent out' and 'as generated' Queensland Region demand (MW) – 10% PoE delivered forecast

| | Station 'as generated' demand | Station auxilliaries and losses | Station 'sent out' demand | Transmission losses | Delivered from network demand (1) |
|---|---|---|---|---|---|
| Winter state peak | | | | | |
| 2010 | 8,588 | 612 | 7,976 | 329 | 7,647 |
| 2011 | 8,845 | 631 | 8,215 | 349 | 7,866 |
| 2012 | 9,260 | 660 | 8,600 | 377 | 8,223 |
| 2013 | 9,870 | 704 | 9,167 | 402 | 8,765 |
| 2014 | 10,546 | 752 | 9,794 | 430 | 9,365 |
| 2015 | 11,109 | 792 | 10,317 | 452 | 9,865 |
| 2016 | 11,564 | 824 | 10,740 | 471 | 10,269 |
| 2017 | 11,951 | 852 | 11,099 | 487 | 10,612 |
| 2018 | 12,248 | 873 | 11,375 | 499 | 10,876 |
| 2019 | 12,603 | 898 | 11,705 | 513 | 11,191 |
| Summer state peak | | | | | |
| 2010/11 | 10,349 | 658 | 9,690 | 487 | 9,203 |
| 2011/12 | 10,773 | 685 | 10,087 | 510 | 9,577 |
| 2012/13 | 11,294 | 718 | 10,575 | 499 | 10,076 |
| 2013/14 | 12,028 | 765 | 11,263 | 532 | 10,731 |
| 2014/15 | 12,637 | 804 | 11,833 | 558 | 11,274 |
| 2015/16 | 13,235 | 842 | 12,393 | 585 | 11,808 |
| 2016/17 | 13,743 | 874 | 12,869 | 607 | 12,261 |
| 2017/18 | 14,148 | 900 | 13,248 | 625 | 12,623 |
| 2018/19 | 14,501 | 922 | 13,578 | 641 | 12,937 |
| 2019/20 | 14,853 | 945 | 13,908 | 656 | 13,251 |

Note:

(1) 'Delivered from network demand' includes the demand taken directly from the transmission network as well as net power output from embedded scheduled generators (currently Condamine, Barcaldine, Roma and the 66kV output component of Townsville power stations).

## 2.5 Zone forecasts

The 10 geographical zones referred to throughout this report are defined in Table 2.12.

**Table 2.12 Zone definitions**

| Zone | Area covered |
|---|---|
| Far North | North of Tully, including Chalumbin |
| Ross | North of Proserpine and Collinsville, including Tully, but excluding the Far North zone |
| North | North of Broadsound and Dysart, including Proserpine and Collinsville, but 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 | Specifically, the Powerlink transmission network connecting Gladstone Power Station, Callemondah (railway supply), Gladstone South, QAL supply, Wurdong and Boyne Smelter supply. |
| Wide Bay | Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie |
| Bulli | Goondiwindi (Waggamba) load and the 275/330kV network south of Braemar and west of Millmerran |
| South West | Tarong and Middle Ridge load areas west of Postmans Ridge |
| Moreton | South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone |
| Gold Coast | South of Coomera to the Queensland/New South Wales border |

It is important to note that each zone normally experiences its own zone peak demand, which is usually greater than that shown in Tables 2.16 to 2.19, as the zone peak typically does not coincide with the time of maximum demand for the whole Queensland Region.

Table 2.13 shows the average ratio of forecast zone peak native demand to zone native demand at the time of forecast Queensland Region peak demands. These values can be used to multiply demands in Tables 2.16 to 2.19 to estimate each zone's individual peak demand, which are not necessarily coincident with the time of Queensland Region peak demand. The ratios are based on historical trends and future expectations of customers.

Table 2.13 Average ratio of zone peak native demand to zone native demand at time of Queensland Region peak

| Zone | Winter | Summer |
|---|---|---|
| Far North | 1.17 | 1.14 |
| Ross | 1.27 | 1.18 |
| North | 1.17 | 1.13 |
| Central West | 1.09 | 1.06 |
| Gladstone | 1.00 | 1.01 |
| Wide Bay | 1.09 | 1.11 |
| Bulli | 1.00 | 1.02 |
| South West | 1.00 | 1.02 |
| Moreton | 1.00 | 1.02 |
| Gold Coast | 1.00 | 1.02 |

Tables 2.14 and 2.15 show the forecast of energy supplied from the transmission network and embedded scheduled generators for the medium economic outlook for each of the 10 zones in the Queensland Region. Forecasts are presented as delivered demand and native demand.

Tables 2.16 and 2.17 show the forecast of winter demand delivered from the transmission network and embedded scheduled generators (coincident with the Queensland Region winter peak) for each of the 10 zones within Queensland. It is based on the medium economic outlook and average winter weather. Forecasts are presented as delivered demand and native demand.

Tables 2.18 and 2.19 show the forecast of summer demand delivered from the transmission network and embedded scheduled generators (coincident with the Queensland Region summer peak) for each of the 10 zones within Queensland. It is based on the medium economic outlook and average summer weather. Forecasts are presented as delivered demand and native demand.

**Table 2.14 Annual delivered energy by zone**

Actual and forecast annual delivered energy (GWh) delivered from the transmission network including from embedded scheduled generators in each zone for the medium economic outlook is shown below. This includes reduction effects of non-scheduled embedded generators.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2002/03 | 1,549 | 2,934 | 2,296 | 3,109 | 9,098 | 1,256 | 1,738 | | 16,149 | 2,721 | 40,850 |
| 2003/04 | 1,631 | 3,095 | 2,397 | 3,174 | 9,285 | 1,327 | 1,828 | | 16,984 | 2,942 | 42,662 |
| 2004/05 | 1,673 | 3,010 | 2,542 | 3,269 | 9,452 | 1,419 | 1,943 | | 17,548 | 3,034 | 43,890 |
| 2005/06 | 1,745 | 2,937 | 2,571 | 3,363 | 9,707 | 1,468 | 2,092 | | 18,472 | 3,253 | 45,609 |
| 2006/07 | 1,770 | 3,087 | 2,733 | 3,163 | 9,945 | 1,461 | 2,047 | | 18,470 | 3,225 | 45,900 |
| 2007/08 | 1,818 | 3,191 | 2,728 | 3,165 | 10,058 | 1,399 | 1,712 | 87 | 18,683 | 3,283 | 46,125 |
| 2008/09 | 1,851 | 3,168 | 2,779 | 3,191 | 10,076 | 1,430 | 1,773 | 94 | 19,533 | 3,408 | 47,303 |
| Projected 2009/10 | 1,819 | 3,408 | 2,645 | 3,238 | 10,167 | 1,454 | 1,752 | 89 | 19,744 | 3,529 | 47,845 |
| Forecasts | | | | | | | | | | | |
| 2010/11 | 2,087 | 3,950 | 2,801 | 3,266 | 10,445 | 1,644 | 1,829 | 95 | 20,549 | 3,587 | 50,253 |
| 2011/12 | 2,137 | 4,068 | 2,909 | 3,829 | 10,580 | 1,707 | 1,975 | 96 | 21,273 | 3,713 | 52,288 |
| 2012/13 | 2,202 | 4,176 | 3,218 | 3,959 | 11,016 | 1,754 | 2,059 | 1,007 | 22,061 | 3,851 | 55,305 |
| 2013/14 | 2,248 | 4,242 | 3,581 | 4,094 | 11,195 | 1,811 | 3,211 | 1,607 | 22,678 | 3,959 | 58,626 |
| 2014/15 | 2,295 | 4,341 | 3,920 | 4,169 | 11,373 | 1,855 | 4,404 | 2,208 | 23,213 | 4,052 | 61,831 |
| 2015/16 | 2,343 | 4,407 | 4,202 | 4,210 | 11,747 | 1,903 | 5,618 | 2,209 | 24,028 | 4,194 | 64,861 |
| 2016/17 | 2,391 | 4,504 | 4,361 | 4,254 | 11,988 | 1,946 | 5,926 | 2,209 | 24,678 | 4,308 | 66,564 |
| 2017/18 | 2,440 | 4,579 | 4,483 | 4,308 | 12,231 | 2,000 | 5,931 | 2,209 | 25,335 | 4,423 | 67,938 |
| 2018/19 | 2,488 | 4,645 | 4,584 | 4,352 | 12,481 | 2,033 | 6,292 | 2,209 | 26,106 | 4,557 | 69,745 |
| 2019/20 | 2,536 | 4,712 | 4,684 | 4,396 | 12,730 | 2,065 | 6,653 | 2,209 | 26,876 | 4,692 | 71,553 |

### Table 2.15 Annual native energy by zone

Actual and forecast annual native energy (GWh) delivered from the transmission network, embedded scheduled and significant non-scheduled generators in each zone for the medium economic outlook are shown below. Native demand for years prior to 2006/07 is the same as delivered demand. This is due to insignificant amounts of non-scheduled embedded generation online during these periods.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2006/07 | 1,770 | 3,141 | 2,761 | 3,270 | 9,945 | 1,461 | 2,068 | | 18,545 | 3,225 | 46,186 |
| 2007/08 | 1,818 | 3,371 | 2,771 | 3,455 | 10,058 | 1,413 | 1,970 | 87 | 18,821 | 3,283 | 47,046 |
| 2008/09 | 1,851 | 3,336 | 2,950 | 3,479 | 10,076 | 1,437 | 2,040 | 94 | 19,665 | 3,408 | 48,336 |
| Projected 2009/10 | 1,819 | 3,601 | 2,645 | 3,588 | 10,167 | 1,473 | 1,917 | 89 | 19,889 | 3,529 | 48,719 |
| Forecasts | | | | | | | | | | | |
| 2010/11 | 2,117 | 4,130 | 3,111 | 3,596 | 10,445 | 1,657 | 2,078 | 95 | 20,711 | 3,615 | 51,557 |
| 2011/12 | 2,167 | 4,249 | 3,219 | 4,158 | 10,580 | 1,721 | 2,224 | 96 | 21,435 | 3,742 | 53,592 |
| 2012/13 | 2,232 | 4,357 | 3,529 | 4,289 | 11,016 | 1,768 | 2,308 | 1,007 | 22,224 | 3,879 | 56,608 |
| 2013/14 | 2,278 | 4,422 | 3,892 | 4,423 | 11,195 | 1,824 | 3,460 | 1,607 | 22,840 | 3,987 | 59,930 |
| 2014/15 | 2,325 | 4,522 | 4,230 | 4,498 | 11,373 | 1,869 | 4,653 | 2,208 | 23,375 | 4,081 | 63,135 |
| 2015/16 | 2,374 | 4,587 | 4,512 | 4,540 | 11,747 | 1,916 | 5,867 | 2,209 | 24,190 | 4,223 | 66,165 |
| 2016/17 | 2,422 | 4,684 | 4,672 | 4,584 | 11,988 | 1,960 | 6,175 | 2,209 | 24,840 | 4,336 | 67,868 |
| 2017/18 | 2,470 | 4,759 | 4,793 | 4,638 | 12,231 | 2,013 | 6,180 | 2,209 | 25,497 | 4,451 | 69,241 |
| 2018/19 | 2,518 | 4,826 | 4,894 | 4,681 | 12,481 | 2,046 | 6,541 | 2,209 | 26,268 | 4,585 | 71,049 |
| 2019/20 | 2,567 | 4,892 | 4,994 | 4,725 | 12,730 | 2,079 | 6,902 | 2,209 | 27,039 | 4,720 | 72,857 |

**Table 2.16 State winter peak delivered demand by zone**

Actual and forecast delivered demand (MW) on the transmission network and embedded scheduled generators in each zone at the time of coincident state winter peak 50% PoE demand for average weather and diversity conditions and medium economic outlook as shown below. This includes reduction effects of non-scheduled embedded generators.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2001 | 184 | 378 | 255 | 442 | 1,019 | 189 | 301 | | 2,475 | 487 | 5,731 |
| 2002 | 163 | 339 | 285 | 383 | 1,055 | 160 | 286 | | 2,548 | 452 | 5,671 |
| 2003 | 177 | 348 | 295 | 412 | 1,009 | 181 | 318 | | 2,825 | 500 | 6,066 |
| 2004 | 206 | 354 | 323 | 425 | 1,092 | 216 | 345 | | 2,867 | 539 | 6,366 |
| 2005 | 192 | 257 | 277 | 431 | 1,081 | 261 | 343 | | 3,146 | 564 | 6,553 |
| 2006 | 207 | 322 | 325 | 409 | 1,157 | 228 | 361 | | 3,279 | 594 | 6,882 |
| 2007 | 219 | 309 | 286 | 442 | 1,165 | 297 | 410 | | 3,449 | 590 | 7,166 |
| 2008 | 216 | 363 | 361 | 432 | 1,161 | 253 | 375 | 17 | 3,654 | 666 | 7,497 |
| 2009 | 195 | 436 | 331 | 410 | 1,123 | 209 | 342 | 19 | 3,383 | 601 | 7,049 |
| Forecasts | | | | | | | | | | | |
| 2010 | 216 | 326 | 318 | 410 | 1,195 | 239 | 342 | 15 | 3,827 | 655 | 7,543 |
| 2011 | 224 | 351 | 317 | 440 | 1,210 | 249 | 364 | 15 | 3,930 | 659 | 7,759 |
| 2012 | 229 | 365 | 335 | 514 | 1,251 | 257 | 394 | 47 | 4,039 | 678 | 8,110 |
| 2013 | 235 | 374 | 365 | 554 | 1,298 | 265 | 439 | 126 | 4,292 | 700 | 8,647 |
| 2014 | 239 | 377 | 405 | 572 | 1,314 | 273 | 618 | 217 | 4,502 | 726 | 9,242 |
| 2015 | 244 | 354 | 444 | 580 | 1,334 | 280 | 803 | 309 | 4,616 | 744 | 9,739 |
| 2016 | 248 | 390 | 478 | 587 | 1,370 | 287 | 991 | 309 | 4,722 | 758 | 10,141 |
| 2017 | 252 | 399 | 495 | 594 | 1,397 | 295 | 1,040 | 309 | 4,917 | 782 | 10,480 |
| 2018 | 257 | 403 | 507 | 602 | 1,426 | 302 | 1,043 | 309 | 5,092 | 799 | 10,740 |
| 2019 | 261 | 408 | 520 | 611 | 1,454 | 310 | 1,047 | 309 | 5,245 | 815 | 10,978 |

**Table 2.17** **State winter peak native demand by zone**

Actual and forecast native demand (MW) on the transmission network, embedded scheduled and significant non-scheduled generators in each zone at the time of coincident state winter peak 50% PoE demand for average weather and diversity conditions and medium economic outlook is shown below. Native demand for winters prior to 2007 is the same as delivered demand due to insignificant amounts of non-scheduled embedded generation online during these periods.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2007 | 219 | 309 | 291 | 467 | 1,165 | 298 | 410 | | 3,475 | 590 | 7,224 |
| 2008 | 216 | 362 | 365 | 470 | 1,161 | 253 | 407 | 17 | 3,676 | 666 | 7,593 |
| 2009 | 195 | 441 | 375 | 449 | 1,123 | 209 | 372 | 19 | 3,381 | 601 | 7,165 |
| Forecasts | | | | | | | | | | | |
| 2010 | 223 | 340 | 363 | 449 | 1,195 | 239 | 372 | 15 | 3,833 | 655 | 7,683 |
| 2011 | 231 | 365 | 362 | 479 | 1,210 | 249 | 394 | 15 | 3,936 | 659 | 7,900 |
| 2012 | 235 | 379 | 380 | 554 | 1,251 | 257 | 424 | 47 | 4,045 | 678 | 8,251 |
| 2013 | 242 | 387 | 410 | 594 | 1,298 | 265 | 441 | 154 | 4,298 | 700 | 8,788 |
| 2014 | 246 | 391 | 450 | 612 | 1,314 | 273 | 620 | 245 | 4,507 | 726 | 9,383 |
| 2015 | 250 | 368 | 488 | 620 | 1,334 | 280 | 806 | 336 | 4,622 | 744 | 9,880 |
| 2016 | 255 | 404 | 523 | 627 | 1,370 | 287 | 993 | 336 | 4,728 | 758 | 10,282 |
| 2017 | 259 | 413 | 540 | 634 | 1,397 | 295 | 1,043 | 337 | 4,922 | 782 | 10,621 |
| 2018 | 263 | 417 | 552 | 642 | 1,426 | 302 | 1,046 | 337 | 5,098 | 799 | 10,881 |
| 2019 | 268 | 421 | 562 | 649 | 309 | 1,453 | 1,103 | 337 | 5,272 | 819 | 11,193 |

**Table 2.18 State summer peak delivered demand by zone**

Actual and forecast delivered demand (MW) on the transmission network and embedded scheduled generators in each zone at the time of coincident state summer 50% PoE peak demand with average weather and diversity conditions and medium economic outlook is shown below. This includes reduction effects of non-scheduled embedded generators.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2001/02 | 278 | 504 | 355 | 436 | 1,040 | 222 | 258 | | 2,644 | 447 | 6,183 |
| 2002/03 | 264 | 410 | 307 | 426 | 1,048 | 200 | 298 | | 2,896 | 488 | 6,336 |
| 2003/04 | 265 | 452 | 318 | 459 | 1,087 | 253 | 339 | | 3,277 | 570 | 7,020 |
| 2004/05 | 277 | 425 | 342 | 482 | 1,107 | 276 | 349 | | 3,415 | 609 | 7,282 |
| 2005/06 | 284 | 447 | 373 | 492 | 1,115 | 292 | 351 | | 3,422 | 596 | 7,373 |
| 2006/07 | 329 | 461 | 452 | 509 | 1,164 | 296 | 375 | | 3,635 | 611 | 7,832 |
| 2007/08 | 292 | 372 | 386 | 476 | 1,193 | 243 | 315 | 15 | 3,465 | 600 | 7,357 |
| 2008/09 | 280 | 424 | 317 | 459 | 1,178 | 278 | 367 | 19 | 3,933 | 667 | 7,922 |
| 2009/10 | 317 | 473 | 414 | 503 | 1,177 | 269 | 301 | 11 | 3,923 | 729 | 8,117 |
| Forecasts | | | | | | | | | | | |
| 2010/11 | 347 | 467 | 407 | 521 | 1,212 | 267 | 376 | 18 | 4,422 | 711 | 8,748 |
| 2011/12 | 358 | 492 | 429 | 597 | 1,220 | 276 | 401 | 18 | 4,561 | 750 | 9,104 |
| 2012/13 | 372 | 510 | 463 | 641 | 1,298 | 283 | 444 | 132 | 4,700 | 746 | 9,589 |
| 2013/14 | 382 | 521 | 508 | 662 | 1,317 | 291 | 625 | 224 | 4,923 | 772 | 10,224 |
| 2014/15 | 393 | 539 | 552 | 673 | 1,337 | 298 | 809 | 315 | 5,047 | 792 | 10,754 |
| 2015/16 | 403 | 551 | 592 | 683 | 1,375 | 305 | 996 | 315 | 5,234 | 817 | 11,271 |
| 2016/17 | 414 | 567 | 613 | 693 | 1,402 | 312 | 1,046 | 315 | 5,491 | 848 | 11,702 |
| 2017/18 | 424 | 580 | 629 | 704 | 1,431 | 320 | 1,050 | 315 | 5,718 | 872 | 12,044 |
| 2018/19 | 435 | 593 | 641 | 714 | 1,459 | 326 | 1,108 | 316 | 5,864 | 888 | 12,344 |
| 2019/20 | 445 | 605 | 654 | 724 | 1,488 | 332 | 1,166 | 316 | 6,011 | 904 | 12,645 |

**Table 2.19 State summer peak native demand by zone**

Actual and forecast native demand (MW) on the transmission network, embedded scheduled and significant non-scheduled generators in each zone at the time of coincident state summer 50% PoE peak demand with average weather and diversity conditions and medium economic outlook is shown below. Native demand for summers prior to 2006/07 is the same as delivered demand due to insignificant amounts of non-scheduled embedded generation online during these periods.

| Year | Far North | Ross | North | Central West | Gladstone | Wide Bay | South West | Bulli | Moreton | Gold Coast | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Actuals | | | | | | | | | | | |
| 2006/07 | 329 | 492 | 457 | 527 | 1,164 | 297 | 376 | | 3,636 | 611 | 7,889 |
| 2007/08 | 292 | 404 | 390 | 488 | 1,193 | 243 | 326 | 15 | 3,513 | 600 | 7,464 |
| 2008/09 | 280 | 423 | 331 | 486 | 1,178 | 278 | 397 | 17 | 3,964 | 667 | 8,021 |
| 2009/10 | 317 | 504 | 453 | 536 | 1,177 | 269 | 331 | 11 | 3,965 | 729 | 8,293 |
| Forecasts | | | | | | | | | | | |
| 2010/11 | 353 | 497 | 449 | 556 | 1,212 | 269 | 403 | 17 | 4,456 | 711 | 8,924 |
| 2011/12 | 364 | 522 | 471 | 632 | 1,220 | 277 | 429 | 17 | 4,596 | 750 | 9,280 |
| 2012/13 | 378 | 539 | 505 | 675 | 1,298 | 285 | 447 | 156 | 4,735 | 746 | 9,765 |
| 2013/14 | 388 | 550 | 550 | 697 | 1,317 | 292 | 628 | 247 | 4,958 | 772 | 10,400 |
| 2014/15 | 399 | 568 | 594 | 708 | 1,337 | 300 | 812 | 339 | 5,081 | 792 | 10,930 |
| 2015/16 | 409 | 580 | 633 | 718 | 1,375 | 307 | 1,000 | 339 | 5,268 | 817 | 11,447 |
| 2016/17 | 420 | 597 | 654 | 728 | 1,402 | 314 | 1,050 | 339 | 5,525 | 848 | 11,877 |
| 2017/18 | 430 | 610 | 670 | 739 | 1,431 | 321 | 1,054 | 339 | 5,752 | 872 | 12,219 |
| 2018/19 | 441 | 622 | 683 | 749 | 1,459 | 328 | 1,112 | 339 | 5,899 | 888 | 12,520 |
| 2019/20 | 451 | 634 | 696 | 759 | 1,488 | 334 | 1,170 | 340 | 6,045 | 904 | 12,821 |

## 2.6 Daily and annual load profiles

The daily load profiles for the Queensland Region on the days of 2009 winter and 2009/10 summer peak demand delivered from the transmission network and embedded scheduled generators are shown in Figure 2.10.

The annual cumulative load duration characteristic for the Queensland Region demand delivered from the transmission network and from embedded scheduled generators is shown in Figure 2.11 for the 2008/09 financial year.

**Figure 2.10** Winter 2009 and summer 2009/10 as delivered peak demands

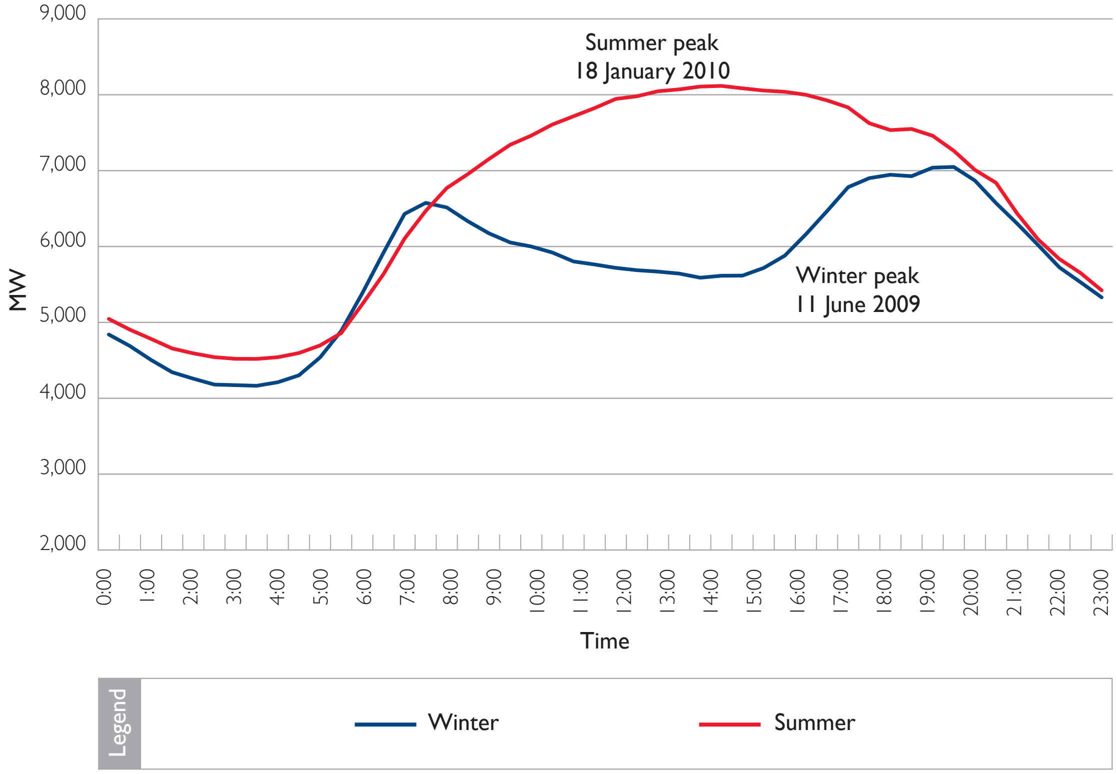
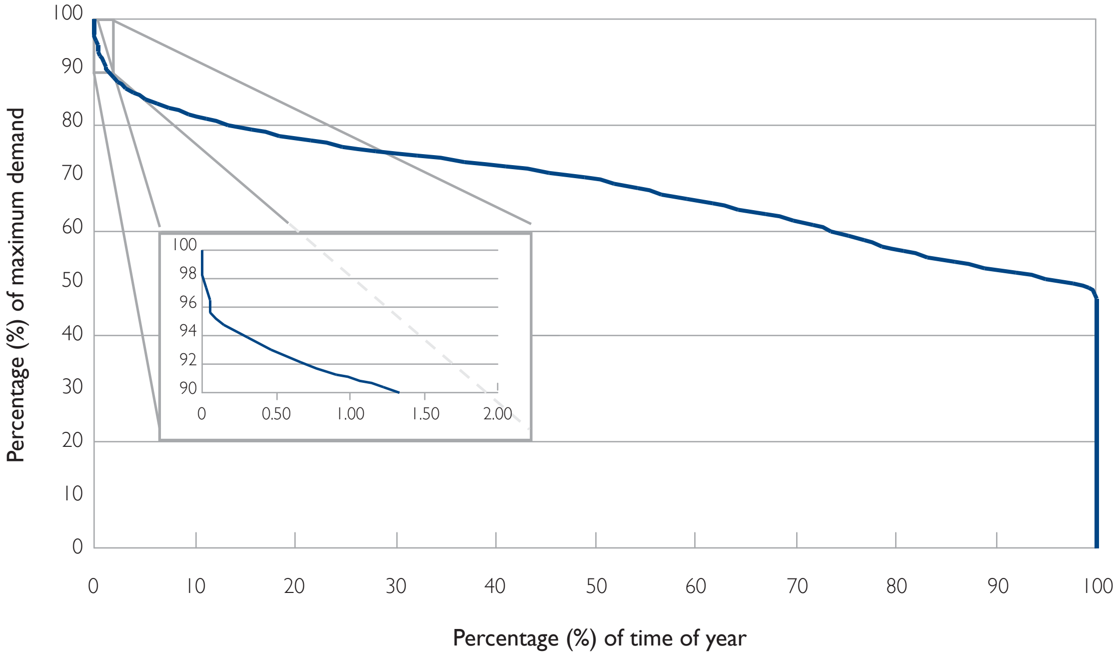


Figure 2.11 Normalised cumulative annual as delivered load duration 2008/09



# chapter 3 Committed and commissioned network developments

# Chapter 3

## 3.1 Transmission network

The 1,700km long Queensland transmission network comprises 275kV transmission from Cairns in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones and providing some backup to the 275kV network. In addition, 330kV lines link Braemar, Middle Ridge, Millmerran and Bulli Creek to the New South Wales network.

The single line diagrams of the Queensland network shown in Figure 3.1 and Figure 3.2 have been updated to include the recently completed augmentations outlined in this chapter.

## 3.2 Committed transmission projects

Table 3.1 lists transmission network developments commissioned since Powerlink's 2009 Annual Planning Report (APR) was published.

Table 3.2 lists transmission network developments which are committed and under construction at June 2010.

Table 3.3 lists transmission connection works that have been commissioned since Powerlink's 2009 APR was published.

Table 3.4 lists new transmission connection works for supplying loads which are committed and under construction at June 2010. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 3.5 lists network replacements which are committed and under construction at June 2010.

**Table 3.1 Commissioned transmission developments since June 2009**

| Project | Purpose | Zone location | Date commissioned |
|---|---|---|---|
| Major developments | | | |
| Ross to Yabulu South 275kV line and Yabulu South Substation | Increase supply capability within the greater Townsville area | Ross | October 2009 |
| Nebo to Strathmore 275kV line (Stage 2 of the three stage CQ-NQ project) | Increase supply capability to North, Ross and Far North Queensland zones | North | November 2009 |
| Bouldercombe to Pandoin 132kV line and Pandoin 132/66kV Substation | Increase supply capability to Rockhampton City and Keppel Coast | Central West | October 2009 |
| Larcom Creek 275/132kV Substation | Increase supply capability to the Gladstone area | Gladstone | October 2009 |
| South Pine 275/110kV transformer augmentation (1) | Increase supply capability to north eastern Brisbane | Moreton | October 2009 |
| South Pine to Sandgate 275kV line (2) | Increase supply capability to north eastern Brisbane | Moreton | November 2009 |
| Palmwoods 132/110kV transformer augmentation | Increase supply capacity to the Caboolture and Beerwah areas | Moreton | November 2009 |
| Network support arrangements | | | |
| Contract with local generators to provide network support in North Queensland | Part of solution to maintain supply reliability to North Queensland | Ross, North | New arrangements established from mid 2008 |
| Minor developments | | | |
| Tarong 200MVAr 275kV capacitor bank | Increase supply capability to South West and South East Queensland | South West | November 2009 |
| Greenbank 200MVAr 275kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | September 2009 |
| Mt England second 120MVAr 275kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | October 2009 |
| South Pine fourth 120MVAr 275kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | October 2009 |

Notes:

(1) Powerlink completed construction works associated with installation and commissioning of the new 275/110kV transformer in March 2009. Replacement and final configuration of the associated 110kV eastern bus was completed in October 2009.

(2) Powerlink has completed construction works associated with this project and commissioning will be performed in stages to co-ordinate with expansion of ENERGEX Sandgate Substation.

Table 3.2 Committed and under construction transmission developments at June 2010

| Project | Purpose | Zone location | Proposed commissioning date |
|---|---|---|---|
| Major developments | | | |
| Strathmore to Ross 275kV line (Stage 3 of the three-stage CQ-NQ project) | Increase supply capability to North, Ross and Far North Queensland zones | Ross, North | Summer 2010/11 |
| Bowen North to Strathmore 132kV line and Bowen North 132/66kV Substation | Increase supply capability to the Bowen area | North | Summer 2010/11 |
| Western Downs to Halys 275kV line and Western Downs and Halys 275kV substations | Increase supply capability between Bulli and South West zones | Bulli, South West | Summer 2012/13 |
| Halys to Blackwall 500kV line operating at 275kV | Increase supply capability to South East Queensland | South West, Moreton | Summer 2014/15 |
| Minor developments | | | |
| Kemmis 40MVAr 132kV capacitor bank | Capacitor compensation to meet increasing reactive demand | North | Summer 2010/11 |
| Moura 20MVAr 132kV capacitor bank | Capacitor compensation to meet increasing reactive demand | Central West | Summer 2010/11 |
| Gladstone South 132kV harmonic filter | Maintain quality of supply in the Gladstone area | Gladstone | Winter 2010 |
| Millmerran first 200MVAr 330kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Bulli | Summer 2011/12 |
| Middle Ridge first and second 120MVAr 330kV capacitor bank | Capacitive compensation to meet increasing reactive demand | South West | Summer 2011/12 |
| Ashgrove West third 50MVAr 110kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | Summer 2011/12 |
| Loganlea fourth 50MVAr 110kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | Summer 2011/12 |
| Belmont third 120MVAr 275kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | Summer 2011/12 |
| Belmont fourth 120MVAr 275kV capacitor bank | Capacitive compensation to meet increasing reactive demand | Moreton | Summer 2012/13 |

## Table 3.3 Commissioned connection works since June 2009

| Project | Purpose | Zone location | Date commissioned |
|---|---|---|---|
| Mt Stuart Power Station Unit 3 connection | Connection of new generation unit | Ross | September 2009 |
| Alligator Creek 132kV connection for Louisa Creek | Provide supply to new Ergon Energy substation | North | November 2009 |
| Alligator Creek 132kV connection for QR Network Mackay Ports | New supply to QR Network Dalrymple Bay Coal Terminal | North | May 2010 |
| Yarwun 132kV Substation | New connection point to Rio Tinto Aluminium (RTA) Yarwun and Ergon Energy Boat Creek Substation | Gladstone | November 2009 |
| Pandoin 132kV connection for Keppel | Provide supply to new Ergon Energy substation | Central West | September 2009 |

## Table 3.4 Committed and under construction connection works at June 2010

| Project | Purpose | Zone location | Proposed commissioning date |
|---|---|---|---|
| Moranbah 132kV connection for Broadlea | Increase supply capability to Broadlea | North | Summer 2010/11 |
| Goonyella Riverside Mine connection | Increase supply capability for coal mine expansion | North | Winter 2012 |
| QR Rail Supply for electrification of Blackwater system | Increase supply capability to Raglan, Wycarbah, Bluff and Duaringa rail sites | Central West | Summer 2012/13 |
| QGC Kumbarilla Park connection | New connection for CSM/LNG compression | Bulli | Summer 2012/13 |
| Braemar 3 Power Station connection | New connection for new generation unit | Bulli | Summer 2012/13 |
| Middle Ridge 110kV connection for Postmans Ridge | Increase ENERGEX supply capability to Lockyer Valley | South West | Winter 2011 |
| Bundamba 110/11kV transformer augmentation | Increase supply capability to Bundamba | Moreton | Summer 2010/11 |
| South Pine 110kV connection for Hays Inlet | New supply to ENERGEX Hays Inlet Substation | Moreton | Summer 2010/11 |
| South Pine 110kV connection for Griffin | New supply to ENERGEX Griffin Substation | Moreton | Summer 2010/11 |
| Loganlea 110kV connection for Jimboomba | New supply to ENERGEX Jimboomba Substation | Moreton | Summer 2011/12 |
| Palmwoods 132kV connection for Pacific Paradise | New supply to ENERGEX Pacific Paradise Substation | Moreton | Summer 2011/12 |
| Molendinar 110/33kV transformer augmentation | Increase ENERGEX supply capability to Gold Coast | Gold Coast | Summer 2011/12 |

**Table 3.5 Committed and under construction network replacements at June 2010**

| Project | Purpose | Zone location | Proposed commissioning date |
|---|---|---|---|
| Major replacements | | | |
| Ingham to Yabulu 132kV line replacement | Maintain supply reliability in the Ross zone | Ross | Summer 2011/12 |
| Gladstone Substation primary plant replacement | Maintain supply reliability to the Gladstone zone | Gladstone | Winter 2013 |
| Bouldercombe to South Pine overhead earthwire replacement | Maintain supply reliability to southern Queensland | Central West, Gladstone, Wide Bay and Moreton | Progressively from winter 2007 |
| Gin Gin 275/132kV transformer replacements | Maintain supply reliability to the Wide Bay zone | Wide Bay | Summer 2011/12 |
| South Pine 275/110kV transformer replacement and 110kV substation replacement (1) | Maintain supply reliability to the Moreton zone | Moreton | Summer 2010/11 |
| Belmont 275/110kV transformer replacements and 110kV substation replacement | Maintain supply reliability to the Moreton zone | Moreton | Progressively from summer 2010/11 to winter 2011 |
| Swanbank 110kV Substation replacement | Maintain supply reliability to the Moreton zone | Moreton | Winter 2011 |

Note:

(1) Powerlink has completed construction works associated with replacement of the South Pine 110kV eastern bus. Replacement of the 110kV western bus and project commissioning will be completed by summer 2010/11.

Figure 3.1 Existing 275/132kV network June 2010 – North and Central Queensland

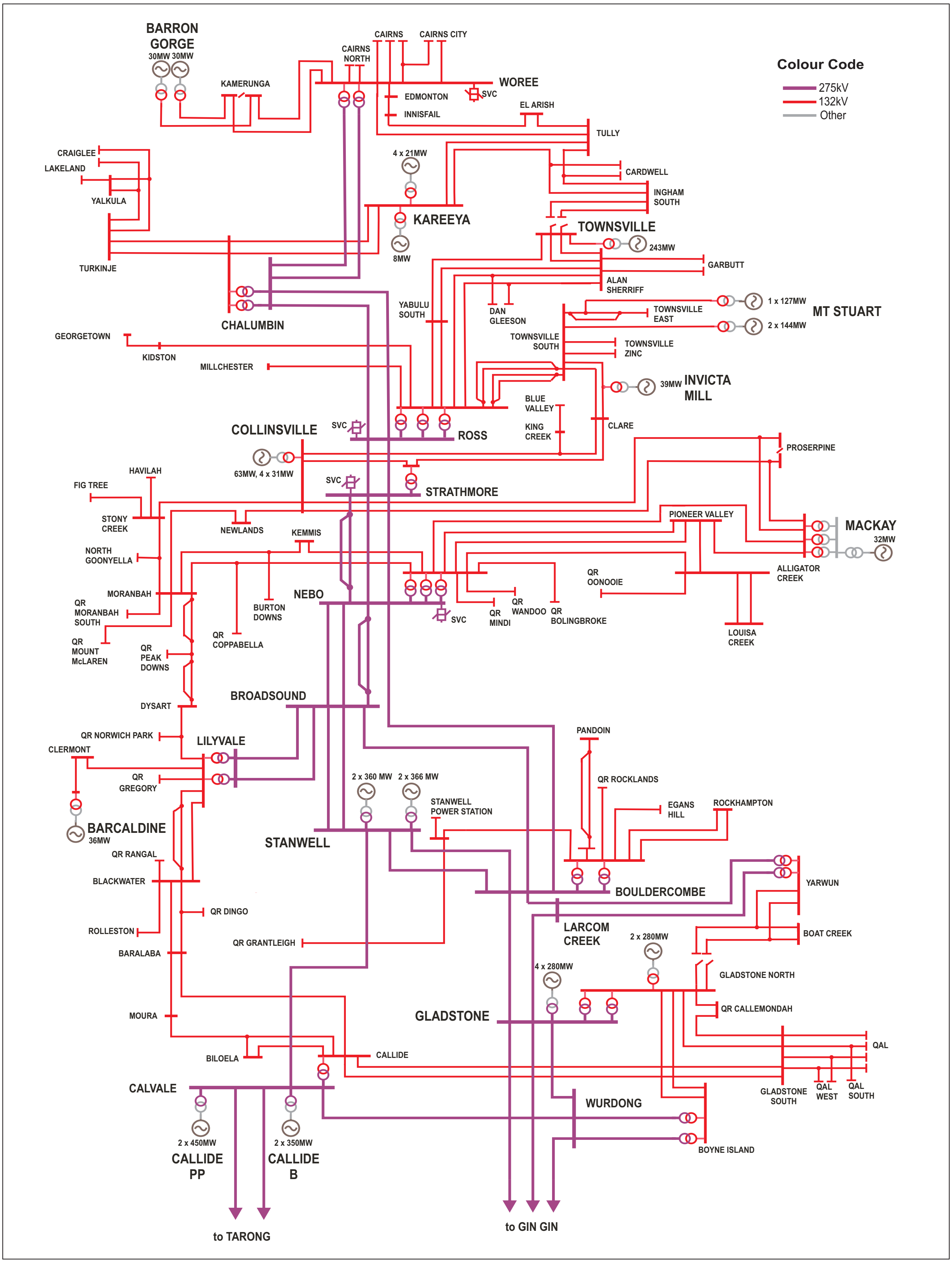
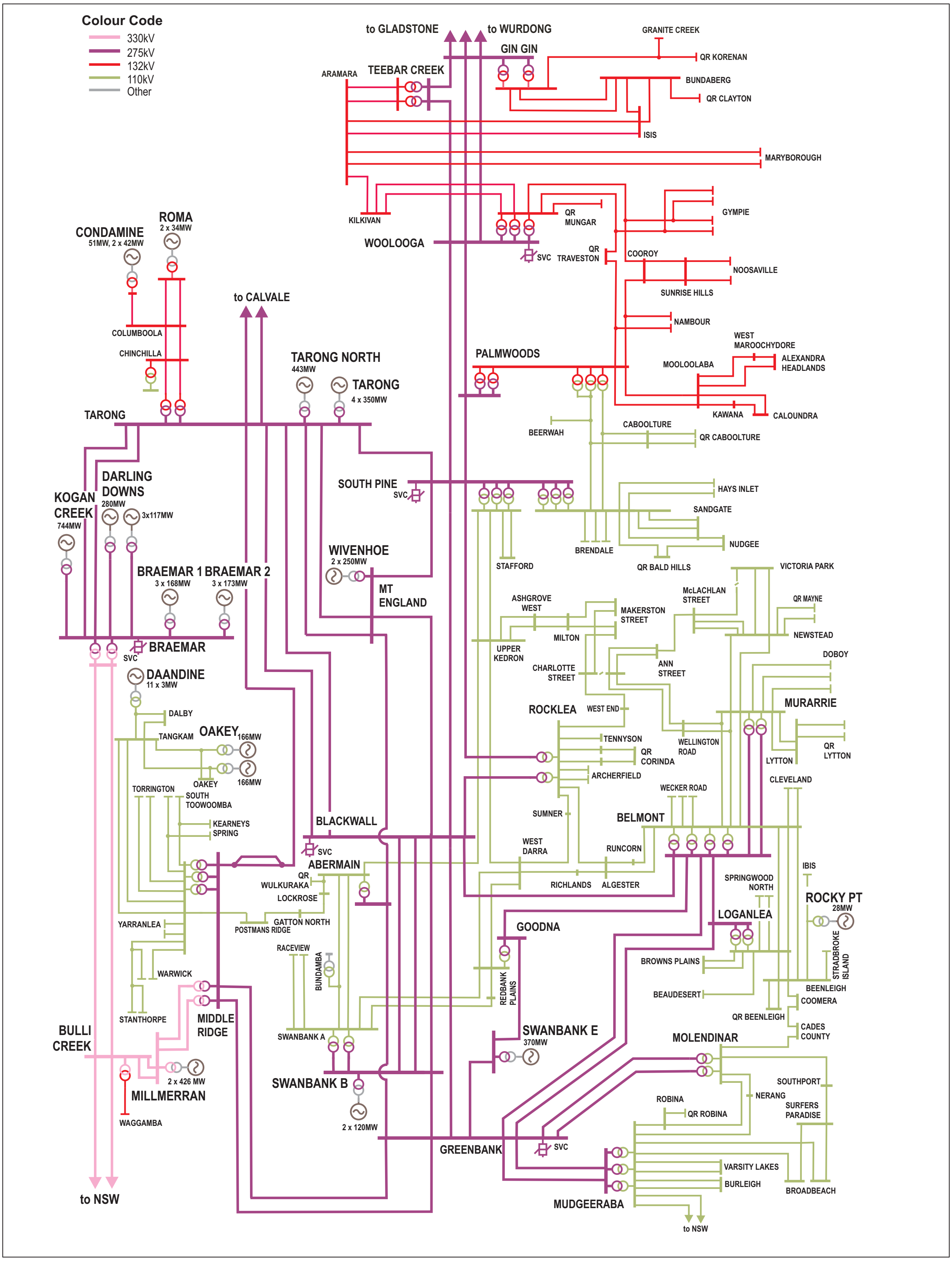


Figure 3.2 Existing 330/275/132/110kV network June 2010 – South Queensland



# chapter 4 Intra-regional proposed network developments within five years

# Chapter 4

## 4.1 Introduction

The National Electricity Rules (NER) (Clause 5.6.2A(b)(3)) require the Annual Planning Report (APR) 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 1, 3 and 5 years". In addition, there is a requirement (Clause 5.6.2A (3a)) of the NER to estimate load reductions that might defer forecast limitations for a period of 12 months.

This chapter on proposed network developments provides this and other related information. It contains:

- background on factors that influence network capability
- sample power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and generation dispatch patterns
- a qualitative explanation of factors affecting power transfer capability at key sections on the Powerlink Queensland network
- identification of emerging future limitations with potential to affect supply reliability and an estimate of load reductions required to defer these forecast limitations by 12 months
- a table summarising the outlook for network constraints and network limitations over a five-year horizon
- 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
- a table summarising works for assets reaching the end of their technical life.

Identification of forecast limitations in this chapter does not mean that there is an imminent supply reliability risk. The NER requires identification of such limitations which are expected to occur some years into the future, assuming that demand for electricity continues to grow as outlined in this document. Early identification allows Powerlink to implement appropriate solutions in a timely manner, as outlined in this chapter, to maintain a reliable power supply to customers.

The capability of Powerlink's transmission network to meet forecast demand is dependent on a number of factors. In general terms, Queensland's transmission network is more highly utilised during summer than winter. During higher summer temperatures, reactive power requirements are greater and transmission plant has lower power carrying capability. Also, high summer peak demands generally last for many hours, whereas winter peak demands are lower and last for short evening periods (as shown in Figure 2.10).

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 flow levels can also be higher at times of local area or zone peak demands (refer to Table 2.13), as distinct from those at the time of Queensland Region maximum demand, and when embedded generation is lower than forecast.

This chapter outlines some of these sensitivities using illustrative power flows over the next three years under a range of interconnector flows and sample generation dispatch patterns in Queensland. Qualitative explanation is also provided on factors that impact power transfer capability at key sections on the Powerlink network and on the cause of emerging limitations which may affect supply reliability.

## 4.2 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 over the period winter 2010 to summer 2012/13 for 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).

The dispatch assumed is broadly based on the relative outputs of generators but is not intended to imply a prediction of future market behaviour. The southerly power flow on Terranora Interconnector is based on expected levels to meet reliability requirements in northern New South Wales (NSW) until the expected commissioning of TransGrid's Dumaresq to Lismore 330kV augmentation (mid 2014).

Power flows in Appendix C are based on existing network configuration and committed projects (listed in Table 3.2 and Table 3.4), and assume all network elements are available. Power flows can be higher than those levels during network or generation contingencies, during times of local area peak demands and/or different generation dispatch periods.

This information is based on sample generation dispatch patterns to meet forecast Queensland Region maximum demand conditions and only provides an indication of potential power flows. Actual power flows can vary significantly for different load conditions and generator bidding behaviour. In providing this information, Powerlink has not attempted to predict market outcomes.

## 4.3 Transfer capability

### 4.3.1 Location of grid sections and observation points

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 each of these grid sections to quantify maximum secure power transfer. Maximum power transfer may be set by transient stability, voltage stability, thermal plant ratings or protection relay load limits. The Australian Energy Market Operator (AEMO) has incorporated these limit equations as part of constraints within the National Electricity Market Dispatch Engine (NEMDE).

In addition to these grid sections, Powerlink also monitors power flows across several 'observation points' to define maximum secure power transfer, particularly under network outage conditions. Figure C.2 in Appendix C shows the location of relevant grid sections (where limit equations apply) and 'observation points' on the Queensland network. Potential limitations where power flows may reach transfer capability in the next five years are summarised in Table 4.8.

### 4.3.2 Determining transfer capability

Transfer capability across each grid section varies with different system operating conditions. Transfer limits in the National Electricity Market (NEM) are not generally amenable to definition by a single number. Instead, Transmission Network Service Providers (TNSPs) define capability of their network using multi-term equations. These equations quantify the relationship between system operating conditions and transfer capability, and are implemented into NEMDE for optimal dispatch of generation. This is relevant in Queensland as the transfer capability is highly dependent on which generators are in service and their dispatch level. This limit equation approach aims to maximise transmission capability available to electricity market participants under prevailing system conditions.

The trade-off for this maximisation of transfer capability is the complexity of analysis required to define network capability. The process of developing limit equations from a large number of network analysis cases involves regression techniques and is time consuming. It also involves a due diligence process by AEMO before these equations are implemented in NEMDE.

Limit equations derived by Powerlink which are current at the time of publication of this report are provided in Appendix D. It should be noted that limit equations will change over time with demand, generation and network development.

Such detailed and extensive analysis on the future limit equations has not been carried out for future network and generation developments for this report. Section 4.4 provides a qualitative description of the main system conditions that affect capability of each grid section.

## 4.4 Grid section performance

This section is a qualitative summary of major system conditions that affect transfer capability across key grid sections of the Queensland transmission network.

Powerlink has also provided a qualitative outlook for the likelihood that these grid sections will translate into future restrictions on generator dispatch (binding limits). This outlook is provided to assist readers to understand information provided in Appendix C, and is in no way meant to imply that this outlook holds true for system conditions other than those in sample power flows. Transfer capability and power flows are highly sensitive to demand and generator dispatch patterns and embedded non-scheduled generation, and Powerlink makes no prediction of market outcomes in the information provided.

It should be noted that 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 peak 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.

For each grid section, the proportion of time that the limit equation has recently bound is provided for two periods, namely from April to September 2009 (winter period) and from October 2009 to March 2010 (summer period). This information on binding periods, sourced from the NEM InfoServer, includes all dispatch intervals in the relevant period. No attempt has been made to distinguish dispatch intervals when planned or forced outages may have affected network capability. This binding constraint information is not intended to imply that historical information represents a prediction of constraints in the future.

Table C.1 in Appendix C shows power flows across each grid section with all network elements available, at time of forecast Queensland Region peak demand, corresponding to the sample generation dispatch shown in Figures C.3 to C.20. It also shows the mode of instability that determines the limit. 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 forecast demand conditions.

### 4.4.1 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 significant effect on transfer capability:

- the ratio of Far North zone to northern Queensland[1] demand
- generation in the Far North zone
- local reactor and capacitor banks online.

Local hydro generation reduces transfer capability but allows more demand to be securely supported in the Far North zone. This is because reduction in grid section transfer capability is more than offset by reduction in power transfers resulting from increased local generation.

Information pertaining to duration of constrained operation for the FNQ grid section over the period April 2009 to March 2010 is summarised in Table 4.1.

**Table 4.1 Far North Queensland grid section constraint times for April 2009 – March 2010**

| FNQ grid section | Time equation bound (hours) | Proportion of time constraint equation bound (%) |
|---|---|---|
| April to September 2009 | 0.00 | 0.00 |
| October 2009 to March 2010 | 3.00 | 0.07 |

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

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C at times of local area peak demands or during more severe weather than 50% PoE forecast conditions. Power flows can also be higher during non-availability or low generation of the hydro generators, or if output from embedded generators at sugar mills and the wind farm in FNQ is lower than forecast.

Powerlink is implementing a condition based, staged replacement, of the coastal 132kV lines between Yabulu South and Woree substations. The replacement lines are being built as a dual voltage double circuit line (275kV and 132kV). Both circuits will initially operate at 132kV. The replacement of the sections of this line from Tully to Woree has been completed. Replacement lines for the southern sections from Yabulu South to Tully are planned to be progressively rebuilt with the continuity of the coastal link re-established by summer 2012/13.

Following these works, further action to maintain reliability of supply to the Far North zone in the form of additional reactive power support may again be required from summer 2015/16 onwards. This is discussed in Section 4.5.1.

### 4.4.2 Central Queensland to North Queensland grid section

Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section is set by transient stability, voltage stability or thermal plant rating following a transmission or generation contingency.

Maximum transfer capability may be set by thermal ratings associated with an outage of a Strathmore to Ross 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by stability limitations associated with the contingency of the Townsville gas turbine or a 275kV transmission contingency.

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

- generation of Townsville gas turbine
- local capacitor banks available
- local reactors online.

Information pertaining to the duration of constrained operation for the CQ-NQ grid section over the period April 2009 to March 2010 is summarised in Table 4.2.

**Table 4.2 CQ-NQ grid section constraint times for April 2009 – March 2010**

| CQ-NQ grid section(1)(2) | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 0.00 | 0.00 |
| October 2009 to March 2010 | 20.42 | 0.47 |

Notes:

(1) Powerlink has network support agreements with generators in northern Queensland to manage power flows across this grid section within the transfer capability.

(2) The figures do not include occurrences of binding constraints associated with these network support agreements. AEMO does not consider that periods of congestion that are managed through a network support agreement contribute to the total number of hours of a binding constraint.

Summer peak demand requirements in northern Queensland are currently met by the transmission network operating in conjunction with local generators.

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C at times of local area or northern Queensland peak demands or during more severe weather than 50% PoE forecast conditions. Power flows can also be higher during non-availability or low output of local generators, or if output from embedded generators at sugar mills and the wind farm in northern Queensland is lower than forecast.

Powerlink has commissioned the first two stages of a three-stage augmentation of the network between CQ and NQ:

- Stage 1 – Construction of a Broadsound to Nebo 275kV transmission line and installation of a 275kV static VAr compensator (SVC) at Strathmore Substation
- Stage 2 – Construction of a Nebo to Strathmore 275kV transmission line.

The third stage, construction of a Strathmore to Ross 275kV transmission line, is expected to be in service for summer 2010/11.

Ongoing load growth in North Queensland increases power transfers on this grid section. Depending on load developments in northern Queensland, augmenting the network could become economic as early as summer 2014/15. These network augmentations are discussed further in Section 4.5.3.

### 4.4.3 Gladstone grid section

The maximum power transfer across this grid section is set by the thermal rating of the Calvale to Wurdong or the Calvale to Stanwell 275kV circuits, or the Calvale 275/132kV transformer.

If the rating would otherwise be exceeded following a critical contingency, generation is re-dispatched to alleviate power transfers. To minimise market impact, Powerlink updates the rating of the circuits to take account of prevailing ambient weather conditions. The appropriate ratings are updated in NEMDE.

Powerlink also implements network switching and support strategies when transfers reach the capability of this grid section. These strategies minimise the incidence of network constraints. These strategies extend to opening the 132kV lines at Gladstone South and/or Baralaba. Due to ongoing demand growth, from late 2010 a 132kV circuit outage results in unacceptably low voltage conditions in the Moura area during summer peak demand periods. This limitation is being addressed by a committed project to install a 132kV capacitor bank at Moura Substation by summer 2010/11 (refer to Table 3.2).

Information pertaining to the duration of constrained operation for the Gladstone grid section over the period April 2009 to March 2010 is summarised in Table 4.3.

**Table 4.3 Gladstone grid section constraint times for April 2009 – March 2010**

| Gladstone grid section(1) | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 50.75 | 1.16 |
| October 2009 to March 2010 | 473.83 (2) | 10.85 |

Notes:

(1) This constraint is managed by Gladstone thermal limit equations developed by AEMO.

(2) Power flow across this grid section increased compared to summer 2008/09 due largely to the generation dispatch. Increases in incidence of binding constraints were due to lower CQ-SQ transfers, higher generation at Callide and higher CQ-NQ transfers.

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C under market dispatch scenarios that lead to higher Callide generation and lower Gladstone generation.

In summer 2009/10, Powerlink established Larcom Creek 275/132kV Substation (refer to Table 3.1) in the Gladstone State Development Area (GSDA) in response to ongoing load growth in the Gladstone area. In addition, increasing power transfer between Central and North Queensland increases loading on this grid section. Based on committed generation, operational measures will no longer be sufficient to manage the thermal limits by summer 2013/14. This is discussed in Section 4.5.4.

### 4.4.4 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 and voltage stability following a transmission 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
- generation at Gladstone Power Station.

Information pertaining to the duration of constrained operation for the CQ-SQ grid section over the period from April 2009 to March 2010 is summarised in Table 4.4.

**Table 4.4 CQ-SQ grid section constraint times for April 2009 – March 2010**

| CQ-SQ grid section(1) | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 5.67 | 0.13 |
| October 2009 to March 2010 | 14.33 | 0.33 |

Note:

(1) The duration of binding events includes periods when spare capability across this grid section was fully utilised by the QNI or Terranora Interconnector transferring power south into NSW.

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C at times of more severe weather than 50% PoE forecast conditions and/or different generation patterns. The latter is the most variable and has the largest potential for increasing transfers across the grid section.

The introduction of additional plant in South Queensland, which may displace generation in central or northern Queensland, can reduce the level of power transfers across this grid section. The advent of large load developments in central or northern Queensland (additional to those included in the forecasts), without corresponding increases in central or northern Queensland generation, can also significantly reduce the levels of CQ-SQ transfers.

### 4.4.5 South West Queensland grid section

The South West Queensland (SWQ) grid section defines the capability of the transmission system to transfer power from generating stations located in the Bulli zone and northerly flow on QNI, to the rest of Queensland.

The capability of this grid section may be limited by transmission plant thermal capacity, the ability to maintain stable voltage levels or to maintain transient stability following critical contingencies. Thermal limitations may occur on a 330/275kV transformer at Middle Ridge or a Braemar to Tarong 275kV circuit under contingency conditions. These thermal limitations are sensitive to the distribution of generation dispatched in the Bulli and South West zones. Generation at Millmerran and northerly flow on QNI increases the loading on the Middle Ridge 330/275kV transformers, whereas generation at Braemar leads to higher power flows on the Braemar to Tarong circuits.

For voltage stability, the critical contingency is the outage of one of the 275kV or 330kV circuits that make up this grid section. Voltage instability results from exhaustion of reactive power reserves in southern Queensland.

Information pertaining to the duration of constrained operation for the South West Queensland grid section over the period April 2009 to March 2010 is summarised in Table 4.5.

**Table 4.5 South West Queensland grid section constraint times for April 2009 – March 2010**

| SWQ grid section | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 0.00 | 0.00 |
| October 2009 to March 2010 | 0.33 | 0.01 |

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C under market dispatch scenarios that lead to higher Bulli generation and/or northerly QNI power transfer.

Following the commissioning of Braemar 2 and Darling Downs power stations, sufficient generation exists in the Bulli zone to encroach transfer limits. In such circumstances, NEMDE manages transfers to within the transmission capability. This capability will be initially set by the thermal rating of a Middle Ridge 330/275kV transformer. This limitation is forecast to impact supply reliability from summer 2010/11.

In June 2009, Powerlink issued a Final Report recommending a series of works involving additional shunt compensation, an operation scheme to manage thermal overloads and a major transmission line and substation projects. This is discussed in Section 4.5.5.

### 4.4.6 Tarong grid section

Maximum power transfer across the Tarong grid section is set by voltage stability associated with loss of a large generating unit, a 275kV circuit between central and southern Queensland, or a 275kV circuit between the South West zone and greater Brisbane load centre. The limitation arises from insufficient reactive power reserves in South Queensland.

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

- transfer on the QNI and generation in the South West and Bulli zones
- number of generators online in the Moreton zone
- generation in the Moreton zone
- capacitive compensation levels within the Moreton and Gold Coast zones.

There is inter-dependence between the CQ-SQ transfer and the Tarong transfer capability. High power flows between central and southern Queensland reduce Tarong transfer capability.

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 demand. This is because reduction in transfer capability is more than offset by reduction in power transfers resulting from increased generation east of this grid section.

Information pertaining to the duration of constrained operation for the Tarong grid section over the period April 2009 to March 2010 is summarised in Table 4.6.

**Table 4.6 Tarong grid section constraint times for April 2009 – March 2010**

| Tarong grid section | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 0.00 | 0.00 |
| October 2009 to March 2010 | 0.00 | 0.00 |

Based on the sample generation scenarios shown in Figures C.3 to C.20 of Appendix C, power flows across this grid section are forecast to increase steadily over time. These scenarios are based on 50% PoE demand forecasts with all generation plant being available in the Moreton zone.

The outlook for this grid section is for power transfers to increase. Powerlink published a Final Report in June 2009, forecasting the re-emergence of a limitation in summer 2012/13.

The Final Report recommended a series of works involving additional shunt compensation and the construction of a new 500kV double circuit line between Halys and Blackwall substations, initially operated at 275kV, by summer 2013/14.

Since the publication of the Final Report, Powerlink has reviewed the timing of this major transmission project to take account of changes in the load forecast and to the outlook for generation capacity in Queensland. As a result of this review the timing of the new 500kV double circuit line has been deferred by one year to summer 2014/15.

The recommended solutions are discussed in Section 4.5.6.

### 4.4.7 Gold Coast grid section

Maximum power transfer across the Gold Coast grid section is set by voltage stability associated with loss of the Swanbank E generating unit, Greenbank to Molendinar, or Greenbank to Mudgeeraba 275kV circuit.

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

- number of generating units online in Moreton zone
- loading of Terranora Interconnector
- capacitive compensation levels within the Moreton and Gold Coast zones
- the ratio of the Moreton to the Gold Coast demand.

Voltage limits are higher when more Swanbank B or Swanbank E units are online. Reducing southerly flow on Terranora Interconnector reduces transfer capability, but increases overall amount of supportable Gold Coast demand. This is because reduction in transfer capability is more than offset by reduction in power transfers resulting from the reduction in southerly flow on Terranora Interconnector.

Information pertaining to the duration of constrained operation for the Gold Coast grid section over the period April 2009 to March 2010 is summarised in Table 4.7.

**Table 4.7 Gold Coast grid section constraint times for April 2009 – March 2010**

| Gold Coast grid section | Time equations bound (hours) | Proportion of time constraint equations bound (%) |
|---|---|---|
| April to September 2009 | 0.00 | 0.00 |
| October 2009 to March 2010 | 0.00 | 0.00 |

Power flows across this grid section can be higher than shown in Figures C.3 to C.20 of Appendix C under local area peak demands, during more severe weather than 50% PoE forecast conditions and/or under market dispatch scenarios that lead to higher southerly Terranora Interconnector power transfer.

Further action to maintain reliability of supply to the Gold Coast zone in the form of additional 275/110kV transformer capacity may be required from 2015 onwards. This is discussed in Section 4.5.7.

### 4.4.8 Interconnector limits (QNI and Terranora Interconnector)

The QNI was designed and constructed of assets having plant ratings of at least 1,000MW. However, the actual transfer capability will vary depending on system conditions.

For intact system operation, the southerly transfer capability of QNI is most likely to be set by the following:

- transient stability associated with loss of the largest load in Queensland
- transient stability associated with transmission faults in Queensland
- transient stability associated with transmission faults in the Hunter Valley
- transient stability associated with transmission faults in Victoria
- thermal ratings of the 132kV transmission network in northern NSW
- oscillatory stability upper limit of 1,078MW (conditional on availability of online stability monitoring).

For intact system operation, the combined northerly transfer capability of QNI and Terranora Interconnector are most likely to be set by the following:

- transient and voltage stability associated with transmission faults in the Hunter Valley
- transient and voltage stability associated with the loss of generating units in Queensland
- transient stability associated with transmission faults in Queensland
- thermal ratings of the 330kV and 132kV transmission network in NSW
- oscillatory stability upper limit of 700MW.

Powerlink and TransGrid published a Final Report in October 2008 relating to the potential upgrade of the interconnection between Queensland and New South Wales. Powerlink and TransGrid have also agreed to undertake further investigations to re-evaluate the economic viability and optimal timing of an upgrade to QNI in light of recent market developments. This is discussed further in Section 5.2.3.

## 4.5 Forecast reliability limitations

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. Under its Transmission Authority, Powerlink must plan and develop its network so that it can supply the forecast peak demand, even if the most critical network element is out of service (the N-1 criterion). Forward planning allows Powerlink adequate time to implement appropriate solutions to maintain a reliable power supply to customers.

Identification of forecast limitations in this chapter can therefore be viewed as triggers for planning action, not indicators of a supply reliability risk. The NER requires identification of such limitations which are expected to occur some years into the future, assuming that demand for electricity continues to grow as forecast in this document. In addition there is a new requirement (defined under clause 5.6.2A (3a)) of the NER to estimate the demand reduction required to defer the forecast limitation for a period of 12 months. This reduction in demand must be available on a firm basis to ensure any deferral will still allow demand to be reliably supplied.

Powerlink will consult with AEMO, Registered Participants and interested parties on feasible solutions identified through this 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.

The information presented in this section provides advance notice of anticipated consultation processes and thereby extends the time available to interested parties to develop solutions. Further information will be provided during the relevant consultation process, as and when this is required (refer to Section 4.7 for current and anticipated consultation processes).

### 4.5.1 Far North zone

*Far North Queensland voltage control*

#### Forecast limitation

Sufficient capability is forecast to be available in this zone until summer 2015/16. Following a critical contingency, unstable voltage levels are forecast to occur from this time without action to augment supply.

#### Possible solutions

A feasible network solution to the identified voltage limitation is the installation of a capacitor bank in the Cairns area at an approximate cost of $2 million to $4 million.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

#### Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 10MW within the Cairns/Edmonton area.

### 4.5.2 Ross zone

*Townsville area 132/66kV transformer capability*

#### Forecast limitation

Sufficient transformer capability is forecast to be available in the Townsville area until summer 2013/14, from which time thermal limitations are forecast to occur under critical contingency conditions without action to augment supply.

#### Possible solutions

A feasible network solution to the identified thermal limitation is the installation of an additional 132/66kV transformer in the Townsville area at an approximate cost of $10 million to $15 million, together with Ergon Energy 66kV works.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

#### Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 10MW within the Townsville area.

### 4.5.3 North zone

*Supply to Bowen area*

#### Forecast limitation

Demand in the Bowen area is expected to grow strongly due to the staged expansion of the Abbot Point coal loading terminal and possible electrification of rail traffic projects within the five-year outlook period. Voltage and thermal limitations are expected to occur under critical contingency conditions in the local 66kV distribution network without action to augment supply.

#### Committed solution

A committed project is under way to address the identified voltage and thermal limitations and involves establishing a new 132/66kV Bowen North Substation and constructing a Strathmore to Bowen North 132kV transmission line by summer 2010/11 (refer to Table 3.2), followed by connecting the second 132kV circuit at Bowen North Substation by summer 2013/14.

*CQ-NQ transfer limit*

Forecast limitation

Summer peak demand requirements in northern Queensland are currently met by the transmission network operating together with local generators. Powerlink previously identified that this combined capability was insufficient to meet required reliability of supply to northern Queensland from summer 2007/08.

Committed solution

Powerlink committed to staged augmentation between Broadsound and Ross substations as follows:

- Stage 1 – Construction of a Broadsound to Nebo 275kV transmission line and installation of a 275kV SVC at Strathmore Substation
- Stage 2 – Construction of a Nebo to Strathmore 275kV transmission line
- Stage 3 – Construction of a Strathmore to Ross 275kV transmission line.

The Strathmore SVC was commissioned in October 2007. The Broadsound to Nebo 275kV transmission line was commissioned in October 2008 and the Nebo to Strathmore 275kV transmission line was commissioned in November 2009 (refer to Table 3.1). The third stage, involving the construction of a Strathmore to Ross 275kV transmission line, is expected to be completed by summer 2010/11 (refer to Table 3.2).

Forecast limitation

Following the staged augmentation between Broadsound and Ross substations, power transfer capability into northern Queensland may again be limited by thermal, voltage or transient instability. Depending on future generation and/or load development in northern Queensland, thermal limitations are forecast to occur following a Stanwell to Broadsound contingency without action to augment supply. The timing of the forecast network limitations is not expected to occur within the five-year outlook period of this APR. However additional, as yet uncommitted, load developments in northern Queensland may require earlier action.

Possible solution

In 2002, Powerlink constructed a Stanwell to Broadsound 275kV double circuit transmission line with only one circuit strung. A feasible network solution to address the identified thermal limitation, voltage or transient instability is to string the second circuit. As generation costs are much higher in northern Queensland due to the reliance on liquid fuels, advancing the timing of the augmentation to address this emerging reliability limitation could provide an economic advantage. Depending on load developments in northern Queensland, augmenting the network could become economic as early as summer 2014/15.

*Supply to Bowen Basin coal mining area*

Forecast limitation

Demand in the Bowen Basin coal mining area may grow strongly within the five-year outlook period due to new export coal mining developments in the Moranbah area. As a result, thermal limitations are expected to occur under critical contingency conditions in the 132kV network supplying the area by summer 2013/14, without action to augment supply. In addition to this identified limit, the network operates very close to the prescribed quality of supply limitations. Any future developments will need to ensure that quality of supply standards are maintained for all network customers in the area.

Possible solutions

A feasible network solution to the identified thermal limitation is the construction of a new 275kV transmission line (initially operated at 132kV) from Nebo Substation to the Moorvale area and associated 132kV injection into Ergon Energy network with an approximate cost of $100 million to $110 million.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 40MW in the Moranbah area.

### 4.5.4 Central West and Gladstone zones

*Rockhampton area 275/132kV transformer capability*

Forecast limitation

Sufficient transformer capability is available in the Rockhampton area until summer 2012/13 at which time thermal limitations are forecast to occur under critical contingency conditions without action to augment supply.

Possible solution

A proposed new small network asset comprising installation of a third 275/132kV transformer at Bouldercombe Substation has been recommended to address the identified thermal limitation at an estimated cost of $13.9 million (refer to Appendix E).

Non-network solutions may include:

- generation in the Rockhampton area; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 15MW in the Rockhampton area.

*Supply to Blackwater area*

Forecast limitation

Demand in the Blackwater area is expected to grow strongly due to new large industrial loads comprising additional committed coal haulage rail traffic projects (refer to Table 3.4). As a result, thermal limitations are expected to occur under critical contingency conditions in the 132kV network supplying the area by summer 2012/13, without action to augment supply.

Possible solutions

In 2007, Powerlink constructed a Blackwater to Lilyvale 132kV double circuit transmission line that is currently operated as a single circuit. A feasible network solution to the identified thermal limitation is to unparallel the transmission line to provide an additional circuit at an approximate cost of $3 million to $4 million.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 30MW in the Blackwater area.

*Supply to inland Central Queensland area*

Forecast limitation

Sufficient capability is forecast to be available until summer 2010/11 when the 132kV transmission capability between Callide, Biloela and Moura substations is expected to be reached under critical contingency conditions. Opening the 132kV transmission lines north of Baralaba to alleviate this overload will result in unacceptably low voltage conditions in the Moura area during summer peak demand periods without action to augment supply.

Committed solution

This limitation is being addressed by a committed project to install a 132kV capacitor bank at Moura Substation by summer 2010/11 (refer to Table 3.2).

*Supply within Central Queensland*

Forecast limitation

As detailed in Section 4.4.3, thermal limitations are forecast to occur between Central West and Gladstone zones under critical contingency conditions. These limitations arise due to power transfer from Central West zone to the Gladstone zone and then beyond to North and South Queensland. These thermal limitations are currently managed by operational strategies and redispatch of generation. These operational strategies include re-rating critical transmission lines to take account of prevailing ambient weather conditions and network rearrangement. It is forecast that by summer 2013/14 peak demand will be such that use of operational measures will no longer be sufficient to manage the thermal limits of the critical transmission lines without action to augment supply.

Possible solutions

An Application Notice published during June 2010 (refer to Section 4.7.3) proposed a feasible network solution to address the identified thermal limitation which involves construction of a new 275kV transmission line between Calvale and Stanwell substations.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 80MW either in the Gladstone area or north of the Stanwell/Bouldercombe area.

*Gladstone area harmonics*

Forecast limitation

Large industrial enterprises are located in the Gladstone area. They include refineries, processing plants, smelters and traction loads. It is typical for these types of activities to generate harmonics, which causes voltage waveform distortion and quality of supply issues.

Committed solution

Planning studies have identified that harmonic levels are expected to exceed prescribed values. This limitation is being addressed by a committed project to install a harmonic filter at Gladstone South Substation by winter 2010 (refer to Table 3.2).

### 4.5.5 Bulli and South West zones

*South West Queensland transfer limit*

Forecast limitations

Maximum power transfer across the Bulli to South West Queensland grid section may be limited by transmission plant thermal capacity, the ability to maintain stable voltage levels, or to maintain transient stability following critical contingencies.

Due to ongoing demand growth in Queensland and the commitment of new generation capacity in the Bulli zone, power transfer across the South West Queensland grid section will continue to increase. This required power transfer across the South West Queensland grid section is forecast to reach the capability of the existing network from summer 2010/11.

Network limitations in summer 2010/11 relate to thermal overload of a 330/275kV transformer at Middle Ridge Substation following an outage of the parallel transformer and voltage stability limitations in South West Queensland from summer 2011/12 following a critical transmission outage.

The initial transformer thermal limitation is planned to be addressed by an automatic network switching solution at Middle Ridge Substation. For voltage stability, the critical contingency is an outage of one of the 275kV or 330kV circuits that make up this grid section. The voltage instability results from exhaustion of reactive power reserves in southern Queensland.

Following a credible contingency, there may also be insufficient generation beyond the Bulli zone to allow AEMO to return the power system to a secure state while maintaining a reliable supply to all customers. Under these conditions, the maximum power transfer between the Bulli and South West zones is limited by the occurrence of unstable voltage levels or transient instability. These limitations may mean that a portion of the available generation capacity within the Bulli zone cannot be dispatched, resulting in a supply deficit. Without a supply augmentation, mandated reliability of supply obligations could not be met from summer 2011/12.

Fault level issues are forecast to occur coincidental with future network connections, including future generating plant required to meet forecast increases in demand. Action to address the fault levels is required to ensure reliability of supply.

#### Committed solutions

A Final Report published during June 2009 recommended a series of works to address the limitations detailed above. These committed projects (refer to Table 3.2) comprise:

- installing 330kV capacitor banks at Millmerran and Middle Ridge substations by summer 2011/12
- establishing two new 275kV substations at Western Downs and Halys by summer 2012/13. It is also recommended to split the 275kV bus at Braemar Substation combined with operational switching to split the 330kV bus to address the fault level issues at Braemar Substation by summer 2012/13
- constructing a new 275kV transmission line from Western Downs to Halys substations and rearranging the existing 275kV transmission line between Braemar Substation and Kogan Creek Power Station to connect Western Downs and Braemar substations, all by summer 2012/13. Powerlink and CS Energy (as the owner of Kogan Creek Power Station) have agreed on utilising the existing 275kV transmission line between Kogan Creek Power Station and Braemar Substation as an overall lower cost solution to consumers instead of constructing a new 275kV transmission line between Braemar and Western Downs substations.

### *Supply to Surat Basin north west area*

#### Forecast limitation

The Surat Basin north west area is defined as the area north west of Braemar Substation. The area has significant development potential given the vast reserves of gas and coal fields. Electricity demand in the area is forecast to grow substantially due to new developments of liquefied natural gas (LNG) upstream processing facilities and a large coal mine together with the supporting infrastructure and services. As a result, thermal limitations are expected to occur under critical contingency conditions in the 132kV and 66kV network supplying the area as early as winter 2013, without action to augment supply.

#### Proposed solution

An Application Notice published during June 2010 (refer to Section 4.7.3) proposed a feasible network solution to address the identified thermal limitations which involves construction of a new 275kV line from Western Downs to Columboola, and a new 275kV line from Columboola to a new substation in the Wandoan South area.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

#### Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the Surat Basin 132kV network by between 100MW and 350MW within the Surat Basin north west area in 2013.

### 4.5.6 Moreton zone

*CQ-SQ transfer limit*

Forecast limitation

The CQ-SQ transmission capability must at minimum meet the shortfall between the South Queensland load, and the combined supply capability from South Queensland generation and maximum secure northerly power transfer from QNI and Terranora Interconnector. Due to ongoing demand growth, South Queensland may require increased power transfer across CQ-SQ depending on the location of future generation developments. Based on existing and committed generation listed in Table 5.1, network limitations between Central and South Queensland may occur unless action is taken to augment supply from summer 2014/15.

Possible solutions

Depending on future generation developments, feasible network solutions may include establishment of a switching station and series capacitors near the future Auburn River Substation at an approximate cost of $90 million to $110 million, or an additional 275kV transmission line development between central and southern Queensland at an approximate cost of $170 million to $410 million.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

Load reduction estimate

Depending on the location of future generation developments, to defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 370MW in the southern Queensland area.

*Supply to northern Sunshine Coast area*

Forecast limitation

Bulk supply to the Sunshine Coast area is provided from the Woolooga and Palmwoods 275/132kV substations. Electricity is then transferred over the ENERGEX 132kV and 110kV network to supply Gympie, Cooroy, Nambour, Sunshine Coast and Caboolture substations.

Taking into account ENERGEX committed minor upgrades, sufficient capability is forecast to be available until summer 2014/15. From summer 2014/15, thermal limitations are expected to occur in the ENERGEX 132kV network between Woolooga and Gympie during critical 132kV network outages without action to augment supply.

Possible solution

The least cost solution to the thermal limitation identified is the construction of a new 275kV transmission line from Woolooga to a 275/132kV substation in the north Sunshine Coast area (Eerwah Vale) at an approximate cost of $90 million to $100 million.

Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 7MW in the northern Sunshine Coast and Gympie areas.

*South East Queensland voltage control*

Forecast limitation

The South East Queensland area is the most densely populated part of Queensland. Growing demand results in higher reactive power loadings, as well as greater reactive losses in the system due to increased transmission and transformer loadings. The combined effect is an annual increase in reactive demand above that already being supplied through existing reactive devices. This increasing reactive demand must be met by an acceptable balance between static and dynamic reactive power compensation in South East Queensland to maintain voltage stability. Augmentation of supply is required to ensure adequate reserves of reactive power over the period to summer 2011/12. This limitation is being addressed by a number of committed projects.

#### Committed solutions

The committed projects to summer 2011/12 comprise installation of capacitor banks at Ashgrove West (50MVAr), Loganlea (50MVAr) and Belmont (120MVAr) (refer to Table 3.2).

### *Moreton 110/11kV transformer capability*

#### Forecast limitation

Due to ongoing demand growth from summer 2010/11, an outage of the 110/11kV transformer at Bundamba Substation is forecast to result in thermal limitations in the ENERGEX 11kV network in the local area during summer peak demand periods without action to augment supply.

#### Committed solution

A committed project is under way to address the identified thermal limitation comprising the installation of a second 110/11kV transformer at Bundamba Substation by summer 2010/11 (refer to Table 3.4).

### *Supply to Lockyer Valley*

#### Forecast limitation

Due to ongoing demand growth, thermal limitations are forecast to occur in the ENERGEX 110kV network supplying Lockyer Valley under critical contingency conditions by winter 2011 without action to augment supply.

#### Committed solution

A committed project is under way to address the identified thermal limitation comprising establishment of a second 110kV supply to ENERGEX's Postmans Ridge Substation from Middle Ridge Substation and rearrangement of part of Powerlink's existing Tarong to Middle Ridge 275kV line to operate a circuit at 110kV. Additional ENERGEX works are required to complete the connection to ENERGEX's Postmans Ridge Substation (refer to Table 3.4).

### *Supply within southern Brisbane area*

#### Forecast limitation

The South Brisbane area is defined as the area east of West Darra Substation, north to Murarrie Substation and south to Logan City. Under critical contingency conditions, thermal limitations are forecast to occur initially in the ENERGEX 33kV network supplying the South Brisbane area by summer 2015/16. In the following year, thermal limitations are forecast to occur in Powerlink's 110kV network supplying the area following the loss of a Rocklea 275/110kV transformer, or one of the 110kV lines supplying Richlands Substation without action to augment supply.

#### Possible solutions

A feasible network solution to address the initial thermal limitations in the ENERGEX 33kV network is to establish a bulk supply 110/33kV substation at Larapinta and construct a 110kV line between Algester and Larapinta substations. A feasible network solution to address the subsequent thermal limitations in Powerlink's 110kV network is to install a 275/110kV transformer at Larapinta Substation. The staged network solution is estimated to cost approximately $80 million to $90 million.

Non-network solutions may include:

- local generation; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

#### Load reduction estimate

To defer the forecast limitation for a period of 12 months, proposed non-network solutions must be available on a firm basis to reduce the loading on the transmission network by approximately 40MW in the southern Brisbane area.

*Supply to southern Brisbane, CBD and eastern suburbs*

Forecast limitation

Sufficient capability is forecast to be available until summer 2016/17, from which time thermal limitations are expected to occur on the 275kV transmission lines from Blackwall to Belmont and Greenbank to Loganlea, under critical contingency conditions without action to augment supply.

Possible solutions

A feasible network solution to address the identified thermal limitations is the construction of a new 275kV transmission line from the Blackwall and Swanbank area, to a point west of the transmission corridor between Loganlea and Belmont substations, together with rearranging sections of the existing 275kV transmission lines in the local area, at an approximate cost of $90 million to $110 million.

Non-network solutions may include:

- local generation; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

*Supply to South East Queensland*

Forecast limitation

Power is supplied to South East Queensland from local generation and transmission connections from adjacent zones. The majority of power is transferred to the area via seven 275kV transmission lines between Tarong and the wider Brisbane area, and from Middle Ridge to Greenbank Substation.

Local generation available to supply South East Queensland will also reduce following the announcement from CS Energy that Swanbank B Power Station will be progressively closed. Units 4 and 2 are to be closed in May and June 2010, followed by Unit 1 in April 2011 and Unit 3 in April 2012. This announcement increases the required power transfer into South East Queensland to meet reliability of supply obligations.

A committed program of capacitor bank installations (refer to Table 3.2) provides sufficient capability until summer 2012/13, when voltage limitations are again forecast to re-emerge following a critical contingency. This will limit power transfers into South East Queensland due to insufficient reactive power reserves without action to augment supply.

Committed solutions

A Final Report was published during June 2009 detailed the re-emergence of the forecast limitation in summer 2012/13.

The Final Report recommended a series of works involving additional shunt compensation and the construction of a new 500kV double circuit line between Halys and Blackwall substations, initially operated at 275kV, by summer 2013/14.

Since the publication of the Final Report, Powerlink has reviewed the timing of this major transmission project to take account of changes in the load forecast and to the outlook for local generation within South East Queensland. As a result of this review the timing of the new 500kV double circuit line has been deferred by one year to summer 2014/15.

The committed projects (refer to Table 3.2) comprise:

- installation of capacitor banks at Belmont (120MVAr) and South Pine (50MVAr) substations by summer 2012/13
- construction of a new Halys to Blackwall 500kV transmission line (initially operated at 275kV) by summer 2014/15.

### 4.5.7 Gold Coast zone

*Supply to Gold Coast area*

Forecast limitations

Due to ongoing demand growth, supply to the Gold Coast area may be limited by thermal capacity of transmission plant following critical contingencies. The network limitation relates to thermal overload of a 275/110kV transformer at Molendinar Substation following an outage of a parallel transformer without action to augment supply by summer 2016/17.

A future thermal network limitation also emerges on one of the two Greenbank to Mudgeeraba 275kV circuits, following an outage of the parallel circuit. This limitation occurs beyond 2020 without action to augment supply.

Investigations indicate that based on existing and committed capacity of the ENERGEX 110kV network between Molendinar and Mudgeeraba, the outages to implement solutions to address the above thermal limitation between Greenbank and Mudgeeraba may only be feasible until 2015. However, on completion of a number of ENERGEX projects (some of which are due to condition based replacement), the solution to address the above thermal limitation can be deferred beyond 2020.

Possible solutions

A feasible network solution to address the identified thermal limitation at Molendinar Substation is the installation of a third 275/110kV transformer at Molendinar Substation at an estimated cost of $30 million to $40 million.

Subject to the ENERGEX distribution network reinforcement program, a feasible network solution to address the Greenbank to Mudgeeraba line limitations may include replacing an existing Greenbank to Mudgeeraba 275kV circuit with a 275kV double circuit transmission line, at an estimated cost of $90 million to $120 million. This would involve lengthy outages of the existing Greenbank to Mudgeeraba 275kV line. To ensure reliable supply, construction would occur during the winter and shoulder months over a two-year period.

Non-network solutions may include:

- local generation, in addition to existing and committed plant; and/or
- demand side management initiatives in addition to that already assumed in the delivered demand forecast.

## 4.6 Summary of forecast network limitations

Limitations discussed in sections 4.4 and 4.5 have been summarised in Table 4.8.

This table provides an outlook (based on demand, generation and committed network development assumptions contained in Chapters 2, 3 and 6) for potential limitations in Powerlink's transmission network over a one-, three- and five-year timeframe.

Table 4.8 Summary of forecast network limitations

| Anticipated limitation | Reason for limitation | Time limitation may be reached | | |
|---|---|---|---|---|
| | | 1 year outlook | 3 year outlook | 5 year outlook |
| Far North and Ross zones | | | | |
| Far North Queensland voltage control | 275kV outages in Far North Queensland may result in unacceptable voltage conditions | | | 2015/16 |
| Townsville area 132/66kV transformer capability | Future 132/66kV transformer capability limitations in Townsville area under contingency conditions | | | 2013/14 |
| North zone | | | | |
| Supply to Bowen area | Due to potential industrial load growth, voltage and thermal limitations expected to occur under contingency conditions | Stage 1, 2010/11 committed project in progress (1) | | Stage 2, 2013/14 (2) |
| CQ-NQ transfer limit | Voltage, dynamic instability and thermal limitations expected under contingency conditions | To 2010/11 committed projects in progress (1) | | 2014/15 (3) |
| Supply to Bowen Basin coal mining area | Due to potential mining growth, thermal limitations expected to occur under contingency conditions | | | 2013/14 (2) |
| Central West and Gladstone zones | | | | |
| Rockhampton area 275/132kV transformer capability | Future 275/132kV transformer capability limitations in Bouldercombe area under contingency conditions | | 2012/13 | |
| Supply to Blackwater area | Due to new industrial load growth, thermal limitations expected to occur under contingency conditions | | 2012/13 | |
| Supply to inland Central Queensland area | Due to demand growth, 132kV network between Callide, Biloela and Moura is expected to reach thermal capability limitations under contingency conditions and may result in unacceptably low voltages in the Moura area | 2010/11 committed project in progress (1) | | |
| Supply within Central Queensland | Power transfer limitations out of Central West and Gladstone zones under contingency conditions | Currently managed by switching and support arrangements | | 2013/14 (4) |
| Gladstone area harmonics | Mitigating increasing harmonic levels in the Gladstone area | Winter 2010 committed project in progress (1) | | |
| Bulli and South West zones | | | | |
| SWQ transfer limit | Continued demand growth is expected to lead to SWQ transfer limit being reached under contingency conditions | Currently managed by switching and support arrangements | 2011/12 to 2012/13, committed projects in progress (1) | |

Table 4.8 Summary of forecast network limitations (continued)

| Anticipated limitation | Reason for limitation | Time limitation may be reached | | |
|---|---|---|---|---|
| | | 1 year outlook | 3 year outlook | 5 year outlook |
| Supply to Surat Basin north west area | Due to potential future large industrial demand growth, future 132/66kV supply capability limitations are anticipated under contingency conditions | | Winter 2013 (2) (4) | |
| Moreton zone | | | | |
| CQ-SQ transfer limit | Continued demand growth in South Queensland is expected to lead to CQ-SQ limit being reached under contingency conditions | | | 2014/15 (2) |
| Supply to northern Sunshine Coast area | Demand growth expected to result in thermal limitations in the ENERGEX 132kV network between Woolooga and Gympie under contingency conditions | | | 2014/15 |
| South East Queensland voltage control | Increasing reactive demand due to demand growth is expected to require a program of action to satisfy voltage control standards | To 2011/12 committed projects in progress (1) | | |
| Moreton 110/11kV transformer capability | Due to demand growth, future 110kV transformer limitations are forecast under contingency conditions | 2010/11, committed project in progress (1) | | |
| Supply to Lockyer Valley | Due to demand growth, thermal limitations in the ENERGEX 110kV network is expected to be reached under contingency conditions | | 2011/12, committed project in progress (1) | |
| Supply within southern Brisbane area | Due to demand growth, thermal limitations in the ENERGEX 110kV network, followed by thermal limitations in Powerlink's 275/110kV network supplying this area are forecast to occur under contingency conditions | | | 2015/16 and 2016/17 (5) |
| Supply to southern Brisbane, CBD and eastern suburbs | Demand growth is forecast to result in thermal limitations in sections of 275kV transmission lines from Blackwall to Belmont Substation and from Greenbank to Loganlea Substation under contingency conditions | | | 2016/17 (5) |
| Supply to South East Queensland | High demand growth is expected to result in limitations in supply to South East Queensland area under contingency conditions | | 2012/13, committed projects in progress (1) | 2014/15, Committed project in progress (1) |
| Gold Coast zone | | | | |
| Supply to Gold Coast area | Due to demand growth, thermal capacity limitations on a 275/110kV Molendinar transformer is expected to be reached under contingency conditions | | | 2016/17 onwards (5) |

Notes:

(1) Refer to Tables 3.2 and 3.4 – Committed Augmentations.

(2) The actual timing of the forecast limitation will be driven by major industrial developments and/or new generation.

(3) The economic timing will be driven by major industrial developments and/or new generation (refer to Section 4.5.3).

(4) Refer to Section 4.7 – Proposed Network Developments.

(5) Associated site and or easement acquisition project falls within the outlook period.

## 4.7 Proposed network developments

Network development to meet forecast demand depends 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, where a significant amount of new large generation capacity has entered the market over the past few years.

The previous section of this report outlined forecast limitations that may arise in Powerlink's transmission network in the near future. Proposals for developing the network to address the forecast limitations are progressed under the provisions of Clause 5.6.6 of the NER. Accordingly, and where action is considered necessary, Powerlink will:

- notify of anticipated limitations within the timeframe required for action
- seek information from Registered Participants and interested parties on feasible non-network solutions to address anticipated constraints
- seek input, generally via the APR, on potential solutions to network limitations which may result in new network investments
- issue detailed information papers outlining emerging network limitations which may assist in identifying non-network solutions as possible genuine alternatives to new network investments
- carry out detailed analysis to determine feasible network solutions that Powerlink may propose to address identified network constraints
- consult with Registered Participants and interested parties on all genuine and feasible alternatives (network and non-network) and recommended solutions
- implement the recommended solution in the event a regulated solution (network or network support) is found to satisfy the Australian Energy Regulator's (AER's) Regulatory Test.

Alternatively, Powerlink may undertake network augmentations under the 'funded augmentation' provisions of the NER.

The first part of this section focuses on those limitations for which Powerlink has completed consultations on during the past 12 months and is implementing new large network assets. The second and third parts of this section discuss those limitations for which Powerlink is currently consulting on and plans to consult on within the next 12 months.

Potential connection point proposals are also discussed.

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

### 4.7.1 Completed consultations

During 2009/10, Powerlink finalised consultations under the AER's Regulatory Test covering a network solution that addresses a number of forecast limitations detailed in sections 4.4 to 4.6. The solution comprises a series of works outlined in Table 4.9 and also in Table 3.2 as committed transmission developments.

**Table 4.9 New network investment consultations finalised in 2009/10**

| Project name | Description of works | Cost | Expected commissioning date |
|---|---|---|---|
| South West to South East Queensland | Series of works comprising:<br>• installing capacitor banks at Millmerran, Middle Ridge, Belmont and South Pine substations<br>• establishing new 275kV substations at Western Downs and Halys and a 275kV line between the substations<br>• rearranging an existing 275kV line between Kogan Creek Power Station and Braemar Substation, to connect Western Downs Substation<br>• splitting the 275kV bus at Braemar Substation<br>• constructing a new 500kV line between Halys and Blackwall substations (initially operated at 275kV). | $ 651.24m | Progressively 2011–2014 |

### 4.7.2 Current consultations – proposed new large network assets

Proposals for new large network assets that address limitations detailed in sections 4.4 to 4.6 are progressed under the provisions of Clause 5.6.6 of the NER. Powerlink carries out separate consultation processes for each proposed new large network asset.

Powerlink has a number of consultations currently under way and are summarised in this APR. These consultations are being progressed consistent with the provisions of Clause 11.29 prescribed by the NER, which requires Powerlink to utilise the AER's Regulatory Test consultation process.

The consultations currently under way are listed in Table 4.10. Registered Participants and interested parties are referred to consultation documents published on Powerlink's website for further information.

**Table 4.10 Consultation currently under way**

| Area | Publication of Application Notice | Publication of Final Report |
|---|---|---|
| Surat Basin north west area | June 2010 | October 2010 |
| Central Queensland | June 2010 | August 2010 |

### 4.7.3 Future consultations – proposed new network investments

#### Anticipated consultations

Powerlink anticipates undertaking a number of consultations within the next 12 months that could give rise to implementing new network investments that address limitations detailed in section 4.4 to 4.6.

These consultations will be progressed under new regulatory consultation process changes released by the Australian Energy Market Commission (AEMC) during July 2009. The new regulatory consultation processes prescribed by the NER come into effect from 1 August 2010 and require Powerlink to apply the Regulatory Investment Test for Transmission (RIT-T).

The consultations likely to be initiated within the next 12 months under the RIT-T are summarised in Table 4.11.

**Table 4.11 Consultations likely within 12 months**

| Area (1) |
|---|
| Supply to Northern Bowen Basin |

Note:

(1) For further details on each of these limitations, refer to sections 4.4 and 4.5.

Emerging limitations other than those listed will be monitored and Powerlink will initiate action, including consultation with interested parties, should this be required.

#### Request for proposal

The NER requires Powerlink to state, for forecast constraints that can be deferred by 12 months by a reduction of forecast load, whether it plans to issue requests for proposals. A request for proposals is for augmentation or non-network alternatives that address limitations detailed in sections 4.4 to 4.5 (refer to Clause 5.6.2A (3a)).

Powerlink will utilise the AER's RIT-T consultation process to satisfy this requirement. Under the RIT-T consultation process, Powerlink is required to undertake consultations on issues and options which address forecast limitations detailed in this APR. This includes publishing a Project Specification Consultation Report where the most expensive option to address the identified need that is technically and economically feasible, has an estimated capital cost that exceeds the cost threshold determination made by the AER. The Project Specification Consultation Report seeks input from Registered Participants, AEMO and other interested parties on the credible options presented and the issues addressed. Powerlink considers that the Project Specification Consultation Report meets the requirements of a request for proposals and Table 4.11 above lists these future consultations.

### 4.7.4 Connection point proposals

Table 4.12 lists connection works that may be required over the next five years. 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 or be initiated by generators or customers.

Table 4.12 Connection point proposals

| Potential project | Purpose | Zone | Possible commissioning date |
|---|---|---|---|
| Kamerunga 132kV connection for Kewarra Beach | New supply to Ergon Energy Kewarra Beach Substation | Far North | Summer 2013/14 |
| High Road Wind Farm | New generation plant connection | Far North | Summer 2013/14 |
| Pioneer Valley 132/66kV transformer augmentation | Increase transformer capacity to meet Ergon Energy network requirements | North | Summer 2012/13 |
| Blackwater Power Station | Connection of new generation units | Central West | Summer 2011/12 |
| Multiple new coal mine 132kV connections | New industrial plant connections in the Bowen Basin area | Central West | Progressively from summer 2012/13 |
| Multiple new coal mine 132kV connections | New industrial plant connection in the Galilee Basin area | Central West | Summer 2013/14 |
| Multiple upstream gas compression facilities connections | Multiple new connections for coal seam methane/liquefied natural gas compression facilities in the Surat Basin North West area | Bulli and South West | Winter 2012 to summer 2014/15 |
| New coal mine connection | New industrial plant connection in the Surat Basin north west area | South West | Summer 2013/14 |
| Loganlea 110/33kV transformer augmentation | Increase transformer capacity to meet growing demand | Moreton | Summer 2013/14 |
| Rocklea 110kV connection for Woolloongabba | New supply to ENERGEX Woolloongabba Substation | Moreton | Summer 2013/14 |
| Abermain 110kV connection for Wulkuraka | New supply to ENERGEX Wulkuraka Substation | Moreton | Summer 2014/15 |
| Molendinar 110kV connection for Southport | Increase supply to ENERGEX Southport Substation | Gold Coast | Summer 2011/12 |
| Molendinar 110kV connection for Cades County | Increase supply to ENERGEX Cades County Substation | Gold Coast | Summer 2011/12 |

## 4.8 Proposed network replacements

In addition to developing its network to meet forecast electricity demand, Powerlink is also required to maintain the capability of its existing network. Powerlink undertakes asset replacement projects when assets are determined to reach the end of their life. Table 4.13 lists potential replacement works over the value of $5 million that are expected to occur in the next five years.

The identification of potential replacement projects does not indicate a supply reliability risk. Replacement programs are planned some years into the future to allow Powerlink to schedule works such that it can continue to provide a reliable power supply to customers.

Table 4.13 Possible replacement works

| Project description | Purpose | Zone | Possible commissioning date | Indicative costs | Alternatives |
|---|---|---|---|---|---|
| Kareeya Substation primary plant replacement | Maintain supply reliability to the Far North zone | Far North | Summer 2012/13 | $15m (approximate) | Establish a new 132/22kV substation |
| Cardwell to Ingham 132kV line replacement | Maintain supply reliability to the Ross zone | Ross | Summer 2012/13 | $50m (approximate) | New local generation in the Far North zone with distribution network reinforcement |
| Garbutt to Alan Sherriff 132kV line life extension | Maintain supply Reliability to the Ross zone | Ross | Summer 2012/13 | $10m (approximate) | New local generation in the Townsville area with distribution network reinforcement |
| Tully to Cardwell 132kV line replacement | Maintain supply reliability to the Ross zone | Ross | Summer 2013/14 | $65m (approximate) | New local generation in the Far North zone with distribution network reinforcement |
| Moranbah Substation primary plant replacement (including transformers) | Maintain supply reliability to the North zone | North | Progressively from summer 2012/13 to winter 2013 | $10m (approximate) | Establish a new 132/66kV substation |
| Collinsville Substation primary plant replacement | Maintain supply reliability to the North zone | North | Winter 2013 | $10m (approximate) | Establish a new 132/33kV substation |
| Mackay Substation primary plant replacement | Maintain supply reliability to the North zone | North | Summer 2013/14 | $25m (approximate) | Establish a new 132/33kV substation |
| Nebo transformers replacement | Maintain supply reliability to the North zone | North | Progressively from winter 2013 to winter 2014 | $10m (approximate) | Extend the transmission and distribution networks and transfer part of the load from Nebo Substation |
| Callide A Substation primary plant replacement | Maintain supply reliability to the Central West zone | Central West | Summer 2014/15 | $25m (approximate) | Establish a new 132kV substation |
| Lilyvale transformers replacement | Maintain supply reliability to the Central West zone | Central West | Progressively from winter 2014 to winter 2015 | $15m (approximate) | Extend the transmission and distribution networks and transfer part of the load from Lilyvale Substation |
| Moura Substation primary plant replacement | Maintain supply reliability to the Central West zone | Central West | Summer 2014/15 | $20m (approximate) | Establish a new 132kV substation |
| Gin Gin Substation primary plant replacement | Maintain supply reliability to the Wide Bay zone | Wide Bay | Summer 2014/15 | $40m (approximate) | Establish a new 275kV substation |

Table 4.13 Possible replacement works (continued)

| Project description | Purpose | Zone | Possible commissioning date | Indicative costs | Alternatives |
|---|---|---|---|---|---|
| Woolooga transformers replacement | Maintain supply reliability to the Wide Bay zone | Wide Bay | Summer 2014/15 | $10m (approximate) | Extend the distribution network from Palmwoods Substation and transfer part of the load from Woolooga Substation |
| Swanbank B Substation primary plant replacement | Maintain supply reliability to the Moreton zone | Moreton | Summer 2012/13 | $55m (approximate) | Extend the transmission and distribution networks and establish additional 275/110kV transformation in the Ipswich area |
| Richlands Substation primary plant replacement | Maintain supply reliability to the Moreton zone | Moreton | Summer 2012/13 | $20m (approximate) | New local generation in the Moreton zone with distribution network reinforcement |

# chapter 5 Other relevant planning issues

## 5.1 Existing and committed generation developments

### 5.1.1 Generation

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

The majority of new generators recently commissioned are situated within the South West Queensland area. There continues to be a high level of interest for generator connections in this same area and ERM's Braemar 3 Power Station has reached an advanced stage of commitment.

CS Energy has announced that Swanbank B power station will be progressively closed by April 2012.

Table 5.1 summarises the registered capacity of power stations connected or committed for connection to the Powerlink Queensland transmission network including the non-scheduled market generators at Invicta and Koombooloomba. This table also includes scheduled embedded generators at Barcaldine, Roma and Condamine.

The information within this table has been provided to the Australian Energy Market Operator (AEMO) by the owners of the generators.

**Table 5.1 Generation capacity**

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

| Location | Capacity MW generated (1) | | | | | |
|---|---|---|---|---|---|---|
| | Winter 2010 | Summer 2010/11 | Winter 2011 | Summer 2011/12 | Winter 2012 | Summer 2012/13 |
| **Coal-fired** | | | | | | |
| Collinsville | 187 | 187 | 187 | 187 | 187 | 187 |
| Stanwell | 1,453 | 1,397 | 1,460 | 1,404 | 1,466 | 1,404 |
| Gladstone | 1,680 | 1,680 | 1,680 | 1,680 | 1,680 | 1,680 |
| Callide A (2) | 30 | 30 | 30 | 30 | 30 | 30 |
| 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 |
| Swanbank B (3) | 240 | 240 | 120 | 120 | – | – |
| Kogan Creek | 744 | 724 | 744 | 724 | 744 | 724 |
| Millmerran | 852 | 852 | 852 | 852 | 852 | 852 |
| **Total coal-fired** | **8,629** | **8,553** | **8,516** | **8,440** | **8,402** | **8,320** |
| **Combustion turbine** | | | | | | |
| Townsville (Yabulu) | 243 | 235 | 243 | 235 | 243 | 235 |
| Mt Stuart | 415 | 387 | 415 | 387 | 415 | 387 |
| Mackay | 32 | 27 | 32 | 27 | 32 | 27 |
| Barcaldine | 36 | 36 | 36 | 36 | 36 | 36 |
| Yarwun (4) | 167 | 152 | 167 | 152 | 167 | 152 |
| Roma | 68 | 54 | 68 | 54 | 68 | 54 |
| Condamine | 135 | 135 | 135 | 135 | 135 | 135 |
| Oakey (5) | 332 | 275 | 332 | 275 | 332 | 275 |
| Swanbank E | 370 | 350 | 370 | 350 | 370 | 350 |
| Braemar 1 | 504 | 435 | 504 | 435 | 504 | 435 |
| Braemar 2 | 519 | 462 | 519 | 462 | 519 | 462 |
| Darling Downs | 630 | 605 | 630 | 605 | 630 | 605 |
| Braemar 3 (6) | – | – | – | – | – | 600 |
| **Total combustion turbine** | **3,451** | **3,153** | **3,451** | **3,153** | **3,451** | **3,753** |
| **Hydro electric** | | | | | | |
| Barron Gorge | 60 | 60 | 60 | 60 | 60 | 60 |
| Kareeya (including Koombooloomba) | 94 | 94 | 94 | 94 | 94 | 94 |
| Wivenhoe (7) | 500 | 500 | 500 | 500 | 500 | 500 |
| **Total hydro electric** | **654** | **654** | **654** | **654** | **654** | **654** |
| **Sugar mills** | | | | | | |
| Invicta | 39 | 39 | 39 | 39 | 39 | 39 |
| **Total all stations** | **12,773** | **12,399** | **12,660** | **12,286** | **12,546** | **12,766** |

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 step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) One generating unit of the Callide A Power Station is to be used in the CS Energy Oxyfuel Clean Coal Project. The experimental nature of this project makes it difficult to predict when this capacity will be available.

(3) CS Energy has announced that Swanbank B will be progressively closed, with Units 4 and 2 to be placed in storage in May and June 2010, followed by Unit 1 in April 2011 and Unit 3 in April 2012.

(4) Rio Tinto Alcan (RTA) Yarwun is expected to be commissioned in winter 2010.

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

(6) ERM Braemar 3 Power Station has reached an advanced stage of commitment. The first 300MW unit is expected to be commissioned in September 2012, with the second 300MW unit by early 2013.

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

## 5.2 Changes to supply capability

### 5.2.1 Generation

Since the 2009 Annual Planning Report (APR), ERM has reached an advanced stage of commitment to commission a 600MW (two units) power station to connect to Powerlink's Braemar 275kV Substation. Both units are planned to be operational by early 2013.

Rio Tinto Alcan (RTA) is well advanced in commissioning the 167MW Yarwun gas cogeneration power station.

Generation projects commissioned since the 2009 APR include:

- Mt Stuart Power Station third unit (liquid fuel)
- Braemar 2 Power Station (open cycle gas)
- Condamine Power Station (combined cycle gas)
- Darling Downs Power Station (combined cycle gas).

These recently commissioned and committed generators in Queensland have been incorporated within Table 5.1.

### 5.2.2 Interconnectors

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

The combined QNI plus Terranora Interconnector maximum northerly capability is limited by thermal ratings, voltage stability, transient stability and oscillatory stability (as detailed within Section 4.4.8).

The capability of these interconnectors can vary significantly depending on the status of plant and load conditions in both Queensland and NSW. For these reasons, QNI capability is regularly reviewed particularly when new generation enters the market.

### 5.2.3 Interconnector upgrades

Powerlink and TransGrid published a Final Report in October 2008 relating to the potential upgrade of interconnection between Queensland and New South Wales. The Final Report detailed outcomes of comprehensive technical and economic assessment of technically feasible upgrade options (each delivering different increments in interconnection transfer capability) carried out in accordance with the Australian Energy Regulator (AER) Regulatory Test.

The Final Report also responded to submissions from market participants to the Interim Report for Public Consultation published earlier that year.

The Final Report indicated that installation of series compensation with an estimated cost of around $120 million provided the highest net market benefits in the majority of scenarios considered. The optimum timing under the most plausible scenario is 2015/16. Based on that timing, TransGrid and Powerlink considered it premature at that time to recommend an upgrade.

Since the 2008 Powerlink/TransGrid report, there have been a number of market developments, including mooted generation investments, the expanded renewable energy target, and the revision of the Regulatory Test. In the light of these developments, the two organisations have agreed to undertake further investigations to evaluate the economic viability (and optimal timing) of a potential upgrades to QNI, based on the principles and methodology of the Regulatory Investment Test for Transmission (RIT-T). Depending on the results which emerge from this economic analysis, the organisations may decide to formally progress an upgrade through the National Electricity Rules process.

## 5.3 Supply demand balance

The outlook for the supply demand balance for the Queensland Region was published in the AEMO 2009 Electricity Statement of Opportunities (ESOO). As part of the normal annual planning cycle, AEMO will publish a revised outlook in the 2010 ESOO. Interested parties who require information regarding future supply demand balance should consult that document.

# chapter 6 National transmission flow path developments

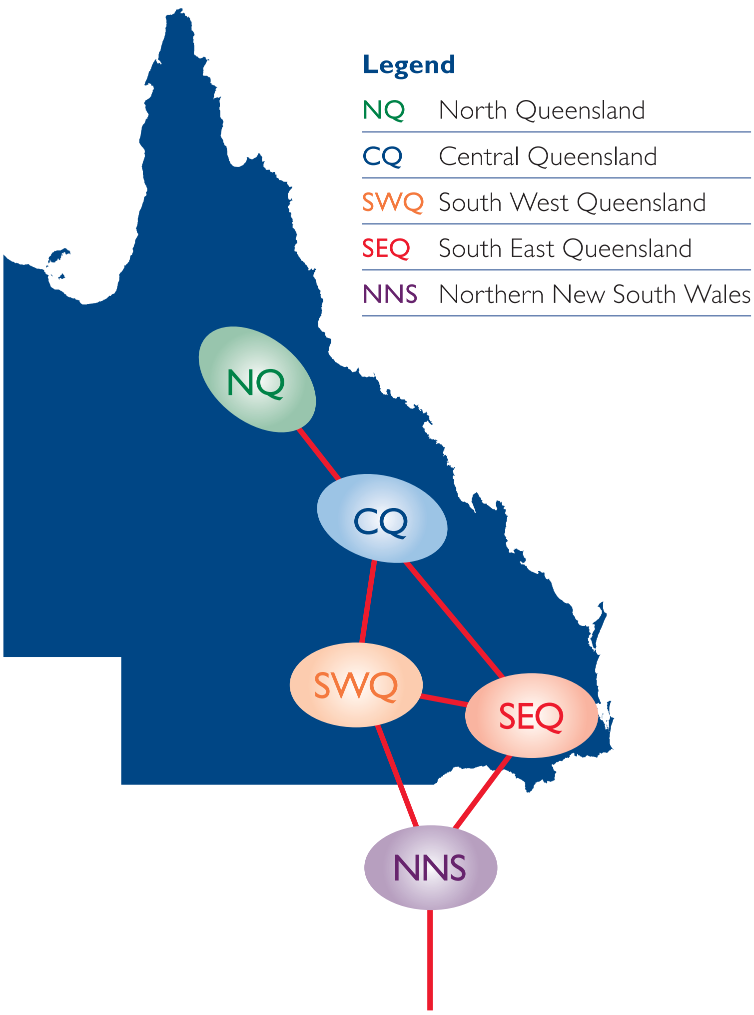
## 6.1 Background

The Australian Energy Market Operator (AEMO) is responsible for production of the National Transmission Network Development Plan (NTNDP). The purpose of the NTNDP is to provide a view for the efficient development of the national transmission grid for at least a 20-year planning horizon across a range of credible scenarios.

The National Electricity Rules (NER) state that the NTNDP is required to define a development strategy for each current and potential National Transmission Flow Path (NTFP). The NER defines the NTFP as that portion of a transmission network or transmission networks used to transport significant amounts of electricity between major generation and load centres.

The NTFPs for the Queensland Region corresponding to this definition are shown in Figure 6.1. These flow paths also align with key intra-regional grid sections described in Section 4.3, and are consistent with the flow paths in AEMO's 2009 National Transmission Statement (NTS).

**Figure 6.1 Queensland national transmission flow paths**



## 6.2 Network developments

The NTNDP is required to consider relevant intra-jurisdictional developments that may be needed to coordinate national transmission flow path planning. The committed projects or projects currently under consultation which impact on Queensland's transmission flow paths are detailed in Table G.1 of Appendix G.

The NER also specifies that development strategies for NTFPs are required to take into account potential technically feasible network and non-network options, and that these investment options should be co-optimised to maximise market economic benefits.

To assist with this process, a range of credible potential network options which preserve or increase the transfer capability across NTFPs for Queensland have been prepared. These potential network options are detailed within Tables G.2 and G.3 of Appendix G. This table also includes information on the indicative costs of these options, the potential impacts on network limits, and affected constraints within AEMO's market dispatch systems. These network options range from incremental developments to large projects capable of delivering significant increases in power transfer capability.

It should be noted that some of the information presented for potential network options in Appendix G is indicative only, and based on preliminary power system studies. As the projects reach higher levels of certainty, more detailed and comprehensive studies are carried out to better define the scope of the augmentation, and corresponding power transfer capability increases.

The need and timing for potential network projects across the medium to longer term is dependent on a range of factors, including the location and capacity of new generation developments, advent of large scale industrial loads, underlying demand growth, decentralised supply side technologies, and demand side initiatives. A very high level indication of the timing of network developments for Queensland NTFPs across this timeframe under different demand, generation and demand side cases is provided in Tables G.4 and G.5 of Appendix G.

# Appendices

A Temperature and diversity corrected area demands

B Forecast of connection points

C Estimated network power flows

D Limit equations

E Small network augmentations

F Estimated maximum short circuit levels

G National transmission flow path projects

H Abbreviations

## Appendix A – Temperature and diversity corrected area demands

### The Queensland multiple area forecasting model

Compared to other states in the National Electricity Market (NEM), Queensland's load distribution is decentralised, with greater than 40% outside the south east corner of the State. A significant amount of Queensland's load growth is industrial, scattered across the rest of the State, with an emphasis on the mining industry.

Diverse load and weather patterns across the State require load forecasting methods to be applied to five distinct components of load, before combining in a way that accounts for the appropriate weather and load diversity between these components.

For analysis of the dependence of summer and winter daily maximum demands on ambient temperature conditions across parts of Queensland the weather station records listed in Table A.1 are used. These reference temperatures have been recently revised by the National Institute of Economic and Industrial Research (NIEIR) to account for recent historical weather and to include a global warming trend factor.

**Table A.1 Reference temperatures at associated probability of exceedence (PoE) conditions**

| Weather station / load area | Average daily temperature percentiles (°C) (1) | | | | | |
|---|---|---|---|---|---|---|
| | Summer | | | Winter | | |
| | 10% PoE | 50% PoE | 90% PoE | 10% PoE | 50% PoE | 90% PoE |
| Townsville for northern non-industrial native load (2) | 32.7 | 31.0 | 30.3 | 26.5 | 25.3 | 24.1 |
| Rockhampton for central non-industrial native load | 33.2 | 32.0 | 30.5 | 11.2 | 12.3 | 13.7 |
| Toowoomba for south west native load | 30.2 | 28.0 | 26.3 | 4.7 | 6.0 | 7.0 |
| Archerfield (Brisbane) for south east native load – winter only (3) | – | – | – | 10.0 | 11.0 | 12.4 |
| Amberley (Brisbane) for south east native load – summer only (3) | 32.3 | 30.0 | 28.5 | – | – | – |

Notes:

(1) This is the average of the maximum temperature on the day and the minimum temperature during the prior night/morning.

(2) In this area winter demand increases with higher ambient temperature.

(3) ENERGEX and NIEIR have recommended the use of Amberley summer temperatures for Brisbane, as it is more reliable than Archerfield and more representative of South East Queensland on summer afternoons.

### Observed demand sensitivity to temperature

Observed temperature sensitivities for the northern, central and south west areas are defined by linear regression of the daily maximum demands against daily average temperatures on working weekdays. This also applies to the south east area for winter analysis. These sensitivities are listed in Table A.2 and show that sensitivity of demand to ambient temperature is higher in summer compared to winter across all areas of Queensland.

The observed temperature sensitivity for South East Queensland in summer is now defined by 'S-curve' working day analysis. This assumes that demand to temperature sensitivity is zero on a cool summer day with an average temperature of 20°C, increases to peak sensitivity at 27°C, and then saturates back to zero sensitivity at 34°C, which is higher than the 10% PoE reference temperature. At the latter temperature it is assumed that all available domestic air conditioning in occupied houses is operating. In South East Queensland there have been several recent summers with very few days of temperatures within the reference temperatures. A normalised analysis over all available data of the last 12 years has found that this 'S-curve' approach has a very high correlation, and therefore is better able to correct demands to the reference temperature levels. The maximum sensitivity at 27°C is listed in Table A.2.

Figure A.1 shows the summer 2009/10 'S-Curve' for South East Queensland. It represents the 'curve of best fit' for daily native peak demand against Amberley average temperature. This 'S-Curve' illustrates temperature sensitivity noting that it is a non-linear relationship. The methodology used to derive the 'S-Curve' is aimed at deriving the curve shape only and is done so based on average daily summer demands, i.e. actual values fall evenly either side of this curve. In order to assess temperature correction for seasonal peak demand, the 'S-Curve' is offset and applied to a subset of the data. This subset includes working weekdays with high demand and temperatures close to the 50% PoE temperature.

**Figure A.1 South East Queensland native daily peak demand 'S-curve' against Amberley temperature on working days of summer 2009/10**

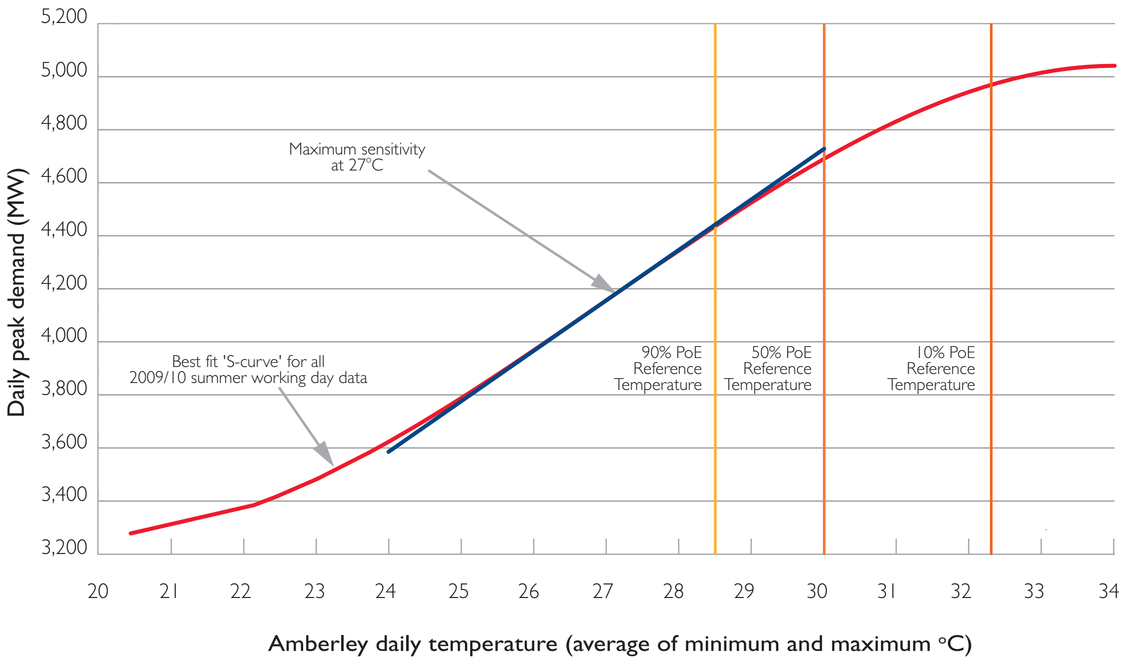


Table A.2 Observed temperature sensitivity of daily peak demands

| | Demand change dependence on average daily temperature (MW per °C) (1) | | | |
|---|---|---|---|---|
| | South East (2) | South West | Northern non-industrial | Central non-industrial |
| Summer | | | | |
| 2000/01 | 65 | 7.0 | 24 | 16 |
| 2001/02 | 72 | 5.0 | 28 | 14 |
| 2002/03 | 69 | 7.0 | 32 | 18 |
| 2003/04 | 115 | 8.6 | 37 | 18 |
| 2004/05 | 147 | 9.0 | 33 | 19 |
| 2005/06 | 162 | 11.1 | 40 | 24 |
| 2006/07 | 160 | 12.0 | 46 | 24 |
| 2007/08 | 154 | 11.2 | 50 | 19 |
| 2008/09 | 196 | 11.6 | 46 | 25 |
| 2009/10 | 168 | 14.5 | 41 | 20 |
| Winter | | | | |
| 2000 | - 48 | - 6.9 | N/A (3) | N/A (4) |
| 2001 | - 39 | - 6.3 | 6.9 | |
| 2002 | - 40 | - 6.3 | 8.8 | |
| 2003 | - 46 | - 6.7 | 7.0 | |
| 2004 | - 44 | - 7.4 | 3.8 | |
| 2005 | - 46 | - 6.6 | 6.8 | |
| 2006 | - 56 | - 9.8 | N/A (3) | |
| 2007 | - 93 | -11.8 | 7.1 | |
| 2008 | -108 | -11.0 | N/A (3) | |
| 2009 | -26 | -9.4 | 10 | |

Notes:

(1) Over summer, the working weekdays in the period mid November to mid March are analysed and the holiday period from Christmas to the first week of January is excluded. Over winter, the working weekdays in the period mid May to early September are analysed. In summer, if the previous day is hotter during a hot period, then the average temperature is adjusted by using a 25% weighting of the previous day's temperature with a 75% weighting of the current day's temperature. Similarly, in winter, if the previous day is colder during a cold period, then the average temperature is adjusted by using a 25% weighting of the previous day's average temperature with a 75% weighting of the current day's average temperature (except for North Queensland).

(2) Due to the lack of relatively hot summer days in South East Queensland over four of the last five summers, the summer temperature correction method is now based on fitting data to a normalised 'S-curve' derived from all data of the previous 12 summers. Also, Amberley summer temperatures are now used to create the whole of summer demand to temperature response curve, based on ENERGEX and NIEIR recommendations. The sensitivity in the table is the maximum of the 'S-curve' at 27°C average daily Amberley temperature.

(3) Poor correlation of data in this winter.

(4) Poor correlation of data over most winters. Accordingly, this area's demand is taken to be relatively insensitive to winter temperatures.

### History of area demands

Tables A.3 and A.4 show the last 10 years of area and industrial summer and winter peak demands, their demand at time of the actual Queensland Region peak demand, and their temperature corrected peak demands, calculated using the observed sensitivities as above.

**Table A.3 Area summer 50% PoE demand temperature corrections and coincidence at state peak native (1) demand**

| | South East (2) | South West (3) | Northern non-industrial (4) | Central non-industrial (5) | Major industrial (6) |
|---|---|---|---|---|---|
| Actual at time of Queensland peak demand/actual own peak demand (one value if coincident) | | | | | |
| 2000/01 | 2,977 | 270 / 282 | 902 / 911 | 664 / 744 | 1,017 / 1,037 |
| 2001/02 | 3,091 / 3,120 | 258 / 284 | 1,037 / 1,044 | 765 / 801 | 1,032 / 1,062 |
| 2002/03 | 3,383 | 298 / 303 | 938 / 980 | 714 / 769 | 1,003 / 1,085 |
| 2003/04 | 3,846 | 339 / 340 | 933 / 1,079 | 818 / 831 | 1,083 / 1,108 |
| 2004/05 | 4,024 | 349 / 358 | 1,016 / 1,089 | 883 | 1,009 / 1,110 |
| 2005/06 | 4,018 / 4,141 | 351 / 401 | 1,041 / 1,140 | 909 / 925 | 1,054 / 1,141 |
| 2006/07 | 4,246 / 4,300 | 376 / 396 | 1,238 | 967 / 984 | 1,060 / 1,180 |
| 2007/08 | 4,092 / 4,114 | 341 / 347 | 1,060 / 1,158 | 895 / 925 | 1,058 / 1,183 |
| 2008/09 | 4,631 / 4,635 | 414 / 415 | 960 / 1,218 | 909 / 964 | 1,107 / 1,186 |
| 2009/10 | 4,694 / 4,740 | 342 / 432 | 1,247 / 1,256 | 950 / 961 | 1,058 / 1,196 |
| Temperature corrected area peak demand | | | | | |
| 2000/01 | 2,999 | 303 | 946 | 779 | N/A (7) |
| 2001/02 | 3,197 | 298 | 991 | 801 | |
| 2002/03 | 3,376 | 314 | 1,005 | 806 | |
| 2003/04 | 3,713 | 333 | 1,060 | 833 | |
| 2004/05 | 4,073 | 360 | 1,081 | 908 | |
| 2005/06 | 4,246 | 406 | 1,137 | 968 | |
| 2006/07 | 4,433 | 395 | 1,253 | 948 | |
| 2007/08 | 4,531 | 386 | 1,218 | 970 | |
| 2008/09 | 4,907 | 429 | 1,214 | 964 | |
| 2009/10 | 4,914 | 421 | 1,342 | 1,019 | |

Notes:

(1) Some corrections have been made in the last three years due to recent acquisition of revenue metering data for some significant embedded non-scheduled generation to account for native demand values.

(2) South East Queensland is taken as Moreton plus Gold Coast zones, and its summer demand corrections have been recalculated in recent years to consider Amberley temperatures, as recommended by ENERGEX and NIEIR, and also to align with a more robust demand to temperature correlation using 'S-curve' rather than linear analysis.

(3) South West Queensland is taken as the South West and Bulli zones and is compared to Toowoomba temperatures.

(4) Northern non-industrial is taken as Far North, Ross and North zones less the Sun Metals and Queensland Nickel industrial loads, and is compared to Townsville temperatures.

(5) Central non-industrial is taken as Central West, Gladstone and Wide Bay zones less the Boyne Island Smelter and QAL industrial loads, and is compared to Rockhampton temperatures.

(6) Industrial is taken here as the sum of Sun Metals, Queensland Nickel, Boyne Island Smelter and QAL direct connected industrial loads.

(7) These major industrial loads have negligible sensitivity to temperature.

Table A.4 Area winter 50% PoE demand temperature corrections and coincidence at state peak native (1) demand

| | South East | South West | Northern non-industrial | Central non-industrial | Major industrial |
|---|---|---|---|---|---|
| Actual at time of Queensland peak demand/actual own peak demand (one value if coincident) | | | | | |
| 2000 | 2,968 / 2,992 | 291 / 318 | 694 / 776 | 647 / 709 | 1,009 / 1,021 |
| 2001 | 2,962 / 2,975 | 301 / 313 | 714 / 781 | 734 / 735 | 1,019 / 1,052 |
| 2002 | 2,999 | 286 / 307 | 685 / 796 | 648 / 710 | 1,053 / 1,060 |
| 2003 | 3,325 | 318 / 322 | 719 / 806 | 691 / 739 | 1,012 / 1,068 |
| 2004 | 3,407 / 3,504 | 345 / 350 | 803 / 813 | 751 / 797 | 1,061 / 1,099 |
| 2005 | 3,731 | 343 / 368 | 706 / 840 | 752 / 792 | 1,021 / 1,130 |
| 2006 | 3,882 | 361 / 373 | 788 / 850 | 783 | 1,077 / 1,162 |
| 2007 | 4,064 / 4,120 | 410 / 416 | 784 / 926 | 895 / 905 | 1,069 / 1,185 |
| 2008 | 4,341 | 424 / 432 | 861 / 923 | 853 / 874 | 1,114 / 1,189 |
| 2009 | 3,981 | 391 / 417 | 872 / 964 | 781 / 873 | 1,137 / 1,186 |
| Temperature corrected area peak demand | | | | | |
| 2000 | 2,963 | 320 | 776 | N/A (2) | N/A (3) |
| 2001 | 3,036 | 329 | 783 | | |
| 2002 | 3,078 | 325 | 816 | | |
| 2003 | 3,327 | 329 | 815 | | |
| 2004 | 3,511 | 365 | 821 | | |
| 2005 | 3,713 | 372 | 848 | | |
| 2006 | 3,882 | 409 | 850 | | |
| 2007 | 4,039 | 419 | 916 | | |
| 2008 | 4,341 | 449 | 919 | | |
| 2009 | 4,005 | 407 | 964 | | |

Notes:

(1) Some corrections have been made in the last three years due to recent acquisition of revenue metering data for some significant embedded non-scheduled generation to account for native demand values.

(2) This area exhibits low and inconsistent sensitivity to winter temperatures.

(3) These major industrial loads have negligible sensitivity to temperature.

### Diversity of area peak demands across Queensland

The Queensland Region is very large and accordingly, the region peak demand depends not only on the weather patterns within the northern, central, south western and south eastern areas and the varying level of direct large industrial load, but also on the degree of coincidence of these weather patterns across the state. This diversity of peak demands is measured using coincidence factors, which are calculated from the data in Tables A.3 and A.4.

The historical coincidence factor averages developed for each of these areas and for the major industrial loads, are shown in Tables A.5 and A.6, and are used to enable overall correction of Queensland Region summer and winter demands, as shown in Table A.7.

Recent Queensland Region summer peak demands have been driven by a substantially lower than average coincidence over recent summers, as shown in Figure A.2. This contrasts to a relatively consistent level of coincidence over recent winters, as shown in Figure A.3.

The rolling 10-year average of these coincidence factors are also shown on Figures A.2 and A.3. These are used to recalculate recent Queensland corrected region peak demands, and as a basis for forecasting future region peak demands, in accordance with recommendations made by KEMA to the National Electricity Market Management Company in June 2005.

**Table A.5 Queensland summer native peak area demand diversity (1)**

| Year | South East | South West | North non-industrial | Central non-industrial | Industrial | Queensland Diversity (2) |
|---|---|---|---|---|---|---|
| 2000/01 | 99.3% | 89.0% | 95.3% | 85.3% | 98.1% | 96.2% |
| 2001/02 | 96.7% | 86.5% | 104.7% | 95.5% | 97.2% | 97.5% |
| 2002/03 | 100.2% | 94.7% | 93.4% | 88.6% | 92.4% | 96.3% |
| 2003/04 | 103.6% | 101.9% | 88.0% | 98.2% | 97.8% | 99.7% |
| 2004/05 | 98.8% | 97.0% | 93.9% | 97.3% | 90.9% | 96.6% |
| 2005/06 | 94.6% | 86.5% | 91.6% | 93.9% | 92.4% | 93.3% |
| 2006/07 | 95.8% | 95.8% | 98.8% | 102.0% | 89.8% | 96.1% |
| 2007/08 | 90.3% | 88.9% | 87.1% | 91.6% | 89.5% | 89.8% |
| 2008/09 | 94.4% | 96.6% | 79.0% | 94.3% | 93.3% | 92.1% |
| 2009/10 | 95.5% | 81.2% | 92.9% | 93.2% | 88.5% | 95.5% |
| Last 10-year average | 96.9% | 91.8% | 92.4% | 93.9% | 92.9% | 95.3% |

Notes:

(1) Diversity is expressed as a coincidence factor. Coincidence factors greater than 100% imply that the actual area demand at the time of State peak demand exceeded the area's own temperature corrected peak. This means that the area actual peak demand has been temperature corrected downwards.

(2) Queensland diversity is measured by the load weighted average of the component coincidence factors.

### Table A.6 Queensland winter native peak area demand diversity (1)

| Year | South East | South West | North non-industrial | Central non-industrial | Industrial | Queensland Diversity (2) |
|---|---|---|---|---|---|---|
| 2000 | 100.2% | 90.9% | 89.4% | 91.3% | 98.8% | 96.9% |
| 2001 | 97.6% | 91.7% | 91.2% | 99.8% | 96.8% | 96.6% |
| 2002 | 97.4% | 87.9% | 83.9% | 91.3% | 99.3% | 94.7% |
| 2003 | 99.9% | 96.6% | 88.2% | 93.6% | 94.8% | 96.6% |
| 2004 | 97.0% | 94.6% | 97.8% | 94.2% | 96.5% | 96.6% |
| 2005 | 100.5% | 92.0% | 83.2% | 95.0% | 90.4% | 95.6% |
| 2006 | 99.8% | 88.4% | 92.8% | 100.0% | 92.7% | 97.2% |
| 2007 | 100.6% | 98.1% | 85.5% | 98.9% | 90.2% | 96.8% |
| 2008 | 100.0% | 94.5% | 93.7% | 97.6% | 93.7% | 97.7% |
| 2009 | 99.4% | 96.1% | 89.3% | 89.4% | 95.9% | 96.2% |
| Last 10-year average | 99.2% | 93.1% | 89.5% | 95.1% | 94.9% | 96.5% |

Notes:

(1) Diversity is expressed as a coincidence factor. Coincidence factors greater than 100% imply that the actual area demand at the time of State peak demand exceeded the area's own temperature corrected peak. This means that the area actual peak demand has been temperature corrected downwards.

(2) Queensland diversity is measured by the load weighted average of the component coincidence factors.

### Table A.7 Queensland Region actual and 50% PoE temperature and diversity corrected peak native demands

| Winter | Actual (1) | Corrected (3) | Summer | Actual (1) | Corrected (2) |
|---|---|---|---|---|---|
| 2000 | 5,609 | 5,600 | 2000/01 | 5,830 | 5,772 |
| 2001 | 5,731 | 5,742 | 2001/02 | 6,183 | 6,046 |
| 2002 | 5,671 | 5,795 | 2002/03 | 6,336 | 6,275 |
| 2003 | 6,066 | 6,082 | 2003/04 | 7,020 | 6,718 |
| 2004 | 6,366 | 6,389 | 2004/05 | 7,282 | 7,188 |
| 2005 | 6,553 | 6,646 | 2005/06 | 7,373 | 7,533 |
| 2006 | 6,882 | 6,873 | 2006/07 | 7,889 | 7,830 |
| 2007 | 7,223 | 7,238 | 2007/08 | 7,444 | 7,910 |
| 2008 | 7,593 | 7,544 | 2008/09 | 8,021 | 8,310 |
| 2009 | 7,165 | 7,219 | 2009/10 | 8,293 | 8,489 |

Notes:

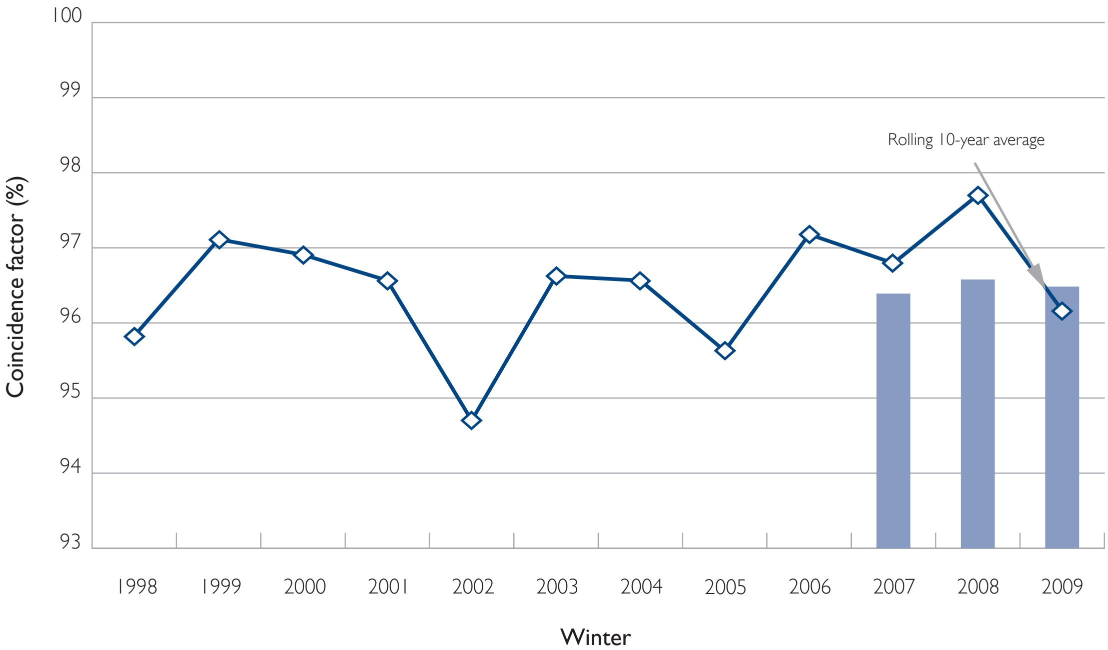
(1) Some corrections have been made in the last three years due to recent acquisition of revenue metering data for some significant embedded non-scheduled generation to account for native demand values.

(2) Corrections for summer are based on average diversity ratios for the 10 years to summer 2009/10. As the coincidence factor has been significantly lower over three of the last four summers compared to previous history, the average coincidence factor of the last 10 years has fallen significantly in recent years. Accordingly, the earlier corrected demands have been reduced accordingly to match the average diversity.

(3) Corrections for winter are now based on average diversity ratios for the 10 years to winter 2009. This last 10-year average has changed only slightly in recent years and accordingly there is negligible revision of earlier year corrected demands.

Figure A.2 Coincidence of actual Queensland Region summer peak demand compared to the sum of area and industrial corrected summer peak demands


Figure A.3 Actual Queensland Region winter peak demand compared to the sum of area and industrial corrected winter peak demands




### Summer seasonal weather conditions

The coincidence factors shown above suggest that summer weather conditions across Queensland over the last 10 years has exhibited far more variability than for winter weather conditions. This will impact summer peak demands. Figure A.4 shows that there were no extreme weather conditions in Queensland which would be expected to drive peak demand.

Table A.8 shows average summer temperatures and these have shown little variation to the long-term average.

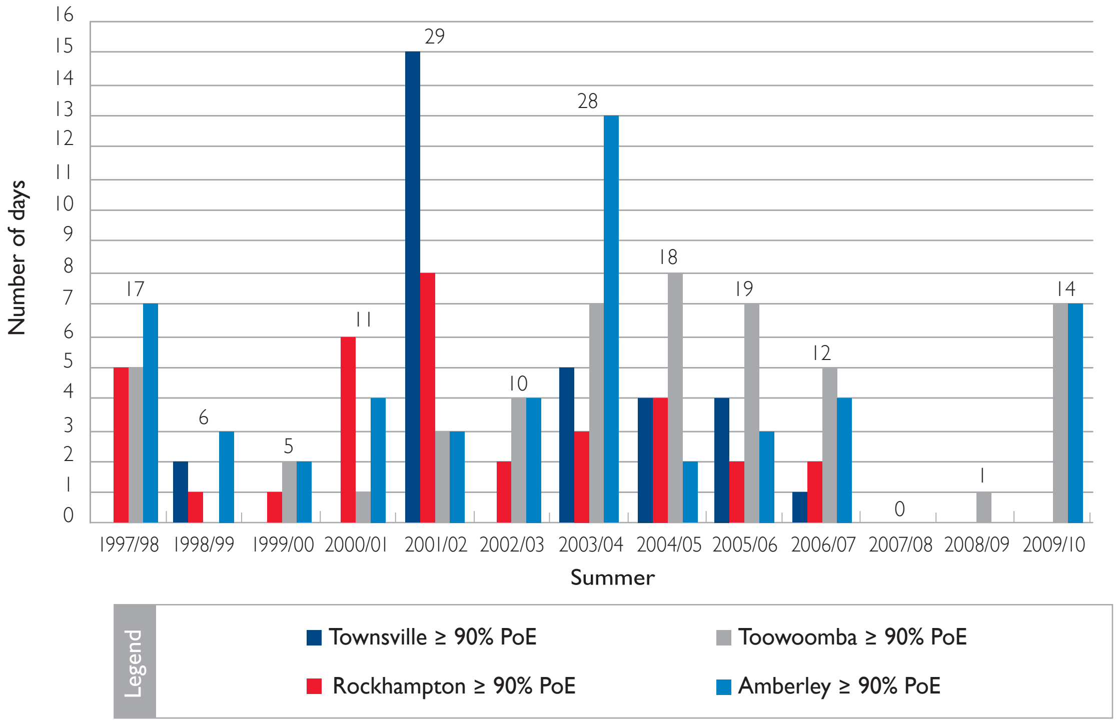
**Table A.8 Queensland average summer temperatures (°C)**

| Year | Amberley | Archerfield | Toowoomba | Rockhampton | Townsville |
|---|---|---|---|---|---|
| 2000/01 | 24.93 | 24.39 | 22.09 | 25.75 | 26.71 |
| 2001/02 | 25.90 | 25.58 | 23.87 | 28.54 | 29.27 |
| 2002/03 | 24.65 | 24.41 | 21.96 | 26.97 | 28.31 |
| 2003/04 | 26.07 | 26.01 | 23.31 | 27.77 | 28.77 |
| 2004/05 | 24.95 | 25.09 | 22.56 | 27.27 | 28.39 |
| 2005/06 | 26.48 | 26.20 | 24.12 | 28.42 | 28.65 |
| 2006/07 | 24.19 | 24.00 | 21.75 | 26.22 | 27.27 |
| 2007/08 | 24.14 | 24.23 | 21.17 | 26.11 | 27.66 |
| 2008/09 | 24.86 | 25.05 | 22.24 | 27.24 | 27.60 |
| 2009/10 | 25.40 | 25.51 | 22.91 | 27.05 | 27.87 |
| 10-year average | 25.16 | 25.05 | 22.60 | 27.13 | 28.05 |
| 50-year average | 24.91 | 25.30 | 21.63 | 26.90 | 27.80 |

Notes:

In South East Queensland there have been no days greater than 50% PoE conditions since summer 2006/07.

**Figure A.4 The recent trend to a lower number of hot summer days across Queensland population growth**

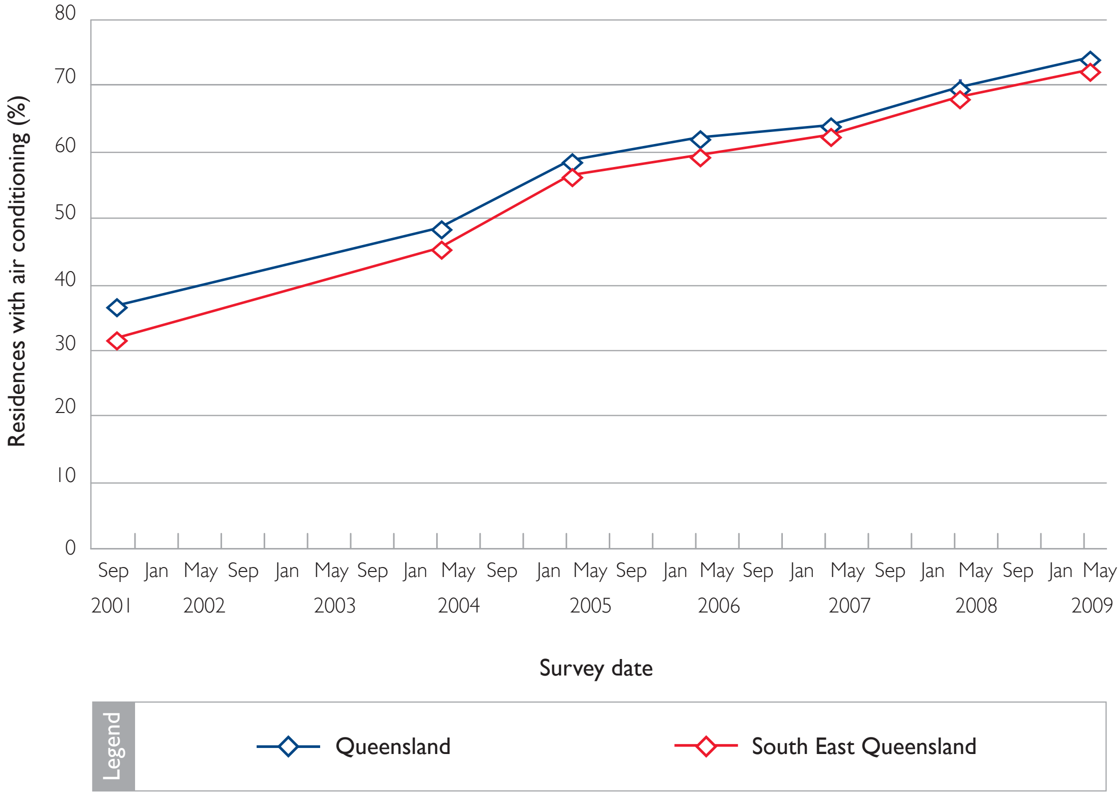


### Increase in air condition installation

Recent surveys of domestic air conditioning penetration rates are shown in Figure A.5. The percentage of South East Queensland residences with air conditioning installed increased from 68% to 72% over the May 2008 to May 2009 survey, a greater increase than over the previous annual survey period (62% in May 2007 to 68% in May 2008).

Similarly, the surveys showed that the air conditioning penetration rate over all of Queensland increased to 74% in May 2009, up from 69.2% in May 2008 and being a greater increase than from 63.9% in May 2007.

Figure A.5 Number of residences with air conditioners by survey



## Appendix B – Forecast of connection points

Tables B.1 and B.2 show the 10-year forecasts of native summer and winter demand at connection points, or groupings of connection points, coincident with the time of forecast total Queensland Region maximum demand.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

It should be noted that generally connection points will have their own summer and winter maximum demands at times other than coincident with Queensland Region maximum demand and these may be significantly higher than as shown in the tables.

In Tables B.1 and B.2 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 |
| GL | Gladstone zone |
| WB | Wide Bay zone |
| SW | South West zone |
| B | Bulli zone |
| M | Moreton zone |
| GC | Gold Coast zone |

Table B.1 Forecasts of connection point native demands (MW) coincident with state summer maximum demand

| Connection point | Zone | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Abermain 110kV (Lockrose, Wulkuraka BS and QR) | M | 53.9 | 54.7 | 54.6 | 56.1 | 68.4 | 70.3 | 73.1 | 75.6 | 77.0 | 78.5 |
| Abermain 33kV | M | 90.6 | 97.6 | 108.3 | 114.7 | 110.0 | 130.6 | 140.4 | 146.0 | 148.1 | 150.1 |
| Alan Sherriff 132kV | R | 20.3 | 20.9 | 21.6 | 22.3 | 23.0 | 23.7 | 24.4 | 25.1 | 25.7 | 26.4 |
| Algester 33kV | M | 73.5 | 75.6 | 75.1 | 77.0 | 98.1 | 99.9 | 103.5 | 106.3 | 107.6 | 108.9 |
| Alligator Creek 33kV | N | 12.7 | 13.2 | 13.7 | 14.2 | 14.7 | 15.3 | 15.8 | 16.3 | 16.8 | 17.3 |
| Ashgrove West 33kV | M | 75.3 | 76.2 | 73.7 | 76.0 | 77.1 | 79.0 | 82.3 | 85.0 | 86.6 | 88.2 |
| Belmont 110kV (Cleveland and Capalaba North) | M | 155.9 | 162.8 | 168.1 | 174.4 | 177.6 | 183.8 | 192.1 | 199.4 | 204.0 | 208.7 |
| Biloela 66kV | CW | 31.4 | 33.0 | 33.2 | 33.4 | 33.6 | 33.8 | 34.0 | 34.2 | 34.4 | 34.6 |
| Blackwater 66kV | CW | 91.5 | 111.6 | 113.2 | 114.7 | 116.3 | 117.8 | 119.4 | 120.9 | 122.5 | 124.0 |
| Bowen North 66kV | R | 25.7 | 25.9 | 26.0 | 26.0 | 31.4 | 31.4 | 36.7 | 36.7 | 36.7 | 36.7 |
| Broadlea 66kV | N | 0.0 | 0.0 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 |
| Bundamba 110kV | M | 40.3 | 41.2 | 41.3 | 42.7 | 43.5 | 44.7 | 46.6 | 48.3 | 49.3 | 50.4 |
| Cairns 22kV | FN | 75.0 | 77.7 | 80.3 | 82.9 | 85.5 | 88.1 | 90.6 | 93.2 | 95.7 | 98.3 |
| Cairns City 132kV | FN | 52.6 | 54.1 | 59.1 | 60.6 | 62.1 | 63.5 | 65.0 | 66.4 | 67.8 | 69.2 |
| Cairns North 132kV | FN | 31.6 | 32.6 | 33.6 | 34.6 | 35.7 | 36.8 | 38.0 | 39.1 | 40.4 | 41.6 |
| Cardwell 22kV | R | 3.8 | 3.8 | 3.9 | 3.9 | 4.0 | 4.0 | 4.1 | 4.1 | 4.2 | 4.3 |
| CBD (Brisbane) East 110kV | M | 404.4 | 415.2 | 488.0 | 541.6 | 549.0 | 580.9 | 599.8 | 618.7 | 627.6 | 636.4 |
| CBD (Brisbane) South 110kV | M | 63.1 | 58.2 | 59.0 | 82.9 | 84.7 | 87.4 | 91.5 | 95.2 | 97.7 | 100.1 |
| CBD (Brisbane) West 110kV | M | 136.0 | 136.8 | 152.3 | 165.1 | 167.8 | 159.6 | 168.1 | 175.7 | 180.8 | 186.0 |
| Clare 66kV | R | 66.6 | 67.4 | 68.2 | 68.9 | 69.7 | 70.5 | 71.3 | 72.1 | 72.9 | 73.7 |
| Collinsville 33kV | N | 14.6 | 14.7 | 14.8 | 14.9 | 14.9 | 15.0 | 15.1 | 15.2 | 15.3 | 15.4 |
| Dan Gleeson 66kV | R | 86.1 | 88.7 | 91.3 | 93.8 | 96.4 | 99.2 | 101.6 | 104.4 | 107.2 | 110.1 |
| Dysart 66kV | CW | 46.4 | 58.7 | 59.2 | 59.8 | 60.3 | 60.8 | 61.4 | 61.9 | 62.5 | 63.0 |
| Edmonton 22kV | FN | 39.7 | 41.1 | 42.6 | 44.0 | 45.5 | 46.9 | 48.3 | 49.8 | 51.2 | 52.7 |
| Egans Hill 66kV | CW | 43.0 | 47.5 | 48.7 | 50.0 | 52.1 | 53.3 | 54.5 | 55.6 | 56.8 | 57.9 |
| El Arish 22kV | FN | 3.3 | 3.4 | 3.5 | 3.6 | 3.8 | 3.9 | 4.0 | 4.1 | 4.2 | 4.3 |
| Garbutt 66kV | R | 85.1 | 88.5 | 94.1 | 96.7 | 99.8 | 102.7 | 105.7 | 108.6 | 111.6 | 114.6 |
| Gin Gin 132kV (Bundaberg) | WB | 99.8 | 101.2 | 102.6 | 104.1 | 105.4 | 106.7 | 108.0 | 109.3 | 110.6 | 112.0 |

Table B.1 Forecasts of connection point native demands (MW) coincident with state summer maximum demand (continued)

| Connection point | Zone | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gladstone 132kV (Boat Creek and Yarwun) | GL | 45.0 | 45.6 | 47.4 | 47.4 | 55.1 | 55.1 | 55.4 | 55.4 | 55.4 | 55.4 |
| Gladstone North 132kV | GL | 13.2 | 18.7 | 18.9 | 21.7 | 21.9 | 32.3 | 32.4 | 32.5 | 32.7 | 32.8 |
| Gladstone South 66kV | GL | 71.6 | 73.7 | 75.8 | 77.9 | 80.1 | 82.2 | 84.3 | 86.4 | 88.5 | 90.7 |
| Goodna 33kV | M | 83.3 | 96.7 | 117.3 | 130.4 | 110.0 | 115.0 | 126.4 | 132.6 | 137.0 | 141.4 |
| Ingham 66kV | R | 18.7 | 22.9 | 23.3 | 23.7 | 24.1 | 24.6 | 25.0 | 25.5 | 25.9 | 26.4 |
| Innisfail 22kV | FN | 26.6 | 26.9 | 27.2 | 27.5 | 27.8 | 28.1 | 28.4 | 28.7 | 29.0 | 29.3 |
| Kamerunga 22kV | FN | 50.1 | 52.2 | 54.2 | 56.2 | 58.2 | 60.2 | 62.2 | 64.3 | 66.3 | 68.3 |
| Larapinta 33kV | M | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 31.7 | 33.3 | 36.0 | 38.3 | 40.5 |
| Lilyvale 132kV (Clermont and Barcaldine) | CW | 42.0 | 42.5 | 43.1 | 43.6 | 44.2 | 44.7 | 45.2 | 45.8 | 46.3 | 46.9 |
| Lilyvale 66kV | CW | 90.6 | 109.2 | 115.9 | 118.5 | 119.9 | 121.2 | 122.5 | 124.8 | 126.1 | 127.4 |
| Loganlea 110kV | M | 512.2 | 502.0 | 512.1 | 526.0 | 545.3 | 537.4 | 572.4 | 606.5 | 632.9 | 659.2 |
| Loganlea 33kV | M | 104.3 | 106.1 | 105.6 | 108.4 | 109.5 | 114.3 | 118.4 | 121.9 | 121.9 | 122.0 |
| Mackay 33kV | N | 68.5 | 70.1 | 71.7 | 73.3 | 74.8 | 76.4 | 78.0 | 79.5 | 81.1 | 82.6 |
| Middle Ridge 110kV | SW | 229.1 | 236.1 | 244.1 | 255.0 | 258.0 | 264.5 | 271.8 | 278.2 | 284.7 | 291.2 |
| Middle Ridge 110kV (Postmans Ridge and Gatton) | M | 56.0 | 58.8 | 75.9 | 77.2 | 77.1 | 77.9 | 79.7 | 81.0 | 81.3 | 81.6 |
| Molendinar 110kV | GC | 395.3 | 427.7 | 424.4 | 440.7 | 454.4 | 469.5 | 485.1 | 496.6 | 504.9 | 513.2 |
| Moranbah 66kV and 11kV | N | 119.8 | 119.3 | 55.6 | 72.5 | 84.1 | 84.5 | 84.9 | 85.3 | 85.7 | 86.1 |
| Moura 66kV | CW | 37.7 | 39.1 | 39.5 | 47.6 | 48.0 | 48.4 | 48.8 | 49.2 | 49.6 | 50.0 |
| Mudgeeraba 110kV | GC | 315.8 | 322.7 | 321.5 | 330.9 | 337.3 | 347.3 | 362.7 | 375.2 | 382.8 | 390.4 |
| Murarrie 110kV (Doboy, Lytton BS and QR and Wakerley) | M | 272.6 | 278.5 | 281.1 | 286.9 | 293.3 | 305.0 | 322.9 | 333.4 | 336.9 | 340.3 |
| Nebo 11kV | N | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 | 2.7 | 2.8 | 2.8 | 2.9 | 3.0 |
| Newlands 66kV | N | 21.6 | 24.8 | 24.9 | 25.0 | 25.1 | 25.3 | 25.4 | 25.5 | 25.6 | 25.8 |
| Palmwoods 132kV and 110kV | M | 331.0 | 344.6 | 363.2 | 396.7 | 425.5 | 456.3 | 485.0 | 509.3 | 517.9 | 526.5 |
| Pandoin 66kV | CW | 48.8 | 50.3 | 53.7 | 55.3 | 56.9 | 58.6 | 60.4 | 62.2 | 64.0 | 65.9 |
| Pioneer Valley 66kV | N | 52.8 | 54.4 | 56.1 | 57.8 | 59.5 | 61.2 | 62.9 | 64.6 | 66.3 | 68.0 |
| Proserpine 66kV | N | 44.9 | 47.2 | 49.1 | 51.2 | 53.1 | 55.3 | 57.4 | 59.6 | 61.8 | 63.9 |

Table B.1 Forecasts of connection point native demands (MW) coincident with state summer maximum demand (continued)

| Connection point | Zone | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Redbank Plains 11kV | M | 23.4 | 24.9 | 17.8 | 19.2 | 20.3 | 21.5 | 23.1 | 24.6 | 25.9 | 27.1 |
| Richlands 33kV | M | 104.0 | 105.6 | 107.3 | 113.1 | 115.0 | 117.4 | 122.7 | 126.4 | 128.3 | 130.2 |
| Rockhampton 66kV | CW | 83.0 | 86.9 | 90.3 | 95.3 | 98.0 | 100.6 | 103.2 | 105.7 | 108.2 | 110.7 |
| Rocklea 110kV (Archerfield) | M | 98.3 | 100.2 | 99.5 | 102.2 | 78.9 | 80.6 | 83.7 | 86.3 | 87.7 | 89.1 |
| Ross 132kV (Kidston, Milchester and Georgetown) | FN | 37.6 | 44.5 | 47.6 | 48.4 | 49.2 | 50.0 | 50.8 | 51.6 | 52.3 | 53.1 |
| Runcorn 33kV | M | 69.8 | 69.0 | 68.7 | 70.6 | 67.3 | 68.2 | 70.2 | 71.7 | 83.0 | 94.3 |
| South Pine 110kV | M | 988.8 | 1,040.8 | 1,055.6 | 1,104.2 | 1,124.7 | 1,155.1 | 1,200.4 | 1,239.2 | 1,265.4 | 1,291.6 |
| Sumner 11kV | M | 47.4 | 48.2 | 48.1 | 49.6 | 50.2 | 51.4 | 53.4 | 55.2 | 56.1 | 57.1 |
| Sun Water Pumps (King Creek) 132kV | N | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Sun Water Pumps (Stony Creek) 132kV | N | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Swanbank 110kV (Raceview) | M | 96.8 | 95.7 | 96.7 | 99.7 | 130.0 | 141.8 | 151.1 | 164.5 | 175.5 | 186.5 |
| Tangkam 110kV (Dalby and Oakey) | SW | 51.4 | 52.8 | 55.1 | 56.6 | 58.0 | 59.5 | 60.9 | 62.3 | 63.8 | 65.2 |
| Tarong 132kV (Chinchilla and Roma) | SW | 79.1 | 82.8 | 83.9 | 85.4 | 86.8 | 88.3 | 89.7 | 91.2 | 92.6 | 94.0 |
| Tarong 66kV | SW | 39.2 | 40.4 | 41.4 | 42.4 | 43.3 | 44.3 | 45.2 | 46.2 | 47.2 | 48.1 |
| Teebar Creek 132kV (Isis and Maryborough) | WB | 151.3 | 158.1 | 163.4 | 169.3 | 174.8 | 180.4 | 185.6 | 191.2 | 195.8 | 200.3 |
| Tennyson 33kV | M | 193.9 | 219.2 | 194.9 | 193.1 | 195.5 | 186.4 | 193.6 | 199.6 | 203.0 | 206.3 |
| Townsville East 66kV | R | 36.7 | 37.8 | 39.0 | 40.1 | 41.3 | 42.5 | 43.6 | 44.8 | 46.1 | 47.3 |
| Townsville South 66kV | R | 64.6 | 69.4 | 71.6 | 73.7 | 76.2 | 78.3 | 80.1 | 83.1 | 85.3 | 87.4 |
| Tully 22kV | R | 14.4 | 14.7 | 15.0 | 15.2 | 15.5 | 15.8 | 16.0 | 16.3 | 16.6 | 16.8 |
| Turkinje 132kV (Craiglee and Lakeland) | FN | 17.0 | 17.2 | 17.4 | 17.7 | 17.9 | 18.2 | 18.4 | 18.6 | 18.9 | 19.1 |
| Turkinje 66kV | FN | 57.4 | 58.7 | 59.9 | 61.2 | 62.4 | 63.7 | 64.9 | 66.2 | 67.5 | 68.7 |
| Waggamba 132kV | B | 17.6 | 17.8 | 17.9 | 18.1 | 18.3 | 18.5 | 18.7 | 18.9 | 19.1 | 19.3 |
| Wecker Rd 33kV (Belmont) | M | 182.5 | 188.0 | 170.7 | 143.7 | 150.7 | 155.0 | 161.6 | 167.5 | 171.0 | 174.6 |
| Woolooga 132kV (Gympie) | M | 193.0 | 193.8 | 194.6 | 200.7 | 206.3 | 211.6 | 224.3 | 240.8 | 252.6 | 264.4 |

Table B.1 Forecasts of connection point native demands (MW) coincident with state summer maximum demand (continued)

| Connection point | Zone | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Woolooga 132kV (Kilkivan) | WB | 12.3 | 12.6 | 12.8 | 13.1 | 13.3 | 13.5 | 13.7 | 13.9 | 14.1 | 14.4 |
| Direct connected industrial loads (Sun Metals, Qld Nickel and Invicta load – R, BSL and QAL – GL) | Various | 1,116.8 | 1,116.9 | 1,190.9 | 1,204.0 | 1,214.9 | 1,239.8 | 1,264.7 | 1,291.6 | 1,317.5 | 1,343.4 |
| Transmission grid connected mining and LNG loads (Burton Downs, Goonyella North and Hail Creek – N, Rolleston – CW, Columboola and Wandoan South – B) | Various | 53.3 | 70.5 | 252.8 | 531.9 | 826.3 | 1,036.4 | 1,089.6 | 1,092.1 | 1,145.9 | 1,199.7 |
| Transmission grid connected QR substations (Mt McLaren, Coppabella, Moranbah South, Oonooie, Wandoo, Peak Downs, Bolingbroke and Mindi – N, Gregory, Rangal, Dingo, Grantleigh, Rocklands and Norwich Park – CW, Callemondah – GL, Korenan and Mungar – WB) | Various | 117.3 | 137.6 | 163.5 | 164.3 | 164.5 | 164.8 | 165.2 | 165.6 | 165.8 | 166.1 |
| Total Queensland summer native peak | | **8,924** | **9,280** | **9,765** | **10,400** | **10,930** | **11,447** | **11,877** | **12,219** | **12,520** | **12,821** |

Table B.2 Forecasts of connection point native demands (MW) coincident with state winter maximum demand

| Connection points | Zone | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Abermain 110kV (Lockrose, Wulkuraka BS and QR) | M | 49.9 | 49.8 | 50.0 | 51.5 | 53.1 | 63.9 | 64.9 | 67.0 | 68.8 | 70.6 |
| Abermain 33kV | M | 79.4 | 81.6 | 84.8 | 95.0 | 100.8 | 111.9 | 117.1 | 123.1 | 126.9 | 129.7 |
| Alan Sherriff 132kV | R | 12.0 | 12.2 | 12.4 | 12.6 | 12.8 | 12.9 | 13.1 | 13.3 | 13.5 | 13.7 |
| Algester 33kV | M | 66.3 | 67.3 | 67.3 | 69.1 | 71.1 | 84.2 | 84.6 | 86.8 | 88.6 | 90.4 |
| Alligator Creek 33kV | N | 10.5 | 11.0 | 11.5 | 11.9 | 12.4 | 12.9 | 13.4 | 13.8 | 14.3 | 14.8 |
| Ashgrove West 33kV | M | 77.7 | 77.6 | 78.0 | 78.0 | 80.6 | 81.8 | 82.7 | 85.4 | 87.7 | 90.0 |
| Belmont 110kV (Cleveland and Capalaba North) | M | 153.0 | 154.3 | 161.8 | 168.0 | 174.5 | 177.7 | 181.8 | 188.6 | 194.6 | 200.7 |
| Biloela 66kV | CW | 27.5 | 27.7 | 29.3 | 29.5 | 29.7 | 29.8 | 30.0 | 30.2 | 30.4 | 30.5 |
| Blackwater 66kV | CW | 69.9 | 84.4 | 103.8 | 105.0 | 106.1 | 107.3 | 108.4 | 109.6 | 110.7 | 111.9 |
| Bowen North | R | 0.0 | 21.9 | 22.0 | 22.2 | 22.2 | 26.8 | 26.8 | 31.3 | 31.3 | 31.3 |
| Broadlea 66kV | N | 0.0 | 0.0 | 0.0 | 50.2 | 50.2 | 50.2 | 50.2 | 50.2 | 50.2 | 50.2 |
| Bundamba 110kV | M | 38.9 | 39.3 | 39.8 | 41.3 | 42.8 | 43.5 | 44.2 | 45.8 | 47.1 | 48.5 |
| Cairns 22kV | FN | 44.5 | 44.6 | 44.7 | 44.7 | 44.7 | 44.8 | 44.8 | 44.8 | 44.8 | 44.7 |
| Cairns City 132kV | FN | 32.5 | 33.6 | 34.7 | 37.8 | 38.9 | 40.0 | 41.0 | 42.1 | 43.1 | 44.1 |
| Cairns North 132kV | FN | 19.6 | 20.2 | 20.8 | 21.5 | 22.1 | 22.8 | 23.5 | 24.3 | 25.0 | 25.8 |
| Cardwell 22kV | R | 2.8 | 2.9 | 2.9 | 3.0 | 3.1 | 3.2 | 3.3 | 3.3 | 3.4 | 3.5 |
| CBD (Brisbane) East 110kV | M | 282.9 | 300.2 | 298.7 | 373.2 | 428.0 | 432.8 | 451.1 | 459.8 | 471.7 | 482.1 |
| CBD (Brisbane) South 110kV | M | 39.1 | 35.4 | 35.8 | 37.5 | 58.4 | 59.6 | 60.6 | 62.9 | 65.0 | 67.1 |
| CBD (Brisbane) West 110kV | M | 84.3 | 99.2 | 98.6 | 114.8 | 124.7 | 126.7 | 118.3 | 123.7 | 128.4 | 133.2 |
| Clare 66kV | R | 46.3 | 44.9 | 45.8 | 46.7 | 47.5 | 48.4 | 49.3 | 50.2 | 51.1 | 52.0 |
| Collinsville 33kV | N | 9.4 | 11.0 | 11.0 | 11.0 | 11.1 | 11.1 | 11.1 | 11.1 | 11.2 | 11.2 |
| Dan Gleeson 66kV | R | 56.1 | 56.9 | 57.4 | 58.0 | 58.5 | 59.0 | 59.5 | 60.0 | 60.6 | 61.1 |
| Dysart 66kV | CW | 41.7 | 42.1 | 52.8 | 53.3 | 53.7 | 54.2 | 54.6 | 55.1 | 55.6 | 56.0 |
| Edmonton 22kV | FN | 19.6 | 20.3 | 21.0 | 21.7 | 22.4 | 23.1 | 23.8 | 24.5 | 25.3 | 26.0 |
| Egans Hill 66kV | CW | 46.4 | 32.8 | 37.3 | 37.8 | 38.2 | 39.5 | 39.9 | 40.2 | 40.6 | 40.9 |
| El Arish 22kV | FN | 2.2 | 2.3 | 2.3 | 2.4 | 2.5 | 2.5 | 2.6 | 2.7 | 2.8 | 2.8 |
| Garbutt 66kV | R | 63.8 | 64.9 | 66.2 | 69.2 | 70.0 | 71.1 | 71.9 | 73.2 | 73.9 | 74.7 |
| Gin Gin 132kV (Bundaberg) | WB | 88.8 | 90.7 | 92.6 | 94.5 | 96.5 | 98.4 | 100.2 | 102.0 | 103.8 | 105.7 |

Table B.2 Forecasts of connection point native demands (MW) coincident with state winter maximum demand (continued)

| Connection points | Zone | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gladstone 132kV (Boat Creek and Yarwun) | GL | 36.1 | 41.9 | 42.5 | 44.2 | 44.2 | 51.6 | 51.6 | 51.9 | 51.9 | 51.9 |
| Gladstone North 132kV | GL | 12.4 | 12.6 | 17.9 | 18.0 | 20.8 | 20.9 | 31.0 | 31.1 | 31.2 | 31.4 |
| Gladstone South 66kV | GL | 59.8 | 61.7 | 63.3 | 64.8 | 66.4 | 68.0 | 69.5 | 71.1 | 72.7 | 74.2 |
| Goodna 33kV | M | 69.7 | 73.4 | 85.0 | 107.2 | 119.3 | 103.5 | 106.7 | 116.9 | 122.0 | 127.3 |
| Ingham 66kV | R | 11.5 | 11.6 | 15.0 | 15.0 | 15.1 | 15.1 | 15.2 | 15.2 | 15.3 | 15.4 |
| Innisfail 22kV | FN | 18.6 | 18.7 | 18.8 | 19.0 | 19.1 | 19.2 | 19.4 | 19.5 | 19.6 | 19.7 |
| Kamerunga 22kV | FN | 33.7 | 34.9 | 36.1 | 37.4 | 38.6 | 39.8 | 41.0 | 42.3 | 43.5 | 44.7 |
| Larapinta 33kV | M | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 27.8 | 28.9 | 32.1 | 34.6 |
| Lilyvale 132kV (Clermont and Barcaldine) | CW | 24.2 | 31.6 | 31.8 | 31.9 | 32.1 | 32.2 | 32.4 | 32.5 | 32.7 | 32.8 |
| Lilyvale 66kV | CW | 90.9 | 93.1 | 114.7 | 123.0 | 126.4 | 128.0 | 129.7 | 131.3 | 134.2 | 135.9 |
| Loganlea 110kV | M | 439.7 | 455.4 | 449.5 | 474.5 | 493.0 | 511.0 | 497.9 | 526.9 | 555.9 | 587.5 |
| Loganlea 33kV | M | 89.2 | 96.0 | 96.5 | 99.3 | 102.2 | 103.2 | 106.0 | 109.0 | 111.5 | 112.0 |
| Mackay 33kV | N | 71.7 | 43.7 | 44.2 | 44.8 | 45.3 | 45.8 | 46.3 | 46.8 | 47.4 | 47.9 |
| Middle Ridge 110kV | SW | 227.4 | 241.6 | 249.3 | 258.0 | 267.8 | 273.9 | 281.0 | 288.9 | 296.0 | 303.2 |
| Middle Ridge 110kV (Postmans Ridge and Gatton) | M | 47.7 | 52.5 | 54.2 | 74.5 | 75.6 | 75.5 | 75.3 | 76.4 | 77.2 | 77.9 |
| Molendinar 110kV | GC | 332.9 | 335.0 | 353.3 | 365.0 | 380.2 | 391.3 | 400.3 | 410.4 | 416.2 | 426.7 |
| Moranbah 66kV and 11kV | N | 100.1 | 108.3 | 107.7 | 47.6 | 63.4 | 74.2 | 74.5 | 74.7 | 75.0 | 75.3 |
| Moura 66kV | CW | 36.0 | 36.4 | 37.8 | 38.2 | 46.2 | 46.5 | 46.9 | 47.3 | 47.7 | 48.1 |
| Mudgeeraba 110kV | GC | 321.8 | 323.6 | 325.2 | 334.6 | 345.5 | 352.5 | 358.1 | 372.0 | 382.4 | 392.7 |
| Murarrie 110kV (Doboy, Lytton BS and QR and Wakerley) | M | 233.3 | 241.8 | 245.9 | 254.5 | 260.1 | 266.4 | 273.3 | 288.5 | 296.7 | 302.1 |
| Nebo 11kV | N | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 2.0 | 2.0 | 2.1 | 2.1 |
| Newlands 66kV | N | 18.0 | 18.1 | 20.9 | 21.0 | 21.2 | 21.4 | 21.5 | 21.7 | 21.8 | 22.0 |
| Palmwoods 132kV and 110kV | M | 314.6 | 324.6 | 338.6 | 367.5 | 399.8 | 431.2 | 455.0 | 478.6 | 494.4 | 511.1 |
| Pandoin 66kV | CW | 0.0 | 42.7 | 44.2 | 47.5 | 48.9 | 50.3 | 51.8 | 53.3 | 54.9 | 56.5 |
| Pioneer Valley 66kV | N | 6.3 | 36.0 | 37.1 | 38.2 | 39.2 | 40.3 | 41.4 | 42.4 | 43.5 | 44.6 |
| Proserpine 66kV | N | 41.2 | 26.0 | 27.1 | 27.9 | 28.9 | 29.8 | 30.8 | 31.8 | 32.8 | 33.9 |

Table B.2 Forecasts of connection point native demands (MW) coincident with state winter maximum demand (continued)

| Connection points | Zone | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Redbank Plains 11kV | M | 22.0 | 21.9 | 23.0 | 16.9 | 18.2 | 19.2 | 20.1 | 21.4 | 22.7 | 24.1 |
| Richlands 33kV | M | 80.1 | 81.7 | 82.1 | 86.1 | 90.9 | 92.3 | 93.1 | 96.5 | 98.8 | 101.1 |
| Rockhampton 66kV | CW | 84.3 | 59.7 | 62.1 | 64.0 | 66.8 | 68.1 | 69.3 | 70.5 | 71.6 | 72.7 |
| Rocklea 110kV (Archerfield) | M | 76.9 | 76.5 | 76.8 | 79.0 | 81.5 | 66.6 | 67.3 | 69.4 | 71.2 | 73.1 |
| Ross 132kV (Kidston, Milchester and Georgetown) | FN | 24.7 | 25.2 | 31.1 | 33.6 | 34.0 | 34.4 | 34.9 | 35.3 | 35.7 | 36.2 |
| Runcorn 33kV | M | 59.3 | 59.6 | 58.0 | 59.8 | 61.7 | 58.8 | 58.8 | 60.2 | 61.2 | 71.5 |
| South Pine 110kV | M | 867.5 | 857.9 | 921.8 | 966.9 | 1,014.3 | 1,032.3 | 1,046.5 | 1,081.0 | 1,109.8 | 1,141.3 |
| Sumner 11kV | M | 31.4 | 35.4 | 35.6 | 36.8 | 38.0 | 38.5 | 38.9 | 40.1 | 41.2 | 42.2 |
| Sun Water Pumps (King Creek) 132kV | N | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Sun Water Pumps (Stony Creek) 132kV | N | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Swanbank 110kV (Raceview) | M | 74.2 | 76.7 | 72.9 | 76.4 | 79.0 | 103.8 | 113.4 | 121.1 | 132.7 | 144.0 |
| Tangkam 110kV (Dalby and Oakey) | SW | 42.5 | 43.8 | 44.7 | 46.2 | 47.1 | 48.0 | 49.0 | 49.9 | 50.8 | 51.7 |
| Tarong 132kV (Chinchilla and Roma) | SW | 62.8 | 68.5 | 71.6 | 72.2 | 73.1 | 74.0 | 75.0 | 75.9 | 76.8 | 77.7 |
| Tarong 66kV | SW | 39.0 | 40.2 | 41.5 | 42.3 | 43.1 | 43.9 | 44.7 | 45.5 | 46.4 | 47.2 |
| Teebar Creek 132kV (Isis and Maryborough) | WB | 133.0 | 139.6 | 145.7 | 150.7 | 156.1 | 161.2 | 166.2 | 171.1 | 176.4 | 180.9 |
| Tennyson 33kV | M | 185.6 | 198.9 | 206.9 | 187.0 | 185.6 | 173.1 | 173.6 | 178.9 | 183.4 | 187.8 |
| Townsville East 66kV | R | 22.4 | 22.7 | 22.9 | 23.1 | 23.3 | 23.5 | 23.7 | 23.9 | 24.1 | 24.4 |
| Townsville South 66kV | R | 42.4 | 43.1 | 44.8 | 45.4 | 46.0 | 46.8 | 47.2 | 47.6 | 48.7 | 49.1 |
| Tully 22kV | R | 8.8 | 8.9 | 9.1 | 9.2 | 9.4 | 9.5 | 9.7 | 9.8 | 10.0 | 10.1 |
| Turkinje 132kV (Craiglee and Lakeland) | FN | 14.0 | 14.4 | 14.7 | 15.0 | 15.3 | 15.6 | 16.0 | 16.3 | 16.6 | 16.9 |
| Turkinje 66kV | FN | 38.2 | 42.0 | 42.1 | 42.2 | 42.3 | 42.4 | 42.4 | 42.5 | 42.6 | 42.7 |
| Waggamba 132kV | B | 14.6 | 14.8 | 14.9 | 15.1 | 15.2 | 15.4 | 15.5 | 15.7 | 15.8 | 16.0 |
| Wecker Rd 33kV (Belmont) | M | 171.5 | 182.1 | 185.4 | 174.9 | 139.9 | 146.8 | 149.1 | 154.4 | 159.2 | 163.9 |
| Woolooga 132kV (Gympie) | M | 187.5 | 190.5 | 191.4 | 201.8 | 207.6 | 211.1 | 213.4 | 224.5 | 242.4 | 252.2 |

Table B.2 Forecasts of connection point native demands (MW) coincident with state winter maximum demand (continued)

| Connection points | Zone | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Woolooga 132kV (Kilkivan) | WB | 14.2 | 14.5 | 14.8 | 15.1 | 15.3 | 15.6 | 15.9 | 16.2 | 16.4 | 16.7 |
| Direct connected industrial loads (Sun Metals, Qld Nickel and Invicta load – R, BSL and QAL – GL) | Various | 1,126.6 | 1,133.7 | 1,165.3 | 1,208.8 | 1,220.5 | 1,231.5 | 1,256.4 | 1,281.3 | 1,308.1 | 1,334.0 |
| Transmission grid connected mining and LNG loads (Burton Downs, Goonyella North and Hail Creek – N, Rolleston – CW, Columboola and Wandoan South – B) | Various | 36.9 | 43.2 | 96.6 | 244.3 | 522.1 | 815.0 | 1023.3 | 1075.6 | 1077.7 | 1131.1 |
| Transmission grid connected QR substations (Mt McLaren, Coppabella, Moranbah South, Oonooie, Wandoo, Peak Downs, Bolingbroke and Mindi – N, Gregory, Rangal, Dingo, Grantleigh, Rocklands and Norwich Park – CW, Callemondah – GL, Korenan and Mungar – WB) | Various | 118.4 | 111.6 | 132.7 | 157.2 | 158.0 | 158.2 | 158.4 | 158.7 | 158.9 | 159.2 |
| Total Queensland winter native peak | | **7,683** | **7,900** | **8,251** | **8,788** | **9,383** | **9,880** | **10,282** | **10,621** | **10,881** | **11,193** |

## Appendix C – Estimated network power flows

Appendix C illustrates 18 sample power flows (Figures C.3 to C.20) for the Queensland region for each summer and winter over three years from winter 2010 to summer 2012/13. Each sample shows possible power flows at the time of winter or summer region 50% probability of exceedance (PoE) forecast peak demand, with a range of import and export conditions on the Queensland/New South Wales Interconnector (QNI).

The sample power flows include southerly power flows on the Terranora Interconnector that are based on the expected levels to meet reliability requirements in northern New South Wales up until the expected commissioning of TransGrid's Dumaresq to Lismore 330kV augmentation (mid 2014).

Sample conditions[1] include:

| | | |
|---|---|---|
| Figure C.3 | Winter 2010 | Queensland peak 300MW northerly QNI flow |
| Figure C.4 | Winter 2010 | Queensland peak zero QNI flow |
| Figure C.5 | Winter 2010 | Queensland peak 700MW southerly QNI flow |
| Figure C.6 | Winter 2011 | Queensland peak 300MW northerly QNI flow |
| Figure C.7 | Winter 2011 | Queensland peak zero QNI flow |
| Figure C.8 | Winter 2011 | Queensland peak 700MW southerly QNI flow |
| Figure C.9 | Winter 2012 | Queensland peak 300MW northerly QNI flow |
| Figure C.10 | Winter 2012 | Queensland peak zero QNI flow |
| Figure C.11 | Winter 2012 | Queensland peak 700MW southerly QNI flow |
| Figure C.12 | Summer 2010/11 | Queensland peak 200MW northerly QNI flow |
| Figure C.13 | Summer 2010/11 | Queensland peak zero QNI flow |
| Figure C.14 | Summer 2010/11 | Queensland peak 400MW southerly QNI flow |
| Figure C.15 | Summer 2011/12 | Queensland peak 200MW northerly QNI flow |
| Figure C.16 | Summer 2011/12 | Queensland peak zero QNI flow |
| Figure C.17 | Summer 2011/12 | Queensland peak 400MW southerly QNI flow |
| Figure C.18 | Summer 2012/13 | Queensland peak 200MW northerly QNI flow |
| Figure C.19 | Summer 2012/13 | Queensland peak zero QNI flow |
| Figure C.20 | Summer 2012/13 | Queensland peak 400MW southerly QNI flow |

1 The single line transmission network diagrams shown in this appendix are high level representations only, used to indicate grid sections, observation points and committed large capital projects. For a detailed network diagram refer to Figures 3.1 and 3.2.

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 peak load (2) (3) | | | | | | Limit due to (4) |
|---|---|---|---|---|---|---|---|
| | Winter 2010 | Winter 2011 | Winter 2012 | Summer 2010/11 | Summer 2011/12 | Summer 2012/13 | |
| 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 | |
| **Far North Queensland**<br>Ross into Chalumbin 275kV (2 circuits)<br>Tully into Kareeya 132kV (1 circuit)<br>Tully into Woree (1 circuit)<br>Tully into El Arish (1 circuit)<br>Ingham South/Cardwell into Kareeya 132kV (1 circuit) | 170/170/170 | 177/177/178 | 181/181/181 | 300/301/309 | 308/309/309 | 356/356/356 | V |
| **CQ-NQ**<br>Bouldercombe into Nebo 275kV (1 circuit)<br>Broadsound into Nebo 275kV (3 circuits)<br>Dysart to Peak Downs 132kV (1 circuit) | 547/555/547 | 577/579/579 | 615/615/494 | 820/823/690 | 751/618/491 | 821/821/559 | Th<br>V |
| **Gladstone observation point**<br>Bouldercombe into Gladstone 275kV (1 circuit)<br>Bouldercombe into Larcom Creek 275kV (1 circuit)<br>Calvale into Wurdong 275kV (1 circuit)<br>Callide A into Gladstone South 132kV (2 circuits) | 791/788/680 | 680/677/684 | 712/713/707 | 699/698/706 | 654/739/705 | 664/661/743 | Th |
| **CQ-SQ**<br>Wurdong into Gin Gin 275kV (1 circuit)<br>Gladstone into Gin Gin 275kV (2 circuits)<br>Calvale into Tarong 275kV (2 circuits, becomes Calvale into Halys from summer 2012/13) | 1480/1434/1617 | 1548/1545/1545 | 1585/1585/1515 | 1521/1519/1538 | 1294/1640/1796 | 953/952/1113 | Tr<br>V |
| **SWQ**<br>Braemar to Tarong 275kV (2 circuits, becomes Braemar to Halys from summer 2012/13)<br>Millmerran to Middle Ridge 330kV (2 circuits)<br>Western Downs to Halys 275kV (2 circuits, from summer 2012/13) | 1758/1707/1570 | 1869/1884/1932 | 2128/2128/2249 | 2495/2500/2492 | 3092/2735/2493 | 3235/3020/2677 | Tr<br>Th<br>V |
| **Tarong**<br>Tarong to South Pine 275kV (1 circuit)<br>Tarong to Mt England 275kV (2 circuts)<br>Tarong to Blackwall 275kV (2 circuits)<br>Middle Ridge to Greenbank 275kV (2 circuits) | 3487/3517/3457 | 3671/3688/3729 | 3893/3893/3970 | 4211/4212/4210 | 4587/4439/4374 | 4783/4792/4654 | 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 peak load (2) (3) | | | | | | Limit due to (4) |
|---|---|---|---|---|---|---|---|
| | Winter 2010 | Winter 2011 | Winter 2012 | Summer 2010/11 | Summer 2011/12 | Summer 2012/13 | |
| 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**<br>Greenbank into Mudgeeraba 275kV (2 circuits)<br>Greenbank into Molendinar 275kV (2 circuits)<br>Coomera into Cades County 110kV (1 circuit) | 822/825/864 | 830/830/871 | 853/853/895 | 941/942/952 | 986/986/996 | 984/984/994 | 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 intact (i.e. all network circuits in service) are based on the existing network configuration, and committed projects. Power flows within each grid section can be higher at times of local zone peak.

(3) All power flows studied were stable.

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

Table C.2 Transformer capacity and sample loadings of 275kV substations

| 275kV substation (1)(2)(3) (Number of transformers x MVA nameplate rating) | Possible MVA loading at Queensland Region peak (4)(5)(6) | | | | | | Dependence other than local load | | Other Comments |
|---|---|---|---|---|---|---|---|---|---|
| | Winter 2010 | Winter 2011 | Winter 2012 | Summer 2010/10 | Summer 2011/12 | Summer 2012/13 | Significant dependence on | Minor dependence on | |
| Woree 275/132kV (2x375MVA) | 151 | 154 | 155 | 250 | 255 | 323 | Barron Gorge generation | Kareeya generation | |
| Chalumbin 275/132kV (2x200MVA) | 129 | 112 | 144 | 167 | 136 | 126 | Kareeya generation | Barron Gorge, Townsville and Mt Stuart generation | |
| Ross 275/132kV (2x250MVA and 1x200MVA) | 77 | 116 | 115 | 116 | 277 | 185 | Mt Stuart, Townsville and Invicta generation | Collinsville generation | |
| Strathmore 275/132kV (1x375MVA) | 90 | 81 | 83 | 51 | 64 | 47 | Collinsville and Invicta generation | Townsville and Mt Stuart generation | |
| Nebo 275/132kV (2x200MVA and 1x250MVA) | 285 | 265 | 285 | 341 | 339 | 376 | Mackay GT generation | Collinsville generation | |
| Lilyvale 275/132kV (2x375MVA) | 259 | 248 | 311 | 287 | 344 | 322 | Barcaldine generation | CQ-NQ flow | |
| Bouldercombe 275/132kV (2x200MVA) | 140 | 143 | 152 | 196 | 208 | 225 | – | – | Summer 2012/13 – new 1x375MVA transformer |
| Larcom Creek 275/132kV (2x375MVA) | 79 | 86 | 121 | 90 | 91 | 41 | Yarwun generation | | |
| Calvale 275/132kV (1x250MVA) | 173 | 164 | 174 | 175 | 173 | 215 | Callide, Yarwun and Gladstone generation | Barcaldine, Stanwell and CQ-SQ flow | |
| Gin Gin 275/132kV (2x120MVA) | 152 | 156 | 164 | 167 | 186 | 189 | 132kV transfers to/from Teebar Creek | CQ-SQ flow | 132kV network can have open points to reduce loading |
| Teebar Creek 275/132kV (2x375MVA) | 126 | 117 | 130 | 139 | 120 | 142 | 132kV transfers to/from Woolooga | CQ-SQ flow | |
| Woolooga 275/132kV (2x120MVA and 1x250MVA) | 220 | 231 | 231 | 235 | 242 | 240 | 132kV transfers to/from Gin Gin and Teebar Creek | CQ-SQ flow | |

Table C.2 Transformer capacity and sample loadings of 275kV substations (continued)

| 275kV substation (1)(2)(3) (Number of transformers x MVA nameplate rating) | Possible MVA loading at Queensland Region peak (4)(5)(6) | | | | | | Dependence other than local load | | Other Comments |
|---|---|---|---|---|---|---|---|---|---|
| | Winter 2010 | Winter 2011 | Winter 2012 | Summer 2010/10 | Summer 2011/12 | Summer 2012/13 | Significant dependence on | Minor dependence on | |
| Palmwoods 275/132kV (2x375MVA) | 358 | 358 | 369 | 371 | 390 | 402 | 132/110kV transfers to/ from South Pine and Woolooga | CQ-SQ flow | |
| Tarong 275/132kV (2x90MVA) | 70 | 75 | 95 | 94 | 116 | 68 | Roma and Condamine generation | | |
| Tarong 275/66kV (2x90MVA) | 42 | 43 | 44 | 43 | 44 | 45 | – | | |
| South Pine East 275/110kV (3x375MVA) | 721 | 694 | 738 | 809 | 854 | 856 | 110kV transfers to/from Palmwoods | CQ-SQ flow and Swanbank generation | |
| South Pine West 275/110kV (1x375 and 1x250MVA) | 315 | 355 | 357 | 354 | 357 | 357 | 110kV transfers to/from Rocklea | CQ-SQ flow and Swanbank generation | |
| Murarrie 275/110kV (2x375MVA) | 468 | 373 | 389 | 437 | 454 | 479 | 110kV transfers to/from Belmont | | |
| Belmont 275/110kV (1x200MVA, 2x250MVA and 1x375MVA) | 431 | 689 | 681 | 764 | 814 | 809 | 110kV transfers to/from Loganlea | 110kV transfers to/from Rocklea | Summer 2010/11 – 1x375MVA transformer to replace 1x200MVA |
| Rocklea 275/110kV (2x375MVA) | 466 | 461 | 451 | 518 | 544 | 538 | 110kV transfers to/from South Pine and Belmont | 110kV transfers to/from Swanbank and Swanbank B generation | |
| Abermain 275/110kV (1x375MVA) | 138 | 144 | 169 | 155 | 192 | 177 | 110kV transfers to/from Swanbank and Goodna | Tarong flow | |
| Goodna 275/110kV (1x375MVA) | 80 | 80 | 91 | 63 | 133 | 110 | 110kV transfers to/from Swanbank and Abermain | Tarong flow | |
| Swanbank 275/110kV (Blackstone) (1x250MVA and 1x240MVA) | 168 | 170 | 108 | 197 | 120 | 179 | 110kV transfers to/from South Pine and Rocklea | | Winter 2012 – Swanbank's 275/110kV transformer connection will be shifted to Blackstone |

Table C.2 Transformer capacity and sample loadings of 275kV substations (continued)

| 275kV substation (1)(2)(3) (Number of transformers x MVA nameplate rating) | Possible MVA loading at Queensland Region peak (4)(5)(6) | | | | | | Dependence other than local load | | Other Comments |
|---|---|---|---|---|---|---|---|---|---|
| | Winter 2010 | Winter 2011 | Winter 2012 | Summer 2010/10 | Summer 2011/12 | Summer 2012/13 | Significant dependence on | Minor dependence on | |
| Loganlea 275/110kV (2x375MVA) | 489 | 457 | 458 | 498 | 500 | 499 | 110kV transfers to/from Belmont | 110kV transfers to/ from Molendinar and Mudgeeraba | |
| Middle Ridge 275/110kV (3x250MVA) | 342 | 362 | 412 | 380 | 453 | 494 | Oakey generation | Swanbank B generation | |
| Molendinar 275/110kV (2x375MVA) | 465 | 469 | 475 | 517 | 528 | 562 | 110kV transfers to/ from Loganlea and Mudgeeraba | Terranora Interconnector | |
| Mudgeeraba 275/110kV (3x250MVA) | 463 | 468 | 477 | 512 | 520 | 495 | 110kV transfers to/ from Molendinar and Terranora Interconnector | 110kV transfers to/from Loganlea | |

Notes:

(1) Not included are the 275/132kV tie transformers within the power station switchyard at Gladstone. Loading on these transformers vary considerably with local generation.

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

(3) 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.

(4) 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 (i.e. all network elements in service) 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 peak demand times or different availability of local and downstream capacitor banks.

(5) 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.

(6) 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

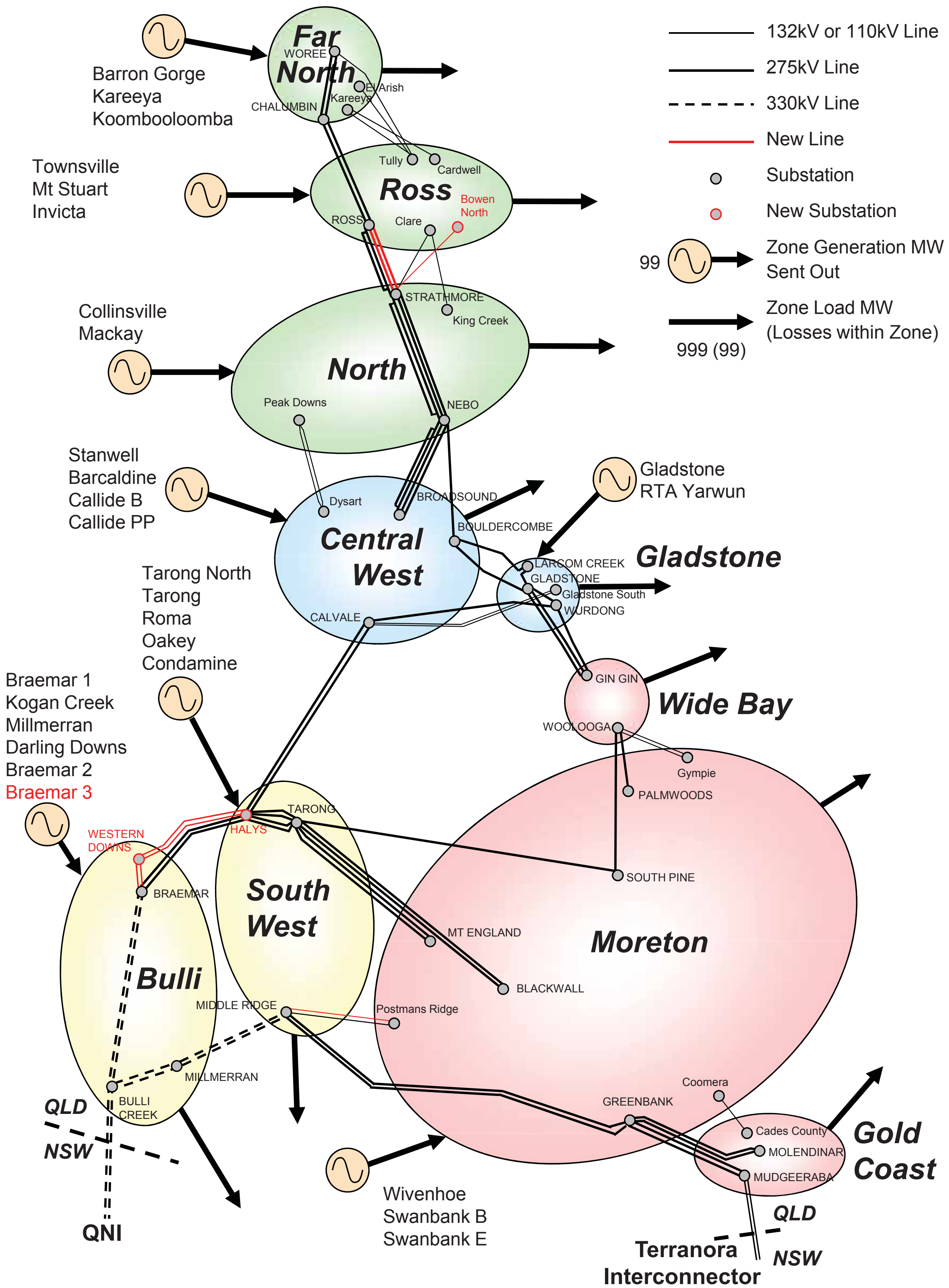


Figure C.2 Observation point and Grid section legend for Figures C.3 to C.20

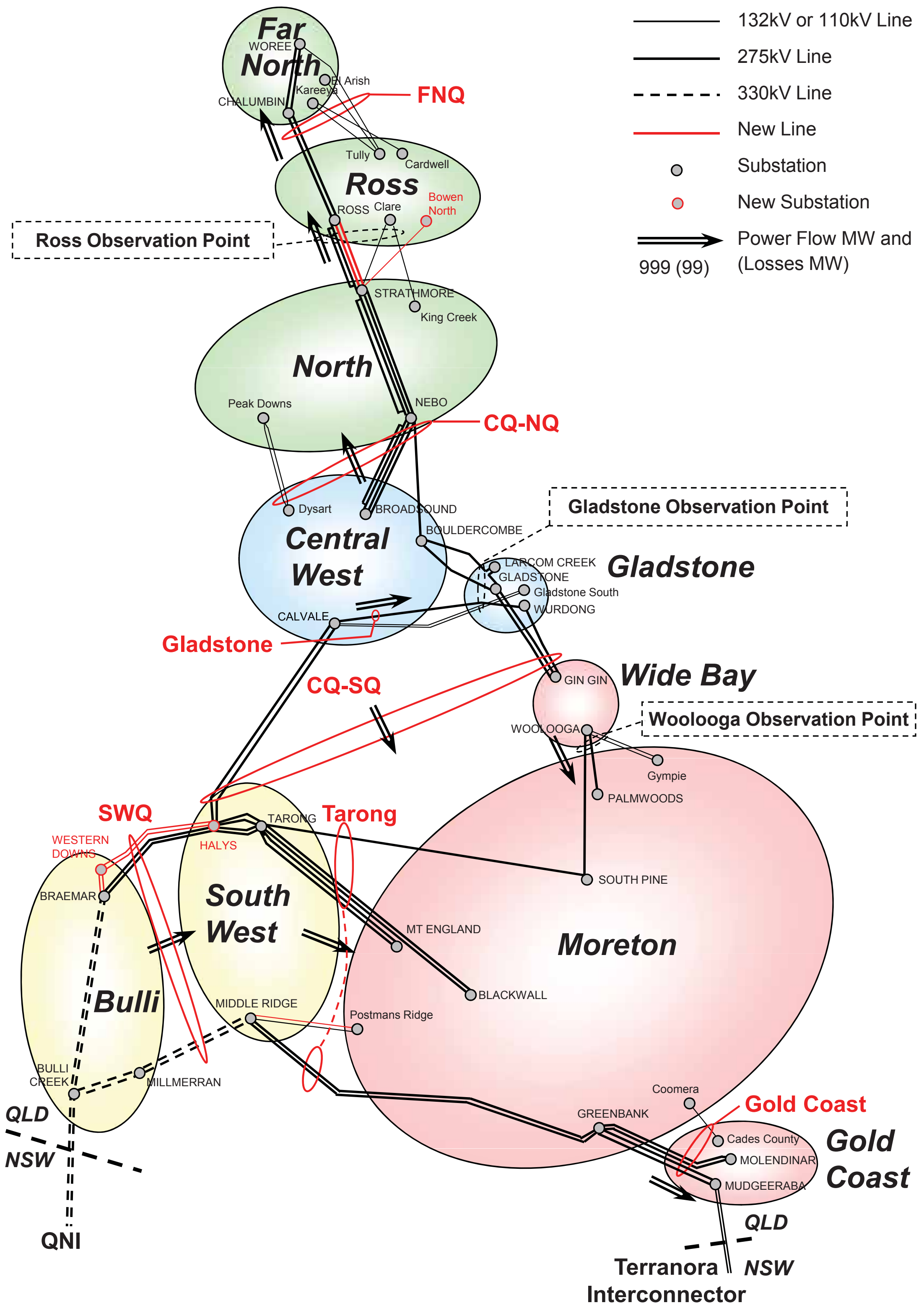


Figure C.3 Winter 2010 Queensland peak 300MW northerly QNI flow

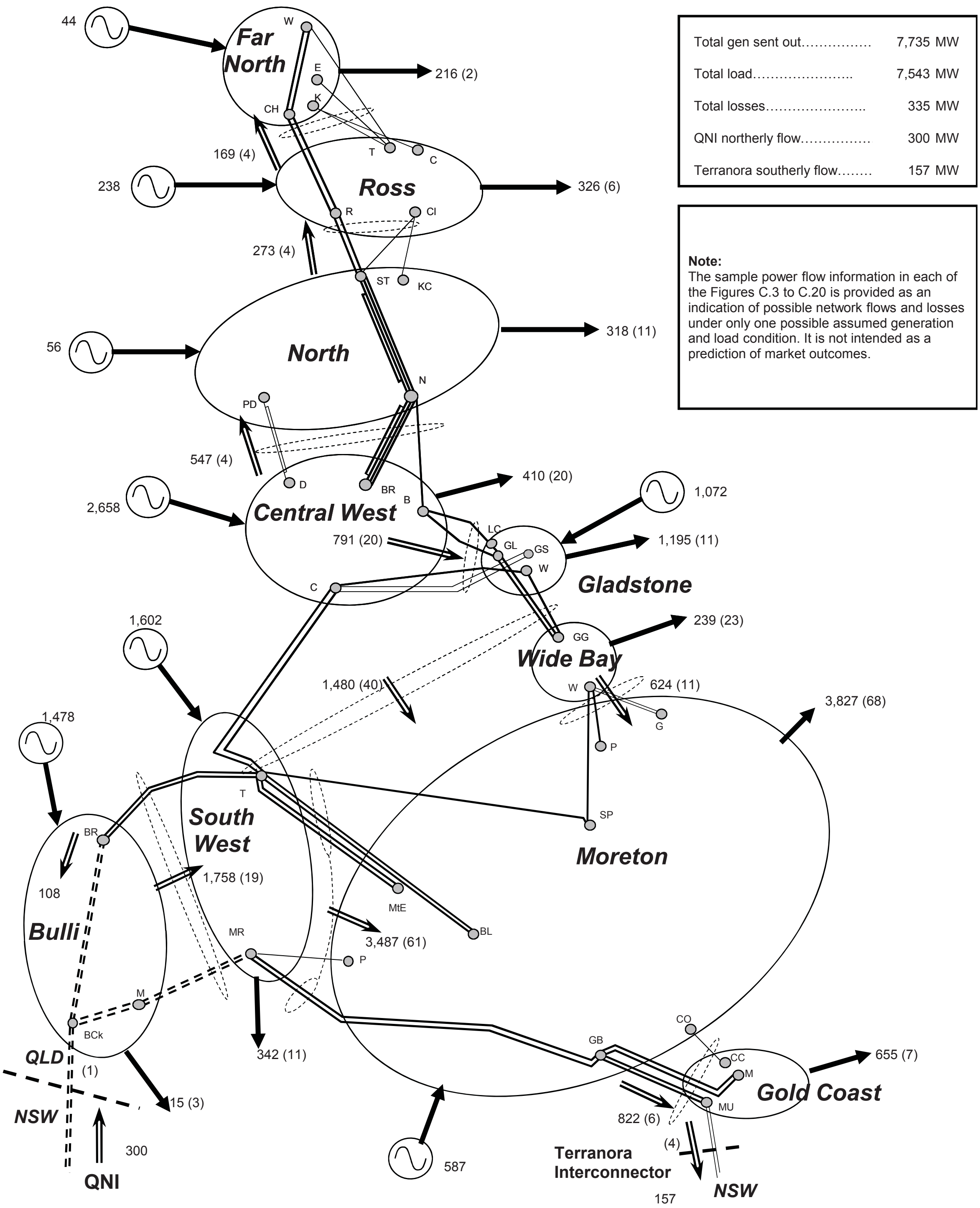
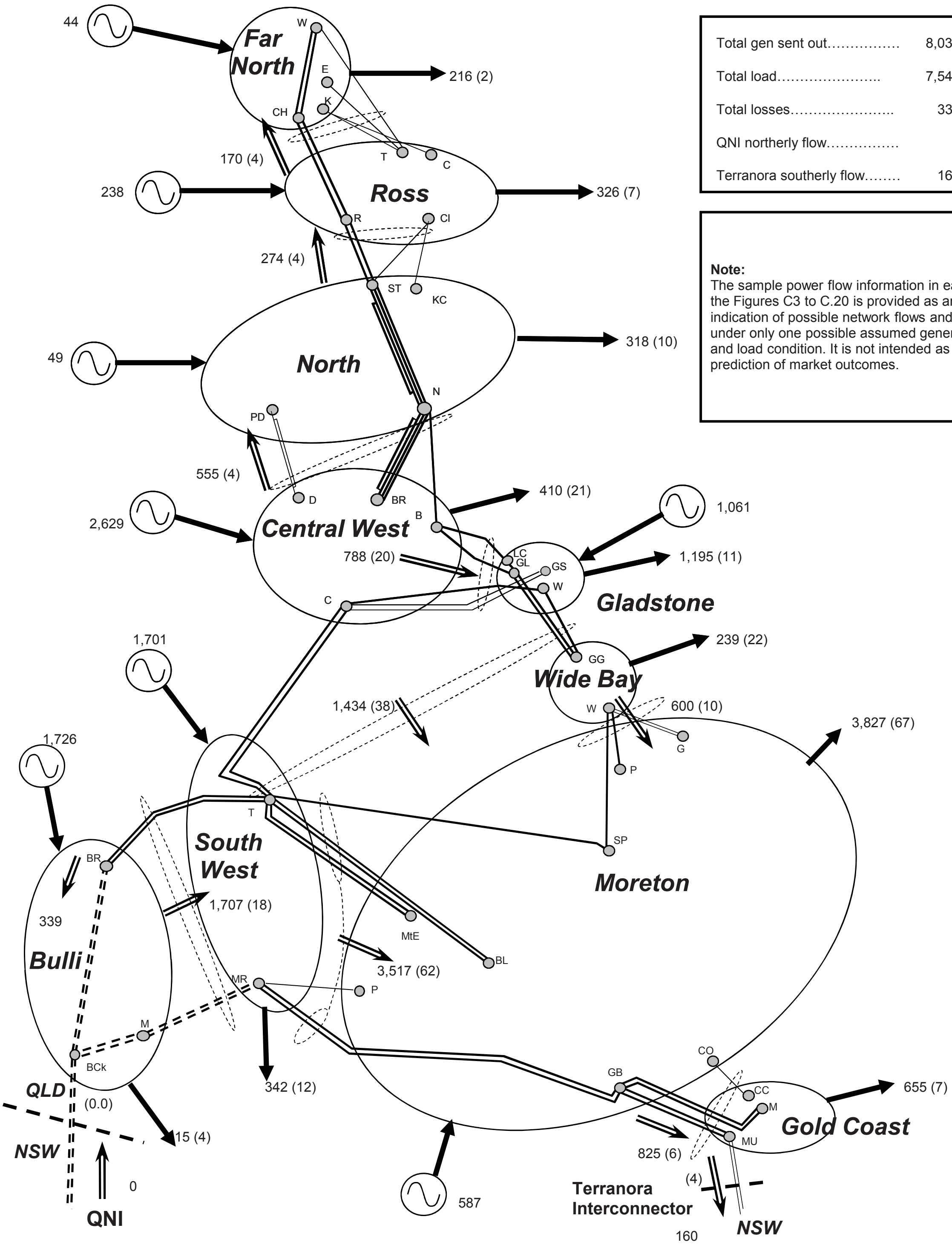


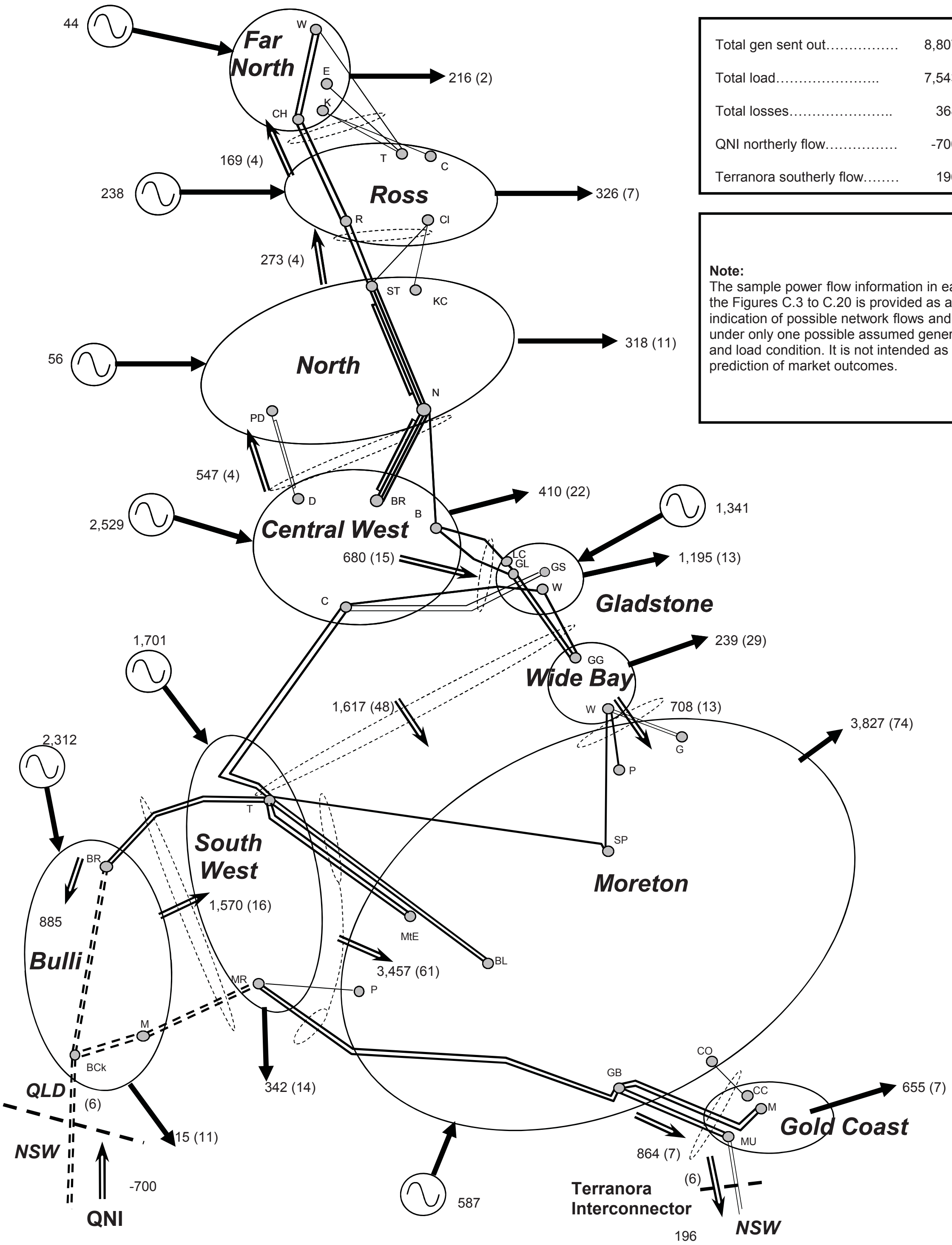
Figure C.4 Winter 2010 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out…………… | 8,035 MW |
| Total load………………….. | 7,543 MW |
| Total losses………………….. | 332 MW |
| QNI northerly flow…………… | 0 MW |
| Terranora southerly flow…….. | 160 MW |

**Note:**
The sample power flow information in each of the Figures C3 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 2010 Queensland peak 700MW southerly QNI flow




| | |
|---|---|
| Total gen sent out................ | 8,807 MW |
| Total load....................... | 7,543 MW |
| Total losses...................... | 368 MW |
| QNI northerly flow................ | -700 MW |
| Terranora southerly flow........ | 196 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 2011 Queensland peak 300MW northerly QNI flow

| | |
|---|---|
| Total gen sent out................ | 7,966 MW |
| Total load....................... | 7,759 MW |
| Total losses....................... | 346 MW |
| QNI northerly flow................ | 300 MW |
| Terranora southerly flow........ | 161 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.

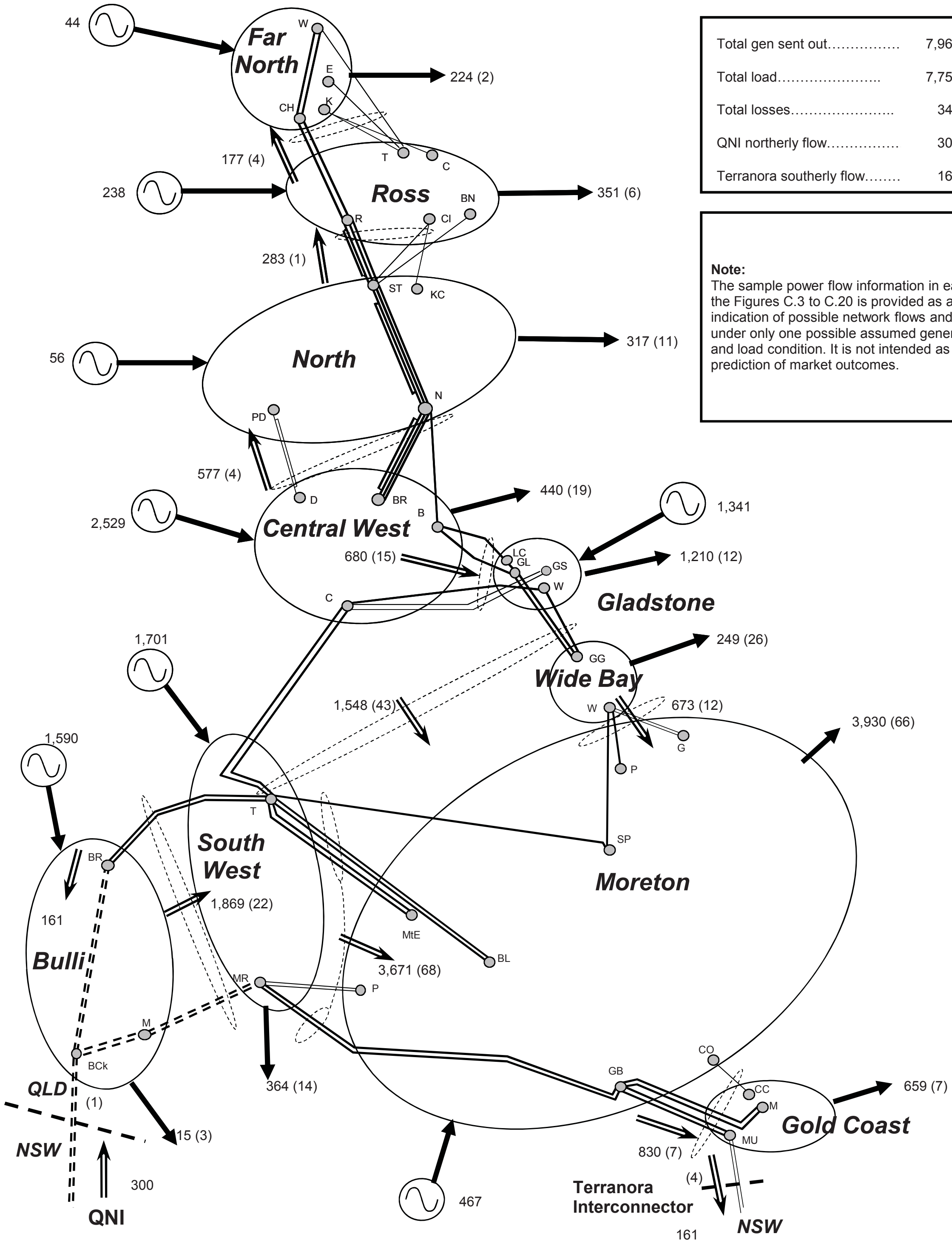
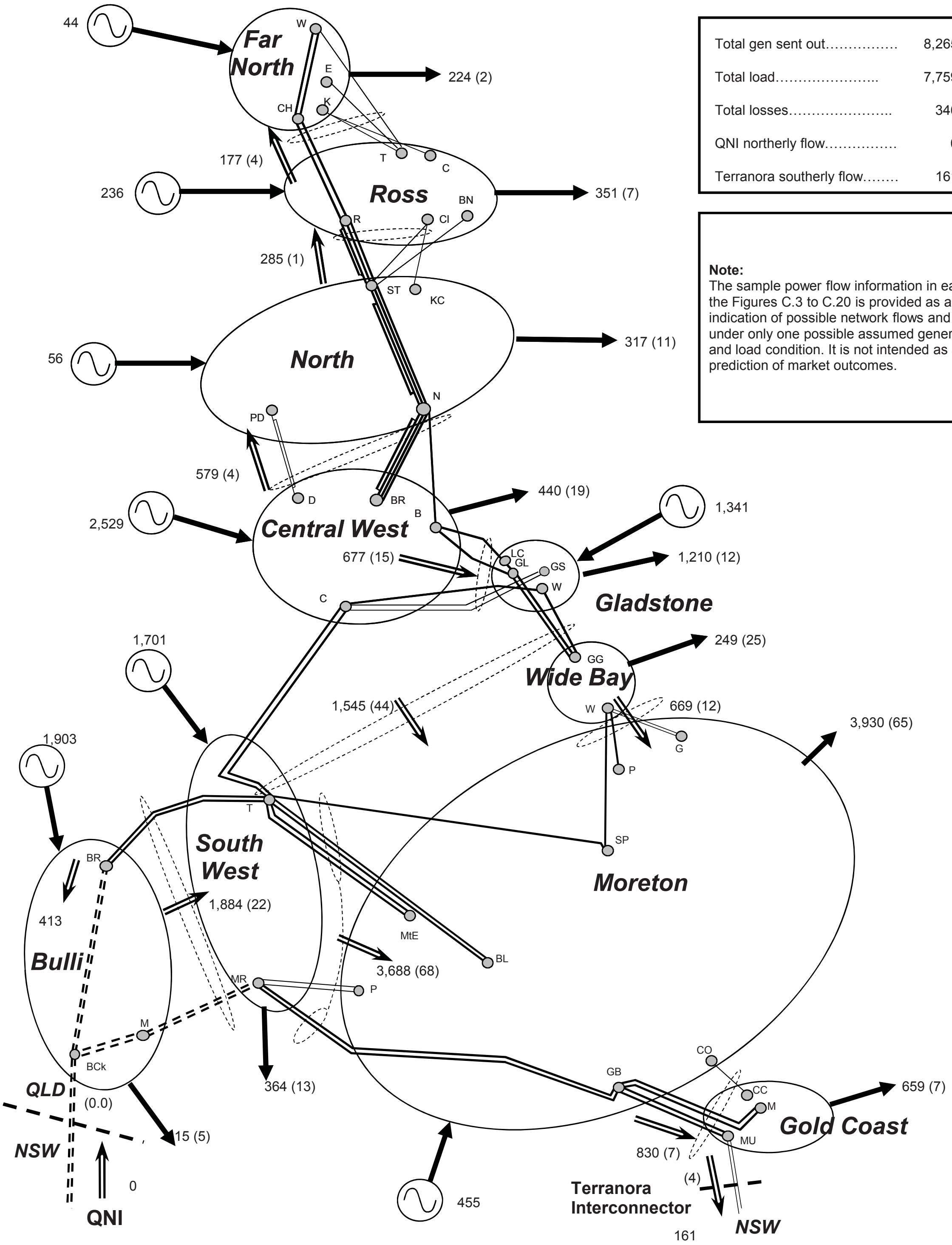


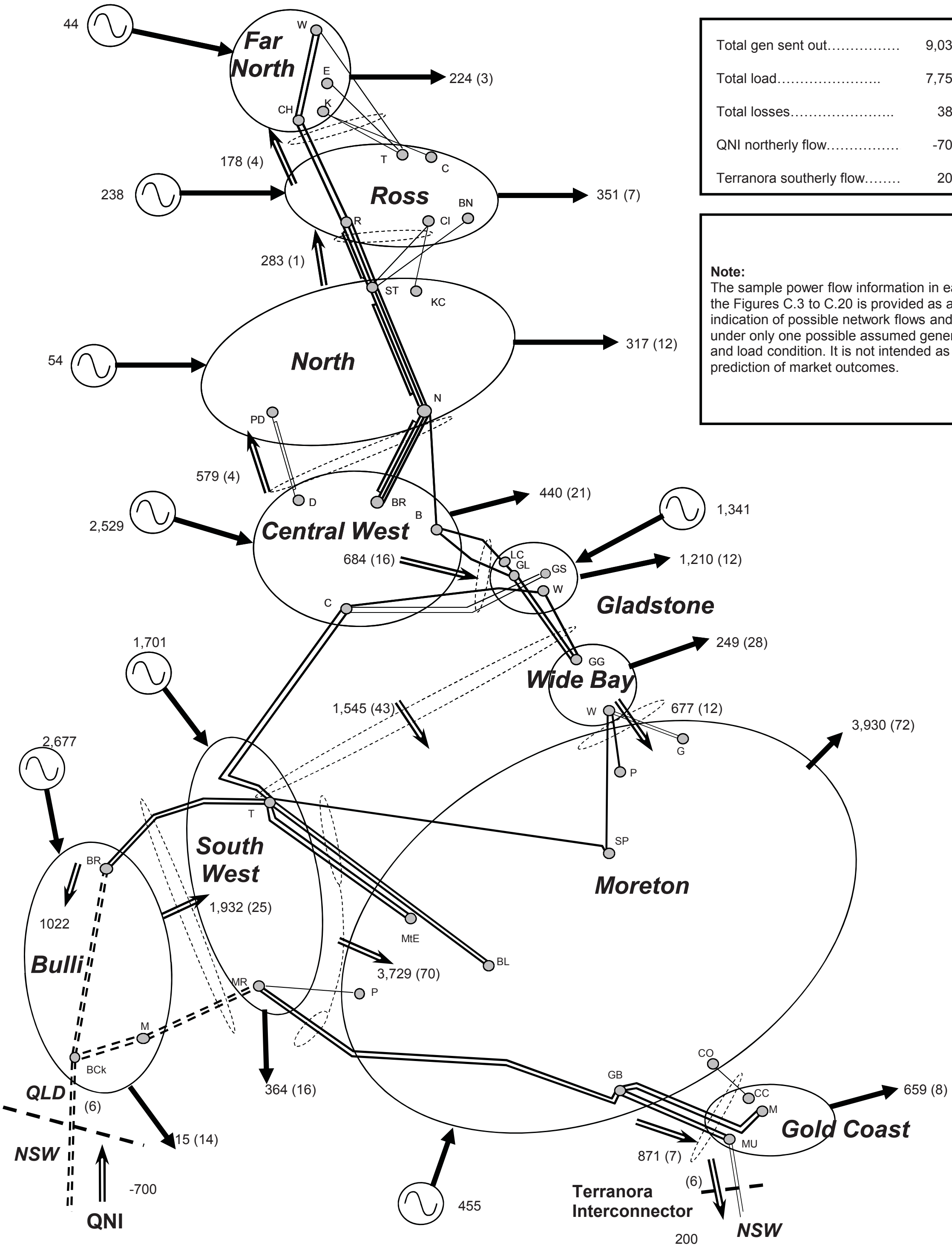
Figure C.7 Winter 2011 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out……………. | 8,265 MW |
| Total load………………….. | 7,759 MW |
| Total losses………………….. | 346 MW |
| QNI northerly flow……………. | 0 MW |
| Terranora southerly flow…….. | 161 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.

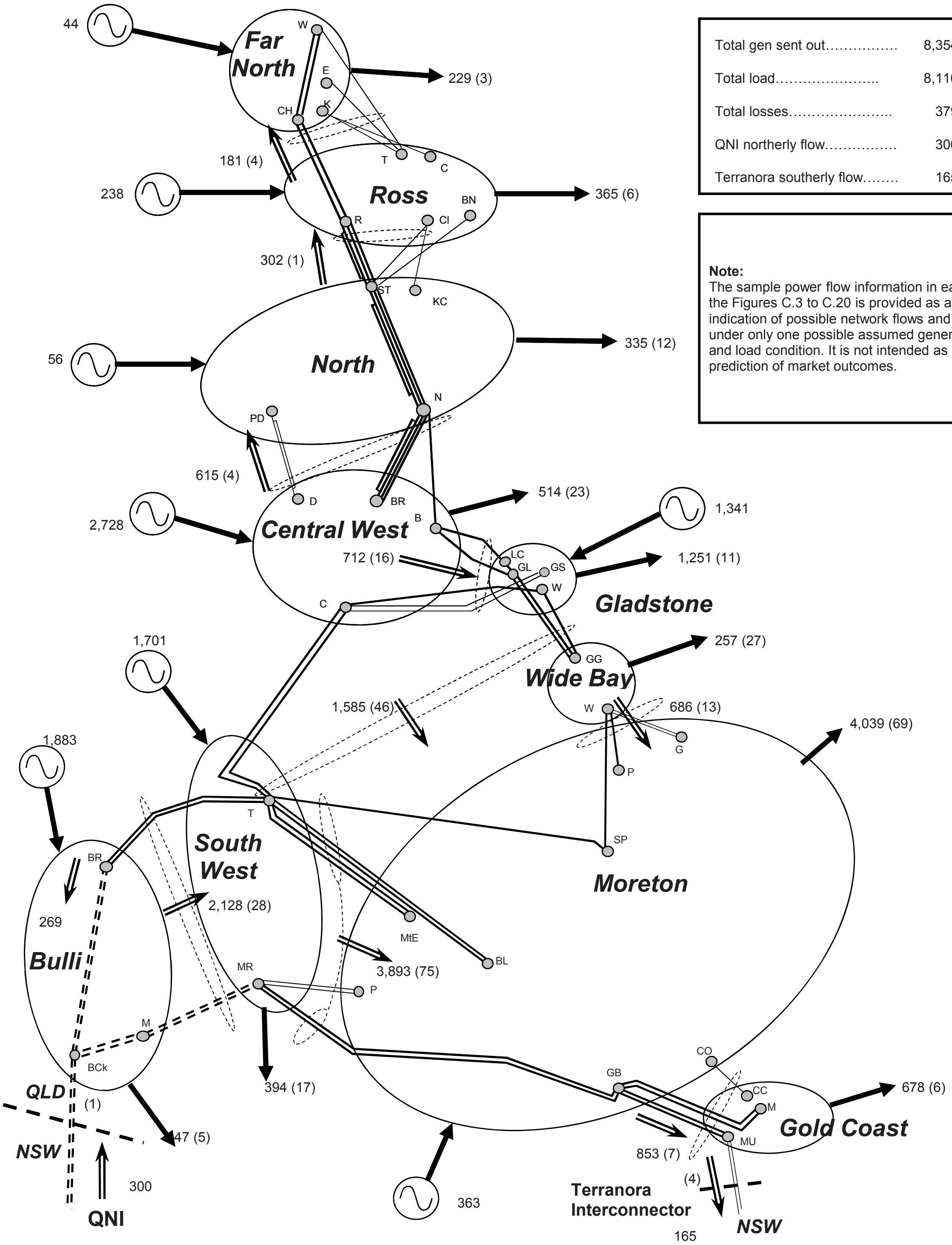
Figure C.8 Winter 2011 Queensland peak 700MW southerly QNI flow




| | |
|---|---|
| Total gen sent out…………… | 9,039 MW |
| Total load………………….. | 7,759 MW |
| Total losses………………….. | 380 MW |
| QNI northerly flow…………… | -700 MW |
| Terranora southerly flow…….. | 200 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.

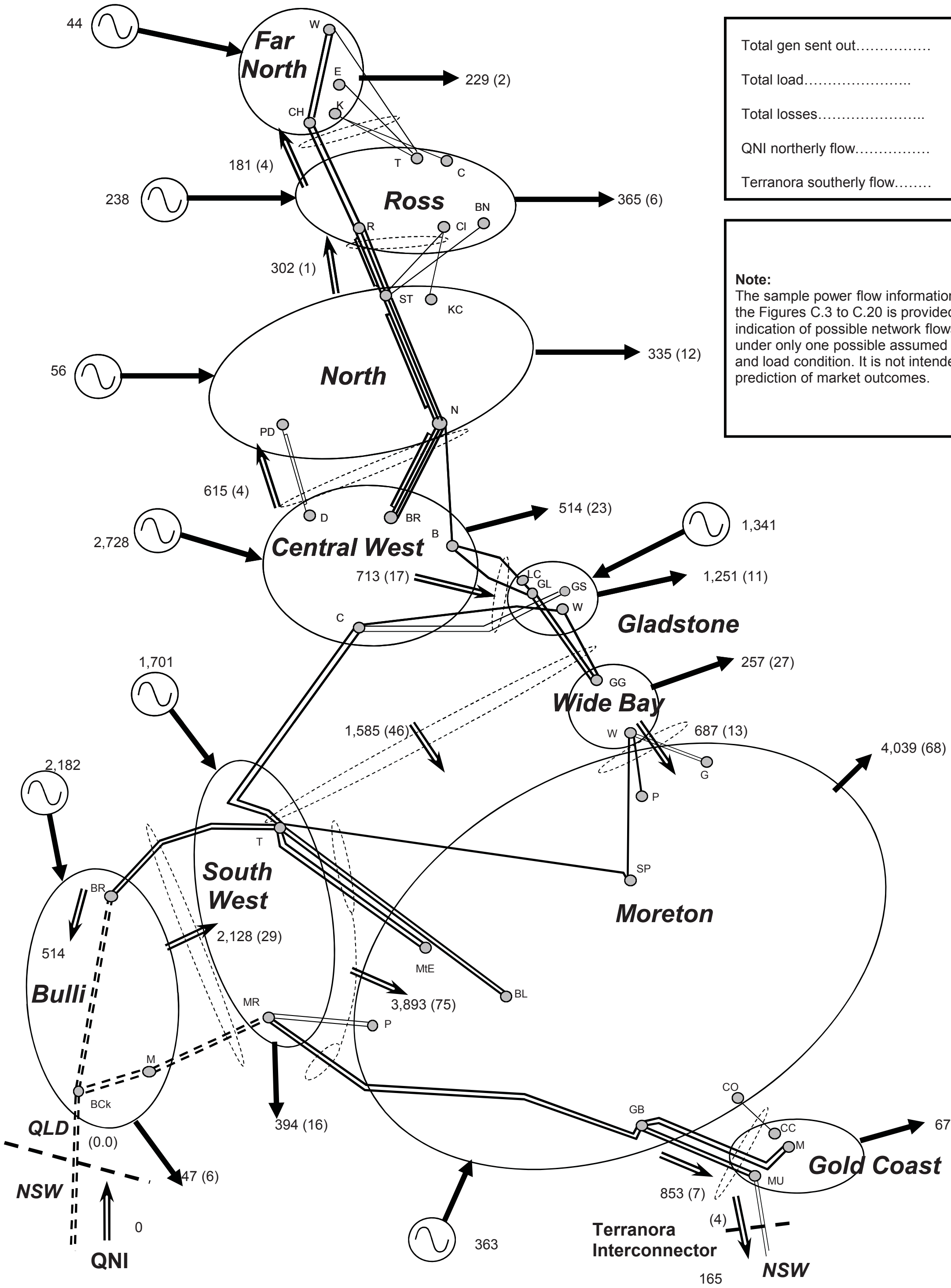
Figure C.9 Winter 2012 Queensland peak 300MW northerly QNI flow




| | |
|---|---|
| Total gen sent out................ | 8,354 MW |
| Total load........................ | 8,110 MW |
| Total losses...................... | 379 MW |
| QNI northerly flow................ | 300 MW |
| Terranora southerly flow........ | 165 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 2012 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out……………. | 8,653 MW |
| Total load………………….. | 8,110 MW |
| Total losses………………….. | 378 MW |
| QNI northerly flow……………. | 0 MW |
| Terranora southerly flow…….. | 165 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 2012 Queensland peak 700MW southerly QNI flow

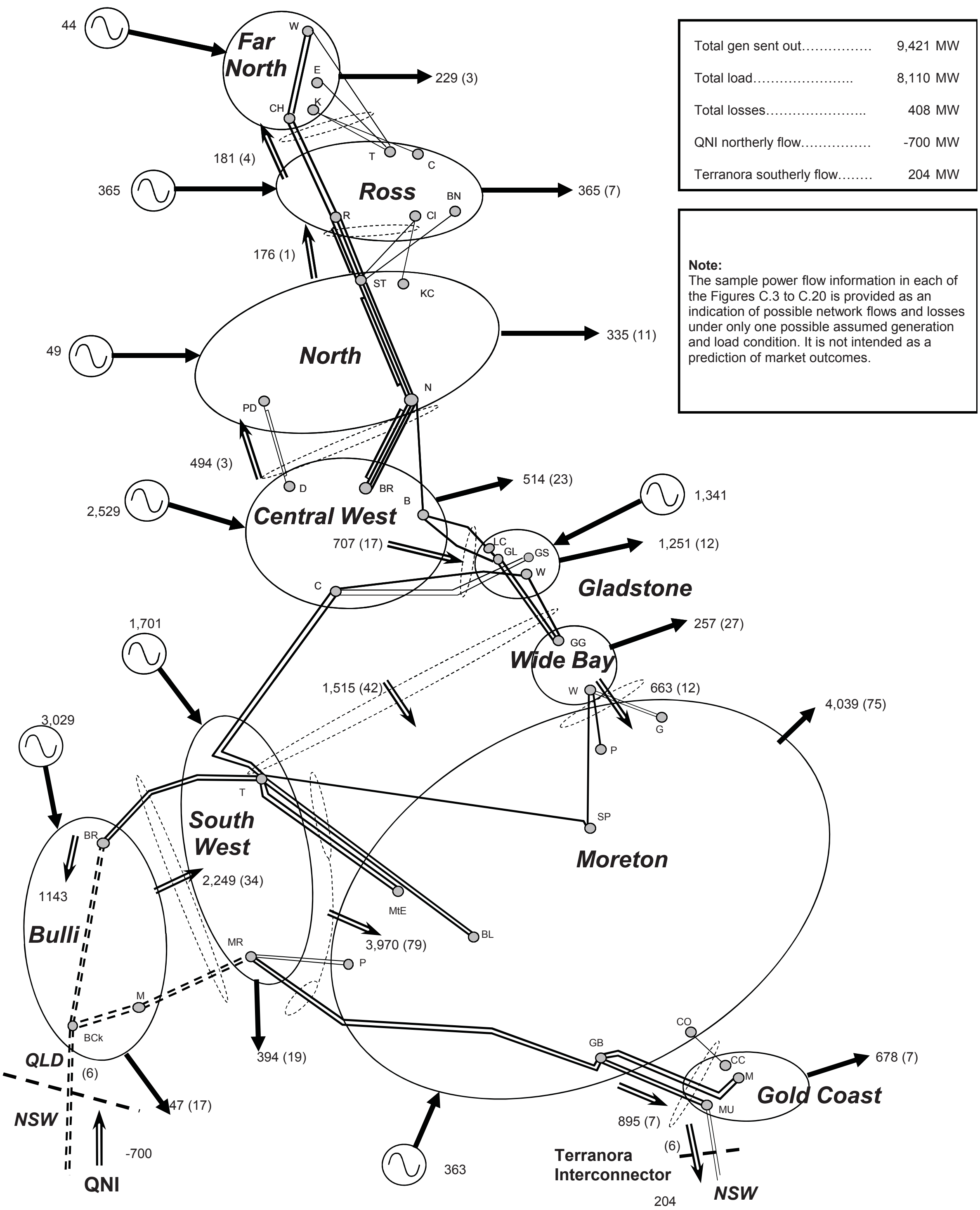
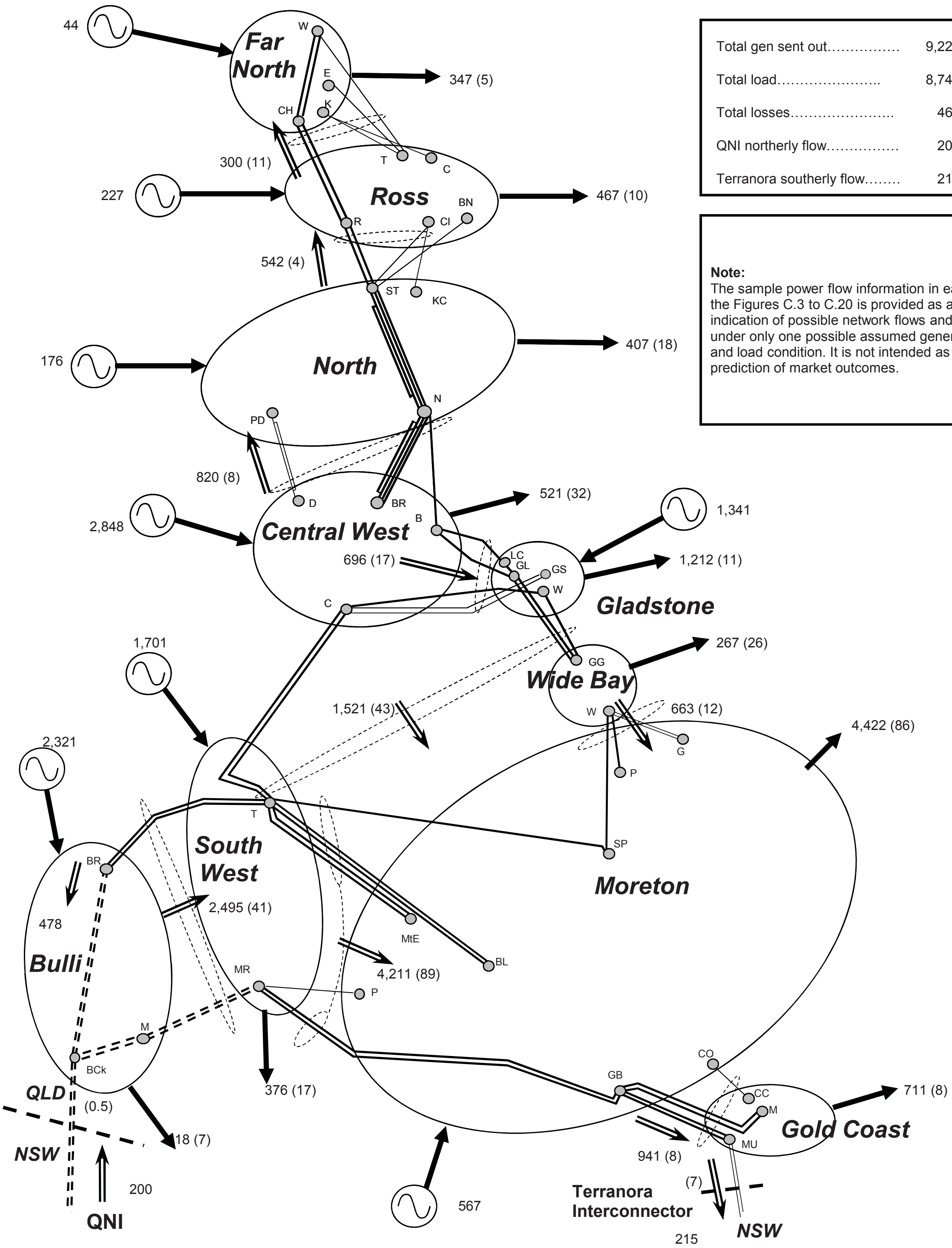


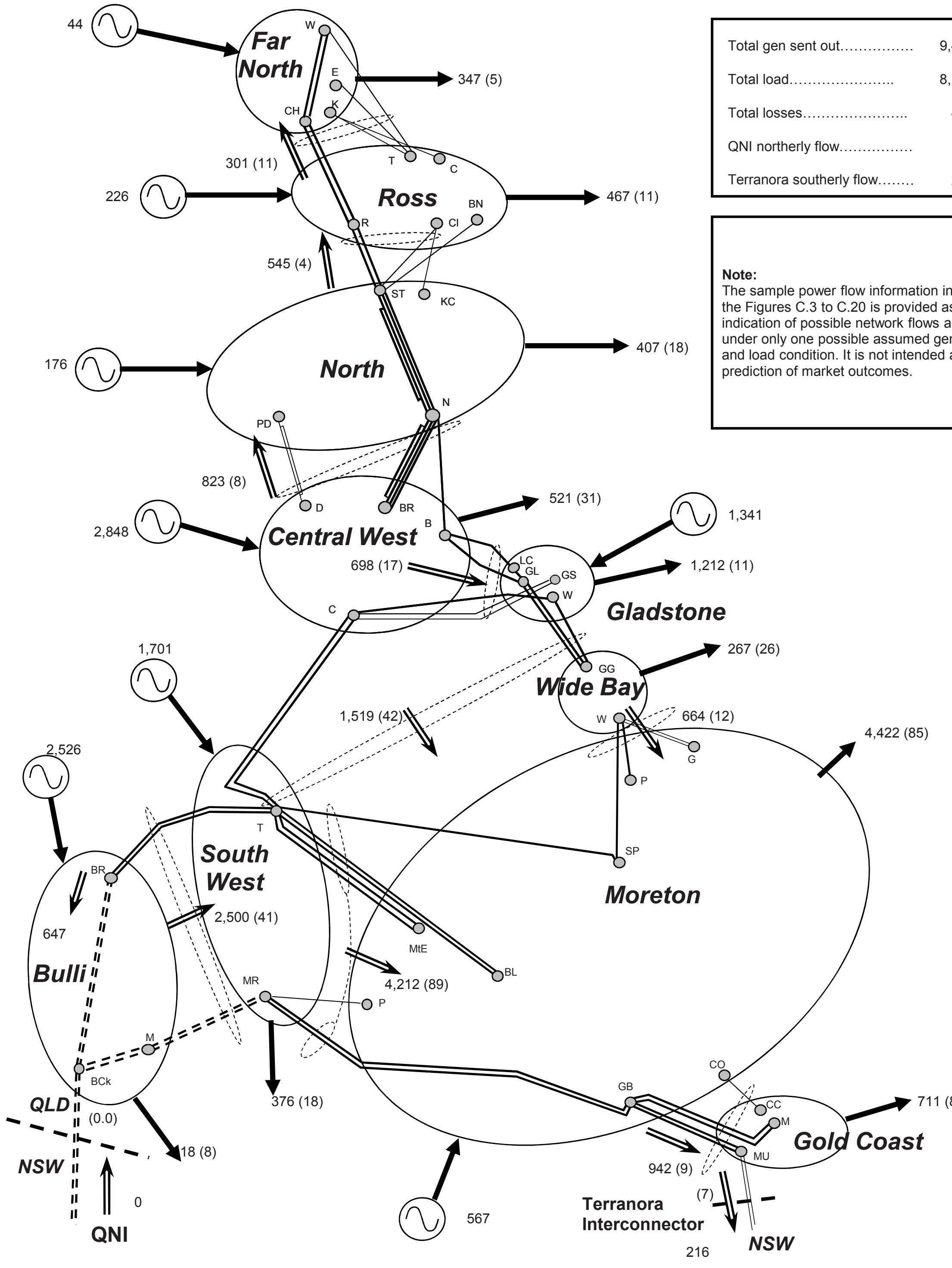
Figure C.12 Summer 2010/11 Queensland peak 200MW northerly QNI flow




| | |
|---|---|
| Total gen sent out................ | 9,223 MW |
| Total load....................... | 8,748 MW |
| Total losses....................... | 460 MW |
| QNI northerly flow................ | 200 MW |
| Terranora southerly flow........ | 215 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.

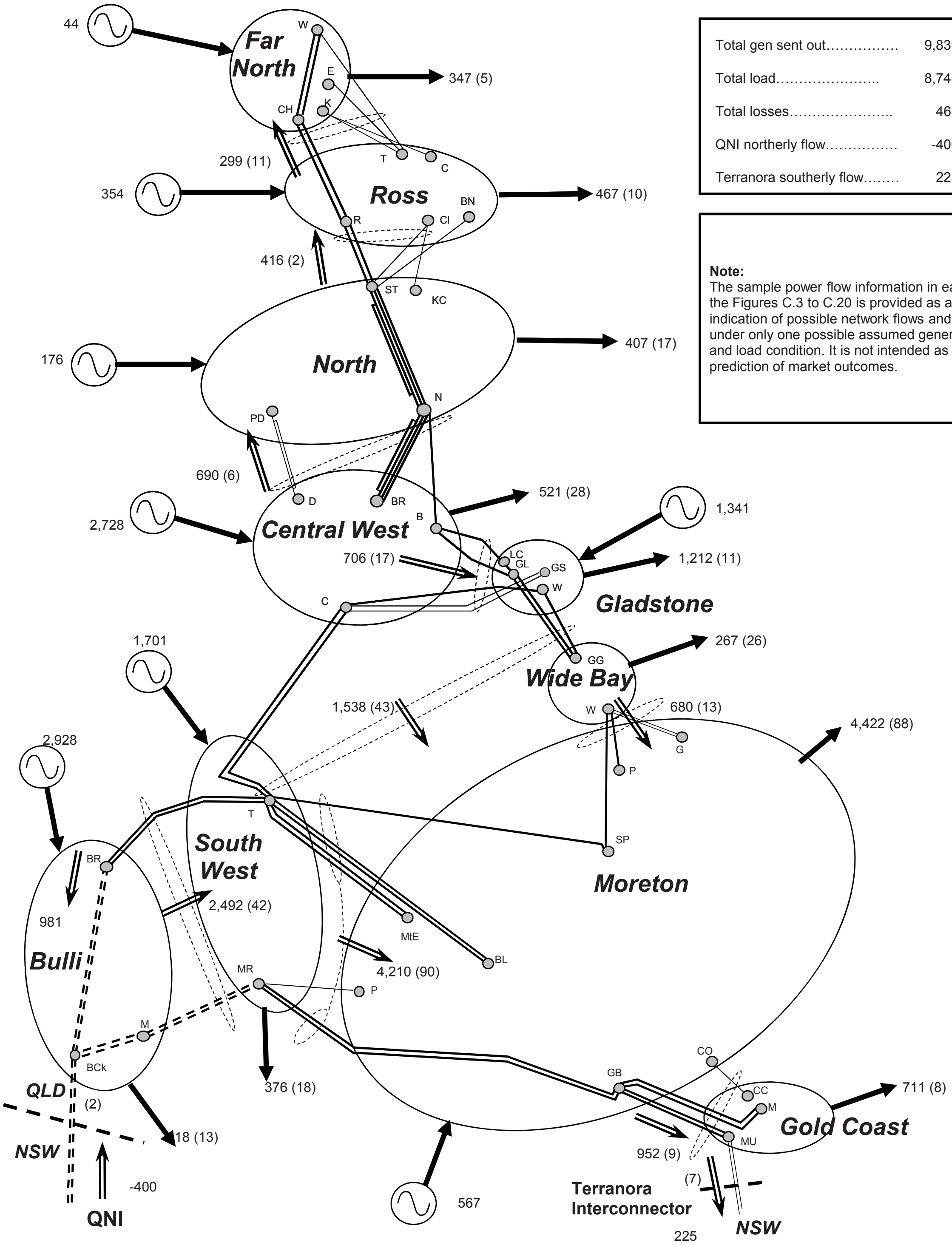
Figure C.13 Summer 2010/11 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out……………. | 9,427 MW |
| Total load………………….. | 8,748 MW |
| Total losses………………….. | 462 MW |
| QNI northerly flow……………. | 0 MW |
| Terranora southerly flow…….. | 216 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.

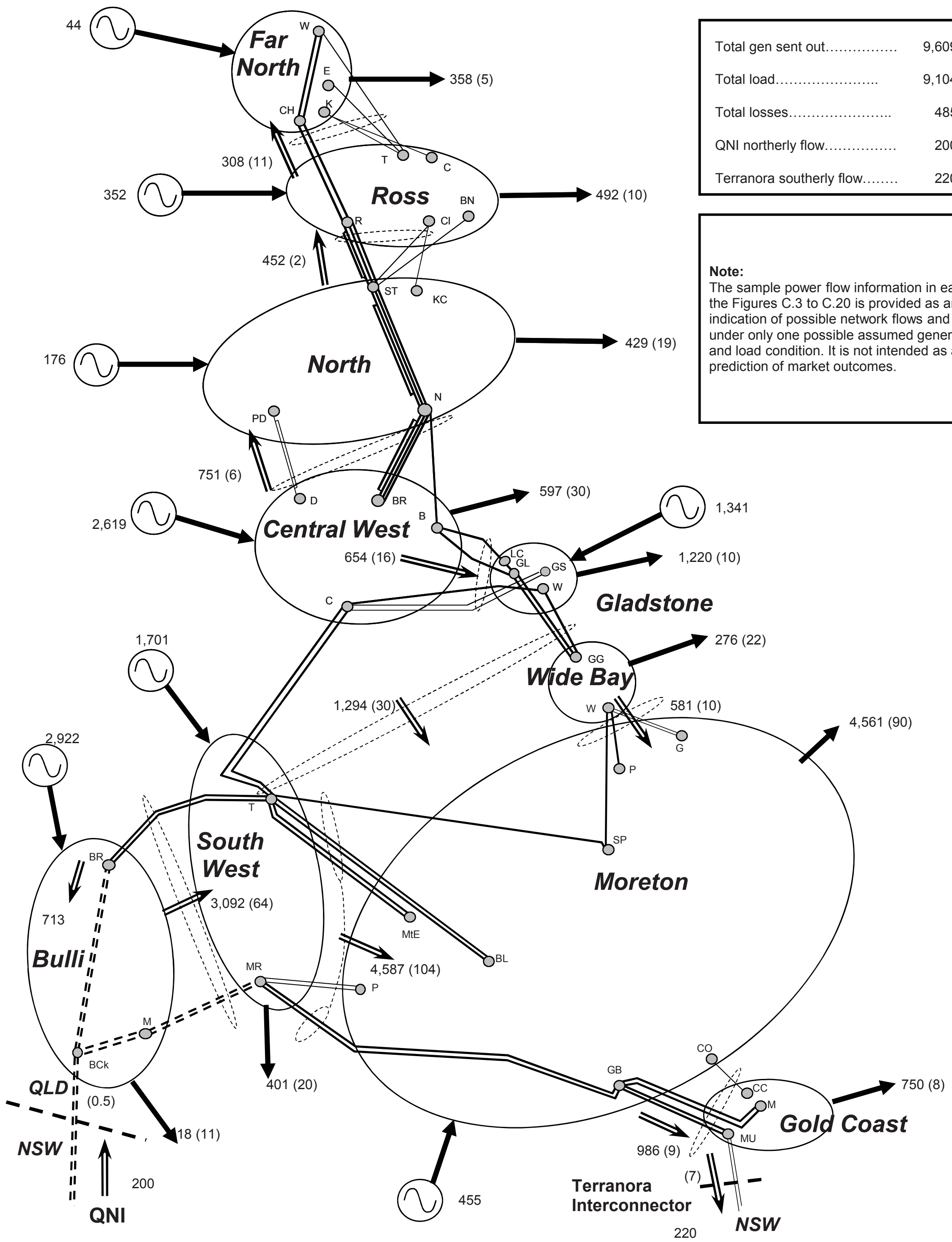
Figure C.14 Summer 2010/11 Queensland peak 400MW southerly QNI flow




| | |
|---|---|
| Total gen sent out…………… | 9,839 MW |
| Total load………………….. | 8,748 MW |
| Total losses………………….. | 465 MW |
| QNI northerly flow…………… | -400 MW |
| Terranora southerly flow…….. | 225 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.

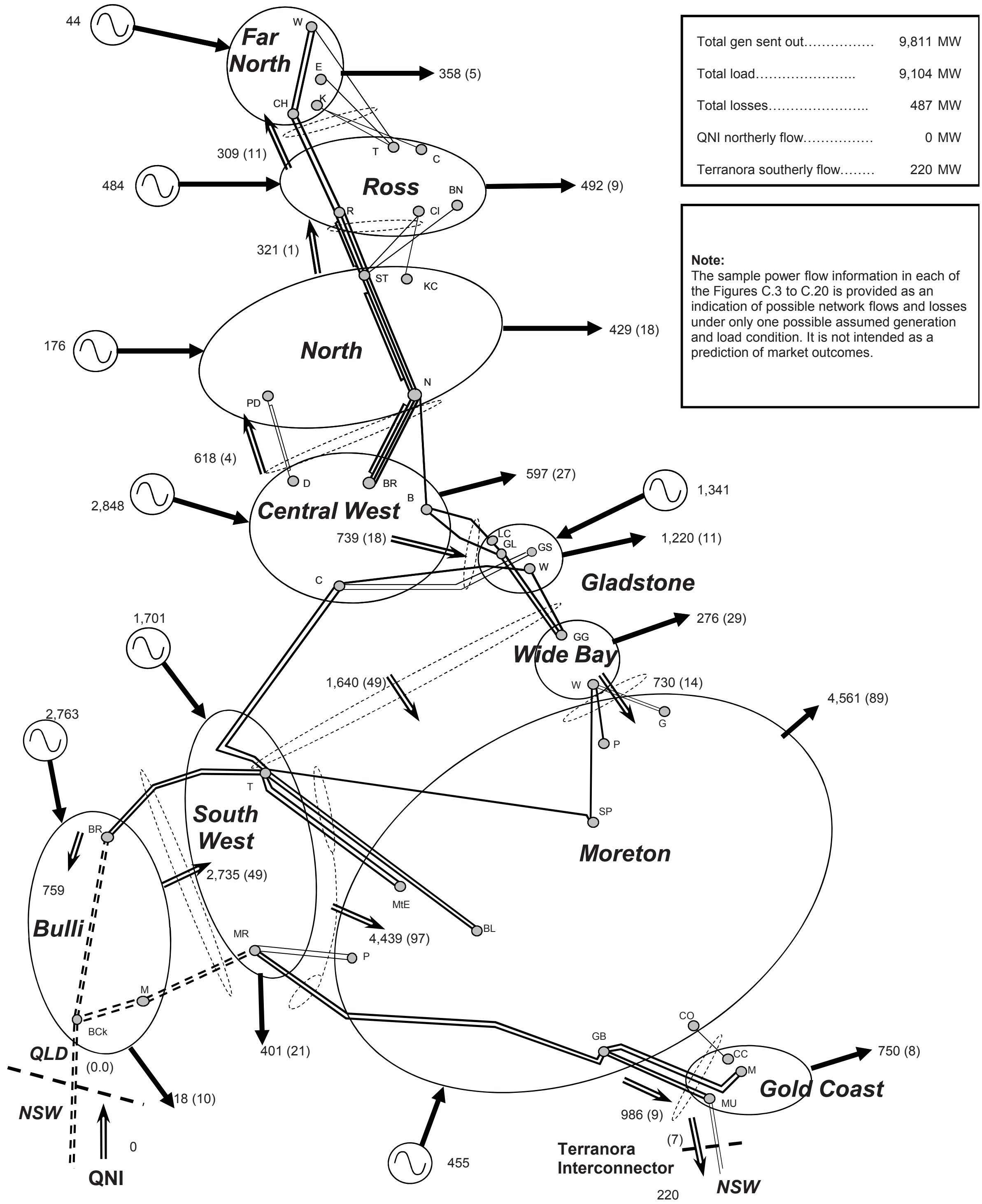
Figure C.15 Summer 2011/12 Queensland peak 200MW northerly QNI flow




| | |
|---|---|
| Total gen sent out................ | 9,609 MW |
| Total load....................... | 9,104 MW |
| Total losses...................... | 485 MW |
| QNI northerly flow................ | 200 MW |
| Terranora southerly flow........ | 220 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.

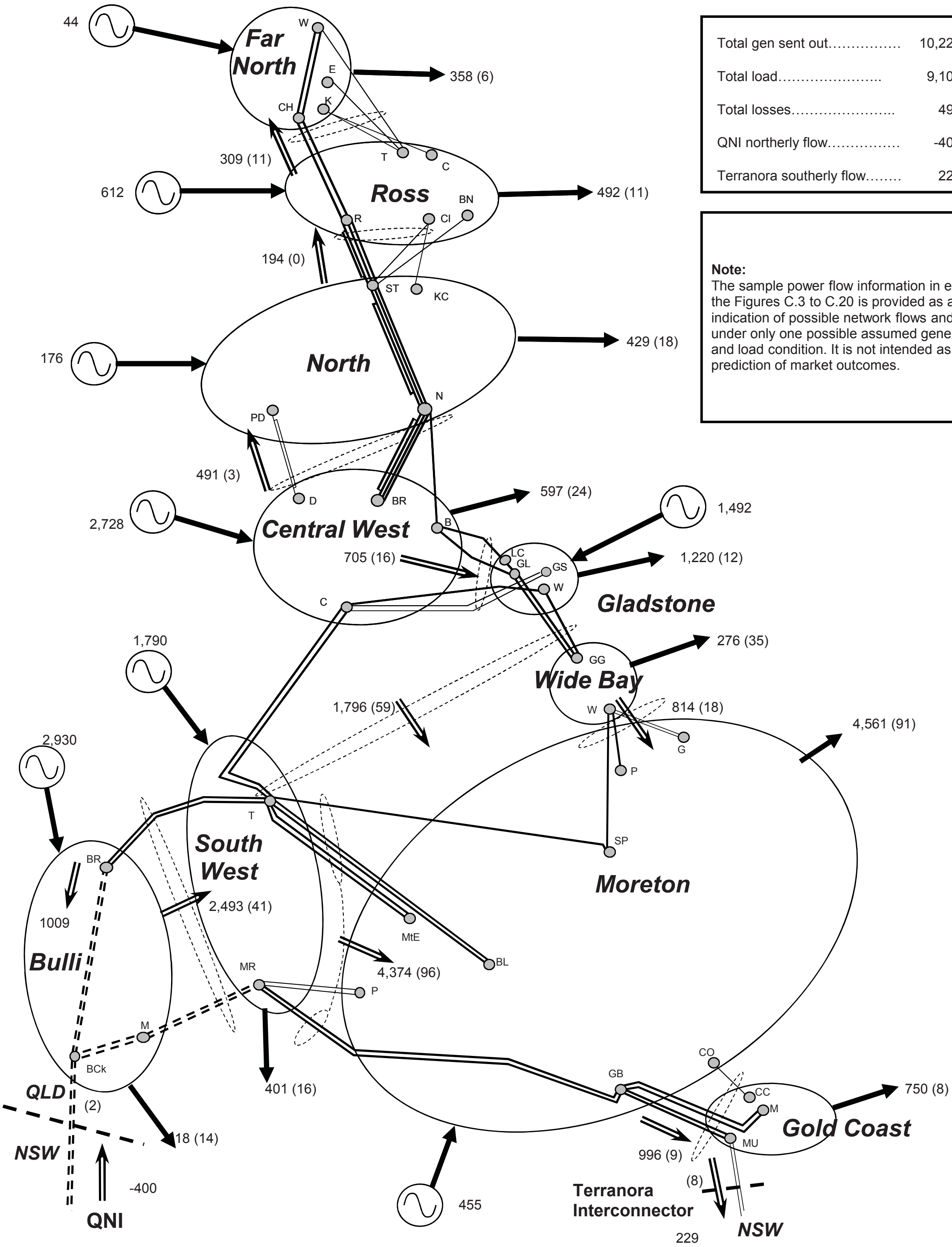
Figure C.16 Summer 2011/12 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out……………. | 9,811 MW |
| Total load………………….. | 9,104 MW |
| Total losses………………….. | 487 MW |
| QNI northerly flow……………. | 0 MW |
| Terranora southerly flow…….. | 220 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 2011/12 Queensland peak 400MW southerly QNI flow




| | |
|---|---|
| Total gen sent out……………. | 10,228 MW |
| Total load………………….. | 9,104 MW |
| Total losses…………………. | 495 MW |
| QNI northerly flow……………. | -400 MW |
| Terranora southerly flow…….. | 229 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 2012/13 Queensland peak 200MW northerly QNI flow

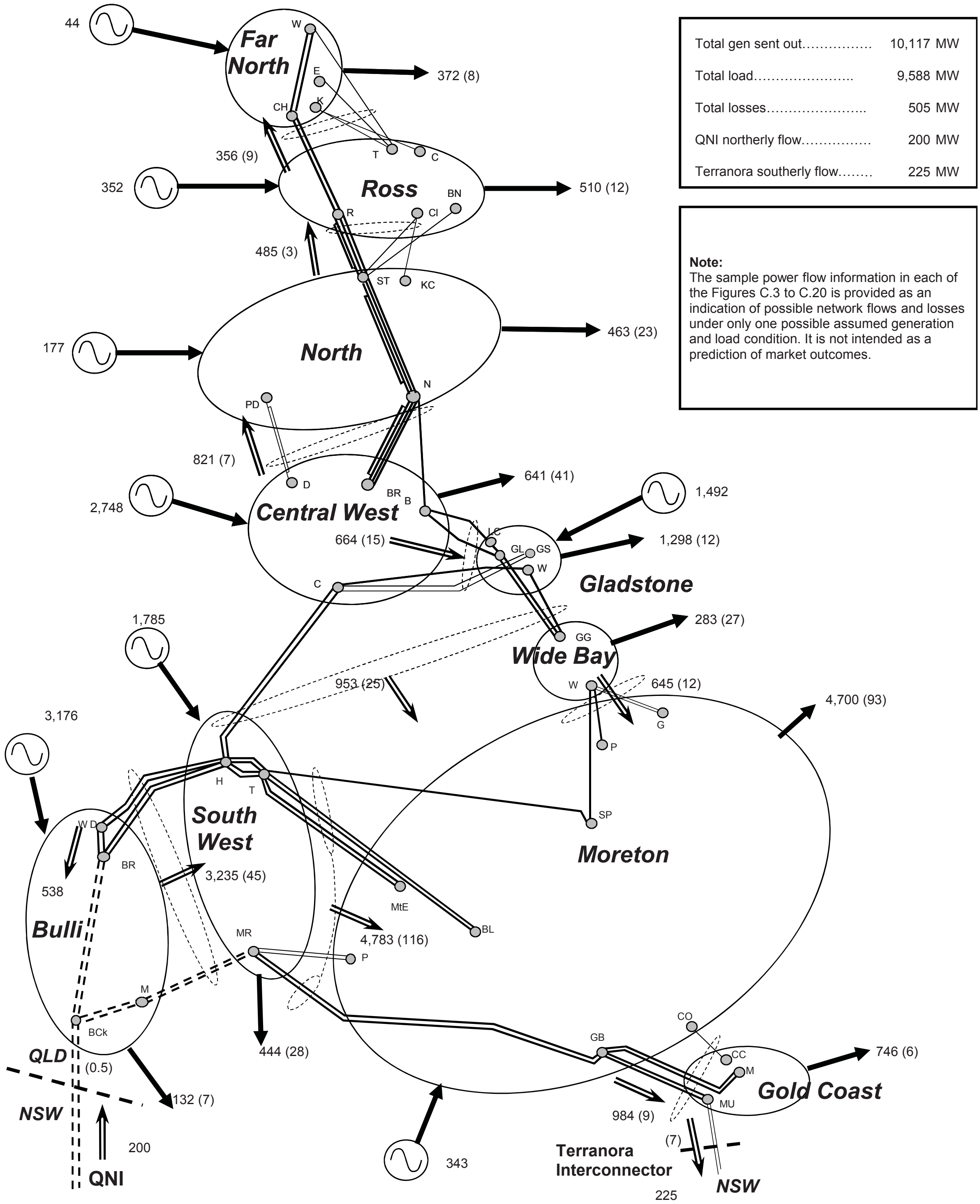
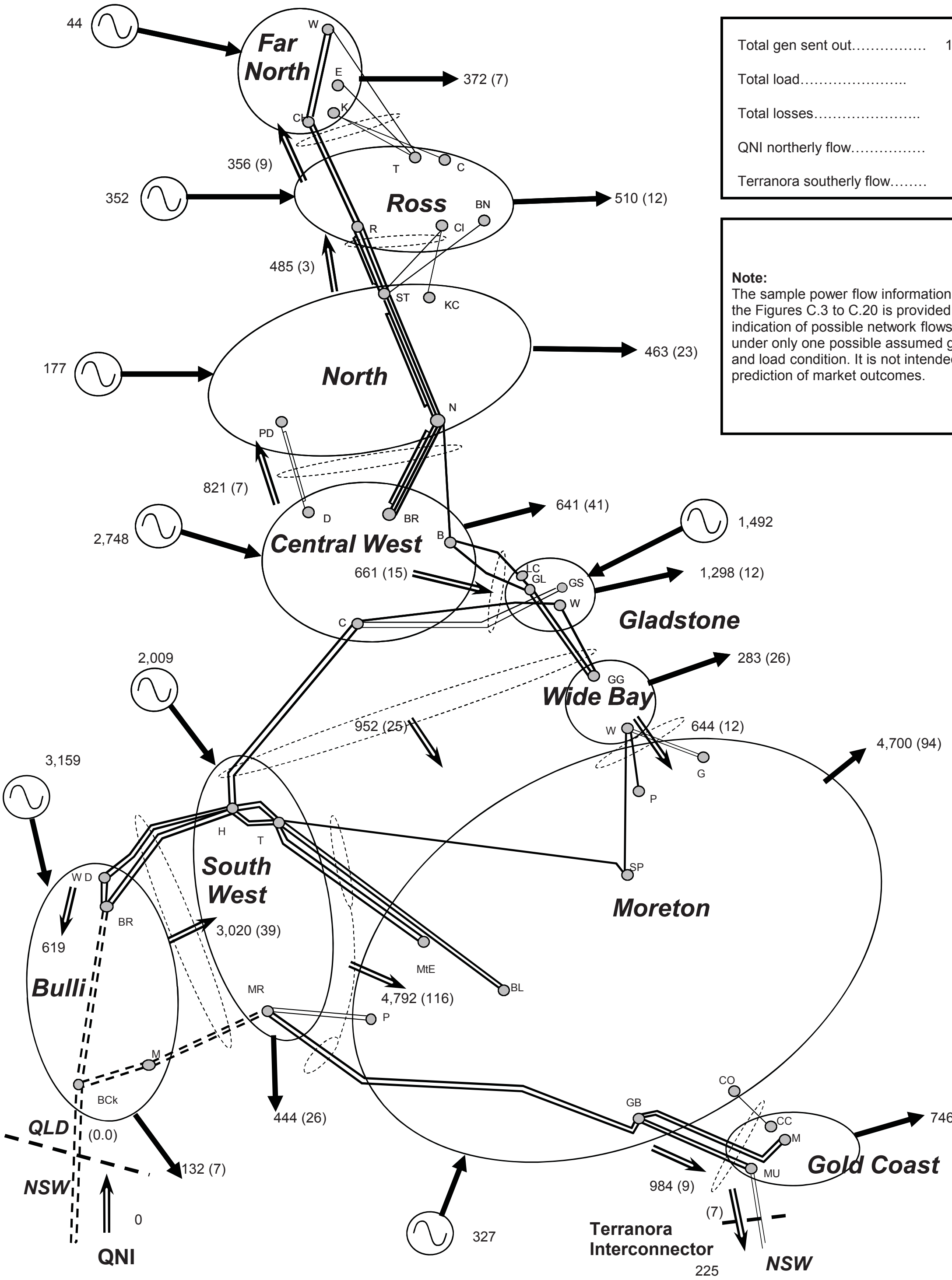


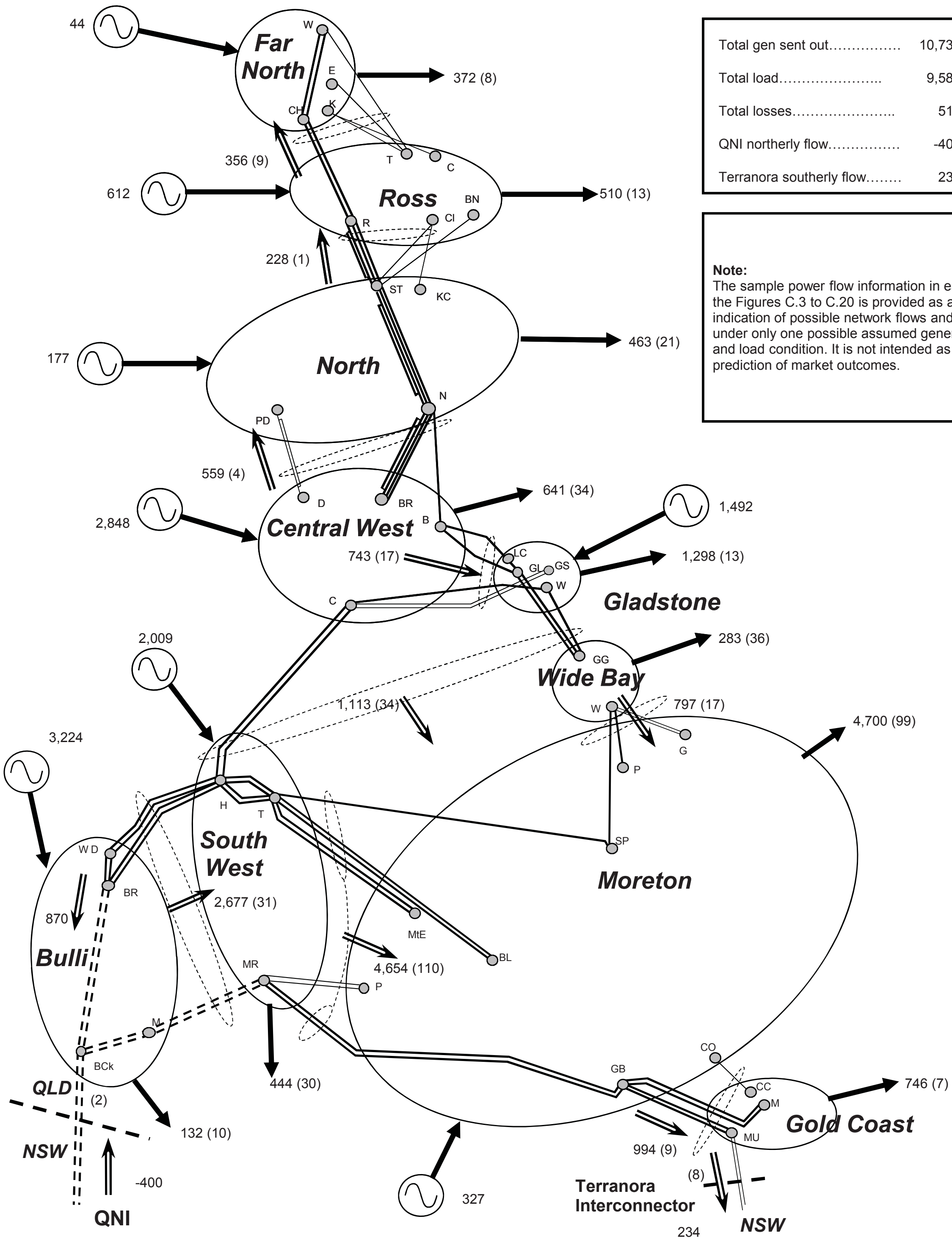
Figure C.19 Summer 2012/13 Queensland peak zero QNI flow




| | |
|---|---|
| Total gen sent out................ | 10,309 MW |
| Total load........................ | 9,588 MW |
| Total losses....................... | 496 MW |
| QNI northerly flow................ | 0 MW |
| Terranora southerly flow........ | 225 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 2012/13 Queensland peak 400MW southerly QNI flow




| | |
|---|---|
| Total gen sent out................ | 10,733 MW |
| Total load....................... | 9,588 MW |
| Total losses...................... | 511 MW |
| QNI northerly flow................ | -400 MW |
| Terranora southerly flow........ | 234 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 their 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.

**Table D.1 Far North Queensland voltage stability equation**

| Measured variable | Coefficient |
|---|---|
| Constant term (intercept) | -56 |
| FNQ demand percentage (1) (2) | 14.5545 |
| Total MW generation at Barron Gorge, Kareeya and Koombooloomba | -0.5892 |
| Total MW generation at Mt Stuart and Townsville | 0.2392 |
| Total MW generation at Collinsville and Mackay | 0.1432 |
| Total nominal MVAr shunt capacitors on line within nominated North Queensland locations (3) | 0.1179 |
| Total nominal MVAr shunt reactors on line within nominated North Queensland locations (4) | -0.1179 |

Notes:

(1) $\text{FNQ demand percentage} = \dfrac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + Collinsville + Invicta + Mackay) generation

(2) The FNQ demand percentage is bounded between 22 and 31.

(3) The shunt capacitor bank locations, nominal sizes and quantities comprise the following:

| | |
|---|---|
| Chalumbin 132kV: | 1 x 50MVAr |
| Ross 132kV: | 1 x 50MVAr |
| Townsville South 132kV: | 2 x 50MVAr |
| Townsville South 66kV: | 2 x 20MVAr |
| Dan Gleeson 66kV: | 2 x 24MVAr |
| Garbutt 66kV: | 2 x 15MVAr |
| Clare 132kV: | 1 x 20MVAr |

(4) The shunt reactor bank locations, nominal sizes and quantities comprise the following:

| | |
|---|---|
| Chalumbin 275kV: | 2 x 29.4MVAr |
| Chalumbin 19.1kV: | 1 x 20.2MVAr |
| Ross 275kV: | 2 x 29.4MVAr |
| Ross 19.1kV: | 2 x 20.2MVAr |

Table D.2 Central to North Queensland voltage stability equations

| Measured variable | Coefficient | |
|---|---|---|
| | Equation 1 | Equation 2 |
| | Feeder contingency | Townsville contingency (1) |
| Constant term (intercept) | 1,292 | 1,484 |
| 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 Collinsville | -0.598 | -0.404 |
| 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 online not available to the Nebo Q optimiser (8) | 0.296 | 0.470 |

Notes:

(1) This limit is only applicable if Townsville is generating.

(2) The nominated 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 nominated shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

| | |
|---|---|
| Ross 275kV: | 2 x 29.4MVAr |
| Ross 19.1kV: | 2 x 20.2MVAr |

(4) The nominated shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

| | |
|---|---|
| Clare 132kV: | 1 x 20MVAr |
| Collinsville 132kV: | 1 x 20MVAr |

(5) The nominated shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

| | |
|---|---|
| Strathmore 275kV: | 1 x 84MVAr |

(6) The nominated shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

| | |
|---|---|
| Mackay 33kV: | 2 x 15MVAr |
| Alligator Creek 132kV: | 1 x 20MVAr |
| Pioneer Valley 132kV: | 1 x 30MVAr |

(7) The nominated shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

| | |
|---|---|
| Nebo 275kV: | 1 x 84MVAr, 1 x 20.2MVAr |
| Nebo 19.1kV: | 2 x 21.9MVAr |

(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 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 online [2 to 4] | 57.5992 |
| Number of Gladstone 132kV units online [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 1] | 51.1534 |
| Number of 45MVAr capacitor banks available at Boyne Island [0 to 2] | 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 3] | 3.2522 |
| Equation lower limit | 1,550 |
| Equation upper limit | 2,100 (2) |

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank B, 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.

Table D.4 Tarong voltage stability equations

| Measured variable | Coefficient (1) | | | | |
|---|---|---|---|---|---|
| | Equation 1 | Equation 2 | Equation 3 | Equation 4 | Equation 5 |
| | Calvale-Tarong contingency | Swanbank E contingency (2) | Wivenhoe contingency (3) | Woolooga-Palmwoods contingency | Tarong-Blackwall contingency |
| Constant term (intercept) | 885 | 1380 | 1400 | 1493 | 1456 |
| Total MW generation at Callide B and Callide C | 0.1222 | 0.1392 | 0.1347 | 0.1277 | 0.1303 |
| Total MW generation at Gladstone 275kV and 132kV | – | – | – | -0.0321 | -0.0149 |
| Total MW generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran and QNI transfer (4) | 0.7279 | 0.6186 | 0.6093 | 0.5891 | 0.5892 |
| Total MW generation at Wivenhoe, Swanbank B and Swanbank E | -0.1552 | – | – | -0.2776 | -0.2752 |
| Generation MW at Swanbank E | – | -0.4058 | – | – | – |
| Total MW generation at Wivenhoe and Swanbank B | – | -0.2551 | – | – | – |
| Generation MW from highest generating Wivenhoe unit | – | – | -0.4474 | – | – |
| Total MW generation at Wivenhoe, Swanbank B and Swanbank E minus generation MW from highest generating Wivenhoe unit | – | – | -0.2282 | – | – |
| Active power transfer (MW) across Terranora Interconnector (4) | -0.1228 | -0.1411 | -0.1477 | -0.1753 | -0.1534 |
| Reactive power transfer (MVAr) across Terranora Interconnector (4) | 0.0550 | 0.1461 | 0.1650 | 0.1602 | 0.1604 |
| Number of Tarong units on line [0 to 4] | – | – | – | 4.8347 | – |
| Number of Tarong North units on line [0 to 1] | – | – | – | 17.4310 | – |
| Number of Wivenhoe units on line [0 to 2] | 14.7432 | 34.8879 | 23.5168 | 38.7378 | 38.2470 |
| Number of Swanbank B units on line [0 to 4] | – | 7.3111 | 7.3318 | 7.9680 | 9.8885 |
| Number of Swanbank E units on line[0 to 1] | 25.8245 | – | 43.0343 | 50.1199 | 58.6689 |
| Number of 200MVAr capacitor banks available (5) | 14.9145 | 39.6326 | 43.8212 | 44.8377 | 44.4988 |
| Number of 120MVAr capacitor banks available (6) | 14.0807 | 24.9870 | 26.7932 | 31.2391 | 28.7603 |
| Number of 50MVAr capacitor banks available (7) | 5.9449 | 10.2726 | 11.7433 | 13.4240 | 12.7283 |
| Reactive to active demand percentage (8) (9) | -5.2917 | -10.7480 | -12.0261 | -14.8056 | -12.8996 |
| Equation lower limit | 3,200 | 3,200 | 3,200 | 3,200 | 3,200 |

Notes:

(1) Equations are offset by – 60MW when the Middle Ridge to Abermain 110kV loop is run closed.

(2) This limit is only applicable if Swanbank E unit is generating.

(3) This limit is only applicable if either of the Wivenhoe units is generating.

(4) Positive transfer denotes northerly flow.

(5) There are currently 4 capacitor banks sized 200MVAr which may be available within this area.

(6) There are currently 14 capacitor banks sized 120MVAr which may be available within this area.

(7) There are currently 36 capacitor banks sized 50MVAr which may be available within this area.

(8) 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.

(9) The Reactive to Active Demand percentage is bounded between 25 and 50.

### Table D.5 Gold Coast 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 B units on line [0 to 4] | 8.5650 |
| 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 |

Notes:

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

(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 sized 200MVAr which may be available within this area.

(5) There are currently 14 capacitor banks sized 120MVAr which may be available within this area.

(6) There are currently 34 capacitor banks sized 50MVAr which may be available within this area.

# Appendix E – Small network augmentations

## E.1 Rockhampton area 275/132kV transformer capability

Project name: Rockhampton area 275/132kV transformer capability

Proposed timing: Summer 2012/13

Estimated cost: $13.9 million

*Background*

The Bouldercombe 275/132kV Substation serves as the primary supply point for the Rockhampton area. It supplies the 132/66kV substations at Rockhampton, Pandoin, Egans Hill and QR Rocklands, as well as 132kV supply to Stanwell Power Station's auxiliary support facility and QR's Grantleigh 132/50kV Substation. Summer peak demand for electricity in the Rockhampton area continues to grow strongly and is forecast to grow at a high rate due mostly to committed increases in electrified coal haulage rail traffic in the area by early 2013.

As disclosed in the Annual Planning Report 2009, sufficient 275/132kV transformer capability is forecast to be available in the Rockhampton area until summer 2012/13. From this time, transformer thermal limitations are forecast to occur following an outage of a parallel 275/132kV transformer at Bouldercombe Substation.

Powerlink has reliability and quality of supply obligations under the National Electricity Rules (NER), its Transmission Authority and connection agreements with customers. 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. Under its Transmission Authority, Powerlink plans and develops its network to supply forecast peak demand during a single network element outage. Without action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the Australian Energy Regulator (AER). For a reliability augmentation, this test requires that a proposed solution minimises the present value cost of meeting objective performance standards compared with other feasible alternatives.

*Network options considered*

**Option 1 Bouldercombe transformer**

Under this option it is proposed to install a third 275/132kV 375MVA transformer at Bouldercombe Substation by summer 2012/13.

Installing an additional transformer at Bouldercombe Substation is a feasible network solution that provides sufficient capacity to meet forecast demand, following an outage of a parallel 275/132kV transformer at Bouldercombe Substation. The total cost of this option is $13.9 million.

**Option 2 Stanwell transformer and line**

This option involves a feasible network solution comprising the installation of a 275/132kV 375MVA transformer at Stanwell Substation and constructing a 132kV single circuit transmission line between Stanwell and Bouldercombe substations by summer 2012/13.

Installing an additional transformer at Stanwell Substation addresses the identified transformer limitation and the new 132kV Stanwell to Bouldercombe line addresses thermal limitations that are expected to occur on the existing 132kV line from Bouldercombe to Stanwell through to QR Grantleigh substations, following an outage of a 275/132kV transformer at Bouldercombe Substation. The total cost of this option is $36.4 million.

**Option 3 Non-network options considered**

Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of summer 2012/13.

*Summary of options and economic analysis*

There are two feasible options that are capable of addressing the forecast thermal limitations in the Rockhampton area by summer 2012/13. The present value cost of each of these options was calculated over a period of 15 years.

The results of this economic analysis for the medium growth forecast are summarised in Table E.1.

**Table E.1** Summary of economic analysis for medium economic outlook for Bouldercombe transformer

| Options | Present value (PV) cost $m (medium outlook) | Ranking |
|---|---|---|
| 1. Bouldercombe transformer | $7.97 | 1 |
| 2. Stanwell transformer and line | $20.86 | 2 |
| 3. Non-network options | N/A | N/A |

A range of market scenarios were used to assess the economic feasibility of the options and range from high to low demand growth based on estimates of economic growth rates in Australia. The market scenario analysis is shown in Table E.2. below and the results of these scenarios are in Tables E.4 to E.6. The possible introduction of new embedded generation in the Rockhampton area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

**Table E.2** Summary of scenario analysis

| | Option One Bouldercombe transformer | | Option Two Stanwell transformer and line | |
|---|---|---|---|---|
| | PV $m | Ranking | PV $m | Ranking |
| Scenario A high growth | $7.97 | 1 | $20.86 | 2 |
| Scenario B medium growth | $7.97 | 1 | $20.86 | 2 |
| Scenario C low growth | $6.98 | 1 | $18.28 | 2 |

The sensitivity of the present value calculations to key input variables such as discount rate and capital costs (variation of +/ – 15%) has been examined and the results are summarised in Table E.3. Sensitivity to the commissioning date was not examined, as both options are required to be in service by summer 2012/13 to meet forecast peak load.

Table E.3 Results of sensitivity analysis for Bouldercombe transformer

| | Discount rate 7% | | Discount rate 9% | | Discount rate 11% | |
|---|---|---|---|---|---|---|
| | Best ranked option | Frequency of wins | Best ranked option | Frequency of wins | Best ranked option | Frequency of wins |
| Scenario A high growth | 1 | 100% | 1 | 100% | 1 | 100% |
| Scenario B medium growth | 1 | 100% | 1 | 100% | 1 | 100% |
| Scenario C low growth | 1 | 100% | 1 | 100% | 1 | 100% |

The result of the analysis is that Option 1 Bouldercombe transformer minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

*Recommendation*

It is recommended to install a third 275/132kV (375MVA) transformer at Bouldercombe Substation by summer 2012/13.

Table E.4 Cash flow for Bouldercombe transformer

| Scenario A | | Medium growth | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| | | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
| **Option 1** | | | | | | | | | | | | | | | | |
| Bouldercombe transformer | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 1.532 | 1.512 | 1.492 | 1.471 | 1.451 | 1.430 | 1.410 | 1.389 | 1.369 | 1.349 | 1.328 | 1.308 |
| Total for Option 1 | $7.97 | | | | | | | | | | | | | | | |
| **Option 2** | | | | | | | | | | | | | | | | |
| Stanwell transformer and line | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 4.013 | 3.960 | 3.906 | 3.853 | 3.799 | 3.746 | 3.692 | 3.639 | 3.585 | 3.532 | 3.478 | 3.425 |
| Total for Option 2 | $20.86 | | | | | | | | | | | | | | | |

Table E.5 Cash flow for Bouldercombe transformer

| Scenario B | High growth | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| | | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
| **Option 1** | | | | | | | | | | | | | | | | |
| Bouldercombe transformer | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 1.532 | 1.512 | 1.492 | 1.471 | 1.451 | 1.430 | 1.410 | 1.389 | 1.369 | 1.349 | 1.328 | 1.308 |
| Total for Option 1 | $7.97 | | | | | | | | | | | | | | | |
| **Option 2** | | | | | | | | | | | | | | | | |
| Stanwell transformer and line | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 4.013 | 3.960 | 3.906 | 3.853 | 3.799 | 3.746 | 3.692 | 3.639 | 3.585 | 3.532 | 3.478 | 3.425 |
| Total for Option 2 | $20.86 | | | | | | | | | | | | | | | |

Table E.6 Cash flow for Bouldercombe transformer

| Scenario C | Low growth | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| | | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
| **Option 1** | | | | | | | | | | | | | | | | |
| Bouldercombe transformer | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 0.000 | 1.532 | 1.512 | 1.492 | 1.471 | 1.451 | 1.430 | 1.410 | 1.389 | 1.369 | 1.349 | 1.328 |
| Total for Option 1 | $6.98 | | | | | | | | | | | | | | | |
| **Option 2** | | | | | | | | | | | | | | | | |
| Stanwell transformer and line | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 0.000 | 4.013 | 3.960 | 3.906 | 3.853 | 3.799 | 3.746 | 3.692 | 3.639 | 3.585 | 3.532 | 3.478 |
| Total for Option 2 | $18.28 | | | | | | | | | | | | | | | |

## Appendix F – Estimated maximum short circuit levels

Tables F.1 to F.3 show estimates of the maximum three phase and single phase to earth short circuit levels in the Powerlink Queensland transmission network in the period 2010 to 2012. They also show the short circuit capacity of the lowest rated equipment at each location.

This information should be taken only as an approximate guide to conditions at each location. The effects of some of the more significant embedded non-scheduled generators are included as noted in the tables. However, other embedded non-scheduled generators have been excluded. Some of these excluded generators are also noted in the tables. As a result, fault levels may be higher at some locations than shown. Interested parties needing to consider the effects of their proposals on system short circuit levels should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for detailed information.

The short circuit level calculations were determined:

- using a simple system model, in which generators are represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with system loads and all shunt admittances not represented.

The short circuit levels shown in Tables F.1 to F.3 have been determined on the basis of the generation capacity shown in Table 5.1 (together with any noted embedded non-scheduled generators) and on the network development as at the end of each calendar year. These network models are based on the existing network configuration and committed projects.

The fault levels determined assume the grid is in its 'normal' or 'intact' state, that is, all network elements in service. At some locations where the short circuit level appears to be above the equipment, either only a portion of the total fault current flows through the equipment and that portion is less than the equipment rating over the three year outlook period, or operational measures are taken to ensure that short circuit levels are within the equipment rating.

No account has been taken of short circuit interruption capability of equipment in the distribution systems.

Table F.1 Estimated maximum short circuit levels – Northern Queensland – Powerlink transmission network 2010 to 2012

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA |
| Alan Sherriff | 132 | 40.0 | 12.4 | 13.0 | 12.4 | 13.0 | 12.5 | 13.1 |
| Alligator Creek | 132 | 25.0 | 4.4 | 5.8 | 4.4 | 5.7 | 4.5 | 5.9 |
| Bollingbroke | 132 | 40.0 | 2.2 | 1.7 | 2.2 | 1.7 | 2.3 | 1.7 |
| Bowen North | 132 | 40.0 | 2.4 | 2.6 | 2.3 | 2.6 | 2.4 | 2.6 |
| Burton Downs | 132 | 19.3 | 5.2 | 4.9 | 5.1 | 4.9 | 5.2 | 4.9 |
| Cairns (2T) | 132 | 25.0 | 5.0 | 6.7 | 5.0 | 6.7 | 4.6 | 6.3 |
| Cairns (3T) | 132 | 25.0 | 5.0 | 6.7 | 5.0 | 6.7 | 4.6 | 6.3 |
| Cairns (4T) | 132 | 25.0 | 5.0 | 6.8 | 5.0 | 6.7 | 4.6 | 6.3 |
| Cardwell | 132 | 19.3 | 2.3 | 2.2 | 1.9 | 1.5 | 2.9 | 1.9 |
| Chalumbin | 275 | 25.0 | 3.6 | 3.8 | 3.6 | 3.8 | 3.6 | 3.8 |
| Chalumbin | 132 | 31.5 | 6.1 | 7.1 | 6.1 | 7.1 | 6.0 | 7.0 |
| Clare South | 132 | 40.0 | 7.7 | 8.0 | 7.7 | 7.9 | 7.8 | 8.0 |
| Collinsville | 132 | 10.9 | 12.6 | 14.1 | 12.5 | 14.0 | 12.7 | 14.3 |
| Coppabella | 132 | 31.5 | 3.1 | 3.4 | 3.1 | 3.4 | 3.1 | 3.4 |
| Dan Gleeson (Bus 1) | 132 | 31.5 | 11.8 | 12.5 | 11.8 | 12.6 | 12.0 | 12.7 |
| Dan Gleeson (Bus 2) | 132 | 40.0 | 11.8 | 12.4 | 11.8 | 12.4 | 11.9 | 12.6 |
| Edmonton | 132 | 40.0 | 4.6 | 5.8 | 4.6 | 5.7 | 4.2 | 5.4 |
| El Arish | 132 | 40.0 | 3.0 | 3.7 | 3.0 | 3.6 | 2.0 | 2.5 |
| Garbutt | 132 | 40.0 | 10.3 | 10.4 | 10.3 | 10.4 | 10.4 | 10.5 |
| Ingham South | 132 | 40.0 | 2.0 | 2.3 | 3.8 | 3.5 | 2.8 | 2.9 |
| Innisfail | 132 | 40.0 | 2.7 | 3.4 | 2.7 | 3.3 | 2.1 | 2.7 |
| Invicta | 132 | 19.3 | 5.2 | 4.7 | 5.2 | 4.7 | 5.3 | 4.7 |
| Kamerunga | 132 | 15.3 | 4.0 | 4.9 | 4.0 | 4.8 | 3.8 | 4.6 |
| Kareeya | 132 | 10.9 | 6.0 | 7.0 | 6.0 | 7.0 | 5.7 | 6.6 |
| Kemmis | 132 | 31.5 | 5.8 | 6.4 | 5.7 | 6.4 | 5.9 | 6.5 |
| King Creek | 132 | 40.0 | 5.1 | 4.1 | 5.1 | 4.1 | 5.1 | 4.2 |
| Mackay | 132 | 10.9 | 6.3 | 6.8 | 6.2 | 6.7 | 6.4 | 6.9 |
| Mackay Ports | 132 | 40.0 | 3.3 | 3.7 | 3.4 | 4.1 | 3.5 | 4.1 |
| Mindi | 132 | 40.0 | 5.1 | 4.3 | 5.0 | 4.2 | 5.2 | 4.3 |
| Moranbah | 132 | 10.9 | 7.0 | 8.2 | 7.0 | 8.2 | 7.1 | 8.3 |
| Moranbah South | 132 | 31.5 | 5.2 | 4.9 | 5.2 | 4.9 | 5.3 | 4.9 |

Table F.1 Estimated maximum short circuit levels – Northern Queensland – Powerlink transmission network 2010 to 2012 (continued)

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA |
| Mt Mclaren | 132 | 31.5 | 2.0 | 2.2 | 2.0 | 2.2 | 2.0 | 2.2 |
| Nebo | 275 | 31.5 | 9.8 | 10.1 | 9.2 | 9.6 | 10.6 | 10.6 |
| Nebo | 132 | 15.3 | 12.2 | 13.6 | 11.9 | 13.3 | 12.6 | 13.9 |
| Newlands | 132 | 25.0 | 3.3 | 3.7 | 3.3 | 3.7 | 3.6 | 4.0 |
| North Goonyella | 132 | 19.3 | 3.5 | 2.8 | 3.4 | 2.8 | 4.4 | 4.2 |
| Oonooie | 132 | 31.5 | 3.1 | 3.7 | 3.1 | 3.6 | 3.1 | 3.7 |
| Peak Downs | 132 | 31.5 | 5.0 | 4.3 | 5.0 | 4.3 | 5.1 | 4.3 |
| Pioneer Valley | 132 | 31.5 | 6.6 | 7.1 | 6.5 | 7.0 | 6.7 | 7.2 |
| Proserpine | 132 | 25.0 | 3.7 | 3.9 | 3.7 | 3.9 | 3.7 | 3.9 |
| Ross | 275 | 25.0 | 7.8 | 8.7 | 7.6 | 8.7 | 7.9 | 8.9 |
| Ross | 132 | 25.0 | 16.3 | 18.8 | 16.5 | 19.5 | 16.8 | 19.8 |
| Stony Creek | 132 | 40.0 | 3.8 | 3.6 | 3.7 | 3.6 | 3.9 | 3.8 |
| Strathmore | 275 | 31.5 | 8.7 | 9.0 | 8.4 | 8.8 | 9.0 | 9.3 |
| Strathmore | 132 | 40.0 | 12.1 | 13.2 | 12.0 | 13.1 | 12.3 | 13.3 |
| Townsville East | 132 | 40.0 | 12.5 | 12.3 | 12.3 | 12.2 | 12.5 | 12.3 |
| Townsville South | 132 | 20.0 | 16.2 | 19.9 | 16.5 | 20.4 | 16.7 | 20.7 |
| Townsville GT PS | 132 | 31.5 | 9.9 | 10.6 | 9.9 | 10.7 | 10.0 | 10.7 |
| Tully | 132 | 31.5 | 3.8 | 4.1 | 3.6 | 3.8 | 2.0 | 2.3 |
| Turkinje | 132 | 19.3 | 2.6 | 3.0 | 2.6 | 3.0 | 2.6 | 3.0 |
| Wandoo | 132 | 31.5 | 4.4 | 3.1 | 4.4 | 3.1 | 4.5 | 3.1 |
| Woree (1T) | 275 | 40.0 | 2.4 | 2.9 | 2.4 | 2.9 | 2.4 | 2.8 |
| Woree (2T) | 275 | 40.0 | 2.4 | 2.9 | 2.4 | 2.8 | 2.4 | 2.8 |
| Woree | 132 | 25.0 | 5.2 | 7.1 | 5.1 | 7.1 | 4.8 | 6.6 |
| Yabulu South | 132 | 40.0 | 11.4 | 10.9 | 11.4 | 11.2 | 11.5 | 11.3 |

Table F.2 Estimated maximum short circuit levels – Central Queensland – Powerlink transmission network 2010 to 2012

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 PHASE kA | L – G kA | 3 Phase kA | L – G kA |
| Baralaba | 132 | 15.3 | 4.8 | 3.9 | 4.8 | 3.9 | 4.8 | 4.1 |
| Biloela | 132 | 10.0 | 7.8 | 8.0 | 7.8 | 7.9 | 7.8 | 8.0 |
| Blackwater | 132 | 10.9 | 5.8 | 6.8 | 5.8 | 6.8 | 5.9 | 7.1 |
| Bluff | 132 | 40.0 | – | – | – | – | 2.8 | 3.6 |
| Bouldercombe | 275 | 31.5 | 17.6 | 17.7 | 17.6 | 17.7 | 19.6 | 19.1 |
| Bouldercombe | 132 | 21.8 | 9.6 | 11.3 | 9.6 | 11.3 | 9.8 | 11.7 |
| Broadsound | 275 | 31.5 | 11.1 | 8.6 | 12.4 | 9.2 | 13.1 | 9.5 |
| Callemondah | 132 | 31.5 | 22.0 | 22.4 | 21.9 | 22.3 | 21.9 | 22.3 |
| Callide A | 132 | 11.0 | 10.9 | 11.2 | 10.8 | 11.2 | 10.9 | 11.2 |
| Calvale | 275 | 31.5 | 20.5 | 23.1 | 20.4 | 23.1 | 23.3 | 25.6 |
| Calvale | 132 | 40.0 | 10.9 | 11.3 | 10.9 | 11.3 | 10.9 | 11.3 |
| Dingo | 132 | 31.5 | 2.8 | 2.9 | 2.8 | 2.9 | 2.8 | 3.0 |
| Duaringa | 132 | 40.0 | – | – | – | – | 2.1 | 2.8 |
| Dysart | 132 | 10.9 | 4.5 | 5.1 | 4.6 | 5.2 | 4.6 | 5.2 |
| Egans Hill | 132 | 31.5 | 6.4 | 6.8 | 6.4 | 6.8 | 6.6 | 6.9 |
| Gladstone | 275 | 31.5 | 21.2 | 24.6 | 21.2 | 24.5 | 21.3 | 24.6 |
| Gladstone (1) | 132 | 31.5 | 27.9 | 34.1 | 27.8 | 33.9 | 27.8 | 34.0 |
| Gladstone South | 132 | 40.0 | 18.4 | 18.7 | 18.3 | 18.6 | 18.3 | 18.6 |
| Grantleigh | 132 | 31.5 | 2.5 | 2.6 | 2.5 | 2.6 | 2.5 | 2.7 |
| Gregory | 132 | 31.5 | 8.9 | 10.2 | 9.1 | 10.4 | 9.2 | 10.5 |
| Larcom Creek | 275 | 40.0 | 15.0 | 15.0 | 14.9 | 15.1 | 15.0 | 15.2 |
| Larcom Creek | 132 | 40.0 | 12.4 | 14.4 | 12.3 | 14.4 | 12.4 | 14.5 |
| Lilyvale | 275 | 31.5 | 5.7 | 5.7 | 5.9 | 5.8 | 6.0 | 5.9 |
| Lilyvale | 132 | 25.0 | 9.3 | 11.0 | 9.5 | 11.2 | 9.6 | 11.3 |
| Moura | 132 | 10.9 | 4.1 | 4.4 | 4.1 | 4.4 | 4.1 | 4.4 |
| Norwich Park | 132 | 31.5 | 3.5 | 2.6 | 3.6 | 2.7 | 3.6 | 2.7 |
| Pandoin | 132 | 40.0 | 5.4 | 5.0 | 5.4 | 5.0 | 5.5 | 5.1 |
| Raglan | 275 | 40.0 | – | – | – | – | 11.8 | 10.4 |
| Rockhampton | 132 | 10.9 | 6.5 | 7.0 | 6.5 | 7.0 | 6.6 | 7.1 |
| Rocklands | 132 | 40.0 | 6.1 | 5.6 | 6.1 | 5.6 | 6.2 | 5.7 |
| Stanwell Switchyard | 275 | 31.5 | 19.0 | 20.9 | 19.1 | 21.1 | 22.1 | 23.7 |

Table F.2 Estimated maximum short circuit levels – Central Queensland – Powerlink transmission network 2010 to 2012 (continued)

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 PHASE kA | L – G kA | 3 Phase kA | L – G kA |
| Stanwell Switchyard | 132 | 31.5 | 5.0 | 4.6 | 5.0 | 4.7 | 5.0 | 5.8 |
| Wurdong | 275 | 31.5 | 16.8 | 16.1 | 16.8 | 16.2 | 16.8 | 16.2 |
| Wycarbah | 132 | 40.0 | – | – | – | – | 3.9 | 5.0 |
| Yarwun | 132 | 40.0 | 12.9 | 16.4 | 12.9 | 16.1 | 12.9 | 16.1 |

Note:

(1) The lowest rated equipment at these locations is required withstand and/or interrupt a short circuit current which is less than the maximum fault current and below the equipment rating.

Table F.3 Estimated maximum short circuit levels – Southern Queensland – Powerlink transmission network 2010 to 2012

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA |
| Abermain | 275 | 40.0 | 16.5 | 16.3 | 16.1 | 16.0 | 18.7 | 19.5 |
| Abermain | 110 | 31.5 | 20.9 | 23.5 | 20.2 | 22.9 | 21.2 | 23.9 |
| Algester | 110 | 40.0 | 21.8 | 21.2 | 21.5 | 20.9 | 21.5 | 21.1 |
| Ashgrove West | 110 | 25.0 | 19.9 | 18.8 | 19.1 | 18.3 | 19.1 | 18.7 |
| Belmont | 275 | 21.0 | 17.1 | 18.8 | 16.7 | 18.3 | 16.8 | 18.5 |
| Belmont (1) | 110 | 18.3 | 30.3 | 37.5 | 29.7 | 36.9 | 29.8 | 37.2 |
| Blackwall | 275 | 37.0 | 23.3 | 25.5 | 22.4 | 24.5 | 22.4 | 24.3 |
| Blackstone | 275 | 40.0 | – | – | – | – | 21.3 | 23.6 |
| Blackstone | 110 | 40.0 | – | – | 22.0 | 18.4 | 25.3 | 20.9 |
| Braemar (East) | 330 | 50.0 | 21.6 | 23.9 | 21.5 | 23.9 | 16.1 | 17.9 |
| Braemar West | 330 | 50.0 | – | – | – | – | 13.8 | 14.3 |
| Braemar (East) | 275 | 40.0 | 30.5 | 36.1 | 30.4 | 35.9 | 24.8 | 30.0 |
| Braemar West | 275 | 40.0 | – | – | – | – | 19.3 | 20.9 |
| Bulli Creek | 330 | 37.0 | 17.9 | 14.1 | 17.8 | 14.0 | 18.3 | 14.3 |
| Bulli Creek | 132 | 40.0 | 3.8 | 4.3 | 3.8 | 4.3 | 3.8 | 4.3 |
| Bundamba | 110 | 40.0 | 16.9 | 16.2 | 15.9 | 15.5 | 16.8 | 16.2 |
| Gin Gin | 275 | 14.5 | 11.0 | 9.6 | 11.0 | 10.4 | 11.0 | 10.5 |
| Gin Gin | 132 | 20.0 | 10.4 | 10.9 | 14.4 | 15.7 | 14.4 | 15.7 |
| Goodna | 275 | 40.0 | 15.0 | 15.3 | 14.7 | 15.0 | 15.8 | 15.4 |
| Goodna | 110 | 40.0 | 23.9 | 25.9 | 23.8 | 25.8 | 25.3 | 26.9 |
| Greenbank | 275 | 40.0 | 21.8 | 24.1 | 21.2 | 23.5 | 20.4 | 22.6 |
| Halys | 275 | 40.0 | – | – | – | – | 32.1 | 26.5 |
| Kumbarilla Park | 275 | 40.0 | – | – | – | – | 16.7 | 15.7 |
| Kumbarilla Park | 132 | 40.0 | – | – | – | – | 13.5 | 15.0 |
| Loganlea | 275 | 40.0 | 15.3 | 15.6 | 14.9 | 15.4 | 14.9 | 15.4 |
| Loganlea (1) | 110 | 25.0 | 23.1 | 27.0 | 22.7 | 26.7 | 22.8 | 27.0 |
| Middle Ridge (4T) | 330 | 50.0 | 12.7 | 12.3 | 12.6 | 12.3 | 12.6 | 12.2 |
| Middle Ridge (5T) | 330 | 50.0 | 13.1 | 12.7 | 13.0 | 12.7 | 13.0 | 12.6 |
| Middle Ridge | 275 | 40.0 | 18.3 | 18.3 | 18.1 | 18.2 | 18.0 | 18.2 |
| Middle Ridge | 110 | 26.3 | 20.4 | 24.0 | 20.4 | 24.1 | 20.2 | 23.9 |
| Millmerran | 330 | 50.0 | 18.3 | 19.6 | 18.2 | 19.6 | 18.5 | 19.8 |

Table F.3 Estimated maximum short circuit levels – Southern Queensland – Powerlink transmission network 2010 to 2012 (continued)

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 3 Phase kA | Fault levels 2010 L – G kA | Fault levels 2011 3 Phase kA | Fault levels 2011 L – G kA | Fault levels 2012 3 Phase kA | Fault levels 2012 L – G kA |
|---|---|---|---|---|---|---|---|---|
| Molendinar (1T) | 275 | 40.0 | 8.5 | 8.1 | 8.4 | 8.1 | 8.3 | 8.1 |
| Molendinar (2T) | 275 | 40.0 | 8.5 | 8.1 | 8.4 | 8.1 | 8.3 | 8.1 |
| Molendinar | 110 | 40.0 | 20.0 | 24.1 | 19.7 | 24.0 | 20.0 | 25.3 |
| Mt England | 275 | 31.5 | 22.7 | 23.0 | 22.2 | 22.6 | 22.6 | 22.9 |
| Mudgeeraba | 275 | 31.5 | 9.7 | 9.7 | 9.5 | 9.6 | 9.4 | 9.5 |
| Mudgeeraba | 110 | 25.0 | 18.4 | 22.5 | 18.1 | 22.2 | 18.7 | 22.8 |
| Murarrie (2T) | 275 | 40.0 | 13.3 | 13.4 | 13.0 | 13.2 | 13.1 | 13.6 |
| Murarrie (3T) | 275 | 40.0 | 13.3 | 14.5 | 13.0 | 13.3 | 13.1 | 13.4 |
| Murarrie | 110 | 40.0 | 25.3 | 29.3 | 24.9 | 29.2 | 25.0 | 30.2 |
| Oakey GT PS | 110 | 31.5 | 10.9 | 12.1 | 10.8 | 12.0 | 10.6 | 11.8 |
| Oakey | 110 | 40.0 | 10.1 | 10.0 | 10.0 | 10.0 | 9.8 | 9.9 |
| Palmwoods | 275 | 31.5 | 8.5 | 9.0 | 8.4 | 8.9 | 8.4 | 8.9 |
| Palmwoods | 132 | 21.9 | 13.2 | 15.9 | 13.1 | 15.7 | 13.1 | 15.7 |
| Palmwoods | 110 | 20.0 | 7.5 | 8.5 | 7.7 | 8.4 | 7.6 | 8.4 |
| Redbank Plains | 110 | 31.5 | 19.4 | 18.0 | 19.7 | 17.1 | 21.2 | 17.9 |
| Richlands | 110 | 18.3 | 18.0 | 18.2 | 17.7 | 18.0 | 22.1 | 22.5 |
| Rocklea (1T) | 275 | 31.5 | 13.6 | 13.0 | 13.3 | 12.5 | 13.2 | 12.5 |
| Rocklea (2T) | 275 | 31.5 | 8.9 | 8.7 | 8.7 | 8.4 | 8.8 | 8.5 |
| Rocklea | 110 | 31.5 | 25.2 | 28.9 | 24.6 | 28.5 | 24.9 | 28.8 |
| Runcorn | 110 | 18.4 | 19.6 | 19.8 | 19.4 | 19.6 | 19.4 | 19.7 |
| South Pine | 275 | 31.5 | 19.0 | 22.0 | 18.6 | 21.3 | 18.7 | 21.2 |
| South Pine (East) | 110 | 40.0 | 23.3 | 27.2 | 20.4 | 23.5 | 20.4 | 23.5 |
| South Pine (West) | 110 | 40.0 | 21.7 | 27.7 | 21.4 | 27.5 | 21.5 | 27.5 |
| Sumner | 110 | 40.0 | 20.8 | 20.5 | 20.4 | 20.2 | 20.7 | 20.4 |
| Swanbank A (1) | 110 | 18.3 | 21.4 | 17.7 | 21.2 | 16.8 | 23.3 | 17.9 |
| Swanbank B | 275 | 21.0 | 21.4 | 23.7 | 20.5 | 22.1 | – | – |
| Swanbank E | 275 | 40.0 | 16.6 | 18.3 | 16.3 | 17.9 | 21.0 | 23.2 |
| Tangkam | 110 | 31.5 | 12.8 | 12.1 | 12.8 | 12.1 | 12.4 | 11.8 |
| Tarong | 275 | 31.5 | 31.0 | 32.9 | 30.6 | 32.6 | 33.6 | 35.2 |
| Tarong | 132 | 25.0 | 5.6 | 6.0 | 5.6 | 5.9 | 5.7 | 6.0 |
| Tarong (1) | 66 | 16.0 | 15.0 | 16.2 | 14.9 | 16.2 | 15.1 | 16.3 |

**Table F.3** Estimated maximum short circuit levels – Southern Queensland – Powerlink transmission network 2010 to 2012 (continued)

| Substation | Voltage kV | Equipment rating (lowest kA) | Fault levels 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | | | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA | 3 Phase kA | L – G kA |
| Teebar Creek | 275 | 40.0 | 7.4 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 |
| Teebar Creek | 132 | 40.0 | 10.3 | 11.4 | 10.2 | 11.3 | 10.2 | 11.3 |
| Tennyson | 110 | 40.0 | 16.2 | 15.7 | 16.0 | 15.5 | 16.1 | 15.6 |
| Upper Kedron | 110 | 40.0 | 22.5 | 18.8 | 21.1 | 18.1 | 21.2 | 18.3 |
| West Darra | 110 | 40.0 | 24.1 | 23.2 | 23.7 | 22.8 | 24.9 | 23.9 |
| Western Downs | 275 | 40.0 | – | – | 20.9 | 19.8 | 19.5 | 19.0 |
| Woolooga | 275 | 31.5 | 9.8 | 10.9 | 9.7 | 10.8 | 9.7 | 10.8 |
| Woolooga | 132 | 20.0 | 13.1 | 15.3 | 13.1 | 15.5 | 13.1 | 15.5 |

Note:

(1) These locations are operated with open points to keep short circuit levels below equipment ratings.

## Appendix G – National transmission flow path projects

This appendix provides information relating to committed network projects, projects currently under consultation, and potential future network projects that can impact Queensland's National Transmission Flow Paths (NTFPs).

This appendix also provides information on indicative timings for potential future network projects under different demand, generation and demand side management cases.

The information presented for potential future network projects should be considered indicative only. The timings for potential future network developments are based on high level preliminary assessments, particularly for those projects in the medium to longer term.

For some augmentations, the increase in transfer capability across a flow path may assume that other potential future network projects have already occurred. This is relevant if the increase in transfer capability assumes prior projects address other limitations which would otherwise cap the flow path capability of future projects. Under these situations, the inter-dependency of specific projects need to be recognised. The sequencing of projects shown in this appendix take account of these inter-dependencies.

As the need for potential future network projects reach higher levels of certainty, comprehensive studies will be carried out to better determine the scope and cost of the project and the corresponding power transfer capability.

**Table G.1** Committed network projects or projects under consultation at June 2010

| Network project | Anticipated timing | Potential impact on network limits | Potentially affected constraint identifiers (1) (2) |
|---|---|---|---|
| Central Queensland (CQ) to North Queensland (NQ) flow path | | | |
| Strathmore to Ross 275kV double circuit line | Summer 2010/11 | Increases CQ-NQ limit to around 1500MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Calvale to Stanwell 275kV double circuit line | Summer 2013/14 | Decreases post-contingent flow across the Gladstone limit (ie circuit 871) | Q>>NIL_855_871 |
| South West Queensland (SWQ) to South East Queensland (SEQ) flow path | | | |
| Belmont 275kV 120MVAr capacitor bank, Ashgrove West and Loganlea 110kV 50MVAr capacitor banks | Summer 2011/12 | Increases Tarong voltage stability limit by around 55MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 20MW | Q^NIL_GC |
| Middle Ridge two 330kV 120MVAr capacitor banks and Millmerran 330kV 200MVAr capacitor bank | Summer 2011/12 | Preserves SWQ limit transfer capability | Q>Q_SWQ |
| Western Downs to Halys and Braemar 275kV double circuit line, Western Downs and Halys substations | Summer 2012/13 | Increases SWQ thermal limit by around 800MW | Q>Q_SWQ |
| Belmont 275kV 120MVAr capacitor bank and South Pine 110kV 50MVAr capacitor bank | Summer 2012/13 | Increases Tarong voltage stability limit by around 40MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 15MW | Q^NIL_GC |
| Halys to Blackwall 500kV double circuit line (initially operating at 275kV) | Summer 2014/15 | Increases SWQ thermal limit by around 800MW | Q>Q_SWQ |
| | | Increases Tarong voltage stability limit by around 350MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 75MW | Q^NIL_GC |

Notes:

(1) These constraint identifiers correspond to the forward looking constraints which are anticipated to be used within the AEMO 2010 NTNDP studies.

(2) The '/' symbol denotes different suffix variations to the common part of the constraint identifier.

Table G.2 Potential network projects (1)

| Network project | Indicative cost | Potential impact on network limits | Potentially affected constraint identifiers (2) (3) |
|---|---|---|---|
| CQ to NQ flow path | | | |
| Stanwell to Broadsound 275kV stringing of an additional circuit | $40m (approximately) | Increases CQ-NQ limit by around 200MW to 300MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Broadsound to Nebo 275kV series capacitors | $45m (approximately) | Increases stability components of the CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Nebo to Strathmore 275kV series capacitors | $45m (approximately) | Increases stability components of the CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Strathmore to Ross 275kV series capacitors | $45m (approximately) | Increases stability components of the CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Broadsound to Nebo 275kV double circuit line | $150m (approximately) | Increases CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Nebo to Strathmore 275kV double circuit line | $160m (approximately) | Increases CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Strathmore to Ross 275kV double circuit line | $200m (approximately) | Increases CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Stanwell to Broadsound 275kV double circuit line | $150m (approximately) | Increases CQ-NQ limit by up to 200MW | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| Calvale to Larcom Creek 275kV double circuit line and rebuild Larcom Creek to Gladstone 275kV double circuit line | $155m (approximately) | Increases Gladstone limit by around 1500MW | Q>>NIL_855_871 |
| CQ to SWQ and CQ to SEQ flow paths | | | |
| Calvale to Halys 275kV switching station (Auburn River) and series capacitors | $100m (approximately) | Increases CQ-SQ limit by around 650MW | Q::NIL_CS, Q^NIL_CS |
| Calvale to Halys 275kV double circuit line (western route) | $360m (approximately) | Increases CQ-SQ limit by around 800MW | Q::NIL_CS, Q^NIL_CS |
| Calvale to South Pine 275kV double circuit line (eastern route) | $570m (approximately) | Increases CQ-SQ limit by around 800MW | Q::NIL_CS, Q^NIL_CS |
| Central to South Queensland 500kV double circuit line (western route) | $780m (approximately) | Increases CQ-SQ limit by around 1600MW | Q::NIL_CS, Q^NIL_CS |

**Table G.2** Potential network projects (1) (continued)

| Network project | Indicative cost | Potential impact on network limits | Potentially affected constraint identifiers (2) (3) |
|---|---|---|---|
| SWQ to SEQ flow path | | | |
| Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV | $270m (approximately) | Increases SWQ thermal limit by around 1800MW | Q>Q_SWQ |
| Halys to Greenbank 500kV double circuit line (initially operating at 275kV) | $400m (approximately) | Increases Tarong voltage stability limit by around 350MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 75MW | Q^NIL_GC |
| Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV | $190m (approximately) | Increases SWQ thermal limit by around 1100MW | Q>Q_SWQ |
| | | Increases Tarong voltage stability limit by around 350MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 80MW | Q^NIL_GC |
| Western Downs to Halys 500kV double circuit line (northern route second build) and upgrade Halys to Greenbank to 500kV | $420m (approximately) | Increases SWQ thermal limit by around 4200MW | Q>Q_SWQ |
| | | Increases Tarong voltage stability limit by around 2400MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 100MW | Q^NIL_GC |
| Halys to North Moreton 500kV double circuit line | $430m (approximately) | Increases Tarong voltage stability limit by around 3000MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 80MW | Q^NIL_GC |
| Halys to South Moreton 500kV double circuit line | $520m (approximately) | Increases Tarong voltage stability limit by around 3000MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 120MW | Q^NIL_GC |

Table G.2 Potential network projects (1) (continued)

| Network project | Indicative cost | Potential impact on network limits | Potentially affected constraint identifiers (2) (3) |
|---|---|---|---|
| SEQ to Northern NSW (NNS) flow path | | | |
| Molendinar third 275/110kV 375MVA transformer and associated substation works | $35m (approximately) | Increases Gold Coast voltage stability limit by around 15MW | Q^NIL_GC |
| | | Increases Tarong voltage stability limit by around 15MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| Greenbank to Mudgeeraba 275kV single circuit rebuild to double circuit and upgrade of two Mudgeeraba 275/110kV transformers | $110m (approximately) | Increases Gold Coast voltage stability limit by around 30MW | Q^NIL_GC |
| | | Increases Tarong voltage stability limit by around 25MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| Mudgeeraba third 275/110kV transformer upgrade | $10m (approximately) | Increases Gold Coast voltage stability limit by around 15MW | Q^NIL_GC |
| | | Increases Tarong voltage stability limit by around 15MW | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| SWQ to NNS flow path | | | |
| Armidale second 330kV SVC | $50m (approximately) | Increases QNI stability limits by around 150MW in the northerly direction | (4) |
| High speed protection schemes and Loy Yang braking resistor | $35m (approximately) | Increases QNI stability limits by up to 300MW in the southerly direction | (4) |
| Bulli Creek to Dumaresq and Dumaresq to Armidale 330kV thyristor controlled series capacitors (and supporting works) | $125m (approximately) | Increases QNI stability limits by up to 400MW in both directions | (4) |
| Bulli Creek or Dumaresq 1,500MW HVDC back to back asynchronous link | $490m (approximately) | Increases QNI transfer capability by around 500MW in both directions | (4) |
| Bulli Creek to Bayswater 330kV double circuit line (with intermediate switching stations) | $950m (approximately) | Increases QNI transfer capability by around 500MW in the northern direction and around 1,000MW in the southern direction | (4) |

**Table G.2** Potential network projects (1) (continued)

| Network project | Indicative cost | Potential impact on network limits | Potentially affected constraint identifiers (2) (3) |
|---|---|---|---|
| Western Downs to Bayswater 500kV double circuit line (with intermediate switching stations and dynamic compensation devices) | $2,000m (approximately) | Increases QNI transfer capability by around 1,800MW in both directions | Constraint identifiers as per the Bulli Creek to Bayswater 330kV project above |

Notes:

(1) The estimated impacts of network projects within NTNDP zones which maintain or increase voltage stability limits across NTFPs by reactive compensation or reducing reactive losses (such as capacitor banks, transformers and line reinforcements) are provided in aggregate form within Table G.3.

(2) These constraint identifiers correspond to the forward looking constraints which are anticipated to be used within the AEMO 2010 NTNDP studies.

(3) The '/' symbol denotes different suffix variations to the common part of the constraint identifier.

(4) The constraint identifiers for this project are detailed in Appendix 1 of the Powerlink and TransGrid Final Report: Potential Upgrade of QNI Appendix 1 (13 October 2008) available on either the Powerlink or TransGrid web sites.

Table G.3 Impacts of potential network projects within NTNDP zones (1)

| Network project | Potential timing | Potential impact on network limits | Potentially affected constraint identifiers (2) (3) |
|---|---|---|---|
| CQ to NQ flow path | | | |
| Network projects within the NQ zone | Summer 2012/13 onwards | Preserves the transfer capability of the CQ-NQ voltage stability limit components | Q^NIL_CN_FDR, Q^NIL_CN_GT |
| SWQ to SEQ flow path | | | |
| Network projects within the SEQ zone | Summer 2015/16 onwards | Increases Tarong voltage stability limit by around 250MW per year | Q^^NIL_TR_CLTR/SWBE/WV/WOPW/TRBK |
| | | Increases Gold Coast voltage stability limit by around 50MW per year | Q^NIL_GC |

Notes:

(1) The estimated impacts of network projects within NTNDP zones which maintain or increase voltage stability limits across NTFPs by reactive compensation or reducing reactive losses (such as capacitor banks, transformers and line reinforcements) are provided in aggregate form within this table.

(2) These constraint identifiers correspond to the forward looking constraints which are anticipated to be used within the AEMO 2010 NTNDP studies.

(3) The '/' symbol denotes different suffix variations to the common part of the constraint identifier.

Table G.4 Description of economic growth, generation and demand side management cases

| CQ to NQ flow path | | | | |
|---|---|---|---|---|
| Case identifier | Economic outlook | New entry generation | | |
| | | NQ zone | CQ zone | SWQ or SEQ zones |
| CQ-NQ-M-G1 | Medium | No new entry | Market driven | Market driven |
| CQ-NQ-M-G2 | Medium | 300MW around 2020 (1) (2) | Market driven | Market driven |
| CQ-NQ-M-G3 | Medium | 300MW around 2020 and further 300MW around 2025 (1) | Market driven | Market driven |
| CQ-NQ-H-G1 | High | No new entry | Market driven | Market driven |
| CQ-NQ-L-G1 | Low | No new entry | Market driven | Market driven |

| CQ to SWQ and CQ to SEQ flow paths | | | |
|---|---|---|---|
| Case identifier | Economic outlook | New entry generation | |
| | | NQ or CQ zones | SWQ or SEQ zones |
| CQ-SQ-M-G1 | Medium | Market driven | Around 200MW per year (3) |
| CQ-SQ-M-G2 | Medium | Market driven | Around 300MW per year (3) |
| CQ-SQ-H-G1 | High | Market driven | Around 300MW per year (3) |
| CQ-SQ-L-G1 | Low | Market driven | Around 200MW per year (3) |

| SWQ to SEQ flow path | | | | |
|---|---|---|---|---|
| Case identifier | Economic outlook | New entry generation | | |
| | | NQ or CQ zones | SWQ zone | SEQ zone |
| SWQ-SEQ-M-G1 | Medium | No new entry | Market driven | No new entry |
| SWQ-SEQ-H-G1 | High | No new entry | Market driven | No new entry |
| SWQ-SEQ-L-G1 | Low | No new entry | Market driven | No new entry |

Notes:

(1) An alternative to new generation is demand side management equivalent to the electrical amount (MW) shown (minus station auxiliaries and losses).

(2) For example this new entry generating station could take the form of 2 x 150MW combustion turbines within the northern Queensland area.

(3) Denotes average amount of new entry generation per year starting from around 2012.

Table G.5 Sensitivity of the timing of potential network projects to economic growth, generation and demand side management

| Case identifier (1) | Network project(s) | Indicative timing (2) |
|---|---|---|
| CQ to NQ flow path | | |
| CQ-NQ-M-G1 | Stanwell to Broadsound 275kV stringing of an additional circuit | Summer 2016/17 (3) |
| | Broadsound to Nebo 275kV series capacitors | Summer 2023/24 |
| | Stanwell to Broadsound 275kV double circuit line | Summer 2026/27 |
| | Calvale to Larcom Creek 275kV double circuit line and rebuild Larcom Creek to Gladstone 275kV double circuit line | Summer 2028/29 |
| CQ-NQ-M-G2 | Stanwell to Broadsound 275kV stringing of an additional circuit | Summer 2016/17 (3) |
| | Broadsound to Nebo 275kV series capacitors | Summer 2027/28 |
| | Calvale to Larcom Creek 275kV double circuit line and rebuild Larcom Creek to Gladstone 275kV double circuit line | Summer 2029/30 |
| CQ-NQ-M-G3 | Stanwell to Broadsound 275kV stringing of an additional circuit | Summer 2016/17 (3) |
| CQ-NQ-H-G1 | Stanwell to Broadsound 275kV stringing of an additional circuit | Summer 2013/14 (3) |
| | Broadsound to Nebo 275kV series capacitors | Summer 2017/18 |
| | Calvale to Larcom Creek 275kV double circuit line and rebuild Larcom Creek to Gladstone 275kV double circuit line | Summer 2018/19 |
| | Stanwell to Broadsound 275kV double circuit line | Summer 2021/22 |
| | Broadsound to Nebo 275kV double circuit line | Summer 2024/25 |
| | Nebo to Strathmore 275kV series capacitors | Summer 2027/28 |
| CQ-NQ-L-G1 | Stanwell to Broadsound 275kV stringing of an additional circuit | Summer 2024/25 |
| CQ to SWQ and CQ to SEQ flow paths | | |
| CQ-SQ-M-G1 | Calvale to Halys 275kV switching station (Auburn River) and series capacitors | Summer 2020/21 |
| CQ-SQ-M-G2 | No reliability based network projects (4) | – |
| CQ-SQ-H-G1 | Calvale to Halys 275kV switching station (Auburn River) and series capacitors | Summer 2021/22 |
| CQ-SQ-L-G1 | No reliability based network projects (4) | – |

**Table G.5** Sensitivity of the timing of potential network projects to economic growth, generation and demand side management (continued)

| Case identifier (1) | Network project(s) | Indicative timing (2) |
|---|---|---|
| SWQ to SEQ flow path | | |
| SWQ-SEQ-M-G1 | Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV | Summer 2017/18 |
| | Halys to Greenbank 500kV double circuit line (initially operating at 275kV) | Summer 2019/20 |
| | Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV | Summer 2019/20 |
| | Western Downs to Halys 500kV double circuit line (northern route second build) and upgrade Halys to Greenbank to 500kV | Summer 2021/22 |
| | Halys to North Moreton 500kV double circuit line | Summer 2025/26 |
| SWQ-SEQ-H-G1 | Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV | Summer 2013/14 |
| | Halys to Greenbank 500kV double circuit line (initially operating at 275kV) | Summer 2015/16 |
| | Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV | Summer 2015/16 |
| | Western Downs to Halys 500kV double circuit line (northern route second build) and upgrade Halys to Greenbank to 500kV | Summer 2016/17 |
| | Halys to North Moreton 500kV double circuit line | Summer 2021/22 |
| | Halys to South Moreton 500kV double circuit line | Summer 2025/26 |
| SWQ-SEQ-L-G1 | Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV | Summer 2025/26 |
| | Halys to Greenbank 500kV double circuit line (initially operating at 275kV) | Summer 2027/28 |
| | Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV | Summer 2027/28 |
| SEQ to NNS flow path | | |
| SWQ-SEQ-M-G1 | Molendinar third 275/110kV transformer | Summer 2016/17 |
| | Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade | Summer 2021/22 (5) |
| | Mudgeeraba third 275/110kV transformer upgrade | Summer 2029/30 (6) |
| SWQ-SEQ-H-G1 | Molendinar third 275/110kV transformer | Summer 2015/16 |
| | Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade | Summer 2020/21 (5) |
| | Mudgeeraba third 275/110kV transformer upgrade | Summer 2028/29 (6) |

Table G.5 Sensitivity of the timing of potential network projects to economic growth, generation and demand side management (continued)

| Case identifier (1) | Network project(s) | Indicative timing (2) |
|---|---|---|
| SWQ-SEQ-L-G1 | Molendinar third 275/110kV transformer | Summer 2017/18 |
| | Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade | Summer 2022/23 (5) |

Notes:

(1) Refer to Table G.4 for description of the case identifiers (for example 'M' within the case identifier denotes medium economic growth).

(2) The timing for these network projects, particularly within the later years, are based on very preliminary high level assessments.

(3) The timing for this project is based on reliability criteria, and that there may be economic advantages in advancing the augmentation.

(4) There are no reliability based projects expected to be required across the 20 year study horizon for this case.

(5) The two Mudgeeraba transformers may possibly need to be replaced at a time earlier than shown due to condition.

(6) The third Mudgeeraba transformer may possibly need to be replaced at a time earlier than shown due to condition.

## Appendix H – Abbreviations

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| APR | Annual Planning Report |
| BSL | Boyne Smelters Limited |
| CBD | Central Business District |
| COAG | Council of Australian Governments |
| CQ | Central Queensland |
| CSM | Coal Seam Methane |
| DNSP | Distribution Network Service Provider |
| FNQ | Far North Queensland |
| ESOO | Electricity Statement of Opportunity |
| GSDA | Gladstone State Development Area |
| GWh | Gigawatt hour |
| JPB | Jurisdictional Planning Body |
| kA | Kiloampere |
| kV | Kilovolt |
| LNG | Liquefied Natural Gas |
| MVA | Megavolt Amperes |
| MVAr | Megavolt ampere reactive |
| MW | Megawatt |
| NEM | National Electricity Market |
| NEMDE | National Electricity Market Dispatch Engine |
| NER | National Electricity Rules |
| NIEIR | National Institute of Economic and Industrial Research |
| NNS | Northern New South Wales |
| NTFP | National Transmission Flow Path |
| NTNDP | National Transmission Network Development Plan |
| NTS | National Transmission Statement |
| NSW | New South Wales |
| NQ | North Queensland |
| PoE | Probability of Exceedance |
| QAL | Queensland Alumina Limited |
| QLD | Queensland |
| QNI | Queensland/New South Wales Interconnector |
| QR | Queensland Rail |
| RIT-T | Regulatory Investment Test for Transmission |
| RTA | Rio Tinto Aluminium |
| SEQ | South East Queensland |
| SQ | South Queensland |
| SVC | Static VAr compensator |
| SWQ | South West Queensland |
| TNSP | Transmission Network Service Provider |

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