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

CONSULTATION PAPER

JULY 2003

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1. EXECUTIVE SUMMARY

This paper has been prepared to provide a basis for TransGrid and Country Energy to consult with Code Participants and interested parties so as to identify options for the development of electricity supply to the Mid North Coast of New South Wales that will be included in an application of the ACCC's regulatory test. Section 1 provides a description of the Mid North Coast area and the context of the consultation paper within the regulatory approval process. It is proposed to allow interested parties to make submissions and provide other feedback in the period to the end of August 2003. An application of the regulatory test and a decision on the preferred option is envisaged by October 2003.

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, together with hypothetical Demand Management and hypothetical local generation options. Options 1A and 1B, which were discarded primarily due to cost considerations, 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 transformation at the existing 132/66 kV substation. The hypothetical Demand Management and local generation options are sized to give a one year delay in the emergence of the network limitations.

In Section 6 the results of a preliminary application of the regulatory test are presented. The main conclusions are that:

- The only feasible option at present is construction of a 330/132 kV substation adjacent to the existing 132/66 kV substation at Coffs Harbour, together with a short section (approximately two kilometres) of 330 kV transmission line. This is the option presently being pursued by TransGrid and Country Energy.

- Should Demand Management or local generation proposals be made, they may cost effectively delay the need for the substation.

2. IDENTIFICATION OF A NECESSITY FOR AUGMENTATION

2.1. Purpose and Scope

This paper has been prepared to provide a basis for TransGrid and Country Energy to consult (in accordance with Clause 5.6.2 (f) of the National Electricity Code) 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.

It includes:

- 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 these options that has been carried out in accordance with the requirements of the ACCC's regulatory test.

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.

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, 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

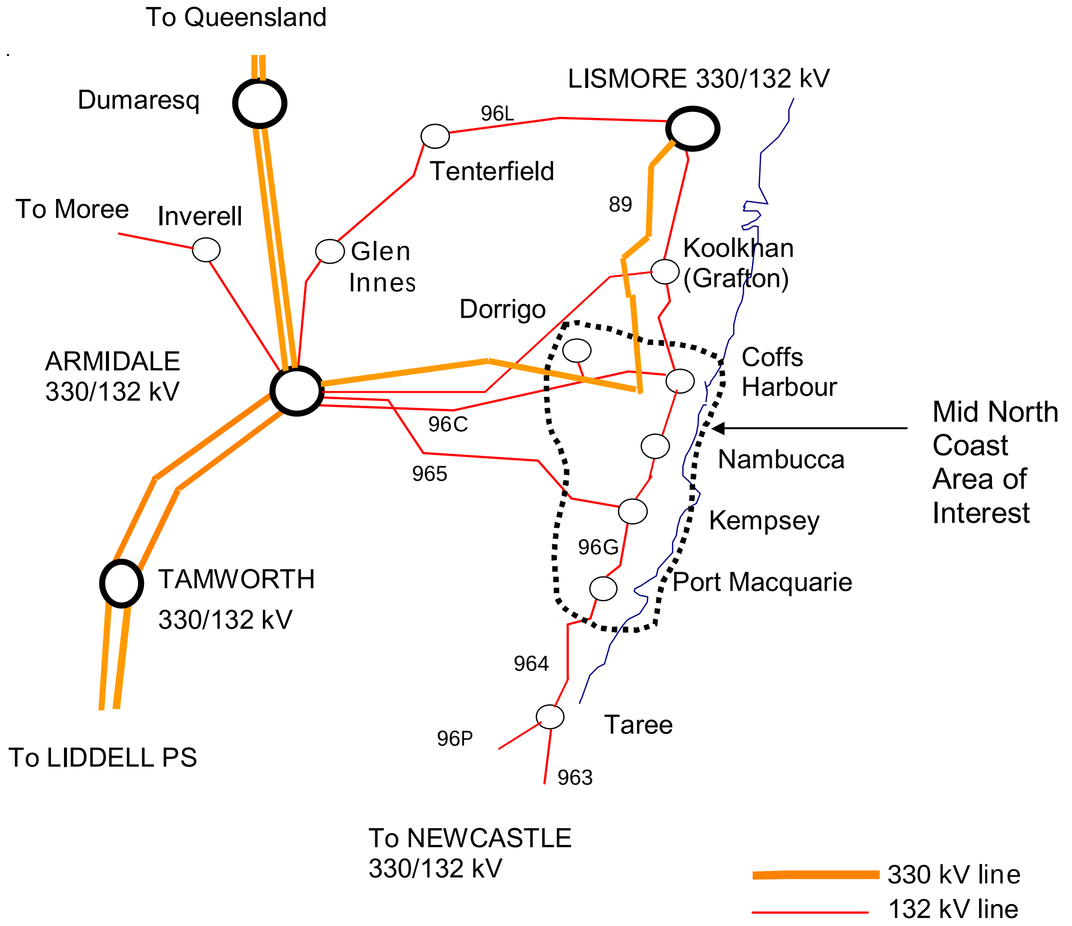
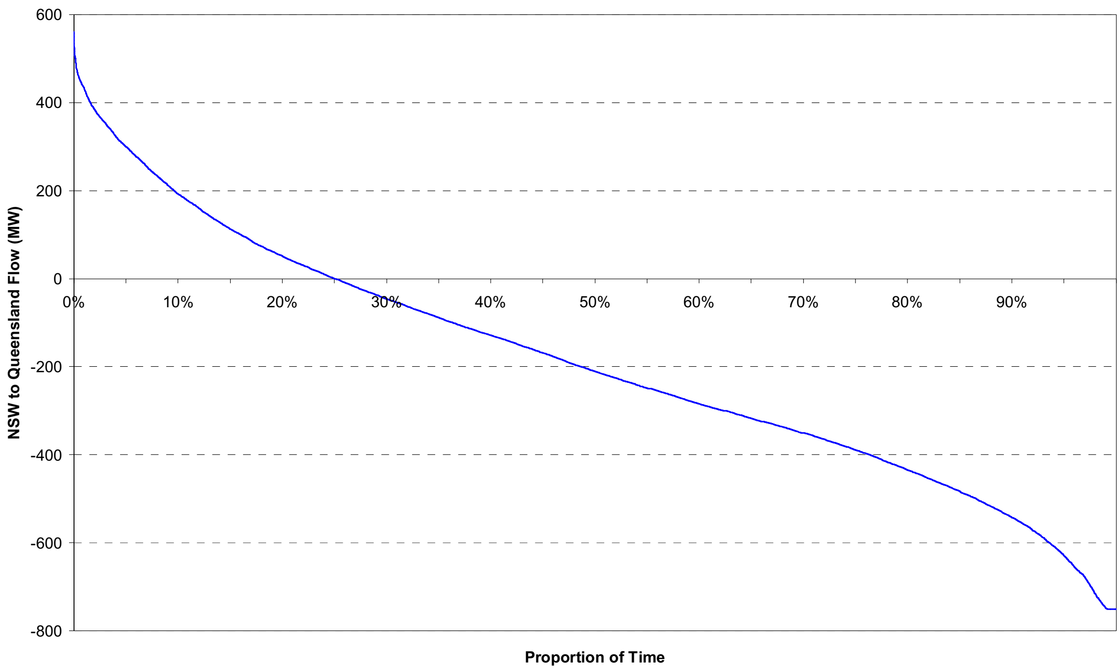


Figure 2 Flows on QNI in 2002



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 will continue 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 to Date

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 Report for 2002.

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 may be 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. To date there has been no response from any interested party.

In addition to the activities described above TransGrid and Country Energy have developed a number of network augmentation options that would address the transmission system limitations over an appropriate planning horizon. These are described in detail in Section 3.2 and Section 4 of this document.

2.3.3. Process to be Followed

The purpose of publishing this consultation paper is, similarly to the needs statement, to seek feedback on the proposed service standard and on possible solutions to the transmission system limitations. In addition feedback is sought on the methodology and data to be used in applying the regulatory test.

TransGrid and Country Energy will apply the regulatory test to a range of options including those that are presented in this paper, and any new or revised options that may arise as a result of feedback from interested parties. TransGrid and Country Energy will prepare a final report of the consultation, in accordance with Clause 5.6.2(h) of the Code, which will include a determination as to the action to be taken.

The proposed timetable for this process is:

Final date for submissions to this consultation paper	29 August 2003
Application of the regulatory test to revised range of options	September 2003
Final report and determination of action to be taken	October 2003

3. IDENTIFICATION OF A NECESSITY FOR AUGMENTATION

3.1. Code Requirements

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

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

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 (such as described above).

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 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 (Ref 1). 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 26 June 2003.

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

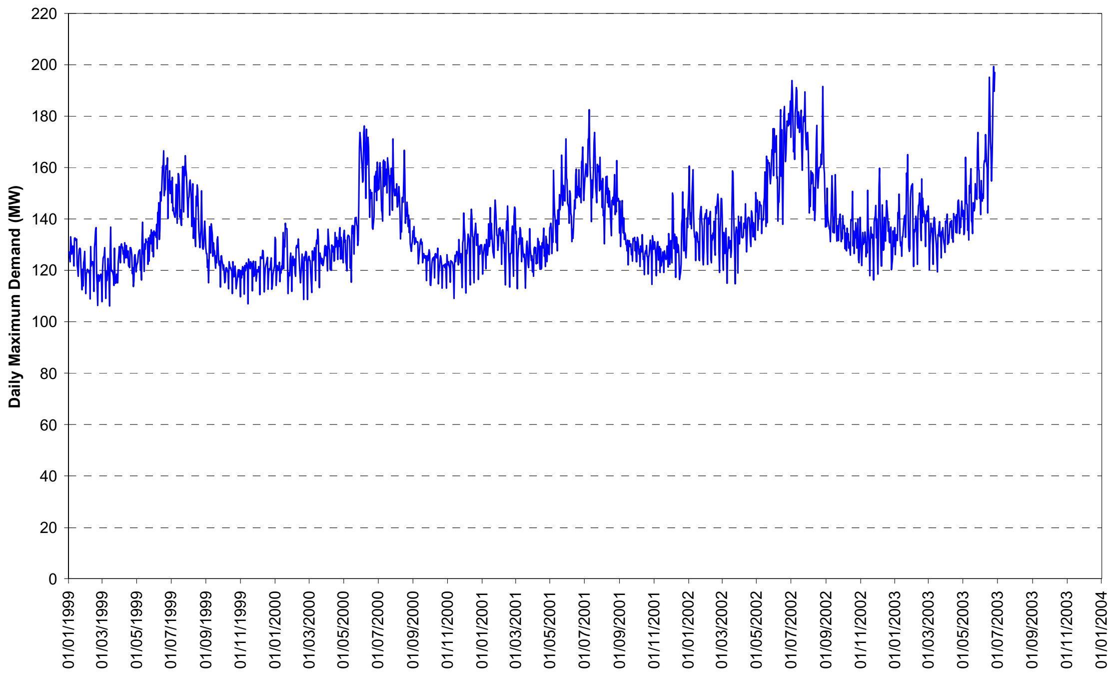
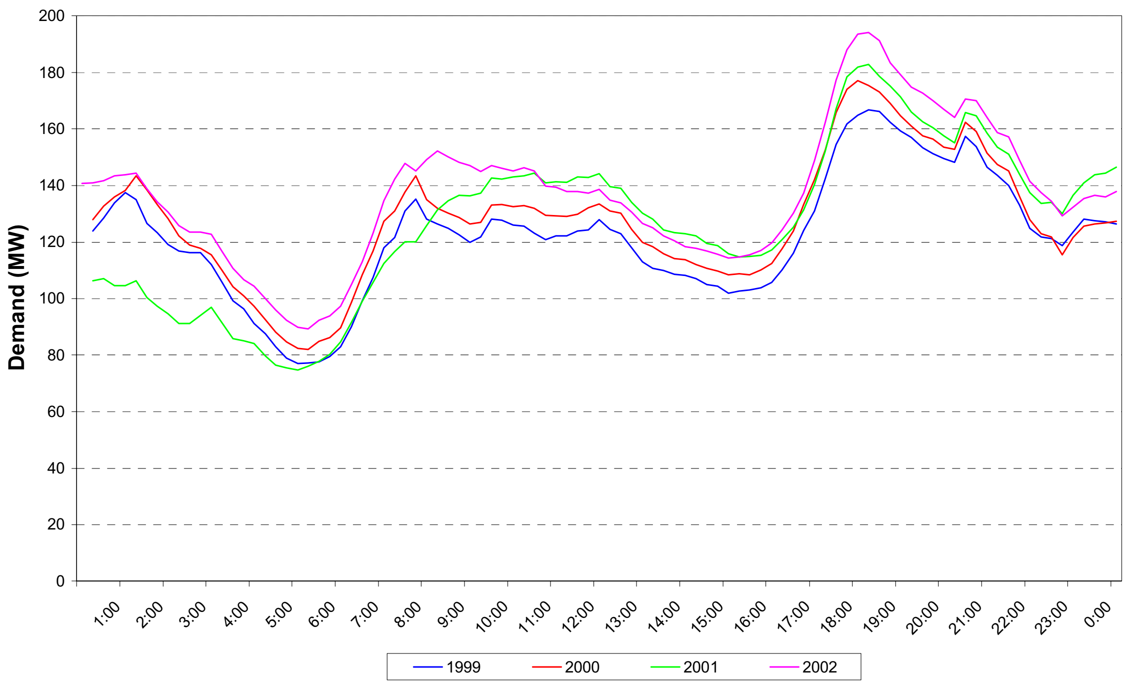


Figure 4 below shows the load on the days of maximum demand in 1999, 2000, 2001 and 2002. The impact of Country Energy's existing demand management (load control) system is clearly visible. Load has been shifted from the morning and the evening peaks to after the evening peak (from the period commencing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

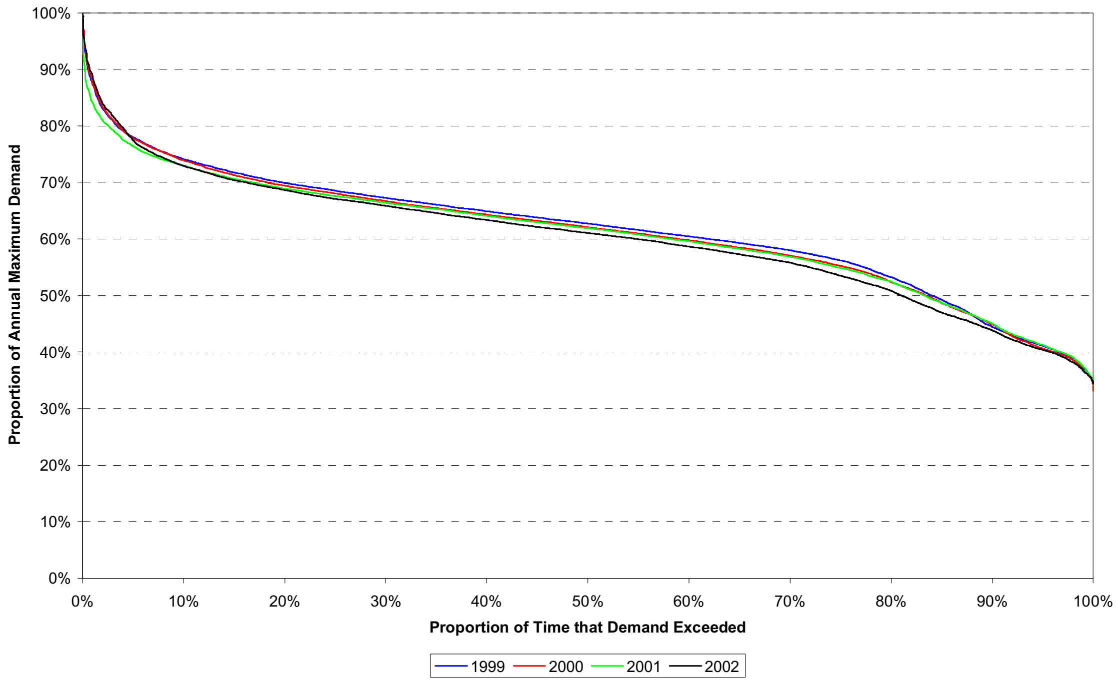
Figure 4 Load Profile on Days of Maximum Demand



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

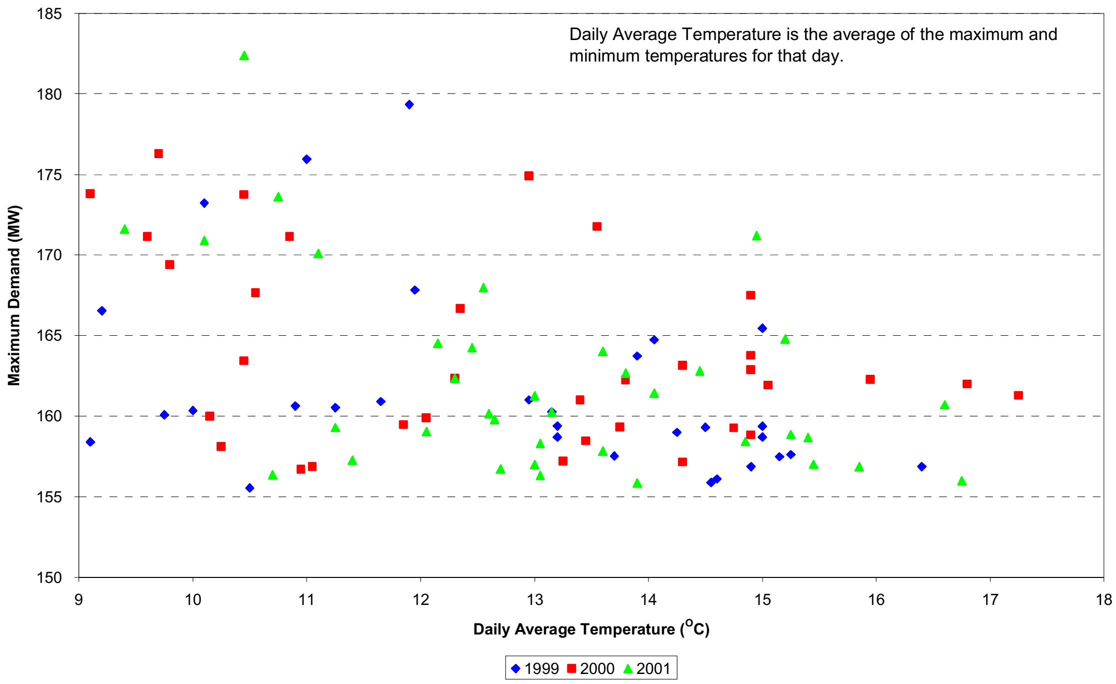
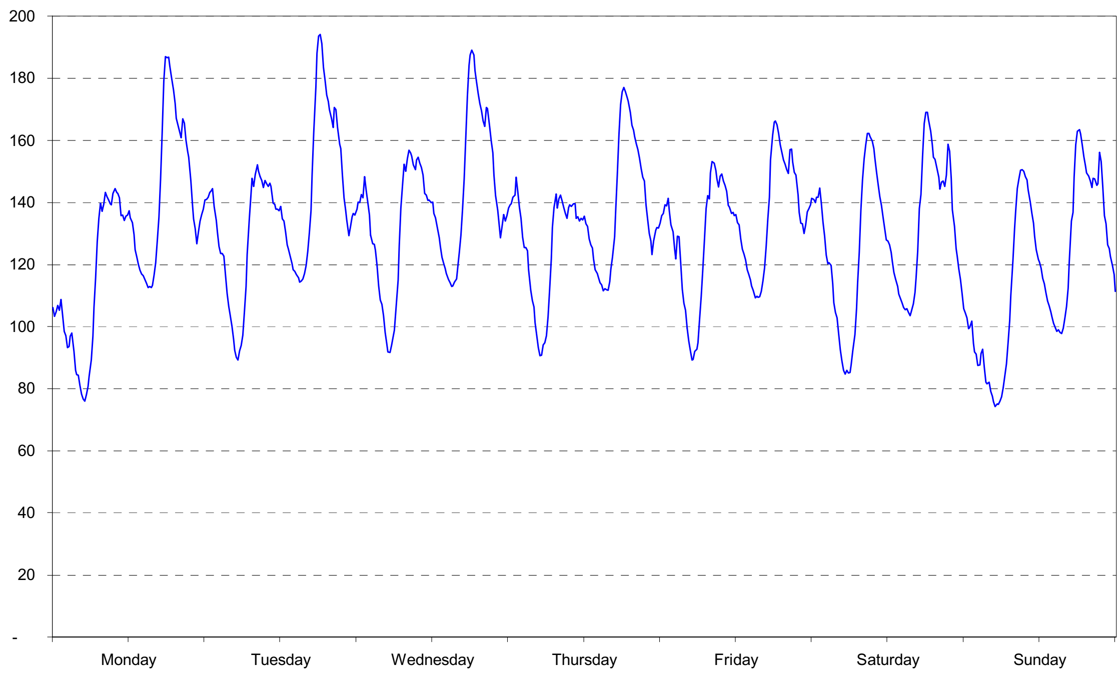


Figure 7 Demand Profile in the Week of Maximum Demand in 2002



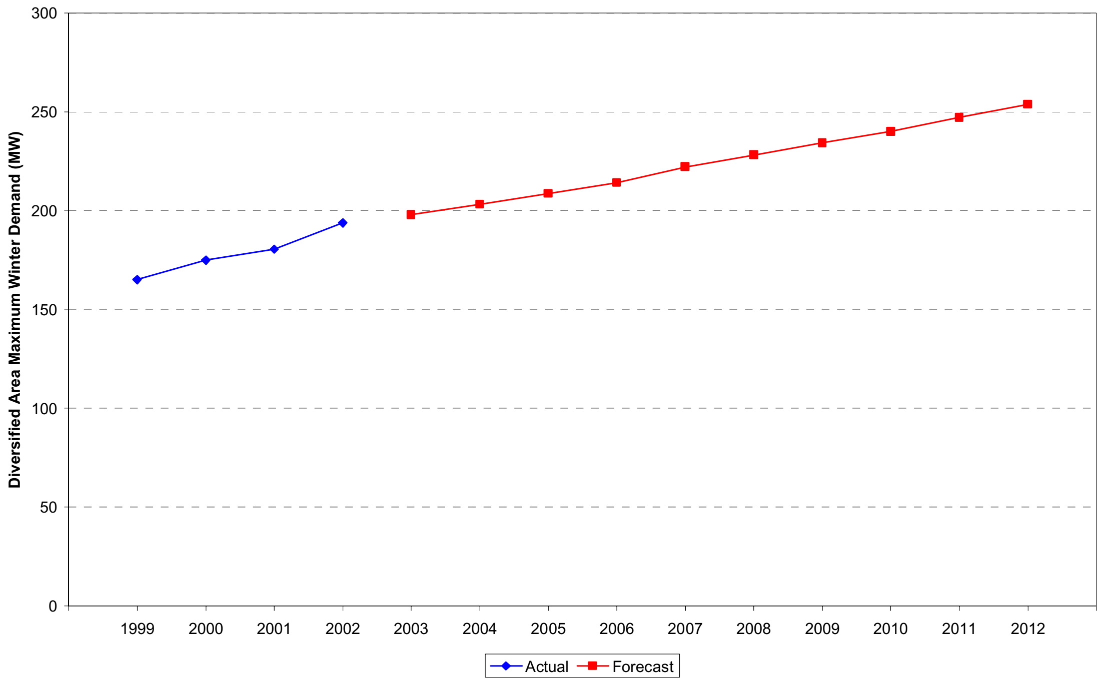
3.5.2. The Load Forecast

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	0.0	0.0	14.0	14.4	14.9	15.3	15.8	16.2	16.7	17.2
Raleigh	0.0	0.0	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

As indicated in Section 2.3.2, the network constraints have previously been described in TransGrid's Annual Planning Statements for 1999, 2000 and 2001 and its Annual Planning Report for 2002 as well as a document 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. To date TransGrid has not received any enquiries from parties interested in addressing any aspect of these constraints, including proposals for demand management or local generation projects.

The mid north coast has few local fuel or renewable energy resources which could be used to provide local generation sufficient to meet the local area load growth. It is therefore unlikely that viable local generation proposals will emerge.

Nevertheless, proponents of demand management or local generation projects which may delay the onset of the network limitations described in Section 3.2 are encouraged to submit those proposals.

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).

This consultation paper addresses 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.

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 option 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:

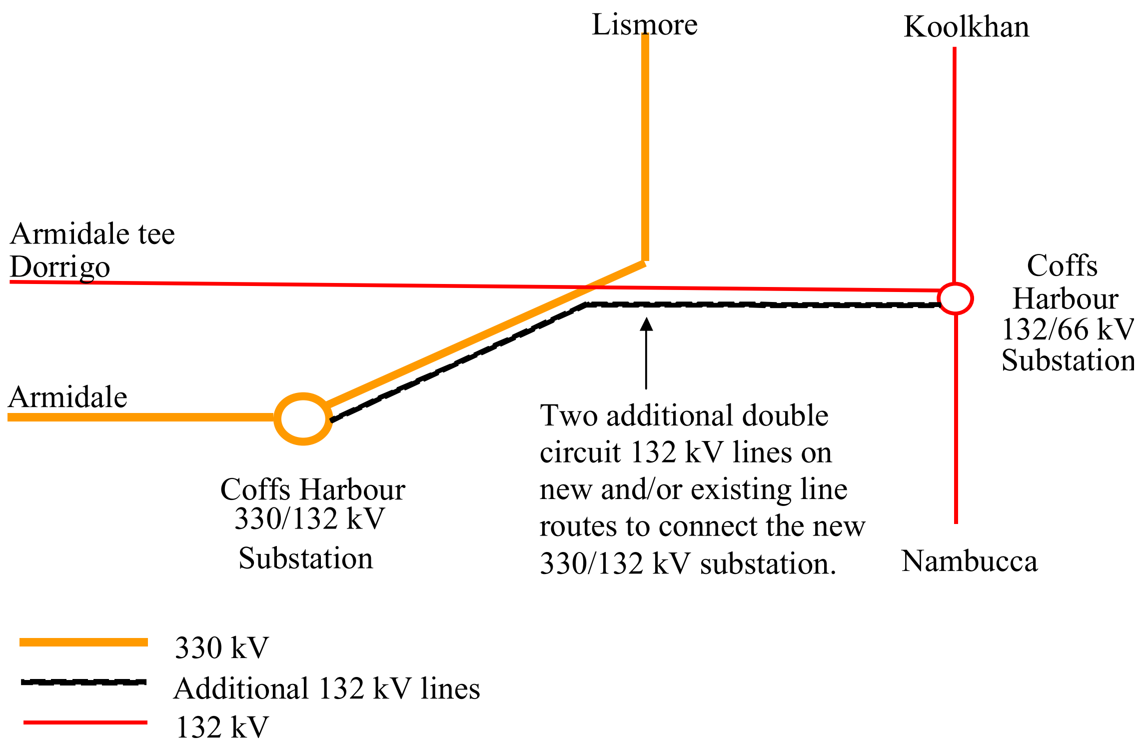
- on a site adjacent to the 330 kV line approximately three to four kilometres from the 132/66 kV substation; and
- adjacent to the existing 330/132 kV substation.

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 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.

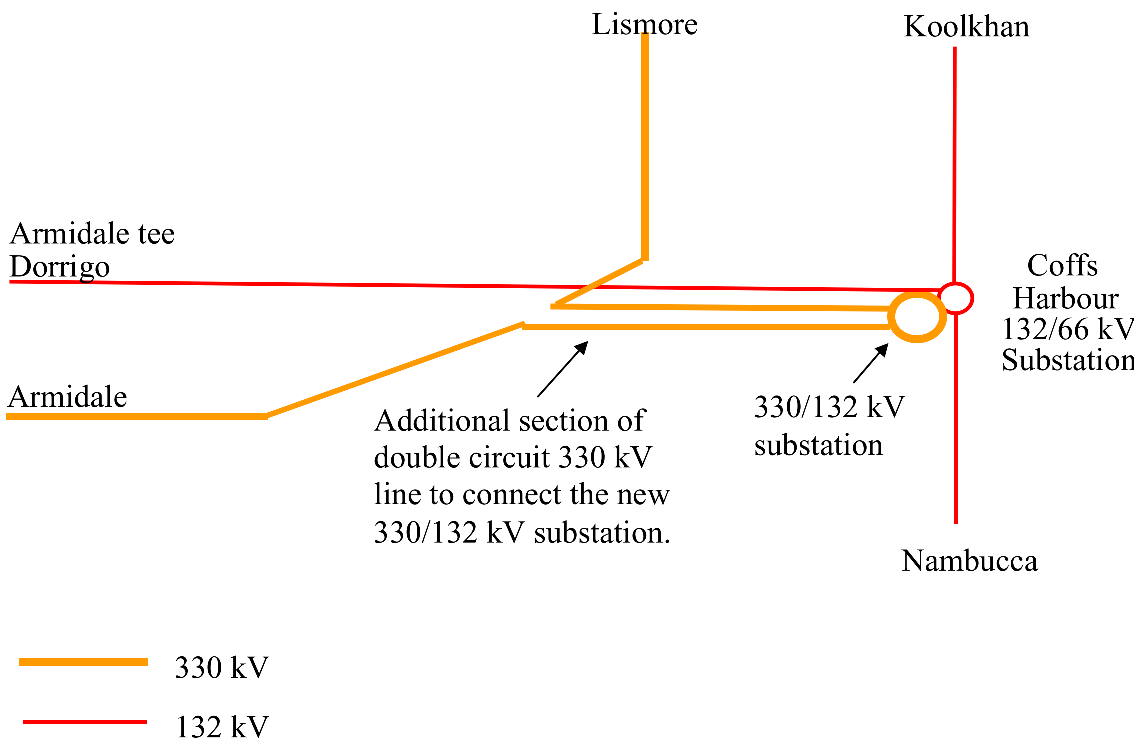
Both these variants would entail reconstruction of existing lines and the attendant need to undertake this at times of lower load could delay completion of the project.

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, in place of the double circuit 132 kV lines, a section of 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 in Section 2.3.2, TransGrid and Country Energy have not received any responses or enquiries from parties interested in providing Demand Management or Local Generation options. In the absence of specific proposals, hypothetical options were modelled.

Due to the high load growth in the area and the lack of specific proposals, TransGrid and Country Energy consider it unlikely that Demand Management or Local Generation projects which would significantly delay the onset of the network constraints will emerge. Consequently, the hypothetical options were assumed to be sufficiently large to provide a one year deferment of the onset of the network constraints.

4.3.1. Option 3: Hypothetical Demand Management Option Delaying the Substation

The hypothetical Demand Management option was assumed to reduce the demand throughout the area by a uniform proportion, such that the peak load reduction was 7 MW.

In evaluating this option it was also assumed that the demand reductions would be achieved through a "one off" programme, implemented over a limited period, and that those reductions would reduce to zero over a five year period.

Two programmes were considered:

1. An energy efficiency programme, which was assumed to reduce demand at all times by a uniform proportion.
2. A "peak lopping" programme which was assumed to reduce demand only at times of highest demand.

The assumed demand and energy reductions are shown in Table 3.

Table 3 Assumed Reduction in Area Peak Demand and Annual Energy Consumption

	Year 1	Year 2	Year 3	Year 4	Year 5
Energy Efficiency Programme					
Reduction in Peak Demand (MW)	7	5.6	4.2	2.8	1.4
Reduction in Annual Energy Consumption (GWh)	36.2	28.9	21.7	14.5	7.2
Peak Lopping Programme					
Reduction in Peak Demand (MW)	7	5.6	4.2	2.8	1.4
Reduction in Annual Energy Consumption (GWh)	Small	Small	Small	Small	Small

4.3.2. Option 4: Hypothetical Local Generation Option Delaying the Substation

As demand growth in the area is approximately 7 MW p.a., the effect of a hypothetical 7 MW generator located in the Coffs Harbour area was modelled. As there are no local suitable low cost fuel sources, it was assumed that the generator would utilise a fuel such as diesel or LPG.

A fuel cost of $10/GJ, which equates to diesel costing approximately $0.4/litre, was used. Other operation and maintenance costs were ignored.

Three operating regimes were modelled:

1. The generator operating in “peak lopping” mode. That is operating for only short periods at critical times.
2. The generator operating in peak lopping mode, but being relocated after one year when the network constraints remerge and the substation is constructed. It was assumed that 80% of the cost of installing the generator could be recovered when it was removed.
3. The generator operating for 90% of the time.

5. COST COMPARISON OF OPTIONS CONSIDERED

5.1. Capital Costs

Table 1 below summaries the estimated costs of the network options considered.

Table 4 Capital Cost of Options Considered ($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

While the costs of establishing the initial single transformer substation are similar under all options, Option 2 has lower capital costs in the medium and long term. Consequently, the two variants of Option 1 have not been considered further.

Table 5 Capital Cost of Non-Network Options

Option	Capital Cost ($ M)
Hypothetical Generation Option	5.3 (based on 7 MW at $750/kW)
Hypothetical Demand Management Option	1.75 (based on 7 MW at $250/kW) NOTE 1

NOTE 1: A report on Demand Management and Local Generation potential in the former Advance Energy area of NSW estimates that most of the more cost effective domestic sector demand management initiatives for that area would cost around $250/kW of peak demand reduction.

5.2. 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, the loss reductions offered by the various options 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 6 below shows the expected loss reductions in 2006.

Table 6 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					
Substation	40.1	13.3	1.4	7.3	0.6
Generation					
"Continuous" Mode	8.2	3.1	0.3	1.7	0.1
Peak Lopping Mode	Small	3.1	Small	1.6	Small
DSM					
Energy Efficiency	18.5	6.9	0.6	3.8	0.3
Peak Lopping	Small	6.9	Small	3.5	Small
1,000 MW Import to NSW on QNI					
Substation	42.6	15.0	1.6	8.2	0.7
Generation					
"Continuous" Mode	-4.0	1.4	-0.1	0.6	-0.1
Peak Lopping Mode	Small	1.4	Small	0.5	Small
DSM					
Energy Efficiency	-3.4	4.0	-0.1	2.0	-0.1
Peak Lopping	Small	4.0	Small	2.0	Small
750 MW Export to Queensland on QNI					
Substation	34.2	13.5	1.2	7.3	0.5
Generation					
"Continuous" Mode	22.3	6.9	0.8	3.8	0.3
Peak Lopping Mode	Small	6.9	Small	3.5	Small
DSM					
Energy Efficiency	44.8	12.9	1.6	7.1	0.7
Peak Lopping	Small	12.9	Small	6.5	Small

The value of loss reductions using the three valuation methods described above are shown in Figure 11, Figure 12 and Figure 13 below.

Figure 11 Value of Loss Reductions in 2006 (based on $35/MWh)

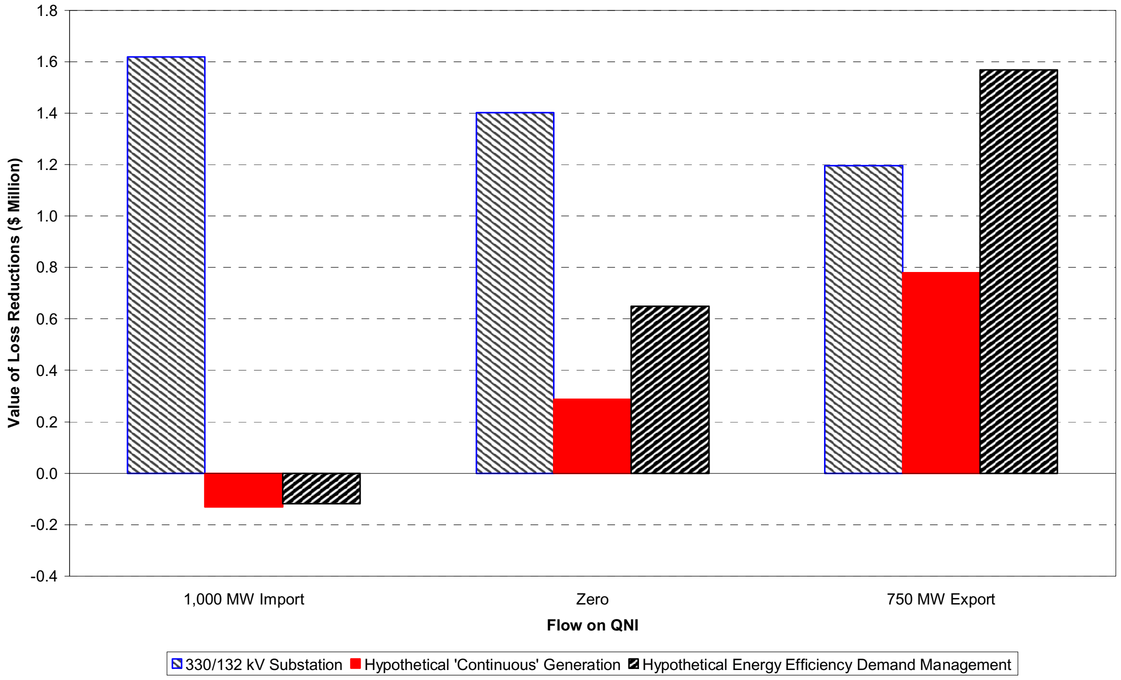


Figure 12 Value of Loss Reductions in 2006 (based on $500/kW and $15/MWh)

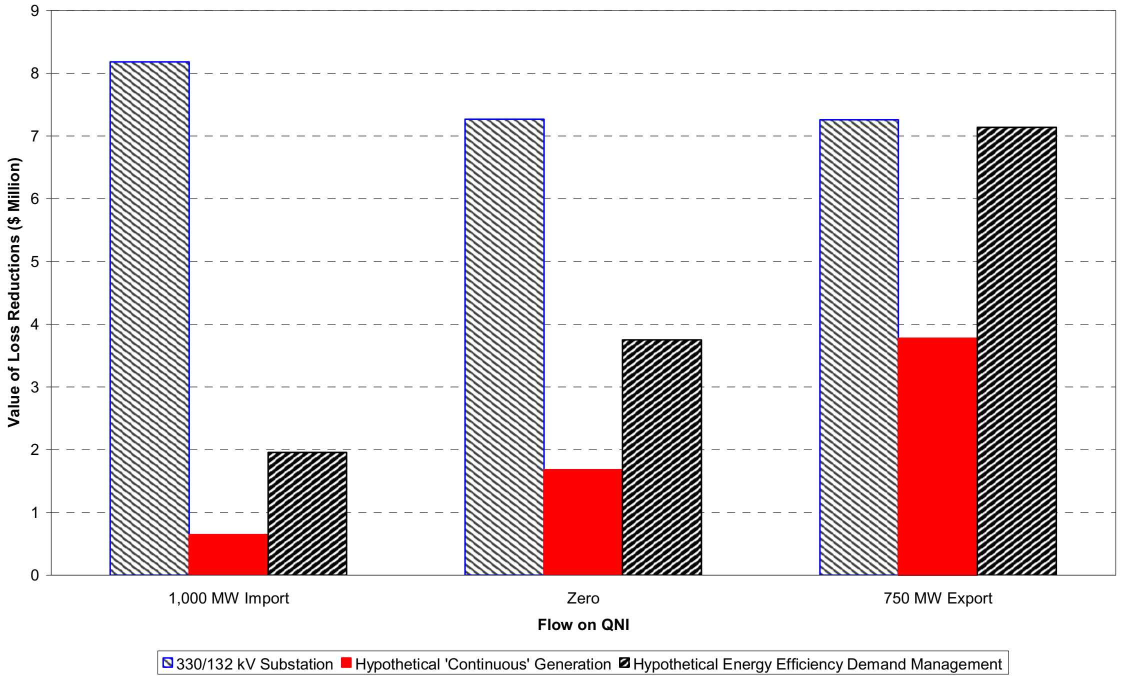
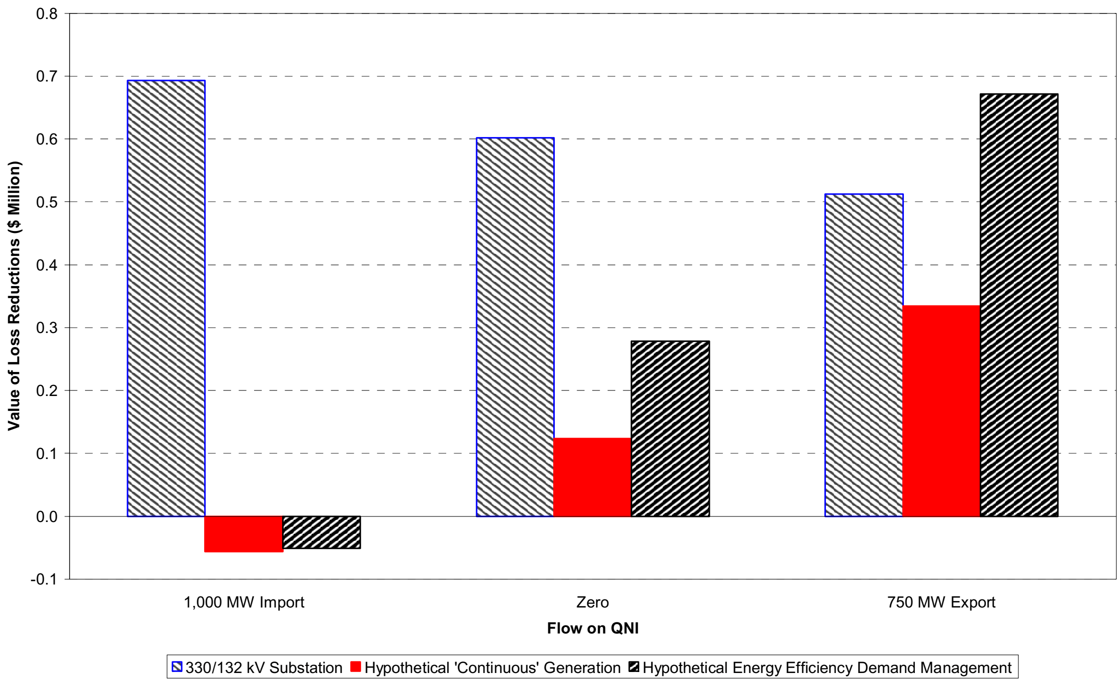


Figure 13 Value of Loss reductions in 2006 (based on at $15/MWh)



In most situations, establishment of a 330/132 kV substation gives the greatest reduction in losses. This is the expected result as the establishment of a new 330/132 kV substation significantly reduces the loading on the long 132 kV lines presently supplying the area from Armidale.

Overall, the hypothetical Demand Management options are not as effective in reducing losses as establishment of a 330/132 kV substation. It is of interest that under conditions of high QNI import to NSW, the Demand Management programmes actually increased energy losses, as the reduced mid north coast load results in the imported power being transmitted further south before being used. For much of the time, the losses involved in transmitting the power further south outweigh the reduction in losses due having a lower load in the mid north coast area.

The hypothetical 7 MW local generator at Coffs Harbour is less effective than both the substation and the hypothetical DSM option in reducing losses. It too increased losses under conditions of high QNI import to NSW.

The estimated loss reductions are shown in Appendix B.

5.3. 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

6. PRELIMINARY APPLICATION OF THE REGULATORY TEST

6.1. Basis of the Test

A preliminary application of the Regulatory Test, has been carried out. It considered the following options:

- Option 2: Establish a single transformer 330/132 kV substation adjacent to the existing Coffs Harbour 132/66 kV substation;
- Option 3A: Defer establishment of the 330/132 kV substation by implementing a hypothetical energy efficiency Demand Management programme;
- Option 3B: Defer establishment of the 330/132 kV substation by implementing a hypothetical "peak lopping" Demand Management programme;
- Option 4A: Defer establishment of the 330/132 kV substation by installing hypothetical local generation operating for 90% of the time;
- Option 4B: Defer establishment of the 330/132 kV substation by installing hypothetical local generation which operates in "peak lopping" mode for one year before being removed; and
- Option 4C: Defer establishment of the 330/132 kV substation by installing hypothetical local generation operating in "peak lopping" mode.

This analysis incorporates:

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

Sensitivity studies have been undertaken, covering:

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

The base case assumptions and the range over which sensitivity checks were conducted are shown in Table 9 and the results of the analysis in Table 10. The output of the base case economic model is shown in Appendix C.

In these analyses, the benefits of demand reductions due to Demand Management programmes have been valued in the same way as the benefits due to loss reductions. Also, the benefits in reductions in unserved energy have been valued at $10,000/MWh, the Value of Lost Load (VOLL) in the National Electricity Market.

Table 9 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
Local Generation	Taken to be fuel costs only	
Demand Management	Zero	
Asset Lifetimes		
Substations	30 years	20 and 40 years
Transmission Lines	45 years	30 and 60 years
DM Programmes	5 years	3 and 10 years
Generation	20 years	15 and 25 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

Table 10 Nett Present Values of Costs ($ million)

	Option 2	Option 3A	Option 3B	Option 4A	Option 4B	Option 4C
Base Case	2	0	10	20	3	4
7% Discount Rate	0	-2	11	24	1	3
13% Discount Rate	3	1	9	18	3	5
Reduced O&M Costs	1	-1	9	20	2	4
Increased O&M Costs	3	1	10	21	3	5
Extended Asset Lives	2	-2	9	20	2	4
Reduced Asset Lives	3	1	10	21	3	5
20% Increase in Capital Costs	4	2	12	23	4	7
1,000 MW Import via QNI	1	0	10	21	2	3
750 MW Export via QNI	3	-1	10	18	4	5
Losses Valued at $500/kW + $15/MWh	-1	-4	0	21	0	0
Losses Valued at $15/MWh	7	5	10	30	7	8

6.2. Conclusion

At present the only feasible option is Option 2, establishment of a 330/132 kV substation adjacent to the present 132/66 kV substation. However, should Demand Management or local generation options akin to the hypothetical Options 3A and 4B, be proposed they may cost effectively delay the need for the substation.

At this stage, subject to this consultation process, TransGrid and Country Energy will pursue Option 2.

7. CONTACT DETAILS FOR SUBMISSIONS AND ENQUIRIES

Proposals for options must be in the form of written submissions, which may be in hard copy or suitable electronic format and must be provided by 29th August 2003. Proposals or other enquiries should be directed to either of the contacts listed below:

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

Gordon Burbidge
Principal Engineer/Project Development
TransGrid
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Phone: 02 9284 3092
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

Table 11 Estimated Loss Reductions

	2006	2007	2008	2009	2010	2011	2012
No Flow on QNI							
330/132 kV Substation							
Reduction in Peak Losses (MW)	13	15	17	18	20	22	23
Reduction in Annual Losses (GWh)	40	43	45	47	50	52	54
Energy Efficiency DM							
Reduction in Peak Losses (MW)	7	7	8	8	9	10	10
Reduction in Annual Losses (GWh)	19	19	20	21	22	23	24
"Peak Lopping" DM							
Reduction in Peak Losses (MW)	7	7	8	8	9	10	10
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
"Continuous" Generation							
Reduction in Peak Losses (MW)	3	4	4	4	5	5	6
Reduction in Annual Losses (GWh)	8	9	9	10	10	10	11
"Peak Lopping" Generation							
Reduction in Peak Losses (MW)	3	4	4	4	5	5	6
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
Substation + Energy Efficiency DM							
Reduction in Peak Losses (MW)	0	19	21	23	25	27	29
Reduction in Annual Losses (GWh)	0	57	60	63	66	69	71
Substation + "Continuous" Generation							
Reduction in Peak Losses (MW)	17	18	19	20	21	22	23
Reduction in Annual Losses (GWh)	46	48	49	51	53	55	57
1,000 MW Import to NSW on QNI							
330/132 kV Substation							
Reduction in Peak Losses (MW)	15	17	19	21	23	25	27
Reduction in Annual Losses (GWh)	46	49	51	53	56	58	61
Energy Efficiency DM							
Reduction in Peak Losses (MW)	4	5	6	7	8	9	10
Reduction in Annual Losses (GWh)	-3	-3	-2	-2	-1	0	0
"Peak Lopping" DM							
Reduction in Peak Losses (MW)	4	5	6	7	8	9	10
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
"Continuous" Generation							
Reduction in Peak Losses (MW)	1	2	2	3	3	4	4
Reduction in Annual Losses (GWh)	-4	-3	-3	-3	-3	-2	-2
"Peak Lopping" Generation							
Reduction in Peak Losses (MW)	1	2	2	3	3	4	4
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
Substation + Energy Efficiency DM							
Reduction in Peak Losses (MW)	0	18	20	21	23	24	25
Reduction in Annual Losses (GWh)	0	39	42	45	49	52	55
Substation + "Continuous" Generation							
Reduction in Peak Losses (MW)	14	16	18	19	21	23	24
Reduction in Annual Losses (GWh)	36	39	42	45	48	50	53

	2006	2007	2008	2009	2010	2011	2012
750 MW Export to QLD on QNI							
330/132 kV Substation							
Reduction in Peak Losses (MW)	13	15	16	18	19	20	22
Reduction in Annual Losses (GWh)	34	36	39	41	43	45	47
Energy Efficiency DM							
Reduction in Peak Losses (MW)	13	15	17	19	21	23	25
Reduction in Annual Losses (GWh)	45	49	54	58	63	67	72
"Peak Lopping" DM							
Reduction in Peak Losses (MW)	13	15	17	19	21	23	25
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
"Continuous" Generation							
Reduction in Peak Losses (MW)	7	9	10	12	14	16	18
Reduction in Annual Losses (GWh)	22	24	27	29	31	33	36
"Peak Lopping" Generation							
Reduction in Peak Losses (MW)	7	9	10	12	14	16	18
Reduction in Annual Losses (GWh)	Small	Small	Small	Small	Small	Small	Small
Substation + Energy Efficiency DM							
Reduction in Peak Losses (MW)	0	35	39	43	47	50	54
Reduction in Annual Losses (GWh)	0	89	92	96	100	104	108
Substation + "Continuous" Generation							
Reduction in Peak Losses (MW)	21	23	26	28	31	34	36
Reduction in Annual Losses (GWh)	58	61	64	67	70	74	77

APPENDIX C

Table 12 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**															

Table 13 Base Case Analysis of Option 3A (Delay the Substation by One Year by Implementing Hypothetical "Energy Efficiency" DM)

	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	0	15	0	0	0	0	0	0	0	0	0	-10.5
330 kV Line	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-0.7
DSM	0	0	0	0	1.8	0	0	0	0	0	0	0	0	0	0	0.0
O&M Costs ($ million)																
Network	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	
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
NEM Costs Avoided by DSM																
Peak Demand Reduction (MW)	0	0	0	0	7.0	5.6	4.2	2.8	1.4	0	0	0	0	0	0	
Energy Reduction (GWh)	0	0	0	0	36.2	28.9	21.7	14.5	7.2	0	0	0	0	0	0	
Value of Demand and Energy Reduction ($ million)	0	0	0	0	-1.3	-1.0	-0.8	-0.5	-0.3	0	0	0	0	0	0	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	6.9	19.4	21.4	23.4	25.5	27.5	29.5	31.5	33.5	35.6	37.6	
Loss Reduction (GWh)	0	0	0	0	18.5	53.8	53.7	53.4	52.8	52.1	54.5	56.9	59.2	61.6	64.0	
Value of Loss Reduction ($ million)	0	0	0	0	-0.6	-1.9	-1.9	-1.9	-1.8	-1.8	-1.9	-2.0	-2.1	-2.2	-2.2	
Reduction in Unserved Energy																
Reduction (MWh)	0	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	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	-0.2	15.5	2.3	-2.0	-1.7	-1.5	-1.6	-1.7	-1.8	-1.9	-2.0	-12.8
NPV of Costs	**$0 million**															

Table 14 Base Case Analysis of Option 3B (Delay the Substation by One Year by Implementing Hypothetical “Peak Lopping” DM)

	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	0	15	0	0	0	0	0	0	0	0	0	-10.5
330 kV Line	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-0.7
DSM	0	0	0	0	1.8	0	0	0	0	0	0	0	0	0	0	0
O&M Costs ($ million)																
Network	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	
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
NEM Costs Avoided by DSM																
Peak Demand Reduction (MW)	0	0	0	0	7.0	5.6	4.2	2.8	1.4	0	0	0	0	0	0	
Energy Reduction (GWh)	0	0	0	0	Small	Small	Small	Small	Small	0	0	0	0	0	0	
Value of Demand and Energy Reduction ($ million)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	6.9	19.4	21.4	23.4	25.5	27.5	29.5	31.5	33.5	35.6	37.6	
Loss Reduction (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Value of Loss Reduction ($ million)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Reduction in Unserved Energy																
Reduction (MWh)	0	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	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	1.8	18.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	-12.2
NPV of Costs	**$10 million**															

Table 15 Base Case Analysis of Option 4A (Delay the Substation by One Year by Implementing Hypothetical "Continuous" Local Generation)

	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	0	15	0	0	0	0	0	0	0	0	0	-10.5
330 kV Line	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-0.7
Local Generation	0	0	0	0	5.3	0	0	0	0	0	0	0	0	0	0	-2.9
O&M Costs ($ million)																
Network	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	
Local Generation (fuel cost only)	0	0	0	0	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	
NEM Costs Avoided by Local Generation																
Peak Demand Reduction (MW)	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	
Energy Reduction (GWh)	0	0	0	0	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	
Value of Demand and Energy Reduction ($ million)	0	0	0	0	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	-1.9	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	3.1	18.0	18.9	19.9	20.8	21.7	22.6	23.5	24.4	25.3	26.2	
Loss Reduction (GWh)	0	0	0	0	8.2	47.7	49.5	51.3	53.2	55.0	56.8	58.7	60.5	62.3	64.2	
Value of Loss Reduction ($ million)	0	0	0	0	-0.3	-1.7	-1.7	-1.8	-1.9	-1.9	-2.0	-2.1	-2.1	-2.2	-2.2	
Reduction in Unserved Energy																
Reduction (MWh)	0	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	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	8.7	20.4	2.4	2.3	2.3	2.2	2.1	2.1	2.1	2.0	2.0	-15.7
NPV of Costs	**$20 million**															

Table 16 Base Case Analysis of Option 4B (Delay the Substation by One Year by Implementing Hypothetical "Peak Lopping" Local Generation which is Removed After One Year)

	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	0	15	0	0	0	0	0	0	0	0	0	-10.5
330 kV Line	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-0.7
Local Generation	0	0	0	0	5.3	-4.2	0	0	0	0	0	0	0	0	0	0
O&M Costs ($ million)																
Network	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	
Local Generation (fuel cost only)	0	0	0	0	Small	0	0	0	0	0	0	0	0	0	0	
NEM Costs Avoided by Local Generation																
Peak Demand Reduction (MW)	0	0	0	0	7	-7	0	0	0	0	0	0	0	0	0	
Energy Reduction (GWh)	0	0	0	0	Small	0	0	0	0	0	0	0	0	0	0	
Value of Demand and Energy Reduction ($ million)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	3.1	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	0	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	0	-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	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	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	5.3	12.8	-1.2	-1.3	-1.4	-1.4	-1.5	-1.6	-1.6	-1.7	-1.7	-12.8
NPV of Costs	**$3 million**															

Table 17 Base Case Analysis of Option 4C (Delay the Substation by One Year by Implementing Hypothetical "Peak Lopping" Local Generation)

	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	0	15	0	0	0	0	0	0	0	0	0	-10.5
330 kV Line	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	-1.6
Additional Armidale 330 kV Switchbay	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-0.7
Local Generation	0	0	0	0	5.3	0	0	0	0	0	0	0	0	0	0	-2.9
O&M Costs ($ million)																
Network	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	
Local Generation (fuel cost only)	0	0	0	0	Small	Small	Small	Small	Small	Small	Small	Small	Small	Small	Small	
NEM Costs Avoided by Local Generation																
Peak Demand Reduction (MW)	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	
Energy Reduction (GWh)	0	0	0	0	Small	Small	Small	Small	Small	Small	Small	Small	Small	Small	Small	
Value of Demand and Energy Reduction ($ million)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Loss Reductions																
Peak Loss Reduction (MW)	0	0	0	0	3.1	18.0	18.9	19.9	20.8	21.7	22.6	23.5	24.4	25.3	26.2	
Loss Reduction (GWh)	0	0	0	0	0	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	0.0	-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	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	-0.1	-0.1	-0.2	
Total Costs	0	0	0	0	5.3	16.9	-1.2	-1.3	-1.4	-1.5	-1.6	-1.7	-1.8	-1.9	-2.0	-15.7
NPV of Costs	**$4 million**															