annual planning report 2002

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COMMONLY USED ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
APR	Annual Planning Report
CB	Circuit Breaker
CCGT	Combined Cycle Gas Turbine
DNSP	Distribution Network Service Provider
GT	Gas Turbine
GWh	Gigawatt hour, one million kilowatt hours
IRPC	Inter Regional Planning Committee
kA	kiloamperes, one thousand amperes
kV	kilovolts, one thousand volts
MNSP	Market Network Service Provider
MVAr	Megavar, megavolt amperes reactive, one thousand kilovolt amperes reactive
MW	Megawatt, one thousand kilowatts
NEC	National Electricity Code
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NIEIR	National Institute of Economic and Industrial Research
POE	Probability of Exceedance
PSS	Power System Stabiliser
QNI	Queensland-New South Wales Interconnection
SCADA	Supervisory Control and Data Acquisition
SOO	Statement of Opportunities, published annually by NEMMCO
SVC	Static Var Compensator
TNSP	Transmission Network Service Provider

EXECUTIVE SUMMARY

Powerlink Queensland has been appointed by the Queensland government to undertake transmission network planning in the State, and is the owner and operator of the Queensland electricity transmission network.

Powerlink has prepared this Annual Planning Report to document the annual planning review it has carried out, as required by the National Electricity Code.

The Annual Planning Report provides information about the electricity transmission network to Code 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. Summer maximum demand delivered from the transmission grid is forecast to increase at an average annual rate of 3.75% p.a. from 6246MW in 2001/02 to 9041MW in 20011/12. Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.25% p.a. over the next ten years for the medium growth scenario. Areas contributing most to this growth include Moreton North, Moreton South and Gold Coast/Tweed Zones, which are experiencing energy growth of 5.0, 4.3 and 4.0% p.a. respectively.

This high level of load growth will require substantial augmentation of the capability of the Queensland transmission network to ensure grid capacity keeps pace with demand. The most significant project completed since the 2001 Annual Planning Report was the extension of the 275kV network to Cairns in the Far North, to meet growing loads in the Cairns area. This grid augmentation is presently operating at 132kV, but will be uprated to 275kV by September 2002. Following consultations with participants and interested parties, Powerlink is also carrying out major augmentations of its system supplying southern Brisbane and within the Gold Coast, and is constructing a 275kV line between Stanwell and Broadsound to increase the grid transfer capacity between Central and North Queensland. Smaller augmentations such as the installation of capacitor banks and transformer upgrades are also underway to satisfy network reliability standards.

As noted in previous planning reports, the development of the network to meet forecast load depends on the location and capacity of new scheduled generation developments, on future generation patterns in the National Electricity Market and on the development of non-scheduled embedded generation. For several years, Queensland has been characterised by considerable electricity supply side uncertainty that has made planning the transmission grid very difficult. While the uncertainty associated with the competitive market remains, the generation outlook in Queensland is slowly becoming clearer. The 840MW Callide Power Plant has been commissioned since the publication of the 2001 Annual Planning Report. By the winter of 2003, 1634MW of additional generating capacity will be placed in service with Millmerran, Swanbank E and Tarong North power stations commencing operation. The Queensland Government has also recently announced the preferred developer for conversion of the Townsville (Yabulu) power station to baseload operation by 2005.

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.

Some market commentators are predicting that flows on the Queensland-New South Wales interconnector will reach transfer limits for significant periods of time in coming years. Powerlink will continue to monitor interconnector flows closely, and is working with its NSW counterpart, TransGrid to identify augmentation options that could be implemented to relieve potential future constraints should this be warranted.

Within Queensland, two sections of Powerlink's transmission grid reached transfer limits for more than 1% of the time during the six months from October 2001 to March 2002. These were the Far North Limit and the CQ-NQ Limit, both of which were strongly impacted by the extreme weather conditions (high temperatures and drought conditions which simultaneously increased loads and reduced local generation) experienced in North Queensland in 2001/02. Powerlink's view is that these limits are unlikely to be reached for significant periods over the outlook period covered by the Annual Planning Report. This expectation is based on committed transmission augmentations, the implementation of grid support arrangements with market generators and the anticipated return to more typical loads and hydro generation output in north Queensland.

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 grid support arrangements.

Not surprisingly with a high load growth and a long, thin grid, the predominant driver for augmentations to network capability will be the need to maintain reliability standards. Reliability has long been the predominant driver for grid augmentation in Queensland.

Emerging areas of need include supply to the Darling Downs area in south-west Queensland, supply within the Townsville area, supply to the Bowen Basin mining area in central Queensland and supply to the Gold Coast/Tweed area. Powerlink expects to initiate consultation processes to determine appropriate solutions to these limitations within the next twelve months so that the necessary augmentations can be implemented in a timely manner if justified. Work has started on addressing the Darling Downs limitations, with Powerlink recently issuing a paper to inform market participants and interested parties about the emerging issues, and to seek possible solutions.

This Annual Planning Report also contains details of three proposed new small network assets. Three 120MVAr 275kV capacitor banks are proposed for installation - at Wurdong, Mt England and Palmwoods substations. Powerlink invites submissions on these proposed augmentations by Monday 29th July, 2002.

1. INTRODUCTION

Powerlink Queensland is the entity designated by the Queensland government to be responsible for transmission network planning in the State, and owns and operates the Queensland electricity transmission network.

Powerlink has prepared this Annual Planning Report to document the annual planning review it has carried out. The Report also contains information that allows and encourages input by interested parties to facilitate identification of the most appropriate developments for maintaining the capability of the transmission network in the face of the continued high load growth in the State. This makes it an important part of the process of planning the Queensland transmission network to meet the needs of participants in the National Electricity Market and end-use customers.

The Annual Planning Report includes information on electricity demand forecasts, the existing electricity supply system including committed generation and transmission network developments, and forecasts of grid capability.

Information is also provided about emerging limitations in the capability of the grid. Proposals, including both network and non-network solutions, to overcome some immediate limitations are identified.

1.1 Purpose of the Annual Planning Report

Under Clause 5.6.2A of the National Electricity Code (NEC), Powerlink Queensland is required to publish an Annual Planning Report setting out the results of its annual planning review conducted in accordance with Clause 5.6.2(a) and (b) of the NEC.

The purpose of the Report is to provide information about the Queensland electricity transmission network to Code 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
- 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.

Powerlink also recommends that interested parties review this document in conjunction with the Statement of Opportunities (SOO) published by NEMMCO. The SOO provides information relevant to the entire National Electricity Market, including the supply/demand balance in the Queensland region of the NEM. NEMMCO's 2002 SOO is expected to be published by 31 July 2002.

1.2 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 Transmission Network Service Provider under the National Electricity Code. In this role, and in the context of this Annual Planning Report, 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 National Electricity Code.

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

4. Advise Code 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 Distributors and consultation with Code 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. 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 National Electricity Code.

Powerlink has also been nominated by the Queensland Government as the entity having transmission system planning responsibility in the State, with respect to Clause 5.6.3(b) of the NEC. In this role, Powerlink represents the Queensland jurisdiction on the Inter-Regional Planning Committee. 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 Statement of Opportunities and carrying out the annual interconnector planning review
- bringing forward to the Committee, where necessary, Queensland augmentations which have a material inter-network impact
- participating in inter region system tests associated with new or augmented interconnections
- 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 NEC.

1.3 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 the augmentation 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.

1.3.1 Planning of Connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and electricity distributors (DNSP's). Planning of new or augmented connections involves consultation between Powerlink and the connected party, determination of technical requirements and completion of connection agreements.

1.3.2 Planning of the Shared Network Within Queensland

Powerlink is responsible for planning the transmission grid within Queensland. The National Electricity Code sets out the planning process and requires Powerlink to apply the Regulatory Test promulgated by the ACCC 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,
- the forecast of generation and its location, capacity and expected operation,
- the assessment of future network capability,
- planning criteria for the network, and
- prediction of future loads on the transmission network.

Powerlink obtains a ten year forecast of electrical demand and energy for the whole of the Queensland region from an independent forecaster, the National Institute of Industrial and Economic Research. The DNSPs and major customers connected to Powerlink Queensland's transmission grid provide ten-year forecasts of demand and energy at each connection point on the grid. Local factors inherent in the DNSP and customer forecasts are used to modify the trends inherent in the NIEIR forecasts.

These forecasts are used together with forecast generation patterns to determine potential flows on transmission system elements. The location and capacity of existing and committed generation in Queensland is sourced from the NEMMCO Statement of Opportunities, unless modified based on advice from relevant participants. Information about existing and committed generation embedded 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 in accordance with the provisions of Clause 5.6.2 of the NEC. 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. It is a condition of Powerlink's transmission authority 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."

Powerlink also has legal obligations to consider environmental and social issues in the development of its transmission network.

In addition, more specific planning criteria are contained in the technical standards in schedule S5.1 to Chapter 5 of the NEC. The Code sets out minimum performance requirements of the network and connections.

New network developments may be proposed to meet these legislative and Code obligations. Powerlink may also propose network augmentations that would deliver a net economic benefit when measured in accordance with the ACCC Regulatory Test.

The requirements for initiating new regulated network developments are set down in the Clauses 5.6.2, 5.6.6A and 5.6.6 of the code. These clauses apply to different types of proposed developments. 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 an augmentation is justified – 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, new generation capacity 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 ACCC's regulatory test. In the case of an augmentation required to meet service standards, this involves a cost effectiveness analysis to determine the option that minimises net present value of costs. In all other cases, the regulatory test requires that the proposed development maximises the net market benefit as defined in the regulatory test.
- Consultation and publication of a recommended course of action to address the identified network limitation.

1.3.3 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 Annual Planning Report. The Code 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 Statement of Opportunities (SOO) which provides information on load and generation forecasts and committed network developments with an inter-regional impact.

- NEMMCO and the IRPC carry out an annual interconnector review.

- This review provides information relevant to the technical and economic need for inter regional augmentations. This includes information on the significance of forecast losses and constraints on power transfers between regions. It also identifies options, both network and non-network, for reduction or removal of future constraints and for reduction of losses.

- The interconnector review will form part of the SOO. NEMMCO and the IRPC also publish a program for the periodic review of options for the removal or reduction of constraints and network losses.

2. DEMAND AND ENERGY FORECASTS

2.1 Background to Load Forecasts

2.1.1 Sources of Load Forecasts

In accordance with Clause 5.6.1 of the National Electricity Code, Powerlink has obtained demand forecasts over a ten-year horizon from Distribution Network Service Providers (DNSPs) and directly-connected customers at each connection point in Powerlink's transmission system.

These individual connection point forecasts were aggregated into estimated demand forecasts for the total Queensland region and for ten geographical zones as defined in Section 2.5, using diversity factors observed from historical records up to the end of March 2002.

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

The National Institute of Economic and Industrial Research (NIEIR) was engaged to provide an independent assessment of energy and demand forecasts for the Queensland region and for the former DNSP areas within Queensland. NIEIR also provided economic outlook analysis for the high and low growth scenario forecasts and temperature sensitivity analysis of demand forecasts. These economic growth scenarios correspond to those provided by NIEIR to NEMMCO for its 2002 Statement of Opportunities.

In response to NEMMCO's request, this annual forecast has for the first time been prepared immediately following a summer to reflect the increasing trend to higher summer loadings in Queensland and generally across the NEM and to take advantage of the latest available data.

2.1.2 Basis of Load Forecasts

Economic Activity:

Three forecast scenarios of economic activity were provided by NIEIR. 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 growth for the High, Medium and Low Growth Scenarios developed by NIEIR, over the ten-year period 2001/02 to 2011/12 are:

	HIGH	MEDIUM	LOW
Australian Gross Domestic Product (average growth p.a.)	4.1%	3.2%	2.4%
Queensland Gross State Product (average growth p.a.)	4.7%	3.7%	2.8%

These growth rates are all slightly higher than last year's NIEIR ten year outlook predictions, as outlined in the Powerlink 2001 Annual Planning Statement. However, it should be noted that for the first five years, the Queensland medium scenario average growth rate is 3.5% per annum, slightly lower than as forecast last year (3.6%), but has a higher growth rate in the second five year period. This difference is reflected in the ten-year profile of the new forecast of energy delivered from the transmission grid.

Weather Conditions:

Within each of these three economic scenarios, three forecasts were also prepared by NIEIR incorporating sensitivity of maximum summer and winter demands to prevailing weather conditions, namely;

(i) a 10% probability of exceedance (POE), corresponding to one year in ten hot summer or cold winter conditions
(ii) a 50% POE, corresponding to one year in two (average summer or average winter) conditions
(iii) a 90% POE corresponding to mild summer or mild winter conditions, which would be expected to be exceeded in nine years out of ten.

Cogeneration and Renewable Energy Source Generation

In this Report, the forecasts again account for predictions, provided by NIEIR, of long term growth in new cogeneration and renewable energy source generation projects in Queensland. These may be either embedded or connected to the transmission network, and could be either scheduled or non-scheduled under the National Electricity Market.

This year, NIEIR's predictions of new cogeneration and renewable energy source generation projects in Table 2.1, provide for a substantially lower level of such developments than in last year's predictions. This is due to several factors:

- There has been less development over the last year than previously expected, particularly in the area of sugar mill generation expansion. Only minor development is now expected to 2005 with some acceleration then coinciding with proposed initiation of the Queensland 13% Gas Scheme (a key initiative of the Queensland Government Energy Policy).

- The possibility of large new scheduled cogeneration gas-fired power plant, probably connected directly to the transmission grid, has become harder to predict. Accordingly, NIEIR's new forecast focuses on smaller plant, and does not take account of potential large gas delivery infrastructure projects, such as gas from New Guinea or Timor Sea nor large-scale coal seam methane gas supply developments.

Table 2.1: Forecast of Cogeneration and Renewables

NIEIR Forecasts of Queensland Total Cogeneration and Renewable Energy Source Annual Generation (GWh p.a.) (1) (2)

Year	Forecast for APR 2002 Economic Growth Scenario		
	Low	Medium	High
2001/02 projected		1,981	
2002/03	1,981	2,039	2,096
2003/04	2,105	2,140	2,224
2004/05	2,125	2,200	2,403
2005/06	2,163	2,275	2,590
2006/07	2,320	2,546	3,004
2007/08	2,546	2,810	3,445
2008/09	2,722	3,075	3,797
2009/10	2,898	3,339	4,150
2010/11	2,933	3,452	4,509
2011/12	2,950	3,546	4,677

Notes:
(1) This includes total generator output for new scheduled and non-scheduled cogeneration plant plus new scheduled and non-scheduled renewable energy source plant, and does not account for energy required for the plant's own use.
(2) The format of this table has been changed from similar forecasts in the 2001 Annual Planning Report. Table 2.1 shows the total contribution from all cogeneration and renewables including existing plant. The 2001 Report provided a forecast of the contribution of cogeneration and renewables above 1999/2000 levels.

The energy delivered to the Wivenhoe pumps is excluded from both the demand and energy forecasts in this report. This is because the level of Wivenhoe pumping depends on the level of Wivenhoe generation and Powerlink has not attempted to specifically forecast this under the market environment.

Other Loads

Interconnector Loads

Energy flows across the Queensland New South Wales Interconnection (QNI) and the Directlink market network service provider do not need to be specified in these forecasts, as they are not part of the Queensland customer load. These flows will add or subtract to dispatch of generation within Queensland to meet the forecast levels and will therefore be considered in Chapter 4 of this report when examining network capability.

New Queensland Loads

The forecast includes a new load in Queensland at Goondiwindi from winter 2003 onwards. This area is then planned to be supplied by a new 132kV line from Bulli Creek, with the existing 66kV supply from NSW becoming a standby supply for increased reliability.

New Large Loads – Committed

These forecasts also include the committed new Comalco Alumina Refinery plant at Yarwun (near Gladstone), Hail Creek coal mine (west of Nebo), and minor load increases at existing aluminium and zinc smelter plants.

New Large Loads – Uncommitted

There are a range of announced proposals for large metal processing loads which are not yet considered to be committed and are therefore <u>not</u> included in the load forecast. These developments include:

- the new aluminium smelter west of Gladstone (Aldoga);
- the proposed magnesium smelter at Stanwell;
- possible major expansions of existing aluminium and zinc smelter plants (Gladstone/Townsville).

While the load forecast does not include the above yet uncommitted large metal processing loads, consideration to the impacts of these potential developments is given in the assessment of network capability in Chapter 4 of this report. These developments could translate to the following additional loading on the network.

Zone	Metal Processing	Possible Load
Gladstone	Aluminium	0 – 1000MW
Central West	Magnesium	0 – 200MW
Ross	Zinc	0 – 100MW

NIEIR and DNSP Forecast Reconciliation

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

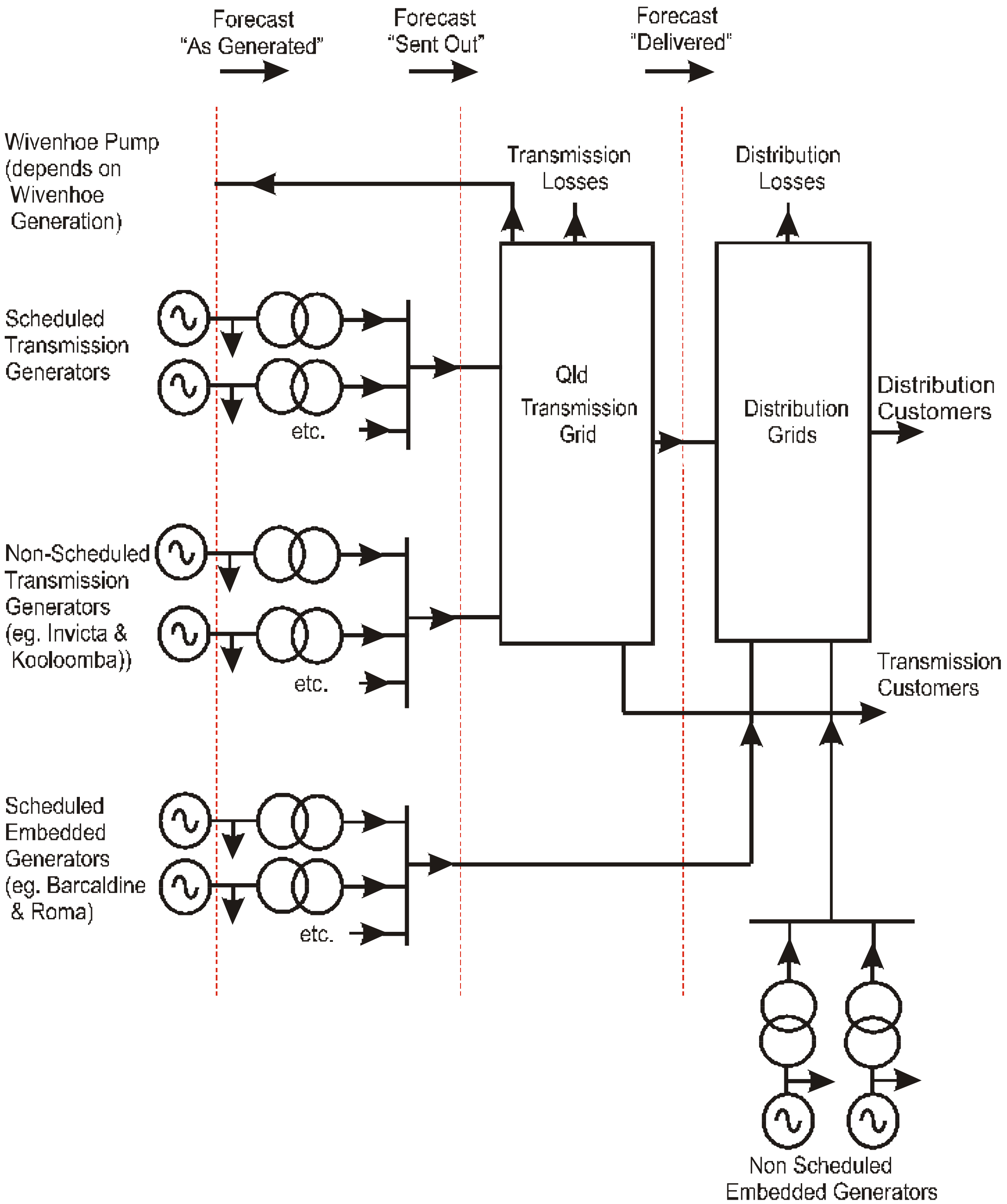
The recent extreme summer weather resulted in much higher than expected demand and energy consumption. All parties needed to correct for this abnormality and close agreement was found between the degree of correction, so that the average weather demand forecasts were on a similar basis.

Overall the customer and NIEIR demand and energy forecasts closely agreed over the ten-year period.

2.1.3 Load Forecast Definitions

The relationship between the classes of generation and the forecast quantities in this Report is shown in Figure 2.1.

Figure 2.1: Load Forecast Definitions



Eg. Sugar mills, wind farms, waste generation plant, and large industrial customer internal plant

2.2 2001/02 Energy and Demands – Weather Correction

In the recent 2001/02 summer, Queensland experienced sustained dry and hot weather which caused very high levels of irrigation pumping and domestic air conditioning usage. Most major centres outside of south-east Queensland experienced the hottest average recorded summer temperatures in the last fifty years. Accordingly, energy delivered over summer 2001/2002 was substantially above expectations and presented a challenge of how to account for this in forecasting future electricity consumption.

Figure 2.2 shows the actual percentage growth in the recent Queensland region's season energy and maximum demand over the corresponding season of the previous year. The impact of the ramping up of the new SunMetals Zinc Plant in Townsville, over the period April 1999 to June 2000 was discounted in deriving the growth rates in Figure 2.2, so that this graph provides an insight into the underlying growth rates over the last two years.

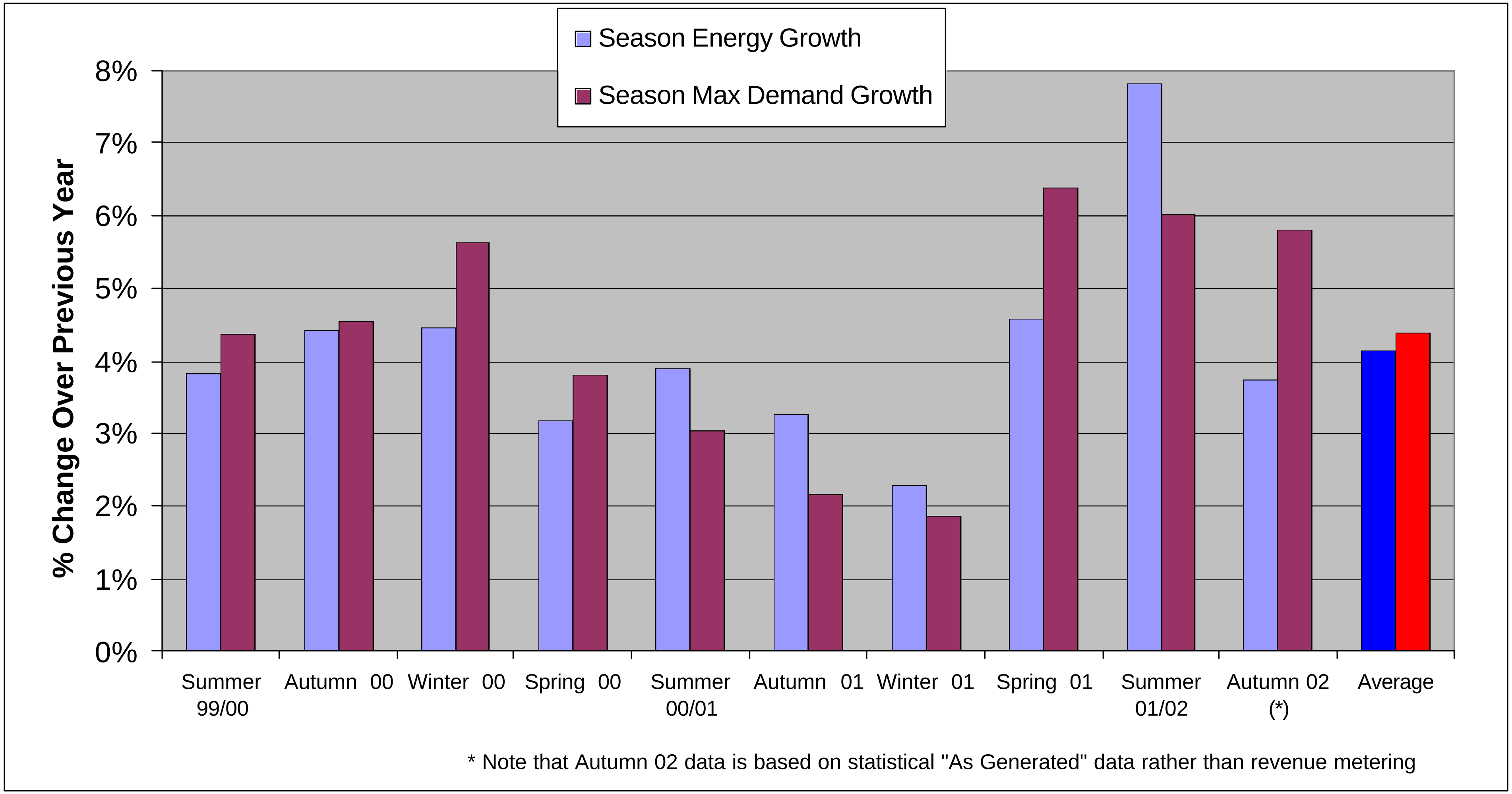
The previously predicted downturn in Queensland economic growth rate during 2000/01 did eventuate. This helps to explain the decline in seasonal growth rates for energy and demand in that period, as shown in Figure 2.2. Queensland economic growth predictions for 2001/02 were only slightly higher than for 2000/01 and still well below the growth rates in 1998/99 and 1999/00. The large jump in energy and demand growth rates over the last nine months are largely due to the extreme weather conditions, noting that spring 2001 and autumn have also been warmer and drier than average.

This recent period of high growth has lifted the average energy and demand growth rates over the last two years to about 4% per annum, as shown on Figure 2.2 Correcting the recent weather back to more average conditions, these growth rates would have been about 3.2 to 3.7% per annum, and such levels are regarded as the recent underlying electricity growth rate.

Analysis has confirmed that the sensitivity of peak demands to weather conditions has increased significantly across Queensland over the last three years consistent with the large growth in domestic air-conditioning installation. This can be seen in a larger variation of demand between adverse weather and average weather compared to the previous forecast, as shown in Figures 2.5 and 2.6.

Figure 2.2 Recent Queensland Seasonal Energy and Demand Growth Rates

Discounted for the ramping up of the SunMetals Zinc Plant - April 99 to June 00



2.3 Changes from 2001 Annual Planning Report

For the last two years, Powerlink's Annual Planning Reports have included predictions of substantial growth in future embedded non-scheduled generators, which would reduce the supply from the transmission grid.

For this 2002 Annual Planning Report, NIEIR has provided an updated forecast of new cogeneration and renewable energy source plant for Queensland over the next ten years. As outlined in Section 2.1, the forecast level of such generation is substantially lower than in the 2001 Report. Accordingly, forecasts of energy and demand supplied from the transmission grid are based on a much smaller reduction corresponding to the substantially lower forecast of new embedded non-scheduled generation.

For the Medium Growth Scenario, energy sent out to the grid is forecast to increase at an average rate of 3.25% p.a. over the next ten years (marginally higher than 3.2% as in the 2001 Report). This forecast of energy sent out to the grid allows for the medium growth scenario forecast of embedded non-scheduled generation. Most of the embedded generation is expected to come from renewable sources (such as bagasse) and may not be available at the time of summer peak demand. Accordingly, there is expected to be a relatively lower impact on potentially reducing summer demand forecasts than on delivered energy, due to these generators.

There has been a slight decrease in forecast load factor, which gives rise to changing relative rates of energy and demand growth. This is a result of higher load factor loads (industrial loads etc) being forecast to grow at a lower rate than general load. These factors result in the average growth rates of 3.75% p.a for summer maximum demand and 3.45% p.a. for winter maximum demand over this 10-year outlook for the medium economic growth scenario and average weather.

2.4 Forecast Data

The forecasts are shown in Tables and Figures as follows:

- Figure 2.1 shows the relationship between the classes of generation and the forecast quantities in this Report.
- Table 2.1 shows the NIEIR forecast of cogeneration and renewable energy source generation.
- Figure 2.2 shows recent growth in energy and demand by seasons to illustrate the impact of the recent very hot and dry weather across Queensland.
- Table 2.2 summarises forecast annual growth rates under different economic growth scenarios.
- Figure 2.3 and Table 2.3 shows the adjustment to the Medium Growth Scenario energy forecast to account for the expected increase in embedded non scheduled cogeneration and renewable energy generation.
- Figure 2.4 and Table 2.4 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 Medium Growth scenario. Table 2.4 also shows forecasts for the Low and High Growth scenarios.

- Figure 2.5 and Table 2.5 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. The actual peak delivered demand recorded in summer 2001/02 was 6246MW. This peak occurred on an unusual day where very hot weather was experienced simultaneously across all of Queensland.

- Figure 2.6 and Table 2.6 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 2.7 shows the **Medium Growth** Scenario forecast of **average weather** winter and summer maximum coincident region electricity **demand** including estimates of Power Station Sent Out and As Generated Demands.

- Table 2.8 shows the **Medium Growth** forecast of **one in ten year or 10% POE** weather winter and summer maximum co-incident region electricity **demand** including estimates of Power Station Sent Out and As Generated Demands.

- 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 2004/05 is shown in Table A2 of Appendix A. These loadings can be higher at the time of local area maximum demand, but 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 March 2002, and are based on assumptions and third party predictions which may or may not prove to be correct. The forecast energy is provided as part of a long term trend. The “projected actual” forecast for the 2001/02 year accounts for actual energy delivery in the first nine months of the financial year, i.e. up to end of March 2002 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 as follows:

Table 2.2: Average Annual Growth Rate

Average Annual Growth Rate (% p.a)			
Economic Growth Scenario	**High**	**Medium**	**Low**
Queensland Gross Domestic Product	4.7%	3.7%	2.8%
Energy Delivered (1)	5.0%	3.25%	2.0%
Summer Peak Demand	5.7%	3.75%	2.3%
Winter Peak Demand	5.5%	3.45%	1.85%

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 non-scheduled generation above current levels the average forecast growth rate in energy delivered would be 3.5% per annum under the medium growth scenario.

Table 2.3: Annual Energy Delivered

Adjustment to Medium Economic Growth Scenario Annual Energy (GWh) Forecast to Account for Expected Increase in Embedded Non-Scheduled Cogeneration and Renewable Energy Generation.

Forecast Year	Existing Basis Delivered Energy Forecast (1) GWh p.a.	Estimated Increase in Embedded Non-Scheduled Generation Output of New and Upgraded Cogeneration and Renewable Energy Plant Above 2001/2002 Levels GWh p.a.			Adjusted Forecast of Energy Delivered from Grid & Scheduled Embedded Generators(3) GWh p.a.
		New Output	New Sales to Distribution Grid	Output for Own Use (2)	
2002/03	41,284	58	28	30	41,241
2003/04	43,053	159	70	89	42,938
2004/05	44,495	219	100	119	44,335
2005/06	46,090	293	145	148	45,871
2006/07	47,696	565	310	255	47,258
2007/08	49,614	828	467	361	48,966
2008/09	51,050	1,093	625	468	50,191
2009/10	52,835	1,357	783	574	51,775
2010/11	54,717	1,470	860	610	53,552
2011/12	56,795	1,564	918	646	55,554

Notes:

(1) This is the forecast energy (medium economic scenario) that all NEM Scheduled generators and transmission connected Non-Scheduled generators (only Invicta and Koombooloomba at present) would be supplying on a net sent out basis, if there were no increase in the current level of embedded non-scheduled generation in Queensland. The transmission grid energy losses would also need to be supplied by this plant.

(2) It has been assumed that 50% of this own use generation would reduce electricity purchases which would otherwise be required from the Distribution network, with 50% being required to supply new loads associated with the new or upgraded plant.

(3) Based on the above assumptions this is equal to the Existing Basis Forecast less new sales to the Grid by new embedded non-Scheduled plant less 50% of the new own use generation of that plant.

Figure 2.3 Impact of New Cogeneration and Renewable Energy Source Generation

On Annual Energy Forecasts (GWh p.a.) Medium Economic Growth Scenario

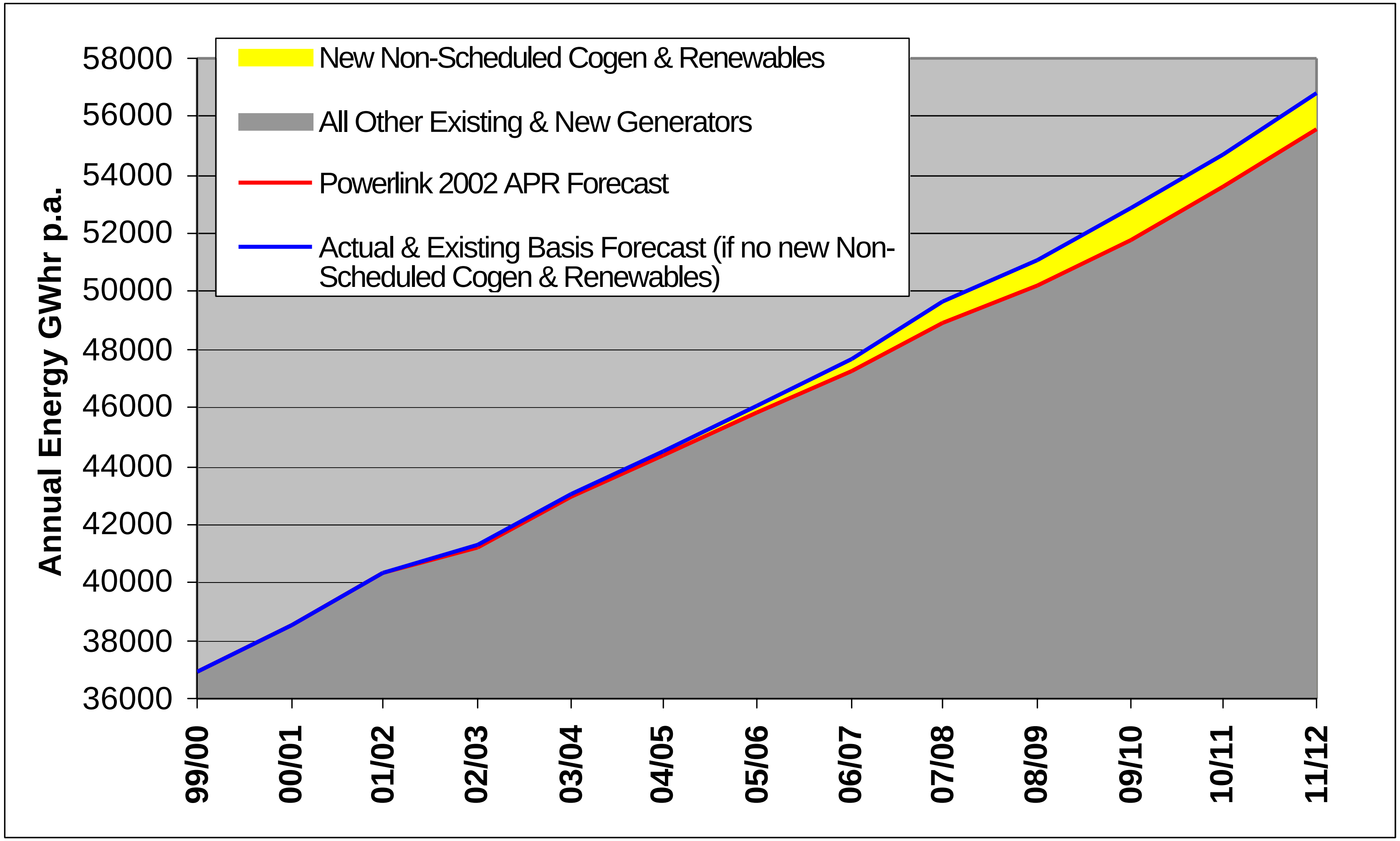


Table 2.4: Annual Energy - Actual and Forecasts

Sent Out to (GWh) and Delivered from the Transmission Grid and from Embedded Scheduled Generation (Except to Wivenhoe Pumps) Actual and Forecasts for Different Economic Growth Scenarios

Year	Sent Out (1)			Delivered		
92/93	26,521			25,179		
93/94	27,664			26,253		
94/95	29,240			27,813		
95/96	30,255			28,758		
96/97	31,375			29,869		
97/98	35,675			34,013		
98/99	36,555			34,999		
99/00	38,439			36,953		
00/01	40,203			38,561		
01/02 (2)	42,260			40,330		
Forecast GWhr p.a.	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
02/03	42,836	43,207	43,911	40,895	41,241	41,898
03/04	44,164	44,985	46,376	42,171	42,938	44,236
04/05	44,854	46,482	48,818	42,815	44,335	46,511
05/06	45,555	48,007	51,309	43,577	45,871	48,954
06/07	46,468	49,459	53,551	44,460	47,258	51,078
07/08	47,642	51,308	56,603	45,547	48,966	53,887
08/09	48,298	52,636	59,178	46,154	50,191	56,250
09/10	49,169	54,358	62,146	46,959	51,775	58,967
10/11	50,183	56,291	65,504	47,896	53,552	62,030
11/12	51,417	58,475	69,293	49,033	55,554	65,474

Notes:

(1) This is the grid input energy that Queensland Scheduled generators, Invicta Mill Koombooloomba and Imports to Queensland will compete to supply on a net sent out basis. Accordingly, the energy to Wivenhoe Pumps is assumed to be netted off any Wivenhoe generation output in this Table.

(2) These projected end of financial year values are based on revenue metering data up to 31 March 2002 and statistical metering up to 4 June 2002.

Figure 2.4: History and Forecasts of Annual Energy Delivered

From Transmission Grid as from Embedded Scheduled Generators (GWh p.a.) - Medium Economic Growth Scenario

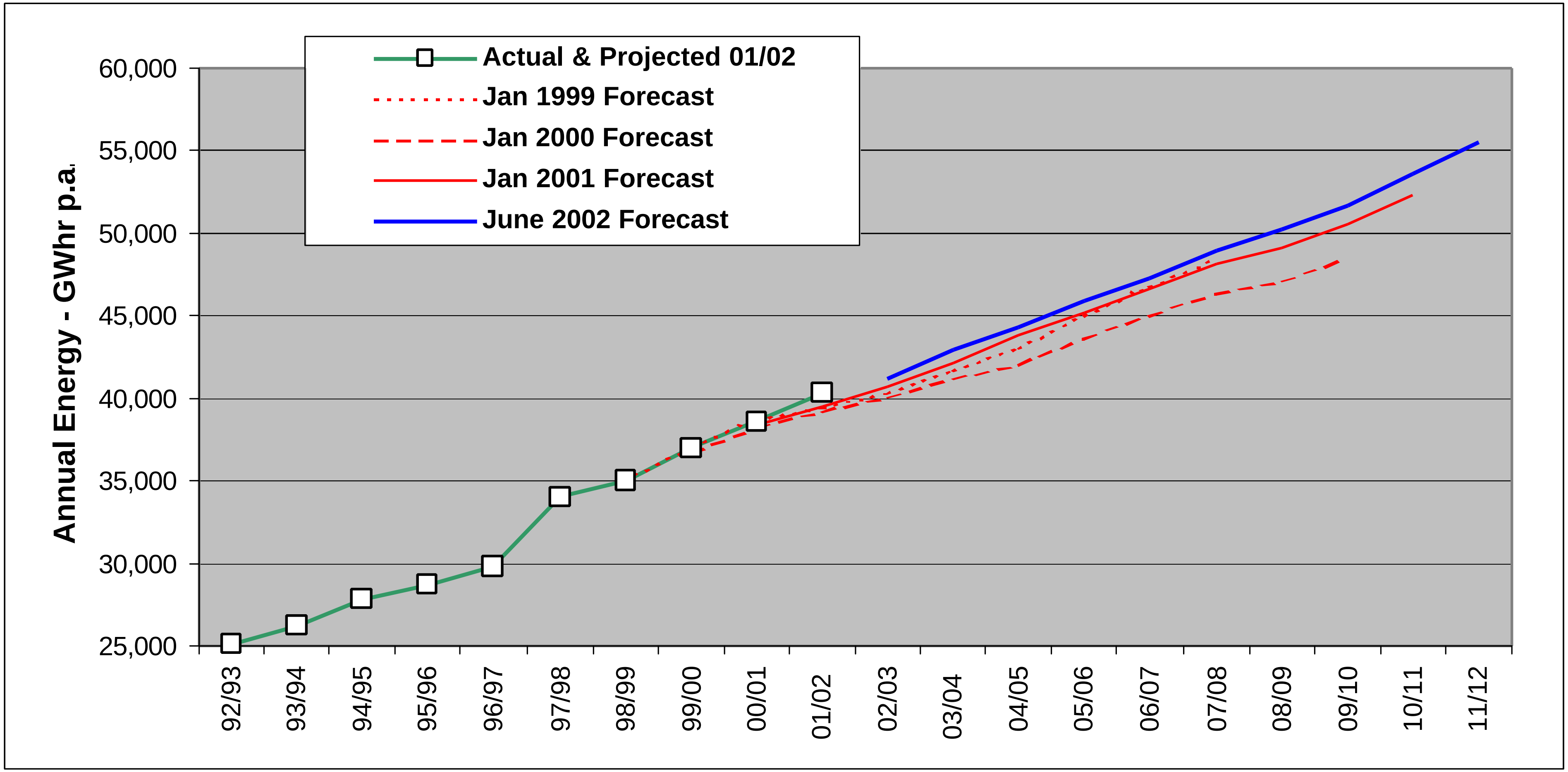


Table 2.5: Peak Summer Demand (MW)

Delivered from the Transmission Grid as well as from Embedded Scheduled Generators – June 2002 Forecast

Summer	Actual	High Economic Scenario			Medium Economic Scenario			Low Economic Scenario		
		H 10%	H 50%	H 90%	M 10%	M 50%	M 90%	L 10%	L 50%	L 90%
92/93	3,752									
93/94	3,901									
94/95	4,073									
95/96	4,323									
96/97	4,576									
97/98	5,161									
98/99	5,386									
99/00	5,685									
00/01	5,891									
01/02	6,246									
02/03		6,695	6,479	6,350	6,561	**6,349**	6,223	6,491	6,281	6,156
03/04		7,141	6,910	6,773	6,879	**6,657**	6,525	6,725	6,507	6,379
04/05		7,614	7,370	7,226	7,182	**6,952**	6,816	6,886	6,665	6,534
05/06		8,070	7,812	7,660	7,462	**7,224**	7,083	7,015	6,790	6,658
06/07		8,471	8,202	8,042	7,723	**7,477**	7,332	7,176	6,948	6,813
07/08		9,001	8,716	8,546	8,042	**7,786**	7,635	7,375	7,140	7,002
08/09		9,506	9,205	9,026	8,322	**8,058**	7,902	7,532	7,293	7,151
09/10		10,062	9,744	9,555	8,656	**8,383**	8,221	7,713	7,469	7,325
10/11		10,577	10,244	10,047	8,940	**8,658**	8,492	7,844	7,597	7,451
11/12		11,247	10,894	10,685	9,334	**9,041**	8,868	8,072	7,818	7,669

Figure 2.5: Queensland Region Summer Peak Demand MW

History and Forecasts, Different Economic Growth and Weather Scenarios

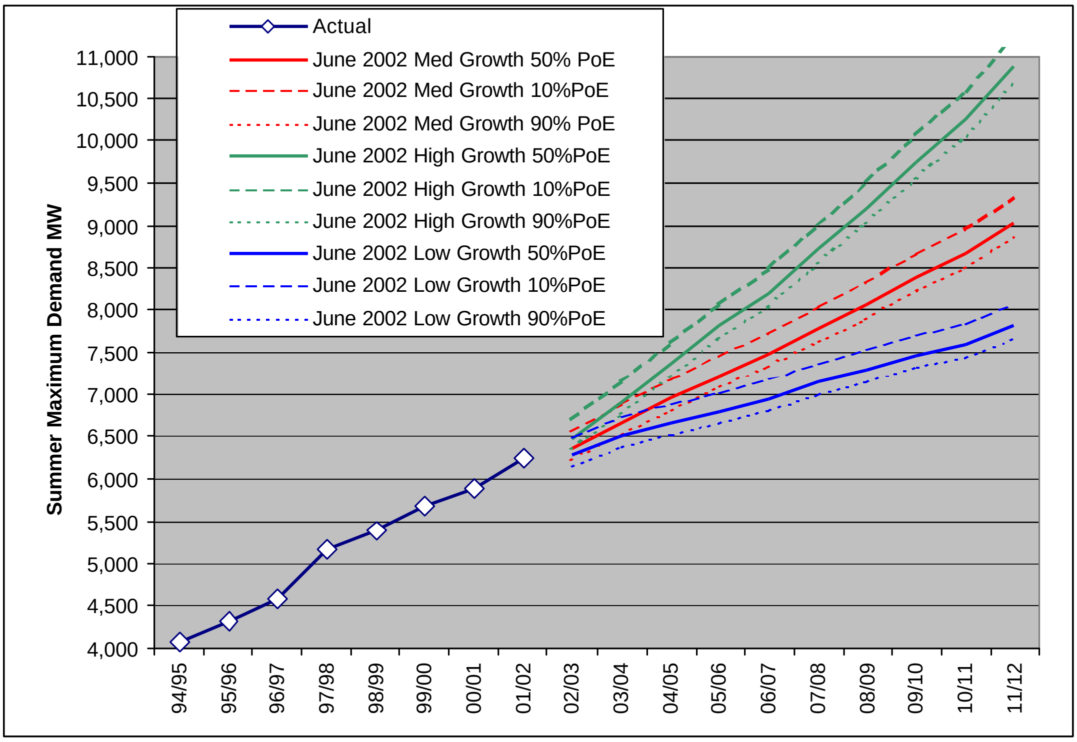


Table 2.6: Peak Winter Demand (MW)

Delivered from the Transmission Grid as well as from Embedded Scheduled Generators – June 2002 Forecast

Winter	Actual	High Economic Scenario			Medium Economic Scenario			Low Economic Scenario		
		H 10%	H 50%	H 90%	M 10%	M 50%	M 90%	L 10%	L 50%	L 90%
1992	3,792									
1993	3,946									
1994	4,085									
1995	4,304									
1996	4,459									
1997	4,770									
1998	5,021									
1999	5,309									
2000	5,688									
2001	5,811									
2002		6,268	6,155	6,044	6,142	**6,031**	5,922	6,075	5,965	5,857
2003		6,619	6,501	6,383	6,374	**6,260**	6,147	6,229	6,118	6,007
2004		7,029	6,904	6,780	6,624	**6,506**	6,389	6,346	6,233	6,121
2005		7,455	7,323	7,193	6,881	**6,759**	6,640	6,459	6,345	6,232
2006		7,832	7,694	7,558	7,122	**6,996**	6,873	6,600	6,484	6,370
2007		8,248	8,103	7,961	7,339	**7,210**	7,083	6,707	6,589	6,473
2008		8,713	8,560	8,410	7,584	**7,451**	7,320	6,831	6,711	6,593
2009		9,152	8,993	8,835	7,819	**7,683**	7,549	6,923	6,803	6,684
2010		9,658	9,490	9,325	8,091	**7,950**	7,812	7,042	6,919	6,799
2011		10,112	9,938	9,765	8,307	**8,163**	8,022	7,118	6,995	6,874

Figure 2.6 Queensland Region Winter Peak Demand MW

History and Forecasts, Different Economic Growth and Weather Scenarios

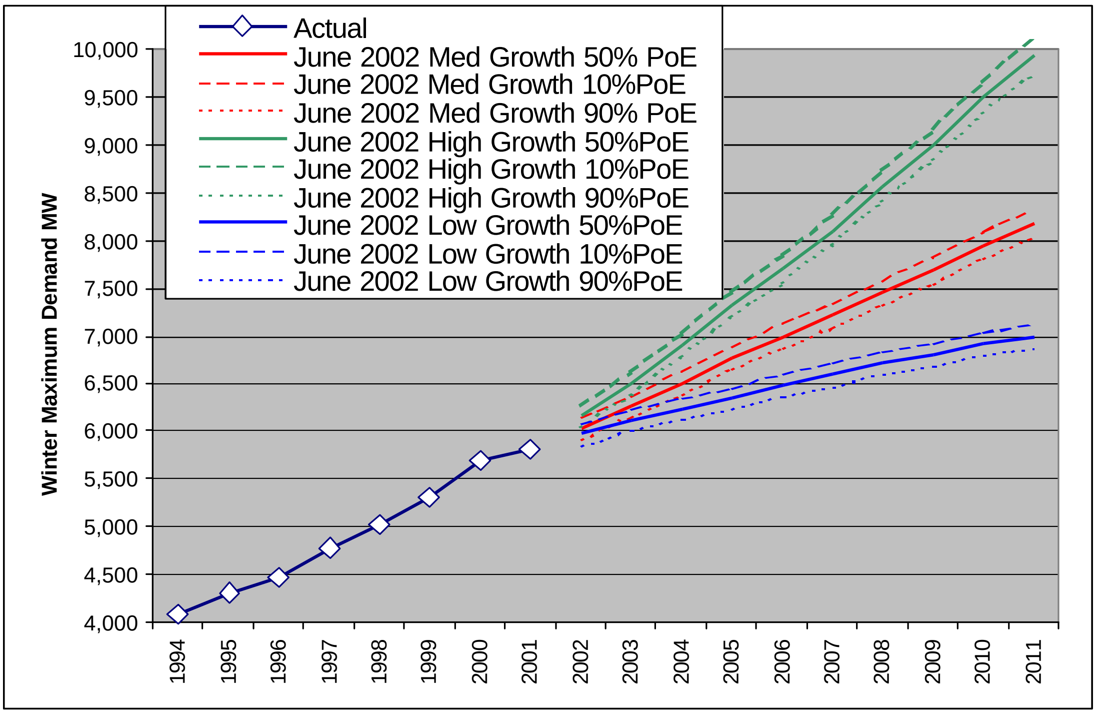


Table 2.7: Maximum Demand – 50% POE Forecast

Queensland Region Maximum Demand Forecast (MW) Medium Growth, 50% Probability of Exceedance (Average) Weather

Year	Station "As Generated" Demand	Station "Sent Out" Demand (2)	Delivered from Grid Demand (1)
2002 W	6,804	6,361	6,031
2002/03 S	7,165	6,699	6,349
2003 W	7,061	6,602	6,260
2003/04 S	7,512	7,024	6,657
2004 W	7,338	6,861	6,506
2004/05 S	7,845	7,336	6,952
2005 W	7,620	7,124	6,759
2005/06 S	8,142	7,613	7,224
2006 W	7,882	7,369	6,996
2006/07 S	8,428	7,880	7,477
2007 W	8,128	7,600	7,210
2007/08 S	8,788	8,217	7,786
2008 W	8,410	7,863	7,451
2008/09 S	9,105	8,513	8,058
2009 W	8,682	8,118	7,683
2009/10 S	9,484	8,868	8,383
2010 W	8,996	8,411	7,950
2010/11 S	9,809	9,171	8,658
2011 W	9,250	8,649	8,163
2011/12 S	10,258	9,591	9,041

Notes:

(1) "Delivered from Grid" includes the demand taken directly from the transmission grid and power from embedded scheduled generators (currently Barcaldine and Roma Power Stations).

(2) Station Auxiliaries and generator transformer losses are now estimated at 6.5% of Station "As Generated" dispatch at times of peak loading.

Table 2.8: Maximum Demand – 10% POE Forecast

Queensland Region Maximum Demand Forecast (MW) Medium Growth, 10% Probability of Exceedance Weather

Year	Station "As Generated" Demand	Station "Sent Out" Demand (2)	Delivered from Grid Demand (1)
2002 W	6,933	6,483	6,142
2002/03 S	7,414	6,932	6,561
2003 W	7,195	6,727	6,374
2003/04 S	7,773	7,268	6,879
2004 W	7,476	6,990	6,624
2004/05 S	8,116	7,588	7,182
2005 W	7,762	7,258	6,881
2005/06 S	8,421	7,874	7,462
2006 W	8,028	7,507	7,122
2006/07 S	8,715	8,149	7,723
2007 W	8,279	7,741	7,339
2007/08 S	9,088	8,497	8,042
2008 W	8,566	8,009	7,584
2008/09 S	9,415	8,803	8,322
2009 W	8,843	8,268	7,819
2009/10 S	9,807	9,170	8,656
2010 W	9,161	8,566	8,091
2010/11 S	10,141	9,482	8,940
2011 W	9,420	8,807	8,307
2011/12 S	10,605	9,916	9,334

Notes:

(1) "Delivered from Grid" includes the demand taken directly from the transmission grid and power from embedded scheduled generators (currently Barcaldine and Roma Power Stations)

(2) Station Auxiliaries and generator transformer losses are now estimated at 6.5% of Station "As Generated" dispatch at times of peak loading.

2.5 Zone Forecasts

The ten geographical zones referred to throughout this report are delineated by sections of the 275kV transmission grid which may at times be heavily loaded compared with their capacity and are defined as follows (refer to Section 3.4 and the diagrams in Figures 3.1 and 3.2):

Table 2.9: Zone Definitions

Zone	Area Covered
Far North	North of Tully including Chalumbin
Ross	North of Proserpine and Collinsville, but excluding the Far North Zone.
North	North of Broadsound and Dysart but excluding the Far North and Ross Zones. Includes planned Hail Creek Coal Mine.
Central West	Collectively encompasses the area south of Nebo and Peak Downs and north of Gin Gin.
Gladstone	Specifically covers the Powerlink transmission network connecting Gladstone Power Station, Callemondah (Railway supply), Gladstone South, QAL supply, Wurdong and Boyne Smelter supply. Includes planned Comalco Alumina Refinery.
Wide Bay	Gin Gin and Woolooga 275kV Substation loads excluding Gympie.
South West	Tarong and Middle Ridge load areas west of Postman's Ridge. From Winter 2003 onwards, includes Goondiwindi load.
Moreton North	South and east of Woolooga and Middle Ridge, but excluding the Moreton South and Gold Coast/Tweed Zones.
Moreton South	South of the Brisbane River, but includes the Energex Victoria Park and Mayne 110kV substation load areas, and excludes the Gold Coast/Tweed Zone.
Gold Coast/Tweed	South of Cades County to the Gold Coast and includes Tweed Shire of NSW. Energex's planned Coomera Substation in 2004 will transfer some load to Moreton South.

Each zone normally experiences its own zone peak demand, which is usually greater than that shown in Table 2.12, and often at a time other than at the time of Queensland region coincident maximum demand.

Table 2.10 below shows the average ratio (based on historical patterns) of zone peak demand to zone demand at the time of Queensland region peak demand. These values can be used to multiply demands in Table 2.12 to estimate each zones individual peak demand, not necessarily co-incident with the time of Queensland region peak demand.

Table 2.10: Average Ratio of Zone Peak Demand to Zone Demand at Time of Queensland Region Peak

Zone	Winter	Summer
Far North	1.208	1.025
Ross	1.164	1.082
North	1.130	1.110
Central West	1.019	1.085
Gladstone	1.026	1.025
Wide Bay	1.082	1.160
South West	1.053	1.044
Moreton North	1.014	1.008
Moreton South	1.024	1.005
Gold Coast / Tweed	1.022	1.045

Table 2.11 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 2.12 shows the forecast of demand delivered from the transmission grid and embedded scheduled generators (coincident with the Queensland region peak) for each of the ten zones within Queensland, for the Medium Growth scenario and average weather.

Table 2.11: Annual Energy (GWh p.a.) by Zone

Actual and Forecast Annual Energy (GWh p.a.) Delivered from the Transmission Grid as well as 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
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
Projected 2001/02	1,540	3,041	2,211	3,043	8,983	1,257	1,723	6,676	8,800	3,052	40,330
Forecasts											
2002/03	1,582	2,992	2,182	3,031	9,082	1,268	1,758	6,991	9,146	3,210	41,241
2003/04	1,632	3,064	2,245	3,087	9,524	1,301	1,880	7,299	9,556	3,351	42,938
2004/05	1,679	3,248	2,304	3,123	9,619	1,335	1,928	7,724	9,964	3,411	44,335
2005/06	1,741	3,372	2,377	3,159	9,724	1,370	1,976	8,158	10,441	3,553	45,871
2006/07	1,788	3,451	2,418	3,196	9,805	1,406	2,027	8,598	10,846	3,724	47,258
2007/08	1,848	3,525	2,461	3,255	10,144	1,475	2,085	9,012	11,291	3,869	48,966
2008/09	1,904	3,570	2,493	3,283	10,168	1,534	2,095	9,407	11,716	4,020	50,191
2009/10	1,970	3,681	2,549	3,344	10,231	1,604	2,121	9,872	12,209	4,195	51,775
2010/11	2,121	3,785	2,599	3,408	10,296	1,679	2,183	10,358	12,747	4,376	53,552
2011/12	2,210	3,926	2,714	3,563	10,395	1,749	2,251	10,870	13,311	4,565	55,554

Table 2.12: State Winter and 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 Winter and Summer Peak Demand - Average Weather

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
1998 W	166	236	214	365	961	152	256	962	1,250	479	**5,042**
1998/99 S	244	292	271	372	959	189	242	992	1,382	444	**5,386**
1999 W	173	238	229	377	994	165	278	1,022	1,315	517	**5,309**
1999/2000 S	234	412	240	346	1,003	197	265	1,055	1,433	499	**5,685**
2000 W	179	354	271	423	986	198	312	1,080	1,350	536	**5,691**
2000/01 S	252	458	294	391	993	195	270	1,068	1,472	498	**5,891**
2001 W	184	378	256	442	1,019	189	301	1,110	1,365	567	**5,811**
2001/02 S	278	504	355	436	1,040	222	258	1,119	1,526	509	**6,246**
Forecasts											
2002 W	200	399	282	414	1,051	208	303	1,140	1,447	589	**6,031**
2002/03 S	267	486	324	409	1,046	217	272	1,188	1,594	544	**6,349**
2003 W	205	405	284	430	1,069	216	330	1,197	1,508	617	**6,260**
2003/04 S	276	498	340	423	1,105	225	293	1,247	1,673	576	**6,657**
2004 W	213	414	298	444	1,126	223	336	1,242	1,563	645	**6,506**
2004/05 S	285	541	356	436	1,121	233	302	1,292	1,801	585	**6,952**
2005 W	220	454	312	458	1,142	232	347	1,278	1,681	636	**6,759**
2005/06 S	298	558	372	449	1,135	246	307	1,361	1,894	604	**7,224**
2006 W	231	467	325	471	1,157	245	358	1,334	1,749	660	**6,996**
2006/07 S	306	573	382	461	1,146	251	313	1,447	1,962	635	**7,477**
2007 W	238	479	333	483	1,167	250	360	1,403	1,812	685	**7,210**
2007/08 S	316	587	389	468	1,193	259	317	1,515	2,076	666	**7,786**
2008 W	246	490	339	490	1,213	258	365	1,457	1,885	709	**7,451**
2008/09 S	326	598	400	478	1,201	265	321	1,593	2,176	700	**8,058**
2009 W	253	498	349	500	1,223	264	369	1,529	1,955	743	**7,683**
2009/10 S	336	618	412	491	1,211	273	329	1,690	2,281	741	**8,383**
2010 W	262	514	358	514	1,233	273	378	1,606	2,036	776	**7,950**
2010/1 S	348	637	422	495	1,216	281	336	1,770	2,378	775	**8,658**
2011W	271	529	367	518	1,237	281	386	1,664	2,100	810	**8,163**
2011/12 S	364	669	442	525	1,221	299	348	1,869	2,483	820	**9,041**

2.6 Daily and Annual Load Profiles

The daily load profile is shown in Figure 2.7 for the whole of the Queensland region, for the 2001 winter peak and 2001/02 summer peak. Figure 2.8 shows the cumulative annual load duration characteristic for the Queensland region. The information in Figures 2.7 and 2.8 is historical, being derived from revenue metering "delivered" demand and energy data.

Figure 2.7 Daily Load Profile

Queensland Region 2001/02 Summer Peak and 2001 Winter Peak

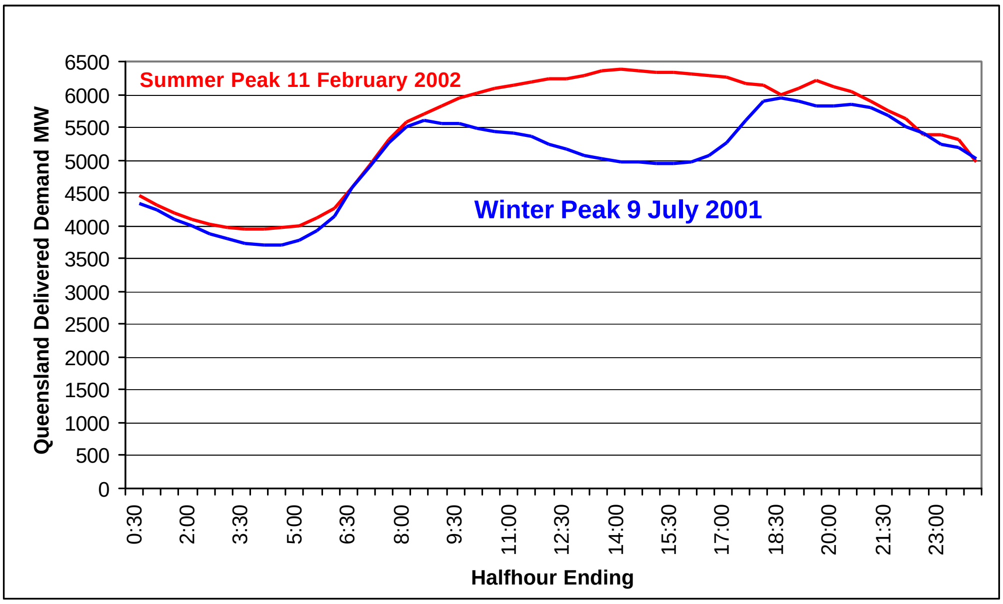
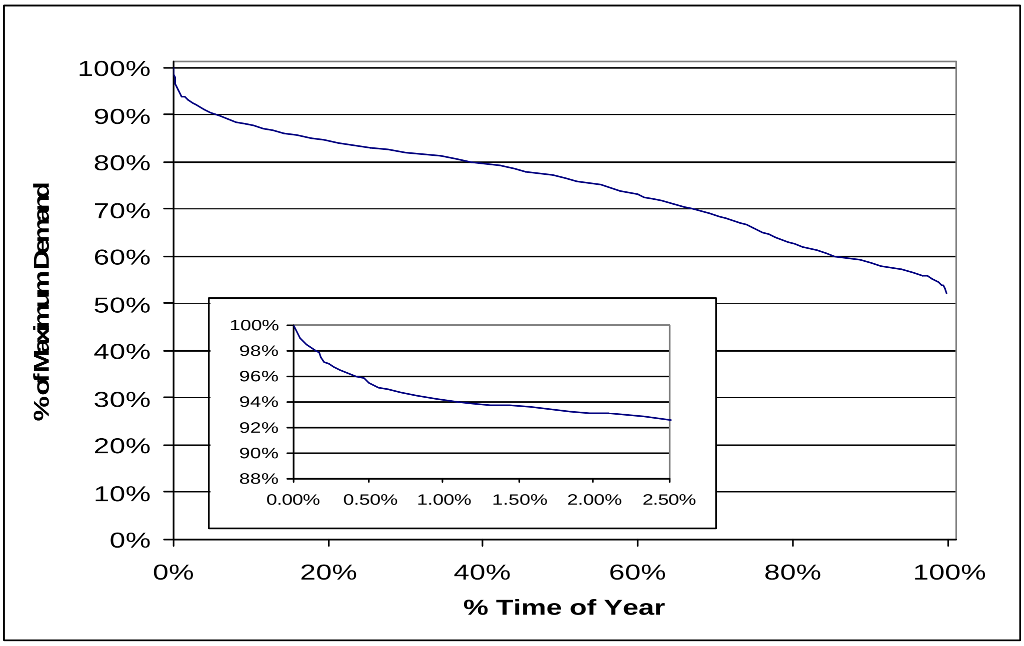


Figure 2.8 Cumulative Load Duration

Queensland Region - 2000/2001



3. EXISTING AND COMMITTED DEVELOPMENTS

3.1 Generation

The bulk of Queensland's power generation is supplied from coal-fired plant in Central and Southern Queensland. A limited amount of run-of-river hydro (with limited water storage) operates in Far North Queensland. The remaining capacity is mostly pumped storage hydro in Southern Queensland and gas turbines at Swanbank, Townsville and other locations.

Table 3.1 summarises the existing and committed power stations connected or to be connected to the Powerlink transmission network, as well as the scheduled embedded generators at Barcaldine and Roma and the non-scheduled market generators at Invicta and Koombooloomba.

Table 3.1 also includes the Queensland New South Wales Interconnection (QNI) and the market network service provider ("Directlink") between Mullumbimby in the New South Wales region and Terranora in the Queensland region.

The following notes apply to Table 3.1:

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.

2. "Various gas turbines" comprise Mackay (34MW Winter/30MW Summer), Gladstone (14/13MW), Tarong (15/14MW) and Swanbank C (28/25MW) – note that Tarong and Gladstone GTs are non scheduled.

3. For the purpose of Table 3.1, the combined import capacity into Queensland of both the Armidale – Tarong 330/275kV interconnection and the Directlink 132/110kV MNSP is assumed to be 500MW.

4. Reductions in generating capacity due to decommissioning or mothballing plant have also been allowed for in Table 3.1 – see Section 3.2.

Table 3.1: Generation Capacity

Connected to Queensland Transmission Network (Existing and Committed Plant only)

Location	**Capacity MW Generated** (1) (4)					
	Winter 2002	**Summer 2002/03**	**Winter 2003**	**Summer 2003/04**	**Winter 2004**	**Summer 2004/05**
Coal Fired						
Callide B	700	700	700	700	700	700
Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Stanwell	1,400	1,400	1,400	1,400	1,400	1,400
Swanbank B	500	500	500	500	500	500
Swanbank A (408)	0	0	0	0	0	0
Callide A (120)	0	0	0	0	0	0
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Collinsville	185	185	185	185	185	185
Callide Power Plant	840	840	840	840	840	840
Millmerran		840	840	840	840	840
Tarong North			450	450	450	450
Total Coal Fired	6,705	7,545	7,995	7,995	7,995	7,995
Combustion Turbines						
Barcaldine	55	53	55	53	55	53
Mt Stuart (Townsville)	295	288	295	288	295	288
Townsville (Yabulu)	160	160	160	160	160	160
Oakey	320	276	320	276	320	276
Swanbank D	37	32	37	32	37	32
Swanbank E (CCGT)		344	366	344	366	344
Roma	74	60	74	60	74	60
Other (various locations) (2)	91	57	63	57	63	57
Hydro Electric						
Barron Gorge	60	60	60	60	60	60
Kareeya	72	72	72	72	72	72
Koombooloomba	7	7	7	7	7	7
Wivenhoe (pumped storage)	500	500	500	500	500	500
Sugar Mills						
Invicta	38.8	38.8	38.8	38.8	38.8	38.8
TOTAL – Other Than Coal (rounded)	1,710	1,948	2048	1,948	2,048	1,948
TOTAL – ALL STATIONS (rounded)	**8,415**	**9,493**	**10,043**	**9,943**	**10,043**	**9,943**
Interconnections Queensland – New South Wales Import Capacity (3)	500	500	500	500	500	500

[Source: NEMMCO and Powerlink]

3.2 Changes to Supply Capacity

3.2.1 Generation

Since Powerlink's 2001 Annual Planning Report was published the Callide Power Plant (840MW) was placed in service.

Committed projects under construction to be commissioned during the next two years, which will compete with existing capacity for the forecast load in Section 2.4 include:

- By summer 2002/03 - Millmerran Unit 1 – 420MW
- By summer 2002/03 - Millmerran Unit 2 – 420MW
- By summer 2002/03 - Swanbank E – 344MW
- By winter 2003 - Tarong North – 450MW

[Source: NEMMCO]

No final commitments to other new supply capacity have occurred since the 2001 Annual Planning Report.

Participants are directed to the following publications for additional information on possible energy developments:

- In May 2000, the Queensland Government released its Queensland Energy Policy, which announced initiatives in its Cleaner Energy Strategy.

- In June 2001, the Queensland government published an information paper on the development of gas fired base load generation in Townsville.

On 4 June 2002, the Queensland Government announced the preferred developer for a combined cycle base load gas-fired power station at Yabulu, near Townsville. The conversion of existing plant is anticipated to lift its capacity from 160MW to 220MW by 2005. This development has not been included as a committed project in this 2002 Annual Planning Report, as it is understood that financial close is not expected before December 2002.

The following reductions in generation capacity have been announced:

- Middle Ridge Gas Turbine (52/44MW) - decommissioned
- Swanbank C Gas Turbine (28/25MW) – to be decommissioned December 2002
- Swanbank A Power Station (408MW) – mothballed from July 2002
- Callide A Power Station (120MW) – planned return to service 2005

[Source: CS Energy]

3.2.2 Interconnection

The combined QNI plus Directlink import capacity is limited to 500MW as outlined in Section 4.4 of this report. Following commissioning of Millmerran Power Station, this combined import capacity is expected to remain at 500MW. The QNI import limit for Millmerran outputs is not yet finalised, but it is expected that the import capability will be limited to less than 500MW when Millmerran is operating above approximately 700MW sent out, due to a thermal transfer limit of 1200MW at Braemar Substation (refer to Section 4.4). However, under these conditions full 500MW combined QNI/Directlink can still be achieved. For the purposes of Table 3.1, a combined QNI/Directlink import of 500MW has been adopted.

3.3 Supply Demand Balance

The outlook for the supply demand balance for the Queensland region was published in NEMMCO's 2001 Statement of Opportunities on 30 March 2001. A revised outlook is expected to be published by NEMMCO in the 2002 SOO by 31 July 2002.

3.4 Transmission Network

The 1700km long Queensland transmission network comprises 275kV transmission from Cairns (end 2002) in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones, and providing limited back up to the 275kV grid. Also, 330kV lines forming part of the QNI project run from Braemar to the New South Wales border near Texas.

Figures 3.1 and 3.2 show the single line diagram of the system in the north, central and southern parts of the State.

As a large proportion of the Queensland generating capacity is located in Central Queensland, relatively high power transfers currently occur from Central to North Queensland and from Central to South 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 in the north; 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 Queensland may alleviate network constraints between Central and South Queensland, but this alone, may exacerbate constraints in the north;

- new loads may be connected in Central Queensland without significantly influencing transmission limits to the north or south; however network constraints may then arise within Central Queensland.

3.5 Committed Transmission Projects

Table 3.2 shows transmission grid augmentations commissioned since Powerlink's 2001 Annual Planning Report was published in July 2001.

Table 3.3 shows transmission grid augmentations which are committed and under construction at June 2002.

Table 3.4 shows connection works that have been commissioned since Powerlink's 2001 Annual Planning Report was published in July 2001.

Table 3.5 shows new transmission connections or connection works for supplying load which are committed and under construction at June 2002. These connection projects resulted from joint planning with the relevant DNSP.

3.6 Possible Connection Projects

Table 3.6 shows connection works which may be required over the next few years. Joint planning will be carried out with the relevant DNSP prior to committing to any of these projects.

Table 3.2: Commissioned Transmission Developments

Commissioned Since June 2001 (1)

Project	Purpose	Zone Location (2)	Date Commissioned
Major Augmentations			
Cairns Reinforcement Stage 2	Provide additional capacity to meet growing Cairns area loads	Far North	April 2002
Loganlea 275kV Substation Establishment	Provide additional capacity in the Logan area	Moreton South	June 2002
Grid Support Arrangements			
Contract with local generators to provide grid support in North Queensland	Provide security in North Queensland	North	January 2002
Minor Augmentations			
2nd Nebo 120MVAr, 275kV Capacitor Bank	Provide voltage support	North	September 2001
Strathmore 275kV Substation Establishment	Provide security in North Queensland	North	December 2001
Chalumbin No. 1, 50MVAr, 132kV Capacitor Bank	Provide voltage support	Far North	December 2001
2nd Rocklea 300 MVA, 275/110kV Transformer	Provide substation capacity to match load growth	Moreton South	March 2002
Middle Ridge 2 x 50MVAr, 110kV Capacitor Banks	Provide voltage support	South West	April 2002
Mudgeeraba 275kV Bus Establishment	Provide voltage support	Gold Coast – Tweed	April 2002
1st Swanbank 200MVA, 275/110kV Transformer	Provide transformer capacity to match load growth	Moreton South	June 2002
Loganlea 2 x 50MVAr, 110kV Capacitor Banks	Provide voltage support	Moreton South	June 2002

Notes:

(1) Does not include new connections

(2) Zone locations are defined in Section 2.5

Table 3.3: Committed Transmission Developments

Committed since June 2001 (1)

Project	Purpose	Zone Location (2)	Planned Commissioning Date
Major Augmentations			
Cairns reinforcement Stage 3	Provide additional capacity to meet growing loads in the Cairns area	Far North	September 2002
Stanwell – Broadsound 275kV line reinforcement	Provide market benefits	Central West	October 2002
Belmont 275kV line reinforcement	Increase supply capacity and security to growing loads in southern areas of Brisbane	Moreton South	October 2003
Molendinar 275kV Substation establishment (and transmission line from Maudsland)	Increase supply capacity and security to growing loads within Gold Coast and surrounding areas	Gold Coast – Tweed	October 2003
Minor Augmentations			
2nd Swanbank 200MVA, 275/110kV Transformer	Provide transformer capacity to match load growth	Moreton South	August 2002
Strathmore 275/132kV Transformer	Provide transformer capacity to match load growth	North	September 2002
Blackwall 1st, 120MVAr, 275kV Capacitor Bank	Provide voltage support	Moreton North	July 2002
Blackwall 2nd, 120MVAr, 275kV Capacitor Bank	Provide voltage support	Moreton North	October 2002
Tarong to Blackwall circuit switching at Mt England	Provide voltage support	Moreton North	October 2002
Woolooga 275/132kV transformer reinforcement	Provide transformer capacity to match load growth	Wide Bay	November 2002
Palmwoods 275/132kV transformer reinforcement	Provide transformer capacity to match load growth	Moreton North	November 2002
Mudgeeraba 120MVAr, 275kV capacitor bank	Provide voltage support	Gold Coast – Tweed	December 2002

Notes:

(1) Does not include new connections

(2) Zone locations are defined in Section 2.5

Table 3.4: Completed Connection Works

Project	Purpose	Location	Commissioning Date
Lilyvale 132/66kV 3rd Transformer	Increase transformer capacity to match load growth	Lilyvale and surrounding areas	June 2001
Townsville South 132/66kV Transformer Upgrade	Increase transformer capacity to match load growth	Southern and Western areas of Townsville and surrounds	July 2001
Cairns 132/22kV Transformer Upgrade	Increase transformer capacity to match load growth	Cairns and surrounding areas	October 2001
Gladstone South 132/66/11kV Transformer Upgrade	Increase transformer capacity to match load growth	Southern areas of Gladstone and surrounds	January 2002
Tennyson 110/33kV Substation Reconstruction	Provide security for increasing load	Southern areas of Brisbane	March 2002
Loganlea 110kV Connections for Browns Plains and Beaudesert	Provide supply to new Energex zone substations	Browns Plains and Beaudesert areas	March 2002

Table 3.5: Committed Connection Works

Project	Purpose	Location	Planned Commissioning Date
Kemmis 132kV Construction Supply	New connection point for Ergon to supply construction power to Hail Creek Coal Mine	New coal mine	June 2002
Abermain 110/33kV Transformer Upgrade and 110kV Connections	Provide transformer and line connection capacity to match load growth	North Ipswich and surrounding areas	September 2002
Mackay 132/33kV Transformer Upgrade	Increase transformer capacity to match load growth	Mackay and surrounding areas	October 2002
Alan Sheriff 132/11kV Substation	132kV connection point for new Ergon zone substation	Inner Western areas of Townsville	November 2002
Murarrie 110kV Switching Station	New connection point to Energex to augment capacity to Australia Trade Coast area	Brisbane Port and other areas south of Brisbane River	March 2003
Kemmis 132/66kV Substation	New connection point for full operating supply to Hail Creek Coal Mine	New coal mine	April 2003
Rocklea 110kV 2nd Connection for Archerfield	Increase capacity to Energex 33kV network to match load growth	Archerfield and surrounding areas	July 2003
Bulli Creek 330/132kV Transformer	Provide new 132kV connection point for Ergon supply to Goondiwindi	Goondiwindi and surrounding areas	September 2003
Molendinar 275/110kV Substation (1)	New connection point to Energex to augment capacity to Gold Coast	Gold Coast area	October 2003

Notes:

(1) Connection point created as a result of Molendinar project included in Table 3.3

Table 3.6: Possible Connection Works

Project	Purpose	Location	Possible Commissioning Date
Proserpine 132/66kV Substation Transformer Upgrade	Increase transformer capacity to match load growth	Proserpine, Bowen and Whitsunday areas	May 2003
Blackwater 132/66kV Substation 3rd Transformer	Increase 66kV capacity for reliable supply to growing load	Bowen Basin mining area	April 2004
Mudgeeraba 110kV Connections for Varsity Lakes	Provide supply to new Energex zone substation	Gold Coast areas near Bond University	October 2004
Pioneer Valley 132/66kV Substation 2nd Transformer	Provide reliable supply to growing load	Areas west of Mackay	October 2004
Edmonton 132/22kV Substation	New connection point to Ergon to supply growing load south of Cairns	Areas between Cairns and Innisfail	October 2004
Belmont or Runcorn 110/33kV Substation 3rd Transformer	Increase 33kV capacity for reliable supply to growing load	South east areas of Brisbane	October 2004
Dan Gleeson 132/66kV Substation 2nd Transformer	Increase 66kV capacity for reliable supply to growing load	South western areas of Townsville	October 2005
Darra South or Sumner 110/33kV Substation	New connection point to Energex to increase 33kV capacity for load growth	Darra and Sumner Park areas	April 2006
Redbank 110/33kV Substation	New connection point to Energex to increase 33kV capacity for load growth	Redbank and surrounding areas	April 2007

Figure 3.1: Existing 275/132/110kV Network June 2002 – North and Central Queensland

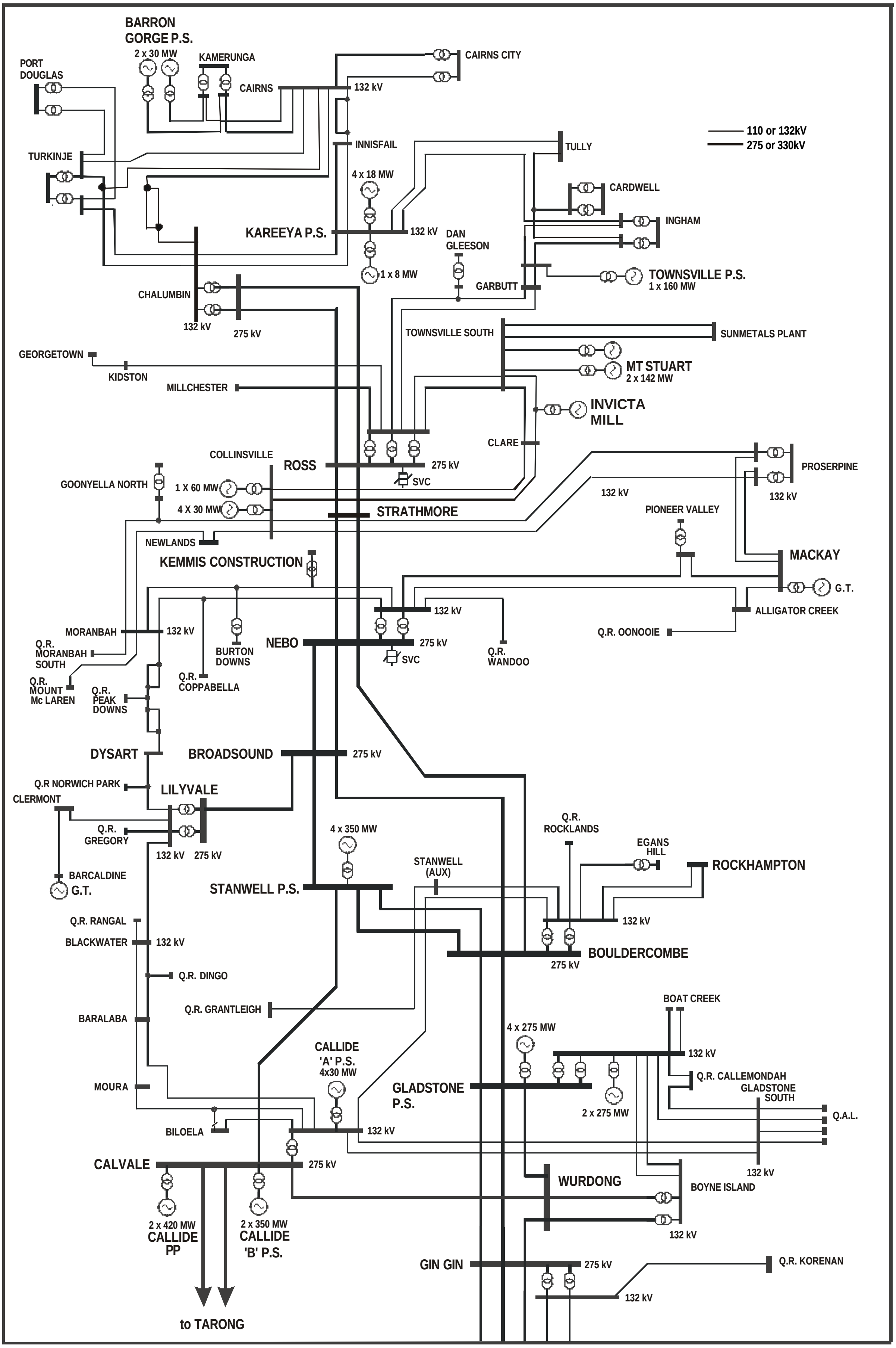
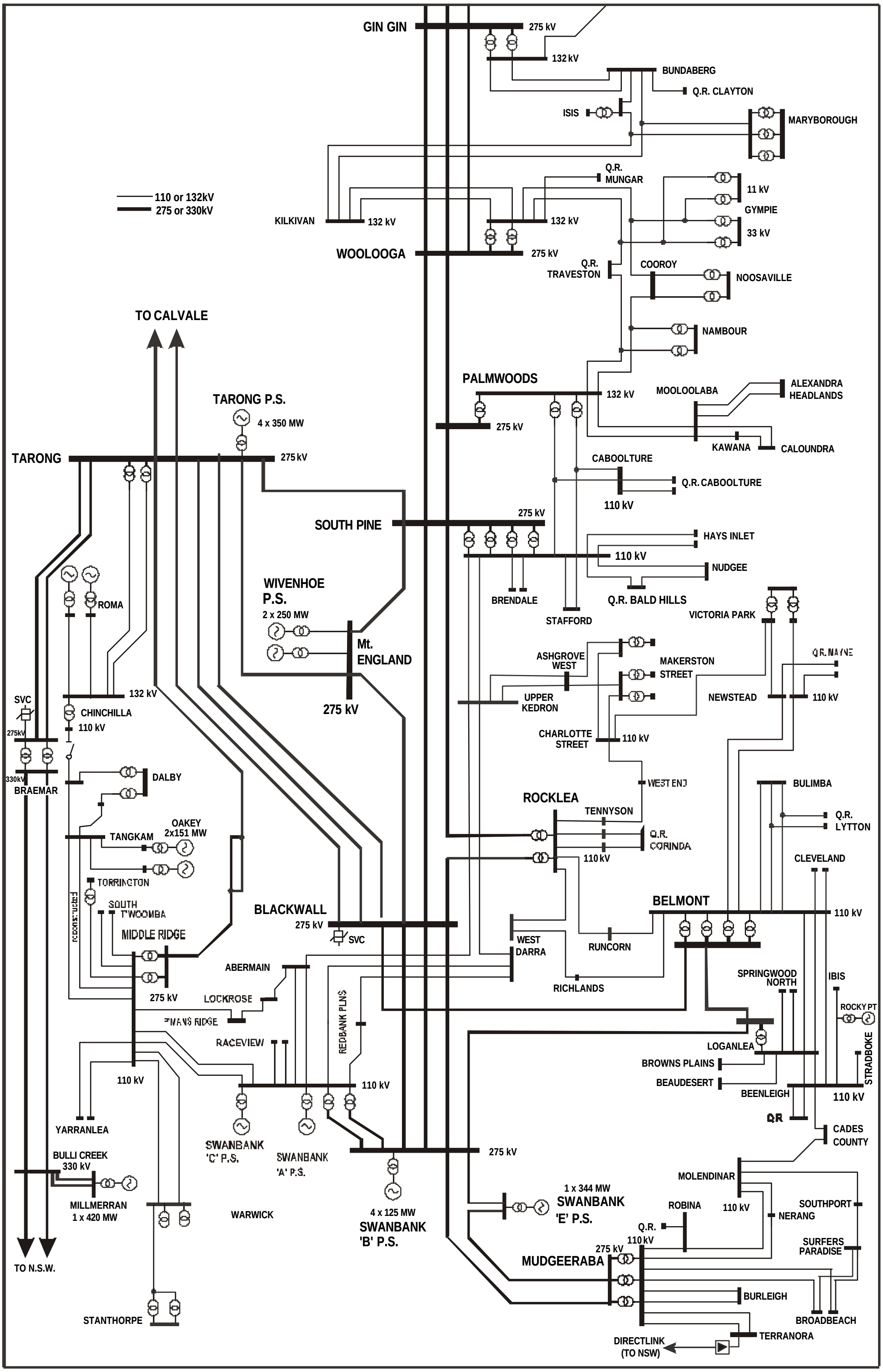


Figure 3.2: Existing 275/132/110kV Network June 2002 – South Queensland



4. NETWORK CAPABILITY

The National Electricity Code (Clause 5.6.2A(b)(3)) requires the Annual Planning Report to set out "a forecast of constraints and inability to meet the network performance requirements set out in NEC Schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years."

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

- Background on the factors that influence network capability
- Diagrams of possible grid power flows under a sample range of scenarios
- Estimates of short circuit levels and transformer capacity
- A qualitative explanation of factors impacting power transfer capability at key 'observation points' on the Powerlink grid
- 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.

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 2.7.

The power flows across most of the Queensland grid are influenced by the location and pattern of power generation. Future generation dispatch patterns are uncertain under the 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 peak demand. Power flows can also be higher when embedded generation levels are lower than forecast.

This chapter outlines some of these sensitivities by illustrating possible grid power flows over the next three years under a sample range of scenarios. Qualitative explanation is also provided on the factors which impact power transfer capability at key 'observation points' on the Powerlink grid, and on the cause of emerging limitations which may impact supply reliability.

4.1 Sample Winter and Summer Grid Power Flows

Powerlink has selected 18 sample scenarios to illustrate possible grid power flows for the Queensland region summer and winter peaks over the period 2002 winter to 2004/05 summer.

This information is based on only one possible sample generation dispatch and load condition for each case and is provided only as an indication of network power flows. These can vary for different load conditions and generator bidding behaviour. In providing this information, Powerlink has not attempted to predict market outcomes.

Illustrative grid power flows at forecast region average weather (50% POE) winter and summer peak demand over the next three years are shown in Appendix A for the Medium Growth Scenario load forecast. 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 as indicated below. The power flows were derived from studies which were based on an earlier version of the load forecast outlined in Chapter 2 of this report.

Grid power flows in Appendix A are based on existing network configuration and committed projects, and assume the grid is in its "normal" state, that is, all circuits in service. Power flows can be higher than those levels during network or generation contingencies.

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 2002 Qld Peak 300MW Import QNI Flow
- Figure A4, Winter 2002 Qld Peak Zero QNI Flow
- Figure A5, Winter 2002 Qld Peak 200MW Export QNI Flow
- Figure A6, Winter 2003 Qld Peak 300MW Import QNI Flow
- Figure A7, Winter 2003 Qld Peak Zero QNI Flow
- Figure A8, Winter 2003 Qld Peak 300MW Export QNI Flow
- Figure A9, Winter 2004 Qld Peak 300MW Import QNI Flow
- Figure A10, Winter 2004 Qld Peak Zero QNI Flow
- Figure A11, Winter 2004 Qld Peak 300MW Export QNI Flow
- Figure A12, Summer 2002/03 Qld Peak 300MW Import QNI Flow
- Figure A13, Summer 2002/03 Qld Peak Zero QNI Flow
- Figure A14, Summer 2002/03 Qld Peak 300MW Export QNI Flow
- Figure A15, Summer 2003/04 Qld Peak 300MW Import QNI Flow
- Figure A16, Summer 2003/04 Qld Peak Zero QNI Flow
- Figure A17, Summer 2003/04 Qld Peak 300MW Export QNI Flow
- Figure A18, Summer 2004/05 Qld Peak 300MW Import QNI Flow
- Figure A19, Summer 2004/05 Qld Peak Zero QNI Flow
- Figure A20, Summer 2004/05 Qld Peak 200MW Export 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 dispatch patterns have not been adjusted to avoid a power flow which would exceed intra-regional grid capacity limits.

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. This is an appropriate assumption for the zero QNI flow cases. However non zero flows on QNI could be accompanied by non zero flows on Directlink if the market spot price difference between the NSW and Queensland regions is significant. In the simplified system representation in Appendix A, actual flows on Directlink would have a similar impact to varying the generation level in the combined Moreton South and Gold Coast/Tweed zones.

4.2 Network Power Transfer Capability

4.2.1 Location of Network "Observation Points"

Powerlink has identified a number of “observation points” which allow grid capability and emerging limits of the whole grid to be assessed in a simplified manner. In some locations where network limits are considered likely to bind under a range of credible conditions, limit equations have been derived to allow such limits to be quantified. NEMMCO has incorporated these limit equations as part of the constraint analyses within its dispatch process.

In deriving limit equations, cases occur where a single set of limit equations in the dispatch process describe the impact of limits at several “observation points”. However, in order to better understand network capability and limitations, this report will examine each of the “observation points” in turn.

Figure A2 in Appendix A shows the location of power transfer limits (where limit equations apply) and “observation points” on the Queensland grid, some of which may be exceeded under some circumstances in the next three years. Potential limitations are summarised in Table 4.8.

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.

4.2.2 Determining Grid Transfer Capacities

The transfer capacity across each grid section varies with different system operating conditions. Transmission limits in the NEM are not generally amenable to definition by a single number. Instead, Transmission Network Service Providers define the capacity of their network in terms of multi-term equations. These equations quantify the relationships between the system operating conditions and the network transfer limit, and are implemented into NEMMCO’s market systems for the optimal dispatch of generation. This is particularly relevant in Queensland where the grid transfer capacity is highly dependent on which generators are in service, and their dispatch level.

This ‘limit equation’ approach maximises 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 multiple network analysis cases (using regression techniques) is very complicated and 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 major network limits 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 if the flow on any grid section is expected to exceed the limit for that particular condition and generation dispatch. Section 4.3 gives a qualitative description of the main system conditions that impact on the capacity of each of the grid sections.

4.2.3 Grid Capacity Ranges

Grid capacity may vary depending on system conditions at the time. The grid capacity is the power transfer below which the system will remain stable for any credible contingency event. Following such a sustained contingency, additional action may be necessary to return the system to a secure operating state, such that it would remain stable for a further contingency.

Table A1 in Appendix A shows the range of possible power flows at each of these sections for normal operation (that is, with all circuits 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 secure limit, and the mode of insecurity that determines the limit.

Coincident region peak demands were used to determine the grid flows shown in Figures A3 to A20. Grid power flows can also be higher than shown in Table A1 at times of local area or zone peak demands or for different generation dispatch patterns.

The factors that influence the transfer capability, and the impact of committed developments are discussed in Section 4.3.

4.3 Transmission Limits

Following is a qualitative summary of the main system conditions that impact transfer capability across key ‘observation points’ in the Queensland transmission network.

Powerlink has also provided a qualitative outlook for the likelihood that these ‘observation points’ will translate into restrictions on generator dispatch (ie binding limits) **based on the sample generation scenarios in Appendix A only**. This outlook is provided to assist readers unfamiliar with loadflows 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 generator dispatch patterns, and embedded non-scheduled generation output, and Powerlink makes no prediction of market outcomes in the information provided.

Note that power flows across the ‘observation points’ can be higher than as 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 bound is provided for two periods, namely from April to September 2001 (winter) and from October 2001 to March 2002 (summer).

This information on binding limits includes all dispatch intervals in the relevant period. No attempt has been made to distinguish between dispatch intervals when planned or forced outages may have affected network capability, or intervals when network flows may have been affected by network support contracts that Powerlink has in place with some generators.

This 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.

4.3.1 Far North Limit

Far North Transfer

The maximum power transfer across the Far North grid section is limited by the occurrence of unstable voltage levels during contingencies.

The present limit equations for the Far North Limit are shown in Table B1 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

- MW generation within the Far North zone
- Generators on-line within the Far North zone; and
- Capacitor banks on-line within the Far North zone.

The limiting event is the outage of a 275kV transmission circuit into Far North Queensland or a transmission circuit outage into the Cairns area. For these contingencies, the availability of local hydro generation provides voltage support (reactive power) and increases the secure power transfer capability. However, the Far North Limit is also sensitive to MW generation from these hydro units. Local hydro MW generation reduces the grid transfer limit, but more load can be securely supported in the Far North zone because the reduction in the grid transfer limit is more than offset by the increase in MW output by the local generators.

Loadings in Far North can vary significantly due to dispatch levels of other embedded generation at sugar mills and wind farms

The constraint information for the period April 2001 to March 2002, for the Far North limit is summarised in the following table:

Table 4.1: Far North Limit Constraint for April 2001 – March 2002

Far North Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2001	Less than 0.1%	3 hours
October 2001 to March 2002	4.4%	190 hours

Unusually low hydro plant operation resulting from the exceptionally dry weather and high temperatures during 2001-02 contributed to extended periods of limit violations in this grid section during the summer period. During this time the actual grid transfer was above the transmission limit. Powerlink and NEMMCO implemented operational arrangements to avoid any pre-contingent load shedding.

Committed augmentations that impact the Far North Limit include augmentation of transmission to Cairns with the staged construction of a 275kV transmission line from Chalumbin to Woree. The addition of a capacitor bank at Chalumbin in December 2001 also assists in preserving reactive power margins at critical voltage control sources in the area.

The outlook for the Far North Limit is that it is considered to be unlikely that power flows across this grid section will encroach on the limit for the assumed sample generation scenarios over the period to 2005, and for average levels of embedded non-scheduled generators in the area.

Key factors which could alter this outlook include non-availability or low MW output of the hydro generators in the Far North zone. Without this local hydro generation, the Far North Limit is likely to be exceeded over summer load periods. Powerlink is considering options to overcome or manage this limitation.

4.3.2 CQ-NQ Limit

Transfer capability at the Ross and CQ-NQ sections will be collectively represented as CQ-NQ limit equations in NEMMCO's dispatch process. The constraint information for the period April 2001 to March 2002, for the CQ-NQ Limit is summarised in the following table:

Table 4.2: CQ-NQ Limit Constraint for April 2001-March 2002

CQ-NQ Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2001	0.6%	26 hours
October 2001 to March 2002	12.5% (1)	547 hours

Note:

(1) Powerlink had grid support arrangements in place with a number of generators from January 2002. This contributed to lower constraint periods – 4.8% (103 hours) of time between January and March 2002.

Ross Transfer

Following the commissioning in 2001 of the Strathmore 275kV switching station (approximately midway between Nebo and Ross), the maximum power transfer across the Ross Limit grid section is limited by transient or voltage instability. The critical contingency is a fault and outage of a Nebo to Strathmore or Strathmore to Ross 275kV transmission circuit.

Where transient instability is the limiting criterion, the power transfer capability is sensitive to the generation dispatch patterns throughout Queensland. In general terms, generators on-line in North Queensland reduce the transfer limit, whereas high generation levels in Central Queensland and low power transfers between Central and Southern Queensland increase the limit.

When limits are due to voltage stability, power transfer capability across the Ross grid section increases with Collinsville generation (despite this being located south of the Ross Limit). Generation within the Ross or Far North zones (eg hydro generators) reduces the Ross transfer limit but increases the amount of secure supportable load by decreasing the flow to a greater degree.

Power flows across this grid section can be higher than shown in Figures A3 to A20 at times of local area or North Queensland peak demands. Flows can also be higher if output from embedded generators in North Queensland are lower than forecast.

The outlook for the Ross limit is that it is unlikely to be reached while the CQ-NQ flow is limited to 800MW (Appendix B, Table B2) as discussed below. However, once the CQ-NQ Limit is increased following completion of the Stanwell – Broadsound augmentation, the Ross flows may encroach on limits under certain system conditions. A new limit equation to cover the contingencies will be developed prior to that time. Powerlink presently has a network support contract with local generators to manage the Ross limit in these circumstances.

CQ-NQ Transfer

The maximum power transfer between Central and North Queensland is currently limited by transient instability. The critical contingency is a fault at Stanwell on the Stanwell to Broadsound 275kV transmission line.

This present transient stability limit is best defined as a single value of 800MW.

This grid section is being augmented by the construction of a new 275kV transmission line from Stanwell to Broadsound, due for completion in late 2002. Following this, the grid section will be limited at significantly higher flows by transient or voltage stability.

The transient stability limit is sensitive to the generation dispatch pattern throughout Queensland. In general terms, generators on-line in North Queensland reduce the transfer limit, whereas high generation levels in Central Queensland and low power transfers between Central and Southern Queensland increase the limit.

When limited by voltage stability, the power transfer capability across the CQ-NQ grid section reduces for additional generation north of the grid section. However, like the Far North and Ross limits, generation north of the grid section increases the amount of secure supportable load, because the reduction in power transfer limit is more than offset by the increase in MW output by the generators.

The outlook for the CQ-NQ Limit is that it is unlikely that the power flow across this grid section will encroach on the limit once the committed new 275kV transmission line from Stanwell to Broadsound is completed in late 2002. As noted above, limitations on transfer across the Ross grid section may occur before the CQ-NQ grid section limits are reached after the new line is in service.

Key factors which could alter this outlook include non-availability or low MW output of the hydro generators in the Far North zone. Without this hydro generation, the CQ-NQ and/or Ross grid sections are likely to be constrained over summer load periods. Powerlink presently has a network support contract with local generators to manage the CQ-NQ limit in these circumstances.

Development of large industrial loads in North Queensland not included in the load forecast, or lower levels of embedded generation than forecast, will result in increased power transfers across the CQ-NQ grid section, and lead to greater reliance on grid support or other forms of capability augmentation.

4.3.3 CQ-SQ Limit

CQ-SQ Transfer

The maximum power transfer across this grid section is limited by the occurrence of unstable voltage levels during contingencies. The critical contingency is 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. As a result, the number of generating units on-line in these zones impacts on the limit. More generating units on-line increases the reactive power support, and therefore increases the limit.

The present voltage stability limit equations for the CQ-SQ Limit are shown in Table B3 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 Central West and Gladstone zones; and
- Generation at the Gladstone Power Station.

At transfers above about 2000MW, the CQ – SQ capability is limited by transient instability.

The constraint information for the period from April 2001 to March 2002, for the CQ-SQ Limit is summarised in the following table:

Table 4.3: CQ-SQ Limit Constraint for April 2001-March 2002

CQ-SQ Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2001	2.0% (1)	87 hours
October 2001 to March 2002	0.1%	5 hours

Note:
(1) The lower proportion of binding limits during October 2001 to March 2002 resulted from a higher value for the CQ-SQ Limit applying in that period. The CQ- SQ Limit ceiling was raised from 1800 to 2000MW in September 2001 following agreement between Ergon Energy and Powerlink on operational arrangements.

Power flows across this grid section can be higher than shown in Figures A3 to A20. The outlook for the CQ-SQ limit is that power flows may approach this limit in winter 2002 under some conditions. However, it is not likely to be approached in subsequent seasons based on the generation patterns in the sample power flows. Factors which could change this outlook include extreme weather and demand patterns and/or different 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.

On the other hand, should any of the possible large metal processing load developments currently under investigation proceed within the review period, CQ-SQ flows are likely to reduce significantly.

4.3.4 Tarong Limit

Transfer capability at the Woolooga, Tarong and Blackwall grid sections are collectively represented as Tarong limit equations in NEMMCO's dispatch process.

The constraint information for the period April 2001 to March 2002, for the Tarong Limit is summarised in the following table:

Table 4.4: Tarong Limit Constraint for April 2001-March 2002

Tarong Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2001	0.1%	6 hours
October 2001 to March 2002	0.6%	25 hours

Tarong Transfer

The maximum power transfer across this grid section is limited by the occurrence of unstable voltage levels. The critical contingency is the loss of a 275kV transmission circuit between Calvale and Tarong. Other critical contingencies which impact on the Tarong limit are discussed under Woolooga Transfer and Blackwall Transfer. The limit results from an exhaustion of reactive power reserves in Southern Queensland.

Over the next three years, the advent of the committed Swanbank E and Tarong North generators will substantially increase the amount of secure supportable load in Southern Queensland for these critical contingencies. In addition, other committed solutions to reliability limitations (eg. installation of shunt capacitors in Southern Queensland, additional switching at Mt England) are likely to improve the transfer limit.

The present limit equations for the Tarong Limit are shown in Table B4 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

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

There is an 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 in southern Queensland. Therefore, reducing the CQ-SQ transfer by increasing generation west of the grid section or import on QNI increases the Tarong limit. As for the other voltage stability limits, increasing the generation east of the grid section reduces the transfer limit, but increases the overall amount of secure supportable southern Queensland load. This is because the reduction in the power transfer limit is more than offset by the increase in MW output of the generators east of the grid section.

The outlook for the Tarong Limit is that, over the period to 2005 the power flows across this grid section are not expected to encroach on the limits because:

- New generation coming on line in south west Queensland will tend to increase the transfer limit;
- New generation within south east Queensland will reduce power flows;
- A range of committed transmission projects will increase the transfer limit; and
- Powerlink plans to investigate the use of grid support contracts to manage this limit under rare events where it may otherwise be exceeded.

This outlook is supported by the sample generation scenarios examined in Appendix A where power flows across this grid section are seen to not encroach on the Tarong transfer capability over the period to 2005.

Power flows across this grid section can be higher than shown in Figures A3 to A20 at time of local area or zone peak demands.

Woolooga Transfer

The maximum power flow across this grid section is limited by the occurrence of unstable voltage levels during contingencies. The critical contingency is an outage of one of the 275kV transmission circuits between Woolooga and Palmwoods or South Pine.

The limit results from an exhaustion of reactive power reserves in Southern Queensland. The contingencies discussed for the Tarong and Blackwall Limits also result in an exhaustion of reactive power reserves in Southern Queensland. Therefore, for convenience and ease of comparison the individual limits for all of these contingencies are expressed with respect to flows across the Tarong grid section in NEMMCO's dispatch software.

The outlook for the Woolooga transfer is that, for the assumed sample generation scenarios, it is unlikely that the power flows across the grid section will encroach on the Woolooga transfer capability to 2005.

Blackwall Transfer

This limit defines the capacity to transfer power on the 275kV circuits to the east of Blackwall as shown in Figure A2 in Appendix A. The maximum flow across this grid section is limited by the occurrence of unstable voltage levels during winter and potentially by thermal 275kV line ratings and voltage instability during summer. The critical contingency is an outage of a 275kV circuit to Belmont.

The voltage stability limit results from an exhaustion of reactive power reserves in Southern Queensland. The contingencies discussed for the Tarong and Woolooga transfers also result in an exhaustion of reactive power reserves in Southern Queensland. Therefore, for convenience and ease of comparison the individual limits for all of these contingencies are expressed with respect to flows across the Tarong grid section in NEMMCO's dispatch software.

Several committed projects within the greater Brisbane area have contributed to increasing this limit. These projects include 275/110kV transformer augmentations at Swanbank and Rocklea, establishment of Upper Kedron 110kV and Loganlea 275kV substations, rearrangement of the 110kV network at West Darra and capacitor bank additions at Blackwall and in the Energex distribution network.

Following a consultation process seeking options to address the potential overload of the lines to Belmont, a project has been initiated to construct an additional 275kV transmission line from Blackwall to Belmont, by October 2003. This project removes any possible overloading of the 275kV circuits into Belmont following contingency conditions and also increases the Blackwall voltage stability limit.

Power flows across this grid section can also be higher than shown in Figures A3 to A20 at times of local area or zone peak demands. For the assumed sample generation patterns it is unlikely that power flows across this grid section will encroach on the voltage stability limits over the period to 2005.

Prior to the commissioning of the Belmont augmentation, the power transfers across this grid section may just encroach on the summer emergency thermal ratings of the 275kV transmission system. The anticipated flow in 2002/03 is only slightly above the emergency rating and will be managed using operational strategies. This thermal limit is insensitive to existing generation within the Moreton South zone.

4.3.5 Gold Coast Limit

Gold Coast Transfer

The maximum power transfer across this grid section is limited by the occurrence of unstable voltage levels during winter and potential 110kV thermal line ratings and unstable voltage levels during summer. The critical contingency is an outage of a 275kV transmission line between Swanbank and Mudgeeraba.

Several committed projects within southern Queensland have contributed to increasing the Gold Coast limit. These projects include the installation of load compensation shunt capacitors at a number of locations in the Energex distribution network, the installation of 275kV switchgear at Mudgeeraba, and the installation of a 275/110kV transformer at Loganlea.

The present equation for the Gold Coast Limit is shown in Table B5 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;
- Reactive power reserve at the Blackwall static var compensator;
- MW loading of Directlink; and
- Reactive power flow into the Gold Coast-Tweed zone.

In general, the voltage stability limit is sensitive to the power factor of the load. As a result, the winter limits are higher than the corresponding limits during summer. The voltage limits are also higher if the Swanbank source voltage is stronger (ie the more Swanbank B or E units on line, the higher the reactive capability). This limit also reduces for Queensland import on Directlink. However, this increases the overall amount of secure supportable load. This is because the reduction in the power transfer limit is more than offset by the increase in Directlink MW import.

The constraint information for the period April 2001 to March 2002, for the Gold Coast Limit is summarised in the following table:

Table 4.5: Gold Coast Limit Constraint for April 2001-March 2002

Gold Coast Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2001	0.7%	31 hours
October 2001 to March 2002	0.9%	40 hours

Power flows across this grid section can also be higher than shown in Figures A3 to A20 at times of local Gold Coast area peak demands (typically up to 5% higher). For the winter system conditions considered, the flow across this grid section is unlikely to encroach on the limit. However, the situation is very different during summer. High loads in summer may result in flows greater than the limit.

For the 2002/03 summer conditions presented in Figures A12 to A14, the flow across the grid section is greater than the corresponding thermal and/or voltage stability limits. A committed project has been initiated to install a 275kV shunt capacitor bank at Mudgeeraba by December 2002. This will increase the voltage stability limit. This increase is sufficient such that the flows during summer 2003/04 should not exceed the voltage stability limit. Energex plan to upgrade a critical 110kV circuit so that thermal limits affecting transfer to the Gold Coast are not exceeded.

However with load growth on the Gold Coast, voltage stability is forecast to present increasing concerns over the outlook period to 2005. By the 2004/05 summer the flow across this grid section may again be greater than the voltage stability limits depending on the generation in the Moreton zones. In addition, the 275kV circuits are forecast to reach thermal rating towards the end of this period. Powerlink will therefore initiate a consultation process to identify options to address these limitations. This is discussed further in Chapter 5.

4.3.6 Other Observation Points

Gladstone Transfer

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 possibly the thermal rating of the Calvale 275/132kV transformer.

The highest loadings on the Calvale to Wurdong 275kV circuit and the Calvale 275/132kV transformer generally occur following a contingency of the Calvale to Stanwell circuit. The power flow on these critical elements varies considerably with different generation at Gladstone, Callide and Stanwell.

For the Calvale to Wurdong circuit, there is a significant margin between the power flows and the emergency thermal rating of the relevant circuits during winter. However, during summer the margin is significantly reduced.

The following table summarises the thermal limits and power flows on the Calvale-Wurdong circuit for the sample scenarios analysed in Appendix A for single contingency conditions.

Table 4.6: Thermal Limits and Power Flows on Calvale-Wurdong Circuit

Loading (MVA) on Calvale – Wurdong 275kV Circuit during Single Contingency Winter Rating 744MVA Normal / 980MVA Emergency Summer Rating 548MVA Normal / 760MVA Emergency			
	QNI Import Sample	**QNI Zero Sample**	**QNI Export Sample**
Winter 2002	560	501	497
Winter 2003	743	653	554
Winter 2004	706	613	528
Summer 2002/03	617	554	507
Summer 2003/04	705	609	547
Summer 2004/05	699	629	623

A critical circuit outage may result in an overload of the Calvale transformer. This overload is currently managed via a network switching strategy such that no pre-contingent constraint on generation is necessary.

The outlook for the Gladstone limit is that power flows are unlikely to encroach on the limit for the assumed sample scenarios over the period of committed projects.

Key factors that could alter this outlook, and cause this limit to be reached, include significant extra load in the Gladstone zone or reduced generation at the Gladstone Power Station.

Braemar Transfer

Following commissioning of the Millmerran Power Station in 2002/03, power flows are expected to increase on the 275kV grid between Tarong and Braemar and at times may reach the grid section capacity. Furthermore, this limit may impact on QNI transfer capability. The flow across the Tarong – Braemar grid section can occur in a northerly or southerly direction.

Queensland Import Conditions

The present northward import limit (that is, combined flow from NSW into Bulli Creek and through Directlink) with zero Millmerran generation is about 500MW, and is expected to be at a similar level with generation of one 420MW unit at Millmerran. The resulting flow from Braemar to Tarong of up to about 900MW is well within the capability of this grid section.

As the Millmerran output increases with commissioning of the second unit, it is expected that flow from Braemar to Tarong will be limited to about 1200MW by the emergency rating of the 330/275kV transformers at Braemar. This may result in constrained QNI flows for high Millmerran outputs. Powerlink Queensland is considering options to overcome or manage this limitation.

Queensland Export Conditions

Limits on the QNI flows south from Bulli Creek of about 1000MW with two units in service at Millmerran are anticipated. With each Millmerran unit having a capacity of 400MW (sent out), it is considered unlikely that southward flows from Tarong to Braemar will exceed 750MW over the outlook period - and may often be much less than that. This is well within the capability of this grid section.

4.4 QNI Limits

The Queensland – New South Wales Interconnection (QNI) was constructed of assets with plant ratings of about 1000MW in each direction. However the actual transfer capability will vary from time to time depending on system conditions.

At the time of publication of this Annual Planning Report, QNI has a maximum southward capacity of 750MW (Queensland export), and a maximum northward capability of QNI and Directlink combined of 500MW (New South Wales export). Transfer capacity is limited by a range of criteria, viz:

Southward: (QNI)

- Transient stability based on faults in Queensland;
- Transient stability based on loss of largest load in Queensland;
- Transient stability based on faults in New South Wales;
- Thermal rating limits of 132kV network in New South Wales;
- Dynamic stability upper limit of 750 MW

Northward: (combined QNI and Directlink)

- Transient stability based on loss of largest generator in Queensland (upper limit of 500MW);
- Transient stability based on faults in New South Wales;
- Thermal rating limits of 330kV network in New South Wales;
- Dynamic stability upper limit of 700 MW.

The 132kV network within NSW which has been imposing thermal limits at times in the southward direction is in the process of being upgraded and is expected to be less of an issue in the limit equations from summer 2002/03 onwards.

Following commissioning of the Millmerran Power Station during the latter part of 2002, QNI is expected to remain stable for higher southerly power transfers with units at Millmerran on line. Further testing will be required to confirm increased dynamic stability performance.

With commissioning of both Millmerran Power Station generators, the QNI limits are expected to have a maximum southward capacity of 1000MW (limited by transient/dynamic stability) and a maximum northward capacity of 400MW – 500MW (limited by transient stability or limits of the Braemar transformers for high Millmerran outputs).

4.5 Transformer Loading at 275kV Substations

Table A2 of Appendix A shows the range of loads on 275/110kV and 275/132kV substations in the period 2002 to 2005 (with all transformers in service) covering committed projects, and corresponding to the sample system conditions in Figures A3 to A20. These transformer loadings depend on load power factor and may be higher than those shown in Table A2 at the time of local zone peaks.

4.6 Short Circuit Levels

Tables C1 to C3 in Appendix C show estimates of the three phase and single phase to earth short circuit levels in the Powerlink transmission network in the period 2002 to 2004. They also show the short circuit interruption capacity of the lowest rated circuit breaker(s) at each location.

The information in Tables C1 to C3 of Appendix C should be taken only as an approximate guide to conditions at each location:

- 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;
- system loads and all shunt admittances are not represented;
- the effects of distribution systems and contribution from any embedded generation are neglected.

The short circuit levels shown in Tables C1 to C3 have been determined on the basis of the generation capacity shown in Table 3.1, including expected plant retirements. The plant retirements at Callide A reduce the fault levels such that previous fault level management strategies are no longer required at the Callide and Gladstone 132kV substations.

At Swanbank 110kV and Gladstone South 132kV substations, normally 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 C1 to C3.

At some locations where the short circuit level appears to be above the switchgear rating in Tables C1 to C3 of Appendix C, 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.

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.

4.7 Emerging ‘Reliability’ Limitations

As a transmission network service provider (TNSP), Powerlink must comply with technical standards relating to reliability and system security in the National Electricity Code. In particular, Schedule 5.1 of the Code sets out requirements related to:

- the power frequency voltage;
- voltage fluctuations;
- harmonic voltage distortion;
- voltage unbalance;
- stable operating state
- fault clearance
- current ratings of equipment

Schedule 5.1 also includes details of credible contingencies and levels of redundancy to be considered in planning and operating the transmission network.

This section identifies areas where limitations in network capability may give rise to an inability to meet minimum performance standards. These potential 'reliability' limitations are summarised in Table 4.8.

4.7.1 Addressing Emerging 'Reliability' Limitations

It is a condition of Powerlink's transmission authority that it meet licence and Code requirements relating to technical performance standards. The limitations described below can therefore be viewed as 'triggers' for action. If no other solutions arise, Powerlink must implement a solution to ensure that a reliable power supply to customers can be maintained.

In accordance with Code requirements, Powerlink will consult with market participants and interested parties on feasible solutions. Solutions may include local generation, provision of grid support by existing generation, demand side solutions and network augmentations.

The information below 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 or when this is required (see next chapter for current consultation processes or those about to start).

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

4.7.2 Emerging Reliability Limitations in the Queensland Grid

Far North Zone: Cairns Voltage Control

Depending on load growth and market developments, it has been determined that some time between 2004 and 2006, a situation will be reached where an outage of the 300MVA transformer at Woree, or the Chalumbin-Woree circuit operating at 275kV, will result in severe voltage problems and possible 132kV feeder overloads. The timing of this emerging limitation will depend on Far North Queensland loads and the seasonal availability of hydro generation.

Non-network solutions to this limitation could include a demand side response or local generation in the Cairns area. Network solutions may include installation of voltage control equipment and/or investing between $12-15M to uprate the second 275kV Chalumbin-Woree circuit (presently operating at 132kV) to its design voltage.

Far North Zone: Chalumbin Voltage Control

It is possible that an outage of a 275kV circuit between Ross and Chalumbin will result in severe voltage problems at Chalumbin. The occurrence of this limitation is dependent on FNQ loads and the seasonal availability of hydro generation. This limitation, currently defined by a limit equation (Appendix B), has the potential to be reached by summer 2002/03.

Non-network solutions to this limitation could include a demand side response or additional generation in FNQ. Network solutions in the shorter term may include investing between $12-25M on the installation of voltage control equipment. This may include series and/or shunt, static and dynamic reactive compensating equipment. Other solutions may be required in the longer term.

Far North Zone: Supply to Edmonton area

Ergon Energy has recently advised that action is urgently required to address high load growth in coastal areas to the south of Cairns. An upturn in local demand is anticipated to cause the capacity of the low voltage (22kV) system to be exceeded within 12-24 months. Potential solutions may include DSM, local generation, distribution network solutions or the establishment of a new 132/22kV connection point at Edmonton. A new transmission connection point might cost in the order of $5-8M.

Ross Zone – Supply to Northern and Western Townsville Areas

Load in the Townsville area has recently grown very rapidly. Average demand growth is expected to be about 4% 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 and Garbutt 132/66kV substations. Primary supply to these substations occurs via 132kV connections from Ross substation. Generation in the Townsville area can alter the flows on these circuits, but does not change their essential role in transferring power within the Townsville area. Studies also indicate that these circuits may become overloaded during Townsville 132kV network contingencies from late 2004 onwards.

Potential solutions may include network augmentation, grid support from local power stations, or a demand side response within the Townsville area. As an indication, transmission augmentations to overcome the limitations would have a potential capital cost in the range $25-45M. Because the Ross-Garbutt transmission lines are over 35 years old and their condition is deteriorating, solutions will need to address refurbishment requirements for these ageing assets.

Ross Zone – Supply to Southern Townsville Areas

Load in the Townsville area has recently grown very rapidly. Average demand growth is expected to be about 4% p.a. for the next several years, but may be much higher in specific areas due to new commercial, industrial and residential developments.

Southern areas of Townsville are supplied from a 132/66kV substation at Townsville South. Primary supply to this substation occurs via 132kV connections from Ross substation. Generation in the Townsville area can alter the flows on these circuits, but does not change their essential role in transferring power within the Townsville area.

Studies indicate that these circuits may become overloaded during an outage of one of the Ross-Townsville South circuits from late 2004 onwards.

Potential solutions may include network augmentation, grid support from local power stations, or a demand side response within the Townsville area. As an indication, the construction of a new transmission line between Ross and Townsville South on an existing spare easement, would have a potential capital cost of $15-25M.

North Zone: 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 in the next three years.

Potential non-network solutions may include local generation or demand side management in the Mackay locality or Bowen Basin mining area. Network augmentation options may include new or upgraded transformers either at Nebo or at an adjacent 275/132kV substation at an approximate cost of $5-8M.

North Zone: Supply to Mackay-Proserpine Area

Load in the Mackay-Proserpine area has recently grown rapidly. A point will soon be reached where the existing network will not be able to maintain a reliable power supply during a 132kV network contingency.

During an outage of a 132kV circuit between Nebo and Alligator Creek or Nebo and Pioneer Valley, unacceptably low voltages are expected to occur in the next 2-3 years. Action will be required to address this issue, with potential solutions including local generation, DSM or the installation of voltage control equipment.

Further limitations in supply to the Mackay-Proserpine area are expected to arise in subsequent years. During a 132kV outage of the above circuits, thermal ratings of the remaining circuits in service will be reached. The timing range for this limitation is dependent on load growth and other network developments, but is anticipated to arise between 2004 and 2007.

Options have not yet been developed, but potential network solutions include substation upgrades to alter 'sharing' of load flows on the 132kV network or the construction of a new line to the area. Non-network solutions such as local generation and demand side management may also be feasible alternatives.

Central Zone - Supply to Southern Bowen Basin and Gladstone

The southern area of the Bowen Basin mining area covering Biloela and Moura, receives its electricity supply from a 275/132kV transformer at Calvale. This transformer also supplies energy to the Gladstone area.

With decrease in output from Callide A the flow through the transformer has increased. The transformer may be overloaded for system normal conditions from the 2003/04 summer. Key factors that could alter this outlook include significant extra load in the Gladstone zone or reduced generation at the Gladstone Power Station.

Potential solutions include local generation at Callide A, and/or a second Calvale 275/132kV transformer with an indicative cost of $5 - 8M. If significant new bulk load developments go ahead in the Gladstone area, a 275kV augmentation between Calvale and Gladstone may occur that may address this overload.

Central West Zone – Supply to Lilyvale (Central Qld Mining Area)

The western Central Queensland area including the Bowen Basin mining area covering Blackwater, Moranbah etc, receives its electricity supply from a 132kV electricity network which operates in parallel to the main 275kV transmission grid.

The major injection of power into this 132kV network occurs via a 275kV single circuit line between Broadsound (on the main 275kV transmission grid north west of Rockhampton) and a 275/132kV substation at Lilyvale.

Analysis by Powerlink has determined that, during an outage of the 275kV line between Broadsound and Lilyvale and without corrective action, the capability to supply peak load in the area will be limited by voltage levels and thermal overloads of local 132kV circuits. This limitation may arise from the summer of 2004/05 onwards.

Potential solutions include local generation, demand side management or a network augmentation to reinforce supply to Lilyvale. A possible solution would be to construct a second 275kV line between Broadsound and Lilyvale at an indicative cost of $25-35M.

Gladstone Zone: Gladstone Voltage Control

Changed generation dispatch and load growth over recent years has resulted in reactive reserves being depleted in the Gladstone area. Forecast additional load growth over the next two years will result in unacceptably low voltages in the Gladstone areas during peak load conditions unless corrective action is taken.

Potential solutions include demand side management or an ongoing program of shunt capacitor installation to keep pace with this growing reactive demand. The first proposed augmentation to address this issue is outlined in the next chapter.

South West Zone – Supply to South West Qld (Darling Downs Area)

Future limitations are expected to arise from late 2004 in the transmission system supplying the Darling Downs area of South West Queensland. Studies show that voltage limitations and thermal overloads will occur during an outage of the 275kV single circuit line between Tarong and Middle Ridge substations.

Corrective action will be required to prevent voltage collapse and allow safe operation of the system. Potential solutions could include local generation, demand side management or network augmentation. Minor network solutions have been exhausted, and major network augmentation options costing $35-60M are being studied. Consultation on this limitation was initiated in June 2002 (refer Chapter 5).

Moreton North & South Zones – SEQ Voltage Control

Growing load in south east Queensland (SEQ) results in higher reactive power requirements and greater reactive losses in the system due to increased transmission line loading.

The net effect is an annual increase in reactive demand of around 80-100MVAr. This requirement is 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 reactive demand. Two proposed augmentations to keep pace with reactive demand are outlined in the next chapter, but this is expected to be an ongoing requirement from 2004 onwards as SEQ electricity demand continues to grow rapidly.

Gold Coast/Tweed Zone – Supply to South Coast

The South Coast (Gold Coast) area is one of the fastest-growing areas in the State, in terms of population, commercial development and load growth. Electricity demand is expected to average 4.0% p.a. for the next ten years.

The South Coast load is supplied or supported by:

- two 275kV transmission lines which run from Swanbank to Mudgeeraba
- A 275kV tee connection to Molendinar to be operational by late 2003.
- a 110kV network which runs from Belmont to Mudgeeraba;
- Directlink, via the Terranora to Mudgeeraba 110kV double circuit line

Powerlink's analysis shows that, due to the high load growth, major reinforcement of supply to the Gold Coast will eventually be required. Emerging reliability limitations will arise due to thermal limits of the 110kV network, voltage stability limits associated with a 275kV network outage, and (in the longer-term) thermal limits of the 275kV transmission lines supplying the Gold Coast area. Anticipated limitations in the coming summer will be addressed by committed projects being undertaken by Powerlink and Energex. However, other limitations will arise from late 2004 onwards.

Consultation and detailed studies relating to this emerging limit will commence shortly (refer to Chapter 5). Because of Directlink's likely impact (both as a potential solution and as an additional load), the study will be run jointly with TransGrid to ensure affected NSW limits are also considered.

4.8 Summary of Forecast Network Limitations

Limitations discussed in Sections 4.3 to 4.7 have been summarised in Table 4.8. This table provides an outlook (based on load, generation and committed network development assumptions contained in Chapters 2, 3 and 4) for potential limitations in Powerlink's transmission network over a one, three and five year timeframe.

Table 4.8: Summary of Forecast Network Limitations

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
FAR NORTH AND ROSS ZONES				
Cairns voltage control	Severe voltage problems may result during contingencies coincident with low Barron output		2004-2006 (1)	2004-2006 (1)
Chalumbin voltage control	Potential for severe voltage problems may result during contingencies coincident with low hydro output.	2002-2007	2002-2007	2002-2007
Supply to Edmonton	Upturn in local demand expected to exceed 22kV capability	2003-2004 (2)	2003-2004 (2)	2003-2004 (2)
Supply to northern & western Townsville	Future line loadings are expected to exceed the capability of the 132kV network within the Townsville area		2004-2005 (1)	2004-2005 (1)
Supply to southern Townsville area	Future line loadings are expected to exceed the capability of the 132kV network within the Townsville area		2004-2005 (1)	2004-2005 (1)
NORTH ZONE				
Grid transfer limit: CQ-NQ Limit	Potential for some NEM generation dispatch scenarios to give rise to binding transfer limits (at CQ-NQ &/or Ross observation points)	Corrective action in progress (3) (4)	Corrective action may be needed (4)	Corrective action may be needed (4)
Collinsville and Clare	Load expected to reach limit of 132kV network capacity to Clare	Corrective action in progress (5)		
Supply to Mackay & Central Queensland	Load expected to reach Nebo transformer capacity limits		2004-2007	2004-2007
Supply to Mackay & Proserpine	Voltage and thermal limitations likely to arise during local 132kV outages		2004-2007	2004-2007
CENTRAL WEST ZONE				
Supply to southern Bowen Basin and Gladstone	Load expected to reach Calvale transformer capacity limits		2003-2004	2003-2004
Gladstone voltage control	Voltage problems may occur during contingencies under some conditions		2004-2007 (1)	2004-2007 (1)
Supply to Lilyvale (central Qld mining area)	Load growth expected to result in loadshedding during outage of existing 275kV single circuit line from Broadsound to Lilyvale		2004-2005 (1)	2004-2005 (1)

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
WIDE BAY AND SOUTH WEST ZONES				
Woolooga transformer limits	Load expected to reach Woolooga transformer capacity limits.	Corrective action in progress (5)		
Supply to SW Queensland	Load growth expected to cause voltage control and thermal limitations during 275kV Tarong-Middle Ridge contingency		2004-2005 (1)	2004-2005 (1)
Grid transfer limit: Braemar to Tarong	Some NEM generation dispatch scenarios may give rise to binding transfer limits for northerly flow (based on the Braemar 330/275 kV limit)		2004-2007	2004-2007
MORETON NORTH AND SOUTH ZONES				
Palmwoods transformer limits	Load expected to reach Palmwoods transformer capacity limits.	Corrective action in progress (5)		
Swanbank transformer limits	Load expected to reach Swanbank transformer capacity limits.	Corrective action in progress (5)		
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 (5)	2004-2007 (1)	2004-2007 (1)
Supply to Brisbane South/Logan area	Load growth expected to result in loadshedding during 275kV Swanbank/Blackwall-Belmont contingency		Corrective action in progress (3)	
Grid transfer limit: Tarong limit	Some NEM generation dispatch scenarios may give rise to binding transfer limits	(6)	(6)	(6)
GOLD COAST/TWEED ZONE				
110kV Supply within South Coast area	Load growth expected to cause overloads of 110kV Gold Coast system and 275kV transformers at Mudgeeraba		Corrective action in progress (3)	
275kV Supply to South Coast	Expected power flows likely to exceed Gold Coast voltage stability limits. Thermal limits also may also arise in Energex system.	2002-2003 summer (5)	2004-2007 (1)	2004-2007 (1)

Notes:
(1) Refer to Network Development Chapter 5
(2) Refer to Table 3.6
(3) Refer Tables 3.3 and 3.5 – Committed Augmentations
(4) Grid support arrangements in place
(5) Corrective action in place from late 2002
(6) Refer discussion in Section 4.3.4

5. NETWORK DEVELOPMENT

5.1 Introduction

The development of the network to meet forecast load depends on the location and capacity of any new generation developments and the pattern of generation dispatch in the national electricity market. This uncertainty is a feature of the competitive electricity market, and is particularly evident in the Queensland region which is experiencing continuing load growth and a significant amount of new large generation capacity entering the market over the next few years. Uncertainty is thus created about the generation pattern (eg. to what extent will the new generation displace existing capacity and which units will be most affected), which in turn creates uncertainty about the power flows on the network, and subsequently which parts of the network will experience limitations.

The previous chapter outlined potential transfer limitations and emerging 'reliability limitations'. The possible timing and severity of limitations is dependent on load growth and market developments.

This chapter focuses on those limitations identified in the previous chapter for which Powerlink intends to take action or initiate consultation with market participants and interested parties in the near future. It should be noted that the information provided in this section regarding Powerlink's network development plans may change, and should therefore be confirmed with Powerlink before any action is taken based on this information.

5.2 Processes for Possible Network Developments

Chapter 4 of this report identified anticipated network limitations and constraints that may arise in the Queensland transmission network over the next five years. Where action is considered to be necessary, Powerlink will:

- Notify Code Participants of anticipated limitations within the time 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 on potential solutions to minor network limitations via the Annual Planning Report. Those that cannot be identified for inclusion in the APR will be the subject of separate consultation with market participants and interested parties.
- For major emerging network limitations, Powerlink's approach is to issue detailed information papers outlining the limitations to assist in identifying feasible non-network solutions.
- Carry out detailed analysis to determine feasible network solutions that Powerlink may propose to address identified network constraints.
- Consult with Code participants and interested parties on all feasible alternatives (network and non-network) and recommended solutions.
- In the event a regulated solution (network or grid support) is found to satisfy the ACCC Regulatory Test, Powerlink will implement the recommended solution.

5.3 Proposed New Small Network Augmentations

This section outlines proposed network augmentations which are required to be progressed under the provisions of Clause 5.6.6A of the NEC (new small network assets). At the time of publication of this report, Powerlink has developed plans for the following proposed new small network augmentations to the point where they can be consulted on through this document.

Table 5.1: Proposed Network Augmentations

Network Augmentation (1)	**Date To Be Operational**	**Cost**
Wurdong 120MVAr 275kV capacitor bank	October 2004	$1.8M
Mt England 120MVAr 275kV capacitor bank	October 2004	$1.7M
Palmwoods 120MVAr 275kV capacitor bank	April 2004	$1.9M

Note:
(1) Greater than $1M expected capitalisation value

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

Code 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 Monday 29th July, 2002. Submissions should be addressed to:

Manager Network Assessments
Powerlink Queensland
PO Box 1193 Virginia QLD 4014
enquiries@powerlink.com.au

Following consideration of any submissions in accordance with Code consultation procedures, Powerlink will publish its conclusions and recommended course of action. Unless changes to its proposals are necessary, Powerlink will proceed to implement these proposed new small network assets in the required timeframes.

Other proposed network augmentations will be subject to separate assessment and consultation as per Clauses 5.6.6 and 5.6.6A of the Code, if commitment is required prior to the publication of the 2003 Annual Planning Report.

5.3.1 Wurdong 120MVAr 275kV Shunt Capacitor Bank

Project Name:	**Wurdong 120MVAr 275kV Shunt Capacitor Bank**
Proposed Timing:	October 2004
Estimated Cost:	$1.8M
Inter-Network Impact:	No material impact

Background:
The central Queensland area in the vicinity of Gladstone contains the highest concentration of industrial loads in the State. The total demand in this area is expected to approach 1000MW in the next few years.

Growing demand and reduced operation of local generators will mean that additional reactive power will soon be required in the Gladstone area. The industrial loads in Gladstone have very high load factors, and are often associated with relatively high reactive demands, and network reactive losses. An adequate supply of reactive power is essential for the maintenance of satisfactory system voltages.

Part of the reactive component of the local load is corrected by the industrial customers themselves to the level required under the Code. However, a considerable quantity of reactive power is still supplied via the grid from Gladstone Power Station and a 120MVAr capacitor bank at Wurdong substation just south of Gladstone.

The existing reactive support available through ancillary services and the capacitor bank is expected to be insufficient to meet reactive power requirements in the Gladstone area from late 2004 onwards. Without corrective action, Powerlink will be unable to meet voltage control requirements in Schedule 5.1 of the Code under some credible operating and contingency conditions. For this reason, proposed solutions are classified as a reliability augmentation.

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

Network Options Considered:
Option 1: Capacitor Bank: A feasible network solution to the emerging voltage control limitation in the Gladstone area is the installation of a second 120MVAr 275kV switched capacitor bank at Wurdong substation by October 2004 at a cost of $1.8M.

Option 2: SVC: A second network option which could feasibly address the emerging limitation is the installation of a static var compensator (SVC) at Wurdong. The SVC would need to have a reactive range of at least 0 to +120MVAr. This would achieve the same benefits as a capacitor bank, at a cost of $10M.

Option 3: Customer Connected Capacitor Banks: It would be feasible that customers in the Gladstone area could install capacitor banks to overcome the network 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 local generation developments or other non-network solutions, which could address the identified limitation. In the analysis conducted it is assumed that reactive support from Gladstone Power Station will continue to be provided at the base levels required under the Code.

Summary of Options and Economic Analysis:
Only two options are feasible ways of overcoming the voltage control limitations in the Gladstone area by the required timing of October 2004. These are option 1, the installation of a capacitor bank at Wurdong, and option 2, the installation of an SVC at Wurdong. The costs and outcomes associated with these options are summarised in the table below:

Options		Net Present Value Cost	Ranking
1.	120MVAr 275kV capacitor bank at Wurdong	$1.8M	1
2.	0 to +120MVAr SVC at Wurdong	$10M	2
3.	Customer connected capacitor bank	N/A	N/A
4.	Non-network options	N/A	N/A

The proposed capacitor bank at Wurdong therefore minimises the net present value cost of addressing the voltage control requirements in the Gladstone area, and as such, is considered to satisfy the Regulatory Test.

Recommendation:
It is recommended that a 120MVAr 275kV capacitor bank at Wurdong be implemented by October 2004, to address emerging voltage control limitations in the Gladstone area.

5.3.2 Mt England 120MVAr 275kV Shunt Capacitor Bank

Project Name:	**Mt England 120MVAr 275kV Shunt Capacitor Bank**
Proposed Timing:	October 2004
Estimated Cost:	$1.7M
Inter-Network Impact:	No material impact

Background:
The load in South East Queensland has been growing at around 4 to 5% per annum, and is expected to continue at about 3 to 4% for the foreseeable future (refer forecasts in Table 2.12). This growth rate equates to about 125MW per annum. In the summer, when reactive power loading tends to be higher, an additional 60MVAr of reactive power is added to the system due to load growth only. This assumes that connected parties meet their power factor requirements in the Code. Added to this are the reactive power losses in the transmission system due to increased transmission line loading. The analysis conducted assumes that existing levels of reactive support continue to be provided by generators, either under their code obligations or as ancillary services under contract to NEMMCO.

The net effect of this is a requirement to increase annual reactive capability in South East Queensland by approximately 80-100MVAr per annum. Powerlink is required to take action to keep pace with this growing reactive power demand. If no corrective action is taken, Powerlink will be unable to meet objective voltage control and stability standards in the Code under some conditions. For this reason, solutions to this emerging network limitation are classified as a reliability augmentation.

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

The need for an additional 120MVAr capacitor bank in South East Queensland each year was identified in the 2001 Powerlink Annual Planning Report. In that report, it was to be located at Blackwall.

Network Options Considered:
Option 1: Capacitor Bank: A feasible network solution to the emerging voltage control limitation in South East Queensland is the installation of a 120MVAr 275kV switched capacitor bank at Mt England substation (near Wivenhoe Dam) by October 2004 at a cost of $1.7M.

Option 2: SVC: A second network option which could feasibly address the emerging limitation is the installation of a static var compensator (SVC) at Mt England. The SVC would need to have a reactive range of 0 +120MVAr. This would achieve the same benefits as a capacitor bank, at a cost of $10M.

Option 3: Customer Connected Capacitor Banks: It would be feasible that customers in the south-east Queensland area could install capacitor banks to overcome the voltage 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, which could address the identified limitation. It is assumed that reactive support from Wivenhoe and Swanbank Power Stations will continue to be provided either at base levels required under the Code or as an ancillary service under contract to NEMMCO.

Summary of Options and Economic Analysis:
Only two options are feasible ways of overcoming the voltage control limitations in the SEQ area by the required timing of October 2004. These are option 1, the installation of a capacitor bank at Mt England, and option 2, the installation of an SVC at Mt England. The costs and outcomes associated with these options are summarised in the table below:

Options		Net Present Value Cost	Ranking
1.	120MVAr 275kV capacitor bank at Mt England	$1.7M	1
2.	0 +120MVAr SVC at Mt England	$10M	2
3.	Customer connected capacitor bank	N/A	N/A
4.	Non-network options	N/A	N/A

The proposed capacitor bank at Mt England therefore minimises the net present value cost of addressing the voltage control requirements in the area, and as such, is considered to satisfy the Regulatory Test.

Recommendation:
It is recommended that a 120MVAr 275kV capacitor bank at Mt England be implemented by October 2004 as part of an ongoing program to address voltage control limitations in South East Queensland.

5.3.3 Palmwoods 120MVAr 275kV Shunt Capacitor Bank

Project Name:	**Palmwoods 120MVAr 275kV Shunt Capacitor Bank**
Proposed Timing:	April 2004
Estimated Cost:	$1.9M
Inter-Network Impact:	No material impact

Background:
In addition to the voltage control limitations in south-east Queensland noted above, the fast-growing Sunshine Coast load to the north of Brisbane also requires additional reactive support. This is needed prior to the winter of 2004 to maintain adequate voltage stability margins and transmission capability to this area. The analysis conducted assumes that existing levels of reactive support continue to be provided by generators, either under their code obligations or as ancillary services under contract to NEMMCO.

The Sunshine Coast load is supplied directly from Palmwoods substation, located in the north coast hinterland.

This is classified as a reliability augmentation because, without corrective action on the north coast, Powerlink will be unable to meet voltage control requirements in Schedule 5.1 of the Code under some conditions.

A regulated network development such as the proposed capacitor bank is required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, it is necessary that the proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered:
Option 1: Capacitor Bank: The emerging network limitation can be addressed by installing a 120MVAr 275kV capacitor bank at Palmwoods substation by April 2004 at a cost of $1.9M. This capacitor bank will meet the local reactive power requirements, and also assist in addressing the broader SEQ voltage control limitations.

Option 2: SVC: A second network option which could feasibly address the emerging limitation is the installation of a static var compensator (SVC) at Palmwoods. The SVC would need to have a reactive range of 0 +120MVAr. This would achieve the same benefits as a capacitor bank, at a cost of $10M.

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

Non-Network Options Considered:
There are no existing power generation facilities close enough to the required location to provide an alternative source of voltage support. Also, Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions, which could address the identified voltage control limitation.

Summary of Options and Economic Analysis:
There are only two feasible options that are capable of overcoming the voltage control limitations in the Sunshine Coast area by the required timing of April 2004. These are option 1, the installation of a capacitor bank at Palmwoods, and option 2, the installation of an SVC at Palmwoods. The costs and outcomes associated with these options are summarised in the table below:

Options		Net Present Value Cost	Ranking
1.	120MVAr 275kV capacitor bank at Palmwoods	$1.9M	1
2.	0 to +120MVAr SVC at Palmwoods	$10M	2
3.	Customer connected capacitor bank	N/A	N/A
4.	Non-network options	N/A	N/A

The proposed capacitor bank at Palmwoods therefore minimises the net present value cost of addressing the voltage control requirements in the Sunshine Coast area, and as such, is considered to satisfy the Regulatory Test.

Recommendation:
It is recommended that a 120MVAr 275kV capacitor bank at Palmwoods be implemented by April 2004, to address voltage control limitations in the Sunshine Coast area.

5.4 Consultation Underway – Supply to the Darling Downs

Powerlink has recently commenced consultation with market participants on emerging supply limitations in South West Queensland. In mid June 2002, an information paper was issued outlining the system limitations expected in the Darling Downs region (ie – the area supplied from the 275/110kV Middle Ridge substation).

This paper, published on the Powerlink website at www.powerlink.com.au, also seeks information on feasible non-network solutions for inclusion in subsequent analysis.

Interested parties are invited to review this document and provide Powerlink with any relevant information by the due date of 26 July 2002. As noted in the chapter on Network Capability, small network augmentations have been implemented in recent years to maintain adequate voltage control levels in the Darling Downs area. No further such minor augmentations are considered feasible. Powerlink is now considering a major network augmentation of supply to the Darling Downs area, with a potential cost of $35-60M. Alternatives may include new local generation, a grid support arrangement and/or demand side alternatives.

5.5 Anticipated Consultation Processes

Powerlink expects to initiate other consultation processes prior to the publication of the 2003 Annual Planning Report for the following major emerging limitations:

Table 5.2: Consultation Likely Within 12 Months

Location	Major Emerging Limitation
Townsville area	Thermal overload issues in Townsville 132kV system
Gold Coast / Tweed Area	Voltage stability and potential thermal limitations during outage of 275kV circuit between Swanbank and Mudgeeraba.
Western Central Queensland (mining area)	Local 132kV system thermal and voltage limitations during outage of 275kV circuit between Broadsound and Lilyvale.
Cairns Voltage Control	Severe voltage problems under some operating conditions.

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

5.6 Interconnector Developments

The Code requires that the IRPC undertake an annual interconnector planning review (Clause 5.6.5). This review will be published as part of NEMMCO's 2002 Statement of Opportunities, to be published by 31 July 2002.

It is expected that this review will indicate increasing instances of congestion on QNI over a ten year period. The review will also outline a range of potential augmentations, delivering a range of capacity increases, which could form the basis of future augmentation assessments.

Powerlink and TransGrid (the NSW transmission network owner) are committed to exploring opportunities for increasing the capacity of the Queensland-New South Wales Interconnector. At this point in time, the following steps are envisaged:

- Undertaking further testing in conjunction with the IRPC and NEMMCO with a view of proving increased dynamic limits southwards following commissioning of the Millmerran power station;
- Examining the findings of the IRPC's Annual Interconnector Review along with any other possible options with a view of undertaking a Regulatory Test assessment should preliminary studies indicate positive market benefits.

APPENDICES

APPENDIX A – ESTIMATED NETWORK POWER FLOWS

Table A1: Summary of Figures A3 To A20 - Possible Grid Power Flows and Limit Stability States

Grid Section (1)		**Illustrative Grid Power Flows (MW) and Limit Stability at Queensland Region Peak Load Time** (2)(3)(4)						**Limit Due To** (5)
		2002 WINTER Fig A3 / A4 / A5	2003 WINTER Fig A6 / A7 / A8	2004 WINTER Fig A9 / A10 / A11	2002/03 SUMMER Fig A12 / A13 / A14	2003/04 SUMMER Fig A15 / A16 / A17	2004/05 SUMMER Fig A18 / A19 / A20	
'<u>Far North' Transfer</u>								
Ross into Chalumbin 275kV (2 circuits)	Flow	152 / 152 / 152	157 / 157 / 157	164 / 164 / 164	196 / 196 / 195	205 / 205 / 205	214 / 214 / 214	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	
'<u>Ross' Transfer</u>								
Strathmore into Ross 275kV (2 circuits)	Flow	493 / 493 / 493	505 / 505 / 505	520 / 520 / 520	667 / 667 / 667	688 / 688 / 688	739 / 739 / 739	Tr,V
Collinsville/Strathmore into Clare 132kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
'<u>CQ-NQ' Transfer</u>								
Broadsound into Nebo 275kV (2 circuits)	Flow	669 / 669 / 669	688 / 688 / 688	719 / 719 / 719	871 / 871 / 871	907 / 907 / 907	987 / 987 / 987	Tr, 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 circuits)								
'<u>Gladstone' Transfer</u>								
Bouldercombe into Gladstone 275kV (2 circuits)		958 / 819 / 806	738 / 828 / 692	873 / 941 / 806	868 / 788 / 708	883 / 796 / 715	703 / 608 / 601	Th
Calvale into Wurdong 275kV (1 circuit)		See Section 4.3.6	See Section 4.3.6	See Section 4.3.6	See Section 4.3.6	See Section 4.3.6	See Section 4.3.6	
Callide A into Gladstone South 132kV (2 circuits)								
'<u>CQ-SQ' Transfer</u>								
Wurdong into Gin Gin 275kV (1 circuit)	Flow	1602 / 1903 / 1913	931 / 1215 / 1511	1077 / 1364 / 1661	1331 / 1500 / 1663	1083 / 1369 / 1538	1089 / 1290 / 1291	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 (2 circuits)								
'<u>Woolooga' Transfer</u>								
Woolooga to South Pine and	Flow	696 / 856 / 854	378 / 511 / 666	444 / 581 / 739	543 / 629 / 711	421 / 570 / 657	430 / 534 / 528	V
Palmwoods 275kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Woolooga to Gympie 132kV (2 circuits)								
'<u>Tarong' Transfer</u>								
Tarong to South Pine, Mt England	Flow	2334 / 2178 / 1993	2753 / 2617 / 2462	2810 / 2671 / 2513	2605 / 2402 / 2190	2869 / 2717 / 2507	2843 / 2654 / 2468	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 Postman's Ridge 110kV (3 circuits)								
'<u>Blackwall' Transfer</u> (6)								
Blackwall to Swanbank, Rocklea and	Flow	1792 / 1781 / 1756	1886 / 1876 / 1865	1969 / 1959 / 1948	1929 / 1814 / 1685	2042 / 2032 / 1909	1971 / 1885 / 1858	V, Th
Belmont 275kV (5 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
South Pine to Rocklea 275kV (1 circuit)								
Middle Ridge into Swanbank 110kV (2 circuits)								
Lockrose into Abermain 110kV (1 circuit)								

Grid Section (1)		Illustrative Grid Power Flows (MW) and Limit Stability at Queensland Region Peak Load Time (2)(3)(4)						Limit Due To (5)
		2002 WINTER Fig A3 / A4 / A5	2003 WINTER Fig A6 / A7 / A8	2004 WINTER Fig A9 / A10 / A11	2002/03 SUMMER Fig A12 / A13 / A14	2003/04 SUMMER Fig A15 / A16 / A17	2004/05 SUMMER Fig A18 / A19 / A20	
'Gold Coast' Transfer								
Swanbank into Mudgeeraba 275kV (2 circuits)	Flow	599 / 599 / 599	631 / 631 / 631	638 / 638 / 638	587 / 587 / 587	614 / 614 / 614	636 / 636 / 636	V,Th
Cades County into Molendinar 110kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	U / U / U	S / S / S	U / S / S	
'Braemar' Transfer								
Bulli Creek into Braemar 330kV (2 circuits)	Flow	692 / 397 / 197	1065 / 771 / 473	1065 / 771 / 474	1084 / 790 / 492	1069 / 775 / 477	1068 / 774 / 576	Tr, Th
	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	

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 of Appendix A. The flows are estimated for system normal (i.e. all network circuits in service), and are based on existing network configurations and committed projects. Power flows within each grid section can be higher at times of local zone peak loading.
(3) Grid capacity is the power flow below which the system will remain stable following a credible single contingency for the range of assumed generation dispatch cases shown within Figures A3 to A20 of Appendix A.
(4) S = Stable condition, U = Unstable conditions.
(5) V = voltage stability limit, Th= thermal limit and Tr = Transient stability limit.
(6) For scenarios from summer 2003/04 onwards, new transmission lines Mt England to Loganlea and Blackwall to Belmont are added to the Blackwall Transfer grid section.

Table A2: Transformer Capacity and Estimates of Loading of 275kV Substations

275kV Substation (1) (2) **Transformers No. x MVA Nameplate Rating** (3)	**Planned Augmentations**	**Possible MVA at Queensland Region Peak** (4)(5)						**Dependence other than Local Load**	
		Winter 2002	**Winter 2003**	**Winter 2004**	**Summer 2002/03**	**Summer 2003/04**	**Summer 2004/05**	**Significant dependence on:**	**Minor dependence on:**
Woree 275/132	Sept 2002 (1 x 375)		111	114	127	125	130	Barron Gorge generation	Kareeya generation
Chalumbin 275/132 (2x200)		154	87	93	119	109	120	Barron Gorge and Kareeya generation	Collinsville generation
Ross 275/132 (3x250)		250	245	252	299	310	336	Mt Stuart, Townsville & Invicta generation	Collinsville generation
Strathmore 275/132	Sept 2002 (1 x 375)		31	32	63	58	56	Collinsville & Invicta generation	Townsville generation
Nebo 275/132 (2x200)		230	223	238	242	251	271	Mackay GT generation	Collinsville & Barcaldine generation
Bouldercombe 275/132 (2x200)		131	134	138	148	152	156		
Lilyvale 275/132 (2x200)		176	174	181	184	187	193	Barcaldine generation	CQ-NQ flow
Gin Gin 275/132 (2x120)		171	148	157	171	166	170	132kV transfers to/from Woolooga	CQ-SQ flow
Woolooga 275/132 (2x120)	3rd TX Nov 2002 (1 x 250)	222	223	234	225	220	221	132kV transfers to/from Gin Gin	CQ-SQ flow
Palmwoods 275/132 (1x300)	2nd TX Nov 2002 (1 x 375)	241	278	294	239	257	277	132/110kV transfers to/from South Pine and Woolooga	CQ-SQ flow
South Pine 275/110 (1x375) (1x250) and (2x200)		708	699	714	731	753	792	110kV transfers to/from Palmwoods and Rocklea	CQ-SQ flow and Swanbank generation
Rocklea 275/110 (2x375)		467	475	458	511	492	523	110kV transfers to/from South Pine, Belmont, Swanbank and Swanbank generation.	
Belmont 275/110 (2x250) (2x200)		615	648	700	688	751	793	110kV transfers to/from Loganlea	110kV transfers to/from Molendinar and Mudgeeraba

275kV Substation (1) (2) **Transformers No. x MVA Nameplate Rating** (3)	**Planned Augmentations**	**Possible MVA at Queensland Region Peak** (4)(5)						**Dependence other than Local Load**	
		Winter 2002	**Winter 2003**	**Winter 2004**	**Summer 2002/03**	**Summer 2003/04**	**Summer 2004/05**	**Significant dependence on:**	**Minor dependence on:**
Loganlea 275/110 (1x375)		301	338	326	307	301	327	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba
Molendinar 275/110	Oct 2003 (1 x 375)			272		273	287	110kV transfers to/from Loganlea and Mudgeeraba	110kV transfers to/from Belmont and Directlink MNSP
Mudgeeraba 275/110 (3x250)		578	623	430	589	401	442	Molendinar 275/110kV establishment and Directlink MNSP	110kV transfers to/from Loganlea
Tarong 275/132 (2x90)		70	72	75	61	63	65	Roma generation	
Tarong 275/66 (2x90)		34	35	36	33	34	36		
Middle Ridge 275/110 (2x200)		329	337	345	310	326	333	Oakey GT generation	
Calvale 275/132 (1x250)		224	248	258	226	255	253	Central Queensland Generation	
Swanbank 275/110 (1x250) and (1x100)	Aug 2002 (1 x 250 upgrade)	170	244	248	244	244	272	110kV transfers to/from South Pine and Rocklea	Swanbank generation

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 substation. Loading on these transformers are dependent on QNI transfer and Millmerran power station 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 of Appendix A. The loadings are estimated for system normal (i.e. all network elements in service), and are based on existing network configurations and committed projects. MVA loadings for transformers depend on power factor, and may be different under coincident region peak demands conditions, other generation patterns, outage conditions or local peak demand times.

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

Figure A1: Generation and Load Legend for Figures A3 to A20

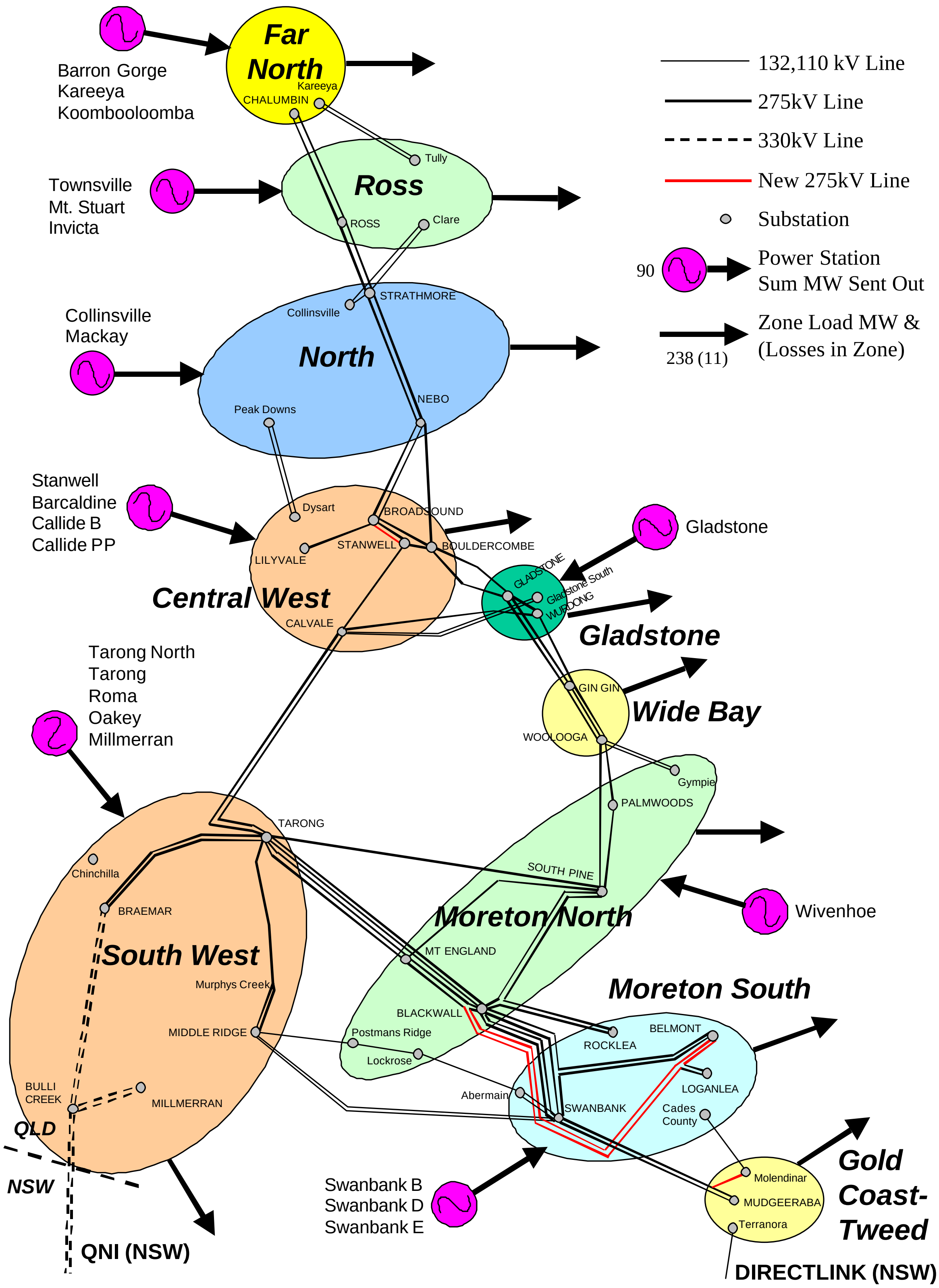


Figure A2: Power Flow and Limits Legend for Figures A3 to A20

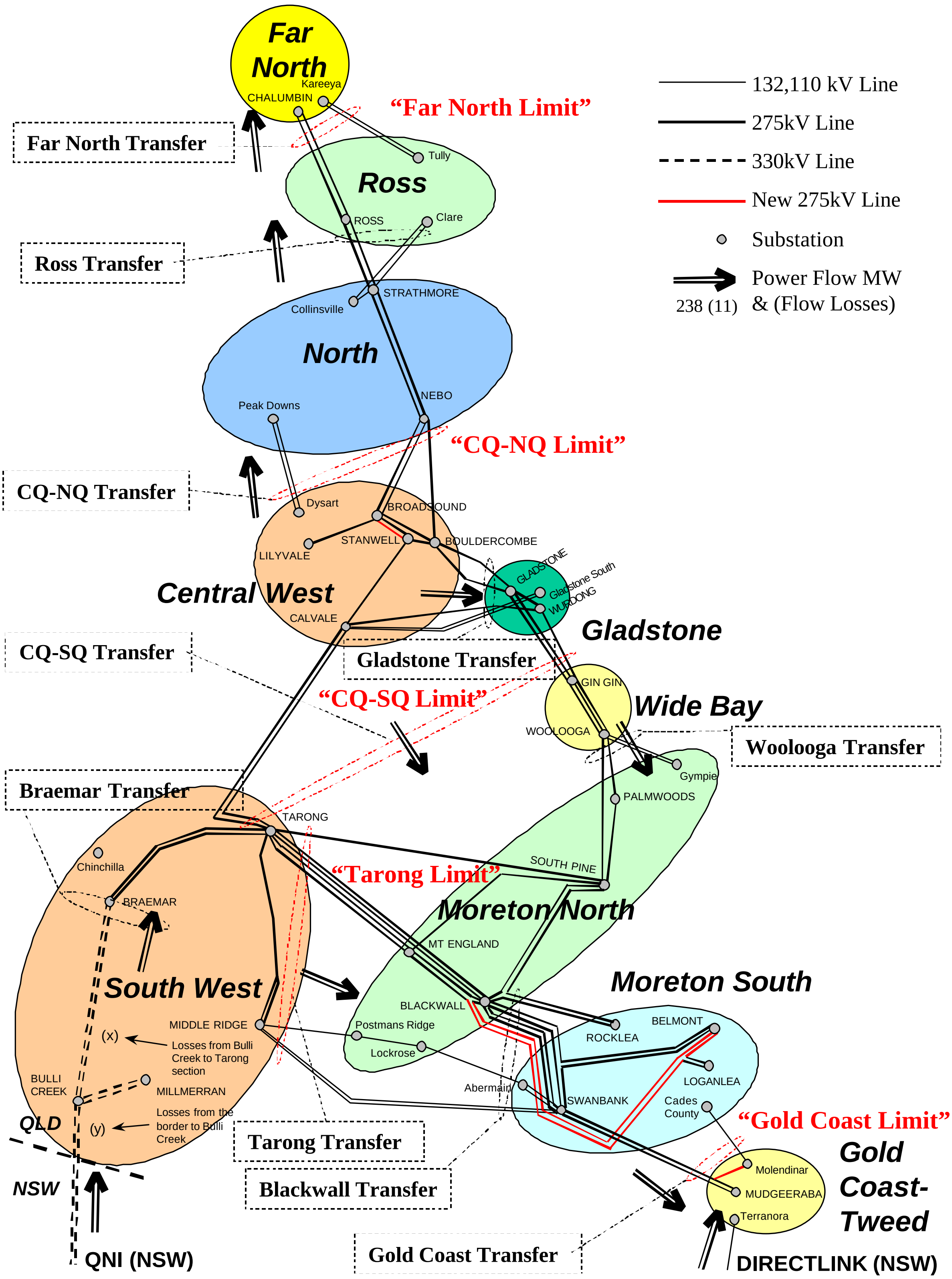


Figure A3: Winter 2002 Qld Peak 300MW Import QNI Flow

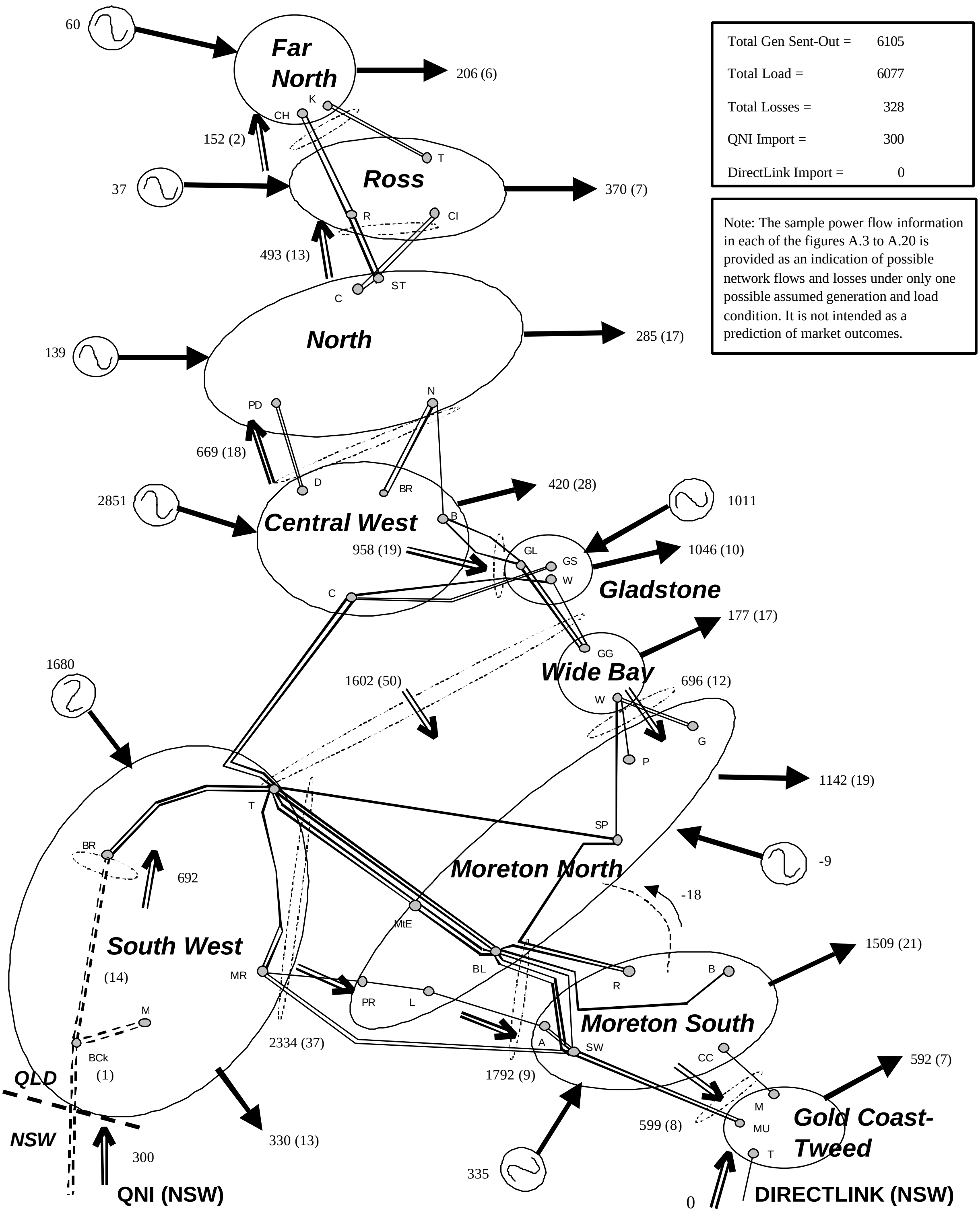


Figure A4: Winter 2002 Qld Peak Zero QNI Flow

Total Gen Sent-Out =	6423
Total Load =	6077
Total Losses =	346
QNI Import =	0
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

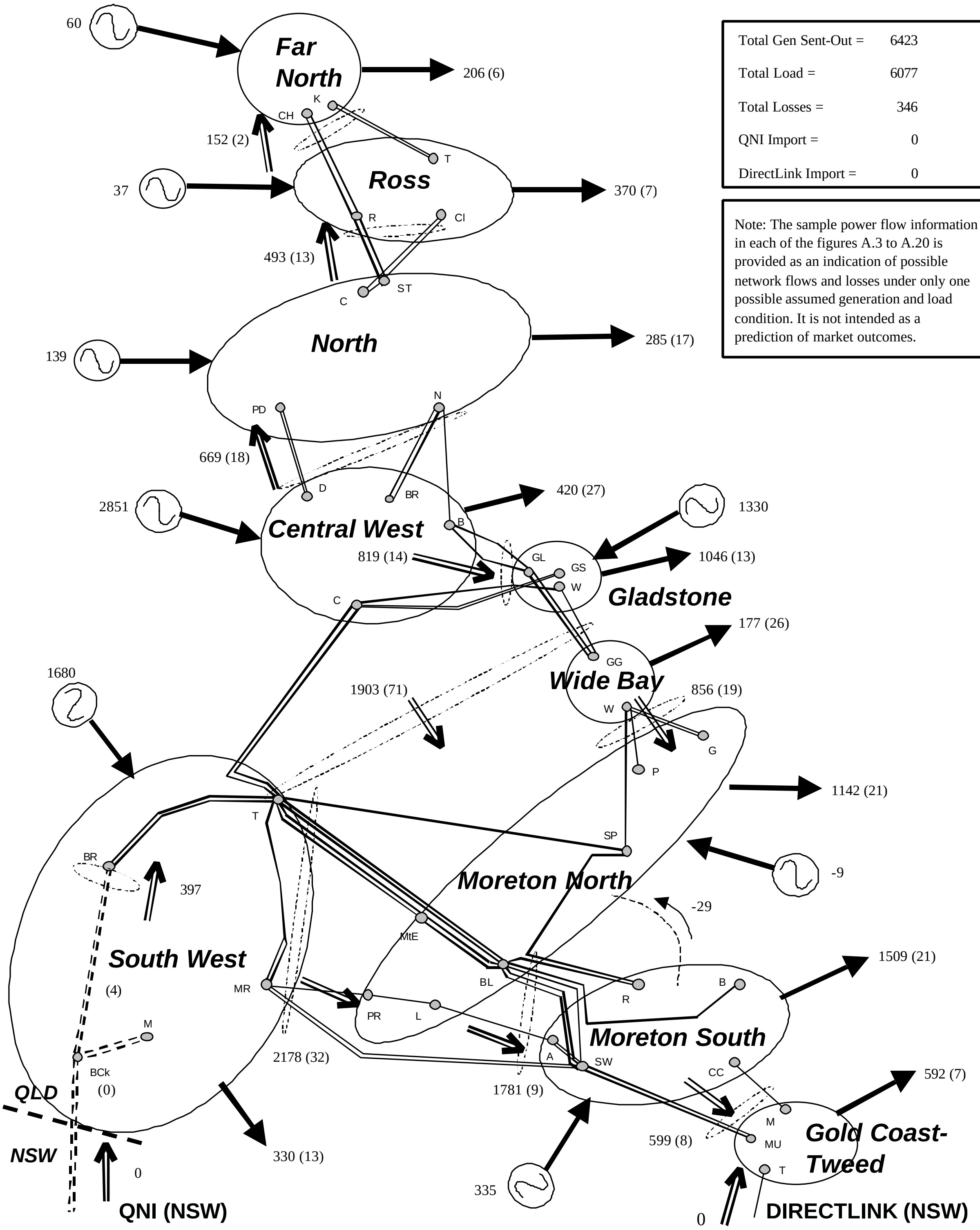


Figure A5: Winter 2002 Qld Peak 200MW Export QNI Flow

Total Gen Sent-Out =	6614
Total Load =	6077
Total Losses =	337
QNI Import =	-200
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

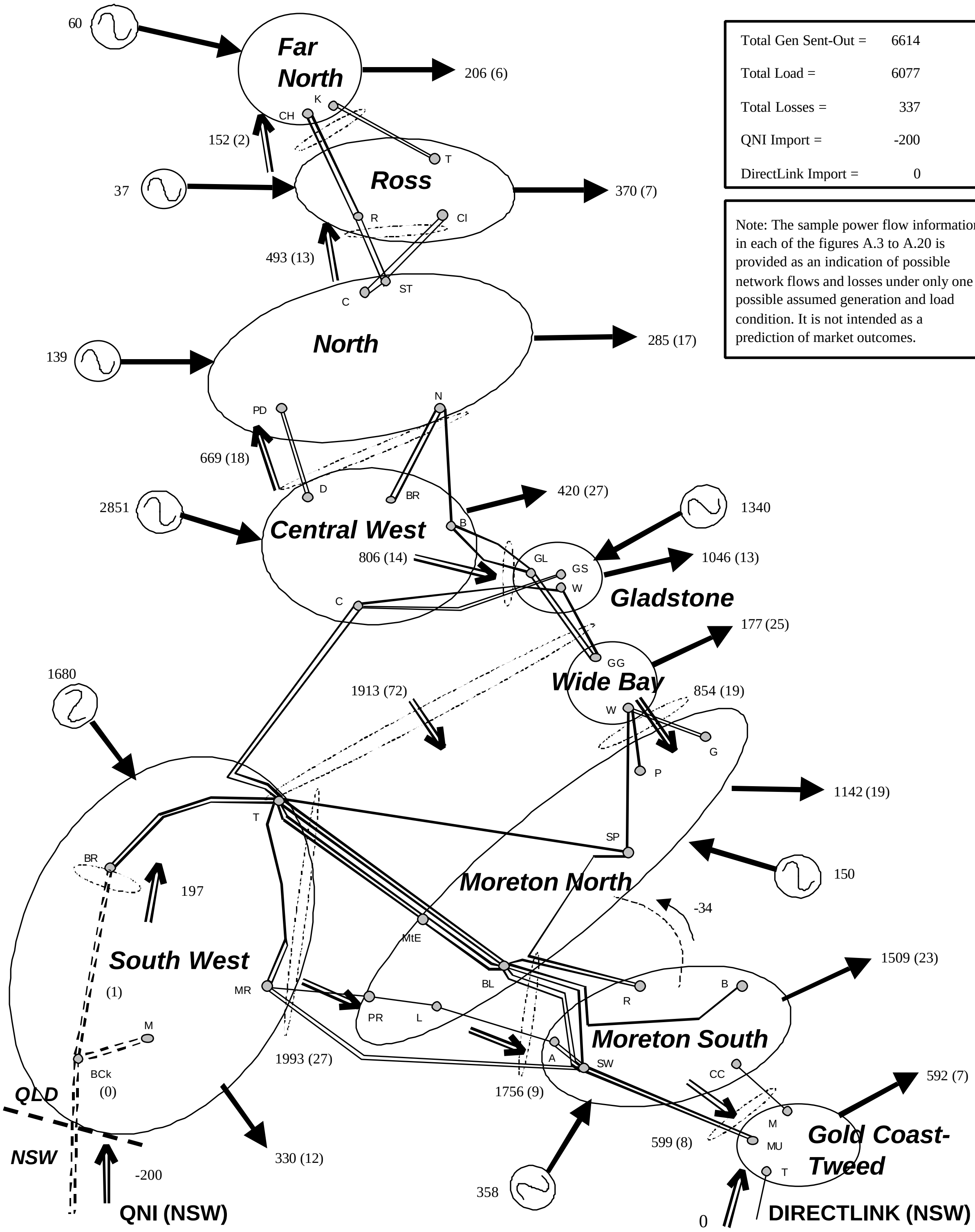
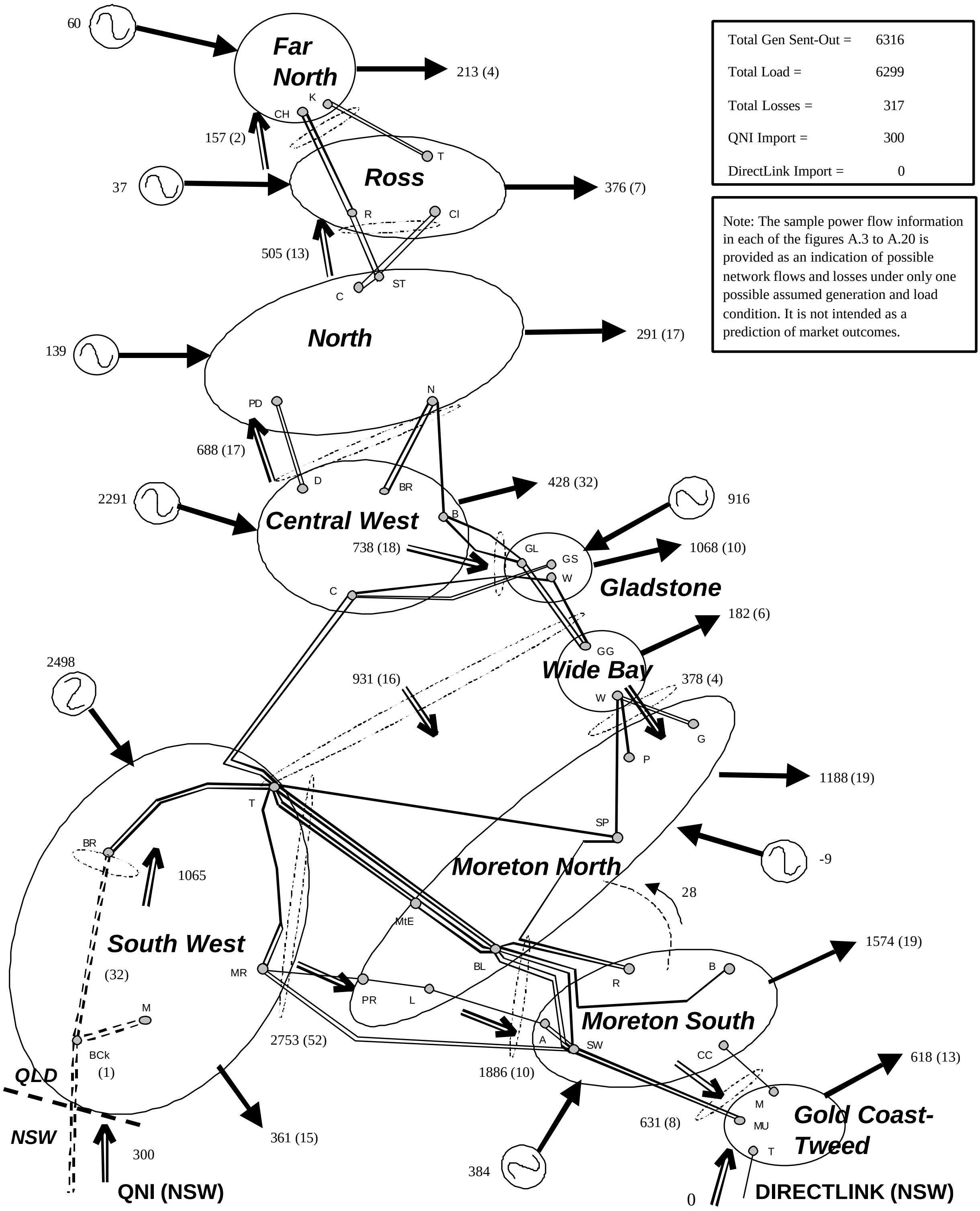


Figure A6: Winter 2003 Qld Peak 300MW Import QNI Flow



Total Gen Sent-Out =	6316
Total Load =	6299
Total Losses =	317
QNI Import =	300
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure A7: Winter 2003 Qld Peak Zero QNI Flow

Total Gen Sent-Out =	6608
Total Load =	6299
Total Losses =	309
QNI Import =	0
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

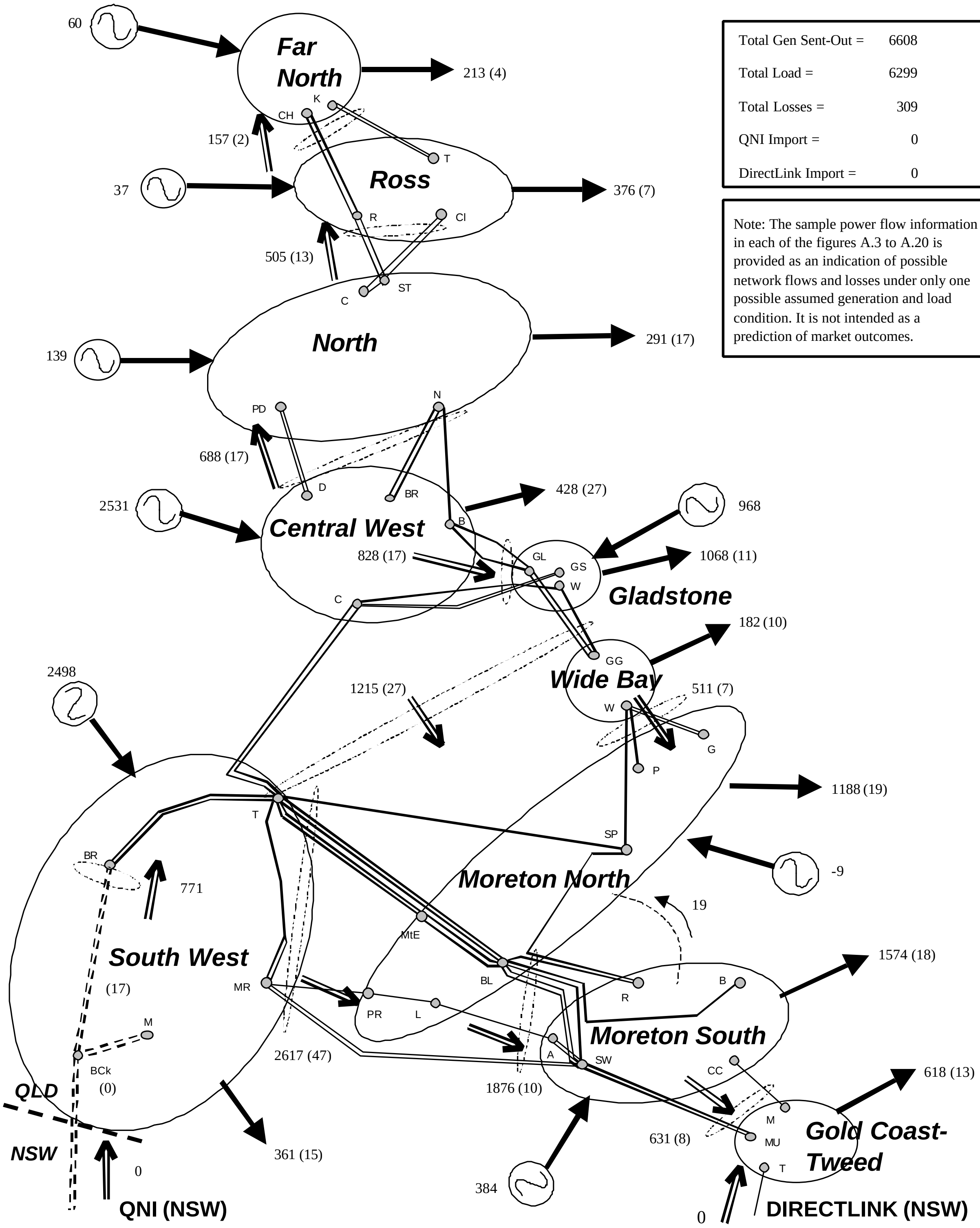
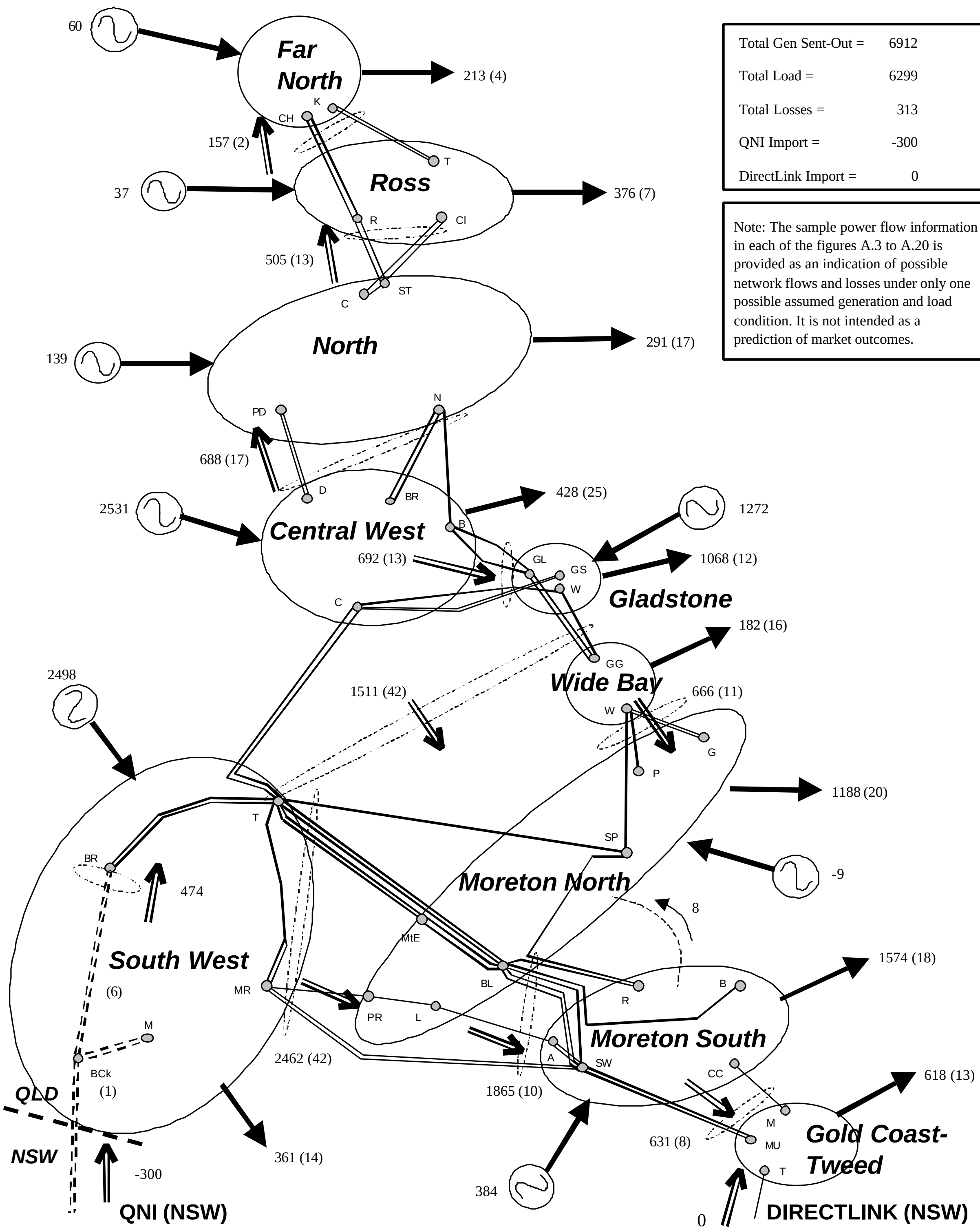


Figure A8: Winter 2003 Qld Peak 300MW Export QNI Flow



Total Gen Sent-Out =	6912
Total Load =	6299
Total Losses =	313
QNI Import =	-300
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure A9: Winter 2004 Qld Peak 300MW Import QNI Flow

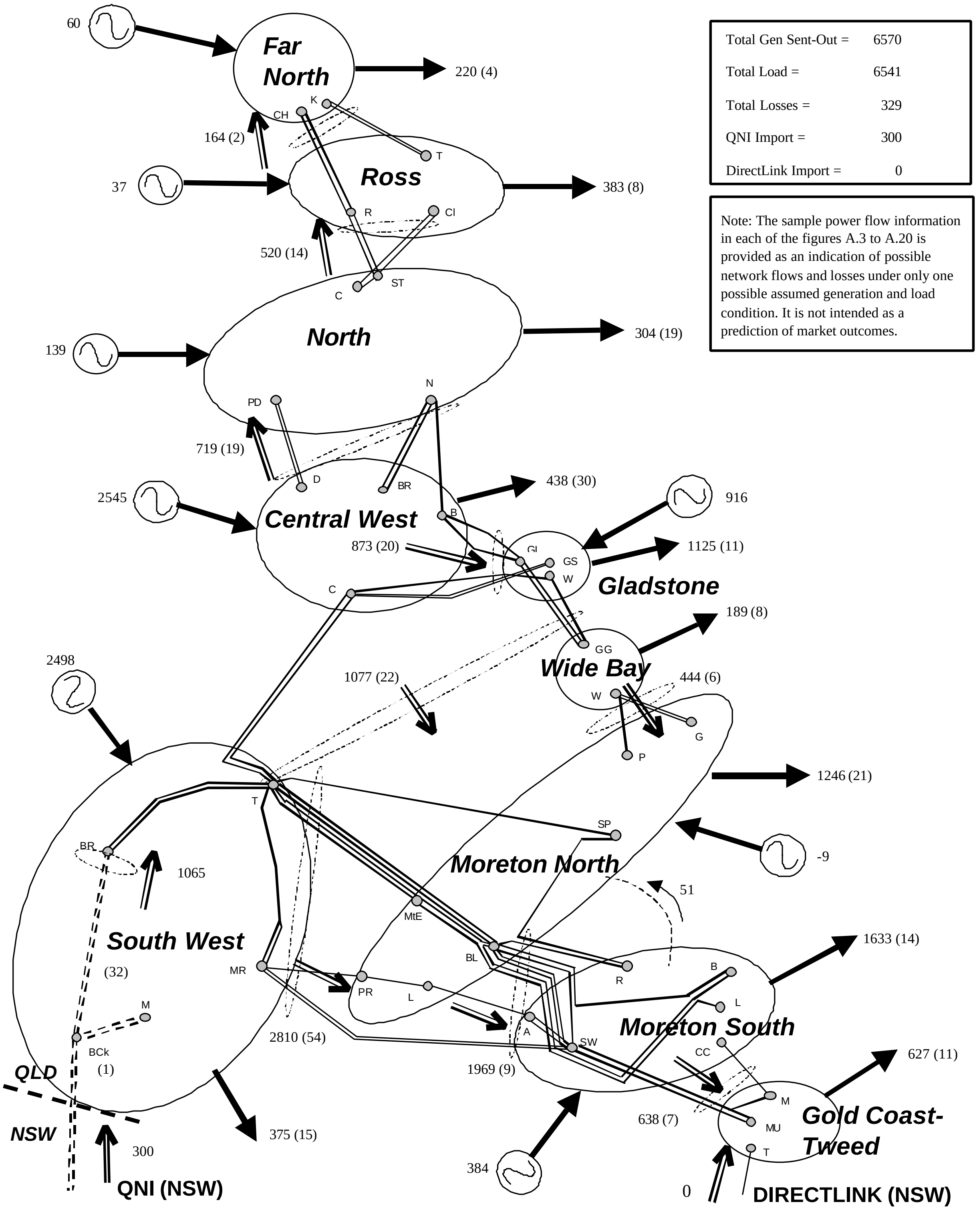


Figure A10: Winter 2004 Qld Peak Zero QNI Flow

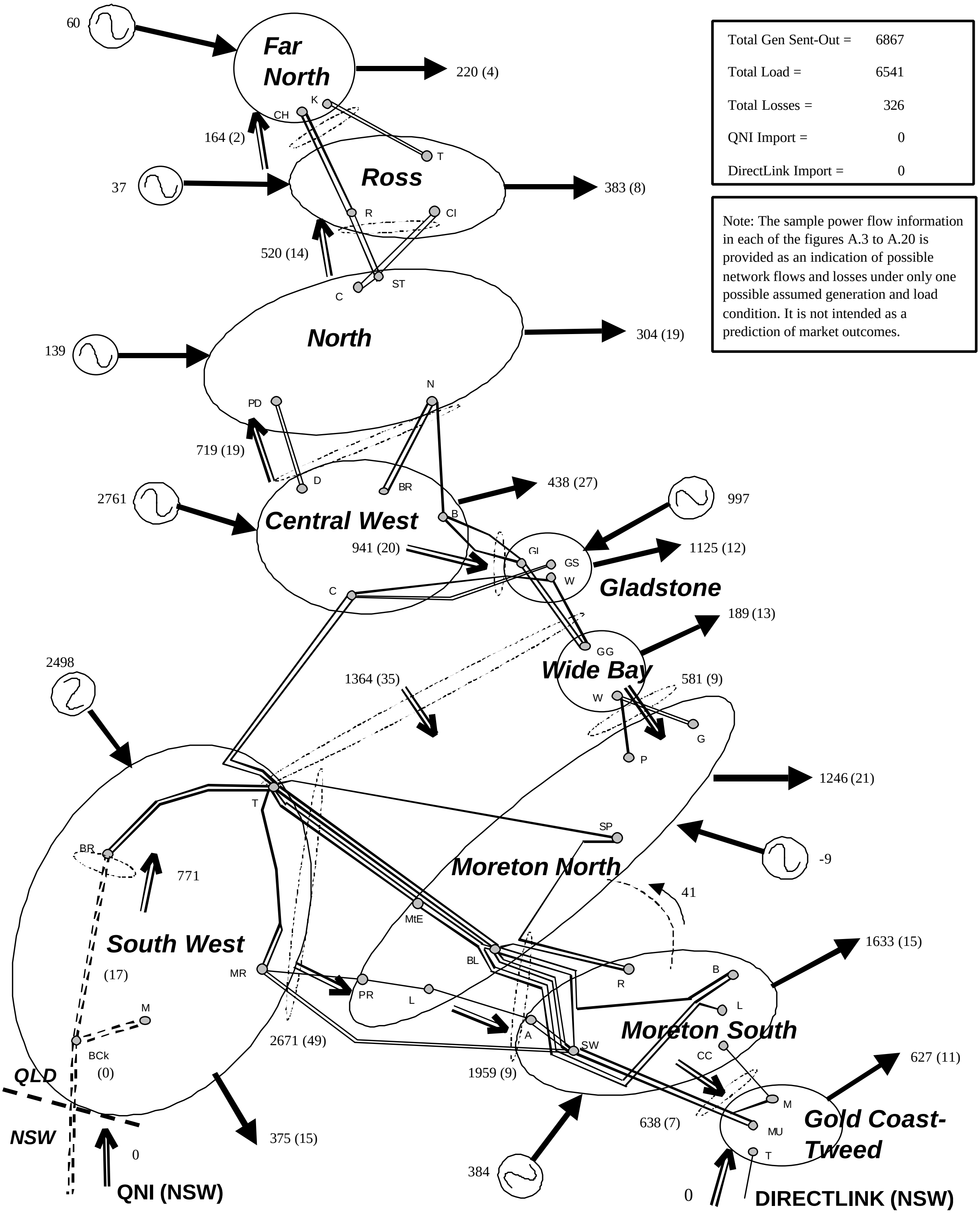


Figure A11: Winter 2004 Qld Peak 300MW Export QNI Flow

Total Gen Sent-Out =	7175
Total Load =	6541
Total Losses =	334
QNI Import =	-300
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

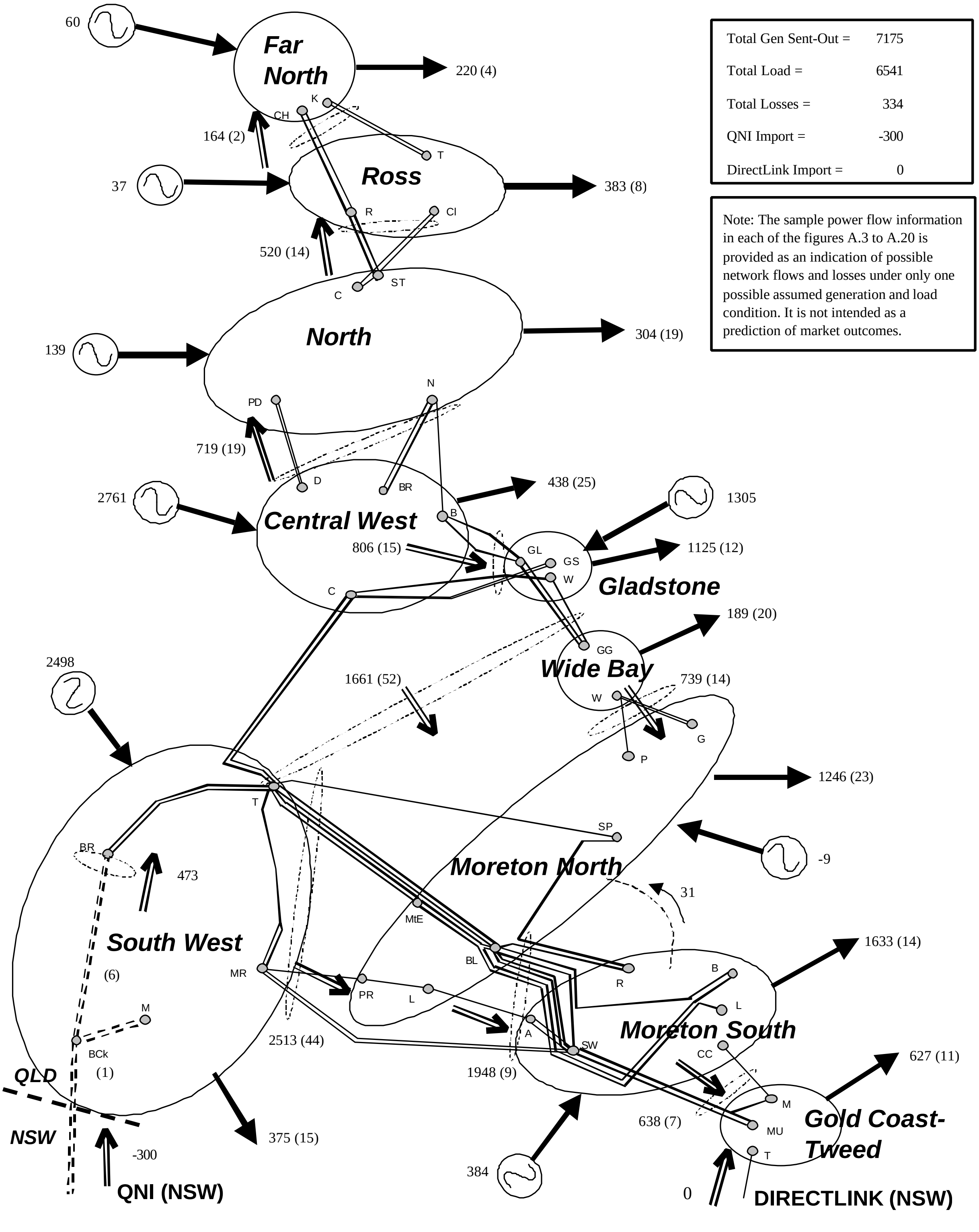


Figure A12: Summer 2002/03 Qld Peak 300MW Import QNI Flow

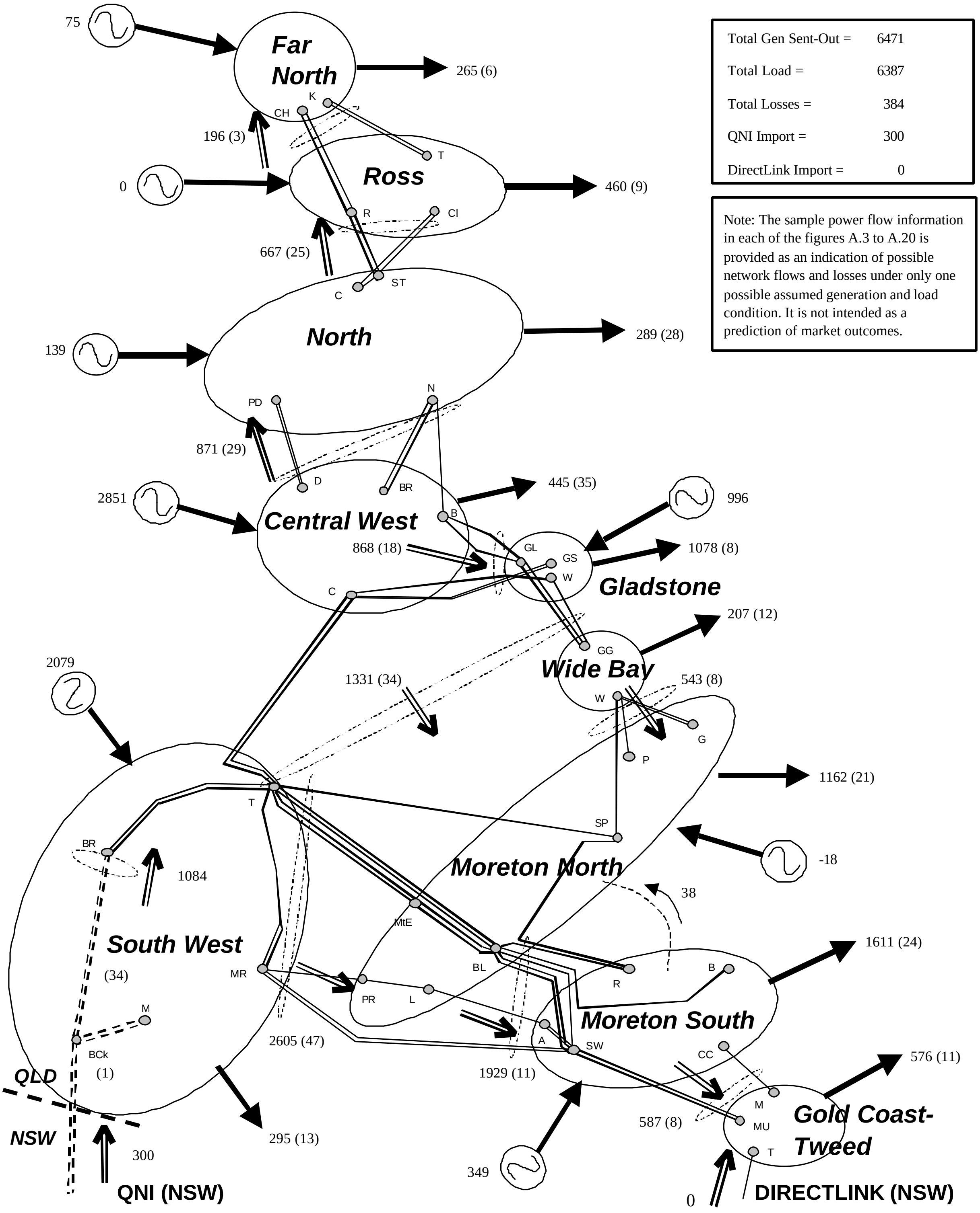


Figure A13: Summer 2002/03 Qld Peak Zero QNI Flow

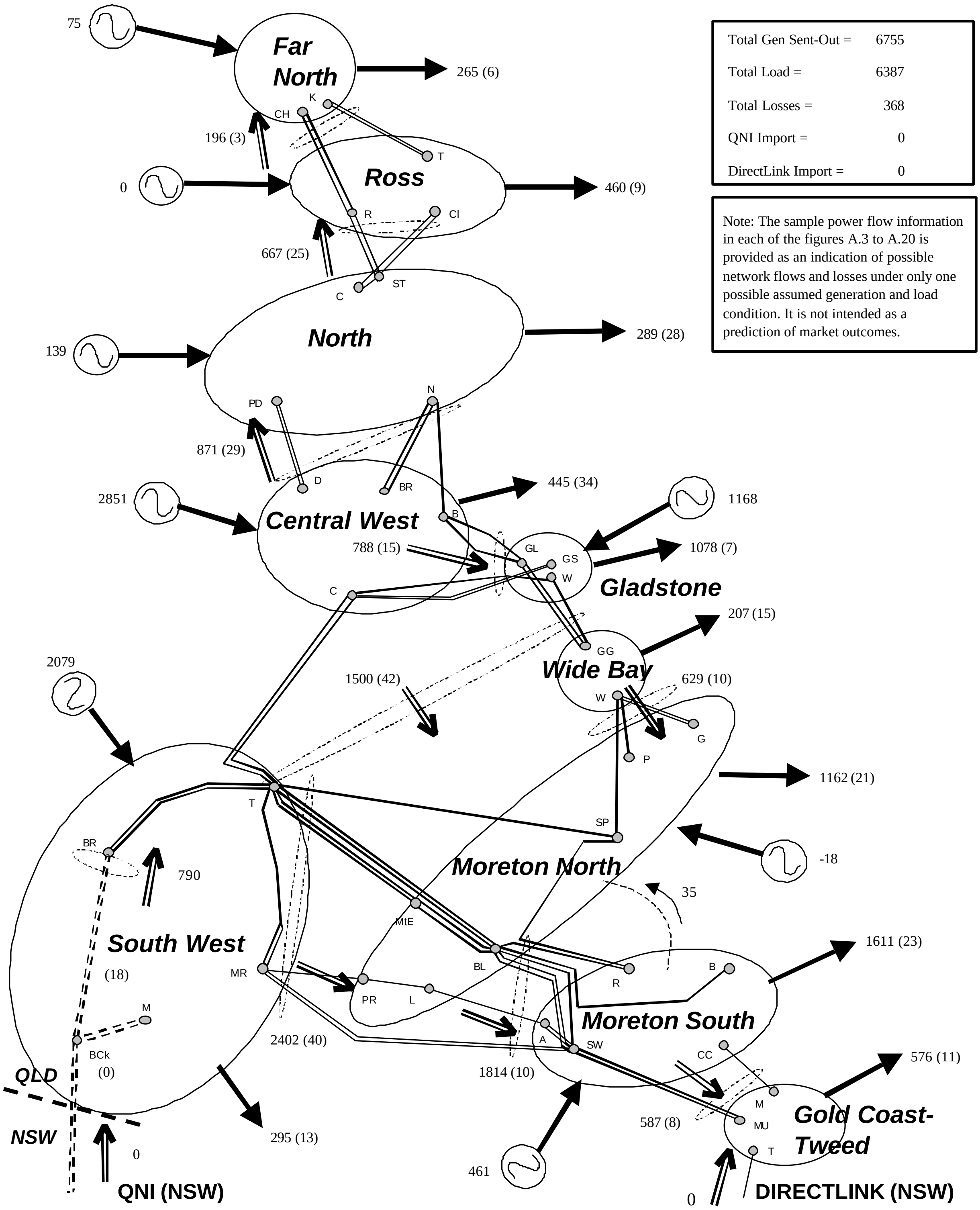
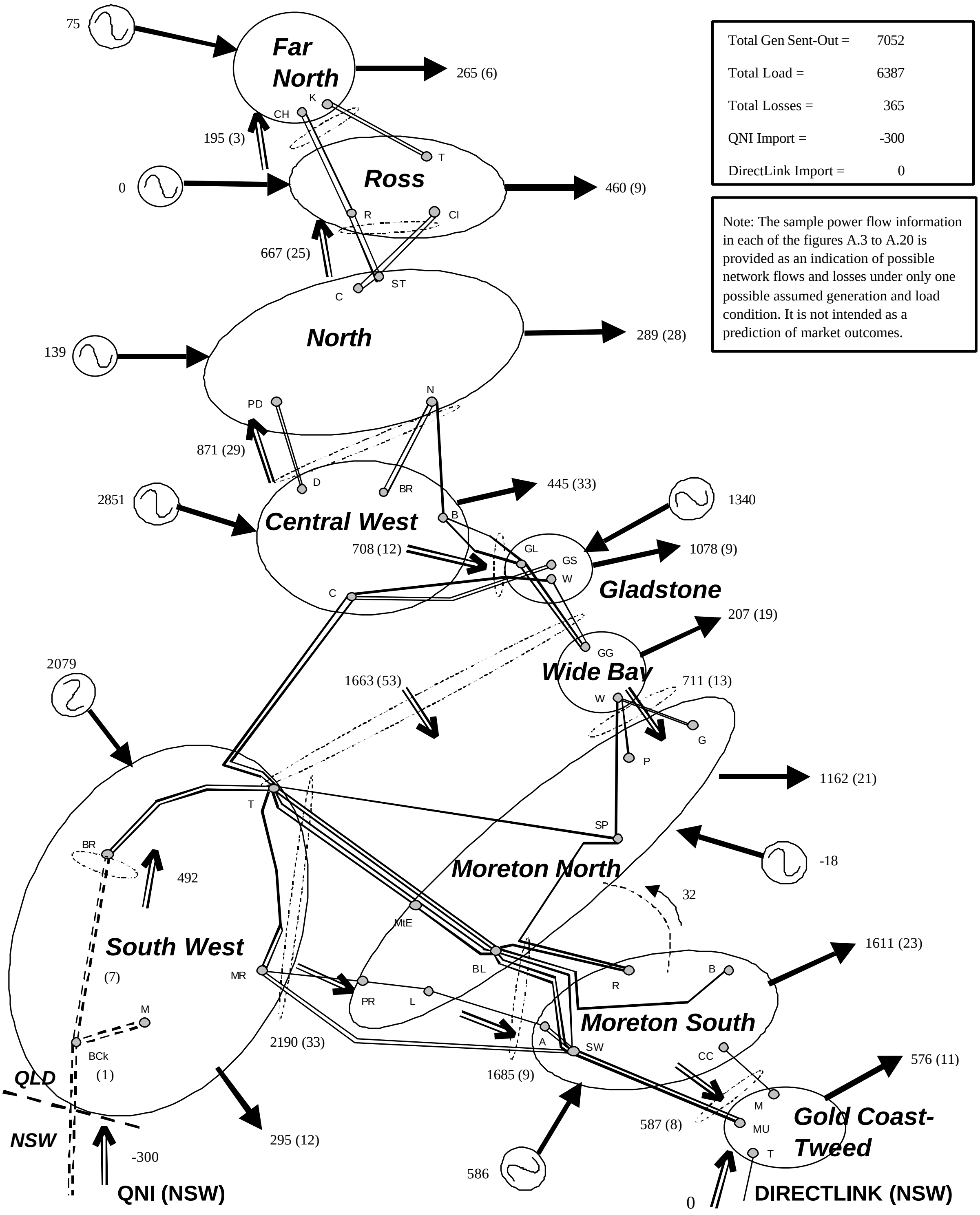


Figure A14: Summer 2002/03 Qld Peak 300MW Export QNI Flow



Total Gen Sent-Out =	7052
Total Load =	6387
Total Losses =	365
QNI Import =	-300
DirectLink Import =	0

Note: The sample power flow information in each of the figures A.3 to A.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure A15: Summer 2003/04 Qld Peak 300MW Import QNI Flow

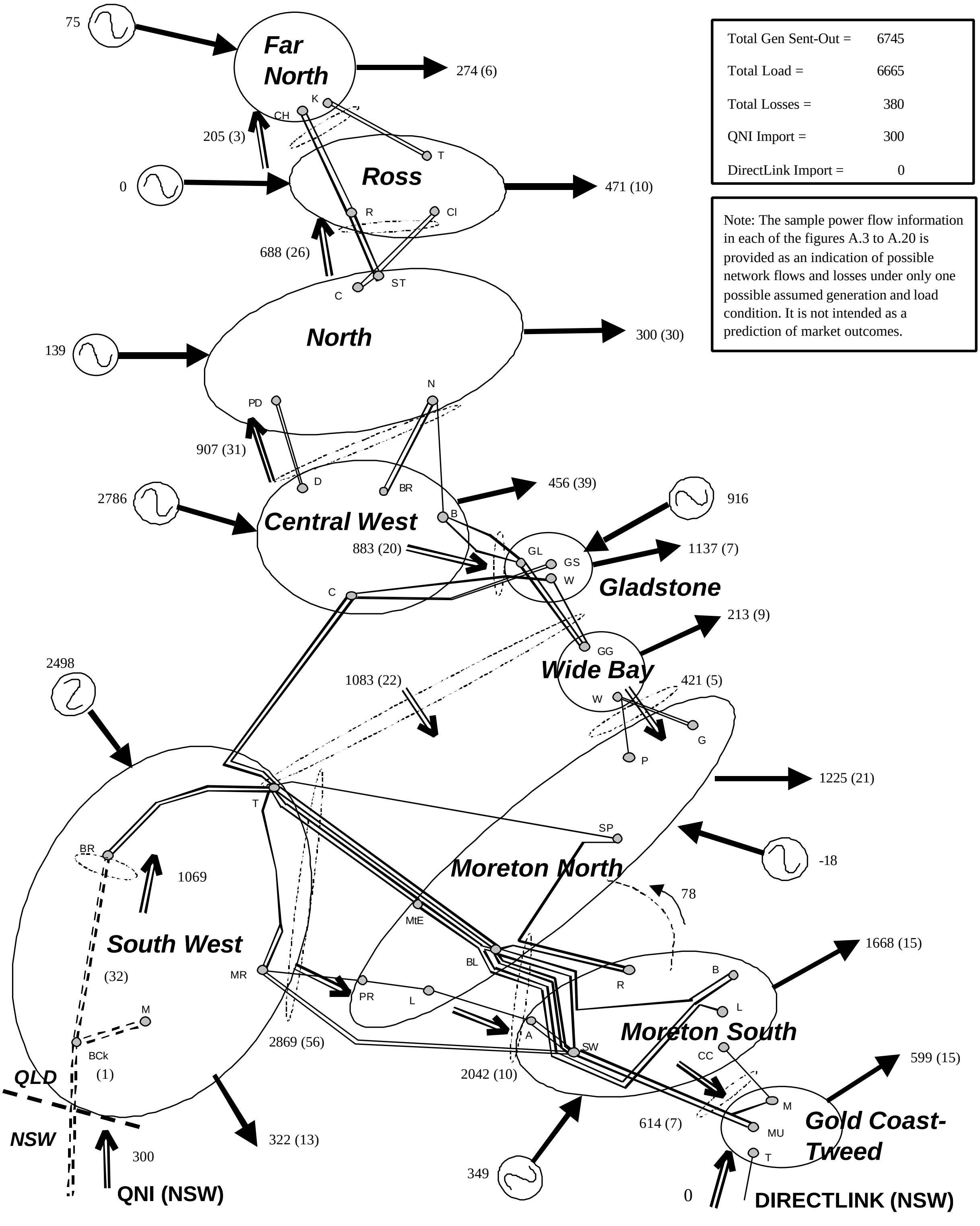


Figure A16: Summer 2003/04 Qld Peak Zero QNI Flow

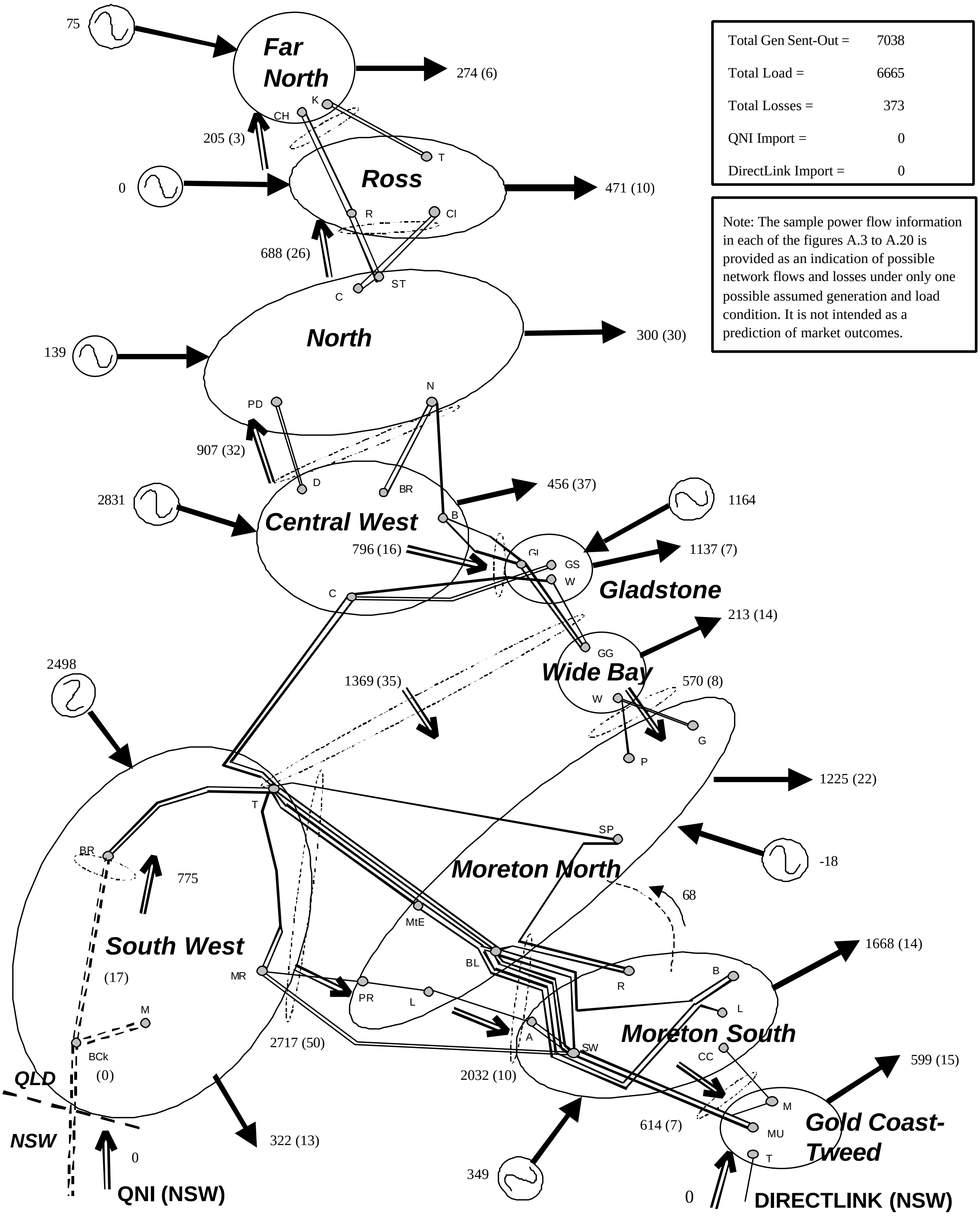


Figure A17: Summer 2003/04 Qld Peak 300MW Export QNI Flow

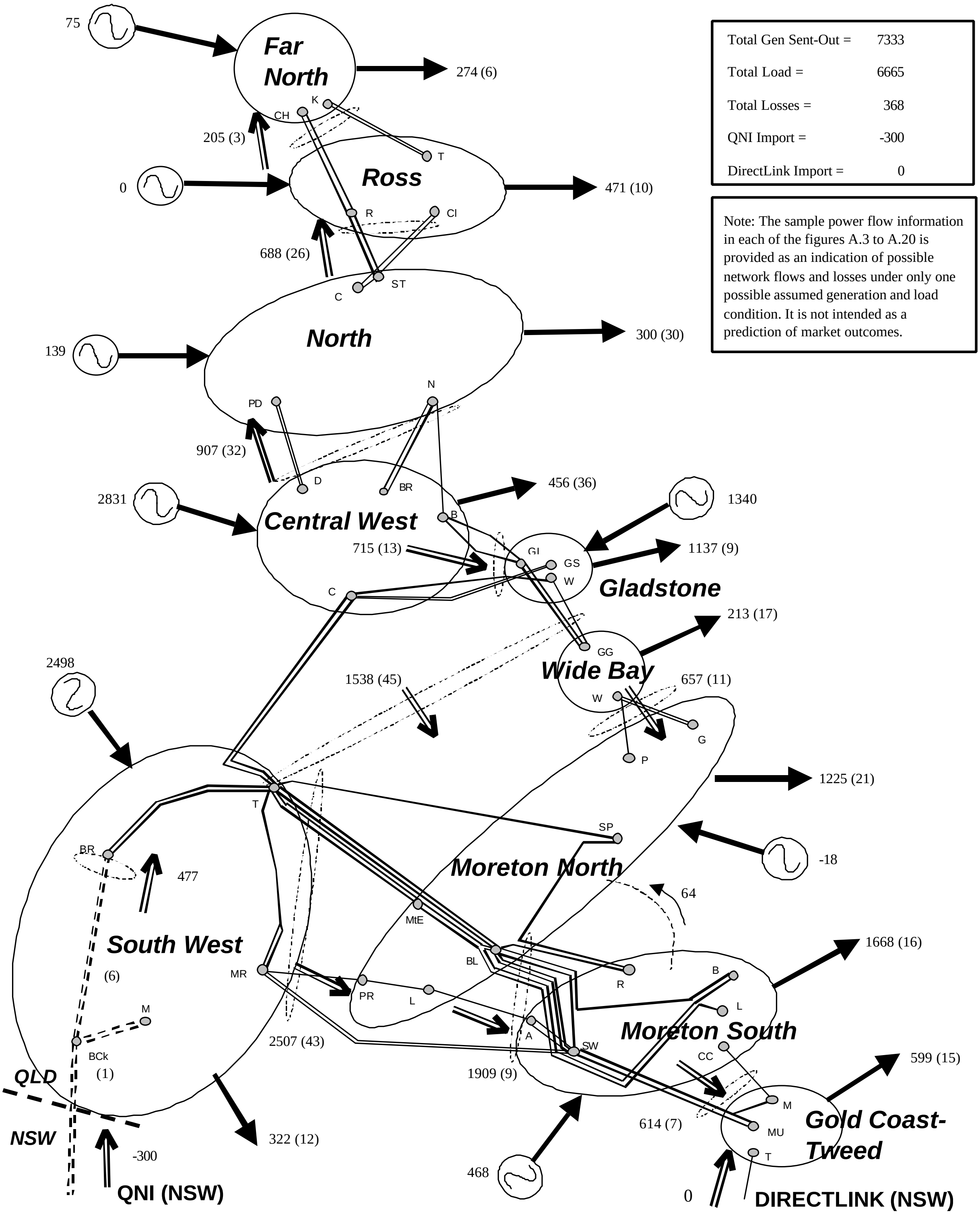


Figure A18: Summer 2004/05 Qld Peak 300MW Import QNI Flow

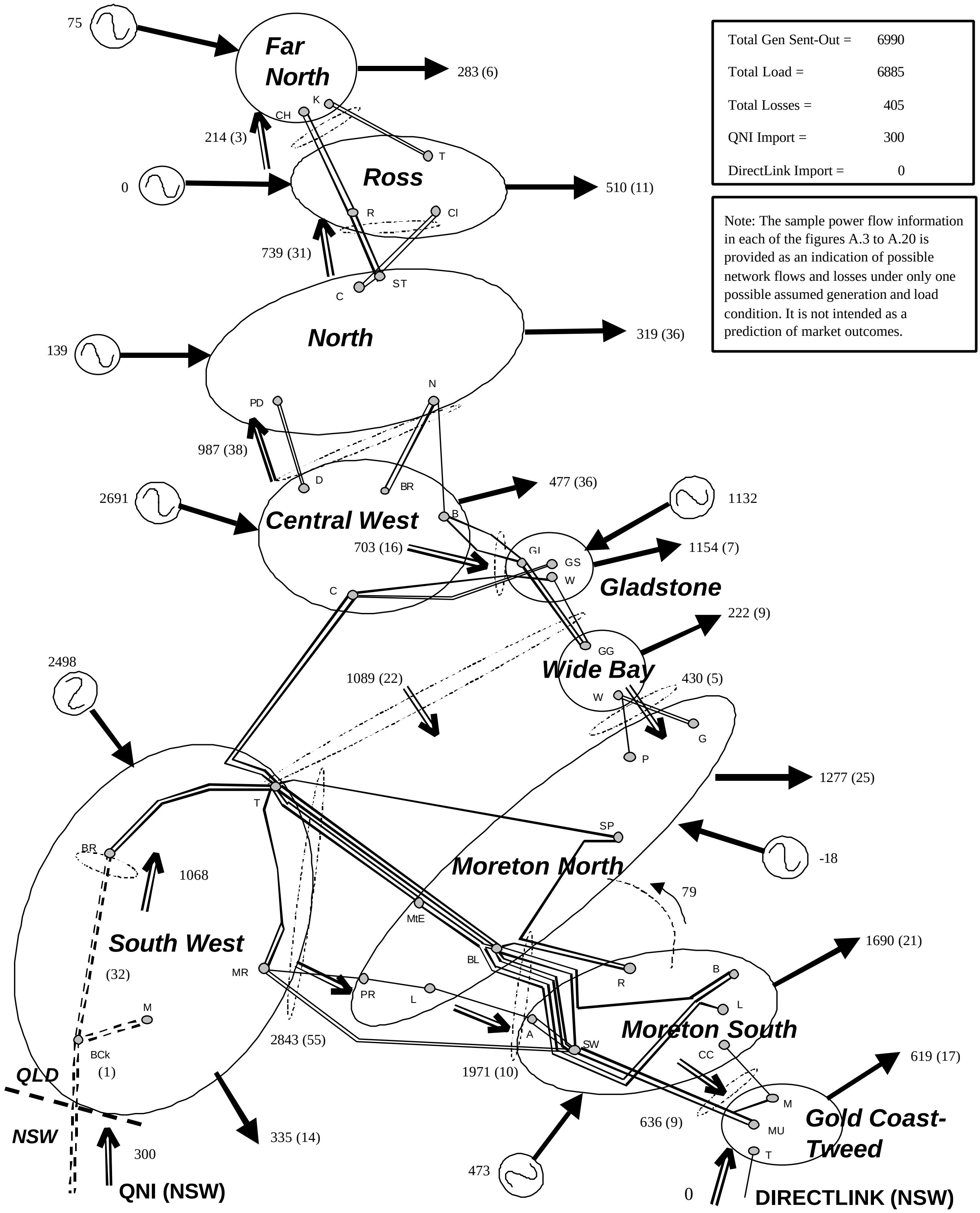


Figure A19: Summer 2004/05 Qld Peak Zero QNI Flow

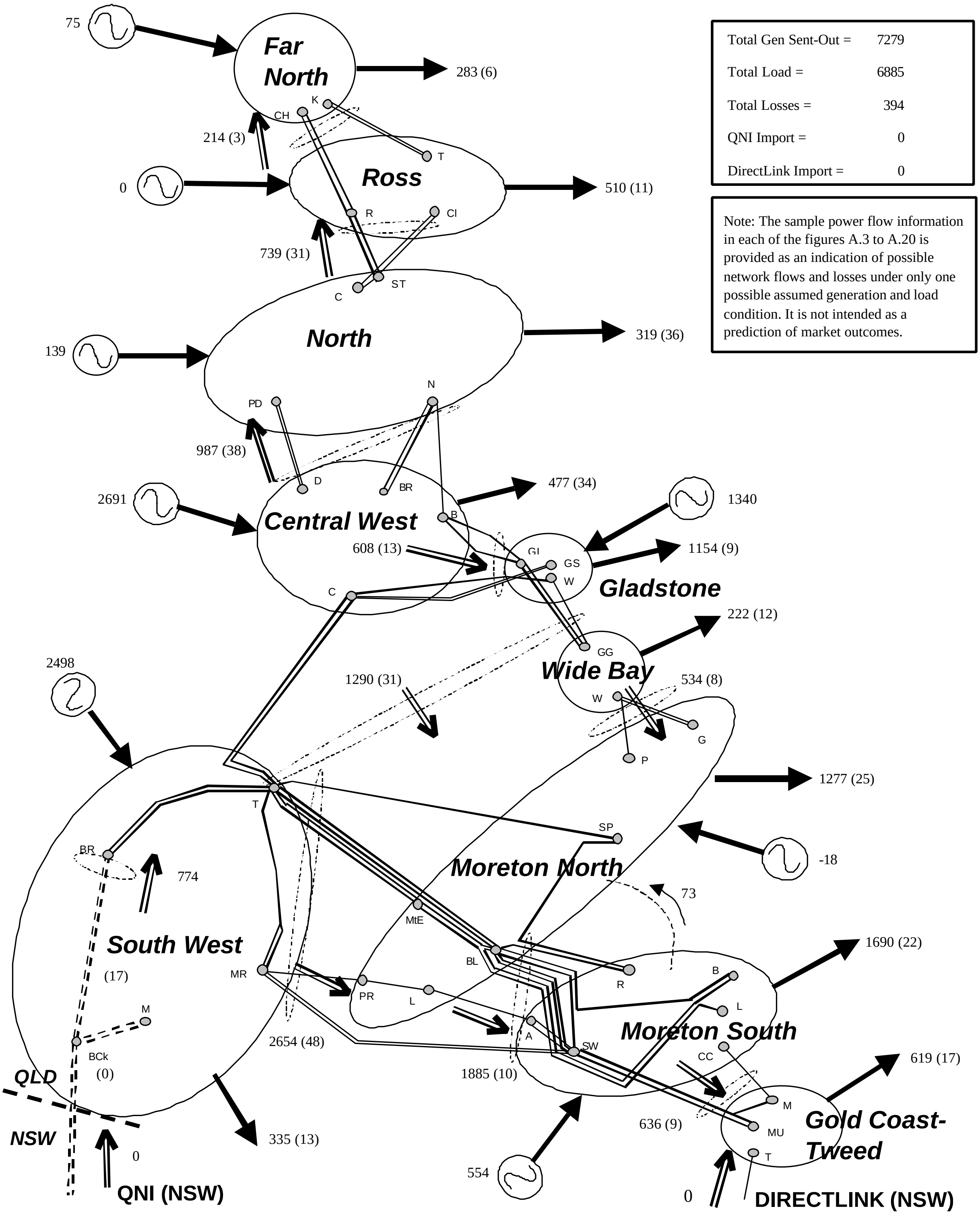
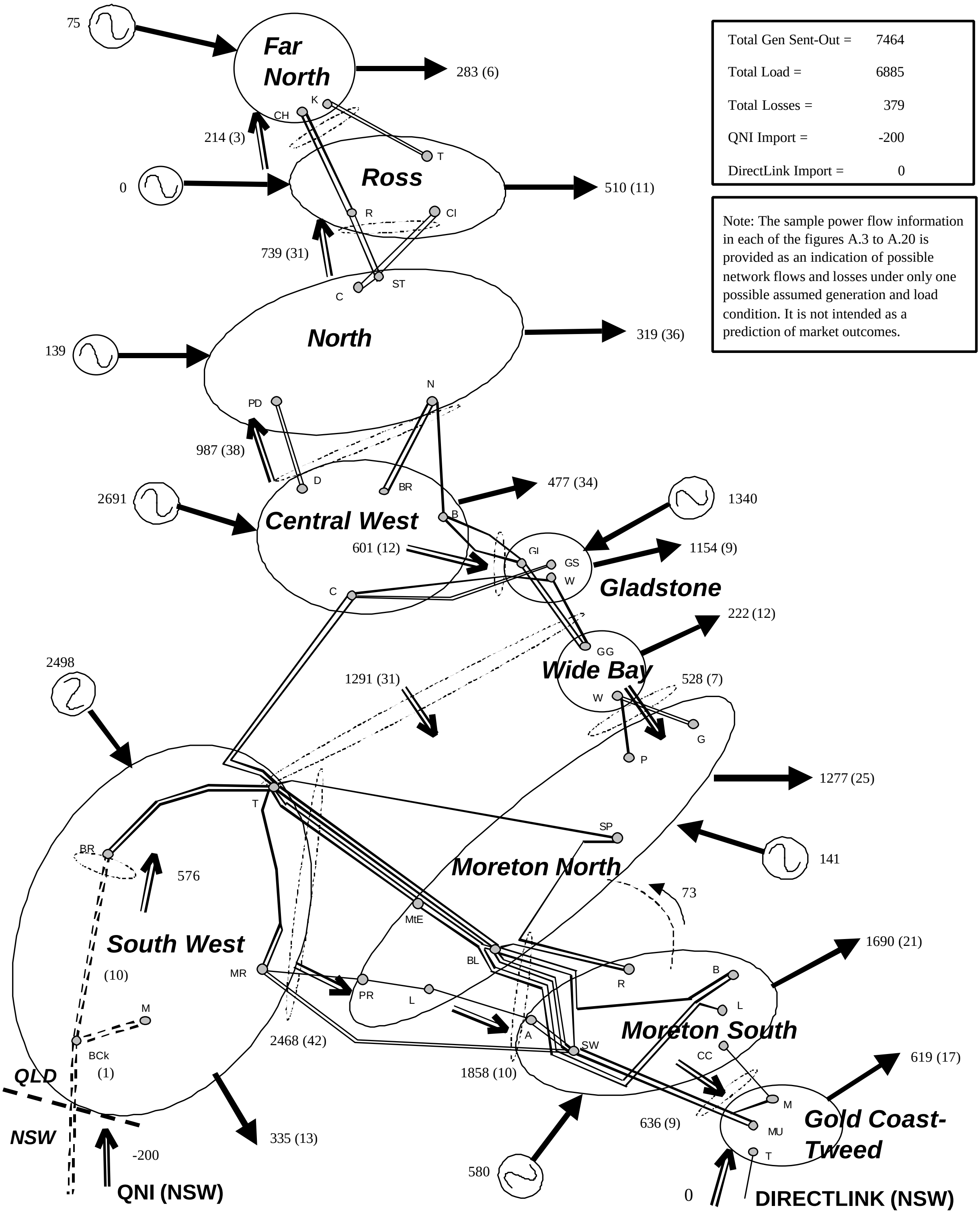


Figure A20: Summer 2004/05 Qld Peak 200MW Export QNI Flow



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 B1: Far North Queensland Voltage Stability Equations

Measured Variable	Coefficient Equation 1 Chalumbin-Cairns Contingency	 Equation 2 Ross-Chalumbin Contingency
Constant Term (Intercept)	213.0	218.1
Summated generation at Barron Gorge	-1.0963	-0.7749
Number of Barron Gorge units on-line	22.4403	11.9831
Summated generation at Kareeya	-1.0377	-0.7649
Number of Kareeya units on-line	8.1967	6.9476
132kV Capacitor Bank at Innisfail (MVArs at the nominal voltage of 132kV)	0.2014	0.3346
132kV Capacitor Banks at Cairns (MVArs at the nominal voltage of 132kV)	0.3682	0.3597
Availability of Chalumbin 132kV Cap Bank (available=1, unavailable=0)	0	24.1485

Table B2: Central to North Queensland Transient Stability Equation

Measured Variable	Coefficient Stanwell-Broadsound contingency
Constant Term (Intercept)	800

Table B3: Central to South Queensland Voltage Stability Equations

Measured Variable	Coefficient Equation 1 Calvale-Tarong Contingency	Coefficient Equation 2 Calvale-Tarong Contingency
Constant Term (Intercept)	1267.2	1277.3
Summated generation at Gladstone units 1, 2, 5 & 6	0.0812	0.0731
Number of Gladstone units on-line connected to the 275kV bus (ie units 1, 2, 5 and 6)	70.3649	72.2846
Summated generation at Gladstone units 3 and 4	0.1152	0.1062
Number of Gladstone units on-line connected to the 132Kv bus (ie units 3 and 4)	73.3362	75.8105
Number of Callide B units on-line	54.0629	47.7783
Number of Callide C units on-line	86.2947	74.2664
(Calvale 275kV p.u. voltage – 1.07) x 1000	0.8860	1.1843
(Gladstone 275kV p.u. voltage – 1.07) x 1000	-1.5181	-1.5421
Dynamic Equation Lower Limit	1800	1800
Dynamic Equation Upper Limit (Transient instability threshold)	2000	2000

Table B4: Tarong Voltage Stability Equations

Measured Variable	Coefficient		
	Equation 1	Equation 2	Equation 3
	Calvale-Tarong Contingency	Woolooga-Palmwoods Contingency	Blackwall-Belmont Contingency
Constant Term (Intercept)	1109.9	1240.5	1287.1
Power transfer on QNI (MW – positive is import into QLD)	0.5725	0.4984	0.4815
Summated Directlink power transfer (MW – positive is import into QLD)	-0.1634	-0.1579	-0.1415
Summated Directlink reactive power (MVAr – positive is import into QLD	0.2597	0.3724	0.4194
Number of Swanbank B units on-line	12.1846	14.8617	15.6918
Number of Swanbank E units on-line	39.6992	42.007	37.732
Number of Swanbank A units on-line	6.6656	9.0078	7.2008
Summated generation at Roma PS	0.5622	0.5061	0.5227
Summated generation at Swanbank A, B, C, D and E	-0.3314	-0.3973	-0.4013
Summated generation at Gladstone 275kV and Gladstone 132kV	-0.0496	-0.0512	-0.0449
Summated generation at Tarong PS	0.5865	0.525	0.5027
Summated generation at Wivenhoe PS	-0.3131	-0.3376	-0.4269
Summated generation at Callide B and Callide C	0.0968	0.0857	0.0874
Summated generation at Oakey PS	0.6622	0.5792	0.5795
Summated generation at Millmerran PS	0.5327	0.4699	0.4557
Number of Wivenhoe synchronous condensors units on-line	31.1409	35.9528	39.5229
Number of Wivenhoe generating units on-line	24.3893	25.1293	33.598

Table B5: Gold Coast Voltage Stability Equation

Measured Variable	Coefficient Swanbank-Mudgeeraba Contingency
Constant Term (Intercept)	-447.2
Number of Wivenhoe units on-line	-10.461
Number of Swanbank B and E units on-line	-9.7254
Number of Swanbank A units on-line	-3.5039
Blackwall SVC Reactive Power Margin (250 – Q output)	-0.4354
(Blackwall 275kV voltage p.u. – 1.06) x 10000	-0.0943
Summated MVAr flow through the Mudgeeraba transformers (measured at the 275kV side) squared and divided by 200	0.9282
Summated MW flow on Directlink (measured at Terranora – positive is import into QLD)	0.4452
Summated MVAr flow on Directlink (measured at Terranora – positive is import into QLD)	-0.1556

APPENDIX C – ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS

Table C1: Estimated Maximum Short Circuit Levels – Southern Queensland

In Powerlink Transmission Network 2002 to 2004 (1)

Location	Voltage (KV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2002	2003	2004	2002	2003	2004
Abermain	110.0	31.5	13.86	14.21	14.21	13.47	13.71	13.71
Ashgrove West	110.0	26.3	20.60	21.00	21.00	21.47	21.62	21.62
Belmont	275.0	31.5	11.82	14.93	14.93	11.92	15.14	15.14
Belmont (4)	110.0	25.0	22.64	24.99	24.99	26.20	29.26	29.26
Blackwall	275.0	50.0	21.15	20.95	20.95	23.02	23.04	23.04
Braemar	330.0	50.0	10.09	10.09	10.09	9.77	9.88	9.88
Braemar	275.0	50.0	12.19	12.19	12.19	12.08	12.21	12.21
Bulli Creek	330.0	50.0	11.22	11.17	11.17	9.83	10.20	10.20
Bulli Creek	132.0	40.0	-	3.43	3.43	-	3.65	3.65
Loganlea	275.0	50.0	12.03	12.01	12.01	11.09	10.94	10.94
Loganlea	110.0	25.0	16.63	17.76	17.76	17.94	18.85	18.85
Middle Ridge	275.0	NO CB	5.24	5.29	5.29	5.20	5.24	5.24
Middle Ridge	110.0	18.8	12.67	12.95	12.95	14.29	14.55	14.55
Millmerran Switch Yard	330.0	50.0	8.64	8.61	8.61	9.78	9.89	9.89
Molendinar	275.0	40	-	7.48	7.48	-	7.17	7.17
Mt England	275.0	31.5	20.56	20.14	20.14	20.89	20.45	20.45
Mudgeeraba	275.0	31.5	7.41	7.47	7.47	7.45	7.81	7.81
Mudgeeraba	110.0	19.3	12.09	13.59	13.59	14.76	16.55	16.55
Murarrie	110.0	25.00	21.92	21.45	21.45	19.92	19.49	19.49
Oakey	110.0	40.0	9.14	9.47	9.47	10.26	10.54	10.54
Palmwoods	275.0	31.5	7.96	8.00	8.00	8.07	8.10	8.10
Palmwoods	132.0	21.8	12.26	12.30	12.30	14.35	14.39	14.39
Palmwoods	110.0	NO CB	5.49	5.49	5.49	5.79	5.79	5.79
Redbank Plains	110.0	31.5	13.59	13.97	13.97	11.60	11.78	11.78
Richlands	110.0	18.8	11.01	11.22	11.22	11.30	11.45	11.45
Rocklea	275.0	40.0	12.43	12.40	12.40	11.36	11.37	11.37
Rocklea	110.0	40.0	21.41	21.79	21.79	24.40	24.75	24.75
Runcorn	110.0	21.9	14.00	14.59	14.59	13.83	14.23	14.23

Location	Voltage (KV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2002	2003	2004	2002	2003	2004
South Pine	275.0	31.5	17.12	17.40	17.40	17.53	17.75	17.75
South Pine (4)	110.0	25.0	24.65	24.97	24.97	28.52	28.85	28.85
Swanbank A (3)	110.0	18.3	15.88	15.88	15.88	14.13	14.13	14.13
Swanbank B	275.0	31.5	19.91	19.97	19.97	23.00	23.11	23.11
Swanbank E	275.0	31.5	19.43	19.48	19.48	22.04	22.15	22.15
Tangkam	110.0	40.0	10.34	10.85	10.85	10.09	10.42	10.42
Tarong	275.0	31.5	26.26	26.76	26.76	28.74	29.20	29.20
Tarong	132.0	31.5	4.89	5.21	5.21	5.31	5.56	5.56
Tarong	66.0	21.9	13.76	13.78	13.78	15.13	15.14	15.14
Tennyson	110.0	40.0	19.33	19.73	19.73	20.53	20.96	20.96
Upper Kedron	110.0	40.0	21.92	22.35	22.35	18.47	18.64	18.64
West Darra	110.0	19.4	13.71	14.02	14.02	10.06	10.17	10.17
Woolooga	275.0	31.5	9.05	9.08	9.08	8.35	8.41	8.41
Woolooga	132.0	21.9	12.30	12.34	12.34	12.76	12.82	12.82

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; the effects of distribution systems and any embedded generation are also neglected.
(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.

Table C2: Estimated Maximum Short Circuit Levels – Central Queensland

In Powerlink Transmission Network 2002 to 2004 (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2002	2003	2004	2002	2003	2004
Baralaba	132.0	15.3	3.99	4.07	4.07	3.34	3.38	3.38
Biloela	132.0	12.3	5.45	7.47	7.47	4.84	6.27	6.27
Blackwater	132.0	12.3	3.20	3.26	3.26	3.79	4.01	4.01
Bouldercombe	275.0	31.5	16.11	16.41	16.41	15.73	15.94	15.94
Bouldercombe	132.0	25.0	10.09	10.70	10.70	11.44	11.95	11.95
Broadsound	275.0	21.9	8.83	8.98	8.98	6.48	6.53	6.53
Callemondah	132.0	31.5	20.33	20.37	20.37	20.48	20.50	20.50
Callide A Power Station	132.0	12.3	10.53	10.58	10.58	10.28	10.32	10.32
Calvale	275.0	31.5	19.77	19.83	19.83	21.82	21.87	21.87
Calvale	132.0	NO CB	10.52	10.57	10.57	10.47	10.51	10.51
Dingo	132.0	31.5	2.18	2.21	2.21	2.40	2.43	2.43
Dysart	132.0	19.9	3.79	3.85	3.85	4.43	4.47	4.47
Egans Hill	132.0	NO CB	6.54	6.82	6.82	6.68	6.91	6.91
Gin Gin	275.0	31.5	10.19	10.21	10.21	8.15	8.65	8.65
Gin Gin	132.0	21.9	8.56	10.63	10.63	8.56	10.89	10.89
Gladstone	275.0	31.5	19.16	19.25	19.25	21.66	21.75	21.75
Gladstone (3)	132.0	31.5	25.77	25.83	25.83	31.32	31.38	31.38
Gladstone South (4)	132.0	40.0	16.84	16.87	16.87	16.72	16.70	16.70
Grantleigh	132.0	31.5	2.44	2.48	2.48	2.54	2.57	2.57
Gregory	132.0	31.5	5.53	5.87	5.87	6.61	6.93	6.93
Korenan	132.0	31.5	2.39	2.52	2.52	1.65	1.72	1.72
Lilyvale	275.0	31.5	3.38	3.51	3.51	3.56	3.66	3.66
Lilyvale	132.0	25.0	5.70	6.06	6.06	6.97	7.32	7.32
Moura	132.0	12.3	3.56	3.72	3.72	3.85	3.99	3.99
Norwich Park	132.0	40.0	2.97	3.03	3.03	2.32	2.34	2.34
Rockhampton	132.0	12.3	6.61	7.22	7.22	6.82	7.54	7.54
Rocklands	132.0	40.0	6.19	6.41	6.41	5.48	5.61	5.61
Stanwell Switch Yard	275.0	31.5	17.24	17.53	17.53	18.93	19.16	19.16
Stanwell Switch Yard	132.0	31.5	4.97	5.11	5.11	4.59	4.67	4.67
Wurdong	275.0	31.5	15.45	15.50	15.50	14.82	14.87	14.87

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; the effects of distribution systems and any embedded generation are also neglected.
(2) Powerlink switchgear ratings – no account taken of distribution switchgear.
(3) 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.
(4) This location allows for operation with open points up to June 2003.

Table C3: Estimated Maximum Short Circuit Levels – Northern Queensland

In Powerlink Transmission Network 2002 to 2004 (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2002	2003	2004	2002	2003	2004
Alan Sherriff	132.0	31.5	7.85	7.95	7.95	8.45	8.53	8.53
Alligator Creek	132.0	31.5	3.15	3.41	3.41	3.71	3.94	3.94
Burton Downs	132.0	19.3	4.18	4.26	4.26	3.95	4.09	4.09
Cairns	132.0	12.1	4.92	5.28	5.28	6.11	6.61	6.61
Cardwell	132.0	19.3	2.59	2.64	2.64	2.07	2.09	2.09
Chalumbin	275.0	21.9	3.16	3.20	3.20	3.44	3.51	3.51
Chalumbin	132.0	31.5	6.15	6.06	6.06	7.16	7.09	7.09
Clare	132.0	8.8	5.88	6.28	6.28	5.75	6.00	6.00
Collinsville	132.0	15.3	10.47	10.89	10.89	11.63	11.98	11.98
Coppabella	132.0	31.5	2.68	2.71	2.71	3.05	3.07	3.07
Dan Gleeson	132.0	40.0	8.37	8.59	8.59	8.98	9.15	9.15
Garbutt (3)	132.0	8.8	8.71	8.88	8.88	9.21	9.34	9.34
Ingham	132.0	10.9	2.71	2.70	2.70	2.25	2.24	2.24
Innisfail	132.0	10.9	4.15	4.18	4.18	4.57	4.60	4.60
Invicta	132.0	16.2	4.02	4.79	4.79	3.92	4.36	4.36
Kamerunga	132.0	21.9	3.80	4.00	4.00	4.53	4.72	4.72
Kareeya	132.0	10.9	6.13	6.01	6.01	7.23	7.10	7.10
Kemmis	132.0	31.5	4.58	4.59	4.59	4.48	4.88	4.88
Mackay	132.0	21.9	3.76	4.50	4.50	4.46	5.16	5.16
Moranbah	132.0	15.3	5.15	5.28	5.28	6.23	6.35	6.35
Moranbah South	132.0	40.0	4.10	4.18	4.18	4.07	4.12	4.12
Mt Mclaren	132.0	31.5	1.81	1.82	1.82	2.00	2.01	2.01
Nebo	275.0	31.5	6.26	6.51	6.51	6.78	6.99	6.99
Nebo	132.0	21.9	7.84	8.31	8.31	8.87	9.31	9.31
Newlands	132.0	31.5	2.98	3.01	3.01	2.98	3.00	3.00
North Goonyella	132.0	19.3	3.03	3.07	3.07	2.40	2.41	2.41

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2002	2003	2004	2002	2003	2004
Oonooie	132.0	31.5	2.40	2.55	2.55	2.88	3.01	3.01
Peak Downs	132.0	40.0	4.07	4.15	4.15	3.58	3.62	3.62
Pioneer Valley	132.0	40.0	3.63	4.11	4.11	3.84	4.44	4.44
Proserpine	132.0	19.7	3.10	3.37	3.37	3.48	3.65	3.65
Ross	275.0	21.9	4.94	5.12	5.12	5.78	5.95	5.95
Ross	132.0	31.5	10.44	10.88	10.88	12.15	12.55	12.55
Strathmore	275.0	50.0	5.44	5.64	5.64	5.06	5.17	5.17
Strathmore	132.0	40.0	9.98	10.36	10.36	10.39	10.66	10.66
Townsville South	132.0	21.9	10.32	10.90	10.90	12.81	13.40	13.40
Townsville Gt Ps	132.0	31.5	7.57	7.49	7.49	8.53	8.46	8.46
Tully	132.0	31.5	3.13	3.26	3.26	2.95	2.99	2.99
Turkinje	132.0	15.7	3.69	3.73	3.73	4.14	4.18	4.18
Wandoo	132.0	40.0	3.63	3.72	3.72	2.72	2.75	2.75
Woree	275.0	N0 CB	2.31	2.54	2.54	2.64	3.12	3.12
Woree	132.0	31.5	4.94	5.31	5.31	6.12	6.65	6.65

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; the effects of distribution systems and any embedded generation are also neglected.

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

(3) 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.