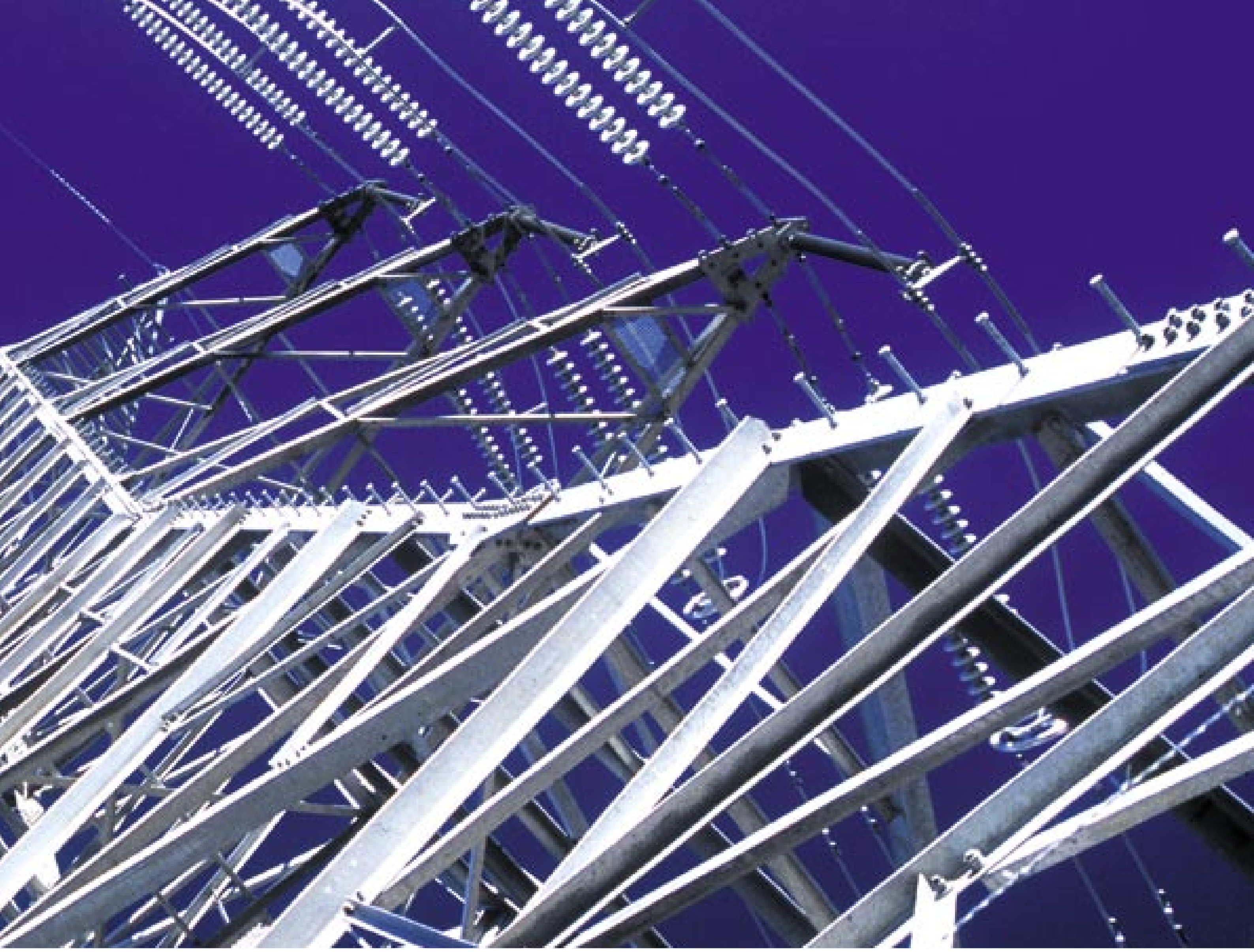

Annual Planning Report 2006

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EXECUTIVE SUMMARY

Transmission network planning and development are integral to Powerlink's business. This Annual Planning Report (APR) is a key part of the 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. There is sufficient time to undertake these future developments.

Electricity Demand Forecast

Electricity usage in Queensland has grown strongly during the past ten years, and this trend is expected to continue in the next ten years. The summer maximum electricity demand (weather and diversity corrected) has grown significantly over the past five years with a state-wide growth of 31%, including a record growth of 42% in South East Queensland.

The growth in summer maximum electricity demand delivered from the transmission grid is forecast to remain high for the next two years, with lower growth for the rest of the ten year forecast period. On average, summer maximum electricity demand is forecast to increase at an average annual rate of 3.9% per annum from 7687MW in 2005/06 to 11267MW in 2015/16.

The continuing high forecast growth in demand for the next two years is attributable to the expected continuation of rapidly increasing penetration and usage of domestic air conditioners and strong population growth. These factors are particularly evident in South East Queensland, where the forecast summer weather corrected demand growth for the next two years is 7.5% per annum.

Beyond 2007/08, domestic air conditioning penetration is forecast to slow, which will cause the annual demand growth rate to move closer to the long term average of about 4% per annum.

The forecast high level of demand growth will require substantial future augmentation to the Queensland transmission network to ensure grid capability keeps pace with demand, particularly in the south eastern part of the state.

Electricity Energy Forecast

Annual energy to be supplied by the Queensland transmission grid is forecast to increase at an average rate of 3.4% per annum over the next ten years for the medium economic growth scenario. Over the same period, average energy growth in South East Queensland is forecast to increase at 4.4% per annum.

These latest energy forecasts are generally consistent with those from the 2005 and 2004 Annual Planning Reports, which predicted state-wide energy growth of 3.2% and 3.1% per annum respectively.

A noticeable feature of the 2005 forecast energy growth was that the majority of the additional forecast increase was expected to occur in the early years of the 10 year outlook period. This expectation remains current and is mainly due to an upward revision in electricity consumption in the coal mining sector over the next five years, the effect of increasing penetration of domestic air-conditioning, some new small industrial loads and the continuation of strong population growth.

Transmission Projects Completed

Significant projects completed since the 2005 Annual Planning Report include:

- The Woree Static VAr Compensator (SVC), which has augmented transmission capability to the Cairns area
- The first stage of the Belmont to Murarrie reinforcement, which has augmented transmission capability to the Brisbane CBD and Australia TradeCoast areas
- 275kV connections to the new Braemar Power Station and the new Kogan Creek Power Station

In addition, new network support contracts were negotiated 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 projects.

Four 275kV transmission lines:

- Between Greenbank (in the Logan area) and Maudsland (in northern Gold Coast) to augment the transmission capability to the Gold Coast area
- Between Broadsound and Nebo, including an SVC at Strathmore, to increase transfer capability between Central and Northern Queensland
- Between Middle Ridge (in Toowoomba area) and Greenbank (in Logan area) to increase transfer capability between South West and South East Queensland
- Between Belmont and Murarrie to further augment transmission capability to the Australia TradeCoast area and Brisbane CBD

Establishment or augmentation of three 275kV substations:

- New substation at Abermain to augment transmission capability to the Ipswich area
- New substation at Teebar Creek to augment transmission capability to the Wide Bay area
- An additional 275/132kV transformer at Woree Substation to augment transmission capability to the Cairns area

Three 132kV transmission lines:

- Between Ross and Townsville South and between Townsville South and Townsville East to augment supply to the southern suburbs and eastern CBD areas of Townsville
- Between Nebo and Pioneer Valley to augment transmission capability to the Mackay – Proserpine area
- Between Lilyvale and Blackwater to augment transmission capability to the Central Queensland coal mining areas

Three new bulk supply substations to augment transmission capability in the south west Brisbane area at Goodna, Algester and Sumner.

Smaller augmentations such as the installation of capacitor banks and transformer upgrades are also underway to satisfy network reliability standards.

Generation Capacity

Market development of new generating capacity in the Queensland region is continuing with a 450MW gas fired power station nearing completion at Braemar (near Dalby), and a 750MW coal fired power station under construction at Kogan Creek (near Chinchilla).

These significant generation developments will alter flows on the Queensland transmission grid, as these generators compete in the wholesale electricity market to supply the forecast electricity demand in Queensland and the interconnected states of New South Wales, Victoria, and South Australia.

Queensland – New South Wales Interconnection (QNI)

The southward maximum transfer capability of the QNI is 1078MW. This limit remains conditional on availability of online stability monitoring equipment. Powerlink is working closely with its New South Wales counterpart, TransGrid, to design and implement controller tunings at various SVCs to allow this limit to be unconditionally available.

Minor works are already underway in New South Wales to improve the availability of the existing QNI maximum transfer capability during summer when there have been thermal limitations on existing transmission plant for both southerly and northerly flows.

Based on preliminary studies undertaken in 2005, Powerlink and TransGrid identified that a low capability upgrade of QNI may be justified based on the Australian Energy Regulator's (AER's) revised Regulatory Test.

Powerlink and TransGrid have therefore committed to undertaking full joint studies, which are now in progress. It is expected that studies will have progressed to the stage where formal consultation could commence by the end of 2006.

Major Flowpaths

Within Queensland, Powerlink's transmission grid performed well over the 2005/06 summer with transfer limits being reached at most grid sections for less than 1% of the time during the six months from October 2005 to March 2006, the period of highest demand.

The Central Queensland – North Queensland (CQ – NQ) limit is managed by the network support arrangements between Powerlink and North Queensland generators which have been approved under the AER Regulatory Test process. The staged CQ – NQ transmission project due for completion from 2007 to 2010 will improve transfer capability to meet forecast electricity demand in North Queensland

The Central Queensland-South Queensland (CQ – SQ) limit bound for 3.5% of the time over the summer period due to the capacity across this grid section being fully utilised during opportunities which arose for export of electricity into New South Wales over QNI and Terranora Interconnector.

The Tarong limit experienced negligible binding over the 2005/06 summer. To keep pace with the high load growth in South East Queensland, the Middle Ridge to Greenbank transmission reinforcement has been committed for the 2007/08 summer. This project will increase transfer capabilities to ensure reliable transmission is maintained for forecast peak electricity demands in South East Queensland.

The Gold Coast limit, which bound for around 4% of the time during winter, was managed by network support arrangements between Powerlink and the owners of the Directlink Market Network Service Provider. These arrangements were approved for the 2005/06 summer under the AER Regulatory Test process. In late 2006, Powerlink will complete a 275kV transmission line project to increase the Gold Coast limit. This project consists of establishment of a new 275kV switching station at Greenbank, construction of a double circuit 275kV transmission line from Greenbank to Maudsland, installation of reactive compensation at Greenbank, and installation of additional transformer capacity at Molendinar.

Future Augmentations

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

The National Electricity Rules requires the APR to identify emerging limitations which are expected to arise some years into the future, assuming that demand for electricity continues to grow as outlined. Early identification allows Powerlink to implement appropriate augmentations to maintain a reliable power supply to customers.

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

Consultation on Network Augmentations

Powerlink has already issued papers to inform Registered Participants and interested parties about forecast future network limitations in the Bowen and Thuringowa areas, and to seek possible solutions. Powerlink expects to initiate consultation processes for a number of other forecast future network limitations within the next twelve months so that augmentations can be planned and implemented in a timely manner.

This Annual Planning Report also contains details of five proposed new small network assets.

These assets include the:

- Expansion of Alligator Creek Substation, south of Mackay
- Installation of a second 110/11kV transformer at Bundamba Substation, near Ipswich
- Installation of a shunt capacitor bank at Edmonton Substation, south of Cairns
- Establishment of a 132/22kV substation at El Arish, near Mission Beach
- Installation of a second 275/110kV transformer at Murarrie Substation, in Brisbane

Powerlink invites submissions on these proposed new small network augmentations by 28 July 2006.

1. INTRODUCTION

CONTENTS

1.1 Introduction

Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) that 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.

Powerlink has an obligation under the National Electricity Rules (NER) to undertake an annual planning review of the capability of its transmission network to meet forecast electricity demand requirements. Powerlink is required to inform industry participants and other interested parties of the findings of this review in its Annual Planning Report (APR) which is published in June each year.

This 2006 APR provides details of Powerlink's latest planning review. The report includes information on electricity 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 supply solutions to address these limitations are discussed. Interested parties are encouraged to provide input to facilitate identification of the most appropriate solution to ensure supply reliability can be maintained to customers in the face of continued strong growth in electricity demand.

Powerlink's annual planning review and report are an important part of the process of planning the Queensland transmission network to continue to meet the needs of participants in the NEM and users 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 National Electricity Rules (NER).

Information from this process is also provided to the National Electricity Market Management Company (NEMMCO) to assist it in preparing the Statement of Opportunities (SOO).

The SOO is the primary document for examining electricity supply and demand issues across all regions in the NEM and covers the following issues:

- Adequacy of NEM electricity supplies to meet projected electricity demand
- The Annual National Transmission Statement (ANTS), which reviews national transmission flow paths, forecast constraints, and options to relieve those constraints
- Supplementary economic, developmental and historical information

Powerlink recommends that interested parties review its 2006 APR in conjunction with NEMMCO's 2006 SOO, which is expected to be published by 31 October 2006.

1.3 Purpose of the Annual Planning Report

The purpose of Powerlink's Annual Planning Report (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 (DSM) initiatives
- Identify locations where major industrial loads could be connected
- Understand how the electricity supply system affects their needs
- Consider the transmission network's capability to transfer quantities of bulk electrical energy
- Provide input into the future development of the transmission grid

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 National Electricity Rules (NER). In this role, and in the context of this APR, Powerlink's transmission network planning and development responsibilities include the following:

- 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 obligations
- Conducting annual planning reviews with Transmission Network Service Providers (TNSP) and Distribution Network Service Providers (DNSP) whose networks are connected to Powerlink's transmission grid (i.e. TransGrid, Energex, Ergon Energy and Country Energy)
- 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 or non-network options and such as local generation and demand side management initiatives.
- Undertaking the role of proponent of regulated transmission augmentations in Queensland

These responsibilities are described more fully in Powerlink's Transmission Authority and Chapter 5 of the NER.

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 (also known as the Jurisdictional Planning Body). In this role, Powerlink represents the Queensland jurisdiction on the Inter-Regional Planning Committee (IRPC).

Powerlink's role on the IRPC includes:

- Providing information on the Queensland network to allow NEMMCO to carry out its obligations, such as publication of the SOO and preparation of the ANTS
- Bringing forward, where necessary, proposed Queensland augmentations which have a material inter-network effect
- Participating in inter-regional system tests associated with new or augmented interconnections
- Participating in the technical evaluation of proposals for network developments which have a material
  inter-network effect

The function of the IRPC is described in Clause 5.6.3 of the NER.

1.5 Overview of Planning Responsibilities

The development of the Queensland regulated transmission grid encompasses the following:

- Connection of new participants, or alteration of existing connections
- The shared network within Queensland
- New interconnectors or augmentation to existing 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 augmentation of 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 grid within Queensland. The NER sets out the planning process and requires Powerlink to apply the Regulatory Test promulgated by the AER to new regulated network augmentation proposals. The planning process requires consultation with 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
- The assessment of future network capability
- Planning criteria for the network
- Prediction of future loadings on the transmission network

The ten-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 the NEMMCO SOO, unless modified following advice from relevant participants. Information about existing and committed embedded generation and demand management within distribution systems is provided by the DNSPs.

Powerlink examines the capability of its existing network, and future capability following any changes resulting from committed augmentations. This involves consultation with the relevant DNSP where the performance of the transmission system may be affected by the distribution system (for example, where the two systems operate in parallel).

Where potential flows on transmission system elements could exceed network capability, Powerlink is required to notify market participants of these forecast network limitations. If augmentation is considered necessary, joint planning investigations are carried out with the DNSPs (or TNSPs if relevant) in accordance with the provisions of 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.

The *Electricity Act 1994 (Qld)* 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 Powerlink plan and develop its transmission grid in accordance with good electricity industry practice such that power quality and reliability standards in the NER are met for intact and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varied by agreement.

Powerlink also has legal obligations to evaluate and must consider environmental effects when developing its transmission network.

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, particularly with respect to consultation with interested parties, the main steps in network planning can be summarised as follows:

- Disclosure of information regarding the need for augmentation. This examines the demand growth, 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 effect, either the agreement of the entities responsible for those affected networks must be obtained, or the development must be examined by the Inter Regional Planning Committee
- Analysis of the 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 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.
- Consultation and publication of a recommended course of action to address the identified 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) are the responsibility of the respective project proponents.

Powerlink will develop plans in association with connected networks to augment interconnection capability where justified. Any plans to establish or augment interconnectors will be outlined in Powerlink's APR (refer Chapter 2). The NER also provides a role to be carried out by the Inter Regional Planning Committee. This committee, convened by NEMMCO, includes a representative of the entity having transmission planning responsibility in each state jurisdiction. The inter-jurisdictional planning process involves NEMMCO publishing the SOO by 31 October each year. The SOO provides information on the projected supply-demand balance for each NEM region.

The ANTS, a component of the SOO, provides information relevant to the technical and economic need for augmentation of major national transmission flow paths. This includes information on the significance of forecast constraints on power transfers between regions. It also identifies options for the reduction or removal of future network constraints.

2. SUMMARY OF RELEVANT MAJOR NATIONAL TRANSMISSION FLOW PATH DEVELOPMENTS

CONTENTS

2.1 Purpose

The Annual National Transmission Statement (ANTS) provides information on the projected need and potential future development of major national transmission flow paths across the National Electricity Market (NEM).

Information relating to potential projects which could affect major transmission flow paths is to be identified by the relevant Transmission Network Service Providers (TNSPs) within their Annual Planning Reports.

This section of the Annual Planning Report (APR) summarises potential projects identified by Powerlink which could affect major transmission flow paths within the Queensland region.

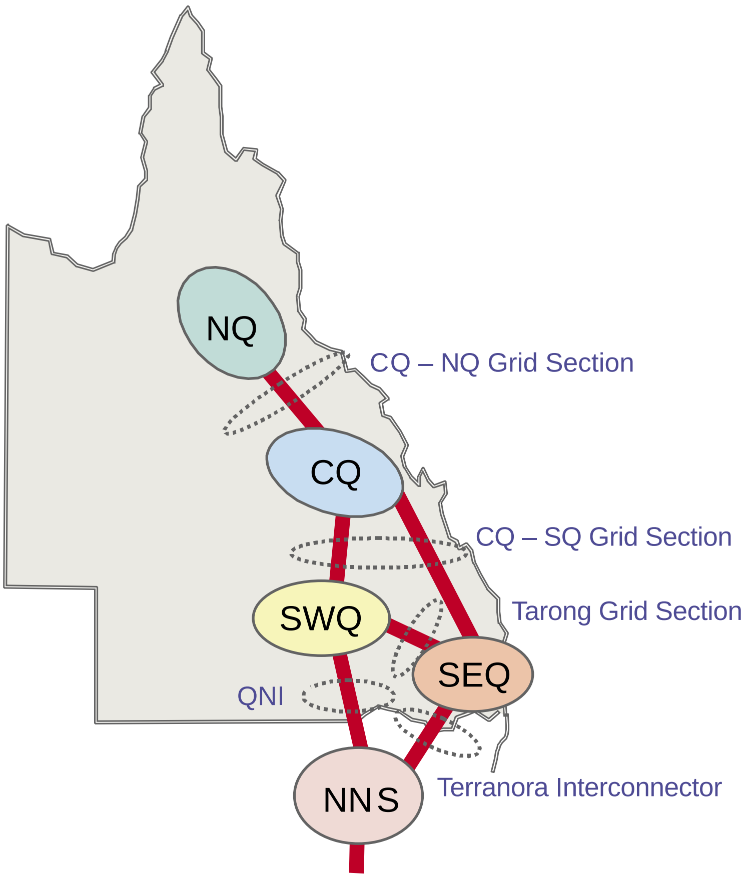
2.2 Major National Transmission Flow Paths

In 2005, NEMMCO defined the criteria for major national transmission flow paths as well as the proposed flowpaths for the 2005 ANTS. These flowpaths remain unchanged for the 2006 ANTS.

The major flow paths within Queensland correspond with parts of the transmission system used to transport significant amounts of electricity between generation and load centres. These flow paths also align with key intra-regional grid sections described within Section 5.3.

The major transmission flow paths for the Queensland region are shown within Figure 2.1.

FIGURE 2.1: QUEENSLAND MAJOR TRANSMISSION FLOW PATHS



Legend

NQ	North Queensland
CQ	Central Queensland
SWQ	South West Queensland
SEQ	South East Queensland
NNS	Northern New South Wales

2.3 Summary of Potential Augmentations to Flow Paths

Potential augmentations which may increase the transfer capability of major flow paths for the Queensland region are summarised within Table 2.1. The augmentations are grouped under the corresponding flow paths. The CQ – SWQ and CQ – SEQ have been combined under the CQ – SQ heading, as this aligns with the current representation of these flow paths within the NEMMCO market dispatch system.

It should be noted that both non-network and network options are required to be evaluated and compared within the NER approval processes for regulated network augmentations. This section provides information relating to network options only.

2.4 Status of Augmentations

NEMMCO is proposing to define three categories to classify the status of flow path augmentations within the 2006 ANTS. These categories indicate the level of certainty of a particular augmentation. Powerlink has indicated the status of potential augmentations according to these categories, which are summarised as follows:

- Committed augmentation: Project approved following completion of NER approval processes for regulated network augmentations.
- Routine augmentation: Projects undertaken to maintain network capability, to meet mandated standards, or to ensure transfer capability is not restricted by equipment that can be installed in a low cost and economic manner.
- Conceptual augmentation: Project identified as a potential network option to increase the transfer capability of the flow path.

Routine and conceptual augmentations are not committed projects and therefore should be considered preliminary. These projects have not necessarily undergone rigorous technical or economic evaluation, and are included as indicative augmentations only. The time horizon for these unapproved projects is up to 5 years.

TABLE 2.1: POTENTIAL AUGMENTATIONS TO FLOW PATHS IN THE QUEENSLAND REGION

Flow Path	Limit Description	Augmentation Basis (1)	Potential Augmentation (2)	Flow Path Improvement	Status
CQ – NQ	Small network projects to ensure transfer capability is maintained	Reliability requirement	Installation of 275kV and/or 132kV capacitor banks	Preserves the CQ – NQ transfer limit	Routine
	Central to north Queensland transfer capability plus local generation may be insufficient to meet future demand	Reliability requirement	**Option 1:** Staged construction of a 275kV transmission line between Broadsound and Ross, and installation of an SVC at Strathmore	Increases maximum CQ – NQ transfer from current levels to around 1250MW	Committed
			As per Option 1 plus Option 2: Stringing of the second side of the existing Stanwell to Broadsound 275kV circuit and substation works at North Queensland substations	Increases maximum CQ – NQ transfer by around 350MW	Conceptual

Notes:

(1) Augmentation justification based on either the reliability or market benefit limb of the AER Regulatory Test.

(2) Potential Augmentation options are dependent on location of potential new generation and are not necessarily substitutable or designed to be implemented in order above.

TABLE 2.1: POTENTIAL AUGMENTATIONS TO FLOW PATHS IN THE QUEENSLAND REGION CONTINUED

Flow Path	Limit Description	Augmentation Basis (1)	Potential Augmentation (2)	Flow Path Improvement	Status
CQ – SQ (combined CQ – SEQ and CQ – SWQ flow paths)	Small network projects to ensure transfer capability is maintained	Reliability requirement	Installation of 275kV and/or 132kV capacitor banks as well as the possibility of an SVC at a location yet to be determined	Preserves the CQ – SQ transfer limit	Routine
	Constraints on transfer capability between central and southern Queensland may occur under scenarios in which significant new base load generation is built in central or north Queensland	Market benefit and potentially reliability requirement (1)	**Option 1:** Installation of an SVC on the coastal CQ – SQ circuit	Increases maximum CQ – SQ transfer limit to around 2000MW	Conceptual
			Option 2: Construction of switching station on the Tarong – Calvale lines at Auburn River	Increases maximum CQ – SQ transfer limit to around 2200MW	Conceptual
			Option 3: Construction of a new double circuit 275kV transmission line from Calvale to Tarong	Increases maximum CQ – SQ transfer limit to around 2700MW	Conceptual
			Option 4: Construction of 500kV double circuit transmission line from central Queensland to South Queensland	Increases maximum CQ – SQ transfer limit up to around 3500MW	Conceptual

Notes:

(1) Augmentation justification based on either the reliability or market benefit limb of the AER Regulatory Test.

(2) Potential Augmentation options are dependent on location of potential new generation and are not necessarily substitutable or designed to be implemented in order above.

TABLE 2.1: POTENTIAL AUGMENTATIONS TO FLOW PATHS IN THE QUEENSLAND REGION CONTINUED

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	Flow Path Improvement	Status
	Small network projects to ensure transfer capability is maintained across the Tarong limit	Reliability requirement	Installation of 275kV and/or 110kV capacitor banks	Preserves the Tarong limit transfer capability	Routine
SWQ – SEQ	Insufficient South West to South East Queensland transfer capability plus local generation may be insufficient to meet future demand	Reliability requirement	Construction of new transmission line from Middle Ridge to Greenbank and installation of second Middle Ridge 330/275kV transformer	Increases the Tarong stability limit by around 250MW(3) and the SWQ limit by around 500 – 700MW	Committed
			Upgrade of the existing Middle Ridge 330/275kV transformer to 1500MVA	Expected to increase the SWQ limit by up to 250MW	Routine
			Installation of series reactors on the Millmerran – Middle Ridge 330kV circuits	Expected to increase the SWQ by up to 150MW(4). This option enables better power sharing between the Braemar – Tarong – SEQ and the Millmeran – SEQ flowpaths	Routine
			Construction of a new double circuit transmission line between Braemar and Tarong	Expected to increase the SWQ limit by around 500MW to 1000MW	Routine
			Establishment of new Halys substation (near Tarong), and construction of new double circuit 500kV transmission line from Halys to Blackwall substation (initially operating at 275kV)	Substantially increases Tarong transfer capability	Conceptual

Notes:

(3) Note that the Tarong voltage stability limit increase for this year may be higher than this value, due to the effects of downstream reliability projects by Powerlink and Energex which increase reactive reserve margins and reduce reactive losses within South East Queensland.

(4) Assuming commissioning of the Middle Ridge to Greenbank reinforcement.

TABLE 2.1: POTENTIAL AUGMENTATIONS TO FLOW PATHS IN THE QUEENSLAND REGION CONTINUED

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	Flow Path Improvement	Status
	Small network projects to ensure transfer capability is maintained across the Gold Coast limit	Reliability requirement	Installation of 275kV and/or 110kV capacitor banks	Preserves the Gold Coast limit transfer capability	Routine
SEQ – NNS	South East to Gold Coast transfer capability plus local generation may be insufficient to meet future demand	Reliability requirement	**Option 1:** Construction of a 275kV line from Greenbank to Molendinar and installation of a second 375MVA 275/110kV transformer at Molendinar substation	This project addresses localised Gold Coast reliability requirements. It will increase the Gold Coast voltage stability limit by around 175MW	Committed
			Option 2: Uprating of the existing Mudgeeraba to Terranora 110kV circuits	Increases the thermal capability of these circuits by around 40 – 60MW	Committed
			Option 3: Installation of a third 375MVA 275/110kV transformer at Molendinar substation	This project potentially further increases the Gold Coast voltage stability limit by around 75MW	Conceptual

TABLE 2.1: POTENTIAL AUGMENTATIONS TO FLOW PATHS IN THE QUEENSLAND REGION CONTINUED

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	Flow Path Improvement	Status
NNS – SWQ and SWQ – NNS	Transfers across QNI can be constrained by thermal, voltage, transient and oscillatory stability limitations	Market benefit	**Option 1:** Thermal rating upgrade of the lower rated Armidale – Tamworth 330kV line	This option expected to increase thermal limits by a nominal 200 – 300MW in both directions	Conceptual
			Option 2: Works as per Option 1 plus the installation of series compensation (most probably located on the Armidale to Dumaresq and Dumaresq to Bulli Creek 330kV circuits), Static VAr Compensators, and power system control equipment	Other voltage, transient and oscillatory stability limits on these NTFPs are likely to increase by up to approximately 300 – 400MW	Conceptual
			Option 3: Establishment of a 1500MW HVDC back to back asynchronous link most likely located at Bulli Creek or Dumaresq substations. To achieve maximum transfer capability additional supporting works would be required on the NSW – Queensland interconnected system and an upgrade of part of the northern NSW 330kV network will also be required	This potentially will provide an equivalent transfer capability of 1500MW in the southerly direction and 1000MW in the northerly direction	Conceptual
			Option 4: Construction of a second AC interconnector between Queensland and New South Wales. It may build on other 330kV and 275kV developments required to meet reliability obligations in each region	Increase in transfer capability between the two regions by a nominal 800 – 1000MW	Conceptual

3. INTRA-REGIONAL ENERGY AND DEMAND PROJECTIONS

CONTENTS

3.1 Background to Load Forecasts

3.1.1 Sources of Load Forecasts

In accordance with the National Electricity Rules (NER), Powerlink has obtained summer and winter demand forecasts over a ten-year horizon from Distribution Network Service Providers (DNSPs) based on their post winter 2005 review, and from directly-connected customers, at each connection supply point in Powerlink's transmission network. These individual connection supply point forecasts were aggregated into estimated demand forecasts for the total Queensland region and for ten geographical zones as defined in Table 3.12 in Section 3.5, using diversity factors observed from historical trends up to the end of April 2006.

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

The National Institute of Economic and Industrial Research (NIEIR) was engaged by Powerlink to provide an independent assessment of energy and demand forecasts for the Queensland region and for the former DNSP[3] areas within Queensland, in December 2005. These forecasts were based on a "top-down" economic growth perspective with high and low growth scenarios and predicted levels of generation from embedded co-generation and other renewable sources.

National Electricity Market Management Company (NEMMCO) also engaged NIEIR to provide an updated independent assessment of economic outlook for all the regions of the National Electricity Market (NEM) in April 2006, including high and low growth scenarios and embedded generation levels. These reports contained no significant changes to the Queensland economic outlooks previously provided, and accordingly the forecasts in this Chapter will be consistent with the Queensland forecasts in NEMMCO's 2006 Statement of Opportunities (SOO).

3.1.2 Basis of Load Forecasts

Economic Activity:
Three forecast scenarios of economic activity in all NEM states were updated by NIEIR in April 2006. The three scenarios can be characterised as:

(i) Medium Growth Scenario (the base case), considered to be most probable
(ii) High Growth Scenario
(iii) Low Growth Scenario

The average economic growth for the High, Medium and Low Growth Scenarios developed by NIEIR, over the ten-year period 2005/06 to 2015/16 are:

TABLE 3.1: ECONOMIC GROWTH

	High	Medium	Low
Australian Gross Domestic Product (average growth p.a.)	3.8%	2.9%	1.9%
Queensland Gross State Product (average growth p.a.)	4.8%	3.9%	3.0%

[3] Prior to the amalgamations that formed Ergon Energy.

For Queensland, these updated growth rates are slightly higher for the medium and low growth scenarios and unchanged for the high growth scenario, compared to the NIEIR prediction outlined in the Powerlink 2005 Annual Planning Report (APR). Consistent with this NIEIR outlook, the revised energy growth rates in Queensland in this 2006 APR are slightly higher over the long term than in the previous forecast (refer to Section 3.4).

Weather Conditions:
Within each of these three economic scenarios, three forecasts were also prepared to incorporate sensitivity of maximum summer and winter demands to prevailing ambient temperature weather conditions, namely:

(i) A 10% probability of exceedance (PoE), corresponding to one year in ten hot summer or cold winter conditions

(ii) A 50% PoE, corresponding to one year in two (average summer or average winter) conditions

(iii) A 90% PoE corresponding to mild summer or mild winter conditions, which would be expected to be exceeded in nine years out of ten

Cogeneration and Renewable Energy Source Generation:
The 2006 forecasts by NIEIR for embedded co-generation and renewable energy source generation projects are at similar levels to those published in the 2005 APR.

Table 3.2 shows the forecast total output of non-scheduled co-generation and other renewable or non-renewable energy source embedded generation projects. It should be noted that Table 3.2 is not the total of all co-generation and renewable energy source generation in Queensland, as it excludes the output of the existing Roma, Barcaldine and Townsville (Yabulu) power stations.

Whilst being embedded in the distribution networks, Roma, Barcaldine and the 66kV output component of Townsville (Yabulu) power stations are scheduled market generators and as such their output is included within the “delivered from grid” forecasts in this APR. However, Table 3.2 does include the output of the existing Invicta Sugar Mill power station, which is non-scheduled despite being connected to the transmission grid. Accordingly, its output is included both within Table 3.2 and within the “delivered from grid” forecasts in this APR.

The Pioneer Sugar Mill generation (embedded non-scheduled) upgrade project, located at Ayr, south of Townsville, has significantly reduced the energy supplied from Clare substation in the Ross zone from 2005/06 onwards. Similarly, a new Isis Central Sugar Mill generation (embedded non-scheduled) project, located south of Bundaberg, will reduce energy supplied from Woolooga and later Teebar Substations in the Wide Bay zone from 2006/07 onwards.

Native Demand
Native demand refers to the actual demand delivered into the distribution networks and to transmission connected consumers. Referring to Figure 3.1, it is the sum of delivered demand (energy) from a TNSP and from significant, embedded generation. In the case of Queensland, non-scheduled embedded generation includes sugar mill co-generation, the most significant being the new large Pioneer Sugar Mill and Isis Central Sugar Mill co-generators. In these forecasts, Queensland delivered demand includes the output of embedded scheduled generation.

TABLE 3.2: FORECAST OF COGENERATION AND OTHER EMBEDDED NON-SCHEDULED GENERATION

NIEIR Forecasts of Queensland Total Cogeneration and Other Non-Scheduled Embedded (Renewable and Non-Renewable Energy Source) Annual Generation (GWh). (1) (2) (3)

Year	Cogeneration	Other Embedded Generation	Total
2006/07	2,569	502	3,071
2007/08	2,569	502	3,071
2008/09	2,569	505	3,074
2009/10	2,652	583	3,235
2010/11	2,652	586	3,238
2011/12	2,652	586	3,238
2012/13	2,744	667	3,411
2013/14	2,744	667	3,411
2014/15	2,744	670	3,414
2015/16	2,744	670	3,414

Notes:

(1) These total generator outputs do not represent export to the distribution network as they include the energy required for the plant's own use.

(2) Invicta Mill bagasse cogeneration output is included in this table despite being connected to Powerlink's transmission grid, as it is non-scheduled.

(3) This table excludes the output of Barcaldine, Roma and the 66kV output component of Townsville (Yabulu) power stations as these are embedded scheduled market generators.

As in previous reports, the energy delivered to the Wivenhoe pumps is excluded from both the demand and energy forecasts in this report.

Other Loads:

Interconnector Loads

Energy flows across the Queensland – New South Wales Interconnection (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 Regional Boundaries

From 20 March 2006, load in the Tweed area was included within the New South Wales forecast instead of Queensland's. Historical data and forecasts within this report have been altered to reflect this. This change does not alter Powerlink's obligations in respect of supply to the Tweed area, and network planning will continue to accommodate this demand.

New Large Loads — Committed

Since the 2005 APR, supplies to the new Comalco Alumina Refinery plant at Yarwun (near Gladstone), a new Morvale coal mine (near Coppabella), and a new large coal handling port facility upgrade at Gladstone have all been commissioned.

The forecasts in this chapter also include increased loading for a new industrial load within the Swanbank Enterprise Park, changed forecasts at numerous existing and new coal mines in the inland Central Queensland and Bowen Basin areas, netting to an 85MW increase by 2010, a further new port handling facility at Dalrymple Bay (south of Mackay), a second new port handling facility in the Gladstone area and expanded port handling facility at Abbot Point (Bowen), amounting to 33MW by 2009. There is also increased loading forecast for Brisbane airport due to expansions and commercial loads.

New Large Loads — Uncommitted

There have been several proposals for large metal processing or other industrial loads which are not yet considered to be committed and are therefore not included in the forecast.

These include the following possible or proposed projects:

- A new aluminium smelter at Aldoga — south west of Gladstone
- Major expansions of an existing aluminium smelter (Gladstone) and an existing zinc smelter plant (Townsville)
- Industrial loads in the Swanbank area (including paper mill and steel mill)
- Several further coal mines in the Central Queensland/Bowen Basin area including some very large electrical loading projects
- Future electrification of the inland Bowen Basin to Abbot Point (Bowen) railway line ("Missing Link") and possible further port handling facility upgrades
- Desalination plant at locations subject to feasibility analysis

Some of these additional demands have been included in the high growth scenario in accordance with customer data provided.

These developments could translate to the following additional loading on the network.

TABLE 3.3: UNCOMMITTED LARGE LOADS

Zone	Type of Plant	Possible Load
Ross	Zinc	0 – 120MW
North	Port facilities and increased railway loadings	0 – 80MW
Gladstone	Aluminium & zinc	0 – 900MW
Moreton South	Paper mill, steel mill and other industries	0 – 250MW
Central West & North	Further increase in coal mining load	0 – 200MW
Gold Coast	Desalination plant	0 – 30MW

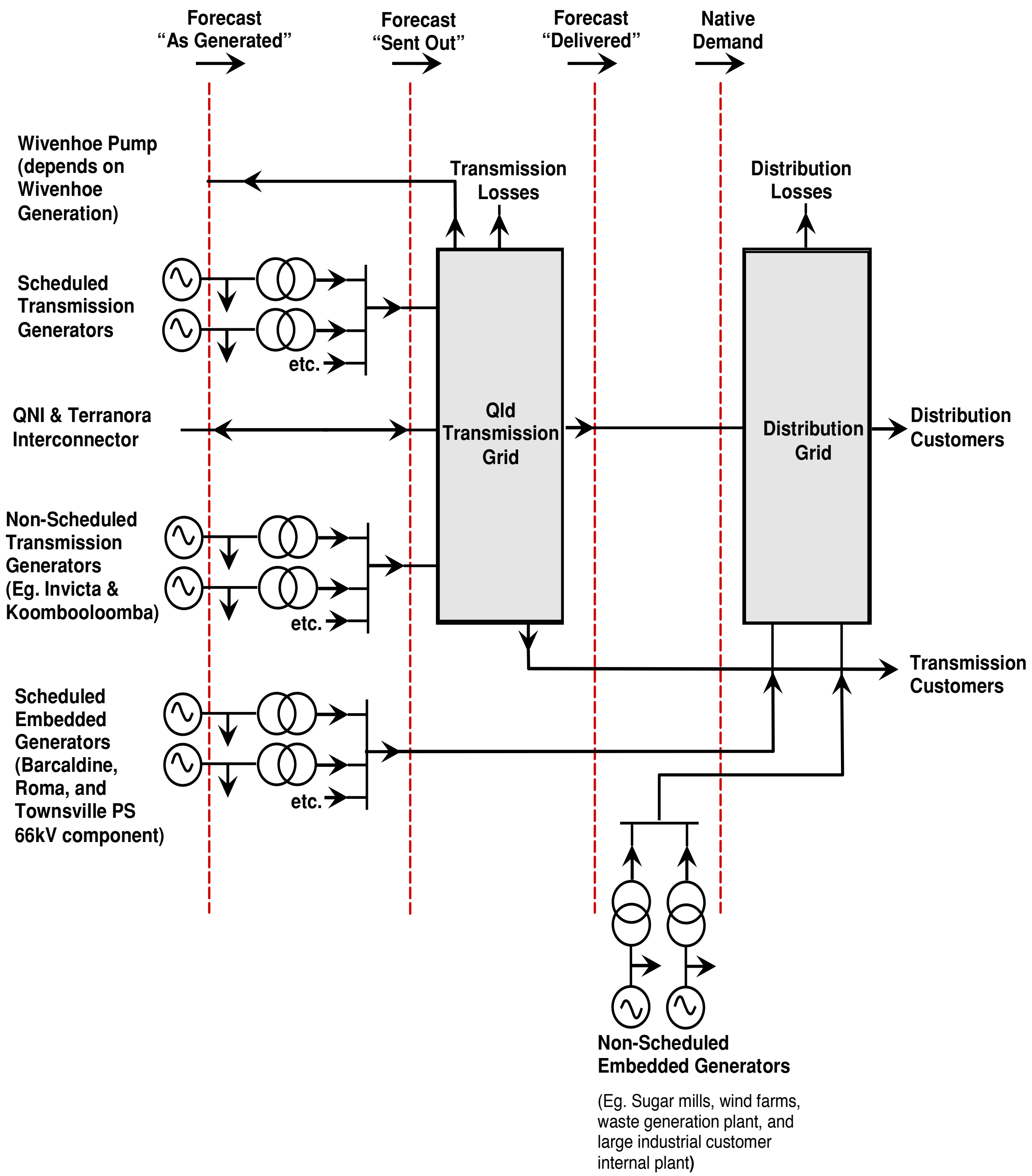
DNSP and NIEIR Forecast Reconciliation:
Powerlink also contracted NIEIR to provide an economic outlook and embedded generation forecast for Queensland. This enabled an independent check with the new DNSP and customer forecasts in Queensland and these again were found to be consistent.

Reconciliation between the NIEIR forecast and the more detailed forecasts provided by DNSPs and customers was undertaken for the medium growth scenario and average weather conditions. Whilst there is good agreement between these load forecasts, NIEIR has flagged that there could be higher growth rates in the second half of the next ten year period should a major new gas pipeline eventuate in Queensland, within that timeframe, creating a flow-on economic growth impetus.

3.1.3 Load Forecast Definitions

The relationship between the classes of generation and the forecast quantities in this Report is shown in Figure 3.1.

FIGURE 3.1: LOAD FORECAST DEFINITIONS



3.2 Recent Energy and Demands

3.2.1 Recent Summers

A summary of recent South East Queensland summer prevailing weather conditions, seasonal energy delivered and electricity demands is shown in Table 3.4. All forecast and historic data now excludes the Tweed Shire electricity load. The 2005/06 South East Queensland summer was most unusual in that very hot conditions did not occur on working weekdays and as a result the expected highest demands on such days, did not occur.

Furthermore at the time of Queensland actual peak demand for summer 2005/06 the diversity across the state was far greater than normal at 93.5% compared with the nine year average of 97.3%. Of particular note is that South East Queensland peak demand was on a different day to the state peak demand, and was 220MW below its own temperature corrected peak at the time of the state peak. In most years it usually peaks coincident with the state peak.

Even with greater diversity than normal, a new Queensland record demand of 8212MW as generated and 7388MW delivered from the grid, was attained in February 2006, though each at different times. The weather and diversity corrected summer maximum demand was 7687MW, as outlined in Appendix F. This has grown from 7329MW in 2004/05 representing a 4.9% increase. Appendix G explains some specific attributes associated with summer 2005/06 that led to the temperature and diversity correction being much higher than ever before.

The growth in actual delivered summer energy in 2005/06 was higher at 7.6%. Despite the absence of very hot daytime conditions on working weekdays, the energy growth rate was higher than that for demand due to sustained hotter than average temperatures, notably at night, on weekends, and in the holiday periods.

This is different to the trend of recent years whereby the growth in summer demand has been significantly greater than for energy. That trend is attributed, along with the very large increase in temperature sensitivity of demand over recent years (refer Appendix F), to the effect of high domestic air-conditioning growth in Queensland. Under forecast assumptions of typical summer conditions, this trend is forecast to continue.

Recently, the extent of domestic air-conditioning new installations and upgrading units in south-east Queensland has continued at record levels, and the latest surveys indicate that this large increase will continue for another two years until the recent rapid rise in penetration level stabilizes.

The growth in air-conditioning installations is most prevalent in South East Queensland, where government surveys indicate the penetration has increased from around 31% to 56% over the period November 2001 to May 2005.

The continuing high level of population migration to Queensland has also contributed to demand growth in recent years.

In previous APRs, Table 3.4 has been presented showing total Queensland load and Brisbane temperature. Given the increased load and weather diversity observed across Queensland during summer 2005/06, it is more meaningful to examine the recent history of South East Queensland summer demand and its seasonal energy relevant to Brisbane summer temperature. This analysis better reflects the close relationship between Brisbane temperatures and South East Queensland demands, given that Queensland peak demand is not always associated with Brisbane temperature, as in summer 2005/06.

TABLE 3.4: COMPARISON OF RECENT SOUTH EAST QUEENSLAND SUMMER DELIVERED LOAD

				Brisbane Temperature (2)		
Summer (1)	Energy GWh	Maximum Demand MW	Prevailing Queensland Weather Conditions	Summer Average °C	Peak Demand Day °C	No Days >28.4°C
1997/98	3,928	2,596	Very hot	26.12	29.00	10
1998/99	3,973	2,762	Average	24.68	29.75	8
1999/00	4,085	2,946	Mild	22.62	31.95	2
2000/01	4,352	2,977	Average, dry	24.39	28.90	4
2001/02	4,694	3,120	Sustained hot and dry Extreme central to north	25.58	26.95	10
2002/03	4,746	3,383	Mild, late wet season in north	24.41	28.95	2
2003/04	5,282	3,847	Extremely hot and humid	26.01	30.60	17 (3)
2004/05	5,373	4,024	Average	25.09	28.10	4
2005/06	5,917	4,149	No very hot working conditions, but high weekday temperatures at other times leading to high energy consumption	26.20	27.90	7 (4)

Notes:

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

(2) In this report, Brisbane temperature is measured at Archerfield — being more representative of general South East Queensland weather conditions than previous reference to Brisbane Airport. 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 hotter.

The 28.4°C is the 50% PoE reference temperature which is expected to be exceeded 2 to 3 days per summer on average.

(3) This included ten days from 12 to 23 February 2004.

(4) Only one of these 7 days was on a working week day. This 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 for South East Queensland of recent winter electricity demands, seasonal energy delivered and prevailing weather conditions, is shown in Table 3.5. All forecast and historic data now excludes Tweed.

The South East Queensland winter of 2005 was relatively mild overall and unusually did not contain any particularly cold snaps. The actual recorded Queensland maximum delivered demand increased by 3.0% to 6551MW. The weather and diversity corrected winter maximum delivered demand was 6644MW representing a true growth of 4.2%, as outlined in Appendix F.

The growth in actual delivered winter energy in 2005 was 2.7% for Queensland and 2.9% for South East Queensland, but as 2005 was even milder than 2004 the true growth is probably a little higher. The effect of increasing domestic air-conditioning on winter electricity consumption is not as clear as in summer, since reverse cycle units may in many cases be replacing less efficient means of household heating. As shown in Appendix F, no discernable trend of a significant increase in sensitivity of winter daily peak demands against Brisbane temperature has yet emerged. As reverse cycle air-conditioning becomes more prevalent in the future, an increase in this sensitivity is expected to emerge.

TABLE 3.5: COMPARISON OF RECENT SOUTH EAST QUEENSLAND WINTER DELIVERED LOAD

				Brisbane Temperature (2)		
Winter (1)	Energy GWh	Maximum Demand MW	Prevailing Queensland Weather Conditions	Winter Average °C	Peak Demand Day °C	No Days >10.9°C
1998	3,982	2,625	Mild to warm	16.45	11.85	0
1999	4,227	2,777	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	3
2002	4,775	2,994	Average	14.57	12.85	1
2003	4,921	3,325	Mild but one 8 day cold snap	14.96	10.95	4
2004	5,094	3,504	Mild	15.40	11.80	0
2005	5,252	3,731	Mild	15.68	10.50	2

Notes:

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

(2) In this report, Brisbane temperature is measured at Archerfield — being more representative of general South East Queensland weather conditions than previous reference to Brisbane Airport. 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 10.9°C is the 50% PoE reference temperature which is expected to be exceeded 2 – 3 days per winter on average.

3.2.3 Seasonal Growth Patterns

The hot summers of 1997/98, 2001/02, 2003/04 and 2005/06 resulted in large increases in summer delivered energy. The relatively cooler than average winters of 1997 and 2000 also resulted in higher winter delivered energy. These effects can be seen in Figure 3.2 by comparison to the trend-line of summer and winter energy delivered to DNSPs over the last seven years. Figure 3.2 excludes the energy delivered to major industrial customers connected directly to the transmission grid, so that it is indicative of the underlying trend of electricity consumption growth in Queensland.

3.2.4 Temperature and diversity correction of Demands

Powerlink analyses the temperature dependence of demands for all ten zones across Queensland, with reference to weather station data from eight locations, as outlined in Appendix F.

Queensland is too large geographically to be accurately described as having a demand dependence on a single location's weather. The two recent very hot summers of 2001/02 and 2003/04 have shown that such an approach can be misleading. In summer 2001/02 the maximum Queensland region demands coincided with the hottest weather and highest demands in northern Queensland. However, in summer 2003/04 the northern Queensland demands and temperatures were relatively low at the times of hottest weather and highest demands in southern Queensland.

The summer of 2005/06 had its maximum demand at a time that didn't correspond to maximum temperature and demand for any one Queensland zone. In fact this summer had the lowest coincident demand since detailed records have begun in 1997/98. Summer 2005/06 was also the first summer where South East Queensland did not peak at the time of state peak. Furthermore, as discussed in Appendix G, the weather conditions in South East Queensland during summer 2005/06 were not the type associated with high peak demands. Consequently, this led to a larger than usual temperature and diversity correction.

Accordingly, Powerlink continues to review and dynamically update the methodology of weather correcting historical Queensland region demand, and continues to separate the analysis into five components for separate correction and combination according to updated average historical coincidence factors. The components are:

- South East Queensland area, (which does not include the Wide Bay area) corrected against Brisbane (Archerfield) temperature
- Major industrial loads which might exhibit fluctuating levels independent of temperature conditions, are corrected to typical levels coincident with time of Queensland region maximum demand
- Northern Queensland area, without its large industrial loads, corrected against Townsville temperature
- Central Queensland area (which includes the Wide Bay area) without its large industrial loads, corrected against Rockhampton temperature
- South west Queensland area, corrected against Toowoomba temperature.

Queensland region corrected demands for all winters and summers from 1998, under the revised methodology, are shown on Figure 3.3. Figure 3.4 shows the same information for South East Queensland alone. The methodology is further outlined in Appendix F.

FIGURE 3.2: HISTORIC ENERGY TO DNSPS IN QLD

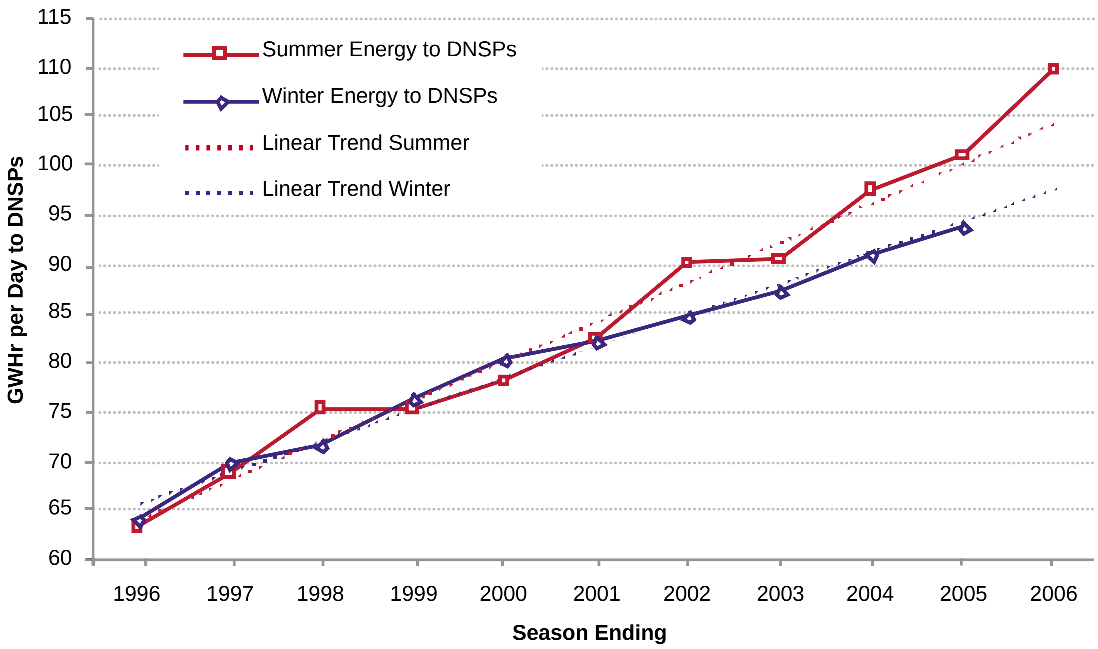


FIGURE 3.3: HISTORIC DEMAND FOR QUEENSLAND (INCLUDING TEMPERATURE AND DIVERSITY CORRECTION)

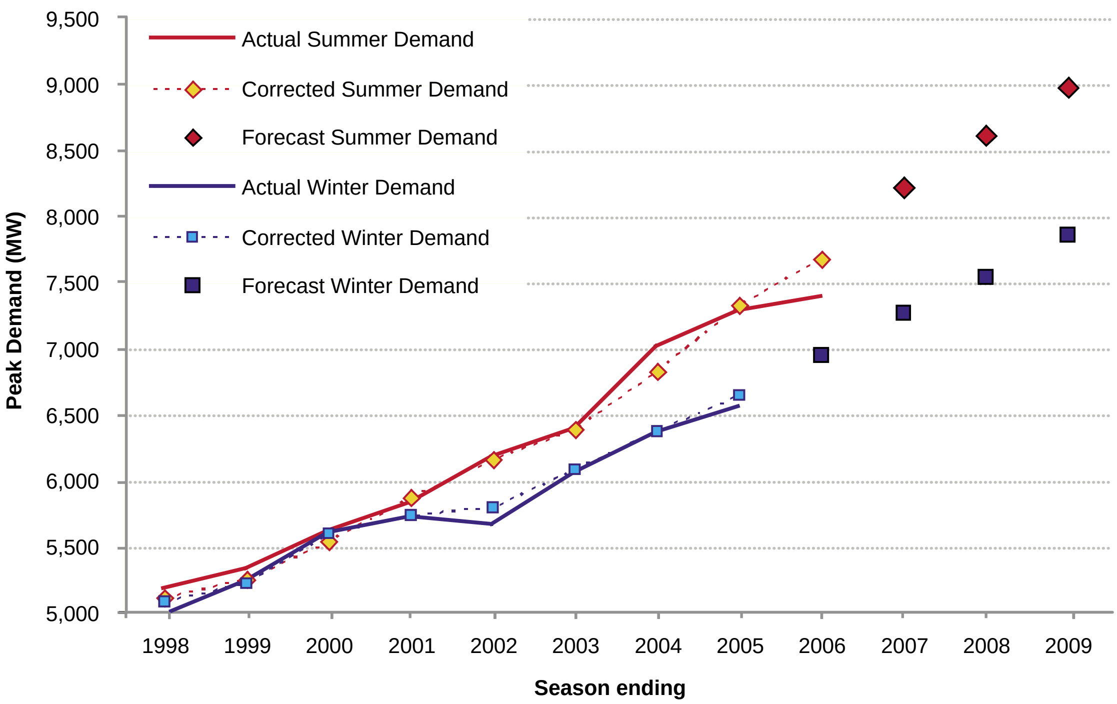
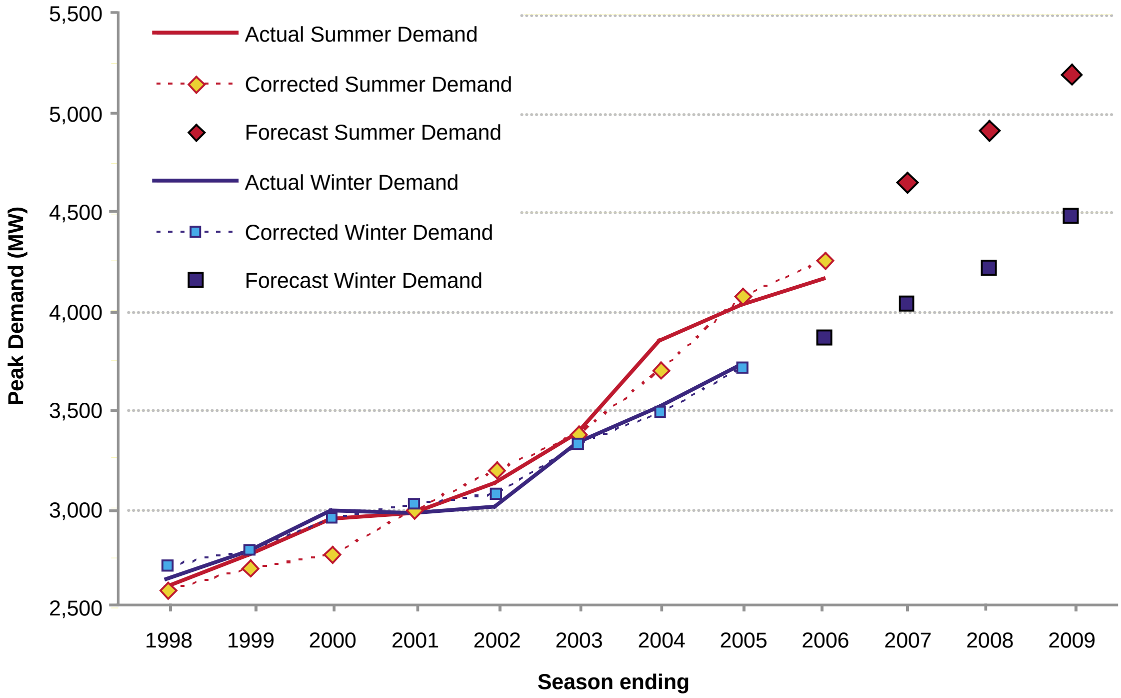


FIGURE 3.4: HISTORIC DEMAND FOR SOUTH EAST QUEENSLAND (INCLUDING TEMPERATURE AND DIVERSITY CORRECTION)



3.3 Comparison with the 2005 Annual Planning Report

In comparison with the 2005 forecast, the forecast in this APR shows a slightly higher demand growth rate for summer on top of the significant increase forecast in 2005. The growth rate in winter demand has fallen slightly. There is a small increase in the forecast growth rate for annual energy delivered from the transmission grid and from embedded scheduled generators, although a significant step increase in forecast energy is evident in the early years. The main factors contributing to these changes are:

- The summer demand growth rate for the first year is greater than the trend from temperature and diversity corrected demands over the last two summers, which can be attributed to new loads connecting to the network. Firstly a new industrial load of around 20MW scheduled to connect into Energex's system prior to summer 2005/06 was delayed but will be in place before summer 2006/07. Secondly, a new load in the Gladstone area of around 20MW is scheduled to connect prior to summer 2006/07.
- The temperature and diversity corrected 2005/06 demand for South East Queensland (4251MW) has increased by 14MW compared with last year's forecast
- An even greater increase in new domestic air-conditioning installations and existing unit upgrades during 2005 compared to the record levels in 2004. This was confirmed by surveys and the massive increase in observed demand-temperature sensitivity.
- Energex, NIEIR and Queensland government surveys all predict a more prolonged increase in new domestic air-conditioning installations than previously forecast, as well as a strong ongoing trend to upgrade older air-conditioning installations

- Recognition that resurgence in South East Queensland population growth rates over the period 2002 – 2004 to levels last seen in the early 1990s (2.5% to 3% per annum), has raised the level of underlying population growth expected for the next ten years
- Current observed levels of development proposals and construction activity in the South East Queensland area remain higher than in the 2000 – 2003 period
- NIEIR predictions of Queensland economic growth rates have been slightly increased generally over the next ten years, and remain substantially higher than the other States of Australia
- A expanded coal handling facility at Dalrymple Bay by 2009
- Expected small increases in output at some existing major industrial loads (Gladstone and Townsville)
- A second new coal handling port facility at Gladstone in 2009
- A deferment of the previously proposed new industrial load within Swanbank Enterprise Park to 2008
- Reduced forecast loadings at an aluminium refinery at Yarwun (west of Gladstone)
- Changed forecast loadings at numerous existing and new coal mines in Central Queensland with a net overall increase of 85MW by 2011
- Little change in expected levels of embedded non-scheduled generation forecasts
- An expectation that under future average winter weather conditions, utilisation of the expanding domestic air-conditioning installations in heating mode will increase at a greater rate than in recent years. This expectation has now been delayed a few years due to recent air-conditioning increase in winter offsetting less efficient heating methods and not yet manifesting as increased loading.

3.4 Forecast Data

The information pertaining to the forecasts are shown in tables and figures as follows:

Energy
Table 3.7 and Figures 3.5 and 3.6 show the historical and ten-year forecast of net energy supplied from the transmission grid together with embedded scheduled generators in the Queensland region for the Low, Medium and High Economic Growth scenarios;

Summer Demand
Table 3.8 and Figure 3.7 show the historical and ten-year Queensland region summer demand forecast (delivered from the grid and embedded scheduled generators) for each of the three economic scenarios and also for 10%, 50% and 90% PoE weather conditions;

Winter Demand
Table 3.9 and Figure 3.8 show the historical and ten-year Queensland region winter demand forecast (delivered from the grid and embedded scheduled generators) for each of the three economic scenarios and also for 10%, 50% and 90% PoE weather conditions;

Transmission Losses and Auxiliaries

Table 3.10 shows the ***Medium Growth*** *Scenario forecast of* ***average weather*** *winter and summer maximum coincident region electricity* ***demand*** *including estimates of Transmission Grid Losses, Power Station Sent Out and As Generated Demands;*

Table 3.11 shows the ***Medium Growth*** *forecast of* ***one in ten year or 10% PoE*** *weather winter and summer maximum coincident region electricity* ***demand*** *including estimates of Transmission Grid Losses, Power Station Sent Out and As Generated Demands;*

Load Profiles

Figure 3.9 shows the daily load profile on the days of the recent 2005 winter and 2005/06 summer Queensland region peak demand delivered from the transmission grid and from embedded scheduled generators. Figure 3.10 shows the cumulative annual load duration curve for 2004/05.

Connection Point Forecasts

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

It should also be noted that the forecasts have been derived from information and historical revenue metering data up to and including April 2006, and are based on assumptions and third party predictions which may or may not prove to be correct. The 'projected actual' forecast for 2005/06 accounts for actual energy delivery in the first ten months of the financial year, i.e. up to end of April 2006 plus forecast energy to end June based on statistical 'as generated' data.

In summary, the forecast average annual growth rates for the Queensland region over the next ten years under low, medium and high economic growth scenarios are shown in Table 3.6. However, these averages mask an accelerated summer demand growth (weather and diversity corrected) over the next three years up to 2008/09, which averages 6.9% per annum in South East Queensland and 5.4% per annum for the whole Queensland region under a medium growth scenario.

TABLE 3.6: AVERAGE ANNUAL GROWTH RATE OVER NEXT TEN YEARS

	Economic Growth Scenario		
	High	Medium	Low
Queensland Gross State Product	4.8%	3.9%	3.0%
Energy Delivered (1)	5.8%	3.4%	2.0%
Summer Peak Demand (50% PoE) (2)	5.8%	3.9%	2.6%
Winter Peak Demand (50% PoE) (2)	5.7%	3.6%	1.8%

Notes:

(1) This is energy delivered from the transmission grid and from embedded scheduled generators, and is reduced by the forecast growth in embedded non-scheduled generation. If there was to be no increase in embedded non-scheduled generation above current levels the average forecast growth rate in energy delivered would be 3.5% per annum under the medium growth scenario.

(2) This is the half-hour average power delivered from the transmission grid and from embedded scheduled generators.

TABLE 3.7: ANNUAL ENERGY GWH — ACTUAL AND FORECAST

Year	Sent Out (1)	Transmission Losses (2)	Delivered
95/96	29,940	1,481	28,458
96/97	31,047	1,490	29,557
97/98	35,311	1,645	33,666
98/99	36,189	1,540	34,649
99/00	38,052	1,471	36,581
00/01	39,805	1,626	38,179
01/02	41,870	1,974	39,896
02/03	42,687	1,837	40,850
03/04	44,573	1,911	42,662
04/05	45,694	1,804	43,890
05/06 (3)	47,322	1,822	45,500

Forecast	Low	Medium	High	Low	Medium	High	Low	Medium	High
06/07	48,060	49,387	50,893	1,850	1,926	2,013	46,210	47,461	48,880
07/08	49,750	51,785	54,264	1,968	2,088	2,236	47,781	49,697	52,028
08/09	51,003	53,771	57,239	2,059	2,225	2,440	48,944	51,546	54,800
09/10	52,047	55,667	60,401	2,138	2,360	2,661	49,909	53,307	57,740
10/11	52,943	57,418	66,965	2,208	2,487	3,117	50,735	54,931	63,848
11/12	53,953	59,266	70,148	2,287	2,625	3,361	51,666	56,641	66,787
12/13	55,140	61,249	73,560	2,379	2,775	3,629	52,762	58,474	69,931
13/14	55,989	63,042	76,864	2,448	2,914	3,895	53,541	60,128	72,969
14/15	56,902	64,927	80,493	2,524	3,063	4,195	54,378	61,865	76,298
15/16	57,816	66,816	84,130	2,600	3,215	4,503	55,216	63,601	79,627

Notes

(1) This is the input energy that is sent into the Queensland Grid from Queensland Scheduled generators, Invicta Mill (transmission connected but non-scheduled), and Net Imports to Queensland. The energy to Wivenhoe Pumps is not included in this table, as it is not predictable and is accordingly assumed to be netted off any Wivenhoe generation.

(2) This includes the Queensland share of losses on the Queensland – New South Wales Interconnection. Recent relatively lower loss levels reflect better load sharing following commissioning of the Millmerran – Middle Ridge 330kV line and increased generation levels in northern Queensland which reduces Central to Northern Queensland power flow levels. The table assumes that future transmission works will provide a partial check against escalating loss levels otherwise due to general growth in power flow levels.

(3) These projected end of financial year values are based on revenue and statistical metering data up until April 2006.

FIGURE 3.5: HISTORY AND FORECASTS OF ANNUAL ENERGY DELIVERED FOR MEDIUM ECONOMIC GROWTH SCENARIO

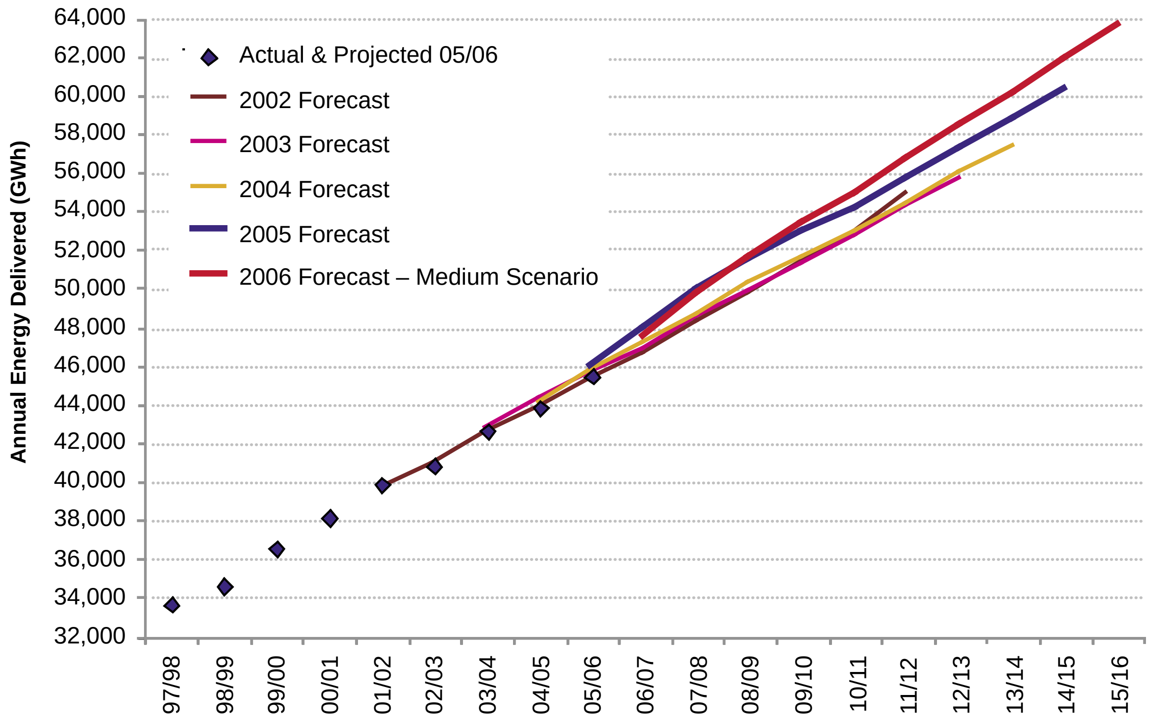


FIGURE 3.6: HISTORY AND FORECAST OF ENERGY DELIVERED FOR LOW, MEDIUM AND HIGH ECONOMIC GROWTH SCENARIOS

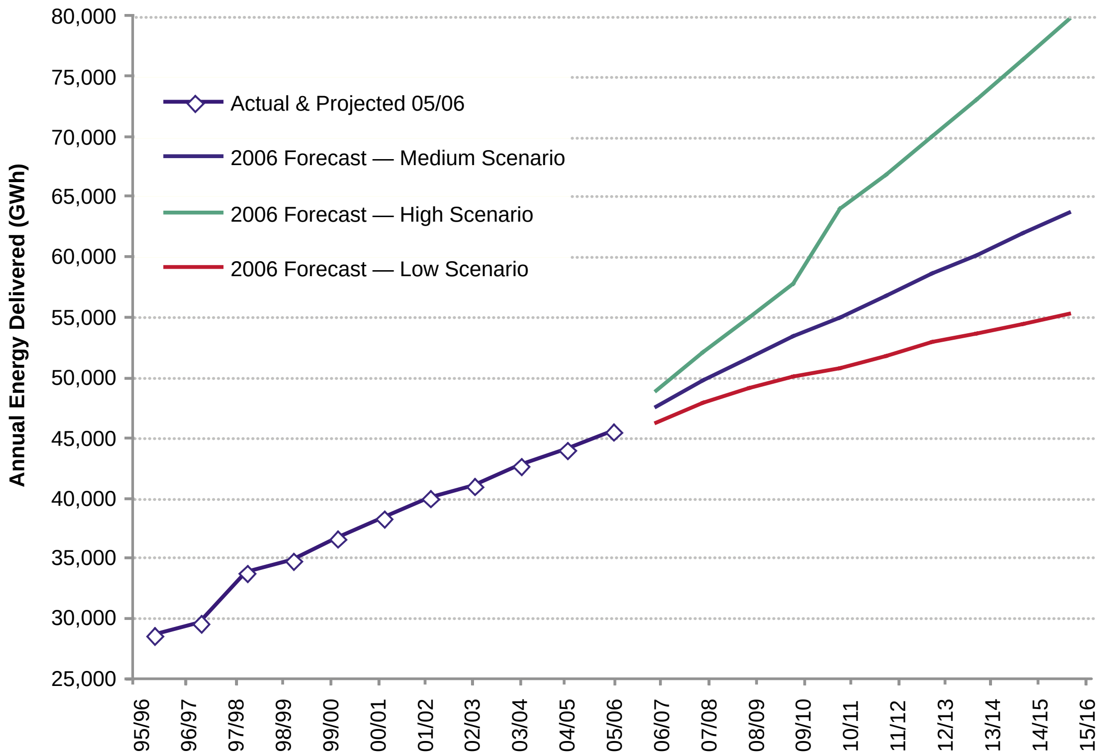


TABLE 3.8: PEAK SUMMER DEMAND

Summer	Actual	50%PoE Temperature and Diversity Corrected Peak Demand
98/99	5,330	5,262
99/00	5,620	5,544
00/01	5,830	5,883
01/02	6,183	6,165
02/03	6,336	6,400
03/04	7,020	6,835
04/05	7,282	7,329
05/06	7,388	7,687

Summer	High Growth Scenario			Medium Growth Scenario			Low Growth Scenario		
Forecasts	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE
06/07	8,893	8,441	8,127	8,669	8,230	7,925	8,422	7,997	7,702
07/08	9,455	8,965	8,625	9,084	8,615	8,290	8,733	8,285	7,974
08/09	10,004	9,479	9,114	9,485	8,990	8,647	9,010	8,544	8,220
09/10	10,534	9,974	9,586	9,834	9,315	8,956	9,223	8,741	8,407
10/11	11,560	10,964	10,551	10,167	9,624	9,247	9,417	8,919	8,575
11/12	12,079	11,448	11,011	10,505	9,937	9,544	9,623	9,110	8,754
12/13	12,608	11,941	11,479	10,848	10,255	9,845	9,849	9,318	8,951
13/14	13,163	12,458	11,970	11,202	10,585	10,157	10,055	9,509	9,130
14/15	13,758	13,012	12,495	11,570	10,926	10,480	10,271	9,709	9,319
15/16	14,353	13,567	13,021	11,938	11,267	10,802	10,488	9,908	9,507

FIGURE 3.7: QUEENSLAND REGION SUMMER PEAK DEMAND

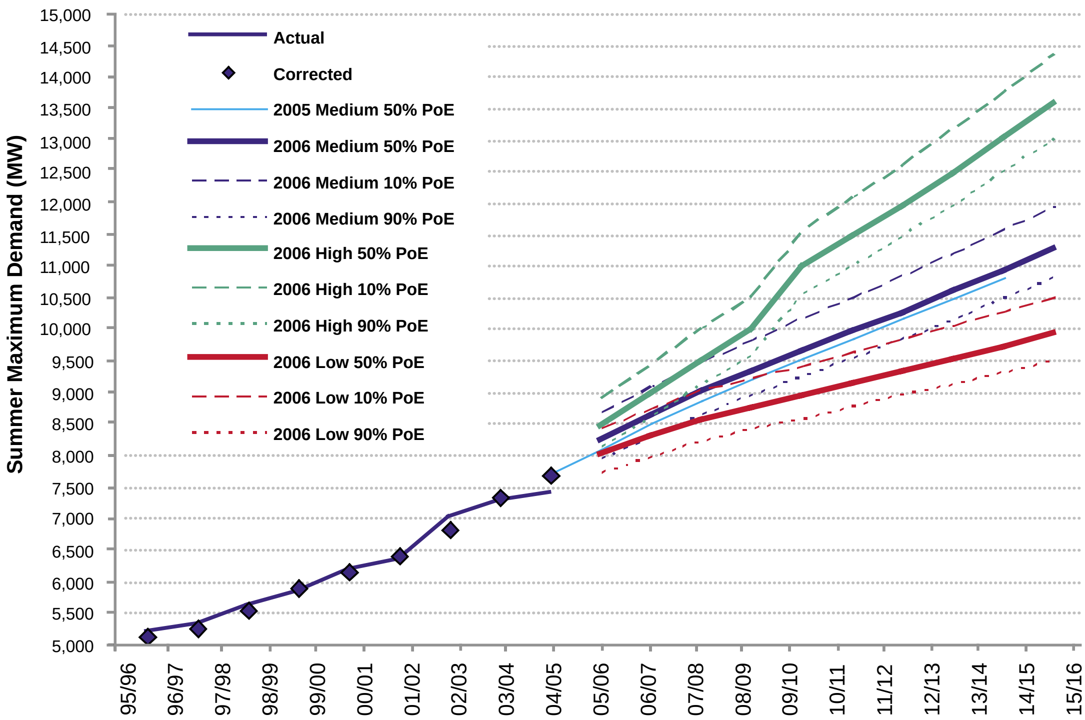


TABLE 3.9: PEAK WINTER DEMAND

Winter	Actual	50%PoE Temperature and Diversity Corrected Peak Demand
1999	5,242	5,232
2000	5,609	5,601
2001	5,731	5,737
2002	5,671	5,803
2003	6,066	6,089
2004	6,366	6,399
2005	6,551	6,644

Winter	High Growth Scenario			Medium Growth Scenario			Low Growth Scenario		
Forecasts	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE
2006	7,266	7,136	7,006	7,080	6,953	6,827	6,888	6,766	6,643
2007	7,710	7,572	7,434	7,402	7,270	7,138	7,016	6,892	6,768
2008	8,139	7,993	7,847	7,680	7,544	7,407	7,064	6,941	6,817
2009	8,593	8,442	8,289	8,008	7,868	7,727	7,264	7,139	7,014
2010	9,541	9,382	9,222	8,300	8,155	8,010	7,444	7,317	7,189
2011	9,974	9,807	9,640	8,581	8,432	8,282	7,621	7,492	7,361
2012	10,390	10,217	10,042	8,837	8,683	8,529	7,743	7,612	7,480
2013	10,841	10,660	10,477	9,098	8,941	8,782	7,867	7,734	7,600
2014	11,311	11,122	10,931	9,368	9,206	9,044	7,979	7,845	7,710
2015	11,877	11,681	11,485	9,647	9,481	9,314	8,115	7,980	7,844

FIGURE 3.8: QUEENSLAND REGION WINTER PEAK DEMAND

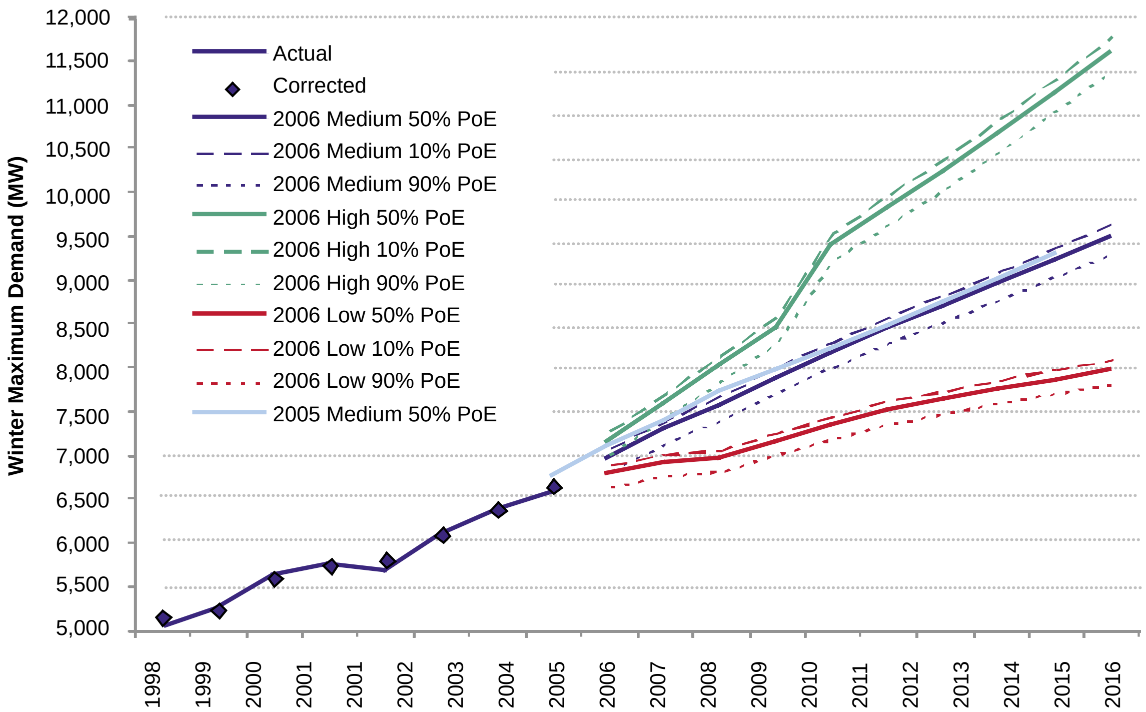


TABLE 3.10: MAXIMUM DEMAND — 50% POE FORECAST

State Peak	Station "As Generated" Demand	Station Auxs & Losses (1)	Station "Sent Out" Demand	Transmission Losses	Delivered From Grid Demand (2)
Winter					
2006	7,730	464	7,266	312	6,953
2007	8,082	485	7,597	327	7,270
2008	8,386	503	7,883	339	7,544
2009	8,746	525	8,221	354	7,868
2010	9,066	544	8,522	366	8,155
2011	9,373	562	8,811	379	8,432
2012	9,653	579	9,074	390	8,683
2013	9,939	596	9,342	402	8,941
2014	10,234	614	9,620	414	9,206
2015	10,539	632	9,907	426	9,481
Summer					
06/07	9,168	550	8,618	388	8,230
07/08	9,597	576	9,021	406	8,615
08/09	10,014	601	9,413	424	8,990
09/10	10,377	623	9,754	439	9,315
10/11	10,720	643	10,077	453	9,624
11/12	11,070	664	10,406	468	9,937
12/13	11,424	685	10,739	483	10,255
13/14	11,791	707	11,084	499	10,585
14/15	12,171	730	11,441	515	10,926
15/16	12,551	753	11,798	531	11,267

Notes:

(1) Station auxiliaries and generator transformer losses are now estimated at 5.6% of station "As Generated" dispatch at times of peak loading, lower than in previous years based on recent trends.

(2) "Delivered from Grid" includes the demand taken directly from the transmission grid as well as net power output from embedded scheduled generators (currently Barcaldine, Roma and the 66kV output component of Townsville (Yabulu) power stations).

TABLE 3.11: MAXIMUM DEMAND — 10% POE FORECAST

State Peak	Station "As Generated" Demand	Station Auxs & Losses (1)	Station "Sent Out" Demand	Transmission Losses	Delivered From Grid Demand (2)
Winter					
2006	7,875	472	7,402	322	7,080
2007	8,233	494	7,739	337	7,402
2008	8,542	513	8,030	350	7,680
2009	8,907	534	8,372	365	8,008
2010	9,232	554	8,678	378	8,300
2011	9,545	573	8,972	391	8,581
2012	9,829	590	9,239	402	8,837
2013	10,120	607	9,512	414	9,098
2014	10,420	625	9,795	426	9,368
2015	10,837	651	10,186	439	9,647
Summer					
06/07	9,675	580	9,094	425	8,669
07/08	10,138	608	9,529	445	9,084
08/09	10,585	635	9,950	465	9,485
09/10	10,975	658	10,316	483	9,834
10/11	11,347	681	10,666	499	10,167
11/12	11,724	703	11,021	516	10,505
12/13	12,107	726	11,381	533	10,848
13/14	12,503	750	11,753	551	11,202
14/15	12,914	775	12,139	569	11,570
15/16	13,325	799	12,525	587	11,938

Notes:

(1) Station auxiliaries and generator transformer losses are now estimated at 5.6% of station "As Generated" dispatch at times of peak loading, lower than in previous years based on recent trends.

(2) "Delivered from Grid" includes the demand taken directly from the transmission grid as well as net power output from embedded scheduled generators (currently Barcaldine, Roma and the 66kV output component of Townsville (Yabulu) power stations).

3.5 Zone Forecasts

The ten geographical zones referred to throughout this report are defined as follows:

TABLE 3.12: ZONE DEFINITIONS

Zone	Area Covered
Far North	North of Tully including Chalumbin.
Ross	North of Proserpine and Collinsville, but excluding the Far North zone (includes Tully).
North	North of Broadsound and Dysart but excluding the Far North and Ross zones (includes Proserpine and Collinsville).
Central West	Collectively encompasses the area south of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding that part defined as the Gladstone zone.
Gladstone	Specifically covers the Powerlink transmission network connecting Gladstone power station, Callemondah (railway supply), Gladstone South, QAL supply, Wurdong and Boyne Smelter supply.
Wide Bay	Gin Gin and Woolooga 275kV substation loads excluding Gympie.
South West	Tarong and Middle Ridge load areas west of Postmans Ridge. From winter 2005 onwards, includes Goondiwindi (Waggamba) load.
Moreton North	South of Woolooga and east of Middle Ridge, but excluding the Moreton South and Gold Coast zones.
Moreton South	Generally, south of the Brisbane River, but currently includes the Energex Victoria Park and Mayne 110kV substation load areas as supplied from Belmont 275/110kV substation, and excludes the Gold Coast zone.
Gold Coast	South of Coomera to the Gold Coast and excludes Tweed Shire of NSW.

Each zone normally experiences its own zone peak demand, which is usually greater than that shown in Tables 3.13 and 3.14, as it does not coincide with the time of Queensland region maximum demand.

Table 3.13 shows the average ratio of forecast zone peak demand to zone demand at the time of forecast Queensland region peak demands. These values can be used to multiply demands in Tables 3.13 and 3.14 to estimate each zone's individual peak demand, 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 DEMAND TO ZONE DEMAND AT TIME OF QUEENSLAND REGION PEAK

Zone	Winter	Summer
Far North	1.20	1.06
Ross	1.40	1.30
North	1.16	1.14
Central West	1.06	1.07
Gladstone	1.03	1.03
Wide Bay	1.13	1.13
South West	1.07	1.06
Moreton North	1.01	1.01
Moreton South	1.01	1.01
Gold Coast	1.02	1.01

Table 3.14 shows the forecast of energy supplied from the transmission grid and embedded scheduled generators for the Medium Growth Scenario for each of the ten zones in the Queensland region.

Table 3.15 shows the forecast of winter demand delivered from the transmission grid and embedded scheduled generators (coincident with the Queensland region winter peak) for each of the ten zones within Queensland. It is based on the Medium Growth scenario and average winter weather.

Table 3.16 shows the forecast of summer demand delivered from the transmission grid and embedded scheduled generators (coincident with the Queensland region summer peak) for each of the ten zones within Queensland. It is based on the Medium Growth scenario and average summer weather.

3.6 Daily and Annual Load Profiles

The daily load profiles for the Queensland region on the days 2005 winter and 2005/06 summer peak demand delivered from the transmission grid and from embedded scheduled generators, are shown on Figure 3.9.

The annual cumulative load duration characteristic for the Queensland region demand delivered from the transmission grid and from embedded scheduled generators, is shown on Figure 3.10 for the 2004/05 financial year.

FIGURE 3.9: SUMMER AND WINTER PEAKS 2005/06

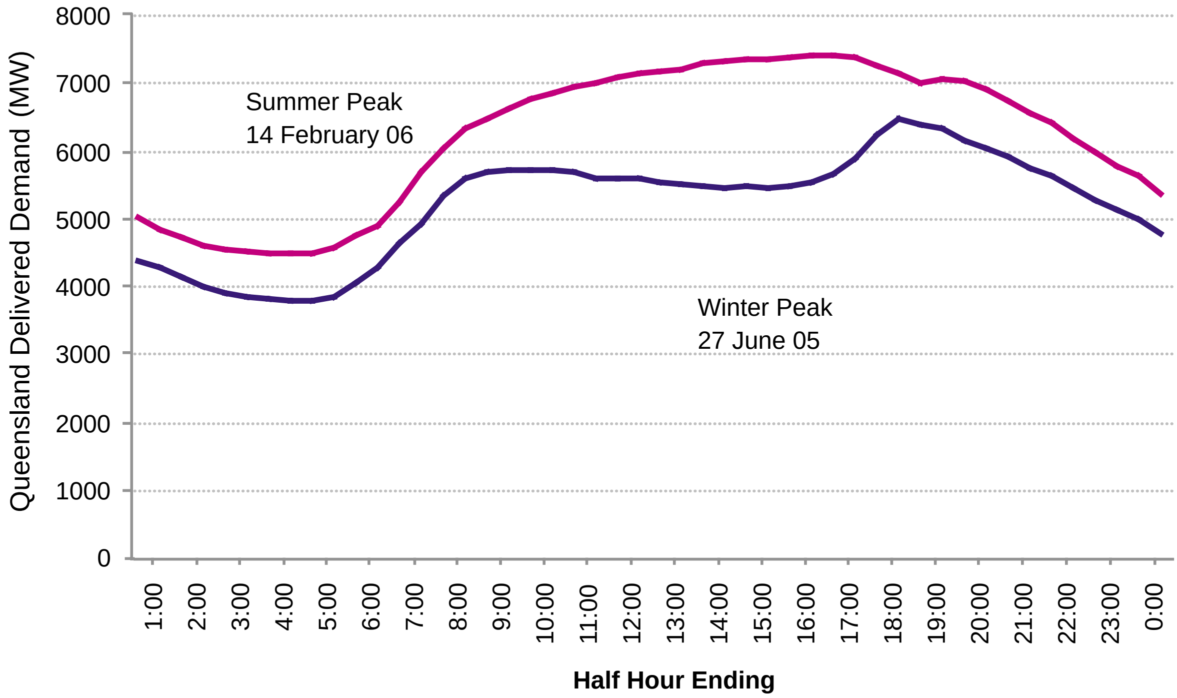


FIGURE 3.10: CUMULATIVE ANNUAL LOAD DURATION 2004/05

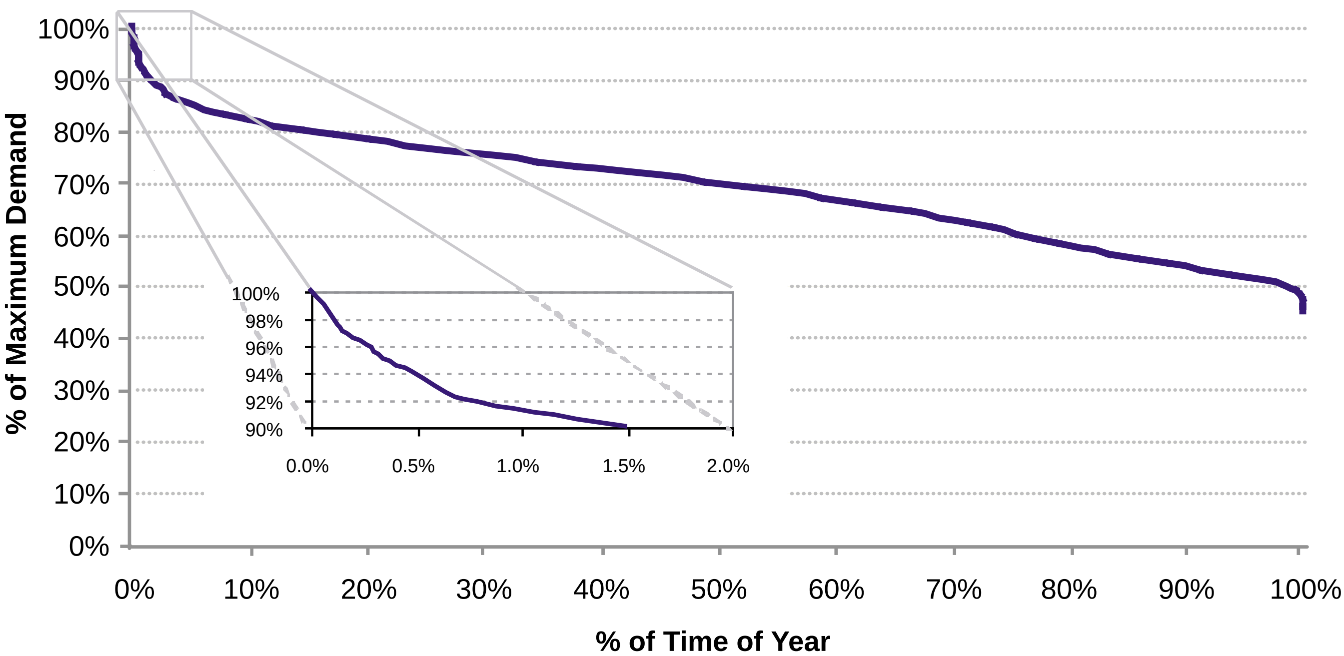


TABLE 3.14: ANNUAL ENERGY BY ZONE

Actual and Forecast Annual Energy (GWh) Delivered from the Transmission Grid including from Embedded Scheduled Generators — In each zone — Medium Growth Scenario.

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1998/99	1,407	2,030	1,809	2,587	8,434	1,024	1,511	5,752	7,808	2,287	**34,649**
1999/00	1,430	2,454	1,963	2,789	8,660	1,088	1,575	6,101	8,116	2,404	**36,581**
2000/01	1,457	2,962	2,055	2,876	8,697	1,187	1,659	6,421	8,333	2,531	**38,179**
2001/02	1,536	2,971	2,219	3,069	8,948	1,257	1,717	6,769	8,746	2,663	**39,896**
2002/03	1,549	2,934	2,296	3,109	9,098	1,256	1,738	6,975	9,174	2,721	**40,850**
2003/04	1,631	3,095	2,397	3,174	9,285	1,327	1,828	7,276	9,708	2,942	**42,662**
2004/05	1,673	3,010	2,542	3,269	9,452	1,419	1,943	7,456	10,092	3,034	**43,890**
Projected 2005/06	1,745	2,855	2,577	3,365	9,679	1,453	2,079	7,885	10,569	3,292	**45,500**
Forecasts											
2006/07	1,852	2,918	2,845	3,741	10,112	1,468	2,093	8,228	10,891	3,312	**47,461**
2007/08	1,918	3,048	2,939	3,986	10,485	1,515	2,135	8,666	11,493	3,513	**49,697**
2008/09	1,974	3,155	3,021	4,122	10,528	1,575	2,179	9,121	12,074	3,797	**51,546**
2009/10	2,033	3,223	3,246	4,233	10,643	1,637	2,226	9,520	12,567	3,978	**53,307**
2010/11	2,105	3,294	3,332	4,318	10,751	1,700	2,271	9,866	13,032	4,260	**54,931**
2011/12	2,174	3,365	3,438	4,409	10,815	1,764	2,317	10,272	13,561	4,526	**56,641**
2012/13	2,242	3,436	3,522	4,499	10,879	1,828	2,364	10,729	14,136	4,839	**58,474**
2013/14	2,311	3,507	3,608	4,590	10,947	1,892	2,410	11,116	14,655	5,094	**60,128**
2014/15	2,379	3,581	3,691	4,678	11,008	1,956	2,457	11,542	15,174	5,399	**61,865**
2015/16	2,448	3,656	3,774	4,766	11,069	2,020	2,504	11,968	15,694	5,704	**63,601**

TABLE 3.15: STATE WINTER PEAK DEMAND BY ZONE

Actual and Forecast Demand (MW) on the Transmission Grid and Embedded Scheduled Generators in each zone at the time of Coincident State Winter Peak 50% PoE Demand — Average Weather and Diversity Conditions, Medium Growth Scenario.

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1999	173	238	229	377	994	165	278	1,022	1,315	450	**5,242**
2000	179	354	271	423	986	198	312	1,080	1,350	454	**5,609**
2001	184	378	255	442	1,019	189	301	1,110	1,365	487	**5,731**
2002	163	339	285	383	1,055	160	286	1,115	1,433	452	**5,671**
2003	177	348	295	412	1,009	181	318	1,250	1,575	500	**6,066**
2004	206	354	323	425	1,092	216	345	1,260	1,607	539	**6,367**
2005	192	257	277	431	1,081	261	343	1,366	1,780	564	**6,551**
Forecasts											
2006	216	309	334	486	1,144	229	375	1,493	1,745	621	**6,953**
2007	224	319	360	539	1,171	235	386	1,521	1,858	658	**7,270**
2008	233	327	367	562	1,207	238	393	1,593	1,931	693	**7,544**
2009	241	333	378	577	1,217	246	399	1,665	2,058	754	**7,868**
2010	249	339	408	592	1,233	254	406	1,757	2,122	794	**8,155**
2011	258	346	414	602	1,253	263	414	1,834	2,206	844	**8,432**
2012	266	352	425	611	1,260	271	420	1,916	2,273	888	**8,683**
2013	275	359	434	620	1,269	280	427	1,990	2,348	939	**8,941**
2014	285	365	443	629	1,277	289	433	2,066	2,429	990	**9,206**
2015	294	372	452	639	1,285	298	440	2,143	2,514	1,044	**9,481**

TABLE 3.16: STATE SUMMER PEAK DEMAND BY ZONE

Actual and Forecast Demand (MW) on the Transmission Grid and Embedded Scheduled Generators in each zone at the time of Coincident State Summer 50% PoE Peak Demand — Average Weather and Diversity Conditions, Medium Growth Scenario.

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1999/00	234	412	240	346	1,003	197	265	1,055	1,433	433	5,620
2000/01	252	458	294	391	993	195	270	1,068	1,472	437	5,830
2001/02	278	504	355	436	1,040	222	258	1,183	1,461	447	6,183
2002/03	264	410	307	426	1,048	200	298	1,243	1,653	488	6,336
2003/04	265	452	318	459	1,087	253	339	1,387	1,890	570	7,020
2004/05	277	425	342	482	1,107	276	349	1,425	1,990	609	7,282
2005/06	284	447	373	492	1,115	292	351	1,439(1)	1,999(1)	596(1)	7,388(2)
Forecasts											
2006/07	321	461	407	583	1,159	251	395	1,615	2,318	721	8,230
2007/08	334	474	421	611	1,196	252	408	1,708	2,442	768	8,615
2008/09	348	485	436	632	1,207	259	422	1,791	2,580	829	8,990
2009/10	362	497	472	653	1,224	266	437	1,883	2,652	870	9,315
2010/11	377	507	483	669	1,243	273	452	1,959	2,739	923	9,624
2011/12	392	519	500	684	1,252	280	466	2,037	2,832	976	9,937
2012/13	407	530	514	700	1,262	287	480	2,116	2,925	1,034	10,255
2013/14	423	542	529	715	1,271	295	494	2,198	3,024	1,093	10,585
2014/15	440	554	544	731	1,281	302	509	2,294	3,119	1,152	10,926
2015/16	457	566	559	747	1,291	309	523	2,390	3,214	1,211	11,267

Notes:

(1) These values are substantially lower than the zone's own peak demand, as the day and time of Queensland peak demand was different to South East Queensland peak demand (Refer Appendix G).

(2) This value is substantially lower than the corrected peak demand due to the unusual diversity of weather patterns and times of area peak demands (Refer Appendix G).

4. INTRA-REGIONAL COMMITTED NETWORK AUGMENTATIONS

CONTENTS

4.1 Transmission Network

The 1700km 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 limited backup to the 275kV grid. Also, 330kV lines link Braemar, Middle Ridge, Millmerran and Bulli Creek to the New South Wales network.

The single line diagrams of the Queensland network as shown in the previous Annual Planning Report (APR) have been updated to include recently completed augmentations outlined in this Chapter. Figures 4.1 and 4.2 show the updated single line diagram of the Queensland network.

The majority of Queensland generating capacity is located in Central and South West Queensland. Consequently, there are significant power transfers from Central Queensland in both a northerly and southerly direction, and from South West Queensland to major load centres in South East Queensland.

The implications of this, together with forecast demand growth, are:

- New generation capacity in Central Queensland may increase power flows from Central Queensland to both North Queensland and South Queensland which may result in transmission limits being reached
- New generation in North Queensland may reduce occurrences of transmission limits being reached from Central to North Queensland, however, this alone may also increase flows from Central to South Queensland which may result in transmission limits being reached in the south
- New generation in South West Queensland may alleviate network constraints between Central and South Queensland, however it may exacerbate constraints to the north. This may also tend to increase power flows into South East Queensland and increase the utilisation of the capability across the Tarong grid section.
- New generation in South East Queensland may alleviate network constraints between Central and South West Queensland and South East Queensland, however it may exacerbate constraints in the north. This will also tend to reduce total flows into South East Queensland and thus reduce utilisation of capability across the Tarong grid section.
- New loads may be connected in Central Queensland and South West Queensland without significantly influencing transmission limits, however network constraints may then arise within local areas particularly in Central Queensland
- New loads in North Queensland may exacerbate constraints between Central and North Queensland
- New loads in South East Queensland may exacerbate constraints associated with the Tarong limit and the CQ – SQ limit

4.2 Committed Transmission Projects

Table 4.1 lists transmission grid developments commissioned since Powerlink's 2005 APR was published in July 2005.

Table 4.2 lists transmission grid developments which are committed and under construction at June 2006.

Table 4.3 lists connection works that have been commissioned since Powerlink's 2005 APR was published in July 2005.

Table 4.4 lists new transmission connections or connection works for supplying load which are committed and under construction at June 2006. These connection projects resulted from agreement reached with relevant connected customers, generators or distribution network service providers as applicable.

TABLE 4.1: COMMISSIONED TRANSMISSION DEVELOPMENTS

Commissioned since June 2005.

Project	Purpose	Zone Location	Date Commissioned Date
Major Developments			
Woree 132kV Static Var Compensator	Increase supply capability to Cairns	Far North	October 2005
Belmont – Murarrie transmission reinforcement — Stage 1	Increase supply capability to the Brisbane CBD and Trade Coast	Moreton South	October 2005
Network Support Arrangements			
Contract with local generators to provide network support in North Queensland	Part of solution to maintain supply reliability to North Queensland	North	New arrangements established from mid – 2005
Minor Developments			
Nebo 3rd 275/132kV transformer	Increase supply capability to Mackay and the mining areas to the west	North	November 2005
Blackwater 40MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Central West	November 2005
Rockhampton 40MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Central West	October 2005
Palmwoods 50MVAr 132kV capacitor bank South Pine 50MVAr 110kV capacitor bank Ashgrove West 50MVAr 110kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton North	November – December 2005
Belmont 50MVAr 110kV capacitor bank Murarrie 2 x 50MVAr 110kV capacitor banks Runcorn 50MVAr 110kV capacitor bank Loganlea 50MVAr 110kV capacitor bank Rocklea 50MVAr 110kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton South	August 2005 – January 2006

TABLE 4.2: COMMITTED TRANSMISSION DEVELOPMENTS

Committed and under construction at June 2006.

Project	Purpose	Zone Location	Planned Commissioning Date
Major Developments			
Belmont – Murarrie transmission reinforcement — Stage 2	Increase supply capability to the Brisbane CBD and Trade Coast	Moreton South	Late 2006
Establishment of Greenbank Substation and Greenbank – Maudsland 275kV line	Increase supply capability to the Gold Coast	Gold Coast	Late 2006
Goodna 275/110kV substation	Increase supply capability to Ipswich	Moreton South	Late 2006
Ross – Townsville South – Townsville East 132kV line and Townsville East 132/66kV substation	Increase supply capability to the Townsville South and East areas	North	Late 2007
Nebo – Pioneer Valley 132kV line	Increase supply capability to the Mackay – Proserpine Area	North	Late 2007
Broadsound – Nebo – Strathmore – Ross 275kV lines Strathmore 275kV Static VAr Compensator	Increase supply capability to North and Far North Queensland	North	Progressively from late 2007– late 2010
Middle Ridge – Greenbank 330kV line	Increase supply capability to South East Queensland	Moreton South	Late 2007
Lilyvale – Blackwater 132kV line	Increase supply capability to Blackwater	Central West	Late 2007
Teebar Creek 275/132kV substation	Increase supply capability to Wide Bay	Wide Bay	Late 2007
Woree second 275/132kV transformer, and line reconfiguration	Increase supply capability to Cairns	Far North	Mid 2008
Abermain 275/110kV substation	Increase supply capability to Ipswich	Moreton South	Late 2008
Minor Developments			
Townsville South 50 MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	North	Late 2006
Gladstone South 50MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Central	Late 2006
Molendinar 50MVAr 110kV capacitor bank Greenbank 120MVAr 275kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Moreton South	Late 2006
Molendinar second 275/110kV transformer	Increase supply capability to Gold Coast	Moreton South	Late 2007

TABLE 4.3: COMMISSIONED CONNECTION WORKS SINCE JUNE 2005

Commissioned since June 2005.

Project	Purpose	Zone Location	Date Commissioned
Dan Gleeson 132/66kV substation 2nd Transformer	Increase 66kV supply capability to Townsville	North	Late 2005
Mudgeeraba 110kV connections for Varsity Lakes	Provide supply to new Energex zone substation	Gold Coast	Late 2005
Rocklea 110kV 2nd connection for Archerfield	Increase supply capability to Archerfield and surrounding areas	Moreton South	Late 2005
Braemar power station connection	Connect new power station	South West	Mid 2006
Kogan Creek power station connection	Connect new power station	South West	Mid 2006

TABLE 4.4: COMMITTED CONNECTION WORKS AT JUNE 2006

Committed and under construction at June 2006.

Project	Purpose	Zone Location	Planned Commissioning Date
Algester 110/33kV substation Goodna 110/33kV substation Sumner 110/11kV substation	New connection points to Energex 33kV and 11kV networks	Moreton South	Late 2006
QR Mindi Rail 132kV Supply	Increase supply capability to Goonyella rail system	North	Early 2007
SunWater Pumps Connection Switchyards	Supply for pumping stations on new Burdekin – Moranbah water pipeline	North	Mid 2007
Belmont 110/33kV substation 3rd transformer	Increase supply capability to Wecker Road	Moreton South	Late 2006
Blackwater 132/66kV substation 3rd transformer	Increase supply capability to Blackwater	Central West	Late 2006
South Pine 110kV extension for Brendale	Increase supply capability to Brendale		Late 2006
Biloela Transformer Augmentation	Increase supply capability to Biloela	Central West	Late 2007
Mudgeeraba 110/33kV substation establishment	Increase supply capability to Mudgeeraba	Moreton South	Late 2007
Loganlea 110kV extension for Browns Plains	Increase supply capability to Browns Plains	Moreton South	Late 2007

FIGURE 4.1 EXISTING 275/132/110KV NETWORK JUNE 2006 — NORTH AND CENTRAL QUEENSLAND

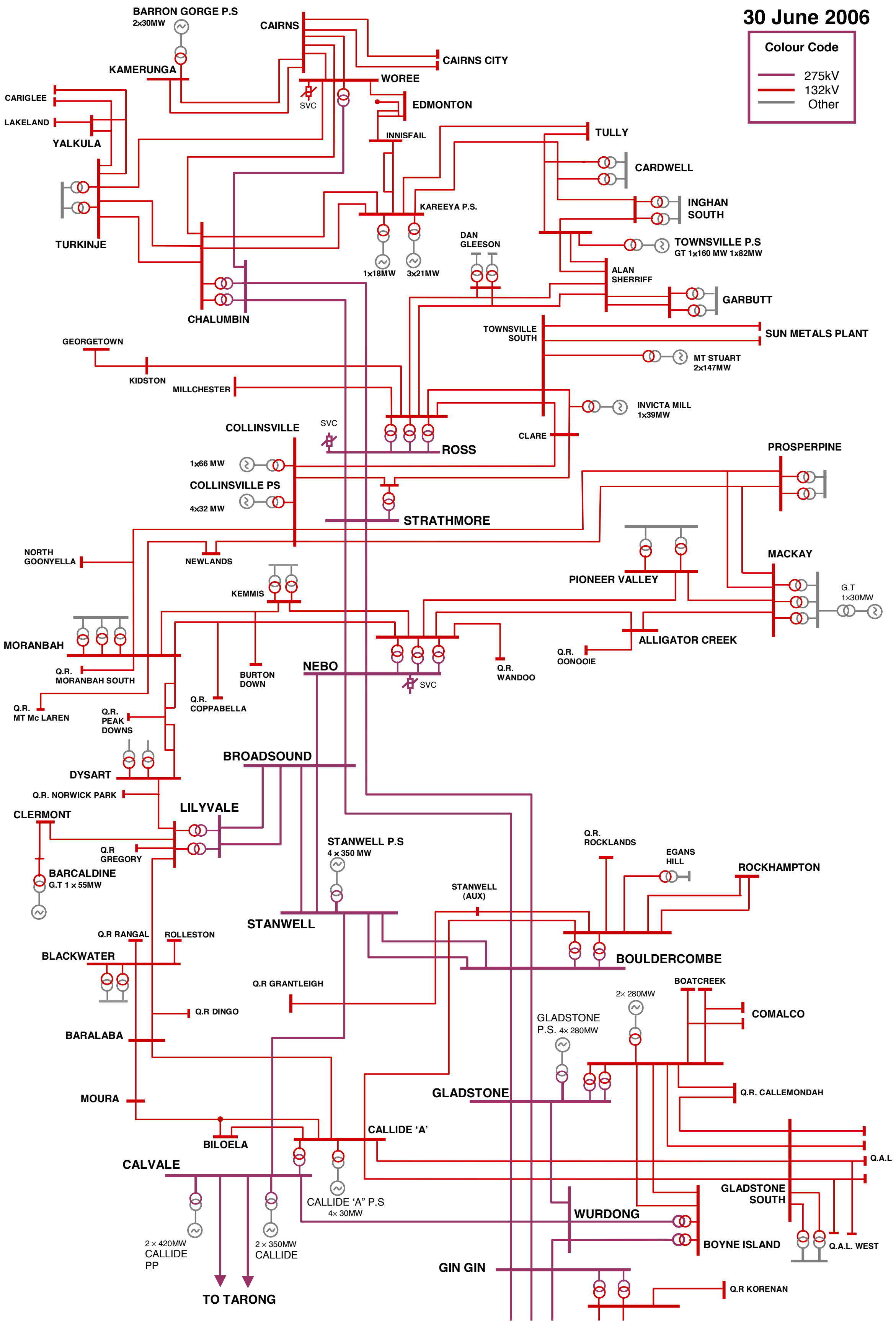
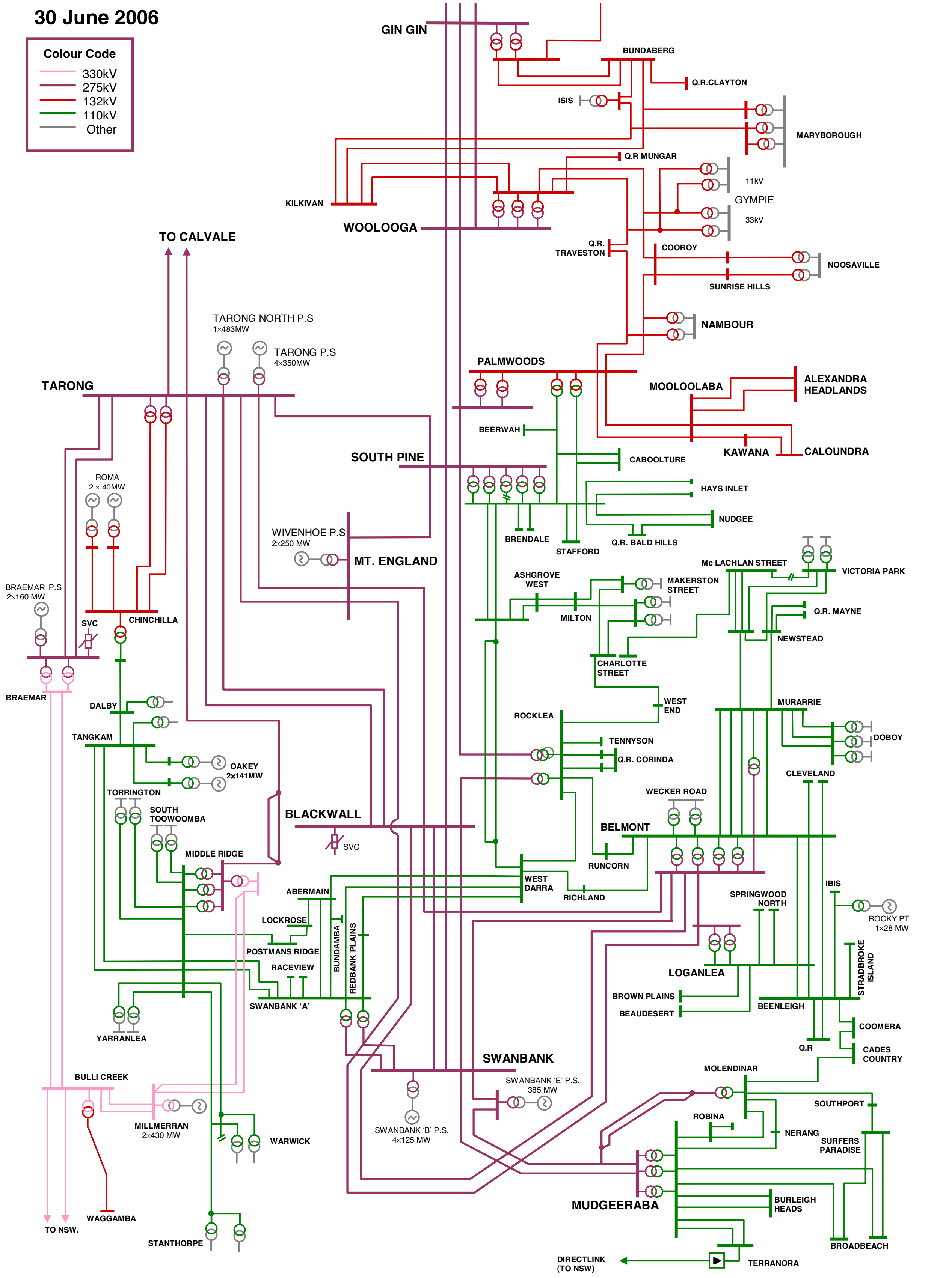


FIGURE 4.2 EXISTING 275/132/110KV NETWORK JUNE 2006 — SOUTH QUEENSLAND



5. INTRA-REGIONAL PROPOSED NETWORK DEVELOPMENTS WITHIN 5 YEARS

CONTENTS

5.1 Introduction

The National Electricity Rules (NER) (Clause 5.6.2A(b)(3)) requires 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 the factors that influence network capability
- Sample grid power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and sample generation dispatch patterns within Queensland
- A qualitative explanation of factors affecting power transfer capability at key grid sections on the Powerlink network
- Identification of emerging limitations with the potential to affect supply reliability
- A table summarising the outlook for grid constraints and network limitations over a five year horizon
- Details of those limitations for which Powerlink intends to implement action or initiate consultation with market participants and interested parties
- A table summarising possible connection point proposals

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

The capability of Powerlink's transmission grid to meet forecast demand is dependent on a number of factors that are subject to considerable uncertainty.

In general terms, the Queensland transmission grid is more highly utilised during summer than during winter. The reactive power requirements are greater in summer than in winter, and transmission plant has lower power carrying capability in the higher summer temperatures. Also, high summer peak demands generally last for many hours, whereas winter peak demands are for short evening periods (as shown in Figure 3.8).

The location and pattern of power generation dispatch influence the power flows across most of the Queensland grid. 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 on transmission grid elements can also vary substantially with planned or unplanned outages of transmission lines and transformers. Power flow levels can also be higher at times of local area or zone peak demands, as distinct from those at the time of Queensland region maximum demand. Power flows can also be higher when embedded generation levels are lower than forecast.

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

5.2 Sample Winter and Summer Grid Power Flows

Powerlink has selected 18 sample scenarios to illustrate possible grid power flows for the forecast Queensland region summer and winter maximum demands over the period 2006 winter to 2008/09 summer.

Illustrative grid power flows at forecast Queensland region (50% Probability of Exceedance (PoE)) winter and summer maximum demand over the next three years are shown in Appendix A for the Medium Economic Growth Scenario demand forecast outlined in Chapter 3 of this report. These show possible grid power flows under a range of import and export conditions on the Queensland-New South Wales Interconnection (QNI) as indicated below. Grid power flows in Appendix A are based on existing network configuration, committed projects and proposed new network assets (as outlined in Section 5.7) only, and assume the grid is in its 'normal' or 'intact' state, that is, all network elements in service. Power flows can be higher than those levels during network or generation contingencies and/or during times of local area or zone peak demands.

This information is based on possible sample generation dispatch patterns to meet nominated forecast Queensland region maximum demand conditions, and only provides an indication of potential network power flows. Actual network 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.

Appendix A also indicates where grid flows are expected to exceed the relevant transfer capability for the system conditions analysed.

Sample conditions in Appendix A include:

- Figure A.1: Generation & Load Legend for Figures A3 to A20
- Figure A.2: Power Flow & Limits Legend for Figures A3 to A20
- Figure A.3: Winter 2006 Qld Peak 400MW Northerly QNI Flow
- Figure A.4: Winter 2006 Qld Peak Zero QNI Flow
- Figure A.5: Winter 2006 Qld Peak 700MW Southerly QNI Flow
- Figure A.6: Winter 2007 Qld Peak 400MW Northerly QNI Flow
- Figure A.7: Winter 2007 Qld Peak Zero QNI Flow
- Figure A.8: Winter 2007 Qld Peak 700MW Southerly QNI Flow
- Figure A.9: Winter 2008 Qld Peak 400MW Northerly QNI Flow
- Figure A.10: Winter 2008 Qld Peak Zero QNI Flow
- Figure A.11: Winter 2008 Qld Peak 700MW Southerly QNI Flow
- Figure A.12: Summer 2006/07 Qld Peak 300MW Northerly QNI Flow
- Figure A.13: Summer 2006/07 Qld Peak Zero QNI Flow
- Figure A.14: Summer 2006/07 Qld Peak 400MW Southerly QNI Flow
- Figure A.15: Summer 2007/08 Qld Peak 300MW Northerly QNI Flow
- Figure A.16: Summer 2007/08 Qld Peak Zero QNI Flow
- Figure A.17: Summer 2007/08 Qld Peak 400MW Southerly QNI Flow
- Figure A.18: Summer 2008/09 Qld Peak 300MW Northerly QNI Flow
- Figure A.19: Summer 2008/09 Qld Peak Zero QNI Flow
- Figure A.20: Summer 2008/09 Qld Peak 400MW Southerly QNI Flow

The power flows shown in Figures A3 to A20 are a sample of possible generation dispatch and grid power flows for the forecast region peak demand conditions nominated. The dispatch assumed is broadly based on the relative outputs of generators since the commencement of the National Electricity Market but is not intended to imply a prediction of future market behaviour.

For the purposes of the sample power flows in Figures A3 to A20, the power flow on DirectLink, between Mullumbimby and Terranora in NSW, is assumed to be zero.

5.3 Network Power Transfer Capability

5.3.1 Location of Network Grid Sections and Observation Points

To assist in more effective planning, Powerlink has identified a number of grid sections that allow grid capability and forecast limitations of the whole grid to be assessed in a simplified manner. For the current system, limit equations have been derived for each of these grid sections. These limit equations quantify the maximum secure power transfer across these grid sections. National Electricity Market Management Company (NEMMCO) has incorporated these limit equations as part of constraints within the market dispatch process (National Electricity Market Dispatch Engine — NEMDE).

In addition to these grid sections, Powerlink also monitors power flows across several ‘observation points’. These ‘observation points’ may be useful to define the maximum secure power transfer particularly under network outage conditions.

Figure A.2 in Appendix A shows the location of grid sections (where limit equations apply) and ‘observation points’ on the Queensland network, where flows may reach transfer capability under some circumstances in the next three years. Potential limitations are summarised in Table 5.8.

The maximum power transfer across these grid sections may be set by transient/dynamic stability, voltage stability, thermal plant ratings or protection relay load limits.

5.3.2 Determining Network Transfer Capability

The transfer capability across each grid section varies with different system operating conditions. Transmission limits in the National Electricity Market (NEM) are not generally amenable to definition by a single number. Instead, Transmission Network Service Providers (TNSPs) define the capability of their network using multi-term equations. These equations quantify the relationship between system operating conditions and the network transfer capability, and are implemented into NEMMCO’s market systems for the optimal dispatch of generation. This is very relevant in Queensland as the grid transfer capability is highly dependent on which generators are in service, and their dispatch level.

This limit equation approach aims to maximise the transmission capability available to electricity market participants at any point in time depending on the prevailing system conditions.

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

The present limit equations applying to the Queensland transmission network grid sections, at the time of publication of this report, are provided in Appendix B. Readers should note that the limit equations will change over time with demand, generation and network development.

Such detailed and extensive analysis has not been carried out for future network and generation developments for this report. Instead, Figures A.3 to A.20 show whether the flow across any grid section is expected to exceed the transfer capability for that particular condition and generation dispatch. Section 5.4 gives a qualitative description of the main system conditions that affect the capability of each of the grid sections.

Table A.1 in Appendix A shows the power flows at each of these grid sections for intact operation (that is, with all network elements in service) at the time of peak demand in the Queensland region, corresponding to the sample generation dispatch shown in Figures A.3 to A.20. It also shows where grid flows are expected to exceed the relevant limit, and the mode of instability that determines the limit.

5.4 Grid Section Performance

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

Powerlink has also provided a qualitative outlook for the likelihood that these grid sections will translate into restrictions on generator dispatch (ie. binding limits). This outlook is provided to assist readers to understand the information provided in Appendix A, and is in no way meant to imply that this outlook holds true for system conditions other than those in the sample power flows. Grid power flows and transfer capability are highly sensitive to actual demand and generator dispatch patterns, and embedded non-scheduled generation output, 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 A.3 to A.20 at times of local area or zone peak demands. However, the transmission capability may also be higher under such conditions depending on how generation or interconnector flow varies to meet the higher local demand levels.

For each of the grid sections discussed below, the proportion of time that the limit equation has recently bound is provided for two periods, namely from April to September 2005 (winter) and from October 2005 to March 2006 (summer).

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 provided for the information of readers and is not intended to imply that the historical information represents a prediction of constraints in the future.

5.4.1 Far North Queensland Grid Section

The maximum power transfer across the Far North Queensland (FNQ) grid section is set by voltage stability associated with an outage of either a Ross to Chalumbin 275kV transmission circuit, or the 275kV transmission circuit from Chalumbin to Woree (Cairns area).

The present limit equation, for each of these critical contingencies, is shown in Table B1 of Appendix B. The equations show that the following variables have the most significant effect on the transfer capability:

- Generation (MW) within the Far North zone
- Generators on-line within the Far North zone
- Capacitor banks on-line within the Far North zone

For the contingencies outlined above, the operation of local hydro generators as synchronous compensators provides voltage support and increases the secure power transfer capability.

However, the FNQ transfer capability is also sensitive to the MW output from the local hydro units. Local hydro MW output reduces the grid transfer capability, but more demand can be securely supported in the Far North zone because the reduction in the grid section transfer capability is more than offset by the reduction in power transfers resulting from increased MW output by the local generators.

Information pertaining to the duration of constrained operation for the FNQ grid section over the period April 2005 to March 2006 is summarised in Table 5.1.

TABLE 5.1: FAR NORTH QUEENSLAND GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

FNQ Grid Section	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	0.51%	22.33
October 2005 – March 2006	0.14%	6.25

The installation of a new 132kV Static VAr Compensator (SVC) at Woree substation on October 2005 has provided an increase in transfer capability across this grid section. The SVC provides dynamic reactive reserves to support system voltages within far north Queensland in the event of a network contingency.

Power transfers across this grid section are expected to be within the transfer capability of the network for the sample generation scenarios shown within Appendix A. This outlook is based on typical 50% PoE demand conditions and average levels of embedded non-scheduled generators in the area.

Power flows across this grid section can be higher than shown in Figures A3 to A20 at times of local area peak demands or during more severe weather than in typical 50% PoE conditions. Flows can also be higher during non-availability or low output of the hydro generators, or if the output from embedded generators at sugar mills and the wind farm in north Queensland is lower than forecast. Powerlink and NEMMCO have implemented operational arrangements to minimise the occurrence of binding transfer capability during these conditions.

Powerlink has a committed project underway to install a second 275/132kV transformer at Woree and energise the second 275kV Chalumbin-Woree circuit currently operating at 132kV for operation at 275kV by summer 2008/09. This is addressed further in Section 5.5.1.

Current Powerlink analysis suggests further action to maintain the reliability of supply to the Far North zone may again be required from the 2011/12 summer onwards.

5.4.2 CQ – NQ Grid Section

The maximum power transfer across the CQ – NQ grid section is set by transient and voltage stability or thermal overload following a transmission or generation contingency.

The maximum transfer capability may be set by thermal ratings associated with an outage of a 275kV transmission circuit between Broadsound and Nebo, or Nebo and Strathmore substations, under certain prevailing ambient conditions.

Power transfers may also be constrained by voltage stability limitations associated with the trip of one of the larger north Queensland gas turbines operating at high generation levels. Stability limitations associated with a 275kV transmission contingency can also constrain power flows if the North Queensland gas turbines are not on-line.

Information pertaining to the duration of constrained operation for the CQ – NQ grid section over the period April 2005 to March 2006 is summarised in Table 5.2.

TABLE 5.2: CQ – NQ GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

CQ – NQ Grid Section (1) (2)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	0.04%	1.58
October 2005 – March 2006 (3)	0.31%	13.42

Notes:

(1) Powerlink has entered into network support agreements with generators in northern Queensland to manage power flows across this grid section to 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 intra-regional constraint.

(3) During October 2005 to March 2006, the flow was controlled to avoid exceeding the CQ – NQ transfer capability for around 1550 hours by generation managed under the network support arrangements.

The existing grid transfer capability is highly utilised, with limits reached at times of summer peak demands in north Queensland. This limitation is currently managed by network support contracts that Powerlink has with local north Queensland generators.

Power flows across this grid section can be higher than as shown in Figures A.3 to A.20 at times of local area or north Queensland peak demands, or during more severe weather than in typical 50% PoE conditions.

Routine planning analysis undertaken by Powerlink has identified that the combined capability of the CQ – NQ transmission network and local NQ generators will be fully utilised by summer 2007/08. Further augmentation will be required by this time to ensure customers continue to receive a reliable electricity supply consistent with Powerlink's reliability obligations.

In this regard, Powerlink finalised regulatory processes during 2005/06 associated with the following proposed new large network assets to ensure supply reliability is maintained from summer 2007/08 onwards:

- Stage 1 — Construction of a 275kV transmission line between Broadsound and Nebo substations, and 275kV Static VAr Compensator at Strathmore substation by late 2007
- Stage 2 — Construction of a 275kV transmission line between Nebo and Strathmore substations by late 2008
- Stage 3 — Construction of a 275kV transmission line between Strathmore and Ross substations by late 2010

Prior to commencing construction of the second and third stages of the transmission reinforcement outlined above, Powerlink will review the key input variables in its analysis (i.e. demand forecasts, latest generation developments) and refine the timing of those stages accordingly. Powerlink will also evaluate the benefits, costs and feasibility of obtaining network support services from North Queensland generators in future years (beyond 2007/08).

5.4.3 Gladstone Grid Section

The maximum power transfer across this grid section is set by the thermal rating of the 275kV lines between the Central West and Gladstone zones (usually the 275kV circuit between Calvale and Wurdong) and potentially the thermal rating of the Calvale 275/132kV transformer. The highest loadings on the Calvale to Wurdong 275kV circuit generally occur following a contingency of the Calvale to Stanwell 275kV circuit.

The present equation for the Gladstone grid section is shown in Table B.3 of Appendix B. The equation predicts the flow on the critical Calvale to Wurdong 275kV circuit following an outage of the Calvale to Stanwell circuit.

Within the NEMMCO market dispatch system, the flow prediction is compared against the most recent rating for the line (accounting for prevailing ambient weather conditions). Powerlink updates these ratings as appropriate and passes them to NEMMCO for their implementation within NEMDE. If the rating would otherwise be violated following the contingency, then generation is re-dispatched to alleviate transfers across this line.

Powerlink has also implemented network switching and support strategies which may be able to be used during times when transfers reach the capability of this grid section. These strategies have been implemented to minimise the effect of generation redispatch on the market.

Flows through the Calvale 275/132kV transformer are currently managed via a network switching strategy to ensure they do not exceed the transformer thermal rating.

Information pertaining to the duration of constrained operation for the Gladstone grid section over the period April 2004 to March 2005 is summarised in Table 5.3.

TABLE 5.3: GLADSTONE GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

Gladstone Grid Section (1)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	0.04%	1.75
October 2005 – March 2006	0.65%	28.5

Notes:

(1) This constraint is managed by the Gladstone Limit Equation. Increasing of Gladstone generation reduces equation binding times.

The number of hours for which the Gladstone transfer capability bound has reduced compared to last year due to more favourable operating conditions.

Power transfers are most likely to reach the transfer capability of this grid section under market dispatch scenarios that lead to high Callide generation.

Other action would be needed if potential major new industrial loads in the Gladstone area eventuate. Powerlink published a Final Report in November 2005 recommending options to address network limitations should any major load developments proceed within this area, including Aldoga Aluminium Smelter and/or Comalco Alumina Refinery Stage 2. At this time none of the developments identified have been committed.

5.4.4 CQ – SQ Grid Section

The maximum power transfer across the CQ – SQ grid section is set by transient and voltage stability or thermal overload following a transmission or generation 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 within these areas increases the reactive power support and therefore the transfer capability.

The present voltage stability limit equations for the CQ – SQ limit are shown in Table B.4 of Appendix B. The equations show that the following variables have the most significant effect on the transfer capability:

- Number of generating units on-line in the Central West and Gladstone zones
- Generation (MW) at the Gladstone power station

At transfers above 1900MW, the CQ – SQ transfer capability may be set by transient stability associated with a fault on a Calvale to Tarong 275kV circuit.

Information pertaining to the duration of constrained operation for the CQ – SQ limit over the period from April 2005 to March 2006 is summarised in Table 5.4.

TABLE 5.4: CQ – SQ GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

CQ – SQ Grid Section (1)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	1.51%	66.25
October 2005 – March 2006	3.51%	153.50

Note:

(1) The duration of binding events outlined in Table 5.4 include periods when spare capability across this grid section was fully utilised by the QNI or DirectLink transferring power south into NSW. Excluding these, the CQ – SQ grid section bound 0.5 hour over the 2005/06 year.

Power flows across this grid section can be higher than shown in Figures A3 to A20 of Appendix A. Factors that could change this outlook include more severe weather than typical 50% PoE conditions and/or generation patterns that result in higher power flows across the CQ – SQ grid section. The latter is the most variable and has the largest potential for producing transfers that reach the limit.

The introduction of additional plant within south Queensland, that displaces generation within Central or North Queensland, can reduce the level of power transfers across this grid section. The advent of large load developments within Central or North Queensland (but not included in the forecasts), without corresponding increases in North or Central Queensland generation, can also significantly reduce the levels of CQ – SQ transfers.

5.4.5 Tarong Grid Section

The maximum power transfer across this grid section is set by voltage stability associated with loss of a 275kV transmission circuit either between central and southern Queensland, or between Tarong and the greater Brisbane load centre. The limitation results from insufficient reactive power reserves within south Queensland.

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

- Calvale to Tarong 275kV transmission circuit
- Woolooga to Palmwoods 275kV transmission circuit
- Tarong to Blackwall 275kV transmission circuit
- Mt England to Loganlea 275kV transmission circuit

The present limit equations for the Tarong limit are shown in Table B.5 of Appendix B. The equations show that the following variables have the most significant effect on the transfer capability:

- Transfer on QNI
- Generation (MW) within the South West zone
- Number of generators on-line in the Moreton North and South zones
- Generation (MW) within the Moreton North and South zones

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

Any increase in generation west of the grid section increases the Tarong limit but reduces the CQ – SQ power flow. 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 the reduction in the transfer capability is more than offset by the reduction in power transfers resulting from increased generation east of the grid section.

Information pertaining to the duration of constrained operation for the Tarong grid section over the period April 2005 to March 2006 is summarised in Table 5.5.

TABLE 5.5: TARONG GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

Tarong Grid Section	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	0.01%	0.50
October 2005 – March 2006	0.00%	0.00

Based on the sample generation scenarios shown within Appendix A, power flows across this grid section increase steadily over time but remain below the Tarong transfer capability. These scenarios are based on 50% PoE demand forecasts and all generation plant being available within the Moreton North and South zones.

The Middle Ridge to Greenbank transmission reinforcement, committed for 2007/08, introduces two new 275kV circuits to the Tarong grid section, thereby increasing it's transfer capability.

5.4.6 Gold Coast Grid Section

The maximum power transfer across this grid section is set by voltage stability associated with loss of the 275kV tee connection from Swanbank to Molendinar and Mudgeeraba.

The maximum transfer capability may also be set by thermal ratings across 275kV or 110kV circuits associated with loss of the tee connection from Swanbank to Molendinar and Mudgeeraba circuit under certain prevailing summer ambient conditions.

The present equation for the Gold Coast transfer capability is shown in Table B.6 of Appendix B. The equation shows that the following variables have the most significant effect on the transfer capability:

- Number of generating units on-line in the Moreton North and South zones
- Loading (MW and MVAr) of DirectLink
- Capacitive compensation levels on the Gold Coast, Moreton North and South zones

The voltage limits are higher when more Swanbank B or E units on-line. Increasing northerly flow on DirectLink reduces the transfer capability, but increases the overall amount of supportable Gold Coast demand. This is because the reduction in the transfer capability is more than offset by the reduction in power transfers resulting from increased generation east of the grid section.

Information pertaining to the duration of constrained operation for the Gold Coast grid section over the period April 2005 to March 2006 is summarised in Table 5.6.

TABLE 5.6: GOLD COAST GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

Gold Coast Grid Section (1) (2)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005 (3)	4.29%	188.50
October 2005 – March 2006	0.91%	39.58

Notes:

(1) The transfer across this grid section is managed through an agreement whereby southerly flows on the DirectLink are runback during binding conditions. Although included in the duration in Table 5.6, NEMMCO does not consider that periods of congestion that are managed through this arrangement contribute to the total number of hours of a binding intra-regional constraint.

(2) The duration of binding events outlined in Table 5.6 include periods when spare capability across this grid section was fully utilised by the DirectLink transferring power south into New South Wales.

(3) The system normal limit bound for less than five hours during this period.

Based on the sample generation scenarios shown within Appendix A, power flows across this grid section increase steadily over time but remain below the transfer capability. These scenarios are based on 50% POE demand forecasts and zero flow on DirectLink.

During the 2006/07 summer period, power transfers may reach the grid section transfer capability when exporting power to New South Wales via DirectLink.

The Gold Coast limit bound for over 4% of the time, in the winter of 2005, which coincided with maintenance works. Powerlink has a committed project underway to increase the transfer capability of the Gold Coast grid section. This project consists of establishment of a new 275kV switching station at Greenbank, construction of double circuit 275kV transmission line from Greenbank to Maudsland, and installation of reactive compensation at Greenbank. This project is due for completion by the 2006/07 summer.

Powerlink has also assessed that the transfer capability across 275/110kV transformers within the Gold Coast area are expected to reach thermal ratings by the 2007/08 summer. A recommendation to address this emerging limitation is discussed in Section 5.5.8.

Based on the sample generation scenarios shown within Appendix A, power flows across this grid section increase steadily over time but remain below the transfer capability. These scenarios are based on 50% PoE demand forecasts and all generation plant being available within the Moreton North and South zones.

5.4.7 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 within south west Queensland (including import from QNI), to the rest of the state.

The Braemar limit equation is presently the only limit equation applied to this grid section. The equation for the Braemar transfer capability is shown within Table B.7 of Appendix B.

Information pertaining to the duration of constrained operation for the Braemar transfer capability over the period April 2005 to March 2006 is summarised in Table 5.7.

TABLE 5.7: BRAEMAR GRID SECTION CONSTRAINT TIMES FOR APRIL 2005 – MARCH 2006

Braemar Grid Section	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April – September 2005	0.00%	0.0
October 2005 – March 2006	0.00%	0.0

The capability of the SWQ grid section is not expected to be reached prior to the advent of new generation within south west Queensland (specifically south west of the SWQ grid section). Beyond this time, the performance of this grid section will depend on the location, capacity and operation of generation entrants.

The capability of this grid section is set by thermal ratings of either the Braemar to Tarong 275kV circuits, Middle Ridge to Tarong 275kV circuit, or the Middle Ridge to Swanbank 110kV circuits. The critical contingency is loss of one of the 275kV circuits between Braemar and Tarong.

In addition, the capability of this grid section may be set by the thermal ratings of the Braemar 330/275kV transformers. The critical contingency in this case is loss of one of the Braemar 330/275kV transformers.

The sample generation scenarios within Appendix A assume the commissioning of the 750MW Kogan Creek coal fired power station (as discussed within Section 6.2). For these sample scenarios, power transfers are below the capability of the SWQ grid section.

5.4.8 QNI Limits

The Queensland to New South Wales Interconnection (QNI) was designed and constructed of assets having plant ratings of at least 1000MW. However the actual transfer capability will vary from time to time depending on system conditions.

Works have been carried out to increase the oscillatory limit of the interconnection. This includes upgrading the design of the existing Power Oscillation Damper Controller at the Blackwall SVC. The damping limit is conditional on availability of on-line stability monitoring equipment.

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

- Transient stability associated with 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
- Thermal ratings of the 132kV transmission network within northern NSW
- Oscillatory stability upper limit of 1078MW (conditional)

For intact system operation, the combined northerly transfer capability of QNI and DirectLink 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 within Queensland
- Transient stability associated with transmission faults in Queensland
- Thermal ratings of the 330kV transmission network in NSW
- Oscillatory stability upper limit of 700MW

Preliminary investigations indicate promise that an upgrade of the transfer capability of the QNI could be economic under the revised AER Regulatory Test. Powerlink and TransGrid are currently undertaking detailed studies to investigate whether such an upgrade would indeed be feasible. This is discussed further within 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. The Transmission Authority also requires Powerlink to plan and develop its network such that forecast peak demand can be supplied during a single network element outage.

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 arise some years into the future, assuming that demand for electricity continues to grow as outlined in this document. This forward planning allows Powerlink 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 generation, Demand Side Management (DSM) initiatives and network augmentations.

The information presented in this section provides advance notice of anticipated consultation processes, and extends the time available to interested parties to develop solutions. Further information will be provided during the relevant consultation process, if and when this is required (see Section 5.7 for current and anticipated consultation processes).

Solution providers should be aware that there is some uncertainty surrounding the timing in which action will be required to address some of the following emerging limitations. Timing is dependent on demand growth in the identified areas and developments in the wholesale electricity market.

5.5.1 Far North Queensland Zone

Voltage Control/Transformer Capacity
Sufficient capability is forecast to be available in this zone until late 2008, when an outage of the 275kV circuit between Chalumbin and Woree is forecast to result in voltage instability at times of high demand without action to augment supply. The thermal capability of the 132kV line between Chalumbin and Woree, during an outage of the adjacent 275kV circuit, is forecast to be reached by late 2010 without action to augment supply.

These identified limitations are being addressed by a committed project comprising the installation of an additional transformer at Woree and energisation of the second Chalumbin to Woree circuit currently operating at 132kV for operation at 275kV by late 2008 (refer Table 4.2).

Supply to Mission Beach Area

Sufficient capability is forecast to be available until summer 2008/09. Due to ongoing demand growth, from summer 2008/09 an outage of one of the 22kV distribution lines from Tully 132/22kV substation is forecast to result in unacceptably low voltage conditions in the Mission Beach area during summer peak demand periods without action to augment supply.

A proposed new small network asset, consisting of a 132/22kV substation at El Arish, has been recommended to address this identified limitation at an estimated total cost of $17.9 million, with shared network component of $7.7 million (refer Section 5.7.4).

Supply to Edmonton/Gordonvale Area

Sufficient capability is forecast to be available until summer 2008/09. Due to ongoing demand growth, from summer 2008/09 an outage of the Woree to Edmonton 132kV line is forecast to result in unacceptably low voltage conditions in the Edmonton/Gordonvale area during summer peak demand periods if action to augment supply is not undertaken.

A proposed new small network asset, consisting of a 30MVAr 132kV capacitor bank, has been recommended to address this identified limitation at an estimated cost of $2 million (refer Section 5.7.4).

5.5.2 Ross Zone

Supply to Northern and Western Townsville Area (Thuringowa)

Demand in the Townsville area has grown consistently in recent years. Average demand growth in the Thuringowa area is expected to be around 3% per annum for the next ten years.

Northern and western areas of Townsville are presently supplied from the Dan Gleeson, Alan Sheriff, and Garbutt 132/66kV substations. Primary supply to these substations occurs via 132kV connections from Ross substation and output from Townsville Power Station.

Sufficient capability is forecast to be available until summer 2008/09 when thermal capability limitations are expected to arise in the 132kV line between Ross and Dan Gleeson under contingency conditions if action to augment supply is not undertaken.

A feasible network solution may involve establishment of a new substation at Yabulu South and construction of a double circuit transmission line from Ross to Yabulu South at a cost in the range of $40–60 million.

Non-network solutions may include local generation and/or DSM initiatives.

A consultation process to address this identified limitation is underway (refer Section 5.7.3).

Supply to Townsville South and CBD/Port Areas
Due to ongoing demand growth, thermal capability limitations are expected to arise in the 132kV transmission network between Ross and Townsville South substations from summer 2006/07 without action to augment supply.

A committed project, comprising the installation of a new capacitor bank at Townsville South, is underway to address this limitation by late 2006 (refer Section 4.2).

Following this small network augmentation, the limitation is expected to recur one year later. A committed project is underway to address this limitation, comprising construction of a new 132kV double circuit transmission line from Ross to Townsville South by late 2007 (refer Table 4.2).

Thermal limitations are also expected to arise in the distribution network supplying the Townsville CBD/Port Area by summer 2007/08 without action to augment supply. A committed project is underway to address this identified limitation, comprising construction of a new 132/66kV substation at Townsville East and a 132kV double circuit transmission line from Townsville South substation to Townsville East substation by late 2007 (refer Table 4.2).

5.5.3 North Zone

Supply to Mackay – Proserpine Area
Electricity demand in the Mackay – Proserpine area is growing steadily at around 3% per annum.

This growth will increase loadings on the 132kV transmission network supplying the area from Nebo and Strathmore substations. Sufficient capability will be available in this network until summer 2007/08, at which time the Nebo-Pioneer Valley 132kV circuit is expected to reach its emergency thermal rating during an outage of the Nebo-Alligator Creek 132kV circuit if action to augment supply is not undertaken.

A committed project is underway to address this identified limitation. The project comprises construction of a 132kV double circuit transmission line between Nebo and Pioneer Valley substations and reconfiguration of the existing 132kV circuit between Alligator Creek and Mackay substations to connect it into the Pioneer Valley substation (refer Table 4.2).

Supply to South Mackay Area
Electricity demand in the South Mackay area is forecast to increase sharply in the near term due to the expansion of the coal loading terminals at Dalrymple Bay and Hay Point and consequent increase in electrified rail traffic.

This forecast demand growth is expected to result in thermal limitations in the 132/33kV transformers at Alligator Creek substation and the local 33kV distribution network during contingency conditions without action to augment supply.

A feasible network solution may involve establishment of an additional 132/33kV transformer at Alligator Creek at an approximate cost of $3–6 million plus associated distribution network upgrades, or construction of a new 132kV line and 132/33kV substation south of Mackay at an approximate cost of $15–25 million.

Non-network solutions may include local generation and/or DSM initiatives.

Supply to Bowen Area
Electricity demand in the Bowen Area may grow strongly due to possible expansion of the Abbot Point coal loading terminal and possible introduction of electrified rail traffic. Should these developments proceed within the five year outlook period, thermal limitations are expected to arise in the local 66kV distribution network if action to augment supply is not undertaken.

A feasible network solution may involve construction of a new 132kV line from either Strathmore or Proserpine substation to a new 132/66kV substation in the Bowen area. The approximate cost of this option is $40–50 million.

Non-network solutions may include local generation and/or DSM initiatives.

A consultation process to address this identified limitation is underway (refer Section 5.7.3).

CQ – NQ and Nebo-Ross Limitations
Summer peak electricity demand requirements in north and far north Queensland are currently met by the transmission system operating in conjunction with local generators. This combined supply capability will be sufficient to reliably meet forecast electricity demand requirements until summer 2007/08.

A committed project is underway to address future requirements from late 2007. The project comprises a staged augmentation of the transmission network between Broadsound and Ross as follows:

- Construction of a 275kV transmission line between Broadsound and Nebo substations and installation of a Static VAr Compensator at Strathmore by late 2007
- Construction of a 275kV transmission line between Nebo and Strathmore substations by late 2008
- Construction of a 275kV transmission line between Strathmore and Ross substations by late 2010, subject to confirmation of scope and timing prior to implementation

To assist in meeting peak demand requirements, network support services will be sourced from local generators and/or DSM providers, if available.

5.5.4 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 the Queensland Alumina plant, Comalco Alumina Refinery and Boat Creek and Gladstone Substations. Moreover, there continues to be several proponents considering additional developments in the area.

At the present time there are transmission limitations between Callide and Gladstone during some generation scenarios. These limitations are currently managed by redispatch of generation, however any new and significant loads may necessitate network augmentation to permit Powerlink to meet reliability obligations. The scope of augmentation/s would be largely driven by the size and location of the developments.

Due to ongoing, smaller scale demand growth it is forecast that the thermal limits of the 275/132kV transformers at Gladstone Substation will be reached from 2009/10, along with limitations in the 132kV network. In addition, the fault level at Gladstone on the 132kV bus has reached the rating of the existing plant.

This is currently managed as required with operational strategies. However, additional 275/132kV transformation capacity must take account of fault level limitations. The connection of any additional generators must also address fault level limitations in the Gladstone area.

With regard to forecast thermal limits, non-network solutions may include local generation (provided fault levels are addressed) and/or DSM initiatives.

5.5.5 Central West Zone

Supply to the Rockhampton Area
Demand growth in the Rockhampton area is forecast to grow at an average of 3.7% per annum over the next five years. This area is supplied from Bouldercombe 275/132kV substation by a double circuit 132kV line to Rockhampton (Glenmore) 132/66kV substation and by a single circuit 132kV line to Egans Hill 132/66kV substation. Sufficient capability is forecast to be available until summer 2009/10 when an outage of either Bouldercombe to Rockhampton circuit is forecast to cause an overload in the companion circuit without action to augment supply.

A feasible network solution may involve establishment of a new 132/66kV substation north of Rockhampton at an approximate cost of $20–30 million.

Non-network solutions may include local generation and/or DSM initiatives.

Supply to Inland Central Queensland Area
The Inland Central Queensland area comprises the towns of Biloela, Moura, Blackwater and Emerald as well as the mining loads of the southern Bowen Basin predominantly centred on Blackwater and Moura. This area is supplied via 132kV transmission lines from 275/132 kV substations at Lilyvale and Calvale/Callide.

Due to increasing mining loads in the area, the 132kV transmission capability between Callide, Biloela, Moura and Blackwater substations is expected to be reached under contingency conditions from summer 2007/08 onwards (in summer peak demand periods) if action to augment supply is not undertaken.

A committed project is underway to address this identified limitation, comprising construction of a 132kV transmission line between Lilyvale and Blackwater substations by late 2007 (refer Table 4.2).

Supply to Bowen Basin Coal Mining Area
Electricity demand in the Bowen Basin Coal Mining Area may grow strongly due to possible new mining developments. Should these developments proceed within the five year outlook period, thermal limitations are expected to arise in the 132kV network supplying the area without action to augment supply.

A feasible network solution may involve construction of a new transmission line between Nebo and Kemmis or Moranbah. The approximate cost of this option is in the range of $20–60 million.

Non-network solutions may include local generation and/or DSM initiatives.

5.5.6 Wide Bay and South West Zones

Supply to Wide Bay Area

The eastern Wide Bay area is supplied from 275/132kV substations at Gin Gin and Woolooga. Electricity demand in this area is growing steadily. Planning studies have forecast that by the summer of 2007/08, the transformer capacity at Gin Gin and the 132kV network supplying the Bundaberg, Isis, Maryborough and Kilkivan areas will need to be augmented to ensure peak demand requirements can continue to be met under contingency conditions.

On 30 May 2006 Powerlink and Ergon Energy made a final recommendation for a project to address this identified limitation, comprising construction of a new 275/132kV substation at Teebar Creek and a double circuit 132kV transmission line from Teebar Creek to Aramara by late 2007 (refer Table 4.2).

Supply to Toowoomba/Lockyer Valley Area

Sufficient capability is forecast to be available until summer 2009. Due to ongoing demand growth in the Toowoomba/Lockyer Valley area, thermal capability limitations are forecast to arise in both Energex's and Ergon Energy's 33kV networks supplying this area by late 2009 if action to augment supply is not undertaken.

Possible network solutions include establishment of new 110/33kV injection points for Postmans Ridge (Energex) and Mt Kynoch (Ergon Energy).

Non-network solutions may include local generation and/or DSM initiatives.

CQ – SQ Transfer Limit

Powerlink has assessed there will be sufficient capability available until the summer of 2008/09, when the combination of local generation and grid transfer capability will be insufficient to maintain reliability of supply to customers within southern Queensland without action to augment supply. This assessment is based on existing and committed generation developments and demand forecasts.

Possible network solutions include establishment of a switching station near Auburn River, a Static VAr Compensator possibly located on the coastal circuits, or an additional Calvale-Tarong transmission line. The estimated cost of these solutions is in the range of $25–200 million.

Non-network solutions may include South Queensland generation and/or DSM initiatives.

SWQ – SEQ Transfer Limit

Due to ongoing strong demand growth in South East Queensland, the SWQ to SEQ transfer limit is expected to be reached from 2011 onwards if action to augment supply is not undertaken.

A feasible network solution would be the construction of a new transmission line between Braemar and Tarong by late 2011 at a cost in the range of $110–$130 million.

Non-network solutions may include generation located in South East Queensland and/or DSM initiatives.

5.5.7 Moreton North and South Zones

Supply to Sunshine Coast Area (Moreton North)
Bulk supply to the Sunshine Coast Area is provided from 275/132kV substations at Woolooga and Palmwoods. Electricity is then transferred over Energex's 132kV network to supply Gympie, Nambour, the Sunshine Coast and Caboolture.

Sufficient capability is forecast to be available until 2010/11 when thermal capability limitations are expected to arise in Energex's 132kV network between Woolooga and Gympie during critical 275kV and 132kV network outages without action to augment supply.

A feasible network solution may involve minor upgrades by Energex followed by construction of a new 275/132kV substation in the Northern Sunshine Coast area at an approximate cost of $60–70 million.

Non-network solutions may include local generation and/or DSM initiatives.

Sunshine Coast Voltage Control (Moreton North)
By late 2009, growing demand on the Sunshine Coast will result 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. In addition, the sensitivity of the Sunshine Coast network increases to the point where the required reactive demand cannot be met through capacitor banks alone. This requires the need for dynamic reactive plant to form part of the solution.

Potential solutions include demand side management or the combination of capacitor banks and a Static VAr Compensator. The costs of these solutions are estimated to be in the range of $10–30 million.

Supply to North Brisbane (Moreton North)
Significant demand growth is forecast to continue in the North Brisbane area as a result of population growth and extensive commercial/industrial development such as the Brisbane Airport commercial precinct. As a result, thermal capability limitations are expected to arise in Energex's 110kV network between South Pine and Nudgee under contingency conditions by summer 2009/10 if action to augment supply is not undertaken. A further thermal limitation is expected to arise in the transformer capacity at South Pine Substation in the next five years without action to augment supply.

A feasible network solution may involve construction of a transmission line between South Pine and the Energex substation at Sandgate, at an approximate cost of $25–40 million.

Non-network solutions may include local generation and/or DSM initiatives.

South East Queensland Voltage Control (Moreton North & South)
Growing demand in South East Queensland (SEQ) will result 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 service arrangements.

Potential solutions include demand side management or a program of shunt capacitor installation in SEQ to keep pace with this growing requirement. The shunt capacitor option would cost approximately $3–7 million per year.

During 2005/06, a small network asset consultation process was undertaken on the proposed installation of a 110kV capacitor bank at Molendinar and a 275kV capacitor bank at Greenbank by summer 2006/07. These projects are now under construction.

There is expected to be an ongoing requirement for additional reactive support needed to address voltage stability issues, as SEQ electricity demand continues to grow rapidly. The 2005 consultation on the South East Queensland Area recommended the installation of capacitor banks at South Pine, Ashgrove West and Rocklea in late 2009 and at Tarong, Mt England, South Pine, Belmont and Loganlea in 2010, subject to confirmation of scope and timing prior to implementation.

There is an increasing need to maintain an acceptable balance between static and dynamic compensation in South East Queensland. This situation will depend on the future operating pattern of Swanbank B Power Station.

A feasible network solution may involve the installation of a Static VAr Compensator near Greenbank at an estimated cost of $20–30 million.

Non-network solutions may include local generation and/or DSM initiatives.

Supply to Brisbane CBD and Inner Suburbs (Moreton North & South)
The Brisbane CBD and inner suburbs are supplied by five 110kV circuits comprising a double-circuit 110kV line from Belmont to Newstead, a double-circuit 110kV line with cable sections from Upper Kedron to Ashgrove West and a single 110kV overhead/underground cable circuit from Rocklea/Tennyson to West End.

By 2006/07, various thermal capability limits are forecast to be reached on this 110kV network and in parts of the distribution network under normal contingency conditions if action to augment supply is not undertaken.

A committed project is underway to address these limitations. The project comprises construction of a new 110kV underground connection to Charlotte Street substation teed from the existing Belmont to Murarrie transmission lines, upgrade of the existing 110kV network supplying the CBD area, construction of a 275kV line between Belmont and Murarrie, and the carrying out of works to provide new substations within the CBD area (refer Table 4.2). These project elements are being progressively commissioned from August 2005 until late 2006.

275/110kV Transformer Limitations (Moreton North & South)
Demand in the Moreton North and Moreton South zones is forecast to grow at over 5% per annum over the next five years. This demand is supplied from the 110kV network, which receives supply via the 275kV system. The 275/110kV transformer capacity must keep pace with demand growth to avoid unacceptable overloads following transformer outages.

Based on forecast demand growth, Powerlink has identified 275/110kV transformer capacity limitations on the South Pine and Murarrie transformers, where the overload during contingency conditions is forecast to become unacceptable by summer 2006/07 and summer 2009/10 respectively without action to augment supply.

A committed project is underway to address the South Pine limitation and involves establishment of a new 375MVA transformer, removal of an old 200MVA transformer, and replacement of a 200MVA transformer with a new 250MVA unit, with commissioning scheduled from mid 2006 until mid 2007.

A proposed new small network asset, consisting of a second 375MVA 275/110kV transformer at Murarrie Substation, has been recommended to address this identified limitation at an estimated cost of $9.2 million (refer Section 5.7.4).

110/33kV and 110/11kV Transformer Limitations (Moreton North & South)

Due to significant ongoing demand growth in the Moreton North and South zones, thermal capability limitations are forecast to arise in Energex's 33kV and 11kV network, and 110/33kV or 110/11kV transformation capacity in the next five year period if action to augment supply is not undertaken.

Possible network solutions include establishment of new 110/33kV or 110/11kV injection points, augmentation of existing transformation capacity (i.e. additional transformers), or upgrade of Energex's 33kV and 11kV network.

Non-network solutions may include local generation and/or DSM initiatives.

Due to ongoing demand growth, from summer 2009/10, an outage of the 110/11kV transformer at Bundamba Substation is forecast to result in the thermal capability of Energex's 33kV network in the local area being exceeded during summer demand peak demand periods without action to augment supply.

A proposed new small network asset, consisting of a second 110/11kV transformer at Bundamba Substation, has been recommended to address this identified limitation at an estimated total cost of $11.8 million, with shared network component of $3.7 million (refer Section 5.7.4).

Supply to South West Brisbane and Ipswich Areas (Moreton South)

Demand growth in the South West Brisbane and Ipswich areas is forecast to increase rapidly at around 7 – 8% per annum for the next three years — driven by significant residential, commercial and industrial development and further penetration of domestic air-conditioning. These areas extend south from Runcorn to Browns Plains and west to Gatton.

Given this level of growth, there are emerging limitations in the 275kV, 110kV and distribution networks supplying these areas. From the summer of 2006/07 onwards, thermal capability limitations are expected to arise in this network during a critical network outage without action to augment supply.

A committed project is underway to establish a number of 110/33kV and 33/11kV substations (and associated connections) by late 2006 to address these identified limitations (refer Table 4.4).

An additional 275/110kV transformer limitation (near Ipswich) is expected to arise from summer 2007 under contingency conditions if action to augment supply is not undertaken. Committed projects are underway to establish 275/110kV substations at Goodna by late 2007 and Abermain by late 2008 to address this identified limitation (refer Section 4.2).

A future 275kV line limitation is expected in the Ipswich area from summer 2011/12 without action to augment supply. A feasible network solution may involve construction of a new 275kV transmission line from Bundamba to Goodna to the Browns Plains area. Depending on the solution adopted, minor initial works may be required as early as 2009/10.

Non-network solutions may include local generation and/or DSM initiatives.

Future 110kV line limitations are also expected in the South West Brisbane and Ipswich Areas from summer 2010/11 without action to augment supply. A feasible network solution may involve establishment of a new 275/110kV substation site in the Browns Plains area and associated 110kV transmission lines at an approximate cost of $40–60 million.

Non-network solutions may include local generation and/or DSM initiatives.

Supply to Murarrie and TradeCoast Areas (Moreton South)
Belmont 275/110kV substation supplies part of the Brisbane CBD, Murarrie and Australia TradeCoast area (Brisbane Port), Redlands Shire, coastal areas and part of the Richlands – Algester – Runcorn area.

Thermal capability limitations in the 110kV network supplying Murarrie are expected by summer 2006 under contingency conditions if action to augment supply is not undertaken.

These identified limitations are being addressed by the committed project to address supply limitations in the Brisbane CBD and inner suburbs (see earlier entry — Supply to Brisbane CBD and Inner Suburbs).

Demand Growth South East Queensland – Logan (Moreton South)
Very high demand growth is occurring in South East Queensland, particularly in the Moreton South zone. Power is supplied to South East Queensland (defined in terms of this reliability requirement as including Moreton North, Moreton South, Wide Bay and Gold Coast zones) from local generation and transmission connections from adjacent zones. The majority of power is transferred to the area via five 275kV circuits between Tarong and the wider Brisbane area.

Sufficient capability is forecast to be available until summer 2007/08 when increasing demand is expected to result in emerging reliability of supply limitations. Supply capability limitations will arise due to a combination of full utilisation of existing local generation sources and the inability to transfer additional power into SEQ on the existing transmission network without action to augment supply.

A committed project is underway to construct a new transmission line between Middle Ridge and Greenbank by late 2007 to address this identified limitation (refer Table 4.2).

5.5.8 Gold Coast Zone

275kV Supply to Gold Coast Area
The Gold Coast area is one of the fastest-growing areas in the state, in terms of population, commercial development and demand growth. Summer electricity demand growth is expected to average close to 6% per annum for the next ten years.

Due to the high demand growth, emerging limitations have been identified in the transmission and distribution system supplying the Gold Coast area. During summer peak demand periods from late 2006 onwards, voltage stability and thermal limitations are expected to arise based on a critical 275kV contingency without action to augment supply.

A committed project is underway to address this identified limitation. The project comprises construction of a 275kV substation at Greenbank and construction of a 275kV transmission line between Greenbank and Maudsland by late 2006 (refer Table 4.2).

275/110kV Transformer Capacity

Based on forecast demand growth, an outage of the Molendinar 275/110kV transformer is forecast to cause the exceedence of the capacity of the Mudgeeraba 275/110kV transformers by late 2007 without action to augment supply.

A committed project comprising the installation of a second 375MVA 275/110kV transformer at Molendinar is underway to address this identified limitation by late 2007 (refer Section 4.2).

As demand continues to grow, the transformer capacity limit is forecast to re-emerge in this area by summer 2010/11 if action to augment supply is not undertaken. A feasible network solution may be the installation of a third 275/110kV transformer at Molendinar at an estimated cost of $15–20 million.

Non-network solutions may include local generation and/or DSM initiatives.

110kV Circuit Capability

Electricity demand in the Tweed area is growing steadily and is forecast to reach the thermal capability of the Mudgeeraba to Terranora 110kV line by late 2007 without action to augment supply. A committed project is underway to uprate the capability of this 110kV line.

Capability limitations are also expected to arise in the distribution network supplying the southern Gold Coast area from late 2010 if action to augment supply is not undertaken.

Solutions may include network support from local generation, suitably located DSM initiatives and/or upgrading or reinforcing the 110kV network in the southern Gold Coast area. Joint planning is not yet sufficiently advanced to provide a scope and estimated cost.

5.6 Summary of Forecast Network Limitations

Limitations discussed in Section 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

Refer Section 5.7 for information on action to address future limitations.

Anticipated Limitation	Reason for Constraint or Limitation	Time Limitation May Be Reached 1 Year Outlook	3 Year Outlook	5 Year Outlook
FAR NORTH AND ROSS ZONES				
Far North Voltage Control/ Transformer Capacity	275kV outages in Far North Queensland may result in unacceptable voltage conditions and thermal overloading of the 132kV network		2008 – 2010 Committed project in progress (1)	
Supply to Mission Beach area	22kV outages in the Mission Beach area may result in unacceptable voltage conditions		2008/09 (2)	
Supply to Edmonton/ Gondonvale area	Outage of the 132kV Woree – Edmonton line may result in unacceptable voltage conditions		2008/09 (2)	
Supply to Northern and Western Townsville Area (Thuringowa)	Future 132kV network thermal capability limitations in meeting demand growth in northern and western Townsville		2008/09 (2)	
Supply to Townsville South and CBD/Port Areas	Future 132kV and 66kV network thermal capability limitations in meeting growing potential new loads in the Townsville South and CBD/Port areas	Committed project in progress (1)	2007/08 Committed project in progress (1)	
NORTH ZONE				
Supply to Mackay – Proserpine Area	Due to demand growth, thermal limitations expected to arise in the Nebo – Pioneer Valley 132kV circuit under contingency conditions		2007/08 Committed project in progress (1)	
Supply to South Mackay Area	Due to industrial demand growth, thermal limitations may occur in 132/33kV transformers at Alligator Creek as well as the 33kV distribution network under contingency conditions		2008/09	
Supply to Bowen Area	Due to potential industrial load growth, thermal limitations may occur in local 66kV distribution network		2008/09 (5)	
CQ – NQ and Nebo – Ross Limitations	Voltage, dynamic instability, and thermal overloading may result from 275kV line outages during periods of high northern Queensland demand	Committed project in progress (3)	2007 – 2010 Committed project in progress (1)	

TABLE 5.8: SUMMARY OF FORECAST NETWORK LIMITATIONS CONTINUED

Refer Section 5.7 for information on action to address future limitations.

Anticipated Limitation	Reason for Constraint or Limitation	Time Limitation May Be Reached 1 Year Outlook	3 Year Outlook	5 Year Outlook
GLADSTONE AND CENTRAL WEST ZONES				
Supply to Gladstone Area	Potential for overload of Calvale – Wurdong 275kV line and/or Calvale and Gladstone 275/132kV tie transformer	Currently managed by switching and support arrangements (4)		2009/10
Supply to Rockhampton Area	Due to demand growth, an outage of one of the Bouldercombe – Rockhampton 132kV circuits may result in thermal overloading of the remaining circuit in service			2009/10
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		2007/08 Committed project in progress (1)	
Supply to Bowen Basin Coal Mining Area	Due to potential mining growth, thermal limitations may occur in the 132kV network supplying this area			2010/11 (5)
WIDE BAY AND SOUTH WEST ZONES				
Supply to Wide Bay Area	Demand growth may result in voltage control and thermal limitations during an outage of the 132kV network between Bundaberg and Woolooga		2007/08 Committed project in progress (1)	
Supply to Toowoomba/ Lockyer Valley area	Due to demand growth, thermal capability limitations are expected in the 33kV networks supplying this area			2009/10
Grid transfer limit: CQ – SQ	Continued demand growth in SQ may give rise to binding transfer limits for flows between CQ and SQ		2008/09	
Grid transfer limit: SWQ – SEQ	Continued demand growth in SEQ may give rise to binding transfer limits for flows between SWQ and SEQ			2011

TABLE 5.8: SUMMARY OF FORECAST NETWORK LIMITATIONS CONTINUED

Refer Section 5.7 for information on action to address future limitations.

Anticipated Limitation	Reason for Constraint or Limitation	Time Limitation May Be Reached		
		1 Year Outlook	3 Year Outlook	5 Year Outlook
MORETON NORTH AND SOUTH ZONES				
Supply to Sunshine Coast Area	Demand growth may result in thermal limitations in Energex's 132kV network between Woolooga and Gympie during a critical 275kV or 132kV outage, following Energex minor upgrade works			2010/11
Sunshine Coast Voltage Control	Increasing reactive demand due to demand growth likely to require action to satisfy voltage control standards			2009/10
Supply to North Brisbane	Demand growth may result in thermal limitations in Energex's 110kV network and Powerlink 275/110kV transformers			2009/10
South East Queensland Voltage Control	Increasing reactive demand due to demand growth likely to require program of action to satisfy voltage control standards. Further action to satisfy voltage control standards may be necessary depending on the operating pattern of Swanbank B.	Committed project in progress (1)		2009 – 2011
Supply to Brisbane CBD and inner suburbs	Increasing demands in Brisbane CBD and inner suburbs leading to thermal capability limits in the distribution and 110kV networks	Committed project in progress (1)		
275/110kV Transformer Capability	Due to demand growth, future 275/110kV transformer capacity limitations are anticipated at multiple locations	Committed project in progress (1)		2009/10 (2)
110/33kV and 110/11kV Transformer Capability	Due to demand growth, future 110kV transformer limitations and 33kV and 11kV line limitations are anticipated at multiple locations	Committed project in progress (1)		
Supply to South West Brisbane and Ipswich Areas	Due to demand growth, thermal capability limitations are expected in the 275kV and 110kV network supplying these areas	Committed project in progress (1)	2007/08 Committed project in progress (1)	2009 – 2011
Supply to Murarrie – Trade Coast Area	Thermal capability limitations of 110kV network to Murarrie in meeting growing and potential new Trade Coast area loads	Committed project in progress (1)		
Demand Growth South East Queensland (Logan)	High demand growth expected to result in limitations in supply to entire south eastern Queensland area		2007 – 2010 (1)	

TABLE 5.8: SUMMARY OF FORECAST NETWORK LIMITATIONS CONTINUED

Refer Section 5.7 for information on corrective action to address future limitations.

Anticipated Limitation	Reason for Constraint or Limitation	Time Limitation May Be Reached 1 Year Outlook	3 Year Outlook	5 Year Outlook
GOLD COAST ZONE				
275kV Supply to Gold Coast Area	Expected power flows likely to exceed Gold Coast voltage stability limits. Thermal limits may also arise in Energex system	Committed project in progress (1)		
275/110kV Transformer Capacity	Due to demand growth, Mudgeeraba 275/110kV transformers expected to reach thermal capacity limitations in the event of an outage of the Molendinar 275/110kV transformer		2007/08 Committed project in progress (1)	2010/11
110kV circuit capability	Due to demand growth, thermal capability limitations expected to arise in 110kV network and distribution network		2007/08 Committed project in progress (1)	2010/11

Notes:

(1) Refer Tables 4.2 and 4.4 — Committed Augmentations.

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

(3) Network support arrangements in place.

(4) Other action may be required if new loads occur in the Gladstone area.

(5) The actual timing of the forecast limitation will be driven by major industrial developments.

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. Following the recent commissioning of major new generators, a new pattern of generation and power flows is becoming more evident although this is likely to change again following any further announcement of new generating plant.

The previous section of this report outlined forecast limitations that may arise in Powerlink's transmission network in the near future. The possible timing and effect of these limitations is dependent on demand growth and market developments.

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

Sections 5.4 – 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
  - Powerlink's general approach is to seek input, 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.
  - For emerging network limitations which may result in new large network assets, Powerlink's approach is to issue detailed information papers outlining the limitations to assist in identifying non-network solutions
- 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
- In the event a regulated solution (network or network support) is found to satisfy the AER's Regulatory Test, Powerlink will implement the recommended solution

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

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 underway, is provided in Section 5.7.3.

Committed New Large Network Assets

Interested parties are advised that during 2005/06, Powerlink finalised regulatory processes associated with the new large network assets outlined in Table 5.9.

TABLE 5.9: NEW LARGE NETWORK ASSETS FINALISED IN 2005/06

Project Name	Description of Works	Cost	Expected Commissioning Date
Inland Central Queensland	Lilyvale – Blackwater 132kV line	$28.8M	Late 2007
Mackay – Proserpine area	Nebo – Pioneer Valley 132kV line and Alligator Creek – Mackay 132kV line reconfiguration	$44.7M	Late 2007
Townsville area	Ross – Townsville South – Townsville East 132kV line and 132/66kV substation at Townsville East	$39.6M	Late 2007
Wide Bay area	Teebar Creek – Aramara 132kV line and 275/132kV substation at Teebar Creek	$66.6M	Late 2007
Ipswich area	275/110kV substations at Goodna and Abermain	$37.9M	Late 2007 (Goodna) Late 2008 (Abermain)
South Eastern Queensland	Middle Ridge – Greenbank line and capacitor banks at various South Eastern Queensland locations	$108.7	Late 2007 (line) Late 2009 & 2010 (capacitor banks)
North and Far North Queensland	Broadsound – Nebo – Strathmore – Ross 275kV line and 275kV Static VAr Compensator at Strathmore	$340.4M	Progressively from late 2007 – late 2010
Cairns area	Energisation of second Chalumbin – Woree line at 275kV and second 275/132kV transformer at Woree	$12.4M	Mid 2008
Gladstone area	275/132kV substation at Larcom Creek and new 275kV line from Larcom Creek to a location to be determined based on potential industrial developments	Range $39.5M – $95.0M	By early 2008, subject to commitment of potential industrial developments

5.7.3 Consultation — New Large Network Assets

Consultations Underway

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 in various areas around the State.

For each limitation, Powerlink has issued an information paper that outlined the emerging limitations and invited submissions from potential solution providers. Powerlink will then undertake a review of all feasible supply solutions, including economic analysis under the AER Regulatory Test, and publish its draft recommendation in an Application Notice in the near future.

TABLE 5.10: CONSULTATIONS UNDERWAY

Area	Date Request for Information Paper Released	Anticipated Date for Publication of Application Notice
Bowen	April 2006	July/August 2006
Thuringowa	September 2005	July 2006

Anticipated Consultation Processes

Other consultation processes likely to be initiated in the next twelve months are summarised in Table 5.11:

TABLE 5.11: CONSULTATION LIKELY WITHIN 12 MONTHS

Location (1)
Rockhampton
Sunshine Coast
North Brisbane
QNI Upgrade
Central – Southern Queensland
South West – South East Queensland
Southern Gold Coast
Gladstone

Note:

(1) For further details on each of these limitations refer to Section 5.4.8 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 Outline of Proposed New Small Network Assets

This section outlines proposed network augmentations which are required to be progressed under the provision of Clause 5.6.6A of the NER (new small network assets — capitalisation value between $1 million and $10 million). At the time of publication of this report, Powerlink has developed plans for the proposed new small network augmentations listed in Table 5.12 to the point where they can be consulted on through this document.

TABLE 5.12: PROPOSED NEW SMALL NETWORK ASSETS

Proposed New Small Network Asset	Date to be Operational	Capital Cost
Alligator Creek 132/33kV substation expansion	Late 2008	$12.4M (1)
Edmonton 132kV shunt capacitor bank	Late 2008	$2.0M
El Arish 132/22kV substation establishment	Late 2008	$17.9M (1)
Bundamba 110/11kV transformer augmentation	Late 2009	$11.8M (1)
Murarrie 275/110kV transformer augmentation	Late 2009	$9.2M

Note:

(1) Contains shared network components less than $10 million which are subject to assessment under the AER Regulatory Test.

Further details on each of these proposed new small network assets, including purpose, possible alternatives and the reasons that Powerlink is recommending these augmentations proceed, are provided in Appendix D.

Registered Participants and interested parties are invited to make submissions regarding these proposed augmentations and any non-network options they consider to be an alternative. The closing date for submissions is 28 July 2006. Submissions should be addressed to:

Network Assessments Consultant

Powerlink Queensland

PO Box 1193

VIRGINIA QLD 4014

networkassessments@powerlink.com.au

If there are any material changes required following consideration of submissions, Powerlink will publish its conclusions and a revised recommendation. If no changes are required, Powerlink will proceed to implement these proposed new small network assets in the required timeframes.

Other proposed new small network assets will be subject to separate assessment and consultation as per Clause 5.6.6A of the NER, if commitment is required prior to the publication of the 2007 Annual Planning Report.

5.7.5 Connection Point Proposal

Table 5.13 lists connection works that may be required over the next few years. Regulatory approval of these projects is not required under the NER. 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 be initiated by generators or customers, or result from joint planning with the relevant DNSP.

TABLE 5.13: POSSIBLE CONNECTION WORKS

Potential Project	Purpose	Location	Possible Commissioning Date
Oakey 110/33kV substation	New connection point to Ergon to increase 33kV capability for demand growth	Oakey	Late 2009
Alligator Creek 132kV bays for Louisa Creek	New connection point to Ergon to increase 33kV capability to port facility	Mackay area	Late 2009
El Arish 132/22kV substation	New connection point to Ergon to cater for increasing demand growth	Mission Beach area	Late 2009
Woree 132kV bays for Cairns North	New supply to Ergon Cairns North Substation	Cairns	Late 2007
Bundamba transformer augmentation	Increase transformer capacity to meet growing demands	Ipswich area	Late 2010
Lilyvale or Blackwater 132kV bay for Emerald	New supply to Ergon's Emerald Substation	Emerald	Late 2010
Middle Ridge 110kV connections for Postmans Ridge and Mt Kynoch	Second supply to Energex's Postmans Ridge Substation and Ergon's Mt Kynoch Substation	Toowoomba	Late 2010
Molendinar transformer augmentation	Increase transformer capacity to meet growing demands	Brisbane area	Late 2008
Palmwoods 132kV bays for Marcoola	New supply to Energex's Marcoola Substation	Sunshine Coast	Late 2009
South Pine 110kV bays for Griffin	New supply to Energex Griffin Substation	Griffin and surrounding areas	Late 2008
West Darra 110/11kV substation	New connection point to Energex to cater for increasing demand growth	Brisbane Area	Late 2009
Abermain 110kV bay for Wulkaraka	New supply to Energex's Wulkaraka Substation	Ipswich area	Late 2009
Calvale 132kV bay for Monto Mine	New supply to Monto Mine	Central Queensland	Late 2010
Daisy Hill 110/11kV substation	New connection point to Energex to increase 11kV capability for demand growth	Logan area	Late 2010
Richlands West 110/11kV substation	New connection point to Energex to increase 11kV capability for demand growth	Ipswich area	Late 2010
Rochedale 110/11kV substation	New connection point to Energex to increase 11kV capability for demand growth	Logan area	Late 2009
Swanbank 110kV bay for Coulson	New supply to Energex's Coulson Substation	Ipswich area	Late 2008
QAL Red Mud Dam connection	New supply to QAL plant	Gladstone	Late 2007
Energy Impact Power Station connection	Connection of new power station	South West Queensland	Mid 2009
QR Bolingbroke 132kV rail supply	New supply to Queensland Rail Substation	Bowen Basin mining area	Late 2007
Swanbank Paper plant connection	Connection of new paper mill	Ipswich area	Late 2008
Origin Energy Spring Gully Power Station 275kV or 330kV connection	Connection of new power station	South West Queensland	Late 2008
CAR Cogeneration connection	Connection of new power station	Gladstone	Late 2008

6. OTHER RELEVANT INTRA-REGIONAL ISSUES

CONTENTS

6.1 Existing and Committed Generation Developments

6.1.1 Generation

The bulk of Queensland's electrical energy is generated by coal-fired power stations located in central and southern Queensland. Three relatively small hydro-electric power stations (with limited water storage) operate in far north Queensland. The remaining capacity is mostly pumped storage hydro in southern Queensland, coal fired at Collinsville and gas turbines (GTs) at Swanbank, Townsville, Oakey and other locations.

Table 6.1 summarises the existing and committed power stations connected or to be connected to the Powerlink transmission network, including the non-scheduled market generators at Invicta and Koombooloomba, as well as the scheduled embedded generators at Barcaldine and Roma.

Information in this table has been provided by the owners of the generators and is consistent with information provided to NEMMCO for their 2005 Statement of Opportunities.

The following notes apply to Table 6.1:

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) 'Other various locations' comprise gas turbines at Mackay (33MW Winter/30MW Summer), Gladstone (14/13MW) and Tarong (15/14MW) — note that Tarong and Gladstone GTs are non-scheduled.

(3) Wivenhoe power station is shown at its full capacity (500MW), however output can be limited depending on water storage in the upper dam.

TABLE 6.1: GENERATION CAPACITY

Connected to Queensland Transmission Network (Existing and Committed Plant only) including Embedded Market Scheduled Generators.

	Capacity MW Generated (1)					
Location	Winter 2006	Summer 2006/07	Winter 2007	Summer 2007/08	Winter 2008	Summer 2008/09
Coal Fired						
Callide B	700	700	700	700	700	700
Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Stanwell	1,440	1,440	1,440	1,440	1,440	1,440
Swanbank B	500	480	500	480	500	480
Callide A	0	0	0	0	0	0
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Collinsville	187	187	187	187	187	187
Callide Power Plant	920	900	920	900	920	900
Millmerran	860	860	860	860	860	860
Tarong North	443	443	443	443	443	443
Kogan Creek	0	0	0	724	763	724
TOTAL — Coal Fired	**8,130**	**8,090**	**8,130**	**8,814**	**8,893**	**8,814**
Combustion Turbines						
Barcaldine	50	48	50	48	50	48
Mt Stuart (Townsville)	294	288	294	288	294	288
Townsville (Yabulu)	238	230	238	230	238	230
Oakey	320	276	320	276	320	276
Swanbank E (CCGT)	385	355	385	355	385	355
Roma	68	54	68	54	68	54
Braemar	320	453	480	453	478	450
Other Various Locations (2)	62	57	62	57	62	57
Hydro Electric						
Barron Gorge	60	60	60	60	60	60
Kareeya (including Koombooloomba)	93	93	93	93	93	93
Wivenhoe (pumped storage) (3)	500	500	500	500	500	500
Sugar Mills						
Invicta	39	39	39	39	39	39
TOTAL — Other Than Coal	**2,429**	**2,453**	**2,589**	**2,453**	**2,587**	**2,450**
TOTAL — ALL STATIONS	**10,559**	**10,543**	**10,719**	**11,267**	**11,480**	**11,264**
Interconnections Queensland – New South Wales Import Capability	**500**	**500**	**500**	**500**	**500**	**500**

Note: (1) Source: NEMMCO and Powerlink.

6.2 Changes to Supply Capability

6.2.1 Generation

Since Powerlink's 2005 Annual Planning Report (APR) was published, there have been several changes to generation connected to the transmission grid.

Refurbishment of the Units at the Kareeya power station has been completed, resulting in a slightly increased capacity at the station.

CS Energy is constructing the Kogan Creek 750MW coal fired power station. The expected date of commercial operation is late 2007.

Braemar Power Pty Ltd is completing construction and commissioning of a 3 x 150MW gas fired OCGT power station at Braemar Substation near Dalby. Full commercial operation of this station will be late 2006.

CS Energy has advised the Callide A power station will not return to service. Accordingly, the generator capacity has been nominated as zero for the purposes of Table 6.1.

Powerlink has not been advised of any other commitments to new generating capacity since the 2005 APR.

6.2.2 Interconnection

Table 6.1 also includes combined northerly flow capability for the Queensland-New South Wales Interconnection (QNI) and the Terranora Interconnector.

The combined QNI plus DirectLink maximum northerly capability is set by transient stability, oscillatory stability and the thermal capability of the 330kV network in New South Wales.

In addition, the combined QNI plus DirectLink maximum northerly capability can also be constrained by intra-regional constraints in northern New South Wales and south-western Queensland.

Based on the above network limits, the combined northerly capability of QNI plus DirectLink is nominated as 500MW for the purposes of the generation capacity schedule shown in Table 6.1.

It should be noted, however, that the capability of QNI in both directions varies significantly depending on the status of plant and load conditions in both New South Wales and Queensland. It should also be noted that the capability of QNI is distinctly asymmetric with the southerly capability much larger than the northerly capability.

6.2.3 Interconnection Upgrades

A preliminary study of several possible QNI Augmentations was undertaken during 2005, and this concluded that an upgrading of QNI may be justified when assessed under an AER regulatory test evaluation. Powerlink and TransGrid are now undertaking a detailed study to examine the economics of upgrading QNI, with a view to justifying and initiating a project.

The study is examining the expected net market benefits of all options in relieving constraints over a range of generation entry scenarios. The overall range of options is outlined in Table 6.2.

TABLE 6.2: QNI UPGRADE OPTIONS

Option	Capability	Description	Estimated Cost
1	Nominal increase of 200 – 300MW in the thermal ratings of 330kV circuits in central New South Wales	Augmentation of a section of the 330kV network in northern NSW. This option is the thermal rating upgrade of the lower rated Armidale – Tamworth 330kV line.	Less than $10M
2	Nominal increase of 300 – 400MW in both directions	Option 1 works, plus transient/oscillatory stability enhancements. This option is series compensation of the 330kV circuits from Armidale to Dumaresq and Dumaresq to Bulli Creek. This option may also include further Static VAr Compensators and power control equipment.	$100 – 120M
3	Nominal overall capability of 1500MW in the southerly direction and 1000MW in the northerly direction	Option 1 works, plus HVDC back-to-back connection on the existing interconnection. This option is the establishment of a 1500MW HVDC back to back asynchronous link, most probably located at Bulli Creek or Dumaresq substations. Additional supporting works may be required on the New South Wales – Queensland interconnected system.	$300 – 400M
4	Nominal increase of 800 – 1000MW both directions	Option 1 works, plus an additional interconnection between Queensland and New South Wales.	$600 – 800M

It should be noted that the various augmentations options have different effects on the northerly and southerly capability.

6.2.4 Interconnection Studies

Powerlink and TransGrid commenced work on studies for possible Interconnection upgrades in late 2005, and have been working on various aspects including:

- The range of options
- The feasibility and cost estimate for each option
- The studies to evaluate overall capability of each option, including sub-synchronous resonance SSR studies (SSR), stability studies and limit equation formulation
- The market simulations for the most viable options

The options are summarised in Table 6.2, and the investigations to date have focussed on the series compensation and HVDC back-to-back options.

Contracts for consultants to undertake the SSR studies and the market simulations were awarded by TransGrid and Powerlink in June, and are expected to take several months to complete.

Powerlink and TransGrid currently expect to commence the AER Regulatory Test consultation phase in November or December 2006.

6.3 Supply Demand Balance

The outlook for the supply demand balance for the Queensland region was published in the NEMMCO 2005 Statement of Opportunities (SOO) in October 2005. As part of the normal annual planning cycle, NEMMCO will publish a revised outlook in the 2006 SOO in October 2006. Interested parties who require information regarding the future supply demand balance will need to consult this document.

It should be noted that as result of the change in the Region Boundary definition in the Tweed area the Queensland demand forecast has changed from previous APRs (refer Section 3.1.2).

APPENDICES

CONTENTS

Appendix A — Estimated Network Power Flows

Appendix A illustrates 18 sample grid power flows for the Queensland region for summer and winter over three years from 2006 to 2008/09.

These show possible grid power flows at the time of forecast winter or summer region peak demand, and with a range of import and export conditions on the Queensland-New South Wales Interconnection (QNI).

Sample conditions in Appendix A include:

- Figure A.3: Winter 2006 Qld Peak 400MW Northerly QNI Flow
- Figure A.4: Winter 2006 Qld Peak Zero QNI Flow
- Figure A.5: Winter 2006 Qld Peak 700MW Southerly QNI Flow
- Figure A.6: Winter 2007 Qld Peak 400MW Northerly QNI Flow
- Figure A.7: Winter 2007 Qld Peak Zero QNI Flow
- Figure A.8: Winter 2007 Qld Peak 700MW Southerly QNI Flow
- Figure A.9: Winter 2008 Qld Peak 400MW Northerly QNI Flow
- Figure A.10: Winter 2008 Qld Peak Zero QNI Flow
- Figure A.11: Winter 2008 Qld Peak 700MW Southerly QNI Flow
- Figure A.12: Summer 2006/07 Qld Peak 300MW Northerly QNI Flow
- Figure A.13: Summer 2006/07 Qld Peak Zero QNI Flow
- Figure A.14: Summer 2006/07 Qld Peak 400MW Southerly QNI Flow
- Figure A.15: Summer 2007/08 Qld Peak 300MW Northerly QNI Flow
- Figure A.16: Summer 2007/08 Qld Peak Zero QNI Flow
- Figure A.17: Summer 2007/08 Qld Peak 400MW Southerly QNI Flow
- Figure A.18: Summer 2008/09 Qld Peak 300MW Northerly QNI Flow
- Figure A.19: Summer 2008/08 Qld Peak Zero QNI Flow
- Figure A.20: Summer 2008/09 Qld Peak 400MW Southerly QNI Flow

TABLE A.1: SUMMARY OF FIGURES A.3 – A.20 — POSSIBLE GRID POWER FLOWS AND LIMIT STABILITY STATES

Grid Section (1)		Illustrative Grid Power Flows (MW) and Limit Stability at Queensland Region Peak Load Time (2)(3)						Limit Due To (4)
		2006 WINTER Fig A3 / A4 / A5	2007 WINTER Fig A6 / A7 / A8	2008 WINTER Fig A9 / A10 / A11	2006/07 SUMMER Fig A12 / A13 / A14	2007/08 SUMMER Fig A15 / A16 / A17	2008/09 SUMMER Fig A18 / A19 / A20	
'Far North' Transfer Ross into Chalumbin 275kV (2 circuits) Tully into Kareeya 132kV (2 circuits) Tully to Innisfail & Woree 132kV (2 circuits)	Flow stability	157 / 157 / 157 S / S / S	165 / 165 / 165 S / S / S	173 / 172 / 173 S / S / S	250 / 249 / 250 S / S / S	262 / 262 / 262 S / S / S	275 / 274 / 275 S / S / S	V
'CQ – NQ' Transfer Broadsound into Nebo 275kV (4 circuits) Bouldercombe into Nebo 275kV (1 circuit) Dysart to Peak Downs 132kV (2 parallel circuits)	Flow stability	464 / 463 / 464 S / S / S	510 / 509 / 454 S / S / S	533 / 532 / 532 S / S / S	796 / 795 / 708 S / S / S	836 / 836 / 836 S / S / S	869 / 869 / 702 S / S / S	Tr,V Th
'Gladstone' Transfer (5) Bouldercombe into Gladstone 275kV (2 circuits) Calvale into Wurdong 275kV (1 circuit) Callide A into Gladstone South 132kV (2 circuits)	Flow stability	1080 / 1187 / 1049 S / S / S	1126 / 1026 / 996 S / S / S	918 / 1078 / 931 S / S / S	726 / 695 / 740 S / S / S	672 / 684 / 663 S / S / S	634 / 660 / 756 S / S / S	Th
CQ – SQ' Transfer Wurdong into Gin Gin 275kV (1 circuit) Gladstone into Gin Gin 275kV (2 circuits) Calvale into Tarong 275kV (2 circuits)	Flow stability	1165 / 1408 / 1744 S / S / S	1369 / 1610 / 1774 S / S / S	871 / 1326 / 1679 S / S / S	1624 / 1652 / 1770 S / S / S	1552 / 1511 / 1637 S / S / S	1470 / 1567 / 1749 S / S / S	Tr,V

'Tarong' Transfer Tarong to South Pine, Mt England & Blackwall 275kV (5 circuits) Middle Ridge to Swanbank 110kV (2 circuits) OR Middle Ridge to Greenbank 275kV (2 circuits) Middle Ridge to Postmans Ridge 110kV (1 circuit)	Flow stability	2977 / 2873 / 2456 S / S / S	3066 / 2924 / 2548 S / S / S	3463 / 3334 / 2940 S / S / S	3300 / 3305 / 3128 S / S / S	3764 / 3773 / 3464 S / S / S	3839 / 3795 / 3711 S / S / S	V
'Gold Coast' Transfer Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera to Cades County 110kV (1 circuit)	Flow stability	724 / 724 / 724 S / S / S	764 / 764 / 764 S / S / S	803 / 803 / 803 S / S / S	825 / 825 / 825 S / S / S	878 / 878 / 878 S / S / S	946 / 946 / 946 S / S / S	Th,V
'SWQ' Transfer Braemar into Tarong 275kV (2 circuits) Middle Ridge into Tarong 275kV (1 circuit) Middle Ridge to Swanbank 110kV (2 circuits) OR Middle Ridge to Greenbank 275kV (2 circuits) Middle Ridge to Postmans Ridge 110kV (1 circuit)	Flow stability	921 / 672 / 114 S / S / S	911 / 666 / 204 S / S / S	1579 / 1185 / 627 S / S / S	1102 / 1049 / 795 S / S / S	1591 / 1631 / 1185 S / S / S	1724 / 1573 / 1391 S / S / S	Th

Notes:

(1) The Grid Sections defined are as illustrated in Figure A2.

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 A3 to A20. The flows are estimated for system intact (i.e. all network circuits in service), and are based on existing network configurations, committed projects, and proposed new assets in Chapter 5. Power flows within each grid section can be higher at times of local zone peak.

(3) S = Stable condition, U = Unstable condition.

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

(5) Depending on the balance of flows between the Calvale to Wurdong 275kV circuit, and the Bouldercombe to Gladstone 275kV circuits, high Gladstone transfers may not always result in thermal limitations across the Gladstone grid section.

TABLE A.2: TRANSFORMER CAPACITY AND ESTIMATES OF LOADING OF 275KV SUBSTATIONS

275kV Substation (1) (2) Transformers No. x MVA Nameplate Rating (3)	Possible MVA at Queensland Region Peak (4) (5)						Dependence other than Local Load		
	Winter 2006	Winter 2007	Winter 2008	Summer 2006/07	Summer 2007/08	Summer 2008/09	Significant Dependence on	Minor Dependance on	Other Comments
Woree 275/132 (1x135)	98	86	154	148	143	222	Barron Gorge generation	Kareeya generation	Winter 2008 – 2nd TX 375MVA
Chalumbin 275/132 (2x200)	67	57	7	113	121	85	Barron Gorge and Kareeya generation	Townsville & Mt Stuart generation	
Ross 275/132 (2x250 and 1x200)	105	92	76	174	188	193	Mt Stuart, Townsville & Invicta generation	Collinsville generation	
Strathmore 275/132 (1x375)	31	43	51	44	42	95	Collinsville & Invicta generation	Townsville & Mt Stuart generation	
Nebo 275/132 (2x200 & 1x250)	230	255	272	290	345	306	Mackay GT generation	Collinsville generation	
Bouldercombe 275/132 (2x200)	151	154	159	210	217	228			
Lilyvale 275/132 (2x375)	215	241	250	261	253	262	Barcaldine generation	CQ – NQ flow	
Calvale 275/132 (1x250)	146	168	172	186	181	193	Central Queensland generation		
Gin Gin 275/132 (2x120)	178	192	143	199	151	158	132kV transfers to/from Woolooga	CQ – SQ flow	132kV network can have open points to reduce loading
Woolooga 275/132 (2x120 and 1 x 200)	269	274	232	285	230	238	132kV transfers to/from Gin Gin/Teebar	CQ – SQ flow	
Palmwoods 275/132 (2x375)	335	411	368	370	399	445	132/110kV transfers to/from South Pine & Woolooga	CQ – SQ flow	
South Pine 275/110 (2x375, 1x250 & 1x200)	863	869	917	962	1068	1102	110kV transfers to/from Rocklea & Palmwoods	CQ – SQ flow & Swanbank generation 06/07	One 200MVA replaced by a 375MVA summer
Rocklea 275/110 (2x375)	441	421	426	530	537	542	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Swanbank & Swanbank B generation	
Belmont 275/110 (2x250 and 2x200)	692	577	630	716	767	780	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea	

Murarrie 275/110 (1x375)	0	213	223	283	324	314	110kV transfers to/from Belmont		Summer 2006/07 – 1st TX 375MVA (Belmont to Murarrie 275kV line)
Swanbank 275/110 (1x250 and 1x240)	265	269	300	196	372	280	110kV transfers to/from South Pine, Millmerran and Oakey GT generation	110kV transfers to/from Rocklea & Swanbank B generation	
Goodna 275/110 (1x375)	0	147	193	119	254	233			Summer 2007/08 – 1st TX 375MVA
Loganlea 275/110 (2x375)	446	416	433	500	525	563	110kV transfers to/from Belmont	110kV transfers to/from Molendinar & Mudgeeraba	
Molendinar 275/110 (1x375)	264	311	468	363	553	537	110kV transfers to/from Loganlea & Mudgeeraba	DirectLink	Summer 2007/08 – 2nd TX 375MVA
Mudgeeraba 275/110 (3x250)	477	460	400	518	440	509	110kV transfers to/from Molendinar & DirectLink	110kV transfers to/from Loganlea	
Middle Ridge 275/110 (3x250)	489	490	292	524	311	324	Oakey GT generation	Swanbank B generation	
Teebar 275/132 (2x375)	0	0	104	0	110	118	132kV transfers to/from Woolooga	CQ – SQ flow	Summer 2007/08 – 2 x 375MVA
Abermain 275/110 (1x375)	0	0	0	0	0	251	110kV transfers to/from Swanbank & Goodna	Tarong flow	Summer 2008/09 – 1 x 375MVA
Tarong 275/132 (2x90)	72	71	72	82	85	87	Roma generation		
Tarong 275/66 (2x90)	44	46	47	42	44	45			

FIGURE A.1: GENERATION AND LOAD LEGEND FOR FIGURES A.3 TO A.20

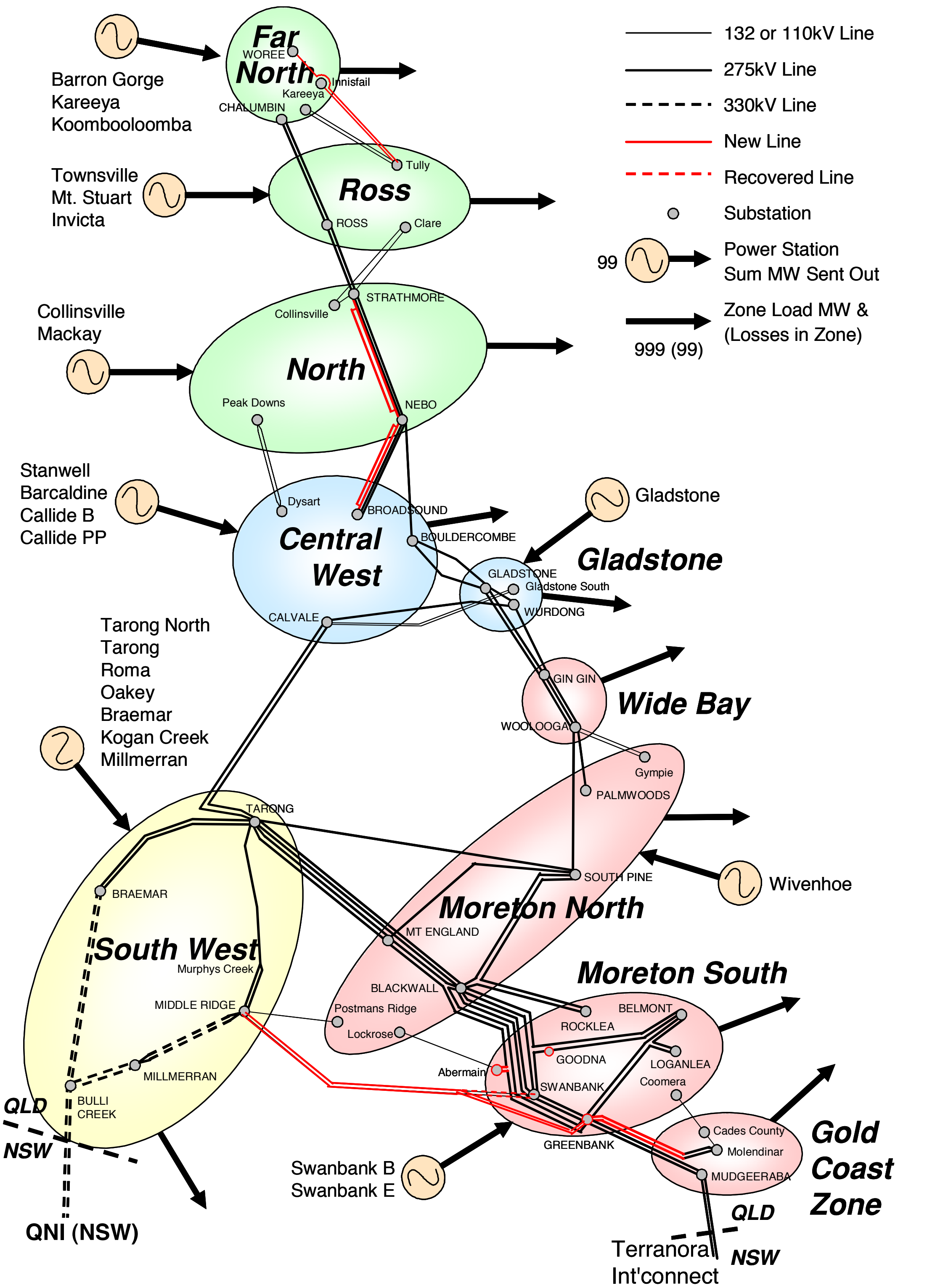


FIGURE A.2: POWER FLOW AND LIMITS LEGEND FOR FIGURES A.3 TO A.20

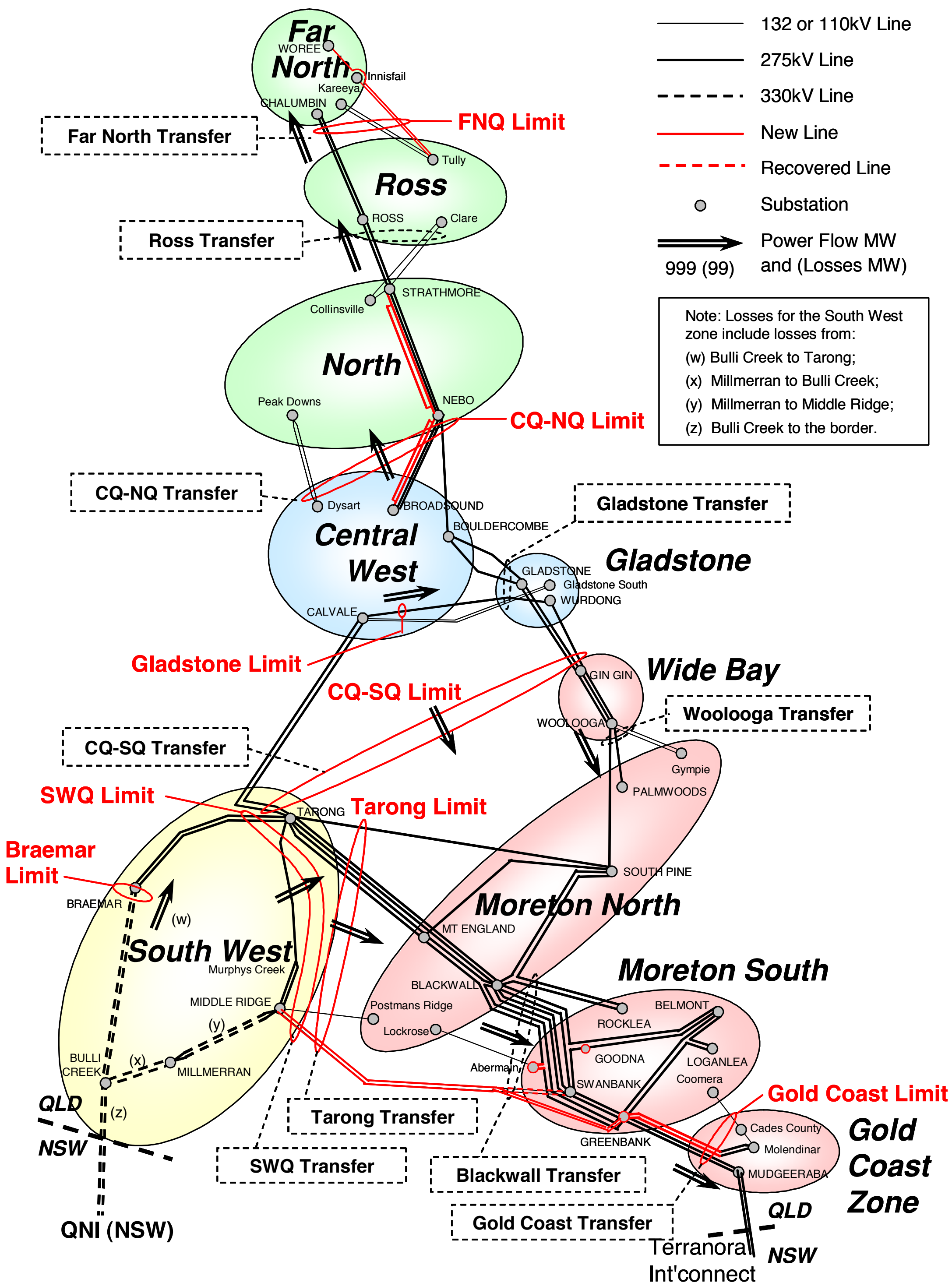
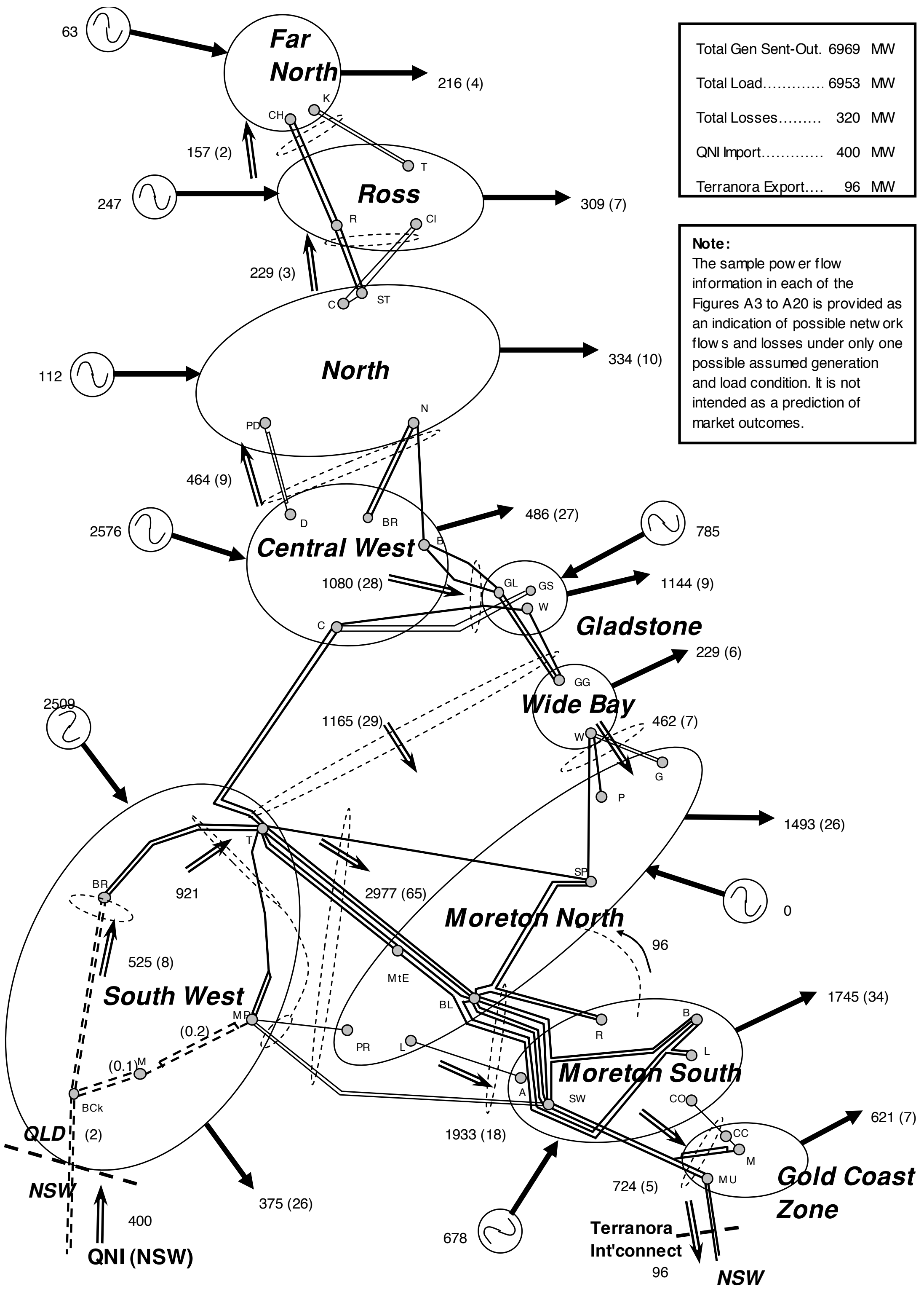


FIGURE A.3: WINTER 2006 QLD PEAK 400MW NORTHERLY QNI FLOW



Total Gen Sent-Out.	6969	MW
Total Load.............	6953	MW
Total Losses.........	320	MW
QNI Import.............	400	MW
Terranora Export....	96	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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 A.4: WINTER 2006 QLD PEAK ZERO QNI FLOW

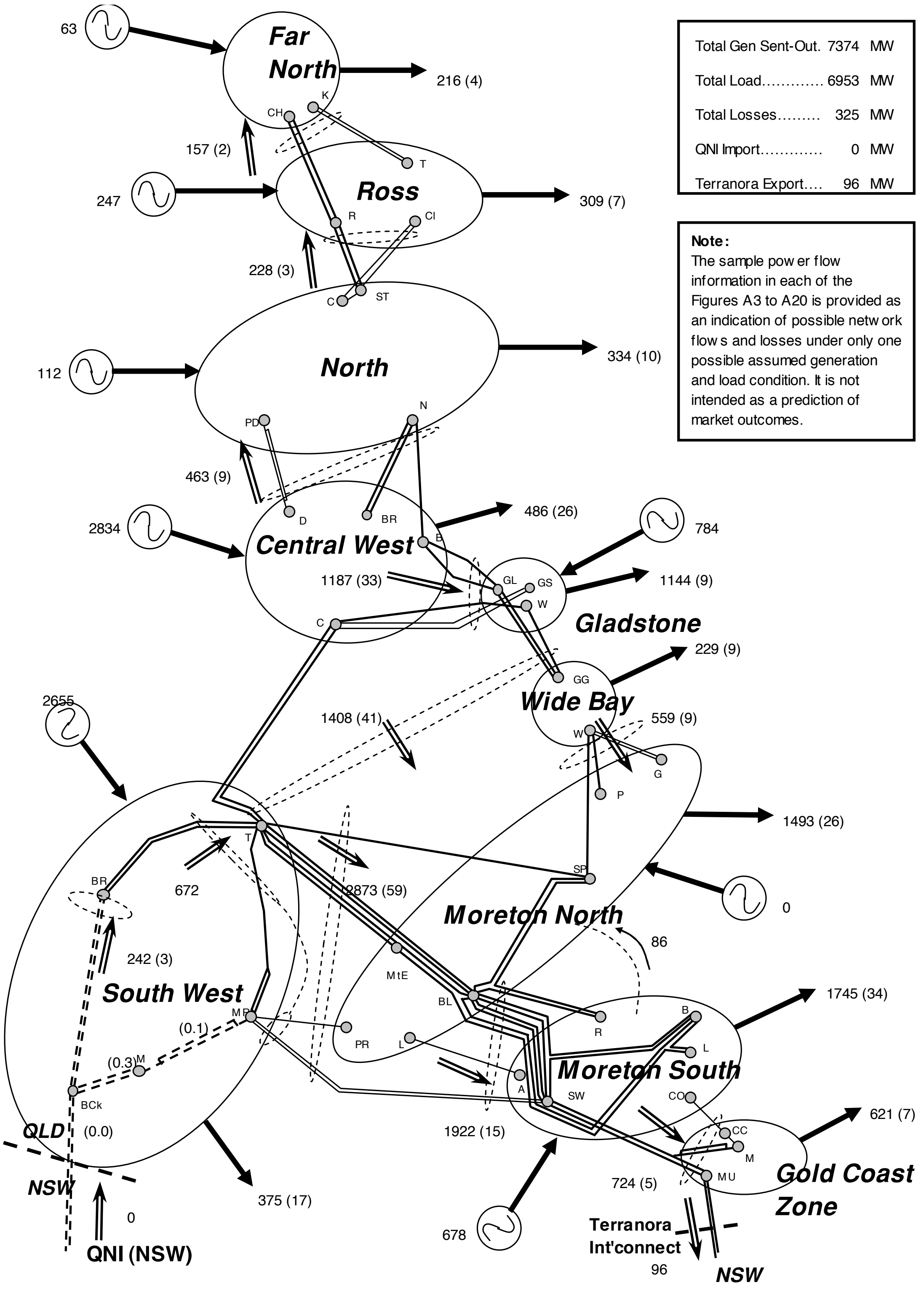
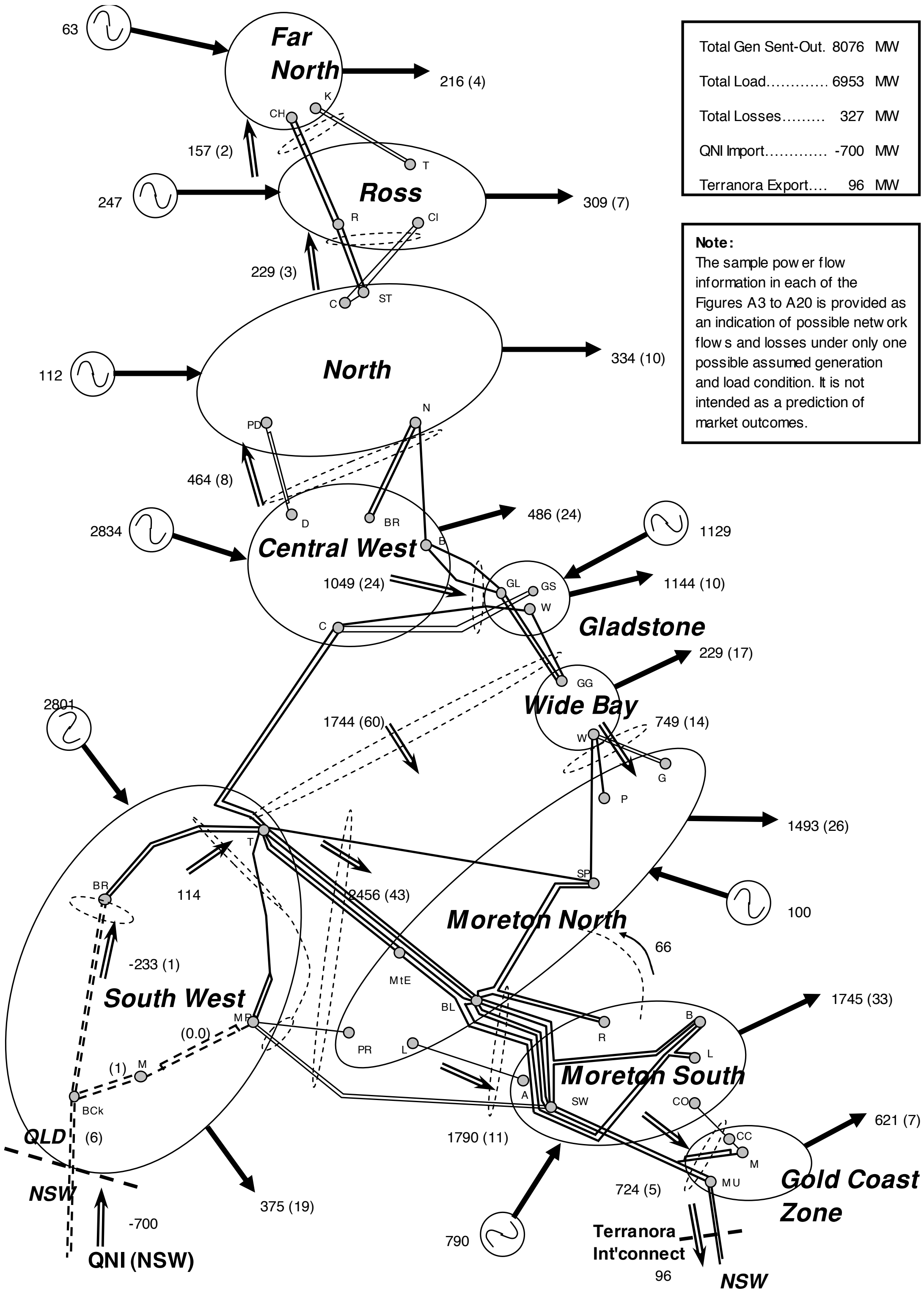


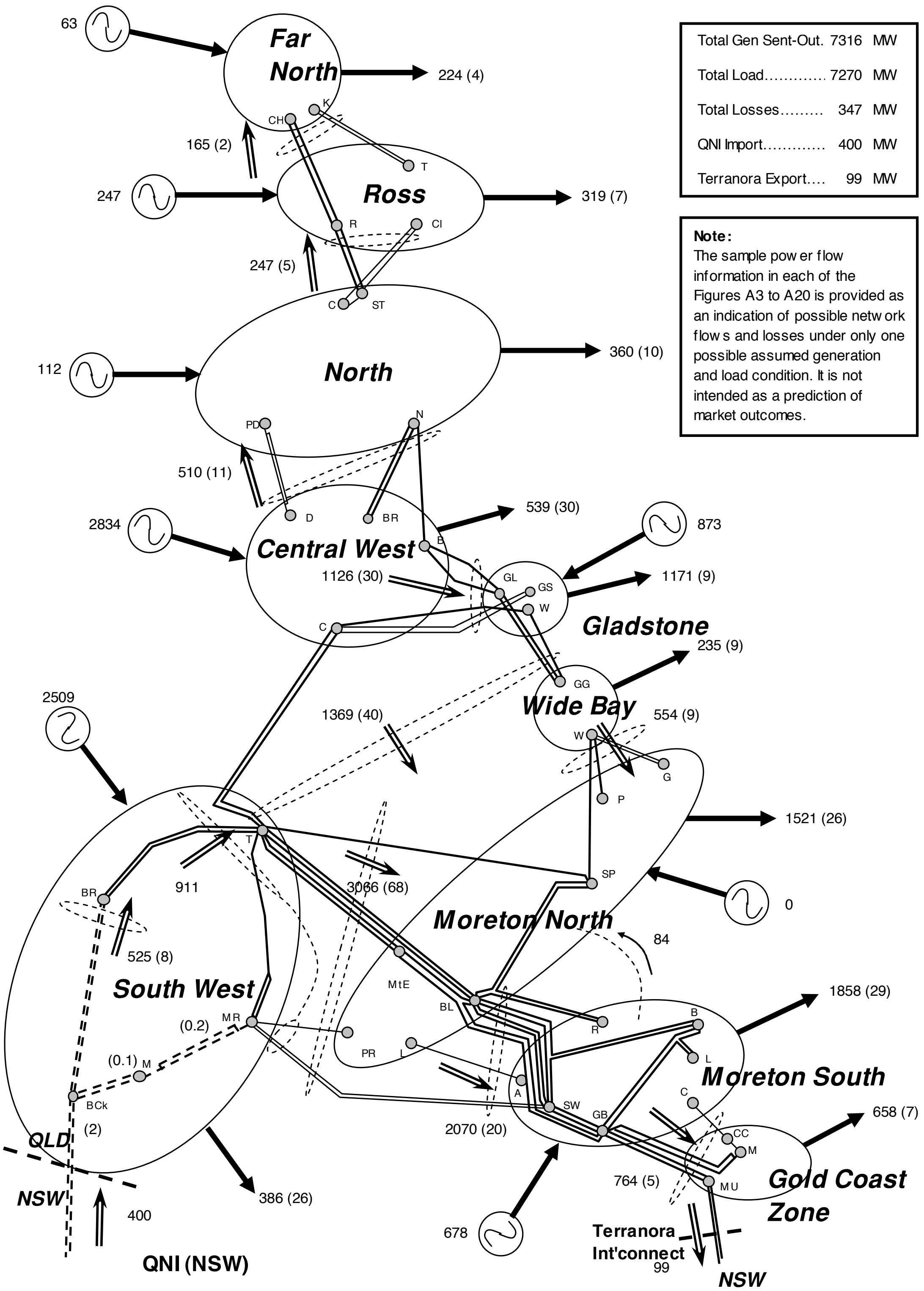
FIGURE A.5: WINTER 2006 QLD PEAK 700MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	8076	MW
Total Load.............	6953	MW
Total Losses.........	327	MW
QNI Import.............	-700	MW
Terranora Export....	96	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

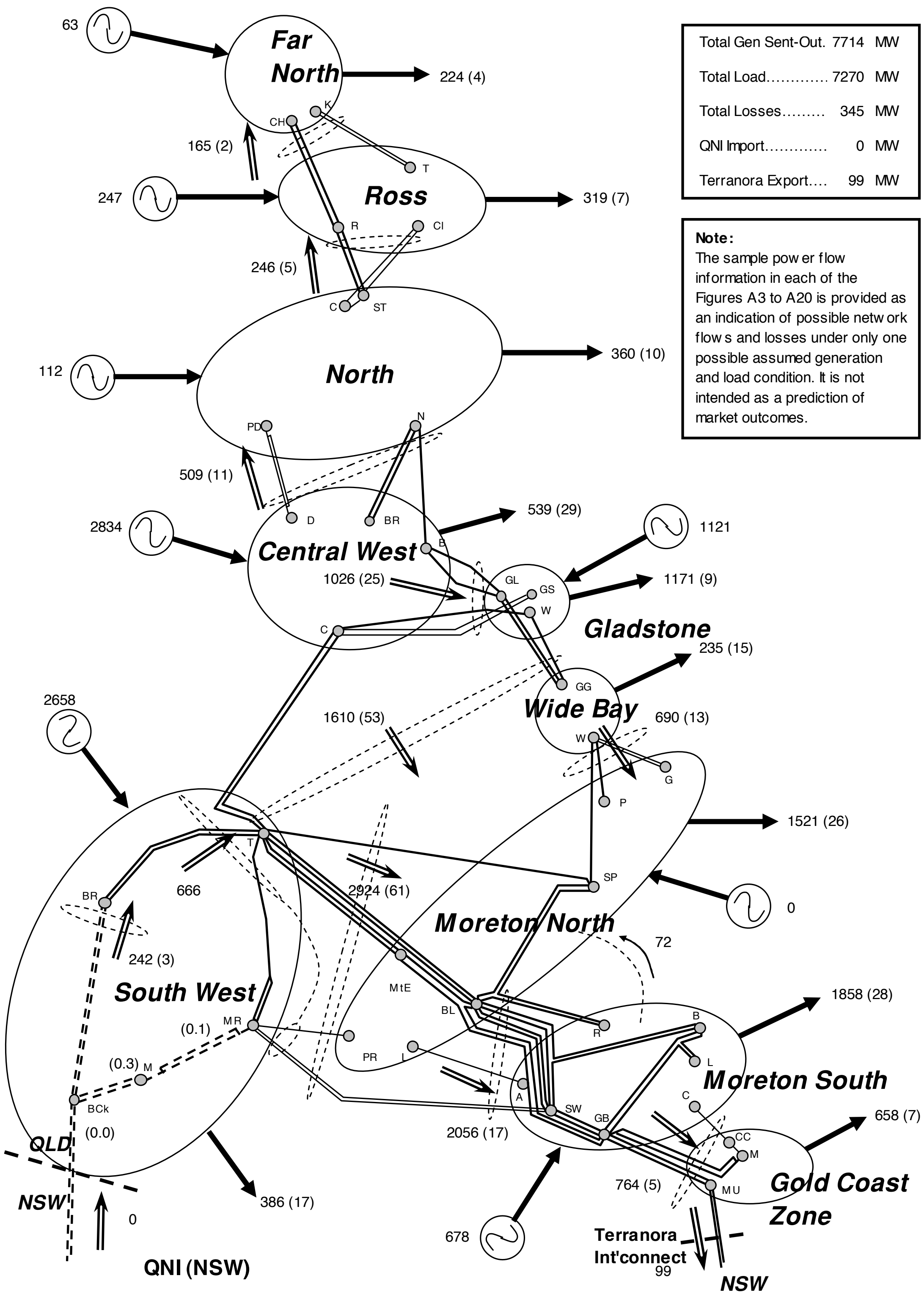
FIGURE A.6: WINTER 2007 QLD PEAK 400MW NORTHERLY QNI FLOW



Total Gen Sent-Out. 7316	MW
Total Load............. 7270	MW
Total Losses......... 347	MW
QNI Import............. 400	MW
Terranora Export.... 99	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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 A.7: WINTER 2007 QLD PEAK ZERO QNI FLOW



Total Gen Sent-Out. 7714 MW

Total Load............. 7270 MW

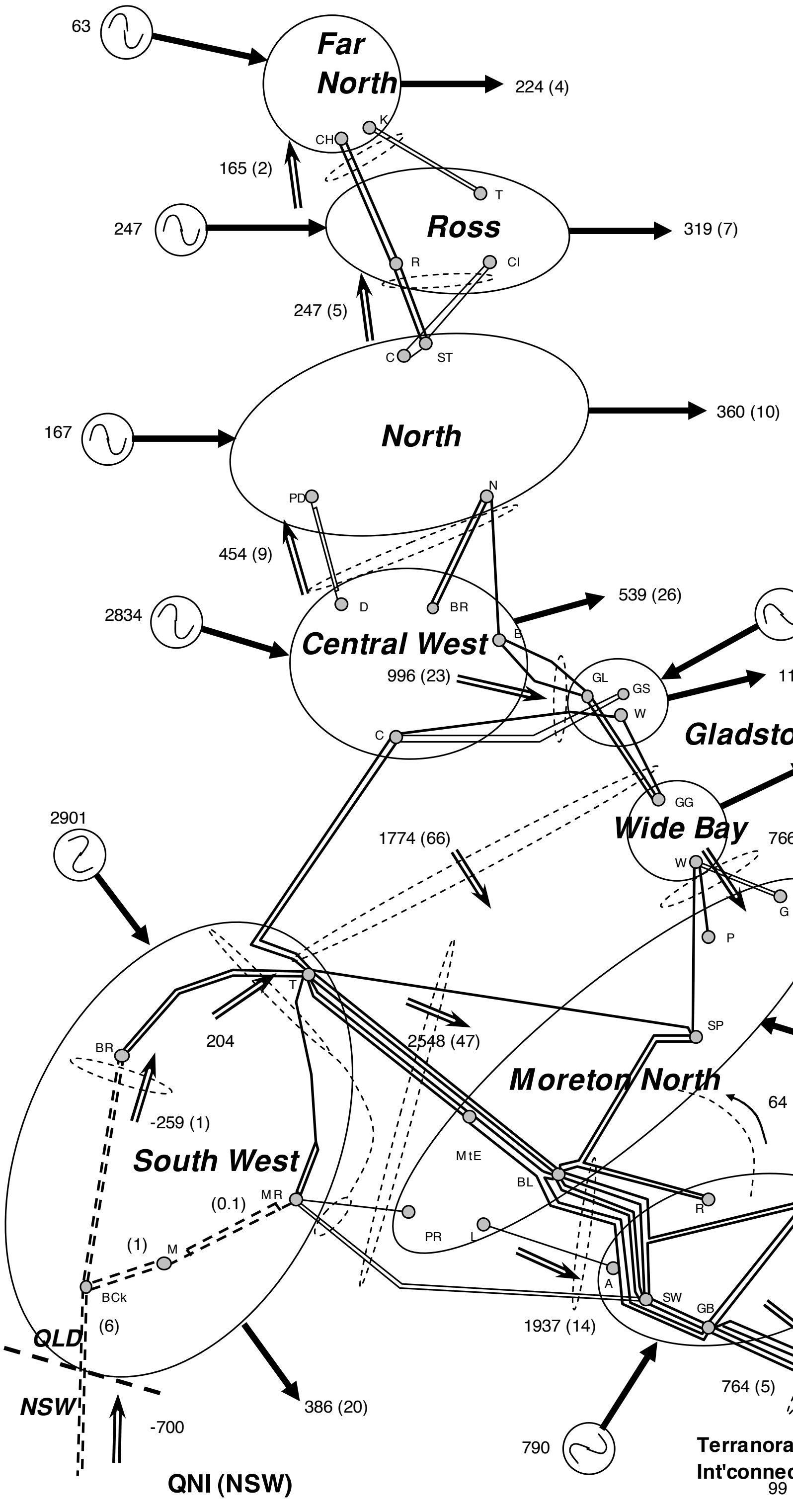
Total Losses......... 345 MW

QNI Import............. 0 MW

Terranora Export.... 99 MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

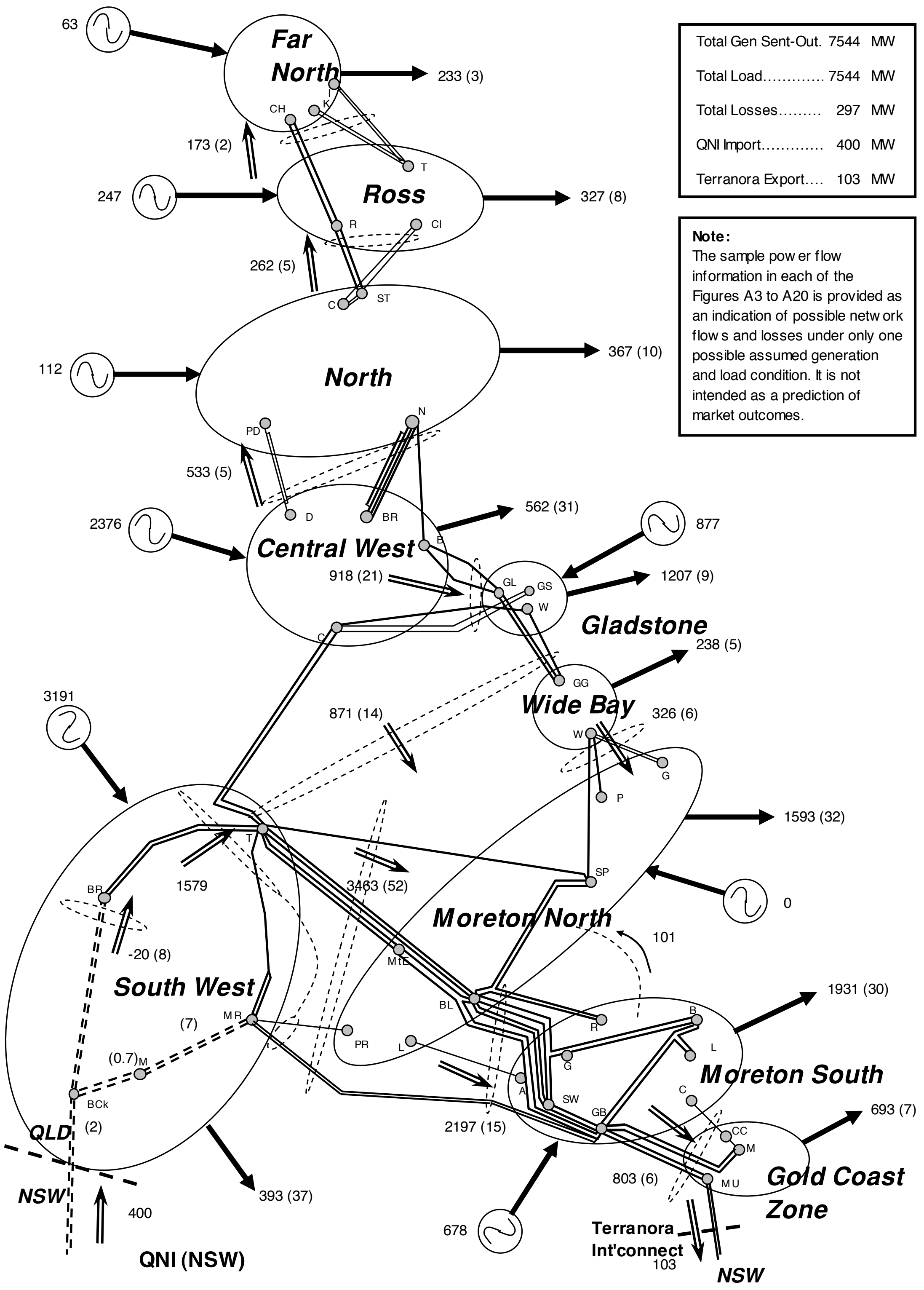
FIGURE A.8: WINTER 2007 QLD PEAK 700MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	8417 MW
Total Load.............	7270 MW
Total Losses.........	348 MW
QNI Import.............	-700 MW
Terranora Export....	99 MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

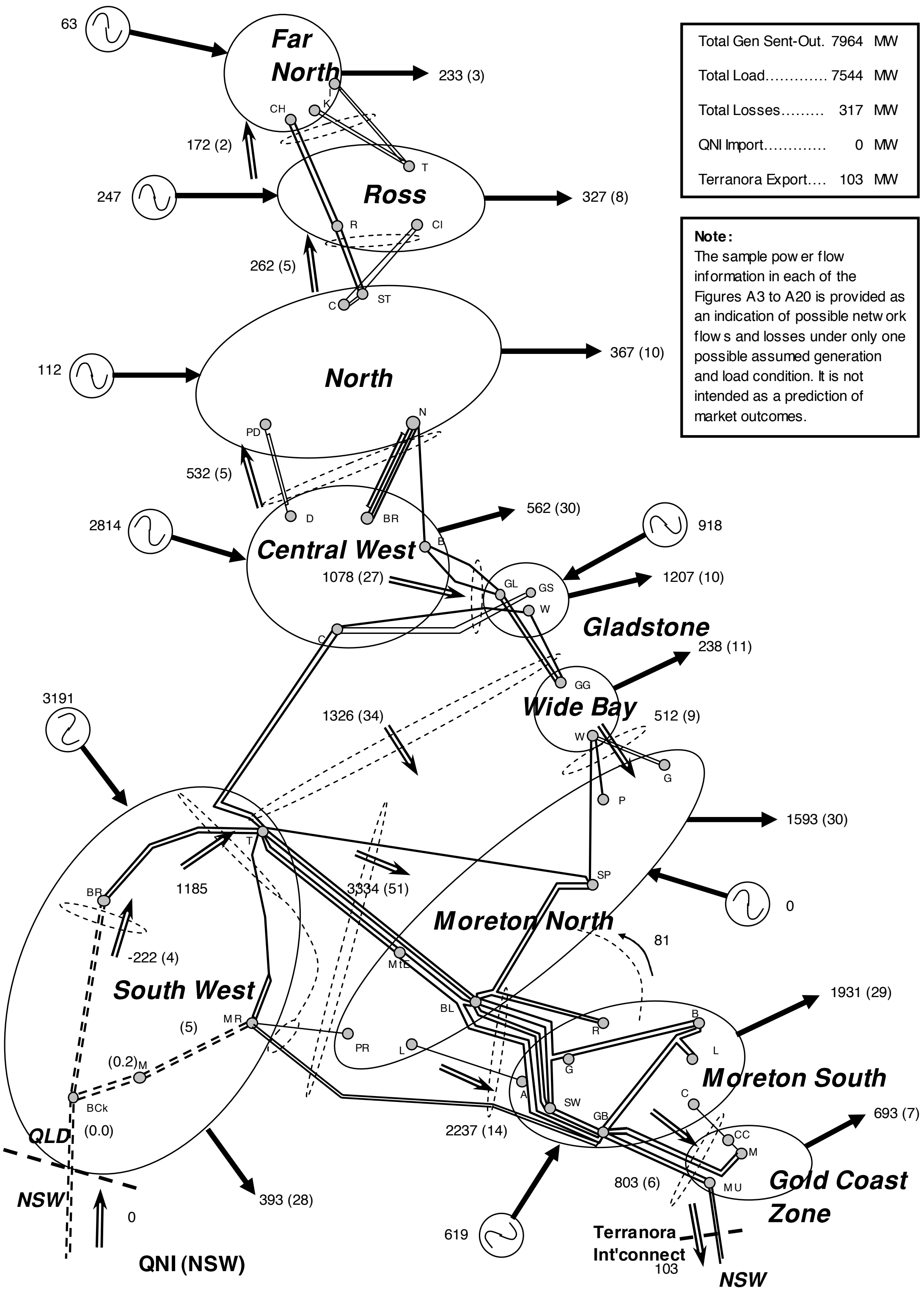
FIGURE A.9: WINTER 2008 QLD PEAK 400MW NORTHERLY QNI FLOW



Total Gen Sent-Out.	7544	MW
Total Load............	7544	MW
Total Losses.........	297	MW
QNI Import............	400	MW
Terranora Export....	103	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

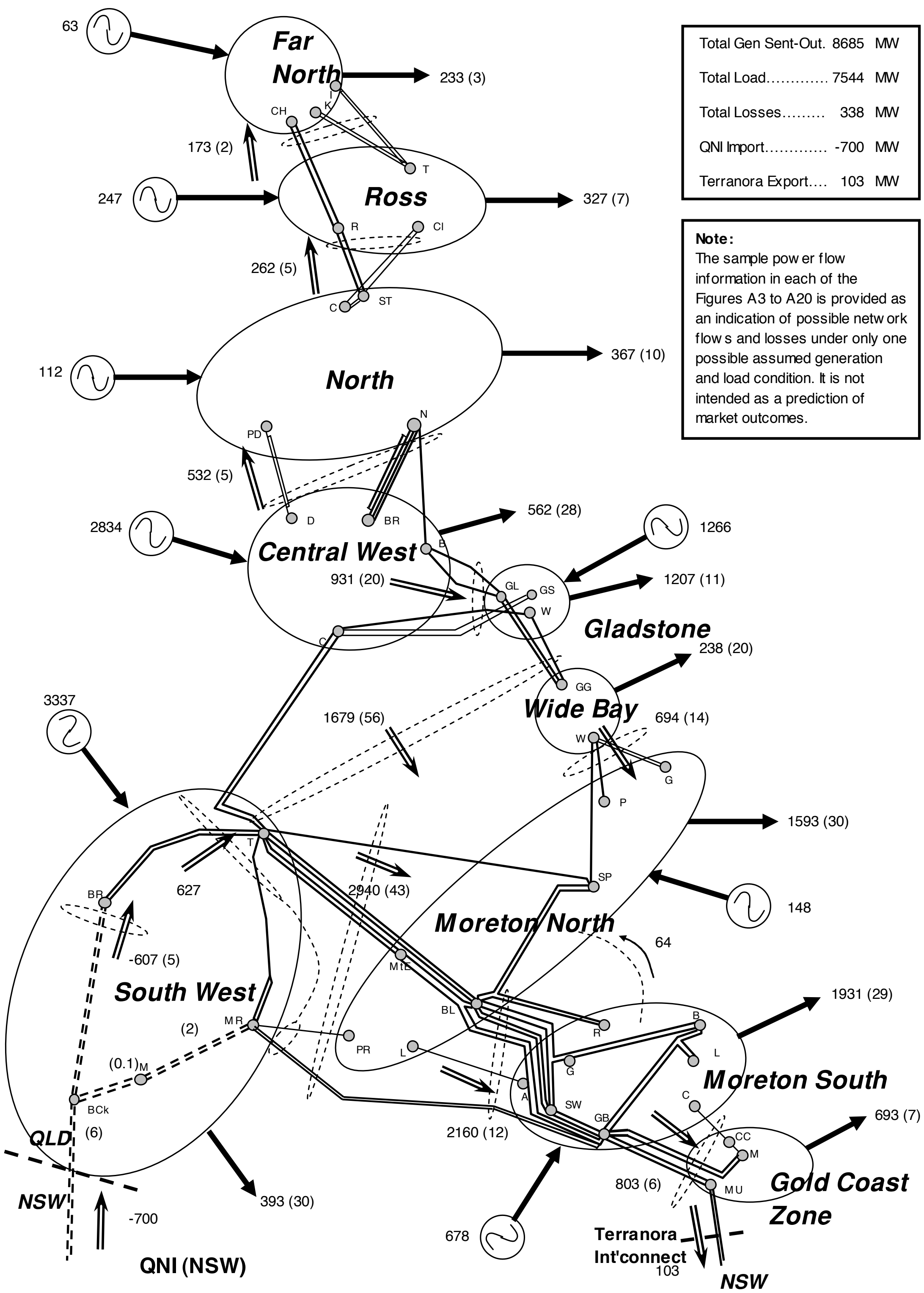
FIGURE A.10: WINTER 2008 QLD PEAK ZERO QNI FLOW



Total Gen Sent-Out.	7964	MW
Total Load.............	7544	MW
Total Losses.........	317	MW
QNI Import............	0	MW
Terranora Export....	103	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

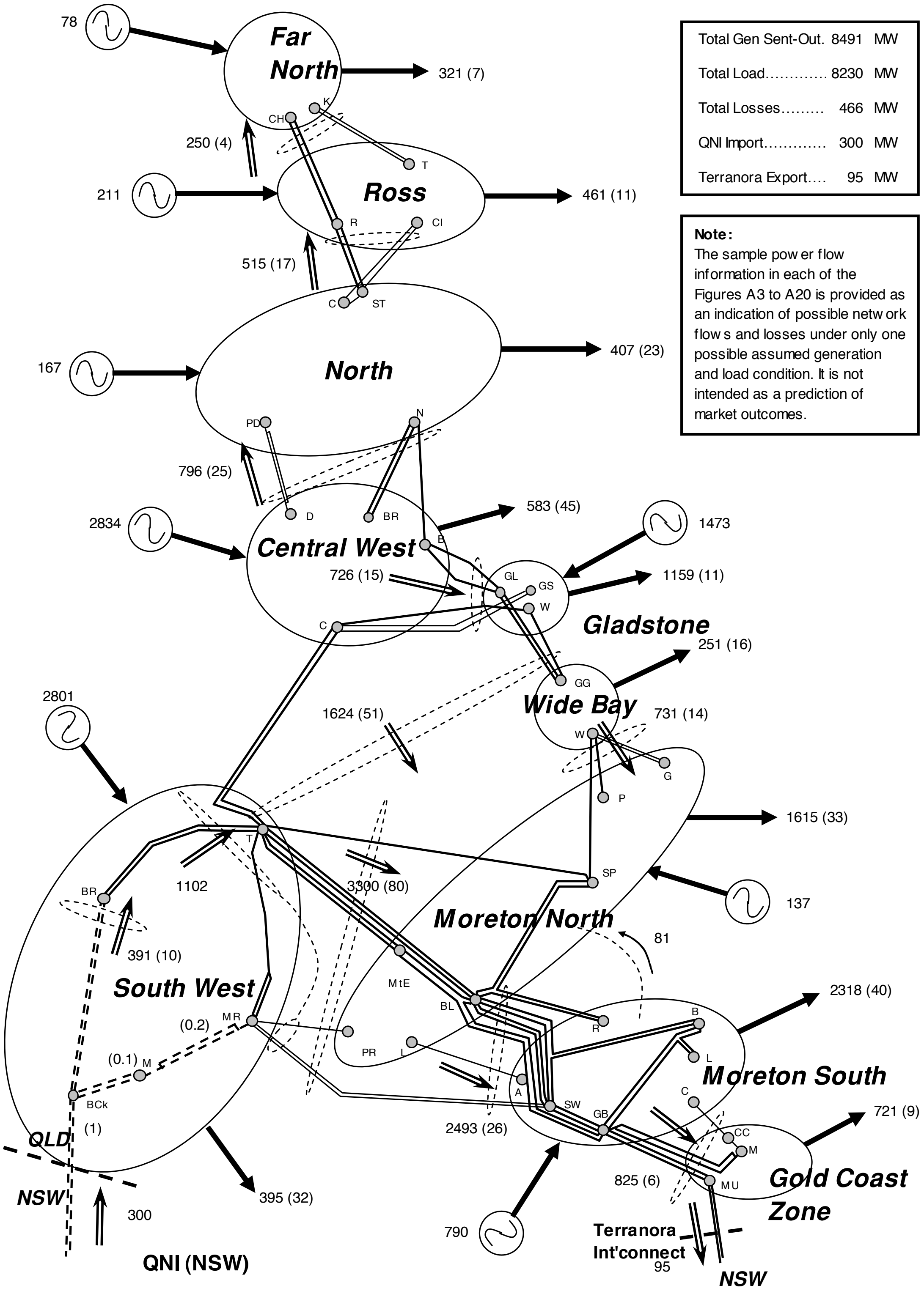
FIGURE A.11: WINTER 2008 QLD PEAK 700MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	8685	MW
Total Load............	7544	MW
Total Losses.........	338	MW
QNI Import............	-700	MW
Terranora Export....	103	MW

Note:
The sample pow er flow information in each of the Figures A3 to A20 is provided as an indication of possible netw ork flow s and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

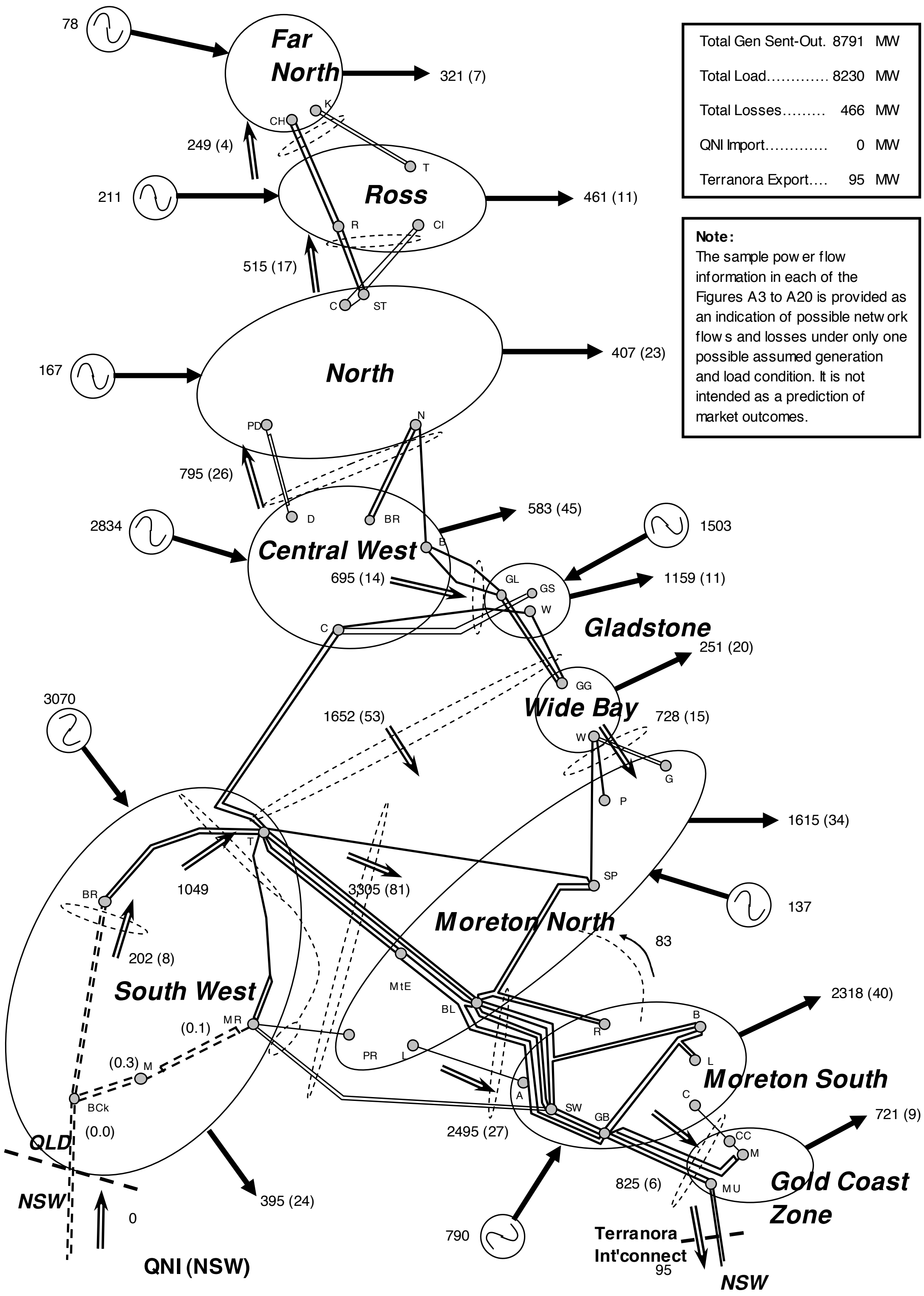
FIGURE A.12: SUMMER 2006/07 QLD PEAK 300MW NORTHERLY QNI FLOW



Total Gen Sent-Out.	8491 MW
Total Load............	8230 MW
Total Losses.........	466 MW
QNI Import............	300 MW
Terranora Export....	95 MW

Note:
The sample pow er flow information in each of the Figures A3 to A20 is provided as an indication of possible netw ork flow s and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

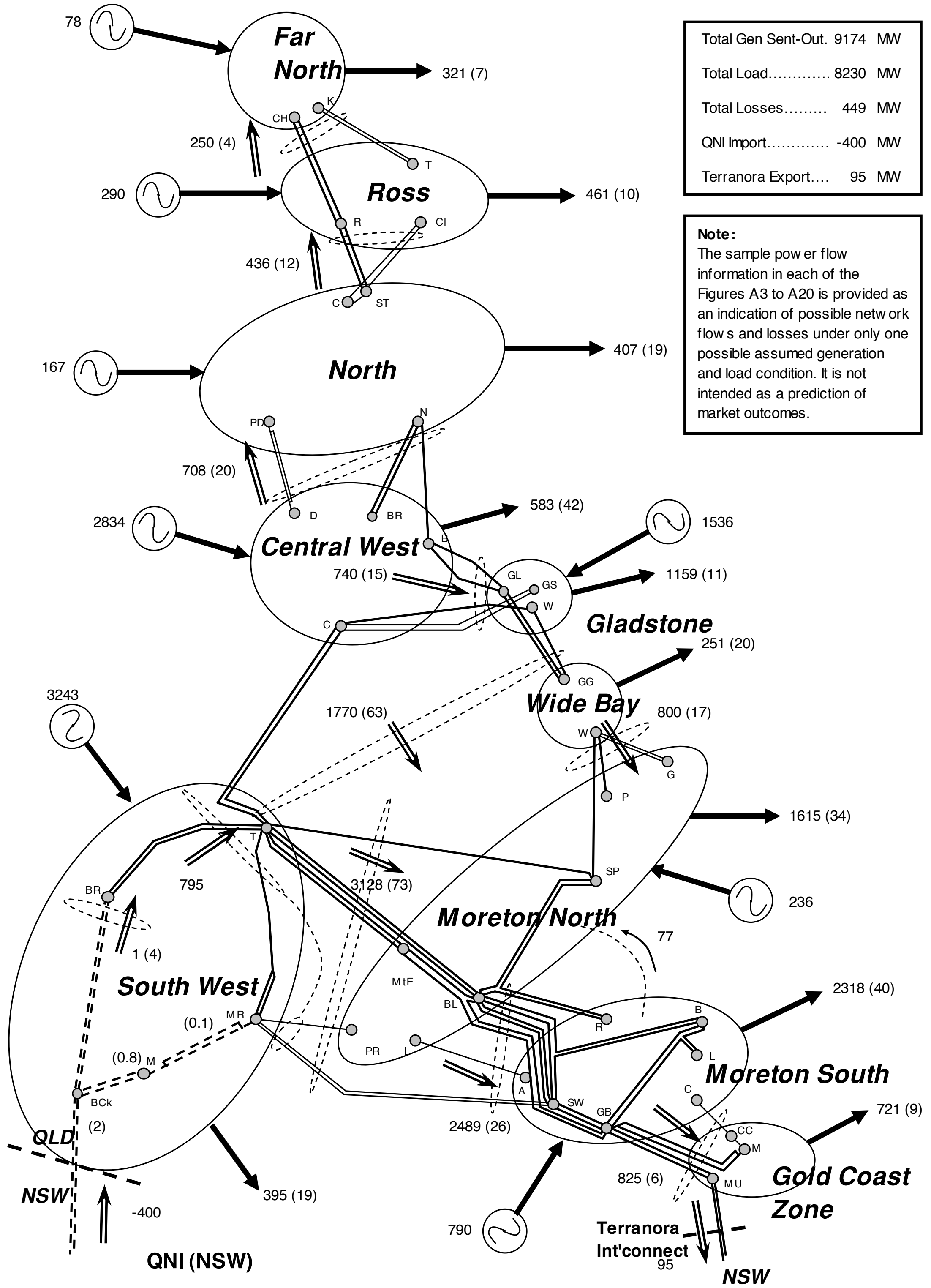
FIGURE A.13: SUMMER 2006/07 QLD PEAK ZERO QNI FLOW



Total Gen Sent-Out.	8791	MW
Total Load.............	8230	MW
Total Losses.........	466	MW
QNI Import............	0	MW
Terranora Export....	95	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

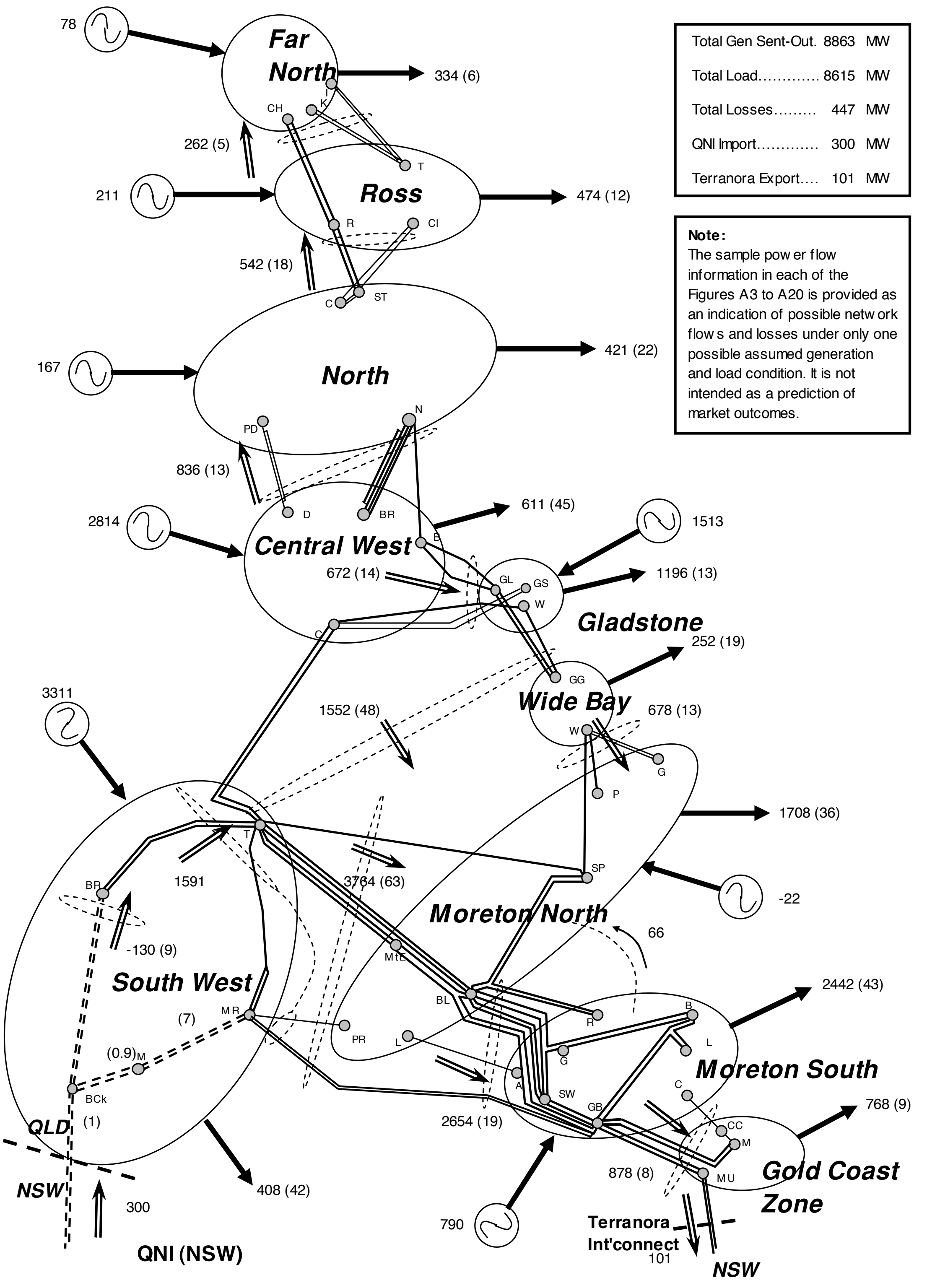
FIGURE A.14: SUMMER 2006/07 QLD PEAK 400MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	9174	MW
Total Load.............	8230	MW
Total Losses.........	449	MW
QNI Import.............	-400	MW
Terranora Export....	95	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

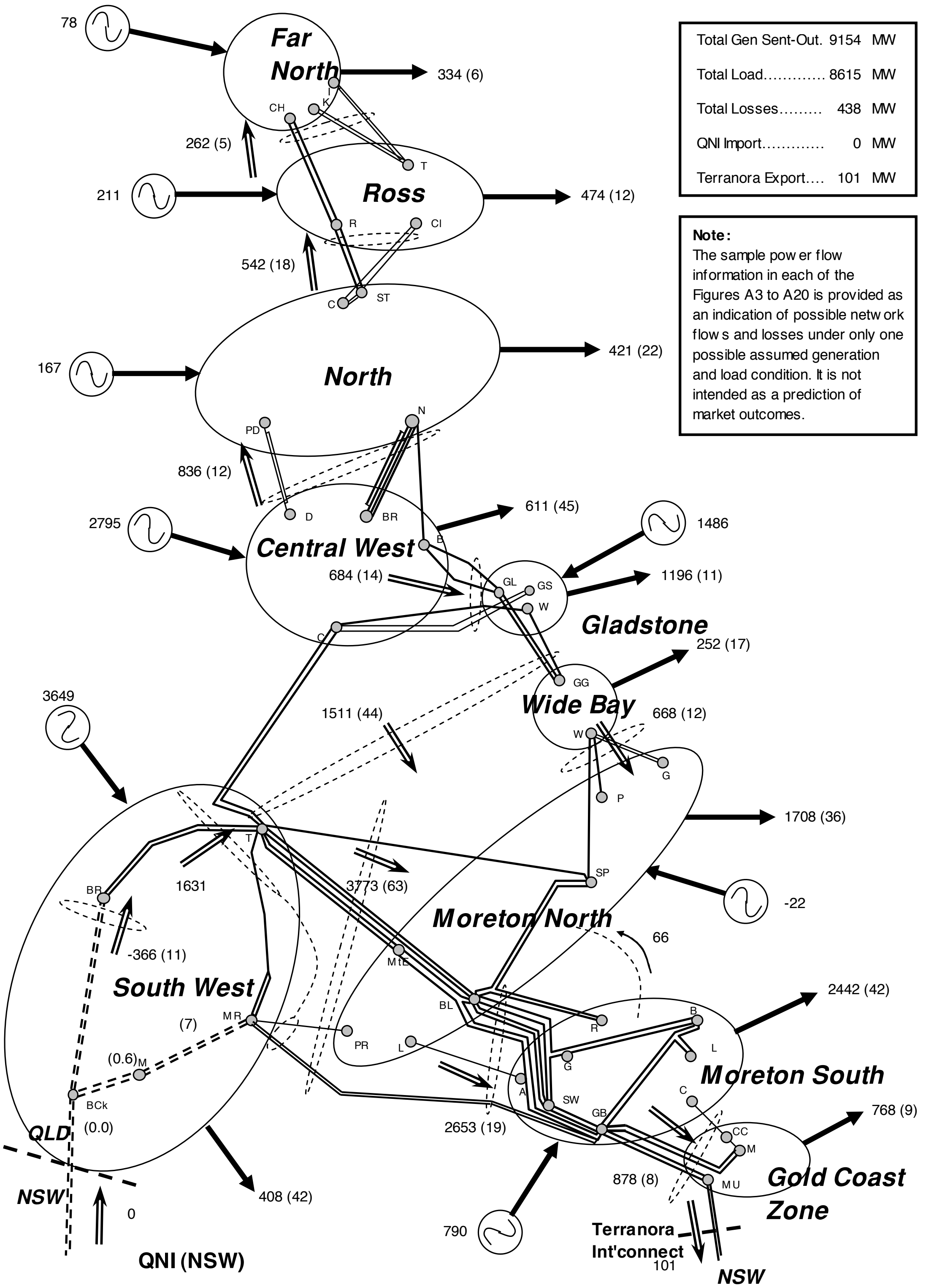
FIGURE A.15: SUMMER 2007/08 QLD PEAK 300MW NORTHERLY QNI FLOW



Total Gen Sent-Out.	8863	MW
Total Load.............	8615	MW
Total Losses.........	447	MW
QNI Import.............	300	MW
Terranora Export....	101	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

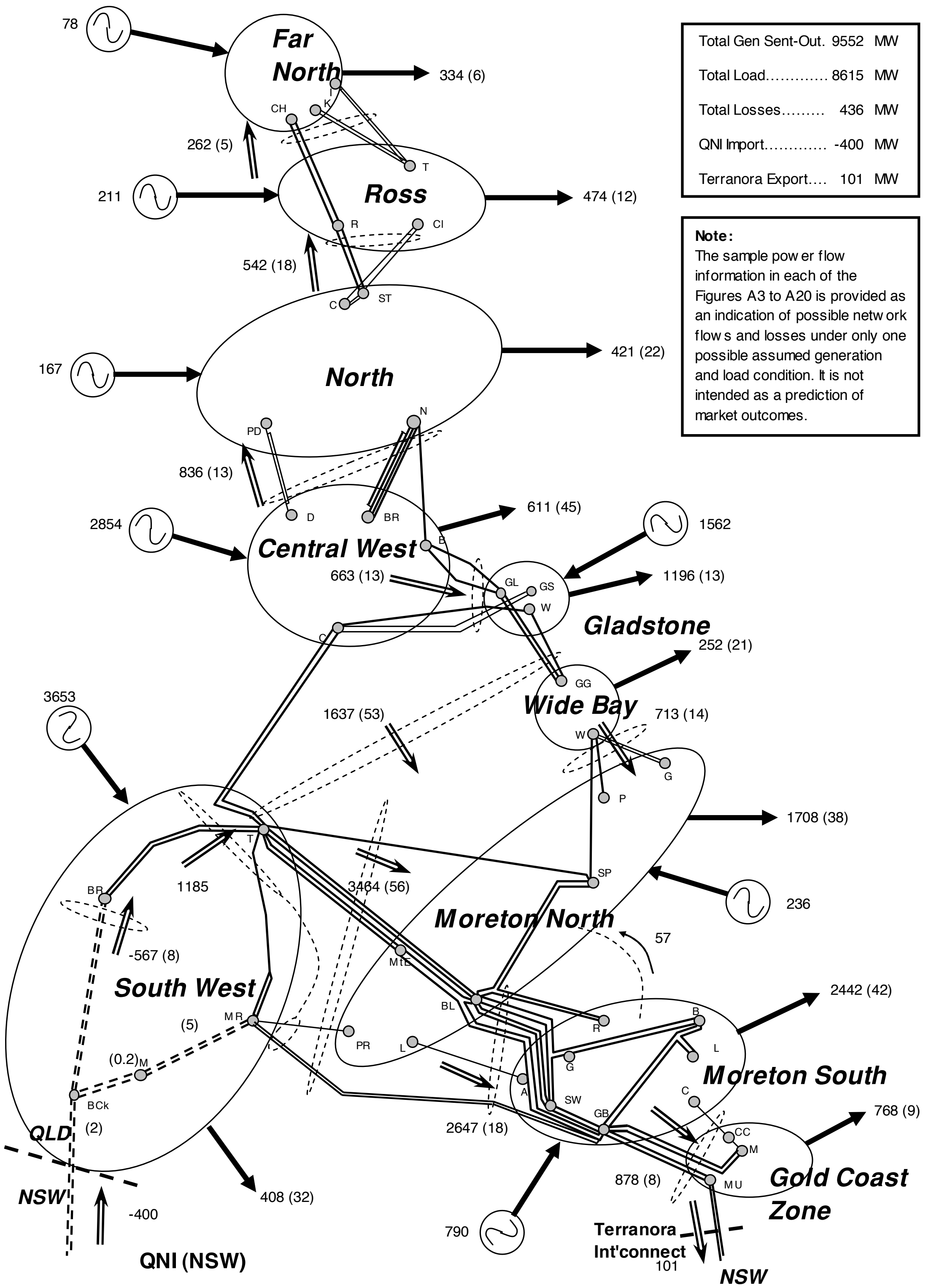
FIGURE A.16: SUMMER 2007/08 QLD PEAK ZERO QNI FLOW



Total Gen Sent-Out.	9154	MW
Total Load.............	8615	MW
Total Losses.........	438	MW
QNI Import.............	0	MW
Terranora Export....	101	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

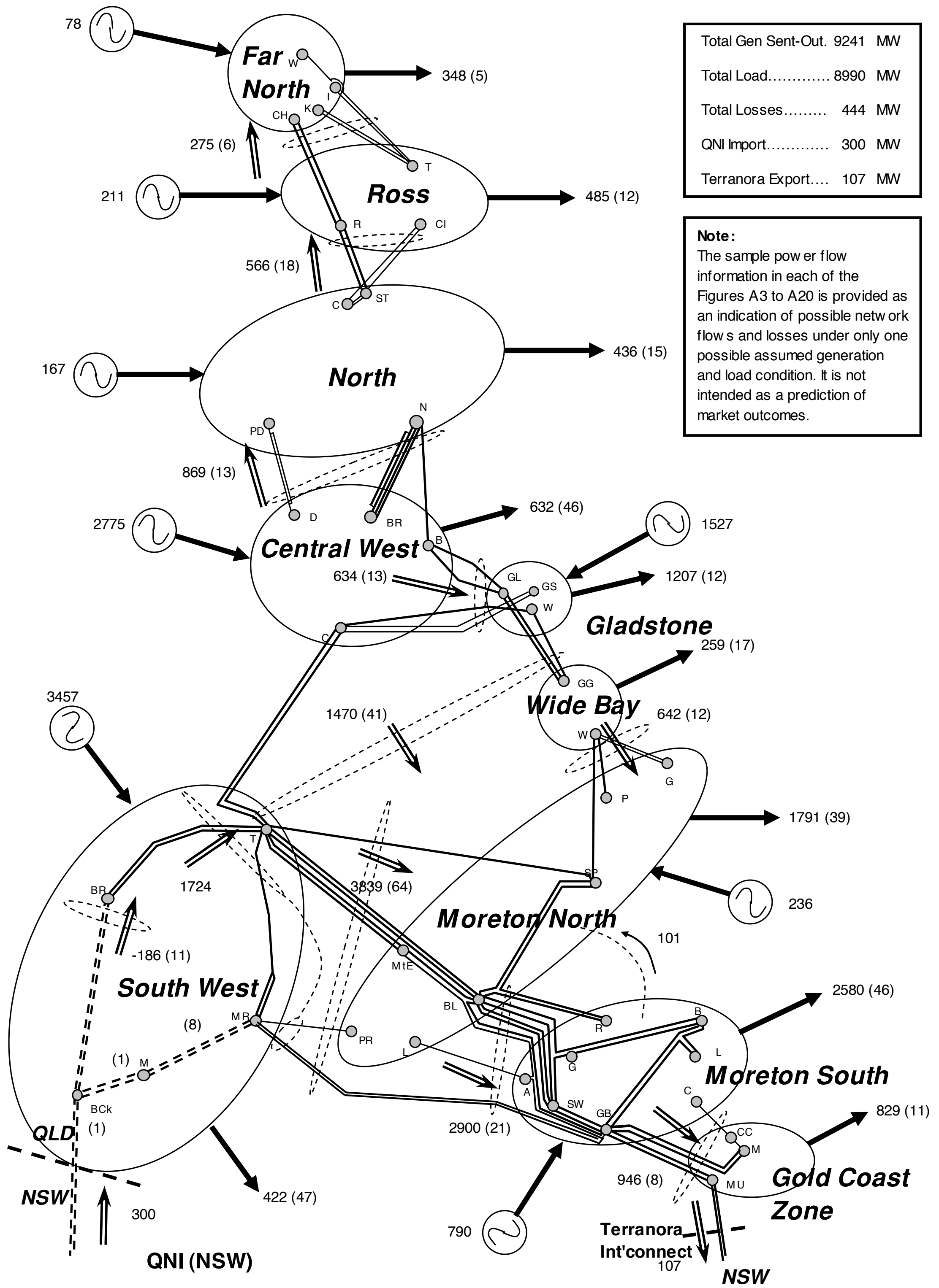
FIGURE A.17: SUMMER 2007/08 QLD PEAK 400MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	9552 MW
Total Load.............	8615 MW
Total Losses.........	436 MW
QNI Import.............	-400 MW
Terranora Export....	101 MW

Note:
The sample power flow information in each of the Figures A3 to A20 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.

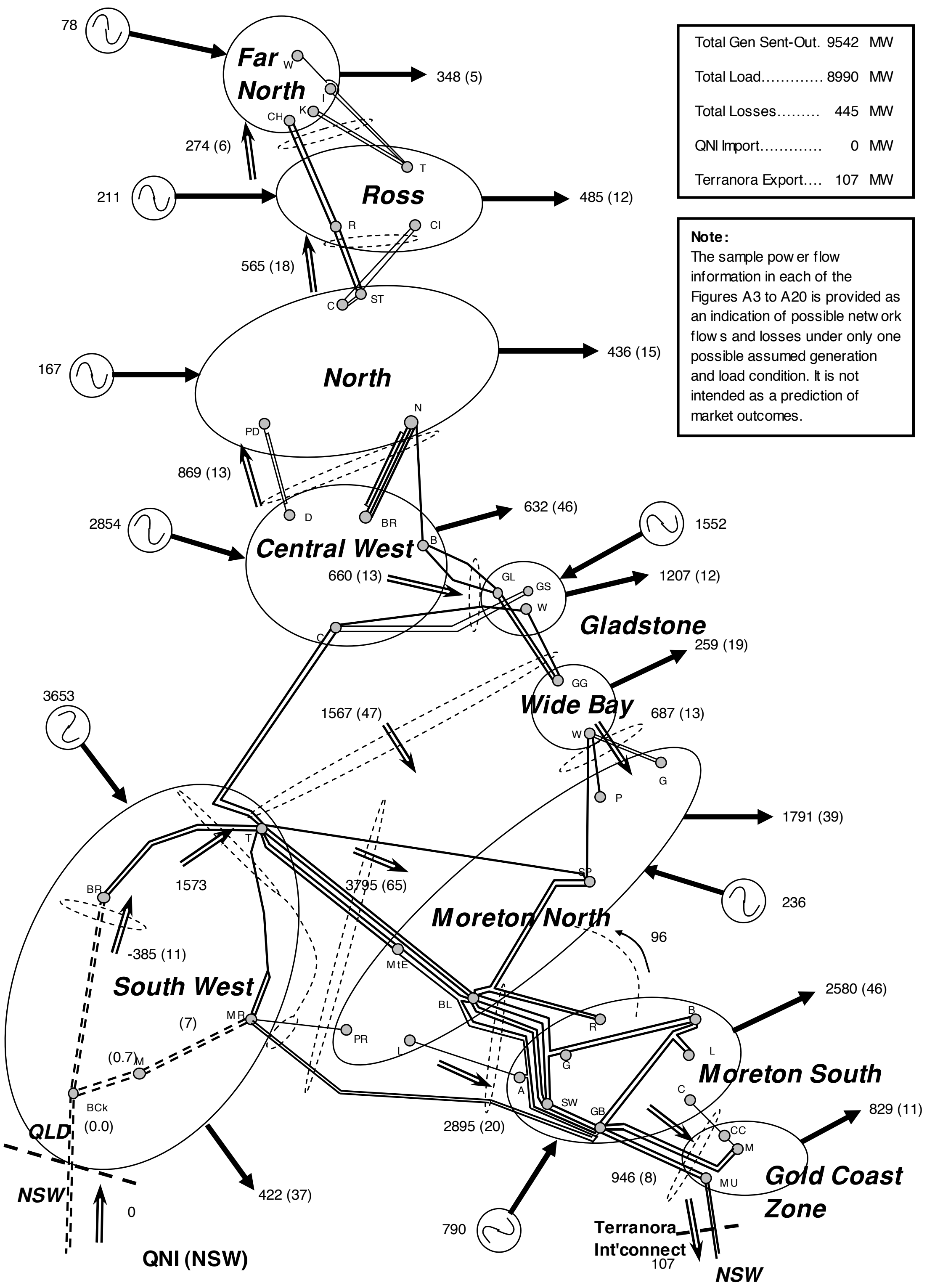
FIGURE A.18: SUMMER 2008/09 QLD PEAK 300MW NORTHERLY QNI FLOW



Total Gen Sent-Out. 9241	MW
Total Load............ 8990	MW
Total Losses......... 444	MW
QNI Import............ 300	MW
Terranora Export.... 107	MW

Note: The sample power flow information in each of the Figures A3 to A20 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.

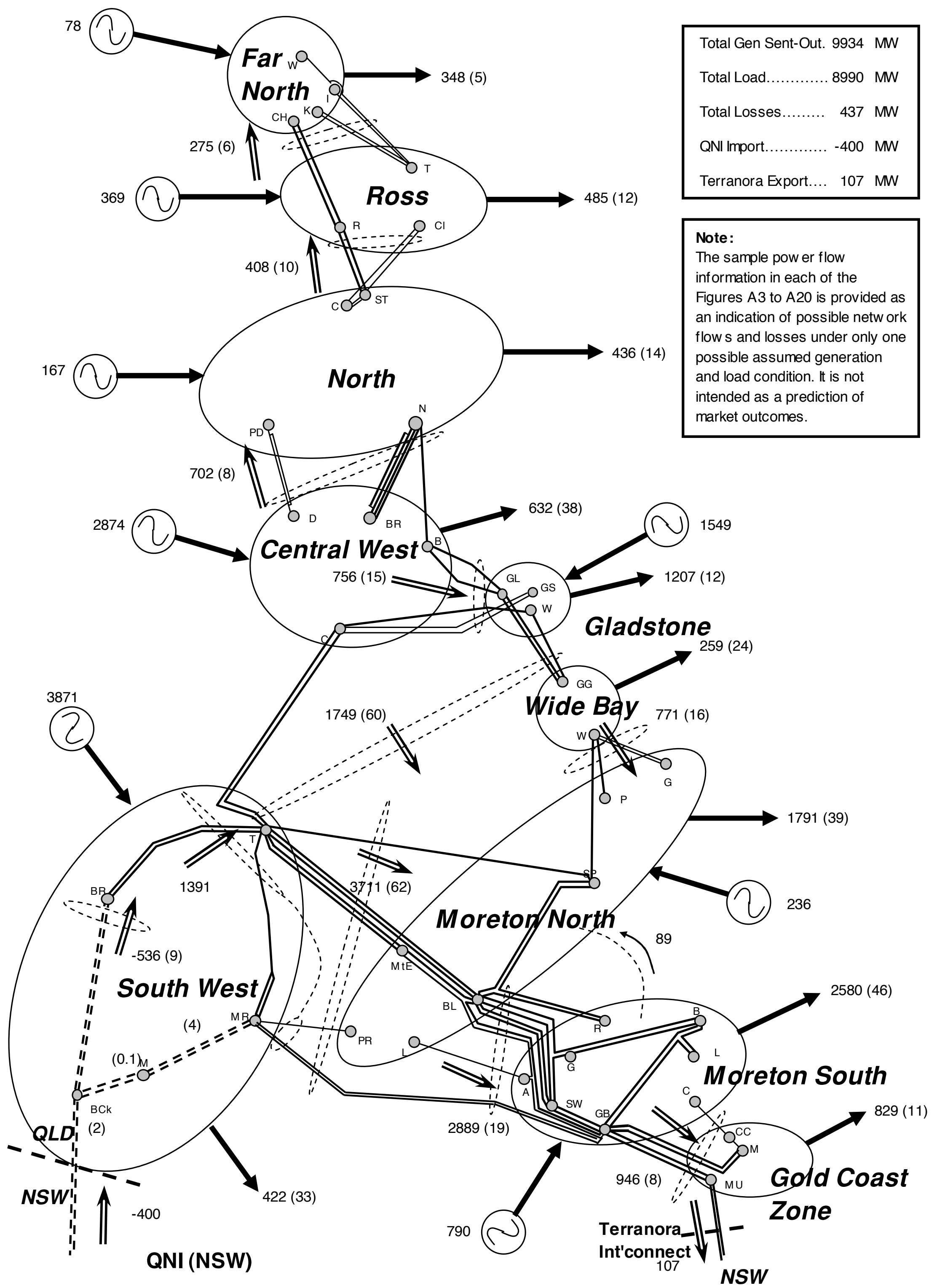
FIGURE A.19: SUMMER 2008/09 QLD PEAK ZERO QNI FLOW



Total Gen Sent-Out.	9542	MW
Total Load.............	8990	MW
Total Losses.........	445	MW
QNI Import............	0	MW
Terranora Export....	107	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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 A.20: SUMMER 2008/09 QLD PEAK 400MW SOUTHERLY QNI FLOW



Total Gen Sent-Out.	9934	MW
Total Load.............	8990	MW
Total Losses.........	437	MW
QNI Import.............	-400	MW
Terranora Export....	107	MW

Note:
The sample power flow information in each of the Figures A3 to A20 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 B — Limit Equations

This appendix contains the Queensland intra-regional limit equations valid at the time of publication.

It should be noted that these equations are continually under review and are revised from time to time to take into account changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation.

TABLE B.1: FAR NORTH QUEENSLAND VOLTAGE STABILITY EQUATIONS

Measured Variable	Coefficient Equation 1 Chalumbin – Woree Contingency	Coefficient Equation 2 Ross – Chalumbin Contingency
Constant Term (Intercept)	271 *(241**(1)**)*	264
Total generation at Barron Gorge PS	– 0.6026	– 0.6841
Number of Barron Gorge units on-line (synchronous compensator)	2.0551	–
Total MW generation at Kareeya PS (Units 1 – 5)	– 0.7224	– 0.6859
4 Kareeya units on-line (0 or 1) (excl K5)	8.4158	5.7651
3 Kareeya units on-line (0 or 1) (excl K5)	7.3440	4.5683
2 Kareeya units on-line (0 or 1) (excl K5)	4.9800	2.9972
1 Kareeya unit on-line (0 or 1) (excl K5)	3.8541	2.1297
Total MW generation at Collinsville PS	0.1439	0.1419
Total MW generation at Mt Stuart PS	0.2395	0.2107
Number of Mt Stuart units on-line (0,1 or 2)	–	4.1095
Total MW generation at Townsville PS	0.2395	0.2163
Number of Townsville units on-line (0 or 1)	–	2.5485
Reactive Output of Woree SVC (MVArs)	– 0.1141	– 0.0374

Note:

(1) At the time of publication of this report, the Chalumbin – Woree limit was reduced by 30MW because of the forced outage of Kareeya to Innisfail by Cyclone Larry.

TABLE B.2: CENTRAL TO NORTH QUEENSLAND DYNAMIC STABILITY EQUATION

Measured Variable	Coefficient Equation 1 GT Online	Equation 2 No GT Online
Constant Term (Intercept)	990	900
Total MW of largest NQ gas turbine	- 1	–
Total generation at Collinsville 132kV PS	- 0.25	0.5
Reactive Output of Ross SVC (MVArs)	- 0.5	–
Number of 120MVAr capacitor banks on-line at Nebo (0, 1 or 2)	85	–
Number reactors on-line at Nebo (0, 1, 2 or 3)	- 14	–
Equation Upper Limit	990	990

TABLE B.3: PREDICTION OF POST CONTINGENT MVA FLOW ON THE CALVALE – WURDONG CIRCUIT

Measured Variable	Coefficient
System normal flow on Calvale – Wurdong (MVA)	1
System normal flow on Calvale – Stanwell (MW)	0.652

TABLE B.4: CENTRAL TO SOUTH QUEENSLAND VOLTAGE STABILITY EQUATIONS

Measured Variable	Coefficient Equation 1 (1) Calvale – Tarong Contingency	Equation 2 (2) Calvale – Tarong Contingency
Constant Term (Intercept)	1227.3	1217.2
Total generation at Gladstone 275kV PS	0.0731	0.0812
Number of Gladstone 275kV units on-line	72.2846	70.3649
Total generation at Gladstone 132kV PS	0.1062	0.1152
Number of Gladstone 132kV units on-line	75.8105	73.3362
Number of Callide B units on-line	47.7783	54.0629
Number of Callide C units on-line	74.2664	86.2947
(Calvale 275kV p.u. voltage – 1.07) x 1000	1.1843	0.8860
(Gladstone 275kV p.u. voltage – 1.07) x 1000	- 1.5421	- 1.5181
Equation Lower Limit	1750	1750
Equation Upper Limit (Transient instability threshold)	1900	1900

Notes:

(1) Equation that preserves the required MVAr margin at Gladstone 275kV.

(2) Equation that preserves the required MVAr margin at Calvale 275kV.

TABLE B.5: TARONG VOLTAGE STABILITY EQUATIONS

Measured Variable	Coefficient Equation 1 Calvale – Tarong Contingency	Equation 2 Woolooga – Palmwoods Contingency	Equation 3 Tarong – Blackwall Contingency	Equation 4 Mt England – Loganlea Contingency
Constant Term (Intercept)	1662	1799	1843	1897
Power transfer on QNI (MW — positive is into Qld)	0.5456	0.5005	0.4867	0.4824
DirectLink power transfer (MW — positive is into Qld)	- 0.2348	- 0.2469	- 0.2397	- 0.2486
DirectLink reactive power (MVAr — positive is into Qld)	0.2132	0.2571	0.2821	0.2808
Number of Swanbank B units on-line	11.4126	12.4993	15.7483	15.5803
Number of Wivenhoe units on-line as generators	29.1678	33.5799	32.9759	32.8392
Number of Wivenhoe synchronous compensators units on-line	33.3364	38.1233	38.4829	38.4418
Number of Swanbank E units on-line	36.4357	41.5434	46.2530	45.5696
Total generation at Roma PS	0.5705	0.5030	0.4925	0.5243
Total generation at Swanbank (B & E)	- 0.3490	- 0.3788	- 0.3867	- 0.4074
Total generation at Gladstone PS (H7 & T5)	- 0.0458	- 0.0533	- 0.0496	- 0.0498
Total generation at Tarong PS & Tarong North	0.5633	0.5358	0.5055	0.5103
Total generation at Wivenhoe PS	- 0.3741	- 0.4017	- 0.4180	- 0.4320
Total generation at Callide PS (B & C)	0.0989	0.0947	0.0987	0.0966
Total generation at Oakey PS	0.5318	0.5073	0.4874	0.4923
Total generation at Millmerran PS	0.5258	0.4862	0.4740	0.4721
Total generation at Braemar PS	0.5258	0.4862	0.4740	0.4721

TABLE B.6: GOLD COAST VOLTAGE STABILITY EQUATION

Measured Variable	Coefficient Swanbank – Mudgeeraba Contingency
Constant Term (Intercept)	457.07
Number of Wivenhoe units on-line	13.3471
Number of Swanbank B units on-line	7.6785
Number of Swanbank E units on-line	26.7207
DirectLink power transfer at Mullimbimby (MW positive is into Qld)	- 0.7996
DirectLink reactive power at Bungalora (MVAr positive is into Qld)	0.2479
Number of Mudgeeraba 110kV Cap Banks available	10.0109
Number of Mudgeeraba 275kV Cap Banks available	16.6693
Number of Molendinar 110kV Cap Banks available	9.3817
No. Moreton South 110kV Cap Banks Online	4.9680
No. Moreton South 275kV Cap Banks Online	10.4727
No. Moreton North 110kV Cap Banks Online	4.0675
No. Moreton North 275kV Cap Banks Online	8.5241

TABLE B.7: BRAEMAR THERMAL AND VOLTAGE STABILITY EQUATION

Measured Variable	Coefficient
Constant Term (Intercept)	1125
Offset [applied depending of the unavailability of southern Queensland capacitive support (including generator lagging capability and 275kV and 110kV capacitor banks)]	- 100

Appendix C — Estimated Maximum Short Circuit Levels

Tables C.1 to C.3 show estimates of the three phase and single phase to earth short circuit levels in the Powerlink transmission network in the period 2006 to 2008. 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 for detailed information.

The short circuit level calculations were determined:

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

The short circuit levels shown in Tables C.1 to C.3 have been determined on the basis of the generation capacity shown in Table 7.1 (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, committed projects and proposed new network assets (as proposed in Chapter 5).

The fault levels determined assume the grid is in its ‘normal’ or ‘intact’ state, that is, all network elements in service. Exceptions to this include potential open points at Belmont 110kV, South Pine 110kV, and Gladstone South 132kV substations. These open points may be necessary to keep the maximum short circuit level below the critical circuit breaker ratings. These open points have been taken into account in the estimates in Tables C.1 to C.3.

At some locations where the short circuit level appears to be above the switchgear rating, 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.

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

TABLE C.1: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS — SOUTHERN QUEENSLAND

In Powerlink Transmission Network 2006 – 2008. (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA) 2006	3 Phase (kA) 2007	3 Phase (kA) 2008	Single Phase (kA) 2006	Single Phase (kA) 2007	Single Phase (kA) 2008
Abermain	275.0	40.0	–	–	15.81	–	–	15.24
Abermain	110.0	31.5	14.84	14.30	20.06	14.75	14.35	22.36
Algester	110.0	40.0	18.24	19.00	18.95	18.46	18.96	18.93
Ashgrove West	110.0	25.0	19.05	19.28	18.48	17.85	17.99	17.47
Belmonth	275.0	31.5	15.56	17.44	17.40	16.69	18.15	18.19
Belmont (4)	110.0	25.0	25.62	27.46	27.41	31.15	33.05	33.14
Blackwall	275.0	50.0	21.73	24.26	24.25	24.94	27.22	27.41
Braemar	330.0	50.0	14.82	17.61	17.61	15.86	17.87	17.87
Braemar	275.0	40.0	18.98	23.42	23.42	21.17	24.57	24.57
Bulli Creek	330.0	50.0	14.74	16.56	16.56	12.33	13.30	13.30
Bulli Creek	132.0	40.0	3.63	3.67	3.67	4.11	4.14	4.14
Bundamba	110.0	40.0	13.30	12.80	15.64	12.05	11.72	14.31
Goodna	275.0	40.0	16.34	17.90	17.92	16.82	17.95	17.99
Goodna	110.0	40.0	21.30	20.68	22.46	23.35	22.82	24.35
Greenbank	275.0	40.0	18.44	22.16	22.05	19.57	22.91	22.92
Kogan Creek	275.0	40.0	13.15	17.90	17.90	14.45	17.88	17.88
Loganlea	275.0	50.0	13.70	15.33	15.29	13.94	15.10	15.11
Loganlea (3)	110.0	25.0	21.06	18.03	18.01	24.04	20.91	20.92
Middle Ridge	330.0	NO CB	10.42	11.29	11.29	9.84	10.94	10.94
Middle Ridge	275.0	40.0	11.80	17.45	17.44	11.98	17.33	17.32
Middle Ridge	110.0	26.2	18.71	18.77	18.76	21.78	22.19	22.19
Millmerran SW/YD	330.0	50.0	15.06	17.40	17.40	16.76	18.82	18.81
Molendinar (1T)	275.0	40.0	7.75	8.32	8.31	7.54	7.92	7.93
Molendinar	110.0	40.0	18.64	19.95	19.91	22.96	24.41	24.46
Mt England	275.0	31.5	21.17	22.75	22.73	21.53	22.67	22.77
Mudgeeraba	275.0	31.5	8.82	9.57	9.55	8.86	9.45	9.44

TABLE C.1: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS — SOUTHERN QUEENSLAND CONTINUED

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA) 2006	3 Phase (kA) 2007	3 Phase (kA) 2008	Single Phase (kA) 2006	Single Phase (kA) 2007	Single Phase (kA) 2008
Mudgeeraba	110.0	31.5	17.54	18.68	18.65	21.13	22.59	22.57
Murarrie	275.0	40.0	12.20	13.31	13.29	12.31	13.04	13.09
Murarrie	110.0	40.0	21.45	22.78	22.74	24.53	25.57	25.74
Oakey	110.0	40.0	10.64	10.53	10.53	11.74	11.42	11.42
Palmwoods	275.0	31.5	8.06	8.19	8.13	8.03	8.15	8.13
Palmwoods	132.0	21.8	12.38	12.51	12.34	14.52	14.70	14.57
Palmwoods	110.0	NO CB	5.52	5.53	5.46	5.81	5.83	5.77
Redbank Plains	110.0	31.5	18.22	17.57	19.10	17.23	16.76	17.85
Richlands	110.0	18.3	13.37	13.72	13.69	14.12	14.27	14.25
Rocklea (1T)	275.0	40.0	12.72	13.52	13.51	12.11	12.59	12.62
Rocklea	110.0	40.0	21.83	22.58	22.41	25.61	26.30	26.14
Runcorn	110.0	21.9	17.01	17.72	17.68	16.24	16.66	16.64
South Pine	275.0	31.5	17.82	18.81	18.78	18.64	19.77	19.88
South Pine (3) (4)	110.0	25.0	25.77	25.53	20.94	31.32	31.11	25.92
Sumner	110.0	40.0	14.98	15.36	15.29	15.06	15.16	15.12
Swanbank A (3)	110.0	18.3	17.70	16.51	18.28	15.47	14.57	15.87
Swanbank B	275.0	31.5	20.95	23.60	23.60	24.79	27.35	27.41
Swanbank E	275.0	40.0	20.51	23.11	23.09	23.82	26.23	26.27
Tangkam	110.0	40.0	12.47	12.50	12.50	11.56	11.46	11.46
Tarong (4)	275.0	31.5	29.44	30.45	30.45	32.57	33.45	33.45
Tarong	132.0	31.5	5.26	5.27	5.27	5.61	5.62	5.62
Tarong	66.0	21.9	13.95	14.00	14.00	15.34	15.37	15.37
Tennyson	110.0	40.0	14.54	14.86	14.79	14.34	14.55	14.50
Upper Kedron	110.0	40.0	21.67	21.80	20.38	17.88	17.95	17.10
West Darra (Bus 1) (4)	110.0	19.3	19.64	19.27	20.88	16.25	16.07	17.11
West Darra (Bus 2)	110.0	19.3	13.23	13.54	13.49	12.38	12.25	12.23
Woolooga	275.0	31.5	9.13	9.25	9.21	8.37	8.99	8.98
Woolooga	132.0	21.9	12.41	12.44	12.35	13.23	13.61	13.55

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.

(2) Powerlink switchgear ratings — no account taken of distribution switchgear.

(3 Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.

(4) 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.

Also note that:

(5) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.

(6) Fault level contributions to the Powerlink network from embedded non-scheduled generators are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

TABLE C.2: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS — CENTRAL QUEENSLAND

In Powerlink Transmission Network 2006 – 2008. (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2006	2007	2008	2006	2007	2008
Baralaba	132.0	15.3	4.14	4.57	4.57	3.52	3.73	3.73
Biloela	132.0	40.0	7.48	7.63	7.63	6.45	7.69	7.69
Blackwater	132.0	12.3	3.47	5.32	5.32	4.38	6.29	6.29
Bouldercombe	275.0	31.5	16.24	16.41	16.41	15.88	16.01	16.01
Bouldercombe	132.0	25.0	10.11	10.14	10.14	11.51	11.53	11.53
Broadsound	275.0	31.5	9.10	9.70	9.71	7.14	8.04	8.04
Callemondah	132.0	31.5	20.44	20.48	20.48	20.90	20.93	20.95
Callide A Pwr Stat.	132.0	12.3	10.58	10.81	10.81	10.42	10.93	10.93
Calvale	275.0	31.5	19.80	19.86	19.86	22.16	22.25	22.25
Calvale	132.0	No CB	10.57	10.79	10.79	10.57	11.02	11.02
Dingo	132.0	31.5	2.26	2.62	2.62	2.49	2.76	2.76
Dysart	132.0	19.9	4.03	4.07	4.07	4.67	4.70	4.70
Egans Hill	132.0	No CB	6.55	6.56	6.67	6.75	6.75	6.77
Gin Gin	275.0	31.5	10.25	10.29	10.28	8.20	8.54	8.54
Gin Gin	132.0	21.9	8.58	8.86	8.85	8.62	8.91	8.91
Gladstone	275.0	31.5	19.35	19.41	19.40	21.84	21.91	21.90
Gladstone (4)	132.0	31.5	25.97	26.02	26.01	31.90	31.96	31.96
Gladstone South	132.0	40.0	16.92	16.96	16.96	16.82	16.85	16.98
Grantleigh	132.0	31.5	2.44	2.44	2.44	2.54	2.54	2.54
Gregory	132.0	31.5	7.56	7.84	7.84	8.85	9.20	9.20
Lilyvale	275.0	40.0	4.87	5.05	5.05	4.98	5.19	5.19
Lilyvale	132.0	25.0	7.88	8.19	8.19	9.47	9.88	9.88
Moura	132.0	12.3	3.75	3.91	3.91	4.04	4.19	4.19
Norwich Park	132.0	40.0	3.26	3.29	3.29	2.50	2.51	2.51
Rockhampton	132.0	12.3	6.62	6.63	6.63	6.96	6.97	6.97
Rocklands	132.0	40.0	6.19	6.20	6.21	5.55	5.55	5.56
Stanwell Sw/yd	275.0	31.5	17.41	17.64	17.64	19.14	19.36	19.36
Stanwell Sw/yd	132.0	31.5	4.97	4.98	4.98	4.60	4.60	4.60
Teebar Creek	275.0	40.0	–	7.01	6.99	–	7.14	7.13
Teebar Creek	132.0	40.0	–	10.51	10.49	–	11.99	11.97
Wurdong	275.0	31.5	15.56	15.60	15.59	14.89	14.93	14.93

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.

(2) Powerlink switchgear ratings — no account taken of distribution switchgear.

(3) Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.

(4) 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.

Also note that:

(5) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.

(6) Fault level contributions to the Powerlink network from embedded non-scheduled generators are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

TABLE C.3: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS — NORTHERN QUEENSLAND

In Powerlink Transmission Network 2006 – 2008. (1)

			3 Phase (kA)			Single Phase (kA)		
Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	2006	2007	2008	2006	2007	2008
Alan Sherriff	132.0	40.0	9.97	10.18	10.19	11.05	11.19	11.20
Alligator Creek	132.0	31.5	3.52	3.97	3.97	4.06	4.47	4.47
Burton Downs	132.0	19.3	4.45	4.59	4.59	4.40	4.50	4.50
Cairns	132.0	12.1	4.48	4.97	5.04	6.01	6.59	6.73
Cardwell	132.0	19.3	2.56	2.86	2.81	2.02	2.24	2.22
Chalumbin	275.0	21.9	3.25	3.34	3.40	3.51	3.59	3.68
Chalumbin	132.0	31.5	6.28	6.43	6.17	7.24	7.39	7.20
Clare	132.0	8.8	6.30	6.42	6.42	6.07	6.18	6.18
Collinsville	132.0	15.3	10.86	11.29	11.29	12.02	12.60	12.60
Coppabella	132.0	31.5	2.77	2.82	2.82	3.14	3.18	3.18
Dan Gleeson	132.0	31.5	9.57	9.81	9.82	10.47	10.70	10.71
Edmonton	132.0	31.5	4.08	4.59	4.63	5.15	5.67	5.76
Garbutt	132.0	NO CB	8.54	8.72	8.72	9.05	9.23	9.24
Ingham South	132.0	40.0	2.59	2.59	2.53	2.83	2.83	2.79
Innisfail	132.0	40.0	2.42	3.86	2.89	2.89	4.33	3.43
Invicta	132.0	19.3	4.71	4.79	4.79	4.35	4.40	4.40
Kamerunga	132.0	15.3	3.69	3.99	4.03	4.54	4.83	4.89
Kareeya	132.0	10.9	6.19	6.36	6.17	7.15	7.34	7.17
Kemmis	132.0	40.0	4.98	5.20	5.20	5.69	5.89	5.89
King Creek	132.0	40.0	–	4.86	4.86	–	4.02	4.03
Mackay	132.0	15.7	4.63	5.49	5.49	5.29	6.03	6.03
Moranbah	132.0	15.3	5.49	5.64	5.64	6.62	6.77	6.77
Moranbah South	132.0	40.0	4.32	4.41	4.41	4.23	4.29	4.29
Mt McLaren	132.0	31.5	1.85	1.86	1.86	2.04	2.05	2.05
Nebo	275.0	31.5	6.57	8.05	8.05	7.23	8.59	8.59
Nebo	132.0	21.9	9.46	10.59	10.59	10.87	12.04	12.04

TABLE C.3: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS — NORTHERN QUEENSLAND CONTINUED

In Powerlink Transmission Network 2006 – 2008. (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA) 2006	3 Phase (kA) 2007	3 Phase (kA) 2008	Single Phase (kA) 2006	Single Phase (kA) 2007	Single Phase (kA) 2008
Newlands	132.0	31.5	3.04	3.07	3.07	3.06	3.12	3.12
North Goonyella	132.0	19.3	3.12	3.16	3.16	2.54	2.61	2.61
Oonooie	132.0	31.5	2.61	2.85	2.85	3.08	3.30	3.30
Peak Downs	132.0	40.0	4.29	4.36	4.36	3.89	3.93	3.93
Pioneer Valley	132.0	40.0	4.25	5.23	5.23	4.77	5.74	5.74
Proserpine	132.0	21.9	3.39	3.52	3.52	3.66	3.77	3.77
Ross	275.0	31.5	5.25	5.50	5.52	6.13	6.48	6.50
Ross	132.0	31.5	11.52	12.18	12.20	13.40	14.62	14.64
Stoney Creek	132.0	40.0	–	3.49	3.49	–	3.38	3.38
Strathmore	275.0	50.0	5.65	6.07	6.08	5.11	6.60	6.61
Strathmore	132.0	40.0	10.28	10.67	10.68	10.71	11.60	11.61
Townsville East	132.0	40.0	–	9.95	9.96	–	10.46	10.47
Townsville South	132.0	21.9	11.25	12.08	12.09	13.93	15.25	15.27
Townsville GT PS	132.0	31.5	8.49	7.86	7.86	9.41	8.72	8.73
Tully	132.0	31.5	3.12	4.10	4.21	2.90	4.04	4.09
Turkinje	132.0	15.7	3.72	3.84	2.49	4.24	4.34	2.90
Wandoo	132.0	40.0	3.94	4.12	4.12	2.87	2.95	2.95
Woree	275.0	50.0	2.29	2.40	2.76	2.73	2.84	3.40
Woree	132.0	40.0	4.61	5.13	5.20	6.30	6.93	7.09

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.

(2) Powerlink switchgear ratings — no account taken of distribution switchgear.

(3) Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.

(4) 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.

Also note that:

(5) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.

Fault level contributions to the Powerlink network from embedded non-scheduled generators are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

Appendix D — Proposed Small Network Assets

D.1 Alligator Creek 132/33kV Substation Expansion

Project Name: Alligator Creek 132/33kV substation expansion
Proposed Timing: Late 2008
Estimated Cost: $12.4 million

Background

Alligator Creek 132/33kV substation (2 x 40MVA transformers) is the bulk supply point for the coal loading terminals of Hay Point, Dalrymple Bay and the surrounding communities to the south of Mackay.

Due to the effects of the humid, tropical environment, and nature of the loads supplied from the substation, a recent condition assessment of the transformers has identified a need for their replacement.

Powerlink has reliability and quality of supply obligations under the National Electricity Rules, its transmission authority and connection agreements with customers. In particular, Powerlink must plan and develop its transmission system in accordance with good electricity industry practice, such that its network is able to meet forecast electricity demand during an outage of the most critical single network element (what is commonly known as an N-1 situation) unless otherwise agreed with affected parties. The existing configuration of the Alligator Creek substation requires Powerlink to expand the substation to facilitate the transformer replacement while continuing to meet it's reliability of supply obligations. The proposed solution therefore is classified as a reliability augmentation.

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

Network Options Considered

Option 1 — Provide additional circuit switching facilities at Alligator Creek

This option involves installing two new 132kV switch bays on the circuits supplying Alligator Creek from Nebo and Pioneer Valley, extending the 132kV busbar, and installing a new bus section circuit breaker. As these works comprise shared network assets they are subject to consultation under the NER and the AER Regulatory Test.

These works would be scheduled to commence in late 2007 to meet the required commissioning date of late 2008.

The total capital cost of this option is $12.4 million for Powerlink, including the cost for replacing the transformers. The shared network component, comprising the additional circuit switching facilities, is estimated to cost $6.6 million.

Option 2 — Establishment of a new 132/33kV substation

This option involves establishing a new 132/33kV substation (2 x 100MVA transformers) adjacent to the existing Alligator Creek substation.

These works would be scheduled to commence in late 2007 to meet the required commissioning date of late 2008.

The total capital cost of this option is $22 million for Powerlink, including the cost for new transformers. Additional expenditure would be required by Ergon Energy to establish the low voltage switchyard. These Ergon works have not been costed.

Non-Network Options Considered

Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of late 2008.

Summary of Options and Economic Analysis

There are two feasible options that are capable of addressing the future supply requirements at the Alligator Creek substation by the required timing of late 2008. The present value cost of each of these options was calculated over a period of 15 years. The results of the economic analysis for the medium growth forecast are summarised in Tables D.1 and D.3.

TABLE D.1: SUMMARY OF ECONOMIC ANALYSIS FOR MEDIUM GROWTH FOR ALLIGATOR CREEK CIRCUIT SWITCHING FACILITIES

Options	Present Value Cost (Medium Growth)	Ranking
1. Alligator Creek circuit switching facilities	$7.11M	1
2. New 132/33kV substation	$12.61M	2
3. Non-network options	N/A	N/A

No market scenarios were considered in the financial analysis as the timing for action is not sensitive to varying economic growth rates.

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) has been examined and the results are summarised in Table D.2. Sensitivity to the commissioning date was not examined, as both options are required to be in service from late 2008 to meet forecast peak demand in the 2008/09 summer.

TABLE D.2: RESULTS OF SENSITIVITY ANALYSIS FOR ALLIGATOR CREEK CIRCUIT SWITCHING FACILITIES

	Discount Rate 8%		Discount Rate 10%		Discount Rate 12%	
	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins
Scenario A Medium Growth	1	100%	1	100%	1	100%

The result of the analysis is that Option 1, installation of additional circuit switching facilities at Alligator Creek substation, minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no effect on other transmission networks.

Recommendation

It is recommended that additional circuit switching facilities be installed at Alligator Creek substation to facilitate replacement of the 132/33kV transformers by late 2008.

TABLE D.3: CASH FLOW FOR ALLIGATOR CREEK CIRCUIT SWITCHING FACILITIES

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario A		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Alligator Creek circuit switching facilities**														
TUOS		0.000	0.000	0.000	1.367	1.349	1.331	1.312	1.294	1.276	1.258	1.240	1.221	1.203	1.185	1.167
PV of TUOS	$7.11M															
Total for Option 1	**$7.11M**															
Option 2		**New 132/33kV substation**														
TUOS		0.000	0.000	0.000	2.426	2.393	2.361	2.328	2.296	2.264	2.231	2.199	2.167	2.134	2.102	2.070
PV of TUOS	$12.61M															
Total for Option 2	**$12.61M**															

D.2 Bundamba 110/11kV Transformer Augmentation

Project Name: Bundamba 110/11kV Transformer Augmentation
Proposed Timing: Late 2009
Estimated Cost: $11.8 million

Background

Bundamba 110/11kV substation (1 x 60MVA transformer) supplies industrial loads including the Capral Aluminium Plant and Bremer Business Park at Bundamba, near Ipswich. This substation is backed up by Energex's 33kV network.

Due to ongoing demand growth, from late 2009 onwards, an outage of this single transformer is forecast to result in the thermal capability of Energex's local 33kV network being exceeded during summer peak demand periods.

Energex's reliability of supply obligations are outlined in its Annual Network Management Plan, and require the forecast peak demand to be supplied with the transformer out of service (n-1). Without action, Energex will be unable to meet these obligations. Solutions to address this forecast limitation are classified as a reliability augmentation under the NER.

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

Powerlink has conducted a joint planning investigation with Energex to identify the least-cost solution to augmenting supply to the Bundamba area.

Network Options Considered

Option 1 — Bundamba transformer augmentation
This option involves installing a second 60MVA transformer and associated switchgear at Bundamba substation, and reconfiguring the 110kV line between Bundamba and the Swanbank-Abermain tee to double circuit operation.

These works would be scheduled to commence in late 2008 to meet the required commissioning date of late 2009.

The total capital cost of this option is $5.3 million for Powerlink (shared network component $3.7 million) and $6.5 million for Energex.

Option 2 — Energex Ebbw Vale 33/11kV substation rebuild
This option involves Energex rebuilding the existing Ebbw Vale substation and uprating the 33kV network supplying the substation.

These works would be scheduled to commence in late 2008 to meet the required commissioning date of late 2009.

The total capital cost of this option is $14 million for Energex.

Non-Network Options Considered

Powerlink and Energex are not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of late 2009.

Summary of Options and Economic Analysis

There are two feasible options that are capable of addressing the future supply requirements by the required timing of late 2009. The present value cost of each of these options was calculated over a period of 15 years. The results of the economic analysis for the medium growth forecast are summarised in Table D.4.

TABLE D.4: SUMMARY OF ECONOMIC ANALYSIS FOR MEDIUM GROWTH FOR BUNDAMBA TRANSFORMER AUGMENTATION

Options	Present Value Cost (Medium Growth)	Ranking
1. Bundamba transformer augmentation	$5.92M	1
2. Ebbw Vale rebuild	$7.03M	2
3. Non-network options	N/A	N/A

A range of market scenarios were also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. The results of the scenario analysis are contained in Tables D.5 and D.7. The possible introduction of new generation in the Bundamba area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

TABLE D.5: SUMMARY OF SCENARIO ANALYSIS FOR BUNDAMBA TRANSFORMER AUGMENTATION

	Option One Bundamba Transformer Augmentation		Option Two Ebbw Vale Rebuild	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	5.92	1	7.03	2
Scenario B High Growth	6.76	1	8.02	2
Scenario C Low Growth	5.15	1	6.11	2

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) has been examined and the results are summarised in Table D.6. Sensitivity to the commissioning date was not examined, as both options are required to be in service from late 2009 to meet forecast peak demand in the 2009/10 summer.

TABLE D.6: RESULTS OF SENSITIVITY ANALYSIS FOR BUNDAMBA TRANSFORMER AUGMENTATION

	Discount Rate					
	7%		9%		11%	
	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins
Scenario A Medium Growth	1	100%	1	100%	1	100%
Scenario B High Growth	1	97%	1	97%	1	97%
Scenario C Low Growth	1	97%	1	97%	1	97%

The result of the analysis is that Option 1, installation of a second 60MVA 110/11kV transformer at Bundamba substation, minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no effect on other transmission networks.

Recommendation
It is recommended that a second 60MVA 110/11kV transformer be installed at Bundamba substation by late 2009.

TABLE D.7: CASH FLOW FOR BUNDAMBA TRANSFORMER AUGMENTATION

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario A		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Bundamba Transformer Augmentation**														
TUOS		0.000	0.000	0.000	0.000	1.301	1.284	1.266	1.249	1.232	1.214	1.197	1.180	1.162	1.145	1.127
PV of TUOS	$5.92M															
Total for Option 1	**$5.92M**															
Option 2		**Ebbw Vale Rebuild**														
TUOS		0.000	0.000	0.000	0.000	1.544	1.523	1.502	1.482	1.461	1.441	1.420	1.399	1.379	1.358	1.338
PV of TUOS	$7.03M															
Total for Option 2	**$7.03M**															

		High Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario B		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Bundamba Transformer Augmentation**														
TUOS		0.000	0.000	0.000	1.301	1.284	1.266	1.249	1.232	1.214	1.197	1.180	1.162	1.145	1.127	1.110
PV of TUOS	$6.76M															
Total for Option 1	**$6.76M**															
Option 2		**Ebbw Vale Rebuild**														
TUOS		0.000	0.000	0.000	1.544	1.523	1.502	1.482	1.461	1.441	1.420	1.399	1.379	1.358	1.338	1.317
PV of TUOS	$8.02M															
Total for Option 2	**$8.02M**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario C		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Bundamba Transformer Augmentation**														
TUOS		0.000	0.000	0.000	0.000	0.000	1.301	1.284	1.266	1.249	1.232	1.214	1.197	1.180	1.162	1.145
PV of TUOS	$5.15M															
Total for Option 1	**$5.15M**															
Option 2		**Ebbw Vale Rebuild**														
TUOS		0.000	0.000	0.000	0.000	0.000	1.544	1.523	1.502	1.482	1.461	1.441	1.420	1.399	1.379	1.358
PV of TUOS	$6.11M															
Total for Option 2	**$6.11M**															

D.3 Edmonton 132kV Shunt Capacitor Bank

Project Name: Edmonton 30MVAr, 132kV Shunt Capacitor Bank
Proposed Timing: Late 2008
Estimated Cost: $2 million

Background

Edmonton 132/22kV substation supplies the Edmonton/Gordonvale area just south of Cairns. This substation is connected to Woree 275/132kV substation and Innisfail 132/22kV substation via double circuit 132kV transmission lines (one circuit in and out of the substation).

Due to ongoing demand growth, from late 2008 onwards, an outage of the Woree to Edmonton 132kV line is forecast to result in unacceptably low voltage conditions in the Edmonton/Gordonvale area during summer peak demand periods. Low voltage conditions can result in ‘brown-outs’ and failure of/damage to customer equipment (i.e. — electric motors).

Powerlink has reliability and quality of supply obligations under the National Electricity Rules, its transmission authority and connection agreements with customers. In particular, Powerlink must plan and develop its transmission system in accordance with good electricity industry practice, such that its network is able to meet forecast electricity demand during an outage of the most critical single network element (what is commonly known as an N-1 situation) unless otherwise agreed with affected parties. Without action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

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

Network Options Considered

Option 1 — 132kV Shunt Capacitor Bank
This option involves establishing a 30MVAr, 132kV shunt capacitor bank at Edmonton substation.

These works would be scheduled to commence in mid 2007 to meet the required commissioning date of late 2008.

The total capital cost of this option is $2 million.

Option 2 — 132kV Static VAr Compensator
This option involves establishing a 132kV Static VAr Compensator (SVC) at Edmonton substation. The SVC would be of similar size to the capacitor bank in Option 1.

These works would be scheduled to commence in late 2007 to meet the required commissioning date of late 2008.

The total capital cost of this option is $11 million.

Option 3 — Customer Connected Capacitor Banks

It would be feasible that customers in the Edmonton/Gordonvale area could install capacitor banks to overcome the forecast network voltage limitation. However, Powerlink has no knowledge of any proposals for such customer-connected capacitor banks to be installed.

Non-Network Options Considered

Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of late 2008.

Summary of Options and Economic Analysis

There are two feasible options that are capable of addressing the future supply requirements in the Edmonton/Gordonvale area by the required timing of late 2008. The present value cost of each of these options was calculated over a period of 15 years. The results of the economic analysis for the medium growth forecast are summarised in Table D.8.

TABLE D.8: SUMMARY OF ECONOMIC ANALYSIS FOR MEDIUM GROWTH FOR EDMONTON SHUNT CAPACITOR BANK

Options	Present Value Cost (Medium Growth)	Ranking
1. Shunt Capacitor Bank	$1.15M	1
2. Static VAr Compensator	$6.3M	2
3. Customer connected capacitor bank	N/A	N/A
4. Non-network options	N/A	N/A

A range of market scenarios were also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. The results of the scenario analysis are contained in Tables D.9 and D.11. The possible introduction of new generation in the Edmonton/ Gordonvale area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

TABLE D.9: SUMMARY OF SCENARIO ANALYSIS FOR EDMONTON SHUNT CAPACITOR BANK

	Option One Shunt Capacitor Bank		Option Two SVC	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	1.15	1	6..3	2
Scenario B High Growth	1.15	1	6.3	2
Scenario C Low Growth	1.0	1	5.52	2

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) has been examined and the results are summarised in Table D.10. Sensitivity to the commissioning date was not examined, as both options are required to be in service from late 2008 to meet forecast peak demand in the 2008/09 summer.

TABLE D.10: RESULTS OF SENSITIVITY ANALYSIS FOR EDMONTON SHUNT CAPACITOR BANK

	Discount Rate					
	7%		9%		11%	
	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins
Scenario A Medium Growth	1	100%	1	100%	1	100%
Scenario B High Growth	1	100%	1	100%	1	100%
Scenario C Low Growth	1	100%	1	100%	1	100%

The result of the analysis is that Option 1, installation of a 132kV shunt capacitor bank at Edmonton substation, minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no effect on other transmission networks.

Recommendation
It is recommended that a 30MVAr, 132kV shunt capacitor bank be installed at Edmonton substation by late 2008.

TABLE D.11: CASH FLOW FOR EDMONTON SHUNT CAPACITOR BANK

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario A		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Shunt Capacitor Bank**														
TUOS		0.000	0.000	0.000	0.221	0.218	0.215	0.212	0.209	0.206	0.203	0.200	0.197	0.194	0.191	0.188
PV of TUOS	$1.15M															
Total for Option 1	**$1.15M**															
Option 2		**Static VAr Compensator**														
TUOS		0.000	0.000	0.000	1.213	1.197	1.180	1.164	1.148	1.132	1.116	1.100	1.083	1.067	1.051	1.035
PV of TUOS	$6.3M															
Total for Option 2	**$6.3M**															
		High Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario B		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Shunt Capacitor Bank**														
TUOS		0.000	0.000	0.000	0.221	0.218	0.215	0.212	0.209	0.206	0.203	0.200	0.197	0.194	0.191	0.188
PV of TUOS	$1.15M															
Total for Option 1	**$1.15M**															
Option 2		**Static VAr Compensator**														
TUOS		0.000	0.000	0.000	1.213	1.197	1.180	1.164	1.148	1.132	1.116	1.100	1.083	1.067	1.051	1.035
PV of TUOS	$6.3M															
Total for Option 2	**$6.3M**															
		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario C		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Shunt Capacitor Bank**														
TUOS		0.000	0.000	0.000	0.000	0.221	0.218	0.215	0.212	0.209	0.206	0.203	0.200	0.197	0.194	0.191
PV of TUOS	$1.0M															
Total for Option 1	**$1.0M**															
Option 2		**Static VAr Compensator**														
TUOS		0.000	0.000	0.000	0.000	1.213	1.197	1.180	1.164	1.148	1.132	1.116	1.100	1.083	1.067	1.051
PV of TUOS	$5.52M															
Total for Option 2	**$5.52M**															

D.4 El Arish 132/22kV Substation Establishment

Project Name: El Arish 132/22kV Substation Establishment
Proposed Timing: Late 2008
Estimated Cost: $17.9 million

Background

Primary supply to the Mission Beach area is provided by 2 x 22kV distribution lines from Tully 132/22kV substation.

Due to ongoing demand growth, from late 2008 onwards, an outage of one of these lines is forecast to result in unacceptably low voltage conditions in the Mission Beach area during summer peak demand periods. Low voltage conditions can result in 'brown-outs' and failure of/damage to customer equipment (i.e. — electric motors).

Ergon Energy's reliability of supply obligations are outlined in its Annual Network Management Plan, and require the forecast peak demand to be supplied with one of these lines out of service (n-1). Without action, Ergon Energy will be unable to meet these obligations. Solutions to address this forecast limitation are classified as a reliability augmentation under the NER.

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

Powerlink has conducted a joint planning investigation with Ergon Energy to identify the least-cost solution to augmenting supply to the Mission Beach area.

Network Options Considered

Option 1 — El Arish 132/22kV Substation Establishment
This option involves establishing a new 132/22kV substation (2 x 65MVA transformers) at El Arish to supply the Mission Beach area.

The new substation would be partly comprised of shared network assets (predominantly the switchgear and associated secondary systems). These shared assets are subject to consultation under the NER and AER Regulatory Test.

These works would be scheduled to commence in late 2007 to meet the required commissioning date of late 2008.

The total capital cost of this option is $13.5 million for Powerlink (shared network component $7.7 million) and $4.4 million for Ergon.

Additional works would be required by late 2015 to address other future supply requirements. These works would comprise construction of additional 22kV feeders.

The total capital cost of these additional works is $4.5 million.

Option 2 — South Mission Beach 22kV Switching Station
This option involves Ergon Energy establishing a new 22kV switching station at South Mission Beach. The existing 22kV network, together with a new 22kV line from Tully substation, would be connected to the switching station.

These works would be scheduled to commence in late 2007 to meet the required commissioning date of late 2008.

The total capital cost of these works is $12.1 million for Ergon.

Additional works would be required by late 2015 to address other future supply requirements. These works would comprise establishment of El Arish substation as per Option 1, and construction of an additional 22kV feeder from El Arish to South Mission Beach.

The total capital cost of these additional works is $22.4 million.

Non-Network Options Considered
Powerlink and Ergon Energy are not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of late 2008.

Summary of Options and Economic Analysis
There are two feasible options that are capable of addressing the future supply requirements in the Mission Beach area by the required timing of late 2008. The present value cost of each of these options was calculated over a period of 15 years. The results of the economic analysis for the medium growth forecast are summarised in Table D.12.

TABLE D.12: SUMMARY OF ECONOMIC ANALYSIS FOR MEDIUM GROWTH FOR EL ARISH 132/22KV SUBSTATION ESTABLISHMENT

Options	Present Value Cost (Medium Growth)	Ranking
1. El Arish 132/22kV Substation Establishment	$11.05M	1
2. South Mission Beach 22kV Switching Station	$11.10M	2
3. Non-network options	N/A	N/A

A range of market scenarios were also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. The results of the scenario analysis are contained in Tables D.13 and D.15. The possible introduction of new generation in the Mission Beach area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

TABLE D.13: SUMMARY OF SCENARIO ANALYSIS FOR EL ARISH 132/22KV SUBSTATION ESTABLISHMENT

	Option One El Arish 132/22kV Substation		Option Two South Mission Beach 22kV Switching Station	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	11.05	1	11.10	2
Scenario B High Growth	11.47	1	13.16	2
Scenario C Low Growth	9.43	2	8.45	1

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) has been examined and the results are summarised in Table D.14. Sensitivity to the commissioning date was not examined, as both options are required to be in service from late 2008 to meet forecast peak demand in the 2008/09 summer.

TABLE D.14: RESULTS OF SENSITIVITY ANALYSIS FOR EL ARISH 132/22KV SUBSTATION ESTABLISHMENT

	Discount Rate					
	7%		9%		11%	
	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins
Scenario A Medium Growth	1	100%	1	100%	1	100%
Scenario B High Growth	1	99%	1	98%	1	95%
Scenario C Low Growth	1	88%	1	92%	1	95%

The result of the analysis is that Option 1, establishment of a new 132/22kV substation at El Arish, minimises the present value cost of addressing the network limitation in the majority of cases, and as such is considered to satisfy the Regulatory Test.

This project has no effect on other transmission networks.

Recommendation

It is recommended that a new 132/22kV substation be established at El Arish by late 2008.

TABLE D.15: CASH FLOW FOR EL ARISH SUBSTATION ESTABLISHMENT

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario A		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**El Arish 132/22kV Substation Establishment**														
TUOS		0.000	0.000	0.000	1.973	1.947	1.921	1.895	1.868	1.842	1.816	2.285	2.253	2.2	2.186	2.154
PV of TUOS	$11.05M															
Total for Option 1	**$11.05M**															
Option 2		**South Mission Beach 22kV Switching Station**														
TUOS		0.000	0.000	0.023	1.368	1.35	1.332	1.315	1.297	1.279	1.261	3.714	3.663	3.612	3.561	3.51
PV of TUOS	$11.10M															
Total for Option 2	**$11.10M**															

		High Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario B		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**El Arish 132/22kV Substation Establishment**														
TUOS		0.000	0.000	0.000	1.973	1.947	1.921	1.895	1.868	2.338	2.306	2.272	2.239	2.207	2.173	2.14
PV of TUOS	$11.47M															
Total for Option 1	**$11.47M**															
Option 2		**South Mission Beach 22kV Switching Station**														
TUOS		0.000	0.000	0.023	1.368	1.35	1.332	1.315	1.297	3.749	3.698	3.648	3.597	3.546	3.495	3.444
PV of TUOS	$13.16M															
Total for Option 2	**$13.16M**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario C		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**El Arish 132/22kV Substation Establishment**														
TUOS		0.000	0.000	0.000	0.000	1.973	1.947	1.921	1.895	1.868	1.842	1.816	1.789	2.259	2.227	2.193
PV of TUOS	$9.43M															
Total for Option 1	**$9.43M**															
Option 2		**South Mission Beach 22kV Switching Station**														
TUOS		0.000	0.000	0.000	0.023	1.368	1.35	1.332	1.315	1.297	1.297	1.261	1.244	3.696	3.645	3.594
PV of TUOS	$8.45M															
Total for Option 2	**$8.45M**															

D.5 Murarrie 275/110kV Transformer Augmentation

Project Name: Murarrie 275/110kV Transformer Augmentation
Proposed Timing: Late 2009
Estimated Cost: $9.2 million

Background

Murarrie 275/110kV substation (1 x 375MVA transformer) is currently under construction and scheduled for commissioning in late 2006. This substation will supply the Trade Coast (Brisbane Port) area and also provide significantly more capability in the electricity network between Belmont and the Brisbane CBD Area via Murarrie and Newstead.

Due to ongoing demand growth, from late 2009 onwards, an outage of this transformer is forecast to result in thermal overloading of the existing Belmont-Murarrie 110kV lines, and 275/110kV transformers at Belmont substation during summer peak demand periods.

Powerlink has reliability and quality of supply obligations under the National Electricity Rules, its transmission authority and connection agreements with customers. In particular, Powerlink must plan and develop its transmission system in accordance with good electricity industry practice, such that its network is able to meet forecast electricity demand during an outage of the most critical single network element (what is commonly known as an N-1 situation) unless otherwise agreed with affected parties. Without action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

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

Network Options Considered

Option 1 — Murarrie transformer augmentation

This option involves installing a second 375MVA transformer at Murarrie and converting the second Belmont-Murarrie circuit to 275kV operation (currently operates at 110kV).

These works would be scheduled to commence in late 2008 to meet the required commissioning date of late 2009.

The total capital cost of this option is $9.2 million for Powerlink.

Additional works would be required by late 2013 to address other future supply requirements. These works would comprise installation of a third transformer at Rocklea Substation, and 110kV cable between Rocklea and Wooloongabba, as per Option 2.

Option 2 — Rocklea transformer augmentation and Rocklea-Wooloongabba 110kV cable

This option involves installing a third 375MVA 275/110kV transformer at Rocklea substation, and 110kV cable between Rocklea and a new substation at Wooloongabba.

These works would be scheduled to commence in late 2008 to meet the required commissioning date of late 2009.

The total capital cost of this option is $18.2 million for Powerlink and $46.8 million for Energex.

Additional works would be required by late 2013 to address other future supply requirements. These works would comprise the installation of a second transformer at Murarrie Substation as per Option 1.

Non-Network Options Considered

Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of late 2009.

Summary of Options and Economic Analysis

There are two feasible options that are capable of addressing the future supply requirements by the required timing of late 2009. The present value cost of each of these options was calculated over a period of 15 years. The results of the economic for the medium growth forecast are summarised in Table D.16.

TABLE D.16: SUMMARY OF ECONOMIC ANALYSIS FOR MEDIUM GROWTH FOR MURARRIE TRANSFORMER AUGMENTATION

Options	Present Value Cost (Medium Growth)	Ranking
1. Murarrie transformer augmentation	$22.08M	1
2. Rocklea transformer augmentation and 110kV cable	$35.11M	2
3. Non-network options	N/A	N/A

A range of market scenarios were also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. The results of the scenario analysis are contained in Tables D.17 and D.19. The possible introduction of new generation in the Murarrie area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

TABLE D.17: SUMMARY OF SCENARIO ANALYSIS FOR MURARRIE TRANSFORMER AUGMENTATION

	Option One Murarrie Transformer Augmentation		Option Two Rocklea Transformer Augmentation and 110kv Cable	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	22.08	1	35.11	2
Scenario B High Growth	26.09	1	40.20	2
Scenario C Low Growth	18.37	1	30.41	2

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) has been examined and the results are summarised in Table D.18. Sensitivity to the commissioning date was not examined, as both options are required to be in service from late 2009 to meet forecast peak demand in the 2009/10 summer.

TABLE D.18: RESULTS OF SENSITIVITY ANALYSIS FOR MURARRIE TRANSFORMER AUGMENTATION

	Discount Rate					
	8%		10%		12%	
	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins	Best Ranked Option	Frequency of Wins
Scenario A Medium Growth	1	100%	1	100%	1	100%
Scenario B High Growth	1	100%	1	100%	1	100%
Scenario C Low Growth	1	100%	1	100%	1	100%

The result of the analysis is that Option 1, installation of a second 375MVA 275/110kV transformer at Murarrie substation, minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no effect on other transmission networks.

Recommendation

It is recommended that a second 375MVA 275/110kV transformer be installed at Murarrie substation by late 2009.

TABLE D.19: CASH FLOW FOR MURARRIE TRANSFORMER AUGMENTATION

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario A		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Murarrie Transformer Augmentation**														
TUOS		0.000	0.000	0.000	0.000	1.014	1.001	0.987	0.974	8.126	8.018	7.908	7.800	7.690	7.582	7.472
PV of TUOS	$22.08M															
Total for Option 1	**$22.08M**															
Option 2		**Rocklea Transformer Augmentation and Rocklea – Wooloongabba 110kV cable**														
TUOS		0.000	0.000	0.000	0.000	7.166	7.071	6.975	6.880	7.798	7.690	7.580	7.471	7.362	7.253	7.144
PV of TUOS	$35.11M															
Total for Option 2	**$35.11M**															

		High Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario B		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Murarrie Transformer Augmentation**														
TUOS		0.000	0.000	0.000	1.014	1.001	0.987	0.974	8.126	8.018	7.908	7.800	7.690	7.582	7.472	7.363
PV of TUOS	$26.09M															
Total for Option 1	**$26.09M**															
Option 2		**Rocklea Transformer Augmentation and Rocklea – Wooloongabba 110kV cable**														
TUOS		0.000	0.000	0.000	7.166	7.071	6.975	6.880	7.798	7.690	7.580	7.471	7.362	7.253	7.144	7.035
PV of TUOS	$40.20M															
Total for Option 2	**$40.20M**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Scenario C		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Option 1		**Murarrie Transformer Augmentation**														
TUOS		0.000	0.000	0.000	0.000	0.000	1.014	1.001	0.987	0.974	8.126	8.018	7.908	7.800	7.690	7.582
PV of TUOS	$18.37M															
Total for Option 1	**$18.37M**															
Option 2		**Rocklea Transformer Augmentation and Rocklea – Wooloongabba 110kV cable**														
TUOS		0.000	0.000	0.000	0.000	0.000	7.166	7.071	6.975	6.880	7.798	7.690	7.580	7.471	7.362	7.253
PV of TUOS	$30.41M															
Total for Option 2	**$30.41M**															

Appendix E — Forecast of Connection Points

Tables E.1 and E.2 show the ten year forecasts of summer and 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 E.1 and E.2 the zones in which connection points are located are allocated by abbreviation as follows:

- FN Far North Zone
- Ross Ross Zone
- North North Zone
- CW Central West Zone
- Glad Gladstone Zone
- WB Wide Bay Zone
- SW South West Zone
- MN Moreton North Zone
- MS Moreton South Zone
- GC Gold Coast

TABLE E.1: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE SUMMER MAXIMUM DEMAND

Connection Points	Zone	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Abermain 110kV (Lockrose, Wulkaraka BS&QR)	MN	38.77	40.51	41.40	54.64	56.05	57.54	59.00	60.51	61.94	63.38
Abermain 33kV	MS	106.61	112.01	115.54	93.35	98.13	100.91	103.63	106.50	109.13	111.75
Alan Sheriff 132kV	Ross	16.15	16.89	17.68	18.49	19.35	20.24	21.18	22.16	23.18	24.21
Algester 33kV	MS	72.25	78.31	76.92	63.06	77.48	80.09	82.66	85.35	87.85	90.35
Alligator Creek 33kV	North	32.89	33.78	34.68	40.06	40.96	41.85	42.75	43.64	44.53	45.43
Ashgrove West 33kV	MN	72.61	76.91	80.21	83.95	87.65	91.57	104.39	108.84	113.13	117.43
Belmont 110kV (Cleveland, Capalaba North)	MS	138.91	147.72	151.54	159.40	165.81	172.62	179.43	228.55	236.58	244.60
Biloela 66kV	CW	32.98	35.10	35.88	37.33	38.11	38.89	39.68	40.46	41.24	42.02
Blackwater 66kV	CW	97.45	102.57	104.83	107.16	109.56	112.04	114.59	117.22	119.93	122.64
Bundamba 110kV	MS	38.54	40.44	42.00	43.81	43.36	45.15	46.92	48.78	50.55	52.32
Cairns 22kV	FN	78.96	82.33	81.32	84.99	88.62	92.41	96.36	100.49	104.79	109.09
Cairns City 132kV	FN	78.80	82.49	77.51	81.59	85.48	89.57	93.88	98.41	103.18	107.94
Cairns North 132kV	FN	0.00	0.00	13.34	13.34	13.94	14.56	15.21	15.89	16.60	17.31
Cardwell 22kV	Ross	3.97	4.11	4.25	4.40	4.54	4.68	4.82	4.97	5.11	5.25
CBD East 110kV	MS	369.94	384.64	391.46	383.89	469.48	484.47	494.51	506.01	517.09	528.18
CBD West 110kV	MN	179.43	187.36	195.65	227.18	238.25	249.83	253.10	265.12	276.90	288.68
Clare 66kV	Ross	61.69	63.65	65.61	66.61	67.61	68.61	69.61	70.61	71.96	73.31
Collinsville 66kV	North	11.25	11.14	11.02	10.90	10.79	10.67	10.56	10.44	10.32	10.21
Dan Gleeson	Ross	63.96	65.48	67.07	68.73	70.47	72.29	74.20	76.19	78.27	80.36
Dysart 66kV	CW	41.76	41.99	42.23	47.55	47.79	48.03	48.27	48.52	48.76	49.00
Edmonton 22kV	FN	27.23	28.53	29.88	31.30	32.79	34.35	35.98	37.69	39.48	41.27
Egans Hill 66kV	CW	55.60	57.83	60.16	62.58	65.10	67.72	70.44	73.28	76.23	79.17
Garbutt 66kV	Ross	121.48	123.26	125.08	126.96	128.88	130.85	132.88	134.96	137.09	139.23
Gin Gin 132kV (Bundaberg)	WB	109.39	105.73	108.02	110.37	112.77	115.22	117.73	120.29	122.91	125.53
Gladstone 132kV (Boast Creek & Comalco)	Glad	69.13	92.42	94.16	95.07	97.95	98.71	99.47	100.23	100.98	101.74
Gladstone North 132kV	Glad	30.00	30.00	30.00	42.00	54.00	54.00	54.00	54.00	54.00	54.00
Gladstone South 66kV	Glad	52.56	55.69	58.96	62.41	66.05	69.90	73.96	78.25	82.77	87.29
Goodna 33kV	MS	74.30	77.33	84.14	91.23	93.36	95.64	97.81	100.09	102.12	104.16
Ingham 66kV	Ross	17.47	17.87	18.28	18.70	19.13	19.57	20.02	20.48	20.96	21.43
Innisfail 22kV	FN	29.69	30.72	31.78	32.88	34.02	35.20	36.42	37.68	38.99	40.29
Kamerunga 22kV	FN	39.49	41.24	43.00	44.75	46.51	48.26	50.02	51.77	53.53	55.28
Larapinta 33kV	MS	0.00	0.00	0.00	0.00	35.00	36.31	37.66	39.05	40.47	41.88
Lillyvale 132 kV (Barcaldine & Claremont)	CW	29.40	36.87	37.45	38.03	38.61	39.20	39.78	40.37	40.96	41.55
Lillyvale 66kV	CW	130.73	133.65	136.58	139.50	142.42	145.35	148.27	151.20	154.12	157.05
Loganlea 110kV	MS	377.27	408.21	451.92	517.36	521.19	530.64	549.05	568.23	586.49	604.75
Loganlea 33kV	MS	109.06	98.70	76.37	34.41	25.33	35.00	35.68	36.37	36.94	37.50
Mackay 33kV	North	108.68	114.15	119.91	125.98	127.62	134.35	141.44	148.90	156.76	164.62
Middle Ridge 110kV	SW	240.51	249.15	258.60	268.33	277.77	286.74	295.72	304.48	313.25	322.02

TABLE E.1: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE SUMMER MAXIMUM DEMAND CONTINUED

Connection Points	Zone	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Middle Ridge 110kV (Postman's Ridge and Gatton)	MN	37.51	38.60	38.88	39.40	39.76	40.15	40.48	40.81	41.03	41.26
Molendinar 110kV and 33kV	GC	346.17	367.55	468.99	497.41	508.85	539.67	572.90	605.36	637.83	670.30
Moranbah 66kV and 11kV	North	94.13	97.08	100.95	109.46	114.73	120.00	122.85	125.69	128.54	131.39
Moura 66kV	CW	43.22	44.12	45.01	45.91	46.81	47.70	48.60	49.49	50.39	51.28
Mudgeeraba 110kV and 33kV	GC	374.42	400.37	359.82	372.26	413.93	436.33	461.00	487.61	514.28	540.94
Murarrie 110kV (Doboy, Lynton, Lynton QR, Wakerley)	MS	228.32	237.54	246.13	258.74	271.76	282.21	293.74	305.80	319.07	332.34
Nebo 11kV	North	1.87	1.95	2.03	2.11	2.20	2.28	2.36	2.44	2.52	2.61
Newlands 66kV (N)	North	23.58	22.54	22.81	23.10	23.27	23.44	23.61	23.78	23.95	24.12
Palmwoods 132kV and 110kV	MN	315.89	334.95	352.52	365.34	380.39	395.95	411.69	428.15	447.84	467.53
Pioneer Valley	North	10.44	10.81	11.18	11.55	11.92	12.29	12.66	13.03	13.40	13.77
Proserpine 66 kV	North	55.31	58.76	62.06	67.30	69.37	71.46	73.58	75.72	77.88	80.05
Redbank Plains 11kV	MS	16.41	17.39	18.75	19.55	18.89	19.66	20.43	21.24	22.02	22.80
Richlands 33kV	MS	112.31	120.01	113.72	114.32	107.27	111.00	114.66	118.47	122.02	125.57
Richlands West 33kV	MS	0.00	0.00	0.00	0.00	11.00	11.44	11.90	12.37	12.87	13.36
Rockhampton 66kV	CW	126.68	133.57	138.58	143.13	147.78	152.69	157.24	161.79	165.97	170.15
Rocklea 110kV (Archerfield)	MS	93.05	94.36	95.87	111.31	92.49	95.78	99.04	102.47	105.73	108.99
Ross 132 kV (Kidston and Georgetown)	Ross	33.10	34.84	35.55	36.26	36.99	37.74	38.50	39.27	40.06	40.85
Runcorn 33kV	MS	63.10	67.25	69.98	70.53	70.63	73.64	76.71	79.98	83.22	86.47
South Pine 110kV	MN	855.41	907.00	954.58	989.29	1030.06	1072.18	1114.82	1159.38	1212.69	1266.01
Sumner 11kV	MS	22.27	22.97	23.69	19.73	20.30	20.87	21.46	22.05	22.63	23.20
SunWater Pumps (Blue Valley, Havilah and Fig Tree)	North	3.50	3.50	3.50	7.84	7.84	7.84	7.84	7.84	7.84	7.84
Swanbank 110kV (Raceview)	MS	79.94	84.84	88.73	100.10	106.36	110.75	115.12	119.70	124.11	128.52
Tangkam 110kV (Dalby and Oakey)	SW	28.03	29.11	30.15	31.24	32.33	33.42	34.52	35.62	36.72	37.82
Tarong 132kV (Chinchilla and Roma)	SW	75.13	77.45	79.16	81.56	84.01	86.50	89.04	91.63	94.27	96.90
Tarong 66 kV (Wide bay)	SW	36.46	37.65	38.85	40.04	41.24	42.43	43.63	44.82	46.02	47.21
Tennyson 33kV	MS	182.81	192.84	200.88	207.51	183.18	185.37	190.64	196.13	201.20	206.27
Townsville South 66kV	Ross	89.01	92.58	96.00	99.54	103.19	106.96	110.87	114.57	118.41	122.25
Tully 22kV	Ross	13.59	13.88	14.18	14.48	14.78	15.10	15.42	15.75	16.08	16.42
Turkinjie 132kV (Craiglee and Lakeland)	FN	18.14	19.19	20.24	21.29	22.34	23.39	24.44	25.49	26.54	27.59
Turkinjie 66kV	FN	48.38	49.80	50.72	51.64	53.05	53.98	54.91	55.85	56.79	57.74
Waggamba 132kV Bulli Creek)	SW	14.63	15.10	15.57	16.04	16.51	16.98	17.46	17.93	18.40	18.87
Wecker Road 33kV (Belmont)	MS	168.07	180.20	188.77	192.61	151.01	158.50	166.10	132.50	138.88	145.26
West Darra 11kV	MS	0.00	0.00	0.00	16.01	16.18	16.36	16.50	16.64	16.69	16.75
Woolooga 132 kV (Killivan)	WB	140.25	145.02	149.78	154.55	159.32	164.09	168.86	173.63	178.40	183.16

TABLE E.1: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE SUMMER MAXIMUM DEMAND CONTINUED

Connection Points	Zone	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Woolooga 132kV (Gympie)	MN	173.62	184.09	193.74	200.79	209.06	217.61	226.27	235.31	246.13	256.95
Direct Connected Industrial Loads (SunMetals, QLD Nickel, Invicta Load – Ross, and BSL, QAL – Glad, and Swanbank Paper Mill – MN)		1043.81	1064.54	1131.92	1133.33	1134.25	1138.59	1143.38	1148.19	1153.02	1157.86
Transmission Grid Connected Mining Loads (Rolleston – CW, Burton Downs – N, Goonyella North – N, Hail Creek – N)		34.24	34.43	40.61	45.06	45.25	45.44	45.62	45.81	46.00	46.19
Transmission Grid Connected Queensland Rail Substations (Dingo, Grantleigh, Gregory, Norwich Park, Rangal, Rocklands – CW, and Coppabella, Moranbah South, Mt McLaren, Oonooie, Peak Downs, Wandoo – North, and Callemondah – Glad, and Korenan, Mungar – WB, Mindi – North and Corinda – MS)		68.36	70.56	71.48	72.51	73.52	74.53	75.54	76.54	77.53	78.51
TOTAL QLD SUMMER PEAK		**8,230**	**8,615**	**8,990**	**9,315**	**9,624**	**9,937**	**10,255**	**10,585**	**10,926**	**11,267**

TABLE E.2: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE WINTER MAXIMUM DEMAND

Connection Points	Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Abermain 110kV (Lockrose, Wulkaraka BS&QR)	MN	49.67	38.09	39.48	40.76	54.12	55.63	63.73	65.39	67.07	68.76
Abermain 33kV	MS	82.38	72.68	75.96	78.91	60.70	63.86	57.34	58.68	60.05	61.40
Alan Sheriff 132kV	Ross	9.28	9.71	10.16	10.63	11.12	11.63	12.17	12.73	13.32	13.94
Algester 33kV	MS	0.00	63.51	67.32	66.06	56.37	63.49	65.50	67.49	69.52	71.55
Alligator Creek 33kV	North	31.30	31.85	32.39	32.94	38.87	39.42	39.96	40.51	41.05	41.60
Ashgrove West 33kV	MN	69.00	71.68	74.88	78.67	82.74	86.43	90.14	99.57	103.66	107.82
Belmont 110kV (Cleveland)	MS	225.67	140.71	147.95	152.21	161.01	168.02	175.09	182.27	220.30	228.65
Biloela 66kV	CW	34.50	34.87	36.80	37.17	38.32	38.69	39.06	39.44	39.81	40.18
Blackwater 66kV	CW	85.09	92.02	96.76	98.26	99.80	101.38	102.98	104.63	106.30	108.02
Bundamba 110kV	MS	31.51	32.32	33.57	35.19	36.96	36.61	38.12	39.64	41.20	42.78
Cairns 22kV	FN	51.63	54.38	56.77	56.28	58.89	61.48	64.19	67.02	69.97	73.06
Cairns City 132kV	FN	44.16	45.48	46.85	42.97	44.43	45.69	47.00	48.35	49.74	51.17
Cairns North 132kV	FN	0.00	0.00	0.00	8.48	8.48	8.86	9.25	9.66	10.09	10.54
Cardwell 22kV	Ross	2.88	2.91	2.95	2.99	3.02	3.06	3.10	3.13	3.17	3.20
CBD East 110kV	MS	21.58	113.44	115.75	119.61	115.10	199.51	209.24	216.14	223.23	230.35
CBD West 110kV	MN	160.75	107.70	111.28	117.20	134.53	142.01	148.85	149.91	156.92	164.11
Clare 66kV	Ross	43.92	46.36	47.41	48.46	49.35	50.24	51.13	52.02	52.91	54.19
Collinsville 66kV	North	10.27	12.57	12.78	12.99	13.20	13.41	13.62	13.84	14.05	14.26
Dan Gleeson	Ross	55.85	56.97	58.14	59.36	60.64	61.98	63.38	64.84	66.37	67.98
Dysart 66kV	CW	39.39	46.41	46.76	47.11	52.81	53.17	53.53	53.89	54.26	54.63
Edmonton 22kV	FN	15.81	16.56	17.35	18.17	19.04	19.94	20.89	21.88	22.92	24.01
Egans Hill 66kV	CW	43.00	43.71	44.42	45.15	45.89	46.64	47.41	48.18	48.97	49.77
Garbutt 66kV	Ross	90.71	91.75	92.81	93.89	95.00	96.14	97.31	98.51	99.74	101.01
Gin Gin 132kV (Bundaberg)	WB	90.57	93.67	91.46	94.51	97.66	100.92	104.29	107.79	111.40	115.14
Gladstone 132kV (Boast Creek & Comalco)	Glad	79.67	82.85	115.18	117.24	118.54	121.76	122.91	124.06	125.21	126.36
Gladstone North 132kV	Glad	0.00	27.50	27.50	27.50	39.50	51.50	51.50	51.50	51.50	51.50
Gladstone South 66kV	Glad	64.73	48.94	50.76	52.66	54.66	56.76	58.97	61.29	63.73	66.27
Goodna 33kV	MS	0.00	63.96	65.94	72.02	78.21	80.21	82.14	84.04	85.96	87.85
Ingham 66kV	Ross	11.00	11.07	11.15	11.22	11.29	11.36	11.44	11.51	11.59	11.66
Innisfail 22kV	FN	14.09	14.40	14.73	15.06	15.40	15.75	16.11	16.48	16.85	17.23
Kamerunga 22kV	FN	32.85	34.23	35.62	37.01	38.39	39.78	41.16	42.55	43.94	45.32
Larapinta 33kV	MS	0.00	0.00	0.00	0.00	0.00	31.73	32.91	34.11	35.36	36.64
Lillyvale 132 kV (Barcaldine & Claremont)	CW	27.62	28.11	36.00	36.50	37.00	37.50	38.00	38.51	39.01	39.52
Lillyvale 66kV	CW	108.71	129.98	132.61	135.25	137.89	140.52	143.16	145.79	148.43	151.07
Loganlea 110kV	MS	334.24	341.88	365.76	385.84	448.93	448.46	453.28	468.04	482.09	496.20
Loganlea 33kV	MS	91.83	95.72	90.82	72.09	32.53	24.17	33.79	34.47	35.15	35.79
Mackay 33kV	North	69.61	76.39	78.94	81.58	84.31	82.83	85.76	88.80	91.95	95.20

TABLE E.2: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE WINTER MAXIMUM DEMAND CONTINUED

Connection Points	Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Middle Ridge 110kV	SW	231.24	239.85	243.57	248.05	252.77	257.22	261.21	265.20	268.96	272.73
Middle Ridge 110kV (Postman's Ridge and Gatton)	MN	19.47	33.90	34.46	34.96	35.82	36.20	39.81	40.14	40.45	40.73
Molendinar 110kV and 33kV	GC	279.39	297.57	312.95	397.19	423.56	434.19	457.80	485.70	512.24	539.81
Moranbah 66kV and 11kV	North	90.33	98.19	101.31	105.23	113.20	118.33	123.47	126.50	129.54	132.58
Moura 66kV	CW	29.73	41.96	42.33	42.71	43.08	43.46	43.83	44.20	44.58	44.95
Mudgeeraba 110kV and 33kV	GC	341.63	360.11	380.17	356.89	370.69	409.54	430.01	452.98	477.93	503.86
Murarrie 110kV (Doboy, Lynton, Lynton QR, Wakerley)	MS	217.48	289.50	296.50	307.81	326.58	345.31	356.56	367.20	379.01	398.03
Nebo 11kV	North	1.66	1.72	1.77	1.82	1.88	1.93	1.99	2.04	2.10	2.15
Newlands 66kV (N)	North	26.43	26.67	25.27	25.51	25.76	25.94	26.13	26.32	26.51	26.69
Palmwoods 132kV and 110kV	MN	292.12	305.72	320.97	335.85	350.08	365.85	380.64	395.78	411.26	427.13
Pioneer Valley	North	5.45	5.32	5.18	5.05	4.91	4.78	4.64	4.51	4.38	4.24
Proserpine 66 kV	North	40.52	42.71	44.65	47.06	51.45	52.57	53.70	54.84	56.00	57.16
Redbank Plains 11kV	MS	16.06	17.10	17.93	19.52	20.50	19.85	20.67	21.49	22.34	23.19
Richlands 33kV	MS	103.37	83.42	85.93	79.25	81.08	75.74	78.33	80.90	83.54	86.17
Richlands West 33kV	MS	0.00	0.00	0.00	0.00	0.00	8.29	8.62	8.96	9.32	9.69
Rockhampton 66kV	CW	88.19	91.41	95.75	98.39	100.62	102.93	105.50	107.73	109.95	111.85
Rocklea 110kV (Archerfield)	MS	56.51	58.01	58.46	59.87	69.58	57.98	60.06	62.15	64.31	66.49
Ross 132 kV (Kidston and Georgetown)	Ross	26.01	27.82	29.64	30.37	31.12	31.87	32.64	33.42	34.21	35.02
Runcorn 33kV	MS	119.69	61.00	64.65	67.98	69.52	68.99	71.95	74.99	78.20	81.53
South Pine 110kV	MN	791.03	827.86	869.15	909.43	947.98	990.69	1030.73	1071.73	1113.65	1156.61
Sumner 11kV	MS	0.00	16.01	16.38	17.01	13.57	13.97	14.37	14.78	15.19	15.61
SunWater Pumps (Blue Valley, Havilah and Fig Tree)	North	0.00	3.50	3.50	3.50	7.84	7.84	7.84	7.84	7.84	7.84
Swanbank 110kV (Raceview)	MS	93.79	63.91	66.99	70.62	69.37	74.67	77.76	80.89	84.13	87.41
Tangkam 110kV (Dalby and Oakey)	SW	24.07	24.88	25.49	26.06	26.67	27.29	27.90	28.51	29.13	29.74
Tarong 132kV (Chinchilla and Roma)	SW	63.57	64.11	64.64	64.03	64.57	65.12	65.67	66.23	66.79	67.35
Tarong 66 kV (Wide Bay)	SW	39.61	40.70	41.80	42.89	43.98	45.08	46.17	47.26	48.36	49.45
Tennyson 33kV	MS	162.45	165.12	171.97	182.07	188.51	164.22	166.49	171.44	176.49	181.52
Townsville South 66kV	Ross	28.25	30.85	32.13	33.34	34.58	35.87	37.20	38.58	39.85	41.18
Tully 22kV	Ross	1.24	1.28	1.31	1.35	1.38	1.42	1.46	1.50	1.54	1.58
Turkinjie 132kV (Craiglee and Lakeland)	FN	15.35	16.23	17.12	18.00	18.88	19.77	20.65	21.53	22.42	23.30
Turkinjie 66kV	FN	42.32	43.06	44.08	44.78	45.49	46.51	47.22	47.93	48.65	49.37

TABLE E.2: FORECASTS OF CONNECTION POINT DEMANDS (MW) COINCIDENT WITH STATE WINTER MAXIMUM DEMAND CONTINUED

Connection Points	Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Waggamba 132kV (Bulli Creek)	SW	16.43	16.91	17.38	17.86	18.33	18.81	19.29	19.76	20.24	20.71
Wecker Road 33kV (Belmont)	MS	132.52	141.74	150.22	158.94	162.84	126.56	133.00	139.64	119.40	125.53
West Darra 11kV	MS	0.00	0.00	0.00	0.00	13.48	13.66	13.82	13.94	14.05	14.13
Woolooga 132 kV (Killivan)	WB	137.14	140.00	145.19	150.41	155.65	160.92	166.20	171.51	176.85	182.20
Woolooga 132kV (Gympie)	MN	160.55	168.02	176.41	184.58	192.40	201.07	209.20	217.52	226.03	234.75
Direct Connected Industrial Loads (SunMetals, QLD Nickel, Invicta Load – Ross, and BSL, QAL – Glad, and Swanbank Paper Mill – MN)		1036.33	1048.21	1051.29	1128.38	1129.69	1132.78	1137.19	1142.05	1146.92	1151.82
Transmission Grid Connected Mining Loads (Rolleston – CW, Burton Downs – N, Goonyella North – N, Hail Creek – N)		29.33	29.57	29.67	35.41	38.78	38.88	38.98	39.08	39.18	39.29
Transmission Grid Connected Queensland Rail Substations (Dingo, Grantleigh, Gregory, Norwich Park, Rangal, Rocklands – CW, and Coppabella, Moranbah South, Mt McLaren, Oonooie, Peak Downs, Wandoo – North, and Callemondah – Glad, and Korenan, Mungar – WB, Mindi – North and Corinda – MS)		70.89	71.96	72.76	73.63	74.58	75.49	76.40	77.30	78.21	79.11
TOTAL QLD WINTER PEAK		**6,953**	**7,270**	**7,544**	**7,868**	**8,155**	**8,432**	**8,683**	**8,941**	**9,206**	**9,481**

Appendix F — Temperature and Diversity Corrected Area Demands

For analysis of the dependence of summer and winter daily maximum demands on ambient temperature conditions across parts of Queensland, eight weather station records are used, as shown in Table F.1.

TABLE F.1: REFERENCE TEMPERATURES AT ASSOCIATED POE CONDITIONS

	Average Daily Temperature Percentiles (°C) (1)					
Weather Station	Summer			Winter		
	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE
Cairns (2)	32.1	30.4	29.1	25.9	24.8	23.7
Townsville (2)	32.0	30.4	29.8	25.7	24.2	23.2
Mackay	30.9	29.3	28.3	11.3	12.4	13.5
Rockhampton	32.6	30.7	29.3	10.2	11.6	12.9
Bundaberg	30.2	28.8	27.7	10.5	11.7	13.0
Toowoomba	29.0	27.0	25.3	4.7	6.0	7.0
Archerfield (Brisbane)	30.5	28.4	27.3	9.6	10.9	12.3
Cooloongatta	29.0	27.1	24.5	9.3	10.6	12.2

Notes:

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

(2) In these areas winter demand increases with higher ambient temperature.

Graphs of daily maximum demands plotted against daily average temperatures on working week days, are used to determine observed estimates of sensitivity for parts of Queensland.

As shown in Table F.2, sensitivity of demand to ambient temperature is highest in summer across Queensland. Rapidly increasing summer sensitivity, at levels greater than in proportion to growth, is evident in all areas with the most dramatic change occurring in South East Queensland.

TABLE F.2: OBSERVED TEMPERATURE SENSITIVITY OF DAILY PEAK DEMANDS

	Demand Change Dependence on Average Daily Temperature (MW per °C) (1)			
	South East	South West	Northern Non-Industrial	Central Non-Industrial
Summer				
1997/98	40	4.8	22	10.3
1998/99	43	4.6	18	10.9
1999/00	50	4.8	23	11.5
2000/01	63	7.0	24	16.2
2001/02	67	5.0	28	14.3
2002/03	79	7.1	32	18.2
2003/04	125	8.6	37	17.8
2004/05	118	9.0	35	19.0
2005/06	170	11.0	40	24.1
Winter				
1998	- 41	- 6.4	4.2	–
1999	- 37	- 6.1	6.0	–
2000	- 50	- 6.9	(2)	(3)
2001	- 39	- 6.3	6.9	–
2002	- 41	- 6.3	8.8	–
2003	- 47	- 6.7	7.0	–
2004	- 44	- 7.4	3.8	–
2005	- 42	- 6.6	6.8	–

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, a 25% weighting of that day's average temperature is included, to capture higher remnant heat in buildings. Similarly, in winter, if the previous day is colder during a cold period, a 25% weighting of that day's average temperature is included.

(2) Poor correlation of data in this winter.

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

In order to determine temperature corrected demands for each of the four geographic areas designated in Table F.3, correction techniques are applied to certain days. Only days which are both within the fifteen highest demands of a season, and within the fifteen most severe weather observations (hottest in summer, coolest in winter), are corrected to avoid distortions. The observed sensitivities, as shown in Table F.2, and difference to the reference 50% PoE temperature, are used to provide a correction to each of these day's demands. The highest corrected demands may not always correspond to the day of actual highest demand. These results are shown in Tables F.3 and F.4.

Major industrial loads are not corrected to weather conditions but any variability to their loading level at time of state peak demand is recognised as shown in Table F3.

TABLE F.3: AREA SUMMER DEMAND TEMPERATURE CORRECTIONS

	South East (1)	South West (2)	Northern Non-Industrial (3)	Central Non-Industrial (4)	Major Industrial (5)
Actual Peak Demands					
1997/98	2,596	244	842	686	893
1998/99	2,762	254	845	662	900
1999/00	2,946	268	887	704	1,017
2000/01	2,977	282	911	744	1,037
2001/02	3,120	284	1,044	801	1,062
2002/03	3,383	303	980	769	1,085
2003/04	3,847	340	1,079	831	1,108
2004/05	4,024	358	1,089	883	1,110
2005/06	4,149	401	1,140	925	1,141
Temperature Corrected Area Peak Demand					
1997/98	2,593	247	860	686	–
1998/99	2,703	265	868	684	–
1999/00	2,774	267	938	720	–
2000/01	2,998	303	946	779	–
2001/02	3,194	298	991	801	N/A(6)
2002/03	3,378	314	1,005	806	–
2003/04	3,699	333	1,060	833	–
2004/05	4,073	360	1,083	908	–
2005/06	4,251	406	1,137	968	–
Historical average ratio of demand at time of Qld region peak to area corrected peak	100%	93.7%	93.7%	92.6%	95.7%

Notes:

(1 South East Queensland is taken here as Moreton North, Moreton South and Gold Coast compared to Archerfield (Brisbane) temperatures.

(2) South West Queensland is taken as the South West zone and is compared to Toowoomba temperatures.

(3) Northern Non-Industrial is taken as Far North, Ross and North zones less the SunMetals and Queensland Nickel industrial loads, and is compared to Townsville temperatures.

(4) 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.

(5) Industrial is taken here as the sum of SunMetals, Queensland Nickel, Boyne Island smelter and QAL direct connected industrial loads.

(6) These major industrial loads are not significantly sensitive to temperature.

TABLE F.4: AREA WINTER 50% POE DEMAND TEMPERATURE CORRECTIONS AND COINCIDENCE RATIOS WITH STATE PEAK DEMAND

	South East	South West	Northern Non-Industrial	Central Non-Industrial	Major Industrial
Actual Peak Demands					
1998	2,625	283	733	623	895
1999	2,777	297	731	665	921
2000	2,992	318	776	709	1,021
2001	2,975	313	781	735	1,052
2002	2,994	307	796	710	1,060
2003	3,325	322	806	739	1,068
2004	3,504	350	813	797	1,099
2005	3,731	368	840	792	1,130
Temperature Corrected Area Peak Demand					
1998	2,703	294	732		
1999	2,779	302	725		
2000	2,966	320	776		
2001	3,027	329	783	N/A	N/A
2002	3,067	325	816		
2003	3,327	329	815		
2004	3,501	365	821		
2005	3,711	372	848		
Historical average ratio of demand at time of Qld region peak to area corrected peak	98.8%	91.6%	88.9%	95.2%	96.5%

The historical coincidence factor averages developed for each of these areas and for the major industrial loads, are used to enable overall correction of Queensland Region summer and winter demands, as shown in Tables F.3, F.4 and F.5

TABLE F.5: QUEENSLAND REGION ACTUAL AND 50% POE TEMPERATURE AND DIVERSITY CORRECTED PEAK DEMANDS

Summer	Actual	Corrected	Winter	Actual	Corrected
1997/98	5,183	**5,122**	1998	5,035	**5,093**
1998/99	5,330	**5,262**	1999	5,242	**5,232**
1999/00	5,620	**5,544**	2000	5,609	**5,601**
2000/01	5,830	**5,883**	2001	5,731	**5,737**
2001/02	6,183	**6,165**	2002	5,671	**5,803**
2002/03	6,336	**6,400**	2003	6,066	**6,089**
2003/04	7,020	**6,835**	2004	6,366	**6,399**
2004/05	7,282	**7,329**	2005	6,551	**6,644**
2005/06	7,388	**7,687**	–	–	**–**

Appendix G — Review of Summer 2005/06 Peak Demand

As shown in Table 4.4, Queensland's summer tends to vary considerably making it very difficult to establish what is typical. Last summer, 2005/06 was certainly no exception.

The actual peak demand in Queensland for summer 2005/06 was 7388MW. However, the temperature and diversity corrected 50% PoE demand substantially higher at 7687MW. Summer 2005/06 had some unique attributes that contributed to the actual demand being 299MW below its corresponding temperature and diversity corrected value. These attributes are discussed in the sections below.

The methodology used to temperature and diversity correct demands is discussed in Appendix F. NEMMCO recently commissioned KEMA to review demand forecasting methodologies across the NEM, including temperature and diversity correction methodologies. The outcome of this review indicated that methodologies being used were consistent with good industry practice.

Brisbane's Weather

While 2005/06 was the hottest summer in Brisbane based on the average of daily maximum and minimum temperatures, there were no very high temperature conditions on working weekdays and therefore no exceptionally high demands.

When the record high average temperature of 26.20°C for summer 2005/06 is looked at more closely it is made up of an average of 25.48°C on working weekdays and 27.27°C on other days. This record was brought about without any 'heat waves' or extremely hot days. Instead it was caused by consistently high (but not extreme) daily maximum and sustained high minimum temperatures overnight. Of the seven days that exceeded the 50% PoE temperature of 28.4°C, only one occurred on a working weekday and this was isolated in early summer.

Comparing temperature data for summer 2005/06 (Table G.1) with summer 2003/04 (Table G.2) there are some clear differences. Firstly 2003/04 had seventeen days greater than the 50% PoE temperature (28.4°C) compared with seven days in 2005/06. Of these days 2003/04 had eleven on working weekdays, while 2005/06 had only one. Summer 2003/04 had five days with an average temperature greater than 30°C, while 2005/06 had none. Summer 2003/04 had a ten day heat wave in February which included eight days of greater than 50% PoE temperatures and finishing with two days with a maximum temperature of around 41°C. Summer 2005/06 had no more than two consecutive days with greater than 50% POE temperatures and these were in the holiday period.

Thus while summer 2005/06 had a record high average temperature it did not have any extreme weather conditions necessary to drive very high demands. In fact, when considering the lack of heat waves, lack of very high maximum temperatures and the fact that only one working weekday exceeded the 50% PoE temperature 28.4°C, summer 2005/06 was particularly mild with respect to the drivers for high demands.

TABLE G.1: SUMMER 2005/06 — WHERE TEMPERATURE EXCEEDED 50% POE

	Temperature ºC			
Date	Maximum	Minimum	Average	Type of Day
29 – Dec – 05	36.60	23.40	30.00	Holiday Period
30 – Dec – 05	33.70	24.50	29.10	Holiday Period
4 – Feb – 06	35.20	22.70	28.95	Weekend
27 – Dec – 05	32.70	24.80	28.75	Public Holiday
8 – Dec – 05	32.50	24.90	28.70	Working Weekday
3 – Jan – 06	34.80	22.50	28.65	Holiday Period
25 – Dec – 05	34.00	22.90	28.45	Holiday Period

TABLE G.2: SUMMER 2003/04 — WHERE TEMPERATURE EXCEEDED 50% POE

	Temperature ºC			
Date	Maximum	Minimum	Average	Type of Day
22 – Feb – 04	41.30	27.10	34.20	Weekend
21 – Feb – 04	41.00	25.60	33.30	Weekend
8 – Jan – 04	39.10	26.80	32.95	Working Weekday
16 – Feb – 04	35.80	25.40	30.60	Working Weekday
20 – Feb – 04	34.50	26.60	30.55	Working Weekday
26 – Dec – 03	35.80	24.20	30.00	Public Holiday
7 – Jan – 04	35.80	24.00	29.90	Working Weekday
15 – Feb – 04	34.90	24.80	29.85	Weekend
13 – Feb – 04	34.40	25.20	29.80	Working Weekday
17 – Jan – 04	33.10	26.00	29.55	Weekend
19 – Feb – 04	35.60	23.10	29.35	Working Weekday
12 – Feb – 04	34.00	23.50	28.75	Working Weekday
28 – Jan – 04	34.60	22.80	28.70	Working Weekday
6 – Jan – 04	33.50	23.70	28.60	Working Weekday
9 – Mar – 04	33.10	24.10	28.60	Working Weekday
14 – Feb – 04	32.80	24.30	28.55	Weekend
23 – Feb – 04	33.40	23.70	28.55	Working Weekday

Latent Demand Due to Air Conditioning

Recent surveys have shown that record numbers of air conditioners have been installed in South East Queensland. However, as extreme temperatures were not experienced on working weekdays during summer 2005/06 their effect has not yet been seen. The next time Queensland gets summer weather conditions conducive to high demands their effect will be felt.

The big forecast increase for South East Queensland flagged in the 2005 APR was based on the unmistakeable realisation that the initially thought two year air-conditioning boom immediately after the hot summer 2001/02, was in fact now greater in magnitude and would be sustained much longer. The hot weather experienced in February 2004 contributed strongly to this.

Analysis has shown significant demand/temperature sensitivity increases for both weekdays and weekends during summer 2005/06. When looking at the massive growth in both weekend/non-holiday demand and average of all working weekday demands (corrected) it becomes clear that the recent summer peak demand did not reveal the true underlying picture.

The air conditioning surveys show that there is another one to two years remaining in the air-conditioning boom before reaching South East Queensland saturation and falling back to just a high level of new home installations and some upgrades.

Greater than Normal Diversity

Due to its large size, Queensland normally experiences significant diversity in demand as a result of diversity in temperature. However, the diversity seen across Queensland last summer was much greater than experienced in previous summers. The reason being when the south of the state experienced hot weather on working weekdays the north of the state was experiencing mild weather and vice versa. This led to the actual peak demand being significantly below what would occur for historically typical weather patterns.

Appendix F describes how the state demand is broken into five components for the purpose of temperature correcting demands. Based on the same five components, Table G3 below shows the extent of diversity across the state over recent summers. It shows that Queensland's diversity was substantially greater during summer 2005/06 (93.5%) than has been previously observed. If the average diversity of 97.3% had been observed instead, then the actual peak demand would have been 299MW higher.

TABLE G.3: QUEENSLAND DIVERSITIES (1)

Year	South East	South West	North Non-Industrial	Central Non-Industrial	Industrial	Diversity
97/98	99.85%	97.02%	96.32%	93.29%	99.08%	**98.2%**
98/99	102.12%	91.09%	92.93%	93.00%	98.11%	**98.4%**
99/00	105.20%	99.29%	87.69%	88.49%	95.66%	**98.6%**
00/01	99.32%	89.02%	95.27%	85.27%	98.12%	**96.3%**
01/02	96.71%	86.52%	104.66%	95.52%	97.18%	**97.5%**
02/03	100.15%	94.69%	93.35%	88.60%	92.37%	**96.3%**
03/04	103.92%	101.88%	88.04%	98.18%	97.78%	**99.9%**
04/05	98.83%	97.03%	93.88%	97.25%	90.90%	**96.7%**
05/06	94.93%	86.54%	91.57%	93.91%	92.36%	**93.5%**
Average	100.12%	93.68%	93.75%	92.61%	95.73%	**97.3%**

Note:

(1) Diversities greater than 100% imply that the actual area demand at the time of state peak demand exceeded the temperature and diversity corrected area peak.

Table G4 shows Queensland peak summer 2005/06 demand broken in its five components as forecast in the 2005 APR and as actually occurred at state peak, own peak and corrected peak. The data indicates that in corrected terms the demand in South East Queensland was 14MW above forecast, without considering the 20MW demand that did not connect to Energex's network in time but will be in for next summer. Compared to last years forecast the demands in the South West increased by 11MW, in the North by increased by 34MW, central Queensland reduced by 9MW and the industrials reduced by 61MW.

This data shows that in total, the non-industrial loads at own peaks have exceeded last year's forecast. This outcome supports the survey results showing larger than expected increases in air conditioning installations.

TABLE G.4: QUEENSLAND 2005/06 DIVERSITIES

Year	Forecast in 2005 Annual Planning Report		Actual		
	At State Peak	At Own Peak	At State Peak	Raw Peak	Corrected Peak
South East Queensland	4,237	4,237	4,033	4,149	4,251
South West Queensland	373	394	351	401	406
North Queensland less Industrials	1,037	1,103	1,041	1,140	1,137
Central Queensland less Industrials	903	977	909	925	968
Industrials	1,156	1,201	1,054	1,141	N/A

Appendix H — Abbreviations

AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
CB	Circuit Breaker
CBD	Central Business District
CCGT	Combined Cycle Gas Turbine
CQ	Central Queensland
DNSP	Distribution Network Service Provider
DSM	Demand Side Management
GSP	Gross State Product
GT	Gas Turbine
GWh	Gigawatt hour, one million kilowatt hours
Infoserver	A comprehensive database of market information maintained by NEMMCO and made available to Registered Participants. Data includes regional demands and prices, interconnector limits, binding constraint and billing and settlements data.
IRPC	Inter Regional Planning Committee
JPB	Jurisdictional Planning Body
kA	kiloamperes, one thousand amperes
kV	kilovolts, one thousand volts
MCE	Ministerial Council on Energy
MNSP	Market Network Service Provider
MVAr	Megavar, megavolt amperes reactive, one thousand kilovolt amperes reactive
MW	Megawatt, one thousand kilowatts
NER	National Electricity Rules
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEMDE	National Electricity Market Dispatch Engine
NIEIR	National Institute of Economic and Industrial Research
PV	Present Value
NQ	North Queensland
OCGT	Open Cycle Gas Turbine
PoE	Probability of Exceedance
PSS	Power System Stabiliser
QNI	Queensland – New South Wales Interconnection
SCADA	Supervisory Control and Data Acquisition
SEQ	South East Queensland
SOO	Statement of Opportunities, published annually by NEMMCO
SQ	South Queensland
SVC	Static VAr Compensator
SWQ	South West Queensland
TNSP	Transmission Network Service Provider

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