

DEVELOPMENT OF ELECTRICITY SUPPLY IN THE WESTERN AREA OF NSW

FINAL REPORT

August 2003

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Executive Summary

This document is the final report of a consultation that TransGrid and Country Energy have carried out with Code Participants and interested parties so as to determine recommended actions for the development of electricity supply to the "Western" area of New South Wales.

Section 1 provides a description of the Western area and the context of this report within the regulatory approval process for development of electricity supply to the Western area.

Sections 2 and 3 describe 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 presented.

In Section 4 three augmentation options are described. Each involves the construction of a new 330 kV line to the area with capital costs being in the range of \$60 - \$75 million. As there were no submissions received during the consultation, additional indicative options that were considered in the consultation paper published in May 2003 have been removed from further consideration.

In Section 5 the results of an application of the regulatory test to the three options are presented. Other than allowing for the removal of the three indicative options, this application of the regulatory test is identical to the preliminary application of the regulatory test carried out by economics consultant National Economics Research Associates (NERA), and presented in the consultation paper.

In Section 6 TransGrid and Country Energy conclude that Option 1 (Wollar – Wellington) and Option 2 (Yetholme – Kerr's Creek) may both be considered to satisfy the regulatory test, the choice between them being determined by their relative technical (non-economic) merits. They have determined that Option 1 is the preferred option.

The recommended action is the construction of the Wollar – Wellington project, with start of construction planned for January 2004 and a planned commissioning date of June 2007.

As this report recommends the construction of a new large network asset a 40-day dispute notification period applies.

1. Introduction

1.1. Scope and Purpose

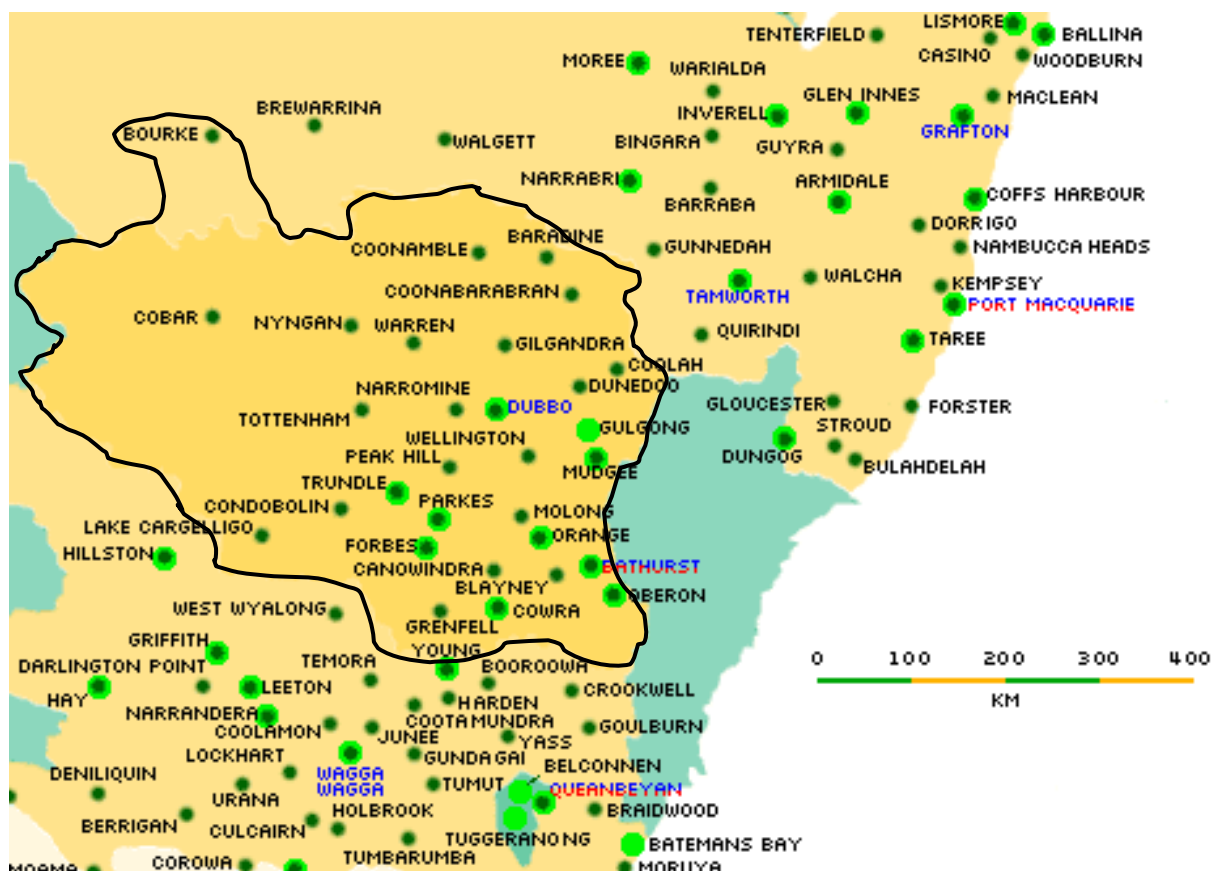
This report has been prepared in accordance with Clause 5.6.2 (h) of the National Electricity Code as in operation immediately prior to 8th March 2002. Its purpose is to make public TransGrid and Country Energy's determination and recommended action for augmentation of the transmission network in the Western area of New South Wales.

It includes:

- A discussion of transmission system limitations that TransGrid and Country Energy have identified that have lead to the need for an augmentation of the transmission network in the area;
- A discussion of the objectively measurable service standard that has been used to determine that a need for augmentation exists;
- A description and assessment of three identified options that would meet the need;
- A discussion of relevant consultations that have been carried out with affected *Code Participants* and *interested parties* and a summary of submissions from those consultations;
- A summary of a cost effectiveness analysis of these options (Ref 2) that has been carried out in accordance with the ACCC's regulatory test;
- TransGrid and Country Energy's determination and recommended action.

Much of the material that appears in this report appeared in TransGrid and Country Energy's May 2003 consultation paper for the Western Area, but for clarity and completeness, has been included in this report.

1.2. Background



The “Western” area of New South Wales as described in this report refers to that part of the Country Energy service area that corresponds to the former Advance Energy service area, plus Lithgow in the Integral Energy service area. The area is outlined in the picture on the previous page and is about 176,000 sq km in size. Within it are a number of country centres of varying sizes including Bathurst, Bourke, Cobar, Dubbo, Forbes, Gulgong, Lithgow, Manildra, Molong, Mudgee, Nyngan, Oberon, Orange, Parkes and Wellington. The total population is about 120,000 with peak consumption of electricity during winter 2002 being approximately 490 MW.

The significance of the Western area as described is that it is supplied by a part of TransGrid’s transmission network that can be considered to be materially separate (from the point of view of transmission planning considerations) from other parts of the transmission network in New South Wales.

The transmission network in the area is depicted in Diagram 1 (geographic) and Diagram 2 (schematic) (see pp 37-38).

1.3. Procedural Context

1.3.1. 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 network development procedures to be carried out in accordance with the Code requirements that were in effect immediately prior to that date.

The consultation for the Western 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 relevant network development procedures for the Western area in accordance with the Code provisions that were in effect immediately prior to 8th March 2002. Thus references to Code clauses in this report generally refer to these Code provisions. Appendix 1 details the relevant clauses.

1.3.2. 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 (as Advance Energy) have been carrying out joint planning to identify and monitor emerging limitations in the transmission network supplying the Western area for many years.

These limitations have been outlined in TransGrid’s Annual Planning Statements for 1999, 2000 and 2001, its Annual Planning Report for 2002 and discussed at the public forums associated with the Annual Planning Reviews for these years. More recently TransGrid’s Annual Planning Report for 2003 (published on 30th June 2003) describes the limitations in the context of a proposal for a new large network asset for the Western area.

In 2001 TransGrid and Country Energy (as Advance Energy) used the services of an energy consultant to identify opportunities for demand management and local generation in the Western area (formerly Advance Energy franchise service area) that may address transmission system limitations in the area (Ref 3).

As discussed above, in January 2002 TransGrid published a notice on its web site that it had commenced the formal phase of consultation as required by clause 5.6.2 (f) of the Code.

In August 2002 TransGrid and Country Energy published the energy consultant’s report on their respective web sites. They also published a paper entitled “Limitations in the Transmission Network Supplying the Western Area of NSW” (the “needs statement”). 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. Material in the needs statement was updated and reproduced in the consultation paper. For clarity and completeness the same material appears in Sections 2,3 and Appendices 2 and 3 of this report.

The purpose of publishing the energy consultant's report and 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.

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

TransGrid engaged the services of economics consultant, National Economic Research Associates (NERA) to apply the ACCC's regulatory test to augmentation options for the Western area. NERA carried out a preliminary application of the regulatory test considering the three transmission augmentation options developed by TransGrid and Country Energy and three other options that included components of demand management or local generation that were based on material from the energy consultant's report, and technical assistance from TransGrid. Their report (Ref 2) was published with the consultation paper in May 2003.

The consultation paper included a summary of NERA's results and conclusions. TransGrid and Country Energy did not come to a definitive conclusion but instead presented a preliminary view, summarised as follows:

- They agreed with NERA's conclusions regarding the relative cost effectiveness of the six options and considered that any of the three transmission options could form all or part of an option that would satisfy the regulatory test;
- The Wollar – Wellington development was the preferred transmission project; and
- A demand management project, similar to the one considered by NERA, may also form part of an option that would satisfy the regulatory test, if shown to be feasible and cost effective.

The consultation paper was published on TransGrid and Country Energy's web sites on 26th May 2003 with a closing date for submissions of 30th June 2003.

There were no responses received to the consultation paper. Nor were any responses (or any other form of feedback) received to the needs statement, or at any time during the formal consultation period that commenced in January 2002. Furthermore no form of feedback has been received in respect to the Western area items that appeared in TransGrid's Annual Planning Statements and Annual Planning Reports from 1999 to 2003 or to "Western Area" items that were presented at the corresponding public forums from 1999 to 2002.

Accordingly TransGrid and Country Energy consider that no further regulatory consultation is necessary for the Western area development. TransGrid will proceed to implement the recommended action contained in this report (Refer Section 6.3) if no disputes are notified by the required date.

1.3.3. Disputes

In accordance with Clause 5.6.2(i) of the Code, as in operation immediately prior to 8th March 2002, Code participants may dispute the recommendations of this report within 40 business days of its being made available. The relevant date will be 40 business days following publication of this report on TransGrid's web site with the precise date being included in the web site notice. Contact details for notification of disputes are given in Section 7.

2. Load Forecast Analysis for the Western Area

As discussed in Section 1.3.2 this material has previously been published in Ref 2. Whilst it has not been necessary to modify this material in any way it is reproduced here for clarity and completeness.

The majority of the transmission lines supplying the Western area emanate from Wallerawang and Mount Piper. The capability of this network to supply the area depends to a large degree on the loads that are remote from these locations. Consequently, this section considers the electrical load in:

- The whole Western area; and
- The “Far Western” area including Mudgee, Gulgong, Parkes, Wellington, Dubbo and areas to the west of Dubbo.

In both of these areas over recent years, the load has shown modest underlying growth punctuated by “step increases” due to the establishment of “spot loads” such as mines. This pattern is expected to continue. Two forecasts have been developed, one includes possible (but as yet uncommitted) spot loads and the other excludes uncommitted spot loads. The latter is considered to be a lower bound forecast with the former being considered a more likely outcome.

2.1. The Whole Western Area

2.1.1. The Nature of the Electrical Load in the Whole Western Area

The demand for electricity in the Western area is seasonal, with the highest demand occurring in winter. Summer maximum demands are typically 80% to 90% of winter maximum demands. Figure 2.1 below shows the maximum daytime demands (averaged over a half hour period) for each day from 1 January 1997 to 31 March 2003.

Figure 2.1 Daily Maximum Demands for the Whole Western Area: January 1997 – March 2003

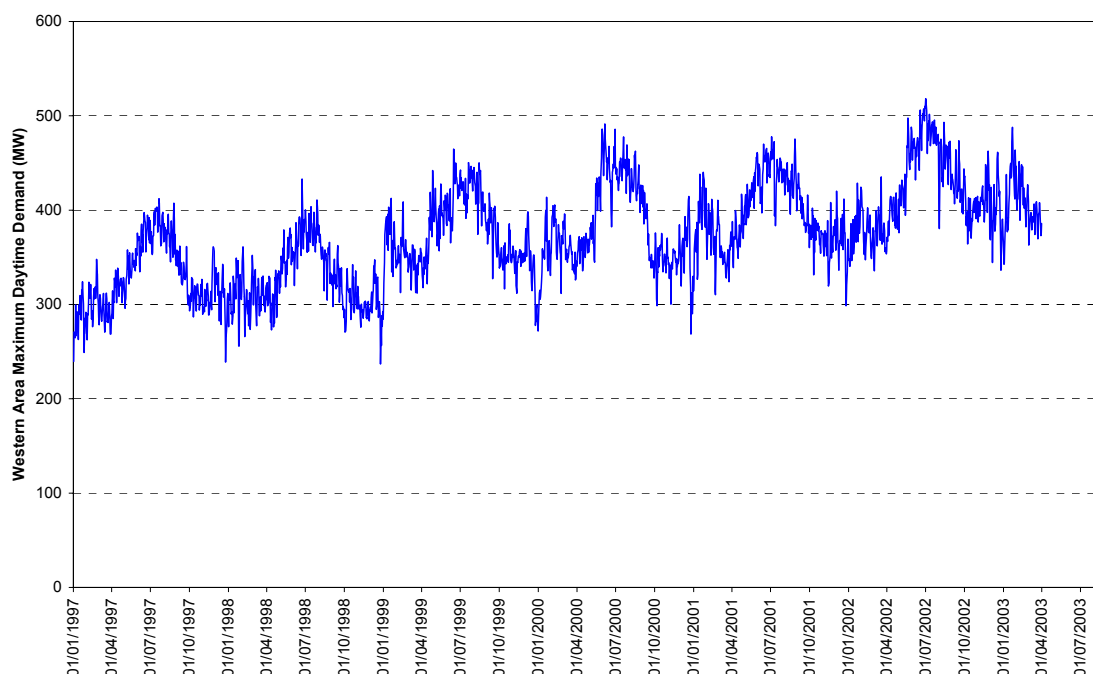
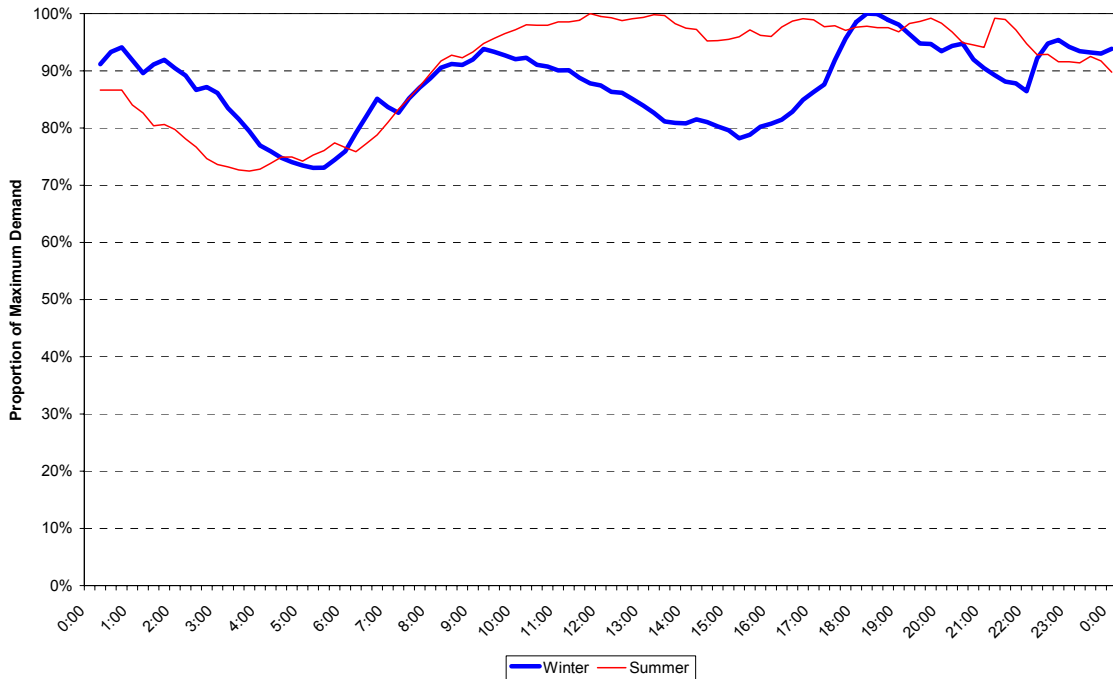


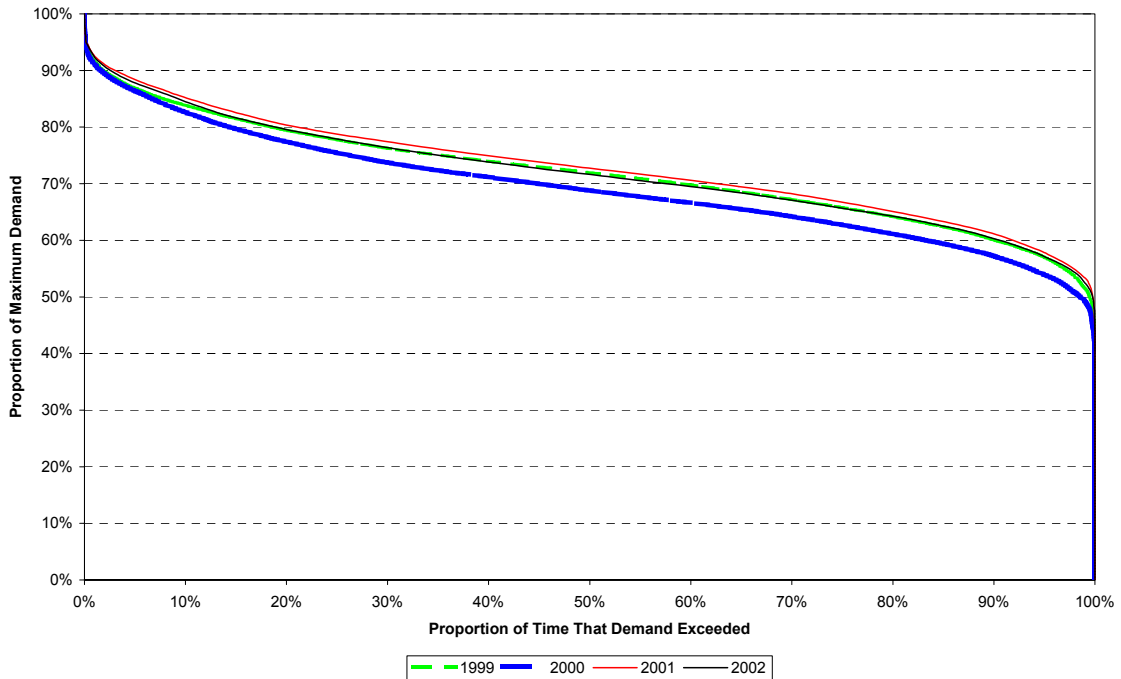
Figure 2.2 below shows a typical load profile on days of high demand in summer and winter.

Figure 2.2 Summer and Winter Load Profiles on Days of High Demand – Whole Western Area



The load can be relatively high for extended periods, especially in summer. Figure 2.3 below shows the amount of time that the load is above particular levels.

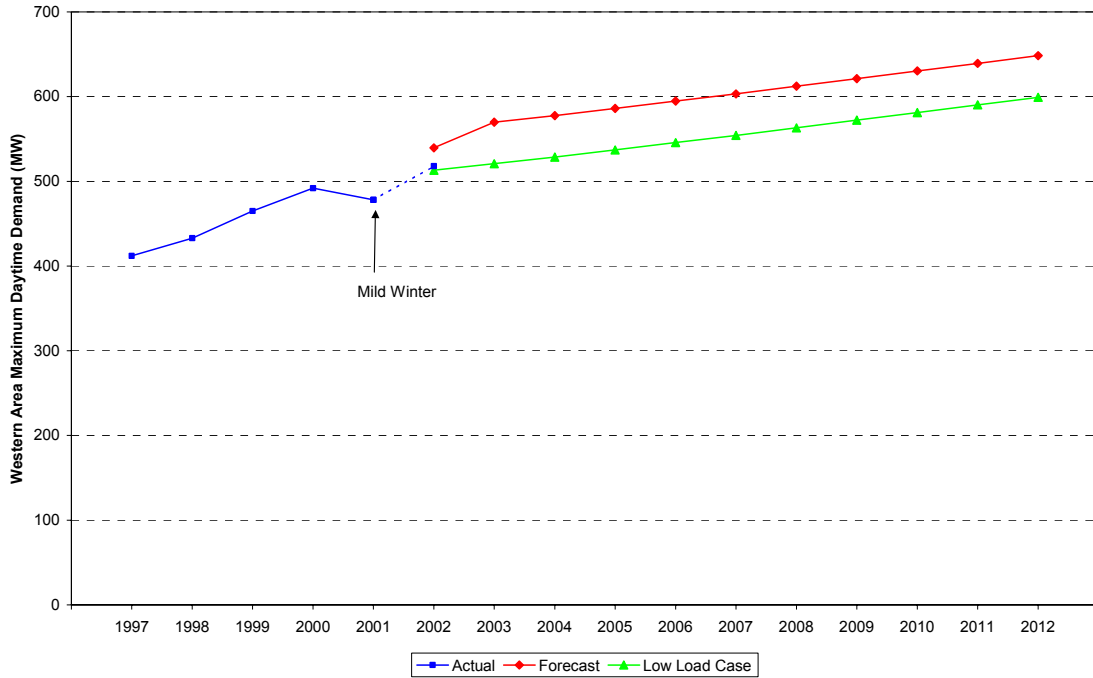
Figure 2.3 Load Duration - Whole Western Area: 1999 - 2002



2.1.2. Load Forecast – Whole Western Area

The forecast maximum demands under the two load growth scenarios are shown in Figure 2.4 below.

Figure 2.4 Forecast Maximum Demands - Whole Western Area



2.2. The Far Western Area

2.2.1. The Nature of the Electrical Load in the Far Western Area

The demand for electricity in this area is also seasonal, with the highest demands generally occurring in winter. Summer maximum demands are typically around 95% of winter maximum demands.

Figure 2.5 below shows the maximum daytime demands (averaged over a half hour period) for each day from 1 January 1997 to 31st March 2003.

Figure 2.5 Daily Maximum Demands for the Far Western Area: January 1997 – March 2003

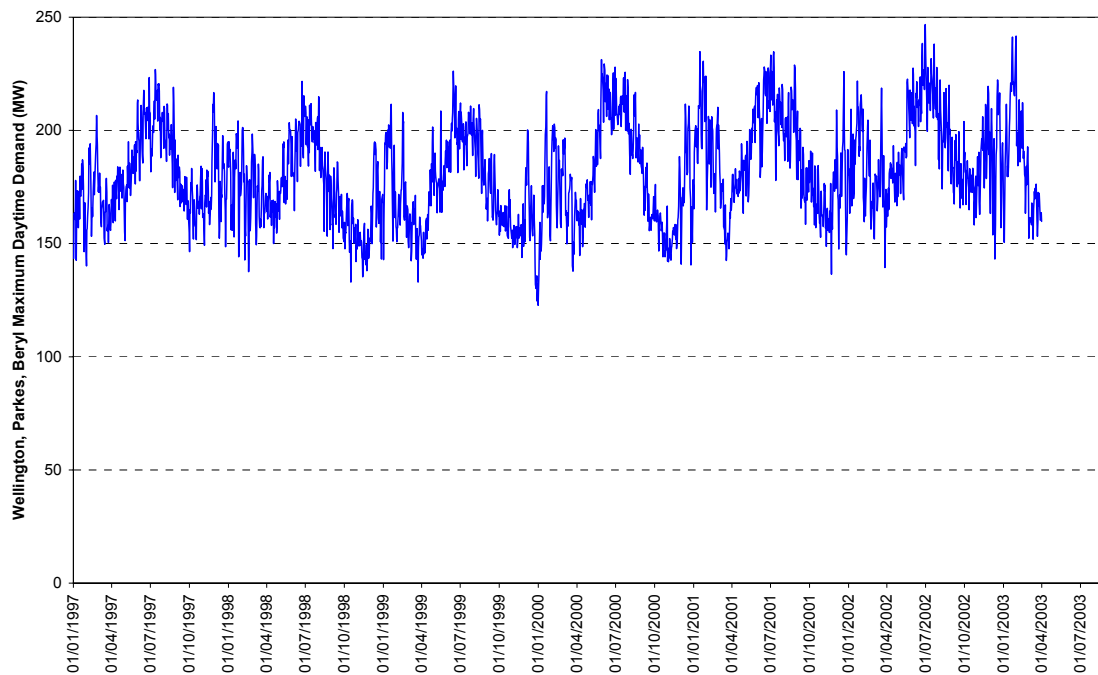
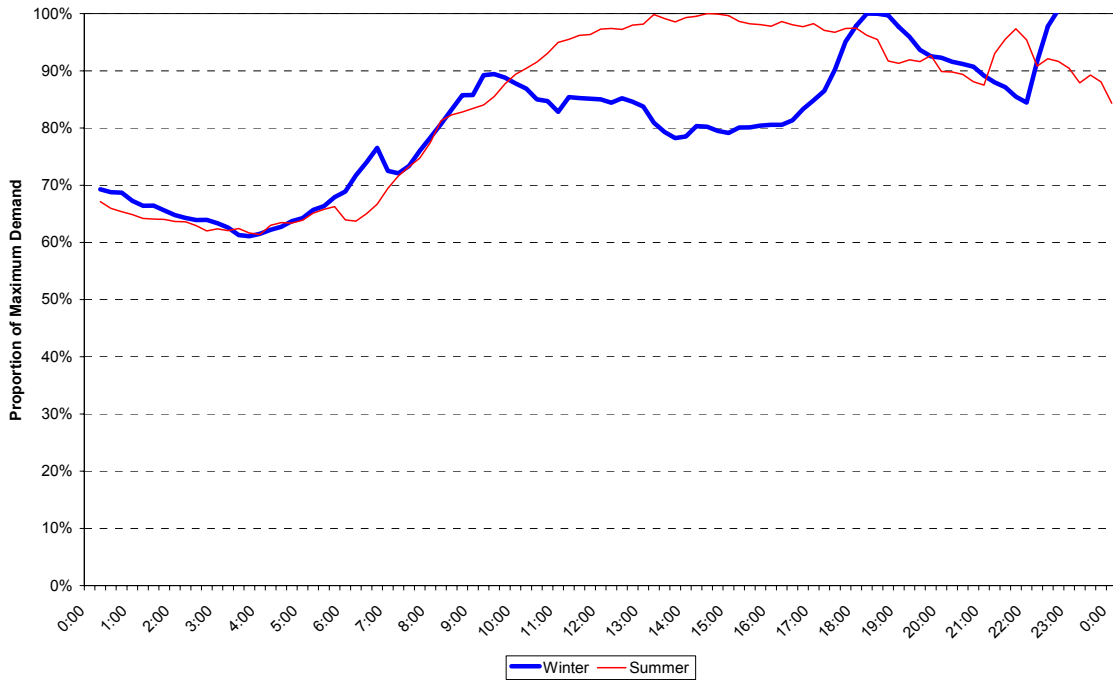


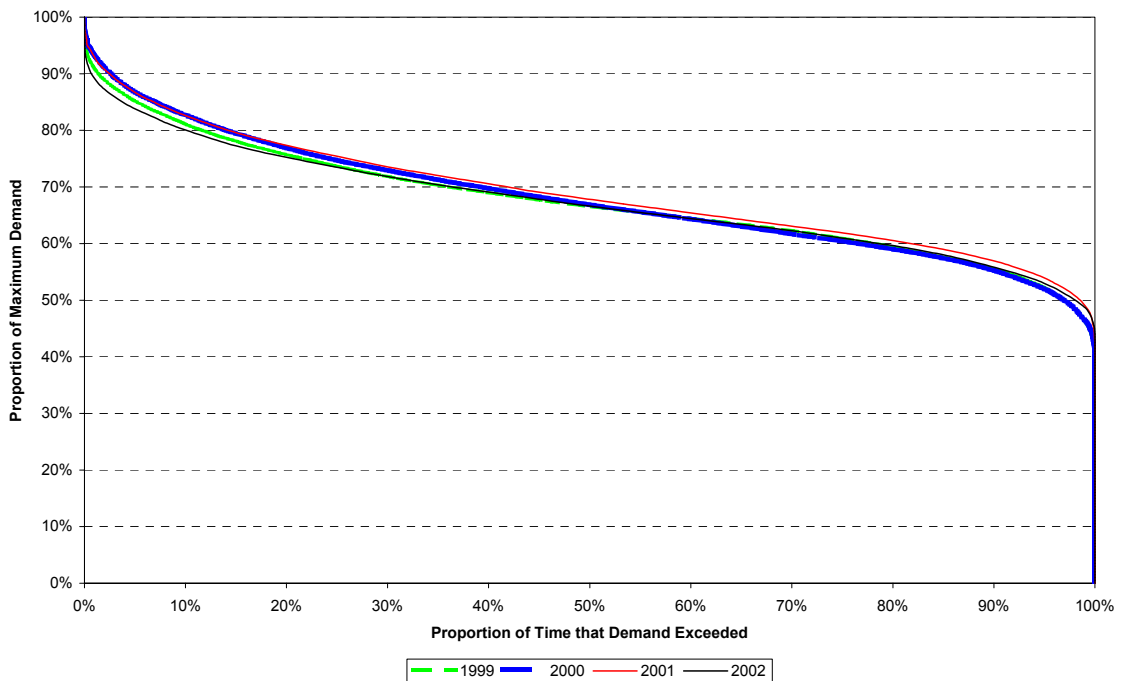
Figure 2.6 below shows a typical load profile on days of high demand in summer and winter.

Figure 2.6 Summer and Winter Load Profiles on Days of High Demand – Far Western Area



The load in this area can also be relatively high for extended periods, as shown in Figure 2.7 below.

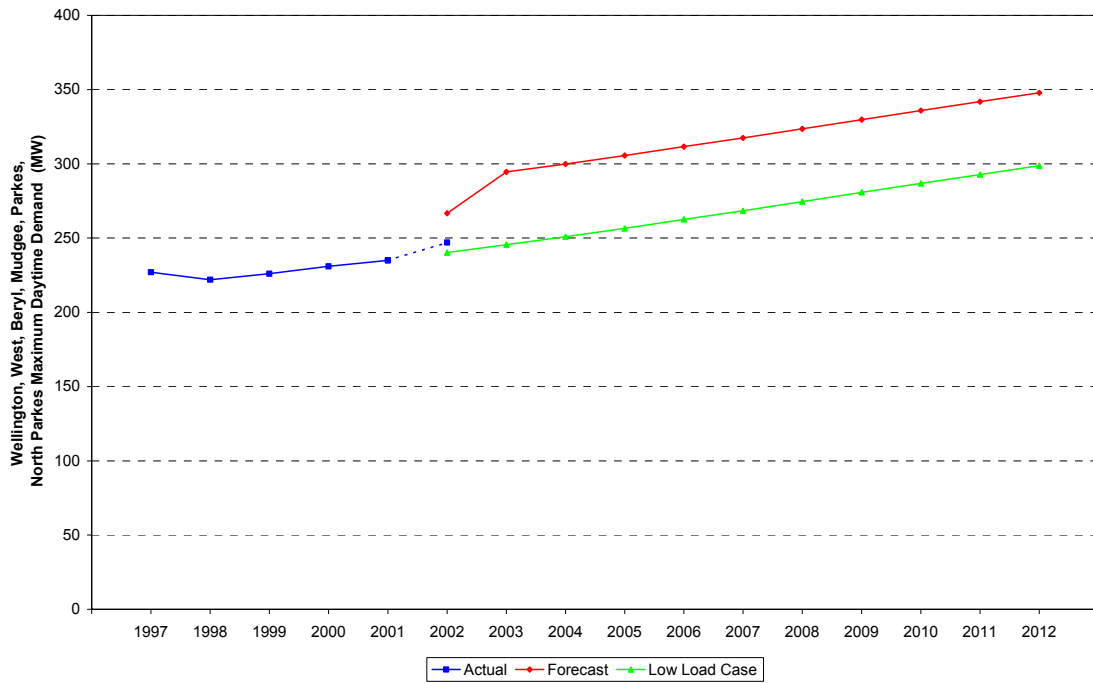
Figure 2.7 Load Duration - Far Western Area: 1999 - 2002



2.2.2. Load Forecast – Far Western Area

The forecast maximum demands under the two load growth scenarios are shown in Figure 2.8 below.

Figure 2.8 Forecast Maximum Demands - Far Western Area



3. Identification of a Need for Augmentation

As discussed in Section 1.3.2 this material has previously been published in Ref 2. Whilst it has only been necessary to make minor modifications to this material it has been fully restated here for clarity and completeness.

3.1. Network Limitations

The part of TransGrid's transmission network that supplies the Western area is depicted in Diagram 1 (approximate geographic representation) and Diagram 2 (schematic representation) (see pp 37-38).

This network is capable of adequately supplying the electrical demand in the area at all times with all elements in service and will continue to do so over a planning horizon of at least ten years for reasonable load forecast scenarios.

However, the network is currently affected by the following limitation:

If the 330 kV line (number 72) between Mount Piper and Wellington 330 kV Substations were to be out of service, voltages in parts of Country Energy's sub-transmission and distribution networks, particularly in the areas west of Wellington, may not be able to be controlled to adequate levels during periods of moderate to high electrical demand.

What this means is that voltages in Country Energy's subtransmission and distribution networks west of Wellington may drop below acceptable limits because of inadequate voltage levels in TransGrid's transmission network, particularly at Wellington. This may result in voltages at points of supply to end use customers being below acceptable limits, with consequences such as:

- Noticeable dimming of incandescent lighting (brownouts); and/or
- Equipment mal-operation; and/or
- Equipment dropouts, with consequent interruptions to processes that depend on that equipment; and/or
- Permanent damage to equipment that is not designed to operate safely with a low supply voltage and does not have internal protection; and
- In extreme cases system voltage collapse.

Country Energy has determined that voltages in their subtransmission and distribution networks west of Wellington may be controlled to acceptable levels if the voltage at Wellington 132 kV busbar is above 132 kV (ie 100% of nominal).

In order to manage this risk and maintain the integrity of customers' equipment and processes Country Energy and TransGrid are currently planning the installation of facilities to automatically shed selected electrical loads should a low voltage situation occur. Following a load shedding event, restoration of load will have to be carefully managed until 72 line is returned to service.

Other emerging limitations detailed below have been investigated. Based on the present load forecast (see Section 2 and Appendix 3) it has been determined that they may not, in isolation, impact materially on planning within a ten year planning horizon. However they do form an integral part of the planning considerations for the area because the timing of their emergence may be highly dependent on:

- The planning standard adopted (see Section 3.3.5); and
 - The emergence of significant blocks of load ("spot loads") with a short lead time. Spot loads typically arise from the connection of a large commercial or industrial customer, such as a mine.
1. If one of the 330/132 kV transformers at Wellington were to be out of service then the loading on the other in service 330/132 kV transformer may exceed its thermal rating. Based on the present load forecast, periods of risk during high electrical demand are expected to emerge for this potential limitation from about 2005/6. However, it is expected that this limitation would be relieved at low cost by installing larger units as part of TransGrid's overall asset management strategy and/or by rematching of transformer capacities at a number of locations including Wellington and/or by switching of 132 kV lines.
 2. If any one of line numbers 944, 948 and 94X were to be out of service the power flows on the remaining two lines may exceed their thermal ratings during periods of high electrical demand.

The timing of the emergence of this limitation may be significantly affected by the development of spot loads in the area. At this point in time with all known potential spot load developments it is not expected that this limitation will emerge within a ten year planning horizon. Should it emerge due to unforeseen spot loads it could be initially mitigated via the installation of shunt capacitors in the area at relatively low cost and with short lead times.

3. If the 330 kV line 72 between Mount Piper and Wellington 330 kV Substations were to be out of service power flows on 132 kV lines 944, 947, 94X and 94M may exceed their thermal ratings during periods of high electrical demand. Based on the present load forecast this limitation is not expected to emerge within a ten year planning horizon.
4. If one of the 330/132 kV transformers at Wallerawang or Mount Piper were to be out of service then the loading on the other two in service 330/132 kV transformers at these locations may exceed their thermal rating. Based on the present load forecast this limitation is not expected to emerge within a ten year planning horizon.

3.2. Code Requirements

The National Electricity Code specifies a number of requirements for developing networks within a region, including that:

- TNSPs and DNSPs establish a need for augmentation and conduct joint planning to develop options.
- Network adequacy should be assessed against an objectively measurable service standard linked to the technical requirements of Schedule 5.1 of the Code.

Effectively the requirement is to state (and “justify”) the planning criteria used and the technical performance required.

3.3. Planning Criteria

3.3.1. General Requirements

The simplest approach (to the development of an objectively measurable service standard) that could be adopted for a network similar to the Western area is to apply a strictly deterministic “N-1” reliability criterion. This type of criterion requires that network limitations do not occur for any single credible contingency (such as an outage of 72 line).

TransGrid and Country Energy have agreed that such a criterion may not be appropriate for the Western Area for the following reasons:

- The risk of a network voltage limitation during an outage of 72 line has emerged and has been in existence for some years.

Considering the high reliability of this line it would seem reasonable to allow consideration of options that may mitigate, without necessarily completely eliminating, this risk, possibly more cost effectively than other options;

- The desirability of considering options that also prevent or delay the onset of the other potential limitations described in 3.1 but may not completely eliminate the risk of the voltage limitation.

TransGrid and Country Energy have agreed to adopt a less risk-averse planning standard than a strictly deterministic “N-1” criterion. An “Expected System Minutes Not Supplied” approach is used (see Appendix 2) because the cost of “Expected Unserved Energy” is a quantity that can be evaluated in an application of the ACCC’s regulatory test. This type of planning criterion accepts that there will be some risk of supply interruptions (at times of moderate to high system demand).

3.3.2. Determination of Risk Exposure Profile

In the case of the Western Area the network consists of several lines that supply a number of loads at geographically diverse supply points. The load at each supply point has its own individual profile throughout the year. In order to assess the impact of these individually varying and geographically separate loads, the system was modelled on an hourly basis. That is, for each year, 8760 load flows were carried out. For future years, the actual 2001 load profile for each supply point was scaled so that the maximum demand was the forecast peak demand for that year.

The risk exposure profile for the far Western area is summarised in Table 3.1 below.

Table 3.1 – Risk Exposure Profiles –Far Western Area

Year	System Max Load (MW)	Max Load at Risk (MW)	Period of Risk (Hours)	Energy at Risk (MWh)	Expected Energy Not Supplied (MWh)	System Minutes at Risk	Expected System Min. Not Supplied
2003	288	136	5,150	210,000	190	43,750	40
2004	294	138	5,420	220,000	200	44,898	41
2005	299	>146	5,670	260,000	240	52,174	48
2006	305	>146	5,850	290,000	270	57,049	52
2007	311	>146	6,050	320,000	290	61,736	56
2008	317	>146	6,320	340,000	310	64,353	59
2009	323	>146	6,420	360,000	330	66,873	61
2010	328	>146	>6,500	380,000	350	69,512	63
2011	334	>146	>6,500	400,000	370	71,856	66
2012	340	>146	>6,500	430,000	390	75,882	69
2013	346	>146	>6,500	450,000	390	78,035	71

Note

Table 3.1 has been derived from detailed load flow studies. Due to diversity between loads at different supply points Energy at Risk may be significantly less than would be apparent by applying a single load duration curve to the area.

3.3.3. Reliability of 72 Line

The values of Expected Energy Not Supplied in Table 3.1 depend on estimates of the probability of an outage of 72 line (see Appendix 2). Transmission lines may be forcibly removed from service for a number of reasons, the most common causes being lightning strikes, bushfires and a variety of different types of equipment malfunctions or failures. TransGrid's records of forced outages of 330 kV transmission lines indicate that the average forced outage rate for a line 173 km in length (the length of 72 line) is approximately 8 hrs pa. This value has been adopted in deriving Table 3.1.

3.3.4. Maintenance Issues

Transmission lines also need to be taken out of service for routine maintenance, equipment upgrades and the like. Planned outages average about 12 hours in duration although they may be significantly longer or shorter, depending on the need. They are normally planned to take place during low load periods (when the load is expected to be below the maximum supportable load) and so do not contribute to the Expected Energy Not Supplied. However, as the period of risk increases it becomes increasingly difficult to schedule planned outages at times such as will avoid the need to curtail load. To avoid a "maintenance constrained" system the period of risk has to be kept to a reasonable value (even if the probability of a forced outage of a relevant system element is very low and would lead to a low value of Expected Energy Not Supplied). Table 3.1 indicates that the Western area is becoming increasingly maintenance constrained. That is, with periods of risk increasing beyond 50% of the time (4380 hrs) it becomes increasingly problematic that maintenance "windows" of about 12 hours duration will be available. (In the Western area, it is considered that maintenance windows on any major network element should be available for 12 hour periods, in daylight hours, on a weekday during low load seasons.)

This would indicate the use of a planning criterion where the period of risk is less than the values in the table.

3.3.5. Objectively Measurable Service Standard

TransGrid and Country Energy have determined the following as an objectively measurable service standard in their application of the regulatory test.

The Expected Energy Not Supplied, (in any year of a ten year planning horizon from 2003) should be less than 10 System Minutes for the worst single-element credible contingency.

The load grouping used to determine the "System Max Load" profile and hence the "System Minutes at Risk and "Expected System Min. Not Supplied" profiles is the total (diversified) load at the following supply points: Wellington, Western area load west of Wellington, Parkes, North Parkes, Beryl and Mudgee.

This standard would correspond, for example, to a value of Expected Energy Not Supplied for 2003 of about 48 MWh and the period of risk would be reduced to less than about 1500 hours. It allows for a reasonable degree of flexibility in maintenance strategies over the 10 year planning horizon.

3.3.6. Need for Augmentation

Comparison of Table 3.1 above with the objectively measurable service standard indicates that it is not satisfied during any year from 2003 onwards. This indicates that there is a need for an augmentation of the network such that the expected system minutes not supplied is to be reduced to less than 10 for any year within the planning horizon (to 2013) for the worst single element contingency.

Because the objectively measurable service standard is not currently being satisfied it will not be possible to construct an option in a particular year so as to just meet it. In other words, the timing of the construction of options will be determined by their lead times rather than by a requirement to optimise a particular in service date.

When applying the ACCC's regulatory test, the cost (to the electricity market) of not meeting the objectively measurable service standard in the years prior to construction has been calculated from the expected energy not supplied.

4. Augmentation Options

As required by the Code in Clause 5.6.2(c) TransGrid and Country Energy have carried out joint planning reviews and have identified augmentation options as described in the following sections.

Three options involving augmentation of TransGrid's transmission network have been developed. These options have been progressed to a stage where there is little risk that TransGrid would not be able to make these options available for service by the indicated dates, should they form all or part of recommended action arising from this consultation.

Clause 5.6.2 (f) of the Code requires that the consideration of options should include but not be limited to demand side, generation and market network services provider options.

Recognising this requirement TransGrid and Country Energy (as Advance Energy) carried out, in 2001, an investigation of possible options involving demand side management and local generation in the Western Area using the services of an energy consultant. The energy consultant's report (Ref 3) was published with the consultation paper. Using information from this report TransGrid, Country Energy and NERA (TransGrid's economics consultant) jointly developed an additional three indicative options that involved components of either demand management or generation that would be located in the Western area.

NERA carried out a preliminary application of the regulatory test including the three transmission options and the three indicative demand management or local generation options.

The indicative options were included in NERA's preliminary application of the regulatory test to:

- Provide a basis for interested parties to propose options that may be similar; and
- Indicate whether such options would be likely to pass the regulatory test.

As discussed in Section 1.3.2 NERA's report was published with TransGrid and Country Energy's consultation paper in May 2003. The results of NERA's preliminary application of the regulatory test indicated that options involving components of local generation, in combination with one of the transmission options, were significantly less cost effective than the other options. They indicated that a demand management project, similar to the one considered by NERA, could form part of an option that satisfies the regulatory test. However, no submissions, or proposals from potential proponents of demand management programs, were received in response to the consultation paper. In fact no feedback of any kind has been received in respect of the Western area network limitations since 1999, when they were first highlighted in TransGrid's Annual Planning Statement for that year.

TransGrid and Country Energy thus conclude that proponents for demand management or local generation options are unlikely to come forward and hence these options have been eliminated from further consideration.

Thus the only options considered in the remainder of this report are the three transmission options described in the consultation paper. The description of these options contains some amendments from the description in consultation paper, being mainly omission of redundant material relating to the indicative options. The remaining material has been reproduced in this report for clarity and completeness.

4.1. Option 1 (Wollar – Wellington)

This option is depicted in Diagrams 3a, 3b and 3c. It involves:

- Establishment of a new 330 kV switching station at Wollar.

Wollar is located on the Bayswater – Mount Piper double circuit 500 kV line no 73/74 (presently operating at 330 kV) about 120 km north of Mount Piper. The switching station would be configured as per Diagram 3b with switchgear suitable for eventual operation at 500 kV and a possible future configuration shown in Diagram 3c. This is required to allow for future operation of 73/74 line at 500 kV.

A number of suitable sites for Wollar Switching Station have been identified with a final choice of site dependent on the route choice for the Wollar – Wellington line.

- Construction of a 330 kV line between Wollar and Wellington 330 kV Substation.

Investigations by TransGrid indicate that a feasible line route would be approximately 115 km in length.

- Connection of the new line at Wollar and Wellington.

At Wollar the new line would be connected to the western circuit (no 74) of the Bayswater – Mount Piper line. At Wellington the double circuit breaker termination of 72 line would be rearranged to terminate 72 line and the new line in single circuit breaker configuration.

- Installation of a new 330 kV reactor switchbay and 50 MVAR 330 kV shunt reactor at Wellington.
- Communications and protection upgrades to accommodate the new system connections.

This option provides a second 330 kV line to Wellington via a completely new route. It completely removes system limitations associated with outages of 72 line until well beyond a ten year planning horizon. This option may also be constructed without any complex staging and potentially risky system rearrangements. For further details of the advantages and disadvantages of this option see Table 4.8.

This option is preferred by TransGrid and County Energy. TransGrid is currently consulting on community impacts of line route and switching station site options.

4.2. Option 2 (Yetholme – Kerr’s Creek)

This option is depicted in Diagrams 4a, 4b and 4c. It involves:

- Establishment of a new 330/132 kV substation at Kerr’s Creek.

Kerr’s Creek is located about 20 km east of Molong on the Mount Piper – Wellington tee Orange 132 kV line no 947. The substation would be initially configured as per Diagram 4b, including a 50 MVAR 330 kV shunt reactor and switchbay similar to that at Wellington under Option 1.

Suitable sites for Kerr’s Creek Substation have been identified.

- Construction of a 330 kV line between Yetholme and Kerr’s Creek Substation.

Yetholme is at the western end of the double circuit 330 kV line from Mount Piper which currently carries part of 72 and 947 circuits

Investigations by TransGrid indicate that a feasible line route is estimated to be about 90 km in length.

- Construction of a new single circuit 132 kV line from Kerr’s Creek to Molong (approx 25 km) and a short double circuit section of 132 kV line from Kerr’s Creek to 947 line.
- Rearrangement of 132 kV lines near Orange and Yetholme to achieve the 132 kV network configuration shown in Diagram 4a.
- 330 kV rearrangements and connections at Kerr’s Creek, Yetholme and Mt Piper to achieve the 330 kV network configuration shown in Diagram 4a.
- Installation of a new 330 kV double circuit breaker switchbay and rearrangement of connections at Mt Piper as shown in Diagram 4c.
- Communications and protection upgrades to accommodate the new system connections.

This option provides a new 330 kV line to a location at Kerr’s Creek, about 2/3 of the distance between Mt Piper and Wellington. A 132 kV line from Kerr’s Creek to Molong and other 132 kV connections are required to offset the loss of an existing 132 kV circuit (some of which is re-used to form part of the new 330 kV line). This option substantially removes the risk of system limitations associated with outages of 72 line. A small risk remains but this is below the level required by the service standard (see Table 4.6). This option also provides an additional 330/132 kV transformer in the area and so addresses the emerging transformer capacity limitations discussed in Section 3.1. For further details of the advantages and disadvantages of this option see Table 4.8.

4.3. Option 3 (Yetholme – Wellington)

This option is depicted in Diagrams 5a and 5b. It involves:

- Construction of a 330 kV line between Yetholme and Wellington via Kerr's Creek.

Yetholme is at the western end of the double circuit 330 kV line from Mount Piper which currently carries part of 72 and 947 circuits

Investigations by TransGrid indicate that a feasible line route is estimated to be about 140 km in length.

- Reconstruction of the existing single circuit 132 kV line 944 between Wallerawang and Yetholme as double circuit 132 kV (about 25 km).

During the reconstruction period the western section of 944 circuit would have to be tee connected to the existing 94C circuit.

- Rearrangement of 132 kV lines near Yetholme and Wallerawang to achieve the 132 kV network configuration shown in Diagram 5a.
- 330 kV rearrangements and connections at Wellington, Yetholme and Mt Piper to achieve the 330 kV network configuration shown in Diagram 5a.
- Installation of a new 330 kV double circuit breaker switchbay and rearrangement of connections at Mt Piper as per Diagram 5b.
- Installation of a new 330 kV reactor switchbay and 50 MVAR 330 kV shunt reactor at Wellington.
- Communications and protection upgrades to accommodate the new system connections.

This option provides for a second 330 kV line to Wellington via a route that roughly parallels the route of the existing 72 line. It completely removes system limitations associated with outages of 72 line until well beyond a ten year planning horizon. This option requires the reconstruction of an existing 132 line between Wallerawang and Yetholme to double circuit construction. This is required to offset the loss of an existing 132 kV circuit (some of which is re-used to form part of the new 330 kV line).

For further details of the advantages and disadvantages of this option see Table 4.8.

4.4. Capital Costs

Table 4.2 details (in \$ Millions) TransGrid and Country Energy's estimates of the capital costs of the options detailed above, that have been used in the cost effectiveness analysis summarised in Section 5.

Table 4.2 - Capital Costs of Transmission Options			
Works	Option 1	Option 2	Option 3
500, 330 kV line works	49.0	44	62
132 kV line works		5	5.5
Wollar Switching Station	7.0		
Kerr's Creek Substation		9.8	
Wellington Reactor	1.5		1.5
Mt Piper 330 kV Mods		2.0	2.0
Communications	3.5	2.0	2.5
Subtotal	61.0	62.8	73.5
Wollar Sub & Transformer	6.7		
Total	67.7	62.8	73.5

Note: The conversion of Wollar to a 500/330 kV substation will only be required if another system development, the conversion of 73/74 line to 500 kV operation eventuates. This project has been described in TransGrid's Annual Planning Report for 2002 and may be required by about 2008.

4.5. Loss Reduction Benefits

A benefit of any major transmission development is the value of the consequent reduction in electrical losses. This benefit will contribute significantly to the cost effectiveness of such developments.

As an illustration of the magnitude of this benefit, based on the cost of losses being estimated at \$25/MWh¹, if the annual loss reduction is 50 GWh (=50,000 MWh) then the annual loss benefit is of the order of \$1,250,000.

Table 4.5 details, for all three options, TransGrid and Country Energy's estimates of the annual reduction in losses (in GWh) relative to the losses that are estimated if no augmentation occurs.

Calendar Year	Option 1	Option 2	Option 3
2003	-	-	
2004	-	-	
2005	-	-	-
2006	-	-	-
2007	47	46	47
2008	48	47	48
2009	51	49	51
2010	52	50	52
2011	54	52	54
2012	55	53	55
2013	57	54	56

4.6. Avoided Unserved Energy Benefits

An economic benefit of developments that improve reliability of supply is the reduction in estimates of the expected cost of energy not supplied (the value of unserved energy).

Tables 4.6 and 4.7 detail, for all three transmission options, TransGrid's estimates of the Expected Energy Not Supplied. The values in the first table are expressed in system minutes and the second table in MWh. The system minute table illustrates the capacity of various system augmentations to satisfy the "10 system minute" service standard (see Section 3.3.5).

To enable an avoided unserved energy benefit of each option to be calculated relative to a "Do Nothing" (ie no augmentation) case the estimated unserved energy for this case is included in the tables.

Calendar Year	Option 1	Option 2	Option 3	Do Nothing
2003	39	39	39	40
2004	42	42	42	41
2005	47	47	47	48
2006	53	53	53	52
2007	0	0.2	0	56
2008	0	0.4	0	59
2009	0	0.7	0	61
2010	0	1.0	0	63
2011	0	1.5	0	66
2012	0	2.0	0	69
2013	0	2.7	0	73

¹

This cost estimate is based on the operating cost of a gas-fired CCGT

Calendar Year	Option 1	Option 2	Option 3	Do Nothing
2003	188	188	188	188
2004	204	204	204	204
2005	235	235	235	235
2006	268	268	268	268
2007	0	1.0	0	288
2008	0	2.1	0	309
2009	0	3.5	0	328
2010	0	5.6	0	345
2011	0	8.2	0	365
2012	0	11.6	0	385
2013	0	15.6	0	410

4.7. Strategic Advantages, Disadvantages and Risks

In addition to the above costs and benefits, the options have a number of strategic advantages, disadvantages and risks that are potentially significant, but where it is impractical to assign a particular dollar value. Nevertheless they should be taken into account in the selection of a preferred option, where the quantifiable costs and benefits of different options result in similar economic benefits (or costs) because they are, in principle, measurable as financial transactions in the electricity market and therefore should be included in an application of the regulatory test.

TransGrid and Country Energy have considered the advantages, disadvantages and risks of the three options. The outcomes of these considerations is summarised in the Table 4.8 on the following page. Based on these considerations, TransGrid and County's Energy's view is that the Wollar – Wellington development is the preferred transmission project. This view would only be likely to change if an application of the regulatory test clearly indicates to the contrary. The analysis (see Section 5) does not indicate this.

In parallel with this regulatory consultation, TransGrid is consulting with local communities on the environmental and other impacts of the Wollar – Wellington development.

Table 4.8 - Comparison of Transmission Options Advantages, Disadvantages and Risks

Apart from the relative cost effectiveness of the Western area options the following table sets out issues that are relevant when making a choice between them.

Option 1: Wollar - Wellington		Option 2: Yetholme – Kerr’s Creek		Option 3: Yetholme - Wellington	
Pros	Cons	Pros	Cons	Pros	Cons
Provides significant route diversity with 72 line.	Increases the cost of a future project to uprate the Bayswater – Mount Piper line to 500 kV because the cost of the Wollar transformer has to be included in that evaluation.	Provides an extra 330/132 kV transformer in the area.	A section of 132 kV line between Orange and Yetholme is unused (although this is mitigated by looping 947 line into Orange).	Facilitates construction of a future substation in the Kerr’s Creek area as the new line would pass to the west of 72 line and close to potential sites in this area.	Only minor route diversity with 72 line.
Project risks are relatively small as there are no complex and potentially risky 132 kV line rearrangements.	The Wollar transformer, if required, would be non-standard if built to minimum requirements. Alternatively a more expensive but standard transformer could be installed.	Enables 947 line to be looped into Orange without an extra switchbay at Orange.	Project risks are higher than for the Wollar option as there are complex and potentially risky 132 kV line and 330 kV rearrangements near Yetholme and Kerr’s Creek.	No new substation sites are required (at least initially).	Project risks are higher than for the Wollar option as there are complex and potentially risky 132 kV line rearrangements near Yetholme.
The option to construct a future 330 kV substation at Icelly is retained.	The proposed site for Wollar is relatively difficult for MW radio access.	Communications is suited for further development towards Orange, Cowra Forbes and Parkes	An outage of 72 line to install an OPGW may be required prior to commissioning of the new substation.	Completely eliminates voltage problem at Wellington for an outage of 72 line for many years.	An outage of 72 line to install an OPGW may be required prior to commissioning of new line.
Completely eliminates voltage problem at Wellington for an outage of 72 line for many years.	Partial sunk costs in Mt Piper – Yetholme 330 kV circuit (offset by its use at 132 kV).		The risk of voltage problems at Wellington for an outage of 72 line are not completely overcome.	The option to construct a future 330 kV Substation at Icelly is retained.	Longest length of new 330 kV line (of any of the options considered).
	Does not provide additional 330/132 kV transformer capacity in the area.		There is a risk that the Kerr’s Creek area may not be the optimal long term location for the substation.		Does not provide additional 330/132 kV transformer capacity in the area.
	The cost of constructing a 330/132 kV substation in the Kerr’s Creek area (if appropriate in the future) is higher than for the Yetholme - Wellington option as 72 line is not near the most desirable sites.		Only minor route diversity with 72 line.		

5. Summary of Cost Effectiveness Analysis

As discussed in section 1.3.2 TransGrid engaged the services of economic consultants, National Economic Research Associates (NERA) to apply the ACCC's regulatory test to augmentation options for the Western area. NERA carried out a preliminary application of the regulatory test and their report (Ref 2) was published on TransGrid and Country Energy's web sites with the Western area consultation paper.

NERA based their preliminary application of the regulatory test on:

- The objectively measurable service standard described in Section 3,
- The three options described in Section 4 plus three indicative options involving components of demand management or local generation (see Ref 2 for details);
- Information relating to capital costs, loss benefits and unserved energy benefits described in Section 4 plus additional material relating to the three indicative options (see Ref 2 for details);
- Load forecast information detailed in Section 2 and Appendix 3.

As discussed in Section 4 the three indicative options that NERA considered in their preliminary application of the regulatory test have been eliminated from further consideration. However, the three transmission options are unchanged, including the cost assumptions detailed in Sections 4.4 - 4.6.

Thus, in applying the regulatory test to the remaining three options TransGrid and Country Energy have used NERA's results (see Ref 2 for details) with the following interpretive modifications.

- The results for Options 1-3 are unchanged;
- The results for Options 4-6 have been eliminated; and
- The ranking of Options 1-3 reflects the elimination of Options 4-6;

NERA identified four market development scenarios that may materially affect the relative cost effectiveness and/or timing of options:

- "Base" and "low" demand forecast scenarios; and
- Two scenarios wherein another transmission project (a possible upgrade of the existing Bayswater – Mt Piper 500 kV line to its design voltage of 500 kV) does (first scenario) or does not (second scenario) eventuate by January 2008. The cost effectiveness of Option 1 differs under these scenarios because additional equipment is required at Wollar if the upgrade proceeds.

5.1. Base Case Results

The results of financial modelling of the three options, for the four market development scenarios for a base set of assumptions is set out in Table 5.1 (adapted from Ref 2 p 71).

Table 5.1 - Results of Cost effectiveness analysis – Base Case Assumptions

	Market Scenario A		Market Scenario B		Market Scenario C		Market Scenario D	
	Base Demand No 500 kV upgrade		Base Demand 500 kV upgrade		Low Demand No 500 kV upgrade		Low Demand 500 kV upgrade	
	NPV	Rank	NPV	Rank	NPV	Rank	NPV	Rank
Option 1 (Wollar to Wellington)	-\$24	1	-\$29	2	-\$34	1	-\$39	2
Option 2 (Yetholme to Kerr's Creek)	-\$27	2	-\$27	1	-\$36	2	-\$36	1
Option 3 (Yetholme to Wellington)	-\$34	3	-\$34	3	-\$44	3	-\$44	3

The main conclusions to be drawn from the base case modeling are:

- If the Bayswater – Mt Piper line is not upgraded, the Wollar to Wellington option is around \$2 million more cost effective than the Yetholme to Kerr’s Creek option;
- If the Bayswater – Mt Piper line is upgraded, the Yetholme to Kerr’s Creek option is around \$3 million more cost effective than the Wollar to Wellington option; and
- The Yetholme – Wellington option is somewhat less cost effective than the other two options under all scenarios.

5.2. One at a Time Sensitivity Test Results

NERA tested the robustness of their base case results by carrying out sensitivity tests for a number of financial and other assumptions for each of the scenarios. The results for a selection of “one at a time” sensitivity tests for scenario A are set out in the following table (adapted from Ref 2 p 77).

Table 5.2 - Results of Cost Effectiveness Analysis

Sensitivity Tests for Market Development Scenario A

	Option 1	Option 2	Option 3
	NPV	NPV	NPV
“Base”	-\$24.3	-\$26.6	-\$34.3
High Discount Rate	-\$25.5	-\$27.3	-\$34.3
Low Discount Rate	-\$20.2	-\$23.2	-\$31.7
High Capex	-\$33.8	-\$36.4	-\$45.8
Low Capex	-\$14.8	-\$16.8	-\$22.8
High Opex	-\$25.8	-\$28.2	-\$36.2
Low Opex	-\$22.7	-\$24.9	-\$32.3
Long Asset Lives	-\$24.2	-\$26.5	-\$34.2
High VoLL 2006	-\$5.0	-\$7.8	-\$15.0
Environmental scenarios (CO2 emissions trading)			
High Cost/2005 Intro	-\$17.9	-\$20.4	-\$27.9
Low Cost/2010 Intro	-\$21.3	-\$23.6	-\$31.2

Note: The most cost effective option for each sensitivity test is indicated in bold. The results for the ‘most cost effective option’ have been reinterpreted by TransGrid and Country Energy in light of the reduced number of options.

The main conclusions from the “one at a time” sensitivity tests for scenario A is that the ranking of the options is robust to reasonable changes in individual assumptions. Similar conclusions were reached for the other scenarios.

5.3. Compounded Sensitivity Test Results

NERA carried out selected compounded sensitivity tests, wherein a number of underlying assumptions are varied, with the objective of determining the range of assumptions under which the rankings of the options would be altered (see Ref 2 for details).

The main conclusion that can be drawn from these tests, (allowing for the elimination of the indicative options) is that only relatively small changes in the relative capital costs of Options 1 and 2 would be required to alter their relative ranking (NERA’s other conclusions related to the eliminated options).

5.4. Conclusions

The conclusions that can be drawn from the application of the regulatory test by NERA (interpreted in the light of the elimination of the indicative options) are:

1. The modelling suggested that, of the three transmission options, either the Wollar to Wellington or the Yetholme to Kerr's Creek network augmentation would provide the most cost effective means of meeting the system reliability standard that TransGrid and Country Energy have determined for the Western Area.
2. Whether the Wollar to Wellington or the Yetholme to Kerr's Creek network augmentation is more cost effective will depend on whether or not the Mt Piper to Bayswater line is upgraded from 330kV to 500kV:
3. The ranking of the options is robust to (reasonable) changes in the underlying assumptions when these are undertaken one at a time and consistently across options.

6. Conclusions and Recommended Actions

6.1. Summary of Submissions

Clause 5.6.2(h)(3) of the Code, as in operation immediately prior to March 8th 2002, requires this report to summarise the submissions from the consultations.

As described elsewhere in this report no submissions were received.

6.2. Conclusions and Determination

The results of the application of the regulatory test summarised in Section 5 indicate that there is only a small difference in the calculated cost effectiveness of Option 1 (Wollar – Wellington) and Option 2 (Yetholme – Kerr's Creek), compared to their cost (about 3-4% of capital costs). This is true across all scenarios, even though their relative rankings are robust to variations in a range of financial and other parameters. In scenarios where the Bayswater to Mount Piper line remains in operation at 330 kV then Option 1 is the more cost effective, whereas in scenarios where the Bayswater to Mount Piper line is upgraded to 500 kV operation then Option 2 is the more cost effective. The results also suggest that Option 3 (Yetholme – Wellington) is sufficiently less cost effective (about 10% of capital costs) across all scenarios and sensitivities, than the other two options, to be eliminated from further consideration.

Therefore TransGrid and Country Energy conclude that either Option 1 or Option 2 satisfies the regulatory test.

Thus the preferred option depends on considerations of the relative technical (ie non-economic) merits of Options 1 and 2. As discussed in Section 4.7 TransGrid and Country Energy have considered the strategic advantages, disadvantages and risks associated with all three options and have determined that Option 1 (Wollar – Wellington) is the preferred option.

6.3. Recommended Action

The recommended action is the construction of the Wollar – Wellington project, as described in Section 4.1 and Diagrams 3a, 3b, and 3c.

6.4. Construction Start, Construction time and Commissioning Date

The planned commissioning date for the Wollar – Wellington project is June 2007.

Start of construction is expected early to mid, 2004, when it will be necessary to commence acquisition of transmission line easements, Wollar Switching Station site and communication network sites to meet the planned commissioning date. Construction of the Wollar – Wellington line, Wollar Switching Station and communication network extensions are expected to commence by mid 2005.

Construction time is thus estimated to be approximately three to three and one half years.

7. Contact Details for Notification of Disputes

This report recommends the construction of a *new large network asset*. Therefore Clause 5.6.2 (i) of the Code, as in operation immediately before March 8th 2002, provides for *Code Participants* to dispute its recommendations.

Code Participants who intend to dispute the recommendations of this report must notify TransGrid by close of business 40 business days following publication of this report on TransGrid's web site. The final date for notification of disputes will be included in the web site notice.

Contact details for notification of disputes are:

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Appendix 1

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 2

Determination of an Objectively Measurable Service Standard by Specifying a Maximum Value of System Minutes Not Supplied

Referring to Diagram 6 a load duration curve (red) is determined for supply to an area. This is done by measuring the electrical load during each hour (load trace) over a suitably long period (eg a year) and sorting values from highest to lowest. For each value of the curve on the Y axis (load) the corresponding value of the curve on the X axis (hours) represents the number of hours that the supply of load to the area exceeds the Y axis value.

Following a credible contingency a network may not be able to supply load above a certain value because, for example, some technical limit of the network will be exceeded. This is the Maximum Supportable Load (for the credible contingency in question).

When the load is above the Maximum Supportable Load there is a certain amount of load at risk of not being able to be supplied (that is, it could not be supplied if the relevant credible contingency were to occur at that point in time). On the load duration curve for loads above the Maximum Supportable Load then the Load at Risk is the difference between the load and the Maximum Supportable Load.

The area of the load duration curve above the Maximum Supportable Load is the Energy at Risk.

The Expected Energy Not Supplied (that is, the statistical mean value of the Energy At Risk) is then found by multiplying the Energy at Risk by the probability (that is, the proportion of the period covered by the load duration curve) that the relevant credible contingency will be in effect. Thus,

$$\begin{array}{rcccl} \text{Expected} & & \text{Energy} & & \text{Probability of} \\ \text{Energy Not} & = & \text{at} & \times & \text{Relevant Credible} \\ \text{Supplied} & & \text{Risk} & & \text{Contingency} \end{array}$$

The Expected Energy Not Supplied is more commonly referred to as the Unserved Energy.

Objectively measurable service standards similar to those described in clause S5.1.2.2 (b) of the Code can be related to the Expected Energy Not Supplied.

For example if, for the most severe single credible contingency, the Maximum Load can continue to be supplied by the network then the Maximum Supportable Load is greater than the Maximum Load. The Energy at Risk and the Expected Energy Not Supplied are zero. This corresponds to the example given in Code clause S5.1.2.2 (b) (4). Networks with this feature are commonly said to satisfy an N-1 planning criterion.

For “single element” (ie radial) networks the Maximum Supportable Load (following outage of a radial element) is zero and the Energy At Risk is the entire area under the load duration curve. This corresponds to the example given in Code clause S5.1.2.2 (b) (1). Networks with this feature are can said to satisfy an N planning criterion if the Maximum Load can be supplied by the network with the radial element in normal operation.

Networks with intermediate values of Energy at Risk, Expected Energy Not Supplied and Maximum Supportable Load may be used to specify other objectively measurable service standards. If the Maximum Supportable Load were specified to be 70% of the Maximum Load this would correspond to the example given in Code clause S5.1.2.2 (b) (3).

The method used in this paper to define an objectively measurable service standard is to specify that the Expected Energy Not Supplied should be less than a value that is proportional to the Maximum Load (in any one year). This is done by expressing the value for each year in “Expected System Minutes Not Supplied”.

“System Minutes” refers to an amount of energy (in MW x Minutes) equal to the maximum rate of consumption of electricity x the number of minutes referred to.

For example, if the maximum load is 120 MW then 10 system minutes means $120 \times 10 = 1200$ (MW-Min) = $1200/60$ MWh = 20 MWh.

Thus,

$$\text{System Minutes at Risk} = \frac{\text{Energy at Risk} \times 60}{\text{Maximum Load}}$$

and

$$\text{Expected System Minutes Not Supplied} = \text{System Minutes at Risk} \times \text{Probability of Relevant Credible Contingency}$$

For example (see Table 3.1 for 2003), if a load area has a maximum load of 288 MW and, for a credible contingency whose probability of occurrence is 8hrs/annum (ie 8/8760) then if the energy at risk is determined (via a load duration curve and the determined maximum supportable load) to be 210,000 MWh then;

$$\text{System minutes at risk} = 210,000 \times 60 / 288 = 43,750$$

and

$$\text{Expected System Minutes not Supplied} = 43,750 \times 8 / 8760 = 40$$

Conversely if, for example, we specify an objectively measurable service standard by requiring:

$$\text{Expected System Minutes Not Supplied} \leq 10$$

then this is equivalent to requiring that:

$$\text{Expected Energy Not Supplied} \leq 10 \times 288 / 60 = 48 \text{ MWh}$$

Hence the corresponding "At Risk" quantities are derived using the probability of the relevant credible contingency:

$$\text{System Minutes At Risk} \leq 10 \times 8760 / 8 = 10,960$$

or

$$\text{Energy At Risk} \leq 10,960 \times 288 / 60 = 52,618 \text{ MWh}$$

Thus, by specifying an objectively measurable service standard in terms of an allowed "Expected Not Supplied" quantity, the corresponding "At Risk" quantities and the minimum allowed value of the maximum supportable load depend on the probability of the relevant credible contingency.

This contrasts with the type of service standard given in Code clause S5.1.2.2 (b) (3) where the minimum allowed value of the maximum supportable load is independent of the probability of the relevant credible contingency and the corresponding "Expected Not Supplied" quantities are dependent on this probability.

Appendix 3

Load Forecast Summary

The following load forecast information has been provided to TransGrid by Country Energy and reviewed by TransGrid. It represents their joint view as to the likely increases in maximum loads at points of supply to Country Energy in the Western area over the period 2002 – 2009. It has been used in loadflow simulations to model the performance of the network and determine the timing and extent of emerging network constraints in the area.

The information presented in the tables on the following pages relates to forecast maximum loads in summer and winter only. Loads used in loadflow studies at other times have been estimated by scaling up average hourly load traces, which are available for calendar year 2000. Interested parties may contact TransGrid to obtain this information.

“Best Estimate” Summer and Winter Maximum Demand Forecast

This forecast is based on TransGrid and Country Energy’s view of their “best estimate” of increases in maximum loads during summer and winter in the period to winter 2009. It is based on:

- Increases in general loads of 2%-4% pa at points of supply as indicated
- Power factors for general loads remain constant
- Connection of certain spot loads as indicated
- Various load transfers between supply points

This forecast is summarised in Table A3.1

“Low” Summer and Winter Maximum Demand Forecast

This forecast is based on a more moderate level of increases in maximum loads during summer and winter in the period to winter 2009. It is based on:

- Increases in general loads of 2%-4% pa at points of supply as indicated
- Power factors for general loads remain constant
- Connection of a reduced set of spot loads as indicated
- Load transfers between supply points as per the best estimate forecast

This forecast is summarised in Table A3.2

Table A3.1 Best Estimate Summer and Winter Maximum Demand Forecast

Supply Point		Beryl	Cowra	Forbes	Mudgee	Orange, Molong & Cadia	Panorama	Parkes & North Parkes	Wellington 132 kV	Wellington Town
Load growth pa		4%	2%	2%	4%	2%	2%	2%	2%	2%
Spot load MW					15.0	25.0		2 x 5.0+20	7.0	
Spot load MVA					5.5	9.2		2 x 1.8+7.3	1.5	
Spot load Season					2002	2002		2002, 2002/3 & 2003	2002	
2001/02	MW	31.2	27.0	34.6	18.7	112.7	69.6	45.6	152.8	7.2
	MVA	12.2	10.5	15.7	6.9	44.1	21.7	16.6	31.0	2.8
2002	MW	34.0	25.7	34.9	37.3	145.8	76.7	52.9	166.7	8.5
	MVA	13.3	10.0	15.9	13.7	56.7	24.0	19.2	33.8	3.3
2002/03	MW	32.4	27.5	35.3	34.4	138.9	71.0	71.0	162.9	7.4
	MVA	12.7	10.7	16.0	12.7	53.8	22.2	25.8	33.1	2.9
2003	MW	35.3	26.2	35.6	38.2	147.2	78.3	78.4	169.9	8.7
	MVA	13.8	10.2	16.2	14.0	57.3	24.4	28.5	34.5	3.4
2003/04	MW	33.7	28.0	36.0	35.2	140.1	72.4	76.4	166.0	7.5
	MVA	13.2	11.0	16.3	13.0	54.3	22.6	27.8	33.7	2.9
2004	MW	36.7	26.7	36.3	39.1	148.5	79.8	78.8	173.2	8.8
	MVA	14.4	10.4	16.5	14.4	57.8	24.9	28.6	35.2	3.5
2004/05	MW	35.0	28.6	36.7	36.0	141.3	73.8	76.8	169.2	7.7
	MVA	13.7	11.2	16.7	13.3	54.8	23.1	27.9	34.3	3.0
2005	MW	38.2	27.3	37.1	40.1	149.9	81.4	79.3	176.5	9.0
	MVA	14.9	10.6	16.8	14.7	58.4	25.4	28.8	35.8	3.5
2005/06	MW	36.5	29.2	37.4	36.8	142.5	75.3	77.3	172.4	7.8
	MVA	14.2	11.4	17.0	13.6	55.3	23.5	28.1	35.0	3.1
2006	MW	39.7	27.8	37.8	41.1	151.3	83.1	79.8	179.9	9.2
	MVA	15.5	10.9	17.2	15.1	59	25.9	29.0	36.5	3.6
2006/07	MW	37.9	29.8	38.2	37.7	143.8	76.8	77.7	175.7	8.0
	MVA	14.8	11.6	17.3	13.9	55.8	24.0	28.2	35.7	3.1
2007	MW	41.3	28.4	38.5	42.1	152.7	84.7	80.3	183.3	9.4
	MVA	16.1	11.1	17.5	15.5	59.5	26.5	29.2	37.2	3.7
2007/08	MW	39.4	30.4	39.0	38.6	145	78.3	78.2	179.1	8.1
	MVA	15.4	11.9	17.7	14.2	56.4	24.5	28.4	36.4	3.2
2008	MW	43.0	28.9	39.3	43.2	154.2	86.4	80.8	186.9	9.6
	MVA	16.8	11.3	17.9	15.9	60.2	27.0	29.3	37.9	3.7
2008/09	MW	41.0	31.0	39.7	39.6	146.3	79.9	78.6	182.5	8.3
	MVA	16.0	12.1	18.0	14.6	56.9	25.0	28.6	37.1	3.2
2009	MW	44.7	29.5	40.1	44.3	155.6	88.2	81.3	190.5	9.8
	MVA	17.5	11.5	18.2	16.3	60.8	27.5	29.5	38.7	3.8

Table A3.2 “Low” Summer and Winter Maximum Demand Forecast

Supply Point		Beryl	Cowra	Forbes	Mudgee	Orange, Molong & Cadia	Panorama	Parkes & North Parkes	Wellington 132 kV	Wellington Town
Load growth pa		4%	2%	2%	4%	2%	2%	2%	2%	2%
Spot load MW						25.0				
Spot load MVA						9.2				
Spot load Season						2002				
2001/02	MW	28.7	24.8	30.8	17.4	103.5	66.1	42.2	151.5	6.6
	MVA	12.2	10.5	15.7	6.9	43.9	21.7	16.4	30.8	0.7
2002	MW	31.3	23.6	31.1	20.8	133.9	72.9	44.4	148.6	7.8
	MVA	13.3	10.0	15.9	8.2	56.3	24.0	17.2	30.2	0.9
2002/03	MW	29.8	25.3	31.4	18.1	127.6	67.4	42.6	145.0	6.8
	MVA	12.7	10.7	16.0	7.2	53.4	22.2	16.5	29.4	0.7
2003	MW	32.5	24.1	31.7	21.6	135.1	74.4	44.8	151.6	8.0
	MVA	13.8	10.2	16.2	8.5	56.9	24.4	17.4	30.8	1.0
2003/04	MW	31.0	25.8	32.1	18.8	128.7	68.8	42.9	147.9	6.9
	MVA	13.2	11.0	16.3	7.5	53.9	22.6	16.7	30.0	0.8
2004	MW	33.8	24.6	32.4	22.4	136.3	75.8	45.2	154.6	8.1
	MVA	14.4	10.4	16.5	8.9	57.4	24.9	17.5	31.4	1.0
2004/05	MW	32.3	26.3	32.7	19.6	129.8	70.1	43.3	150.9	7.0
	MVA	13.7	11.2	16.7	7.8	54.4	23.1	16.8	30.6	0.8
2005	MW	35.2	25.1	33.0	23.3	137.6	77.4	45.6	157.7	8.3
	MVA	14.9	10.6	16.8	9.2	58.0	25.4	17.7	32.0	1.0
2005/06	MW	33.6	26.9	33.4	20.4	130.9	71.5	43.7	153.9	7.2
	MVA	14.2	11.4	17.0	8.1	54.9	23.5	17.0	31.2	0.8
2006	MW	36.6	25.6	33.7	24.3	138.9	78.9	46.1	160.9	8.5
	MVA	15.5	10.9	17.2	9.6	58.6	25.9	17.9	32.7	1.0
2006/07	MW	34.9	27.4	34.0	21.2	132.0	73.0	44.2	157.0	7.3
	MVA	14.8	11.6	17.3	8.4	55.4	24.0	17.1	31.9	0.8
2007	MW	38.0	26.1	34.3	25.2	140.2	80.5	46.6	164.1	8.6
	MVA	16.1	11.1	17.5	10.0	59.1	26.5	18.1	33.3	1.0
2007/08	MW	36.3	27.9	34.7	22.0	133.2	74.4	44.6	160.1	7.5
	MVA	15.4	11.9	17.7	8.7	56.0	24.5	17.3	32.5	0.8
2008	MW	39.6	26.6	35.0	26.2	141.5	82.1	47.0	167.4	8.8
	MVA	16.8	11.3	17.9	10.4	59.8	27.0	18.2	34.0	1.1
2008/09	MW	37.7	28.5	35.4	22.9	134.4	75.9	45.0	163.3	7.6
	MVA	16.0	12.1	18.0	9.1	56.5	25.0	17.5	33.1	0.8
2009	MW	41.1	27.2	35.7	27.3	142.8	83.7	47.5	170.7	9.0
	MVA	17.5	11.5	18.2	10.8	60.4	27.5	18.4	34.6	1.1

Appendix 4

List of References

- 1. The National Electricity Code**
- 2. Augmentation of Supply to the Western Area
Preliminary Cost Effectiveness Analysis**

Report by NERA - May 2003
- 3. Development Options Involving Demand Side Management and Local
Generation in the Advance Energy Area**

**Report to TransGrid and Advance Energy
by C Crawford-Smith et al - March 2001**
- 4. Limitations in the Network Supplying the Western Area of NSW**

Report by TransGrid and Country Energy – July 2002
- 5. Limitations in the Network Supplying the Western Area of NSW**

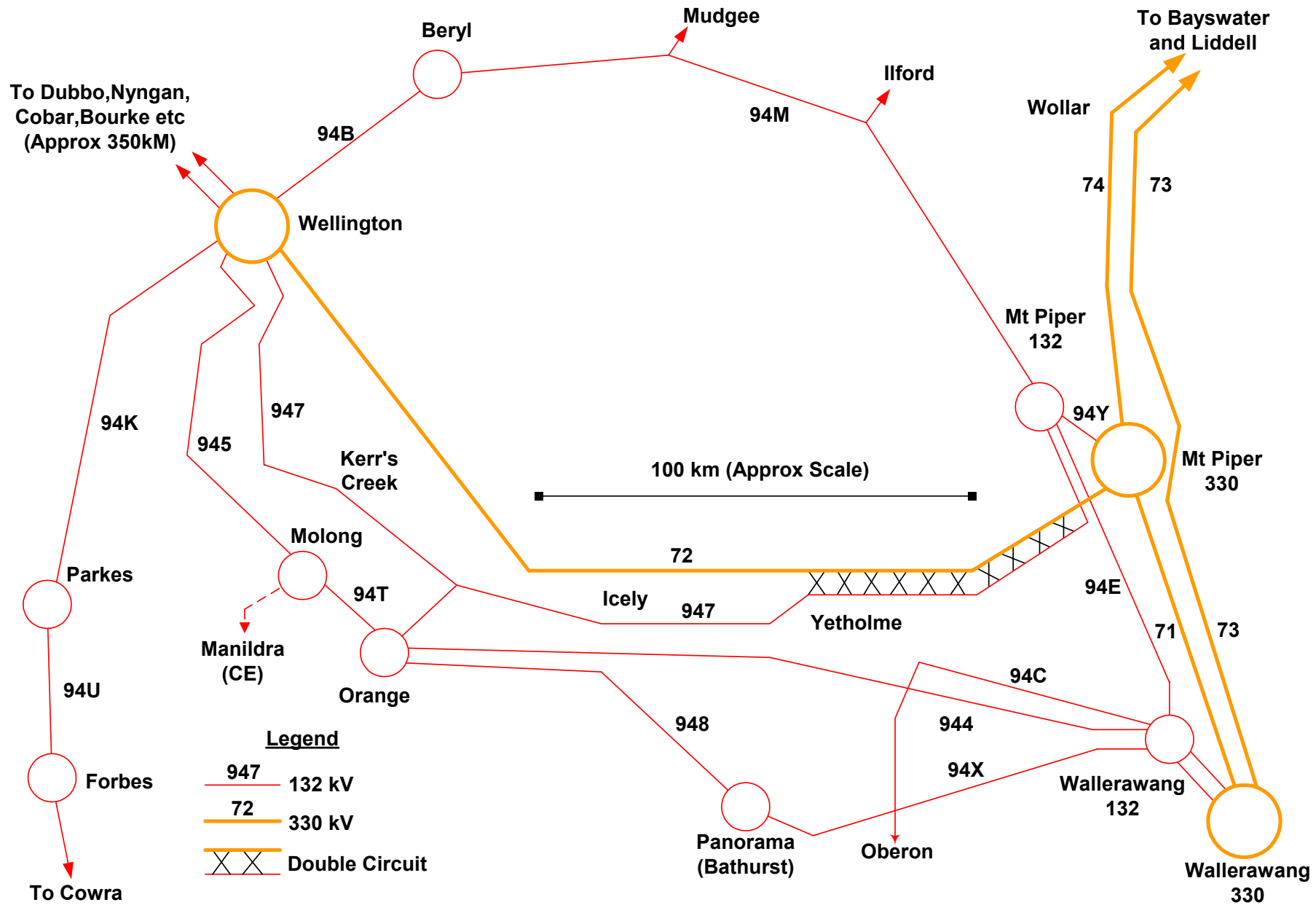
Consultation Paper by TransGrid and Country Energy – May 2003

Appendix 5

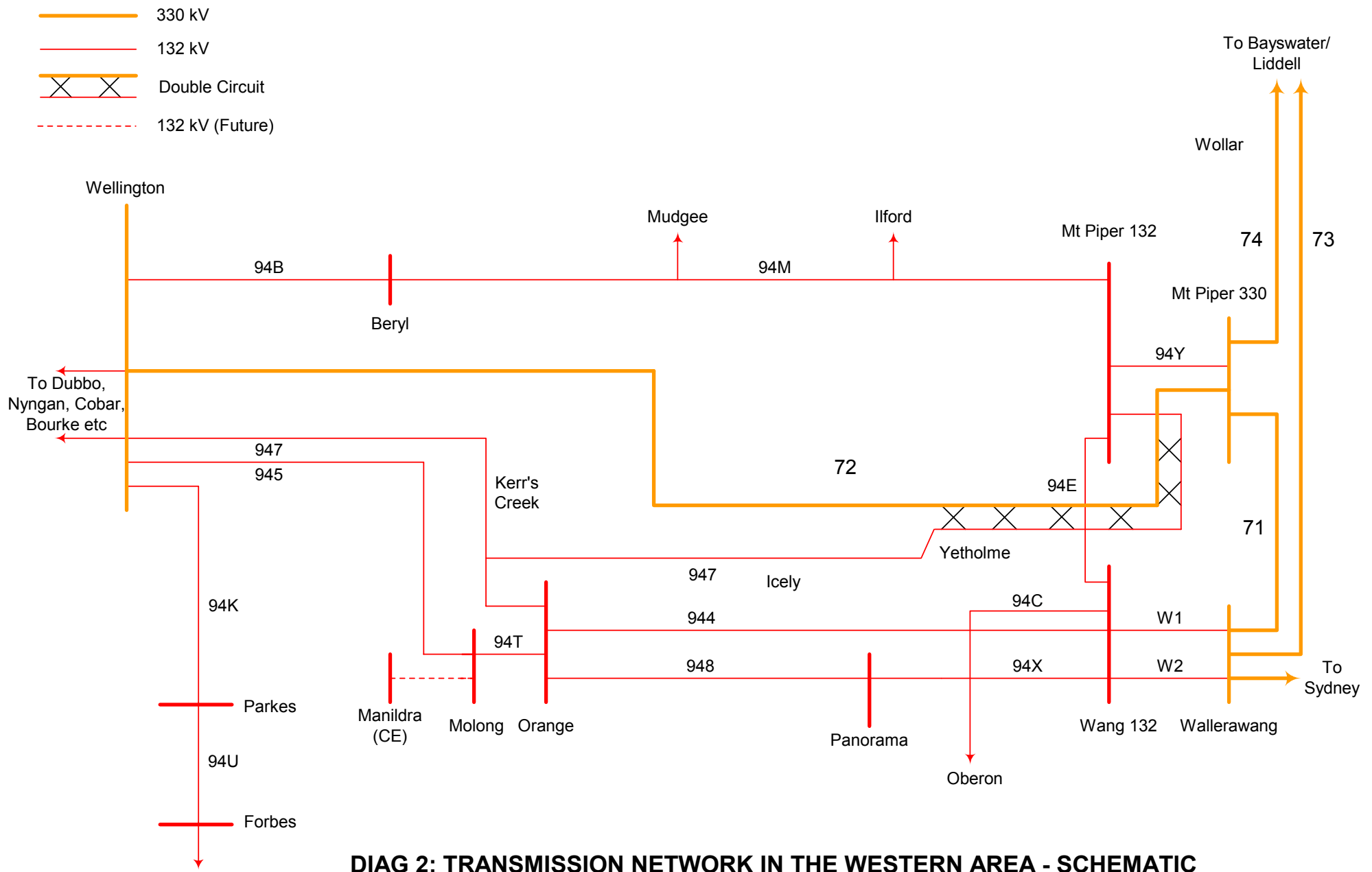
Diagrams 1 to 6

The following pages contain diagrams referenced in the text.

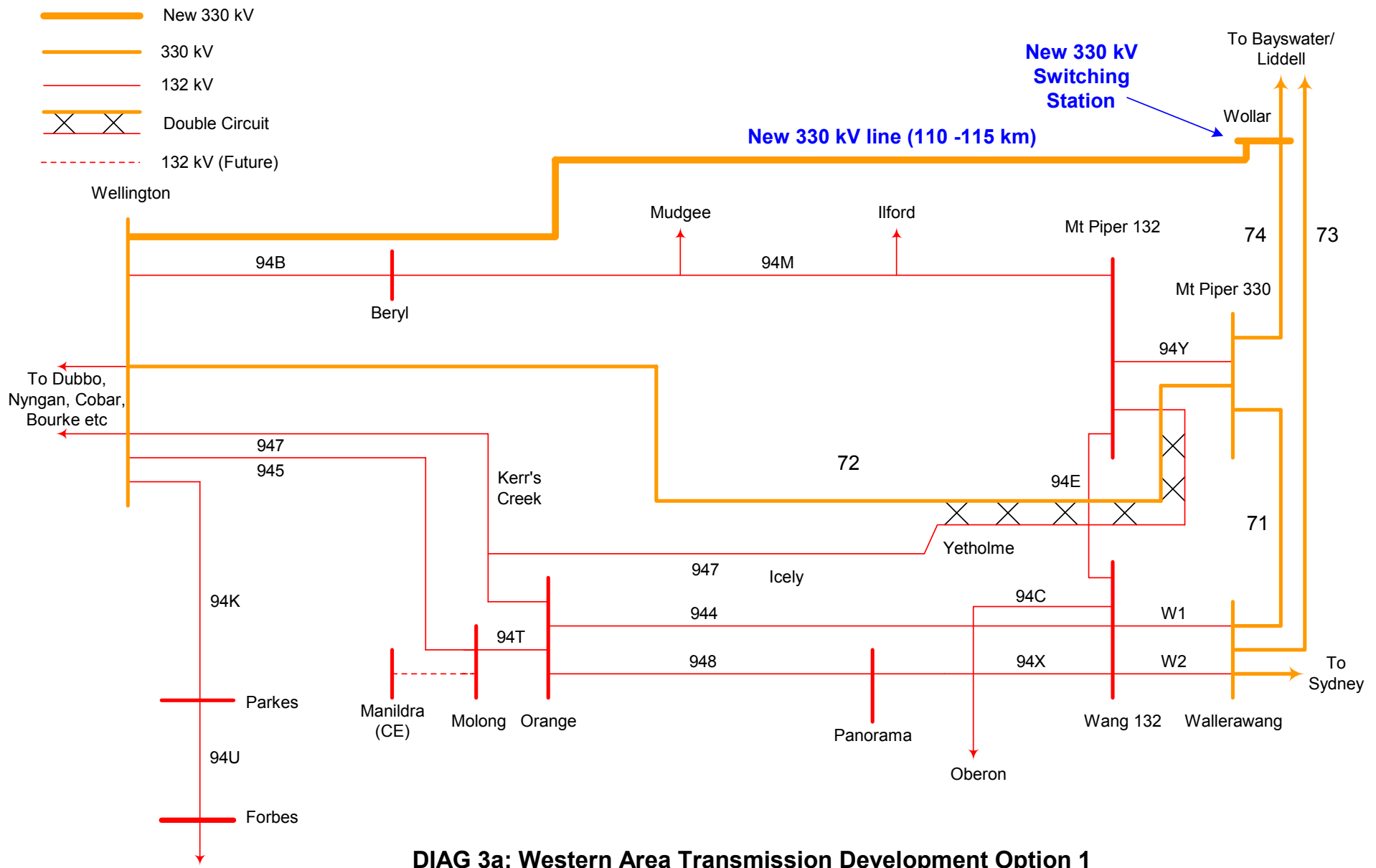
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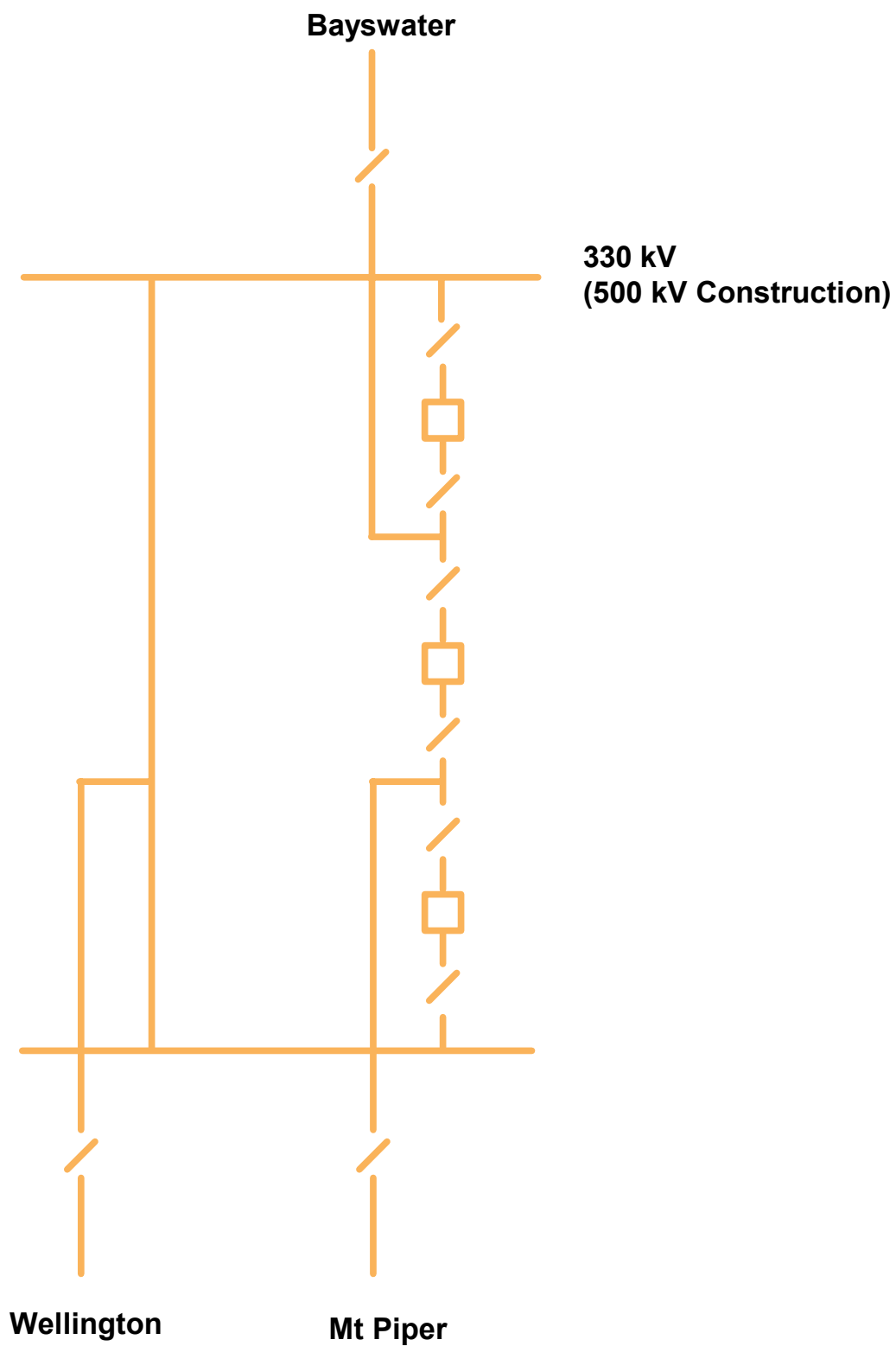
DIAG 1: TRANSMISSION NETWORK IN THE WESTERN AREA - GEOGRAPHIC



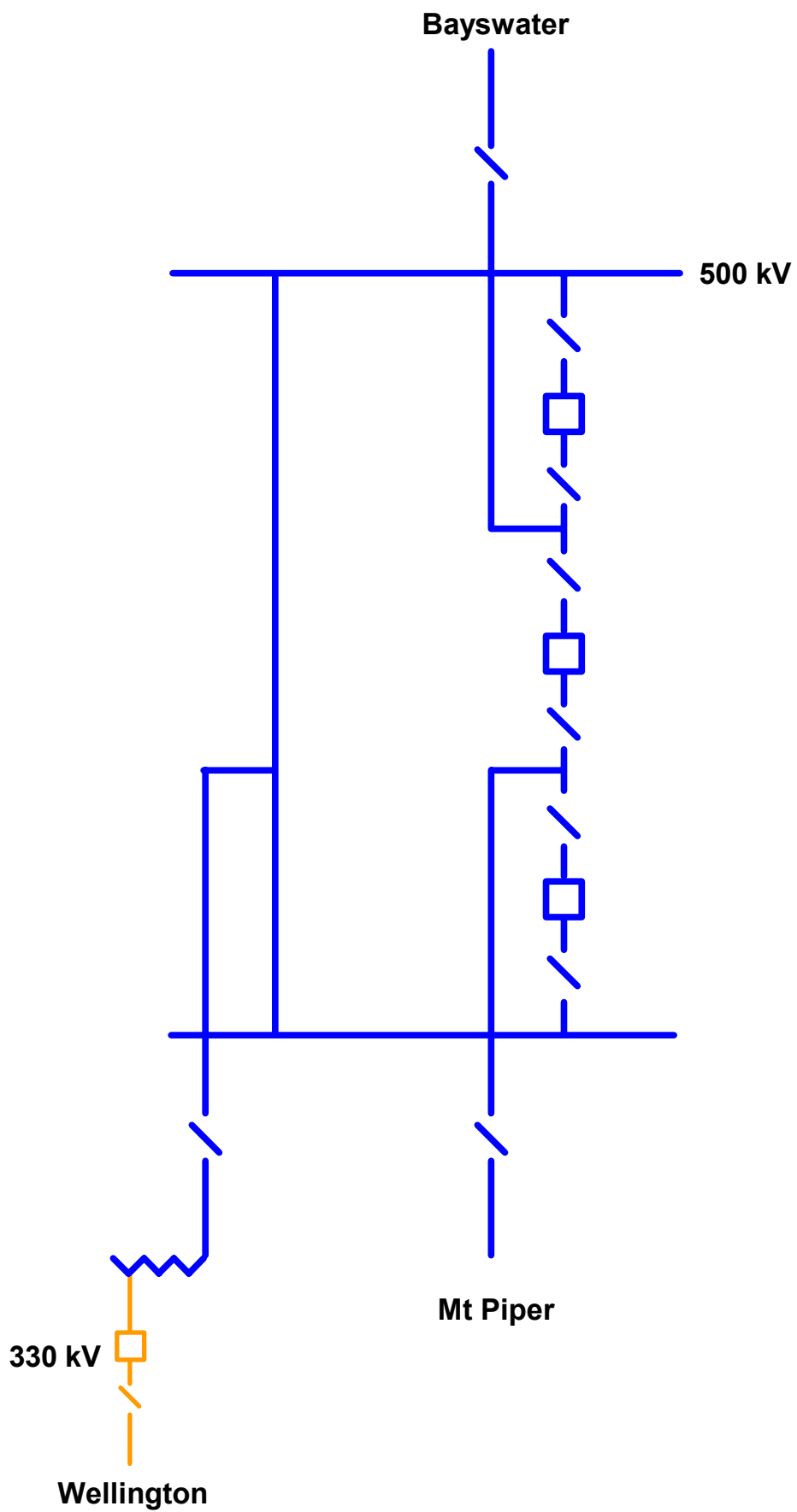
DIAG 2: TRANSMISSION NETWORK IN THE WESTERN AREA - SCHEMATIC



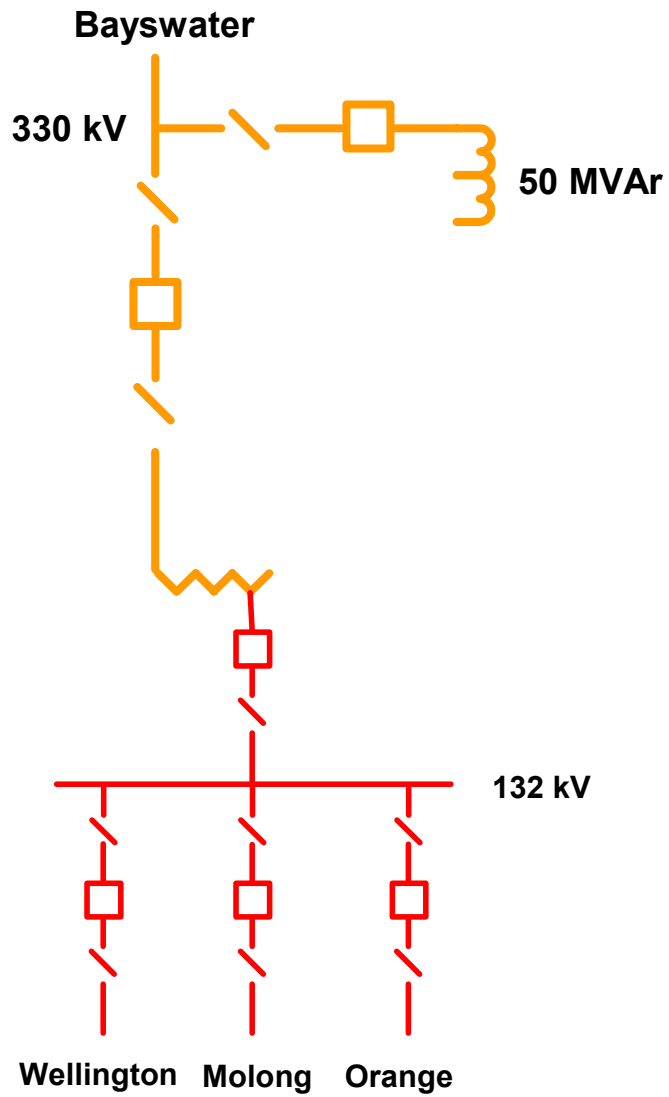
DIAG 3a: Western Area Transmission Development Option 1



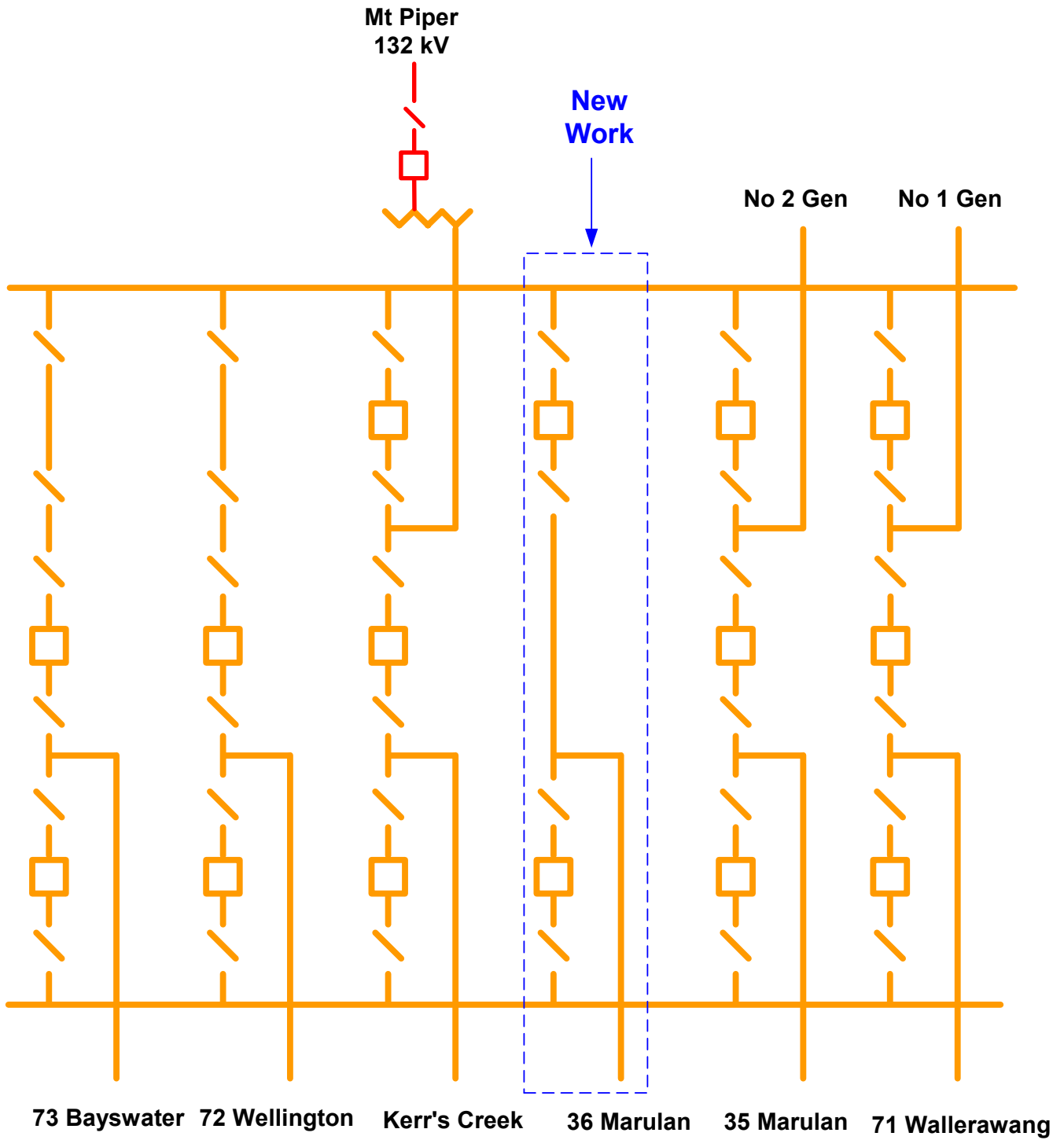
DIAG 3b: Wollar - Configuration as per Transmission Option 1



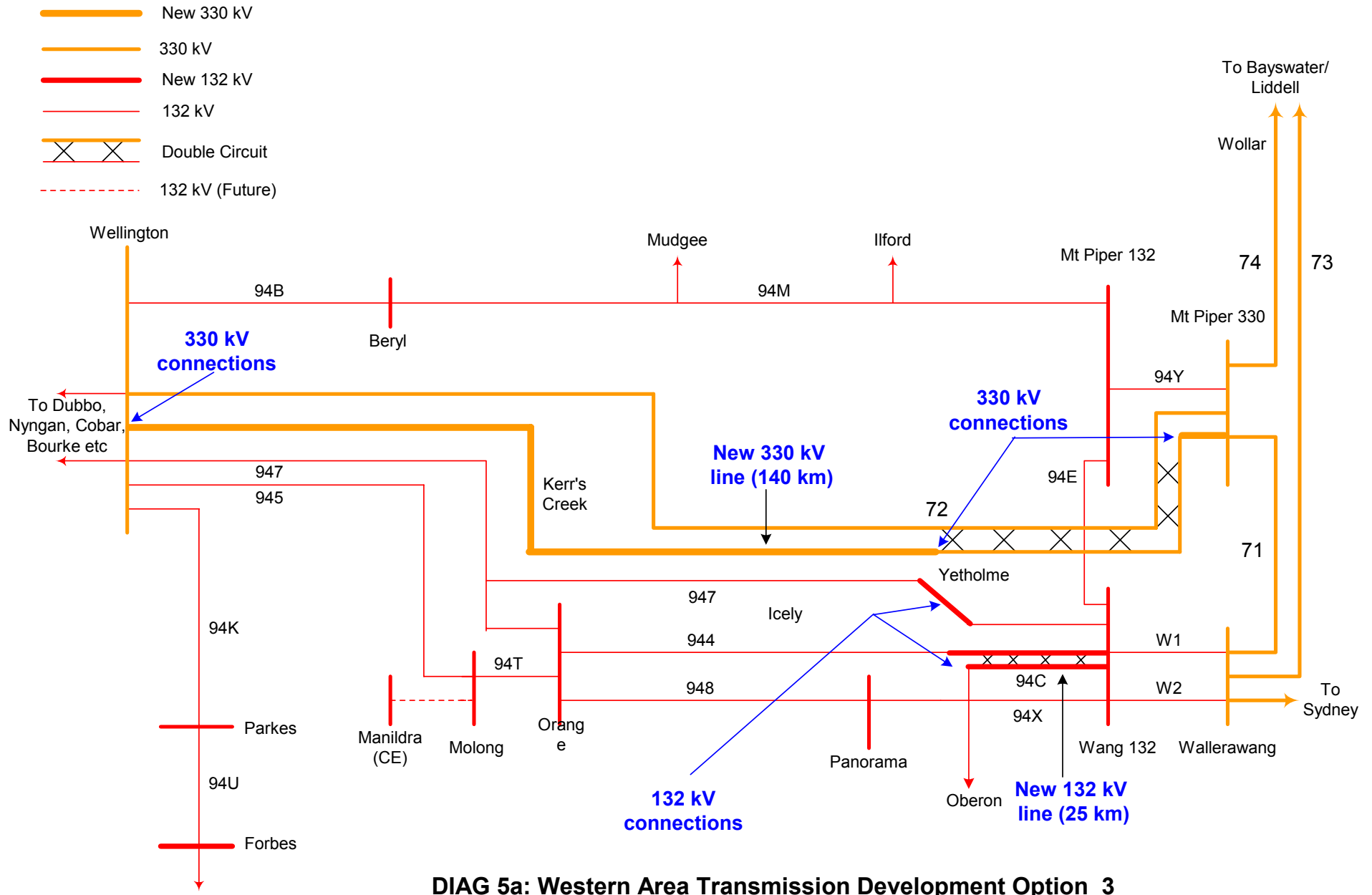
DIAG 3c: Wollar - Possible Future Configuration



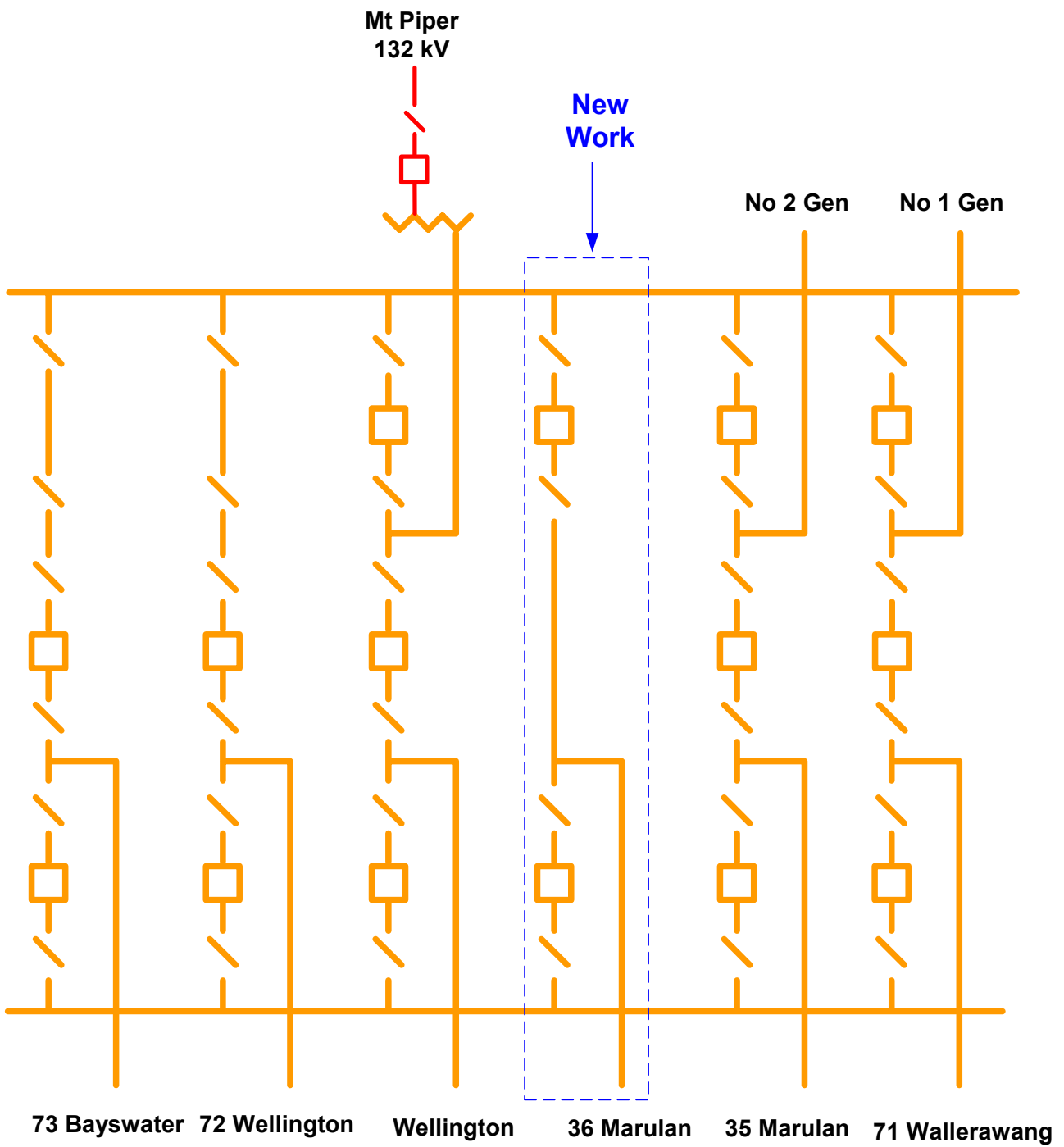
DIAG 4b: Kerr's Creek - Configuration as per Transmission Option 2



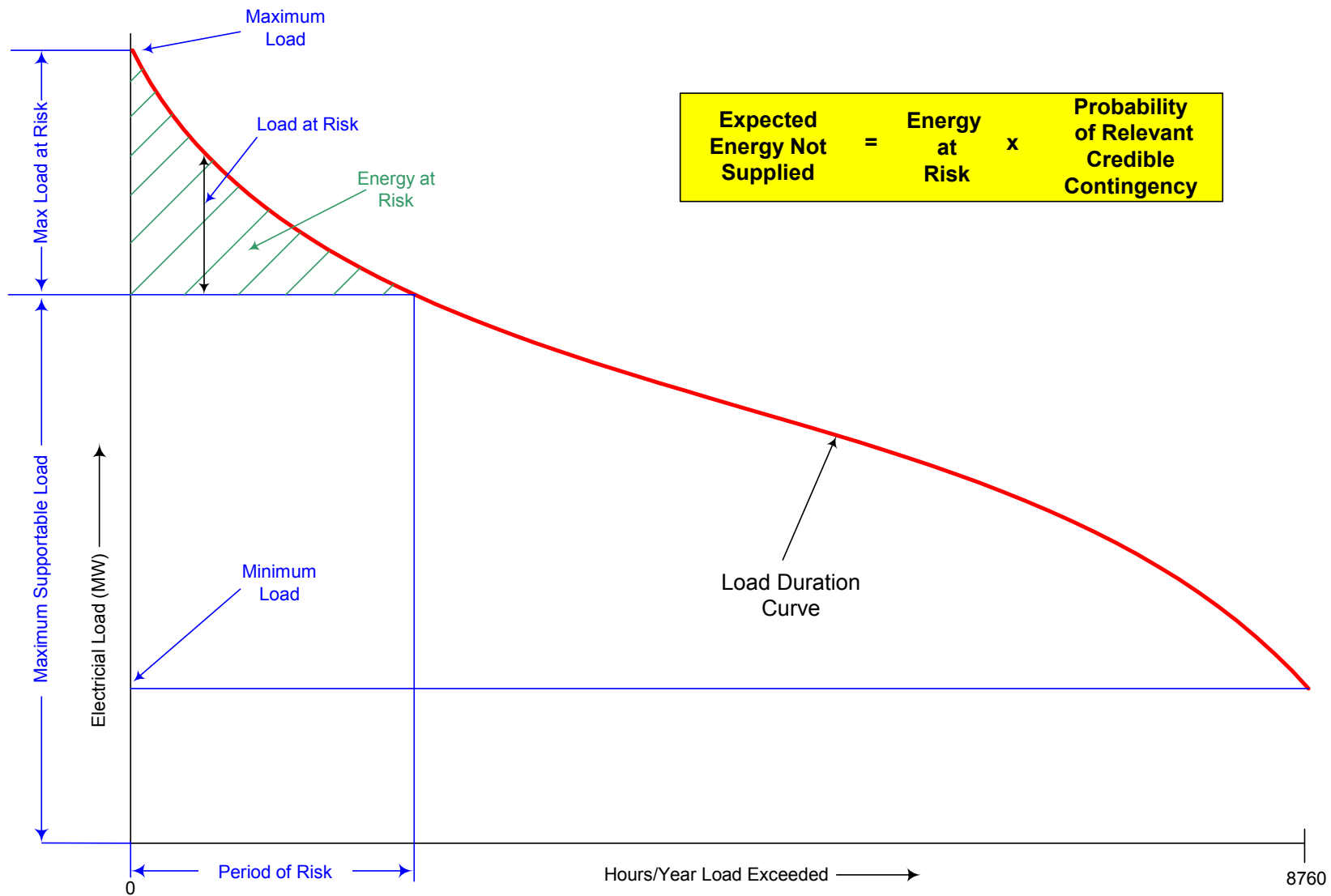
DIAG 4c: Mt Piper PS Switchyard - New Work for Transmission Option 2



DIAG 5a: Western Area Transmission Development Option 3



DIAG 5b: Mt Piper PS Switchyard - New Work for Transmission Option 3



DIAG 6: DETERMINATION OF EXPECTED ENERGY NOT SUPPLIED