DEVELOPMENT OF ELECTRICITY SUPPLY TO THE NEW SOUTH WALES MID NORTH COAST

FINAL REPORT

OCTOBER 2003

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1. EXECUTIVE SUMMARY

This paper has been prepared to advise *Code Participants* and interested parties of the results of TransGrid and Country Energy's consultation on options for the development of electricity supply to the Mid North Coast of New South Wales, and application of the ACCC's regulatory test.

Section 2 provides a description of the Mid North Coast area and the context of this final report within the regulatory approval process.

Section 3 describes in detail the nature of the growing load in the area, the limitations affecting the transmission network in the area and the need for augmentation of supply to the area. The objectively measurable service standard (planning criterion), against which the need and effectiveness of augmentation options are to be assessed, is also presented.

In Section 4 two feasible network options, one of which has two variants, are described. Options 1A and 1B involve establishment of a new 330/132 kV substation approximately three kilometres from the existing Coffs Harbour 132/66 kV substation. Option 2 involves establishing a 330/132 kV substation adjacent to the existing 132/66 kV substation, together with a short section of double circuit 330 kV line to connect it. Demand Management and local generation options have been excluded as no proponents for these types of developments have emerged.

Section 5 discusses the only submission received in response to the Consultation Paper. This submission made no substantive comments on the options being considered or the way in which they were evaluated and no additional options were proposed.

In Section 6 the results of the application of the regulatory test are presented. The only viable options are those involving establishment of a 330/132 kV substation near Coffs Harbour. The most cost effective of these is Option 2, which is the recommended option.

2. INTRODUCTION

2.1. Purpose and Scope

In July 2003 TransGrid and Country Energy published a Consultation Paper (in accordance with Clause 5.6.2 (f) of the National Electricity Code) to consult with Code Participants and interested parties so as to identify options for the development of electricity supply in the Mid North Coast area of New South Wales.

That paper included:

- a discussion of transmission system limitations identified by TransGrid and Country Energy that have lead to the necessity for an augmentation of the transmission network in the area;
- a discussion of the service standard that has been adopted for planning purposes;
- descriptions of options for development of electricity supply in the area; and
- details of a preliminary cost effectiveness analysis of each of those options that was carried out in accordance with the requirements of the ACCC's regulatory test.

It also foreshadowed publication of this final report of the consultation, in accordance with clause 5.6.2 (h) of the Code. In addition to the matters addressed in the Consultation Paper, this Final Report:

- summarises comments received in response to the Consultation Paper;
- gives the results of TransGrid's and Country Energy's application of the ACCC's regulatory test; and
- provides a recommendation of the action to be taken.

2.2. Background

2.2.1. Introduction

The part of the NSW Mid North Coast considered in this document is the area from Coffs Harbour to Port Macquarie. It has a population of around 200,000. This area is shown in Figure 1.

The area electrical load is characterised primarily by urban residential loads and commercial/light industrial loads in the main population centres and rural and semi-rural loads in surrounding areas.

2.2.2. Local Supply Arrangements

This area is supplied via a 132 kV transmission network emanating from 330/132 kV substations at Armidale, Lismore and Newcastle, as shown in Figure 1.

This 132 kV network supplies substations at Coffs Harbour, Dorrigo, Nambucca, Kempsey and Port Macquarie, which in turn supply the lower voltage Country Energy networks in those areas. A new 132 kV line between Coffs Harbour and Kempsey and the associated 132/66 kV substation at Nambucca was commissioned in early June 2002.

The 132 kV network operates in parallel with the main 330 kV network and consequently power flows on the 132 kV network are affected, to a small degree, by flows on the 330 kV network. The flows on the 330 kV network are determined by loads and generation patterns in the National Electricity Market (which covers the eastern and southern states). Power flows on the 330 kV network in the north of NSW are influenced by the amount of power being imported from or exported to Queensland on the Queensland – NSW Interconnector (QNI).

As an indication of historical flows on QNI, the distribution of flows for 2002 are shown in Figure 2. This figure shows that for approximately three quarters of that year power flowed from Queensland to NSW.

Figure 1 Supply System on the Mid North Coast

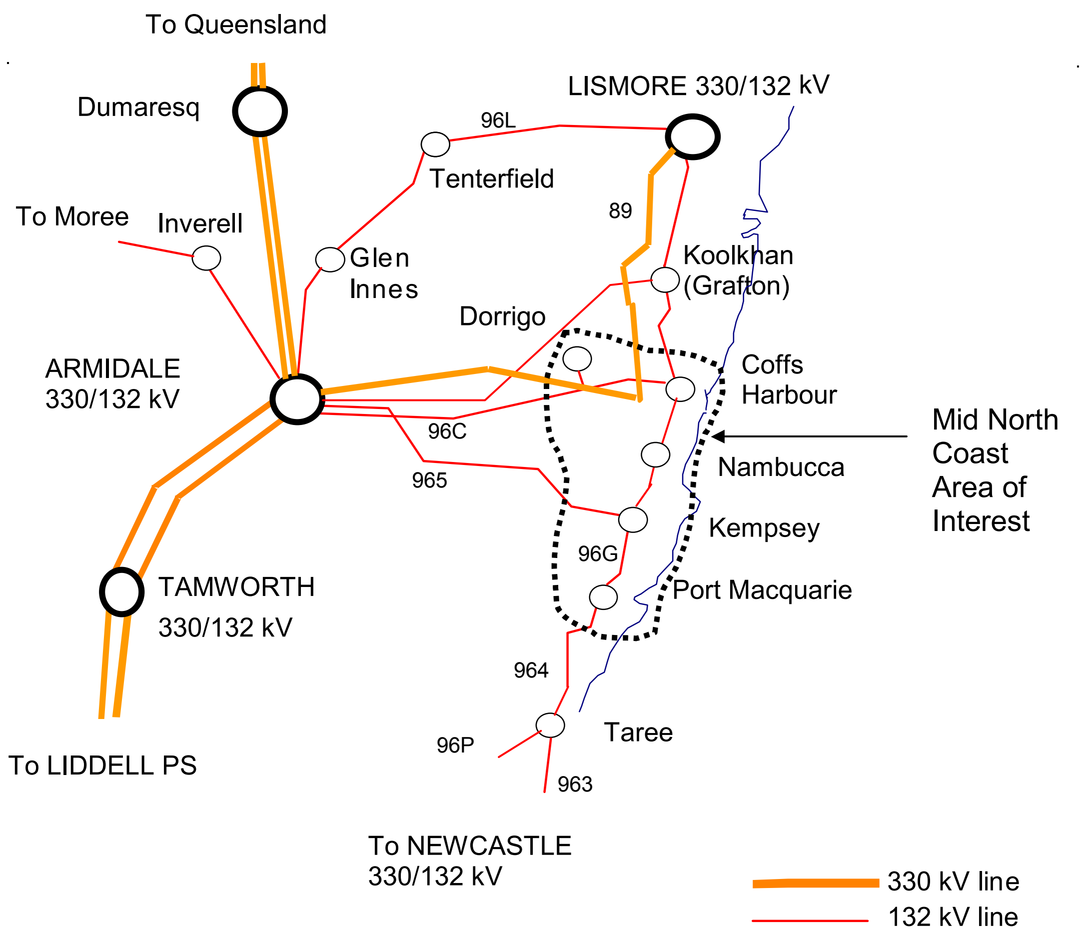
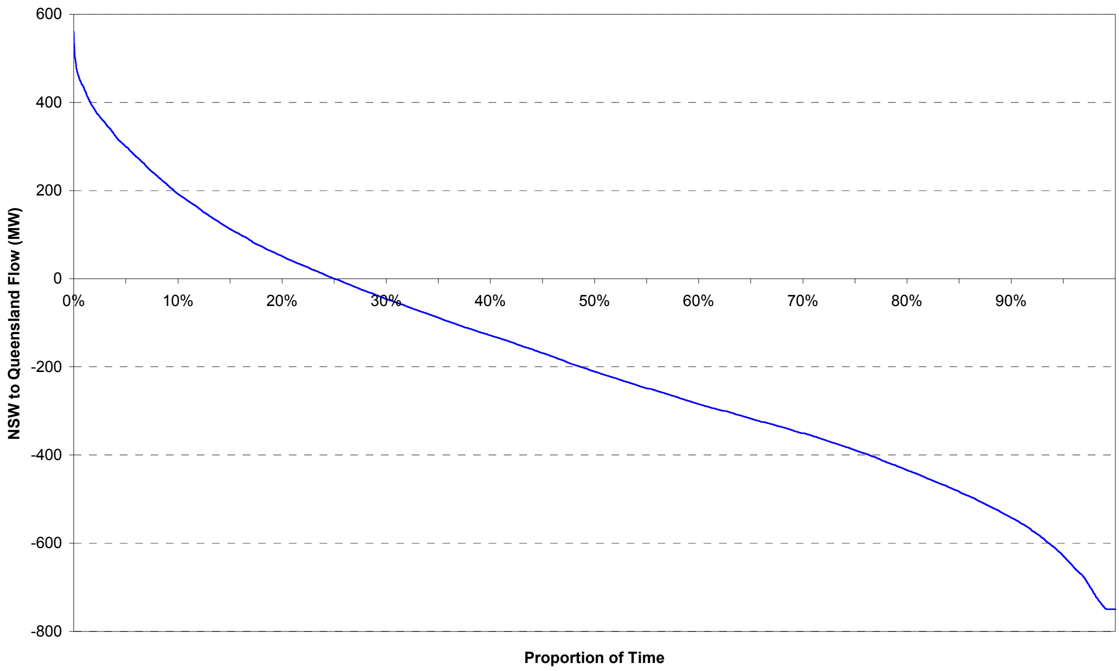


Figure 2 Flows on QNI in 2002



The capacity of the existing 132 kV system is limited by unacceptably low voltages on outage of critical lines at times of high load. The 132/66 kV transformer at the recently commissioned Nambucca substation has an extended tap-changer range to assist in maintaining adequate voltage levels at Nambucca.

In addition, over the years, TransGrid has installed numerous capacitor banks at the 132 kV substations to improve voltages both with all system elements (transmission lines and transformers) in service and following outage of one network element. As the reactive power loads at the major 132 kV substations are fully compensated (or very close to fully compensated), the installation of additional capacitors would be of marginal benefit.

2.3. Procedural Context

2.3.1. National Electricity Code Requirements

The consultation process that is being followed is as required by the National Electricity Code (the Code).

Code changes gazetted on 8th March 2002 provide for significant changes in consultation procedures to be followed for *new large network assets* where the consultation commenced on or after 8th March 2002. However clause 5.6.2(a2) of the Code provides, where the consultation commenced before 8th March 2002, for consultations to be carried out in accordance with the Code requirements that were in effect immediately prior to that date.

The consultation for the Mid North Coast area commenced on 25th January 2002 with publication of a notice to that effect on TransGrid's web site. Therefore TransGrid and Country Energy have carried out this consultation in accordance with the Code provisions that were in effect immediately prior to 8th March 2002. Thus references to Code clauses in this document generally refer to these Code provisions. Appendix A details the relevant clauses.

2.3.2. Process Followed

Clause 5.6.2 (c) of the Code indicates that a necessity for an *augmentation* or *extension* to the transmission system should be identified. Furthermore clauses 5.6.2 (f) and (g) state that *Network Service Providers* must consult with Code Participants and interested parties on possible options to address this need and carry out an economic cost effectiveness analysis of these options.

TransGrid and Country Energy have been carrying out joint planning to identify and monitor emerging limitations in the transmission network supplying the Mid North Coast for many years. These limitations have been outlined in TransGrid's Annual Planning Statements for 1999, 2000 and 2001 and its Annual Planning Reports for 2002 and 2003.

In June 2002 TransGrid and Country Energy published a paper entitled "Request For Proposals for Demand Management or Local Generation on the Mid North Coast", which described the emerging system limitations and sought proposals for demand management or local generation options that may address these limitations.

In July 2002 TransGrid and Country Energy published a paper entitled "Emerging Transmission Network Limitations on the New South Wales Mid North Coast" (the "needs statement") on their websites. The needs statement describes the transmission system limitations in detail and proposes an objectively measurable service standard that has been used to determine the need for an augmentation of the transmission network supplying the area. Much of the material in the needs statement has been reproduced and in some cases updated in Section 3 of this document.

The purpose of publishing the needs statement was to seek feedback on the proposed service standard and on possible solutions to the transmission system limitations, particularly those that may involve components of demand management and/or local generation. No responses were received in regard to these issues.

In July 2003 TransGrid and Country Energy published a Consultation paper which described options being considered to overcome the transmission system limitations and gave details of a preliminary cost effectiveness analysis of those options that was carried out in accordance with the requirements of the ACCC's regulatory test.

One response to the Consultation Paper was received. It is addressed in Section 5 of this report. This response made no substantive comments on the options being considered or the way in which they were evaluated and no additional options were proposed.

2.3.3. Process to be Followed

Following publication of this final report there is a period of 40 business days during which *Code Participants* can lodge a dispute under Clause 5.6.2 (i) of the Code. Accordingly, if no notification has been received by 31 December 2003, the regulatory approval process will be completed (refer to Section 7 for contact details).

3. IDENTIFICATION OF A NECESSITY FOR AUGMENTATION

3.1. Code Requirements

Clause 5.6.2 (c) of the Code indicates that a necessity for an *augmentation* or *extension* to the transmission system should be identified. Furthermore clause 5.6.2 (g) states

> *"Each Network Service providers must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test…" See Appendix 1*

These requirements, and the ACCC's regulatory test imply that, for intra-regional augmentations, limb (a) of the test should be used. That is, an option that passes the regulatory test is one that minimises the cost of meeting an objectively measurable service standard linked to the technical requirements of Schedule 5.1 of the Code.

In order to identify whether there is a necessity for an *augmentation* to a transmission system that is capable of supplying load at all times in its normal state it is necessary to:

- Determine whether any technical requirements of the network are not satisfied during a credible contingency i.e. determine whether there are (or will be over the planning horizon) any network constraints.

- Determine the proportion of load that could be supplied and compare this against an agreed objectively measurable standard.

3.2. Description of Network Constraints

If all elements of the network are in service, it is expected to be capable of adequately supplying the area at all times over the next ten years. However, with any one of three critical lines out of service, the increased loading on the remaining lines results in large voltage drops along those lines. This results in low voltages at the 132 kV substations. The limit of the network's capacity is reached when the transformer tap changers at the 132 kV substations and at the substations within the Country Energy network can no longer restore the voltage to within the acceptable range at end use customer premises.

The three critical outages are described in the following sections.

3.2.1. Outage of the Armidale – Coffs Harbour 132 kV Line

This line is the primary supply for the Coffs Harbour area. When it is out of service, the voltage drops on the two remaining lines, one via Grafton (Koolkhan) and the other via Kempsey, may result in inadequate voltage levels at Coffs Harbour and Nambucca at times of high demand. It is presently expected that this would occur from around winter 2006.

3.2.2. Outage of the Armidale – Kempsey 132 kV Line

This line is the primary supply for the Kempsey area. It also normally supplies much of the Port Macquarie load. When it is out of service, the voltage drops on the two remaining lines from Coffs Harbour and Taree, may result in inadequate voltages at Kempsey and Port Macquarie at times of high demand. It is presently expected that this would occur from around winter 2005.

3.2.3. Outage of the Kempsey to Port Macquarie 132 kV Line

When this line is out of service, supply to Port Macquarie is provided from Newcastle, via Taree. Under this condition, the voltage drops in the lines from Newcastle may result in inadequate voltage levels at Port Macquarie. It is presently expected that this would occur from around winter 2004.

3.3. Determination of an Objectively Measurable Service Standard

TransGrid and Country Energy have jointly agreed that the objectively measurable service standard to be applied to this area is:

1. With all network elements in service, the loading on each element is not to exceed the continuous rating of that element.

2. Following outage of one network element, the loading on each remaining element is not to exceed the short time emergency rating of that element whilst operator actions, such as opening of other network elements and transferring of loads via lower voltage networks, are taking place.

3. With one network element out of service and following operator actions:

   - the loading on each remaining element is not to exceed the sustained emergency rating of that element;

   - the voltage levels at end-user premises are to be within acceptable levels following switching of reactive plant and operation of transformer tap-changers. This requires that voltages at the 33 kV busbars at Port Macquarie and Kempsey and the 66 kV busbar at Coffs Harbour are maintained at or above nominal. [At present the minimum acceptable voltages at Port Macquarie and Kempsey are above these levels. However, over the next two years Country Energy intends to undertake minor works to overcome these limitations].

In terms of reliability standards as defined by the Code, this constitutes a nominal "N-1" reliability criterion (as described in S5.1.2.2 (b) (4)).

3.4. Joint Planning

Country Energy and TransGrid have jointly planned the 330 kV and 132 kV network supplying the Mid North Coast for many years. The most recent major increase in supply capacity, the establishment of the Coffs Harbour – Nambucca – Kempsey double circuit 132 kV line and Nambucca 132/66 kV substation, was the result of joint planning.

TransGrid and Country Energy have carried out joint annual planning reviews as required by Clause 5.6.2 (b) of the National Electricity Code (refer to Appendix A). As required by Clause 5.6.2(c) they have identified that the above constraints give rise to a need for network augmentations and have carried out joint planning to determine options for these augmentations.

3.5. Local Load Forecast

The demand for electricity in the Coffs Harbour to Port Macquarie area is seasonal, with the highest demands occurring during winter. Summer maximum demands are typically around 80% of the winter maximum demands. Figure 3 below shows the maximum demands (averaged over a half hour period) for each day from 1 January 1999 to 31 August 2003.

Figure 3 Daily Maximum Demands for the Coffs Harbour to Port Macquarie Area

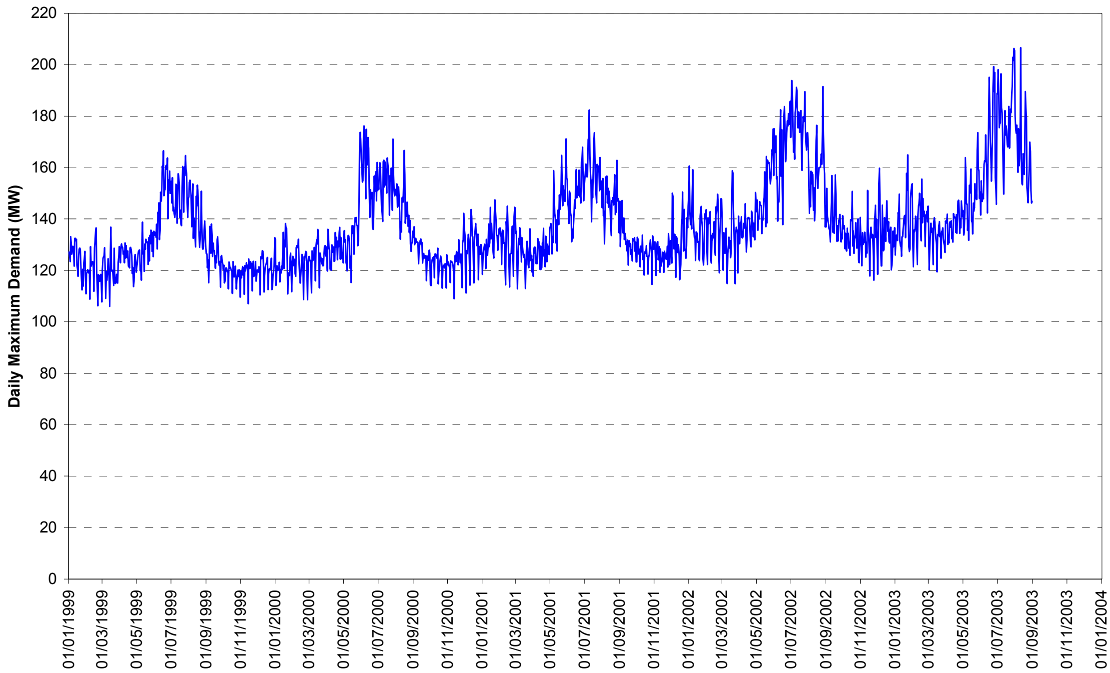
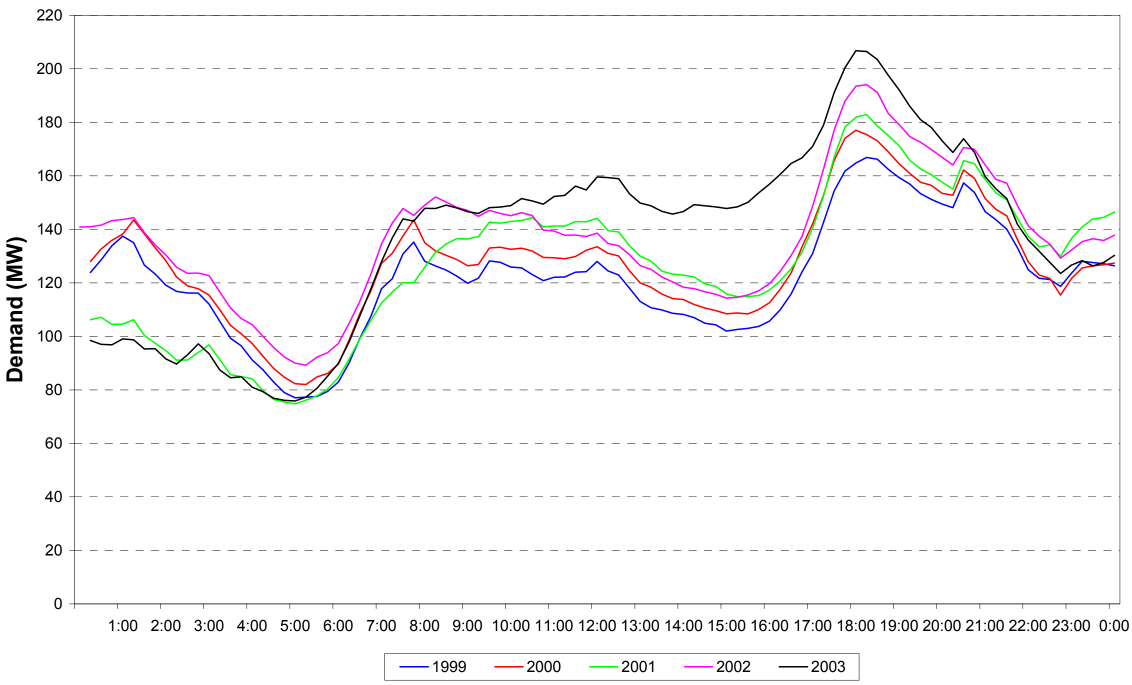


Figure 4 below shows the load on the days of maximum demand in 1999, 2000, 2001, 2002 and 2003. The impact of Country Energy's existing demand management (load control) system is clearly visible. Load has been shifted from the morning and the evening peaks to after the evening peak (from the period commencing about 7 am to the period commencing around 8 pm and extending through until the early hours of the morning).

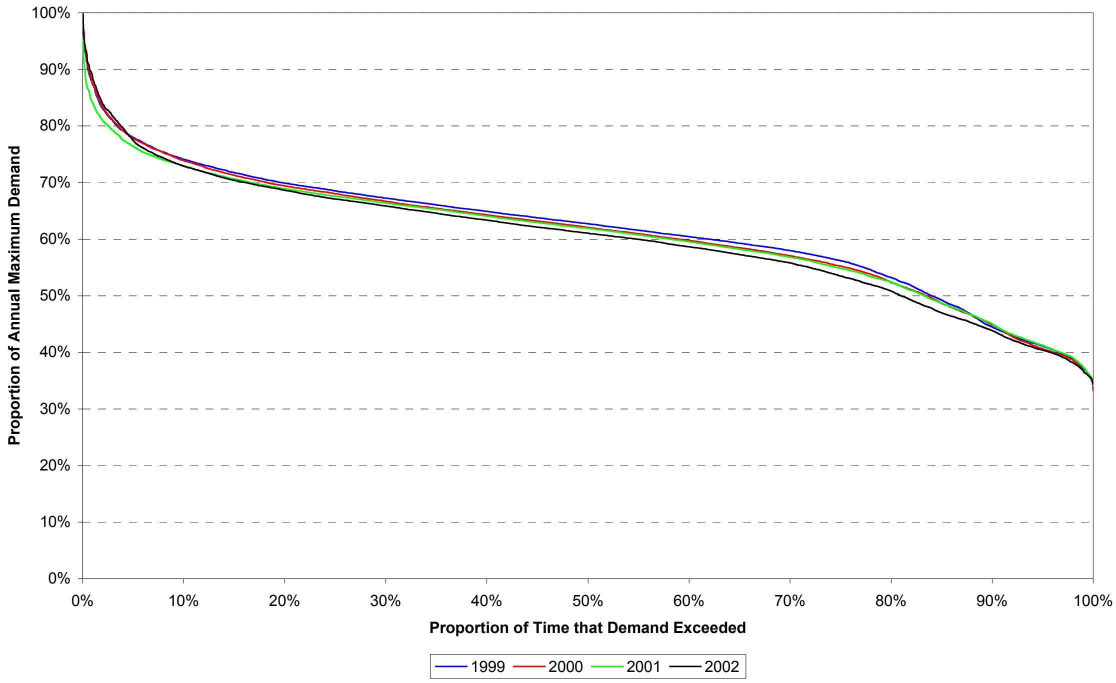
Figure 4 Load Profile on Days of Maximum Demand



The highest demands exist for only comparatively short periods. For example, demands above approximately 90% of the annual peak demand, occur primarily in “blocks” of two hours duration or less and those above approximately 95% of the annual peak demand, occur primarily in “blocks” of one hour duration or less.

Figure 5 shows the load duration curves for 1999, 2000, 2001 and 2002. These curves show the proportion of time that particular demands (expressed as a proportion of the maximum demand for that year) are exceeded.

Figure 5 Load Duration Curves for the Coffs Harbour to Port Macquarie Area



3.5.1. What Causes the Peak Demand?

As the highest demands occur during winter and are typically around 6:00 pm to 7:00 pm, it is likely that space heating and other domestic activities, such as cooking, are major contributors to those demands.

An inspection of the demand and Coffs Harbour ambient temperature data for the days of highest demand in 1999, 2000 and 2001 shows that:

- There is only a weak link between maximum demand and ambient temperature (as shown by the wide scattering of points in Figure 6 below).
- The highest demands tend to occur in June and July.
- The highest demands occur less frequently on Fridays, Saturdays and Sundays than on other days, suggesting different human activities on those days. The demand profile for the week of maximum demand in 2002 is shown in Figure 7 below.

Figure 6 Maximum Daily Demand as a Function of Daily Average Temperature

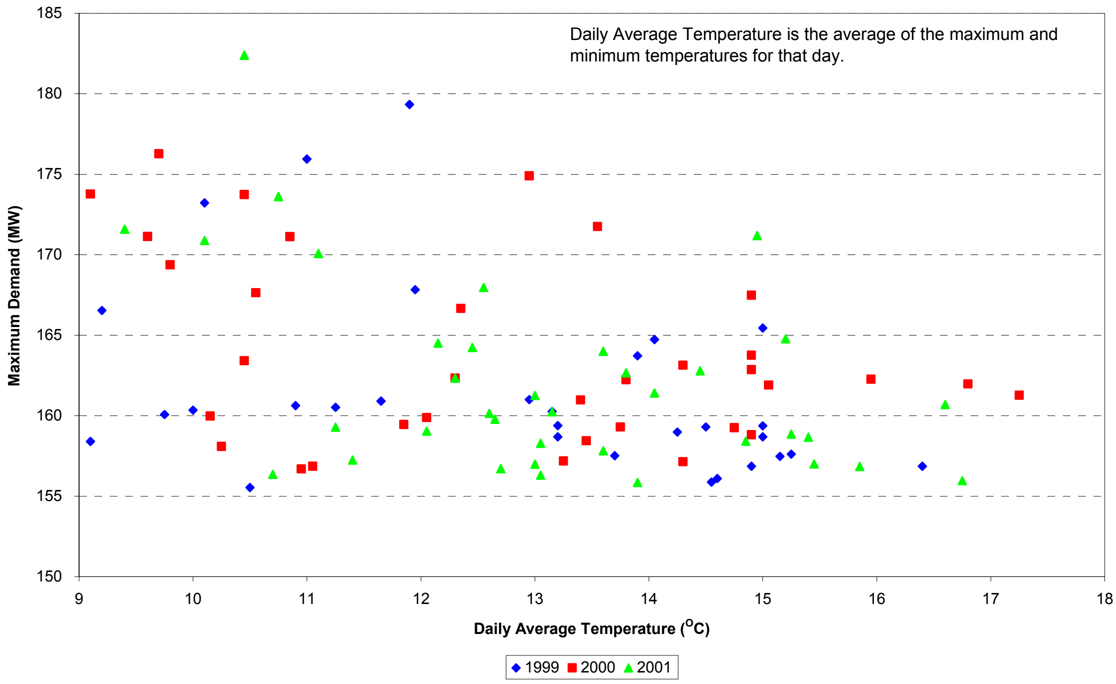
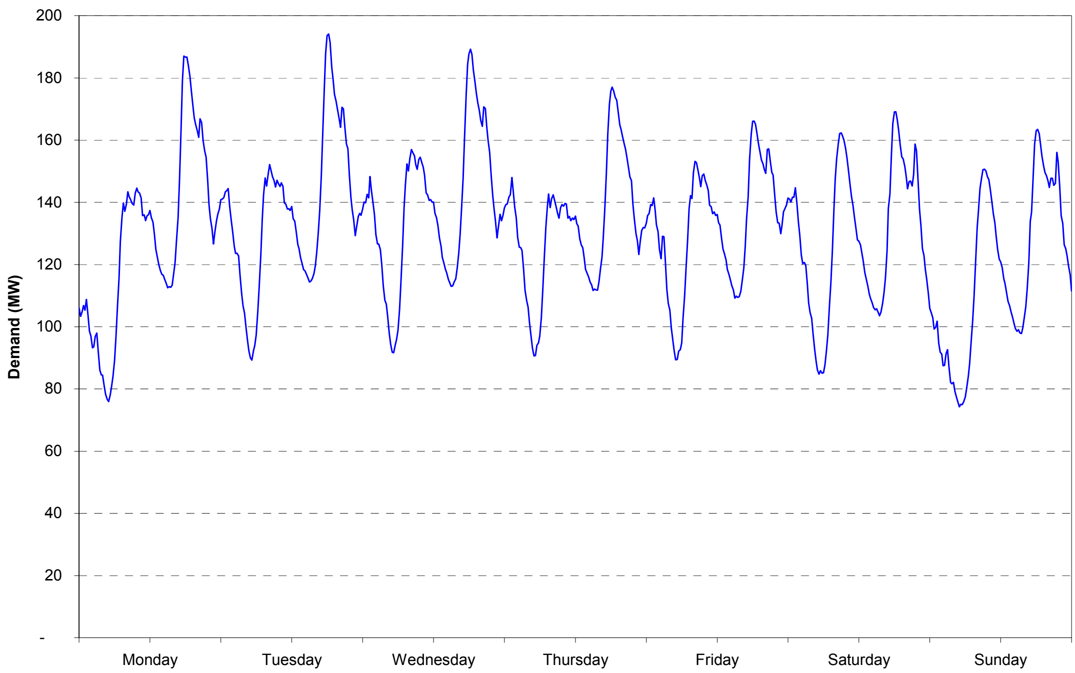


Figure 7 Demand Profile in the Week of Maximum Demand in 2002



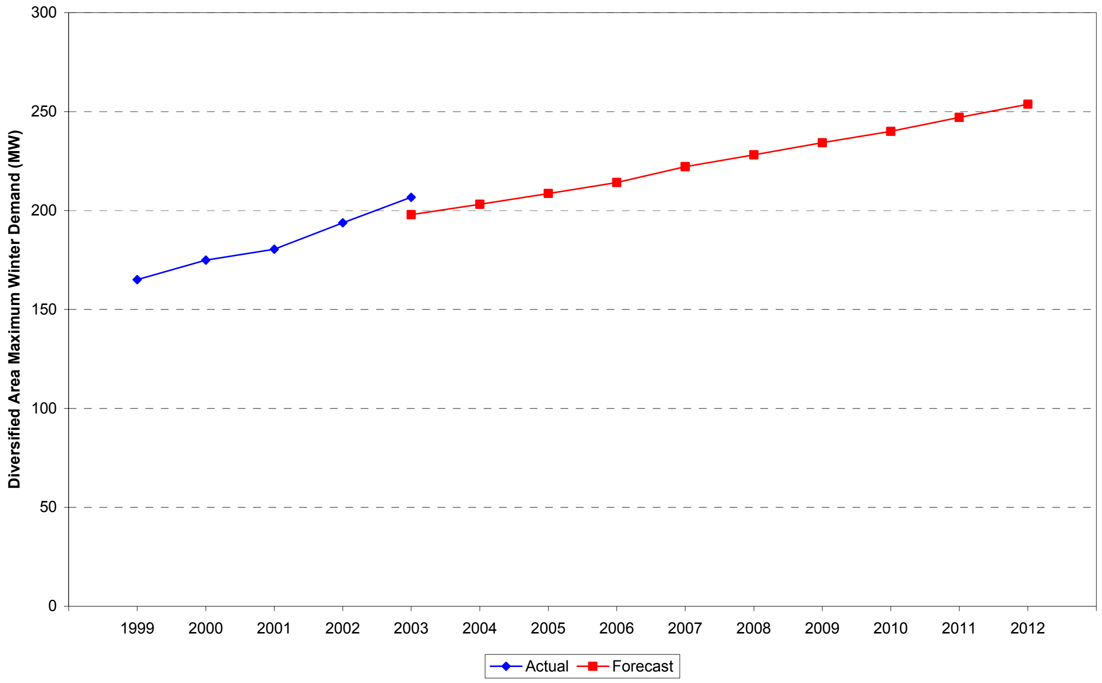
3.5.2. The Load Forecast

The forecast peak demands for the Coffs Harbour to Port Macquarie area are shown in Table 1 below.

Table 1 Winter Peak Demand Forecasts (MW)

Supply Point	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coffs Harbour	66.0	68.0	56.0	57.7	59.4	61.2	63.1	64.9	66.9	68.9
Dorrigo	4.0	4.0	4.0	4.0	5.3	5.4	5.5	5.0	5.7	5.8
Sawtell (132 kV)			14.0	14.4	14.9	15.3	15.8	16.2	16.7	17.2
Raleigh (132 kV)			12.0	12.4	12.7	13.1	13.5	13.9	14.3	14.8
Nambucca	30.0	30.8	19.5	20.0	20.5	21.0	21.5	22.1	22.6	23.2
Kempsey 33 kV	35.1	35.8	36.5	37.2	37.9	38.6	39.3	40.0	40.7	41.4
Kempsey 66 kV	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0
Port Macquarie	69.0	71.1	73.2	75.4	77.7	80.0	82.4	84.9	87.4	90.0
Total	206	212	217	223	224	231	244	250	257	264
Diversified Total	198	204	208	214	215	222	234	240	247	253

Figure 8 Forecast Maximum Diversified Winter Demand for the Area



3.6. Consideration of DSM and Local Generation

The network constraints have previously been described in:

- TransGrid's Annual Planning Statements for 1999, 2000 and 2001;
- TransGrid's Annual Planning Reports for 2002 and 2003;
- documents titled "Emerging Transmission Network Limitations on the New South Wales Mid North Coast" and "Request For Proposals for Demand Management or Local Generation on the Mid North Coast", both jointly published with Country Energy;
- the Consultation Paper, also jointly published with Country Energy

TransGrid and Country Energy have received submissions or enquiries from only one party concerning these constraints. That submission was in response to the Consultation Paper and is addressed in Section 5 of this Final Report.

As no proponent has emerged for demand management or local generation options these are no longer being considered.

3.7. Quantification of Network Constraints

The network constraints are discussed in Section 3.2 above. The timing of the expected occurrence of each constraint is shown in Table 2 below.

Table 2 Expected Occurrence of Network Constraints

Constraint	**Expected to Occur From**
Unacceptably low voltages at Coffs Harbour and Nambucca on outage of the 96C Armidale – Coffs Harbour 132 kV line.	Winter 2005 (1,000 MW Import via QNI) Winter 2006 (No QNI Flow) Winter 2007 (750 MW Export via QNI)
Unacceptably low voltages at Kempsey and Port Macquarie on outage of the 965 Armidale – Kempsey 132 kV line.	Winter 2003 (1,000 MW Import via QNI) Winter 2005 (No QNI Flow) Winter 2004 (750 MW Export via QNI)
Unacceptably low voltages at Port Macquarie on outage of the 96G Kempsey – Port Macquarie 132 kV line.	Winter 2004

4. OPTIONS CONSIDERED

4.1. General

The constraints in Section 3.2 fall into two broad categories:

1. two of them relate to supply capacity to the mid north coast from the Armidale area (outages of the 96C Armidale – Coffs Harbour and 965 Armidale – Kempsey 132 kV lines); and

2. the other relates to supply capacity within the mid north coast network (outage of the 96G Kempsey – Port Macquarie 132 kV line).

The Consultation Paper addressed supply to the mid north coast from the Armidale area. The constraint within the mid north coast network will be addressed in a separate consultation document.

In the Consultation Paper TransGrid and Country Energy described two network options and a number of hypothetical demand management and local generation options. As no proponent for demand management or local generation options has emerged, they have not been considered in this Final Report.

The two network options described in the Consultation Paper are unchanged. For completeness, their description is repeated below.

4.2. Network Options

Establishment of a 330/132 kV substation in the Coffs Harbour area, supplied from the existing Armidale – Lismore 330 kV line, is the only network development which was considered to be feasible. Options such as construction of additional 132 kV or 330 kV transmission lines from Armidale (the nearest 330 kV substation) to the Coffs Harbour/Kempsey area were not considered due to the need to secure additional line routes (as it would not be possible to reconstruct existing lines without first having completed a major reinforcement of the network supplying the area). It is expected that the substation and other associated works could be completed by mid 2006. Thus there would be a small risk of load being interrupted over winter 2003, 2004 and 2005.

The substation would initially have a single 375 MVA transformer. In the medium term, a second transformer may be required. In the longer term, it is possible, but unlikely, that connection of a third 330 kV line may be required. No specific provision will be made to accommodate a third 330 kV circuit at this stage. Additional 132 kV line connections may also be required in the longer term.

To facilitate maintenance and to improve security of supply to Coffs Harbour and Lismore, a second 330 kV switchbay is to be provided at Armidale for the existing 89 Armidale – Lismore 330 kV line. This switchbay is expected to cost around $1 million.

Three stages of substation development were considered:

1. the initial single transformer arrangement with the minimum 330 kV and 132 kV developments;
2. following installation of a second 330/132 kV transformer; and
3. the tentative ultimate development with additional 132 kV and 330 kV line connections and additional reactive plant.

Two locations for the substation were considered, namely:

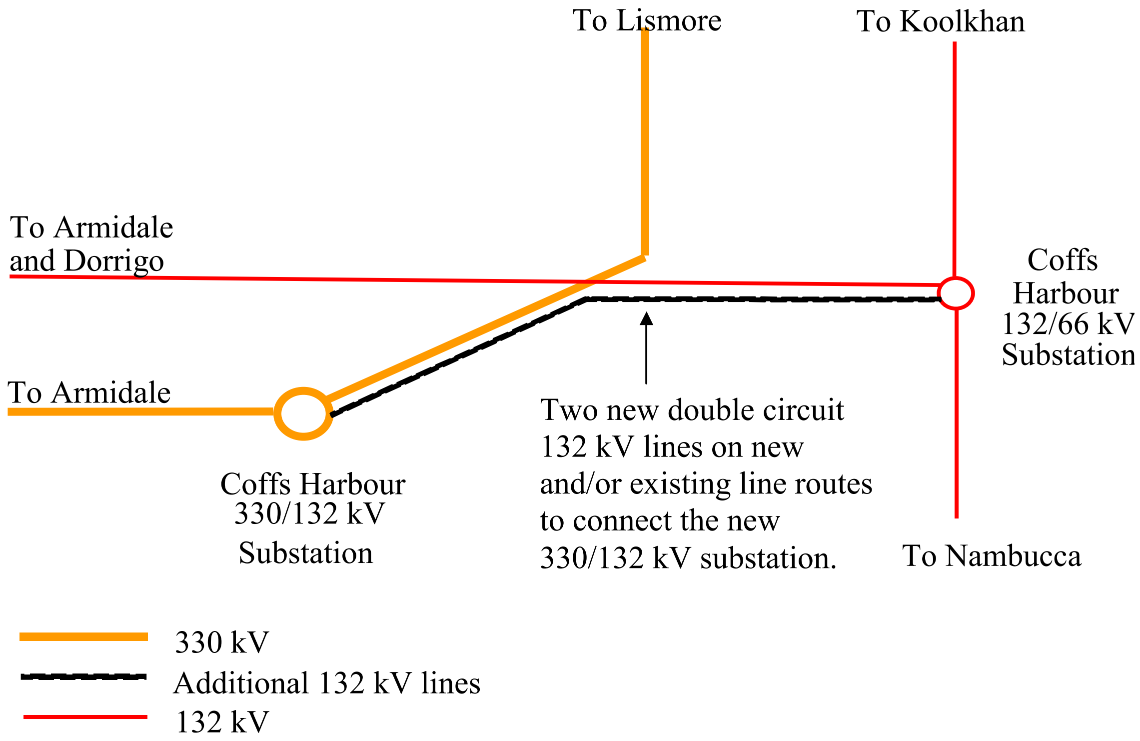
- on a site adjacent to the 330 kV line approximately three to four kilometres from the 132/66 kV substation; and
- adjacent to the existing 132/66 kV substation.

These location options are described in the following sections.

4.2.1. Option 1: 330/132 kV Substation Adjacent to the Existing 330 kV Line

This option is shown in Figure 9. It would utilise a site adjacent to the 330 kV line that was purchased a number of years ago for a 330/132 kV substation. It would entail establishing a new independent substation and two high capacity double circuit 132 kV lines to the 132/66 kV substation. Connection of the 330 kV line would be relatively straight forward.

Figure 9 Substation Site Adjacent to the 330 kV Line



As the site is traversed by water courses and does not have all weather road access, significant civil works would be required.

Two variants of this option covering different 132 kV line routes were investigated, namely:

- Reconstructing existing 132 kV lines as double circuit lines to form the high capacity connections between the substations; and
- Obtaining a new route for one of the double circuit 132 kV lines.

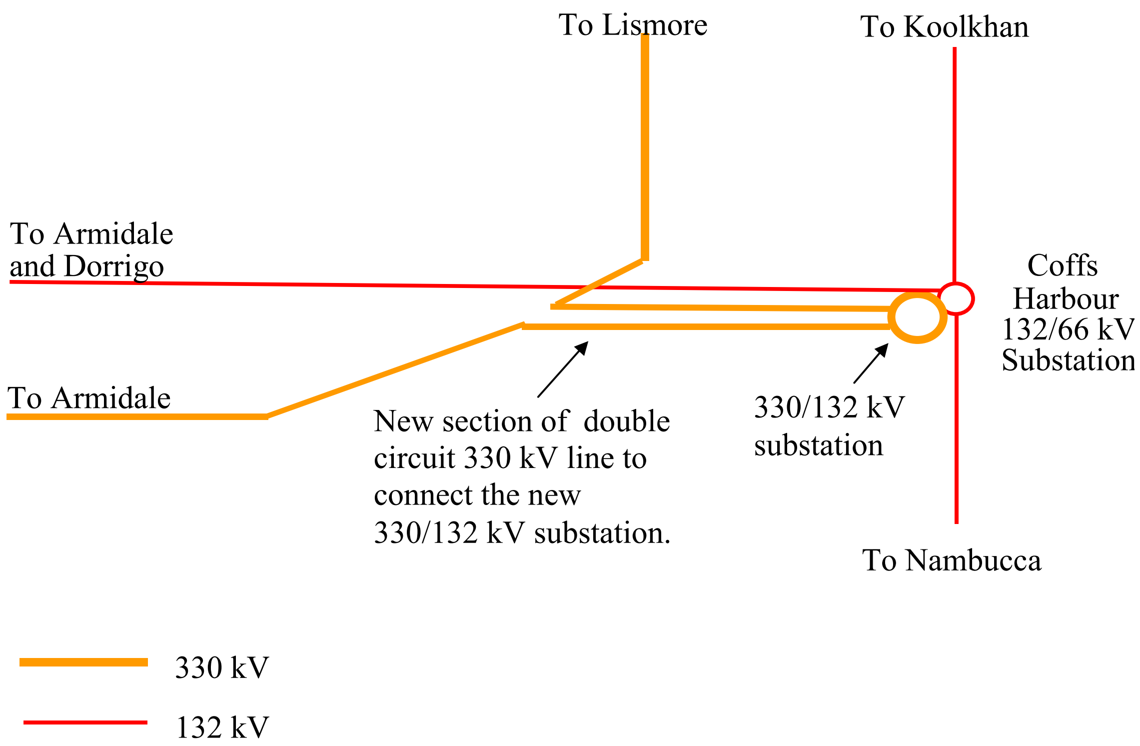
Both these variants would entail reconstruction of existing lines and the attendant need to undertake this at times of lower load could delay completion of the project.

This is the less preferable network option as it has the higher long term capital cost and is expected to have a larger environmental impact. Consequently, this option has been discarded.

4.2.2. Option 2: 330/132 kV Substation Adjacent to the Existing 132/66 kV Substation

This option is shown in Figure 10. It would enable existing infrastructure, such as the 132 kV busbar at Coffs Harbour 132/66 kV substation to be used. It would also remove the need to establish high capacity 132 kV lines between the 330 kV and 132 kV substations. However, instead of the two double circuit 132 kV lines, one section of new double circuit 330 kV line would be required.

Figure 10 Substation Adjacent to the Existing 132/66 kV Substation



4.3. Demand Management and Local Generation Options

As indicated above, no proponents for demand management or local generation options have emerged. Consequently, they are not considered to be viable options and have not been considered in this report, although they were considered in the Consultation Paper.

5. RESPONSES TO THE CONSULTATION PAPER

One response to the Consultation Paper was received from Tarong Energy. The text of that letter, together with the text of TransGrid's reply is included in Appendix B.

Tarong Energy was concerned that the Consultation Paper did not provide sufficient information on:

- the relationship between the onset of the voltage related constraints on the mid north coast and flows on the Queensland to New South Wales Interconnector (QNI); and
- the reasons why constraints imposed by low voltages on the Mid North Coast are managed in a different way to constraints imposed by the thermal rating of one of the 132 kV lines supplying the Mid North Coast.

Tarong Energy also mentioned that they were considering opportunities to install local generation on the Mid North Coast to allow higher southward flows on QNI. However, no decision had been made as the technical and commercial viability had not been assessed. As Tarong Energy's considerations are at an early stage, they have not been included in the application of the regulatory test in this report.

Tarong Energy's observation that the onset of two of the voltage related constraints depends on the magnitude and direction of flows on QNI is correct. The analysis conducted by TransGrid and Country Energy did not attempt to model actual likely flows on QNI as these depend on numerous factors including generator bidding behaviour. Instead, three cases for QNI flows were considered (high flow south, high flow north and no flow) to give the range of dates by which the constraints are likely to emerge.

TransGrid and Country Energy accept that there is a small risk of not being able to supply all of the load on the Mid North Coast prior to Coffs Harbour 330/132 kV substation being commissioned in 2006. This risk is minimal as it would involve high flows on QNI coincident with high demands for electricity on the Mid North Coast and either the Armidale – Coffs Harbour or Armidale – Kempsey 132 kV line being forced out of service.

Tarong Energy has also observed that constraints due to the thermal rating of the Armidale – Kempsey 132 kV line are managed in a different way to those related to unacceptable voltage levels. This stems from the fundamental difference between these types of constraints. Essentially, the voltage constraints can only be relieved by strengthening the transmission network supplying the Mid North Coast. In this case the best approach is to establish a 330/132 kV substation near Coffs Harbour. Such a development would also reduce the loading on the Armidale – Kempsey 132 kV line and the likelihood of its thermal rating being exceeded.

Whilst establishment of the Coffs Harbour 330/132 kV substation would relieve the thermal limitations in the medium term, TransGrid believes that it is important that they be relieved before 2006. Thermal limitations can also be addressed by increasing clearances between the line conductors and ground at critical locations. These works can generally be completed at lower cost and more rapidly than construction of a major new substation. TransGrid is presently undertaking remedial works on the Armidale – Kempsey 132 kV line to increase conductor clearances at a number of locations. It is expected that these works will be completed over the next several months.

Should Tarong Energy decide to install generators on the Mid North Coast, TransGrid and Country Energy would be pleased to work with Tarong Energy to determine specific locations and operating regimes which would best meet both its needs and the needs of the transmission system.

6. APPLICATION OF THE REGULATORY TEST

6.1. Background

The Consultation Paper described two options to establish a 330/132 kV substation in the Coffs Harbour area, one of which had two variants. The technical performance (other than cost in the medium to long term) of these variants are almost identical. However, establishment of the substation adjacent to the present 132/66 kV substation (Option 2) offers the lowest cost in the medium to long term. Consequently only that network option was considered in the analysis in the Consultation Paper.

For completeness, the estimated costs of the network options considered in the Consultation Paper are shown in Table 3 below.

Table 3 Capital Cost of Options Considered in the Consultation Paper ($M)

Option		One Transformer	Two Transformers	Tentative Ultimate
Option 1A	(330/132 kV substation adjacent to the 330 kV line, existing 132 kV lines reconstructed)	18	30	33
Option 1B	(330/132 kV substation adjacent to the 330 kV line, one new 132 kV line route available)	18	30	32
Option 2	(330/132 kV substation adjacent to the existing 132/66 kV substation)	17	24	25

As indicated above, no proposals for demand management or local generation have been received. Nor were any additional options proposed. Consequently, demand management and local generation are not considered to be viable options.

The only remaining option is Option 2, establishment of a 330/132 kV substation adjacent to the existing 132/66 kV substation together with construction of a short section of double circuit 330 kV line to connect it to the existing Armidale – Lismore 330 kV line.

For completeness, the analysis of Option 2 from the Consultation Paper is included in Appendix C.

6.2. Recommended Action

The most cost effective feasible option is Option 2, establishment of a 330/132 kV substation adjacent to the existing 132/66 kV substation, together with construction of a short section of double circuit 330 kV transmission line to connect the substation to the existing Armidale – Lismore 330 kV line.

TransGrid and Country Energy recommend that Option 2 be implemented. It is expected that these works will be completed by mid 2006.

7. CONTACT DETAILS

This report recommends the construction of a new large network asset. Therefore *Code Participants* may dispute the recommendations of the report under Clause 5.6.2 (i) of the Code. Code Participants who intend to dispute the recommendations of this report must notify TransGrid by close of business on 31 December 2003.

Contact details for notification of disputes are:

Erik Beerden

Market Compliance Manager

TransGrid

PO Box A1000

Sydney South NSW 1235

or

Email: erik.beerden@transgrid.com.au

Phone: 02 9284 3196

Fax: 02 9284 3050

APPENDIX A

Clause 5.6.2 of the National Electricity Code in Operation from 6th December 2001 to 7th March 2002

5.6.2 Development of networks within a region

(a1) The terms *Network Service Provider, Transmission Network Service Provider* and *Distribution Network Service Provider* when used in this clause 5.6.2 are not intended to refer to, and should not be read or construed as referring to, any *Network Service Provider* in its capacity as a *Market Network Service Provider*.

(a) Each *Transmission Network Service Provider* and *Distribution Network Service Provider* must analyse the expected future operation of its *transmission networks* or *distribution networks* over an appropriate planning period, taking into account the relevant forecast *loads,* any future *generation,* market network service, demand side and *transmission* developments and any other relevant data.

(b) Each *Transmission Network Service Provider* must conduct an annual planning review with each *Distribution Network Service Provider connected* to that *transmission network* within each *region.* The annual planning review must incorporate the forecast *loads* submitted by the *Distribution Network Service Provider* in accordance with clause 5.6.1 or as modified in accordance with clause 5.6.1(d) and must include a review of the adequacy of existing *connection points* and relevant parts of the *transmission system* and planning proposals for future *connection points*.

(c) Where the necessity for *augmentation* or *extension* is identified by the annual planning review, joint planning must be undertaken by the relevant *Network Service Providers* in order to determine plans that can be considered by relevant *Code Participants* and *interested parties*

(d) The annual planning review is to comprise a planning period of 5 years for *distribution networks* and 10 years for *transmission networks.*

(e) *Network Service Providers* may extrapolate the forecasts provided by *Code Participants* for the purpose of planning and where this analysis indicates that any relevant technical limits of the *transmission* and *distribution systems* will be exceeded, either in normal conditions or following the contingencies specified in schedule 5.1, the *Network Service Provider* must notify any affected *Code Participants* of these limitations and advise those *Code Participants* of the expected time required to allow appropriate corrective *augmentation* of the *network* or modifications to *connection facilities* to be undertaken.

(f) Within the time for corrective action notified in clause 5.6.2(e) the *Network Service Provider* must consult with affected *Code Participants* and *interested parties* on the possible options, including but not limited to demand side options, *generation* options and market network services provider options to address the projected limitations of the *relevant transmission system* or *distribution system* except that a *Network Service Provider* does not need to consult on a *network* option which would be a *new small network asset*.

(g) Each *Network Service Provider* must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the *regulatory* test, while meeting the technical requirements of schedule 5.1 of the *Code* and where the *Network Service Provider* is required by clause 5.6.2(f) to consult on the option this analysis and allocation must form part of, the consultation on that option.

(h) Following conclusion of the process outlined in clauses 5.6.2(f) and (g), the *Network Service Provider* must prepare a report that is to be made available to affected *Code Participants* and *interested parties* which:

- (1) includes assessment of all identified options;
- (2) includes details of the *Network Service Provider's* preferred proposal and details of:
  - (A) its economic cost effectiveness analysis in accordance with clause 5.6.2(g)(1); and
  - (B) both its determination in accordance with clause 5.6.2(g)(2) and its consultations conducted for the purposes of that determination.

(3) summarises the submissions from the consultations; and

(4) recommends the action to be taken.

(i) *Code Participants* may dispute the recommendation of the report prepared under clause 5.6.2(h) within 40 *business days* after the report is made available in respect of any proposal that is a *new large network asset* or is reasonably likely to change the *use of system service* charges applicable to that *Code Participant* by more than 2% at the date of the next price review, based on the assumption that the same approach to *network pricing* is taken for the next review period as that taken for the current review period.

(j) Where any *Code Participant* disputes a recommendation under clause 5.6.2(i), the *Network Service Provider* and the affected *Code Participants* must negotiate in good faith with a view to reaching agreement on the action to be taken.

(k) The relevant *Network Service Provider* must arrange for the *network* operations (if any) recommended by its report made in accordance with clause 5.6.2(h) to be available for service by the agreed time:

(1) upon completion of the 40 *business day* period referred to in clause 5.6.2(i) or on resolution of any dispute in accordance with clause 8.2 of this *Code* in relation to proposals to which clause 5.6.2(j) applies; and

(2) upon completion of the report referred to in clause 5.6.2(h) for any other network option recommended by the report,

the relevant *Network Service Provider* must arrange for the project to be available for service by the agreed time and the *Network Service Provider* must include the cost of the relevant assets in the calculation of *transmission service* and *distribution service* prices determined in accordance with Chapter 6 of the *Code.*

(l) If a *use of system service* or the provision of a service at a *connection point* is directly affected by an *augmentation,* appropriate amendments to relevant *connection agreements* must be negotiated in good faith between the parties to them.

(m) Where the *Network Service Provider* decides to implement a *generation* option as an alternative to *network augmentation*, the *Network Service Provider* must:

(1) register the *generating unit* with *NEMMCO* and specify that the *generating unit* may be periodically used to provide a *network* support function and will not be eligible to set *spot prices* when *constrained on* in accordance with clause 3.9.7; and

(2) include the cost of this *network* support service in the calculation of *transmission service* and *distribution service* prices determined in accordance with Chapter 6 of the *Code*.

APPENDIX B

Text of Letter from Tarong Energy and TransGrid's Reply

Tarong Energy Letter

29 August 2003

Mr Leon Arkinstall
Principal Engineer / Project Development
TransGrid
PO Box A1000
Sydney South NSW 1235

Dear Mr Arkinstall,

DEVELOPMENT OF ELECTRICITY SUPPLY TO THE NEW SOUTH WALES MID NORTH COAST

Tarong Energy is pleased to make this submission to TransGrid in response to the above consultation. While Tarong Energy generally agrees with the conclusions reached by TransGrid we are concerned the TransGrid appears to have not completely put forward the relationship between QNI flows and local network constraints on the mid north coast.

Relationship with QNI Flows
In section 3.7 of the Consultation Document TransGrid identify the expected occurrence of the network constraint as a function of QNI flow. The unmistakable impression created by this table is that the direction and magnitude of QNI flow determines the timing of when corrective action is required. This is contrary to the operating experience already seen to date where potential overloads to line 965 have been managed by constraining QNI flow.

It is not stated why the treatment of low voltage following a contingency should be different to the treatment of thermal overloads following a contingency. TransGrid have not proposed the establishment of Coffs Harbour 330/132 kV substation to relieve line overloads but have instead been content to see the QNI southward flow constrained, to the considerable cost of NSW consumers. Now that the problems are seen to be extending to voltage control TransGrid seems prepared to adopt a different approach. TransGrid should clearly state why there is a difference of approach to these two similar circumstances.

At this time Tarong Energy is considering an approach to the ACCC in respect of the next revenue determination for TransGrid on this subject. Tarong Energy believes that the limitations of the northern NSW 132 kV network that have constrained QNI flow require a reduction in the regulated return to TransGrid from the QNI assets. The nature of the limitations seen is to reduce the southward capability of QNI right at the times of highest demand (and price) in NSW when imports from Queensland are most needed. NSW customers are paying for the supposed capability of QNI throughout the year, and then paying again in the form of higher energy prices when the capability isn't available at the time they most value it.

Local Generation Options
A reduction in the TransGrid regulated revenue from QNI would provide some compensation to NSW electricity customers, and we believe is necessary to provide incentives for TransGrid to address these network limitations. However, in the short term Tarong Energy is assessing some options that will compensate for these limitations, and may help to defer the time at which the Coffs Harbour 330 kV substation is required to be established.

Briefly, Tarong Energy is considering opportunities for placing several MWs (up to 10 MW is being considered) of diesel powered generation in the area. The intent is that this will limit the impact of the 965 limits and allow greater southward flow on QNI during high NSW demand periods. This generation would be operated at times when the contingency risk to the 132 kV network is constraining the flow of QNI and it would be profitable for Tarong Energy to increase QNI flow southward. This may not correspond to times of maximum demand in the mid north coast area.

For this reason Tarong Energy would be interested in discussing with TransGrid and Country Energy the potential for certain operating patterns of the proposed generation to assist in managing other network constraint conditions in the area. It should be noted that Tarong Energy has not committed to any such project in the area and is still assessing the technical and commercial feasibility of such an approach. Should a decision be made to proceed with such a project we believe it could be completed quite rapidly through leasing of diesel generation instead of outright purchase.

Yours sincerely

Greg Hesse
SENIOR MANAGER, REGULATORY AFFAIRS

TransGrid Reply dated 8 September 2003

Mr Greg Hesse
Senior Manager, Regulatory Affairs
Tarong Energy Corporation Ltd
GPO Box 800
BRISBANE QLD 4001

Dear Mr Hesse

Development of Electricity Supply to the New South Wales Mid North Coast

Thank you for your letter of 29 August 2003 concerning the consultation paper on options to relieve constraints on the transmission network supplying the New South Wales mid north coast.

Your observation that the onset of network constraints (low voltages at substations on the mid north coast) depends on flows on QNI is correct. There is however a fundamental difference between constraints imposed by low voltages and those resulting from the thermal rating of the 965 Armidale – Kempsey 132 kV line, namely that the latter can be managed by “the market” (by limiting flows on QNI).

In analysing the options to relieve network constraints TransGrid must consider the requirements of the Regulatory Test. As you are no doubt aware, the Regulatory Test considers overall net costs and benefits to the producers and users of electricity within the NEM and excludes consideration of transfer payments between users and producers such as those resulting from high pool prices. The ACCC is currently reviewing the Regulatory Test in response to concerns such as those you have raised about the impact of high pool prices on electricity users.

The consultation paper did not include the overall benefits of reductions in the magnitude, frequency and duration of constraints on QNI flows resulting from the thermal rating of 965 line as, on completion of remedial works on 965 to be undertaken over the next several months, those benefits are expected to be small.

As you are aware, the technical limitations to flows on QNI are given by a number of constraint equations, of which the “965 constraint” is but one. These constraint equations describe the complex interactions between several parameters, including generation patterns and demands in Queensland and New South Wales. TransGrid has no influence over many of these parameters, for example end-use customers determine demands and generators (through their bidding behaviour) determine generation dispatch patterns.

With respect to the possibility of Tarong Energy establishing local generation on the mid north coast, we would be pleased to discuss the location, operating regimes and connection arrangements which would best meet both your requirements and those of the transmission network. In anticipation of such discussions, I have forwarded a copy of your letter to Country Energy.

Should you wish to discuss any of these issues further, please contact me or our Mr Gordon Burbidge on 02 9284 3092 or by email Gordon.Burbidge@transgrid.com.au.

Yours sincerely

Mal Park
Executive Manager/Strategic Network Development

APPENDIX C

Analysis of Option 2

1. Basis of the Analysis

The preliminary application of the Regulatory Test in the Consultation Paper incorporated:

- Capital costs.
- Operation and Maintenance (O&M) costs.
- Benefits of reductions in losses.
- Benefits of reductions in expected unserved energy.

Sensitivity studies covered:

- discount rate;
- asset lives;
- escalation of costs;
- flows on QNI; and
- method of valuing losses.

The base case assumptions and the range over which sensitivity checks were conducted are shown in Table 4.

Table 4 Base Case Values and Range of Values Used in Sensitivity Checks

Parameter	Base Case Value	Sensitivity Checks at
Real Discount Rate	10%	7% and 13%
Annual O&M Cost Network option	 2% of Capital Cost	 1% and 3% of Capital Cost
Asset Lifetimes Substations Transmission Lines	 30 years 45 years	 20 and 40 years 30 and 60 years
Capital Costs		20% increase
Flow on QNI	Zero	1,000 MW import and 750 MW export
Method of Valuing Losses	Based on $35/MWh	Based on $500/kW + $15/MWh and based on $15/MWh

In the analysis, the benefits in reductions in unserved energy were valued at $10,000/MWh, the Value of Lost Load (VOLL) in the National Electricity Market.

2. Losses

Due to the extended nature of the 132 kV network supplying the Mid North Coast and it being heavily loaded, electrical losses are relatively high. Consequently, loss reductions are an important consideration.

The loss reductions depend to a limited extent on interstate flows to or from Queensland. In quantifying the loss reductions, three conditions were considered:

1. no flow on QNI;
2. 1,000 MW import to NSW on QNI (the nominal import capacity); and
3. 750 MW export to Queensland on QNI (the nominal export capacity).

The value of the loss reductions was estimated using three different approaches:

1. Valuing the annual energy reduction at $35/MWh (an estimate of the long term average NSW pool price in the National Electricity Market); and
2. Valuing the reduction in peak losses at $500/kW (an estimate of the capital cost of installing new large scale peaking generation which may otherwise be required) and the annual energy reduction at $15/MWh (an estimate of the savings in fuel and variable operating costs, assuming that the majority of the losses would otherwise be supplied by black coal fuelled power stations).
3. Valuing the annual energy reduction at $15/MWh (assuming that a reduction in peak losses has no material effect on when new peaking generation is installed).

Table 5 below shows the expected loss reductions in 2006.

Table 5 Expected Loss Reductions in 2006

Option	Annual Energy (GWh)	Peak Losses (MW)	Value of Loss Reduction ($ million)		
			Based on $35/MWh	Based on $500/kW + $15/MWh	Based on $15/MWh
No Flow on QNI	40.1	13.3	1.4	7.3	0.6
1,000 MW Import to NSW on QNI	46.2	15.0	1.6	8.2	0.7
750 ME Export to Queensland on QNI	34.2	13.5	1.2	7.3	0.5

The estimated loss reductions are shown in Table 6 below.

Table 6 Estimated Loss Reductions due to Establishment of a 330/132 kV Substation

	2006	2007	2008	2009	2010	2011	2012
No Flow on QNI							
Reduction in Peak Losses (MW)	13	15	17	18	20	22	23
Reduction in Annual Losses (GWh)	40	43	45	47	50	52	54
1,000 MW Import to NSW on QNI							
Reduction in Peak Losses (MW)	15	17	19	21	23	25	27
Reduction in Annual Losses (GWh)	46	49	51	53	56	58	61
750 MW Export to QLD on QNI							
Reduction in Peak Losses (MW)	13	15	16	18	19	20	22
Reduction in Annual Losses (GWh)	34	36	39	41	43	45	47

3. Expected Level of Unserved Energy

As indicated above, network limitations are expected to emerge from 2003. Should a critical line be forced out of service at a critical time, it would be necessary to interrupt some load to restore voltages to acceptable levels. The amount of load at risk of interruption is shown in Table 7. It should be noted that these estimates are conservative as they assume that load interruptions can be "fine tuned" so that the minimum amount of load is interrupted. In practice "blocks" of load would be interrupted and it is likely that more than the minimum amount of load would be interrupted.

Table 7 Load at Risk

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Outage of 96C Armidale – Coffs Harbour Line									
No QNI Flow									
Maximum Load at Risk (MW)	0	0	0	3	9	14	19	22	26
Energy at Risk (MWh)	0	0	0	3	10	30	115	350	820
Hours the Load at Risk	0	0	0	1	2	8	17	45	105
1,000 MW Import via QNI									
Maximum Load at Risk (MW)	0	2	5	15	28	30	31	32	33
Energy at Risk (MWh)	0	2	5	25	120	350	660	1,500	2,850
Hours the Load at Risk	0	1	1	4	16	36	67	140	237
750 MW Export via QNI									
Maximum Load at Risk (MW)	0	0	0	4	11	14	17	21	24
Energy at Risk (MWh)	0	0	0	4	30	100	190	500	1,100
Hours the Load at Risk	0	0	0	1	4	10	25	60	135
Outage of 965 Armidale – Kempsey Line									
No QNI Flow									
Maximum Load at Risk (MW)	0	0	7	8	9	11	13	13	14
Energy at Risk (MWh)	0	0	10	40	100	250	540	1,000	1,750
Hours the Load at Risk	0	0	3	10	20	50	95	160	305
1,000 MW Import via QNI									
Maximum Load at Risk (MW)	4	9	14	15	17	17	17	18	19
Energy at Risk (MWh)	4	35	75	250	410	800	1,380	2,400	3,750
Hours the Load at Risk	1	7	13	50	70	130	200	300	450
750 MW Export via QNI									
Maximum Load at Risk (MW)	0	4	9	11	13	13	14	14	14
Energy at Risk (MWh)	0	7	40	150	240	600	1,000	2,000	2,900
Hours the Load at Risk	0	2	7	20	50	100	180	300	430
Total (Outage of Either Line)									
No QNI Flow									
Maximum Load at Risk (MW)	0	0	7	8	9	14	19	22	26
Energy at Risk (MWh)	0	0	10	43	110	280	655	1,350	2,570
Hours the Load at Risk	0	0	3	10	20	50	95	160	305
1,000 MW Import via QNI									
Maximum Load at Risk (MW)	4	9	14	15	28	30	31	32	33
Energy at Risk (MWh)	4	37	80	275	530	950	2,040	3,500	6,600
Hours the Load at Risk	1	7	13	50	70	130	200	300	450
750 MW Export via QNI									
Maximum Load at Risk (MW)	0	4	9	11	13	14	17	21	24
Energy at Risk (MWh)	0	7	39	154	270	700	1,190	2,500	4,000
Hours the Load at Risk	0	2	7	20	50	100	180	300	430

The average forced outage rate for both the 96C Armidale – Coffs Harbour and 965 Armidale – Kempsey 132 kV lines is approximately four and a half hours per year. The expected energy interrupted, sometimes referred to as Expected Unserved Energy, is shown in Table 8. These estimates are based on the energy at risk multiplied by the probability of a critical line being forced out of service.

Table 8 Expected Unserved Energy (MWh)

	2003	2004	2005	2006	2007	2008	2009	2010	2011
No QNI Flow	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.7	1.3
1,000 MW Import	0.0	0.0	0.0	0.1	0.3	0.5	1.0	1.8	3.4
750 MW Export	0.0	0.0	0.0	0.1	0.1	0.4	0.6	1.3	2.1

4. Results

The results of the analysis are shown in Table 9. The output of the base case economic model is shown in Table 10.

Table 9 Net Present Values of Costs ($ million)

	Option 2
Base Case	2
7% Discount Rate	0
13% Discount Rate	3
Reduced O&M Costs	1
Increased O&M Costs	3
Extended Asset Lives	2
Reduced Asset Lives	3
20% Increase in Capital Costs	4
1,000 MW Import via QNI	1
750 MW Export via QNI	3
Losses Valued at $500/kW + $15/MWh	-1
Losses Valued at $15/MWh	7

Table 10 Base Case Analysis of Option 2 (Establishment of a 330/132 kV Substation Adjacent to the Existing 132/66 kV Substation)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Residual
Capital Costs ($ million)																
Coffs Harbour 33/132 kV Substation	0	0	0	0	15	0	0	0	0	0	0	0	0	0	0	-10.0
330 kV Line	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	-0.7
O&M Costs ($ million)																
Network	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	13.4	15.1	16.8	18.4	20.1	21.7	23.4	25.1	26.7	28.4	30.1	
Loss Reduction (GWh)	0	0	0	0	40.1	42.5	44.9	47.3	49.7	52.1	54.5	56.9	59.2	61.6	64.0	
Value of Loss Reduction ($ million)	0	0	0	0	-1.4	-1.5	-1.6	-1.7	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.2	
Reduction in Unserved Energy																
Reduction (MWh)	0	0	0	0	0	0.1	0.2	0.3	0.7	1.3	2.3	3.9	6.4	10.1	15.6	
Value of Reduction ($ million)	0	0	0	0	0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	17.0	-1.1	-1.2	-1.3	-1.4	-1.4	-1.5	-1.6	-1.6	-1.7	-1.7	-12.2
NPV of Costs	**$2 million**															