ANNUAL PLANNING REPORT 2005

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EXECUTIVE SUMMARY

This Annual Planning Report 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, estimates of grid capability and potential network developments.

Electricity usage in Queensland has grown strongly during the past ten years, and this trend is expected to continue. The summer maximum demand has grown significantly over the past five years with a statewide growth of 31%, including a record growth of 29% in the south east Queensland over the last three years.

Summer maximum demand (weather corrected) delivered from the transmission grid is forecast to increase at an average annual rate of 4% p.a. from 7424MW in 2004/05 to 10959MW in 2014/15. However, this ten year average masks the accelerated summer demand increase forecast for the near future. This accelerated demand growth is attributable to the expected continuing rapid increase in penetration and usage of domestic air conditioners and strong population growth, which have been evidenced in recent years, particularly in south east Queensland. Here the forecast summer weather corrected demand for the three year period up to 2007/08 will have an average growth rate of almost 6% per annum.

Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.2% p.a. over the next ten years for the medium growth scenario. Similarly, an average energy growth of 4.2% p.a. is expected in south east Queensland.

In 2004, the 10 year energy forecast showed an average annual increase of 3.1% per annum. A noticeable feature of the 2005 forecast of 3.2% p.a. energy growth is that the majority of the additional forecast increase is expected to occur in the early years of the 10 year outlook period. This is mainly due to an upward revision in population growth rate projections, the impact of domestic air-conditioning loadings, some new small industrial loads and expected increased coal mining production.

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

The most significant projects completed since the 2004 Annual Planning Report include the Millmerran to Middle Ridge 330kV transmission line, which has augmented transmission capacity into the Darling Downs area, and the Broadsound to Lilyvale 275kV transmission line, which has augmented transmission to the Central Queensland mining area. In addition, network support contracts were renegotiated with power stations in north Queensland to allow ongoing management of network limitations.

Following consultation with participants and interested parties, Powerlink is constructing a 275kV transmission line between Greenbank and Maudsland to augment the transmission capacity to the Gold Coast area, and is constructing a 275kV transmission line between Belmont and Murarrie to augment transmission capacity to the Trade Coast area and Brisbane CBD.

Work has also commenced on three new bulk supply substations at Goodna, Algester and Sumner in the south west part of Brisbane. Construction of a Static VAr Compensator (SVC) at Woree in Cairns is well advanced. Smaller augmentations such as the installation of capacitor banks and transformer upgrades are also underway to satisfy network reliability standards.

Market development of new generating capacity in the Queensland region is continuing with the conversion and upgrade of the Townsville power station to gas operation now completed, and the 750MW coal fired power station at Kogan Creek (near Chinchilla) now committed. A 450MW gas fired power station has also recently been announced for Braemar (near Dalby).

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 load in Queensland and the interconnected states of NSW, Victoria, and South Australia.

Since the 2004 Annual Planning Report, the southward maximum transfer capacity of the Queensland-New South Wales Interconnection (QNI) has been increased from 950 MW to 1078MW. This new limit remains conditional on availability of online stability monitoring equipment. Powerlink is working closely with its NSW counterpart TransGrid, to design and implement controller tunings at various SVC's to allow this new damping limit to be released unconditionally.

Powerlink and TransGrid are carrying out investigations to identify market benefits associated with possible augmentations of QNI. The first studies were undertaken in 2004, and concluded that no major upgrade option was justified, applying the previous AER regulatory test to evaluate options. As a result of revisions to the regulatory test in late 2004 the studies are being reviewed. These current studies will also take account of generation developments which have been committed since the earlier studies. The results of the new studies will be available in the first quarter of 2005/06.

Within Queensland, Powerlink's transmission grid reached transfer limits at most grid sections for less than 1% of the time during the six months from October 2004 to March 2005, the period of highest loads. Some of the transmission grid in north Queensland reached transfer limits for 2 to 3% of the time. The CQ-NQ limit would have been reached for much longer durations, but this was managed by the network support arrangement between Powerlink and north Queensland generators.

Powerlink's expectation is that other grid sections, such as that between Tarong and Brisbane, and the grid supplying the Gold Coast, will continue to be heavily loaded relative to their capacity after considering committed generation and transmission developments, and network support arrangements. The Tarong limit experienced negligible binding over the 2004/05 summer due to the recently commissioned south Queensland power stations and recently completed reliability augmentation works near Brisbane and on the Gold Coast.

Not surprisingly, the predominant driver for augmentations to network capability will continue to be the need to maintain reliability standards. Reliability has long been the predominant driver for grid augmentation in Queensland.

Two Application Notices have recently been issued. These have recommended network support for North Queensland, and additional 275/110kV transformation capacity in the Ipswich area. Powerlink has also issued papers to inform market participants and interested parties about several emerging limitations, and to seek possible solutions. Powerlink expects to initiate consultation processes for a number of other limitations within the next twelve months so that corrective action can be implemented in a timely manner. This report identifies twenty-six different emerging needs in the Queensland transmission network over the next five years.

This Annual Planning Report also contains details of four proposed new small network augmentations. These augmentations comprise the installation of shunt capacitor banks at Molendinar and Greenbank in south east Queensland, a shunt capacitor bank at Gladstone South in central Queensland, a shunt capacitor bank at Townsville South in North Queensland and a second 275/110kV transformer at Molendinar. Powerlink invites submissions on these proposed new small network augmentations by 28 July 2005.

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2. INTRODUCTION

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2.1 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 Code (NEC) 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. From 1 July 2005, the NEC will be replaced by the National Electricity Rules (NER). All further references in this document will be to the NER.

This 2005 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.

2.2 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) and the Annual National Transmission Statement (ANTS) each year. ANTS is part of national transmission planning arrangements that were introduced by the Ministerial Council on Energy (MCE) in 2003, in conjunction with industry participants.

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

- projections of demand and energy requirements for each Region of the NEM;
- capabilities of existing and committed generating units;
- planned plant retirements;
- network capabilities and constraints, and information on potential solutions; and
- operational and economic information about the market.

Powerlink recommends that interested parties review its 2005 APR in conjunction with NEMMCO's 2005 SOO/ANTS. The SOO and ANTS are expected to be published by 31 October 2005.

2.3 Purpose of the Annual Planning Report

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

It aims to provide information that assists interested parties to:

- identify locations that would benefit from significant electricity supply capacity or demand side management (DSM) initiatives;
- identify locations where major industrial loads could be connected;
- understand how the electricity supply system impacts on their needs;
- consider the transmission network's capability to transfer quantities of bulk electrical energy; and
- provide input into the future development of the transmission 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.

2.4 Role of Powerlink Queensland

As the owner and operator of the electricity transmission network in the state of Queensland, Powerlink Queensland is registered with NEMMCO as a TNSP under the NER. In this role, and in the context of this APR, Powerlink's transmission network planning and development responsibilities include the following:

1. Ensure that its network is operated with sufficient capacity, and augmented if necessary, to provide network services to customers.

2. Ensure that its network complies with technical and reliability standards contained in the NER and jurisdictional obligations.

3. Conduct annual planning reviews with Transmission Network Service Providers (TNSP) and Distribution Network Service Providers (DNSP) whose networks are connected to Powerlink's transmission grid (ie. TransGrid, Energex, Ergon Energy and Country Energy).

4. Advise Registered Participants and interested parties of emerging network limitations within the time required for corrective action.

5. Develop 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. Options may be proposed by providers other than Powerlink, such as local generation, demand side management initiatives and alternatives involving other networks.

6. Undertake the role of proponent of regulated transmission augmentations in Queensland.

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

Powerlink has also been nominated by the Queensland Government as the entity having transmission network planning responsibility in the state, with respect to Clause 5.6.3(b) of the NER also known as the JPB. 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 impact;
- participating in inter-regional system tests associated with new or augmented interconnections; and
- participating in the technical evaluation of proposals for network developments which have a material inter-network impact.

The role of the IRPC is described in Clause 5.6 of the NER.

2.5 Overview of Planning Responsibilities

Planning the development of the Queensland regulated transmission grid comprises a number of different categories:

- the connection of a new participant, or alteration of an existing connection;
- the shared network within Queensland; and
- new interconnectors or augmentation to existing interconnectors between Powerlink's network and networks owned by other TNSPs.

2.5.1 Planning of Connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and DNSPs. Planning of new or augmentation of existing connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements.

2.5.2 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; and
- 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 based on 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 impacted 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 emerging 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 emerging 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 consider environmental impacts 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 load growth, generation and network capability to determine the time when corrective action is required – for example, when the technical standards can no longer be met in supplying the forecast load;
- consultation on assumptions made and potential solutions, which may include transmission or distribution network augmentation, local generation or demand side management;
- where a network development has a material inter-network impact, either the agreement of the entities responsible for those impacted 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's 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; and
- consultation and publication of a recommended course of action to address the identified network limitation.

2.5.3 Planning 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 capacity where justified. Any plans to establish or augment interconnectors will be outlined in Powerlink's APR. 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. In summary, the inter-jurisdictional planning process involves the following main steps:

- NEMMCO publishes the annual SOO which provides information on load and generation forecasts and committed network developments with an inter-regional impact;
- NEMMCO, with assistance from the jurisdictional planning bodies, prepares the ANTS. This document was published for the first time in 2004 and replaced the previous Annual Interconnector Review;
- ANTS 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; and
- The ANTS is expected to be published by NEMMCO by 31 October 2005.

3. SUMMARY OF RELEVANT MAJOR NATIONAL TRANSMISSION FLOW PATH DEVELOPMENTS

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3.1 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 impact on 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 impact on major transmission flow paths within the Queensland region.

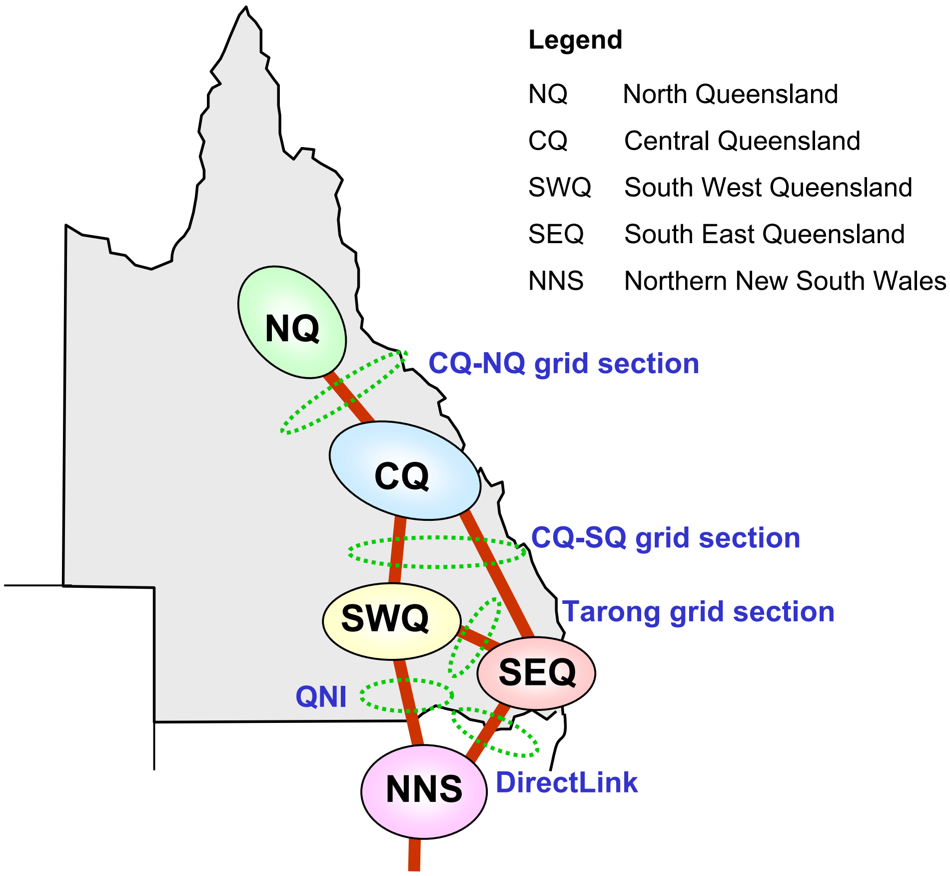
3.2 Major National Transmission Paths

The criteria for defining major national transmission flow paths, and proposed flow paths for the 2005 ANTS, were recently the subject of a consultation process by NEMMCO.

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 6.3.

The major transmission flow paths for the Queensland region are shown within Figure 3.1.

Figure 3.1: Queensland Major Transmission Flow Paths



3.3 Summary of Potential Augmentations

Potential augmentations which may increase the transfer capability of major flow paths for the Queensland region are summarised within Table 3.1. 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.

3.4 Status of Augmentations

NEMMCO are proposing to define three categories to classify the status of flow path augmentations within the ANTS 2005. These categories indicate the level of certainty of a particular augmentation. Powerlink has indicated the status of potential augmentations according to these categories. The categories are summarised as follows:

- Committed augmentation: Project approved following completion of NER approval processes for regulated network augmentations.
- Routine augmentation: Projects which are undertaken to maintain network capability, 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.

It should be noted that projects shown as conceptual augmentations must be considered preliminary and uncertain. These projects have not necessarily undergone rigorous technical or economic evaluation, and are included as indicative augmentations only.

Table 3.1: Potential Augmentations in the Queensland Region

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	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 capacity plus local generation may be insufficient to meet future load.	Reliability requirement	Option 1: Construction of 275kV transmission line between Broadsound and Ross (single side strung only), and installation of capacitive compensation.	Increases maximum CQ-NQ transfer from current levels to around 1250MW.	Conceptual
			Option 2: Construction of 275kV transmission line between Broadsound and Ross (both sides strung), stringing of third circuit between Stanwell and Broadsound, and installation of capacitive compensation.	Increases maximum CQ-NQ transfer from current levels to around 1600MW.	Conceptual
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.	Preserves the CQ-SQ transfer limit.	Routine
	Constraints on transfer capacity 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	Option 1: Construction of switching station on the Tarong-Calvale lines at Auburn River.	Increases maximum CQ-SQ transfer limit from 1900MW to around 2050MW.	Conceptual
			Option 2: Establishment of Auburn River substation and installation of series capacitors.	Increases maximum CQ-SQ transfer limit from 1900MW to around 2150MW.	Conceptual
			Option 3: Construction of new 275kV transmission lines from central to south Queensland.	Increases maximum CQ-SQ transfer limit to around 2800MW.	Conceptual
			Option 4: Construction of 500kV double circuit transmission line from central Queensland to south Queensland.	Increases maximum CQ-SQ transfer limit to around 3500MW.	Conceptual

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	Flow Path Improvement	Status
SWQ-SEQ	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
	Insufficient network capability plus local generation to meet forecast SEQ load (assuming no additional local generation).	Reliability requirement	Option 1: Construction of new transmission line from Middle Ridge to Greenbank and installation of second Middle Ridge 330/275kV transformer.	Expected to increase the Tarong limit by approximately 450MW from current levels.	Conceptual
			Option 2: Construction of new 500kV double circuit transmission line from south west Queensland to south east Queensland.	Expected to increase the Tarong limit by up to 1000MW from current levels.	Conceptual
SEQ-NNS	Insufficient network capability plus local generation to meet forecast Gold Coast load may restrict the southerly capability of DirectLink.	Reliability requirement	Option 1: Involves entering into network support arrangements with DirectLink for the 2005/06 summer, and establishment of new Greenbank 275kV substation, construction of new 275kV double circuit from Greenbank to Maudsland, and installation of capacitive compensation by the 2006/07 summer.	This committed project addresses reliability requirements for supply to the Gold Coast. It is expected to increase the Gold Coast limit by around 100MW from current levels, which will provide greater opportunities for southward flow on DirectLink.	Committed
			Option 2: Installation of second Molendinar 275/110kV transformer, and reconfiguration of the existing Greenbank to Molendinar 275kV circuits.	This project addresses localised Gold Coast reliability requirements. Likely to further increase the Gold Coast voltage stability limit, which will provide greater opportunities for southward flow on DirectLink.	Conceptual[1]

[1] This project is uncommitted, but is currently undergoing consultation through this document as a proposed new small network asset.

Flow Path	Limit Description	Augmentation Basis	Potential Augmentation	Flow Path Improvement	Status
NNS-SWQ	Northward transfer between northern NSW and south west Queensland across QNI may be constrained by limitations across the SWQ intra-regional grid section. This limitation is not expected to emerge prior to new generation entering the SW zone.	Market benefit and potentially reliability requirement	Option 1: Construction of a new double circuit transmission line from Braemar to Tarong, and installation of third Braemar 330/275kV transformer.	Expected to increase the SWQ limit by around 900MW+. Hence this option may reduce the likelihood of NNS-SWQ constraints.	Conceptual
			Option 2: Construction of new transmission line from Middle Ridge to Greenbank and upgrading of the transformers. This has common elements to the potential reliability augmentation listed for the SWQ-SEQ flow path.	Expected to increase the SWQ limit by around 600-800MW. Hence this option may reduce the likelihood of NNS-SWQ constraints.	Conceptual
NNS-SWQ and **SWQ-NNS**	Transfers across QNI can be constrained by thermal, voltage, transient and oscillatory stability limitations.	Market benefit	Option 1: Works to alleviate thermal limitations within the northern NSW 132kV network	This option helps preserve the current southerly transfer capability. TransGrid are presently investigating this option.	Conceptual
			Option 2: Works as per Option 1 plus the installation of series compensation devices, Static VAr Compensators, and power system control equipment.	Expected to increase limits associated with voltage, transient and oscillatory stability by a nominal 150MW in both directions. Note that transfers may still be constrained by thermal and intra-regional limitations.	Conceptual
			Option 3: Works as per Option 2 plus an upgrade of part of the northern NSW 330kV network.	Expected to increase transfer capability by a nominal 150-200MW in both directions.	Conceptual
			Option 4: An additional Queensland to NSW HVAC interconnection.	Increase in transfer capability between the two regions by a nominal 800-1000MW.	Conceptual
			Option 5: A new separate Queensland to NSW HVDC interconnection.	Increase in transfer capability between the two regions by a nominal 2000MW.	Conceptual

4. INTRA-REGIONAL ENERGY AND DEMAND PROJECTIONS

CONTENTS

4.1 Background to Load Forecasts

4.1.1 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 2004 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 4.10 in Section 4.5, using diversity factors observed from historical trends up to the end of April 2005.

Energy forecasts for each connection supply point were obtained from the DNSP's 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 also engaged by Powerlink to provide an independent assessment of energy and demand forecasts for the Queensland region and for the former DNSP[1] areas within Queensland, in December 2004. 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 2005, 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 2005 Statement of Opportunities (SOO).

4.1.2 Basis of Load Forecasts

Economic Activity:

Three forecast scenarios of economic activity in all NEM states were updated by NIEIR and provided to NEMMCO in April 2005. 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 2014/15 are:

	High	Medium	Low
Australian Gross Domestic Product (average growth p.a.)	3.8%	2.9%	2.0%
Queensland Gross State Product (average growth p.a.)	4.8%	3.8%	2.8%

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

For Queensland, these growth rates are slightly higher for all growth scenarios, compared to the NIEIR prediction outlined in the Powerlink 2004 Annual Planning Report (APR). Consistent with this NIEIR outlook, the revised energy growth rates in Queensland in this 2005 APR are slightly higher over the long term than in the previous forecast. However, peak demand forecast growth rates have been increased substantially (refer to Section 4.4).

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; and

(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 2005 forecasts by NIEIR for embedded co-generation and renewable energy source generation projects, are at similar levels to those published in the 2004 APR. This has confirmed previous reductions in forecast levels from earlier forecasts and reflects the unfavourable economic position of the sugar industry and uncertainty in potential new gas pipeline projects.

Table 4.1 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 4.1 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 4.1 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 4.1 and within the “delivered from grid” forecasts in this APR.

The Pioneer Sugar Mill generation upgrade project, located at Ayr, south of Townsville, is forecast to significantly reduce the energy supplied from Clare substation in the Ross zone from 2005/06 onwards.

Table 4.1: 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
2005/06	2,358	254	2,612
2006/07	2,564	438	3,002
2007/08	2,564	441	3,005
2008/09	2,564	480	3,044
2009/10	2,585	483	3,068
2010/11	2,585	483	3,068
2011/12	2,585	483	3,068
2012/13	2,722	516	3,240
2013/14	2,722	518	3,242
2014/15	2,753	518	3,271

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 DirectLink Market Network Service Provider (MNSP) 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 to meet the load demand.

New Queensland Loads

This APR includes forecast load for Ergon's Waggamba 132/66kV (Goondiwindi) substation from winter 2005 onwards. This is now supplied from a recently commissioned Bulli Creek to Waggamba 132kV line which will provide the normal supply to the Goondiwindi area. The former normal 66kV supply network from NSW will be retained for stand-by supply purposes.

New Large Loads – Committed

Since the 2004 APR, supply to the aluminium extrusion plant at Bundamba (north of Swanbank) and the Rolleston coal mine (south west of Blackwater) have been commissioned.

The forecasts in this Chapter also include increased loading at the committed 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. It also includes relatively minor load increases at existing aluminium and zinc smelter plants, slightly above levels previously forecast, and an allowance for a new industrial load within the Swanbank Enterprise Park.

New Large Loads – Uncommitted

Since the 2004 APR, development work on a large chemical products plant at Yarwun (west of Gladstone) has been curtailed and a proposed new aluminium smelter at Aldoga (south west of Gladstone) remains uncommitted. However, these potential loads were also not included in the previous forecasts.

There have been several other announced 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 developments include:

- possible major expansions of an existing aluminium smelter (Gladstone) and an existing zinc smelter plant (Townsville);
- a new zinc smelter plant at Yarwun (west of Gladstone);
- port facility upgrades at Dalrymple Bay (south of Mackay) and Abbot Point (Bowen) of unknown load size; and
- industrial loads in the Swanbank area (including proposed paper mill and steel mill).

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

Zone	Type of Plant	Possible Load
Ross	Zinc	0-120 MW
North	Port facilities and increased railway loadings	0-80MW
Gladstone	Aluminium & zinc	0-1100 MW
Moreton South	Paper mill, steel mill and other industries	0-200 MW

Whilst the load forecast does not include the above uncommitted large loads, some consideration to the impacts of these potential developments is given in Chapter 6.

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.

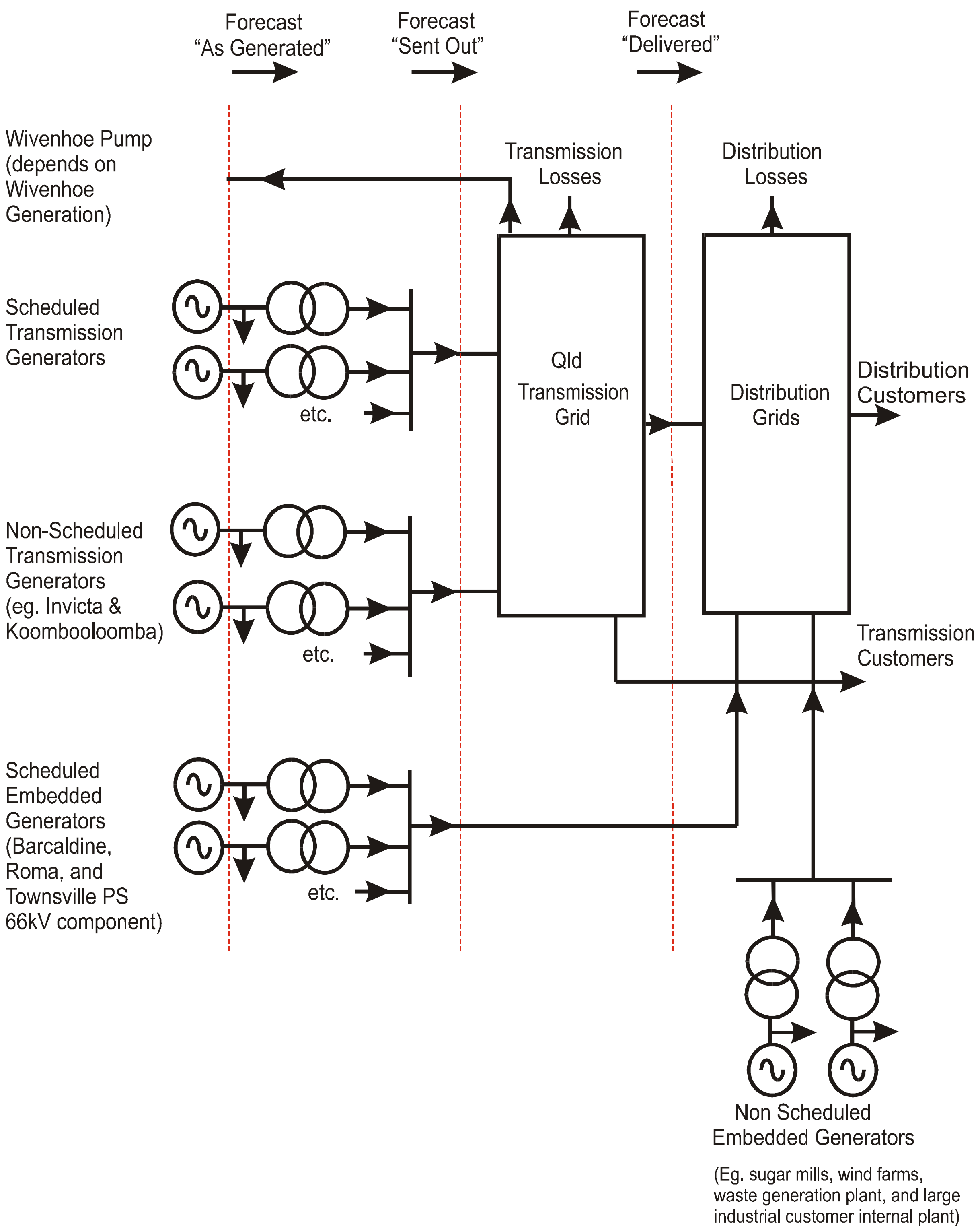
Reconciliation between the NIEIR forecast and the more detailed forecasts provided by DNSPs and customers were undertaken for the medium growth scenario and average weather conditions.

Overall, the customer and NIEIR demand and energy forecasts closely agreed over the ten-year period. However, it was noted that NIEIR would expect higher growth rates in the second half of the next ten year period should a major new gas pipeline supply come to Queensland, creating a flow on economic growth impetus.

4.1.3 Load Forecast Definitions

The relationship between the classes of generation and the forecast quantities in this Report is shown in Figure 4.1.

Figure 4.1: Load Forecast Definitions



4.2 Recent Energy and Demands – Weather Correction

4.2.1 Recent Summers

A summary of recent summer prevailing weather conditions, seasonal energy delivered and electricity demands is shown in Table 4.2.

The 2004/05 Queensland summer was close to average in terms of number of very hot days and average summer temperature, in contrast to the extremely hot and humid 2003/04 summer. Nevertheless, very strong growth in summer demand occurred, with the actual recorded maximum delivered demand increasing by 3.7% to 7368MW. At the time of this peak, industrial loading was unusually low and the Brisbane (Archerfield) temperature on the day was below the 50% PoE reference base. Application of temperature and industrial load correction, as outlined in Appendix F, shows corrected summer demand growing from 6955MW in 2003/04 to 7424MW in 2004/05, a substantial real growth of 6.7%. This followed corrected demand growth of 7.4% from the mild summer of 2002/03 to the hot/humid summer of 2003/04.

The growth in actual delivered summer energy in 2004/05 was much lower at 2.3%, after correction for the extra leap year day in 2003/04. This much lower growth rate than for demand is directly due to the return to average summer conditions compared to the prolonged very hot 2003/04 conditions, which accordingly yielded a strong 6.4% energy growth over 2002/03.

The significantly greater growth in summer demand than for energy continues a trend that has been evident over the last few years. It can be attributed, along with the very large increase in temperature sensitivity of demand over recent years (refer Appendix F), to the impact of massive air-conditioning growth in Queensland.

According to NIEIR, a new sales record for domestic air-conditioning in Queensland was again recorded during 2004 following the extremely hot 2003/04 summer. Approximately 20% growth in new installations occurred, in a similar pattern to the 20% annual growth that occurred following the hot 2001/02 summer. During the early 1990's, typical annual growth levels of domestic air-conditioning were below 7% per annum. However, the hot 1997/98 summer sparked four years at higher growth rates of about 10% per annum, with the last three years seeing annual growth rates of 20%, 13% and 20%.

The growth in air-conditioning installations is most prevalent in south east Queensland, where government surveys indicate the penetration rate has increased from around 35% to close to 50% over the last three or four years.

An increase in population migration to Queensland has also contributed to demand growth in recent years.

Table 4.2: Comparison of Recent Queensland Summer (1) Delivered Load

Summer (1)	Energy GWh	Maximum Demand MW	Prevailing Queensland Weather Conditions	Brisbane Temperature (2)		
				Summer Average °C	Peak Demand Day °C	No days >28.4°C
1997/98	8,746	5,234	Very hot	26.12	29.00	10
1998/99	8,796	5,386	Average	24.68	29.75	8
1999/00	9,285	5,685	Mild	22.62	31.95	2
2000/01	9,678	5,891	Average, dry	24.39	28.90	4
2001/02	10,434	6,259	Sustained hot and dry Extreme central to north	25.58	26.95	10
2002/03	10,530	6,402	Mild, late wet season in north	24.41	28.95	2
2003/04	11,330	7,103	Extremely hot and humid	26.01	30.60	17 (3)
2004/05	11,458	7,368	Average	25.09	28.10	4

Notes:

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

(2) In this report, Brisbane temperature is now 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 February 2004 to 23 February 2004.

4.2.2 Recent Winters

A summary of recent winter electricity demands, seasonal energy delivered and prevailing weather conditions, is shown in Table 4.3.

The winter of 2004 was relatively mild overall and unusually did not contain a particularly cold snap. The actual recorded maximum delivered demand increased by 4.9% to 6450MW. Application of temperature and industrial load correction, as outlined in Appendix F, marginally corrects upwards both the 2003 and 2004 peak demands, so that the corrected growth is 5.0% (from 6185MW to 6496MW).

The growth in actual delivered winter energy in 2004 was 3.9%, but as 2004 was even milder than 2003 the true growth is probably a little higher. The impact 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 4.3: Comparison of Recent Queensland Winter Delivered Load

Winter (1)	Energy GWh	Max Demand MW	Prevailing Queensland Weather Conditions	Brisbane Temperature (2)		
				Winter Average °C	Peak Demand Day °C	No days <10.9°C
1998	8,633	5,042	Mild to warm	16.45	11.85	0
1999	9,116	5,309	Mild	15.32	15.50	0
2000	9,668	5,691	Cooler than average	14.32	8.80	2
2001	9,912	5,811	Mild	14.99	10.10	3
2002	10,177	5,743	Average	14.57	12.85	1
2003	10,392	6,149	Mild but one 8 day cold snap	14.96	10.95	4
2004	10,794	6,450	Mild	15.40	11.80	0

Note:

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

(2) In this report, Brisbane temperature is now 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 to 3 days per winter on average.

4.2.3 Seasonal Growth Patterns

The hot summers of 1997/98, 2001/02 and 2003/04 resulted in large increases in summer delivered energy. The relatively cooler than average winters of 1997 and 2000 also resulted in higher delivered energy. These effects can be seen in Figure 4.2 by comparison to the trend-line of summer and winter energy delivered to DNSPs over the last seven years. Figure 4.2 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.

4.2.4 Temperature 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 2004/05 also produced an unusual pattern of coincident demands whereby for the first time the state maximum demand coincided with the time of peak demand in the Wide Bay zone.

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; and
- 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 4.3. The methodology is further outlined in Appendix F. Powerlink will continue to conduct further research with independent bodies as to the appropriateness of also correcting demands against a temperature – humidity composite factor, as no statistically acceptable method for Queensland has been found to date.

Figure 4.2: Recent Summer & Winter Energy Delivered to DNSPs in Qld (excluding energy to the major direct industrial customers)

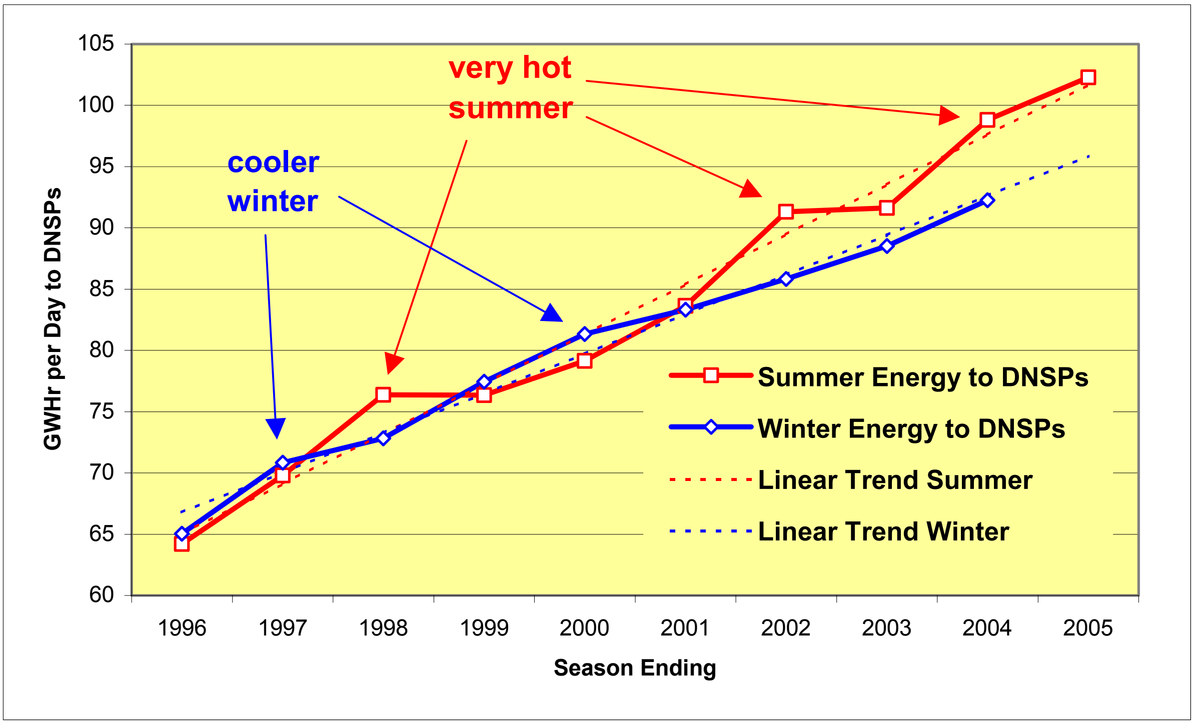
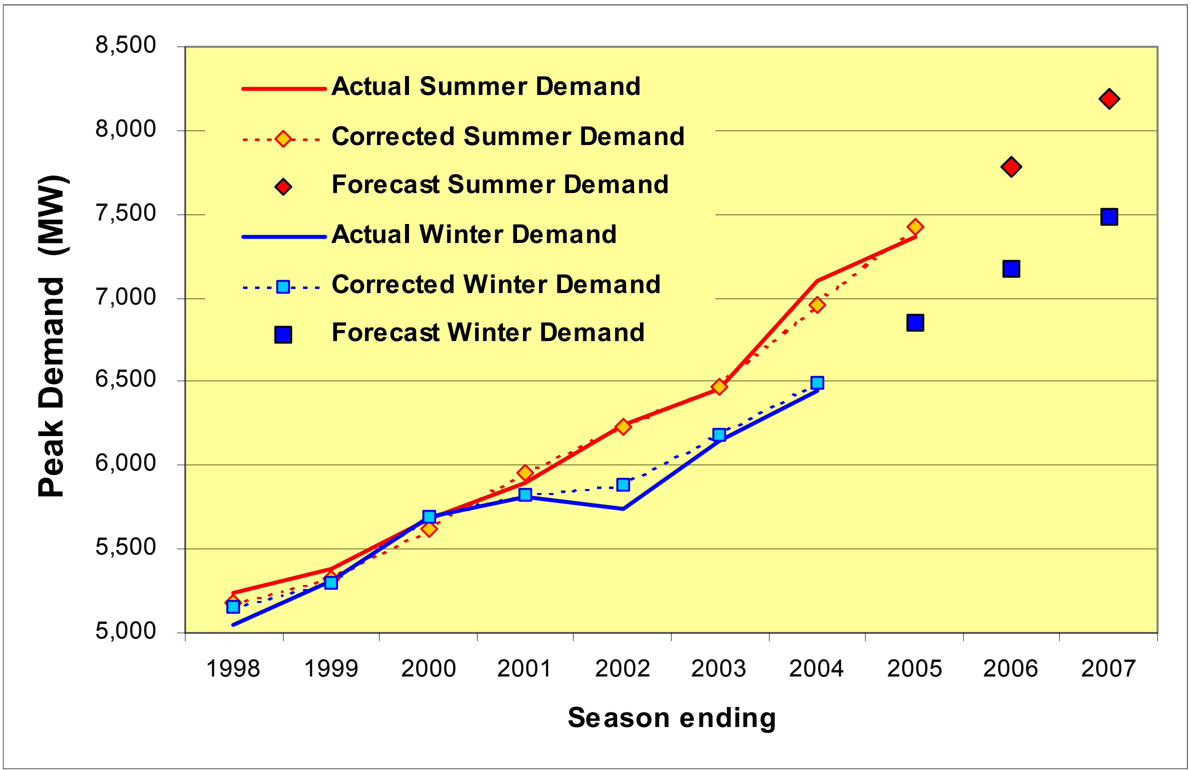


Figure 4.3: Recent Summer and Winter Actual and Temperature Corrected Demands MW Compared to Initial Values of New Forecast



4.3 Comparison with the 2004 Annual Planning Report

In comparison with the 2004 forecast, the forecast in this APR shows a large increase in both summer and winter demand growth rates. The new forecasts revise the recent three year burst of demand growth into an expectation of a further four years of strong growth, particularly in south east Queensland. By contrast, there is only 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:

- a substantial increase in air-conditioning installation during 2004 yielded very strong growth in winter 2004 and summer 2004/05 temperature corrected demands, and accordingly has increased the starting values for the next ten year forecasts;
- 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 last two years to levels last seen in the early 1990's (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 are higher than in recent years;

- 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;
- expected small increases in output at some existing major industrial loads (Gladstone and Townsville);
- a new coal handling port facility at Gladstone in 2006 and a new industrial load within Swanbank Enterprise Park in 2007;
- increased forecast loadings at an aluminium refinery at Yarwun (west of Gladstone);
- increased forecast loadings at several coal mines in central Queensland;
- little change in expected levels of embedded non-scheduled generation forecasts; and
- 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.

4.4 Forecast Data

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

- Figure 4.1 shows the relationship between the classes of generation and the definitions of forecast quantities used in this Report;
- Table 4.1 shows the NIEIR forecast of cogeneration and other embedded generation (both renewable and non-renewable energy source);
- Tables 4.2 and 4.3 show recent summer and winter demands, seasonal energy delivered and prevailing weather conditions for comparison purposes;
- Figure 4.2 shows recent growth in energy by seasons to illustrate the impact of the three very hot recent summers (1997/98, 2001/02 and 2003/04) but generally mild winters. Only 1997 and 2000 were slightly cooler than average winters;
- Figure 4.3 shows recent summer and winter demands and estimated temperature corrections to show consistency with initial values of the new forecast demands;
- Table 4.4 shows average growth rates of Queensland Gross State Product (GSP), energy, summer and winter peak demands for the next ten years;
- Table 4.5 and Figures 4.4 and 4.5 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;
- Table 4.6 and Figure 4.6 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;
- Table 4.7 and Figure 4.7 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;

- Table 4.8 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;
- Figure 4.8 shows the daily load profile on the days of the recent 2004 winter and 2004/05 summer Queensland region peak demand delivered from the transmission grid and from embedded scheduled generators;
- Table 4.9 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;
- Figure 4.9 shows the cumulative load duration curve for the 2002/03 and 2003/04 financial years; and
- The forecast loading at Powerlink Queensland 275kV substations at the time of the coincident Queensland region maximum demand, under a range of possible generation dispatch patterns and up to summer 2007/08 are shown in Table A2 of Appendix A. These loadings can be higher at the time of local area maximum demand, and can also vary under different generation dispatch patterns.

It should also be noted that the forecasts have been derived from information and historical revenue metering data up to and including April 2005, and are based on assumptions and third party predictions which may or may not prove to be correct. The 'projected actual' forecast for 2004/05 accounts for actual energy delivery in the first ten months of the financial year, ie. up to end of April 2005 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 4.4. However, these averages mask an accelerated summer demand growth (weather corrected) over the next four years up to 2008/09, which averages 5.3% p.a. in south east Queensland and 4.9% p.a. for the whole Queensland region under a medium growth scenario.

Table 4.4: Average Annual Growth Rate Over Next Ten Years

	Economic Growth Scenario		
	High	Medium	Low
Queensland Gross State Product	4.8%	3.8%	2.8%
Energy Delivered (1)	4.9%	3.2%	1.7%
Summer Peak Demand (50% PoE) (2)	6.0%	4.0%	2.3%
Winter Peak Demand (50% PoE) (2)	5.8%	3.8%	2.1%

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 were to be no increase in embedded non-scheduled generation above current levels the average forecast growth rate in energy delivered would be 3.3% p.a. under the medium growth scenario.

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

Table 4.5: Annual Energy – Actual and Forecast

Year	Sent Out (1)			Transmission Losses (2)			Delivered		
94/95	29,240			1,427			27,813		
95/96	30,255			1,497			28,758		
96/97	31,375			1,506			29,869		
97/98	35,675			1,662			34,013		
98/99	36,555			1,556			34,999		
99/00	38,439			1,486			36,953		
00/01	40,203			1,642			38,561		
01/02	42,291			1,994			40,297		
02/03	43,120			1,855			41,264		
03/04	45,035			1,943			43,092		
04/05 (3)	46,445			1,995			44,450		
Forecast	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
05/06	47,259	48,487	50,151	2,008	2,085	2,191	45,251	46,402	47,961
06/07	48,780	50,715	53,148	2,125	2,250	2,410	46,655	48,465	50,738
07/08	49,923	52,866	55,911	2,219	2,414	2,620	47,704	50,452	53,290
08/09	50,679	54,588	58,655	2,285	2,548	2,831	48,393	52,039	55,824
09/10	51,381	56,130	61,677	2,346	2,671	3,066	49,034	53,459	58,611
10/11	52,001	57,529	64,139	2,401	2,785	3,265	49,599	54,745	60,874
11/12	52,906	59,176	67,170	2,479	2,920	3,515	50,427	56,256	63,655
12/13	53,815	60,944	70,191	2,558	3,069	3,773	51,257	57,875	66,418
13/14	54,598	62,614	73,294	2,629	3,212	4,043	51,970	59,402	69,250
14/15	55,392	64,281	76,499	2,701	3,358	4,329	52,691	60,924	72,170

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. Since 2001/02, increasing net average southerly power flow on QNI has increased transmission losses on this part of the network. Transmission losses can be reduced through network augmentation, as occurred in 1998/99 and 1999/2000 due to the commissioning of the major Calvale-Tarong and Tarong-Blackwall 275kV transmission lines. However, loss levels are also highly dependent on generation dispatch patterns that can create power flow changes in different parts of the state. For example, in 2001/02, higher summer central to northern Queensland power flows and losses occurred due to low hydro dispatch in far north Queensland. In 2002/03, loss levels decreased due to the substantial new generation in southern Queensland reducing the power flows from central to southern Queensland. Over the last two years transmission losses have been partially contained in relative terms due to increased generation in northern Queensland preventing an escalation in central to northern Queensland power flow levels. Future generation dispatch pattern changes may both increase and decrease loss levels by creating power flow changes not related to normal growth-related escalation. This table assumes that the level of future transmission works, will only provide a partial check against the normal growth related power flow increases and associated loss levels.

(3) These projected end of financial year values are based on revenue metering data up to April 2005 and statistical metering for May 2005. April to early June 2005 has been abnormally mild weather conditions and the projected levels have been reduced accordingly.

Figure 4.4: History and Forecasts of Annual Energy Delivered for Medium Economic Growth Scenario

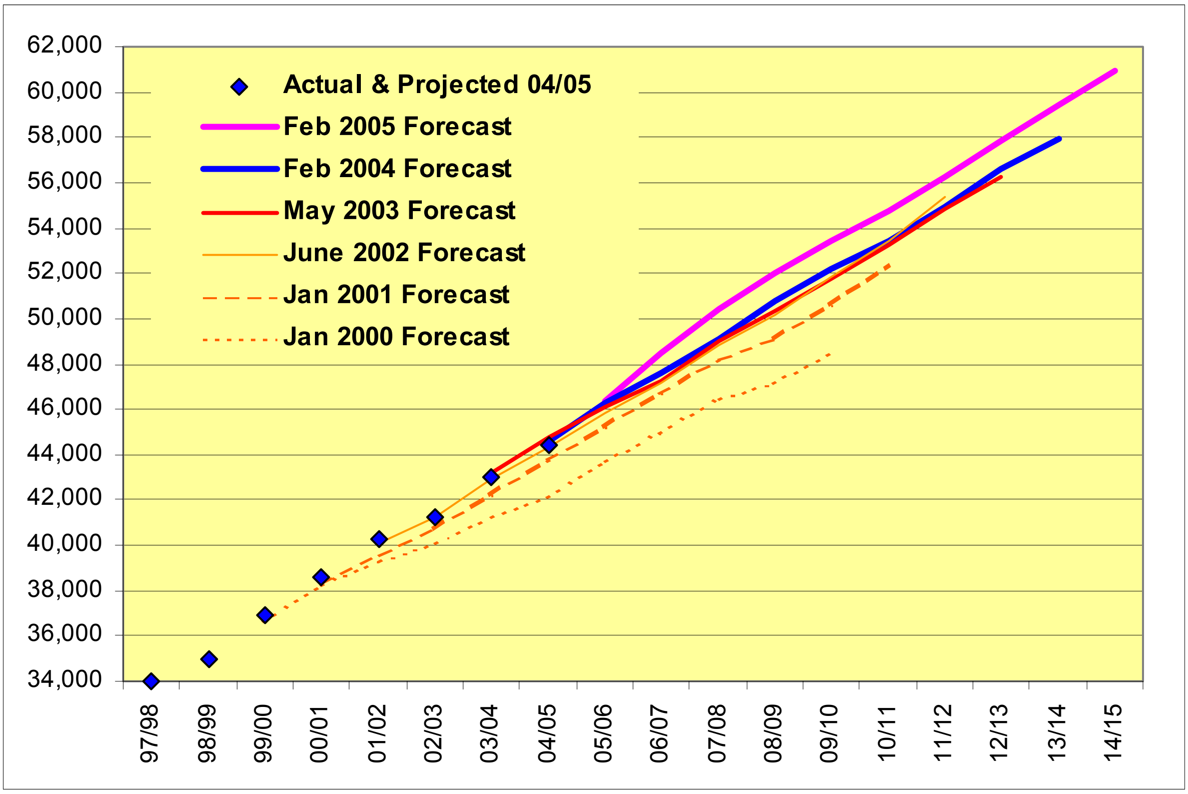


Figure 4.5: History and Forecast of Energy Delivered for Low, Medium and High Economic Growth Scenarios

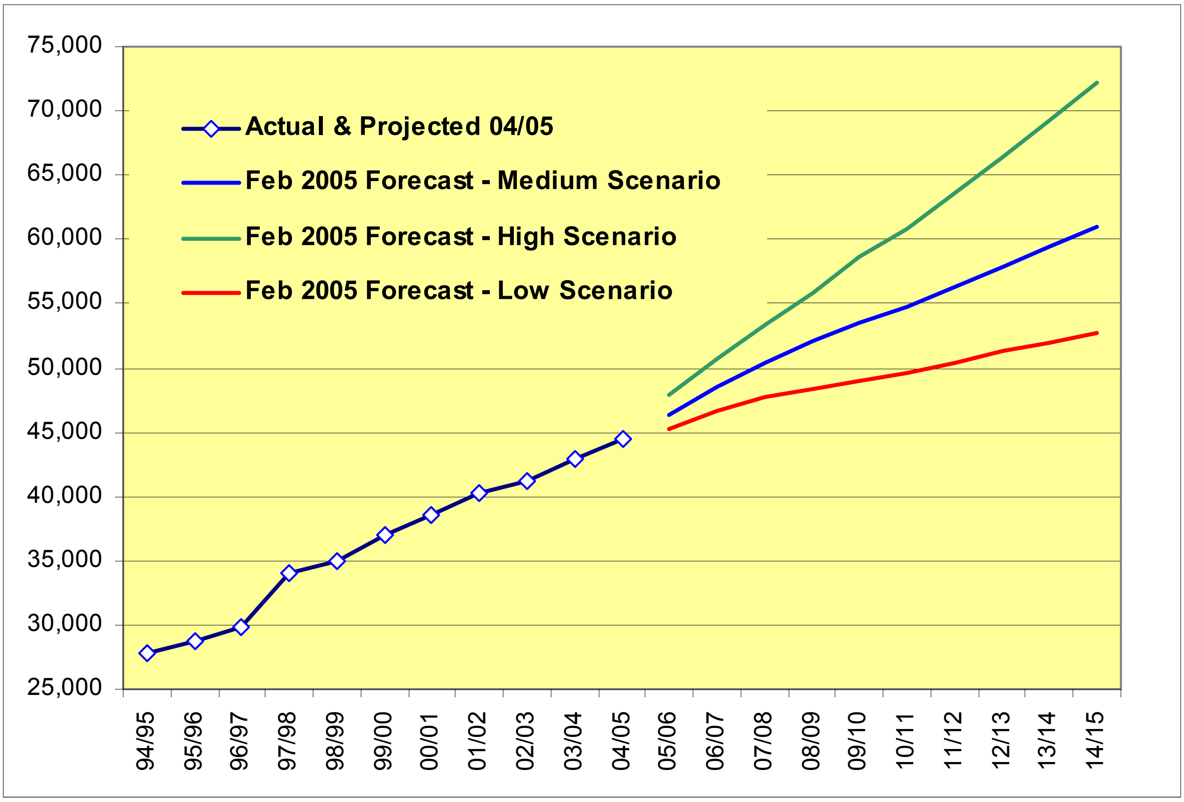


Table 4.6: Peak Summer Demand

Summer	Actual	50%PoE Temperature Corrected Peak Demand
97/98	5,234	**5,180**
98/99	5,386	**5,325**
99/00	5,685	**5,618**
00/01	5,891	**5,952**
01/02	6,246	**6,236**
02/03	6,462	**6,475**
03/04	7,103	**6,955**
04/05	7,368	**7,424**

Summer Forecasts	High Growth Scenario			Medium Growth Scenario			Low Growth Scenario		
	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE
05/06	8,408	8,100	7,919	8,084	**7,789**	7,614	7,847	7,560	7,391
06/07	8,971	8,643	8,449	8,499	**8,188**	8,005	8,123	7,826	7,652
07/08	9,526	9,180	8,977	8,935	**8,612**	8,421	8,382	8,079	7,900
08/09	10,110	9,743	9,527	9,318	**8,981**	8,782	8,570	8,260	8,078
09/10	10,761	10,370	10,140	9,674	**9,323**	9,118	8,755	8,439	8,254
10/11	11,321	10,910	10,668	10,018	**9,656**	9,443	8,940	8,617	8,428
11/12	11,923	11,490	11,235	10,349	**9,974**	9,754	9,124	8,795	8,602
12/13	12,506	12,052	11,785	10,690	**10,303**	10,077	9,298	8,963	8,767
13/14	13,139	12,661	12,381	11,041	**10,641**	10,407	9,472	9,131	8,931
14/15	13,769	13,267	12,974	11,371	**10,959**	10,718	9,630	9,283	9,080

Figure 4.6: Queensland Region Summer Peak Demand

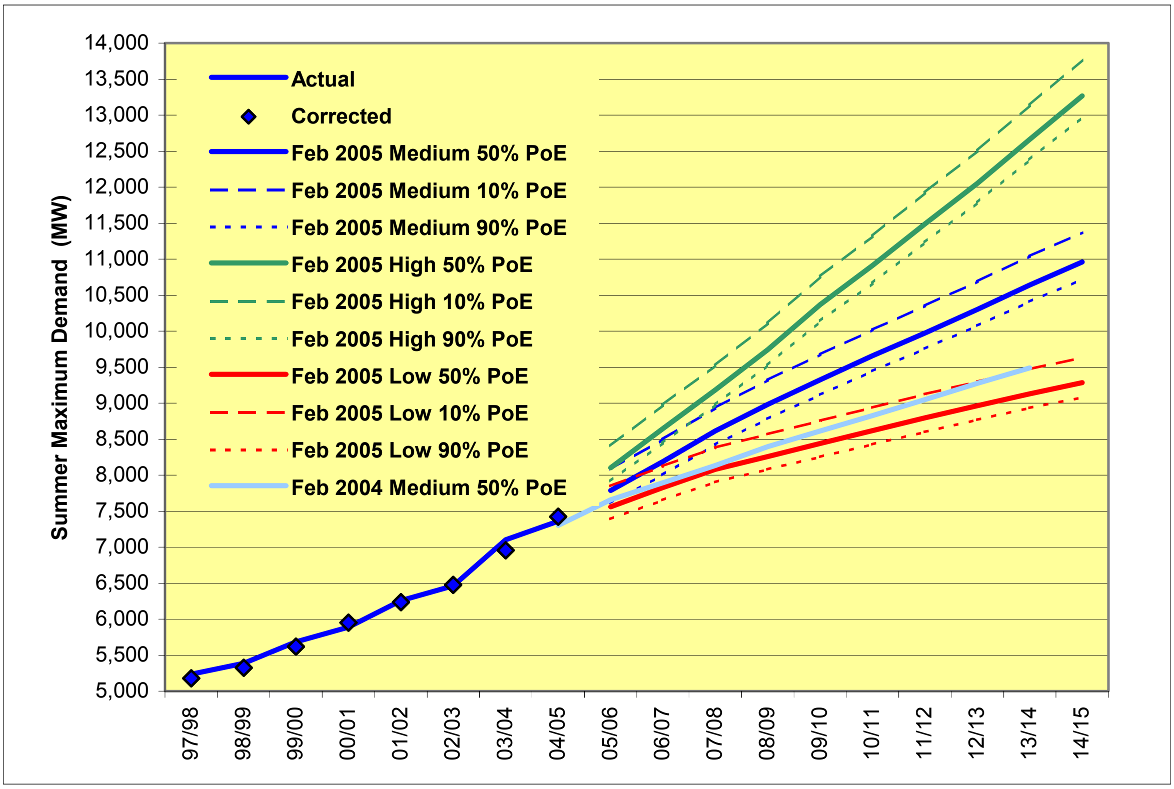


Table 4.7: Peak Winter Demand

Winter	Actual	50%PoE Temperature Corrected Peak Demand
1998	5,042	**5,158**
1999	5,309	**5,310**
2000	5,691	**5,696**
2001	5,811	**5,829**
2002	5,743	**5,888**
2003	6,149	**6,185**
2004	6450	**6,496**

Winter Forecasts	High Growth Scenario			Medium Growth Scenario			Low Growth Scenario		
	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE	10%PoE	50%PoE	90%PoE
2005	7,138	7,006	6,874	6,983	**6,857**	6,730	6,863	6,740	6,618
2006	7,598	7,459	7,320	7,310	**7,178**	7,047	7,065	6,939	6,813
2007	8,025	7,879	7,734	7,621	**7,485**	7,348	7,210	7,082	6,955
2008	8,543	8,390	8,237	7,958	**7,818**	7,678	7,372	7,244	7,115
2009	9,060	8,899	8,737	8,209	**8,065**	7,921	7,473	7,343	7,214
2010	9,510	9,341	9,173	8,465	**8,317**	8,169	7,587	7,456	7,325
2011	10,021	9,844	9,667	8,728	**8,576**	8,424	7,719	7,586	7,453
2012	10,514	10,328	10,143	9,001	**8,845**	8,688	7,843	7,709	7,574
2013	11,051	10,856	10,662	9,282	**9,121**	8,960	7,967	7,831	7,694
2014	11,619	11,415	11,211	9,573	**9,407**	9,241	8,100	7,961	7,823

Figure 4.7: Queensland Region Winter Peak Demand

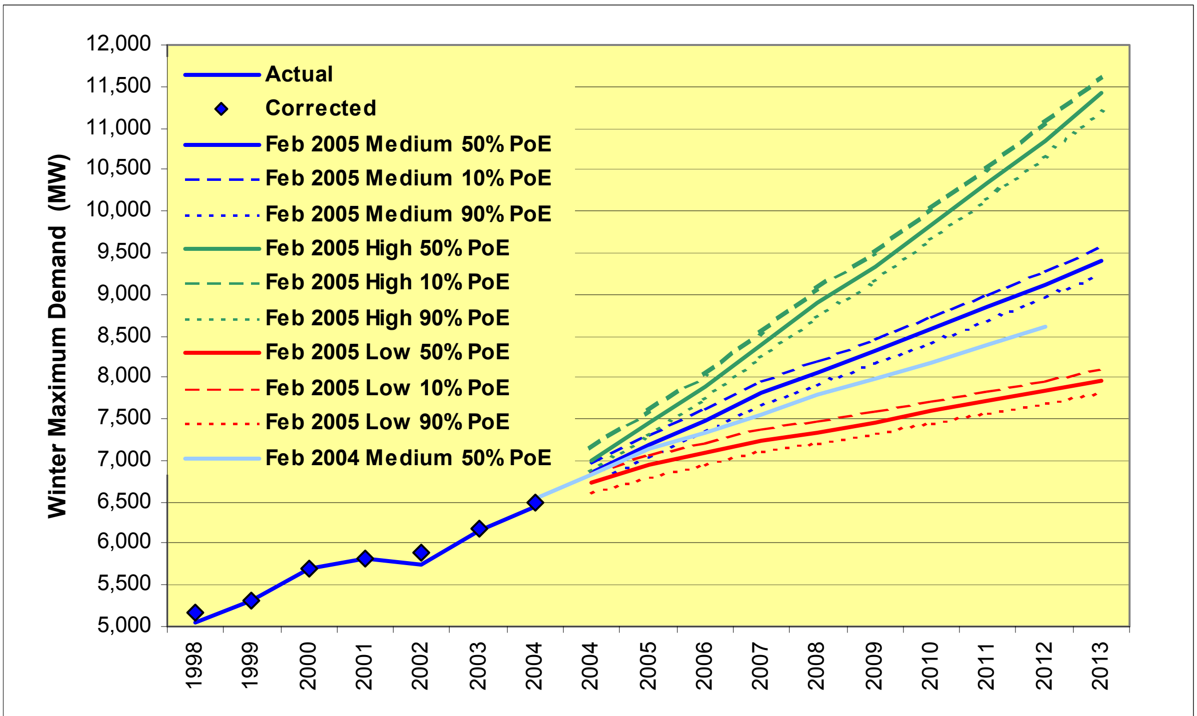


Table 4.8: Maximum Demand – 50% PoE Forecast

	Station "As Generated" Demand	Station Auxs & Losses (1)	Station "Sent Out" Demand	Transmission Losses	Delivered from Grid Demand (2)
Winter State Peak					
2005	7,644	428	7,216	359	6,857
2006	8,002	448	7,554	376	7,178
2007	8,344	467	7,877	392	7,485
2008	8,716	488	8,228	410	7,818
2009	8,991	504	8,488	423	8,065
2010	9,271	519	8,752	436	8,317
2011	9,561	535	9,025	449	8,576
2012	9,860	552	9,308	463	8,845
2013	10,169	569	9,599	478	9,121
2014	10,487	587	9,900	493	9,407
Summer State Peak					
05/06	8,702	487	8,215	426	7,789
06/07	9,148	512	8,636	448	8,188
07/08	9,622	539	9,083	471	8,612
08/09	10,034	562	9,472	492	8,981
09/10	10,417	583	9,834	510	9,323
10/11	10,788	604	10,184	529	9,656
11/12	11,144	624	10,520	546	9,974
12/13	11,512	645	10,867	564	10,303
13/14	11,889	666	11,224	583	10,641
14/15	12,245	686	11,559	600	10,959

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 4.9: Maximum Demand – 10% PoE Forecast

	Station "As Generated" Demand	Station Auxs & Losses (1)	Station "Sent Out" Demand	Transmission Losses	Delivered from Grid Demand (2)
Peak State Winter					
2005	7,790	436	7,354	371	6,983
2006	8,155	457	7,698	388	7,310
2007	8,501	476	8,025	405	7,621
2008	8,878	497	8,381	423	7,958
2009	9,158	513	8,645	436	8,209
2010	9,443	529	8,914	449	8,465
2011	9,737	545	9,192	463	8,728
2012	10,041	562	9,479	478	9,001
2013	10,355	580	9,775	493	9,282
2014	10,679	598	10,081	508	9,573
Summer State Peak					
05/06	9,046	507	8,539	455	8,084
06/07	9,510	533	8,977	478	8,499
07/08	9,998	560	9,438	503	8,935
08/09	10,426	584	9,842	524	9,318
09/10	10,824	606	10,218	544	9,674
10/11	11,210	628	10,582	564	10,018
11/12	11,580	648	10,931	582	10,349
12/13	11,962	670	11,292	602	10,690
13/14	12,354	692	11,662	621	11,041
14/15	12,723	712	12,011	640	11,371

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).

4.5 Zone Forecasts

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

Table 4.10: 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/Tweed 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/Tweed zone. From 2004 onwards some other parts of the Brisbane CBD area and inner suburbs will transfer from being in Moreton North to being in Moreton South, also supplied from Belmont and Murarrie.
Gold Coast/Tweed	South of Coomera to the Gold Coast and includes Tweed Shire of NSW.

Each zone normally experiences its own zone peak demand, which is usually greater than that shown in Tables 4.13 and 4.14, as it does not coincide with the time of Queensland region maximum demand.

Table 4.11 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 4.13 and 4.14 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.

Table 4.11: Average Ratio of Zone Peak Demand to Zone Demand at Time of Queensland Region Peak

Zone	Winter	Summer
Far North	1.120	1.065
Ross	1.120	1.100
North	1.120	1.180
Central West	1.050	1.080
Gladstone	1.020	1.010
Wide Bay	1.140	1.120
South West	1.030	1.035
Moreton North	1.007	1.004
Moreton South	1.007	1.008
Gold Coast / Tweed	1.010	1.025

Table 4.12 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 4.13 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 4.14 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.

4.6 Daily and Annual Load Profiles

The daily load profiles for the Queensland region on the days 2004 winter and 2004/05 summer peak demand delivered from the transmission grid and from embedded scheduled generators, are shown on Figure 4.8.

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 4.9 for the 2003/04 financial year.

Figure 4.8: Summer and Winter Peaks 2004/05

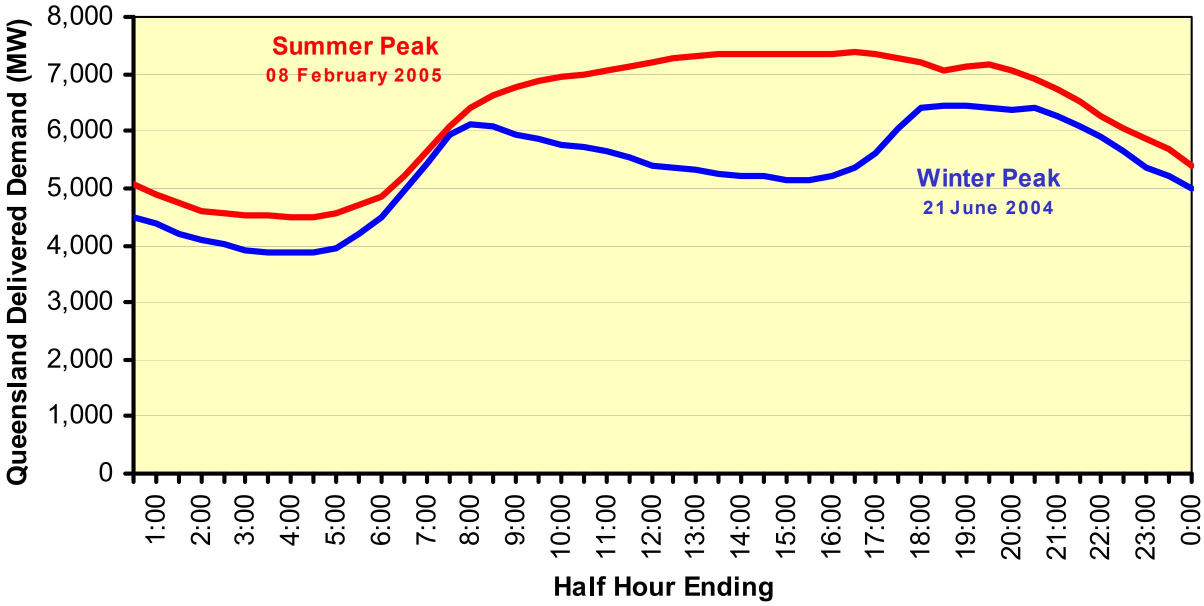


Figure 4.9: Cumulative Annual Load Duration 2003/04

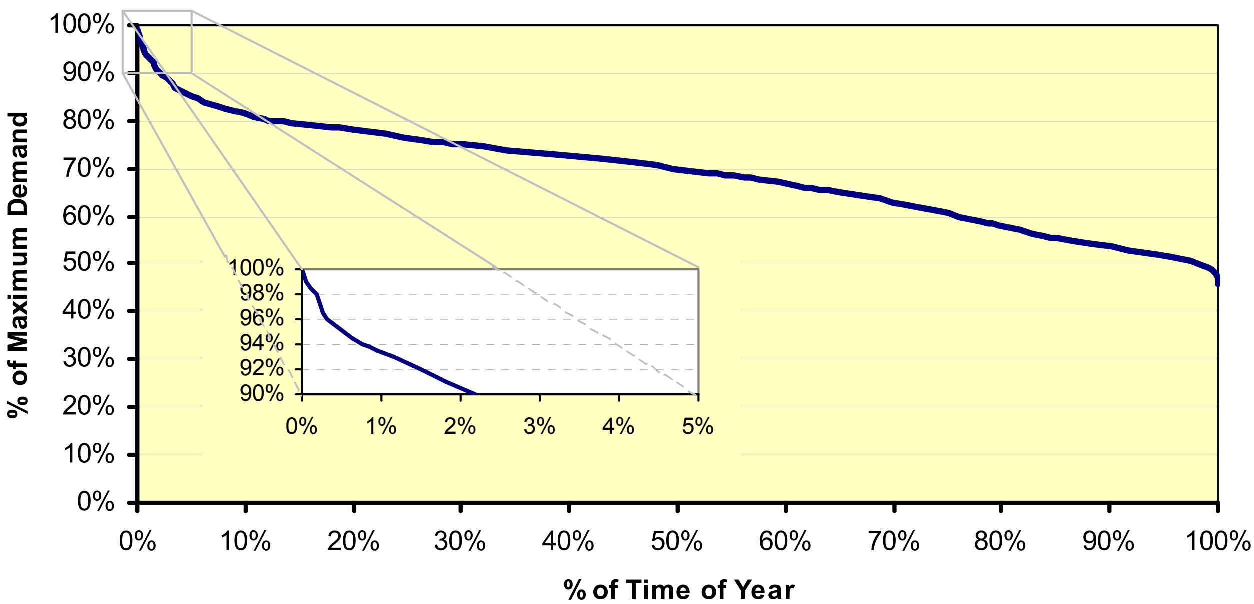


Table 4.12: Annual Energy by Zone

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											
1997/98	1,364	1,967	1,844	2,638	7,925	1,051	1,482	5,530	7,684	2,529	**34,013**
1998/99	1,407	2,030	1,809	2,587	8,434	1,024	1,511	5,752	7,808	2,637	**34,999**
1999/00	1,430	2,454	1,963	2,789	8,660	1,088	1,575	6,101	8,116	2,777	**36,953**
2000/01	1,457	2,962	2,055	2,876	8,697	1,187	1,659	6,421	8,333	2,913	**38,561**
2001/02	1,536	2,971	2,219	3,069	8,948	1,257	1,717	6,769	8,746	3,064	**40,297**
2002/03	1,549	2,934	2,296	3,109	9,098	1,256	1,738	6,970	9,178	3,135	**41,264**
2003/04	1,631	3,095	2,397	3,174	9,285	1,327	1,828	7,276	9,644	3,436	**43,092**
projected 2004/05	1,671	3,047	2,536	3,292	9,460	1,424	1,946	7,500	10,080	3,500	**44,450**
Forecasts											
2005/06	1,762	3,048	2,688	3,559	9,860	1,484	2,085	7,951 (1)	10,234 (1)	3,731	**46,402**
2006/07	1,831	3,197	2,793	3,705	10,468	1,506	2,126	8,040 (1)	10,811 (1)	3,988	**48,465**
2007/08	1,882	3,268	2,894	3,795	10,573	1,570	2,170	8,187	11,282	4,202	**50,452**
2008/09	1,936	3,341	2,973	3,844	10,654	1,637	2,215	9,257	11,668	4,515	**52,039**
2009/10	1,991	3,416	3,067	3,900	10,726	1,707	2,259	9,572	12,034	4,787	**53,459**
2010/11	2,046	3,492	3,147	3,954	10,790	1,777	2,303	9,832	12,350	5,054	**54,745**
2011/12	2,101	3,568	3,229	4,011	10,853	1,847	2,348	10,157	12,766	5,376	**56,256**
2012/13	2,156	3,644	3,309	4,071	10,916	1,917	2,393	10,620	13,152	5,696	**57,875**
2013/14	2,211	3,720	3,391	4,125	10,981	1,992	2,439	10,983	13,527	6,033	**59,402**
2014/15	2,266	3,796	3,472	4,182	11,045	2,061	2,484	11,347	13,888	6,383	**60,924**

Note:

1) Net transfer of load will occur from Moreton North to Moreton South zones due to the rearrangement of the 110kV network supplying the Brisbane CBD and inner suburbs area.

Table 4.13: 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 Demand - Average Weather Conditions

Year	Far North	Ross	North	Central West		Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1998	166	236	214	365	961	152	256	962	1,250	479	**5,042**
1999	173	238	229	377	994	165	278	1,022	1,315	517	**5,309**
2000	179	354	271	423	986	198	312	1,080	1,350	536	**5,691**
2001	184	378	255	442	1,019	189	301	1,110	1,365	567	**5,811**
2002	163	339	285	383	1,055	160	286	1,122	1,425	523	**5,743**
2003	177	348	295	412	1,009	181	318	1,251	1,574	583	**6,149**
2004	206	354	323	425	1,092	216	345	1,260	1,608	622	**6,450**
Forecasts											
2005	214	412	312	443	1,146	212	360	1,350	1,726	682	**6,857**
2006	225	434	329	487	1,198	219	377	1,397 (1)	1,805 (1)	707	**7,178**
2007	236	450	343	500	1,254	222	385	1,440 (1)	1,908 (1)	748	**7,485**
2008	245	459	358	521	1,270	230	392	1,563	1,992	788	**7,818**
2009	256	469	370	534	1,285	237	402	1,628	2,057	828	**8,065**
2010	266	479	385	547	1,294	244	412	1,693	2,128	868	**8,317**
2011	277	489	398	560	1,305	252	422	1,757	2,204	912	**8,576**
2012	288	500	411	573	1,316	260	432	1,831	2,278	956	**8,845**
2013	299	511	425	586	1,328	268	442	1,921	2,344	998	**9,121**
2014	311	522	439	600	1,339	276	452	2,003	2,421	1,046	**9,407**

Note:

(1) Significant net transfer of load will occur from Moreton North to Moreton South zones due to the rearrangement of the 110kV network supplying the Brisbane CBD and inner suburbs area.

Table 4.14: 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 Peak Demand - Average Weather Conditions

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1998/99	244	292	271	372	959	189	242	992	1,381	444	**5,386**
1999/00	234	412	240	346	1,003	197	265	1,055	1,433	499	**5,685**
2000/01	252	458	294	391	993	195	270	1,068	1,472	498	**5,891**
2001/02	278	504	355	436	1,040	222	258	1,183	1,461	509	**6,246**
2002/03	264	470	307	426	1,048	200	298	1,243	1,653	554	**6,462**
2003/04	265	452	318	459	1,087	253	339	1,387	1,890	653	**7,103**
2004/05	277	425	342	482	1,107	276	349	1,425	1,990	695	**7,368**
Forecasts											
2005/06	300	526	347	497	1,181	244	373	1,489 (1)	2,085 (1)	746	**7,789**
2006/07	314	549	362	510	1,252	254	389	1,515 (1)	2,241 (1)	802	**8,188**
2007/08	327	562	379	532	1,263	262	404	1,667	2,360	856	**8,612**
2008/09	341	575	393	546	1,278	269	421	1,765	2,478	915	**8,981**
2009/10	355	588	409	560	1,286	277	438	1,853	2,589	970	**9,323**
2010/11	369	601	423	573	1,297	285	455	1,934	2,692	1,026	**9,656**
2011/12	384	615	439	587	1,307	293	473	2,015	2,782	1,078	**9,974**
2012/13	400	630	454	601	1,319	301	491	2,116	2,862	1,129	**10,303**
2013/14	416	644	470	615	1,330	309	510	2,206	2,956	1,185	**10,641**
2014/15	430	658	485	629	1,335	317	528	2,291	3,048	1,238	**10,959**

Note:

(1) Significant net transfer of load will occur from Moreton North to Moreton South zones due to the rearrangement of the 110kV network supplying the Brisbane CBD and inner suburbs area.

5. INTRA-REGIONAL COMMITTED NETWORK AUGMENTATIONS

CONTENTS

5.1 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 Millmerran and Middle Ridge and between Braemar and the New South Wales border near Texas.

The single line diagrams of the Queensland network as shown in the 2004 Annual Planning Report (APR) have been updated to include recently completed augmentations outlined in this Chapter. Figures 5.1 and 5.2 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 load 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 capacity 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 capacity 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; and
- new loads in south east Queensland may exacerbate constraints associated with the Tarong limit and the CQ-SQ limit.

5.2 Committed Transmission Projects

Table 5.1 lists transmission grid developments commissioned since Powerlink's 2004 APR was published in July 2004.

Table 5.2 lists transmission grid developments which are committed and under construction at June 2005.

Table 5.3 lists connection works that have been commissioned since Powerlink's 2004 APR was published in July 2004.

Table 5.4 lists new transmission connections or connection works for supplying load which are committed and under construction at June 2005. These connection projects resulted from agreement reached with relevant connected customers, generators or distribution network service providers as applicable.

5.3 Possible Shared Grid and Connection Projects

Discussion of possible future developments of the shared transmission grid and connection points is presented in Chapter 6.

Table 5.1: Commissioned Transmission Developments

Commissioned since June 2004

Project	Purpose	Zone Location	Date Commissioned
Major Developments			
Lilyvale 275kV reinforcement	Increase supply capacity to maintain reliability to inland central Queensland mining area	Central West	December 2004
Darling Downs transmission reinforcement	Increase supply capacity to maintain reliability of supply to Darling Downs	South West	April 2005
Network Support Arrangements			
Contract with local generators to provide network support in north Queensland	Part of solution to provide market benefits relating to supply to NQ	North	Ongoing from January 2002
Minor Developments			
Ross and Chalumbin 275kV line switching	Provide improved switching arrangement	Far North	October 2004
Alligator Creek 20MVAr, 132kV capacitor bank	Provide voltage support	North	October 2004
Loganlea 2nd 275/110kV transformer	Increase supply capacity to maintain reliability to Logan area	Moreton South	December 2004
Molendinar 50MVAr, 110kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Gold Coast	October 2004
Ross-Dan Gleeson 132kV transmission line retension	Increase thermal rating to maintain reliability to the north Townsville area	Ross	November 2004

Table 5.2: Committed Transmission Developments

Committed and under construction at June 2005

Project	Purpose	Zone Location	Planned Commissioning Date
Major Developments			
Woree 132kV Static VAr Compensator	Increase supply capacity to maintain reliability to Cairns and Far North Queensland	Far North	October 2005
Belmont-Murarrie 275kV reinforcement (1)	Increase supply capacity to maintain reliability to Brisbane CBD and Trade Coast	Moreton South	October 2006
Gold Coast transmission reinforcement	Increase supply capacity to maintain reliability to Gold Coast	Gold Coast	October 2006
Minor Developments			
Nebo 3rd 275/132kV transformer	Increase supply capacity to maintain reliability to the Mackay area and mining areas to the west	North	October 2005
Blackwater 40MVAr 132kV capacitor bank	Capacitive compensation to meet increasing reactive demand	Central West	October 2005
Rockhampton 40MVAr 132kV capacitor bank	Increase supply capacity to maintain reliability to Rockhampton	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	October 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	October 2005

Notes:

(1) Referred to as Brisbane CBD 110kV project in Table 5.4 of 2004 APR which establishes new connection points at Belmont and Murarrie

Table 5.3: Commissioned Connection Works since June 2004

Commissioned since June 2004

Project	Purpose	Location	Date Commissioned
Pioneer Valley 132/66kV substation 2nd transformer	Provide reliable supply to growing load	Areas west of Mackay	August 2004
Biloela substation refurbishment and switching upgrade	Provide improved switching arrangement	Central West	October 2004
Edmonton 132/22kV substation	New connection point to Ergon to increase 22kV capacity to growing load south of Cairns	Areas between Cairns and Innisfail	January 2005
Bundamba 110/11kV substation	New connection point to Energex 11kV network	Moreton South	May 2005
Blackwater 132kV supply to Rolleston	New connection point for mining and other developments	Central West	June 2005
Ingham 132/66kV substation reconstruction and transformer replacement	Replace end of life assets and increase transformer capacity to meet load growth	North	June 2005

Table 5.4: Committed Connection Works at June 2005

Committed and under construction at June 2005

Project	Purpose	Location	Planned Commissioning Date
Dan Gleeson 132/66kV substation 2nd Transformer	Increase 66kV capacity for reliable supply to growing load	South western areas of Townsville	October 2005
Mudgeeraba 110kV connections for Varsity Lakes	Provide supply to new Energex zone substation	Gold Coast area	October 2005
Rocklea 110kV 2nd connection for Archerfield	Increase capacity to Energex to match growth in Archerfield and surrounding areas	Moreton South	October 2005
Braemar power station connection	Connect new power station	South West	April 2006
Kogan Creek power station connection	Connect new power station	South West	June 2006
Algester 110/33kV substation	New connection point to Energex 33kV network	Moreton South	October 2006
Goodna 110/33kV substation	New connection point to Energex 33kV network	Moreton South	October 2006
Sumner 110/11kV substation	New connection point to Energex 11kV network	Moreton South	October 2006
Blackwater 132/66kV substation 3rd transformer	Provide additional capacity to meet growing mining load	Central West	October 2006
Belmont 110/33kV substation 3rd transformer	Provide additional capacity to meet growing load	Moreton South	November 2006

Figure 5.1 Existing 275/132/110kV Network June 2005 – North and Central Queensland

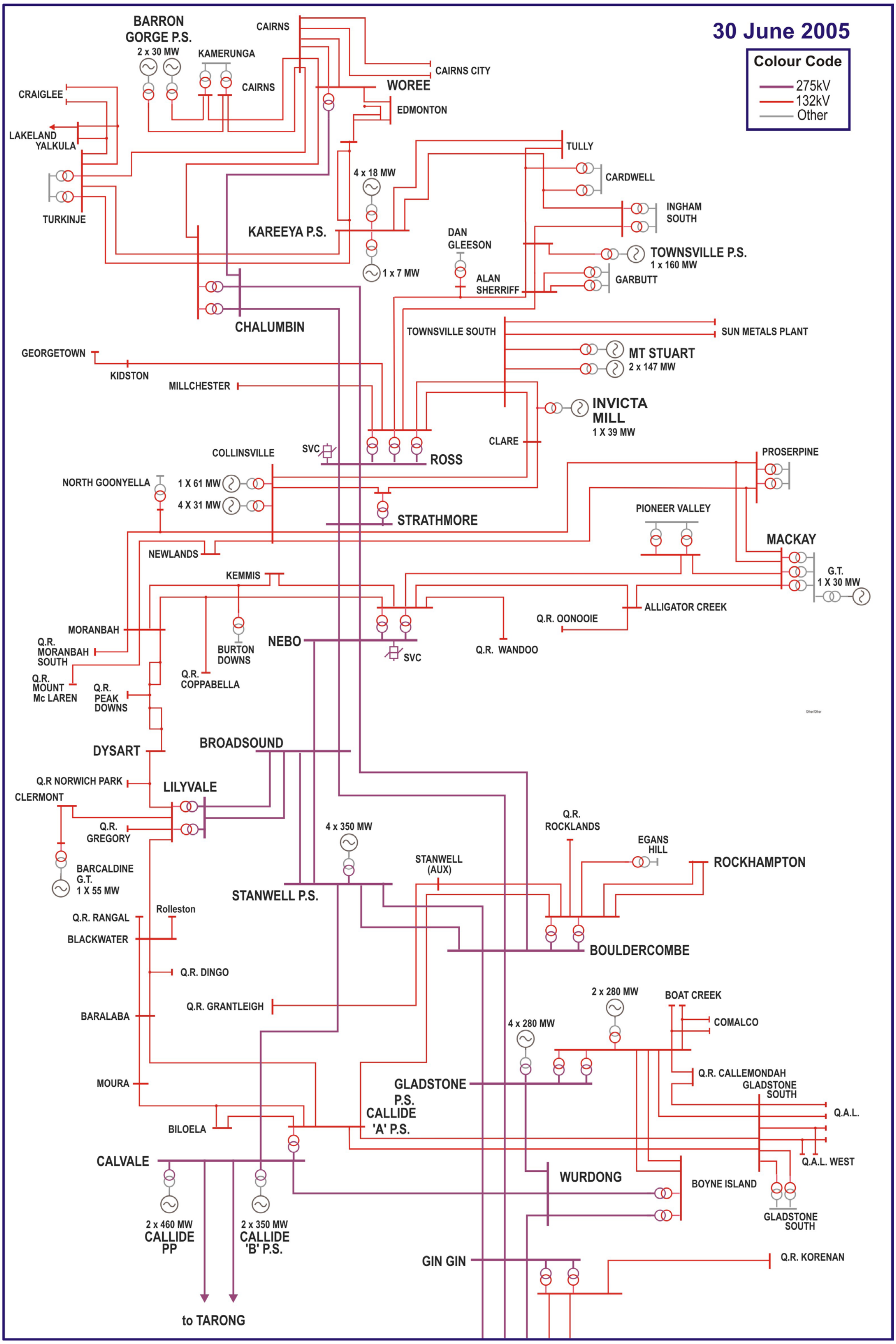
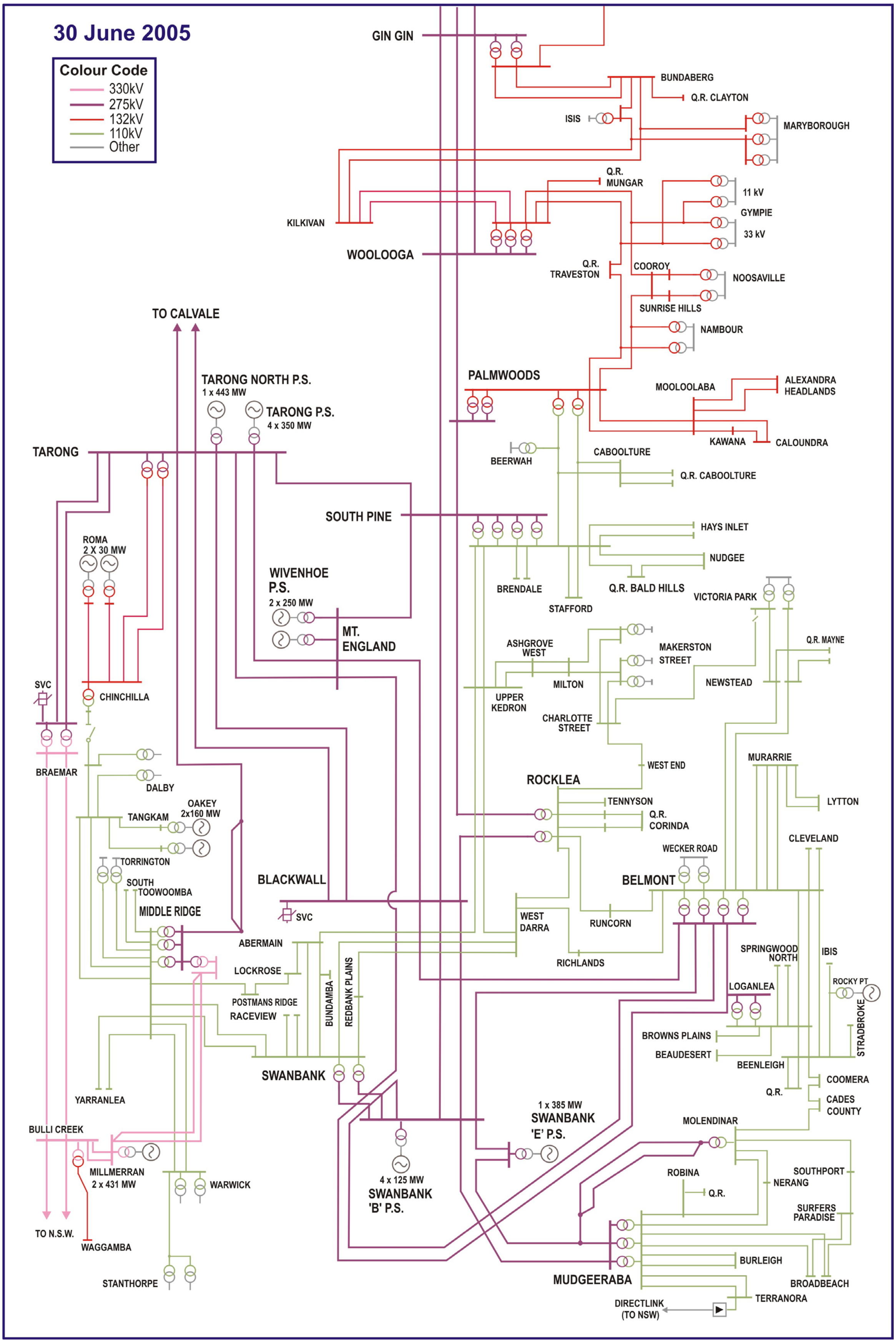


Figure 5.2 Existing 275/132/110kV Network June 2005 – South Queensland



6. INTRA-REGIONAL PROPOSED NETWORK DEVELOPMENTS WITHIN 5 YEARS

CONTENTS

6.1 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 impacting power transfer capability at key grid sections on the Powerlink network;
- identification of emerging limitations with the potential to impact on 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 corrective action or initiate consultation with market participants and interested parties; and
- a table summarising possible connection point proposals.

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 loaded relative to its capacity during summer than during winter. The reactive power requirements are greater in summer than in winter, and transmission plant has lower power carrying capacity 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 4.8).

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 can also vary substantially due to the impact 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 impact supply reliability.

6.2 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 2005 winter to 2007/08 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 load forecast outlined in Chapter 4 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 6.7) 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 limit for the system conditions analysed.

Sample conditions in Appendix A include:

- Figure A1: Generation & Load Legend for Figures A3 to A20
- Figure A2: Power Flow & Limits Legend for Figures A3 to A20
- Figure A3: Winter 2005 Qld Peak 400MW Northerly QNI Flow
- Figure A4: Winter 2005 Qld Peak Zero QNI Flow
- Figure A5: Winter 2005 Qld Peak 700MW Southerly QNI Flow
- Figure A6: Winter 2006 Qld Peak 400MW Northerly QNI Flow
- Figure A7: Winter 2006 Qld Peak Zero QNI Flow
- Figure A8: Winter 2006 Qld Peak 500MW Southerly QNI Flow
- Figure A9: Winter 2007 Qld Peak 400MW Northerly QNI Flow
- Figure A10: Winter 2007 Qld Peak Zero QNI Flow
- Figure A11: Winter 2007 Qld Peak 400MW Southerly QNI Flow
- Figure A12: Summer 2005/06 Qld Peak 400MW Northerly QNI Flow
- Figure A13: Summer 2005/06 Qld Peak Zero QNI Flow
- Figure A14: Summer 2005/06 Qld Peak 300MW Southerly QNI Flow
- Figure A15: Summer 2006/07 Qld Peak 400MW Northerly QNI Flow
- Figure A16: Summer 2006/07 Qld Peak Zero QNI Flow
- Figure A17: Summer 2006/07 Qld Peak 200MW Southerly QNI Flow
- Figure A18: Summer 2007/08 Qld Peak 400MW Northerly QNI Flow
- Figure A19: Summer 2007/08 Qld Peak Zero QNI Flow
- Figure A20: Summer 2007/08 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.

The impact of DirectLink, between Mullumbimby and Terranora in NSW, is uncertain as the flows could vary in either direction in its role as a Market Network Service Provider. For the purposes of the sample power flows in Figures A3 to A20, the power flow on this link is assumed to be zero except for Figures A12 to A14 (summer 2005/06) where northerly flow on DirectLink has been assumed as under a network support agreement to the Gold Coast.

6.3 Network Power Transfer Capability

6.3.1 Location of Network Grid Sections and Observation Points

Powerlink has identified a number of grid sections that allow grid capability and emerging limits 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) have 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 A2 in Appendix A shows the location of grid sections (where limit equations apply) and 'observation points' on the Queensland network, where flows may encroach on transfer limits under some circumstances in the next three years. Potential limitations are summarised in Table 6.6.

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

6.3.2 Determining Grid Transfer Capacities

The transfer capacity 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 capacity of their network using multi-term equations. These equations quantify the relationship between system operating conditions and the network transfer limit, and are implemented into NEMMCO's market systems for the optimal dispatch of generation. This is very relevant in Queensland as the grid transfer capacity is highly dependent on which generators are in service, and their dispatch level.

This limit equation approach aims to maximise the transmission capacity 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 capacity is the complexity of analysis required to define grid capacity. 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 load, 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 A3 to A20 show whether the flow across any grid section is expected to exceed the limit for that particular condition and generation dispatch. Section 6.4 gives a qualitative description of the main system conditions that impact on the capacity of each of the grid sections.

6.3.3 Grid Capacity Ranges

Grid capacity may vary depending on system conditions at the time. The grid capacity is the maximum power transfer for which the system will remain stable for any single credible contingency.

Table A1 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 A3 to A20. It also shows where grid flows are expected to exceed the relevant limit, and the mode of instability that determines the limit.

Forecast connection point demands coincident with Queensland (50% PoE) region maximum demands, as outlined in Chapter 4 and as detailed in Appendix E, were used to determine the grid flows shown in Figures A3 to A20. Grid power flows can be higher than shown in Table A1 at times of local area or zone peak demands, extreme weather conditions, lower embedded non-scheduled generation output or for different scheduled generation dispatch patterns.

The factors that influence the transfer capability and the impact of committed developments are discussed in Section 6.4.

6.4 Transmission Limits

This section is a qualitative summary of the main system conditions that impact on 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 capability limits 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 A3 to A20 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 load 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 2004 (winter) and from October 2004 to March 2005 (summer).

This information on binding limits 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.

6.4.1 Far North Queensland Grid Section

The maximum power transfer across the Far North Queensland (FNQ) grid section is limited 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 limit:

- Generation (MW) within the Far North zone;
- generators on-line within the Far North zone; and
- capacitor banks on-line within the Far North zone.

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

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

Information pertaining to the duration of constrained operation for the FNQ grid section over the period April 2004 to March 2005 is summarised in Table 6.1.

Table 6.1: Far North Queensland Limit Constraint Times for April 2004-March 2005

FNQ Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.01%	0.3
October 2004 to March 2005	2.11%	92.0

The installation of a new 132kV Static VAr Compensator (SVC) at Woree substation by September 2005 will provide 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.

With the commissioning of the Woree SVC, 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 limits during these conditions.

Further action to maintain the reliability of supply to the Far North zone may again be required from the 2007/08 summer onwards. This is addressed further in Section 6.5.1.

6.4.2 CQ-NQ Grid Section

The potential for transient instability, unstable voltage levels or thermal overload, following a transmission or generation contingency, limits the maximum power transfer across the CQ-NQ grid section.

The maximum transfer capability may be limited 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 whilst operating at high generation levels. Dynamic 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 2004 to March 2005 is summarised in Table 6.2.

Table 6.2: CQ-NQ Limit Constraint Times for April 2004-March 2005

CQ-NQ Limit (1)(2)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.03%	1.4
October 2004 to March 2005 (3)	3.5%	15.5

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 2004 to March 2005, the flow was controlled to avoid exceeding the CQ-NQ limit for around 365 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 loads 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 A3 to A20 at times of local area or north Queensland 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, reduced output from Collinsville power station, or if the output from embedded generators in north Queensland is lower than forecast.

Key factors which could increase the reliance on network support include:

- Non-availability or low output of the hydro generators in the Far North zone;
- Development or expansion of large industrial loads in north Queensland which have not been accounted for within the load forecast;
- Lower levels of embedded generation than accounted for within the forecast, and;
- Reduced availability of generating plant within north Queensland at times of high network loadings.

The development of additional generation capacity within north Queensland, which operates regularly due to market dispatch, could reduce reliance on grid support.

Powerlink has assessed that by the summer of 2007/08, the combination of local generation and grid transfer capacity will be insufficient to maintain reliability of supply to customers within north Queensland. This assessment is based on existing committed generation developments and load forecasts.

Powerlink initiated a consultation process in May 2004 to review the existing network support arrangements for the CQ-NQ grid section. Powerlink has also initiated a separate consultation process to address the emerging reliability limitation. These are discussed further in Section 6.7.

6.4.3 Gladstone Grid Section

The maximum power transfer across this grid section is limited by the thermal rating of the 275kV lines between the Central West and Gladstone zones (usually the circuit from Calvale to 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 circuit.

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. This strategy has been assumed to be in place for all of the 18 sample power flows shown in Figures A3 to A20 of Appendix A.

The present equation for the Gladstone grid section is shown in Table B3 of Appendix B. The current 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 encroach on the capability of this grid section. These strategies have been implemented to minimise the impact of generation redispatch on the market.

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 6.3.

Table 6.3: Gladstone Limit Constraint Times for April 2004-March 2005

Gladstone Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.72%	31.6
October 2004 to March 2005	6.31%	275.7

Power transfers are most likely to encroach on the transfer capability of this grid section under market dispatch scenarios that lead to high Callide but low Gladstone generation. For the sample power flows shown in Figures A3 to A20, these conditions generally occur for the northerly QNI flow cases.

Other action would be needed if potential major new industrial loads in the Gladstone area eventuate. Powerlink expects to shortly publish an Application Notice 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. This is referred to within Section 6.7.

6.4.4 CQ-SQ Grid Section

The maximum power transfer across this grid section is limited by voltage stability associated with an outage of a Calvale to Tarong 275kV transmission circuit. The limit results from an exhaustion of reactive power reserves in the Central West and Gladstone zones. More generating units on-line within these areas increases the reactive power support and therefore the limit.

The present voltage stability limit equations for the CQ-SQ limit are shown in Table B4 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

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

At transfers above 1900MW, the CQ-SQ transfer capability may be limited 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 2004 to March 2005 is summarised in Table 6.4.

Table 6.4: CQ-SQ Limit Constraint Times for April 2004-March 2005

CQ-SQ Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.01%	0.3
October 2004 to March 2005	0.01%	0.3

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 encroach on 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.

6.4.5 Tarong Grid Section

The maximum power transfer across this grid section is limited 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 an exhaustion of reactive power reserves within south Queensland.

Depending on generation patterns and power system conditions, one of four critical contingencies can currently 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; and
- Mt. England to Loganlea 275kV transmission circuit.

The present limit equations for the Tarong limit are shown in Table B5 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

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

There is inter-dependence between the CQ-SQ transfer and the Tarong limit. High flows between central and southern Queensland reduce the Tarong limit. This reduction is due to the high reactive losses between central and southern Queensland eroding the reactive power reserves within southern Queensland.

Reducing the CQ-SQ transfer by increasing generation west of the grid section increases the Tarong limit. Increasing generation east of the grid section reduces the limit, but increases the overall amount of supportable south east Queensland load. This is because the reduction in the limit 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 over the period April 2004 to March 2005 for the Tarong grid section is summarised in Table 6.5.

Table 6.5: Tarong Limit Constraint Times for April 2004-March 2005

Tarong Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.00%	0.0
October 2004 to March 2005	0.05%	2.3

Several projects, currently committed or under construction, will contribute to increasing the transfer capability across the Tarong grid section. For example, the Greenbank to Maudsland transmission reinforcement, currently under construction to address emerging reliability limitations to the Gold Coast, will reduce reactive losses within south east Queensland.

Based on the sample generation scenarios shown within Appendix A, power flows across this grid section increase steadily but do not encroach on the Tarong limit. These scenarios are based on 50% PoE load forecasts and all generation plant being available within the Moreton North and South zones.

However, power flows across this grid section can be higher than shown in Figures A3 to A20 at times of zonal peak demands, or during more severe weather than typical 50% PoE conditions. Flows can also be higher during planned or unplanned outages of generating plant in the Moreton North and South zones. Combinations of these conditions may result in flows encroaching on the Tarong limit.

Powerlink and NEMMCO have implemented operational arrangements to minimise the occurrence of binding limits during these unusual conditions. However, as the load in SEQ continues to grow, additional action will be necessary to maintain reliability of supply to SEQ.

Powerlink has assessed that by the summer of 2007/08, the combination of local generation and grid transfer capacity will be insufficient to maintain reliability of supply to customers within south east Queensland. This assessment is based on existing committed generation developments and load forecasts.

Powerlink will be initiating a public consultation process to address this emerging reliability limitation in the near future. This is discussed further within Section 6.5.7.

6.4.6 Gold Coast Grid Section

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

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

The present equation for the Gold Coast limit is shown in Table B6 of Appendix B. The equation shows that the following variables have the most significant effect on the limit:

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

The voltage limits are higher if the Swanbank source voltage is stronger (ie. the reactive capability is higher for more Swanbank B or E units on-line). The amount of secure supportable load also increases for northerly flow on DirectLink.

Information pertaining to the duration of constrained operation over the period April 2004 to March 2005 for the Gold Coast limit is summarised in Table 6.6.

Table 6.6: Gold Coast Limit Constraint Times for April 2004-March 2005

Gold Coast Limit (1) (2)	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	2.02%	88.8
October 2004 to March 2005	1.72%	75.1

Notes:

(1) The transfer across this grid section is managed through an agreement whereby southerly flows on the DirectLink MNSP are runback during binding conditions. Although included in the duration in Table 6.6, 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 6.6 include periods when spare capacity across this grid section was fully utilised by the DirectLink MNSP transferring power south into NSW.

During the 2005/06 summer period, power transfers may encroach on the grid section limit. Powerlink has entered into a network support agreement with the market network service provider DirectLink to manage power flows to within the transfer capability of the grid section during these times.

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 encroach on thermal ratings by the 2007/08 summer. A recommendation to address this emerging limitation is discussed in Section 6.7.

6.4.7 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, and the Queensland to New South Wales interconnector (QNI), to the network outside of south west Queensland.

The capability of the transmission system to transfer power from south west Queensland was previously defined as the Braemar grid section. It has been necessary to redefine this grid section due to the completion of the Millmerran to Middle Ridge transmission reinforcement. This project, required to address reliability limitations within the Darling Downs area, provides an alternative power transfer path out of south west Queensland under certain market conditions.

Information pertaining to the duration of constrained operation over the period April 2004 to March 2005 for the Braemar limit is summarised in Table 6.7. The equation for the Braemar limit is shown within Table B7 of Appendix B.

Table 6.7: Braemar Limit Constraint Times for April 2004-March 2005

Braemar Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound (Hours)
April to September 2004	0.00%	0.0
October 2004 to March 2005	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 and capacity of new generation entrants.

The capability of this grid section is limited 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, depending on the connection location of new generation, the capability of this grid section may be limited 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 and the 450MW gas fired power station at Braemar (as discussed within Section 7.2). For these sample scenarios, power transfers are within the capability of the SWQ grid section. A network switching strategy to manage transfers across the Middle Ridge to Swanbank 110kV circuits has been used within the 2007/08 summer scenarios (ie Figures A18 to A20).

It is possible that transfers may encroach on the capability of this grid section for higher levels of south west Queensland generation and/or northerly QNI flows than those shown within the Appendix A scenarios. The further addition of new generation within south west Queensland will increase the likelihood of this grid section limit being encroached.

The construction of new transmission circuits which provide additional paths of power transfer out of south west Queensland will alleviate possible congestion across this grid section.

It is not expected that transfers in the southerly direction will encroach on the capability of this grid section due to southward limitations within the Queensland to NSW interconnection (refer Section 6.4.8).

6.4.8 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.

Over the past year, Powerlink, together with NEMMCO, TransGrid, VENCorp and ElectraNet have carried out works to increase the oscillatory stability limit of the interconnection.

These works have included upgrading the design of the existing Power Oscillation Damper Controller at the Blackwall SVC. Research in conjunction with the University of Adelaide was also undertaken to better quantify the differences between simulated and measured levels of damping.

Following extensive system testing, the maximum transfer capacity of QNI in the southerly direction was increased from 950MW to 1078MW in November 2004. This new limit remains conditional on availability of on-line stability monitoring equipment. Powerlink is working closely with TransGrid to design and implement controller tunings at Blackwall and Armidale SVCs to allow this new damping limit to be released unconditionally.

Works are currently underway to implement power oscillation damper facilities on the Armidale SVC in NSW and the Braemar SVC in Queensland. This should further increase the oscillatory stability limit.

For intact system operation, the southerly transfer capacity of QNI is most likely to be limited 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 limited 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.

Powerlink and TransGrid are currently undertaking studies in association with an external consultant to investigate whether an upgrade of the transfer capability of QNI is economic under the revised AER Regulatory Test. This is discussed further within Section 7.2.3.

6.5 Emerging 'Reliability' Limitations

It is a condition of Powerlink's Transmission Authority that it meet licence and NER requirements relating to technical performance standards during intact and contingency conditions. The Transmission Authority also requires Powerlink to plan and develop the network such that peak demand can be supplied during a single network element outage. The limitations described in this section can therefore be viewed as 'triggers' for action. Powerlink must ensure a solution is implemented to maintain a reliable power supply to customers.

In accordance with NER requirements, Powerlink will consult with market participants and interested parties on feasible solutions. 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 6.7 for current and anticipated consultation processes).

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

6.5.1 Far North Queensland Zone Emerging Reliability Limitations

Voltage Control/Transformer Capacity

By late 2005, depending on generation and load assumptions, an outage of one of the 275kV circuits between Chalumbin and Woree or Ross and Chalumbin, will result in voltage instability at times of high demand. A 132kV Static VAr Compensator at Woree substation will be commissioned to address this limitation by October 2005 (refer Table 5.2). This limitation is expected to emerge again between 2007 and 2010, when further action will be necessary.

The thermal capacity of the 132kV line between Chalumbin and Woree, during an outage of the adjacent 275kV circuit, is also forecast to be reached in this timeframe unless corrective action is implemented. A feasible network solution may involve the installation of an additional transformer at Woree and uprating of the second Chalumbin to Woree circuit to 275kV operation, at an approximate cost of $12-18M.

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

6.5.2 Ross Zone Emerging Reliability Limitations

Supply to Northern and Western Townsville Areas

Load in the Townsville area has grown consistently in recent years. Average demand growth is expected to be about 3% to 3.5% p.a. for the next several years, but may be much higher in specific areas due to new commercial, industrial and residential developments.

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.

From summer 2008/09 onwards, thermal capacity limitations are expected to arise in the 132kV line between Ross and Dan Gleeson under contingency conditions.

The loading across these circuits may be impacted by possible network reinforcement of the Townsville CBD/Port Area (see below). This reinforcement may off-load the Dan Gleeson and Garbutt 132/66kV substations, which could reduce the transfers across the Ross to Dan Gleeson circuits.

A feasible network solution may involve developing the 132kV or 275kV network between Ross substation and Townsville Power Station at an approximate cost of $20-40M.

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

Supply to Townsville South and CBD/Port Areas

Due to ongoing load growth, thermal capacity limitations are expected to arise in the 132kV transmission network between Ross and Townsville South substations from summer 2006/07.

A proposed small network asset, consisting of a new capacitor bank, has been recommended for 2006/07 to address the forecast transmission limitation (see Section 6.7.4).

Following this small network augmentation, the limitation is expected to re-occur one year later. A feasible network solution to address the future transmission limitations from October 2007 may involve reinforcement of the 132kV network between Ross and Townsville South substations at an approximate cost of $15-25M.

Thermal limitations are also expected to arise in the distribution network supplying the Townsville CBD/Port Area during summer 2007/08. A feasible network solution to address the forecast distribution limitation may involve extension of the 132kV network into the Townsville CBD/Port Area at an approximate cost of $15-25M.

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

A consultation process to address these limitations is underway (refer Section 6.7.3).

6.5.3 North Zone Emerging Reliability Limitations

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 capacity will be available in this network until summer 2007/08, at which time power flows on the Nebo-Pioneer Valley 132kV circuit will reach its emergency thermal rating during an outage of the Nebo-Alligator Creek 132kV circuit.

A feasible network solution may involve reinforcement of the 132kV network between Nebo and Pioneer Valley substations at an approximate cost of $15-25M.

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

A consultation process to address this limitation is underway (refer Section 6.7.3).

Nebo Transformer Limitations

Nebo substation is a major bulk supply point in North Queensland. Due to load growth in the Mackay and Central Queensland areas, including increases in mining load, the existing Nebo 275/132kV transformers are expected to reach capacity limitations by late 2005. A third transformer at Nebo substation will be commissioned by October 2005 to address this limitation (refer Table 5.2).

Supply to South Mackay Area

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

Should these industrial developments proceed within the five year outlook period, the load growth is expected to result in thermal limitations in the 132/33kV transformers at Alligator Creek substation during contingency conditions.

A feasible network solution may involve establishment of an additional 132/33kV transformer at Alligator Creek at an approximate cost of $8-12M together with associated sub-transmission upgrades, or construction of a new 132kV line and 132/33kV substation south of Mackay at an approximate cost of $15-25M.

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.

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 $20-30M.

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

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 capacity will be sufficient to reliably meet forecast electricity demand requirements until summer of 2007/08.

Solutions which could address the future requirements beyond this time, whether individually or in combination, include:

- Suitably located generation in NQ and FNQ of sufficient energy and capacity to meet the annual increase in load expected in these zones;
- Suitably located DSM initiatives in NQ and FNQ of sufficient energy and capacity to meet the annual increase in load expected in these zones; and
- A staged augmentation of the transmission network between Broadsound and Ross at a total cost in the range of $200-300M.

A consultation process to address this limitation is underway (refer Section 6.7.3).

Depending on the solution implemented, this limitation may re-emerge in subsequent years.

6.5.4 Gladstone Zone Emerging Reliability Limitations

Supply to the Gladstone Area

The network in the Gladstone area is very heavily loaded in some areas. The Boyne Island aluminium smelter dominates this load, but there is also significant demand at the Queensland Alumina plant and at the Gladstone area 132/66kV substations. There have also been public announcements about significant new metal processing plants to the north and west of Gladstone that could come into production in the next few years.

At the present time, there are transmission limitations between the Callide and Gladstone areas during certain generation scenarios.

Should major new metal processing plants proceed in the Gladstone area, the transmission network will need to be augmented to address reliability obligations. Consequently, the scoping and costing of options varies over a wide range.

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

6.5.5 Central West Zone Emerging Reliability Limitations

Supply to the Rockhampton Area

Load growth in the Rockhampton area is forecast to grow at an average of 3.5% p.a. 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. By the summer of 2005/06 an outage of either Bouldercombe to Rockhampton circuit will cause an overload in the companion circuit. A committed project to install a 40MVAr 132kV capacitor bank at Rockhampton substation has been initiated to address this emerging limitation (refer Table 5.2).

Planning analysis indicates that this limitation is likely to once again emerge from the summer of 2007/08 onwards. A feasible network solution may involve establishment of a new 132/66kV substation north of Rockhampton at an approximate cost of $25-35M.

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 capacity between Callide, Biloela and Moura substations will be reached under contingency conditions from summer 2007/08 onwards (in summer peak demand periods).

A feasible network solution may involve reinforcement of the 132kV network between Lilyvale and Blackwater at an approximate cost of $15-$30M.

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

A consultation process to address this limitation is underway (refer Section 6.7.3).

6.5.6 Wide Bay Zone Emerging Reliability Limitations

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 2008/09, 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.

Feasible network options may involve construction or upgrading of 275/132kV substations and associated line works at an approximate cost of $30-50M.

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

6.5.7 Moreton North and South Zones Emerging Reliability Limitations

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.

Due to rapidly increasing load in the Sunshine Coast area, planning studies have identified that in the period 2008-2009, thermal capacity limitations are expected to arise in Energex's 132kV network between Woolooga and Gympie during critical 275kV and 132kV network outages.

A feasible network solution may involve construction of a new 275/132kV substation in the Imbil area at an approximate cost of $30-40M.

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

Supply to North Brisbane (Moreton North)

Significant load growth is forecast to continue in the north Brisbane area as a result of population growth, as well as extensive commercial/industrial development such as the Brisbane Airport commercial precinct. As a result, thermal capacity limitations are expected to arise in Energex's 110kV network between South Pine and Nudgee under contingency conditions by summer 2008/09. A further thermal limitation is expected to arise in the transformer capacity at South Pine substation in the next five years.

A feasible network solution may involve construction of a 275kV line between South Pine and a new 275/110kV substation at Nudgee, at an approximate cost of $55-80M.

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

South East Queensland Voltage Control (Moreton North & South)

Growing load 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 $3-7M per year.

During 2004/05, a small network asset consultation process was undertaken on the proposed installation of 132 or 110kV capacitor banks at Palmwoods, Belmont, South Pine and Ashgrove by summer 2005/06 at a cost of $3.5M. These projects are now under construction.

A proposed small network asset, consisting of new capacitor banks, to keep pace with reactive demand in the summer 2006/07 period has also been recommended (see Section 6.7.4).

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.

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 2005/06 and 2006/07, various thermal capacity limits are expected to be reached on this 110kV network and in parts of the distribution network under normal contingency conditions.

A committed Energex/Powerlink 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 5.2).

275/110kV Transformer Limitations (Moreton North & South)

Load in the Moreton North and Moreton South zones is forecast to grow at over 5% p.a. over the next five years. This load is supplied from the 110kV network, which receives supply via the 275kV system. The 275/110kV transformer capacity must keep pace with load growth to avoid unacceptable overloads following transformer outages.

The emergence of transformer capacity limitations is monitored closely by considering the impact of future load growth, and the loading of existing and committed future transformers.

Based on forecast load growth, 275/110kV transformer capacity limitations will occur at a number of existing locations within the Moreton North and Moreton South zones over a 5 year outlook period. Identified limitations involve the loading on the South Pine and Murarrie transformers, where the overload during contingency conditions becomes unacceptable by summer 2006/07 and summer 2009/10 respectively.

A committed project is underway at South Pine 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.

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

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

Due to significant ongoing load growth in the Moreton North and South zones, thermal capacity 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.

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

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

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

Load growth in the South West Brisbane and Ipswich areas is forecast to increase rapidly at around 7-8% p.a. 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 capacity limitations are expected to arise in this network during a critical network outage.

A committed Powerlink/Energex project is underway to establish a number of 110/33kV and 33/11kV substations (and associated connections) by late 2006 to address these limitations (refer Table 5.4).

An additional 275/110kV transformer limitation (near Ipswich) is expected to arise from summer 2007 under contingency conditions. A consultation process is currently underway to address this limitation (refer Section 6.7.3).

A draft recommendation has been issued to address this limitation and comprises substation works at Goodna and Abermain at an estimated cost of $37.9M.

Future 110kV line limitations are also expected in the South West Brisbane and Ipswich Areas from summer 2009/10. A feasible network solution may involve establishment of a new 275/110kV substation site and associated 110kV transmission lines at an approximate cost of $25-40M.

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

Supply to Murarrie and Trade Coast Areas (Moreton South)

Belmont 275/110kV substation supplies part of the Brisbane CBD, Murarrie and Trade Coast (Brisbane Port), Redlands Shire, coastal areas and part of the Richlands-Algester-Runcorn area.

Thermal capacity limitations in the 110kV network supplying Murarrie are expected by 2006 to 2008 under contingency conditions.

These 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).

Load Growth South Eastern Queensland – Logan (Moreton South)

Very high load growth is occurring in south eastern Queensland, particularly in the Moreton South zone. Power is supplied to this area (defined in terms of this reliability requirement as including Moreton North, Moreton South, Wide Bay and Gold Coast/Tweed 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.

The increasing demand is expected to result in emerging reliability of supply limitations by summer 2007/08. 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.

A feasible network solution may involve a new transmission line between Middle Ridge and Greenbank at an approximate cost of $90-120M. Non-network solutions may include local generation and/or DSM initiatives.

6.5.8 Gold Coast/Tweed Zone Emerging Reliability Limitations

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 load growth. Summer electricity demand growth is expected to average close to 6% per annum for the next ten years.

Due to the high load growth, emerging limitations have been identified in the transmission and distribution system supplying the Gold Coast area. During summer peak demand periods from late 2005/06 onwards, voltage stability and thermal limitations are expected to arise based on a critical 275kV contingency.

These limitations are being addressed by a committed project comprising network support by DirectLink for the summer of 2005/06, followed by establishment of a 275kV substation at Greenbank and construction of a 275kV transmission line between Greenbank and Maudsland by late 2006 (refer Table 5.2).

275/110kV Transformer Capacity

Based on forecast load growth, transfer through the Mudgeeraba 275/110kV transformers is forecast to exceed their capacity by late 2007 following an outage of the Molendinar 275/110kV transformer, unless corrective action is taken.

A proposed new small network asset, consisting of a second 375MVA 275/110kV transformer at Molendinar, has been recommended to address this limitation at an estimated cost of $6.9M (see Section 6.7.4).

110kV Circuit Capacity

Electricity demand in the Tweed area is growing steadily and is forecast to reach the thermal capacity of the Mudgeeraba to Terranora 110kV line by late 2009.

Prior to that time, capacity limitations are also expected to arise in the distribution network supplying Currumbin/Kirra.

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

6.6 Summary of Forecast Network Limitations

Limitations discussed in Section 6.4 and 6.5 have been summarised in Table 6.6. This table provides an outlook (based on load, generation and committed network development assumptions contained in Chapters 4, 5 and 6) for potential limitations in Powerlink's transmission network over a one, three and five year timeframe.

Table 6.6: Summary of Forecast Network Limitations

Refer Section 6.7 for information on corrective action to address future limitations

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr 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.	Corrective action in progress (1)	2007-2010 (2)	
Supply to Northern and Western Townsville Area	Future 132kV network thermal capacity limitations in meeting load growth in northern and western Townsville.			2008/09 (2)
Supply to Townsville South and CBD/Port Areas	Future 132kV and 66kV network thermal capacity limitations in meeting growing potential new loads in the Townsville South and CBD/Port areas.		2006/07 and 2007/08 (2)	
NORTH ZONE				
Supply to Mackay-Proserpine Area	Due to load growth, thermal limitations expected to arise in the Nebo-Pioneer Valley 132kV circuit under contingency conditions.		2007/08 (2)	
Nebo Transformer Limitation	Due to load growth, Nebo transformers expected to reach thermal capacity limitations.	Corrective action in progress (1)		
Supply to South Mackay Area	Due to potential industrial load growth, thermal limitations may occur in 132/33kV transformers at Alligator Creek under contingency conditions.			2009/10 (5)
Supply to Bowen Area	Due to potential industrial load growth, thermal limitations may occur in local 66kV distribution network.			2009/10 (5)
CQ-NQ and Nebo-Ross Limitations	Voltage, dynamic instability, and thermal overloading may result from 275kV line outages during periods of high northern Qld load.	Corrective action in progress (3)	2007/08 (2)	
GLADSTONE AND CENTRAL WEST ZONES				
Supply to Gladstone Area	Potential for overload of Calvale-Wurdong 275kV line and/or Calvale 275/132kV tie transformer.	Currently managed by switching and support arrangements (4)		

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
Supply to Rockhampton Area	Due to load growth, an outage of one of the Bouldercombe-Rockhampton 132kV circuits may result in thermal overloading of the remaining circuit in service.	Corrective action in progress (1)	2007/08 (2)	
Supply to Inland Central Queensland Area	Due to load growth, 132kV network between Callide, Biloela and Moura expected to reach thermal capacity limitations in the event of a single contingency.		2007/08 (2)	
Grid Transfer from Central Zone	Additional base load generation in CQ may result in transfer limits between CQ and SQ being reached.		2006-2008 (2)	
WIDE BAY AND SOUTH WEST ZONES				
Supply to Wide Bay Area	Load growth may result in voltage control and thermal limitations during an outage of the 132kV network between Bundaberg and Woolooga.			2008/09 (2)
Grid transfer limit: South West Queensland	Some NEM generation dispatch scenarios may give rise to binding transfer limits for northerly flows.		2006-2008	
MORETON NORTH AND SOUTH ZONES				
Supply to Sunshine Coast Area	Load growth may result in thermal limitations in Energex's 132kV network between Woolooga and Gympie during a critical 275kV or 132kV outage.			2008-2009
Supply to North Brisbane Area	Load growth may result in thermal limitations in Energex's 110kV network and Powerlink 275/110kV transformers.			2008/09
South East Qld Voltage Control	Increasing reactive demand due to load growth likely to require program of corrective action to satisfy voltage control standards.	Corrective action in progress (1)	2006-2009 (2)	
Supply to Brisbane CBD and inner suburbs	Increasing loads in Brisbane CBD and inner suburbs leading to thermal capacity limits in the distribution and 110kV networks.	Corrective action in progress (1)		
275/110kV Transformer Capability	Due to load growth, future 275/110kV transformer capacity limitations are anticipated at multiple locations.		2006/07 Corrective action in progress (1)	2009/10
110/33kV Transformer Capability	Due to load growth, future 110kV transformer limitations and 33kV and 11kV line limitations are anticipated at multiple locations.		2006-2010	

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
Supply to South West Brisbane and Ipswich Areas	Due to load growth, thermal capacity limitations are expected in the 275kV and 110kV network supplying these areas.		Corrective action in progress (1) 2007/08 (2)	2009/10
Supply to Murarrie-Trade Coast Area	Thermal capacity limitations of 110kV network to Murarrie in meeting growing and potential new Trade Coast area loads.	Corrective action in progress (1)		
Load Growth South East Queensland (Logan)	High load growth expected to result in limitations in supply to entire south eastern Queensland area.		2007-2009 (2)	
GOLD COAST/TWEED 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.	Corrective action in progress (1)		
Gold Coast/Tweed 275/110kV Transformer Capacity	Due to load 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 (2)	
Gold Coast/Tweed 110kV circuit capacity	Due to load growth, thermal capacity limitations expected to arise in 110kV network and distribution network.			2009/10 (2)

Notes:

(1) Refer Tables 5.2 and 5.4 – Committed Augmentations
(2) Refer to Section 6.7 – Proposed Network Developments
(3) Network support arrangements in place
(4) Other corrective action may be required if major new loads occur in the Gladstone area
(5) The actual timing of the forecast limitation will be driven by major industrial developments

6.7 Proposed Network Developments

As outlined in Chapter 4, electricity demand in Queensland is expected to grow strongly in the near term – driven by continued residential, commercial and industrial development. This growth will be particularly evident in the south east corner of the state where demand is forecast to increase by around 5% p.a. over the next ten years.

Network development to meet forecast load 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 severity of these limitations is dependent on load growth and market developments.

This section focuses on those limitations for which Powerlink intends to implement corrective action or initiate consultation with market 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.

6.7.1 Processes for Proposed Network Developments

Sections 6.4-6.6 of this report identified anticipated network limitations and constraints that may arise in the Queensland transmission network over the next 5 years. Where action is considered necessary, Powerlink will:

- Notify Registered Participants of anticipated limitations within the timeframe required for corrective action.
- Seek information from market 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 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 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 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.

6.7.2 Proposed New Large Network Assets

Proposals for new large network assets are required to be progressed under the provisions of Clause 5.6.6 of the NER.

Powerlink is required to carry 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 6.7.3.

Committed New Large Network Assets

Interested parties are advised that during 2004/05, Powerlink finalised regulatory processes associated with the following new large network assets –

Table 6.7: New Large Network Assets Committed In 2004/05

Project Name	Description of works	Cost	Expected commissioning date
Gold Coast	Network support from DirectLink, followed by 275kV augmentation between Greenbank and Maudsland	$51.6M	October 2005 and October 2006
South West Brisbane	Joint Powerlink/Energex project to establish a number of 110/33kV and 33/11kV substations at Algester, Goodna and Sumner (and associated 33kV connections)	$91.4M	October 2006

Proposed New Large Network Asset – Network Support 2005-2007

Since late 2000, summer peak demand requirements in North and Far North Queensland have been met by power transfers over Powerlink's 132kV and 275kV transmission network, and growing reliance on additional output from local generating plant. To ensure sufficient local generation output is provided at times of peak demand, Powerlink entered into a number of network support agreements in 2001 with Enertrade – the market trader of several power stations at Collinsville and Townsville.

Routine planning analysis undertaken by Powerlink has identified that, in the period to summer 2007/08, supply reliability can continue to be met by a combination of transmission capacity and local generation, as sufficient local generation is already available to reliably meet forecast demand requirements.

For the periods that the transmission network is operating at maximum capacity, local high-cost generation will be required to operate to meet customer demand requirements even though lower cost generators are available elsewhere. As the demand for electricity continues to grow, these local generators will operate for longer periods and at higher levels.

Given these expected operating levels, and the fact that the existing network support agreements have now been in place for some time, Powerlink has undertaken a review of the existing arrangements. This review aimed to identify and evaluate any alternative supply options that may provide additional net market benefits in addressing the forecast transmission constraints in North and Far North Queensland in the period to summer 2007/08.

The outcomes of this review, including the economic analysis of feasible supply options under the AER Regulatory Test, were published in an Application Notice issued on 7 June 2005.

The draft recommendation outlined in the Application Notice comprises:

- Provision of network support services from power stations at Collinsville, Townsville, Mt Stuart and Pioneer Sugar Mill for the period to summer 2007/08. This arrangement has an estimated total cost of \$13M-\$38M for 2005/06 and \$13M-\$26M for 2006/07.

The Application Notice can be accessed on the Powerlink website at www.powerlink.com.au. A Final Report is anticipated to be released under the relevant NER provisions in the near future and will be available for access on the Powerlink website.

Proposed New Large Network Asset – Ipswich Area (Moreton South Zone)

Powerlink has identified a need for additional transformer capacity in the Ipswich Area to ensure continued reliable electricity supply. This area extends from Gatton in the west to Goodna in the east and from Abermain in the north to Ripley/Swanbank in the south.

High load growth will place extra demand on the 275/110kV transformers supplying the 110kV network in this area. Network analysis has revealed that for summer peak conditions in 2007/08, the outage of either Swanbank transformer will result in the rating of the remaining transformer being exceeded.

Powerlink has carried out consultation to identify and determine feasible options to address the future supply requirements. Analysis of options was carried out in accordance with the AER Regulatory Test, and the solution that met the reliability requirements at the lowest total present value cost to electricity customers was recommended for implementation.

The recommended solution comprises:

- Establishment of a new 275/110kV substation at Goodna, to be completed in late 2007, at an estimated capital cost of \$18.3M.
- Establishment of a new 275/110kV substation at Abermain, to be completed in late 2008, at an estimated capital cost of \$19.6M.

An Application Notice for this new large network asset was issued on 3 June 2005 and can be accessed on the Powerlink website at www.powerlink.com.au. This proposed augmentation is being progressed under the relevant NER provisions. A Final Report will be released in the near future and will also be available on the Powerlink website.

6.7.3 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 6.8 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 6.8: Consultations Underway

Area	Date Request for Information Paper released	Anticipated Date for Publication of Application Notice
North and Far North Queensland 2007 onwards	May 2004	July/August 2005
Townsville	April 2005	July/August 2005
Mackay-Proserpine	April 2005	September 2005
Inland Central Queensland	June 2005	September 2005

Anticipated Consultation Processes

Other consultation processes likely to be initiated in the next twelve months are summarised in Table 6.9:

Table 6.9: Consultation Likely Within 12 Months

Location (1)
Far North Queensland
Northern and Western Townsville area
Bowen area
South Eastern Queensland
Gladstone area
Wide Bay area
Sunshine Coast area
North Brisbane area
QNI Upgrade

Note:
(1) For further details on each of these limitations refer to Section 6.4.8 and 6.5

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

6.7.4 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 $1M and $10M). At the time of publication of this report, Powerlink has developed plans for the proposed new small network augmentations listed in Table 6.10 to the point where they can be consulted on through this document.

Table 6.10: Proposed New Small Network Assets

Proposed New Small Network Asset	Date to be Operational	Capital Cost
Townsville South 50MVAr 132kV capacitor bank	October 2006	$1.2M
Gladstone South 50MVAr 132kV capacitor bank	October 2006	$1.2M
SEQ capacitor banks		
• Molendinar 50MVAr 110kV capacitor bank	October 2006	$1.2M
• Greenbank 120MVAr 275kV capacitor bank	October 2006	$1.4M
Molendinar 375MVA 275/110kV transformer	October 2007	$6.9M

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 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 2005. 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 2006 Annual Planning Report.

6.7.5 Connection Point Proposals

Table 6.11 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 6.11: Possible Connection Works

Potential Project	Purpose	Location	Possible Commissioning Date
Mackay area transformer augmentation	Increase transformer capacity to meet growing loads	Mackay area	October 2006
South Pine 110kV bays for Brendale	New supply to Energex Brendale substation	Brendale and surrounding areas	October 2006
Biloela transformer augmentation	Increase transformer capacity to meet growing loads	Biloela	June 2007
Oakey 110/33kV substation	New connection point to Ergon to increase 33kV capacity for load growth	Oakey	October 2007
Townsville East 132/66kV substation	New connection point to Ergon to increase 66kV capacity for load growth	Townsville	October 2007
Woree 132kV bays for Cairns North	New supply to Ergon Cairns North substation	Cairns	October 2007
Middle Ridge 110kV bays for Postmans Ridge	New supply to Energex Postmans Ridge substation	Toowoomba	October 2007
QR Mindi 132kV rail supply	New supply to Queensland Rail substation	Bowen Basin mining area	December 2007
Spring Gully power station 275kV or 330kV connection	Connection of new power station	South West Queensland	January 2008
El Arish 132/22kV substation	New connection point to Ergon to increase 22kV capacity for load growth	Innisfail area	October 2008
Bowen 132/66kV substation	New connection point to Ergon to increase 66kV capacity for load growth (rail and port loads)	Bowen	October 2009
Egans Hill transformer augmentation	Increase transformer capacity to meet growing loads	Rockhampton	October 2008
Wide Bay 275/132kV substation	New connection point to Ergon to increase 132kV capacity for load growth	Wide Bay	October 2008
Brisbane Area Substation works • South Pine • Nudgee • Ferny Hills • Kenmore • North Capalaba • Upper Mt Gravatt West Darra • Richlands West • Richlands • Runcorn • Mudgeeraba	New connection points to Energex to cater for increasing load growth	Brisbane area	October 2009
QR Bolingbroke 132kV rail supply	New supply to Queensland Rail substation	Bowen Basin mining area	October 2009
Ripley Valley 110kV substation	New connection point to Energex to increase capacity for load growth	Ipswich area	October 2009

7. OTHER RELEVANT INTRA-REGIONAL ISSUES

CONTENTS

7.1 Existing and Committed Generation Developments

7.1.1 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 7.1 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 7.1:

(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) The Townsville power station was converted from liquid fuelled open cycle gas turbine (OCGT) to gas fuelled combined cycle gas turbine (CCGT) in early 2005. Note that the steam turbo-alternator is connected to the Ergon distribution network.

(3) '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.

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

Table 7.1: Generation Capacity

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

Location	Capacity MW Generated (1)					
	Winter 2005	Summer 2005/06	Winter 2006	Summer 2006/07	Winter 2007	Summer 2007/08
Coal Fired						
Callide B	700	700	700	700	700	700
Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Stanwell	1,430	1,430	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	188	188	188	188	188	188
Callide Power Plant	920	900	920	900	920	900
Millmerran	863	853	863	853	863	853
Tarong North	443	443	443	443	443	443
Kogan Creek	0	0	0	0	0	724
TOTAL – Coal Fired	8,124	8,074	8,134	8,084	8,134	8,808
Combustion Turbines						
Barcaldine	50	48	50	48	50	48
Mt Stuart (Townsville)	288	288	288	288	288	288
Townsville (Yabulu) (2)	238	230	238	230	238	230
Oakey	330	310	330	310	330	310
Swanbank E (CCGT)	385	355	385	355	385	355
Roma	68	54	68	54	68	54
Braemar	0	0	0	450	450	450
Other (various locations) (3)	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) (4)	500	500	500	500	500	500
Sugar Mills						
Invicta	39	39	39	39	39	39
TOTAL – Other Than Coal (rounded)	2,113	2,034	2,113	2,484	2,563	2,484
TOTAL – ALL STATIONS (rounded)	**10,237**	**10,108**	**10,247**	**10,568**	**10,697**	**11,292**
Interconnections Queensland – New South Wales **Import Capacity**	500	500	500	500	500	500

[Source: NEMMCO and Powerlink]

7.2 Changes to Supply Capacity

7.2.1 Generation

Since Powerlink's 2004 Annual Planning Report (APR) was published, there has been no change to generation connected to the transmission grid, other than the conversion of the Townsville power station from liquid fuel to gas fuel along with the addition of a steam turbine. The steam turbo-alternator (80 MW) is connected to the distribution network while the output of the existing transmission connected generator has been reduced from 160 MW to 150 MW.

Units at the Kareeya power station are undergoing refurbishment on a progressive basis, resulting in a slightly increased capacity of the station.

CS Energy announced during May 2004, that it has committed to construction of the proposed Kogan Creek 750MW coal fired power station. Expected date of commercial operation is late 2007.

Wambo Power Ventures Pty Ltd announced commitment to a 3 x 150 MW gas fired OCGT power station at Braemar. It has been advised that this station will be available by late 2006.

CS Energy have 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 7.1.

Powerlink has not been advised of any other commitments to new generating capacity since the 2004 APR.

7.2.2 Interconnection

Table 7.1 also includes combined northerly flow capability for the Queensland-New South Wales Interconnection (QNI) and the market network service provider (DirectLink) between Mullumbimby and Terranora in New South Wales.

The combined QNI plus DirectLink maximum northerly capacity is limited 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 capacity 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 7.1.

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 NSW and Qld. It should also be noted that the capability of QNI is distinctly asymmetric with the southerly capability much larger than the northerly capability.

7.2.3 Interconnection Upgrades

Powerlink and TransGrid are currently undertaking a high level study to examine the economics of upgrading QNI. A study was done in 2004 and this did not indicate any significant benefits, which would justify any augmentation to increase capacity. Since then, further generation projects have been committed and the regulatory test criteria have been modified in the market benefits area. The new study was commenced in February 2005 using an external consultant, and results are expected in July 2005.

The study is examining the expected net market benefits of Options B and C in relieving constraints over a range of generation entry scenarios. The overall range of options is outlined in Table 7.2.

Table 7.2: QNI Upgrade Options

Option	Capacity Increase	Description	Estimated Cost
A	Maintain current southerly capacity over time	Works to alleviate thermal limitations in northern NSW network	TransGrid are currently studying this option.
B	Nominal 150MW both directions, subject to possible lower thermal limits	Option A works, plus transient/oscillatory stability enhancements (Series Capacitors, Static VAr Compensators and power control equipment)	$60-120 M (depending on required scope)
C	Nominal 150 - 200MW both directions	Option A and B works, plus augmentation of a section of the 330kV network in northern NSW.	$200 - $250 M
D	Nominal 800 - 1000 MW both directions	An additional Queensland - New South Wales HVAC interconnection (duplication of the existing connection)	$700-900M
E	Nominal 2000MW both directions	A separate Queensland - New South Wales HVDC connection	$1500-2000M

It should be noted that the possible augmentations have different impacts on the northerly and southerly capability, and the scope of works will vary greatly depending on which direction results in the best market benefits.

If the study concludes that at least option B has a reasonable expectation of passing a full regulatory test evaluation, Powerlink and TransGrid will proceed with an intensive study during 2005/06, with a view to justifying and initiating a project.

7.3 Supply Demand Balance

The outlook for the supply demand balance for the Queensland region was published in NEMMCO's 2004 Statement of Opportunities (SOO) in July 2004. A revised outlook is expected to be published by NEMMCO in the 2005 SOO in October 2005.

8. APPENDICES

CONTENTS

8.1 Appendix A – Estimated Network Power Flows

Appendix A illustrates the 18 sample grid power flows for the Queensland region for summer and winter over three years from 2005 to 2007/08.

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 A1: Generation and Load Legend for Figures A3 to A20
- Figure A2: Power Flow and Limits Legend for Figures A3 to A20
- Figure A3: Winter 2005 Qld Peak 400MW Northerly QNI Flow
- Figure A4: Winter 2005 Qld Peak Zero QNI Flow
- Figure A5: Winter 2005 Qld Peak 700MW Southerly QNI Flow
- Figure A6: Winter 2006 Qld Peak 400MW Northerly QNI Flow
- Figure A7: Winter 2006 Qld Peak Zero QNI Flow
- Figure A8: Winter 2006 Qld Peak 500MW Southerly QNI Flow
- Figure A9: Winter 2007 Qld Peak 400MW Northerly QNI Flow
- Figure A10: Winter 2007 Qld Peak Zero QNI Flow
- Figure A11: Winter 2007 Qld Peak 400MW Southerly QNI Flow
- Figure A12: Summer 2005/06 Qld Peak 400MW Northerly QNI Flow
- Figure A13: Summer 2005/06 Qld Peak Zero QNI Flow
- Figure A14: Summer 2005/06 Qld Peak 300MW Southerly QNI Flow
- Figure A15: Summer 2006/07 Qld Peak 400MW Northerly QNI Flow
- Figure A16: Summer 2006/07 Qld Peak Zero QNI Flow
- Figure A17: Summer 2006/07 Qld Peak 200MW Southerly QNI Flow
- Figure A18: Summer 2007/08 Qld Peak 400MW Northerly QNI Flow
- Figure A19: Summer 2007/08 Qld Peak Zero QNI Flow
- Figure A20: Summer 2007/08 Qld Peak 400MW Southerly QNI Flow

Table A.1: Summary of Figures A3 to A20 - Possible Grid Power Flows and Limit Stability States

Grid Section (1)		2005 WINTER Fig A3 / A4 / A5	2006 WINTER Fig A6 / A7 / A8	2007 WINTER Fig A9 / A10 / A11	2005/06 SUMMER Fig A12 / A13 / A14	Fig A15 / A16 / A17	2007/08 SUMMER Fig A18 / A19 / A20	Due To (4)
'Far North' Transfer								
Ross into Chalumbin 275kV (2 circuits)	Flow	140 /140 / 140	152 / 151 /151	162 / 160 /162	229 /229 / 229	244 / 244 / 244	256 / 256 / 256	V
Tully into Kareeya 132kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
'CQ-NQ' Transfer								
Broadsound into Nebo 275kV (2 circuits)	Flow	522 / 522 / 466	577 / 577 / 577	620 / 618 / 563	772 / 772 / 772	834 / 834 / 835	881 / 881 / 881	Tr, Th,V
Bouldercombe into Nebo 275kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Dysart to Peak Downs 132kV (2 parallel circuits)								
'Gladstone' Transfer (5)								
Bouldercombe into Gladstone 275kV (2 circuits)	Flow	1040 / 922 / 994	925 / 1037 / 855	1074 / 906 / 890	866 / 728 / 728	761 / 741 / 787	820 / 801 / 728	Th
Calvale into Wurdong 275kV (1 circuit)	Stability	U / S / S	U / S / S	S / S / S	S / S / S	S / S / S	U / U / S	
Callide A into Gladstone South 132kV (2 circuits)								
'CQ-SQ' Transfer								
Wurdong into Gin Gin 275kV (1 circuit)	Flow	1036 / 1305 / 1902	1108 / 1496 / 1889	1341 / 1734 / 1863	1507 / 1787 / 1764	1619 / 1636 / 1533	1424 / 1458 / 1592	Tr,V
Gladstone into Gin Gin 275kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Calvale into Tarong 275kV (2 circuits)								
'Tarong' Transfer								
Tarong to South Pine, Mt England	Flow	2966 / 2696 / 2281	2962 / 2773 / 2448	3061 / 2840 / 2511	3123 / 2897 / 2649	3280 / 3113 / 3067	3697 / 3680 / 3369	V
and Blackwall 275kV (5 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Middle Ridge to Swanbank and Postmans Ridge 110kV (3 circuits)								
'Gold Coast' Transfer (6)								
Swanbank into Mudgeeraba 275kV (2 circuits)	Flow							V,Th
Maudsland Tee into Molendinar 275kV (2 circuits operating in parallel as one line)	Stability	689 / 689 / 689	714 / 714 / 714	756 / 756 / 756	683 / 683 / 683	812 / 812 / 812	869 / 869 / 869	
Coomera to Cades County 110kV (1 circuit)		S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	

Grid Section (1)		Illustrative Grid Power Flows (MW) and Limit Stability at Queensland Region Peak Load Time (2)(3)						Limit Due To (4)
		2005 WINTER Fig A3 / A4 / A5	**2006 WINTER Fig A6 / A7 / A8**	**2007 WINTER Fig A9 / A10 / A11**	**2005/06 SUMMER Fig A12 / A13 / A14**	**2006/07 SUMMER Fig A15 / A16 / A17**	**2007/08 SUMMER Fig A18 / A19 / A20**	
'SWQ' Transfer								
Braemar into Tarong 275kV (2 circuits)	Flow	919 / 529 / -168	906 / 516 / 20	901 / 511 / 115	909 / 524 / 273	1047 / 814 / 801	1612 / 1530 / 1137	
Middle Ridge into Tarong 275kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Middle Ridge to Swanbank and Postmans Ridge 110kV (3 circuits)								Th

Notes:

(1) 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 (ie all network circuits in service), and are based on existing network configurations, committed projects, and proposed new assets in Chapter 6. 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.
(6) The Gold Coast grid section is defined for the winter 2005 network configuration.
Following the establishment of Greenbank 275kV substation by summer 2006/07, the grid section will be defined as:
- Greenbank into Mudgeeraba 275kV (2 circuits);
- Greenbank into Molendinar 275kV (2 circuits operating in parallel as one line);
- Coomera into Cades County 110kV (1 circuit).

Following the proposed installation of the second Molendinar 275/110kV transformer by summer 2007/08, the grid section will be defined as:
- Greenbank into Mudgeeraba 275kV (2 circuits);
- Greenbank into Molendinar 275kV (2 circuits);
- Coomera into Cades County 110kV (1 circuit).

Table A.2: Transformer Capacity and Estimates of Loading of 275kV Substations

275kV Substation (1) (2)	Possible MVA at Queensland Region Peak (4)(5)						Dependence other than Local Load		Other Comments
Transformers No. x MVA Nameplate Rating (3)	Winter 2005	Winter 2006	Winter 2007	Summer 2005/06	Summer 2006/07	Summer 2007/08	Significant dependence on:	Minor dependence on:	
Woree 275/132 (1x375)	77	81	94	121	132	128	Barron Gorge generation	Kareeya generation	
Chalumbin 275/132 (2x200)	53	74	73	101	110	115	Barron Gorge and Kareeya generation	Townsville & Mt Stuart generation	
Ross 275/132 (2x250 and 1x200)	134	167	160	213	225	239	Mt Stuart, Townsville & Invicta generation	Collinsville generation	
Strathmore 275/132 (1x375)	40	41	48	33	49	42	Collinsville & Invicta generation	Townsville & Mt Stuart generation	
Nebo 275/132 (2x200)	203	238	245	264	276	287	Mackay GT generation	Collinsville generation	Summer 2005/06 3rd TX - 250MVA
Lilyvale 275/132 (2x375)	193	221	226	227	239	246	Barcaldine generation	CQ-NQ flow	
Bouldercombe 275/132 (2x200)	137	147	150	152	154	159			
Calvale 275/132 (1x250)	176	190	177	176	184	201	Central Queensland generation		
Gin Gin 275/132 (2x120)	177	183	182	186	186	189	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)	257	263	268	259	270	274	132kV transfers to/from Gin Gin	CQ-SQ flow	
Palmwoods 275/132 (2x375)	316	327	353	324	350	387	132/110kV transfers to/from South Pine & Woolooga	CQ-SQ flow	
South Pine 275/110 (1x375, 1x250 and 2x200)	752	752	792	884	908	967	110kV transfers to/from Rocklea & Palmwoods	CQ-SQ flow & Swanbank generation	One 200MVA replaced by a 375MVA winter 2006, and one 200MVA replaced by a 250MVA summer 06/07.
Rocklea 275/110 (2x375)	496	496	480	563	535	562	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Swanbank & Swanbank B generation	

275kV Substation (1) (2)	Possible MVA at Queensland Region Peak (4)(5)						Dependence other than Local Load		Other Comments
Transformers No. x MVA Nameplate Rating (3)	Winter 2005	Winter 2006	Winter 2007	Summer 2005/06	Summer 2006/07	Summer 2007/08	Significant dependence on:	Minor dependence on:	
Belmont 275/110 (2x250 and 2x200)	653	718	604	824	703	727	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea	
Murarrie 275/110 (1x375)	n/a	n/a	218	n/a	275	319			Summer 2006/07 – 1st TX 375MVA (Belmont to Murarrie 275kV line)
Swanbank 275/110 (1x250 and 1x240)	267	252	267	291	278	338	110kV transfers to/from South Pine, Millmerran and Oakey GT generation	110kV transfers to/from Rocklea & Swanbank B generation	
Goodna 275/110 (1x375)	n/a	n/a	n/a	n/a	n/a	197			Summer 2007/08 – 1st TX 375MVA (proposed new large network asset)
Loganlea 275/110 (2x375)	423	446	417	482	455	455	110kV transfers to/from Belmont	110kV transfers to/from Molendinar & Mudgeeraba	
Molendinar 275/110 (1x375)	231	244	298	253	356	462	110kV transfers to/from Loganlea & Mudgeeraba	DirectLink MNSP	Summer 2007/08 – 2nd TX 375MVA (proposed new small network asset)
Mudgeeraba 275/110 (3x250)	441	466	469	456	498	509	110kV transfers to/from Molendinar & DirectLink MNSP	110kV transfers to/from Loganlea	
Middle Ridge 275/110 (3x250)	485	492	499	507	529	324	Oakey GT generation	Swanbank B generation	
Tarong 275/132 (2x90)	71	71	72	66	69	61	Roma generation		
Tarong 275/66 (2x90)	37	38	40	38	40	41			

Notes:

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

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

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

(4) Substation loadings are derived from the assumed generation dispatch cases shown within Figures A3 to A20. The loadings are estimated for system normal (i.e. all network elements in service), and are based on existing network configurations, committed projects, and proposed new assets in Chapter 6. MVA loadings for transformers depend on power factor, and may be different under other generation patterns, outage conditions, local or zone peak demand times or different availability of local and down stream capacitor banks.

(5) Substation loadings are the maximum of each of the northerly/zero/southerly QNI scenarios for each year/season shown within the assumed generation dispatch cases in Figures A3 to A20.

Figure A.1: Generation and Load Legend for Figures A3 to A20

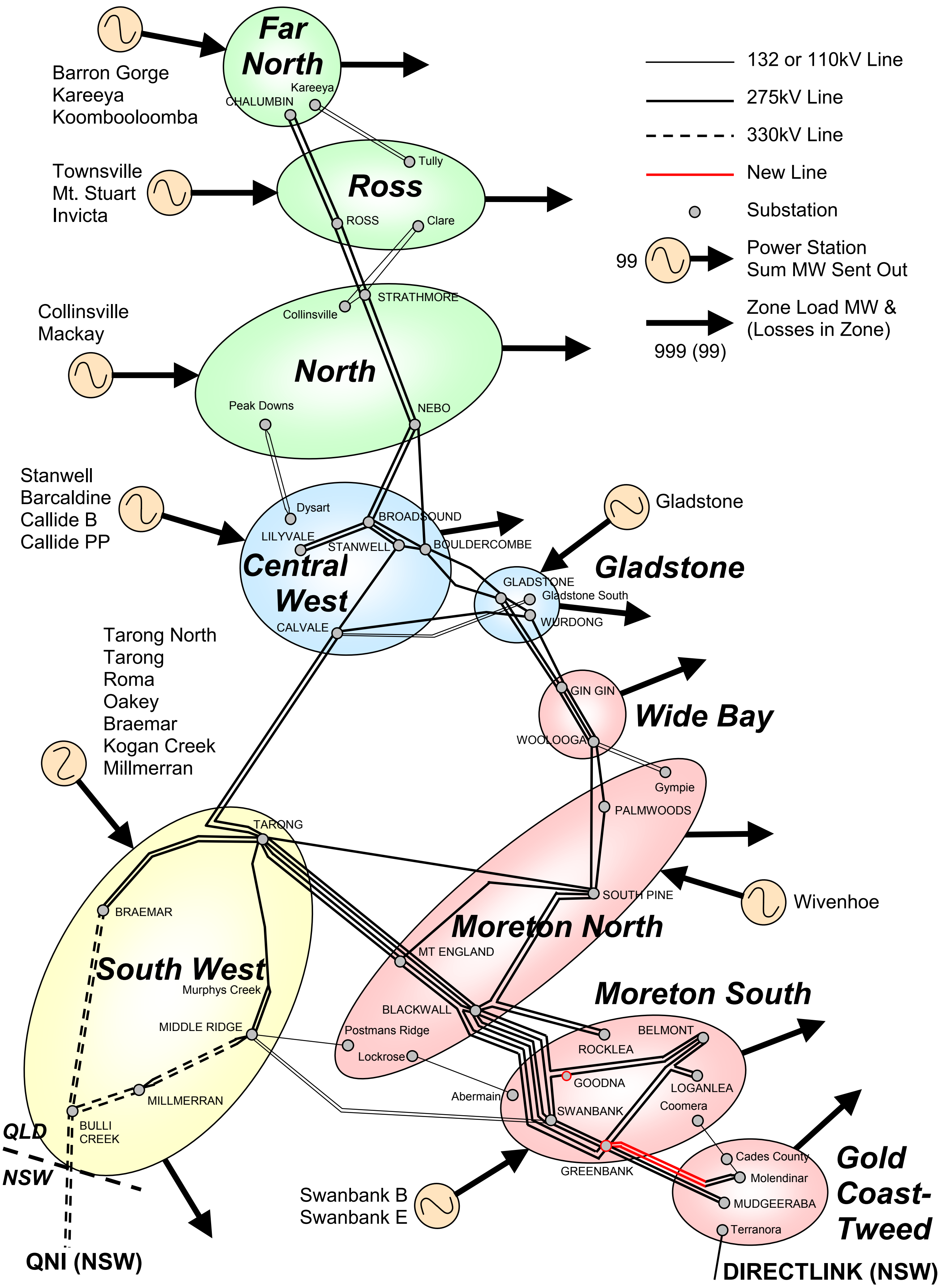


Figure A.2: Power Flow and Limits Legend for Figures A3 to A20

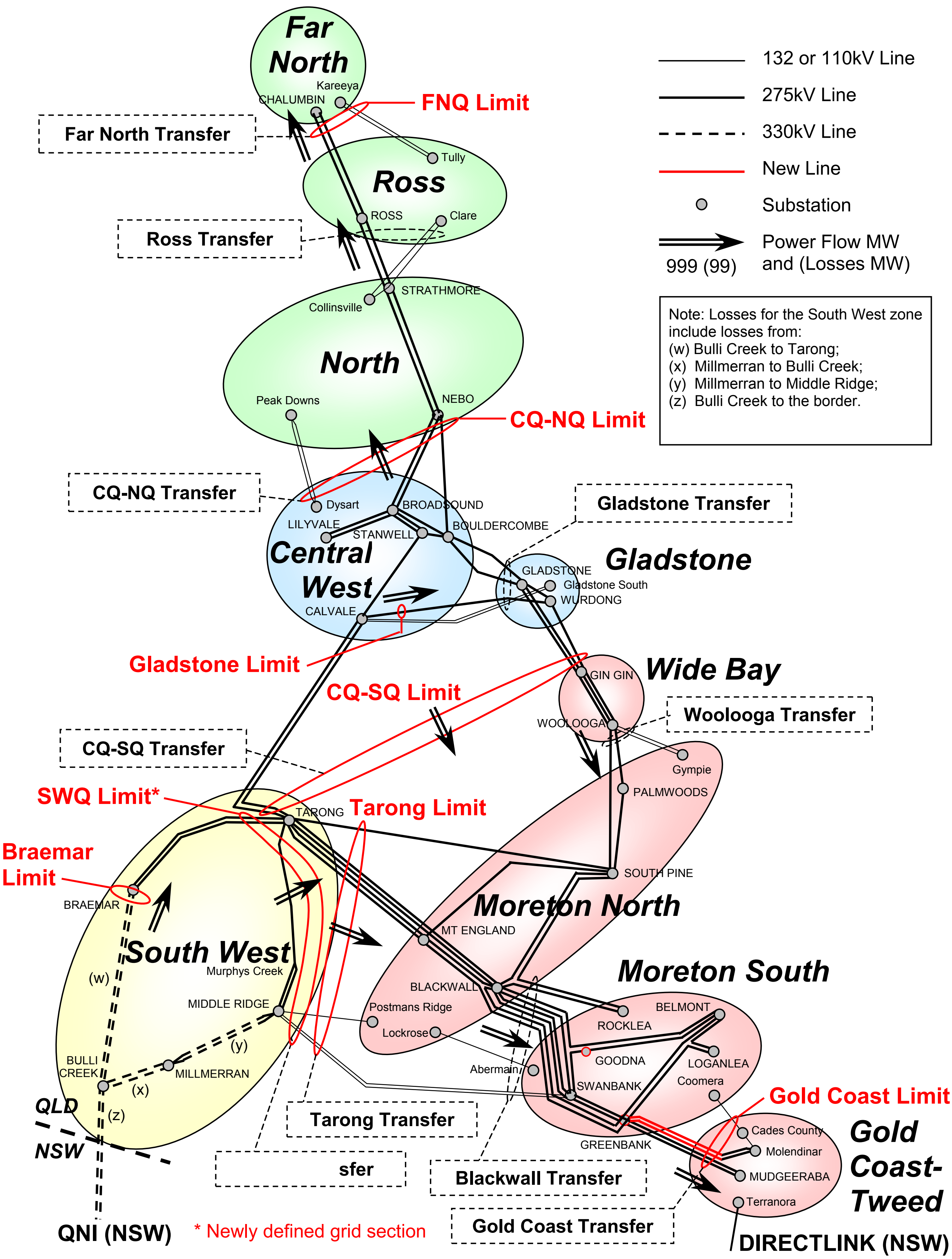
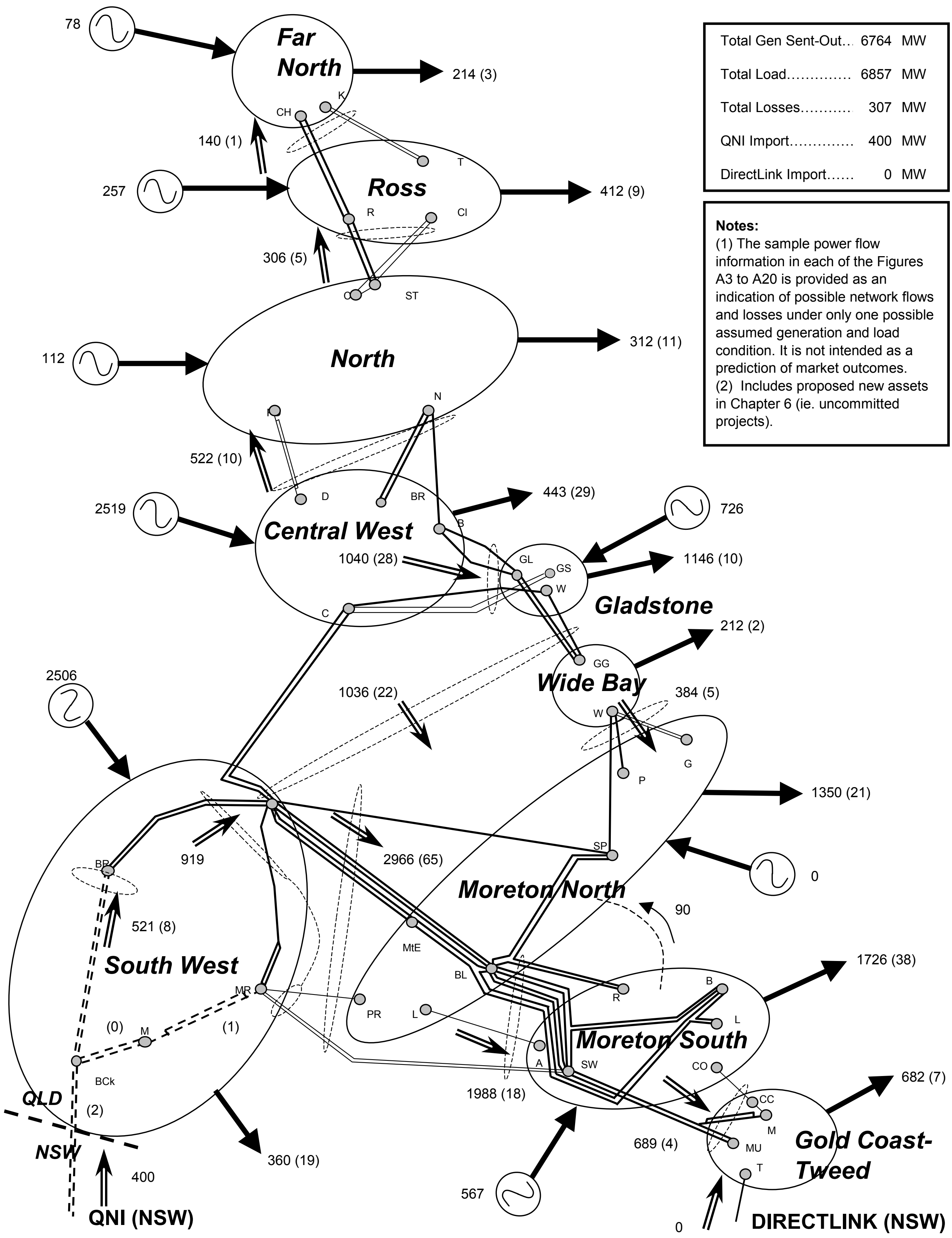


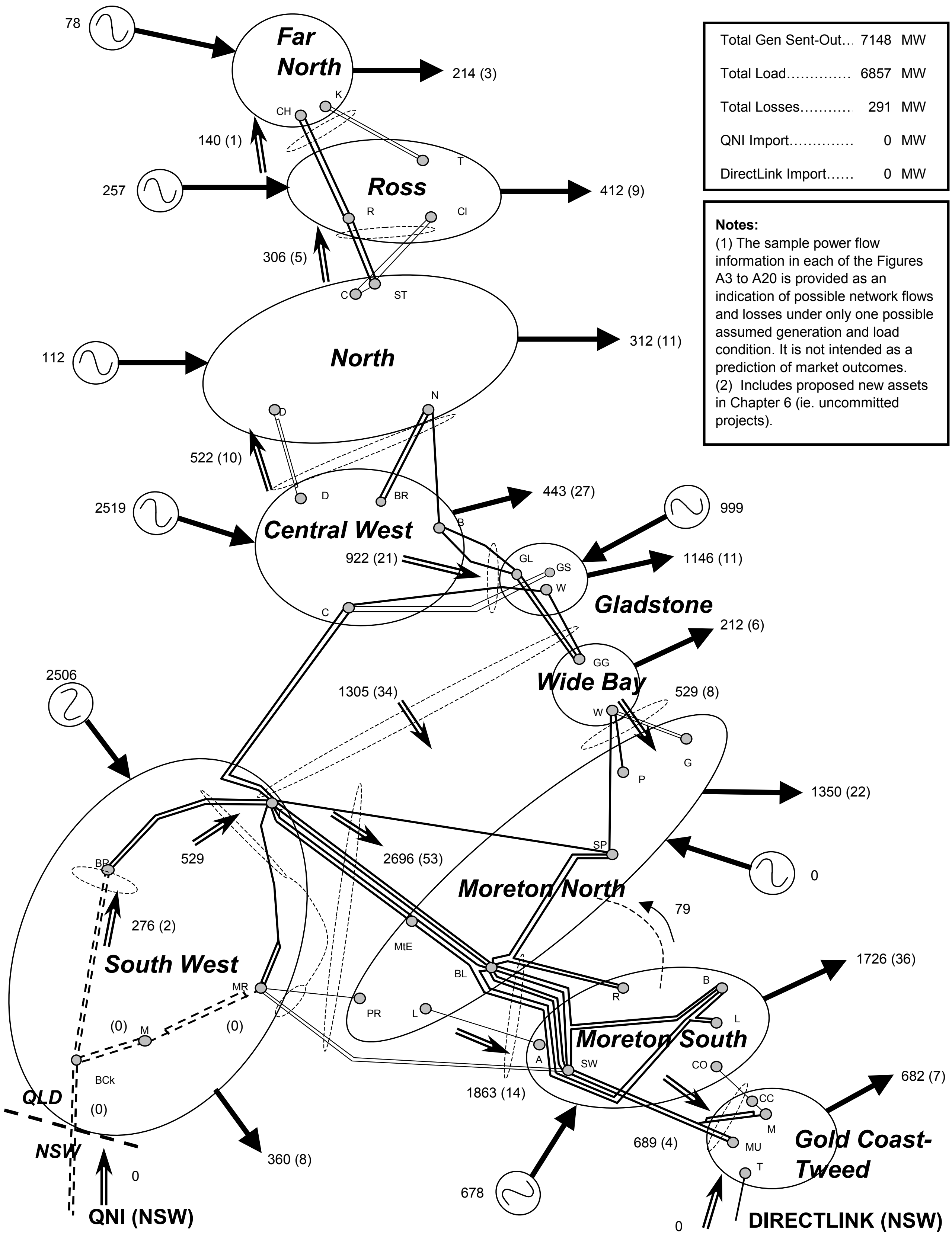
Figure A.3: Winter 2005 Qld Peak 400MW Northerly QNI Flow



Total Gen Sent-Out…	6764	MW
Total Load…………..	6857	MW
Total Losses………..	307	MW
QNI Import………….	400	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

Figure A.4: Winter 2005 Qld Peak Zero QNI Flow



Total Gen Sent-Out..	7148	MW
Total Load..............	6857	MW
Total Losses...........	291	MW
QNI Import.............	0	MW
DirectLink Import......	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

Figure A.5: Winter 2005 Qld Peak 700MW Southerly QNI Flow

Total Gen Sent-Out…	7889 MW
Total Load……………	6857 MW
Total Losses…………	332 MW
QNI Import…………	-700 MW
DirectLink Import……	0 MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

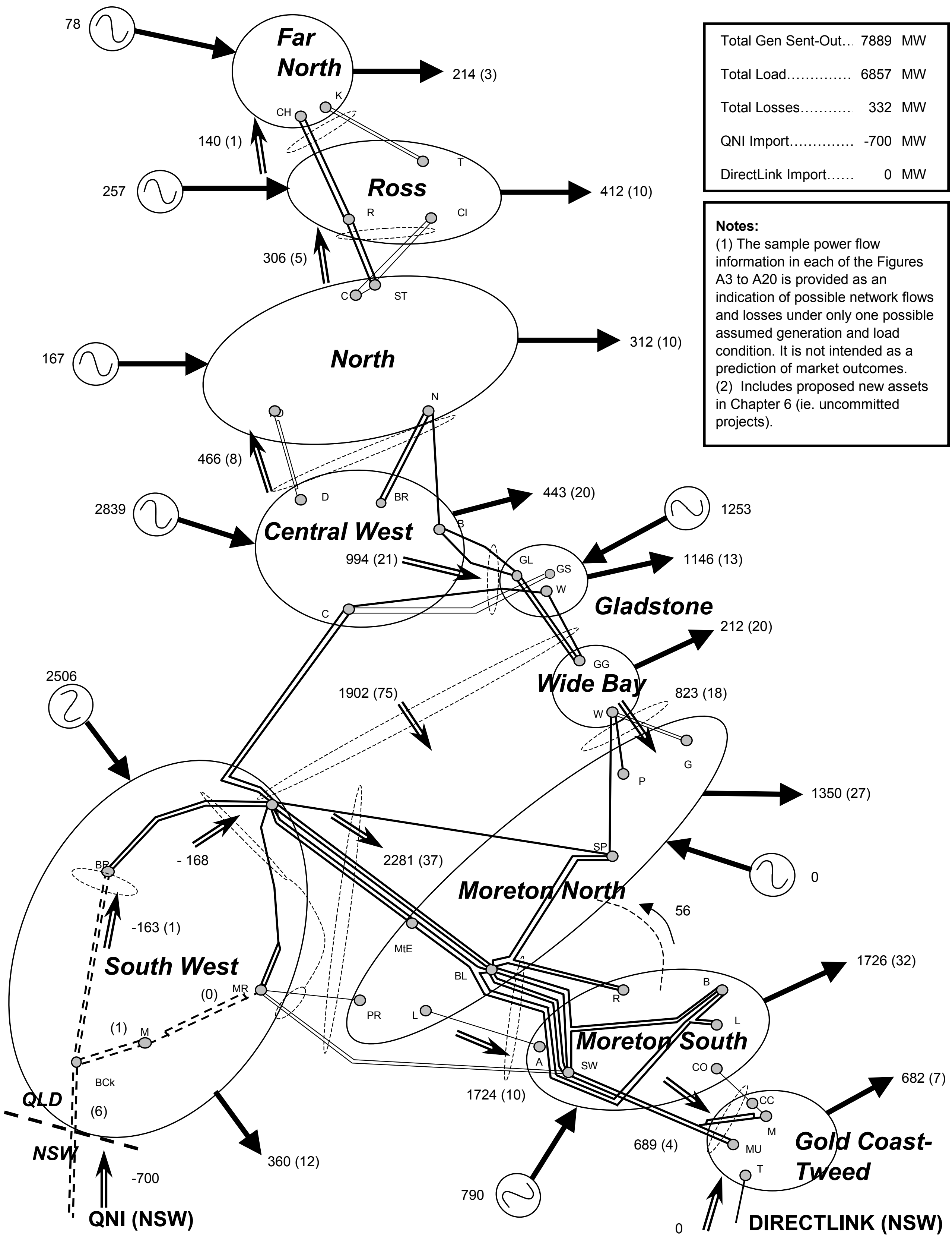


Figure A.6: Winter 2006 Qld Peak 400MW Northerly QNI Flow

Total Gen Sent-Out...	7104	MW
Total Load..............	7178	MW
Total Losses...........	326	MW
QNI Import.............	400	MW
DirectLink Import......	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

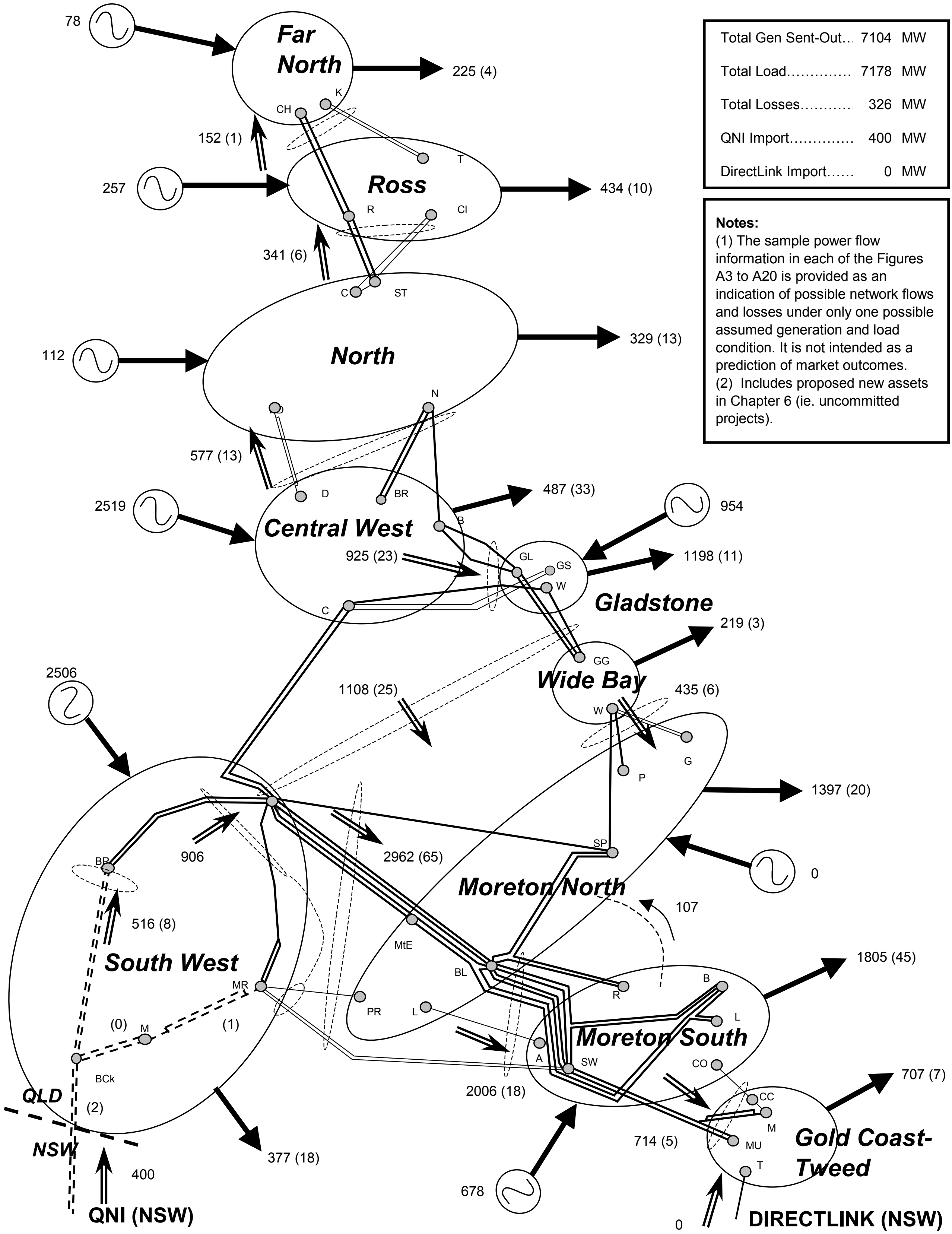


Figure A.7: Winter 2006 Qld Peak Zero QNI Flow

Total Gen Sent-Out…	7510	MW
Total Load…………..	7178	MW
Total Losses………..	332	MW
QNI Import………….	0	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

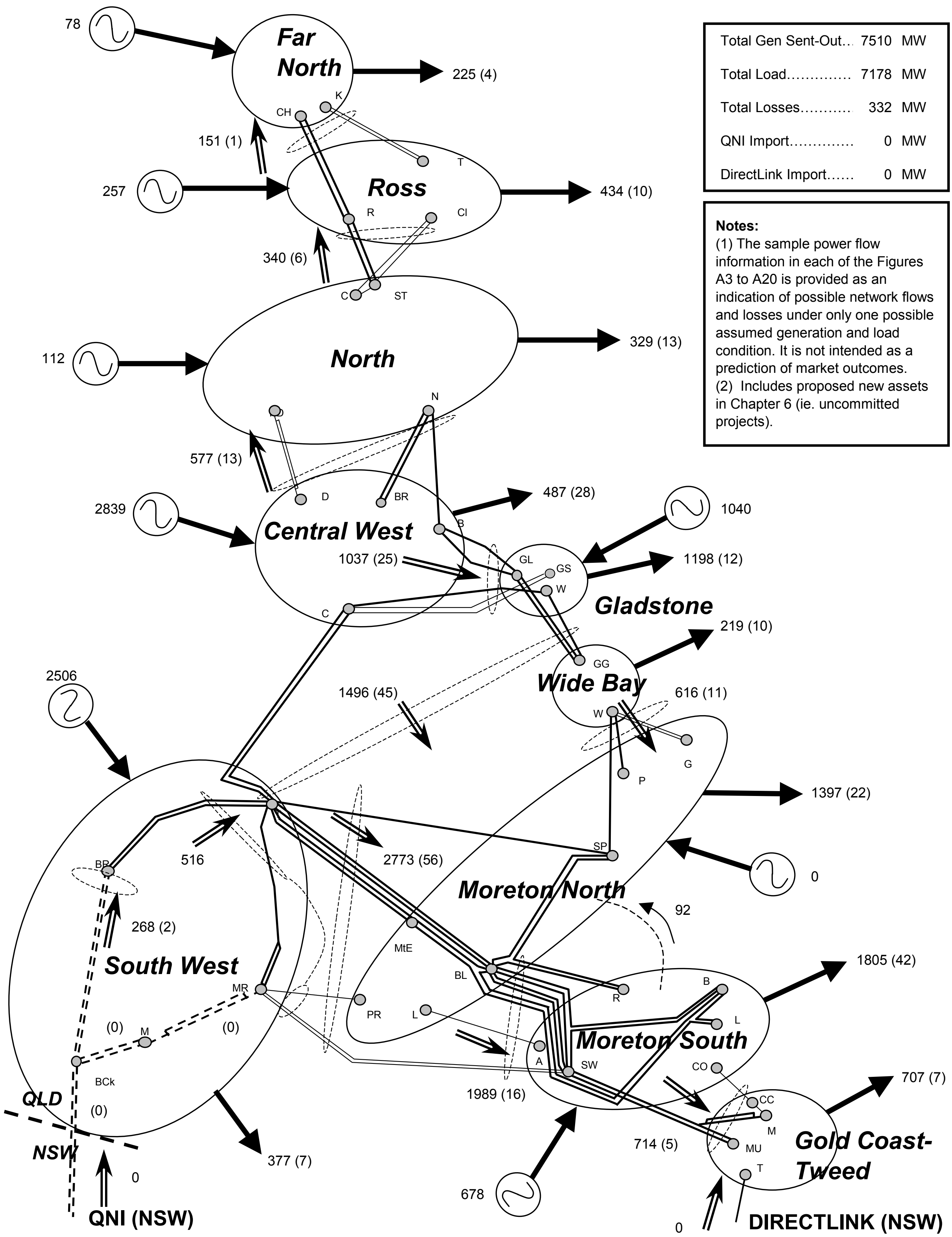
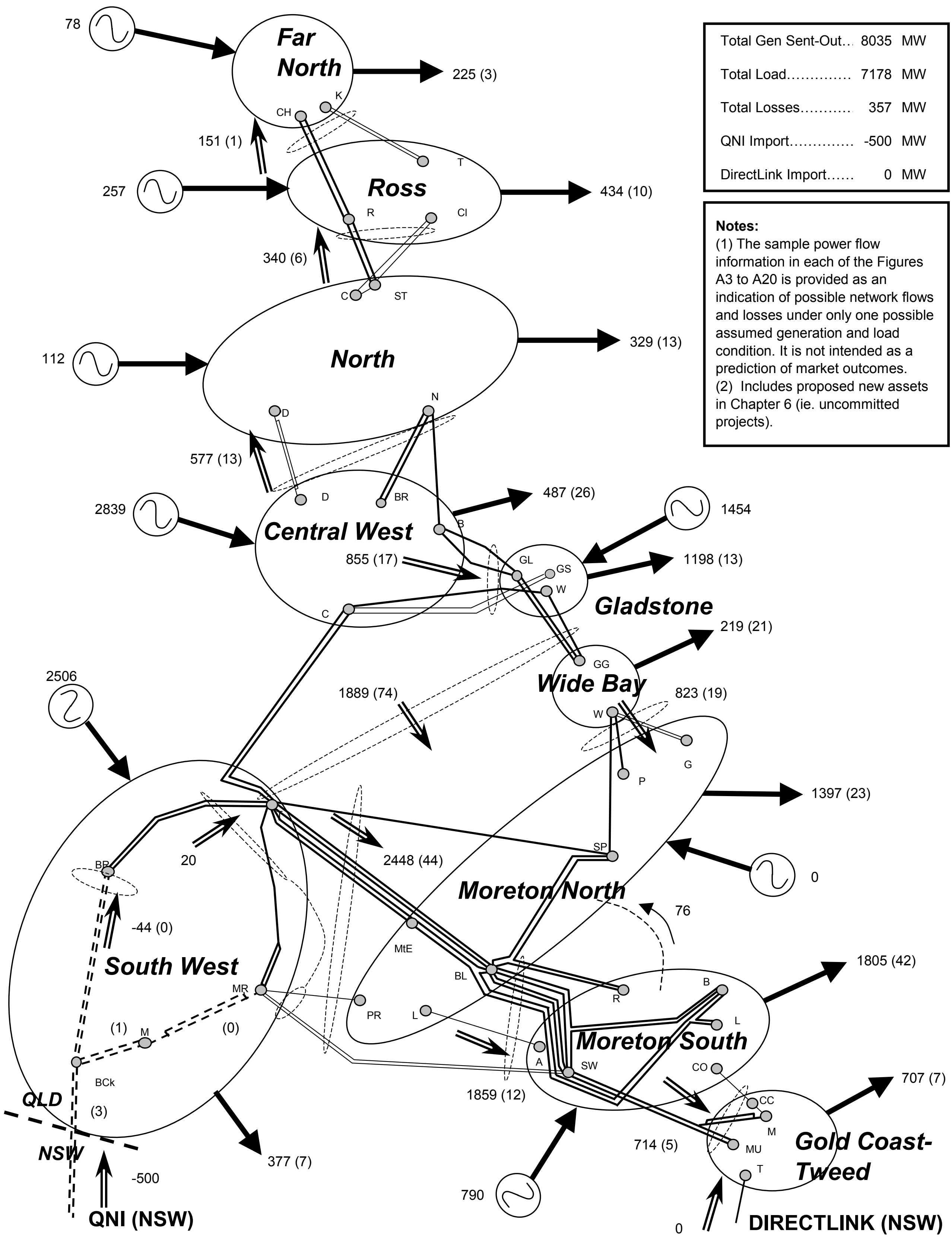


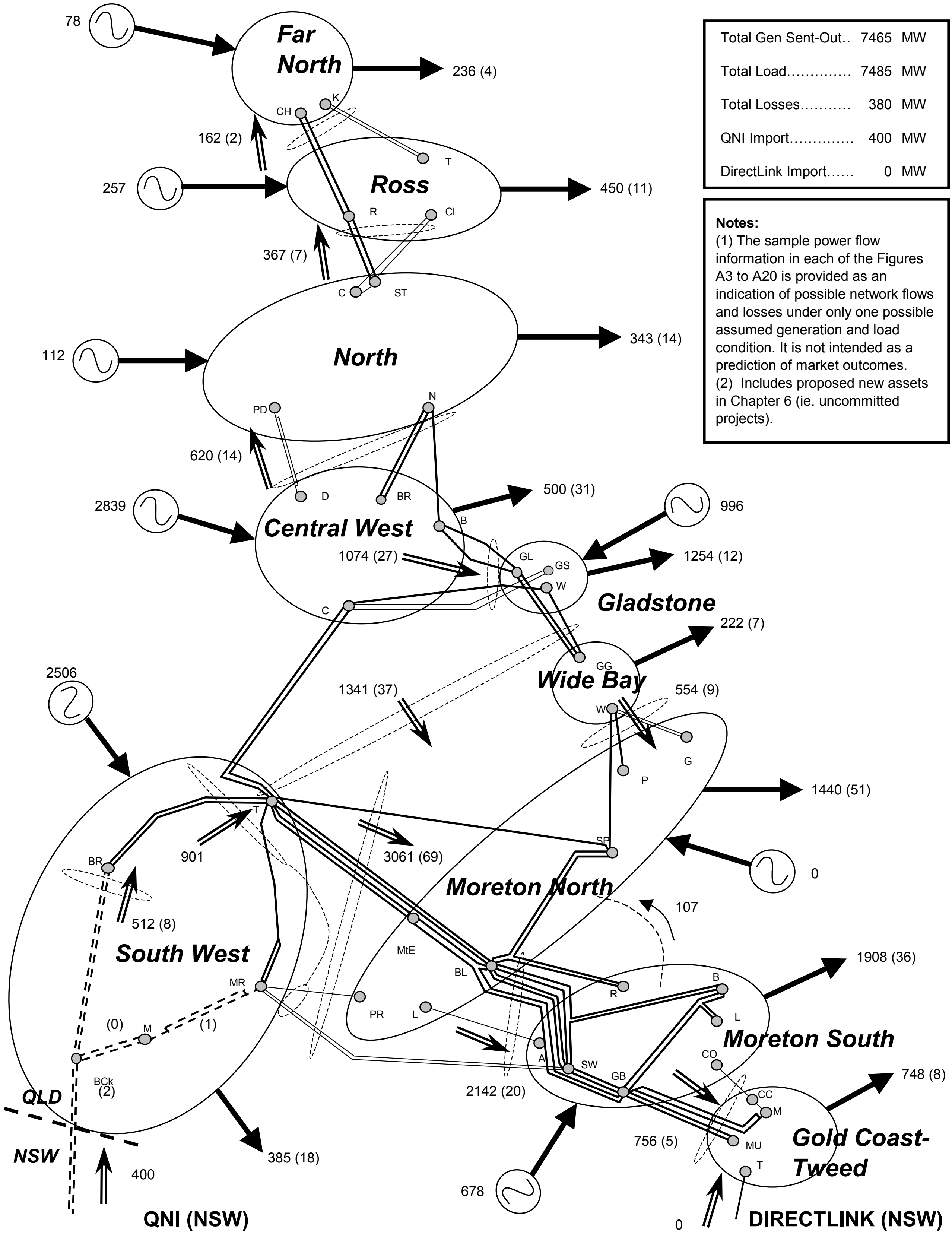
Figure A.8: Winter 2006 Qld Peak 500MW Southerly QNI Flow



Total Gen Sent-Out...	8035	MW
Total Load..............	7178	MW
Total Losses...........	357	MW
QNI Import.............	-500	MW
DirectLink Import......	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

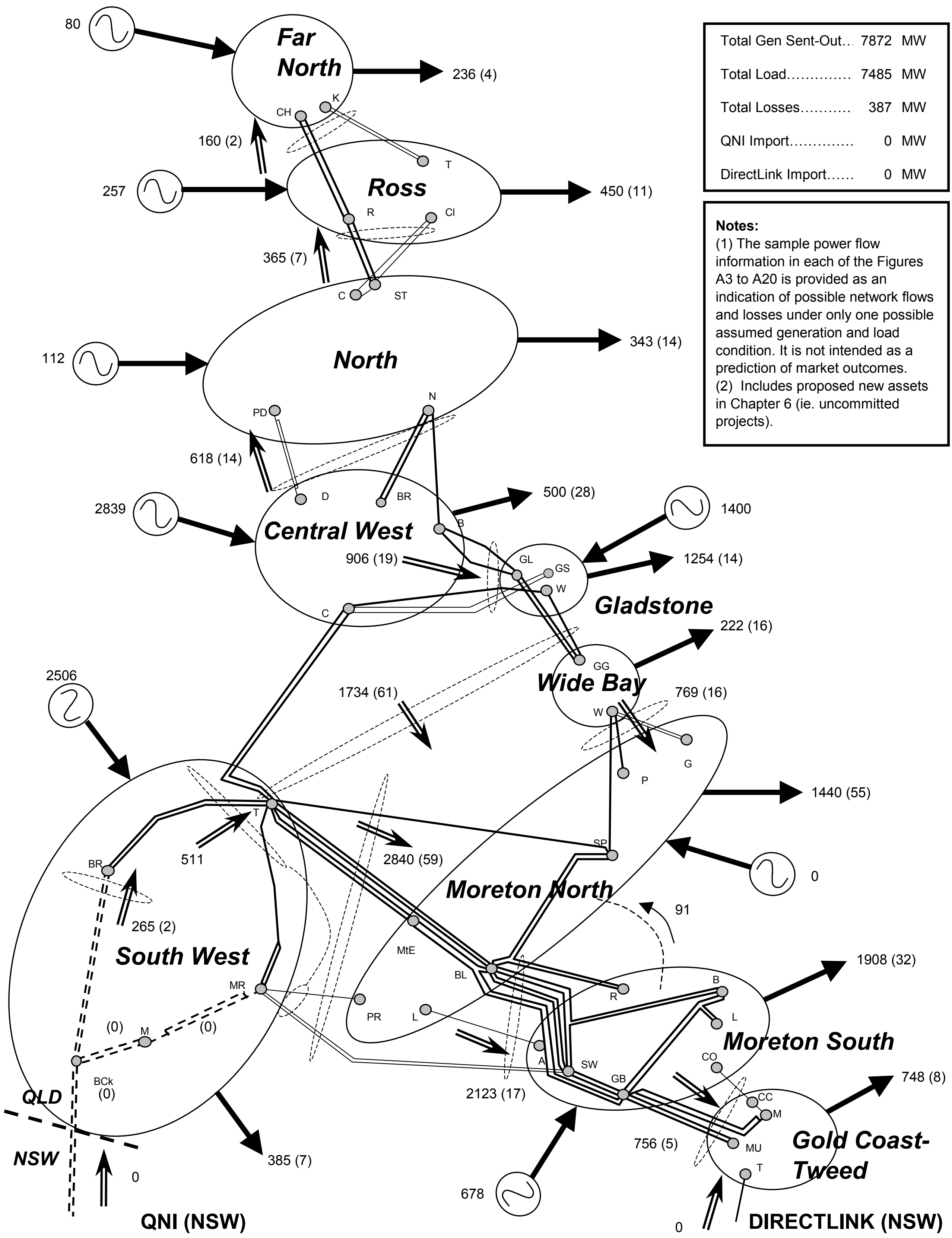
Figure A.9: Winter 2007 Qld Peak 400MW Northerly QNI Flow



Total Gen Sent-Out…	7465	MW
Total Load…………..	7485	MW
Total Losses………..	380	MW
QNI Import………….	400	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

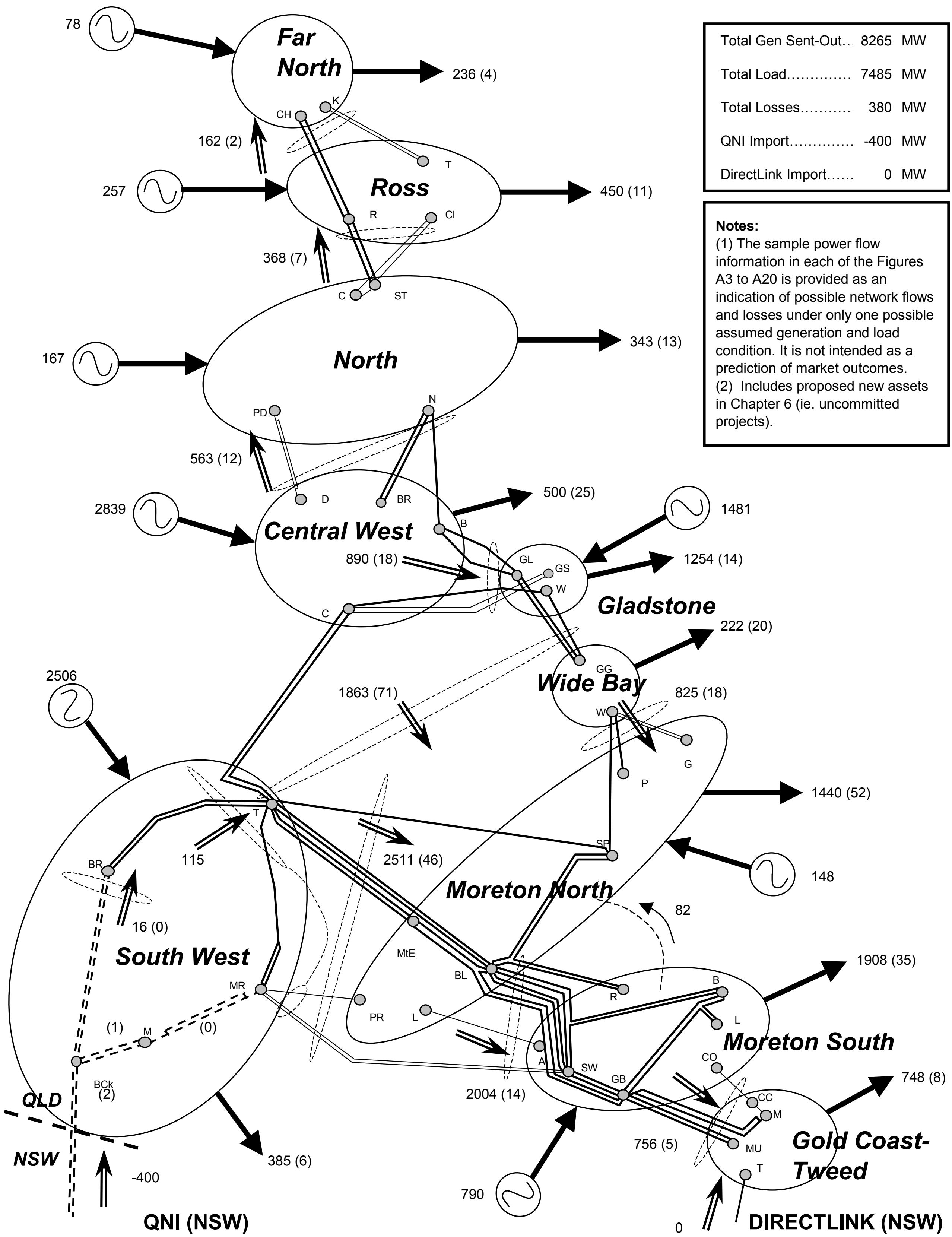
Figure A.10: Winter 2007 Qld Peak Zero QNI Flow



Total Gen Sent-Out...	7872	MW
Total Load.............	7485	MW
Total Losses...........	387	MW
QNI Import.............	0	MW
DirectLink Import......	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

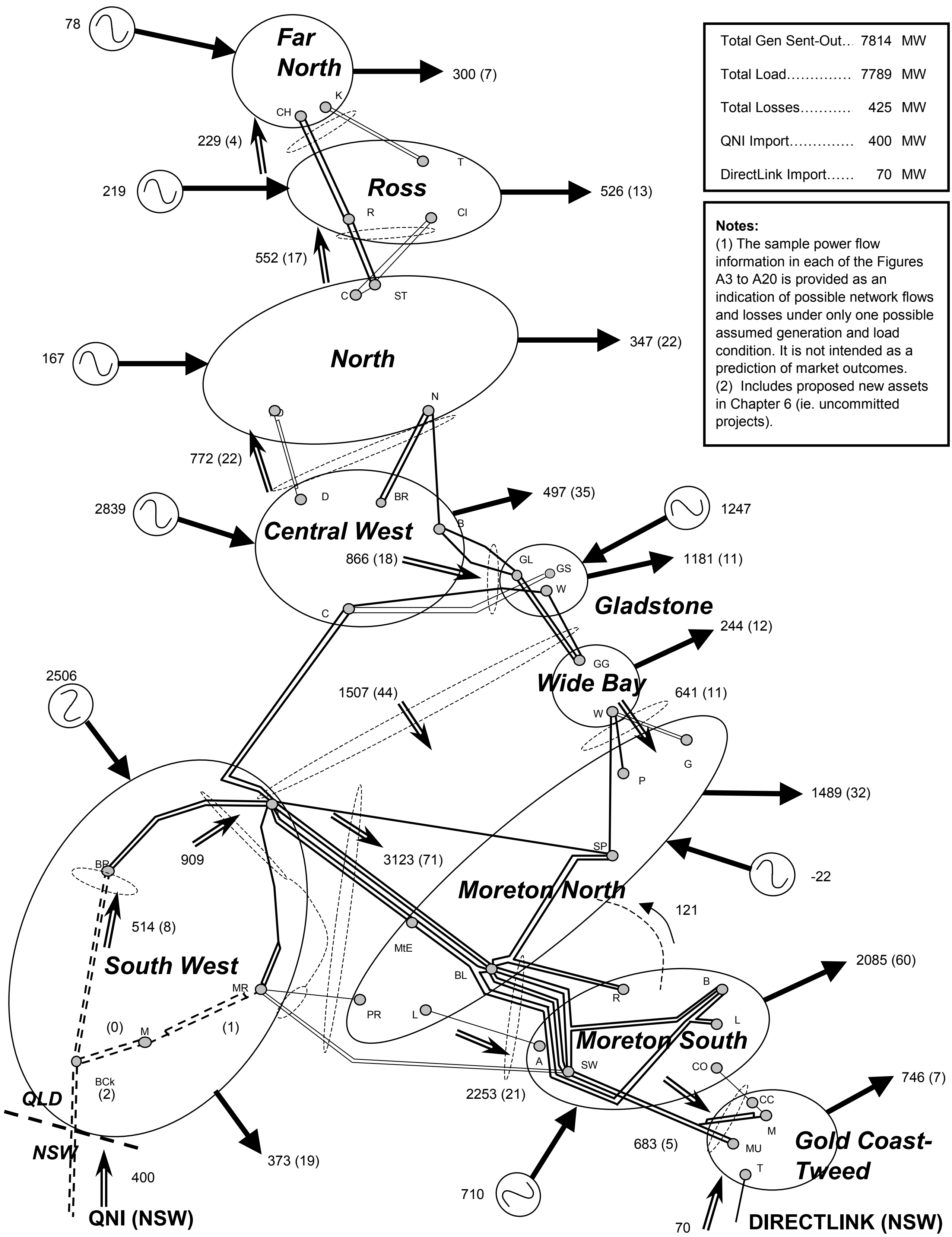
Figure A.11: Winter 2007 Qld Peak 400MW Southerly QNI Flow



Total Gen Sent-Out...	8265 MW
Total Load..............	7485 MW
Total Losses...........	380 MW
QNI Import..............	-400 MW
DirectLink Import......	0 MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

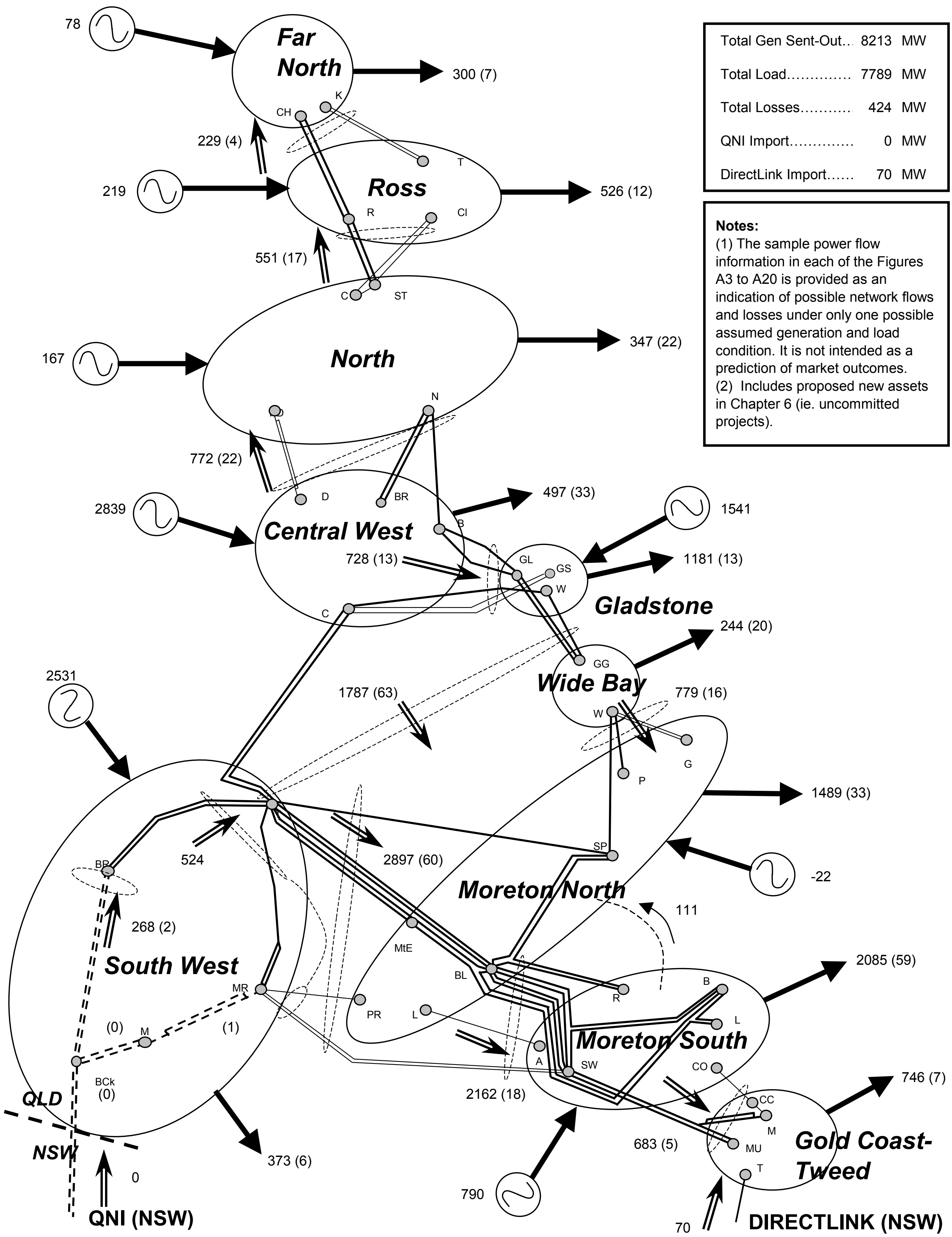
Figure A.12: Summer 2005/06 Qld Peak 400MW Northerly QNI Flow



Total Gen Sent-Out…	7814	MW
Total Load…………..	7789	MW
Total Losses………..	425	MW
QNI Import………….	400	MW
DirectLink Import……	70	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

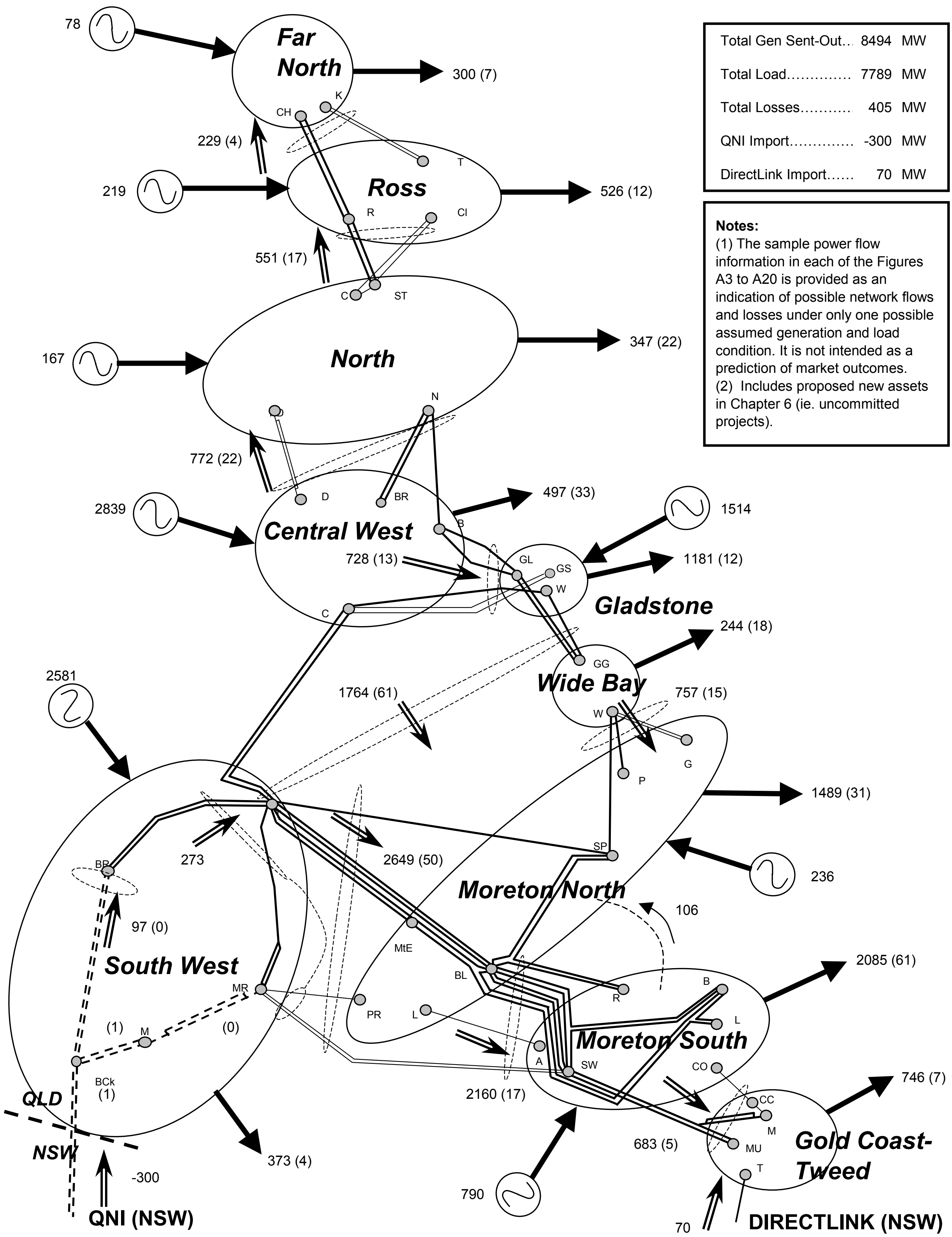
Figure A.13: Summer 2005/06 Qld Peak Zero QNI Flow



Total Gen Sent-Out…	8213	MW
Total Load…………..	7789	MW
Total Losses………..	424	MW
QNI Import………….	0	MW
DirectLink Import……	70	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

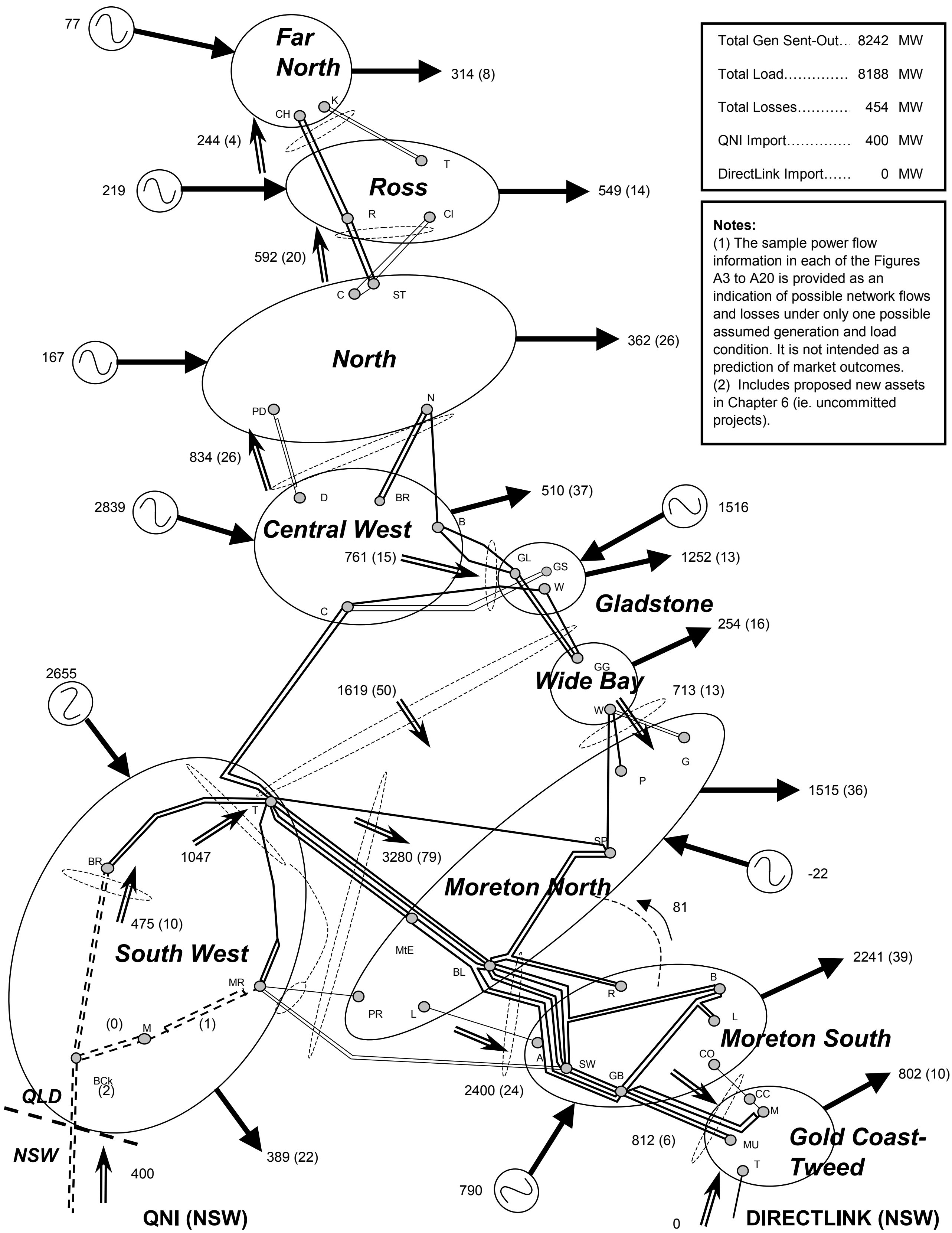
Figure A.14: Summer 2005/06 Qld Peak 300MW Southerly QNI Flow



Total Gen Sent-Out…	8494	MW
Total Load…………..	7789	MW
Total Losses………..	405	MW
QNI Import………….	-300	MW
DirectLink Import……	70	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

Figure A.15: Summer 2006/07 Qld Peak 400MW Northerly QNI Flow



Total Gen Sent-Out…	8242	MW
Total Load…………..	8188	MW
Total Losses………..	454	MW
QNI Import………….	400	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

Figure A.16: Summer 2006/07 Qld Peak Zero QNI Flow

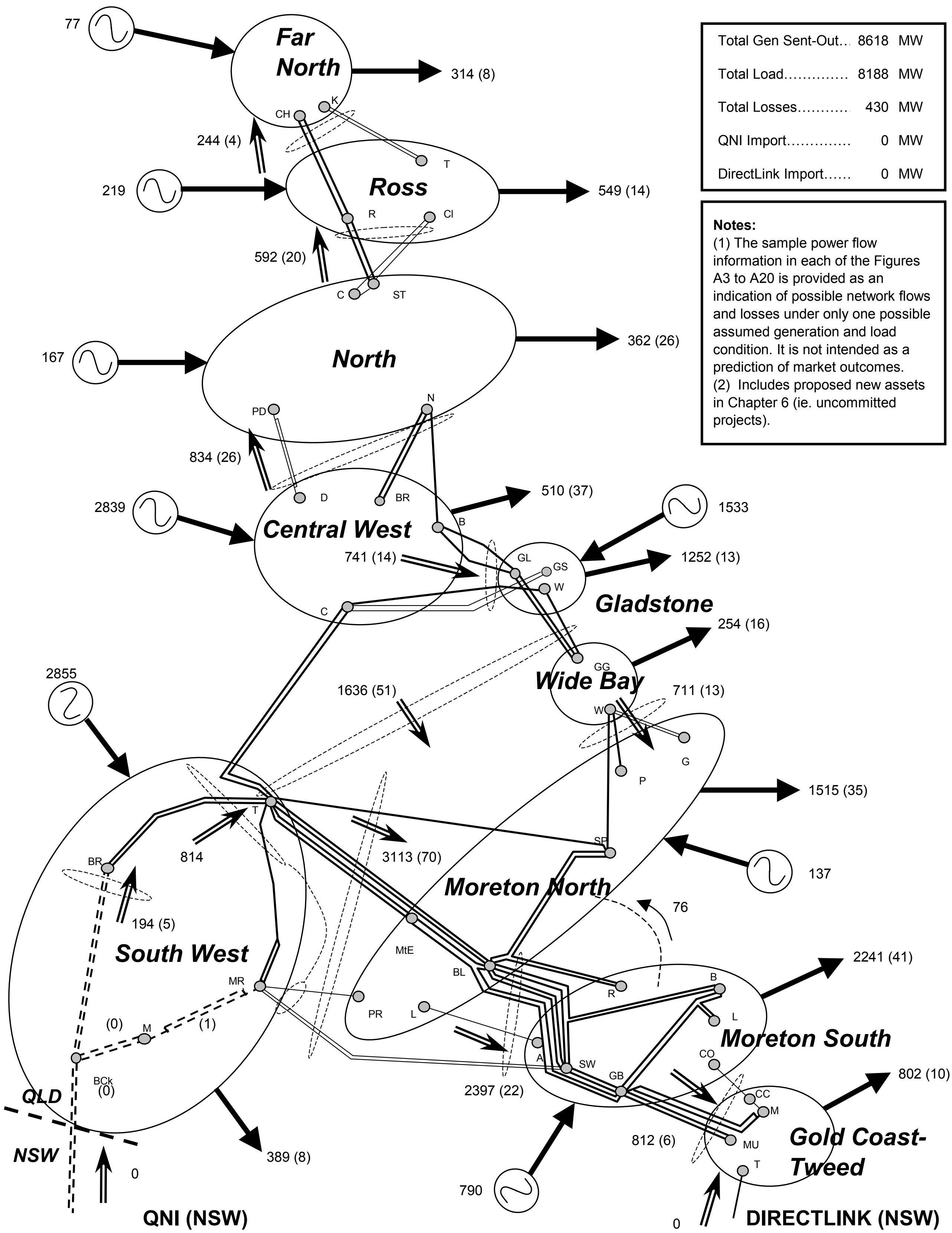
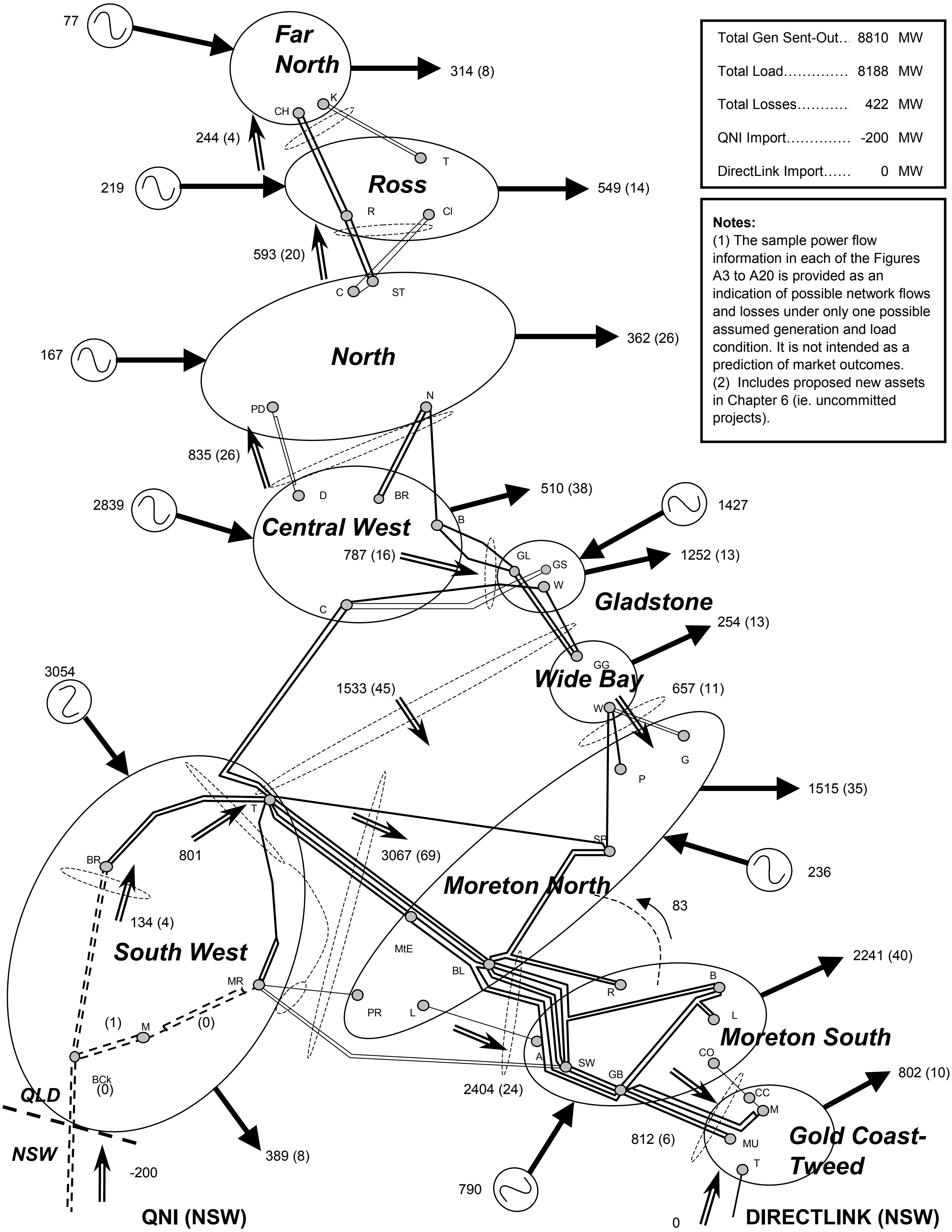


Figure A.17: Summer 2006/07 Qld Peak 200MW Southerly QNI Flow



Total Gen Sent-Out…	8810	MW
Total Load…………..	8188	MW
Total Losses………..	422	MW
QNI Import………….	-200	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

Figure A.18: Summer 2007/08 Qld Peak 400MW Northerly QNI Flow

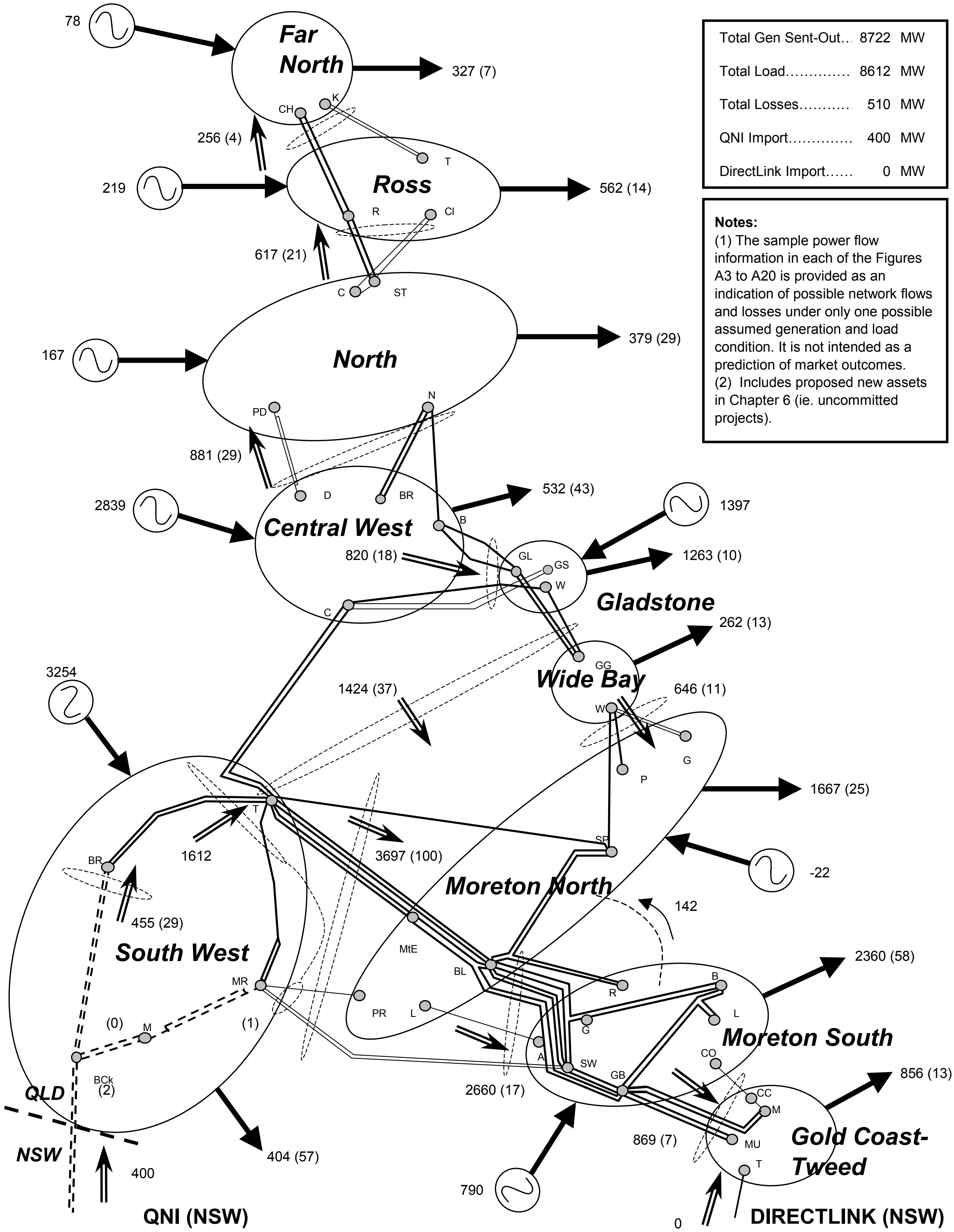


Figure A.19: Summer 2007/08 Qld Peak Zero QNI Flow

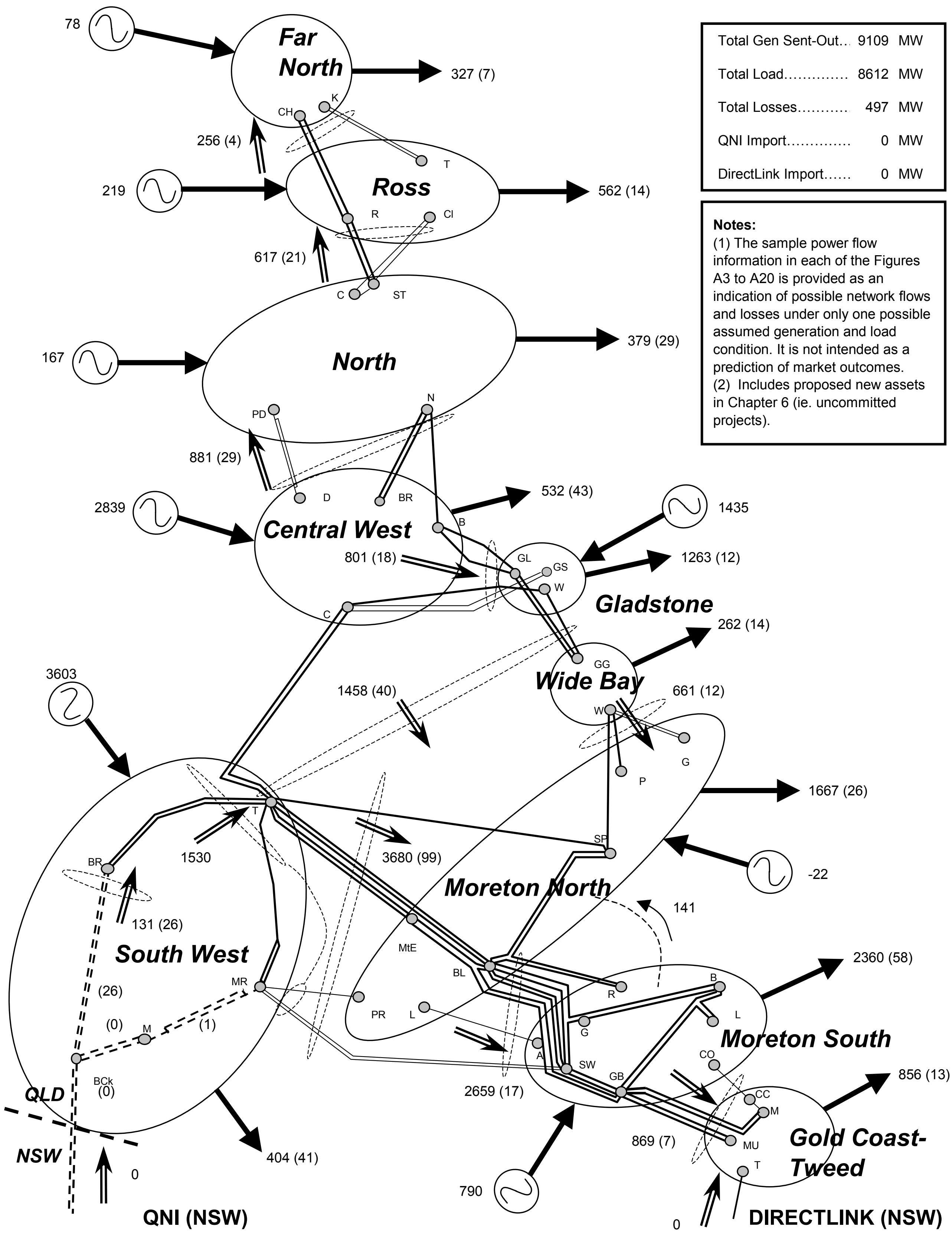
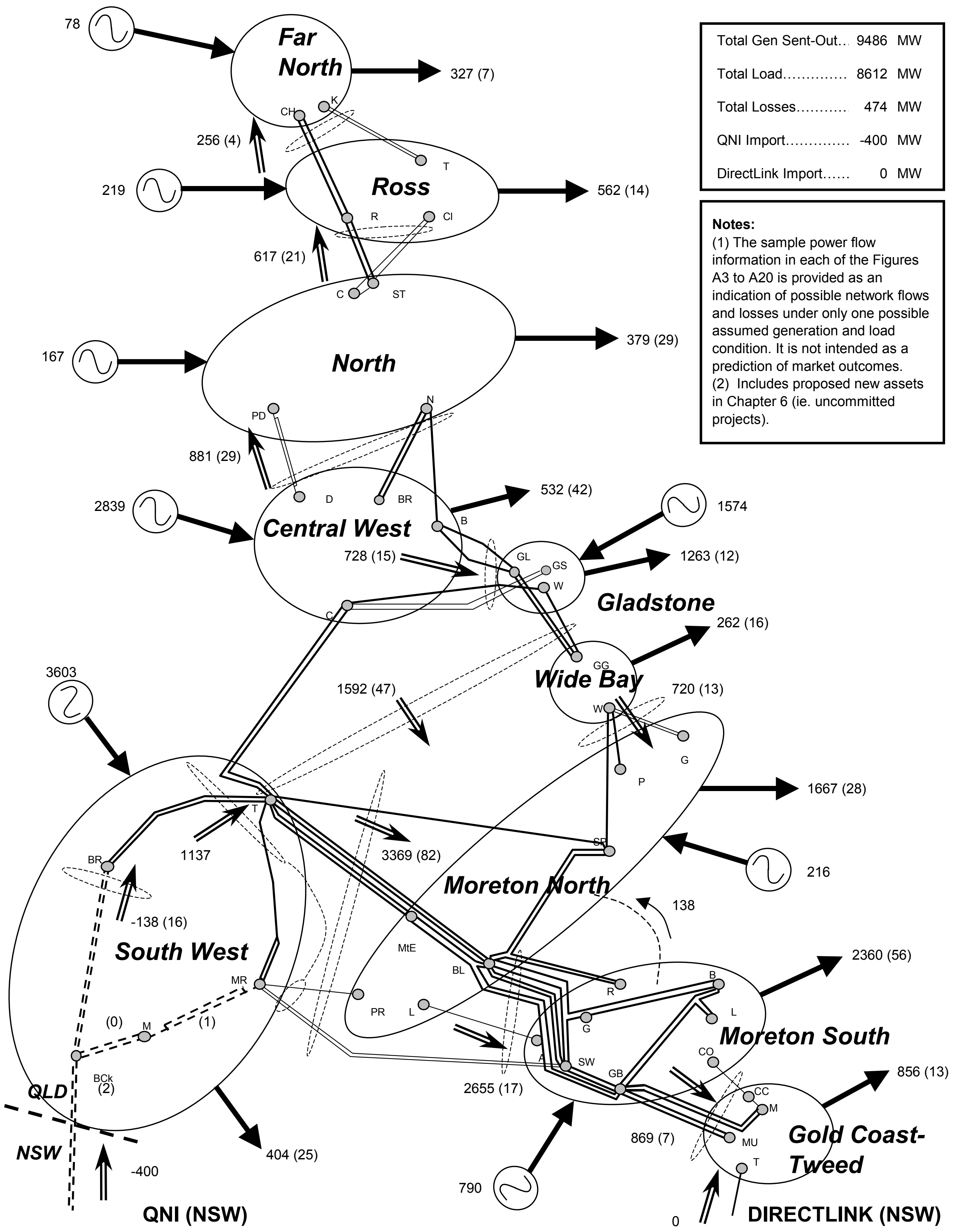


Figure A.20: Summer 2007/08 Qld Peak 400MW Southerly QNI Flow



Total Gen Sent-Out…	9486	MW
Total Load…………..	8612	MW
Total Losses………..	474	MW
QNI Import…………..	-400	MW
DirectLink Import……	0	MW

Notes:
(1) 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.
(2) Includes proposed new assets in Chapter 6 (ie. uncommitted projects).

8.2 Appendix B – Limit Equations

Note: Limit Equations are valid at time of publication of this Annual Planning Report. The equations are continually under review and are revised from time to time to take account of changing market, climatic 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	Equation 2 Ross-Chalumbin Contingency
Constant Term (Intercept)	221.9	252.0
Total generation at Barron Gorge PS	-0.5941	-0.626
Number of Barron Gorge units on-line (generating)	14.2359	11.2428
Number of Barron Gorge units on-line (synchronous condenser)	24.5456	17.3656
Total MW generation at Kareeya PS (Units 1-5)	-1.0201	-0.7917
4 Kareeya units on-line (0 or 1) (excl K5)	28.69	26.9103
3 Kareeya units on-line (0 or 1) (excl K5)	21.51	18.2581
2 Kareeya units on-line (0 or 1) (excl K5)	14.20	9.4847
1 Kareeya unit on-line (0 or 1) (excl K5)	6.35	0
Total MW generation at Collinsville PS	0	0.0245
Total MW generation at Mt Stuart PS	0	0.0058
Number of Mt Stuart units on-line (0,1 or 2)	0	1.8413
Total MW generation at Townsville PS	0	0.0194
Number of Townsville units on-line	0	1.6650
Sum of Innisfail on-line nominal MVAr 132kV	0.2708	0.4219
Sum of Cairns on-line nominal MVAr 132kV	0.3732	0.4595
Availability of H32 Chalumbin 50MVAr Cap Bank to be switched (0 to 1)	0	18.305
Sum of Chalumbin reactors on-line nominal MVAr (0 to negative value)	0.0605	0

Table B.2: Central to North Queensland Stability Equations

	Coefficient	
	Equation 1 GT Online	Equation 2 No GT Online
Constant Term (Intercept)	990 *(930*)*	900 *(840*)*
Total generation at Collinsville 132kV PS		0.5

* At the time of publication of this report, the CQ-NQ transfer limit was reduced by 60MW while the Nebo SVC was undergoing a control system replacement.

Table B.3: Prediction of Post Contingent 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	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	Blackwall Contingency	Equation 4 Mt England- Contingency
Constant Term (Intercept)	1461.4	1571.6	1610.7	1652.6
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 condensors 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 and E)	-0.3490	-0.3788	-0.3867	-0.4074
Total generation at Gladstone PS (H7 and 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 (A, B and 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

Table B.6: Gold Coast Voltage Stability Equation

Measured Variable	Coefficient Swanbank-Mudgeeraba Contingency
Constant Term (Intercept)	439.85
Number of Wivenhoe units on-line	9.8157
Number of Swanbank B units on-line	7.3772
Number of Swanbank E units on-line	22.7096
DirectLink power transfer at Mullimbimby (MW positive is into Qld)	-0.8066
DirectLink reactive power at Bungalora (MVAr positive is into Qld)	0.2367
Number of Palmwoods 275kV Cap Banks available	5.6787
Number of Palmwoods 110kV Cap Banks available	2.3485
Number of South Pine 275kV Cap Banks available	6.3888
Number of South Pine 110kV Cap Banks available	3.4867
Number of Rocklea 110kV Cap Banks available	4.6379
Number of Belmont 275kV Cap Banks available	9.4149
Number of Belmont 110kV Cap Banks available	5.5223
Number of Blackwall 275kV Cap Banks available	9.7235
Number of Mt England 275kV Cap Banks available	5.5123
Number of Loganlea 110kV Cap Banks available	6.2596
Number of Mudgeeraba 275kV Cap Banks available	18.3897
Number of Mudgeeraba 110kV Cap Banks available	9.9775
Number of Molendinar 110kV Cap Banks available	10.2958

Table B.7: Braemar Thermal and Voltage Stability Equation

Measured Variable	Coefficient
Constant Term (Intercept)	1125
Off-set If [total unavailability of southern Queensland capacitive support (including generator lagging capability and 275kV and 110kV capacitor banks)] $\geq$ 820MVAr	-100

8.3 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 2005 to 2007. 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 impacts 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; and
- 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 6).

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 2005 to 2007 (1)

Location		Lowest Switchgear Rating (kA) (2)	3 Phase kA			Single Phase (kA)		
			2005	2006	2007	2005	2006	2007
Abermain	110.0	31.5	13.36	13.40	14.81	13.17	13.42	14.83
Algester	110.0	40.0	-	18.46	18.44	-	19.45	19.41
Ashgrove West	110.0	25.0	18.71	18.71	19.07	18.01	17.64	17.90
Belmont	275.0	31.5	14.79	15.64	15.78	15.02	16.57	16.71
Belmont (3) (4)	110.0	25.0	23.56	24.02	24.10	27.65	29.02	29.11
Blackwall	275.0	50.0	21.23	21.76	21.93	23.36	24.93	25.14
Braemar	330.0	50.0	10.48	13.56	15.78	10.05	15.17	16.83
Braemar	275.0	50.0	12.54	17.02	20.64	12.35	19.95	22.94
Bulli Creek	330.0	50.0	12.58	14.19	15.03	10.99	12.09	12.40
Bulli Creek	132.0	40.0	3.57	3.62	3.59	4.05	4.09	4.06
Bundamba	110.0	40.0	12.46	12.18	13.27	11.07	11.09	12.13
Goodna	275.0	40.0	-	-	16.33	-	-	16.11
Goodna	110.0	40.0	-	16.14	21.19	-	14.24	22.51
Greenbank	275.0	40.0	-	18.39	18.52	-	18.72	18.86
Kogan Creek	275.0	40.0	-	12.18	16.20	-	13.70	16.63
Loganlea	275.0	50.0	12.02	13.68	13.76	11.94	13.73	13.80
Loganlea	110.0	25.0	20.07	21.08	21.11	22.78	23.95	23.97
Middle Ridge	330.0	NO CB	9.81	10.29	10.46	9.31	9.59	9.65
Middle Ridge	275.0	40.0	11.21	11.68	11.84	11.17	11.48	11.54
Middle Ridge	110.0	26.2	18.05	18.57	18.65	21.01	21.48	21.51
Millmerran Switch Yard	330.0	50.0	13.53	14.69	15.23	15.44	16.46	16.84
Molendinar	275.0	40.0	7.40	8.38	8.38	7.22	7.46	7.53
Mt England	275.0	31.5	20.51	21.20	21.34	20.76	21.55	21.63
Mudgeeraba	275.0	31.5	7.48	8.64	8.65	7.90	8.58	8.58
Mudgeeraba	110.0	19.3	13.22	16.08	16.07	16.50	19.21	19.20

Location	Voltage kV	Lowest Switchgear Rating (kA) (2)	3 Phase kA			Single Phase (kA)		
			2005	2006	2007	2005	2006	2007
Murarrie	275.0	40.0	-	12.25	12.31	-	12.29	12.35
Murarrie	110.0	25.00	18.37	21.52	21.55	17.18	24.28	24.29
Oakey	110.0	40.0	10.14	10.61	10.60	11.10	11.72	11.69
Palmwoods	275.0	31.5	8.05	8.09	8.08	8.00	8.04	8.04
Palmwoods	132.0	21.8	12.36	12.40	12.39	14.47	14.56	14.56
Palmwoods	110.0	NO CB	5.51	5.52	5.50	5.81	5.81	5.80
Redbank Plains	110.0	31.5	14.07	15.20	18.30	11.73	13.31	17.88
Richlands	110.0	18.3	11.33	13.50	13.47	11.99	13.52	13.49
Rocklea	275.0	40.0	12.57	12.74	12.77	11.79	12.45	12.46
Rocklea	110.0	40.0	21.59	22.00	22.05	25.06	26.35	26.38
Runcorn	110.0	21.9	14.48	17.03	17.01	12.03	14.73	14.70
South Pine	275.0	31.5	17.67	17.96	18.04	18.30	18.67	18.71
South Pine (3) (4)	110.0	25.0	22.60	23.26	23.54	26.01	27.06	27.39
Sumner	110.0	40.0	-	14.15	14.14	-	13.56	13.53
Swanbank A (3)	110.0	18.3	15.24	15.95	17.75	12.98	13.63	15.63
Swanbank B	275.0	31.5	20.15	20.95	21.12	23.39	24.46	24.74
Swanbank E	275.0	40.0	19.66	20.51	20.67	22.42	23.61	23.85
Tangkam	110.0	40.0	11.87	12.44	12.43	11.07	11.54	11.51
Tarong (4)	275.0	31.5	27.43	29.07	29.79	29.76	32.25	32.80
Tarong	132.0	31.5	5.15	5.25	5.23	5.51	5.60	5.57
Tarong	66.0	21.9	13.83	13.93	13.88	15.19	15.31	15.25
Tennyson	110.0	40.0	14.43	14.61	14.61	14.20	14.49	14.47
Upper Kedron	110.0	40.0	20.89	20.95	21.66	17.35	17.45	18.01
West Darra Bus 1	110.0	19.3	16.45	16.49	19.46	12.31	14.05	18.88
West Darra Bus 2	110.0	19.3	12.53	13.35	13.33	11.73	13.37	13.34
Woolooga	275.0	31.5	9.11	9.14	9.14	8.35	8.37	8.36
Woolooga	132.0	21.9	12.39	12.42	12.40	13.21	13.23	13.21

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, other than Bulwer Island (BIEP) and Queensland Nickel, 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 2005 to 2007 (1)

Location	Voltage (kV)	Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2005	2006	2007	2005	2006	
Baralaba	132.0	15.3	4.14	4.14	4.14	3.52	3.52	3.52
Biloela	132.0	12.3	7.55	7.56	7.55	6.49	6.49	6.48
Blackwater	132.0	12.3	3.47	3.47	3.46	4.12	4.38	4.38
Bouldercombe	275.0	31.5	16.24	16.21	16.21	15.88	15.85	15.84
Bouldercombe	132.0	25.0	10.11	10.11	10.11	11.51	11.50	11.50
Broadsound	275.0	31.5	9.11	9.10	9.10	7.14	7.14	7.14
Callemondah	132.0	31.5	20.46	20.46	20.45	20.79	20.91	20.91
Callide A Power Station.	132.0	12.3	10.64	10.64	10.63	10.45	10.46	10.45
Calvale	275.0	31.5	19.76	19.80	19.80	22.13	22.16	22.16
Calvale	132.0	NO CB	10.62	10.63	10.62	10.60	10.60	10.59
Dingo	132.0	31.5	2.26	2.26	2.26	2.48	2.49	2.49
Dysart	132.0	19.9	4.04	4.04	4.04	4.67	4.67	4.67
Egans Hill	132.0	NO CB	6.55	6.55	6.55	6.75	6.74	6.74
Gin Gin	275.0	31.5	10.24	10.25	10.25	8.19	8.20	8.19
Gin Gin	132.0	21.9	8.57	8.58	8.57	8.61	8.61	8.60
Gladstone	275.0	31.5	19.34	19.33	19.33	21.79	21.82	21.82
Gladstone (4)	132.0	31.5	25.98	25.98	25.97	31.53	31.91	31.90
Gladstone South	132.0	40.0	16.95	16.95	16.94	16.83	16.84	16.84
Grantleigh	132.0	31.5	2.44	2.44	2.44	2.54	2.54	2.54
Gregory	132.0	31.5	7.56	7.56	7.56	8.85	8.85	8.85
Korenan	132.0	31.5	2.39	2.39	2.39	1.65	1.65	1.65
Lilyvale	275.0	40.0	4.87	4.87	4.87	4.98	4.98	4.98

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2005	2006	2007	2005	2006	2007
Lilyvale	132.0	25.0	7.88	7.88	7.88	9.47	9.47	9.47
Moura	132.0	12.3	3.76	3.76	3.76	4.05	4.05	4.05
Norwich Park	132.0	40.0	3.26	3.26	3.26	2.50	2.50	2.50
Rockhampton	132.0	12.3	6.62	6.62	6.62	6.96	6.96	6.95
Rocklands	132.0	40.0	6.19	6.19	6.19	5.55	5.54	5.54
Stanwell Switch Yard	275.0	31.5	17.40	17.38	17.38	19.13	19.11	19.11
Stanwell Switch Yard	132.0	31.5	4.97	4.97	4.97	4.60	4.60	4.60
Wurdong	275.0	31.5	15.55	15.55	15.55	14.88	14.89	14.88

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, other than Bulwer Island (BIEP) and Queensland Nickel, 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 2005 to 2007 (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2005	2006	2007	2005		2007
Alan Sherriff	132.0	31.5	10.31	10.31	10.31	11.31	11.31	11.31
Alligator Creek	132.0	31.5	3.52	3.52	3.52	4.06	4.06	4.06
Burton Downs	132.0	19.3	4.46	4.46	4.46	4.41	4.41	4.41
Cairns	132.0	12.1	4.95	4.87	4.87	6.62	6.48	6.52
Cardwell	132.0	19.3	2.58	2.58	2.58	2.03	2.03	2.03
Chalumbin	275.0	21.9	3.28	3.28	3.28	3.55	3.55	3.55
Chalumbin	132.0	31.5	6.37	6.37	6.37	7.38	7.38	7.38
Clare	132.0	8.8	6.33	6.33	6.33	6.09	6.09	6.09
Collinsville	132.0	15.3	10.89	10.89	10.89	12.05	12.04	12.04
Coppabella	132.0	31.5	2.78	2.78	2.78	3.14	3.14	3.14
Dan Gleeson	132.0	31.5	9.83	9.83	9.83	10.66	10.66	10.67
Edmonton	132.0	31.5	4.63	4.63	4.63	5.74	5.74	5.76
Garbutt	132.0	NO CB	8.78	8.78	8.78	9.23	9.23	9.23
Ingham	132.0	15.7	2.62	2.62	2.62	2.85	2.85	2.85
Innisfail	132.0	40.0	4.15	4.15	4.15	4.58	4.58	4.59
Invicta	132.0	19.3	4.73	4.73	4.73	4.37	4.37	4.37
Kamerunga	132.0	15.3	3.93	3.93	3.93	4.76	4.77	4.78
Kareeya	132.0	10.9	6.35	6.35	6.35	7.45	7.45	7.45
Kemmis	132.0	31.5	4.98	4.98	4.98	5.70	5.70	5.70
Mackay	132.0	15.7	4.63	4.63	4.63	5.29	5.29	5.29
Moranbah	132.0	15.3	5.50	5.50	5.50	6.63	6.62	6.62
Moranbah South	132.0	40.0	4.32	4.32	4.32	4.23	4.23	4.23
MT McLaren	132.0	31.5	1.85	1.85	1.85	2.04	2.04	2.04
Nebo	275.0	31.5	6.58	6.58	6.58	7.24	7.24	7.23
Nebo	132.0	21.9	9.47	9.47	9.47	10.88	10.88	10.87

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2005	2006	2007	2005	2006	2007
Newlands	132.0	31.5	3.04	3.04	3.04	3.06	3.06	3.06
North Goonyella	132.0	19.3	3.12	3.12	3.12	2.54	2.54	2.54
Oonooie	132.0	31.5	2.62	2.62	2.62	3.08	3.08	3.08
Peak Downs	132.0	40.0	4.30	4.30	4.29	3.89	3.89	3.89
Pioneer Valley	132.0	40.0	4.25	4.25	4.25	4.77	4.77	4.77
Proserpine	132.0	21.9	3.39	3.39	3.39	3.67	3.67	3.67
Ross	275.0	31.5	5.32	5.32	5.32	6.20	6.20	6.20
Ross	132.0	31.5	11.78	11.78	11.78	13.63	13.63	13.63
Strathmore	275.0	50.0	5.68	5.68	5.68	5.13	5.13	5.13
Strathmore	132.0	40.0	10.31	10.31	10.31	10.73	10.73	10.73
Townsville East	132.0	31.5	-	-	8.85	-	-	8.71
Townsville South	132.0	21.9	11.42	11.42	11.42	14.10	14.10	14.27
Townsville GT PS	132.0	31.5	8.94	8.94	8.94	9.77	9.77	9.77
Tully	132.0	31.5	3.16	3.16	3.16	2.93	2.93	2.93
Turkinje	132.0	15.7	3.77	3.77	3.77	4.29	4.29	4.29
Wandoo	132.0	40.0	3.94	3.94	3.94	2.88	2.88	2.88
Woree	275.0	N0 CB	2.36	2.36	2.36	2.80	2.80	2.81
Woree	132.0	40.0	5.03	5.03	5.03	6.82	6.82	6.85

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, other than Bulwer Island (BIEP) and Queensland Nickel, 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.

8.4 Appendix D – Proposed Small Network Assets

8.4.1 Shunt Capacitor Banks for South East Queensland

Project Name: Shunt Capacitor Banks for South East Queensland
Proposed Timing: October 2006
Estimated Cost: $2.6 million

Background

Summer peak electricity demand in South East Queensland has grown rapidly in recent years and is forecast to continue at an average of close to 5% per annum over the next ten years. This ten-year average incorporates an accelerated summer demand increase in the short-term.

The higher short-term growth was confirmed in the recent 2003/04 and 2004/05 summer periods, when the actual level of electricity demand in South East Queensland approached Powerlink's medium economic growth 10% Probability of Exceedance (PoE) (very hot weather) forecasts due to:

1. *Increased temperature sensitivity* – Planning analysis has identified a significant increase in the temperature sensitivity of the load in SEQ. That is, a proportionately larger amount of electricity is now used during periods of very hot weather than has occurred historically. This changing demand characteristic is largely attributed to the high uptake of domestic air conditioning in SEQ in recent years.
2. *Increases in underlying demand* – The new SEQ load forecast provided by Energex shows an accelerated summer demand increase beyond the levels included in their previous 2004 load forecast.

The combination of these two factors means that the forecast SEQ summer demands during very hot weather conditions (10% PoE) in the next few years will be greater than previously anticipated.

Reactive power demand (the need for voltage support) is expected to rise in response to the significant demand growth, increased use of air-conditioners, and higher reactive power losses on the electricity transmission and distribution system (due to higher transformer and line loadings).

Powerlink has identified that 170MVAr of reactive support will be needed in SEQ for summer 2006/07 to ensure supply reliability can continue to be maintained to customers during very hot summer weather conditions (10% PoE).

It is assumed that existing levels of reactive support will continue to be provided by generators and the DirectLink Market Network Service Provider, either under their National Electricity Rule (NER) obligations or as ancillary services under contract to NEMMCO.

Powerlink is required to take action to keep pace with growing reactive power demand. In particular, the voltage stability criteria outlined in Schedule S5.1.8 of the NER requires "*that an adequate reactive power margin must be maintained at every connection point in a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point*". In line with this requirement, a reactive margin of 1% of the maximum fault level (in MVA) at each connection point is required.

In addition, the Connection Agreement between Powerlink and Energex includes obligations regarding reliability of supply as required under Schedule 5.1.2.2 of the NER. Powerlink's transmission authority also includes reliability of supply obligations. Voltage support must be provided in SEQ such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1.

Without corrective 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: Capacitor Banks
Under this option it is proposed to install a 50MVAr, 110kV capacitor bank at Molendinar substation and a 120MVAr, 275kV capacitor bank at Greenbank substation to meet increased SEQ reactive power demand in 2006.

These sites have been chosen based on effectiveness in providing reactive support and the availability of space in the substations to accommodate a new capacitor bank.

Construction of the capacitor banks would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

The total capital cost of this option is $2.6 million.

Option 2: SVC
The increased reactive demand could also be met by the installation of a Static VAr Compensator (SVC) in the SEQ network by late 2006. The SVC would need to have a capacity of 170MVAr to achieve the same result as the capacitor banks described in Option 1.

The total capital cost of this option is $16.0 million.

Construction of the SVC would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

Option 3: Customer Connected Capacitor Banks
It would be feasible that customers in the SEQ area could install capacitor banks to overcome the network loading limitations. 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 October 2006.

Summary of Options and Economic Analysis

There are two feasible options that are capable of supplying the additional reactive demand in SEQ by the required timing of October 2006. The present value cost of each of these options was calculated over a period of 15 years. The results of this economic analysis are included in Table D.4. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D.1.

Table D.1: Summary of Economic Analysis for Medium Growth for Shunt Capacitor Banks for South East Queensland

Options		Present Value Cost (Medium Growth)	
1.	Shunt Capacitor Bank	$1.58M	1
2.	SVC	$9.71M	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. Economic analysis and the results of these scenarios are in Tables D.2 and D.4. The possible introduction of new generation in the south east Queensland 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.2: Summary of Scenario Analysis for Shunt Capacitor Banks for South East Queensland

	Option One Capacitor Banks		Option Two SVC	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	1.58	1	9.71	2
Scenario B High Growth	2.31	1	9.71	2
Scenario C Low Growth	1.49	1	9.71	2

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) have been examined and the results are summarised in Table D.3. Sensitivity to the commissioning date was not examined, as both options are required to be in service from October 2006 to meet forecast peak load in the 2006/07 summer.

Table D.3: Results of Sensitivity Analysis for Shunt Capacitor Banks for South East Queensland

	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, the installation of capacitor banks at Molendinar and Greenbank substations, 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 impact on other transmission networks.

Recommendation
It is recommended that a 50MVAr, 110kV capacitor bank be installed at Molendinar substation and a 120MVAr, 275kV capacitor bank be installed at Greenbank substation by October 2006, to meet the increased reactive demand in SEQ.

Table D.4: Cash Flow for Shunt Capacitor Banks for South East Queensland

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SCENARIO A		**05/06**	**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**
Option 1		**2006 Capacitor Banks**														
120MVAr Capacitor Bank Greenbank																
==> TUOS		0.000	0.000	0.154	0.152	0.150	0.148	0.146	0.144	0.142	0.140	0.138	0.136	0.134	0.132	0.130
==> PV of TUOS	$0.85															
50MVAr Capacitor Bank Molendinar																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Total for Option 1	**$1.58**															
Option 2		**2006 SVC**														
SVC																
==> TUOS		0.000	0.000	1.764	1.740	1.717	1.693	1.670	1.646	1.623	1.599	1.576	1.552	1.529	1.505	1.482
==> PV of TUOS	$9.71															
Total for Option 2	**$9.71**															

SCENARIO B		High Growth Forecast 1 05/06	2 06/07	3 07/08	4 08/09	5 09/10	6 10/11	7 11/12	8 12/13	9 13/14	10 14/15	11 15/16	12 16/17	13 17/18	14 18/19	15 19/20
Option 1		**2006 Capacitor Banks**														
120MVAr Capacitor Bank Greenbank																
==> TUOS		0.000	0.000	0.154	0.152	0.150	0.148	0.146	0.144	0.142	0.140	0.138	0.136	0.134	0.132	0.130
==> PV of TUOS	$0.85															
50MVAr Capacitor Bank Molendinar																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Additional 50MVAr Capacitor Bank																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Total for Option 1	**$2.31**															
Option 2		**2006 SVC**														
SVC																
==> TUOS		0.000	0.000	1.764	1.740	1.717	1.693	1.670	1.646	1.623	1.599	1.576	1.552	1.529	1.505	1.482
==> PV of TUOS	$9.71															
Total for Option 2	**$9.71**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SCENARIO C		05/06	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
Option 1		**2006 Capacitor Banks**														
120MVAr Capacitor Bank Greenbank																
==> TUOS		0.000	0.000	0.154	0.152	0.150	0.148	0.146	0.144	0.142	0.140	0.138	0.136	0.134	0.132	0.130
==> PV of TUOS	$0.85															
50MVAr Capacitor Bank Molendinar																
==> TUOS		0.000	0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113
==> PV of TUOS	$0.64															
Total for Option 1	**$1.49**															
Option 2		**2006 SVC**														
SVC																
==> TUOS		0.000	0.000	1.764	1.740	1.717	1.693	1.670	1.646	1.623	1.599	1.576	1.552	1.529	1.505	1.482
==> PV of TUOS	$9.71															
Total for Option 2	**$9.71**															

8.4.2 Townsville South 50MVAr, 132kV Shunt Capacitor Bank

Project Name: Townsville South 50MVAr, 132kV Shunt Capacitor Bank
Proposed Timing: October 2006
Estimated Cost: $1.2 million

Background
Bulk electricity supply to the Townsville South area is provided from Powerlink's Townsville South 132/66kV substation, which in turn is supplied via a 132kV double circuit transmission line from Ross substation and two 132kV single circuit transmission lines from Clare and Collinsville substations respectively.

Due to ongoing load growth in this area, thermal capacity limitations are forecast to arise in the Ross-Townsville South 132kV line from October 2006 onwards under contingency conditions. During an outage of one of the 132kV circuits, power flows on the adjacent circuit in service are forecast to exceed its summer emergency thermal rating.

Powerlink has reliability of supply obligations under the National Electricity Rules, its transmission authority, and connection agreements with electricity distributors such that forecast peak demand in the Townsville South area can be supplied with the most critical network element out of service (ie. N-1 situation). Without corrective 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: Capacitor Bank
Under this option it is proposed to install a 50MVAr, 132kV capacitor bank at Townsville South substation by October 2006. The capacitor bank will reduce the level of reactive power that must be transferred over the Ross-Townsville South line, thereby reducing the overall loading on the line to within its rating. The capacitor bank will also assist in maintaining the maximum transfer limit of the transmission network between Central and North Queensland.

Construction of the capacitor bank would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

The total capital cost of this option is $1.2 million.

Option 1 would require further corrective action one year later to maintain supply reliability to the Townsville South area. This further action is assumed to comprise construction of the Ross-Townsville South 132kV line outlined in Option 2.

Option 2: Ross-Townsville South 132kV transmission augmentation
This option involves construction of a second 132kV transmission line between Ross and Townsville South substations by October 2006. This would reduce the loading on the existing 132kV line to within its normal rating, thereby addressing the forecast thermal limitation.

Construction of the line would need to commence in August 2005 to meet the required commissioning date of October 2006.

The total capital cost of this option is $17.4 million.

Option 3: SVC
The forecast thermal limitation could also be met by the installation of a second Static VAr Compensator (SVC) in the North Queensland network by late 2006. The SVC would need to have a range similar to the capacitor bank described in Option 1.

Construction of the SVC would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

The total capital cost of this option is $9 million.

Option 3 would require further corrective action one year later to maintain supply reliability. This anticipated work is assumed to comprise construction of the Ross-Townsville South 132kV line outlined in Option 2.

Option 4: Customer Connected Capacitor Banks
It would be feasible that customers in the Townsville South area could install capacitor banks to overcome the network loading limitations for the 2006/07 summer. However, Powerlink has no knowledge of any proposals for such customer-connected capacitor banks to be installed.

Non-Network Options Considered
In April 2005, Powerlink issued a Request for Information paper to NEM participants and interested parties which, amongst other things, provided an overview of the forecast supply limitation and invited submissions from potential non-network solution providers. No non-network solutions were advised to Powerlink as part of this process.

Summary of Options and Economic Analysis
There are 3 feasible options that are capable of addressing the forecast thermal limitation between Ross and Townsville South by the required timing of October 2006. The present value cost of each of these options was calculated over a period of 15 years. The results of this economic analysis are included in Table D.8. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D.5.

Table D.5: Summary of Economic Analysis for Medium Growth for Shunt Capacitor Bank at Townsville South

Options	Present Value Cost (Medium Growth)	Ranking
1. Shunt Capacitor Bank	$9.98M	1
2. Ross-Townsville South 132kV augmentation	$10.56M	2
3. SVC	$14.71M	3
4. Customer connected capacitor bank	N/A	N/A
5. 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. Economic analysis and the results of these scenarios are in Tables D.6 and D.8.

Table D.6: Summary of Scenario Analysis for Shunt Capacitor Bank at Townsville South

	Option One Capacitor Bank		Option Two Ross-Townsville South 132kV Augmentation		Option Three SVC	
	PV $M	Ranking	PV $M		PV $M	
Scenario A Medium Growth	9.98	1	10.56	2	14.71	3
Scenario B High Growth	9.98	1	10.56	2	14.71	3
Scenario C Low Growth	8.69	1	9.25	2	12.83	3

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) have been examined and the results are summarised in Table D.7. Sensitivity to the commissioning date was not examined, as both options are required to be in service from October 2006 to meet forecast peak load in the 2006/07 summer.

Table D.7: Results of Sensitivity Analysis for Shunt Capacitor Bank at Townsville South

	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, the installation of a capacitor bank at Townsville South 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 option will require further work to address the limitation from 2007 onwards, and will be subject to the process for approval of new large network assets under the NER.

This project has no impact on other transmission networks.

Recommendation
It is recommended that a 50MVAr, 132kV capacitor bank be installed at Townsville South substation by October 2006, to address forecast thermal capacity limitations in the Townsville South area for the 2006/07 summer.

Table D.8: Cash Flow for Townsville South 50MVAr, 132kV Shunt Capacitor Bank

		Medium Growth Forecast														
		1	2	3	4	5		7	8	9	10	11	12	13	14	15
SCENARIO A		05/06		07/08	08/09	09/10	10/11	11/12	12/13	13/14				17/18	18/19	19/20
Option 1		**Townsville South 132kV Capacitor Bank**														
Townsville South 132kV capacitor bank																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637
==> PV of TUOS	$9.25															
Total for Option 1	**$9.98**															
Option 2		**Ross-Townsville South 132kV line**														
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637	1.611
==> PV of TUOS	$10.56															
Total for Option 2	**$10.56**															
Option 3		**SVC**														
SVC																
==> TUOS		0.000	0.000	0.992	0.979	0.966	0.953	0.939	0.926	0.913	0.900	0.886	0.873	0.860	0.847	0.833
==> PV of TUOS	$5.46															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637
==> PV of TUOS	$9.25															
Total for Option 3	**$14.71**															

SCENARIO B		High Growth Forecast														
		1	2	3	4	5	6	7	8	9				13	14	15
		05/06	06/07	07/08	08/09	09/10	10/11		12/13	13/14	14/15	15/16	16/17	17/18	18/19	
Option 1		**Townsville South 132kV Capacitor Bank**														
Townsville South 132kV capacitor bank																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637
==> PV of TUOS	$9.25															
Total for Option 1	**$9.98**															
Option 2		**Ross-Townsville South 132kV Line**														
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637	1.611
==> PV of TUOS	$10.56															
Total for Option 2	**$10.56**															
Option 3		**SVC**														
SVC																
==> TUOS		0.000	0.000	0.992	0.979	0.966	0.953	0.939	0.926	0.913	0.900	0.886	0.873	0.860	0.847	0.833
==> PV of TUOS	$5.46															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637
==> PV of TUOS	$9.25															
Total for Option 3	**$14.71**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SCENARIO C		05/06	06/07	07/08	08/09	09/10	10/11	11/12		13/14	14/15	15/16	16/17	17/18	18/19	
Option 1		**Townsville South 132kV Capacitor Bank**														
Townsville South 132kV capacitor bank																
==> TUOS		0.000	0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113
==> PV of TUOS	$0.64															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663
==> PV of TUOS	$8.05															
Total for Option 1	**$8.69**															
Option 2		**Ross-Townsville South 132kV Line**														
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663	1.637
==> PV of TUOS	$9.25															
Total for Option 2	**$9.25**															
Option 3		**SVC**														
SVC																
==> TUOS		0.000	0.000	0.000	0.992	0.979	0.966	0.953	0.939	0.926	0.913	0.900	0.886	0.873	0.860	0.847
==> PV of TUOS	$4.78															
Ross-Townsville South 132kV line																
==> TUOS		0.000	0.000	0.000	0.000	1.918	1.893	1.867	1.842	1.816	1.790	1.765	1.739	1.714	1.688	1.663
==> PV of TUOS	$8.05															
Total for Option 3	**$12.83**															

8.4.3 Molendinar 275kV Transformer Augmentation

Project Name: Molendinar 275/110kV Transformer Augmentation
Proposed Timing: October 2007
Estimated Cost: $6.9 million

Background
Primary electricity supply to the Gold Coast area is provided via Powerlink's 275/110kV substations at Mudgeeraba and Molendinar. Mudgeeraba substation (3 x 250MVA transformers) is supplied via two single circuit 275kV transmission lines from Swanbank, near Ipswich. Molendinar substation (1 x 375MVA transformer) is supplied via a double circuit 275kV line 'teed' into one of the Swanbank-Mudgeeraba lines at Maudsland. This tee connection will be removed from late 2006 and the line will then connect into a new double circuit 275kV line between Greenbank and Maudsland which is under construction.

A secondary supply path is provided from Powerlink's 275kV substations at Belmont and Loganlea to the Gold Coast via Beenleigh. This path consists of single circuit 110kV lines between Beenleigh-Cades County-Molendinar. These lines are owned by Energex. Supply can also be provided from the NSW network via DirectLink and this will be providing support to the Gold Coast area under a Network Support Agreement for the summer of 2005/06.

Due to ongoing load growth in the Gold Coast area, routine planning studies have identified that from summer 2007/08 onwards, thermal capacity and voltage limitations are expected to arise in the Gold Coast network during the most critical network outage, namely loss of the Molendinar transformer. Loss of the only transformer means that no power can be injected at Molendinar during this outage. The resulting load transfer will cause thermal overloads in the transformers at Mudgeeraba.

Furthermore, this outage may also result in voltage instability in the Gold Coast area due to an inability to maintain sufficient reactive margins.

Powerlink has reliability of supply obligations under the National Electricity Rules, its transmission authority, and connection agreements with electricity distributors such that forecast peak demand on the Gold Coast can be supplied with the most critical network element out of service (ie. N-1 situation). Without corrective 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: Molendinar transformer augmentation
Under this option it is proposed to install a second 375MVA 275/110kV transformer at Molendinar substation by summer 2007/08 to address the forecast limitations.

Construction of the transformer would be scheduled to commence in August 2005 to meet the required commissioning date of October 2007.

The total capital cost of this option is $6.9 million.

Option 2: Mudgeeraba transformer augmentation

This option involves installing a fourth 275/110kV transformer (375MVA rating) at Mudgeeraba substation. As the existing substation site is fully developed, adjacent land would need to be acquired to incorporate the new transformer and associated switchgear.

The total capital cost of this option is $7.5 million.

Construction of the transformer would be scheduled to commence in August 2005 to meet the required commissioning date of October 2007.

This option would result in increased power flows through Mudgeeraba substation and would also require associated line and substation upgrades in the Energex network. These additional works have not been costed.

Other Options Considered

Conversion of Energex's Beenleigh-Cades County 110kV line to double circuit operation, to facilitate higher power flows through the northern part of Energex's 110kV Gold Coast network, was considered. However, this would be significantly more expensive than Option 1 and 2 and only result in the deferment of additional transformer capacity by two years. Accordingly, this option was not considered further.

Non-Network Options Considered

Network support from the DirectLink MNSP is not considered a viable option because it is expected that southward flow on DirectLink at times of high load in northern NSW will be required in the summer of 2007/08 and beyond, to defer the requirement for construction of a new 330kV transmission line from Dumaresq to Lismore. The installation of a second transformer at Molendinar and other planned work in the Gold Coast network will provide increased capability to support NSW via DirectLink.

Powerlink is not aware of any other demand side management initiatives, local generation developments or other non-network solutions that could address the future supply requirements by the required timing of October 2007.

Summary of Options and Economic Analysis

There are two feasible options that are capable of addressing the forecast limitations in the Gold Coast area by the required timing of October 2007. The present value cost of each of these options was calculated over a period of 15 years. The results of this economic analysis are included in Table D.12. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D.9.

Table D.9: Summary of Economic Analysis for Medium Growth for Molendinar Transformer Reinforcement

Options	Present Value Cost (Medium Growth)	Ranking
1. Molendinar 2nd transformer	$3.67M	1
2. Mudgeeraba 4th transformer	$3.99M	2

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. Economic analysis and the results of these scenarios are in Tables D.10 and D.12.

Table D.10: Summary of Scenario Analysis for Molendinar Transformer Reinforcement

	Option One		Option Two	
	Molendinar 2nd transformer		Mudgeeraba 4 transformer	
	PV $M	Ranking	PV $M	Ranking
Scenario A Medium Growth	3.67	1	3.99	2
Scenario B High Growth	4.19	1	4.55	2
Scenario C Low Growth	3.67	1	3.99	2

The sensitivity of the present value calculations to key input variables such as the discount rate and capital costs (variation of +/- 10%) have been examined and the results are summarised in Table D.11. Sensitivity to the commissioning date was not examined, as both options are required to be in service from October 2007 to meet forecast peak load in the 2007/08 summer.

Table D.11: Results of Sensitivity Analysis for Molendinar Transformer Reinforcement

	Discount Rate					
	8%		10%		12%	
	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, the installation of a second Molendinar transformer, minimises the present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no impact on other transmission networks.

Recommendation

It is recommended that a second 375MVA, 275/110kV transformer be installed at Molendinar substation by October 2007, to address forecast thermal capacity and voltage stability limitations in the Gold Coast area during critical network contingencies.

Table D.12: Cash Flow for Molendinar Transformer Reinforcement

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8		10	11	12	13	14	15
SCENARIO A		05/06	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
Option 1		**Molendinar 2nd Transformer**														
Molendinar Transformer																
==> TUOS		0.000	0.000	0.000	0.761	0.751	0.740	0.730	0.720	0.710	0.700	0.690	0.680	0.669	0.659	0.649
==> PV of TUOS	$3.67															
Total for Option 1	**$3.67**															
Option 2		**Mudgeeraba 4th Transformer**														
Mudgeeraba Transformer																
==> TUOS		0.000	0.000	0.000	0.827	0.816	0.805	0.794	0.783	0.772	0.761	0.750	0.739	0.728	0.717	0.706
==> PV of TUOS	$3.99															
Total for Option 2	**$3.99**															

		High Growth Forecast														
		1	2		4	5	6		8	9	10	11	12	13	14	15
SCENARIO B		05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13		14/15	15/16	16/17	17/18	18/19	19/20
Option 1		**Molendinar 2nd Transformer**														
Molendinar Transformer																
==> TUOS		0.000	0.000	0.761	0.751	0.740	0.730	0.720	0.710	0.700	0.690	0.680	0.669	0.659	0.649	0.639
==> PV of TUOS	$4.19															
Total for Option 1	**$4.19**															
Option 2		**Mudgeeraba 4th Transformer**														
Mudgeeraba Transformer																
==> TUOS		0.000	0.000	0.827	0.816	0.805	0.794	0.783	0.772	0.761	0.750	0.739	0.728	0.717	0.706	0.695
==> PV of TUOS	$4.55															
Total for Option 2	**$4.55**															

		Low Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SCENARIO C		05/06	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
Option 1		**Molendinar 2nd Transformer**														
Molendinar Transformer																
==> TUOS		0.000	0.000	0.000	0.761	0.751	0.740	0.730	0.720	0.710	0.700	0.690	0.680	0.669	0.659	0.649
==> PV of TUOS	$3.67															
Total for Option 1	**$3.67**															
Option 2		**Mudgeeraba 4th Transformer**														
Mudgeeraba Transformer																
==> TUOS		0.000	0.000	0.000	0.827	0.816	0.805	0.794	0.783	0.772	0.761	0.750	0.739	0.728	0.717	0.706
==> PV of TUOS	$3.99															
Total for Option 2	**$3.99**															

8.4.4 Gladstone South 50MVAr, 132kV Shunt Capacitor Bank

Project Name: Gladstone South 50MVAr, 132kV Shunt Capacitor Bank
Proposed Timing: October 2006
Estimated Cost: $1.2 million

Background
The Gladstone area contains the highest concentration of industrial loads in the State. The Boyne Island aluminium smelter dominates this load, but there is also significant demand at the Queensland Alumina plant and at the Boat Creek bulk supply point.

The industrial loads in the Gladstone area have very high load factors, and are often associated with relatively high reactive demands, and network reactive losses.

The net reactive load in the Gladstone area is forecast to grow by approximately 40MVAr between 2004/05 to 2006/07. This increase already takes account of the reactive component of the local load that is corrected by the industrial customers and Ergon Energy as required under the NER.

In addition to this net reactive load increase, there are also incremental reactive power losses due to the increased utilisation of the sub transmission network. To avoid the erosion of the dynamic reactive power capability in the Gladstone area it is proposed to install an additional 50MVAr of reactive support in 2006/07.

It is assumed that existing levels of reactive support will continue to be provided by generators, either under their NER obligations or as ancillary services under contract to NEMMCO.

Powerlink is required to take action to keep pace with growing reactive power demand. In particular, the voltage stability criteria outlined in Schedule 5.1.8 of the NER requires "*that an adequate reactive power margin must be maintained at every connection point in a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point*". In line with this requirement, a reactive margin of 1% of the maximum fault level (in MVA) at each connection point is required.

In addition, the Connection Agreement between Powerlink and Ergon Energy includes obligations regarding reliability of supply as required under Schedule 5.1.2.2 of the NER. Powerlink's transmission authority also includes reliability of supply obligations. Voltage support must be provided to the Gladstone area such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1.

Corrective action is required to allow Powerlink to meet these obligations and maintain existing capability on its main transmission grid. 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: Capacitor Banks
Under this option it is proposed to install a 50MVAr, 132kV capacitor bank at Gladstone South substation to meet increased reactive power demand in 2006.

Construction of the capacitor bank would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

The total capital cost of this option is $1.2 million.

Option 2: SVC
The increased reactive demand could also be met by the installation of a Static VAr Compensator (SVC) at Gladstone South by late 2006. The SVC would need to have a range similar to the capacitor bank described in Option 1.

The total capital cost of this option is $9.0 million.

Construction of the SVC would be scheduled to commence in August 2005 to meet the required commissioning date of October 2006.

Option 3: Customer Connected Capacitor Banks
It would be feasible that customers in the Gladstone area could install capacitor banks to overcome the network loading limitations. However, Powerlink has no knowledge of any proposals for such customer-connected capacitor banks to be installed.

Non-Network Options Considered
Provision of additional reactive support from Gladstone Power Station is not considered possible as it is assumed that all generating units are already operating and providing this service, in accordance with its NER obligations.

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 October 2006.

Summary of Options and Economic Analysis
There are two feasible options that are capable of supplying the additional reactive demand in the Gladstone area by the required timing of October 2006. The present value cost of each of these options was calculated over a period of 15 years. The results of this economic analysis are included in Table D.15. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D.13.

Table D.13: Summary of Economic Analysis for Medium Growth for Shunt Capacitor Bank at Gladstone South

Options	Present Value Cost (Medium Growth)	Ranking
1. Shunt Capacitor Bank	$0.73M	1
2. SVC	$5.46M	2
3. Customer connected capacitor bank	N/A	N/A
4. Non-network options	N/A	N/A

No market scenarios were considered in the financial analysis as the timing for corrective 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%) have 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 October 2006 to meet forecast peak load in the 2006/07 summer.

Table D.14: Results of Sensitivity Analysis for Shunt Capacitor Bank at Gladstone South

	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%

The result of the analysis is that Option 1, the installation of a capacitor bank at Gladstone South 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 impact on other transmission networks.

Recommendation
It is recommended that a 50MVAr, 132kV capacitor bank be installed at Gladstone South substation by October 2006, to maintain the reactive demand capability and meet increasing reactive demand requirements.

Table D.15: Cash Flow for Gladstone South Capacitor Bank

		Medium Growth Forecast														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SCENARIO A		05/06	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
Option 1		**2006 Capacitor Bank**														
132kV 50MVAr Capacitor Bank																
==> TUOS		0.000	0.000	0.132	0.131	0.129	0.127	0.125	0.123	0.122	0.120	0.118	0.116	0.115	0.113	0.111
==> PV of TUOS	$0.73															
Total for Option 1	**$0.73**															
Option 2		**2006 SVC**														
132kV SVC																
==> TUOS		0.000	0.000	0.992	0.979	0.966	0.953	0.939	0.926	0.913	0.900	0.886	0.873	0.860	0.847	0.833
==> PV of TUOS	$5.46															
Total for Option 2	**$5.46**															

8.5 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
GCT	Gold Coast/Tweed Zone

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
Abermain 110kV (Lockrose)	MN	49.59	35.84	37.72	39.31	40.63	41.87	42.88	43.71	44.73	45.78
Abermain 33kV	MS	133.80	127.39	111.83	117.34	90.66	94.31	97.56	100.48	103.90	107.18
Alan Sheriff 132kV	Ross	15.65	16.31	17.00	17.72	18.47	19.25	20.07	20.92	21.81	22.64
Algester 33kV (possible future)	MS	0.00	84.05	97.28	116.26	121.42	126.38	130.80	134.78	139.37	143.84
Alligator Creek 33kV	North	26.73	27.28	27.83	28.38	28.93	29.48	30.04	30.59	31.14	31.69
Ashgrove West 33kV	MN	73.13	77.82	82.18	87.53	92.13	96.64	100.76	104.57	108.88	113.03
Belmont 110kV (Cleveland)	MS	125.86	132.30	139.93	147.90	155.13	162.19	168.61	174.55	181.38	187.83
Biloela 66kV	CW	26.74	28.70	29.39	30.07	31.40	32.08	32.77	33.46	34.15	34.83
Blackwater 66kV	CW	81.89	81.29	83.34	85.45	87.61	89.84	92.13	94.48	96.90	99.16
Brisbane CBD 110kV (Ashgrove West & Rocklea)	MN & MS	270.94	198.60	204.90	215.01	226.27	237.32	247.47	256.91	267.65	277.83
Brisbane CBD 110kV (Belmont & Murrarie)	MS	492.62	603.10	693.11	722.12	748.14	772.67	793.45	811.32	832.63	853.93
Bundamba 110kV	MS	14.10	13.91	13.81	13.82	48.63	50.30	51.73	52.96	54.42	55.88
Cairns 22kV	FN	78.84	82.04	85.41	84.25	87.71	91.30	95.05	98.95	103.02	106.69
Cairns City 132kV	FN	67.91	72.40	75.48	68.60	71.51	74.54	77.71	81.03	84.49	87.59
Cairns North 132kV	FN				14.91	15.58	16.27	17.00	17.76	18.55	19.26
Cardwell 22kV	Ross	3.93	4.02	4.11	4.20	4.29	4.39	4.49	4.59	4.70	4.80
Clare 66kV	Ross	62.78	63.98	65.17	66.36	67.56	68.75	69.94	71.14	72.33	73.52
Collinsville 33kV	North	10.84	10.96	11.09	11.22	11.35	11.49	11.63	11.77	11.91	12.05
Dan Gleeson 66kV	Ross	52.48	54.69	56.99	59.40	61.90	64.51	67.24	70.07	73.03	75.81
Dysart 66kV	CW	38.49	38.73	38.98	39.23	39.47	39.72	39.98	40.23	40.49	40.74
Edmonton 22kV	FN	28.94	30.32	31.76	33.26	34.84	36.50	38.23	40.05	41.95	43.65
Egans Hill 66kV	CW	51.19	52.85	54.57	56.35	58.18	60.07	62.03	64.04	66.13	68.05
Garbutt 66kV	Ross	95.29	97.49	99.74	102.00	104.27	106.53	108.80	111.06	113.33	115.59
Gin Gin 132kV (Bundaberg)	WB	95.58	97.27	98.99	100.74	102.53	104.35	106.21	108.10	110.03	111.86
Gladstone 132kV (Boat Creek & Comalco)	Glad	101.18	153.46	154.87	156.28	157.70	159.11	160.53	161.94	163.35	164.77
Gladstone South 66kV	Glad	56.24	54.77	57.94	61.16	64.52	68.05	71.75	75.63	79.69	83.30
Goodna 33kV	MS		76.57	82.84	81.81	85.90	89.50	91.28	92.69	94.46	96.86

Connection Points	Zone	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Ingham 66kV	Ross	17.07	17.42	17.80	18.21	18.62	19.04	19.47	19.91	20.37	20.80
Innisfail 22kV	FN	29.32	30.40	31.52	32.69	33.89	35.14	36.43	37.77	39.17	40.44
Kamerunga 22kV	FN	37.74	39.50	41.25	43.01	44.77	46.53	48.28	50.04	51.80	53.56
Lilyvale 66kV	CW	106.10	109.06	112.01	114.97	117.92	120.88	123.83	126.79	129.74	132.70
Lilyvale132kV (Barcaldine & Clermont)	CW	28.42	29.05	29.69	30.32	30.96	31.61	32.25	32.90	33.55	34.20
Loganlea 110kV	MS	333.76	360.52	378.20	391.62	411.49	430.26	447.44	463.42	481.90	499.10
Loganlea 33kV	MS	92.94	88.14	91.23	91.93	95.28	98.40	101.02	103.25	105.87	108.57
Mackay 33kV	North	101.33	106.38	111.69	117.26	123.11	129.26	135.83	142.75	150.03	156.40
Middle Ridge 110kV	SW	228.88	228.85	238.98	249.79	261.13	272.46	284.29	296.39	309.06	320.60
Middle Ridge 110kV (Postman's Ridge and Gatton)	MN	18.74	35.81	36.63	37.21	37.78	38.25	38.52	38.63	38.86	39.17
Molendinar 110kV	GCT	285.41	325.59	342.18	367.83	391.58	415.50	438.25	460.20	484.93	507.52
Moranbah 66kV and 11kV	North	83.83	89.45	94.16	98.02	103.06	106.69	110.32	113.95	117.58	121.20
Moura 66kV	CW	32.15	34.26	34.69	35.12	35.56	36.00	36.69	37.64	38.07	38.79
Mudgeeraba 110kV	GCT	373.29	384.26	416.05	444.38	471.13	497.87	523.04	547.09	574.28	599.34
Nebo 11kV	North	1.59	1.65	1.72	1.80	1.87	1.94	2.01	2.09	2.16	2.23
Newlands 66kV (N)	North	17.02	17.19	18.69	18.88	19.08	19.27	19.47	19.67	19.86	20.06
Palmwoods 132kV and 110kV	MN	274.00	299.41	315.53	343.55	373.49	407.49	439.76	483.13	521.84	556.84
Pioneer Valley 66kV	North	8.16	8.28	8.40	8.52	8.64	8.76	8.88	9.00	9.12	9.24
Proserpine 66kV	North	48.60	51.11	54.20	56.97	59.81	62.94	66.17	69.09	72.12	75.29
Redbank Plains 11kV	MS	14.44	16.26	14.58	15.69	16.32	16.92	17.44	17.90	18.44	18.97
Richlands 33kV	MS	135.66	101.15	96.12	105.57	110.36	114.97	119.05	122.70	126.90	131.04
Richlands West 33kV (possible future)	MS			8.73	9.09	9.54	9.98	10.37	10.73	11.14	11.54
Rockhampton 66kV	CW	103.18	107.15	111.77	115.75	119.72	123.70	127.67	131.65	135.62	139.60
Rocklea 110kV (Archerfield)	MS	81.18	59.06	61.34	63.59	66.06	68.42	70.43	72.19	74.25	76.31
Ross 132kV (Kidston and Georgetown)	Ross	33.10	34.32	35.44	36.60	37.81	39.05	40.34	41.68	43.07	44.38
Runcorn 33kV	MS	149.05	96.58	109.65	116.11	122.20	128.20	133.73	138.92	144.85	150.39
South Pine 110kV	MN	741.96	775.09	815.45	861.42	894.93	926.74	954.15	984.13	1012.44	1042.20
Sumner 110kV (possible future)	MS		9.95	10.17	10.59	10.90	11.18	11.40	11.56	11.78	12.01
Swanbank 110kV (Raceview)	MS	112.42	82.85	87.50	92.37	96.27	100.00	103.26	106.17	109.54	112.87

Connection Points	Zone	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Tangkam 110kV (Dalby and Oakey)	SW	24.69	35.58	37.16	38.70	39.94	41.19	42.45	43.72	45.01	46.27
Tarong 132kV (Chinchilla and Roma)	SW	71.38	74.35	76.20	79.04	82.04	85.06	88.08	91.12	94.18	97.20
Tarong 66kV (Wide Bay)	SW	32.64	33.84	35.05	36.25	37.45	38.65	39.85	41.05	42.25	43.45
Tennyson 33kV	MS	182.55	185.51	190.58	199.68	207.11	214.11	220.06	225.14	231.14	237.24
Terranora 110kV at State border	GCT	87.48	92.42	97.35	102.29	107.22	112.16	117.10	122.03	125.61	130.82
Townsville South 66kV	Ross	95.41	100.53	104.64	108.76	113.03	117.45	122.03	126.77	131.34	136.00
Tully 22kV	Ross	13.44	13.76	14.09	14.43	14.78	15.13	15.50	15.87	16.25	16.61
Turkinje 132kV (Craiglee and Lakeland)	FN	18.51	19.41	20.31	21.21	22.10	23.00	23.90	24.80	25.70	26.60
Turkinje 66kV	FN	38.94	40.27	41.64	43.06	44.52	46.04	47.61	49.23	50.91	52.45
Waggamba 132kV (Bulli Creek)	SW	15.54	16.04	16.54	17.04	17.54	18.04	18.54	19.04	19.54	20.05
Wecker Road 33kV (Belmont)	MS	118.78	129.58	97.12	103.79	110.63	117.54	124.15	130.58	137.84	144.39
Woolooga 132kV (Gympie)	MN	150.59	158.69	168.10	178.00	187.95	189.87	199.19	215.58	225.75	234.06
Woolooga 132kV (Kilkivan)	WB	148.21	155.92	161.88	167.88	173.92	180.01	186.14	192.32	198.54	204.66
Direct Connected Industrial Loads (SunMetals, QLD Nickel, Invicta Load - Ross, and BSL, QAL - Glad, and a new industrial load in Swanbank Enterprise Park - MN)		1155.6	1185.4	1267.9	1278.3	1281.2	1287.1	1293.1	1299.1	1305.1	1305.3
Transmission Grid Connected Mining Loads (Rolleston - CW, Burton Downs - N, Goonyella North - N, Hail Creek - N)		23.44	23.59	32.32	32.48	32.64	32.81	32.97	33.13	33.30	33.46
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, and Corinda – MS)		66.55	67.43	68.42	69.52	70.69	71.83	72.92	73.98	75.07	76.17
TOTAL QLD SUMMER PEAK		**7789**	**8188**	**8612**	**8981**	**9323**	**9656**	**9974**	**10303**	**10641**	**10959**

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

Connection Points	Zone	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Abermain 110kV (Lockrose)	MN	49.47	51.39	37.33	37.96	38.91	39.82	40.84	41.81	42.59	43.54
Abermain 33kV	MS	101.32	104.93	83.67	87.09	89.91	71.98	74.58	77.14	79.42	82.12
Alan Sheriff 132kV	Ross	12.39	12.92	13.46	14.03	14.63	15.25	15.90	16.57	17.27	18.00
Algester 33kV (possible future)	MS			65.47	80.78	96.62	99.61	102.90	106.11	109.03	112.49
Alligator Creek 33kV	North	23.38	27.56	28.13	28.70	29.27	29.84	30.40	30.97	31.54	32.11
Ashgrove West 33kV	MN	61.93	65.17	68.52	71.55	74.81	77.94	81.35	84.73	87.79	91.32
Belmont 110kV (Cleveland)	MS	121.37	125.64	130.83	137.47	143.30	149.43	156.18	162.95	169.25	176.55
Biloela 66kV	CW	31.10	31.92	34.26	35.08	35.90	37.48	38.30	39.12	39.94	40.76
Blackwater 66kV	CW	67.03	79.77	79.19	81.18	83.24	85.35	87.52	89.75	92.04	94.40
Brisbane CBD 110kV (Ashgrove West & Rocklea)	MN & MS	152.88	143.40	106.79	109.02	112.45	117.17	122.32	127.46	132.17	137.61
Brisbane CBD 110kV (Belmont & Murrarie)	MS	352.37	382.41	438.30	526.18	540.44	555.89	573.06	589.67	603.97	621.19
Bundamba 110kV	MS	14.28	13.94	13.59	13.34	13.12	35.89	36.82	37.69	38.41	39.31
Cairns 22kV	FN	49.82	51.94	54.05	56.27	55.51	57.78	60.15	62.62	65.19	67.87
Cairns City 132kV	FN	39.88	43.15	46.01	47.96	43.60	45.44	47.37	49.38	51.49	53.69
Cairns North 132kV						9.82	10.26	10.72	11.20	11.70	12.22
Cardwell 22kV	Ross	3.45	3.59	3.67	3.76	3.84	3.93	4.02	4.11	4.20	4.30
Clare 66kV	Ross	43.41	45.09	45.95	46.80	47.66	48.52	49.38	50.23	51.09	51.95
Collinsville 33kV	North	10.77	10.75	10.87	11.00	11.13	11.26	11.40	11.54	11.68	11.82
Dan Gleeson 66kV	Ross	41.33	43.07	44.89	46.78	48.75	50.81	52.95	55.19	57.52	59.95
Dysart 66kV	CW	37.38	42.02	42.28	42.55	42.82	43.09	43.37	43.64	43.92	44.20
Edmonton 22kV	FN	18.32	19.19	20.10	21.06	22.06	23.10	24.20	25.35	26.55	27.82
Egans Hill 66kV	CW	46.09	47.59	49.14	50.74	52.39	54.09	55.85	57.67	59.55	61.48
Garbutt 66kV	Ross	69.67	71.32	72.96	74.64	76.34	78.03	79.73	81.42	83.12	84.81
Gin Gin 132kV (Bundaberg)	WB	78.1	80.5	83.0	85.7	88.4	91.2	94.1	97.1	100.2	103.4
Gladstone 132kV (Boat Creek & Comalco)	Glad	69.45	101.77	154.13	155.57	157.01	158.45	159.89	161.33	162.77	164.20
Gladstone South 66kV	Glad	65.90	61.04	59.45	62.88	66.37	70.03	73.86	77.87	82.08	86.49
Goodna 33kV	MS			69.94	76.40	74.02	76.56	79.43	80.95	82.10	83.60

Connection Points	Zone	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Ingham 66kV	Ross	12.55	12.81	13.08	13.36	13.67	13.98	14.29	14.62	14.95	15.29
Innisfail 22kV	FN	15.51	16.08	16.67	17.28	17.92	18.58	19.27	19.97	20.71	21.47
Kamerunga 22kV	FN	33.87	35.53	37.18	38.83	40.49	42.14	43.80	45.45	47.11	48.76
Lilyvale 66kV	CW	99.23	106.70	109.67	112.64	115.61	118.58	121.55	124.53	127.50	130.47
Lilyvale132kV (Barcaldine & Clermont)	CW	27.36	27.98	28.60	29.22	29.85	30.48	31.11	31.75	32.39	33.03
Loganlea 110kV	MS	307.48	331.61	358.13	366.61	366.53	380.68	395.72	410.73	424.47	440.69
Loganlea 33kV	MS	96.46	98.59	92.03	92.14	95.72	98.18	100.89	103.47	105.58	108.13
Mackay 33kV	North	73.85	77.90	81.78	85.86	90.15	94.65	99.37	104.42	109.74	115.34
Middle Ridge 110kV	SW	222.47	230.77	220.38	225.85	231.68	237.94	243.85	249.88	255.80	261.85
Middle Ridge 110kV (Postman's Ridge and Gatton)	MN	17.19	17.20	31.54	32.01	32.07	32.27	32.52	32.72	32.79	32.97
Molendinar 110kV	GCT	258.55	254.59	287.23	297.99	314.88	331.65	349.99	368.60	386.34	406.52
Moranbah 66kV and 11kV	North	87.15	92.53	98.66	103.66	107.70	113.08	116.86	120.65	124.43	128.22
Moura 66kV	CW	27.79	32.66	34.81	35.24	35.68	36.12	36.57	37.27	38.23	38.68
Mudgeeraba 110kV	GCT	334.99	360.10	364.40	390.42	409.72	429.54	451.26	473.16	493.76	517.34
Nebo 11kV	North	1.73	1.80	1.88	1.96	2.05	2.13	2.21	2.29	2.37	2.46
Newlands 66kV (N)	North	17.41	17.58	17.74	19.31	19.49	19.69	19.88	20.08	20.27	20.46
Palmwoods 132kV and 110kV	MN	261.76	279.16	301.72	314.60	336.68	362.26	389.45	420.05	459.64	496.20
Pioneer Valley 66kV	North	6.99	7.09	7.20	7.30	7.41	7.51	7.62	7.72	7.82	7.93
Proserpine 66kV	North	38.76	40.80	42.82	45.31	47.57	49.90	52.45	55.08	57.49	59.99
Redbank Plains 11kV	MS	15.49	16.85	18.85	15.57	16.55	17.07	17.64	18.20	18.68	19.26
Richlands 33kV	MS	103.76	107.04	76.62	71.58	77.71	80.40	83.33	86.20	88.72	91.66
Richlands West 33kV (possible future)	MS				7.24	7.40	7.69	7.99	8.30	8.57	8.89
Rockhampton 66kV	CW	80.65	83.88	87.11	90.87	94.10	97.33	100.57	103.80	107.03	110.26
Rocklea 110kV (Archerfield)	MS	39.55	52.84	39.67	40.75	41.50	42.67	43.98	45.22	46.28	47.55
Ross 132kV (Kidston and Georgetown)	Ross	27.39	30.94	32.08	33.10	34.16	35.26	36.40	37.57	38.79	40.06
Runcorn 33kV	MS	129.08	133.94	88.34	99.78	103.83	108.10	112.82	117.52	121.86	126.91
South Pine 110kV	MN	688.78	711.90	735.30	766.20	794.65	817.64	843.09	867.68	895.16	920.60
Sumner 110kV	MS			8.62	8.71	8.91	9.07	9.25	9.42	9.54	9.70
Swanbank 110kV (Raceview)	MS	93.37	99.38	70.53	73.63	76.29	78.72	81.41	84.01	86.28	88.95

Connection Points	Zone	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Tangkam 110kV (Dalby and Oakey)	SW	21.64	22.52	38.00	39.45	40.88	41.83	42.78	43.75	44.74	45.73
Tarong 132kV (Chinchilla and Roma)	SW	66.46	69.71	71.09	70.11	71.33	72.71	74.09	75.48	76.87	78.26
Tarong 66kV (Wide Bay)	SW	34.09	35.09	36.10	37.10	38.11	39.11	40.11	41.12	42.12	43.13
Tennyson 33kV	MS	177.54	161.39	179.81	158.22	162.95	167.41	172.32	177.01	180.96	185.72
Terranora 110kV at State border	GCT	88.58	92.27	95.96	99.64	103.33	107.01	110.70	114.39	118.07	121.76
Townsville South 66kV	Ross	64.63	67.36	70.98	73.88	76.79	79.80	82.92	86.16	89.51	92.73
Tully 22kV	Ross	4.97	5.08	5.21	5.33	5.46	5.59	5.73	5.86	6.00	6.15
Turkinje 132kV (Craiglee and Lakeland)	FN	16.43	17.26	18.10	18.93	19.77	20.61	21.45	22.28	23.12	23.96
Turkinje 66kV	FN	40.65	42.04	43.47	44.95	46.48	48.06	49.70	51.39	53.14	54.95
Waggamba 132kV (Bulli Creek)	SW	15.04	18.57	19.09	19.61	20.13	20.66	21.18	21.70	22.22	22.75
Wecker Road 33kV (Belmont)	MS	115.68	121.52	130.66	92.70	97.20	102.38	108.06	113.86	119.40	125.74
Woolooga 132kV (Gympie)	MN	169.28	176.91	184.46	193.30	201.10	210.28	213.57	223.75	240.08	251.17
Woolooga 132kV (Kilkivan)	WB	132.83	137.43	138.55	143.18	147.82	152.49	157.18	161.90	166.63	171.39
Direct Connected Industrial Loads (SunMetals, QLD Nickel, Invicta Load - Ross, and BSL, QAL - Glad, and a new industrial load in Swanbank Enterprise Park - MN)		1138.6	1173.5	1194.1	1270.4	1280.4	1284.6	1290.6	1296.6	1302.7	1308.7
Transmission Grid Connected Mining Loads (Rolleston - CW, Burton Downs - N, Goonyella North - N, Hail Creek - N)		17.16	25.35	25.54	33.80	34.01	34.21	34.41	34.61	34.82	35.02
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, and Corinda – MS)		72.97	73.89	74.80	75.87	76.99	78.24	79.49	80.73	81.93	83.17
TOTAL QLD WINTER PEAK		**6857**	**7178**	**7485**	**7818**	**8065**	**8317**	**8576**	**8845**	**9121**	**9407**

8.6 Appendix F – Temperature 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

Weather Station	Average Daily Temperature Percentiles (1) °C					
	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
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	-4.9

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 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 (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.

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	2,648	244	842	686	893
1998/99	2,817	254	845	662	900
1999/00	3,011	268	887	704	1,017
2000/01	3,038	282	911	744	1,037
2001/02	3,187	284	1,044	801	1,062
2002/03	3,449	303	980	771	1,085
2003/04	3,930	340	1,079	831	1,108
2004/05	4,110	358	1,065	883	1,110
Temperature Corrected Area Peak Demand					
1997/98	2,646	247	860	686	893
1998/99	2,759	265	868	684	900
1999/00	2,839	267	938	720	1,017
2000/01	3,059	303	946	779	1,037
2001/02	3,261	298	991	801	1,062
2002/03	3,444	314	1,005	806	1,085
2003/04	3,809	333	1,060	833	1,108
2004/05	4,159	360	1,083	908	1,110
Historical average ratio of demand at time of Qld region peak to area corrected peak	100%	94.6%	94.0%	92.4%	96.2%

Notes:

(1) South east Queensland is taken here as Moreton North, Moreton South and Gold Coast Tweed zones and is 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.

Table F.4: Area Winter 50% PoE Demand Temperature Corrections

	South East	South West	Northern Non-Industrial	Central Non-Industrial	Major Industrial
Actual Peak Demands					
1998	2,691	283	733	623	895
1999	2,854	297	731	665	921
2000	3,064	318	776	709	1,021
2001	3,052	313	781	735	1,052
2002	3,078	307	796	710	1,060
2003	3,408	322	806	739	1,068
2004	3,592	350	813	797	1,099
Temperature Corrected Area Peak Demand					
1998	2,776	294	732	623	895
1999	2,855	302	725	665	921
2000	3,046	320	776	709	1,021
2001	3,104	329	782	735	1,052
2002	3,151	325	816	710	1,060
2003	3,411	329	815	739	1,068
2004	3,598	365	821	797	1,099
Historical average ratio of demand at time of Qld region peak to area corrected peak	100%	91.6%	89.9%	94.5%	97.5%

The historical coincidence factor averages developed for each of these areas and for the major industrial loads, are then 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 Corrected Peak Demands

Summer	Actual	Corrected		Actual	Corrected
1997/98	5,234	5,180	1998	5,042	5,158
1998/99	5,386	5,325	1999	5,309	5,310
1999/00	5,685	5,618	2000	5,691	5,696
2000/01	5,891	5,952	2001	5,811	5,829
2001/02	6,246	6,236	2002	5,743	5,888
2002/03	6,402	6,475	2003	6,149	6,185
2003/04	7,103	6,955	2004	6,450	6,496
2004/05	7,368	7,424			

8.7 Appendix G – Glossary

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
SVC	Static VAr Compensator
SWQ	South West Queensland
TNSP	Transmission Network Service Provider