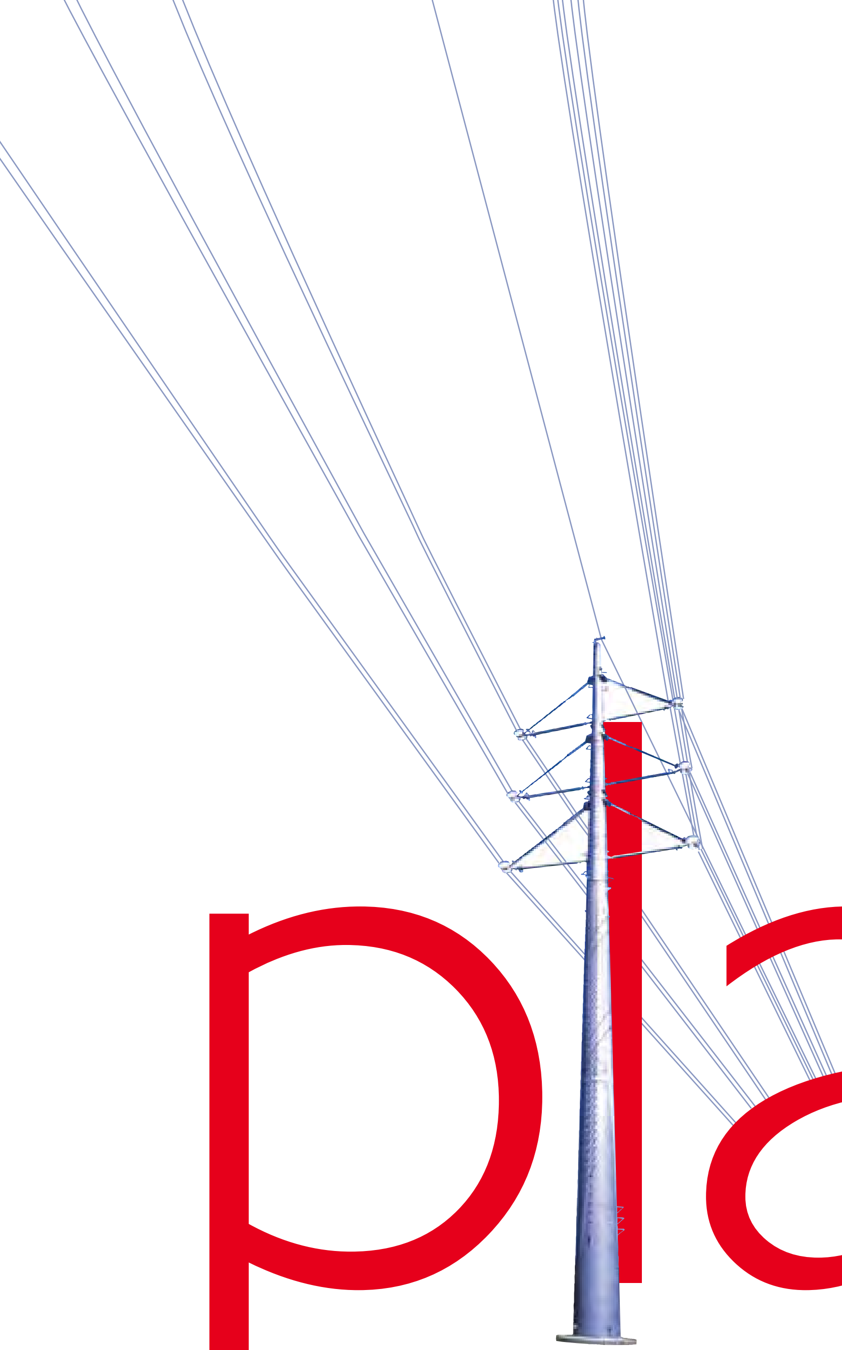

plan

Annual Planning Report 2009

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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

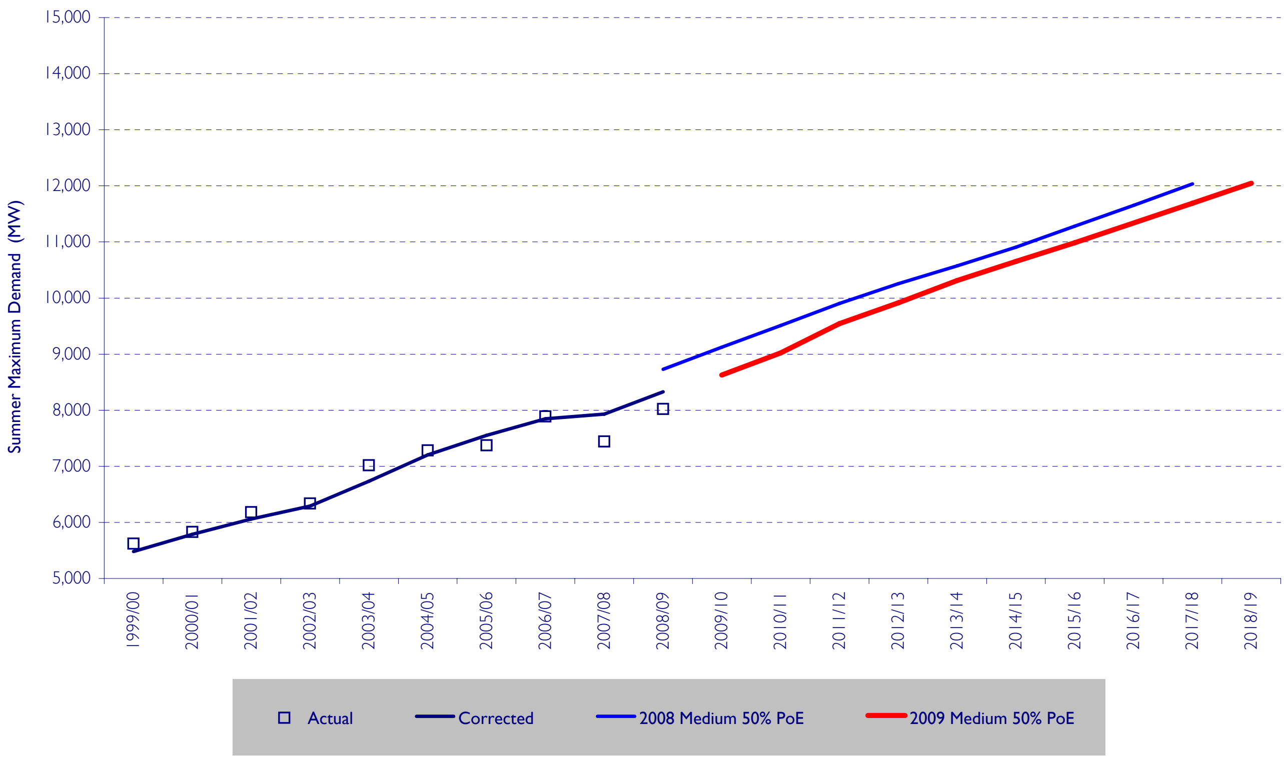
The forecast presented in this APR indicates sustained long-term growth in electricity demand in Queensland over the next 10 years. On average, summer maximum electricity demand is forecast to increase at a rate of 3.8% per annum from 8,330MW in 2008/09 to 12,047MW in 2018/19, based on the medium economic forecast.

Population and economic growth will continue to underpin increases to electricity demand over the 10 year forecast period. The current economic slowdown, the impact of milder weather conditions in summer 2007/08 and summer 2008/09, as well as the introduction and increased uptake of energy efficiency initiatives have all been factored into this forecast.

The effect of the economic slowdown is a slower growth rate for electricity demand for the first two years of the forecast, after which the annual demand growth is expected to return to a growth rate consistent with the forecast population growth and long-term economic growth trends.

The trend of an increased diversity between the demand at the time of State peak and the combined peak demand of each area comprising Queensland is continuing. However, the expected demand growth within each of the areas that make up Queensland remains strong.

A comparison of the 2008 APR and 2009 APR summer peak demand (medium 50% PoE) forecasts is displayed below.



Electricity Energy Forecast

Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.1% per annum over the next 10 years for the medium economic growth scenario.

This continues the trend of energy consumption growing at a slower rate than peak demand.

As with the demand forecast, the current economic slowdown, the impact of milder weather conditions in summer 2007/08 and summer 2008/09, as well as the introduction and increased uptake of energy efficiency initiatives have all 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.

Transmission Projects Completed

Significant projects completed since the 2008 APR include:

- Townsville South to Townsville East 132kV transmission reinforcement, including establishment of the Townsville East 132/66kV Substation which has augmented transmission capability to the Townsville area;
- The Broadsound to Nebo 275kV transmission reinforcement, which has augmented transmission capability to the North, Ross and Far North Queensland zones;
- Installation of the Woolooga 275kV static VAr compensator (SVC), which has augmented transmission capability between central and southern Queensland;
- Installation of the Greenbank 275kV SVC and the South Pine 275kV SVC, which has augmented capacitive compensation in South East Queensland to meet increasing reactive demand;
- Establishment of the Abermain 275/110kV Substation, which has augmented transmission capability to the Ipswich area; and
- Installation of the Murarrie second 275/110kV transformer, which has augmented transmission capability to the Brisbane CBD and Australia Trade Coast.

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.

Four 275kV transmission lines:

- Between Nebo and Strathmore and also between Strathmore and Ross, to increase transfer capability between Central and North Queensland;
- Between South Pine and Sandgate, including additional 275/110kV transformer capacity at South Pine, to increase transfer capability to North East Brisbane; and
- Between Ross (Townsville) and Yabulu South, including the new Yabulu South Substation, to increase transfer capability into the Townsville area.

Establishment of one 275kV substation:

- New 275/132kV substation at Larcom Creek to augment transmission capability to the Gladstone area.

Two 132kV transmission lines:

- Between Strathmore and Bowen North, including the new Bowen North Substation, to augment supply to the Bowen area; and
- Between Bouldercombe and Pandoin, including the new Pandoin Substation, to augment transmission capability to Rockhampton and surrounding areas.

Augmentation of two 132kV substations:

- An additional 132/110kV transformer at Palmwoods Substation, to augment transmission capability to the Caboolture and Beerwah area; and
- Expansion of Alligator Creek 132/33kV Substation, to augment transmission capability to Hay Point and Dalrymple Bay, and the area south of Mackay.

Smaller augmentations, such as the installation of capacitor banks and transformer upgrades, to maintain network reliability standards are also under way.

Generation Capacity

No new generation capacity has been committed in the Queensland Region since the 2008 APR. The commissioning of Condamine and Braemar 2 power stations within the Surat Basin area in South West Queensland is well advanced.

Additional generation is still scheduled to be commissioned by proponents as follows:

- Mt Stuart Power Station third unit (liquid fuel);
- Rio Tinto Aluminium (RTA) Yarwun Power Station (gas); and
- Darling Downs Power Station (combined cycle gas).

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 to recommend an upgrade option. However, both organisations are continuing to monitor developments which could impact on the scope and timing of a potential upgrade of the interconnection, and will proceed with further work where material changes to market developments occur.

Major Flow Paths

A record peak demand was set in the 2008/09 summer, with the actual peak being 7.8% higher than that recorded in the 2007/08 summer. Following the easing of the water-restricted operation of major base load generation in South East Queensland, dispatch has returned to a more typical pattern, resulting in transmission utilisation also returning to previous patterns.

The Central Queensland to South Queensland (CQ-SQ) limit experienced minor incidences of binding over the 2008/09 year. The significant reduction in binding of this grid section compared to the previous year is a result of commissioning of new generating plant in South Queensland and the relaxation of water restrictions.

No binding occurred on the Tarong limit during 2008/09. The 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 stage already completed and the remainder due for completion by 2010, will improve transfer capability to meet forecast electricity demand in North Queensland and reduce transmission losses. Minor binding was experienced on this grid section during 2008/09.

The Gladstone limit bound for a total of 6.1% of the summer period. 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 in the near term.

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

Powerlink is currently undertaking consultation with Registered Participants and interested parties about expected future network limitations in the South West to South East Queensland area.

Powerlink expects to initiate consultation processes for a number of other expected future network limitations within the next 12 months so that augmentations can be planned and implemented in a timely manner. These expected limitations include:

- Supply to North Queensland;
- Supply within Central Queensland/Gladstone Area; and
- Supply to the Brisbane CBD and Greater Brisbane 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.

Introduction

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 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 2009 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.

As part of reform processes initiated by the Council of Australian Governments (COAG), the Australian Energy Market Operator (AEMO) will commence operation on 1 July 2009. As part of its functions, AEMO will take on the roles currently performed by the National Electricity Market Management Company (NEMMCO), and will be responsible for publishing the Statement of Opportunities (SOO).

AEMO will also undertake the new role of National Transmission Planner, and be required to publish the National Transmission Network Development Plan (NTNDP) each year, which will replace the Annual National Transmission Statement (ANTS). For the 2009 calendar year, the Ministerial Council on Energy (MCE) has proposed that a transitional document, referred to as the National Transmission Statement (NTS), be published in place of the NTNDP.

The SOO is the primary document for examining electricity supply and demand issues across all regions in the NEM. The NTS 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 NTS is strategic and longer term. The NTS and APR are intended to complement each other in promoting efficient outcomes. Accordingly, information from the annual planning review process has been provided to NEMMCO, and will be used by AEMO in the preparation of the SOO and NTS. Similarly, information from the NTS (and NTNDP) will be considered in future annual review processes undertaken by TNSPs.

Interested parties may benefit from reviewing Powerlink's 2009 APR in conjunction with AEMO's 2009 SOO and NTS, which are anticipated to be published in August 2009 and December 2009 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; and
- 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 NEMMCO 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; and
- Undertaking the role of the proponent for regulated transmission augmentations in Queensland.

Powerlink has also been nominated by the Queensland Government, under Clause 5.6.3(b) of the NER, as the entity having transmission network planning responsibility in Queensland, known as the Jurisdictional Planning Body (JPB).

As part of changes to the national transmission planning arrangement within the NEM, Powerlink will also be involved with functions to be carried out in future by AEMO, which were previously undertaken by the Inter-Regional Planning Committee (IRPC). These functions include providing advice on network developments which may have material inter-network effects, and participating 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; and
- 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 material new regulated network augmentation proposals. The planning process requires consultation with registered participants and interested parties, including customers, generators and DNSPs.

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; and
- 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 NEMMCO, 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. This 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 the IRPC (or, in future, 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 a cost effectiveness analysis to determine the option that minimises the 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; and
- 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 6.

2 Supporting the National Transmission Statement

2.1 Background

As part of the reform process initiated by the Council of Australian Governments (COAG), the Ministerial Council on Energy (MCE) requested the Australian Energy Market Commission (AEMC) to progress changes to the National Electricity Rules (NER) to establish a national electricity transmission planning function.

On 1 July 2009, the Australian Energy Market Operator (AEMO) will commence operation and take on the role of National Transmission Planner. As part of this function, AEMO is responsible for the publication of a National Transmission Network Development Plan (NTNDP) by December each year. The NTNDP will replace the Annual National Transmission Statement (ANTS) currently prepared by the National Electricity Market Management Company (NEMMCO).

The purpose of the NTNDP is to provide information on the strategic and long-term development of the national power system under a range of scenarios. The NTNDP is expected to consider network and non-network solutions, and assess the optimisation of generation and transmission investment across the long-term planning horizon.

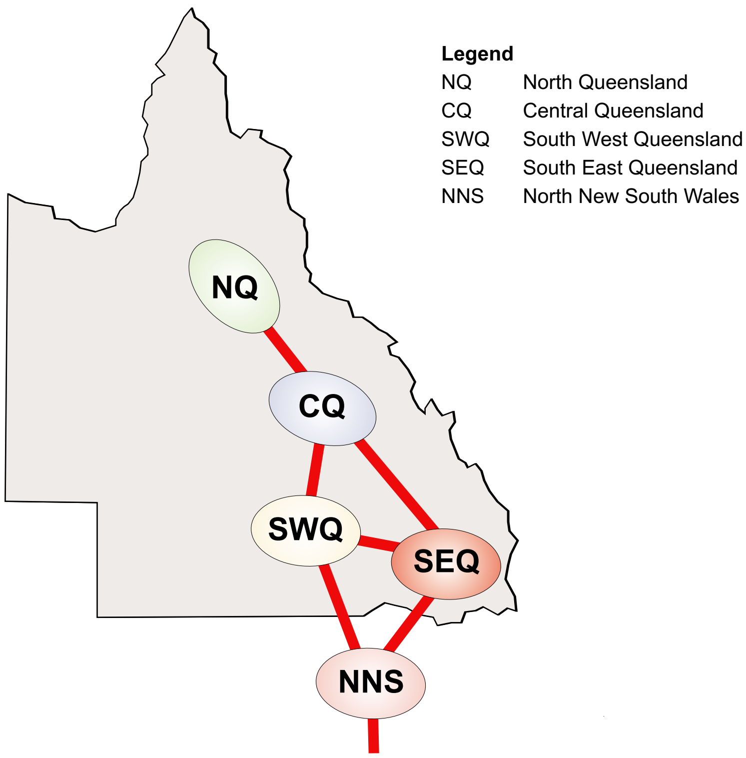
The MCE also determined that the strategic nature of the NTNDP be given practical effect by focusing on National Transmission Flow Paths (NTFPs) across a long-term study timeframe of at least 20 years.

For the 2009 calendar year, the MCE proposed that a transitional document referred to as the National Transmission Statement (NTS) be published in place of the NTNDP. In order to support and assist AEMO in the development of the NTS, Powerlink Queensland has provided a summary of potential augmentations which could affect the transfer capability of NTFPs within the Queensland region, and other relevant planning information.

2.2 National Transmission Flow Paths

The NER define NTFPs as transmission corridors used to transport significant amounts of electricity between major generation and load centres. The NTFPs in the Queensland region corresponding to this definition are shown in Figure 2.1. These flow paths also align with key intra-regional network corridors described in Section 5.3, and are consistent with the flow paths used in the 2008 ANTS.

Figure 2.1: Queensland National Transmission Flow Paths



2.3 Categories of Augmentations

NEMMCO has defined three categories to classify the status of flow path augmentations for the 2009 NTS. These categories indicate the level of certainty of a particular augmentation. Powerlink has indicated the status of potential augmentations described in Section 2.4, according to these categories which are summarised below:

Committed augmentations

Regulated transmission augmentations are considered committed when Board commitment has been achieved, funding has been approved, the project has satisfied the Regulatory Test and NER consultation processes have been completed, and construction has either commenced or a firm date for commencement has been set.

Routine augmentations

Routine network augmentations are not yet committed, but there is reasonable expectation that the augmentation, or a project with similar impact, will proceed following routine planning investigations conducted by Transmission Network Service Providers (TNSPs).

Routine augmentations include minor NTFP upgrades for maintaining power transfer capability, or to ensure that power transfers are not restricted by equipment that can be installed at relatively low cost.

Routine augmentations also include network augmentations that are required to meet reliability requirements (including mandated reliability standards within Queensland) that are identified following planning investigations by TNSPs.

Augmentations that are eventually implemented might differ from the routine augmentations that are identified within this section. These differences may arise following more detailed planning studies and/or during the Regulatory Test consultation phases.

The actual timing of these augmentations may be affected by load growth, demand side management, new generation entry or generation retirement.

Conceptual augmentations

Conceptual augmentations are identified as potential network options which are designed to increase the transfer capability of NTFPs.

2.4 Potential Augmentations to Flow Paths

The different categories of network augmentations to increase the transfer capability of NTFPs in the Queensland region across a 20 year timeframe are detailed in Appendix A, together with other relevant planning information. These tables also include the potential impacts of network augmentations on transmission limits.

3 Intra-Regional Energy and Demand Projections

3.1 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 3.8% per annum from 8,330MW in 2008/09 to 12,047MW in 2018/19. Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.1% per annum over the next 10 years for the medium economic growth scenario.

Population and economic growth will continue to underpin increases to electricity demand over the 10 year forecast period.

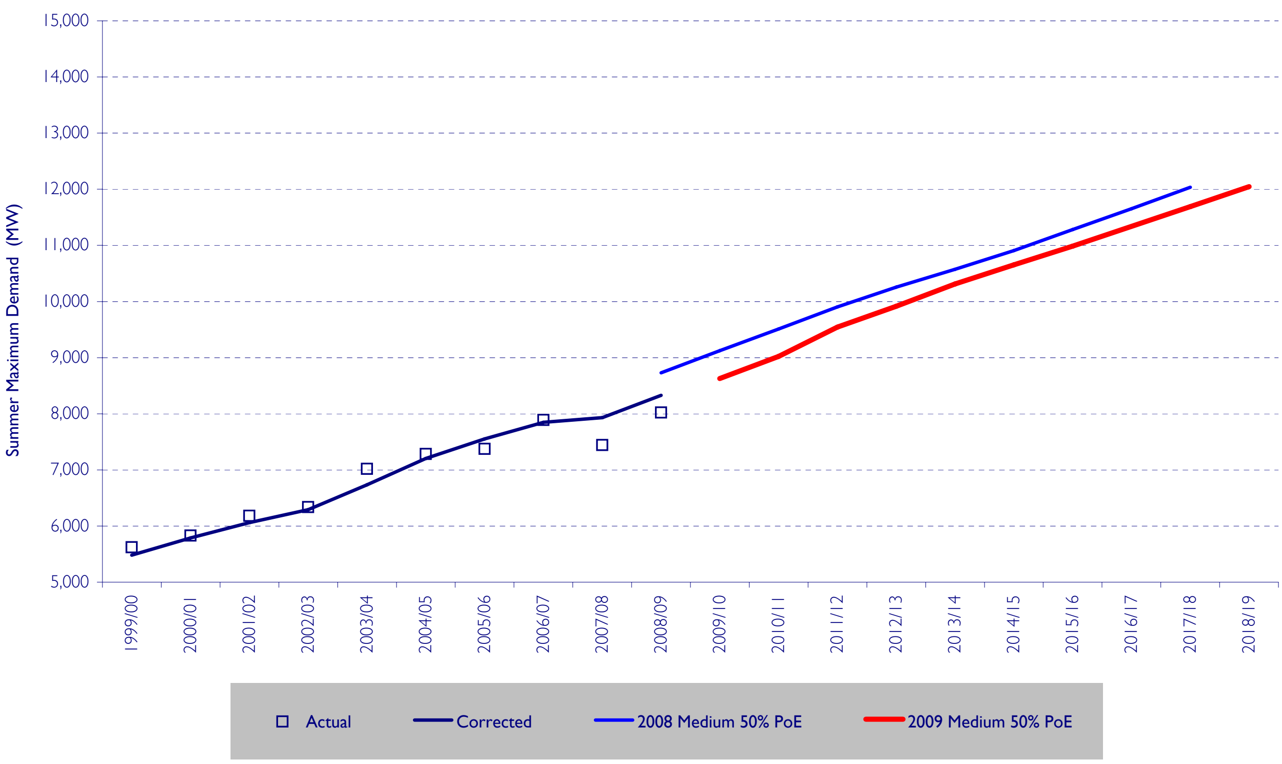
The current economic slowdown, the impact of milder weather conditions in 2007/08 and 2008/09, as well as the introduction and increased uptake of energy efficiency initiatives have been factored into this forecast. The energy efficiency initiatives, by their nature, tend to impact energy consumption much more than the forecast peak demands.

The effect of the economic slowdown is a slower growth rate for electricity demand for the first two years of the forecast, after which the annual demand growth is expected to return to a growth rate consistent with the forecast population growth and long-term economic growth trends.

The trend of an increased diversity between the demand at the time of State peak and the combined peak demand of each area making up Queensland is continuing. However, the expected demand growth within each of the areas that make up Queensland is strong.

A comparison of the 2008 APR and 2009 APR summer peak demands (medium 50% PoE) forecasts is displayed below.

Figure 3.1: Queensland Region Summer Peak Native Demand – Comparison with 2008



3.1.1 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, as defined in Table 3.12 in Section 3.5, using temperature corrections and diversity factors observed from historical trends up to the end of summer 2008/09.

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.

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 growth perspective. Inputs to this model include economic data, specific customer forecast information and expected impacts for the proposed introduction of the Federal Government's Carbon Pollution Reduction Scheme (CPRS). 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 high, medium and low econometric outlooks.

The NIEIR medium outlook forecasts are consistent with the Queensland economic forecast by KPMG for the Australian Energy Market Operator's (AEMO's) 2009 National Transmission Statement (NTS).

3.1.2 Basis of Load Forecasts

Population Growth

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

The average population growths for the low, medium, and high growth scenarios developed by the Australian Bureau of Statistics and the Queensland State and Local Governments, over the period 2008/09 to 2018/19 are included in the table below.

Table 3.1: Population Growth

	Low	Medium	High
South East Queensland (average growth p.a.)	1.6%	2.0%	2.6%
Queensland (average growth p.a.)	1.6%	1.9%	2.5%

Economic Outlook

Three economic growth outlooks for Queensland were updated by NIEIR. The three economic outlooks can be characterised as:

- Low growth economic outlook;
- Medium growth economic outlook; and
- High growth economic outlook.

The average growth for the low, medium, and high economic outlooks developed by NIEIR over the period 2008/09 to 2018/19 are included in the table below.

Table 3.2: Economic Growth

	Low	Medium	High
Australian Gross Domestic Product (average growth p.a.)	1.8%	2.9%	4.0%
Queensland Gross State Product (average growth p.a.)	2.6%	3.8%	4.9%

The updated Queensland gross state product growth rates are lower for all three economic growth outlooks compared with NIEIR predictions outlined in the 2008 APR and the National Electricity Market Management Company's (NEMMCO's) 2008 Statement of Opportunities (SOO). The Australian gross domestic product growth rate forecast is also lower.

These forecasts also include lower growth levels early in this forecast period as a consequence of the global economic slowdown, with assumed recovery in Queensland from 2010/11 and nationally from 2011/12. This pattern is similar to forecasts developed by KPMG for NEMMCO.

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% Probability of Exceedance (PoE) forecast region peak, corresponding to one year in 10 extreme summer or winter conditions;
- A 50% PoE forecast region peak, corresponding to one year in two average summer or average winter conditions; and
- A 90% PoE forecast region peak, corresponding to nine years in 10 mild summer or winter conditions.

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; and
- 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 have more impacts in the much 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

As in previous reports, the 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 the distribution networks and to transmission connected consumers, after adding in 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 off. In the case of Queensland, this non-scheduled embedded generation includes a small number of sugar mill cogenerators, and 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, but only back to 2006/07 as differences between native and delivered demand before then are not material.

KPMG's report to NEMMCO includes a forecast of around 600MW of wind generators over the next 10 years. As the capacity of these generators is expected to exceed 30MW, they will be classified as semi-scheduled, and will therefore be treated in the same way as scheduled generation for the purpose of load forecasting. That is, they are not expected to impact delivered demand.

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 the loading on parts of the transmission network to meet the demand.

New Large Loads – Committed

A number of industrial and port handling facility loads reported as committed in the 2008 APR have encountered delays, and have contributed to reductions to expected energy and demand in the past year. Whilst the initial phase of these load increases is now complete, they are yet to build to full load. The Wiggins Island coal loader in the Gladstone area has been delayed, but environmental approval has now been granted, and it is expected to begin operation in 2011/12.

The second stage of Rio Tinto Aluminium (RTA) Yarwun Alumina Refinery (west of Gladstone) has recently been deferred, and is now expected to be commissioned by summer 2010/11. The forecasts now include a steady increase of loading at the Boyne Island smelters from that time.

Expansion of coal handling port facilities at Dalrymple Bay (Mackay) and associated increase in railway load is expected by late 2009.

The forecast now includes the first two stages of port handling facility upgrades at Abbot Point (Bowen).

New Large Loads – Uncommitted

There have been several proposals for large metal processing or other industrial loads which are not yet committed, and are therefore not included in the medium economic forecast. These include the following projects:

- Major expansions of an existing zinc smelter plant (Townsville);
- Stage three Port Handling facility upgrade at Abbot Point (Bowen);
- Development/electrification of the Goonyella to Abbot Point railway line;
- Further new and expanded coal mines in the Bowen Basin;
- Compressor pumping load to pump Liquified Natural Gas (LNG) to Gladstone; and
- Several additional coal mines in the Wandoan and Surat Basin area.

Some of these additional demands have been included in the high growth outlook in accordance with data provided by customers. These developments could translate to the following additional load, to be supplied by the network.

Table 3.3: Uncommitted Large Loads

Zone	Type of Plant	Possible Load
Ross	Zinc	Up to 120MW
Central West & North	Greater than forecast increase in coal mining and railway load	Up to 120MW
Gladstone	Aluminium and zinc	Up to 800MW
South West	Coal Mining and Compressor/Pumping of LNG (1)	Up to 450MW

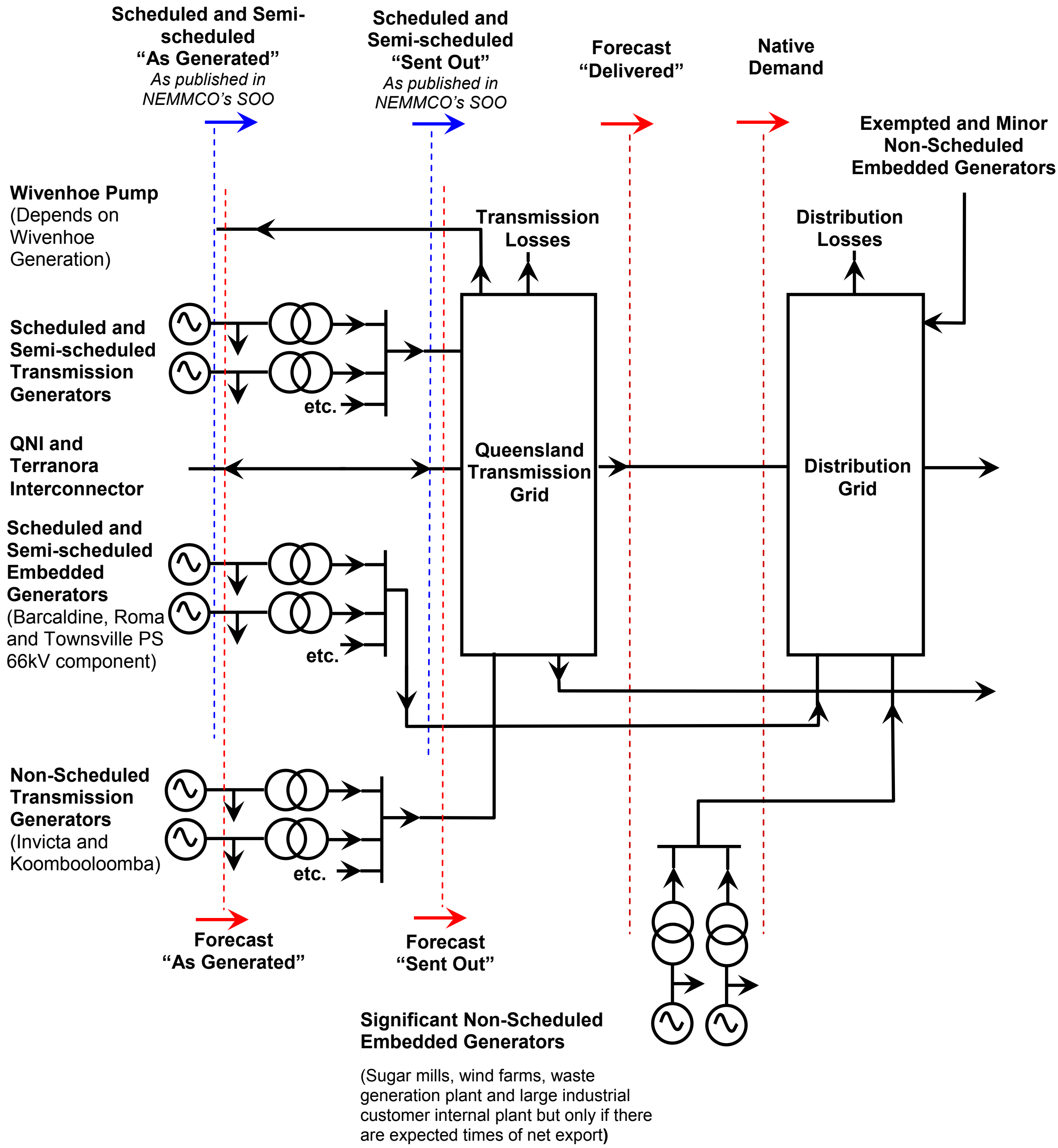
Note:

(1) This load could be accompanied by some embedded generation

3.1.3 Load Forecast Definitions

The relationship between the classes of generation and the forecast quantities in this report is shown in Figure 3.2.

Figure 3.2: Load Forecast Definitions



3.2 Recent Energy and Demands

3.2.1 Recent Summers

A summary for South East Queensland of recent summer electricity demands, seasonal energy and prevailing weather conditions, is shown in Table 3.4.

This year, Powerlink moved to using Amberley rather than Archerfield as the reference location for summer temperature correction in South East Queensland. This change was recommended by NIEIR based on empirical evidence demonstrating a better correlation between demand and temperature. ENERGEX also uses Amberley as a reference location for summer temperature correction in South East Queensland. Archerfield is still used as the reference location for winter temperature correction in South East Queensland. Further information on the temperature correction process and this change in reference location can be found in Appendix B.

Summer 2008/09 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 utilisation. Summer temperatures in North Queensland were slightly below average, with no significant period of above average temperatures.

The weather and diversity corrected, summer 2008/09 maximum native demand for Queensland was 8,330MW, an increase of 5.0% from the 7,929MW peak in summer 2007/08.

At the time of Queensland actual peak demand for summer 2008/09, the weather pattern diversity across the State was 92.1% coincidence compared with the previous 10 year average of 95.6% coincidence. Whilst this is not as low as summer 2007/08, the trend of lower coincidence at the time of state peak is continuing.

The actual delivered summer energy for Queensland in 2008/09 was 3.7% higher than in summer 2007/08, but the growth was 5.0% on a native basis. In South East Queensland, the growth in 2008/09 summer native energy was 6.0% over summer 2007/08.

Recent surveys have shown that air conditioning penetration in South East Queensland continues to increase. Further detail is provided in Appendix B. The higher demand for South East Queensland in summer 2008/09 in part reflects recent strong air conditioning sales combined with a return to more average weather conditions.

Table 3.4: 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)
1998/99	3,973	2,762	Average	24.53	29.20	0
1999/00	4,085	2,946	Mild	23.14	31.85	2+1
2000/01	4,352	2,977	Average, dry	24.93	29.90	0+2
2001/02	4,694	3,120	Very hot over Christmas holiday period only, dry	25.90	30.40	1+6
2002/03	4,746	3,383	Mild	24.65	32.40	3
2003/04	5,282	3,846	Sustained very hot and humid in February	26.07	30.25	7+1
2004/05	5,373	4,024	Average	24.94	29.35	0+2
2005/06	5,917	4,141	Overall a very hot summer, high energy consumption, but a lack of very hot working weekdays	26.48	27.95	1 (5)
2006/07	5,572	4,300	Mild – a lack of very hot days	24.19	28.30	1
2007/08	5,741	4,092 (Friday) 4,114 (Saturday)	Mild and generally overcast with lower daytime temperatures - no very hot days	24.14	27.80 (Friday) 29.70 (Saturday)	0
2008/09	6,074	4,635	Average and wet – no very hot days	24.86	27.35	0

Notes:

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

(2) In this table demands and energy are 'native' for 2006/07 to 2008/09, but are 'delivered' for prior years. In the case of South East Queensland there is only a relatively small amount of embedded non-scheduled market generation to date and this is dominated by Rocky Point and Bromelton (2008/09 onwards) power stations.

(3) In this report, Brisbane summer temperature is now measured at Amberley. Day temperatures refer to average of daily minimum and daily maximum to represent the driver for cooling load, with a 25% loading of the previous day temperatures if it was hotter. For Amberley 30.0°C is the 50% PoE summer reference temperature which is expected to be exceeded two to three days per summer on average.

(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.

3.2.2 Recent Winters

A summary of recent winter electricity demands, seasonal energy and prevailing weather conditions for South East Queensland is shown in Table 3.5.

The South East Queensland winter of 2008 was mild. It contained just one day cooler than the 50% PoE reference temperature. Peak native demand in South East Queensland for winter 2008 was 4,341MW which, after temperature correction, showed a 7.5% increase over winter 2007.

The actual recorded Queensland region maximum winter 2008 native demand was 7,593MW, a significant increase of 5.1% over winter 2007. When temperature and diversity corrected this reduces to 7,517MW.

The growth in actual native winter energy in 2008 was 1.6% for Queensland and 2.5% for South East Queensland. The effect of increasing domestic air conditioning has continued to impact on winter electricity consumption since reverse cycle units have now largely replaced less efficient means of household heating. As shown in Appendix B, a discernable growth in sensitivity of winter daily peak demands against Brisbane temperature has now emerged. As reverse cycle air conditioning becomes even more prevalent in the future, the increase in this sensitivity is expected to continue.

Table 3.5: Comparison of Recent South East Queensland Winter Native Demand

Winter (1)	Native Winter Energy GWh (2)	Max 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	16.45	11.85	0
1999	4,227	2,769	Mild	15.32	15.50	0
2000	4,456	2,992	Cooler than average	14.32	8.80	2
2001	4,543	2,975	Mild	14.99	10.10	1+2
2002	4,775	2,999	Average	14.57	12.85	0+1
2003	4,921	3,325	Mild but one 8 day cold snap	14.96	10.95	4+1
2004	5,094	3,504	Mild	15.40	11.80	0
2005	5,252	3,731	Mild	15.68	10.50	2
2006	5,420	3,882	Mild	15.55	13.85	0
2007	5,610	4,118	Average to Mild	15.14	10.05	3+1
2008	5,734	4,341	Mild	15.21	11.55	2

Notes:

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

(2) In this table energy and demands are 'native' for 2006 and 2007, but are 'delivered' for prior years. In the case of South East Queensland there is only a relatively small amount of embedded non-scheduled market generation to date and this is dominated by Rocky Point and Bromelton (2008/09 onwards) power stations.

(3) In this report, Brisbane winter temperature is still measured at Archerfield. Day temperatures refer to average of daily minimum and daily maximum to represent the driver for heating load, with a 25% loading of the previous day temperatures if cooler. The 11.0°C is the 50% PoE reference winter temperature (recently revised up from 10.9°C). Actual temperatures are expected at this level or lower for two to three days each winter, on average.

(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).

3.2.3 Seasonal Growth Patterns

Energy usage for recent summers and winters to DNSPs is shown in Figure 3.3. Figure 3.3 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.

3.2.4 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 B.

Queensland region corrected demands for all winters and summers from 1998, are shown on Figure 3.4. Figure 3.5 shows the same information for South East Queensland alone. The methodology is further outlined in Appendix B.

Figure 3.3: Historic Native Energy to DNSPs in Queensland

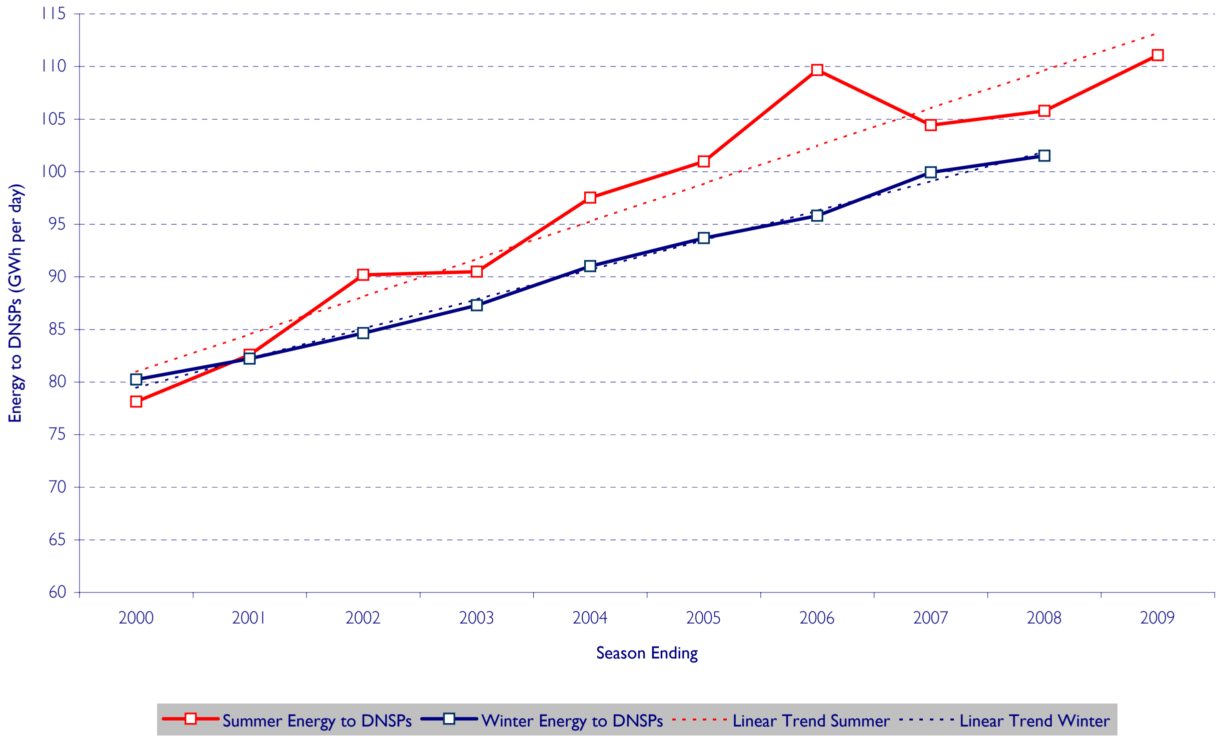


Figure 3.4: Historic Native Demand for Queensland (Including Temperature and Diversity Correction)

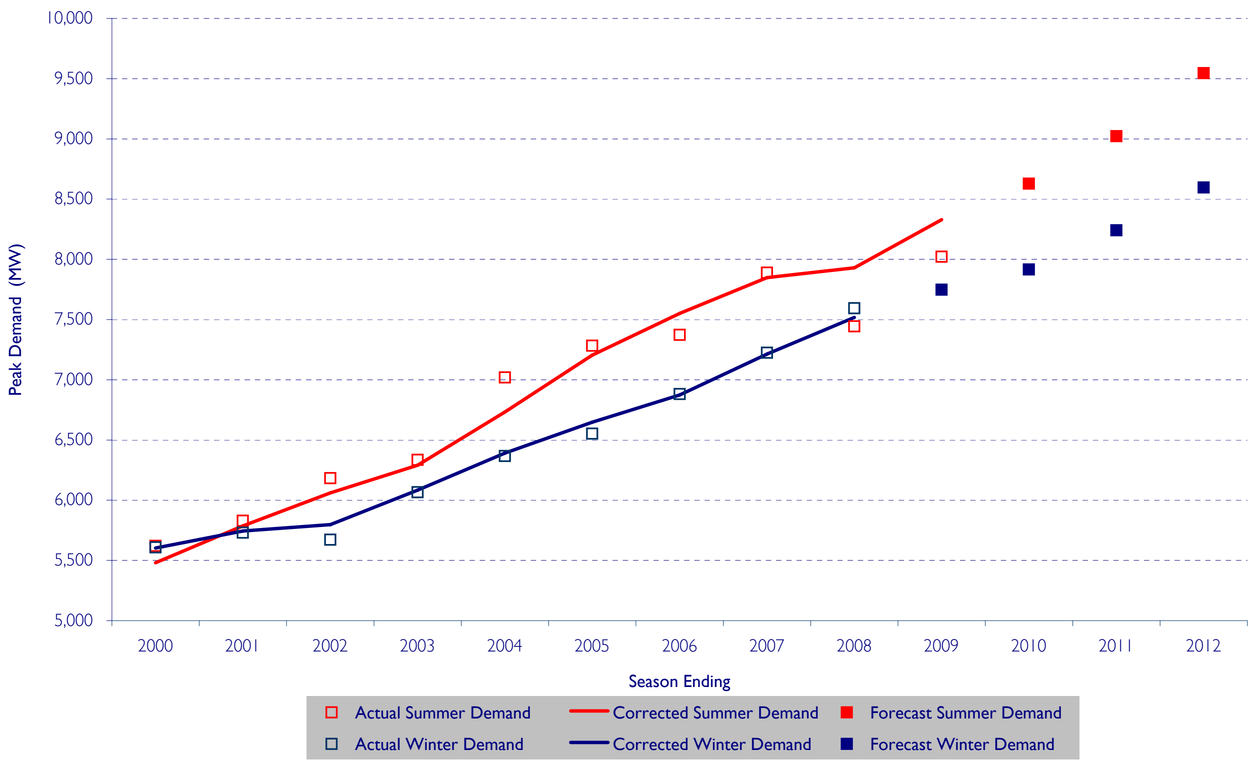
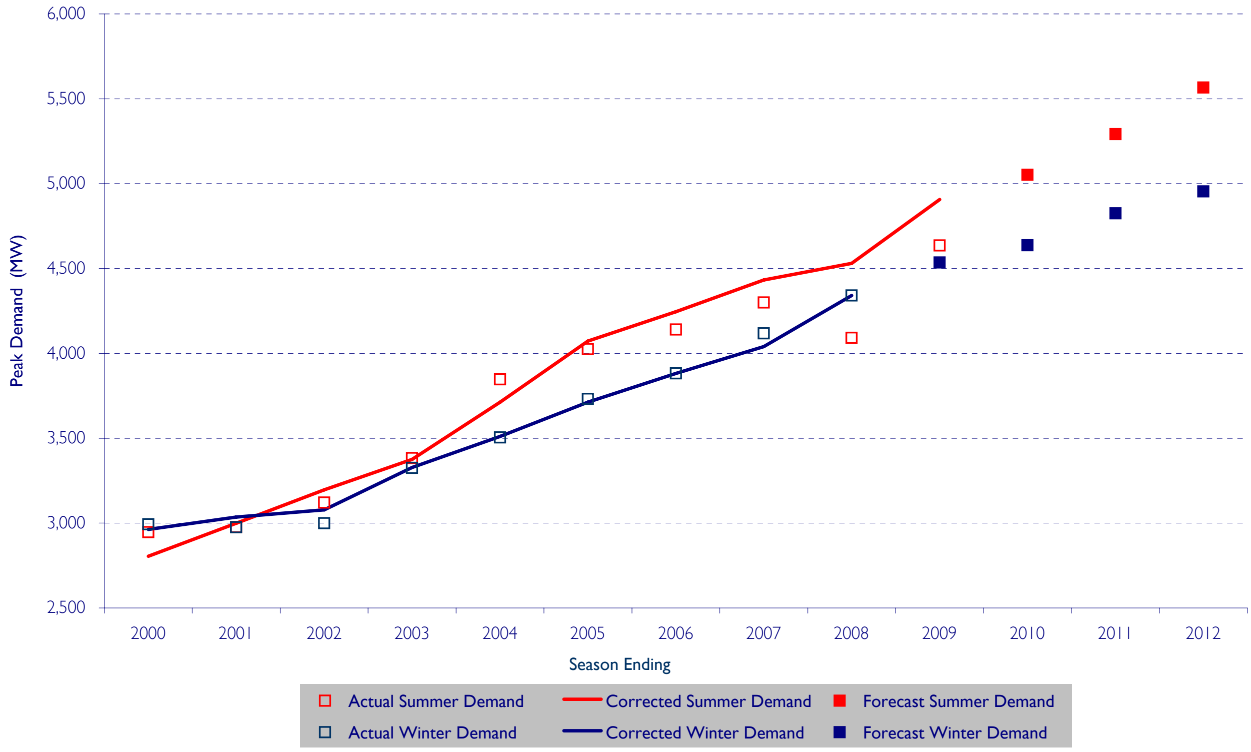


Figure 3.5: Historic Native Demand for South East Queensland (Including Temperature Correction)



3.3 Comparison with the 2008 Annual Planning Report

The major difference in forecasts in this APR compared with the 2008 APR is the effect of the economic slowdown – lower growth rates for the next two years, before a return to a growth rate consistent with the forecast population growth and long-term economic growth trends.

3.4 Forecast Data

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

3.4.1 Energy Forecast

Table 3.7, Figure 3.6 and Figure 3.7 show the historical and 10 year forecast of native energy from the transmission network. It also shows native energy for 2007/08 and projected 2008/09, with an adjustment to add to the various outlook forecasts of delivered energy.

3.4.2 Summer Demand Forecast

Table 3.8 and Figure 3.8 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.

3.4.3 Winter Demand Forecast

Table 3.9 and Figure 3.9 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.

3.4.4 Transmission Losses and Auxiliaries

Table 3.10 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 3.11 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.

3.4.5 Load Profiles

Figure 3.10 shows the daily load profile on the days of the recent 2008 winter and 2008/09 summer Queensland region peak demand delivered from the transmission network and from embedded scheduled generators. Figure 3.11 shows the cumulative annual load duration curve for the completed 2007/08 financial year.

3.4.6 Connection Point Forecasts

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

The 'projected actual' forecast for 2008/09 accounts for actual energy delivery in the first nine months of the financial year, that is, up to the end of March 2009, plus forecast energy from April 2009 to the end of June 2009 which is based on statistical 'as generated' data, and a nominal growth rate applied to equivalent months in 2008.

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 3.6.

Table 3.6: Average Annual Growth Rate over Next 10 Years

	Economic Growth Outlooks		
	High	Medium	Low
Queensland Gross State Product	4.9%	3.8%	1.8%
Native Energy (1)	6.0%	3.1%	1.4%
Native Summer Peak Demand (50% PoE) (2)	5.8%	3.8%	2.3%
Native Winter Peak Demand (50% PoE) (2)	6.2%	3.4%	1.5%

Notes:

(1) This is energy delivered from the transmission network, and from embedded scheduled generators, and from 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, and from embedded scheduled generators, and from 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 3.7: Annual Native Energy GWh – Actual and Forecast

Year	Sent Out (1)			Transmission Losses (2)			Native Energy			Delivered Energy Adjustment (3)
1999/00	38,066			1,490			36,576			0
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 (4)	49,415			1,834			48,548			-967
Forecast	Low	Med	High	Low	Med	High	Low	Med	High	Delivered Energy Adjustment (3)
2009/10	49,365	50,455	52,438	1,809	1,867	1,974	48,604	49,636	51,512	-1,048
2010/11	50,640	52,629	55,884	1,842	1,947	2,124	49,846	51,730	54,809	-1,048
2011/12	51,880	55,561	60,236	1,862	2,056	2,311	51,066	54,554	58,974	-1,048
2012/13	52,456	57,133	63,657	1,868	2,114	2,472	51,636	56,068	62,233	-1,048
2013/14	53,484	58,979	67,199	1,894	2,182	2,636	52,638	57,845	65,611	-1,048
2014/15	54,107	60,617	71,410	1,903	2,243	2,844	53,252	59,422	69,614	-1,048
2015/16	54,614	62,185	74,841	1,907	2,301	3,010	53,755	60,932	72,879	-1,048
2016/17	55,281	63,879	78,624	1,917	2,364	3,194	54,412	62,563	76,478	-1,048
2017/18	55,917	65,642	86,346	1,925	2,429	3,615	55,040	64,262	83,779	-1,048
2018/19	56,541	67,406	89,979	1,933	2,494	3,793	55,656	65,960	87,234	-1,048

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 March 2009.

Figure 3.6: History and Forecasts of Annual Native Energy for Medium Economic Growth Outlooks

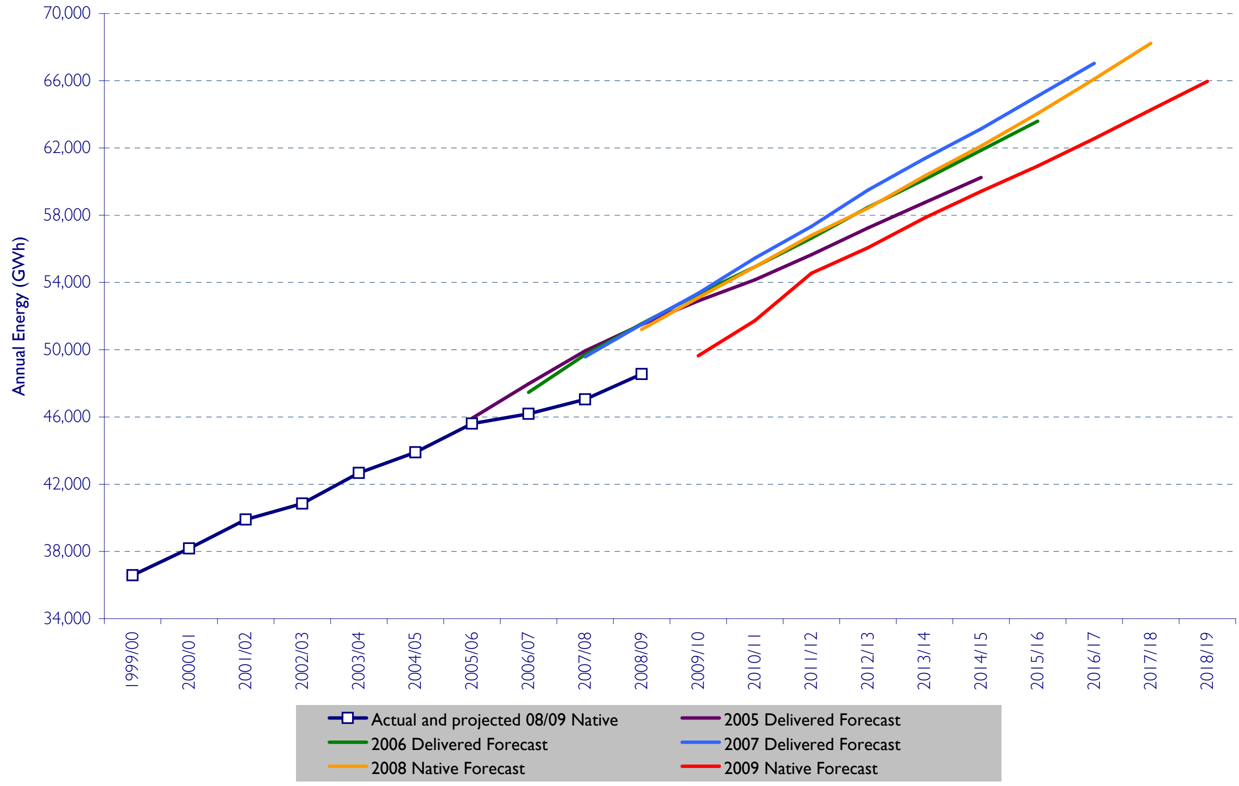


Figure 3.7: History and Forecast of Native Energy for Low, Medium and High Economic Growth Outlooks

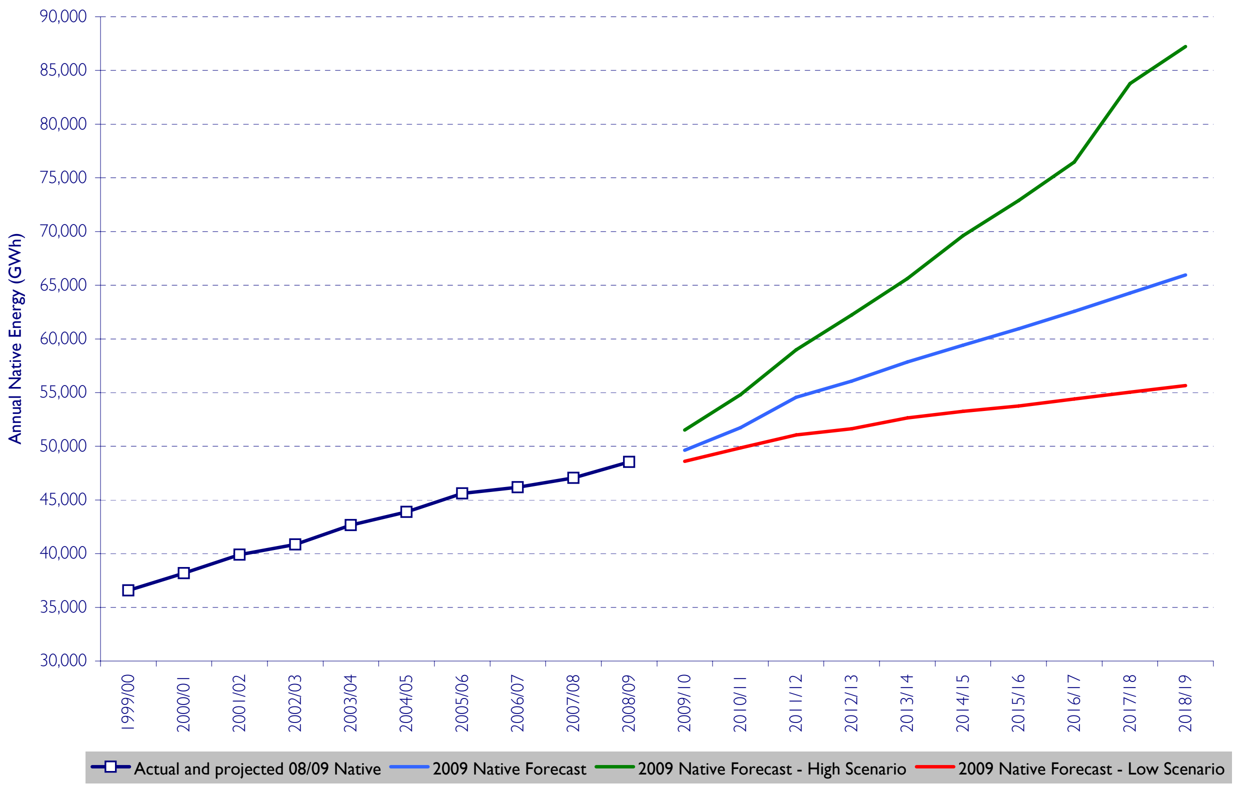


Table 3.8: Peak Summer Native Demand (MW) with Delivered Demand Adjustment

Summer	Actual Native	Actual Delivered (1)	Weather and Diversity Corrected Native Demand	Delivered Demand Adjustment
1999/00	5,620	5,620	5,481	0
2000/01	5,830	5,830	5,786	0
2001/02	6,183	6,183	6,060	0
2002/03	6,336	6,336	6,290	0
2003/04	7,020	7,020	6,734	0
2004/05	7,282	7,282	7,205	0
2005/06	7,373	7,373	7,551	0
2006/07	7,889	7,832	7,849	-57
2007/08	7,444	7,337	7,929	-107
2008/09	8,021	7,922	8,330	-99

Summer Native Demand Forecasts	High Growth Outlook			Medium Growth Outlook			Low Growth Outlook			Delivered Demand Adjustment
	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE	
2009/10	9,353	8,897	8,619	9,071	8,628	8,359	8,872	8,439	8,177	-157
2010/11	10,011	9,525	9,228	9,487	9,023	8,740	9,164	8,716	8,444	-157
2011/12	10,727	10,206	9,887	10,036	9,545	9,246	9,472	9,009	8,728	-157
2012/13	11,385	10,832	10,492	10,426	9,915	9,603	9,709	9,233	8,943	-157
2013/14	12,000	11,416	11,057	10,845	10,313	9,987	10,005	9,514	9,216	-157
2014/15	12,630	12,017	11,641	11,205	10,654	10,317	10,213	9,711	9,406	-157
2015/16	13,207	12,568	12,175	11,555	10,986	10,639	10,401	9,889	9,579	-157
2016/17	14,242	13,572	13,161	11,926	11,338	10,979	10,619	10,096	9,778	-157
2017/18	14,834	14,134	13,704	12,300	11,692	11,322	10,824	10,290	9,967	-157
2018/19	15,426	14,696	14,247	12,674	12,047	11,664	11,030	10,485	10,155	-157

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 and on native demand for the 2006/07 and 2007/08.

Figure 3.8: Queensland Region Summer Peak Native Demand

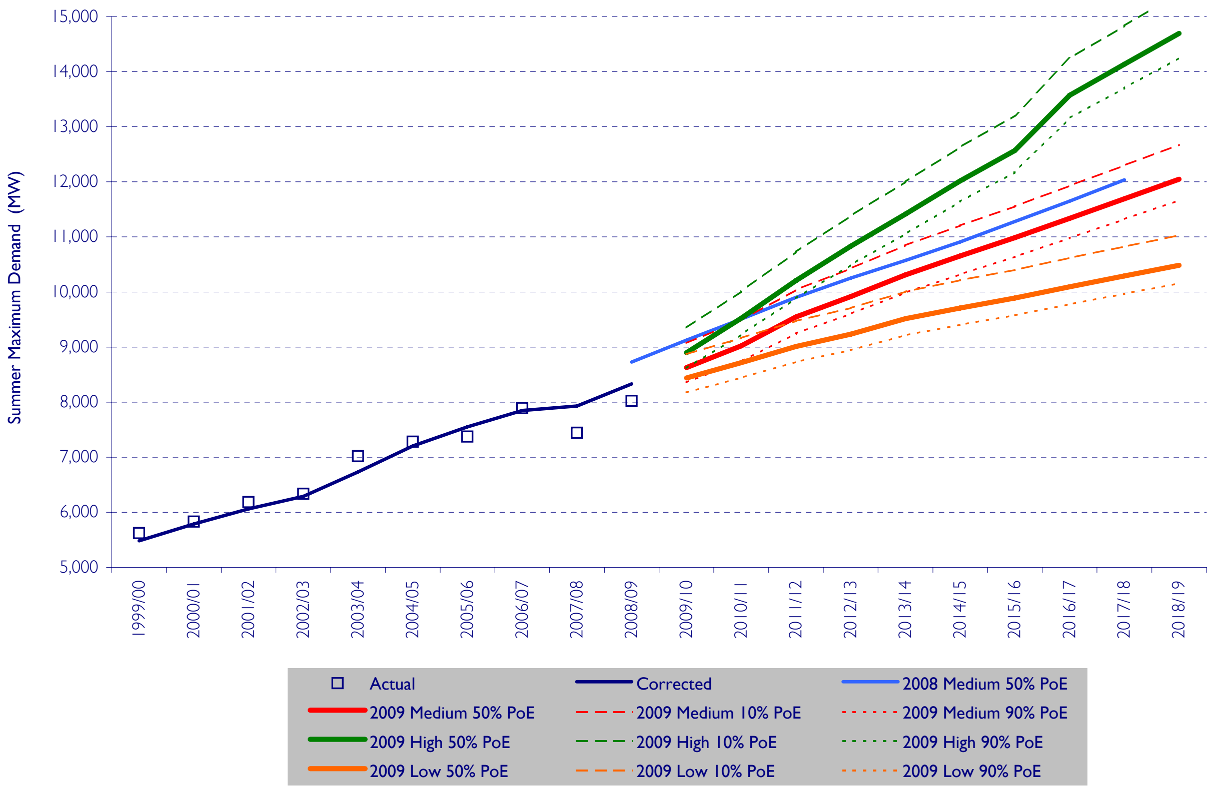


Table 3.9: Peak Winter Native Demand (MW) with Delivered Demand Adjustment

Winter	Actual Native	Actual Delivered (1)	Weather and Diversity Corrected Native Demand	Delivered Demand Adjustment
2000	5,609	5,609	5,603	0
2001	5,731	5,731	5,745	0
2002	5,671	5,671	5,797	0
2003	6,066	6,066	6,084	0
2004	6,366	6,366	6,391	0
2005	6,553	6,553	6,648	0
2006	6,882	6,882	6,875	0
2007	7,224	7,166	7,213	-58
2008	7,593	7,497	7,517	-96

Winter Native Demand Forecasts	High Growth Outlook			Medium Growth Outlook			Low Growth Outlook			Delivered Demand Adjustment
	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE	
2009	8,049	7,939	7,780	7,854	7,747	7,592	7,746	7,640	7,488	-125
2010	8,443	8,326	8,160	8,027	7,916	7,758	7,796	7,689	7,536	-125
2011	9,010	8,885	8,708	8,355	8,240	8,076	7,893	7,785	7,629	-125
2012	9,698	9,563	9,373	8,717	8,596	8,425	8,066	7,955	7,796	-125
2013	10,311	10,166	9,964	9,048	8,922	8,744	8,244	8,131	7,968	-125
2014	10,890	10,736	10,522	9,366	9,235	9,050	8,381	8,266	8,101	-125
2015	11,517	11,355	11,130	9,652	9,517	9,327	8,480	8,363	8,196	-125
2016	12,176	12,006	11,768	9,965	9,826	9,629	8,608	8,490	8,320	-125
2017	13,276	13,096	12,840	10,307	10,162	9,959	8,745	8,625	8,453	-125
2018	13,934	13,743	13,474	10,625	10,477	10,267	8,862	8,741	8,566	-125

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 and on native demand for winter 2007.

Figure 3.9: Queensland Region Winter Peak Native Demand

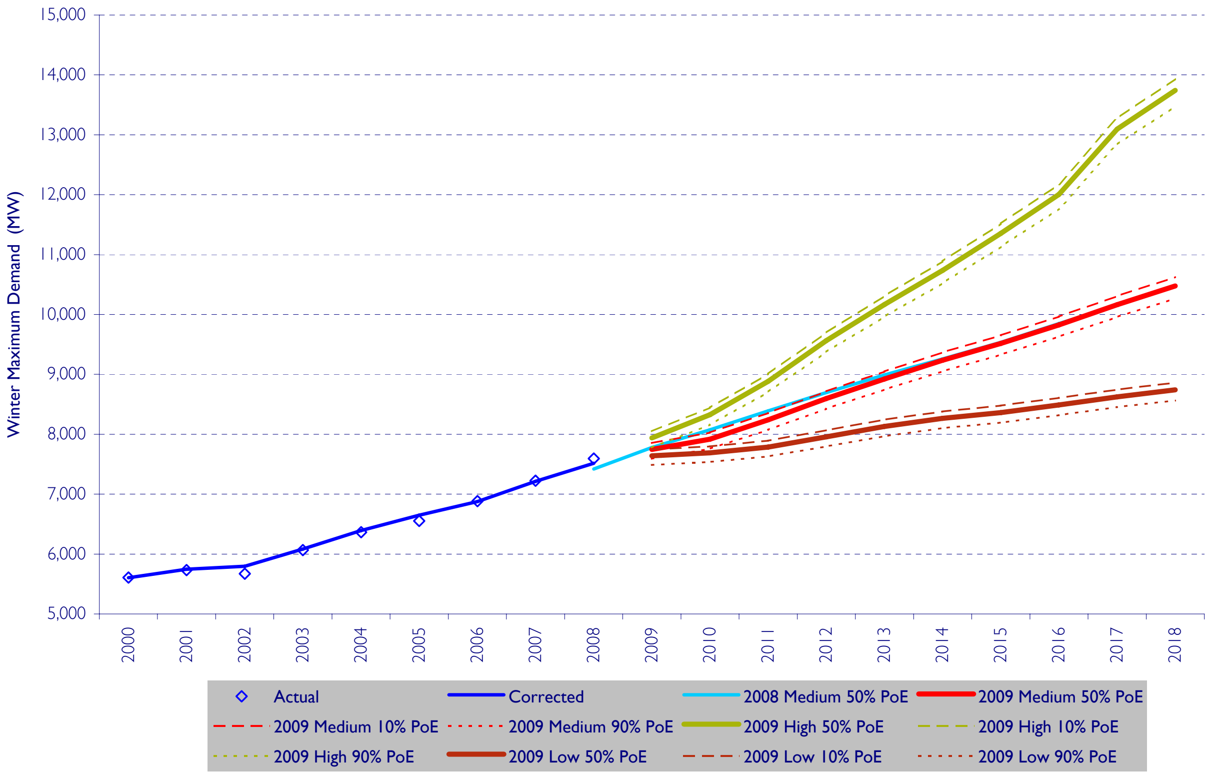


Table 3.10: Maximum Delivered, Sent Out and 'As Generated' Queensland Region Demand (MW) – 50% PoE Delivered Forecast

	Station 'As Generated' Demand	Station Auxilliaries and Losses	Station 'Sent Out' Demand	Transmission Losses	Delivered from Network Demand (1)
Winter State Peak					
2009	8,481	542	7,939	318	7,622
2010	8,667	544	8,123	331	7,792
2011	9,008	556	8,452	337	8,115
2012	9,384	568	8,816	344	8,472
2013	9,726	578	9,148	350	8,797
2014	10,053	586	9,467	357	9,110
2015	10,347	593	9,755	362	9,392
2016	10,666	598	10,068	367	9,701
2017	11,016	606	10,410	373	10,038
2018	11,364	625	10,738	387	10,352
Summer State Peak					
2009/10	9,425	602	8,824	352	8,471
2010/11	9,862	619	9,243	377	8,866
2011/12	10,427	643	9,783	395	9,389
2012/13	10,814	655	10,159	401	9,758
2013/14	11,233	668	10,565	409	10,156
2014/15	11,588	676	10,911	415	10,497
2015/16	11,931	683	11,248	418	10,829
2016/17	12,294	690	11,604	423	11,181
2017/18	12,658	696	11,962	427	11,536
2018/19	13,047	717	12,330	440	11,890

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 3.11: 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					
2009	8,601	550	8,051	322	7,729
2010	8,790	552	8,238	336	7,902
2011	9,136	564	8,572	342	8,231
2012	9,517	576	8,941	349	8,592
2013	9,865	587	9,279	355	8,924
2014	10,198	595	9,603	362	9,241
2015	10,496	601	9,895	367	9,527
2016	10,819	607	10,212	372	9,840
2017	11,175	614	10,560	378	10,182
2018	11,527	634	10,893	392	10,501
Summer State Peak					
2009/10	9,917	633	9,284	371	8,914
2010/11	10,378	651	9,727	397	9,330
2011/12	10,971	677	10,294	415	9,879
2012/13	11,381	689	10,691	422	10,269
2013/14	11,822	703	11,119	431	10,689
2014/15	12,196	712	11,485	436	11,048
2015/16	12,558	719	11,839	440	11,398
2016/17	12,941	727	12,214	445	11,769
2017/18	13,325	733	12,593	449	12,143
2018/19	13,735	755	12,980	463	12,517

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).

3.5 Zone Forecasts

The 10 geographical zones referred to throughout this report are defined in Table 3.12.

Table 3.12: 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 that part defined as 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 3.16 to 3.19, as the zone peak typically does not coincide with the time of maximum demand for the whole Queensland region. As noted earlier, the degree of coincidence across the State is decreasing.

Table 3.13 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 3.16 to 3.19 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 customer future expectations. The higher than previous ratios for the Ross zone reflect increased diversity at the time of Queensland region peak demand of the large industrial loads within this zone.

Table 3.13: 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	1.26	1.18
North	1.17	1.13
Central West	1.06	1.08
Gladstone	1.00	1.01
Wide Bay	1.07	1.14
Bulli	1.00	1.02
South West	1.00	1.02
Moreton	1.00	1.02
Gold Coast	1.00	1.02

Tables 3.14 and 3.15 show the forecast of energy supplied from the transmission network and embedded scheduled generators for the medium growth outlook for each of the 10 zones in the Queensland region. Forecasts are presented as delivered demand, including effects of non-scheduled embedded generators, and native demand, excluding non-scheduled embedded generators.

Tables 3.16 and 3.17 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 growth outlook and average winter weather. Forecasts are presented as delivered demand, including effects of non-scheduled embedded generators, and native demand, excluding non-scheduled embedded generators.

Tables 3.18 and 3.19 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 growth outlook and average summer weather. Forecasts are presented as delivered demand, including effects of non-scheduled embedded generators, and native demand, excluding non-scheduled embedded generators.

Table 3.14: 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 growth scenario. 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											
2000/01	1,457	2,962	2,055	2,876	8,697	1,187		1,659	14,754	2,531	**38,179**
2001/02	1,536	2,971	2,219	3,069	8,948	1,257		1,717	15,515	2,663	**39,896**
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**
Projected 2008/09	1,837	3,162	2,892	3,225	10,071	1,443	1,799	94	19,653	3,404	**47,580**
Forecasts											
2009/10	2,038	3,461	3,195	3,115	10,422	1,562	1,650	89	19,629	3,426	**48,588**
2010/11	2,143	3,592	3,519	3,289	10,639	1,654	1,804	90	20,391	3,560	**50,682**
2011/12	2,268	3,730	3,994	4,006	10,990	1,715	1,864	91	21,155	3,693	**53,505**
2012/13	2,346	3,791	4,261	4,083	11,070	1,764	1,924	92	21,872	3,818	**55,019**
2013/14	2,415	3,860	4,507	4,160	11,310	1,810	1,982	93	22,698	3,962	**56,797**
2014/15	2,487	3,928	4,622	4,222	11,589	1,861	2,040	94	23,440	4,092	**58,374**
2015/16	2,558	3,996	4,706	4,284	11,891	1,913	2,098	95	24,131	4,212	**59,884**
2016/17	2,630	4,064	4,851	4,345	12,142	1,967	2,156	96	24,916	4,349	**61,515**
2017/18	2,698	4,132	4,939	4,406	12,399	2,021	2,214	97	25,803	4,504	**63,213**
2018/19	2,766	4,200	5,028	4,466	12,657	2,075	2,272	98	26,691	4,659	**64,912**

Table 3.15: Annual Native Energy by Zone

Actual and Forecast Annual Native Energy (GWh) delivered from the transmission network including from embedded scheduled generators in each zone for the medium growth scenario. This excludes effects of non-scheduled embedded generators. 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 on line 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**
Projected 2008/09	1,837	3,320	3,015	3,510	10,071	1,450	2,074	94	19,773	3,404	**48,548**
Forecasts											
2009/10	2,069	3,641	3,326	3,404	1,576	1,899	10,422	89	19,771	3,438	**49,636**
2010/11	2,173	3,772	3,650	3,579	1,668	2,053	10,639	90	20,535	3,571	**51,730**
2011/12	2,299	3,910	4,124	4,296	1,729	2,113	10,990	91	21,298	3,704	**54,554**
2012/13	2,376	3,971	4,391	4,373	1,777	2,173	11,070	92	22,016	3,829	**56,068**
2013/14	2,446	4,040	4,637	4,450	1,823	2,231	11,310	93	22,842	3,972	**57,845**
2014/15	2,517	4,108	4,752	4,512	1,875	2,289	11,589	94	23,585	4,101	**59,422**
2015/16	2,589	4,176	4,836	4,573	1,927	2,347	11,891	95	24,276	4,222	**60,932**
2016/17	2,660	4,244	4,981	4,635	1,980	2,405	12,142	96	25,062	4,358	**62,563**
2017/18	2,729	4,312	5,070	4,696	2,034	2,463	12,399	97	25,949	4,513	**64,262**
2018/19	2,797	4,380	5,159	4,756	2,089	2,520	12,657	98	26,837	4,667	**65,960**

Table 3.16: 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 growth scenario. 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											
2000	179	354	271	423	986	198	312		2,430	454	**5,609**
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		3,284	598	**6,891**
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**
Forecasts											
2009	233	334	337	409	1,207	236	341	15	3,833	677	**7,622**
2010	226	340	359	419	1,215	249	356	16	3,923	689	**7,792**
2011	236	350	393	440	1,247	263	372	16	4,084	713	**8,115**
2012	248	367	430	535	1,289	274	386	16	4,211	715	**8,472**
2013	258	372	496	546	1,298	283	397	17	4,401	729	**8,797**
2014	268	377	538	556	1,325	293	423	17	4,562	751	**9,110**
2015	278	382	577	564	1,355	303	433	17	4,718	766	**9,392**
2016	288	386	610	571	1,392	313	444	18	4,896	782	**9,701**
2017	298	392	654	581	1,420	323	454	18	5,091	806	**10,038**
2018	309	397	698	590	1,447	333	464	19	5,264	830	**10,352**

Table 3.17: State Winter Peak Native Demand by Zone

Actual and Forecast Native 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 growth scenario. This excludes effects of non-scheduled embedded generators. Native demand for winters prior to 2007 is the same as delivered demand. This is due to insignificant amounts of non-scheduled embedded generation on line 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**
Forecasts											
2009	239	348	354	449	1,207	236	371	15	3,849	677	**7,747**
2010	232	354	377	460	1,215	249	386	16	3,939	689	**7,916**
2011	242	364	410	481	1,247	263	402	16	4,101	713	**8,240**
2012	255	381	448	575	1,289	274	416	16	4,228	715	**8,596**
2013	265	386	513	586	1,298	283	427	17	4,417	729	**8,922**
2014	274	391	556	596	1,325	293	453	17	4,579	751	**9,235**
2015	284	396	594	604	1,355	303	463	17	4,735	766	**9,517**
2016	294	400	628	612	1,392	313	474	18	4,913	782	**9,826**
2017	305	405	672	621	1,420	323	484	18	5,108	806	**10,162**
2018	316	411	716	631	1,447	333	494	19	5,281	830	**10,477**

Table 3.18: 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 growth scenario. 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											
2000/01	252	458	294	391	993	195	270		2,540	437	**5,830**
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		3,438	596	**7,388**
2006/07	329	461	452	509	1,164	296	375		3,635	611	**7,832**
2007/08	292	372	386	476	1,193	243	330		3,465	600	**7,357**
Actual 2008/09	280	424	317	459	1,178	278	367	19	3,933	667	**7,922**
Forecasts											
2009/10	332	441	442	485	1,220	262	356	17	4,204	710	**8,471**
2010/11	348	460	485	510	1,249	276	374	18	4,409	738	**8,866**
2011/12	366	484	537	604	1,292	285	388	18	4,643	772	**9,389**
2012/13	381	495	613	617	1,302	293	401	19	4,856	783	**9,758**
2013/14	394	506	665	631	1,330	301	427	19	5,069	814	**10,156**
2014/15	408	517	708	643	1,362	309	438	19	5,258	835	**10,497**
2015/16	421	528	747	654	1,400	318	450	20	5,440	852	**10,829**
2016/17	435	540	799	667	1,429	326	461	20	5,632	871	**11,181**
2017/18	449	551	829	679	1,458	336	472	21	5,841	899	**11,536**
2018/19	463	563	860	691	1,488	345	483	21	6,049	927	**11,890**

Table 3.19: State Summer Peak Native Demand by Zone

Actual and Forecast Native 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 growth scenario. This excludes effects of non-scheduled embedded generators. Native demand for summers prior to 2006/07 is the same as delivered demand. This is due to insignificant amounts of non-scheduled embedded generation on line 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	3,493	600	**7,444**
2008/09	280	423	331	486	1,178	278	397	17	3,964	667	**8,021**
Forecasts											
2009/10	338	471	473	515	1,220	264	384	17	4,236	710	**8,628**
2010/11	354	489	516	539	1,249	277	402	18	4,440	738	**9,023**
2011/12	372	513	567	633	1,292	286	416	18	4,675	772	**9,545**
2012/13	387	524	644	647	1,302	294	429	19	4,888	783	**9,915**
2013/14	400	535	695	660	1,330	302	455	19	5,101	814	**10,313**
2014/15	414	546	739	672	1,362	311	466	19	5,289	835	**10,654**
2015/16	428	557	778	684	1,400	319	478	20	5,471	852	**10,986**
2016/17	441	570	830	697	1,429	328	489	20	5,664	871	**11,338**
2017/18	455	581	860	709	1,458	337	500	21	5,873	899	**11,692**
2018/19	469	592	891	721	1,488	347	511	21	6,081	927	**12,047**

3.6 Daily and Annual Load Profiles

The daily load profiles for the Queensland region on the days of 2008 winter and 2008/09 summer peak demand delivered from the transmission network and embedded scheduled generators are shown in Figure 3.10.

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 3.11 for the 2007/08 financial year.

Figure 3.10: Summer and Winter Peaks 2008/09

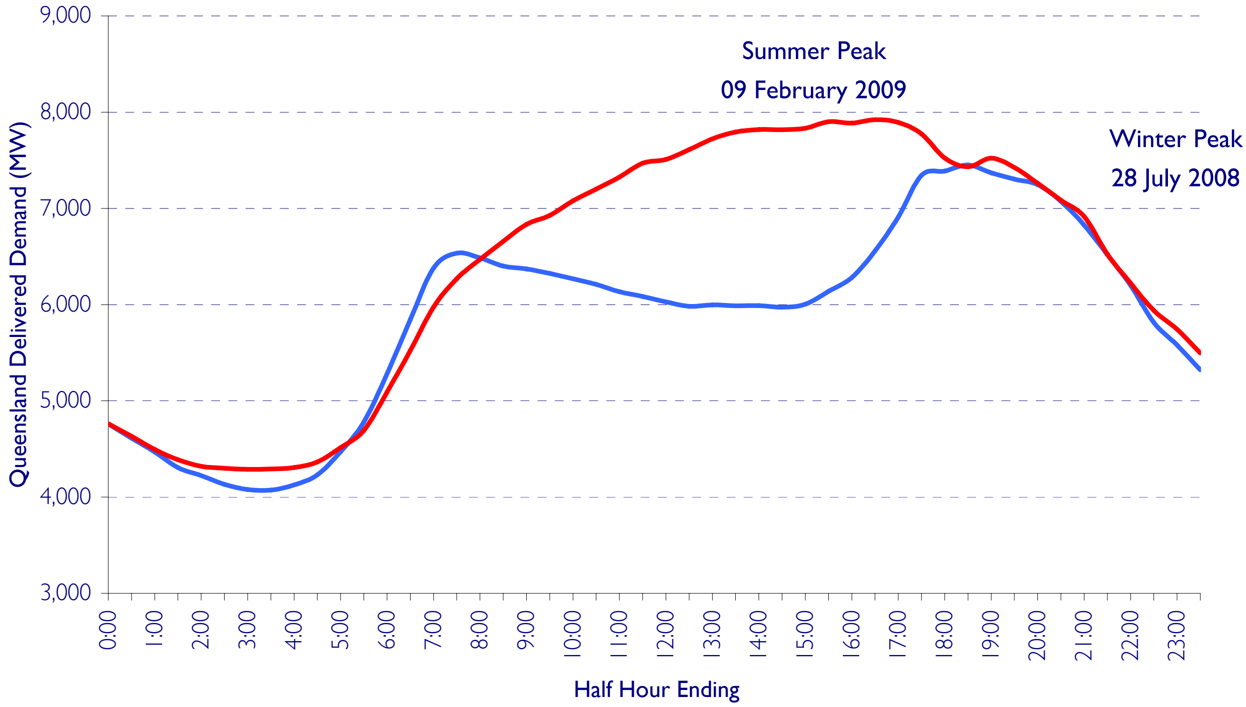
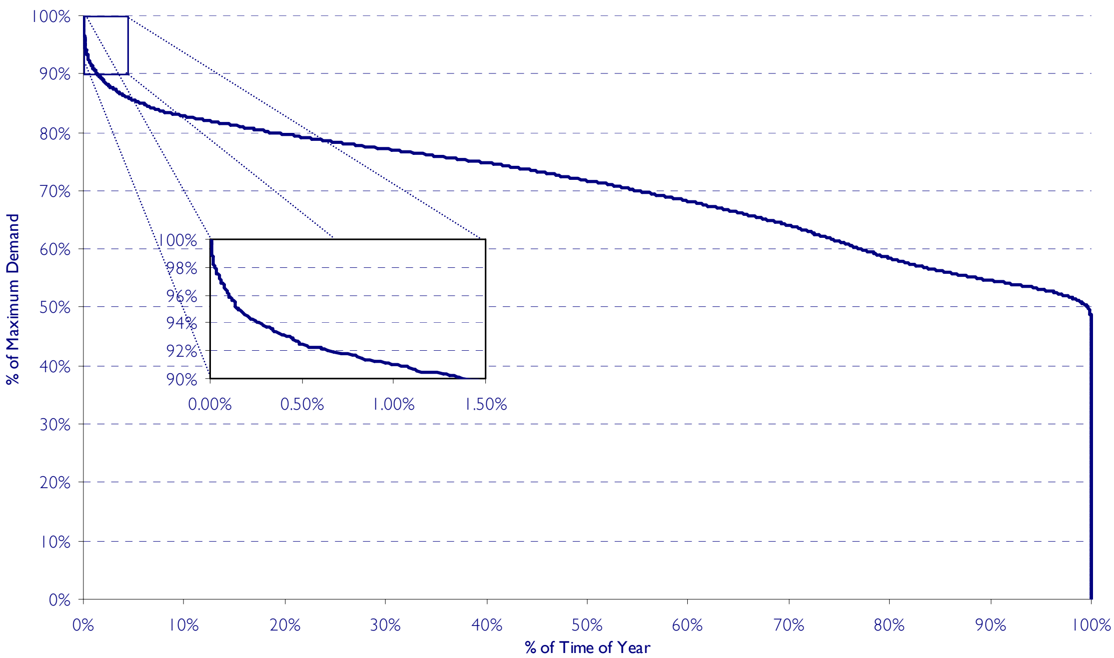


Figure 3.11: Cumulative Annual Load Duration 2007/08



Powerlink

4 Intra-Regional Committed Network Augmentations

4.1 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 4.1 and Figure 4.2 have been updated to include the recently completed augmentations outlined in this chapter.

4.2 Committed Transmission Projects

Table 4.1 lists transmission network developments commissioned since Powerlink's 2008 Annual Planning Report (APR) was published.

Table 4.2 lists transmission network developments which are committed and under construction at June 2009.

Table 4.3 lists transmission connection works that have been commissioned since Powerlink's 2008 APR was published.

Table 4.4 lists new transmission connection works for supplying loads which are committed and under construction at June 2009. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 4.5 lists network replacements which are committed and under construction at June 2009.

Table 4.1: Commissioned Transmission Developments

Commissioned since June 2008

Project	Purpose	Zone Location	Date Commissioned
Major Developments			
Townsville South to Townsville East 132kV line and Townsville East 132/66kV Substation	Increase supply capability to the Townsville area	Ross	July 2008
Broadsound to Nebo 275kV line	Increase supply capability to North, Ross and Far North Queensland zones	North	October 2008
Woolooga 275kV SVC	Increases supply capability between Central and South Queensland	Wide Bay	November 2008
Abermain 275/110kV Substation	Increase supply capability to the Ipswich area	Moreton	March 2009
Greenbank 275kV SVC	Capacitive compensation to meet increasing reactive demand	Moreton	December 2008
Murarrie second 275/110kV transformer (1)	Increase supply capability to the Brisbane CBD and Australia Trade Coast	Moreton	December 2008
South Pine 275kV SVC	Capacitive compensation to meet increasing reactive demand	Moreton	December 2008
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 and North	New arrangements established from mid 2008
Minor Developments			
Edmonton 30MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Far North	December 2008
El Arish 132/22kV Substation	Increase supply capability to Mission Beach	Far North	February 2009
South Pine third 120MVAr 275kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton	December 2008

Note:

(1) The associated work was completed in December 2008 as part of the coordinated work schedule for Belmont 110kV Substation replacement.

Table 4.2: Committed Transmission Developments

Committed and under construction at June 2009

Project	Purpose	Zone Location	Proposed Commissioning Date
Major Developments			
Ross to Yabulu South 275kV line and Yabulu South Substation	Increase supply capability to the Townsville area	Ross	Winter 2009
Nebo to Strathmore to Ross 275kV lines	Increase supply capability to North, Ross and Far North Queensland zones	North and Ross	Progressively from winter 2009 to 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
Bouldercombe to Pandoin 132kV line and Pandoin 132/66kV Substation	Increase supply capability to Rockhampton City and Keppel Coast	Central West	Summer 2009/10
Larcom Creek 275/132kV Substation	Increase supply capability to the Gladstone area	Gladstone	Summer 2009/10
Palmwoods 132/110kV transformer augmentation	Increase supply capacity to the Caboolture and Beerwah area	Moreton	Summer 2009/10
South Pine 275/110kV transformer augmentation	Increase supply capability to North East Brisbane	Moreton	Summer 2009/10
South Pine to Sandgate 275kV line	Increase supply capability to North East Brisbane	Moreton	Summer 2009/10
Minor Developments			
Alligator Creek 132/33kV Substation expansion	Increase supply capability to Hay Point, Dalrymple Bay and south of Mackay	North	Winter 2009
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
Tarong 200MVAr 275kV capacitor bank	Increase supply capability to South West and South East Queensland	South West	Summer 2009/10
South Pine fourth 120MVAr 275kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton	Summer 2009/10
Mt England second 120MVAr 275kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton	Summer 2009/10
Greenbank 200MVAr 275kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton	Summer 2009/10
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

Table 4.3: Commissioned Connection Works

Commissioned since June 2008

Project	Purpose	Zone Location	Date Commissioned
QR Bolingbroke Rail Supply	Increase supply capability to Bolingbroke rail site	North	May 2009
QAL 132/33kV Substation	New connection point to QAL	Gladstone	August 2008
Oakey 110/33kV Substation	New connection point to Ergon Energy	South West	July 2008
Braemar 2 Power Station connection	New connection to Braemar 2 Power Station	Bulli	April 2009
Darling Downs Power Station connection	New connection to Darling Downs Power Station	Bulli	June 2009
Loganlea 110kV connection for Browns Plains	Increase supply capability to Browns Plains	Moreton	November 2008

Table 4.4: Committed Connection Works

Committed and under construction at June 2009

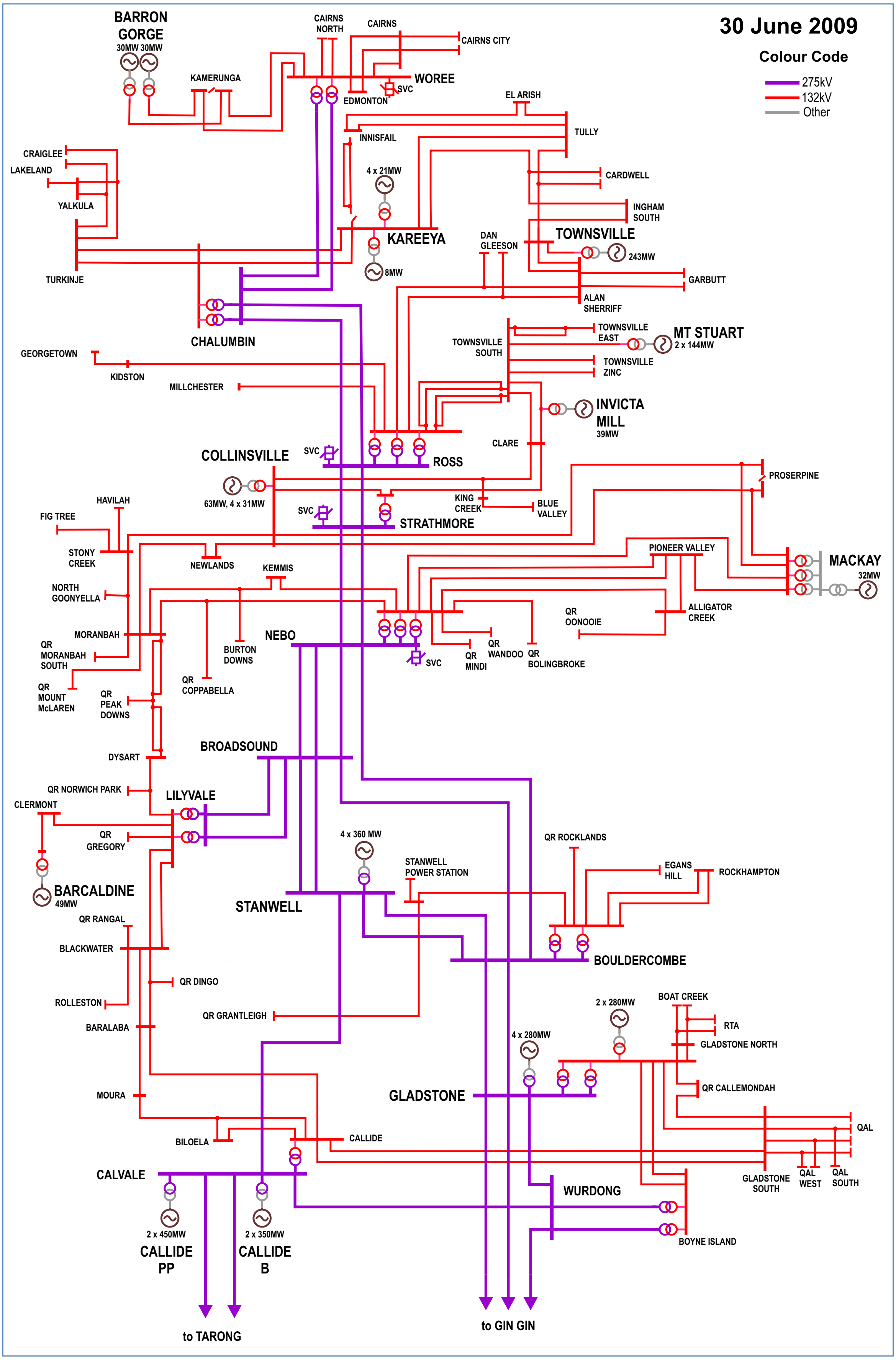
Project	Purpose	Zone Location	Proposed Commissioning Date
Mt Stuart Power Station unit 3 connection	Connection of new generation unit	Ross	Summer 2009/10
Alligator Creek 132kV connection for Louisa Creek	Provide supply to new Ergon Energy substation	North	Winter 2009
Moranbah 132kV connection for Broadlea	Increase supply capability to Broadlea	North	Summer 2010/11
Pandoin 132kV connection for Keppel	Provide supply to new Ergon Energy substation	Central West	Summer 2009/10
Yarwun 132kV Substation	New connection point to Rio Tinto Aluminium (RTA) Yarwun and Ergon Energy Boat Creek Substation	Gladstone	Summer 2009/10
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

Table 4.5: Committed Network Replacements

Committed and under construction at June 2009

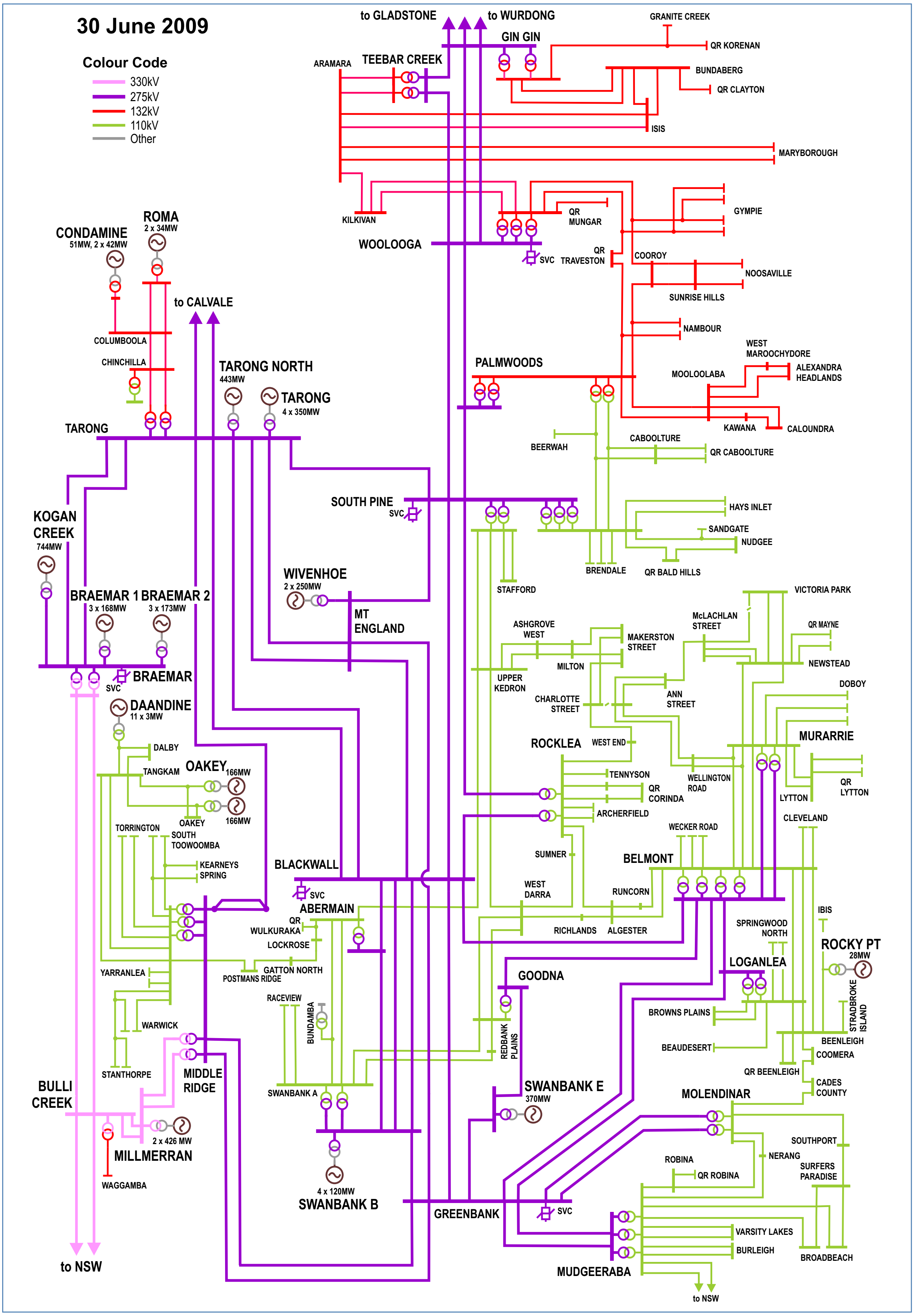
Project	Purpose	Zone Location	Proposed Commissioning Date
Major Replacements			
Innisfail to Edmonton 132kV line replacement	Maintain supply reliability to the Far North zone	Far North	Summer 2009/10
Clare Substation primary plant replacement	Maintain supply reliability to the Ross zone	Ross	Summer 2009/10
Ingham to Yabulu 132kV line replacement	Maintain supply reliability to the Ross zone	Ross	Summer 2011/12
Bouldercombe to South Pine overhead earthwire replacement	Maintain supply reliability to southern Queensland	Central West, Gladstone, Wide Bay and Moreton	Progressively from winter 2007
Woolooga primary plant replacement	Maintain supply reliability to the Wide Bay zone	Wide Bay	Summer 2009/10
Gin Gin 275/132kV transformer replacements	Maintain supply reliability to the Wide Bay zone	Wide Bay	Summer 2011/12
Tarong Substation 275kV circuit breaker replacements	Maintain supply reliability to the South West zone	South West	Winter 2009
West Darra 110kV Substation replacement	Maintain supply reliability to the Moreton zone	Moreton	Winter 2009
South Pine 275/110kV transformer replacement and 110kV substation replacement	Maintain supply reliability to the Moreton zone	Moreton	Summer 2009/10
Belmont 275/110kV transformer replacements and 110kV substation replacement	Maintain supply reliability to the Moreton zone	Moreton	Summer 2010/11 Winter 2011
Swanbank 110kV Substation replacement	Maintain supply reliability to the Moreton zone	Moreton	Winter 2011
Minor Replacements			
Abermain 110/33kV transformer replacement	Maintain supply reliability to Ipswich in South East Queensland	Moreton	Winter 2009

Figure 4.1: Existing 275/132kV Network June 2009 – North and Central Queensland



Powerlink

Figure 4.2: Existing 330/275/132/110kV Network June 2009 – South Queensland



5 Intra-Regional Proposed Network Developments Within Five Years

5.1 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 NER Schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years".

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

- A 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;
- 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; and
- 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 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 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 3.10).

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 3.13), 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.

5.2 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 2009 to summer 2011/12 for 50% Probability of Exceedance (PoE) medium economic growth outlook demand forecast outlined in Chapter 3. These sample scenarios, included in Appendix D, 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 (late 2011).

Power flows in Appendix D are based on existing network configuration and committed projects (listed in Table 4.2 and Table 4.4), 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.

5.3 Transfer Capability

5.3.1 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 National Electricity Market Management Company (NEMMCO) 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 D.2 in Appendix D 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 5.8.

5.3.2 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 NEMMCO 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 E. 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 5.4 provides a qualitative description of the main system conditions that affect capability of each grid section.

Table D.1 in Appendix D 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 D.3 to D.20. It also shows the mode of instability that determines the limit.

5.4 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 D, 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 D.3 to D.20 in Appendix D 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 2008 (winter period) and from October 2008 to March 2009 (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 D.1 in Appendix D 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 D.3 to D.20. 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.

5.4.1 Far North Queensland Grid Section

Maximum power transfer across the Far North Queensland grid section is set by voltage stability associated with an outage of a Ross to Chalumbin 275kV circuit.

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

- The ratio of Far North Queensland to northern Queensland demand;
- Generation in the Far North Queensland zone; and
- Local reactor and capacitor banks on line.

Local hydro generation reduces transfer capability, but allows more demand to be securely supported in the Far North Queensland 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 Far North Queensland grid section over the period April 2008 to March 2009 is summarised in Table 5.1.

Table 5.1: Far North Queensland Grid Section Constraint Times for April 2008 - March 2009

FNQ Grid Section	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	0.00	0.00
October 2008 to March 2009	0.33	0.01

Power flows across this grid section can be higher than shown in Figures D.3 to D.20 of Appendix D 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 Far North Queensland is lower than forecast.

In 2007, Powerlink installed a second 275/132kV transformer at Woree substation and energised the second 275kV Chalumbin to Woree circuit (previously operated at 132kV). Further action to maintain reliability of supply to the Far North Queensland zone in the form of additional reactive power support may again be required from summer 2013/14 onwards. This is discussed in Section 5.5.1.

5.4.2 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 Nebo to Strathmore or 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 largest generating unit in northern Queensland. Stability limitations associated with a 275kV transmission contingency can also constrain power flows.

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

- Highest generation of Townsville or Mt Stuart gas turbines;
- Local capacitor banks available; and
- Local reactors on line.

Information pertaining to duration of constrained operation for the CQ-NQ grid section over the period April 2008 to March 2009 is summarised in Table 5.2.

Table 5.2: CQ-NQ Grid Section Constraint Times for April 2008 - March 2009

CQ-NQ Grid Section (1)(2)	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	6.17	0.14
October 2008 to March 2009	7.08	0.16

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. NEMMCO 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 D.3 to D.20 of Appendix D 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 is committed to the following staged augmentations:

- 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; and
- Stage 3 - Construction of a Strathmore to Ross 275kV transmission line.

Stage 1 has been completed. In addition, ongoing load growth in North Queensland increases power transfers on this grid section. Based on committed generation, it may be economic to augment the CQ-NQ transmission capability from summer 2012/13. These network augmentations are discussed further in Section 5.5.3.

5.4.3 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 4.2).

Information pertaining to duration of constrained operation for the Gladstone grid section over the period April 2008 to March 2009 is summarised in Table 5.3.

Table 5.3: Gladstone Grid Section Constraint Times for April 2008 - March 2009

Gladstone Grid Section (1)	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	19.42	0.44
October 2008 to March 2009	265.75 (2)	6.08

Notes:

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

(2) Power flow across this grid section increased compared to summer 2007/08 due largely to the generation dispatch. Increases in incidence of binding constraints were due to lower Gladstone generation, lower CQ-SQ transfers (due to the easing of water conservation measures at Tarong and Swanbank power stations), higher generation at Callide and higher CQ-NQ transfers.

In response to ongoing load growth in the Gladstone area, Powerlink is proceeding with the establishment of Larcom Creek 275/132kV Substation in the Gladstone State Development Area (GSDA) by summer 2009/10 (refer to Table 4.2).

Power flows across this grid section can be higher than shown in Figures D.3 to D.20 of Appendix D under market dispatch scenarios that lead to higher Callide generation and lower Gladstone generation. 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 5.5.5.

5.4.4 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 on line in these zones increases reactive power support and therefore transfer capability.

The limit equation in Table E.3 of Appendix E shows that the following variables have significant effect on transfer capability:

- Number of generating units on line in the Central West and Gladstone zones; and
- Generation at Gladstone Power Station.

Information pertaining to the duration of constrained operation for the CQ-SQ grid section over the period from April 2008 to March 2009 is summarised in Table 5.4.

Table 5.4: CQ-SQ Grid Section Constraint Times for April 2008 - March 2009

CQ-SQ Grid Section (1)	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	3.25	0.07
October 2008 to March 2009	4.58	0.10

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 D.3 to D.20 of Appendix D 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.

5.4.5 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 (including northerly flow on QNI), to the rest of the State.

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 (for an outage of the respective parallel circuit). 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 duration of constrained operation for the South West grid section over the period April 2008 to March 2009 is summarised in Table 5.5.

Table 5.5: South West Queensland Grid Section Constraint Times for April 2008 - March 2009

South West Grid Section	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	0.00	0.00
October 2008 to March 2009	0.58	0.01

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

Following the commissioning of additional generation at Braemar 2 and Darling Downs power stations, sufficient generation exists in the Bulli zone to encroach transfer limits. In such circumstances, NEMDE will manage 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. This is discussed in Section 5.5.6.

5.4.6 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 South 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.

Depending on generation patterns and power system conditions, one of five critical contingencies can limit maximum secure power transfer across this grid section. These contingencies are:

- Calvale to Tarong 275kV circuit;
- Swanbank E generating unit;
- Wivenhoe generating unit;
- Woolooga to Palmwoods 275kV circuit; and
- Tarong to Blackwall 275kV circuit.

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

- Transfer on QNI and generation in the South West and Bulli zones;
- Number of generators on line in the Moreton zone;
- Generation in the Moreton zone; and
- Capacitive compensation levels on the Gold Coast and Moreton zones.

There is inter-dependence between the CQ-SQ transfer and the Tarong transfer capability. High power flows between Central and South 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 duration of constrained operation for the Tarong grid section over the period April 2008 to March 2009 is summarised in Table 5.6.

Table 5.6: Tarong Grid Section Constraint Times for April 2008 - March 2009

Tarong Grid Section	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	0.00	0.00
October 2008 to March 2009	0.00	0.00

Based on the sample generation scenarios shown in Figures D.3 to D20 of Appendix D, 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 recommended solutions are discussed in Section 5.5.7.

5.4.7 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 E.5 of Appendix E shows that the following variables have significant effect on transfer capability:

- Number of generating units on line in Moreton zone;
- Loading of Terranora Interconnector;
- Capacitive compensation levels on the Gold Coast and Moreton zones; and
- The ratio of the Moreton to the Gold Coast demand.

Voltage limits are higher when more Swanbank B or Swanbank E units are on line. 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 duration of constrained operation for the Gold Coast grid section over the period April 2008 to March 2009 is summarised in Table 5.7.

Table 5.7: Gold Coast Grid Section Constraint Times for April 2008 - March 2009

Gold Coast Grid Section	Time Equation Bound (Hours)	Proportion of Time Constraint Equation Bound (%)
April to September 2008	0.00	0.00
October 2008 to March 2009	0.00	0.00

Power flows across this grid section can be higher than shown in Figures D.3 to D.20 of Appendix D 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 2014 onwards. This is discussed in Section 5.5.8.

5.4.8 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; and
- Oscillatory stability upper limit of 1,078MW (conditional on availability of on line 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; and
- Oscillatory stability upper limit of 700MW.

Powerlink and TransGrid have undertaken detailed studies and consultation processes to investigate whether an upgrade to QNI would be economically justifiable under the Australian Energy Regulator's (AER's) Regulatory Test. This is discussed in Section 6.2.3.

5.5 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).

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. This forward planning allows Powerlink adequate time to implement appropriate solutions to maintain a reliable power supply to customers.

Powerlink will consult with 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 5.7 for current and anticipated consultation processes).

5.5.1 Far North Queensland Zone

Far North Queensland Voltage Control

Sufficient capability is forecast to be available in this zone until summer 2013/14. Unstable voltage levels following a critical contingency are forecast to occur from this time without action to augment supply.

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

Non-network solutions may include local generation and/or other demand side management initiatives.

5.5.2 Ross Zone

Supply to Northern and Western Townsville Area (Thuringowa)

Thermal limitations are expected to occur in either of the Ross to Dan Gleeson 132kV circuits under contingency conditions without action to augment supply.

This limitation is being addressed by a committed project consisting of establishing a new 132kV substation at Yabulu South and constructing a Ross to Yabulu South 275kV transmission line for initial operation at 132kV by winter 2009 (refer to Table 4.2).

Townsville Area 132/66kV Transformer Capability

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

A feasible network solution may be the installation of an additional 132/66kV transformer in the Townsville area at an approximate cost of $10 to $15 million, in conjunction with Ergon Energy 66kV works.

Non-network solutions may include local generation and/or other demand side management initiatives.

5.5.3 North Zone

Supply to Bowen Area

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 in the local 66kV distribution network without action to augment supply.

A committed project is under way to address this limitation 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 4.2), followed by connecting the second 132kV circuit at Bowen North Substation by summer 2012/13.

Supply to South Mackay Area

Demand in the South Mackay area has grown strongly and includes the expansion of the coal loading terminals at Dalrymple Bay, Hay Point and consequential increases in electrified rail traffic.

This demand growth results in thermal limitations in the local 33kV distribution network during contingency conditions without action to augment supply.

A committed project is under way to address these limitations. The project comprises expansion of Alligator Creek Substation by Powerlink to provide for the connection of a new 132kV transmission line to Louisa Creek Substation by winter 2009 (refer to Table 4.2).

CQ-NQ Transfer Limit

Summer peak demand requirements in northern Queensland are currently met by transmission network operating in conjunction 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. As a result, Powerlink committed to staged augmentation from Broadsound to Ross Substation (refer to Tables 4.1 and 4.2) 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; and
- 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 (refer to Table 4.1). The Nebo to Strathmore 275kV transmission line is scheduled to be commissioned by winter 2009. 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 4.2).

Following this 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 may occur following a Stanwell to Broadsound contingency from summer 2016/17, without action to augment supply.

In 2002, Powerlink constructed a Stanwell to Broadsound 275kV transmission line with only one of the double circuits strung. A feasible network solution to address the identified limitations may involve stringing the second circuit at an approximate cost of $20 to $40 million. As generation costs are much higher in northern Queensland due to the reliance on liquid fuels, advancing the timing of the augmentation to as early as summer 2012/13 could provide an economic advantage to address this emerging reliability limitation.

Non-network solutions may include favourably located generation and/or other demand side management initiatives.

Supply to Bowen Basin Coal Mining Area

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 in the 132kV network supplying the area by summer 2013/14, without action to augment supply.

A feasible network solution may involve constructing a new 275kV transmission line from Nebo Substation to the Moorvale area and associated 132kV injection into Ergon Energy distribution network. The approximate cost of this option is in the range of $85 to $95 million.

Non-network solutions may include local generation and/or other demand side management initiatives.

5.5.4 Central West Zone

Supply to the Rockhampton Area

Thermal limitations are expected to occur in either of the Bouldercombe to Rockhampton 132kV circuits under contingency conditions without action to augment supply. In addition, voltage and thermal limitations are forecast to occur in the event of single contingencies in the Ergon Energy 66kV network.

A committed project is under way to address these limitations. The project comprises establishment of a new 132/66kV substation at Pandoin and construction of a new Bouldercombe to Pandoin 132kV transmission line by summer 2009/10 (refer to Table 4.2).

Rockhampton Area 275/132kV Transformer Capability

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

A feasible network solution may be the installation of a third 275/132kV transformer at Bouldercombe Substation. The approximate cost of this option is in the range of $10 to $20 million.

Non-network solutions may include local generation and/or other demand side management initiatives.

Supply to Inland Central Queensland Area

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 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.

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 4.2).

5.5.5 Gladstone Zone

Supply to Gladstone Area

The Boyne Island aluminium smelter dominates the load in the Gladstone area, but there is also significant demand at Queensland Alumina, Rio Tinto Aluminium (RTA) Yarwun, and the Boat Creek, Gladstone North, and Gladstone South substations. Moreover, there continues to be several proponents considering developments in the area.

Due to ongoing demand growth in the Gladstone area, Powerlink is proceeding with establishment of Larcom Creek 275/132kV Substation in the GSDA by summer 2009/10 (refer to Table 4.2).

As detailed in Section 5.4.3, thermal limitations may also occur between Central West and Gladstone zones. 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.

A feasible network solution to the identified thermal limitation may involve construction of a 275kV transmission line within the Central West zone or between Central West and Gladstone zones at an approximate cost of $90 to $150 million.

Non-network solutions may include favourably located generation and/or other demand side management initiatives.

Gladstone Area Harmonics

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.

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 4.2).

5.5.6 Bulli and South West Zones

South West Queensland Transfer Limit

Maximum power transfer across the Bulli to South West 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 the Queensland region 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 NEMMCO 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 levels at Braemar Substation are expected to be just within plant rating, following the connection of Braemar 2 and Darling Downs power stations (refer to Table F.3 in Appendix F). 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.

Powerlink published a Final Report, *Supply to South West and South East Queensland*, in June 2009 recommending a feasible network solution that addresses the forecast thermal and voltage stability limitations. The solution to address the limitations in the Bulli and South West zones comprises:

- Installing 330kV shunt 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; and
- 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.

No non-network solutions were identified as part of Powerlink's detailed consultation process.

5.5.7 Moreton Zone

CQ-SQ Transfer Limit

The CQ-SQ transmission capability must at minimum meet the shortfall between the South Queensland load and South Queensland generation (including maximum secure northerly power transfer from QNI and Terranora Interconnector). Due to ongoing demand growth, South Queensland may require increased power transfer between CQ-SQ where future generation developments do not locate in the South Queensland area. Based on committed generation, network limitations between Central and South Queensland may occur unless action is taken to augment supply from 2013.

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 $80 to $90 million, or an additional 275kV transmission line development between Central and South Queensland at an approximate cost $310 to $410 million.

Non-network solutions may include local generation and/or other demand side management initiatives.

North Sunshine Coast Area

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 ENERGEX 132kV network between Woolooga and Gympie during critical 132kV network outages without action to augment supply.

A feasible least cost network solution has been identified involving construction of a new 275kV transmission line from Woolooga to a 275/132kV substation in the north Sunshine Coast area (Cooroy South) at an approximate cost of $90 to $100 million.

Sunshine Coast 132/110kV Transformer Capability

Palmwoods and South Pine substations supply the Caboolture/Beerwah area via the ENERGEX 110kV network. Due to ongoing demand growth in the area, the transfer capacity from Palmwoods Substation is forecast to be limited by the 132/110kV transformer ratings from summer 2009/10 under a single credible contingency.

A committed project is under way to address this limitation. The project comprises the construction of a new 132/110kV transformer at Palmwoods Substation by summer 2009/10 (refer to Table 4.2).

Supply to North Brisbane

High demand growth is forecast to continue in the North Brisbane area as a result of population growth, infrastructure projects and extensive commercial/industrial development such as the Brisbane Airport commercial precinct. As a result, thermal limitations are expected to occur in ENERGEX 110kV network between South Pine and Nudgee under contingency conditions by summer 2009/10, without action to augment supply. A further thermal limitation is expected to occur in transformer capacity at South Pine Substation in the next five years without action to augment supply.

A committed project is under way to address these limitations. This project comprises construction of a South Pine to Sandgate 275kV transmission line, together with increased transformer capacity at South Pine Substation. Splitting the 110kV bus to create two 275/110kV switchyard sections is also required as a measure to address fault levels at South Pine Substation. These works are scheduled for completion by summer 2009/10 (refer to Table 4.2).

South East Queensland Voltage Control

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 and ancillary services arrangements.

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. The committed projects to summer 2009/10 comprise installation of shunt capacitor banks at Tarong (200MVAr), Mt England (120MVAr), Greenbank (200MVAr) and South Pine (120MVAr) substations. This is followed by installation of shunt capacitor banks at Ashgrove West (50MVAr), Loganlea (50MVAr) and Belmont (120MVAr) substations by summer 2011/12 (refer to Table 4.2).

Moreton 110/11kV Transformer Capability

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 ENERGEX 33kV network in the local area during summer peak demand periods without action to augment supply.

A committed project is under way to address this limitation, comprising installation of a second 110/11kV transformer at Bundamba Substation by summer 2010/11 (refer to Table 4.4).

Supply to Lockyer Valley

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

A feasible network solution may involve establishing a second 110kV supply to ENERGEX Postmans Ridge Substation from Middle Ridge Substation. Part of Powerlink's existing Tarong to Middle Ridge 275kV line may be reconfigured to operate a circuit at 110kV as part of this augmentation, at an approximate cost of $3 to $10 million. Additional ENERGEX works are required to complete the connection to ENERGEX Postmans Ridge Substation.

Non-network solutions may include local generation and/or other demand side management initiatives.

Supply within South Brisbane Area

The South Brisbane area is defined as the area east of West Darra Substation, north to Murarrie Substation and south to Logan City. Sufficient capability is forecast to be available in this area from summer 2013/14, where transformer and 110kV line limitations to Richlands, Algester and Runcorn substations may occur under critical contingencies without action to augment supply.

A feasible network solution would involve establishing a new 275/110kV substation at Larapinta and constructing associated 110kV transmission lines to the area at an approximate cost of $60 to $80 million.

Supply to South Brisbane, CBD and Eastern Suburbs

Sufficient capability is forecast to be available until summer 2013/14, when thermal limitations are expected to occur on the 275kV transmission lines from Blackwall to Belmont and Greenbank to Loganlea, under contingency conditions without action to augment supply.

A feasible network solution may involve construction of a new 275kV transmission line from a point east of the transmission corridor between Blackwall to Swanbank substations, to a point west of the transmission corridor between Loganlea and Belmont substations, together with reconfiguring the existing 275kV transmission lines in the local area, at an approximate cost of $120 to $140 million.

Thermal limitations are also forecast to occur in ENERGEX 110kV network supplying the eastern and western sections of Brisbane CBD by summer 2013/14 without action to augment supply.

A feasible network solution may involve installation of an additional 275/110kV transformer and associated works at Rocklea Substation at an approximate cost of $25 to $35 million, together with ENERGEX 110kV augmentation works into the CBD.

Non-network solutions may include local generation and/or other demand side management initiatives.

Supply to South East Queensland

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. A program of capacitor bank installations to 2011/12 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. In addition, thermal limitations on the Middle Ridge to Greenbank 275kV transmission lines are forecast to be reached by summer 2013/14 without action to augment supply.

Powerlink published a Final Report, *Supply to South West and South East Queensland* in June 2009 recommending a feasible network solution that addresses the forecast thermal and voltage stability limitations. The solution to address the limitations across South East Queensland comprises:

- Installing shunt capacitor banks at Belmont (120MVAr) and South Pine (50MVAr) substations by summer 2012/13; and
- Constructing a new Halys to Blackwall 500kV transmission line (initially operated 275kV) by summer 2013/14.

No non-network solutions were identified as part of Powerlink's detailed consultation process.

5.5.8 Gold Coast Zone

Supply to Gold Coast Area

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 2015/16. A feasible network solution may be the installation of a third 275/110kV transformer at Molendinar Substation at an estimated cost of $20 to $25 million.

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. Subject to the ENERGEX distribution network reinforcement program, a feasible network solution may include replacing an existing Greenbank to Mudgeeraba 275kV circuit with a 275kV double circuit transmission line, at an estimated cost of $90 to $120 million.

Lengthy outages of the Greenbank to Mudgeeraba 275kV circuit would be required for constructing the 275kV transmission line during the winter and shoulder months over a two year period. Investigations indicate that, depending on the ENERGEX distribution network reinforcement program, the ability to schedule the outages to perform the proposed transmission line works may only be feasible for commencement from 2014. Consequently, outage feasibility and constructability requirements could advance the construction of the 275kV double circuit line to 2014, together with the installation of the third 275/110kV transformer at Molendinar Substation mentioned above.

Non-network solutions may include local generation and/or other demand side management initiatives.

5.6 Summary of Forecast Network Limitations

Limitations discussed in Sections 5.4 and 5.5 have been summarised in Table 5.8.

This table provides an outlook (based on demand, generation and committed network development assumptions contained in Chapters 3, 4 and 5) for potential limitations in Powerlink's transmission network over a one, three and five year timeframe.

Table 5.8: 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 voltage control	275kV outages in Far North Queensland may result in unacceptable voltage conditions			2013/14
Supply to northern and western Townsville area (Thuringowa)	Future 132kV network thermal capability limitations in meeting demand growth in northern and western Townsville	2009/10 Committed project in progress (1)		
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 in local 66kV distribution network		Stage 1, 2010/11 Committed project in progress (1)	Stage 2, 2012/13 (4)
Supply to South Mackay area	Due to industrial load growth, voltage and thermal limitations expected to occur in 132/33kV transformers at Alligator Creek as well as the 33kV distribution network under contingency conditions	2009/10 Committed project in progress (1)		
CQ-NQ transfer limit	Voltage, dynamic instability and thermal limitations expected to result from single contingencies during periods of high northern Queensland demand	To 2010/11 Committed projects in progress (1)		2012/13
Supply to Bowen Basin Coal Mining area	Due to potential mining growth, thermal limitations expected to occur in the 132kV network supplying this area			2013/14 (4)

Table 5.8: Summary of Forecast Network Limitations (cont.)

Anticipated Limitation	Reason for Limitation	Time Limitation May Be Reached		
		1 Year Outlook	3 Year Outlook	5 Year Outlook
Central West and Gladstone zones				
Supply to Rockhampton area	Due to demand growth, an outage of one of the Bouldercombe-Rockhampton 132kV circuits expected to result in thermal overloading of the remaining circuit in service	2009/10 Committed project in progress (1)		
Rockhampton Area 275/132kV Transformer Capability	Future 275/132kV transformer capability limitations in Bouldercombe area under contingency conditions			2012/13
Supply to inland Central Queensland area	Due to demand growth, 132kV network between Callide, Biloela and Moura expected to reach thermal capability limitations in the event of a single contingency and may result in unacceptably low voltages in the Moura area		2010/11 Committed project in progress (1)	
Supply to Gladstone area	Due to industrial demand growth, future 275/132kV supply capability limitations are anticipated	2009/10 Committed project in progress (1)		2013/14
	Power transfer limitations out of Central West and Gladstone zones	Currently managed by switching and support arrangements (3)		
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 in SEQ expected to lead to SWQ transfer limit being reached		2010/11 to 2012/13	

Table 5.8: Summary of Forecast Network Limitations (cont.)

Anticipated Limitation	Reason for Limitation	Time Limitation May Be Reached		
		1 Year Outlook	3 Year Outlook	5 Year Outlook
Moreton zone				
CQ-SQ transfer limit	Continued demand growth in South Queensland expected to give rise to binding transfer limits for flows between Central Queensland and South Queensland			2013 onwards (4)
Northern Sunshine Coast area	Demand growth expected to result in thermal limitations in ENERGEX 132kV network between Woolooga and Gympie during a critical 275kV or 132kV outage			2014/15 (5)
Sunshine Coast 132/110kV transformer capability	Transformer limitation forecast in supplying Caboolture and Beerwah Substation from Palmwoods Substation under contingency conditions	2009/10 Committed project in progress (1)		
Supply to North Brisbane	Demand growth expected to result in thermal limitations in ENERGEX 110kV network and Powerlink 275/110kV transformers	2009/10 Committed projects in progress (1)		
South East Queensland voltage control	Increasing reactive demand due to demand growth expected to require 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 ENERGEX 110kV network supplying this area		2011/12	
Supply within South Brisbane area	Due to demand growth, transformer and 110kV transmission line limitations supplying this area are forecast to occur under contingency conditions			2013/14

Table 5.8: Summary of Forecast Network Limitations (cont.)

Anticipated Limitation	Reason for Limitation	Time Limitation May Be Reached		
		1 Year Outlook	3 Year Outlook	5 Year Outlook
Moreton zone (cont.)				
Supply to South Brisbane, CBD and eastern suburbs	Demand growth is forecast to result in thermal limitations in sections of 275kV transmission line from Blackwall to Belmont Substation and from Greenbank to Loganlea Substation as well as the ENERGEX 110kV network supplying eastern and western CBD			2013/14
Supply to South East Queensland	High demand growth expected to result in limitations in supply to South East Queensland area			2012/13 to 2013/14
Gold Coast zone				
Supply to Gold Coast area	Due to demand growth, thermal capacity limitations of a 275/110kV Molendinar transformer due to an outage of a parallel transformer following a critical contingency			2014 onwards

Notes:

(1) Refer to Tables 4.2 and 4.4 - Committed Augmentations.

(2) Refer to Section 5.7 - Proposed Network Developments.

(3) Other action may be required if new loads occur in the supply area.

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

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

5.7 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.

This section focuses on those limitations for which Powerlink intends to implement action or initiate consultation with Registered Participants and interested parties in the near future. Information is also provided on potential connection point proposals.

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.

5.7.1 Processes for Proposed Network Developments

Setions 5.4 to 5.6 of this report identified anticipated network limitations and constraints that may arise in the Queensland transmission network over the next five years. Where action is considered necessary, Powerlink will:

- Notify Registered Participants 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 small network assets. Those that cannot be identified for inclusion in the APR will be the subject of separate consultation with Registered Participants and interested parties;
- Issue detailed information papers outlining emerging network limitations which may assist in identifying non-network solutions as possible genuine alternatives to new large network assets;
- 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; and
- 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.

In response to recent policy changes made by the Ministerial Council on Energy (MCE), the Australian Energy Market Commission (AEMC) released a draft Rule determination that requires the AER to replace the current Regulatory Test with a new methodology known as Regulatory Investment Test for Transmission (RIT-T). This change is expected to occur over the 2009/10 period. Powerlink will continue to use the current Regulatory Test until the RIT-T is promulgated by the AER.

5.7.2 Proposed New Large Network Assets

Proposals for new large network assets 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. Summary information is provided in this APR. Interested parties are referred to consultation documents published on Powerlink's website for further information.

Information on other network limitations that could result in a recommendation to implement a new large network asset, but where consultation on alternative solutions is still under way, is provided in Section 5.7.3.

Committed New Large Network Assets

Interested parties are advised that during 2008/09, Powerlink finalised regulatory processes associated with the new large network assets outlined in Table 5.9.

Table 5.9: New Large Network Asset Consultations Finalised in 2008/09

Project Name	Description of Works	Cost	Expected Commissioning Date
Bowen	Staged construction of a new 132/66kV substation at Bowen North and a Strathmore to Bowen North 132kV transmission line	$83.2M (1)	Progressively 2010-2012
North and Far North Queensland (2)	Construction of the Strathmore to Ross 275kV transmission line and provision of network support services from Origin Energy, CS Energy and CSR Sugar	$183.5M	Summer 2010/11
South East Queensland	Construction of 275kV SVC at South Pine Substation and installation of shunt capacitor banks at Ashgrove West (50MVAr), Loganlea (50MVAr), and Belmont (120MVAr) substations	$35.2M	Progressively to 2011
QNI Upgrade Project (3)	A review of upgrade options and net market benefits in accordance with the AER's Regulatory Test. It was concluded to be premature to commit to an upgrade option	N/A	N/A

Notes:

(1) Joint project with Ergon Energy. Only Powerlink works and costs included in Table 5.9.

(2) Timing based on market benefits (reliability limitation would be later).

(3) Refer to Section 6.2.3 for more information.

5.7.3 Consultation - Proposed New Large Network Assets

Consultation Under Way

Network limitations have been identified that could give rise to a requirement for a proposed new large network asset at a number of locations. Table 5.10 provides a summary of the status of action to address future supply requirements.

Table 5.10: Consultation Under Way

Area	Publication of Application Notice	Publication of Final Report
South West to South East Queensland	March 2009	June 2009

Anticipated Consultation Processes

Other consultation processes likely to be initiated in the next 12 months are summarised in Table 5.11.

Table 5.11: Consultations Likely Within 12 Months

Area (1)
Supply to North Queensland
Supply within Central Queensland/Gladstone Area
Supply to CBD and Greater Brisbane Area

Note:

(1) For further details on each of these limitations refer to Sections 5.4 and 5.5.

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

5.7.4 Connection Point Proposals

Table 5.12 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 5.12: 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
Alligator Creek connection for QR Network Mackay Ports	New supply to QR Network Dalrymple Bay Coal Terminal	North	Winter 2010
Middle Ridge 110kV connection for Postmans Ridge	Second supply to ENERGEX Postmans Ridge Substation	South West and Moreton	Winter 2011
Palmwoods 132kV connection for Pacific Paradise	New supply to ENERGEX Pacific Paradise Substation	Moreton	Summer 2011/12
Loganlea 110kV connection for Jimboomba	New supply to ENERGEX Jimboomba Substation	Moreton	Summer 2012/13
Abermain 110kV connection for Wulkuraka	New supply to ENERGEX Wulkuraka Substation	Moreton	Summer 2012/13
Loganlea 110/33kV transformer augmentation	Increase transformer capacity to meet growing demand	Moreton	Summer 2012/13
South Pine 110kV connection for Strathpine West	New supply to ENERGEX Strathpine West Substation	Moreton	Summer 2012/13
Rocklea 110kV connection for Woolloongabba	New supply to ENERGEX Woolloongabba Substation	Moreton	Summer 2013/14
Molendinar 110kV connection for Southport and Surfers Paradise	New supply to ENERGEX Southport and Surfers Paradise substations	Gold Coast	Summer 2010/11
Molendinar 110/33kV transformer augmentation	Increase transformer capacity to meet growing demand	Gold Coast	Summer 2011/12

5.8 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 5.13 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 5.13: 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 2013/14	$15M (approximately)	Establish a new 132/22kV substation
Cardwell to Ingham 132kV line replacement	Maintain supply reliability to the Ross zone	Ross	Summer 2012/13	$50M (approximately)	New local generation in the Ross zone with distribution network reinforcement
Garbutt to Alan Sherriff 132kV line life extension	Maintain supply reliability to the Ross zone	Ross	Summer 2012/13	$5M (approximately)	New local generation in the Ross zone with distribution network reinforcement
Tully to Cardwell 132kV line replacement	Maintain supply reliability to the Ross zone	Ross	Summer 2013/14	$65M (approximately)	New local generation in the Ross zone with distribution network reinforcement
Proserpine Substation primary plant replacement	Maintain supply reliability to the North zone	North	Winter 2012	$10M (approximately)	Establish a new 132/66kV substation or new local generation with distribution network reinforcement
Collinsville Substation primary plant replacement	Maintain supply reliability to the North zone	North	Winter 2013	$10M (approximately)	Establish a new 132/33kV substation
Callide A Substation primary plant replacement	Maintain supply reliability to the Central West zone	Central West	Summer 2012/13	$25M (approximately)	Establish a new 132kV substation
Gladstone Substation primary plant replacement	Maintain supply reliability to the Gladstone zone	Gladstone	Summer 2012/13	$145M (approximately)	Establish a new 275/132kV substation
Woolooga transformer replacement	Maintain supply reliability to the Wide Bay zone	Wide Bay	Summer 2013/14	$10M (approximately)	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	Winter 2012	$55M (approximately)	Establish a new 275/110kV substation
Richlands Substation primary plant replacement	Maintain supply reliability to the Moreton zone	Moreton	Summer 2012/13	$20M (approximately)	New local generation in the Moreton zone with distribution network reinforcement
Mudgeeraba 110kV Substation replacement	Maintain supply reliability to the Gold Coast zone	Gold Coast	Summer 2013/14	$20M (approximately)	New local generation in the Gold Coast zone with distribution network reinforcement

6 Other Relevant Planning Issues

6.1 Existing and Committed Generation Developments

6.1.1 Generation

Generation in Queensland is principally a combination of coal-fired, gas turbine and hydro electric generators. An increasing number of new generation proposals are being developed for the South West Queensland area with several projects recently being commissioned and committed.

Table 6.1 summarises power stations currently 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 National Electricity Market Management Company (NEMMCO) by the owners of the generators and shows the registered capacity of generating stations.

Table 6.1: Generation Capacity

Existing and Committed Plant Connected to the Powerlink Transmission Network and Embedded Scheduled Generators

Location	Capacity MW Generated (1)					
	Winter 2009	Summer 2009/10	Winter 2010	Summer 2010/11	Winter 2011	Summer 2011/12
Coal-fired						
Collinsville	187	187	187	187	187	187
Stanwell	1,446	1,390	1,453	1,397	1,460	1,404
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Callide A (2)	0	0	0	0	0	0
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	480	480	480	480	480	480
Kogan Creek	744	724	744	724	744	724
Millmerran	852	852	852	852	852	852
Total Coal-fired	**8,832**	**8,756**	**8,839**	**8,763**	**8,846**	**8,770**
Combustion Turbine						
Townsville (Yabulu)	243	235	243	235	243	235
Mt Stuart	288	387	415	387	415	387
Mackay	32	27	32	27	32	27
Barcaldine	49	49	49	49	49	49
RTA Yarwun	-	-	167	152	167	152
Roma	68	54	68	54	68	54
Condamine	135	135	135	135	135	135
Oakey (3)	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 (4)	-	605	630	605	630	605
Total Combustion Turbine	**2,540**	**3,014**	**3,464**	**3,166**	**3,464**	**3,166**
Hydro Electric						
Barron Gorge	60	60	60	60	60	60
Kareeya (including Koombooloomba)	94	94	94	94	94	94
Wivenhoe (5)	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	**12,065**	**12,463**	**12,996**	**12,622**	**13,003**	**12,629**

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

(4) Darling Downs Power Station is expected to be commissioned in summer 2009/10.

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

6.2 Changes to Supply Capability

6.2.1 Generation

No new generation capacity has been committed in the Queensland region since the 2008 Annual Planning Report (APR). Queensland Gas Company is well advanced in commissioning the Condamine 135MW combined cycle gas-fired power station. ERM Power and Southern Power Generation are also well advanced in commissioning the Braemar 2 power station. Both power stations are located within the Surat Basin area in south west Queensland.

Additional generation is still scheduled to be commissioned by proponents as follows:

- Mt Stuart Power Station third unit (liquid fuel);
- Rio Tinto Aluminium (RTA) Yarwun Power Station (gas); and
- Darling Downs Power Station (combined cycle gas).

These recently commissioned and committed generators in Queensland have been incorporated within Table 6.1.

6.2.2 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 set by thermal ratings, voltage stability, transient stability and oscillatory stability (as detailed within Section 5.4.8).

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.

6.2.3 Interconnector Upgrades

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 relating to several 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.

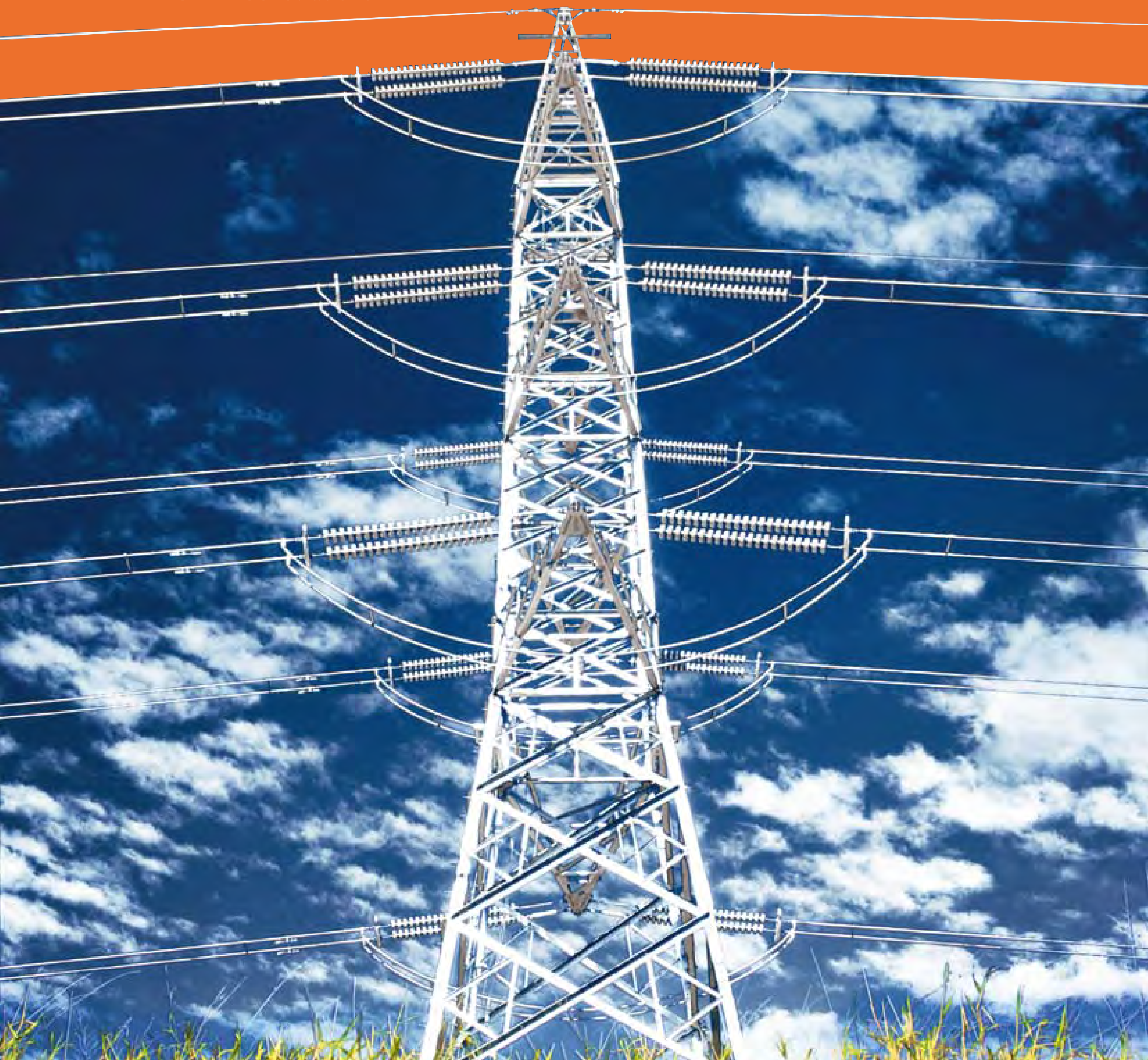
The Final Report indicated that the installation of series compensation with an estimated cost of around $120 million provided the highest net market benefits in the majority of scenarios considered. The optimum timing under the most plausible scenario is 2015/16.

Based on that timing, TransGrid and Powerlink considered it premature to recommend an upgrade option. However, both organisations are continuing to monitor developments which could impact on the scope and timing of a potential upgrade of the interconnection, and will proceed with further work where material changes to market developments occur.

6.3 Supply Demand Balance

The outlook for the supply demand balance for the Queensland region was published in the NEMMCO 2008 Statement of Opportunities (SOO). As part of the normal annual planning cycle, NEMMCO will publish a revised outlook in the 2009 SOO. Interested parties who require information regarding the future supply demand balance should consult that document.

Appendices



Appendix A – National Transmission Flow Path Augmentations

This appendix provides information relating to committed, routine and conceptual augmentations that impact the capability of Queensland National Transmission Flow Paths (NTFPs).

These classes of augmentations and the purpose of the information within this appendix is described in Chapter 2.

Table A.1 provides information on committed augmentations for NTFPs within Queensland. The impact of these projects on transmission limits and constraint equations likely to be affected by these projects are also provided within this table.

Tables A.2 and A.3 provide information on routine network augmentations including alternative projects and the potential impacts of these augmentations to transmission limits. The timing of these augmentations may alter depending on economic growth, new entry generation, generation retirements or demand side management.

Table A.4 provides information on conceptual augmentations which increase the inter-network flow path capability between Queensland and New South Wales.

Tables A.5 and A.6 provide information on the sensitivity of routine augmentation timings to economic growth, generation and demand side management.

It should be noted that some of the information presented within these tables is indicative only and based on preliminary power system studies. As projects reach higher levels of certainty, more detailed and comprehensive studies are carried out to more accurately define the scope of the augmentation and extent of power transfer capability increase.

Table A.1: Committed Augmentations or Augmentations Currently Under Consultation (1)

Augmentation	Expected Timing	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers (2)
Central to North Queensland Flow Path (CQ to NQ)			
Nebo to Strathmore 275kV double circuit line	Winter 2009	Increases the CQ-NQ limit by around 80 to 160MW	Q:NIL_CN1
Strathmore to Ross 275kV double circuit line	Summer 2010/11	Increases the CQ-NQ limit by around 365MW	Q:NIL_CN1
South West to South East Queensland Flow Path (SWQ to SEQ)			
Tarong and Greenbank 275kV 200MVAr capacitor banks, and Mt England and South Pine 275kV 120MVAr capacitor banks	Summer 2009/10	Increases the Tarong voltage stability limit by around 210MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 75MW	Q^NIL_GC
Belmont 275kV 120MVAr capacitor bank, and Ashgrove West and Loganlea 110kV 50MVAr capacitor banks	Summer 2011/12	Increases the Tarong voltage stability limit by around 55MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 20MW	Q^NIL_GC
Middle Ridge two 330kV 120MVAr line connected capacitor banks and Millmerran 330kV 200MVAr capacitor bank	Summer 2011/12	Preserves the existing transfer capability of the South West Queensland voltage stability limit	Q>Q_SWQ
Western Downs and Halys substations and Western Downs to Halys and Braemar 275kV double circuit line	Summer 2012/13	Increases the South West Queensland thermal limit by around 800MW	Q>Q_SWQ
Belmont 275kV 120MVAr capacitor bank and South Pine 110kV 50MVAr capacitor bank	Summer 2012/13	Increases the Tarong voltage stability limit by around 40MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 15MW	Q^NIL_GC
Halys to Blackwall 500kV double circuit line (initially operating at 275kV)	Summer 2013/14	Increases the South West Queensland thermal limit by around 800MW	Q>Q_SWQ
		Increases the Tarong voltage stability limit by around 350MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 75MW	Q^NIL_GC

Notes:

(1) This table includes augmentations currently under consultation as of 30 June 2009.

(2) These constraint identifiers correspond to the forward looking constraints set used within the NEMMCO 2008 ANTS verification studies (included within the NEMMCO SOO/ANTS CD).

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

Table A.2: Routine Augmentations (1)

Augmentation	Indicative Cost	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers (2)
Central to North Queensland Flow Path (CQ to NQ)			
Stanwell to Broadsound 275kV stringing of an additional circuit	$30M (approximately)	Increases the CQ-NQ limit by around 200 to 300MW	Q:NIL_CNI
Calvale to Stanwell 275kV double circuit line	$120M (approximately)	Preserves the CQ-NQ thermal transfer capability	Q:NIL_CNI
		Decreases the Gladstone limit (circuit 871) post-contingent flow	Q>PRE855_871CAL/GL_ST (3)
Broadsound to Nebo 275kV series capacitors	$60M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Nebo to Strathmore 275kV series capacitors	$60M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Strathmore to Ross 275kV series capacitors	$60M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Broadsound to Nebo 275kV double circuit line	$150M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Nebo to Strathmore 275kV double circuit line	$150M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Strathmore to Ross 275kV double circuit line	$190M (approximately)	Increases the CQ-NQ limit by around 200MW	Q:NIL_CNI
Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	$150M (approximately)	Preserves the CQ-NQ thermal transfer capability	Q:NIL_CNI
		Increases the Gladstone thermal limit (circuit 871) by around 1500MW	Q>PRE855_871CAL/GL_ST (3)
Central to South West and South East Queensland Flow Paths (CQ to SWQ and CQ to SEQ)			
Calvale to Tarong 275kV mid-point switching station (Auburn River) and series capacitors	$90M (approximately)	Increases the CQ-SQ transient stability limit by around 600MW	Q^NIL_ICS/2CS (3), Q_CS<2100
Calvale to Tarong 275kV double circuit line (western route)	$310M (approximately)	Increases the CQ-SQ limit by around 750MW	Q^NIL_ICS/2CS (3), Q_CS<2100

Table A.2: Routine Augmentations (1) (cont.)

Augmentation	Indicative Cost	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers (2)
Calvale to South Pine 275kV double circuit line (eastern route)	$410M (approximately)	Increases the CQ-SQ limit by around 950MW	Q^NIL_ICS/2CS (3), Q_CS<2100
Central to South Queensland 500kV double circuit line (western route)	$780M (approximately)	Increases the CQ-SQ limit by around 1600MW	Q^NIL_ICS/2CS (3), Q_CS<2100
South West to South East Queensland Flow Path (SWQ to SEQ)			
Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV	$260M (approximately)	Increases the South West Queensland thermal limit by around 1800MW	Q>Q_SWQ
Halys to Greenbank 500kV double circuit line (initially operating at 275kV)	$385M (approximately)	Increases the Tarong voltage stability limit by around 350MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the 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	$185M (approximately)	Increases the South West Queensland thermal limit by around 1100MW	Q>Q_SWQ
		Increases the Tarong voltage stability limit by around 350MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the 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	$405M (approximately)	Increases the South West Queensland thermal limit by around 4200MW	Q>Q_SWQ
		Increases the Tarong voltage stability limit by around 2400MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 100MW	Q^NIL_GC
Halys to North Moreton 500kV double circuit line	$420M (approximately)	Increases the Tarong voltage stability limit by around 3000MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 80MW	Q^NIL_GC

Table A.2: Routine Augmentations (1) (cont.)

Augmentation	Indicative Cost	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers (2)
Halys to South Moreton 500kV double circuit line	$500M (approximately)	Increases the Tarong voltage stability limit by around 3000MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 120MW	Q^NIL_GC
South East Queensland to Northern NSW Flow Path (SEQ to NNS)			
Molendinar 3rd 275/110kV 375MVA transformer and associated substation works	$25M (approximately)	Increases the Gold Coast voltage stability limit by around 15MW	Q^NIL_GC
		Increases the Tarong voltage stability limit by around 15MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
Greenbank to Mudgeeraba 275kV single circuit rebuild to double circuit and Mudgeeraba two 275/110kV transformers upgrade	$105M (approximately)	Increases the Gold Coast voltage stability limit by around 30MW	Q^NIL_GC
		Increases the Tarong voltage stability limit by around 25MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
Mudgeeraba 3rd 275/110kV transformer upgrade	$10M (approximately)	Increases the Gold Coast voltage stability limit by around 15MW	Q^NIL_GC
		Increases the Tarong voltage stability limit by around 15MW	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)

Notes:

(1) The estimated impacts of routine augmentations within NTS zones, such as capacitor banks, transformers and line reinforcements, which maintain or increase voltage stability limits by reactive compensation or reducing reactive losses are provided in aggregate form within Table A.3.

(2) These constraint identifiers correspond to the forward looking constraints set used within the NEMMCO 2008 ANTS verification studies (included within the NEMMCO SOO/ANTS CD).

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

Table A.3: Routine Augmentations within Zones (1)

Augmentation	Potential Timing	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers (2)
Central to North Queensland Flow Path (CQ to NQ)			
Augmentations within the North Queensland zone	Summer 2012/13 onwards	Preserves the transfer capability of the CQ-NQ voltage stability limit component	Q:NIL_CN1
South West to South East Queensland Flow Path (SWQ to SEQ)			
Augmentations within the South East Queensland zone	Summer 2014/15 onwards	Increases the Tarong voltage stability limit by around 250MW per year	Q^^NIL_TR_CLTR/SWE/WV/WOPW/TRBK (3)
		Increases the Gold Coast voltage stability limit by around 50MW per year	Q^NIL_GC

Notes:

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

(2) These constraint identifiers correspond to the forward looking constraints set used within the NEMMCO 2008 ANTS verification studies (included within the NEMMCO SOO/ANTS CD).

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

Table A.4: Conceptual Augmentations

Augmentation	Indicative Cost	Potential Impact on Network Limits	Potentially Affected Constraint Identifiers
South West Queensland to Northern NSW Flow Path (SWQ to NNS)			
Armidale second 330kV SVC	$35M (approximately)	Increases the voltage stability limits by around 150MW in the northerly direction	See Note (1)
High speed protection schemes and Loy Yang braking resistor	$35M (approximately)	Increases the voltage and stability limits by up to 300MW in the southerly direction	See Note (1)
Bulli Creek to Dumaresq and Dumaresq to Armidale 330kV thyristor controlled component series capacitors (and supporting works)	$120M (approximately)	Increases the voltage, transient and oscillatory limits by up to 400MW in both directions	See Note (1)
Bulli Creek or Dumaresq 1,500MW HVDC back to back asynchronous link	$470M (approximately)	Increases transfer capability by around 500MW in both directions	See Note (1)
Bulli Creek to Bayswater 330kV double circuit line (with intermediate switching stations)	$900M (approximately)	Increases transfer capability by around 500MW in the northerly direction and around 1,000MW in the southerly direction	See Note (1)
Western Downs to Bayswater 500kV double circuit line (with intermediate switching stations and dynamic compensation devices)	$1,900M (approximately)	Increases transfer capability by around 1,800MW in both directions	As per the second 330kV HVAC interconnector augmentation (refer row above)

Note:

(1) The affected constraint identifiers 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 A.5: Description of Economic Growth, Generation and Demand Side Management Cases

Central to North Queensland Flow Path (CQ to NQ)				
Case Identifier	Economic Growth	New Entry Generation		
		North Queensland	Central Queensland	South West or South East Queensland
CQ-NQ-M-G1	Medium	No new entry	Market driven	Market driven
CQ-NQ-M-G2	Medium	300MW prior summer 2020/21 (1) (2)	Market driven	Market driven
CQ-NQ-M-G3	Medium	300MW prior summer 2020/21 and 300MW prior summer 2025/26 (1)	Market driven	Market driven
CQ-NQ-H-G1	High	300MW prior summer 2020/21 (1)	Market driven	Market driven
CQ-NQ-L-G1	Low	No new entry	Market driven	Market driven

Central to South West and South East Queensland Flow Paths (CQ to SWQ and CQ to SEQ)			
Case Identifier	Economic Growth	New Entry Generation	
		North or Central Queensland	South West or South East Queensland
CQ-SQ-M-G1	Medium	Market driven	150 to 200MW per year (3)
CQ-SQ-M-G2	Medium	Market driven	200 to 250MW per year (3)
CQ-SQ-H-G1	High	Market driven	250 to 350MW per year (3)
CQ-SQ-L-G1	Low	Market driven	150 to 200MW per year (3)

South West to South East Queensland Flow Path (SWQ to SEQ)				
Case Identifier	Economic Growth	New Entry Generation		
		North or Central Queensland	South West Queensland	South East Queensland
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 auxilliaries 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 generation per year starting from around 2012.

Table A.6: Sensitivity of the Timing of Routine Augmentations to Economic Growth, Generation and Demand Side Management

Case Identifier (1)	Augmentation(s)	Indicative Timing (2)
Central to North Queensland Flow Path (CQ to NQ)		
CQ-NQ-M-G1	Stanwell to Broadsound 275kV stringing of an additional circuit	Summer 2012/13
	Calvale to Stanwell 275kV double circuit line	Summer 2013/14
	Broadsound to Nebo 275kV series capacitors	Summer 2020/21
	Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	Summer 2023/24
	Nebo to Strathmore 275kV series capacitors	Summer 2023/24
	Strathmore to Ross 275kV series capacitors	Summer 2026/27
CQ-NQ-M-G2	Stanwell to Broadsound 275kV stringing of an additional circuit	Summer 2012/13
	Calvale to Stanwell 275kV double circuit line	Summer 2013/14
	Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	Summer 2023/24
	Broadsound to Nebo 275kV series capacitors	Summer 2024/25
	Nebo to Strathmore 275kV series capacitors	Summer 2027/28
CQ-NQ-M-G3	Stanwell to Broadsound 275kV stringing of an additional circuit	Summer 2012/13
	Calvale to Stanwell 275kV double circuit line	Summer 2013/14
	Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	Summer 2023/24
CQ-NQ-H-G1	Stanwell to Broadsound 275kV stringing of an additional circuit	Summer 2011/12
	Calvale to Stanwell 275kV double circuit line	Summer 2012/13
	Broadsound to Nebo 275kV series capacitors	Summer 2014/15
	Nebo to Strathmore 275kV series capacitors	Summer 2016/17
	Strathmore to Ross 275kV series capacitors	Summer 2018/19
	Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	Summer 2021/22
	Broadsound to Nebo 275kV double circuit line	Summer 2023/24
	Nebo to Strathmore 275kV double circuit line	Summer 2025/26
	Strathmore to Ross 275kV double circuit line	Summer 2027/28

Table A.6: Sensitivity of the Timing of Routine Augmentations to Economic Growth, Generation and Demand Side Management (cont.)

Case Identifier (1)	Augmentation(s)	Indicative Timing (2)
CQ-NQ-L-G1	Stanwell to Broadsound 275kV stringing of an additional circuit	Summer 2013/14
	Calvale to Stanwell 275kV double circuit line	Summer 2014/15
	Calvale to Larcom Creek and Larcom Creek to Gladstone 275kV double circuit line	Summer 2025/26
	Broadsound to Nebo 275kV series capacitors	Summer 2028/29
Central to South West and South East Queensland Flow Paths (CQ to SWQ and CQ to SEQ)		
CQ-SQ-M-G1	Calvale to Tarong 275kV mid-point switching station (Auburn River) and series capacitors	Summer 2021/22
CQ-SQ-M-G2	No reliability augmentations anticipated (3)	-
CQ-SQ-H-G1	Calvale to Tarong 275kV mid-point switching station (Auburn River) and series capacitors	Summer 2017/18
CQ-SQ-L-G1	No reliability augmentations anticipated (3)	-
South West to South East Queensland Flow Path (SWQ to SEQ)		
SWQ-SEQ-M-G1	Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV	Summer 2016/17
	Halys to Greenbank 500kV double circuit line (initially operating at 275kV)	Summer 2018/19
	Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV	Summer 2018/19
	Western Downs to Halys 500kV double circuit line (northern route second build) and upgrade Halys to Greenbank to 500kV	Summer 2020/21
	Halys to North Moreton 500kV double circuit line	Summer 2024/25
SWQ-SEQ-H-G1	Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV	Summer 2012/13
	Halys to Greenbank 500kV double circuit line (initially operating at 275kV)	Summer 2014/15
	Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV	Summer 2014/15
	Western Downs to Halys 500kV double circuit line (northern route second build) and upgrade Halys to Greenbank to 500kV	Summer 2015/16
	Halys to North Moreton 500kV double circuit line	Summer 2020/21
	Halys to South Moreton 500kV double circuit line	Summer 2024/25

Table A.6: Sensitivity of the Timing of Routine Augmentations to Economic Growth, Generation and Demand Side Management (cont.)

Case Identifier (1)	Augmentation(s)	Indicative Timing (2)
SWQ-SEQ-L-G1	Western Downs to Halys 500kV double circuit line (northern route first build) initially operating at 275kV	Summer 2024/25
	Halys to Greenbank 500kV double circuit line (initially operating at 275kV)	Summer 2026/27
	Upgrade Western Downs to Halys (northern route first build) and Halys to Blackwall to 500kV	Summer 2026/27
South East Queensland to Northern NSW Flow Path (SEQ to NNS)		
SWQ-SEQ-M-G1	Molendinar 3rd 275/110kV 375MVA transformer	Summer 2014/15
	Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade	Summer 2015/16
	Mudgeeraba 3rd 275/110kV transformer upgrade	Summer 2018/19
SWQ-SEQ-H-G1	Molendinar 3rd 275/110kV 375MVA transformer	Summer 2013/14
	Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade	Summer 2014/15
	Mudgeeraba 3rd 275/110kV transformer upgrade	Summer 2017/18
SWQ-SEQ-L-G1	Molendinar 3rd 275/110kV 375MVA transformer	Summer 2015/16
	Greenbank to Mudgeeraba 275kV rebuild and Mudgeeraba two 275/110kV transformers upgrade	Summer 2016/17
	Mudgeeraba 3rd 275/110kV transformer upgrade	Summer 2019/20

Notes:

(1) Refer to Table A.5 for the description of the case identifiers (for example 'M' within the case identifier denotes medium economic growth).

(2) It should be noted that the timing for these augmentations, particularly within the later years, are based on very preliminary high level assessments.

(3) There are potentially no reliability augmentations that will be required across the 20 year study time within these cases.

Appendix B – 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 and 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 B.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 B.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 B.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 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 approaching or within the range of 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 B.2.

Figure B.1 shows the derived summer 2008/09 'S-curve' of South East Queensland daily native peak demand against Amberley average of minimum and maximum temperature on the day. This illustrates how temperature sensitivity is maximised at 27°C, is zero at 20°C, and has saturated by 34°C.

Figure B.1: South East Queensland Native Daily Peak Demand 'S-curve' against Amberley Temperature on Working Days of Summer 2008/09

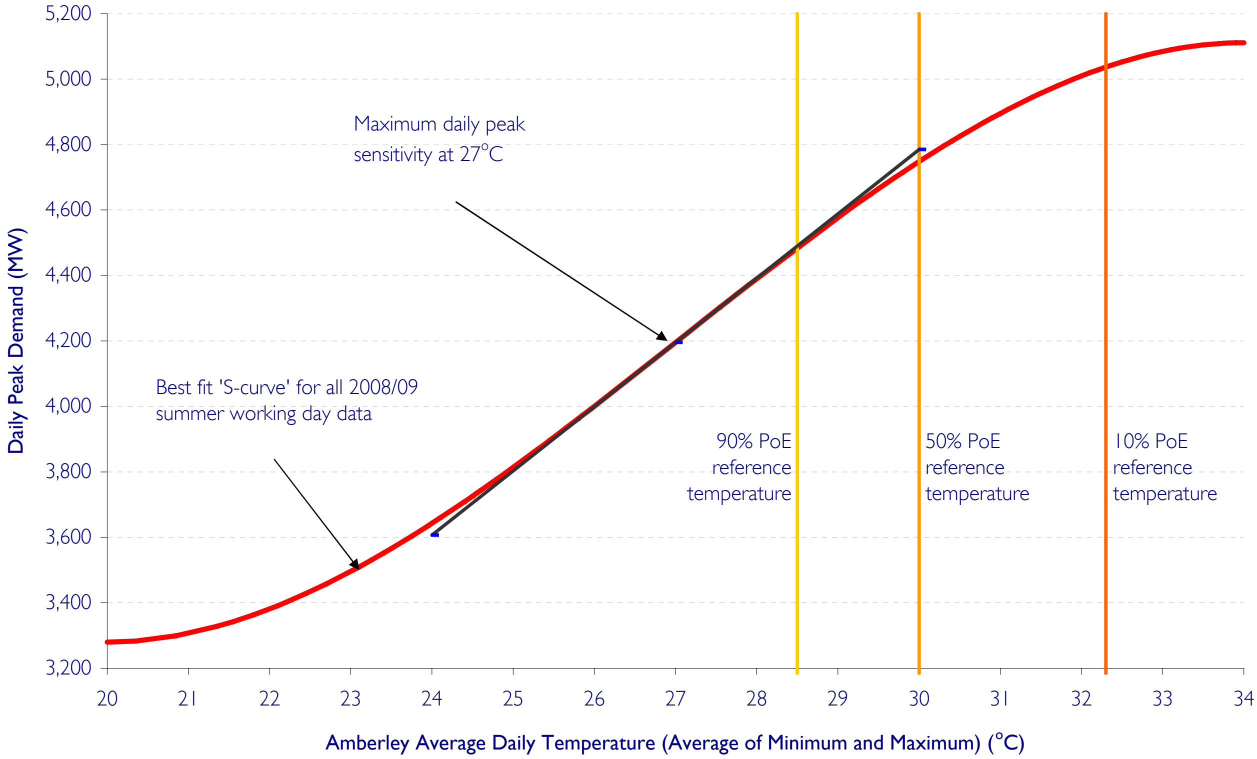


Table B2: Observed Temperature Sensitivity of Daily Peak Demands

	Demand Change Dependence on Average Daily Temperature (MW per °C) (1)			
	South East (2)	South West	Northern Non-Industrial	Central Non-Industrial
Summer				
1999/00	64	4.8	23	11.5
2000/01	65	7.0	24	16.2
2001/02	72	5.0	28	14.3
2002/03	69	7.0	32	18.2
2003/04	115	8.6	37	17.8
2004/05	147	9.0	33	19.0
2005/06	162	11.1	40	24.1
2006/07	160	12.0	46	24.3
2007/08	154	11.2	50	18.8
2008/09	196	11.6	46	24.9
Winter				
1999	-36	-6.1	6.0	N/A (4)
2000	-48	-6.9	N/A (3)	
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)	

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 B.3 and B.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 B.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)					
1999/00	2,922 / 2,946	265 / 268	822 / 887	637 / 704	973 / 1,017
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
Temperature Corrected Area Peak Demand					
1999/00	2,804	267	938	720	N/A (7)
2000/01	2,999	303	946	779	
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	

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 B.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)					
1999	2,777	278 / 297	640 / 731	633 / 655	904 / 921
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
Temperature Corrected Area Peak Demand					
1999	2,775	302	725	N/A (2)	N/A (3)
2000	2,963	320	776		
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		

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 B.3 and B.4.

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

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

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

Table B.5: Queensland Summer Native Peak Area Demand Diversity (1)

Year	South East	South West	North Non-Industrial	Central Non-Industrial	Industrial	Queensland Diversity (2)
1999/00	104.2%	99.3%	87.7%	88.5%	95.7%	98.1%
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%
Last 10 Year Average	97.79%	93.63%	91.94%	93.51%	93.69%	95.6%

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 B.6: Queensland Winter Native Peak Area Demand Diversity (1)

Year	South East	South West	North Non-Industrial	Central Non-Industrial	Industrial	Queensland Diversity (2)
1999	100.1%	92.4%	88.3%	95.2%	98.1%	97.1%
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%
Last 10 Year Average	99.3%	92.7%	89.4%	95.7%	95.1%	96.6%

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 B.7: Queensland Region Actual and 50% PoE Temperature and Diversity Corrected Peak Native Demands

Summer	Actual (1)	Corrected (2)	Winter	Actual (1)	Corrected (3)
			1999	5,233	5,215
1999/00	5,620	5,481	2000	5,609	5,603
2000/01	5,830	5,786	2001	5,731	5,745
2001/02	6,183	6,060	2002	5,671	5,797
2002/03	6,336	6,290	2003	6,066	6,084
2003/04	7,020	6,734	2004	6,366	6,391
2004/05	7,282	7,205	2005	6,553	6,648
2005/06	7,373	7,551	2006	6,882	6,875
2006/07	7,889	7,849	2007	7,223	7,201
2007/08	7,444	7,929	2008	7,593	7,546
2008/09	8,021	8,330			

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 2008/09. 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 2008. This last 10 year average has changed only slightly in recent years and accordingly there is negligible revision of earlier year corrected demands.

Figure B.2: Coincidence of Actual Queensland Region Summer Peak Demand Compared to the Sum of Area and Industrial Corrected Summer Peak Demands

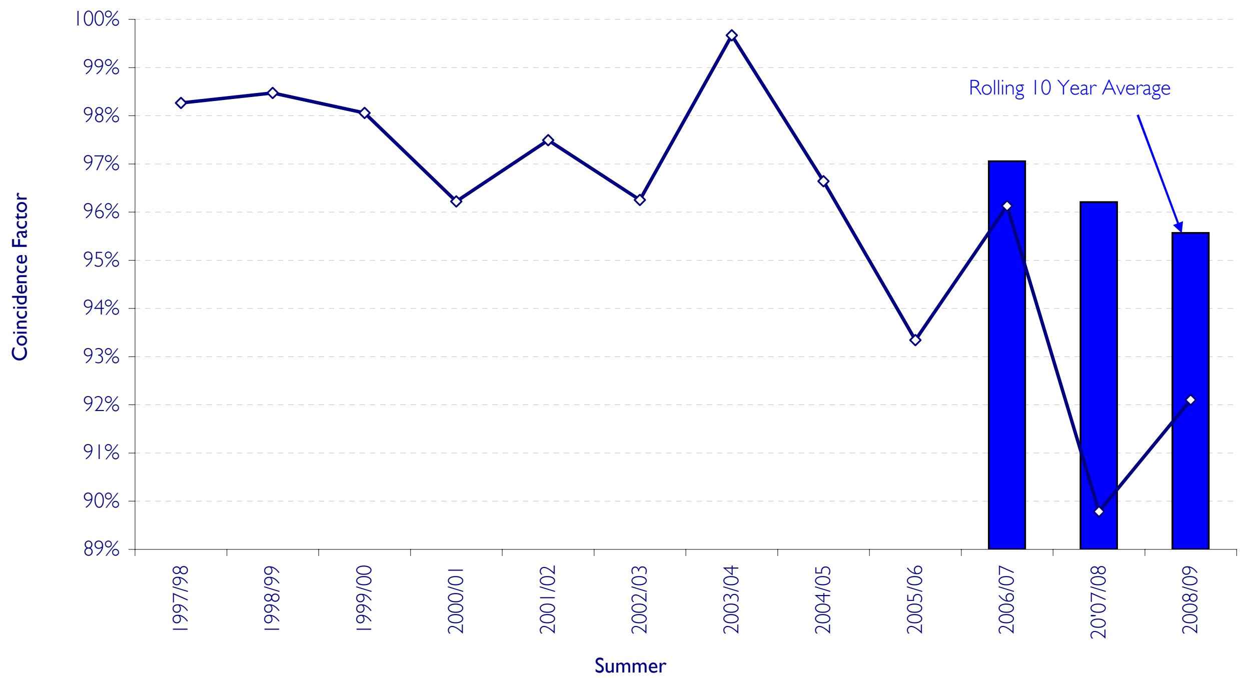


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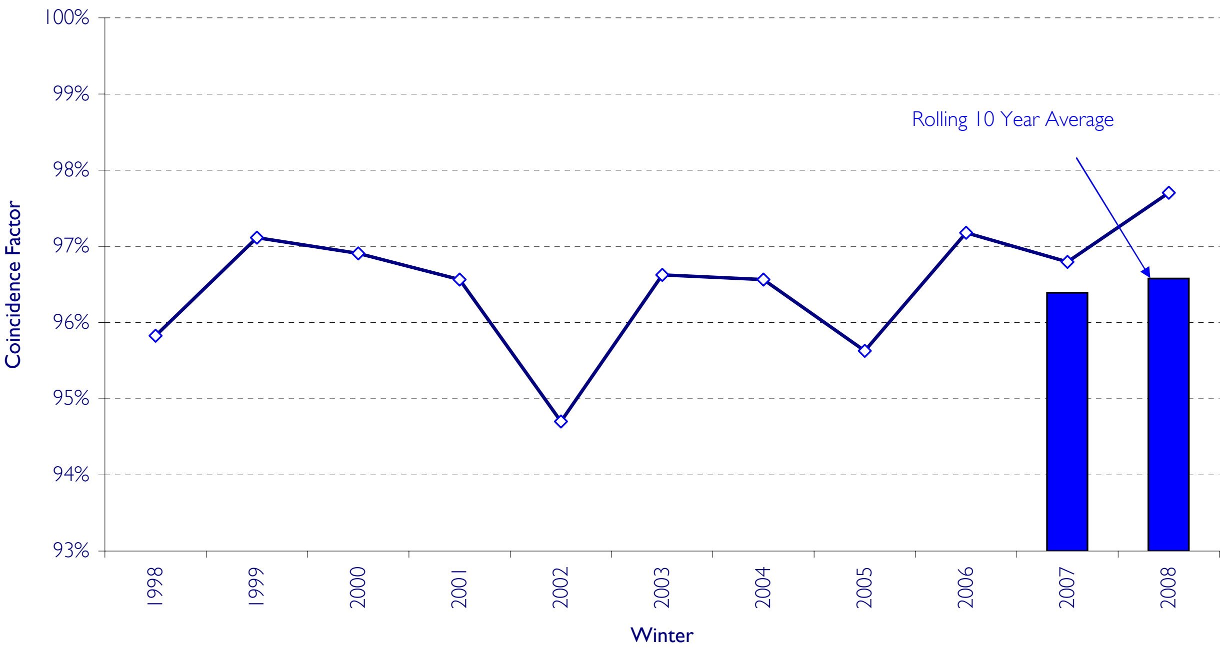
Figure B.3: Actual Queensland Region Winter Peak Demand Compared to the Sum of Area and Industrial Corrected Winter Peak Demands



Summer Seasonal Weather Conditions

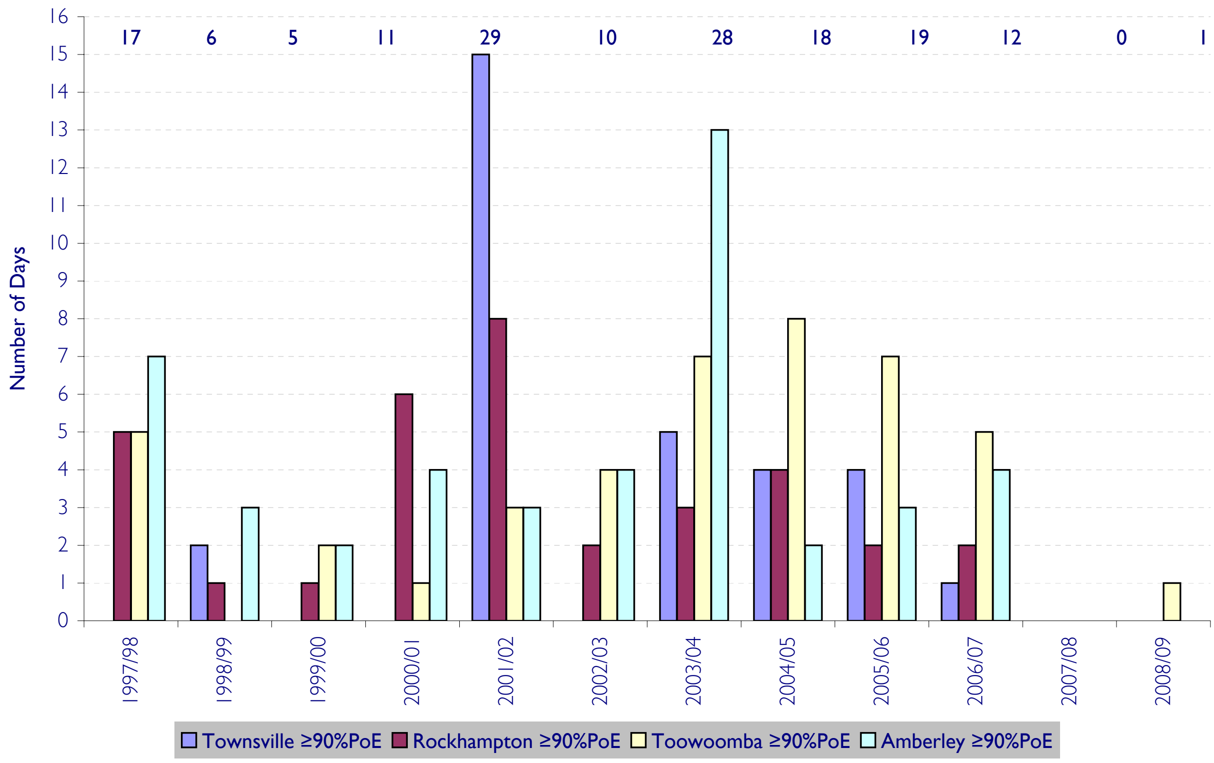
The coincidence factors shown above suggest that summer weather conditions across Queensland over the last 10 years has exhibited far more variability than for winter weather conditions. This will impact summer peak demands. Figure B.4 shows that there were no extreme weather conditions in Queensland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

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

Table B.8: Queensland Average Summer Temperatures (°C)

Year	Amberley	Archerfield	Toowoomba	Rockhampton	Townsville
1999/00	23.14	22.68	19.94	25.46	26.87
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
10 Year Average	24.9	24.8	22.3	27.0	28.0
50 Year Average	24.9	25.3	21.6	26.9	27.8

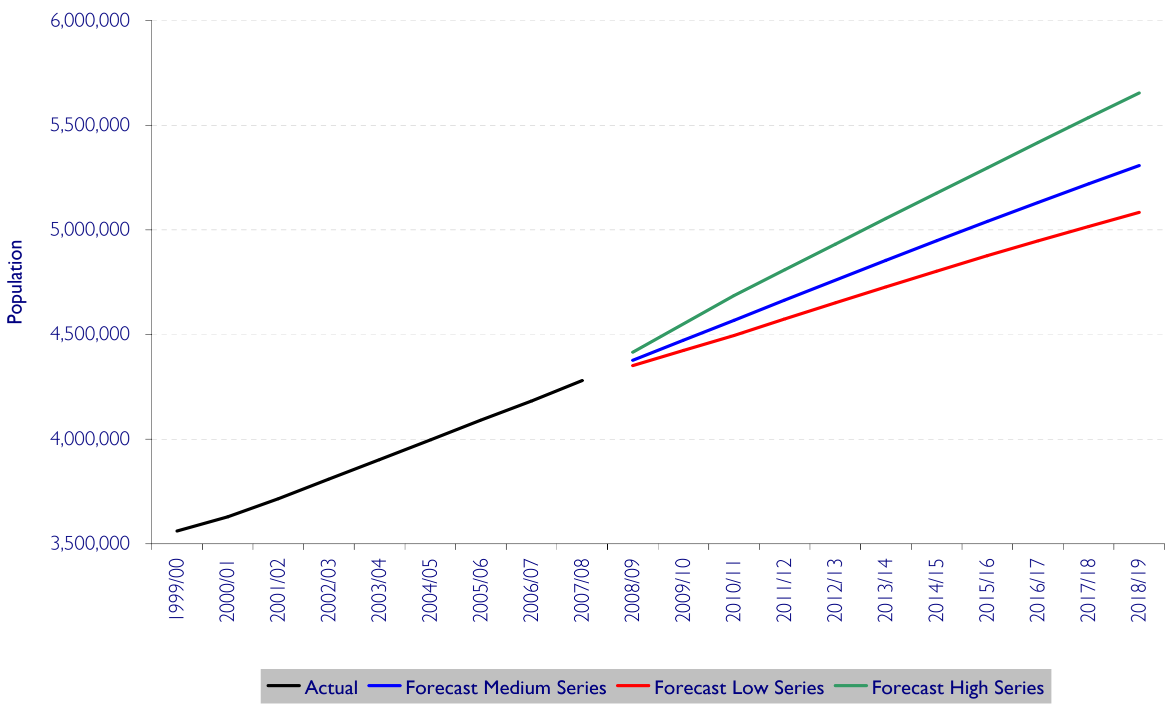
Figure B.4: The Recent Trend to a Lower Number of Very Hot Summer Days Across Queensland



Population Growth

Recent Queensland resident population growth has been estimated at 2.23% from the June 2006 census to June 2007 followed by 2.34% growth to June 2008 (Australian Bureau of Statistics). The 2007/08 growth was slightly higher than as previously forecast at 2.2%. The high, medium and low series range of population forecast scenarios for Queensland was last revised in December 2008. The actual and forecasts are shown in Figure B.5.

Figure B.5: Queensland Resident Population Actual and Forecast

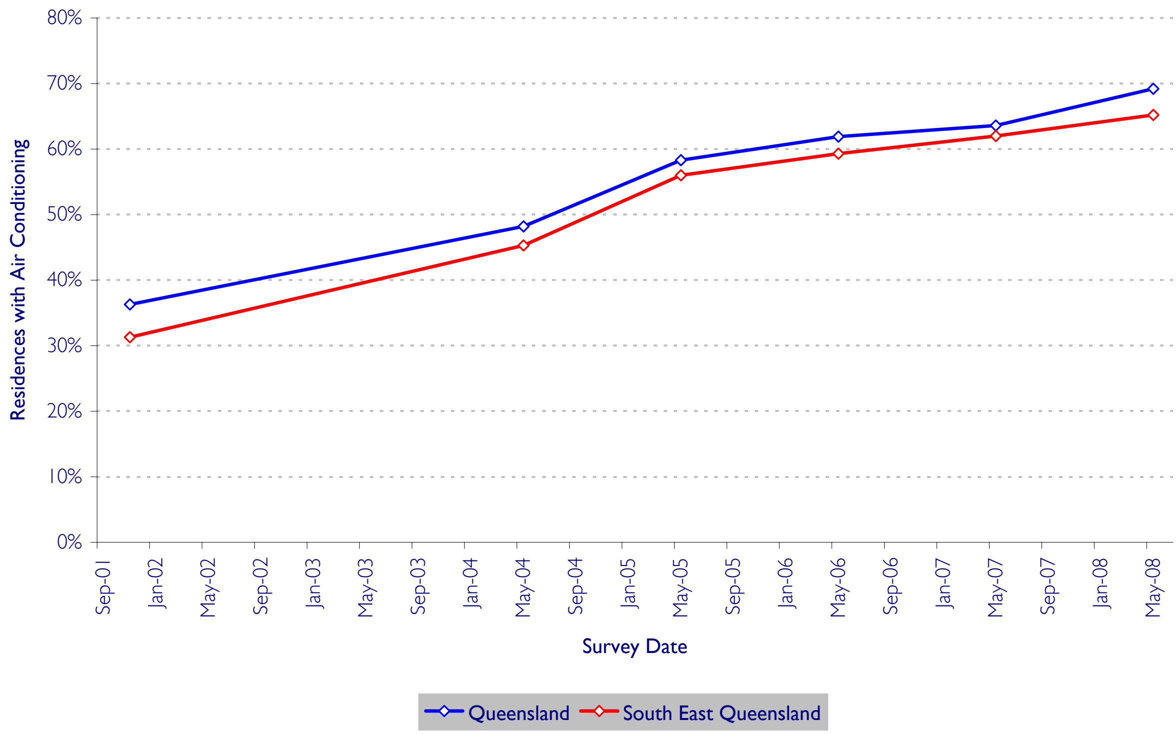


Increase in Air Conditioner Installation

Recent surveys of domestic air conditioning penetration rates are shown on Figure B.6. The percentage of South East Queensland residences with air conditioning installed increased from 62.0% to 65.2% over the May 2007 to May 2008 survey period, a greater increase than over the previous annual survey period (59.3% in May 2006 to 62.0% in May 2007).

Similarly, the surveys showed that the air conditioning penetration rate over all of Queensland increased to 69.2% in May 2008, up from 63.6% in May 2007 and being a greater increase than from 61.9% in May 2006.

Figure B.6: Number of Residences with Air Conditioners by Survey



Energy Efficient Lighting

Recent surveys have shown that the number of Queensland residences indicating that all or most of their indoor lights are converted to using energy efficient globes rose from 26.0% in May 2006 to 35.7% in May 2007 and to 50.6% by May 2008.

Appendix C – Forecast of Connection Points

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

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

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

In Tables C.1 and C.2 the zones in which connection points are located are allocated by abbreviation 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 C.1: Forecasts of Connection Point Native Demands (MW) Coincident With State Summer Maximum Demand

Connection Points	Zone	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Abermain 110kV (Lockrose, Wulkuraka BS and QR)	M	49.9	48.5	49.8	57.8	60.1	61.8	63.1	64.5	66.3	68.3
Abermain 33kV	M	107.8	94.2	107.9	108.5	114.3	117.8	120.9	125.5	130.4	134.4
Alan Sherriff 132kV	R	19.8	20.8	21.8	22.9	24.0	25.2	26.4	27.7	29.0	29.9
Algester 33kV	M	63.8	63.5	54.7	55.0	87.0	83.2	84.4	86.5	69.1	71.2
Alligator Creek 33kV	N	15.7	16.0	26.8	27.1	27.4	27.7	28.0	28.3	28.6	29.5
Ashgrove West 33kV	M	74.7	75.6	76.1	77.9	81.1	83.6	85.7	88.9	92.5	95.4
Belmont 110kV (Cleveland and Capalaba North)	M	146.3	150.0	154.5	163.1	169.7	174.6	178.9	185.4	191.9	197.9
Biloela 66kV	CW	29.2	29.4	31.3	31.5	31.8	32.1	32.3	32.6	32.9	33.9
Blackwater 66kV	CW	72.9	84.0	106.2	108.5	110.9	113.3	115.8	118.4	121.1	124.8
Broadlea 66kV	N	0.0	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	54.9
Bundamba 110kV	M	15.0	34.3	35.9	37.2	41.7	43.7	45.6	48.1	50.9	52.5
Cairns 22kV	FN	76.4	80.2	84.1	87.9	91.7	95.5	99.3	103.0	106.7	110.1
Cairns City 132kV	FN	55.4	57.7	60.0	62.5	65.1	67.7	70.5	73.4	76.4	78.8
Cairns North 132kV	FN	27.0	28.2	29.5	30.8	32.2	33.6	35.1	36.7	38.3	39.5
Cardwell 22kV	R	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.6
CBD (Brisbane) East 110kV	M	436.9	494.5	559.0	584.0	628.9	648.6	674.8	703.3	709.0	731.2
CBD (Brisbane) South 110kV	M	63.7	64.5	62.4	63.8	85.0	87.6	89.9	93.3	96.0	99.0
CBD (Brisbane) West 110kV	M	155.0	171.0	191.0	198.8	210.0	219.0	227.4	230.4	219.2	226.1
Clare 66kV	R	73.4	74.5	75.5	76.5	77.6	78.6	79.6	80.6	81.7	84.2
Collinsville 33kV	N	9.2	9.3	10.2	14.3	14.5	14.7	14.9	15.1	15.3	15.7
Dan Gleeson 66kV	R	78.2	80.8	83.5	86.4	89.4	92.5	95.8	99.2	102.8	106.1
Dysart 66kV	CW	45.4	46.0	60.4	61.0	61.5	62.1	62.7	63.3	63.8	65.8
Edmonton 22kV	FN	38.0	39.5	41.1	42.7	44.3	45.9	47.5	49.0	50.6	52.2

Table C.1: Forecasts of Connection Point Native Demands (MW) Coincident With State Summer Maximum Demand (cont.)

Connection Points	Zone	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Egans Hill 66kV	CW	61.9	60.8	63.7	65.6	67.4	69.2	71.1	72.9	74.7	77.1
El Arish 22kV	FN	3.1	3.2	3.4	3.5	3.7	3.8	4.0	4.2	4.4	4.5
Garbutt 66kV	R	90.3	92.9	95.4	98.0	100.8	103.3	105.6	108.2	110.2	113.7
Gin Gin 132kV (Bundaberg)	WB	110.2	112.5	114.9	117.1	119.4	121.7	124.1	126.5	128.9	132.9
Gladstone 132kV (Boat Creek and RTA Yarwun)	GL	86.9	103.0	132.1	140.6	141.8	149.9	150.9	151.8	152.6	157.4
Gladstone North 132kV	GL	12.4	14.3	19.7	19.8	22.6	22.8	32.9	33.1	33.2	34.2
Gladstone South 66kV	GL	75.9	77.1	79.2	81.2	83.2	85.1	86.9	88.7	90.4	93.2
Goodna 33kV	M	88.7	125.1	142.1	168.1	111.4	118.3	124.8	132.6	140.6	145.0
Ingham 66kV	R	18.0	18.4	18.8	19.2	19.6	20.0	20.4	20.8	21.3	22.0
Innisfail 22kV	FN	25.9	26.1	26.4	26.7	26.9	27.2	27.5	27.7	28.0	28.8
Kamerunga 22kV	FN	46.6	48.6	50.5	52.4	54.3	56.2	58.1	60.0	61.9	63.9
Larapinta 33KV	M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.4	39.6
Lilyvale 132kV (Clermont and Barcaldine)	CW	27.8	28.4	44.6	45.1	45.7	46.2	46.7	47.2	47.8	49.2
Lilyvale 66kV	CW	94.0	96.1	120.1	122.6	124.3	126.1	127.8	130.0	131.8	135.9
Loganlea 110kV	M	518.5	517.7	541.8	564.7	580.3	607.7	629.9	633.6	643.4	663.5
Loganlea 33kV	M	94.4	94.8	94.6	94.8	98.1	92.7	94.5	96.7	99.4	102.5
Mackay 33kV	N	76.0	78.4	80.8	83.2	85.6	87.9	90.3	92.6	95.0	98.0
Middle Ridge 110kV	SW	231.1	245.0	255.5	264.0	272.1	279.5	287.7	295.1	302.5	311.9
Middle Ridge 110kV (Postmans Ridge and Gatton)	M	44.9	49.2	56.2	62.3	63.4	66.6	66.9	68.7	69.7	71.9
Molendinar 110kV	GC	372.7	395.5	420.5	426.6	445.9	462.4	472.4	481.3	496.0	511.5
Moranbah 66kV and 11kV	N	125.6	97.6	124.3	152.7	178.9	195.1	207.2	221.7	240.5	248.0
Moura 66kV	CW	39.9	40.3	40.7	41.1	41.5	41.9	42.4	42.8	43.2	44.6

Table C.1: Forecasts of Connection Point Native Demands (MW) Coincident With State Summer Maximum Demand (cont.)

Connection Points	Zone	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Mudgeeraba 110kV	GC	337.2	342.2	351.2	356.3	368.4	372.4	379.3	390.0	403.4	416.0
Murarrie 110kV (Doboy, Lytton BS and QR and Wakerley)	M	249.1	268.7	265.0	272.1	288.3	298.3	299.5	311.8	322.5	332.6
Nebo 11kV	N	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.7
Newlands 66kV	N	20.8	21.2	21.5	23.9	24.2	24.6	24.9	25.2	25.6	26.4
Nudgee 110kV	M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.4	108.7
Palmwoods 132kV and 110KV	M	303.6	329.2	357.9	388.3	420.0	453.0	480.0	503.9	521.3	537.6
Pandoin 66kV	CW	0.0	9.0	9.3	10.9	11.1	11.5	11.8	12.2	12.5	12.9
Pioneer Valley 66kV	N	41.3	43.0	44.7	46.3	48.0	49.7	51.4	53.0	54.7	56.4
Proserpine 66kV	N	62.1	69.4	71.4	79.7	81.7	89.7	91.7	93.8	95.9	98.9
Redbank Plains 11kV	M	22.6	24.2	25.6	19.5	20.5	21.3	22.0	23.1	24.2	25.0
Richlands 33kV	M	99.7	102.2	102.9	105.6	110.9	114.3	116.8	120.3	123.1	126.9
Rockhampton 66kV	CW	104.3	105.1	110.5	114.1	119.9	123.5	126.9	130.7	134.1	138.3
Rocklea 110kV (Archerfield)	M	91.0	89.4	91.0	91.7	76.4	85.9	87.3	89.8	92.3	95.2
Ross 132kV (Kidston, Milchester and Georgetown)	FN	33.6	36.1	50.0	50.6	51.2	51.8	52.4	53.0	53.6	55.3
Runcorn 33kV	M	64.9	62.5	76.7	77.3	78.9	78.2	79.3	81.4	85.2	87.9
South Pine 110kV	M	869.4	920.3	959.6	1,006.8	1,053.1	1,088.2	1,121.4	1,159.3	1,130.0	1,165.3
Sumner 11kV	M	40.3	45.4	32.1	32.7	34.0	34.6	35.1	36.0	37.0	38.1
Sun Water Pumps (King Creek) 132kV	N	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7
Sun Water Pumps (Stony Creek) 132kV	N	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Swanbank 110kV (Raceview)	M	100.8	96.9	100.1	102.6	147.7	154.8	169.9	187.0	204.4	210.8
Tangkam 110kV (Dalby and Oakey)	SW	41.7	42.9	44.4	45.6	46.7	47.9	49.0	50.2	51.4	53.0
Tarong 132kV (Chinchilla and Roma)	SW	69.8	71.0	72.2	73.5	74.8	76.1	77.3	78.6	79.9	82.4
Tarong 66kV	SW	41.4	42.7	43.8	45.8	61.4	62.6	63.7	64.9	66.0	68.1

Table C.1: Forecasts of Connection Point Native Demands (MW) Coincident With State Summer Maximum Demand (cont.)

Connection Points	Zone	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Teebar Creek 132kV (Isis and Maryborough)	WB	136.4	145.3	151.2	155.9	160.5	165.6	170.4	175.2	180.5	186.2
Tennyson 33kV	M	192.5	194.7	177.2	182.3	181.1	185.0	188.3	193.8	196.6	202.7
Townsville East 66kV	R	35.4	36.3	37.2	38.2	39.2	40.2	41.3	42.4	43.5	44.9
Townsville South 66kV	R	63.8	67.4	68.4	69.3	70.4	71.1	71.7	73.2	73.8	76.1
Tully 22kV	R	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	16.0
Turkinje 132kV (Craiglee and Lakeland)	FN	17.1	17.3	18.3	18.6	18.8	19.0	19.2	19.4	19.7	20.3
Turkinje 66kV	FN	48.9	53.2	58.5	61.5	63.1	64.7	66.3	68.0	69.1	71.3
Waggamba 132kV	B	17.5	17.9	18.3	18.7	19.1	19.5	19.9	20.4	20.8	21.5
Wecker Rd 33kV (Belmont)	M	172.5	156.0	158.7	159.9	134.0	138.0	141.6	146.8	151.8	156.5
West Darra 11kV	M	0.0	0.0	21.9	22.5	23.6	24.4	25.2	26.4	26.6	27.4
Woolooga 132kV (Gympie)	M	166.4	164.2	177.0	187.0	197.6	204.8	214.8	223.9	232.2	239.5
Woolooga 132kV (Kilkivan)	WB	11.2	11.4	11.5	11.6	11.8	11.9	12.1	12.2	12.3	12.7
Direct Connected Industrial Loads (Sun Metals, Qld Nickel, Invicta Load - R, BSL, and QAL - GL)	Various	1,083.7	1,097.4	1,103.4	1,102.4	1,124.3	1,146.2	1,171.0	1,196.9	1,223.8	1,262.0
Transmission Grid Connected Mining Loads (Rolleston - CW, Burton Downs, Goonyella North and Hail Creek - N)	Various	58.2	67.3	77.9	105.9	123.8	138.2	157.9	188.2	192.9	198.9
Transmission Grid Connected QR substations (Gregory, Rangal, Dingo, Grantleigh, Rocklands, Norwich Park - CW, Mt McLaren, Coppabella, Moranbah South, Oonooie, Wandoo, Peak Downs, Bolingbroke, Mindi - N, Callemondah - GL, Korenan and Mungar - WB)	Various	110.4	109.9	112.9	114.5	116.0	117.1	118.4	119.8	121.7	125.5
Total Queensland Summer Native Peak		**8,628**	**9,023**	**9,545**	**9,915**	**10,313**	**10,654**	**10,986**	**11,338**	**11,692**	**12,047**

Table C.2: Forecasts of Connection Point Native Demands (MW) Coincident With State Winter Maximum Demand

Connection Points	Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Abermain 110kV (Lockrose, Wulkuraka BS and QR)	M	52.8	52.6	53.3	53.3	60.6	62.5	64.0	65.4	67.2	69.0
Abermain 33kV	M	103.3	86.6	89.7	103.7	103.0	105.3	107.9	110.6	115.0	119.1
Alan Sherriff 132kV	R	12.0	12.5	13.2	13.8	14.5	15.2	15.9	16.7	17.5	18.3
Algester 33kV	M	57.6	56.1	56.4	47.4	48.0	68.4	66.4	67.4	69.6	56.3
Alligator Creek 33kV	N	32.3	9.4	9.6	19.8	20.1	20.3	20.6	20.8	21.0	21.3
Ashgrove West 33kV	M	77.5	76.6	78.2	76.7	78.9	81.7	83.9	86.2	89.8	93.4
Belmont 110kV (Cleveland and Capalaba North)	M	169.1	166.5	172.4	179.1	173.2	179.2	184.0	188.9	196.9	203.9
Biloela 66kV	CW	25.4	25.4	25.3	26.9	26.8	26.7	26.6	26.6	26.5	26.4
Blackwater 66kV	CW	69.0	70.5	82.0	102.0	103.6	105.2	106.8	108.5	110.2	111.9
Broadlea 66kV	N	0.0	0.0	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4
Bundamba 110kV	M	13.4	30.4	31.4	32.1	33.5	37.5	39.2	40.9	43.3	45.8
Cairns 22kV	FN	54.1	49.7	52.6	55.6	58.8	62.1	65.7	69.4	73.4	77.6
Cairns City 132kV	FN	42.4	34.2	35.9	37.6	39.4	41.3	43.3	45.3	47.5	49.8
Cairns North 132kV	FN	18.8	19.6	20.5	21.4	22.4	23.4	24.4	25.5	26.7	27.8
Cardwell 22kV	R	2.7	2.8	2.9	2.9	3.0	3.1	3.2	3.2	3.3	3.4
CBD (Brisbane) East 110kV	M	264.6	296.8	317.1	367.6	382.3	426.4	436.8	456.7	474.2	479.0
CBD (Brisbane) South 110kV	M	36.8	38.7	36.9	37.2	38.3	52.0	53.4	54.8	57.2	58.7
CBD (Brisbane) West 110kV	M	104.0	108.8	117.8	129.6	135.7	142.2	147.9	153.5	156.3	148.5
Clare 66kV	R	46.0	47.0	47.9	48.9	49.9	50.8	51.8	52.7	53.7	54.7
Collinsville 33kV	N	6.9	7.0	7.1	7.9	11.5	11.7	11.8	12.0	12.1	12.3
Dan Gleeson 66kV	R	60.2	61.1	61.7	62.3	63.0	63.6	64.2	64.9	65.6	66.2
Dysart 66kV	CW	45.0	45.5	46.1	60.3	60.9	61.5	62.1	62.7	63.3	63.9
Edmonton 22kV	FN	19.9	21.0	22.1	23.2	24.4	25.5	26.6	27.8	28.9	30.0

Table C.2: Forecasts of Connection Point Native Demands (MW) Coincident With State Winter Maximum Demand (cont.)

Connection Points	Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Egans Hill 66kV	CW	44.1	50.3	47.4	49.3	50.0	50.6	51.3	52.0	52.7	53.3
El Arish 22kV	FN	0.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	2.9	3.0
Garbutt 66kV	R	69.1	72.1	73.1	74.0	75.0	76.0	77.0	77.7	78.7	79.2
Gin Gin 132kV (Bundaberg)	WB	92.4	95.5	98.6	102.0	105.3	108.7	112.2	115.8	119.5	123.4
Gladstone 132kV (Boat Creek and RTA Yarwun)	GL	81.3	83.8	99.5	129.0	137.4	138.6	146.2	147.2	147.9	148.7
Gladstone North 132kV	GL	13.3	13.4	15.3	20.7	20.9	23.7	23.8	34.1	34.3	34.4
Gladstone South 66kV	GL	62.0	66.3	65.8	67.0	68.1	69.1	70.0	70.8	71.3	71.7
Goodna 33kV	M	83.8	82.3	104.6	116.1	139.5	94.2	99.0	103.8	110.3	116.3
Ingham 66kV	R	11.5	11.6	11.6	11.7	11.8	11.9	12.0	12.1	12.1	12.2
Innisfail 22kV	FN	20.2	19.2	19.3	19.5	19.6	19.7	19.9	20.0	20.2	20.3
Kamerunga 22kV	FN	32.9	34.1	35.4	36.7	37.9	39.2	40.5	41.8	43.0	44.3
Larapinta 33KV	M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.8
Lilyvale 132kV (Clermont and Barcaldine)	CW	23.9	24.1	24.4	36.5	36.7	36.9	37.0	37.2	37.4	37.6
Lilyvale 66kV	CW	95.1	97.2	99.8	135.5	139.4	141.6	143.7	145.8	149.2	151.3
Loganlea 110kV	M	438.6	439.4	460.5	468.8	502.3	514.4	537.2	558.6	562.5	576.9
Loganlea 33kV	M	87.6	87.4	88.6	86.0	86.5	88.9	83.3	84.9	87.2	89.6
Mackay 33kV	N	74.0	46.2	46.8	47.3	47.9	48.5	49.1	49.7	50.2	50.8
Middle Ridge 110kV	SW	242.4	238.5	252.2	262.6	271.4	279.7	287.3	295.8	303.4	311.0
Middle Ridge 110kV (Postmans Ridge and Gatton)	M	45.0	45.1	48.2	53.8	60.0	63.4	63.7	64.0	66.0	66.9
Molendinar 110kV	GC	333.0	351.4	370.0	370.7	377.9	387.7	405.8	414.7	424.4	437.7
Moranbah 66kV and 11kV	N	88.7	110.2	84.1	105.2	129.1	150.3	165.8	177.3	188.6	206.6
Moura 66kV	CW	39.7	40.1	40.5	40.9	41.3	41.7	42.1	42.5	43.0	43.4

Table C.2: Forecasts of Connection Point Native Demands (MW) Coincident With State Winter Maximum Demand (cont.)

Connection Points	Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Mudgeeraba 110kV	GC	344.1	338.1	343.1	344.3	351.5	363.3	360.2	367.4	381.8	392.8
Murarrie 110kV (Doboy, Lytton BS and QR and Wakerley)	M	227.4	226.5	232.9	222.2	228.5	241.3	256.8	266.0	278.1	288.6
Nebo 11kV	N	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0
Newlands 66kV	N	18.2	18.5	18.8	19.1	21.2	21.5	21.8	22.1	22.4	22.7
Nudgee 110KV	M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.3
Palmwoods 132kV and 110kV	M	318.0	332.8	357.7	379.8	416.6	445.0	470.9	502.4	530.0	548.5
Pandoin 66kV	CW	0.0	0.0	9.2	9.5	11.1	11.4	11.8	12.1	12.4	12.8
Pioneer Valley 66kV	N	6.2	27.4	28.3	29.3	30.2	31.2	32.1	33.1	34.0	35.0
Proserpine 66kV	N	40.2	43.1	49.2	50.1	57.1	58.1	64.7	65.7	66.7	67.7
Redbank Plains 11kV	M	23.3	25.7	27.8	28.7	22.4	23.4	24.2	25.1	26.4	27.7
Richlands 33kV	M	75.9	83.2	85.2	84.1	86.6	90.2	92.4	94.2	97.5	99.7
Rockhampton 66kV	CW	79.7	78.8	77.9	81.6	83.7	87.8	89.8	91.6	93.9	95.7
Rocklea 110kV (Archerfield)	M	67.2	68.6	68.1	67.7	68.7	58.8	65.6	66.8	69.0	71.0
Ross 132kV (Kidston, Milchester and Georgetown)	FN	23.1	23.4	25.5	38.4	38.8	39.1	39.5	39.8	40.2	40.5
Runcorn 33kV	M	63.9	62.6	60.7	72.8	73.8	75.5	75.0	76.1	78.5	81.7
South Pine 110kV	M	870.4	899.7	936.7	961.1	994.0	1,034.5	1,067.0	1,100.9	1,145.5	1,124.5
Sumner 11kV	M	31.5	35.4	40.1	27.6	28.2	29.2	29.7	30.1	31.0	31.9
Sun Water Pumps (King Creek) 132kV	N	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Sun Water Pumps (Stony Creek) 132kV	N	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Swanbank 110kV (Raceview)	M	78.6	77.2	78.8	79.5	81.8	116.6	122.7	136.6	152.9	168.6
Tangkam 110kV (Dalby and Oakey)	SW	26.8	43.5	44.3	45.7	46.5	47.3	48.1	48.9	49.7	50.5
Tarong 132kV (Chinchilla and Roma)	SW	62.7	62.3	62.7	63.3	63.9	64.5	65.1	65.7	66.2	66.8
Tarong 66kV	SW	39.0	42.1	43.1	44.0	45.7	61.7	62.6	63.5	64.4	65.3

Table C.2: Forecasts of Connection Point Native Demands (MW) Coincident With State Winter Maximum Demand (cont.)

Connection Points	Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Teebar Creek 132kV (Isis and Maryborough)	WB	124.6	133.8	142.7	149.1	154.0	158.9	164.2	169.2	174.4	180.0
Tennyson 33kV	M	175.8	176.6	186.5	152.5	158.1	155.6	158.6	161.6	167.2	169.5
Townsville East 66kV	R	25.0	25.5	26.1	26.7	27.3	27.9	28.5	29.2	29.9	30.6
Townsville South 66kV	R	36.9	37.0	38.2	38.4	38.6	38.9	38.9	39.0	39.5	39.5
Tully 22kV	R	9.6	8.8	9.0	9.2	9.4	9.6	9.8	10.1	10.3	10.5
Turkinje 132kV (Craiglee and Lakeland)	FN	15.1	15.5	16.0	17.4	17.9	18.3	18.7	19.1	19.6	20.0
Turkinje 66kV	FN	36.0	36.5	38.4	40.8	41.9	42.1	42.3	42.6	42.8	42.8
Waggamba 132kV	B	15.2	15.6	15.9	16.3	16.6	17.0	17.4	17.8	18.1	18.5
Wecker Rd 33kV (Belmont)	M	171.7	175.7	160.6	159.5	161.5	126.9	130.6	134.3	140.0	144.8
West Darra 11kV	M	0.0	0.0	0.0	18.3	18.8	19.6	20.3	21.0	22.0	22.2
Woolooga 132kV (Gympie)	M	206.3	202.6	205.8	217.6	231.7	241.6	249.7	257.0	269.3	279.1
Woolooga 132kV (Kilkivan)	WB	13.9	14.1	14.2	14.4	14.6	14.8	14.9	15.1	15.3	15.4
Direct Connected Industrial Loads (Sun Metals, Qld Nickel, Invicta Load - R, BSL and QAL - GL)	Various	1,094.0	1,094.2	1,111.7	1,117.7	1,116.7	1,138.6	1,160.6	1,185.5	1,211.4	1,238.2
Transmission Grid Connected Mining Loads (Rolleston - CW, Burton Downs, Goonyella North and Hail Creek - N)	Various	45.1	49.7	58.5	63.6	90.7	107.9	121.7	140.7	169.9	174.3
Transmission Grid Connected QR substations (Gregory, Rangal, Dingo, Grantleigh, Rocklands, Norwich Park - CW, Mt McLaren, Coppabella, Moranbah South, Oonooie, Wandoo, Peak Downs, Bolingbroke, Mindi - N, Callemondah - GL, Korenan and Mungar - WB)	Various	85.1	108.6	108.1	110.5	111.6	113.1	114.2	115.5	117.0	118.6
Total Queensland Winter Native Peak		**7,747**	**7,916**	**8,240**	**8,596**	**8,922**	**9,235**	**9,517**	**9,825**	**10,162**	**10,477**

Appendix D – Estimated Network Power Flows

Appendix D illustrates 18 sample grid power flows (Figures D.3 to D.20) for the Queensland region for each summer and winter over three years from winter 2009 to summer 2011/12. Each sample shows possible grid power flows at the time of winter or summer region 50% 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 (late 2011).

Sample conditions[1] in Appendix D include:

Figure D.3: Winter 2009 Queensland Peak 300MW Northerly QNI Flow

Figure D.4: Winter 2009 Queensland Peak Zero QNI Flow

Figure D.5: Winter 2009 Queensland Peak 700MW Southerly QNI Flow

Figure D.6: Winter 2010 Queensland Peak 300MW Northerly QNI Flow

Figure D.7: Winter 2010 Queensland Peak Zero QNI Flow

Figure D.8: Winter 2010 Queensland Peak 700MW Southerly QNI Flow

Figure D.9: Winter 2011 Queensland Peak 300MW Northerly QNI Flow

Figure D.10: Winter 2011 Queensland Peak Zero QNI Flow

Figure D.11: Winter 2011 Queensland Peak 700MW Southerly QNI Flow

Figure D.12: Summer 2009/10 Queensland Peak 200MW Northerly QNI Flow

Figure D.13: Summer 2009/10 Queensland Peak Zero QNI Flow

Figure D.14: Summer 2009/10 Queensland Peak 400MW Southerly QNI Flow

Figure D.15: Summer 2010/11 Queensland Peak 200MW Northerly QNI Flow

Figure D.16: Summer 2010/11 Queensland Peak Zero QNI Flow

Figure D.17: Summer 2010/11 Queensland Peak 400MW Southerly QNI Flow

Figure D.18: Summer 2011/12 Queensland Peak 200MW Northerly QNI Flow

Figure D.19: Summer 2011/12 Queensland Peak Zero QNI Flow

Figure D.20: Summer 2011/12 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 4.1 and 4.2.

Table D.1: Summary of Figures D.3 to D.20 - Possible Power Flows and Limiting Conditions

Grid Section(1)	Illustrative Power Flows (MW) at Queensland Region Peak Load Time (2) (3)						Limit Due To (4)
	Winter 2009	Winter 2010	Winter 2011	Summer 2009/10	Summer 2010/11	Summer 2011/12	
Figure	D.3 / D.4 / D.5	D.6 / D.7 / D.8	D.9 / D.10 / D.11	D.12 / D.13 / D.14	D.15 / D.16 / D.17	D.18 / D.19 / D.20	
Far North Transfer Ross into Chalumbin 275kV (2 circuits) Tully into Kareeya 132kV (1 circuit) Tully into Innisfail/El Arish/Woree 132kV (2 circuits – configuration changes due to staging of ongoing refurbishment project) Ingham South/Cardwell into Kareeya 132kV (1 circuit)	192/192/192	184/184/184	206/206/206	293/293/293	309/309/309	345/345/345	V
CQ-NQ Transfer Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs 132kV (1 circuit)	599/599/599	614/614/615	672/672/672	815/815/815	890/890/758	993/858/729	Th V
Gladstone Transfer Bouldercombe into Gladstone 275kV (2 circuits, one circuit via Larcom Creek from summer 2009/10) Calvale into Wurdong 275kV (1 circuit) Callide A into Gladstone South 132kV (2 circuits)	851/754/671	760/670/670	664/666/669	615/616/618	620/639/685	635/655/689	Th
CQ-SQ Transfer Wurdong into Gin Gin 275kV (1 circuit) Gladstone into Gin Gin 275kV (2 circuits) Calvale into Tarong 275kV (2 circuits)	1022/1296/1555	1264/1524/1534	1410/1410/1409	1251/1251/1251	1118/1215/1443	1041/1156/1337	Tr V

Table D.1: Summary of Figures D.3 to D.20 - Possible Power Flows and Limiting Conditions (cont.)

Grid Section(1)	Illustrative Power Flows (MW) at Queensland Region Peak Load Time (2) (3)						Limit Due To (4)
	Winter 2009	Winter 2010	Winter 2011	Summer 2009/10	Summer 2010/11	Summer 2011/12	
Figure	D.3 / D.4 / D.5	D.6 / D.7 / D.8	D.9 / D.10 / D.11	D.12 / D.13 / D.14	D.15 / D.16 / D.17	D.18 / D.19 / D.20	
SWQ Transfer Braemar to Tarong 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	2164/1869/1666	2031/1775/1808	2118/2125/2167	2319/23267/2333	2797/2708/2495	3048/2959/2570	Tr Th V
Tarong Transfer Tarong to South Pine, Mt England and Blackwall 275kV (5 circuits) Middle Ridge to Greenbank 275kV (2 circuits)	3765/3633/3548	3741/3609/3644	3858/3863/3902	3997/4002/4007	4332/4299/4218	4505/4468/4196	V
Gold Coast Transfer Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	844/850/909	861/866/904	884/889/927	908/914/918	975/986/997	895/895/895	V

Notes:

(1) The Grid Sections defined are as illustrated in Figure D.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 D.3 to D.20. The flows estimated for system intact (that is, 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 D.2: Transformer Capacity and Sample Loadings of 275kV Substations

275kV Substation (1) (2) (No. Transformers x MVA Nameplate Rating)	Possible MVA Loading at Queensland Region Peak (3)(4)						Dependence other than Local Load		Other Comments
	Winter 2009	Winter 2010	Winter 2011	Summer 2009/10	Summer 2010/11	Summer 2011/12	Significant dependence on	Minor dependence on	
Woree 275/132kV (2x375MVA)	170	140	160	245	226	252	Barron Gorge generation	Kareeya generation	
Chalumbin 275/132kV (2x200MVA)	27	90	54	76	90	134	Kareeya generation	Townsville, Barron Gorge and Mt Stuart generation	
Ross 275/132kV (2x250 and 1x200MVA)	148	132	149	248	300	261	Mt Stuart, Townsville and Invicta generation	Collinsville generation	
Strathmore 275/132kV (1x375MVA)	67	76	83	58	38	49	Collinsville and Invicta generation	Townsville and Mt Stuart generation	
Nebo 275/132kV (2x200 and 1x250MVA)	294	282	301	350	368	421	Mackay GT generation	Collinsville generation	
Bouldercombe 275/132kV (2x200MVA)	137	149	141	183	192	200			
Lilyvale 275/132kV (2x375MVA)	193	192	205	203	226	299	Barcaldine generation	CQ-NQ flow	
Calvale 275/132kV (1x250MVA)	248	228	225	232	248	268	Central Queensland generation		
Larcom Creek 275/132kV (2x375MVA)	-	92	110	96	114	147			New substation summer 2009/10
Gin Gin 275/132kV (2x120MVA)	162	171	172	153	171	169	132kV transfers to/ from Teebar Creek	CQ-SQ flow	132kV network can have open points to reduce loading
Teebar Creek 275/132kV (2x375MVA)	105	110	112	113	128	135	132kV transfers to/ from Woolooga	CQ-SQ flow	

Table D.2: Transformer Capacity and Sample Loadings of 275kV Substations (cont.)

275kV Substation (1) (2) (No. Transformers x MVA Nameplate Rating)	Possible MVA Loading at Queensland Region Peak (3)(4)						Dependence other than Local Load		Other Comments
	Winter 2009	Winter 2010	Winter 2011	Summer 2009/10	Summer 2010/11	Summer 2011/12	Significant dependence on	Minor dependence on	
Woolooga 275/132kV (2x120 and 1x250MVA)	223	228	214	203	216	186	132kV transfers to/ from Gin Gin and Teebar Creek	CQ-SQ flow	
Palmwoods 275/132kV (2x375MVA)	379	393	427	340	376	418	132/110kV transfers to/ from South Pine and Woolooga	CQ-SQ flow	
South Pine East 275/110kV (3x375MVA)	769	771	832	751	886	838	110kV transfers to/from Palmwoods	CQ-SQ flow and Swanbank generation	
South Pine West 275/110kV (1x375 and 1x250MVA)	272	273	270	307	324	319	110kV transfers to/from Rocklea	CQ-SQ flow and Swanbank generation	
Rocklea 275/110kV (2x375MVA)	428	432	442	504	529	522	110kV transfers to/ from South Pine and Belmont	110kV transfers to/ from Swanbank and Swanbank B generation	
Belmont 275/110kV (2x250 and 2x200MVA)	736	1,084	1,076	811	1,142	1,203	110kV transfers to/from Loganlea	110kV transfers to/ from Rocklea	Summer 2009/10 - 1 x 375MVA transformer to replace 1 x 200MVA Summer 2010/11 - 1 x 375MVA transformer to replace 1 x 200MVA
Murarrie 275/110kV (2x375MVA)	381	383	408	450	477	499	110kV transfers to/from Belmont		
Swanbank 275/110kV (1x250 and 1x240MVA)	149	147	214	170	170	268	110kV transfers to/ from South Pine, Millmerran and Oakey GT generation	110kV transfers to/from Rocklea and Swanbank B generation	

Table D.2: Transformer Capacity and Sample Loadings of 275kV Substations (cont.)

275kV Substation (1) (2) (No. Transformers x MVA Nameplate Rating)	Possible MVA Loading at Queensland Region Peak (3)(4)						Dependence other than Local Load		Other Comments
	Winter 2009	Winter 2010	Winter 2011	Summer 2009/10	Summer 2010/11	Summer 2011/12	Significant dependence on	Minor dependence on	
Abermain 275/110kV (1x375MVA)	192	196	200	200	209	243	110kV transfers to/from Swanbank and Goodna	Tarong flow	
Goodna 275/110kV (1x375MVA)	138	144	124	181	209	131	110kV transfers to/from Swanbank and Abermain	Tarong flow	
Loganlea 275/110kV (2x375MVA)	474	487	466	563	591	541	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba	
Molendinar 275/110kV (2x375MVA)	492	496	517	515	570	532	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector	
Mudgeeraba 275/110kV (3x250MVA)	470	466	459	478	542	455	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea	
Middle Ridge 275/110kV (3x250MVA)	358	369	379	345	406	409	Oakey GT generation	Swanbank B generation	
Tarong 275/132kV (2x90MVA)	71	70	71	76	77	79	Roma and Condamine generation		
Tarong 275/66kV (2x90MVA)	42	45	46	46	47	48			

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) Also 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) Substation loadings are derived from the assumed generation dispatch cases shown within Figures D.3 to D.20. The loadings are estimated for system normal (that is, 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.

(4) 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 D.3 to D.20.

Figure D.1: Generation and Load Legend for Figures D.3 to D.20

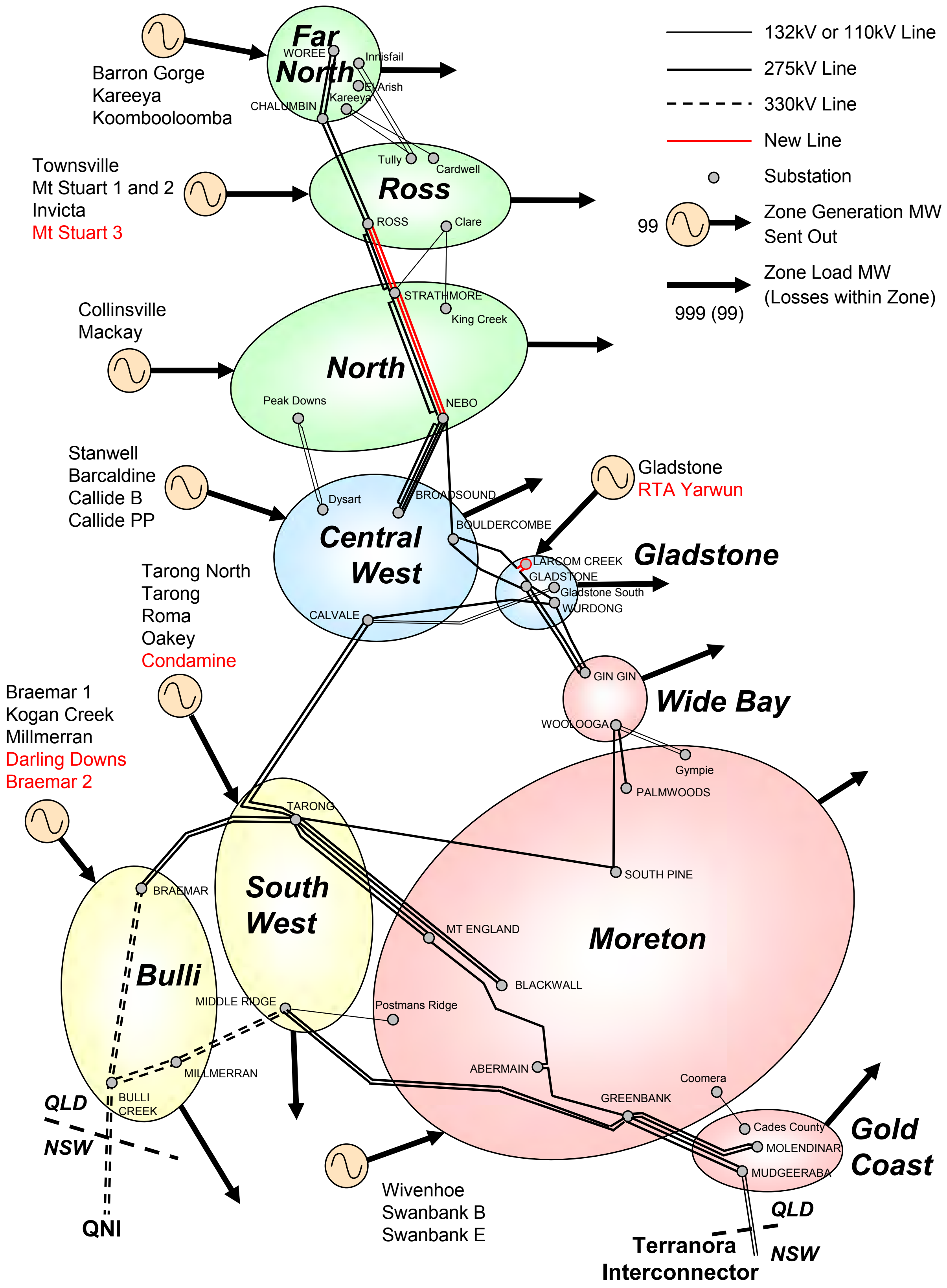


Figure D.2: Observation Point and Grid Section Legend for Figures D.3 to D.20

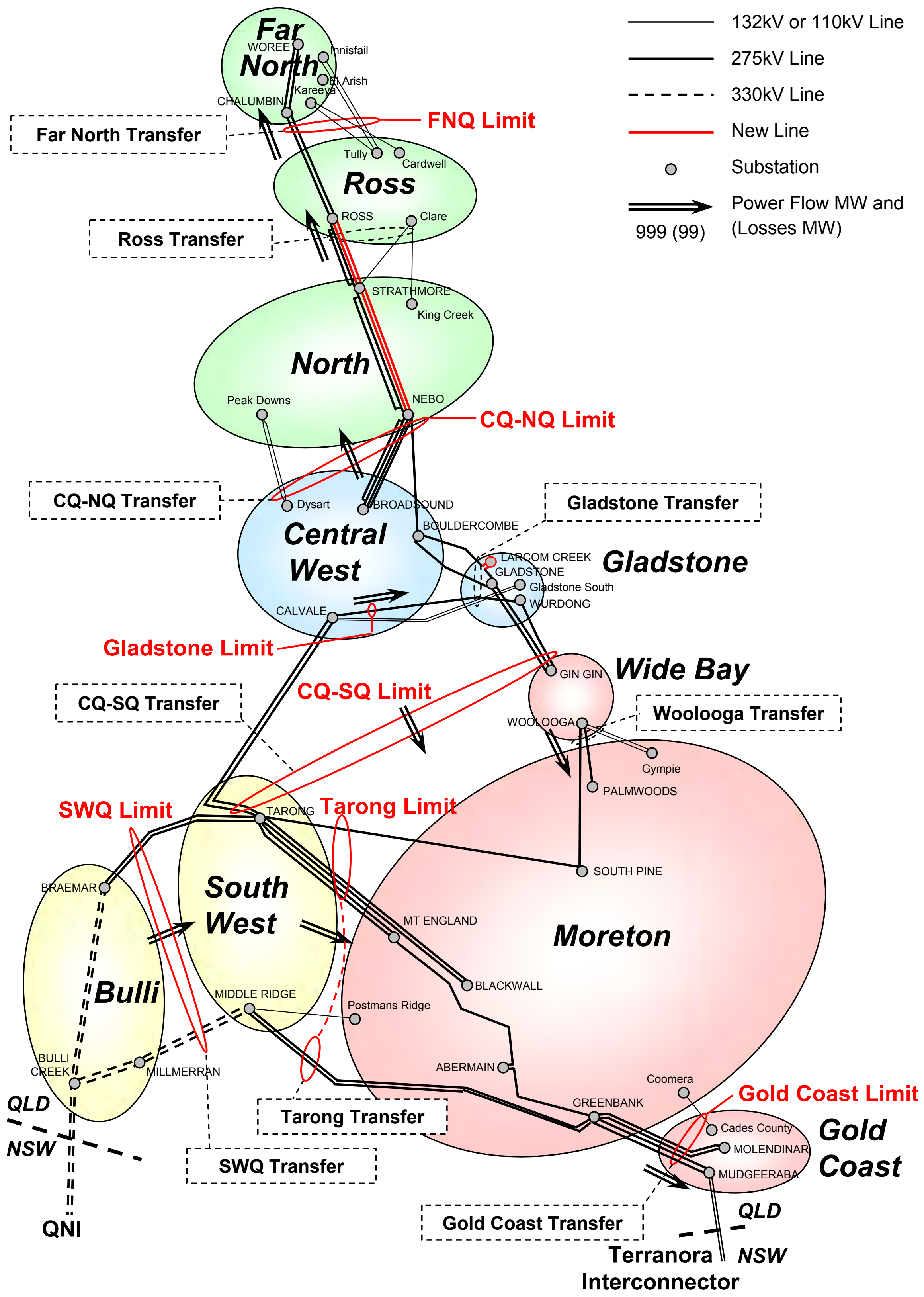
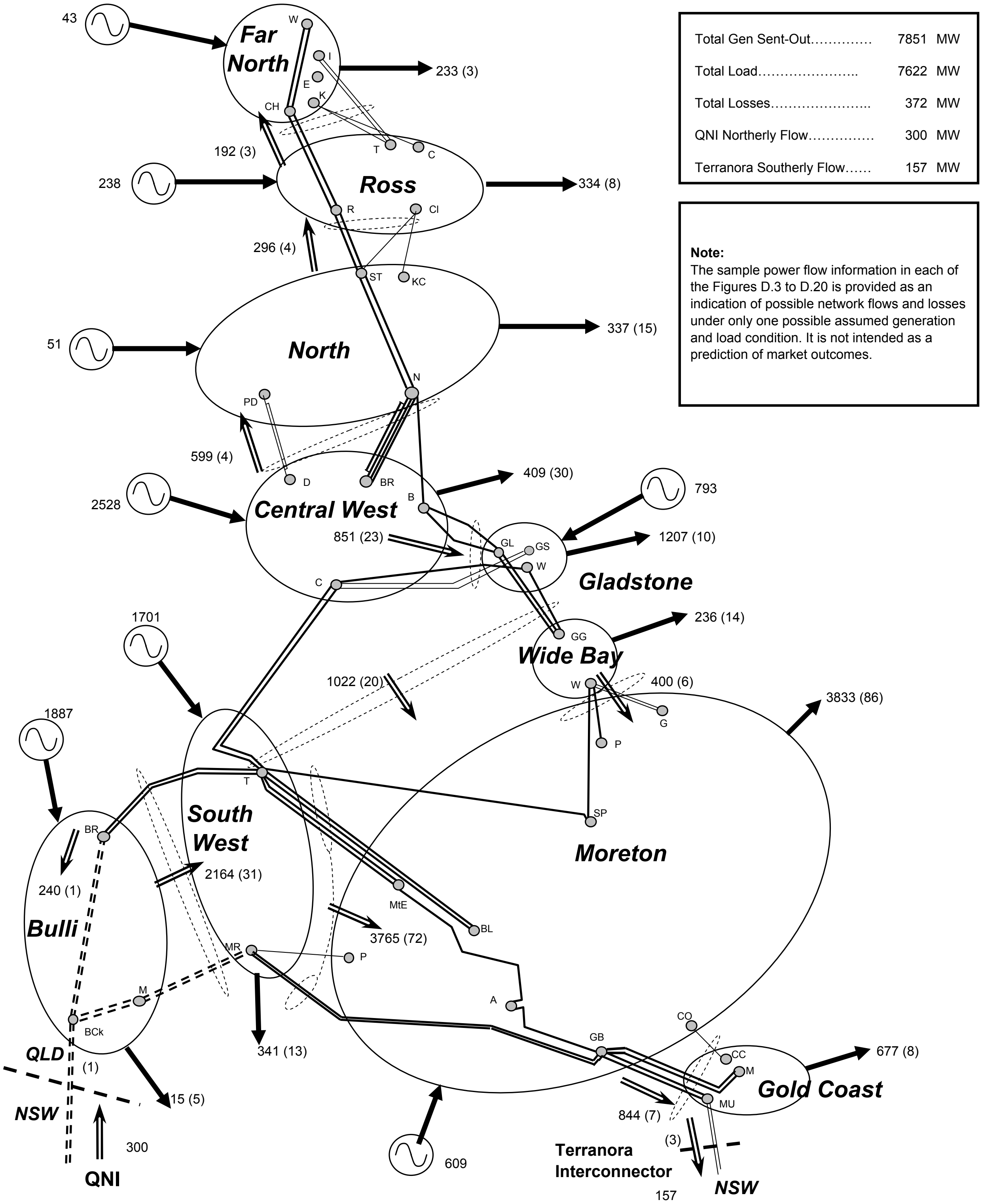


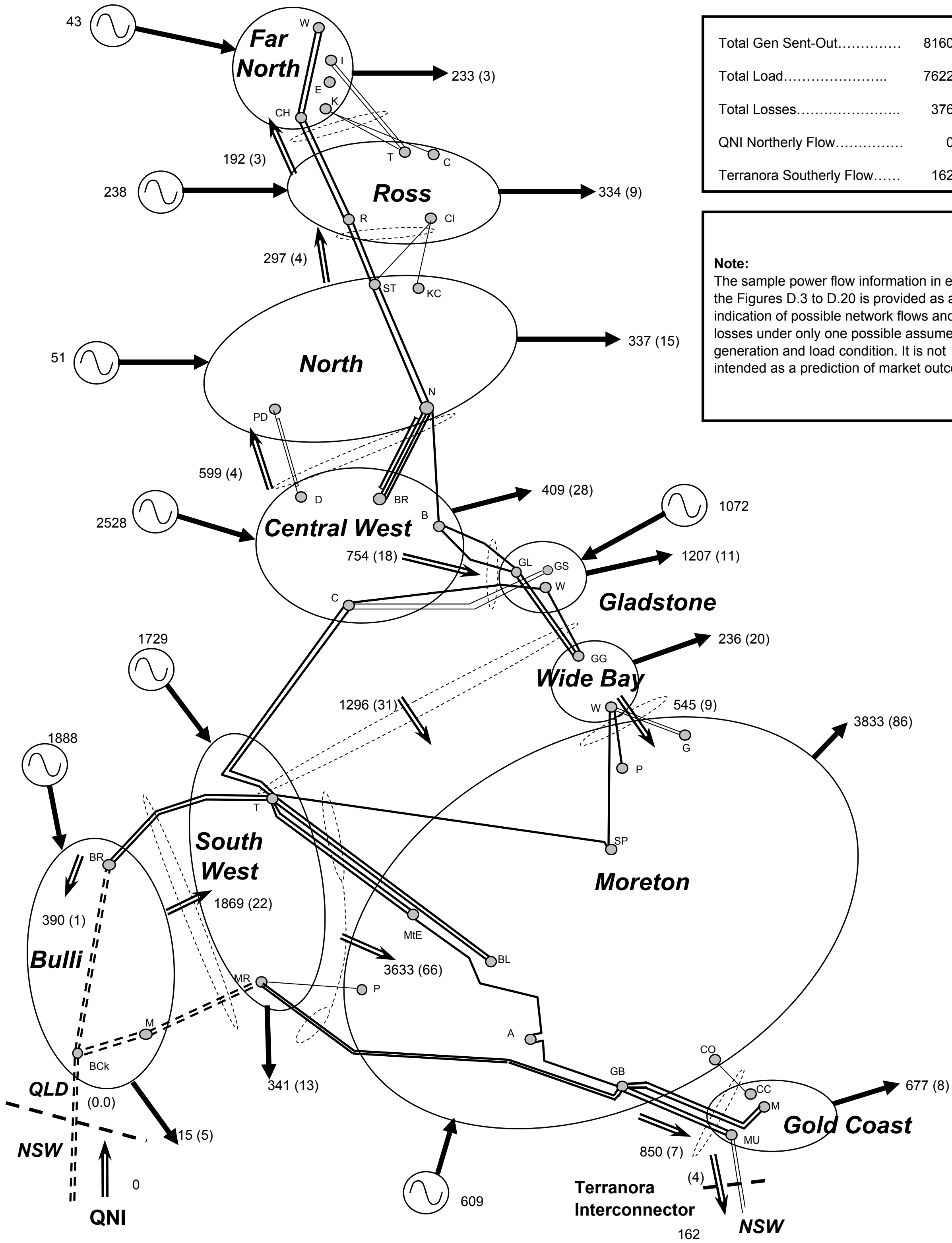
Figure D.3: Winter 2009 Queensland Peak 300MW Northerly QNI Flow



Total Gen Sent-Out.............	7851 MW
Total Load......................	7622 MW
Total Losses......................	372 MW
QNI Northerly Flow..............	300 MW
Terranora Southerly Flow......	157 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

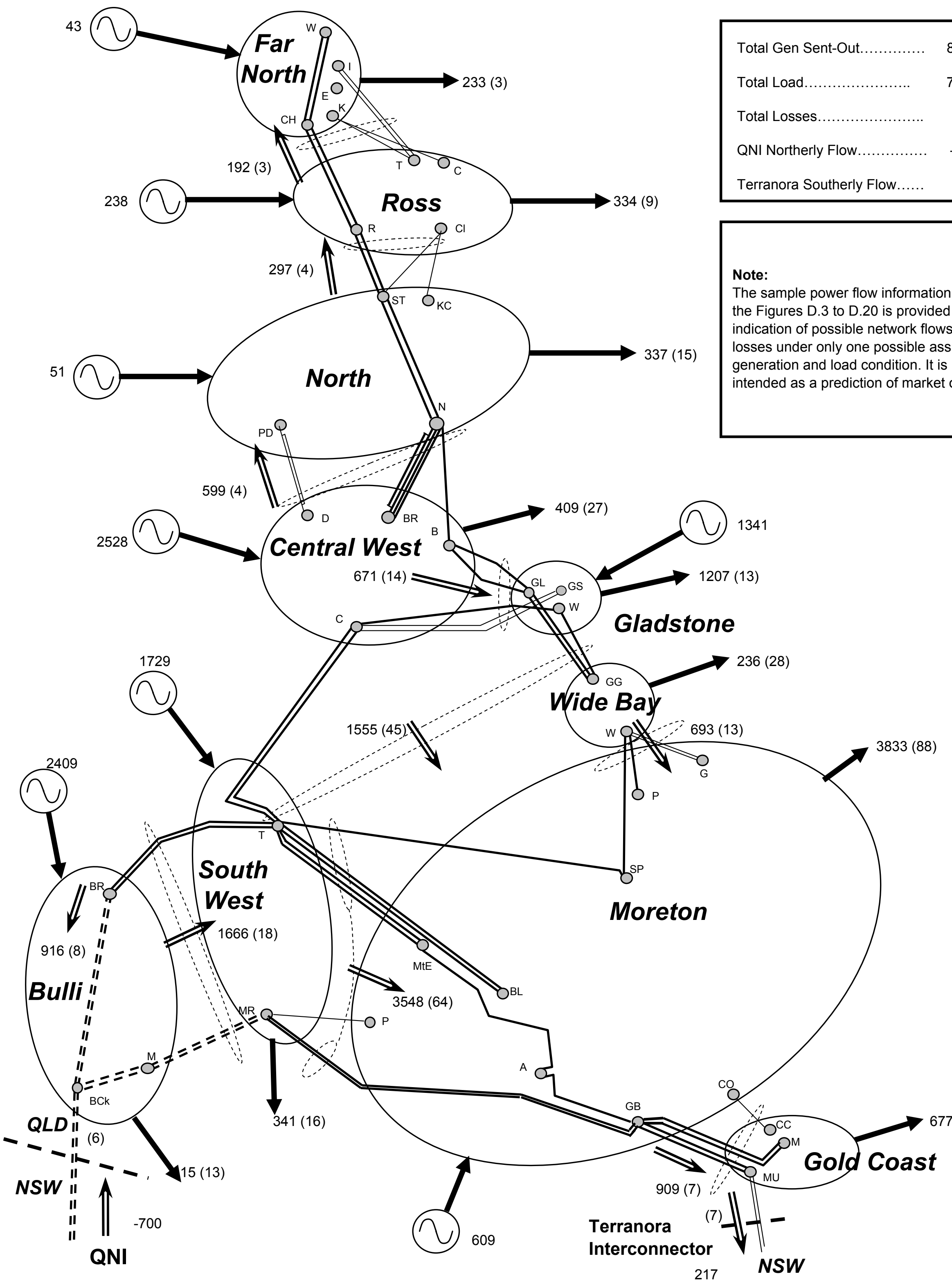
Figure D.4: Winter 2009 Queensland Peak Zero QNI Flow



Total Gen Sent-Out.............	8160 MW
Total Load......................	7622 MW
Total Losses......................	376 MW
QNI Northerly Flow..............	0 MW
Terranora Southerly Flow......	162 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.5: Winter 2009 Queensland Peak 700MW Southerly QNI Flow



Total Gen Sent-Out…………..	8949 MW
Total Load…………………..	7622 MW
Total Losses…………………..	410 MW
QNI Northerly Flow…………..	-700 MW
Terranora Southerly Flow……	217 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.6: Winter 2010 Queensland Peak 300MW Northerly QNI Flow

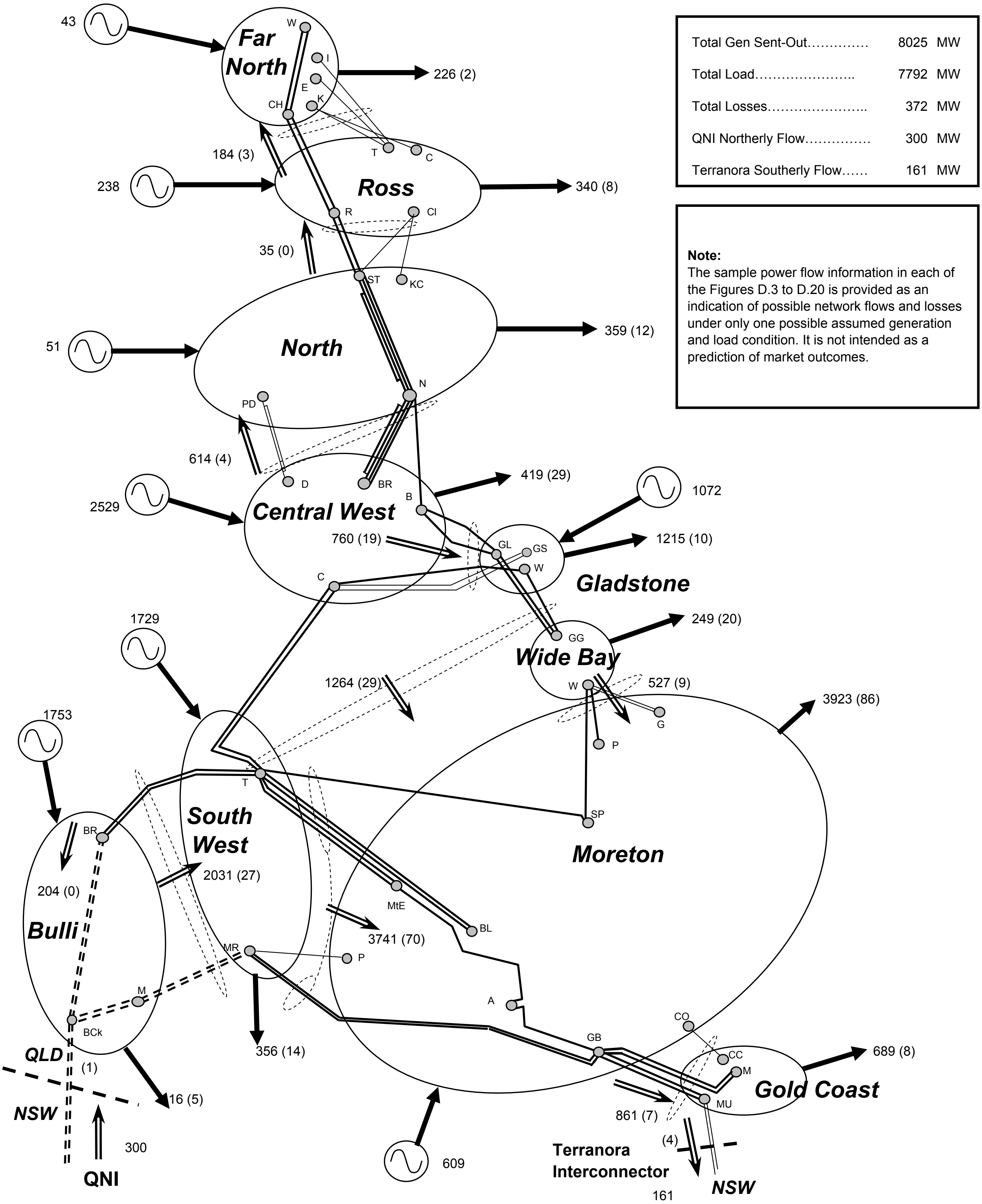
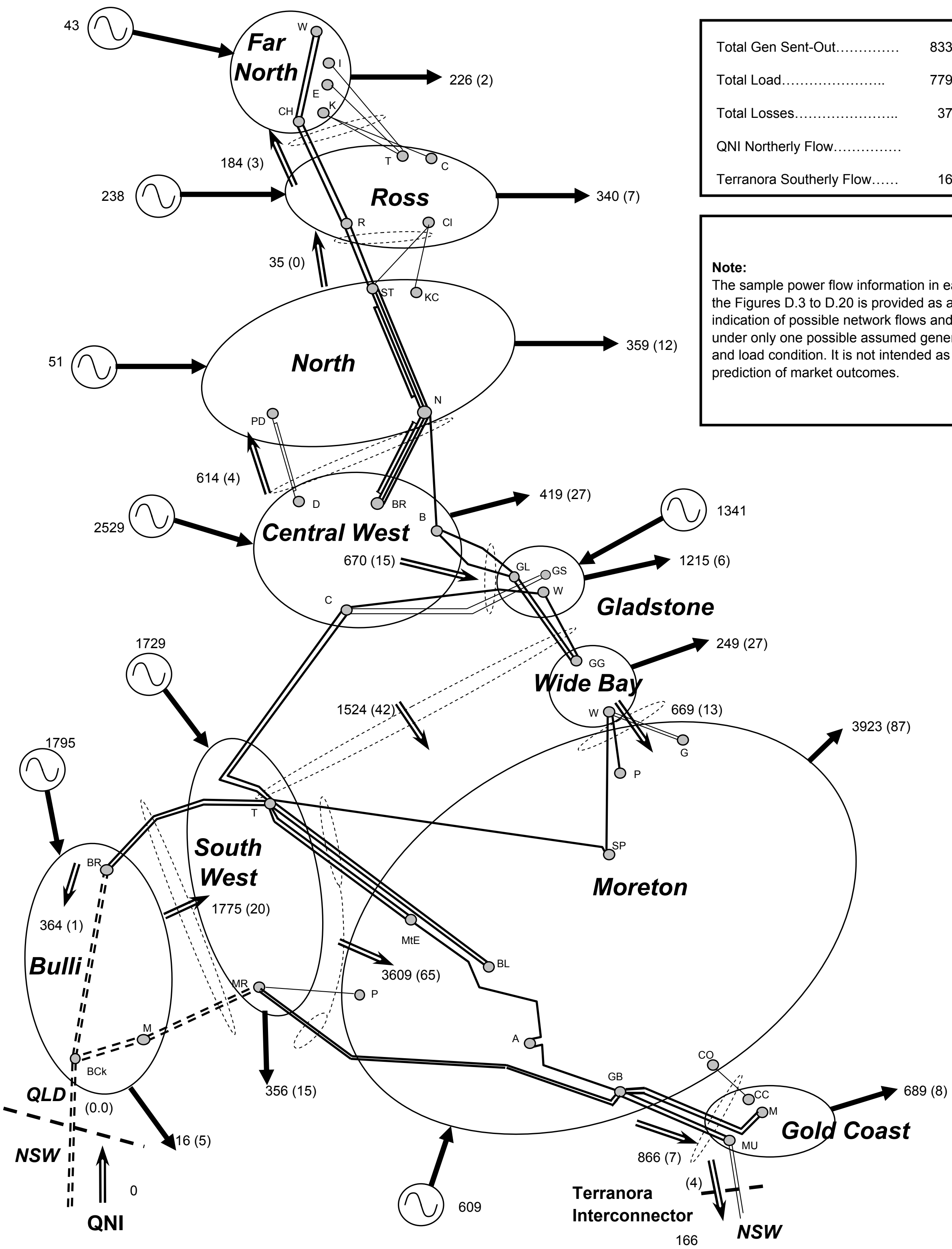


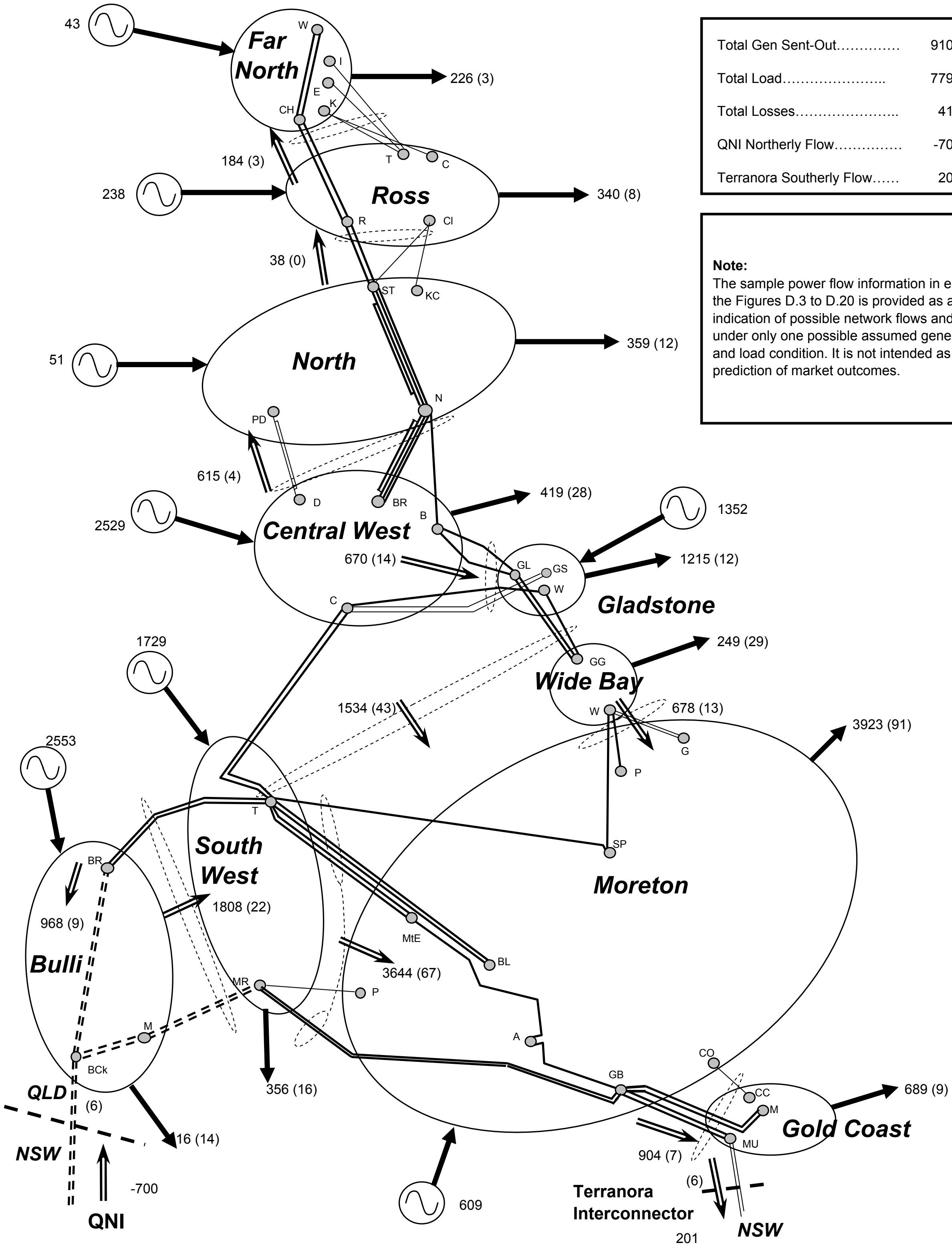
Figure D.7: Winter 2010 Queensland Peak Zero QNI Flow



Total Gen Sent-Out…………..	8335	MW
Total Load…………………..	7792	MW
Total Losses…………………..	377	MW
QNI Northerly Flow…………..	0	MW
Terranora Southerly Flow……	166	MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

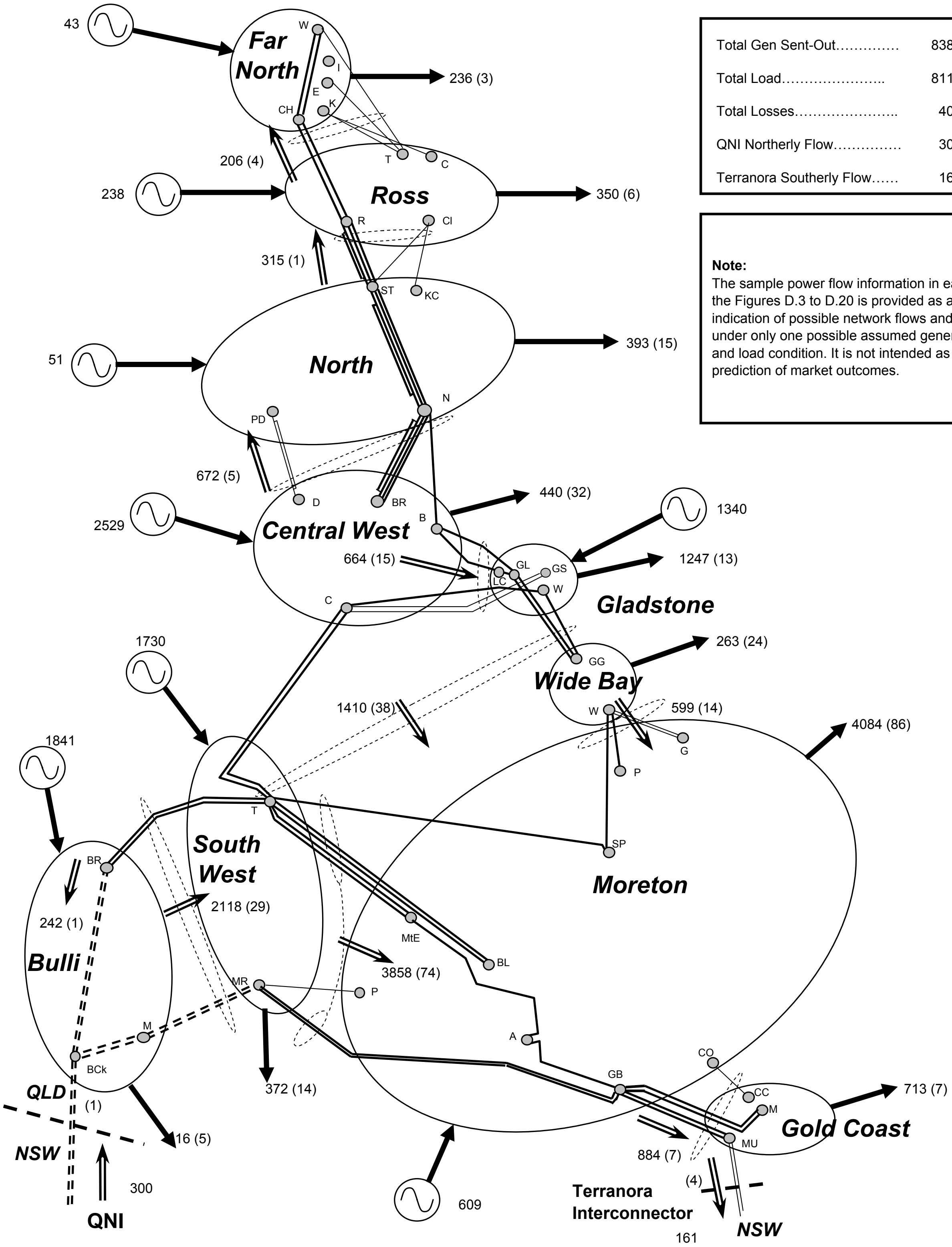
Figure D.8: Winter 2010 Queensland Peak 700MW Southerly QNI Flow



Total Gen Sent-Out..............	9104 MW
Total Load........................	7792 MW
Total Losses.......................	411 MW
QNI Northerly Flow...............	-700 MW
Terranora Southerly Flow......	201 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.9: Winter 2011 Queensland Peak 300MW Northerly QNI Flow



Total Gen Sent-Out…………..	8381	MW
Total Load…………………..	8115	MW
Total Losses…………………..	405	MW
QNI Northerly Flow…………..	300	MW
Terranora Southerly Flow……	161	MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

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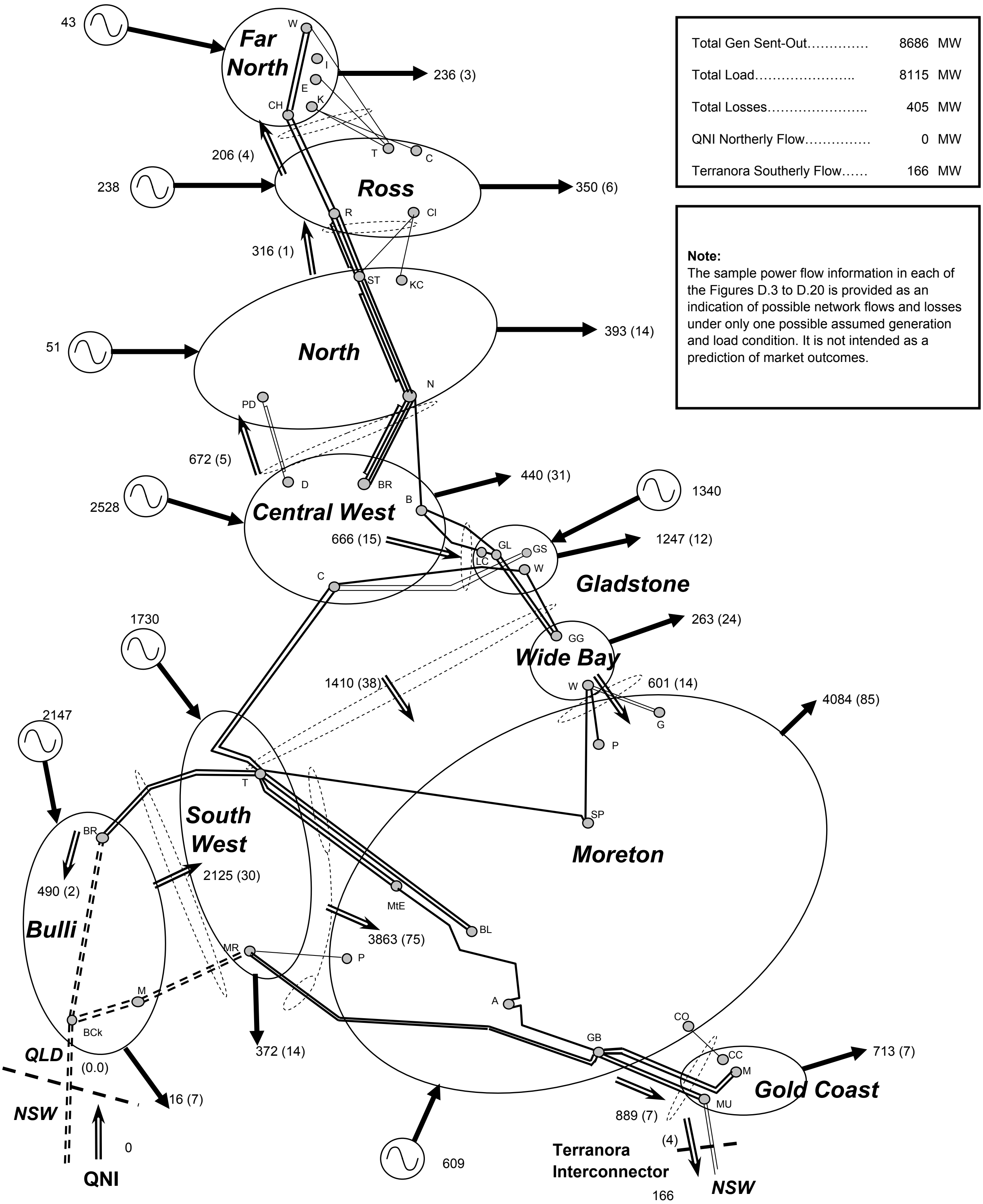
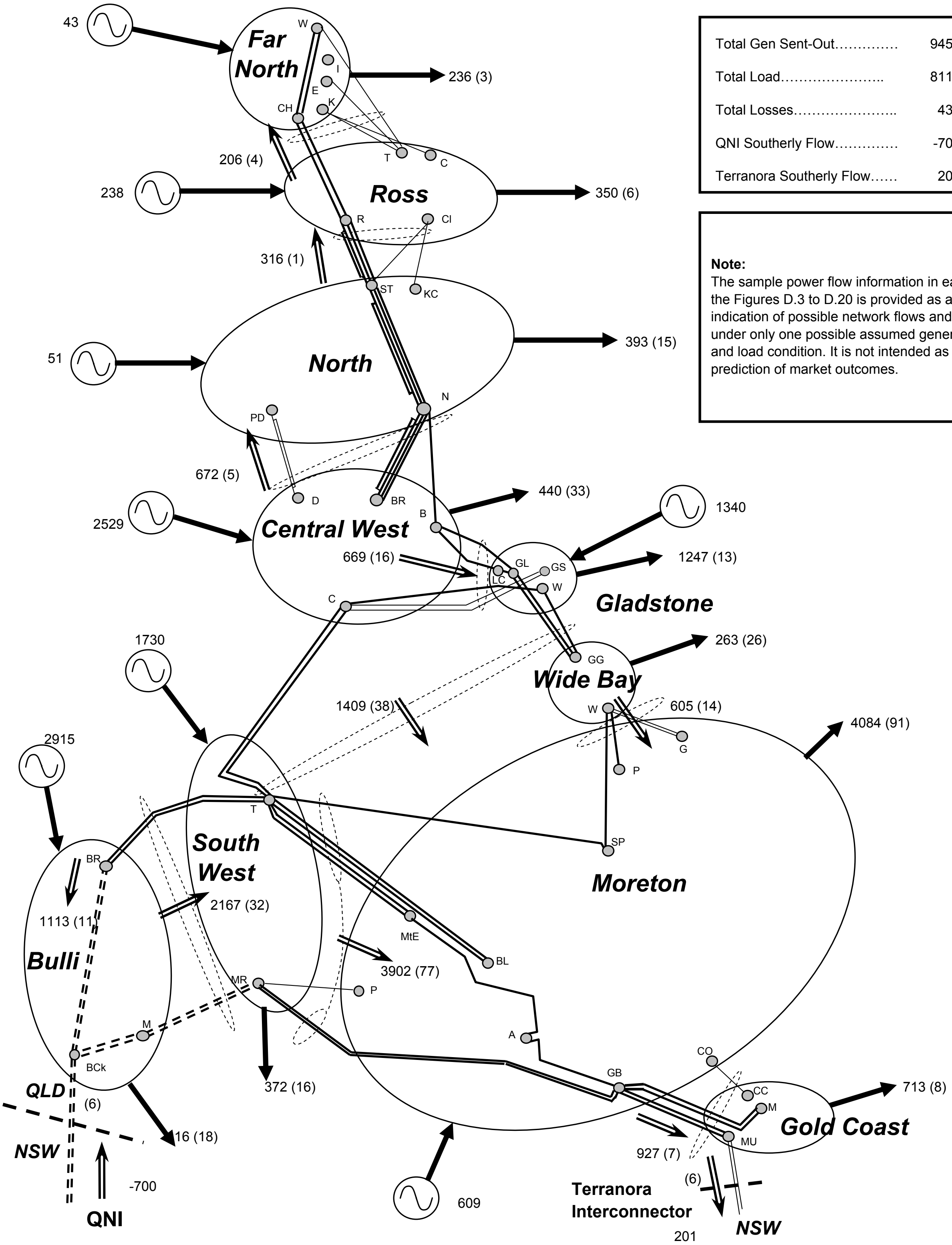
Figure D.10: Winter 2011 Queensland Peak Zero QNI Flow



Total Gen Sent-Out…………..	8686	MW
Total Load…………………..	8115	MW
Total Losses…………………..	405	MW
QNI Northerly Flow……………	0	MW
Terranora Southerly Flow……	166	MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

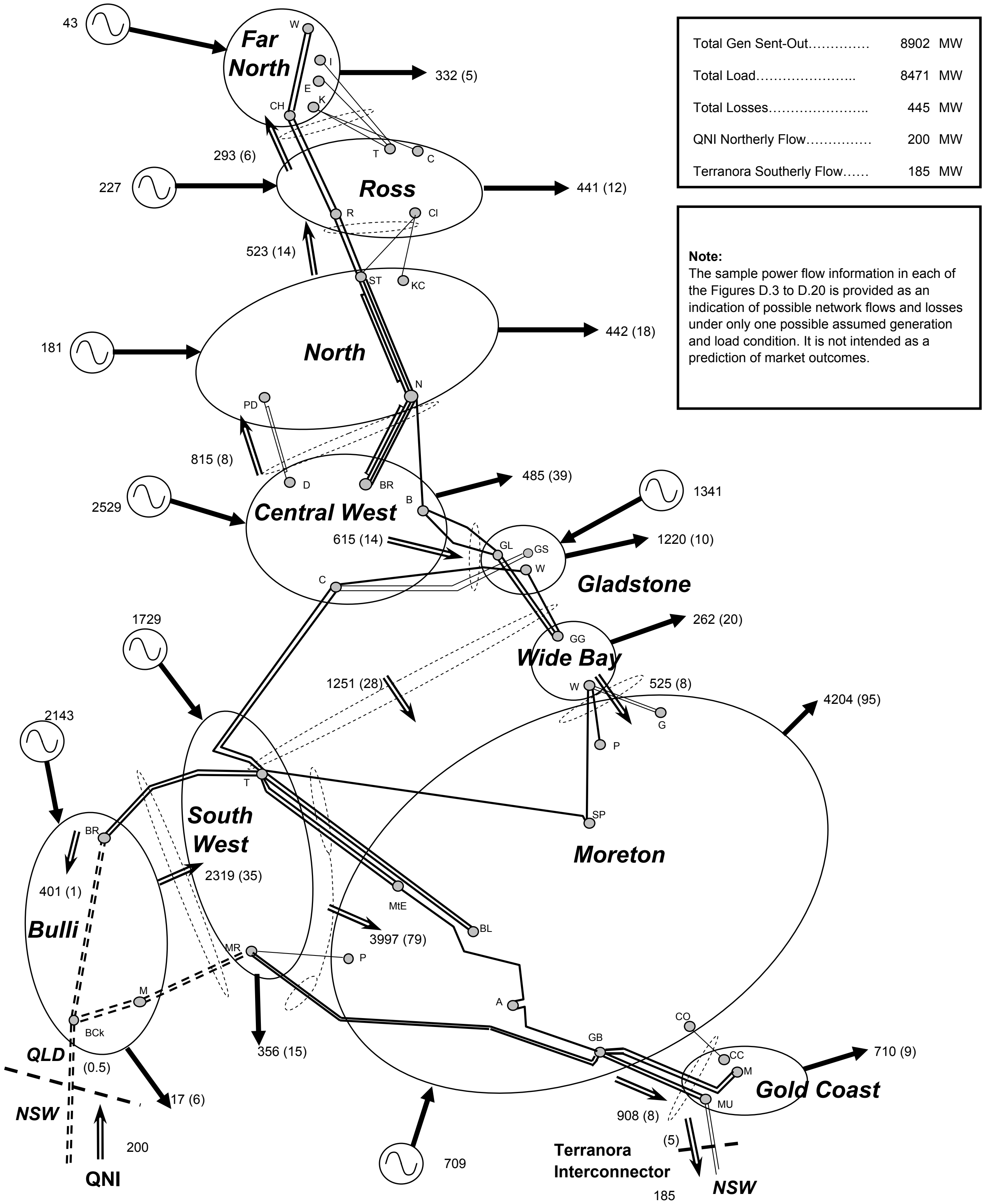
Figure D.11: Winter 2011 Queensland Peak 700MW Southerly QNI Flow



Total Gen Sent-Out…………..	9455 MW
Total Load…………………..	8115 MW
Total Losses…………………..	439 MW
QNI Southerly Flow…………..	-700 MW
Terranora Southerly Flow……	201 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

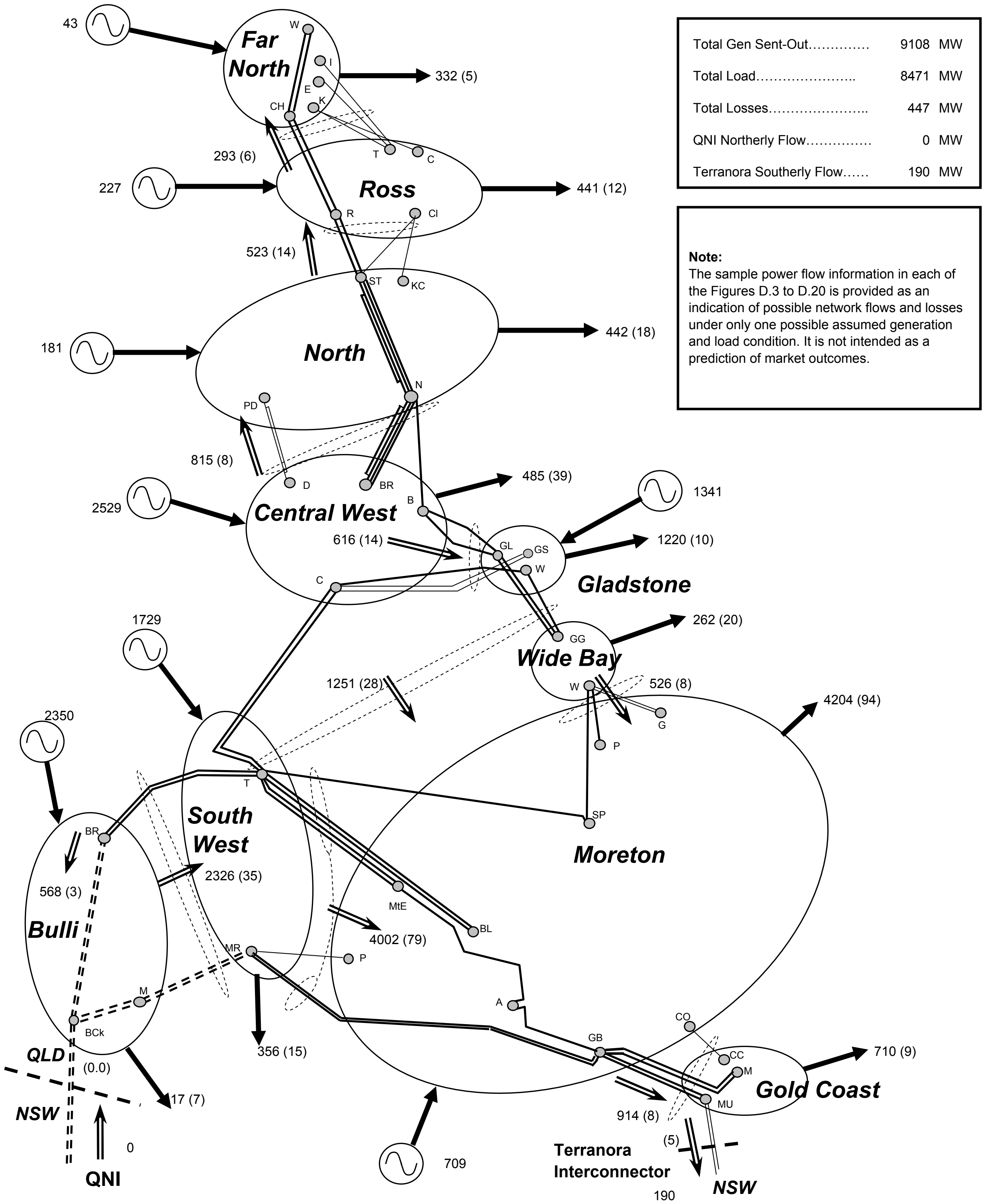
Figure D.12: Summer 2009/10 Queensland Peak 200MW Northerly QNI Flow



Total Gen Sent-Out.............	8902 MW
Total Load........................	8471 MW
Total Losses.......................	445 MW
QNI Northerly Flow..............	200 MW
Terranora Southerly Flow......	185 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.13: Summer 2009/10 Queensland Peak Zero QNI Flow



Total Gen Sent-Out…………..	9108 MW
Total Load…………………..	8471 MW
Total Losses…………………..	447 MW
QNI Northerly Flow…………..	0 MW
Terranora Southerly Flow……	190 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.14: Summer 2009/10 Queensland Peak 400MW Southerly QNI Flow

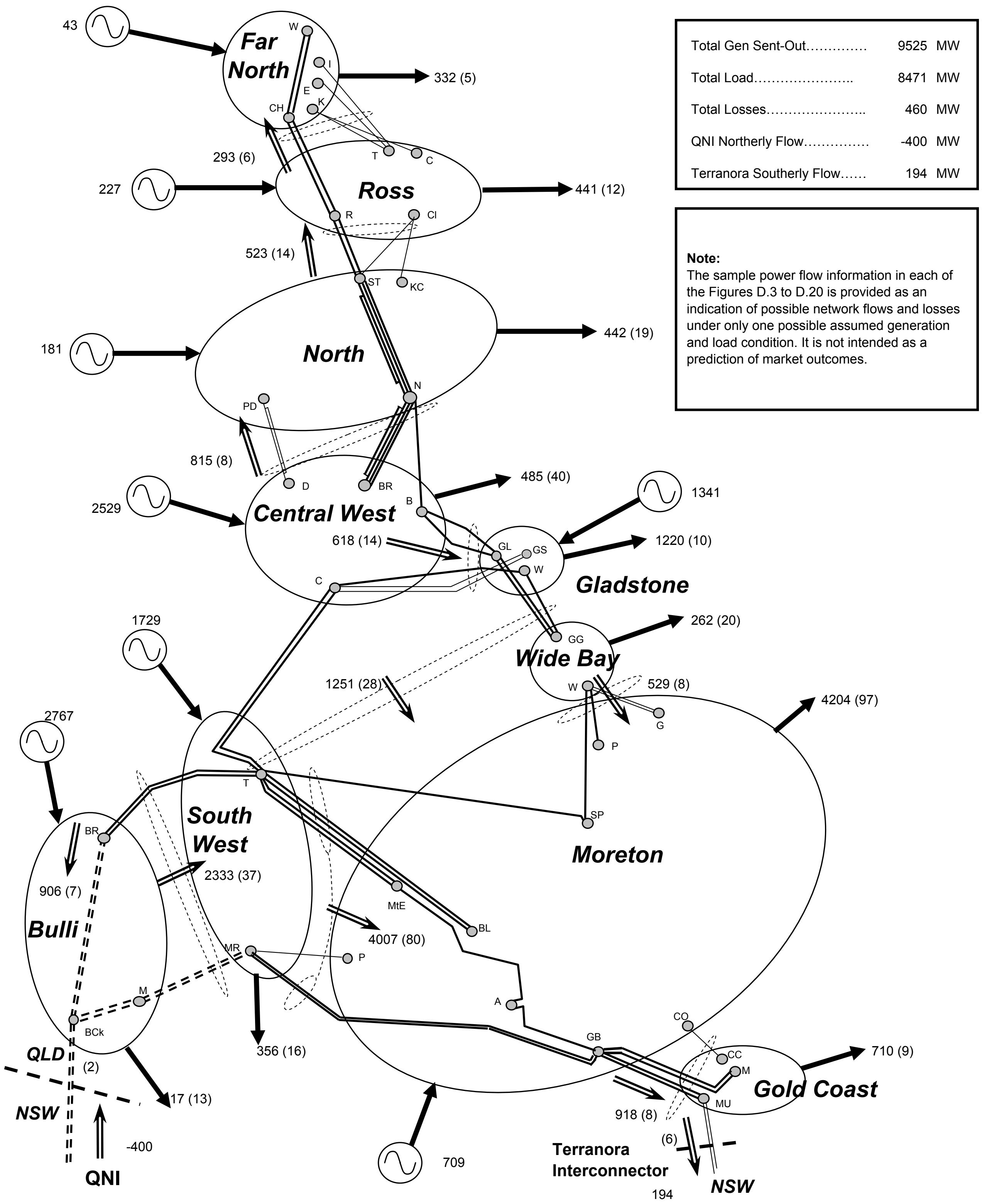
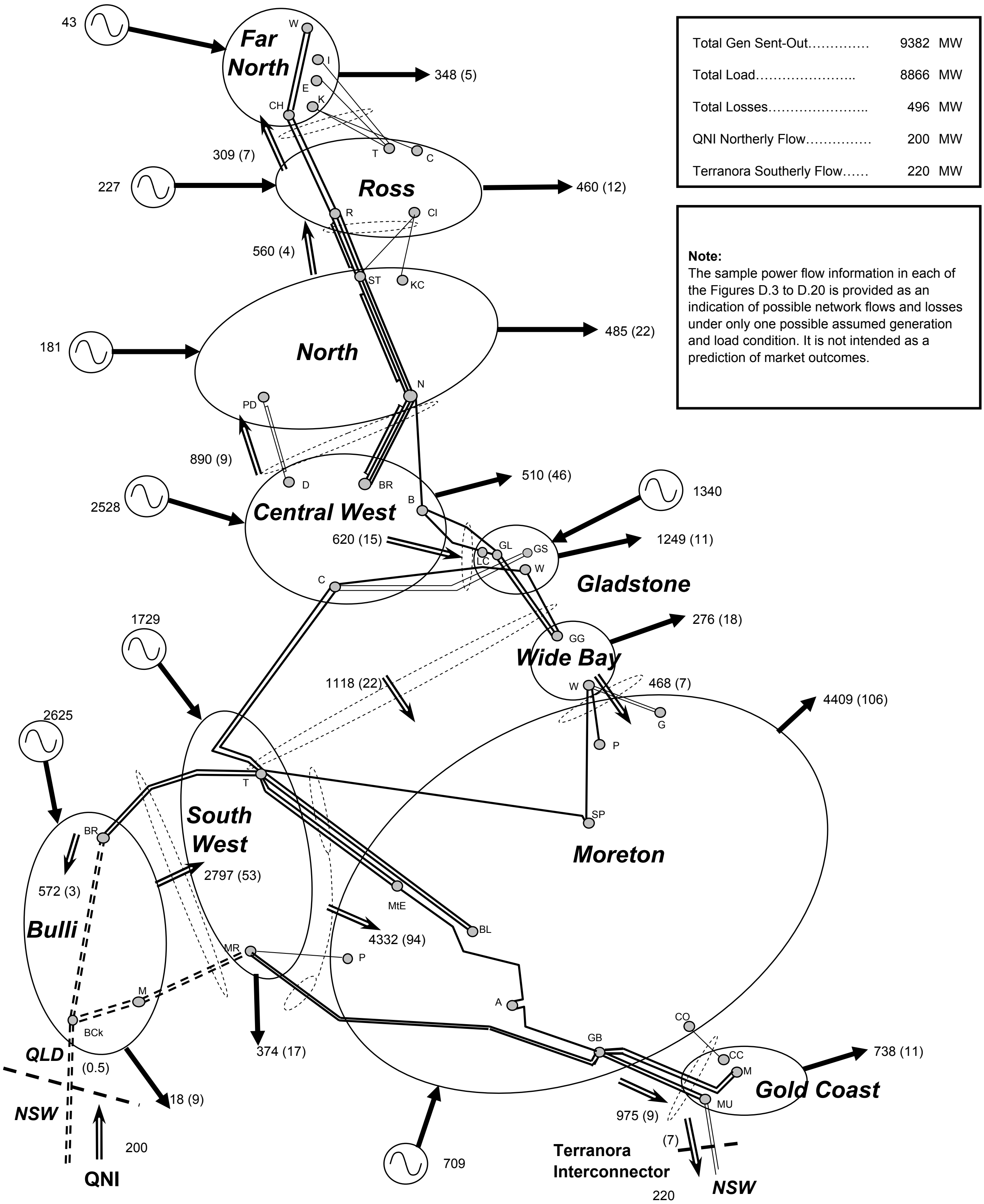


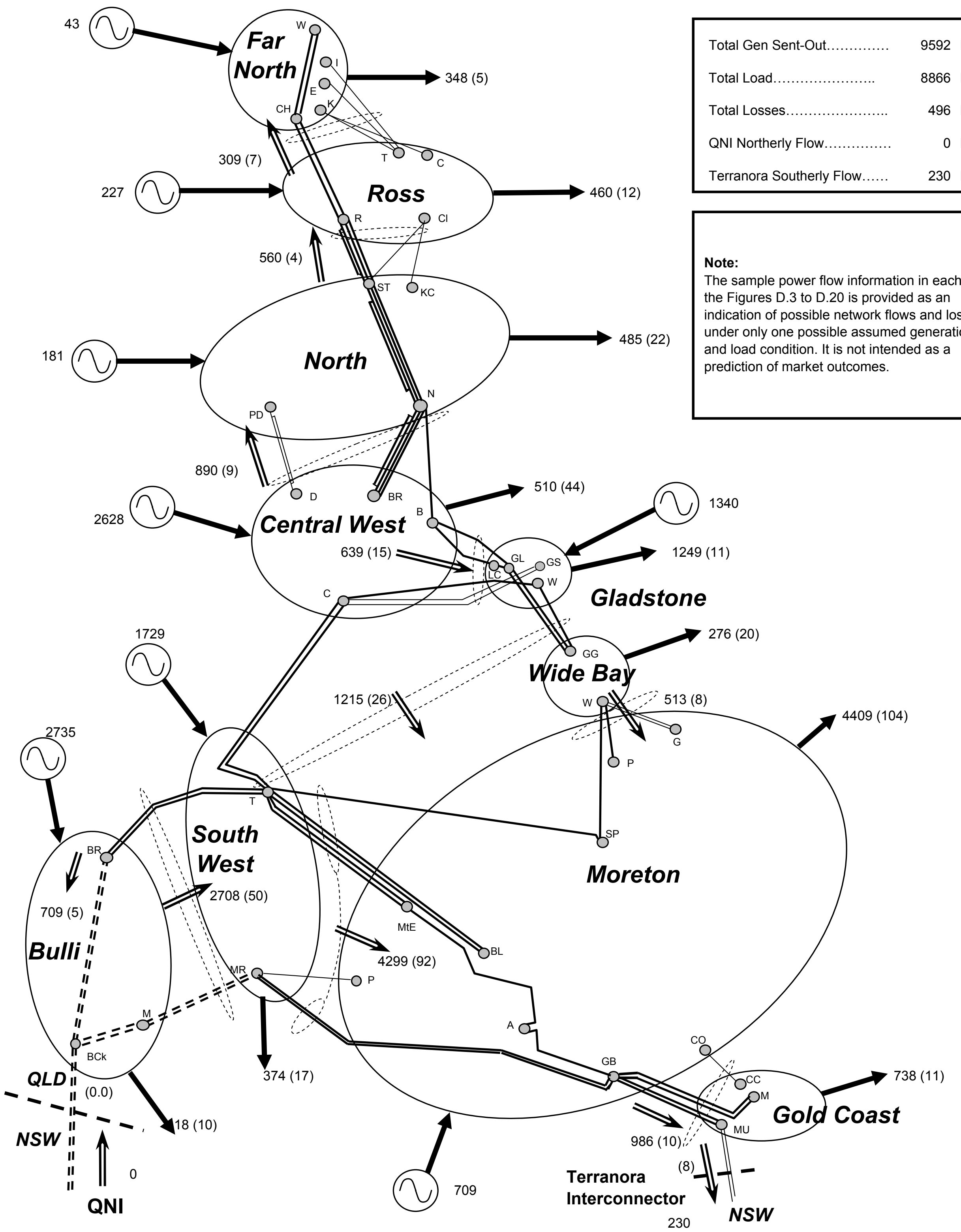
Figure D.15: Summer 2010/11 Queensland Peak 200MW Northerly QNI Flow



Total Gen Sent-Out………….	9382 MW
Total Load…………………..	8866 MW
Total Losses…………………..	496 MW
QNI Northerly Flow……………	200 MW
Terranora Southerly Flow……	220 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

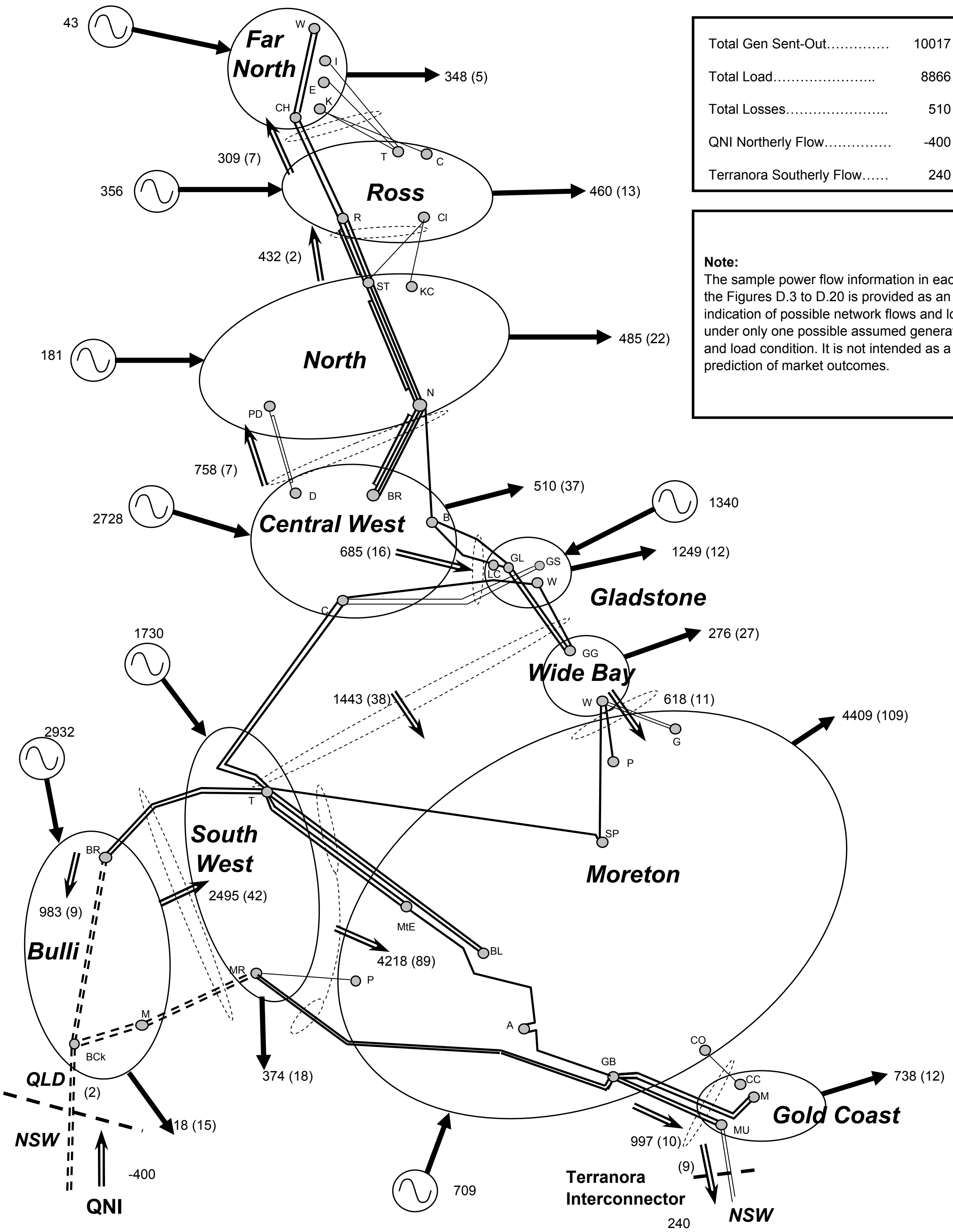
Figure D.16: Summer 2010/11 Queensland Peak Zero QNI Flow



Total Gen Sent-Out.............	9592 MW
Total Load......................	8866 MW
Total Losses......................	496 MW
QNI Northerly Flow..............	0 MW
Terranora Southerly Flow......	230 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

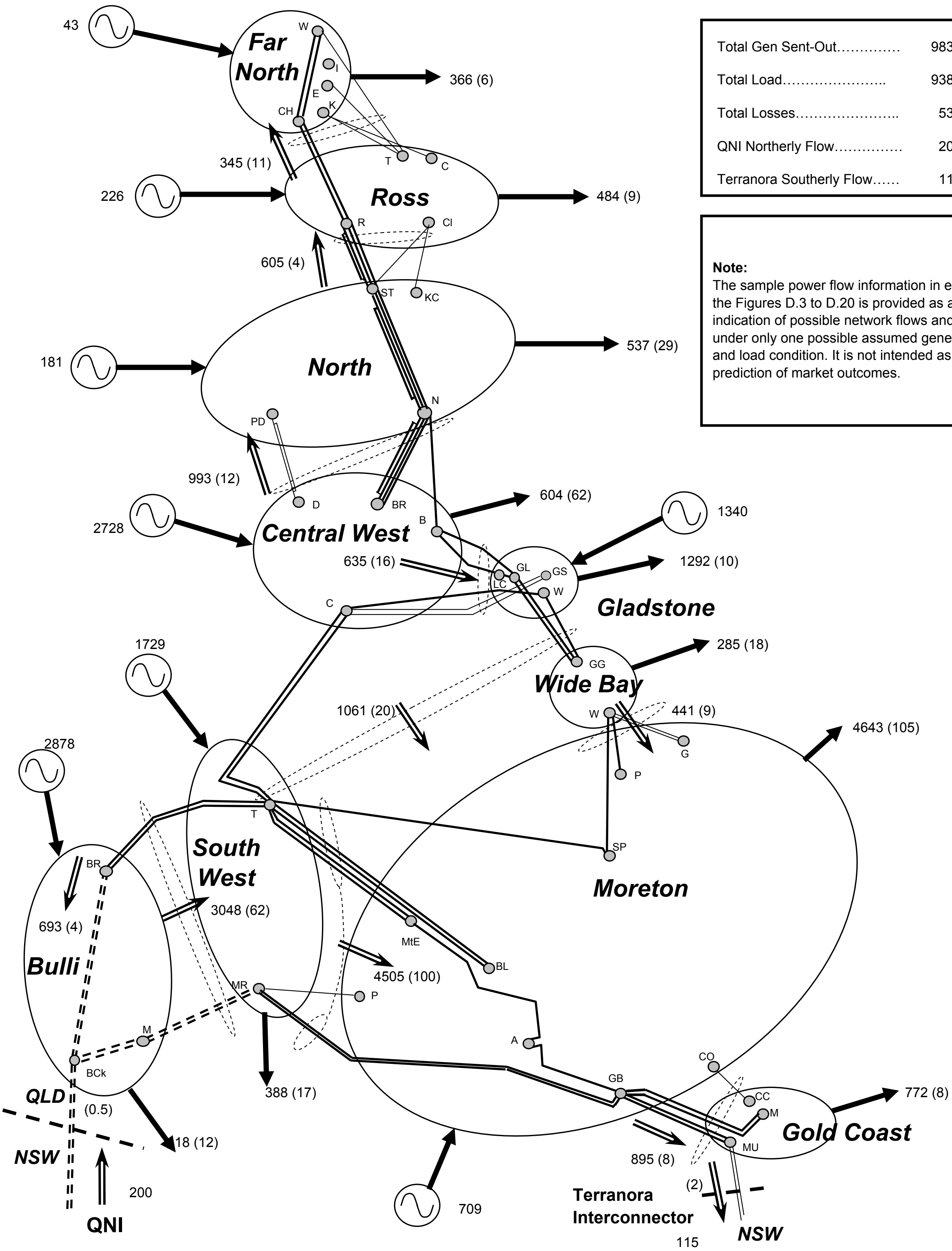
Figure D.17: Summer 2010/11 Queensland Peak 400MW Southerly QNI Flow



Total Gen Sent-Out..............	10017 MW
Total Load.......................	8866 MW
Total Losses.......................	510 MW
QNI Northerly Flow..............	-400 MW
Terranora Southerly Flow......	240 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

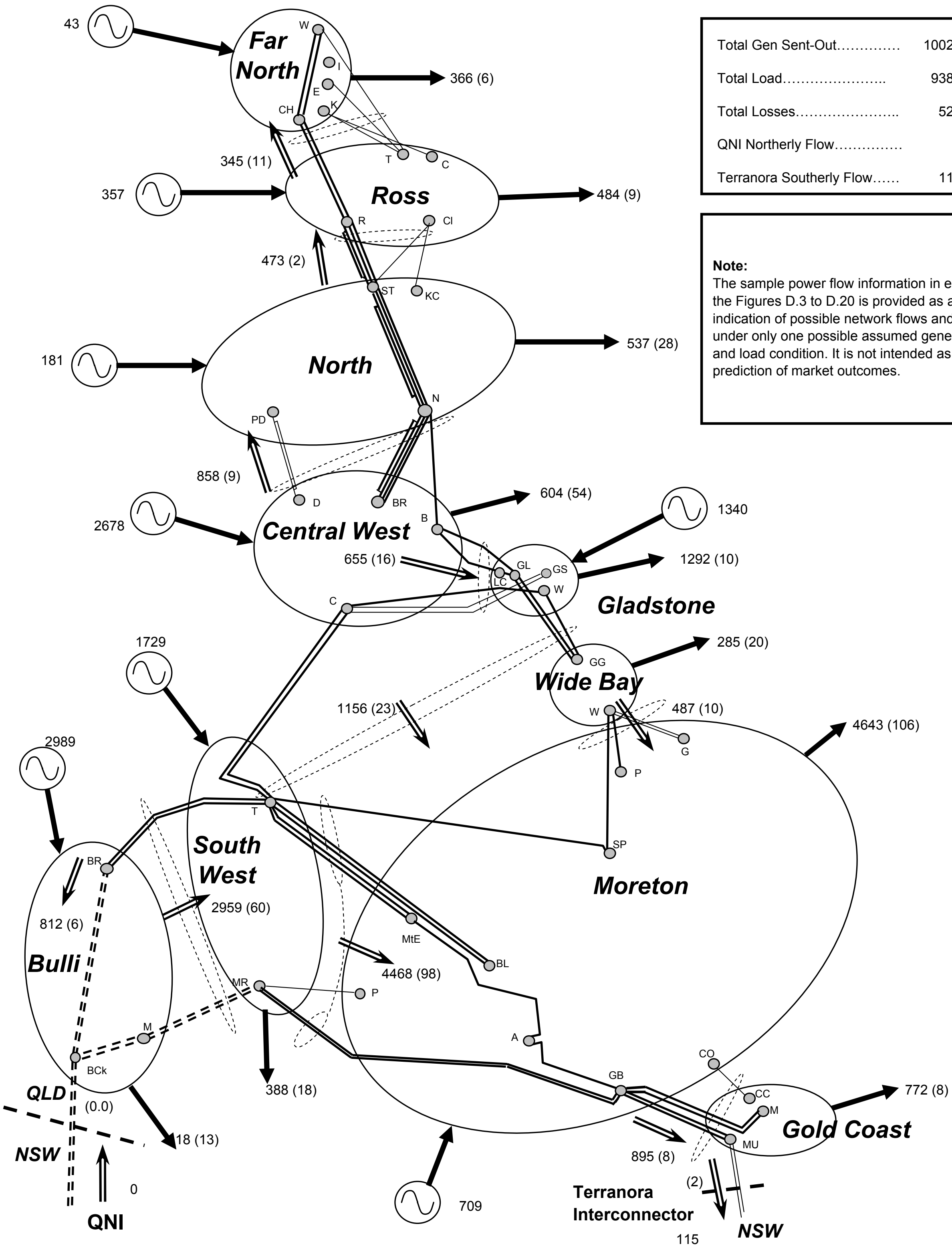
Figure D.18: Summer 2011/12 Queensland Peak 200MW Northerly QNI Flow



Total Gen Sent-Out.............	9834	MW
Total Load......................	9389	MW
Total Losses.....................	531	MW
QNI Northerly Flow..............	200	MW
Terranora Southerly Flow......	115	MW

Note:
The sample power flow information in each of the Figures D.3 to D.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.

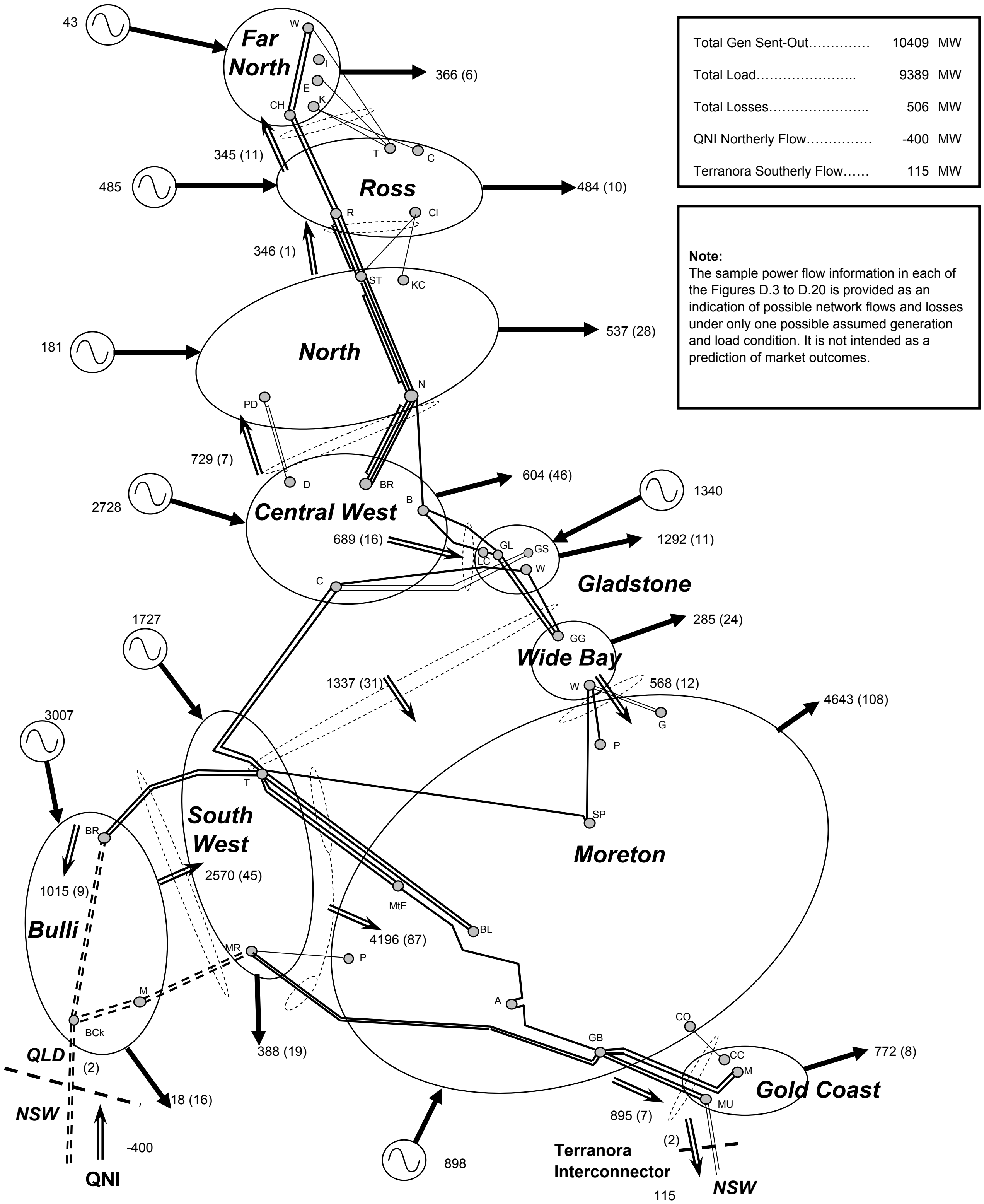
Figure D.19: Summer 2011/12 Queensland Peak Zero QNI Flow



Total Gen Sent-Out…………..	10026 MW
Total Load…………………..	9389 MW
Total Losses…………………..	522 MW
QNI Northerly Flow…………..	0 MW
Terranora Southerly Flow……	115 MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 D.20: Summer 2011/12 Queensland Peak 400MW Southerly QNI Flow



Total Gen Sent-Out.............	10409	MW
Total Load......................	9389	MW
Total Losses......................	506	MW
QNI Northerly Flow..............	-400	MW
Terranora Southerly Flow......	115	MW

Note:
The sample power flow information in each of the Figures D.3 to D.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 E – Limit Equations

This appendix contains the Queensland intra-regional limit equations derived by Powerlink Queensland and are valid at the time of publication. The National Electricity Market Management Company's (NEMMCO's) market systems may also contain other limit equations for the Queensland region. These other equations are derived for thermal limits and are maintained by NEMMCO.

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 E.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) FNQ demand percentage = $\frac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

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

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + 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 of 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 of 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 E.2: Central to North Queensland Stability Equations

Measured Variable	Coefficient
Constant term (intercept)	1,180
Generation MW from highest generating North Queensland gas turbine (1)	-1
Reactive (MVAr) output of Ross SVC	-0.5
Number of 120MVAr capacitor banks available at Nebo [0 to 2]	50
Number of 20MVAr reactors on line at Nebo [0 to 3]	-8
Number of 84MVAr reactors on line at Nebo [0 to 1]	-35
Equation Upper Limit	**1,180**

Note:

(1) North Queensland gas turbine refers to either of the Mt Stuart or Townsville gas turbine units. The combined cycle arrangement at Townsville PS means that both the 132kV and 66kV components can trip as a single contingency.

Table E.3: Central to South Queensland 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**

Note:

(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).

Table E.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	0.0990	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

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
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 two capacitor banks sized 200MVAr which may be available within this area.

(6) There are currently 13 capacitor banks sized 120MVAr which may be available within this area.

(7) There are currently 35 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 E.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 = $\frac{\text{Moreton zone demand}}{\text{Gold Coast zone demand}}$

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

(5) There are currently 13 capacitor banks sized 120MVAr which may be available within this area.

(6) There are currently 33 capacitor banks sized 50MVAr which may be available within this area.

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 2009 to 2011. They also show the short circuit interruption capacity of the lowest rated circuit breaker(s) 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; and
- 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 6.1 (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 switchgear rating, either the critical switchgear is required to interrupt only a portion of the total fault current and that portion is less than the switchgear rating over the three year outlook period, or operational measures are taken to ensure that short circuit levels are within the switchgear rating.

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

Table F.1: Estimated Maximum Short Circuit Levels - Northern Queensland - Powerlink Transmission Network 2009 to 2011

Substation	Voltage kV	CB Fault Rating (Lowest kA)	Fault Levels 2009 3 Phase kA	2009 L - G kA	2010 3 Phase kA	2010 L - G kA	2011 3 Phase kA	2011 L - G kA
Alan Sherriff	132	40.0	11.8	12.5	12.4	13.0	12.1	12.8
Alligator Creek	132	31.5	4.3	5.6	4.3	5.7	4.3	5.7
Bollingbroke	132	40.0	2.2	1.7	2.2	1.7	2.2	1.7
Burton Downs	132	19.3	5.0	4.7	5.0	4.8	5.0	4.8
Cairns (2T)	132	25.0	5.2	6.9	5.3	7.1	5.0	6.7
Cairns (3T)	132	25.0	5.2	6.9	5.3	7.1	5.0	6.7
Cairns (4T)	132	25.0	5.2	7.0	5.3	7.2	5.0	6.7
Cardwell	132	19.3	3.0	2.3	3.0	2.3	2.7	1.9
Chalumbin	275	21.9	3.6	3.9	3.8	4.0	3.5	3.8
Chalumbin	132	31.5	6.6	7.6	6.8	7.7	6.0	7.1
Clare South	132	8.8	7.6	7.8	7.6	7.9	7.6	7.8
Collinsville	132	15.3	12.2	13.7	12.4	13.9	12.4	13.9
Coppabella	132	31.5	3.0	3.3	3.0	3.3	3.0	3.3
Dan Gleeson (Bus 1)	132	40.0	11.2	11.9	11.7	12.4	11.5	12.2
Dan Gleeson (Bus 2)	132	40.0	11.1	11.8	11.7	12.2	11.5	12.1
Edmonton	132	40.0	4.8	5.9	4.9	6.1	4.6	5.7
El Arish	132	40.0	3.3	4.0	3.4	4.0	3.1	3.7
Garbutt	132	NO CB	9.8	10.1	10.2	10.3	10.1	10.2
Ingham South	132	40.0	2.7	2.9	2.7	2.9	3.8	3.5
Innisfail	132	40.0	2.9	3.5	2.9	3.6	2.7	3.4
Invicta	132	19.3	5.2	4.6	5.2	4.7	5.2	4.7
Kamerunga	132	15.3	4.1	4.9	4.2	5.0	4.0	4.8
Kareeya	132	10.9	6.5	7.5	6.7	7.7	5.9	6.9
Kemmis	132	40.0	5.6	6.2	5.6	6.2	5.6	6.2
King Creek	132	40.0	5.0	4.1	5.0	4.1	5.0	4.1
Mackay	132	15.7	6.0	6.6	6.1	6.6	6.1	6.6
Mackay Ports	132	40.0	3.2	3.6	3.3	3.6	3.3	3.6
Mindi	132	40.0	4.9	4.1	5.0	4.2	5.0	4.2
Moranbah	132	15.3	6.8	7.8	6.8	8.0	6.8	8.0
Moranbah South	132	40.0	5.1	4.7	5.1	4.8	5.1	4.8

Table F.1: Estimated Maximum Short Circuit Levels - Northern Queensland - Powerlink Transmission Network 2009 to 2011 (cont.)

Substation	Voltage kV	CB Fault Rating (Lowest kA)	Fault Levels					
			2009		2010		2011	
			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	2.1	2.0	2.1	2.0	2.1
Nebo	275	31.5	9.1	9.5	9.6	9.8	9.6	9.8
Nebo	132	21.9	11.5	12.9	11.8	13.2	11.8	13.2
Newlands	132	31.5	3.2	3.6	3.2	3.6	3.2	3.6
North Goonyella	132	19.3	3.4	2.7	3.4	2.7	3.4	2.7
Oonooie	132	31.5	3.0	3.6	3.0	3.6	3.0	3.6
Peak Downs	132	40.0	4.9	4.2	4.9	4.2	4.9	4.2
Pioneer Valley	132	40.0	6.3	6.8	6.4	6.9	6.4	6.9
Proserpine	132	21.9	3.6	3.8	3.6	3.8	3.6	3.8
Ross	275	31.5	6.5	7.4	7.7	8.5	7.7	8.5
Ross	132	31.5	15.1	17.6	16.2	18.6	16.0	18.5
Stony Creek	132	40.0	3.7	3.5	3.7	3.5	3.7	3.5
Strathmore	275	50.0	7.8	8.1	8.6	8.8	8.6	8.8
Strathmore	132	40.0	11.7	12.6	11.9	12.8	11.9	12.8
Townsville East	132	40.0	11.9	11.9	12.4	12.2	12.3	12.2
Townsville South	132	21.9	15.3	19.0	16.1	19.8	16.0	19.6
Townsville GT PS	132	31.5	10.1	10.8	10.5	11.1	9.7	10.4
Tully	132	31.5	4.3	4.5	4.4	4.5	3.8	4.0
Turkinje	132	15.7	2.7	3.0	2.7	3.1	2.6	3.0
Wandoo	132	40.0	4.2	3.0	4.3	3.0	4.3	3.0
Woree (1T)	275	50.0	2.5	2.9	2.5	3.0	2.4	2.9
Woree (2T)	275	50.0	2.5	2.9	2.5	3.0	2.4	2.8
Woree	132	40.0	5.4	7.4	5.5	7.6	5.1	7.1
Yabulu South	132	40.0	11.1	10.7	11.6	11.0	11.2	11.0

Table F.2: Estimated Maximum Short Circuit Levels - Central Queensland - Powerlink Transmission Network 2009 to 2011

Substation	Voltage kV	CB Fault Rating (Lowest kA)	Fault Levels					
			2009		2010		2011	
			3 Phase kA	L - G kA	3 Phase kA	L - G kA	3 Phase kA	L - G kA
Baralaba	132	15.3	4.6	3.8	4.7	3.8	4.7	3.8
Biloela	132	40.0	7.7	7.9	7.8	7.9	7.8	7.9
Blackwater	132	12.3	5.5	6.5	5.6	6.5	5.6	6.5
Bouldercombe	275	31.5	16.7	16.7	17.1	17.1	17.1	17.1
Bouldercombe	132	25.0	9.1	10.8	9.1	10.8	9.1	10.8
Broadsound	275	31.5	10.5	8.2	10.8	8.3	10.8	8.3
Callemondah	132	31.5	21.0	21.3	21.3	21.5	21.3	21.5
Callide A	132	12.3	11.0	11.7	11.0	11.8	11.0	11.8
Calvale	275	31.5	20.1	22.5	20.2	22.7	20.2	22.7
Calvale	132	NO CB	11.0	11.7	11.0	11.7	11.0	11.7
Dingo	132	31.5	2.7	2.8	2.7	2.8	2.7	2.8
Dysart	132	19.9	4.4	5.0	4.4	5.0	4.4	5.0
Egans Hill	132	NO CB	6.1	6.5	6.1	6.5	6.1	6.5
Gladstone	275	31.5	19.8	22.6	20.8	23.9	20.8	23.9
Gladstone (1)	132	31.5	26.7	32.4	27.2	33.0	27.2	33.0
Gladstone South	132	40.0	17.6	17.8	17.8	18.0	17.8	18.0
Grantleigh	132	31.5	2.4	2.5	2.4	2.5	2.4	2.5
Gregory	132	31.5	8.5	9.8	8.6	9.8	8.6	9.8
Larcom Creek	275	40.0	13.3	13.4	14.5	14.7	14.5	14.7
Larcom Creek	132	NO CB	9.7	11.0	12.0	14.0	12.0	14.0
Lilyvale	275	40.0	5.4	5.4	5.5	5.5	5.5	5.5
Lilyvale	132	25.0	8.9	10.5	9.0	10.6	9.0	10.6
Moura	132	12.3	4.0	4.2	4.0	4.2	4.0	4.2
Norwich Park	132	40.0	3.4	2.6	3.4	2.6	3.4	2.6
Pandoin	132	40.0	5.1	5.1	5.1	5.1	5.1	5.1
Rockhampton	132	12.3	6.2	6.6	6.2	6.7	6.2	6.7
Rocklands	132	40.0	5.8	5.4	5.8	5.4	5.8	5.4
Stanwell	275	31.5	18.1	19.8	18.5	20.3	18.5	20.3
Stanwell	132	31.5	4.7	4.4	4.7	4.5	4.7	4.5
Wurdong	275	31.5	15.9	15.2	16.4	15.6	16.4	15.6
Yarwun	132	40.0	9.4	10.3	12.6	15.7	12.6	15.7

Note:

(1) The lowest rated circuit breaker(s) at these locations are required to interrupt short circuit current which is less than the maximum fault current and below the circuit breaker rating.

Table F.3: Estimated Maximum Short Circuit Levels – Southern Queensland - Powerlink Transmission Network 2009 to 2011

Substation	Voltage kV	CB Fault Rating (Lowest kA)	Fault Levels					
			2009		2010		2011	
			3 Phase kA	L - G kA	3 Phase kA	L - G kA	3 Phase kA	L - G kA
Abermain	275	40.0	16.6	16.2	16.6	16.2	16.6	16.2
Abermain	110	31.5	20.9	23.4	21.1	23.5	21.1	23.4
Algester	110	40.0	21.3	20.5	21.4	20.6	21.5	20.7
Ashgrove West	110	25.0	19.1	18.0	19.1	18.0	19.0	18.5
Belmont	275	31.5	17.3	18.6	17.3	18.6	17.3	18.7
Belmont (1)	110	25.0	29.2	35.5	29.8	36.5	30.2	37.2
Blackwall	275	50.0	24.1	26.1	24.2	26.1	24.2	26.1
Blackstone	110	40.0	-	-	-	-	25.4	20.4
Braemar	330	50.0	23.4	24.8	23.4	24.8	23.4	24.8
Braemar	275	40.0	34.5	38.4	34.5	38.4	34.5	38.4
Bulli Creek	330	50.0	18.2	14.0	18.2	14.0	18.2	14.0
Bulli Creek	132	40.0	3.7	4.2	3.7	4.2	3.7	4.2
Bundamba	110	40.0	16.5	15.9	16.6	15.9	16.6	15.8
Gin Gin	275	31.5	10.5	8.9	10.6	9.0	10.6	9.5
Gin Gin	132	21.9	9.0	9.2	9.0	9.2	12.4	13.4
Goodna	275	40.0	15.1	15.1	15.1	15.1	15.1	15.1
Goodna	110	40.0	25.1	26.6	25.1	26.6	25.1	26.6
Greenbank	275	40.0	22.2	24.2	22.2	24.2	22.2	24.2
Loganlea	275	50.0	15.3	15.4	15.3	15.4	15.3	15.5
Loganlea (1)	110	25.0	22.1	25.8	22.2	26.0	22.8	26.5
Middle Ridge (4T)	330	NO CB	12.5	12.0	12.5	12.0	12.5	12.0
Middle Ridge (5T)	330	NO CB	12.9	12.4	12.9	12.4	12.9	12.4
Middle Ridge	275	40.0	18.1	18.0	18.1	18.0	18.1	18.0
Middle Ridge	110	26.2	19.9	23.3	20.1	23.5	20.1	23.5
Millmerran	330	50.0	18.3	19.4	18.3	19.4	18.3	19.4
Molendinar (1T)	275	40.0	8.3	7.9	8.3	7.9	8.3	7.9
Molendinar (2T)	275	40.0	8.3	7.9	8.3	7.9	8.3	7.9
Molendinar	110	40.0	19.5	23.4	19.5	23.4	19.6	23.8
Mt England	275	31.5	23.2	23.0	23.2	23.0	23.2	23.1
Mudgeeraba	275	31.5	9.5	9.4	9.5	9.4	9.5	9.5
Mudgeeraba	110	31.5	18.0	21.9	18.0	22.0	18.0	22.0
Murarrie (3T)	275	40.0	13.2	13.1	13.2	13.2	13.2	13.2

Table F.3: Estimated Maximum Short Circuit Levels – Southern Queensland - Powerlink Transmission Network 2009 to 2011 (cont.)

Substation	Voltage kV	CB Fault Rating (Lowest kA)	Fault Levels					
			2009		2010		2011	
			3 Phase kA	L - G kA	3 Phase kA	L - G kA	3 Phase kA	L - G kA
Murarrie (2T)	275	40.0	13.2	13.3	13.2	13.3	13.2	13.4
Murarrie	110	40.0	24.7	28.5	24.9	28.9	25.1	29.4
Oakey GT PS	110	40.0	10.7	11.8	10.7	11.8	10.7	11.8
Oakey	110	40.0	9.9	9.8	9.9	9.8	9.9	9.8
Palmwoods	275	31.5	8.3	8.5	8.3	8.5	8.3	8.6
Palmwoods	132	21.8	12.7	15.1	12.7	15.3	12.7	15.4
Palmwoods	110	NO CB	7.2	8.1	7.2	8.1	7.4	8.3
Redbank Plains	110	31.5	20.8	18.9	20.8	18.9	20.8	17.5
Richlands	110	18.3	17.6	17.7	17.7	17.8	17.7	17.9
Rocklea (1T)	275	40.0	13.6	12.5	13.6	12.5	13.6	12.5
Rocklea (2T)	275	40.0	8.7	8.3	8.7	8.3	8.7	8.3
Rocklea	110	40.0	24.9	28.4	24.9	28.4	24.9	28.5
Runcorn	110	21.9	19.0	19.1	19.2	19.2	19.3	19.3
South Pine	275	31.5	19.0	21.5	19.1	21.6	19.1	21.7
South Pine East	110	40.0	20.3	23.2	20.3	23.2	20.3	23.3
South Pine West	110	40.0	21.2	26.6	21.3	26.9	21.3	27.1
Sumner	110	40.0	20.6	20.0	20.6	20.0	20.6	20.2
Swanbank A (1)	110	18.3	25.3	21.1	25.4	21.1	-	-
Swanbank B	275	31.5	19.6	21.3	19.6	21.4	19.6	21.4
Swanbank E	275	40.0	16.7	18.1	16.7	18.1	16.7	18.2
Tangkam	110	40.0	12.6	11.7	12.7	11.7	12.7	11.7
Tarong	275	40.0	31.4	33.1	31.5	33.1	31.5	33.1
Tarong	132	31.5	5.4	5.7	5.4	5.7	5.4	5.7
Tarong	66	21.9	14.0	15.4	14.0	15.4	14.0	15.4
Teebar Creek	275	40.0	7.1	7.0	7.1	7.0	7.1	7.1
Teebar Creek	132	40.0	9.8	10.9	9.8	10.9	9.9	11.0
Tennyson	110	40.0	15.8	15.2	15.8	15.2	15.8	15.2
Upper Kedron	110	40.0	21.2	17.8	21.2	17.8	21.2	18.0
West Darra	110	40.0	24.3	22.9	24.4	22.9	24.4	23.4
Woolooga	275	31.5	9.4	10.4	9.4	10.5	9.4	10.5
Woolooga	132	21.9	12.6	14.6	12.7	15.1	12.7	15.1

Note:

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

Appendix G – Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
BSL	Boyne Smelters Limited
CBD	Central Business District
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CQ	Central Queensland
DNSP	Distribution Network Service Provider
FNQ	Far North Queensland
GSDA	Gladstone State Development Area
GWh	Gigawatt hour
IRPC	Inter-Regional Planning Committee
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
MCE	Ministerial Council on Energy
MVA	Megavolt Amperes
MVAr	Megavolt ampere reactive
MW	Megawatt
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
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
QGC	Queensland Gas Company
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
SOO	Statement of Opportunities
SQ	South Queensland
SVC	Static VAr compensator
SWQ	South West Queensland
TNSP	Transmission Network Service Provider

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