Draft Recommendation:

Addressing Transmission Network Constraints

Powerlink Queensland
10th August 2001

1.0 Executive Summary

The Queensland electricity transmission network experienced significant levels of grid constraints over the 2000/01 summer at the sections of the network known as the CQ-NQ and Ross Limits. Without corrective action, these limitations on power transfer are anticipated to increase in coming years. The consequence is expected to be high costs to participants in the national electricity market.

Powerlink carried out consultation with interested parties to identify and determine feasible options to address the network constraints. The feasible options identified were:

- no action by Powerlink as the transmission network service provider. Under this option, NEMMCO would continue to direct local generation facilities to operate to ensure that electricity supplies are not interrupted and power flows remain within grid capacity.

- grid support from existing local generation facilities controlled by Enertrade (a contract with Powerlink would provide for these power stations to operate to address the grid constraints when the generators would not otherwise be operating in the market).

- combined grid support/network options (partial grid support from Enertrade generators and the construction of a single circuit 275kV transmission network augmentation between Stanwell and Broadsound either by October 2002 or October 2003).

These options were assessed against a range of plausible market development scenarios, including the establishment of a baseload power station at Townsville and load growth variations. This approach is consistent with the Regulatory Test promulgated by the Australian Competition and Consumer Commission.

All regulated solutions to address anticipated network limitations must satisfy the Regulatory Test, which requires that the recommended option maximise benefits to market participants under most, but not necessarily all, plausible scenarios.

To identify the solution that satisfies this Test, power system analysis was first carried out to determine the future capability of the transmission network. This was used to forecast the shortfall in customer energy requirements that cannot be supplied without directing local generation. Once this analysis was completed, the level and costs of grid support, loss savings, transmission investment and other inputs were assessed. A comparison of the options was then made, using a cash flow model to determine the Net Present Value (NPV) of the various options.

The results of the analysis showed that the existing transmission system will be unable to supply all energy requirements for approximately 10% of the time by 2003, rising to more than 18% of the time by 2007. This translates to a forecast energy shortfall unable to be supplied by the grid of approximately 55,000MWh in 2003, rising rapidly to well over 200,000MWh in 2007.

Average costs per MWh for directed-on generation were assumed to be $140/MWh, with sensitivity tests carried out for costs ranging between $100/MWh and $400/MWh. The cost structure used in the analysis for grid support from Enertrade is confidential, but average costs per MWh are mostly in the range of $125-135/MWh. This is lower than directed-on generation costs, largely because a grid support contract will provide Enertrade with more certainty and predictability about operating requirements than short-term directions by NEMMCO. For the transmission solution, the financial analysis considered all cost impacts of the proposed project to market participants. The estimated capital cost of the transmission solution is approximately $33M, and sensitivity tests were carried out using variations in this capital cost estimate of plus and minus 15%.

The conclusions of the net present value analysis based on the power system studies and cost assumptions are as follows:

- It is clear that action to address the network constraints will provide benefits to market participants. The option where no action is taken by Powerlink is the lowest ranked option in almost all the scenarios examined.

- Under almost all the scenarios examined, the option of an augmentation between Stanwell and Broadsound by October 2002, and procuring partial grid support from Enertrade (Option 3) delivers the highest net benefit.

- The only scenario where this option is not ranked highest was the scenario where a baseload power station becomes operational in Townsville by January 2004.

- Sensitivity analysis shows this outcome to be very robust, with the option ranking insensitive to variations in critical parameters.

- In the scenario where the power station is operational by 1 January 2004, the option which provides the maximum net market benefit is a full grid support arrangement with Enertrade for the operation of its existing generators in the relevant area.

- Powerlink makes no assumption about the likelihood of this scenario occurring. The Regulatory Test is satisfied if an option achieves a greater market benefit 'in most, *but not necessarily all*, credible scenarios'. It is clear, on this basis, that Option 3 is the option that satisfies the Regulatory Test.

- In addition to maximisation of benefit, the Regulatory Test requires that a transmission network service provider optimise the timing of any proposed network augmentation that is justified under the Regulatory Test. It is evident from the analysis results that commissioning Stanwell-Broadsound by October 2002, rather than October 2003 is a lower cost solution in all of the scenarios examined.

Based on the conclusions drawn from the analysis, the following draft recommendation is proposed to address the identified network constraints at the CQ-NQ Limit:

(1) Powerlink and Enertrade to enter into a contract for partial grid support from Enertrade's portfolio of existing generators from 1 January 2002, and

(2) Powerlink to immediately initiate construction of a single circuit 275kV transmission line from Stanwell-Broadsound for commissioning by October 2002.

2.0 INTRODUCTION

This report contains a draft recommendation to address identified transmission network constraints at two sections of the Queensland network known as the CQ-NQ and Ross Limits.

This draft recommendation is based on:

- the consequences of the identified transmission constraints in terms of the energy requirements that will be unable to be met by the existing transmission grid

- the consultation undertaken by Powerlink to identify potential solutions to address the constraints,

- and an analysis of feasible options in accordance with the Regulatory Test prescribed by the Australian Competition and Consumer Commission (ACCC).

The recommended option is the option that maximises the net economic benefits to participants in the National Electricity Market. These economic benefits arise from addressing the anticipated network constraints in a way that reliably meets customer demand at the least cost to the market and therefore to end-use customers.

3.0 SITUATION OVERVIEW

The transmission capacity at the sections of the Queensland network known as the CQ-NQ limit and the Ross limit[1] was exceeded for significant periods during the 2000/01 summer.

This resulted in significant additional market costs. These market costs were incurred because NEMMCO was required to direct relatively high cost local generation to operate to ensure that electricity supplies were not interrupted and power flows across the network remained within grid capacity. The high cost local generation displaces much lower cost Central Queensland generation. Such market costs are incurred by market participants and are ultimately passed on to customers.

Powerlink has an obligation to look beyond actual constraints and examine potential future impacts. In Powerlink's view, there is a high likelihood that, without corrective action, constraints will continue during coming summer periods, and increase markedly in future years due to the combination of network transfer limits and growing load in the area.

Due to the potentially high costs that would result from likely future levels of constraints, Powerlink considered it appropriate to investigate the benefits of ameliorating these network transfer limits.

A discussion paper was issued in February 2001 requesting information from interested parties regarding potential solutions to address the constraints. Parties were advised that potential solutions could include demand side management, support from existing local generation, development of new generation facilities in the relevant area, or augmentation of the transmission grid.

Powerlink has been carrying out a strategy of implementing minor works for more than two years to provide modest increments in capacity to the affected area. The strategy was adopted to provide a longer window of time for proposed generation developments to become clearer. As noted in the discussion paper, Powerlink's analysis has shown that the relevant part of the grid is reaching the calculated limit for voltage stability, and capacity augmentation is now required.

Powerlink also advised in its discussion paper that a decision was required by mid 2001 if any option involving transmission line construction is to be in place by the summer of 2002/03.

Due to the complexities of the analysis of constraints necessary for the option comparison in this report, delays to the assessment timetable have occurred. However, Powerlink has taken steps to preserve the option of commissioning a transmission solution by summer 2002/03, and this is still considered achievable.

[1] The CQ-NQ Limit is defined as the sum of 275kV flows into Nebo and the 132kV flows from Dysart to Peak Downs. The Ross Limit is defined as the sum of 275kV flows into Ross and the 132kV flows from Collinsville to Clare.

4.0 CONSULTATION SUMMARY

Powerlink issued a discussion paper in February 2001 as the first step in meeting regulatory requirements related to potential network augmentations. The discussion paper provided information on the current situation and anticipated network constraints. It sought information from Code Participants and interested parties regarding potential solutions to address these identified constraints.

Powerlink received submissions from the following seven (7) parties:

- AES Mt Stuart/Enertrade Consortium
- Stanwell Corporation
- TransEnergie Australia Pty Ltd
- Tarong Corporation/Enertrade/Mitsui Consortium
- Ergon Energy
- Enertrade
- Sun Metals Corporation

Only one of the submissions (Enertrade) offered potential solutions which were realisable in the required timeframe. Following publication of the discussion paper, Powerlink also met with a cogeneration representative.

4.1 Non-Transmission Options Identified

The primary purpose of the initial discussion paper was to identify feasible non-transmission solutions to be included in the analysis. In summary, the consultation identified the following information regarding solutions to address the identified constraints:

(a) *Demand side management (DSM)* – information provided by Ergon Energy indicated it would be difficult to achieve sufficient DSM to address the identified constraints. A large number of customers would need to voluntarily ‘switch off’ at peak periods if DSM were to be an effective solution to the identified constraints. This is due largely to the flat load duration curve characteristic of energy usage in the relevant area, which gives rise to extended periods throughout peak usage times that the existing grid will be unable to supply all energy requirements.

(b) *Grid support from existing generators* –Enertrade’s submission indicated its willingness to enter into a contractual arrangement with Powerlink to operate its existing generators in the area to provide transmission support. Further discussions subsequently occurred with Enertrade, with the resulting option included in the analysis in this paper. No other generators offered a grid support arrangement which was realisable in the timeframe required.

(c) *Local generation – baseload*. Several submissions provided information on the potential development of a baseload generator in Townsville. Respondents noted the importance of analysing options to address the identified constraints in the context of the Queensland Government ‘Queensland Energy Policy’ and the proposed development of a baseload generation facility in Townsville. The analysis in this paper takes this into account, although the timeframe for that generator is not yet firm.

(d) *Smaller local generation* – An allowance for potential cogeneration and renewable energy developments in the relevant area is included in Powerlink’s forecasts of energy and demand. Generation <u>above</u> these allowed levels would be required if local generation is to assist in addressing the identified network constraints. The consultation did not identify any additional recently committed local generation projects in the relevant area. This would suggest either (a) that the forecasts are considered accurate and no additional generation is likely to be available to address the constraints or (b) that the forecast allowance for this type of project is optimistic. Market participants should be aware that if (b) is the case, the levels of energy unable to be supplied by the grid may be higher than outlined in this document.

4.2 Other Comments Raised During Consultation

Various market design issues were raised during the consultation process. Powerlink must work within the current Code and legislative framework, and considers that such issues are more appropriately addressed to market institutions.

Sun Metals Zinc Refinery advised during the consultation phase that proposals for expansion of the refinery may give rise to a doubling of current refinery demand from 100MW to 200MW between 2004 and 2007. Sun Metals noted that the expansion proposals are dependent on the availability of a low cost, reliable power supply.

5.0 OPTIONS CONSIDERED

5.1 Introduction

When considering corrective action to address an identified network limitation, a transmission network service provider must consider all feasible options including local generation and demand side management.

Following the consultation process to identify possible non-transmission solutions, the following options were identified as feasible courses of action to address the anticipated network constraints at the CQ-NQ and Ross Limits over the 2001/02 summer and beyond.

The results of the analysis comparing these options is contained in section 8.0. Note that, as required by ACCC guidelines, options have been assessed in the context of a range of plausible market development scenarios. These scenarios are explained further in section 6.0, and include the development of a baseload power generation facility in Townsville.

5.2 Feasible Options:

Option 1 – "No Action By TNSP"

Option 1 represents the situation where no action is taken by Powerlink as the transmission network service provider (TNSP) to address the identified constraints.

- It is assumed for this option that energy unable to be supplied by the transmission grid is met by dispatch (via NEMMCO direction) of existing generators that can alleviate the problem. This assumption has been adopted as it reflects the actual dispatch patterns during the transmission constraints that occurred over the 2000/01 summer.

Option 2 – "Full Grid Support"*	
2001 2002 onwards	Directed on generation Grid support from Enertrade

This option assumes that, from 1 January 2002, energy unable to be supplied by the transmission grid is met by local generation that operates according to a grid support contract that would be negotiated between Powerlink and Enertrade.

Enertrade controls a portfolio of local generation in the area that includes Collinsville Power Station, Mt Stuart Power Station, and Townsville Power Station. The grid support contract would provide for the operation of this generation to address the identified grid constraints at times when the generation would not otherwise be operating in the market. The contract would be written such that Powerlink can request the generators to operate when required for transmission purposes, rather than the generators being purely driven by spot market prices, or their contracted hedge position.

The cost of operating local generation for transmission purposes under such a contract has been negotiated between Enertrade and Powerlink. The actual total cost of this option is uncertain due to uncertainty with the amount of generation that will be required. The grid support payment will be dependent on the actual energy unable to be supplied by the transmission network, which is in turn dependent on half hourly electricity demand, unplanned generator outages, water availability at local hydro power stations etc.

Estimates of total energy requirements and grid support costs are outlined in section 7.5.2. However, details of the proposed contractual arrangements are not provided for commercial confidentiality reasons. Should the contractual arrangement proceed, Enertrade has indicated its willingness for the full commercial details to be disclosed on a confidential basis to the ACCC for regulatory review purposes.

Note: The feasibility of this grid support option is dependent on the final outcome of the current ACCC Revenue Determination for Powerlink. The draft determination published on July 27th, 2001 noted that the ACCC would allow grid support payments to form part of Powerlink's revenue cap[2] provided a grid support option can be justified as providing a higher net benefit to the market than other alternatives. This approach would allow Powerlink to recover the actual costs of grid support from electricity customers through transmission charges. Powerlink's ability to enter into a contract for grid support is dependent on the ACCC Final Determination confirming the position outlined in the draft decision. The ACCC revenue cap applies from 1 January, 2002, and therefore Powerlink anticipates that any grid support contract will take effect from the start of the 2002 calendar year.

Option 3 – "Network October 2002 + Partial Grid Support"	
2001 2002 2003 onwards	Directed-on generation Stanwell-Broadsound 275kV augmentation + partial grid support Partial grid support

In Option 3, construction of a network augmentation would begin immediately, for completion by October 2002. Until the augmentation is commissioned, grid support would be provided by Enertrade under contract with Powerlink as outlined in Option 2.

The lowest cost network augmentation that can alleviate the grid constraints is a 275kV single circuit transmission line between Stanwell (near Rockhampton) and Broadsound (mid way between Rockhampton and Mackay)[3]. Further details of this network option are contained in section 7.6.

This network augmentation is unable to relieve all of the anticipated constraints on the transmission system over the ten year period of the analysis. Option 3 therefore includes a (smaller) continuing grid support contribution from existing local generators to meet load supply requirements in the relevant area.

[2] The ACCC proposes to permit an annual adjustment of the revenue cap to account for any differences between allowed and actual grid support, provided Powerlink can demonstrate that any adjustment is material, efficient and reasonable.
[3] Powerlink expects that the Stanwell-Broadsound transmission line will also play a role in satisfying future supply requirements of the Bowen Basin mining area supplied from the existing 275kV substation at Lilyvale.

Option 4 – “Network October 2003 + Partial Grid Support”	
2001 2002 2003 2004 onwards	Directed-on generation Grid support Stanwell-Broadsound 275kV augmentation + partial grid support Partial grid support

This option is the same as Option 3, except that construction of the Stanwell-Broadsound network augmentation is deferred for one year, with commissioning by October 2003. This requires additional grid support to be procured to address the anticipated network constraints until October 2003.

As for Option 3, this network augmentation would be unable to relieve all of the constraints on the transmission system. Option 4 therefore also includes a (smaller) continuing grid support contribution from existing local generators.

6.0 MARKET DEVELOPMENT SCENARIOS

6.1 Context for Evaluation of Options

All feasible solutions to the identified network constraints must be viewed in the context of wider developments in the National Electricity Market:

- NEMMCO's Statement of Opportunities (SOO) issued in March 2001 contained information on existing and committed generation developments in Queensland. Approximately 2500MW of new generation capacity is committed for commissioning in Queensland within the next three years.

- The new Commonwealth Government legislation to encourage increased generation from renewable energy sources came into effect on 1st April, 2001. Forecasts provided by the National Institute of Economic and Industry Research (NIEIR) indicate a significant proportion of the national requirement for additional renewable energy will be met from within Queensland. Powerlink has incorporated these independent forecasts into the forecasts of demand and energy used in assessing the expected incidence of future network constraints.

- The Queensland Government published the Queensland Energy Policy in May 2000. This policy will require Queensland energy retailers to source 15% of their energy from gas-fired generation and renewable energy sources from 1 January 2005. Subsequent to the release of this policy document, the Queensland Government has issued an Information Paper regarding the process for development of a baseload gas-fired generation facility in Townsville.

6.1.1. Townsville Baseload Power Station

During the consultation process, several consortiums provided Powerlink with limited information on their project proposals for a Townsville generator. These and other parties noted that it was essential Powerlink consider the proposed establishment of a baseload generation facility in Townsville when assessing options to address the CQ-NQ network transfer limitations.

In June 2001, the Queensland Government initiated a new process which seeks integrated proposals for baseload generation with access to secure long-term gas supply. Proposals are required to meet eligibility criteria which include production of at least 150MW of baseload power generation in Townsville using gas as the fuel, and design capacity and fuel commitments to achieve annual capacity factors of at least 75%. The process is expected to conclude with a government decision in March 2002.

6.2 Assumed Market Development Scenarios

Under the ACCC Regulatory Test, options to address a network limitation must be assessed against a number of plausible market development scenarios. These scenarios need to take account of the existing system, committed and possible generation developments, variations in load growth and transmission network developments. The purpose of utilising this approach is to test the net economic benefits of the options being evaluated under a range of scenarios.

Powerlink has used the committed and potential market developments outlined in 6.1 to define five plausible market development scenarios, against which to assess the options described in section 5.0.

It is important to recognise that this range of scenarios represents assumptions about possible market developments that could occur *independently* of action to address network limitations at the CQ-NQ and Ross Limits. No attempt has been made to rank the probability of these scenarios occurring.

The market development scenarios assumed by Powerlink are:

Scenario A	A new power station is established in the Townsville area in January 2004 Moderate load growth forecast
Scenario B	A new power station is established in the Townsville area in January 2005 Moderate load growth forecast
Scenario C	A new power station is established in the Townsville area in January 2006. Moderate load growth forecast
Scenario D	A new power station is established in the Townsville area in January 2007 Moderate load growth forecast
Scenario E	A new power station is established in the Townsville area in January 2005 Higher customer load[4]

All of the market development scenarios assume that a new baseload power station is established in Townsville based on the current Queensland Government initiative and the Queensland Energy Policy. Preliminary analysis determined that the type and size of the proposed power station had minimal impact on the comparison of options to address the immediate network constraints. However, the evaluation is sensitive to the timing of establishment of the proposed power station, and scenarios were therefore developed for varying timings between 2004 and 2007. It is clear from the trends observed in the analysis that deferral of the power station beyond 2007 will not alter the ranking of options, so such timing scenarios were not examined.

No other transmission works proposed by Powerlink in the affected area (such as the refurbishment/replacement of ageing 132kV assets) have been included in the market development scenarios and options. These projects are independent of the identified network constraints and are considered to have no impact on the analysis as they are common to all scenarios.

6.3 Other Plausible Scenarios

The assumed market development scenarios are not exhaustive, but are designed to demonstrate a range of plausible scenarios that may impact the comparison of options to address the CQ-NQ and Ross network limitations. It is recognised that other plausible market development scenarios for Queensland include the development of additional baseload generation in southern Queensland in response to market price signals (for example, the proposed Kogan Creek project). This plausible scenario has not been modelled in the analysis, as the establishment of additional baseload generation outside the relevant area being supplied has little impact on the energy needing to be transferred to the area via the transmission system.

[4] 2005 was selected as the year in which to test for sensitivity to load variation for two reasons. The Energy Policy requirement for Queensland electricity retailers to source up to 15% of their energy from gas is scheduled to take effect from 1 January, 2005. In addition, Sun Metals noted during the consultation process that expansion of their zinc refinery plant could occur between 2004 and 2007.

7.0 FORMAT AND INPUTS TO ANALYSIS

7.1 Regulatory Test Requirements

The requirements for the comparison of options to address an identified network limitation are contained in the Regulatory Test prescribed by the Australian Competition and Consumer Commission (ACCC).

The Regulatory Test requires that the recommended option be the option that "maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios". To satisfy the Test, a proposed augmentation must achieve a greater market benefit in most, *but not necessarily all*, credible scenarios.

The Regulatory Test contains guidelines for the methodology to be used to calculate the net present value (NPV) of the market benefit. For example, the methodology published by the ACCC defines "market benefit" as the total net benefit to all those who produce, distribute and consume electricity in the National Electricity Market. Information to be considered in determining market benefit includes the 'efficient operating costs of competitively supplying energy to meet forecast demand' and the cost of complying with existing and anticipated laws. However, the Regulatory Test specifically excludes indirect costs and benefits, and costs and benefits that cannot be measured as a benefit or cost in terms of financial transactions in the electricity market.

7.2 Overview of Analysis

Following is an overview of the analysis carried out to determine the most appropriate solution to the identified network constraints. Further details follow in subsequent sections of this report.

Power system analysis has been carried out to determine the transmission network capability, and therefore the shortfall in load in the relevant area which cannot be supplied without directing local generation. This analysis included or excluded proposed transmission augmentations as appropriate to each option.

Once the level and costs of grid support, loss savings, transmission investment and other inputs were assessed, a comparison of the options was made in accordance with the ACCC Regulatory Test. This evaluation used a cash flow model to determine the Net Present Value (NPV) of the various options.

7.3 Defining Network Transfer Capacity

Since the publication of the initial discussion paper, Powerlink has carried out further analysis to determine the anticipated network constraints more comprehensively. This is a complex task, and the process is described briefly below.

The first step was to define the grid transfer capability across the section of the network known as the CQ-NQ and Ross Limits under a range of system conditions, both with and without the augmentation proposed in Options 3 and 4.

To maximise utilisation of the transmission system, Powerlink has developed constraint equations that recognise the sensitivity of the grid transfer capability to the interactions between variables such as generation at specific power stations, area demands and grid flows.

The maximum power transfer across the CQ-NQ and Ross limits is sensitive to many factors, but is mainly limited by voltage and transient stability. That is, power transfers above the grid capability limits could result in the power system becoming unstable following a network fault or credible single contingency. The critical network contingency that determines transfer capability into the relevant area[5] is a fault near Stanwell on the Stanwell to Broadsound 275kV transmission line.

Transient and voltage stability constraint equations were determined for each limit, with the Ross constraint equations 'referred back' to the CQ-NQ transfer to allow subsequent analysis of half hourly network transfer capability.

The second step was to use the constraint equations to estimate the maximum available transmission capacity in each half hour. The constraint equations were applied to a half hour by half hour assessment of the load level and dispatched generation to obtain the actual transmission capacity for each half hour. This is an iterative process as constraining some generation to avoid exceeding transmission capacity also changes that capacity.

Note: The limits identified through these studies were consistent with those published in Powerlink's 2001 Annual Planning Report and the historical 'single number' limit of 780MW being applied in the market. The full constraint equations used in this analysis have not yet been through NEMMCO's due diligence process. This review needs to occur prior to the equations being implemented in the market dispatch system. It is expected that the equations will be made public through NEMMCO's standard processes once the due diligence is complete.

7.4 Determining Energy Unable to be Supplied From the Grid

A large matrix of 365 days by 48 half hour forecast loads for each study year was developed using historical metered data, summer and winter demand forecasts and annual energy forecasts.

The transmission capacity in each half hour was then compared with the likely transfer needed. Where the required transfer was above the transmission limit, generation was constrained on (out of bid order) until the transfer was below the limit. Changes in the limit because of changes in the generation dispatched were taken into account on an iterative basis to satisfactorily simulate the results from NEMMCO's linear equation dispatch software.

In this manner, the amount of constrained on generation and the mix of generation plant required was assessed. The number of units needed and power station unit starts required were also assessed.

7.4.1. Assumptions

The estimate of constrained on energy is based on an assumption of medium growth in electricity demand[6]. One scenario (E) assumed a higher overall customer load.

The analysis assumed the following dispatch pattern for existing generators:

- ❖ The existing hydro and sugar mill generators in North Queensland were assumed to operate at their average output for the past five years. During the consultation process, Stanwell Corporation (the owner of Barron Gorge and Kareeya Power Stations) expressed some concern at the assumption of average output from these hydro stations. Stanwell stated that the past weather

[5] After the committed project to establish a switching station at Strathmore is commissioned in late 2001.
[6] Medium economic growth, average weather (50% probability of exceedance) forecast

pattern of good rains in the power station catchment areas over the past five years cannot be assumed to continue into the future. Given this, it is not considered appropriate to make assumptions of higher than the five-year average output (eg – full output from the hydro generators). Stanwell has indicated that the weather dependence of the stations means that a lower output from these hydro stations than assumed by Powerlink may well occur. If the actual hydro output is less than assumed, additional grid support would be required. The impact of this is considered to be similar to the higher load growth assumption in Scenario E, and therefore has not been specifically analysed.

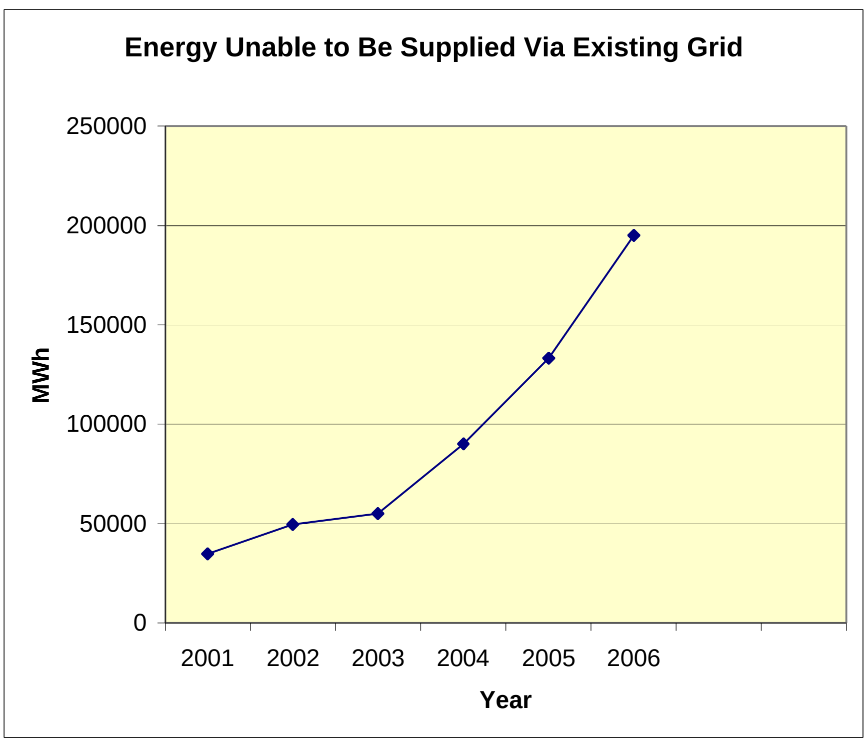
- Collinsville's output is assumed to be approximately 78MW on weekdays, as advised by Enertrade during the consultation process. If the actual Collinsville output is less than this amount, additional grid support would be required.

- Existing generators outside the relevant area were assumed to operate according to a nominal 'market bid stack' based on historical bidding patterns. This assumption is considered to have no impact on the outcome of the analysis, as generators in central and southern Queensland have minimal influence on the supply of energy to the relevant area.

No allowance has been made for forced outages of either generators or transmission elements. Planned outages of generators have been included based on information provided to Powerlink. These assumptions are considered to give conservative results in terms of the costs of grid support.

7.4.2. Results

The results of the analysis show that the existing transmission system will be unable to supply all energy requirements for approximately 10% of the time by 2003, rising to more than 18% of the time by 2007. As shown in the following graph, levels of unsupplied energy are expected to escalate rapidly due to load growth and the flat load duration curve characteristic (ie – peak loads in the relevant area last for the majority of the day during peak periods).



Note: Actual MWh data used in this graph is provided in the next section. The graph shows only minor growth in the energy unable to be supplied via the existing grid for the period 2000 to 2003. This is due to the planned *closure of gold mines and committed increases in generation at Windy Hill and other locations, as included in the load forecasts.*

7.5 Cost Assumptions – Directed On Generation and Grid Support

Costs for directed-on generation and grid support are directly related to the estimated energy that will be unable to be supplied from the transmission grid. Details of the energy assumptions, assumed cost/MWh and total estimated costs are outlined below.

For the purposes of the financial analysis, costs assumed for grid support and directed-on generation have been set to zero when a baseload power station becomes operational in Townsville[7].

7.5.1. Directed-On Generation:

The cost of generation that is directed to operate by NEMMCO is not public information. Powerlink is aware of data provided by an independent consultant that indicates operating costs for the relevant generators in excess of $200/MWh[8]. The base case analysis assumes a cost of $140/MWh for the market payment to directed-on generators (costs less an allowance for pool price). It was suggested to Powerlink during the consultation process that this input assumption was too low due to recent rises in fuel costs and the pool price differential assumed. Any increase in the operating costs of directed generators or reduction in pool price assumptions would act to increase the cost for this option. Powerlink has not altered its base case data, but has carried out sensitivity analysis using costs ranging from $100/MWh - $400/MWh.

The resulting base case cost estimates for Option 1 (no action by Powerlink) are:

Calendar Year	MWh Required	At $140/MWh
2001	34 836	$4.9M
2002	49 668	$7.0M
2003	55 133	$7.7M
2004	90 270	$12.6M
2005	133 511	$18.7M
2006	194 974	$27.3M

For all options analysed, directed-on generation has been assumed to occur for the remainder of 2001 when the network limitations are reached. This is because Powerlink has no mechanisms through its current regulatory arrangements to make payments for grid support. The new revenue cap (ACCC determination process underway) is expected to allow grid support payments when it comes into effect on 1 January 2002.

7.5.2. Grid Support Costs:

As noted previously, Enertrade has provided a cost structure for the provision of grid support from existing generators which is confidential. However, because of the ACCC Regulatory Test

[7] The requirement for grid support, if any, once a baseload power station in Townsville becomes operational, is highly dependent on the size and cost of operation of the proposed power station. The ranking of options is not considered to be sensitive to this factor, as the trends evident in each option (ie – relativities in the levels of energy to be met through grid support) are not likely to change.

[8] IRPC Stage 1 Report Update. Proposed SNI Interconnector. November 2000.

requirements for transparency of analysis, the following total estimated costs for grid support are disclosed:

	Full Grid Support (to meet energy requirements unable to be supplied via the existing transmission system)		**Partial Grid Support** (to meet energy unable to be supplied after Stanwell-Broadsound augmentation)	
	MWh	**Total $M**	**MWh**	**Total $M**
2002	49 668	6.73	-	-
2003	55 133	7.38	9 529	1.91
2004	90 270	12.44	20 865	3.30
2005	133 511	18.71	34 137	4.90
2006	194 974	27.55	65 838	8.24

Average grid support costs per MWh are lower than directed-on generation costs. This is as expected, because a grid support contract will provide Enertrade with more certainty and predictability about operating requirements than responding to short-term directions by NEMMCO.

Grid support requirements are not expected to be confined to peak summer periods, with modelling showing that some energy will be unable to be supplied by the existing transmission grid during winter from 2003 onwards. However, the majority of the grid support will be required during the months of November and December. As time goes on and electricity demand grows, the incidence of grid support during other times of the year will increase.

As noted earlier, for the purposes of the financial analysis, grid support costs have been set to zero when the proposed base load power station becomes operational in Townsville.

It must be emphasised that the total grid support costs are an estimate only, based on the forecast of energy that may be unable to be supplied by the grid. Actual grid support requirements will vary depending on the actual electricity demand, generation pattern, water availability etc.

7.6 Cost Assumptions - Transmission Augmentation

The transmission option proposed in options 3 & 4 is a single circuit 275kV line between Stanwell (near Rockhampton) and Broadsound (mid way between Rockhampton and Mackay) constructed on an existing easement. A line diagram of the existing transmission system in the area and the proposed line is shown in Appendix 1.

The estimated capital cost of this proposed project is approximately $33M. Sensitivity studies have been carried out using variations in this capital cost estimate of plus or minus 15% (see section 8.3).

The financial analysis considers all cost impacts of this project to market participants as defined by regulatory processes. Loss savings have also been estimated, including the impact on losses of the proposed establishment of a baseload generation facility in Townsville.

8.0 FINANCIAL ANALYSIS

8.1 Description of Financial Analysis Approach

The economic analysis undertaken considered the net present value (NPV) of net market benefits of alternative options over the ten year period from 2001 to 2010. Full details of this analysis are contained in Appendix 2.

8.2 Net Present Value Analysis

Financial analysis was carried out to calculate and compare the Net Present Value (NPV) of the costs to market participants of each option under the range of assumed market development scenarios.

A ten year analysis period was selected. Beyond a ten year window, forecasts of constraint levels and energy requirements above the transmission capability become increasingly inaccurate. A discount rate of 10% was selected as a relevant commercial discount rate, and sensitivity analysis was conducted to test this assumption.

Capital and operating costs common to all options were not included in the analysis. These common costs include the capital and operating costs of the proposed baseload power station in Townsville, and other transmission works that Powerlink is proposing in the relevant area (eg – refurbishment/replacement of ageing 132kV assets). Because these costs are independent of the identified network constraints, they are common to all options evaluated in the financial analysis.

As such, they have no impact on the relative ranking of options resulting from the analysis. Under the Regulatory Test, it is the ranking of the options which is important, rather than the actual net present value results. This is because the Regulatory Test requires that the recommended option maximise the net market benefit (in this case have the lowest net present value cost) under most but not necessarily all plausible scenarios.

The following table is a summary of the economic analysis contained in Appendix 2. It shows the net present value of each alternative, and identifies the best ranked option, for the range of scenarios considered.

Discount rate 10%	SCENARIO A Power Station 2004 NPV ($M)	Rank	SCENARIO B Power Station 2005 NPV ($M)	Rank	SCENARIO C Power Station 2006 NPV ($M)	Rank
Option 1 - No action by TNSP	15.98	2	24.61	3	36.22	4
Option 2 - full grid support	15.54	1	24.03	2	35.65	3
Option 3 - Network Oct 02 & partial grid support	20.45	3	21.99	1	24.35	1
Option 4 - Network Oct 03 & partial grid support	23.34	4	24.75	4	27.11	2

Discount rate 10%	SCENARIO D Power Station 2007 NPV ($M)	Rank	SCENARIO E PS 2005 with higher NQ load NPV ($M)	Rank
Option 1 - No action by TNSP	51.63	4	27.07	4
Option 2 - full grid support	51.20	3	26.43	3
Option 3 - Network Oct 02 & partial grid support	28.34	1	23.15	1
Option 4 - Network Oct 03 & partial grid support	31.09	2	26.33	2

8.3 Sensitivity Analysis:

In addition to the variables tested by the different market development scenarios, the sensitivity of the option ranking to other critical parameters was also examined.

The effect of varying these parameters over their credible range was investigated using standard Monte Carlo techniques.[9] The following table shows the parameters that were investigated in the sensitivity analysis, the distribution that was assumed for each parameter and the range of values.

Parameter	Distribution
Capital Cost of Transmission Option	The capital cost was tested for sensitivity to variations of plus or minus 15% from the expected value. We assumed a uniform distribution for this variation. This assumes an equal probability for any outcome in the range $28m to $38m.
Cost for directed generation	The cost for directed generation (which includes compensation for variable costs above pool price and for start-up costs) is assumed to range between $100/MWh and $400 / MWh. We used a triangular probability distribution with a most probable value around $250/MWh.
Customer load growth factor	Scenario E considers a power station in 2005 with a higher customer load growth. In the base case, the higher load growth was represented using a 10% factor to scale up grid support costs. The sensitivity analysis allowed variations to this factor following a normal distribution with a 2% standard deviation.

The Monte Carlo analysis assigns a value to each of the above parameters according to their distribution and then ranks the options. This simulation is done many times (in this case, 1,000 times)

[9] Using the @Risk add-in for Microsoft Excel.

to cover a large number of combinations of parameters. The analysis identifies which option is the best ranked option (the option that has the lowest cost on an NPV basis for the largest number of samples) and gives the frequency for which this option 'wins'.

In addition to the above sensitivities, the sensitivity of the ranking of options to the discount rate assumption was also investigated by repeating the above analysis with a discount rate of 8%, 10% and 12%. The following table shows the 'winning option' and the frequency for which it 'wins' for each scenario and discount rate across the range of parameters assessed.

	Discount Rate		
Scenario	**8%**	**10%**	**12%**
A - Power station in January 2004	2 (97%)	2 (97%)	2 (97%)
B - Power station in January 2005	3 (81%)	3 (99%)	3 (99%)
C - Power station in January 2006	3 (100%)	3 (100%)	3 (100%)
D - Power station in January 2007	3 (100%)	3 (100%)	3 (100%)
E - Power station in January 2005 with higher customer load	3 (99%)	3 (100%)	3 (100%)

As can be seen in this table, Option 3 is the best-ranked option in all scenarios except Scenario A. This outcome is robust in terms of all of the variations in parameters assessed.

9.0 DISCUSSION OF RESULTS

The following conclusions have been drawn from the analysis of the net present value of the market benefit which would arise from the different options considered:

- The option where no action is taken by Powerlink provides the least market benefit under most scenarios. It is clear that action to address the identified network constraints will provide net benefits to market participants.

- Under almost all the scenarios examined, the option of augmenting Stanwell-Broadsound by October 2002 and procuring partial grid support from Enertrade is the solution to the identified network constraints which maximises net benefits.

- This option ranked number one in four of the five scenarios – the only scenario where it was not ranked highest was Scenario A where the proposed Townsville baseload power station is operational by 1 January 2004.

- Sensitivity analysis showed this outcome to be very robust, with the option rankings insensitive to variations in critical parameters used in the analysis.

- In Scenario A, where the power station is operational by 1 January 2004, the option which provides the maximum net market benefit is a full grid support arrangement with Enertrade for the operation of its existing generators in the relevant area.

- Powerlink makes no assumption about the likelihood of this scenario occurring. The Regulatory Test is satisfied if an option achieves a greater market benefit 'in most, *but not necessarily all*, credible scenarios'. It is clear, on this basis, that Option 3 is the option that satisfies the Regulatory Test.

- In addition to maximisation of benefit, the Regulatory Test requires that a transmission network service provider optimise the timing of any proposed network augmentation that is justified under the Regulatory Test. It is evident from the analysis results that commissioning Stanwell-Broadsound by October 2002, rather than October 2003 delivers higher net benefits in all of the scenarios examined.

10.0 DRAFT RECOMMENDATION

Based on the conclusions drawn from the analysis, the following course of action is recommended to address the identified network constraints at the CQ-NQ Limit.

(3) Powerlink and Enertrade to enter into a contract for partial grid support from Enertrade's portfolio of existing generators from 1 January 2002, and

(4) Powerlink to immediately initiate construction of a single circuit 275kV transmission line from Stanwell-Broadsound for commissioning by October 2002.

Powerlink invites submissions from Code Participants and interested parties on this draft recommendation. Submissions on this draft recommendation are requested by Friday 7th September, 2001.

Please address submissions to:

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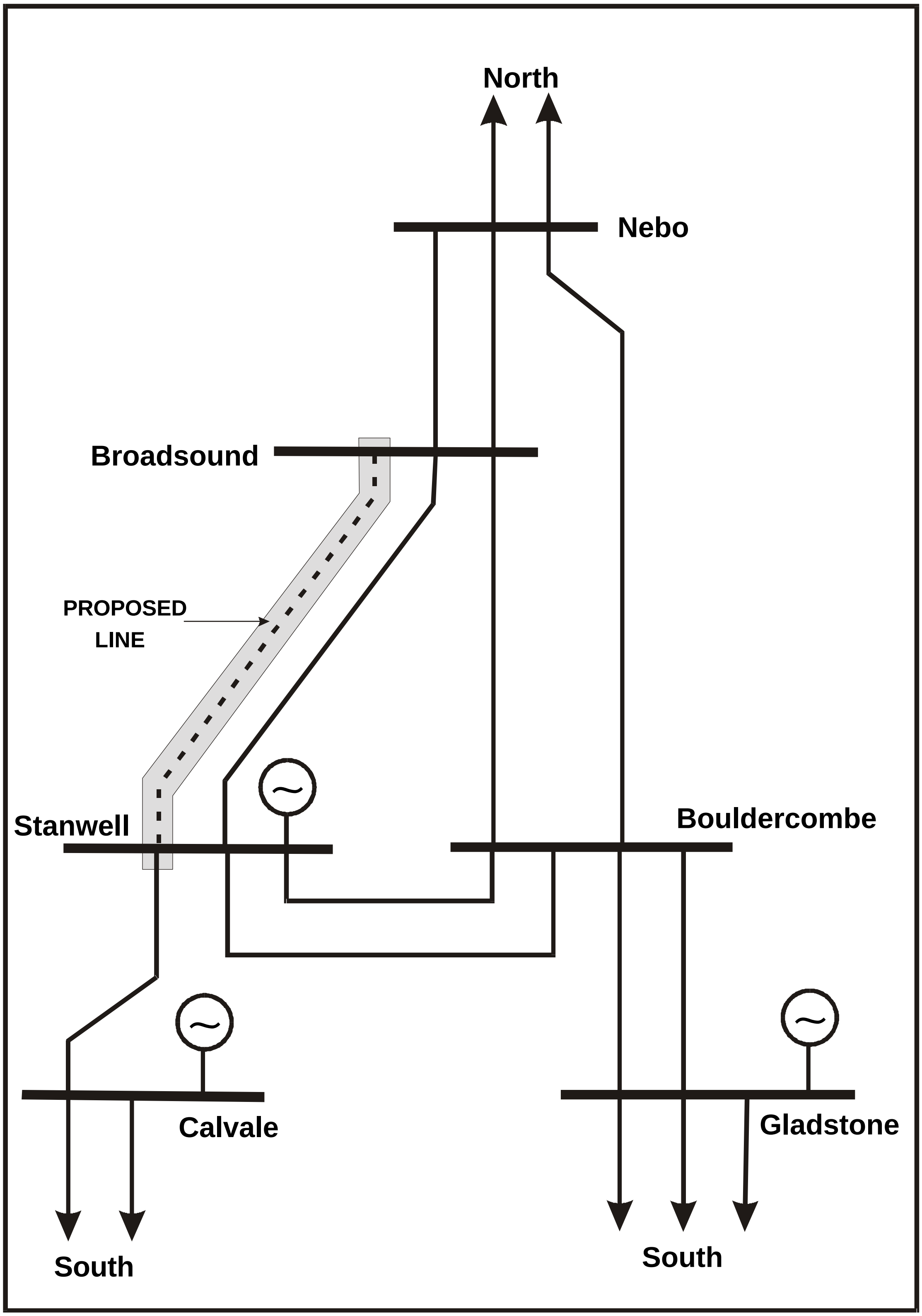
Following consideration of the submissions, Powerlink expects to publish a final recommendation by the end of September 2001.

Appendix 1:

Line Diagram – 275kV Transmission System in Central Queensland



Appendix 2:

Financial Analysis

Discount rate 10%	SCENARIO A Power Station 2004 NPV ($M)	Rank	SCENARIO B Power Station 2005 NPV ($M)	Rank	SCENARIO C Power Station 2006 NPV ($M)	Rank
Option 1 - No action by TNSP	15.98	2	24.61	3	36.22	4
Option 2 - full grid support	15.54	1	24.03	2	35.65	3
Option 3 - Network Oct 02 & partial grid support	20.45	3	21.99	1	24.35	1
Option 4 - Network Oct 03 & partial grid support	23.34	4	24.75	4	27.11	2

Discount rate 10%	SCENARIO D Power Station 2007 NPV ($M)	Rank	SCENARIO E PS 2005 with higher NQ load NPV ($M)	Rank
Option 1 - No action by TNSP	51.63	4	27.07	4
Option 2 - full grid support	51.20	3	26.43	3
Option 3 - Network Oct 02 & partial grid support	28.34	1	23.15	1
Option 4 - Network Oct 03 & partial grid support	31.09	2	26.33	2

SCENARIO A			1	2	3	4	5	6	7	8	9	10
Power Station 2004		NPV ($M)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Option 1 - No action by TNSP		10%										
Directed Operation												
MWhrs			34836	49668	55133							
Cost	$ 140.00 /MWhr	15.98	4.88	6.95	7.72							
NPV Option 1		**15.98**										
Option 2 - full grid support		10%										
Full grid support												
Cost			0.00	6.73	7.38							
NPV for full GS until 2004		11.10										
Directed Operation pre 1 Jan 02		4.43	4.88									
NPV Option 2		**15.54**										
Option 3 - Network Oct 02 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20	3.15
NPV for ST - BR line Oct 2002		13.42										
Loss saving (additional due to line)		-2.33	0.00	-0.21	-1.24	-0.28	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support												
Cost			0.00	4.22	1.91							
NPV for part GS until 2004		4.92										
Directed Operation pre 1 Jan 02		4.43	4.88									
NPV Option 3		**20.45**										
Option 4 - Network Oct 03 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20
NPV for ST - BR line Oct 2003		11.10										
Loss saving (additional due to line)		-1.26	0.00	0.00	-0.05	-0.28	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support												
Cost			0.00	6.73	4.67							
NPV for part GS until 2004		9.07										
Directed Operation pre 1 Jan 02		4.43	4.88									
NPV Option 4		**23.34**										

SCENARIO B		1	2	3	4	5	6	7	8	9	10
Power Station 2005	NPV ($M)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Option 1 - No action by TNSP	10%										
Directed Operation											
MWhrs		34836	49668	55133	90270						
Cost $ 140.00 /MWhr	24.61	4.88	6.95	7.72	12.64						
NPV Option 1	24.61										
Option 2 - full grid support	10%										
Full grid support											
Cost		0.00	6.73	7.38	12.44						
NPV for full GS until 2005	19.60										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 2	**24.03**										
Option 3 - Network Oct 02 & partial grid support											
Transmission	10%										
TUOS		0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20	3.15
NPV for ST - BR line Oct 2002	13.42										
Loss saving (additional due to line)	-3.04	0.00	-0.21	-1.24	-1.32	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support											
Cost		0.00	4.22	1.91	3.30						
NPV for part GS until 2005	7.18										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 3	**21.99**										
Option 4 - Network Oct 03 & partial grid support											
Transmission	10%										
TUOS		0.00	0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20
NPV for ST - BR line Oct 2003	11.10										
Loss saving (additional due to line)	-2.10	0.00	0.00	-0.22	-1.32	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support											
Cost		0.00	6.73	4.67	3.30						
NPV for part GS until 2005	11.32										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 4	**24.75**										

SCENARIO C		1	2	3	4	5	6	7	8	9	10
Power Station 2006	NPV ($M)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Option 1 - No action by TNSP	10%										
Directed Operation											
MWhrs		34836	49668	55133	90270	133,511					
Cost $ 140.00 /MWhr	36.22	4.88	6.95	7.72	12.64	18.69					
NPV Option 1	36.22										
Option 2 - full grid support	10%										
Full grid support											
Cost		0.00	6.73	7.38	12.44	18.71					
NPV for full GS until 2006	31.21										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 2	**35.65**										
Option 3 - Network Oct 02 & partial grid support											
Transmission	10%										
TUOS		0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20	3.15
NPV for ST - BR line Oct 2002	13.42										
Loss saving (additional due to line)	-3.72	0.00	-0.21	-1.24	-1.32	-1.41	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support											
Cost		0.00	4.22	1.91	3.30	4.90					
NPV for part GS until 2006	10.22										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 3	**24.35**										
Option 4 - Network Oct 03 & partial grid support											
Transmission	10%										
TUOS		0.00	0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20
NPV for ST - BR line Oct 2003	11.10										
Loss saving (additional due to line)	-2.79	0.00	0.00	-0.22	-1.32	-1.41	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support											
Cost		0.00	6.73	4.67	3.30	4.90					
NPV for part GS until 2006	14.37										
Directed Operation pre 1 Jan 02	4.43	4.88									
Total NPV Option 4	**27.11**										

SCENARIO D			1	2	3	4	5	6	7	8	9	10
Power Station 2007		NPV ($M)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Option 1 - No action by TNSP		10%										
Directed Operation												
MWhrs			34836	49668	55133	90270	133,511	194,974				
Cost	$140.00 /MWhr	51.63	4.88	6.95	7.72	12.64	18.69	27.30				
NPV Option 1		51.63										
Option 2 - full grid support		10%										
Full grid support												
Cost			0.00	6.73	7.38	12.44	18.71	27.55				
NPV for full GS until 2007		46.76										
Directed Operation pre 1 Jan 02		4.43	4.88									
Total NPV Option 2		**51.20**										
Option 3 - Network Oct 02 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20	3.15
NPV for ST - BR line Oct 2002		13.42										
Loss saving (additional due to line)		-4.39	0.00	-0.21	-1.24	-1.32	-1.41	-1.50	-0.34	-0.36	-0.39	-0.41
Partial Grid Support												
Cost			0.00	4.22	1.91	3.30	4.90	8.24				
NPV for part GS until 2007		14.87										
Directed Operation pre 1 Jan 02		4.43	4.88									
Total NPV Option 3		**28.34**										
Option 4 - Network Oct 03 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20
NPV for ST - BR line Oct 2003		11.10										
Loss saving (additional due to line)		-3.45	0.00	0.00	-0.22	-1.32	-1.41	-1.50	-0.34	-0.36	-0.39	-0.41
Partial Grid Support												
Cost			0.00	6.73	4.67	3.30	4.90	8.24				
NPV for part GS until 2007		19.02										
Directed Operation pre 1 Jan 02		4.43	4.88									
Total NPV Option 4		**31.09**										

SCENARIO E			1	2	3	4	5	6	7	8	9	10
PS 2005 with higher NQ load		NPV ($M)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Option 1 - No action by TNSP		10%										
Directed Operation												
MWhrs	10%		38,319	54,635	60,646	99,297						
Cost	$140.00 /MWhr	27.07	5.36	7.65	8.49	13.90						
NPV Option 1		27.07										
Option 2 - full grid support		10%										
Full grid support	10%											
Cost			0.00	7.40	8.12	13.68						
NPV for full GS until 2005		21.56										
Directed Operation pre 1 Jan 02		4.88	5.36									
Total NPV Option 2		**26.43**										
Option 3 - Network Oct 02 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20	3.15
NPV for ST - BR line Oct 2002		13.42										
Loss saving (additional due to line)		-3.04	0.00	-0.21	-1.24	-1.32	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support	10%											
Cost			0.00	4.64	2.10	3.63						
NPV for part GS until 2005		7.89										
Directed Operation pre 1 Jan 02		4.88	5.36									
Total NPV Option 3		**23.15**										
Option 4 - Network Oct 03 & partial grid support												
Transmission		10%										
TUOS			0.00	0.00	0.00	1.73	3.44	3.39	3.34	3.29	3.25	3.20
NPV for ST - BR line Oct 2003		11.10										
Loss saving (additional due to line)		-2.10	0.00	0.00	-0.22	-1.32	-0.30	-0.32	-0.34	-0.36	-0.39	-0.41
Partial Grid Support	10%											
Cost			0.00	7.40	5.13	3.63						
NPV for part GS until 2005		12.45										
Directed Operation pre 1 Jan 02		4.88	5.36									
Total NPV Option 4		**26.33**										