MURRAYLINK Transmission Company Pty Ltd

On behalf of

MURRAYLINK Transmission Partnership

Appendices A to G

Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12

18 October 2002

Appendix A: Report – Murraylink Transfer Capability Assessment – TransÉnergie Australia

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Murraylink Transfer Capability Assessment
For
Market Benefit Analysis Studies

Report prepared by TransEnergie Australia

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Contents

Executive Summary

TransÉnergie Australia (TEA) has assessed Murraylink's transfer capability for the summer of 2003/04. The objectives of this capability assessment are to:

- establish the transfer limits suitable for TransÉnergie US Ltd (TEUS) to use for its calculation of Murraylink's market benefits; and
- provide a list of augmentations required to achieve those transfer limits.

Key findings of the report are that:

1. In the case where spare generation is available within the Victorian region, Murraylink can deliver up to 220 MW to the South Australian (SA) region under summer peak load conditions with:
    - 1900 MW being imported into the Victorian region from the NSW/Snowy regions, and
    - the implementation of the augmentations listed in section 5 of this report.

2. In the case where no spare generating capacity is available within the Victorian region, Murraylink can deliver up to 110 MW into SA from excess NSW generation, simultaneous with 1900 MW being imported into the Victoria region from the NSW and Snowy regions across the Snowy-Victoria interconnector (SNOVIC). The augmentations listed in section 5 are required to achieve this power transfer capability.

3. Imports into Victoria from the NSW/Snowy regions and Murraylink dispatch into SA, both compete for the same spare capacity on certain parts of the network, particularly in south-west NSW. At times when SNOVIC flow into the Victorian region is less than 1900 MW, spare generation capacity in NSW can be dispatched over SNOVIC to achieve the 220 MW power transfer capability.

4. With runback in place, Murraylink transfer capability from the SA region to the Victorian region is limited by the pre-contingent loading of the two 132 kV lines between Robertstown and North West Bend. Murraylink's transfer capability can be expressed using the following equations:

$$ML \leq 222\ \text{MW} - RL\ (\text{MW}) \qquad \text{(summer)} \qquad \text{To a maximum of 150 MW}$$

$$ML \leq 280\ \text{MW} - RL\ (\text{MW}) \qquad \text{(winter)} \qquad \text{To a maximum of 150 MW}$$

ML = Murraylink transfer capability
RL = Riverland load

This report provides a list of augmentations required to achieve the transfer capabilities described above. These augmentations are to:

- increase reactive margins to account for increased loading on deep transmission elements, and
- implement additional network control schemes (runback) to limit post-contingent loading on specific network elements to acceptable levels.

For all cases where TEA identified a requirement for runback schemes, the analysis presented in this report used network element ratings provided by the IOWG and its participating members. Note that in certain cases it may be possible to reduce the reliance on runback by increasing the short-time rating of particular network elements. Opportunities for such lower-cost solutions will be identified during detailed design studies.

The assessment undertaken by TEA only considers the system at its worst case summer peak load condition (coincident in all relevant regions) with SNOVIC importing maximum power into Victoria. This analysis is consistent with the IOWG methodology for conducting power transfer capability assessments. At times of light load it is expected that actual constraints on Murraylink dispatch will reduce as a result of increased reactive margin and lower loading on network elements. The peak load analysis, and the level of network augmentation proposed by TEA are therefore considered to be conservative.

TEA's transfer capability assessment has been reviewed by the independent expert consultant, Power Technologies (PTI). PTI has confirmed the results of TEA's analysis as set out in this report.

1 Introduction

TransÉnergie Australia (TEA) has assessed Murraylink's transfer capability under network configuration and forecast loads for the summer of 2003/04. The objectives of the capability assessment are:

- to establish the transfer limits suitable for TransÉnergie US Ltd (TEUS) to use for its calculation of Murraylink's market benefits; and
- to provide a list of augmentations required to achieve those transfer limits.

TEA has conducted a number of transfer capability assessments—internally, through independent consultants, and in conjunction with the Inter Regional Planning Committee (IRPC) and its Interconnector Options Working Group (IOWG)[1].

These technical assessments have been conducted:

- in accordance with the planning principles applied to the network by the regional transmission network service providers,
- with regard to the operating procedures typically applied by NEMMCO in its role as the market and system operator responsible for network security, and
- under system normal operating conditions, with due consideration given to anticipated credible contingency events, as identified by the IOWG members for their respective regions.

This report adheres to the principles established in these prior technical assessments.

Murraylink has a fully controllable bi-directional capability up to 220 MW (delivered). Subject to verification by field tests, Murraylink may also have a short time capability of up to 240 MW (delivered). However, irrespective of rated capacity, all network plant can be subject to constraints caused by a variety of factors in the deeper network[2]. Appropriate network augmentations can overcome these constraints.

In this report, augmentations such as new substations or transmission lines are termed 'primary' works. However, some constraints (such as those involving secondary network plant, thermal ratings or local reactive margins) can often be overcome through less extensive augmentations such as:

- the implementation of a network control service (NCS) (e.g. a runback facility in the case of a DC transmission line such as Murraylink),
- the installation of a localised reactive support facility,
- an upgrade to a protective device or secondary plant item (e.g. a wave trap or current transformer), and
- the application of dynamic ratings to plant based on improved network information access.

In this report these less extensive network augmentations are broadly classified as 'secondary' works. Secondary works represent ideal opportunities to increase transmission capacity at a relatively low cost.

In terms of the broader market, identifying and overcoming constraints on power transfers is desirable for the purpose of increasing market benefits. The technical assessments conducted by the IRPC/IOWG and TEA have identified the constraints affecting Murraylink transfer capability and the augmentations necessary to alleviate those constraints.

[1] IOWG 5.6.6(b) Assessment of Murraylink Version. 2.0, August 2001
[2] Transmission Constraints Workshop (QNI), Hosted by Powerlink Queensland and TransGrid, 15 April 2002

2 Murraylink Transfer Capability Definition and Network Augmentation Strategy

Murraylink has a rated capability that is determined by the design of its own components, and a transfer capability that is determined by the capability of the network to which it is connected.

2.1 Murraylink's Design Rated Capability

The power flow across Murraylink is fully controllable in both directions. Murraylink is nominally rated at 220 MW (delivered), with a short-time rating of up to 240 MW (delivered). The Murraylink short-time rating will be verified by actual operational experience. Recent commissioning tests undertaken on Murraylink have indicated no issues with power transfers up to that level. Murraylink has a dynamic reactive capability of up to +140MVAr and –150MVAr.

Losses are incurred in transferring power across any network element, and therefore the sending end power is always higher than the receiving end power. Full load losses across Murraylink have been verified as approximately 6% of the receiving end power.

Murraylink can simultaneously transmit real power, and also provide (or absorb) reactive power at each terminal. Figures 1 and 2 illustrate the Murraylink real (P)/reactive (Q) power capability at both the rectifier (sending end) and the inverter (receiving end).

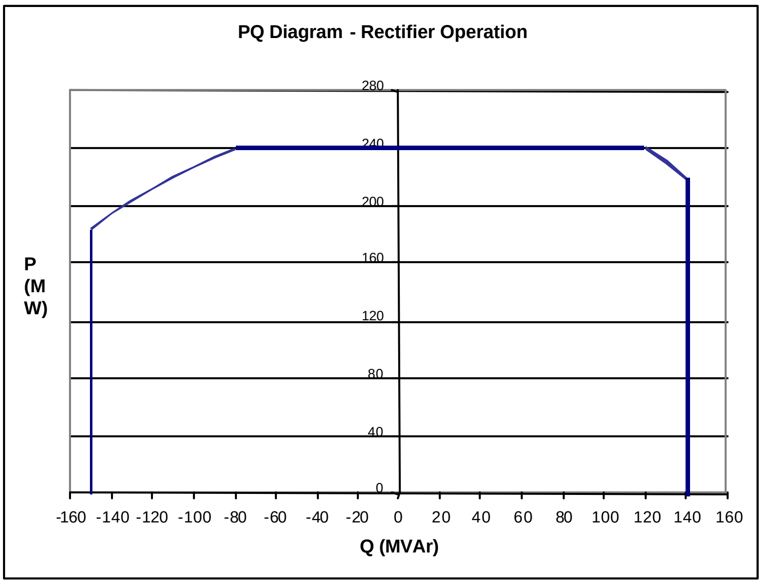


Figure 1 Murraylink Real/Reactive Power Capability Curve (Rectifier)

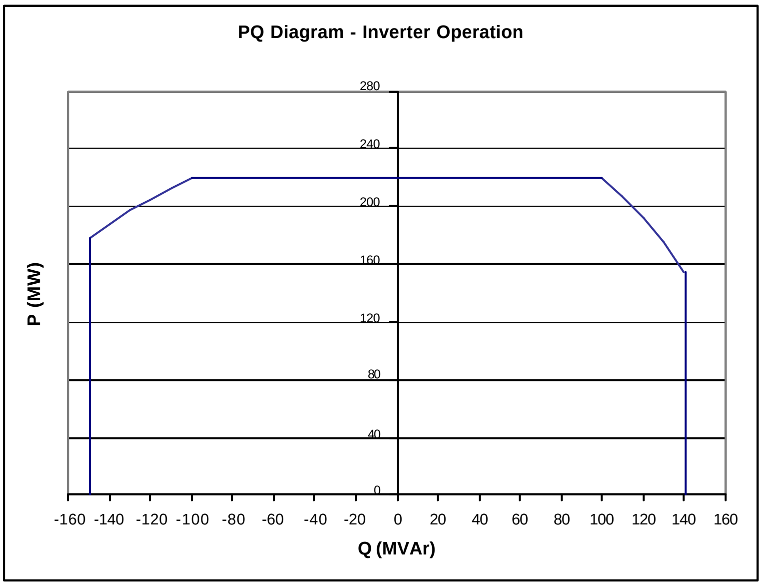


Figure 2 Murraylink Real/Reactive Power Capability Curve (Inverter)

2.2 Murraylink's Transfer Capability

Murraylink's transfer capability was determined under system normal operating conditions (defined as the condition under which all major transmission plant is available) with due consideration given to anticipated credible contingency events.

Murraylink's transfer capability is a function of the networks to which Murraylink is connected. Limits on Murraylink transfer capability may arise in these networks from three primary causes:

- thermal limits,
- voltage control limits, and
- oscillatory stability limits.

This section identifies strategies that alleviate thermal and voltage limits through the use of network control schemes, plant upgrades or additional network reactive support. Simulation studies have also been conducted to determine the impact of Murraylink on system oscillatory stability. These simulations using the MUDPACK software package have shown that there is no reduction in system damping caused by Murraylink operation. Oscillatory stability will not be considered further in this report.

2.3 Assumptions

TEA has made a number of standard transmission planning assumptions to assess Murraylink's transfer capability. These assumptions relate to network loading conditions and configurations that are intended to represent the years immediately subsequent to this assessment.

Primary assumptions are as follows:

- SNOVIC400 project completed,
- generation dispatch patterns consistent with peak summer loading conditions and sufficiently flexible to ensure maximum dispatch (particularly Snowy Hydro and Southern Hydro units),

- coincident peak summer 2003/04 loads[3] (based on study files provided by the IOWG),
- specific network augmentations, and in particular those additional reactive support and network control schemes proposed in Section 5 of this report, and
- the upgrading of other constraining network elements to reduce the requirement for network control schemes.

The following table lists the peak loads used in the TEA assessment.

Load Description	Assumed Value (MW)
Vic region	9000
SA region	3300
Vic state grid	1100
SW-NSW	610
Note: All loads assumed to be coincident	

Load flow data files consistent with these assumptions were employed to establish Murraylink's peak summer transfer capability.

2.4 Murraylink Network Augmentation Strategies

This section discusses augmentation strategies for addressing voltage control and thermal limit constraints. As a general rule, voltage control constraints are addressed through the placement of additional reactive support, and thermal limit constraints through the use of network control schemes.

Murraylink has fully controllable power flow, a feature unique to DC transmission links. This feature fits well with an augmentation strategy involving automatic network control schemes to rapidly reduce Murraylink power flow following the contingency. These automatic control schemes (termed 'runback' schemes) automatically reduce (runback) the power transfer to an acceptable level following a contingency.

Automatic runback schemes can be adjusted in terms of response speed. This allows utilisation of short-term plant ratings with a subsequent increase in the system normal (ie pre-contingent) power flows. Runback can also be used to control post-contingent voltage limits and can therefore be considered as an alternative to the use of additional reactive support.

Murraylink has already installed several runback schemes in the Victorian and South Australian networks, and is presently progressing the NSW runback schemes through the detailed design process. These schemes have and will significantly increase Murraylink transfer capability. This report identifies modifications to existing or planned runback schemes, or new schemes, that will allow full Murraylink dispatch (Victoria to SA) under summer peak load conditions.

2.4.1 Voltage Control

Runback and Reactive Support

Voltage control limitations can be classified into two groups:

- those that cause post-contingent voltages outside specified limits set down in the National Electricity Code (Code) (+/- 10% of nominal), and

[3] For this assessment TEA used the most onerous network loading scenarios and this assumption should be considered very conservative in terms of actual conditions under which Murraylink is likely to be dispatched.

- those that result in unacceptable step changes which exceed Code[4] defined limits (usually a step change with a magnitude defined by the perceptibility and frequency of occurrence).

Runback schemes can be used to alleviate unacceptable post-contingent voltage control conditions. However, in some circumstances the speed of operation of the scheme may become too onerous, and under such circumstances it may be more appropriate to use additional reactive support. For this analysis, TEA has considered each method on its merits in relation to the specific constraint.

Tripping schemes (which in this report are also classified as network control schemes) may also be used to control voltage levels, and these are discussed further in the section 3.4.2. With due consideration for operating times, tripping schemes may provide an effective alternative control strategy for alleviating voltage constraints. The decision to implement a tripping scheme versus a runback scheme is a function of economics and technical feasibility.

Dynamic reactive support is available in the Victorian state grid network from 50 MVAr static VAr compensators (SVC) at both the Horsham and Kerang terminal stations. The voltage control augmentation strategy developed in this assessment is intended to maintain the dynamic range of these SVCs at times of peak load through the addition of static reactive support.

TEA considers that all of the identified reactive support requirements are conservative due to the use of load flow analysis instead of dynamic analysis, and are sufficient to maintain long-term voltage stability. TEA is of the opinion that there may be some opportunity to reduce the recommended level of reactive support when simulations with less conservative load models are performed.

2.4.2 Thermal Limits

Runback

Runback permits pre-contingent dispatch of Murraylink such that post-contingent loading is not greater than five-minute plant ratings. The runback scheme acts to reduce Murraylink dispatch to an acceptable level within the required time period. It is then up to the NEMMCO system operator to return the network to a secure operating state ready for the next credible contingency.

'Slow' runback is usually only considered suitable for addressing thermal limits, through reducing Murraylink power transfer within periods ranging from a few seconds up to minutes. 'Fast' runback schemes typically reduce power transfers within milliseconds. Implementation of fast runback schemes will require detailed design and consideration of fast communications to ensure coordination with existing protection schemes and acceptable outcomes for the system operator.

Plant Upgrades

In some cases it may be more desirable (e.g. less costly) to replace an existing network component rather than rely on a runback scheme.

[4] NEC Clause 3.3a.10 and AS2279 Part 4.

Tripping Schemes

In some circumstances a network control scheme that does not rely on Murraylink runback may be needed. In these cases, selective circuit tripping may be necessary to achieve the required control. Such schemes are already in use within the NEM, relevant examples being the:

- Yass to Wagga 132 kV tripping scheme operated by TransGrid for high Victorian imports over the SNOVIC interconnector,
- Darlington Point 220 kV tripping scheme, and
- Dederang 330 kV bus-splitting scheme.

The operation of a tripping scheme typically results in an immediate re-assessment of network security by NEMMCO, with possible re-dispatch to lower transfer levels to allow restoration of the tripping scheme to the pre-contingent state. In this way, any impact on local customer reliability is minimised.

3 Murraylink Transfer Capability

Murraylink transfer capability has been previously appraised by all affected TNSPs and TEA as part of an IOWG 5.6.6(b) assessment. This assessment identified a number of network elements and load scenarios under which Murraylink transfer capability would be reduced. Following a cost benefit analysis Murraylink has already funded a number of network augmentations and plant upgrades to achieve an increase in transfer capability. This assessment identifies remaining Murraylink constraints and is based upon the work conducted by the IOWG and its participating members, extended to include the latest available information.

3.1 Murraylink Transfer: Victoria to South Australia

Murraylink transfers from the Victorian and NSW regions into South Australia are generally only limited by constraints that arise from within the sending region (i.e. Victoria and/or NSW). There are only a few circumstances (particularly light load conditions in the SA Riverland) when SA constraints arise. However, as a general rule Riverland load is sufficiently high during peak load conditions such that Murraylink is not constrained by SA limits.

Only those constraints within the Victorian and NSW regions are considered as being material to determining the limits of Murraylink transfer to South Australia.

3.1.1 Constraints within the Victorian Region

This section considers both voltage control limits and thermal limits that will arise within the Victorian region when Murraylink is dispatched up to rated capability under peak load conditions.

3.1.1.1 Voltage Control Limits

There are two voltage control related constraints in the Victorian region. These are the local voltage constraint caused by the Ballarat to Horsham 66 kV sub-transmission lines, and the more general reactive limit across the Victorian state grid network.

Ballarat to Horsham 66 kV Sub-transmission Line

The most severe contingency in the Victorian state grid impacting on Murraylink is the overload of the 66 kV sub-transmission tie between Ballarat and Horsham resulting from the outage of the parallel 220 kV line. This contingency causes both voltage and thermal constraints on the network and may require a fast (i.e. 200 milliseconds) runback or a tripping scheme to enable Murraylink to transfer power to its full rated capacity under peak load conditions.

Victorian State Grid Reactive Limit

VENCorp identified the Victorian state grid load (SGL) as the system variable most significantly affecting Murraylink transfer under a voltage control limit. In its submission to the IOWG, VENCorp[5] defined a relationship between Murraylink transfer capability and the Victorian SGL as:

[5] IOWG 5.6.6(b) Assessment of Murraylink, Appendix C VENCorp Report, 25 July 2001

P = 220 – 0.33 x (SGL – 700) MW (high system reactive load – summer) (equation V1)

P = 220 – 0.29 x (SGL – 800) MW (low system reactive load - winter) (equation V2)

Where P = Murraylink's maximum transfer capability

These equations relate to the reactive margin in the Victorian state grid that existed at the time of the initial Murraylink assessment. At that time, VENCorp provided an indicative load range for the Victorian state grid as between 400 MW and 1000 MW. Under peak summer loading conditions the application of this equation would limit Murraylink transfers to approximately 120 MW (with 1000 MW SGL). For this assessment TEA has assumed that the SGL will increase to approximately 1100 MW as forecast in the IOWG summer 2003/04 files. TEA has also assumed that additional reactive support, as specified in accordance with the VENCorp reactive support tender outcome[6], is installed.

For high Victorian state grid loads, the Murraylink transfer limits derived from equations V1 and V2 can be below Murraylink's rated capability. To improve the reactive margin (and therefore Murraylink transfer capability), TEA proposes to add reactive support to the Victorian state grid, specifically, additional static capacitor banks at Kerang, Horsham and Red Cliffs terminal stations.

These additions will extend the dynamic range of the SVC units at each of those terminal stations, including the Murraylink Red Cliffs VSC station.

Additional reactive support at Red Cliffs reduces the pre-contingent voltage drop caused by in-service reactors in the south-west NSW system, particularly those at the Buronga substation. The additional reactive support also reduces post-contingent voltage rise in the south-west NSW system following an outage of the Buronga to Red Cliffs 220 kV transmission line when both Murraylink and SNOVIC are at peak transfer levels.

On the basis of this additional reactive support (described in section 5), the Victorian state grid reactive limit is lifted to a level that will permit dispatch of Murraylink to full rated capacity during peak load conditions.

3.1.1.2 Thermal Limits

A number of network elements impose thermal constraints that limit Murraylink dispatch during peak load conditions.

Ballarat to Horsham 66 kV Sub-transmission Line

The most severe factor in the Victorian state grid impacting on Murraylink is the need to avoid the overload of the 66 kV sub-transmission tie between Ballarat and Horsham (refer to section 4.1.1.1). This factor is particularly significant for Murraylink dispatch in that it may require protection grade runback or an alternative arrangement (such as a tripping scheme) to allow full Murraylink dispatch.

Other Thermal Constraints

There are several other network elements that can limit Murraylink transfer capability. These were defined in the IOWG reports and at that time were addressed through the

[6] VENCorp, Outcome of Tender for the Provision of Network Reactive Support Services for Summer 2001/02 to 2003/04, 20 June 2001

implementation of a combination of runback schemes and constraint equations. This section reviews the existing Victorian runback schemes and proposes additional schemes to enable Murraylink dispatch to rated capacity under full load conditions.

Murraylink transfer capability is dependent on the implementation of runback schemes to relieve the post-contingent loading of a number of Victorian network elements. A number of runback schemes have already been implemented in order to increase Murraylink's transfer capability. Details of these schemes are listed below.

Five-Minute Runback (Slow) Schemes

NEMMCO security requirements permit the use of five-minute thermal ratings provided that an automatic network control scheme (e.g. runback in the case of Murraylink) is enabled to quickly reduce power flows to within acceptable levels. After consultation with VENCorp, Murraylink Transmission Company (the developer of Murraylink) has already installed a number of five-minute runback schemes within the Victorian network. These schemes relate to the:

- Ballarat to Horsham 220 kV transmission line,
- Moorabool 500 kV/220 kV transformer,
- Dederang to Glenrowan #1 220 kV transmission line,
- Moorabool to Ballarat #2 transmission line, and the
- Bendigo to Kerang 220 kV transmission line.

As a result of the current assessment, a number of additional five-minute runback schemes will be implemented. These are listed in Section 5 of this report.

Fast Runback Schemes

TEA has already implemented a fast runback scheme for the outage of the Ballarat to Horsham 220 kV transmission line. TEA studies have shown that with full Murraylink dispatch at peak load conditions certain other contingencies require additional fast run-back schemes. When outage of the monitored network element occurs, Murraylink is runback to reduce loading on all affected plant. The timing of the fast runback is dependant on available communications infrastructure between the monitored element and the Murraylink converter station at Red Cliffs and the required reduction in power flow.

A more economic alternative may be to upgrade the short-time rating of the affected network element to allow use of a slow runback facility. However, this analysis only considers runback facilities, with the caveat that upgrade paths for specific network items may be identified during the detailed design process.

Dederang–Glenrowan–Shepparton 220 kV circuits

The SNOVIC400 network augmentation includes a re-arrangement of the 220 kV circuits between the Dederang and Shepparton terminal stations. These lines previously caused significant limiting thermal constraints on Murraylink dispatch. With the SNOVIC augmentations completed these particular lines are no longer considered to be limiting.

Transient Stability

Murraylink can affect Victorian export limits (VEL), decreasing VEL when it transfers power out of Victoria e.g. to SA, and increasing VEL when it transfers power into Victoria e.g. from

SA. Murraylink can also increase the VEL when it is operating unloaded, by providing dynamic voltage support at the Red Cliffs terminal station[7].

These relationships arise because Murraylink is equivalent to a load in the Victorian state grid when it is transferring power out of Victoria. Similarly, Murraylink can also be considered equivalent to a generator in the Victorian state grid when it is transferring power into Victoria.

Since both Murraylink and SNOVIC will be dispatched optimally in the market environment, it is not appropriate to address the transient stability limit as part of the augmentations in this report. This is consistent with the IOWG scenario suggested for assessing interconnector technical capability under summer peak conditions. Under this scenario, SNOVIC is considered to be importing into Victoria and the export limit case is not relevant.

3.1.2 Constraints within the NSW Region

This section considers both voltage control limits and thermal limits that arise within the NSW region as a result of increasing Murraylink dispatch to rated capability under peak load conditions. Murraylink has already proposed several runback schemes for the NSW system. NSW runback schemes already being implemented to monitor the following network elements:

- Lower Tumut to Wagga 330 kV transmission line,
- Wagga to Darlington Point 330 kV transmission line,
- Darlington Point to Buronga (via Balranald) 220 kV transmission line, and
- Buronga to Red Cliffs 220 kV line.

These schemes are assumed in place in this latest assessment.

3.1.2.1 Voltage Control Limits

Wagga 330 kV Reactive Margin

When SNOVIC imports into the Victorian region are high, Murraylink transfers to the SA region are constrained by the reactive margin at the Wagga 330 kV bus. TEA proposes additional reactive support in the SNOVIC interconnector region (particularly Wagga to Wodonga) to alleviate this constraint. This additional reactive support is particularly relevant when incremental generation capacity to supply Murraylink's dispatch is taken from the NSW region.

Wagga to Darlington Point 330 kV line

Without appropriate schemes in place, an outage of the Wagga to Darlington Point 330 kV line causes significant and unacceptable voltage depression in the 132 kV network that runs in parallel with the 330 kV line. Those circuits most affected are the Yanco/Griffith, and the Deniliquin/Finley circuits. A tripping scheme for this contingency has been included as part of the SNOVIC400 network augmentation. The scheme trips the Darlington Point to Balranald line (at the Darlington Point end only) to reduce the net power transfer through the 132 kV circuits. The subsequent reduction in power flow through the 132 kV network is sufficient to eliminate the voltage constraint.

This SNOVIC tripping scheme is not sufficient to completely eliminate the problems that could occur for Murraylink dispatch under the highest dispatch/load scenarios, due to the post-contingent transfer of load to the Victorian region. This load transfer can lead to binding thermal limitations in Victoria, which in the absence of a runback scheme would require

7 IOWG 5.6.6(b) Assessment of Murraylink, Appendix C VENCorp report, 25 July 2001

reduced Murraylink transfer capability. Therefore Murraylink is implementing a runback scheme for the Wagga to Darlington Point contingency; this scheme will alleviate both the voltage constraint in south-west NSW and the post-contingent thermal constraint in Victoria, sufficient to allow Murraylink transfer up to rated capacity.

Darlington Point to Buronga 220 kV Transmission Line (via Balranald substation)

Outage of this line has similar ramifications to an outage of the Wagga to Darlington Point 330 kV transmission line. As with the SNOVIC tripping scheme, outage of the lines between Darlington Point and Buronga results in significant transfer of load to the Victorian regional network, in particular the line between Shepparton and Bendigo, and the line between Bendigo and Kerang. The post-contingent increase in power flow through the Shepparton to Bendigo to Kerang lines causes a voltage depression at these substations. The runback scheme presently being implemented for this line can be used to control this post-contingent voltage limit.

Buronga to Red Cliffs 220 kV Line

When SNOVIC and Murraylink are dispatched at full capacity, outage of the Buronga to Red Cliffs 220 kV line can cause excessive voltage rise in the network between Buronga and Darlington Point. In order to control this over-voltage at least one of the Buronga reactors, and the Darlington Point 220 kV reactor are required to be in-service during peak load periods to allow full Murraylink dispatch.

Discussions with TransGrid have confirmed that all of these reactors are in-service under normal system operating conditions. TEA proposes that additional capacitors be installed at Red Cliffs (refer section 5) to maintain acceptable pre-contingent voltage profiles at the peak load/dispatch condition considered in this assessment.

3.1.2.2 Thermal Limits

Lower Tumut to Wagga 330 kV Transmission Line

Murraylink Transmission Company has already implemented a runback scheme to relieve constraints that arise following contingent outage of the Lower Tumut to Wagga 330 kV line. With this runback scheme in place, it is not expected that these constraints will limit Murraylink power transfers.

Victorian Network Outages

Outages of certain Victorian state grid lines can potentially cause overloads in the south-west NSW system under peak load conditions and high Murraylink dispatch. Overloads could occur on the 220 kV line sections west of Darlington Point to Buronga, specifically the Darlington Point to Balranald section and the Balranald to Buronga section. Lines that may require monitoring to avoid such overloads are:

- Bendigo to Kerang,
- Bendigo to Shepparton,
- Ballarat to Horsham,
- Kerang to Red Cliffs, and
- Horsham to Red Cliffs.

As an alternative to runback schemes it may be possible to implement a protection upgrade on the Darlington Point to Balranald to Buronga lines to increase their short-time rating sufficient to alleviate the need for fast runback. This would allow a significant reduction in the number of lines requiring monitoring for fast runback, however the requirement for slow runback would remain. Section 5 of this report lists the specific instances where network upgrades may be considered as an alternative to fast runback.

3.2 Murraylink Transfers: South Australia to Victoria

3.2.1 Constraints within the SA Region

The IOWG determined that no significant constraints to Murraylink transfer from the SA to Victorian regions arise as a result of limitations in the Victorian or New South Wales regional networks (the receiving networks). All constraints on Murraylink power transfers from the SA to Victorian region are due to limitations within the SA network (the sending network).

3.2.2 Thermal Constraints

The IOWG found that thermal limitations under contingency conditions determine Murraylink's transfer capability from the SA to Victorian region [8]. These thermal limitations arise primarily because of plant ratings in the 132 kV Riverland network. Murraylink transfer capability is heavily dependent on the Riverland load, which essentially comprises the loads at North West Bend and Berri substations.

Murraylink's transfer limit (SA to Victoria) is a linear function of the Riverland load, expressed as follows:

Murraylink transfer (SA to Vic) <= CPR – Riverland load (MW)

Where CPR = a critical plant rating.

In order to improve the transfer capability Murraylink Transmission Company has funded a number of 'secondary' network upgrades. These upgrades comprised plant items described in the IOWG 5.6.6(b) Murraylink report[9]. The upgrades lifted the Murraylink transfer limits by raising the CPR until a primary plant limit was reached, this being the rating of the Robertstown to North West Bend 132 kV lines. The upgrade works comprised both plant upgrades and runback schemes.

With automatic runback in place it was possible to increase Murraylink transfer limits beyond the CPR of the lowest rated primary network element. TEA has developed the following equations for use in the TEUS market benefit analysis studies:

ML <= 222 MW – RL (MW)	(summer)	To a maximum of 150 MW
ML <= 280 MW– RL (MW)	(winter)	To a maximum of 150 MW

ML = Murraylink transfer capability
RL = Riverland load

Murraylink maximum transfer capability from the SA to Victorian regions at summer peak is approximately 100 MW. This is consistent with the findings of the IOWG[10] and Murraylink transfer limits used in other IRPC market benefit analysis studies[11].

8 IOWG 5.6.6(b) Assessment of Murraylink, Ver. 2.0 August 2001, pp. 10 and 17.
9 IOWG 5.6.6(b) Assessment of Murraylink, Ver. 2.0 August 2001,.p. 14.
10 IOWG 5.6.6(b) Assessment of Murraylink, Ver. 2.0 August 2001, p. 17.
11 IOWG Assessment of VENCorp's Proposed Augmentation of Snowy to Victoria Interconnection, Appendix G Interconnection Constraints following Murraylink Service, October 2001, p. 28.

At times of low Riverland load (or during winter rating periods), Murraylink transfer capability is expected to increase above 100 MW in accordance with the above equations. However TEA has recommended that an upper limit of 150 MW be included in the SA to Victoria transfer capability modelled in the TEUS market benefit analysis.

4 Murraylink Augmentations

This section provides a list of the specific additional augmentations required to achieve the Murraylink transfer limits used by TEUS for the market benefit calculations. As discussed in previous sections, these network augmentations alleviate network limitations on Murraylink transfer capability under summer peak load conditions.

4.1 Augmentations Required for 180 MW Transfer (Victoria to SA)

Reactive Support

The following additional reactive support is required:

Location (Terminal Station)	Value (MVAr)
Kerang	50
Horsham	25
Red Cliffs	80

Runback Schemes

Monitor	To Protect:
Slow Runback	
Ballarat to Moorabool #1	Ballarat to Moorabool #2 Bendigo to Shepparton
Ballarat to Moorabool #2	Ballarat to Moorabool #1 Bendigo to Shepparton
Ballarat to Bendigo	Bendigo to Shepparton
DDTS TX #3	DDTS TX #1 & #2
Buronga to Red Cliffs	Various
Fast Runback	
Bendigo to Kerang	Darlington Point to Balranald
Moorabool TX	Geelong to Keilor #1, 2, 3
Bendigo to Shepparton	Ballarat to Bendigo Darlington Point to Balranald
Ballarat to Horsham	BAN to ART 66 Darlington Point to Balranald
Darlington Point to Balranald	Bendigo to Shepparton (includes voltage control)
Balranald to Buronga	Bendigo to Shepparton (includes voltage control)
Wagga to Darlington Point	Voltage control Wagga to DLPT 132 kV network
Note Shading of specific schemes in the table indicates network elements where it may be more economic to pursue a network upgrade, rather than a fast runback scheme. Specific network elements for which secondary plant upgrade paths exist include: • Darlington Point to Balranald to Buronga transmission line (protection upgrade) • Bendigo to Ballarat 220 kV transmission line (protection upgrade) • Bendigo to Kerang 220 kV transmission line (protection upgrade) • Other upgrade paths may also be identified during detailed design.	

Table 5.1 Runback Schemes for 180 MW Transfer Capability

4.2 Augmentations Required for 220 MW Transfer (Victoria to SA)

Reactive Support

The additional reactive support specified for the 180 MW transfer capability is sufficient for the 220 MW transfer capability.

Runback Schemes

Monitor	To Protect:
Fast Runback	
Ballarat to Moorabool #2	Ballarat to Moorabool #1
Kerang to Red Cliffs	Darlington Point to Balranald
Horsham to Red Cliffs	Darlington Point to Balranald
Buronga to Red Cliffs	Bendigo to Shepparton Bendigo to Kerang
Note Shading of specific schemes in the table indicates network elements where it may be more economic to pursue a network upgrade, rather than a fast runback scheme. Specific network elements for which secondary plant upgrade paths exist include: • Darlington Point to Balranald to Buronga transmission line (protection upgrade) • Other upgrade paths may also be identified during detailed design.	

Table 5.2 Additional Runback Schemes Required for 220 MW Transfer Capability

4.3 Augmentations Required to Source Power from NSW (110 MW transfer Victoria to SA)

Wagga/SNOVIC Reactive Margin

When incremental generation capacity to supply Murraylink's dispatch is required from the NSW region additional reactive support is needed to maintain reactive margin in the Wagga area, and to improve post-contingent voltage in the Dederang area (330 kV). This assumes operation of the Dederang bus splitting scheme following outage of one of the Murray to Dederang 330 kV lines, with the additional Dederang reactive support placed on the Murray to Dederang–South Morang side of the splitting scheme.

Ongoing planned works in the Wagga area may impact on the requirement for reactive support proposed by TEA for both Wagga and Dederang substations (both in quantity and specific location). Under these circumstances, it is envisaged that the actual reactive support requirements would be determined in conjunction with planned future works in this locality.

Location (Terminal Station)	Value (MVAr)
Wagga 330 kV	160
Dederang 330 kV	160
Darlington Point area 132 kV	10

Thermal Constraint Related Upgrades

The five-minute rating of the Lower Tumut–Wagga 330 kV line needs to be raised to 1160 MVA to achieve the Murraylink transfers used in the market analysis, when Murraylink power is wheeled from NSW generators. It is assumed that only minor works are required to achieve this upgrade i.e. re-tensioning specific conductor spans. Alternatively a runback scheme could be used to control post-contingent power flows across this line also.

Location (Terminal Station)	Rating (5 Minute)
Wagga to Lower Tumut 330 kV	1160 MVA

Schedule A – Budget Estimates

Augmentations for Power Transfers (Victorian to SA Regions)

The following tables provide budget estimates for the works required to achieve the power flows described in section 4 of this report. Tables A1 through A5 list those works required to achieve 180 MW power transfer under the peak load conditions. Table A6 lists those incremental works required to achieve 220 MW transfer capability. Note that the majority of the costs are associated with the provision of additional reactive support, both in the Victorian state grid and the Wagga/SNOVIC area. It is assumed that a circuit breaker will be required for each individual capacitor bank and that sufficient spare bays exist at the proposed locations. Costs are best estimates only, and subject to refinement following detailed design.

A1. Reactive Plant – Victorian State Grid (required for 180 MW transfer)

Location (Terminal Station)	Value (MVAr)	Budget Cost ($m)
Kerang	50	1.0
Horsham	25	0.7
Red Cliffs	80	1.2
	TOTAL	**2.9**

A2. Reactive Plant – Wagga/SNOVIC (required for power wheeled from NSW)

Location (Terminal Station)	Value (MVAr)	Budget Cost ($m)
Wagga 330 kV	160	1.4
Dederang 330 kV	160	1.4
Darlington Point area 132 kV	10	0.7
	TOTAL	**3.5**

A3. Line Upgrade (required for power wheeled from NSW)

Location (Terminal Station)	Rating (5 Minute)	Budget Cost ($m)
Wagga to Lower Tumut 330 kV	1160 MVA	0.3

It is assumed that only minor works are required to achieve this upgrade i.e. re-tensioning specific conductor spans. In lieu of a suitable upgrade path for this line an additional runback scheme will be required.

A4. Slow Runback Schemes (required for 180 MW power transfer)

Monitor	To Protect	Cost ($m)	Limitation
Ballarat to Moorabool #1	Ballarat to Moorabool #2 Bendigo to Shepparton	0.07	Conductor Conductor
Ballarat to Moorabool #2	Ballarat to Moorabool #1 Bendigo to Shepparton	0.07	Conductor Conductor
Ballaratt to Bendigo	Bendigo to Shepparton	0.10	Conductor
DDTS TX	DDTS TX	0.15	20 min. rate
Buronga to Red Cliffs	Various	0.08	Various
	TOTAL	**0.47**	

A5. Fast Runback Schemes (required for 180 MW power transfer)

Monitor	To Protect	Cost ($m)	Limitation
Bendigo to Kerang	Darlington Point to Buronga	0.15[a]	Protection
Moorabool TX	Geelong to Keilor #1,2,3	0.15[a]	Conductor
Bendigo to Shepparton	Ballarat to Bendigo Darlington Point to Buronga	0.30[b]	Protection Protection
Ballarat to Horsham	BAN–ART 66 Darlington Point to Buronga	0.20[c]	Conductor Protection
Darlington Point to Balranald	Bendigo to Shepparton (includes voltage control)	0.10[d]	Conductor
Balranald to Buronga	Bendigo to Shepparton (includes voltage control)	0.10[d]	Conductor
Wagga to Darlington Point	Voltage control Wagga to Darlington Point 132 kV network	0.10[d]	Voltage
	TOTAL	**1.10**	

a. Possible upgrades of existing Vic slow runback scheme.

b. New scheme.

c. Possible requirement to implement a tripping scheme/protection standard runback in addition to present scheme for BAN–ART 66 kV.

d. Possible upgrade of NSW runback scheme presently being developed (.ie. incremental cost).

A6. Fast Runback (additional required for 220 MW power transfer)

Monitor	To Protect	Cost ($m)	Limitation
Ballarat to Moorabool #2	Ballarat to Moorabool #1	0.15[a]	Conductor
Kerang to Red Cliffs	Darlington Point to Buronga	0.20[b]	Protection
Horsham to Red Cliffs	Darlington Point to Buronga	0.20[b]	Protection
Buronga to Red Cliffs	Bendigo to Shepparton Bendigo to Kerang	0.15[c]	Conductor Protection
	TOTAL	**0.70**	

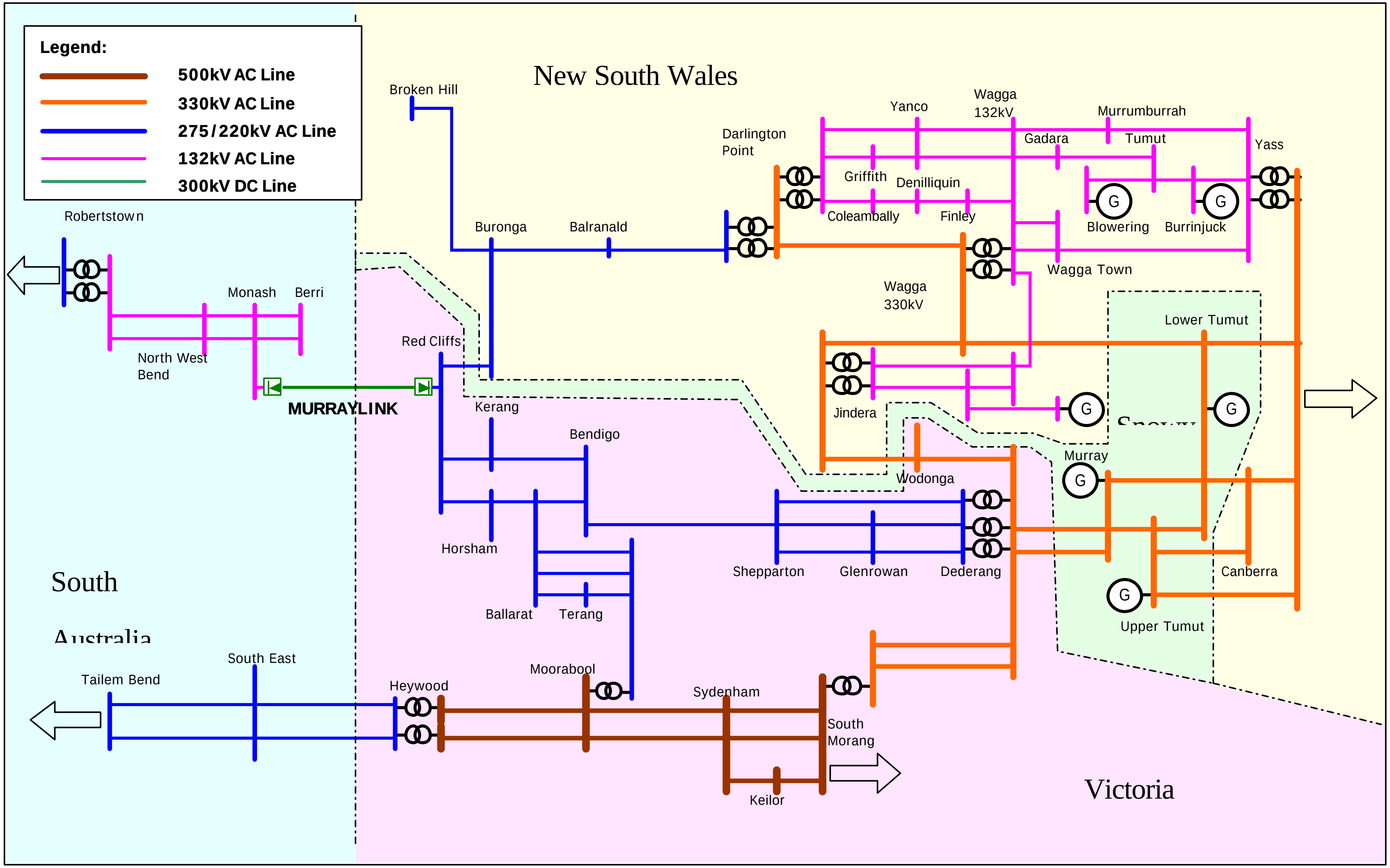
a. Possible upgrades of existing Vic slow runback scheme.

b. New scheme but likely opportunity to utilise infrastructure installed in A5.

c. Possible upgrade of NSW runback scheme presently being developed (i.e. incremental cost).

Shading of specific schemes in Tables A5 and A6 indicates network elements where it may be more economic to pursue a network upgrade rather than a fast runback scheme. For example upgrading the Darlington Point to Balranald to Buronga 220 kV line may alleviate the need for fast runback monitoring on up to five network elements (providing sufficient rating could be achieved).

Schedule B - Network Diagram – for reference only



Appendix B: Report – Due Diligence on Power Transfer Studies – Power Technologies

PTI Report N^{o}. R33-02

Due Diligence on Power Transfer Studies

Prepared for

TransÉnergie Australia
on behalf of
Murraylink Transmission Partnership

Submitted by:
John D Mountford
Power Technologies, Inc.

August 2002
Revised October 15

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Executive Summary

This report presents the findings of a review of work carried out by TEA to identify the limiting transfers across the Murraylink DC tie to South Australia and to comment on the use of those limits as inputs to further market modeling.

Background

TEA studied two supply options for South Australia at peak load. The first was the case when surplus generation is available to the South Australian region from the Victorian region (referred to as the "Victoria swing bus case"). The second was the case when surplus generation is available from New South Wales (NSW) region (referred to as the "NSW swing bus case").

PSSE study files were supplied by TEA and it is understood that the files are based on files compiled by the National Electricity Market Management Company (NEMMCO) of Australia. The study files represent a subsection of the Australian interconnected network comprising four regions (NSW, Victoria, Snowy and South Australia). Loading conditions in the files were for peak summer forecast conditions (summer 2003/04) in Victoria, South Australia and south west NSW.

TEA specified the base case inter-area flows as 1900MW between NSW and Victoria (Victoria importing) and 500MW between Victoria and South Australia (South Australia importing). Flows on Murraylink were set independent of these pre-existing inter-area flows.

For the NSW swing bus case the inter-area flow between NSW and Victoria increased above 1900MW as a result of Murraylink dispatch to South Australia. For the Victoria swing bus case, the NSW generation was trimmed to maintain 1900MW import into Victoria over the NSW-Victoria interconnector.

Supply to South Australia via Murraylink is limited by network thermal constraints and, in some instances, a paucity of voltage support devices necessary to secure high levels of power flow through Murraylink. This reflects the fact that, depending on the DC power flow, the Murraylink tie can have a significant impact on transmission flows. Existing voltage support equipment serves to secure a pre-Murraylink flow pattern.

The findings presented here are based on studies performed by PTI using a different approach from that used by TEA. PTI made more use of automatic contingency analyses, in the PSS/E and MUST[1] program packages, supported by, to a limited extent Optimal Power Flow (OPF).

In addition, PTI, in conjunction with Stone and Webster Consultants, reviewed documents prepared by TransÉnergie US (TEUS):

1. *Incorporating the findings of Murraylink Load Flow Analysis into Prosym Transmission Limits*, (contained in Appendix D)

2. *Incorporating the Findings of a Murraylink Load Flow Analysis in MARS Regional Interface Limits*, (contained in Appendix E).

These documents describe the methodology by which TEUS will use the power transfer limits calculated by TEA as inputs into TEUS's electricity market modeling.

[1] Managing and Utilizing System Transmission

Firm Profile

PTI provides advanced technical consulting services, world-standard analytical software programs, professional education in power systems engineering, and sophisticated instrumentation systems. Founded as an employee-owned company in 1969, PTI evolved into a world-class resource in the electric power industry. Many staff members are internationally acknowledged experts within their respective disciplines.

PTI has conducted business in over 100 countries and has proudly served more than 1200 clients including electric utilities, government agencies, power generators, power marketers, manufacturers, and architect-engineers. Serving the world from its headquarters in Schenectady, NY, PTI has regional offices in the U.S., and a subsidiary in the U.K. Additional affiliations in more than two dozen other countries assist in serving clients worldwide.

PTI offers a wide range of consulting services for the electric power industry. The company provides highly skilled technical staff to support analytical studies, industry renown experts who can provide top-level advice and testimony on specialized engineering fields, and executives who address organizational and industry restructuring issues. Company staff provide a broad range of options in terms of specialization, experience, and know-how. From short-focused operational studies to extended planning studies, we can offer the best blend of capability, skill, experience, and efficiency. In addition, we have access to the best analytical tools in the business. In particular PTI has performed a range of studies related to network impacts of privatization of resources, open access and mergers.

Stone & Webster Consultants has an outstanding background in the energy industry both domestically and internationally. The corporation has served the industry for over one hundred years and have in the past several years played a crucial role assisting utilities, developers, and commissions with industry restructuring issues, strategic business and resource planning, transmission planning, market dynamics, and implementation strategies and tactics.

Key Findings

- PTI's studies confirm the results of TEA's studies, given the limited scenarios and technical inquiry.

- With power supplied from the Victorian to the South Australian region, that is, in the Victorian swing bus case:

  - Murraylink can operate in a secure state at a level of 180 MW under peak load conditions, assuming some minor additional voltage support as indicated by TEA; and

  - A flow up to 220 MW on Murraylink could be made secure under peak load conditions and for all single contingency events but higher levels of voltage support and network control services (e.g. run-back) would be required.

- With power supplied from the NSW to the South Australia region, that is, in the NSW swing bus case, a secure Murraylink flow in the order of 110 MW is sustainable under peak load conditions and for all single contingency events with other minor additional voltage support also suggested by TEA.

- The "Secure" states cited are ones which allows single contingency events without voltage collapse. For certain of those contingencies, subsequent run-back would be needed in order to alleviate network overload conditions.

The following text summarizes general comments and other specific findings in relation to the cases where the swing bus is located in the Victorian and NSW regions, respectively.

General Comments

- Study findings apply only to the peak load-flow scenarios investigated in this study.

- With a Zero flow on Murraylink, (the base-case conditions) the load-flow cases studied indicate some thermal loading and voltage conditions beyond acceptable levels, both for normal conditions (all equipment in service) and during contingency conditions. Increasing loading on Murraylink indicates only a limited impact on these thermal and voltage violations. In some cases the base case violations are reduced. It is concluded that these base case violations generally are independent of and insensitive to Murraylink loading and as such do not factor into an assessment of the impact of Murraylink loading on the network performance.

- Although not specifically studied by TEA or PTI, it is reasonable to expect that the Murraylink transfer limits will be less constrained under off-peak load conditions compared to those limits determined for peak load conditions with stressed power flows on key interfaces such as Snow-Vic.

Victoria Swing Bus

- The conclusions drawn herein are relevant only to the peak scenarios studied. Other demand and dispatch combinations will yield differing results. It is believed, however, that the transfer limits identified are conservative under the reasonable assertion that the limits would be less constraining under off-peak conditions. In particular, lower western Victoria State loading conditions should relieve constraints on Murraylink transfers from Victoria to SA.

- As mentioned above, with power supplied from Victoria to South Australia, Murraylink can operate in a secure state at a level of 180 MW, under peak loading conditions, assuming some additional voltage support as indicated by TEA. Both the studies reported here and those of TEA support this conclusion. During some contingencies, the Murraylink flow subsequently would need to be reduced from 180 MW in order to avoid post-contingency overloads in the network. (Note that even with Zero flow, certain overloads would remain, suggesting that the necessary reduction in Murraylink flow could be limited.)

- With a pre-contingency flow of 180 MW on the Murraylink (assuming the limited amount of voltage support suggested by TEA) it should be possible to allow a “slow” run back of the Murraylink dispatch in order to bring loading levels to within thermal ratings. This might not be possible for critical thermally limiting cases if protection were to act to relieve overload on particular lower voltage circuits such as the BAN-ART 66 kV line. Under such conditions a faster runback would be required.

- With power supplied from Victoria to South Australia, Murraylink could be dispatched at a flow level of 220 MW with the level of additional voltage support suggested by TEA but during a few critical contingencies, the Murraylink power flow would probably need to reduced rapidly to avoid voltage collapse under the peak load conditions analysed here. The success of rapid run-back can be confirmed only with detailed dynamic simulations.

- A flow up to 220 MW on the Murraylink could be made secure under all contingency conditions, but higher levels of voltage support , together with network control services (e.g. run-back) would be required. An increased level of voltage support could comprise only static elements or might need active voltage support equipment such as Static Var Compensators (SVC).

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- The level to which Murraylink must be run back from 180 MW , or higher levels, would depend on the specific contingency. Maximum run-back requirement observed was down to a level of approximately 80 MW for the peak load condition studied. Actual run-back levels would need to be determined for each contingency of concern.

NSW Swing Bus

- A Murraylink flow of 110 MW would be secure, under peak load conditions, with a moderate amount of additional voltage support.. This reduction in capability, compared with the Victoria swing bus case, is due to transmission restrictions across the NSW-Victoria interconnectors.

- With a pre-contingency flow of 110 MW on Murraylink (assuming the limited amount of voltage support suggested by TEA) it will be necessary to initiate a run-back of the Murraylink dispatch in order to bring loading levels to within thermal ratings. For a few contingencies, Murraylink would need to be run back to a level in the order of 90 MW under the peak load condition studied. The run-back could be slow if the level of voltage support suggested by TEA is installed (or equivalent) because the cases do not indicate a rapid voltage collapse condition. See Section 3.5.

- Key transmission limitations exist on the 330 kV route from Murray power station to the Dederang substation. To relieve this 'bottleneck' power can be shifted northwards but soon impinges on transmission sections through the Wagga area.

- Some relief is awarded by shifting generation patterns in the Snowy hydro generators. The limiting thermal capacity of the total interface, however, will limit flows from NSW to Murraylink.

- The option exists to operate Murraylink levels of throughput higher than 110 MW and rely, as previously suggested, on a rapid run-back of Murraylink under contingency conditions. Independent of from where the power is supplied, a significant run-back of Murraylink could impact the 275 kV supply to South Australia, (over the Heywood interconnector). The reduction in Murraylink flow would increase the Heywood interconnector flow by the same amount. The impact, however, would be less than that experienced following a complete trip of Murraylink. More detailed studies would identify the consequences of trip or run-back of Murraylink and necessary mitigation measures.

- One critical contingency (denoted as Vic 5.1) results in about an 11% overloading on the BAN-ART 66 kV line with a flow of 110 MW on Murraylink. A reduction of Murraylink flow by about 40 MW would be needed to bring that line loading to within rating. The study also shows, however, that with a zero Murraylink flow, the BAN-ART line is already at 99% capacity during loss of the parallel 220 kV line (its most critical contingency). It requires an increase of 110 MW flow on Murraylink to increase flow on the BAN-ART line by about only 3 MW. Demanding a decrease in Murraylink flow, in order to maintain this particular line within rating, during a contingency, is a severe exigency.

The PTI Load Flow Studies

The Table below summarizes the study cases analyzed by PTI.

Report Section	Swing Location	Study File	MLINK	TLTG	ACCC	CONV
2.3	Victoria	No Augmentation	0/180/220			✓
2.,4	Victoria	No Augmentation	0 →220	✓		
2.5	Victoria	No Augmentation	0/180/220		✓	
2.6	Victoria	TEA/PTI Caps	180/220			✓
3.3	NSW	No Augmentation	0→220	✓		
3.4	NSW	No Augmentation	0/110		✓	
3.5	NSW	TEA/PTI Caps	110			✓

"MLINK" indicates Murraylink dispatches tested

The "TLTG" routine begins with a zero flow on Murraylink and increases the flow until limiting conditions are identified. It uses a dc (linear) analysis and hence ignores voltage conditions. Since this analysis ignores voltage conditions, it is used only to rapidly identify thermal loading conditions. The thermal loading limits identified are close approximations. If the ac voltage is relatively 'high', the TLTG results are lower than would be found with a full ac solution and vice versa.

The "ACCC" automatic routine tests a given dispatch condition under defined contingencies and identifies those contingencies which result in line overloads and/or bus voltage conditions outside of criteria. Any contingency case which does not converge is not reported. Those are studied using conventional techniques.

"CONV" implies that a conventional ac load flow solution was used to examine critical contingencies which had failed to converge without additional voltage support (Augmentation). The objective was to find Murraylink transfer levels for given augmentation levels.

The conventional cases were, in some cases, supported by analysis with the Optimal Power Flow (OPF) in order to identify minimum voltage support additions necessary to support specific Murraylink flows, under specific contingency conditions.

Section
1

Introduction

1.1 Terms of Reference

Over recent years the Australian state of South Australia has experienced tightening in the availability of generation capacity and, as a result, high average and peak wholesale electricity prices.

TEA has commissioned Murraylink, a DC transmission line between Red Cliffs in Victoria and Berri in South Australia. A converter station is located near to each connection point and the converter stations are connected via two underground HVDC cables, a total distance of around 180km.

Using the ABB HVDC Light technology, the converter stations are also able to provide reactive power support at each connection point, which is controllable independent of the active power transfers, within station rating. First power flow occurred over Murraylink in early September, 2002.

TEA has performed power system modeling to calculate the power transfer capability of Murraylink, using the Power Technologies International PSS/E modeling software.

TEA studied two supply options for South Australia at peak load. The first is the case when surplus generation is available to the South Australian region from the Victorian region (referred to as the "Victoria swing bus case") while the second is the case when surplus generation is available form the NSW region (referred to as the "NSW swing bus case").

In association with TEA studies, TEUS is undertaking market modeling to calculate the energy cost and reliability benefits of Murraylink, using the Henwood Energy Systems Prosym production cost modeling software and the General Electric ("**GE**") -MARS reliability modeling software, respectively. The methodology with which TEUS will use the power transfer limits calculated by TEA as inputs into market modeling is described in two papers prepared by TEUS:

1. *Incorporating the Findings of a Murraylink Load Flow Analysis in MARS Regional Interface Limits*, and

2. *Incorporating the findings of Murraylink Load Flow Analysis into Prosym Transmission Limits*.

The objectives of the work reported here are to independently examine the network studies undertaken by TEA. To reach this objective the work has comprised several Tasks. They are:

1. Examine the basic information provided by TEA
2. Perform analytical studies to confirm the TEA load-flow study findings
3. Document studies, results and overall findings.

The results of PTI's analytical studies, which examine the two swing bus cases, are reported in Sections 2 and 3 respectively. Section 4 discusses the appropriateness of the study results for use in the Prosym and MARS software.

1.2 Study Approach

PTI used conventional and automatic contingency analyses to identify the network's ability to remain within voltage and thermal loading criteria under normal (all lines in service) and first contingency (N -1) conditions.

For voltage limitation the criterion assumed is to require voltages to remain at a minimum level of 90% of nominal during normal and contingency conditions and to display a drop in voltage by no more than 10% of nominal as a result of a contingency outage.

For loading, the data base provided included line ratings; a normal rating (A) and an emergency , or contingency rating (B). These indicate maximum loading limits on lines and equipment for normal and contingency conditions, respectively.

1.2.1 Software Application

TEA's study documentation identified critical contingencies limiting Murraylink transfers. In order to confirm the critical contingencies, PTI used automatic contingency testing routines, in PSS/E, to provide a comprehensive analysis of all local single contingencies before examining the critical contingencies in more detail.

The transmission interchange limit analysis, "**TLTG**", estimates the import or export limits of a specified subsystem of the network using a linearized model. Power transfer distribution factors [2]relating changes in branch and interface flows to a change in study system interchange ar e determined. The maximum study system export is derived by extrapolation subject to the constraint that no monitored element exceeds the specified thermal rating.

For this study, the swing bus at LYPSA and the converter bus at Red Cliffs were designated as export and import buses such that as the LYPSA generation was increased, the dispatch at Murraylink was increased by the same amount.

It should be noted that TLTG uses a linear network such that reactive power effects are ignored as are voltage violations. The intention is to identify thermal limitations of the network. Where the actual bus voltages are high, TLTG will underestimate the flow limits. Where the voltages are low,

[2] For these studies, the distribution factors indicate the change in flow on each transmission line as a fraction of the increase in flow over Murraylink

the estimate of flow limit is high. The errors are small but need to be checked with a non-linear analysis where a more accurate identification is needed. TLTG is often used as a 'filter' prior to performing more detailed studies. The advantage of its use is simplicity and speed.

The AC Contingency Calculation "**ACCC**" calculates a full AC power flow solution for a specified set of contingency cases. The output, when processed, produces a report showing thermal and voltage violations and available capacity.

The Optimal Power Flow, '**OPF**", provides the ability to identify the minimum amount of voltage support, and its location, to obtain a network condition within voltage limits during normal and contingency conditions. The PTI version of this analytical tool provides this information for a given network condition. It does not provide a global solution for all network, dispatch and demand conditions in one analytical run but it is useful in calibrating solutions found in a more heuristic methodology.

The analyses cited above are available in PSS/E. For this study, some work was done with PTI's program Managing and Utilizing System Transmission, "**MUST**". This has both linear and non-linear analyses and is a highly powerful tool for contingency testing; allowing the identification of the influence of identifiable "transactions" and generation conditions.

For application of the contingency analyses cited, the contingencies tested included those critical outages identified by TEA (See Table 1.1) plus all other n-1 conditions in Victoria.

Table 1.1 – TEA Contingency List

Type	Contingency Category	ID	Specific Contingency
1	Loss of large Victorian generator	1.1	LYA 500 MW unit
		1.2	LYA 540 MW unit
		1.3	NPS 500 MW unit
2	Loss of major SNOVIC interconnector component	2.1	MSS- DDTS 330 kV line
		2.2	SMTS – DDTS 330kV line
3	Loss of major Victorian transmission component	3.1	HWTS – ROTS 500 kV line
		3.2	SMTS – ROTS 500 kV line
		3.3	HWTS – SMTS 500 kV line
4	Loss of SW-NSW transmission component	4.1	BURO – RCTS 220 kV line
		4.2	BLND – BURO 220 kV line
		4.3	DLPT – BLND 220 kV line
		4.4	WAGG – DLPT 330 kV line*
		4.5	LTSS – WAGG 330 kV line*
5	Loss of Victorian state grid transmission component	5.1	BATS - HOTS 220 kV line*
		5.2	HOTS – RCTS 220 kV line
		5.3	BETS – KGTS 220 kV line
		5.4	KGTS – RCTS 220 kV line
		5.5	MLTS – BATS 220 kV line
		5.6	BETS – SHTS 220 kV line
		5.7	HYTS 500/275 kV transformer
		5.8	MLTS 500/220 kV transformer

Appendix A shows a listing of the additional single contingencies generated by the PSS/E automatic contingency testing routines.

Section
2

Victoria Swing Bus Analysis

2.1 Input Information

At study initiation, TEA supplied an appropriate base case load-flow in PSS/E format. That scenario represents what has been referred to as a "Do Nothing" situation. The load-flow model represents the existing system with the SNOVIC 400 Project reactive support components and line upgrades. In addition to the SNOVIC components, only those forecast reactive additions up to the summer of 2003/4 were included. The Darlington Point tripping scheme is assumed to be armed.

A second scenario was provided which included additional shunt capacitance to off-load the Kerang and Horsham SVCs at high Murraylink power transfer to SA. Further capacitance was added at the Murraylink converter in Red Cliffs in order to increase the reactive capability at that location. The additional capacitance is intended to increase power transfers across Murraylink which would otherwise be restricted by unacceptably low voltage conditions, or possible voltage collapse, during network contingencies.

The added capacitance was identified to be:

- 50 MVAr at Kerang 220 kV bus
- 20 MVAr at Horsham 220 kV bus
- 80 MVAr at Red Cliffs 220 kV bus

In addition to the load-flow information, TEA provided a document describing that company's studies, the critical contingencies of concern and the identified transfer capabilities of Murraylink during normal and contingency situations, with and without the additional capacitance. This information was accompanied by one-line diagrams and other supporting study documents from the state utilities and NEMMCO.

The studies performed by TEA comprised basic load-flow contingency analysis, using PSS/E. An heuristic approach was used in order to examine the effectiveness of the additional capacitance. Unacceptably low voltage conditions are identifiable if the load-flow solution converges. A failure to converge usually indicates voltage collapse[3].

Further to the documentation and network data provided, members of TEA and PTI personnel held technical discussions via teleconferences during the execution of the studies reported here.

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[3] PSS/E cannot predict the location of the collapse centre nor the speed at which collapse could occur. Additional studies using Optimal Power Flow, non-divergent load-flows and Dynamic simulations are required for a detailed analysis.

2.2 Base Conditions

Because the Murraylink transfer can be expected to modify network flow conditions, compared to those which would exist prior to the presence of Murraylink, it was considered important to identify the network's existing limitations with respect to loading and voltage in order to be able to compare these with any additional violations introduced by non-zero Murraylink dispatches. This comparison was done initially under normal conditions (all lines in service).

PSS/E was used to identify thermal and voltage violations under the following conditions:

- Zero dispatch on Murraylink
- A flow of 180 MW to SA on the Murraylink. Selected because this is a level identified by TEA as an acceptable level which would not introduce security problems.
- A flow of 220 MW to SA on the Murraylink. Selected as the maximum capability of Murraylink.

There were no low voltage violations in these cases under normal conditions

Table 2.1 below shows the elements which are overloaded in these normal cases and summarizes the **differences** in loading and percentage loading on each element with Zero, 220 MW and 180 MW dispatched at Murraylink (220 DIFF, 180 DIFF).

The left column shows the elements which are overloaded in the base cases. The "220 DIFF" and "180 DIFF" columns show the increased MW and % loading on the element with a 220 MW flow and 180 MW flow on Murraylink, respectively, compared to the case with Zero flow.

The "greater than" sign indicates that there was no loading violation with Zero Murraylink flow. The "less than" sign indicates that there was a flow violation with Zero flow on Murraylink but not with either 200 MW or 180 MW flow.

TABLE 2.1 - DIFFERENCES IN BASE LOADING VIOLATIONS

LOADED ELEMENT						220 DIFF		180 DIFF	
BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	PERCENT	LOADING	PERCENT
30449*	DUMGEN	20	35440	LYPS	500	1.4	0.5	1.6	0.5
32010*	ATS	220	39010	ATS/D1	66	-16.7	-9.7	-14.3	-8.3
32100*	BLTS	220	39107	BLTS/D8	66	16	10.1	10.7	6.7
32620	RCTS	220	32621	RCLFVSC	165	> 10	> 4.0	0	0
32680*	RWTS	220	39680	RWTS/D1	22	1.4	2.4	1.4	2.3
32841*	TTS/B1	220	39841	TTS/D1	66	1.5	0.8	0.8	0.4
36100	BLTS	66	39107*	BLTS/D8	66	10.6	6.7	7.6	4.8
36160*	CLPS	66	36460	MBTS	66	-0.1	-0.1	0	0
36200*	ERTS	66	39202	ERTS/D3	66	-0.2	-0.1	0	0
36680*	RWTS	66	39682	RWTS/D3	22	< 2.5	< 3.6	< 2.5	< 3.6
36841	TTS/B12	66	39841*	TTS/D1	66	1.2	0.7	0.7	0.4
37680	RWTS	22	39680*	RWTS/D1	22	1.2	2.2	1.2	2.1

Mainly these results show insignificant loading changes due to Murraylink dispatch. Of note are some increased and decreased loadings:

- The DUMGEN-LYPS transformer is not relevant
- The Red Cliffs loading is a local self-related loading problem at that station. This is the transformer branch between Red Cliffs 220kV bus and the Murraylink VSC. With 220 MW dispatched on Murraylink, the fictitious generator is pumping 91 MVAr into the network. The 75 MVAr shunt capacitor there is injecting 75 MVAr. Total flow through the transformer is 275 MVA. With only 180 MW flow on Murraylink, the transformer flow is 245 MVA.

- The RWTS 66/22 transformer overload appears with Zero dispatch on Murraylink
- The ATS 220/66 transformer loading is reduced as Murraylink is loaded
- Loading increases at the BLTS transformer and 66 kV network are increased by up to 10%

A complete listing of violations for the three dispatch scenarios is shown in Table 2.2 below.

TABLE 2.2 BASE CASE LOADING VIOLATIONS

ZERO DISPATCH - RATE A								
BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
30449*	DUMGEN	20	35440	LYPS	500	518.7	300	172.9
32010*	ATS	220	39010	ATS/D1	66	201.9	171	118
32100*	BLTS	220	39107	BLTS/D8	66	234.2	159	147.3
32620	RCTS	220	32621	RCLFVSC	165		NO VIOLATION	
32680*	RWTS	220	39680	RWTS/D1	22	79.1	57	138.8
32841*	TTS/B1	220	39841	TTS/D1	66	259.8	173	150.2
36100	BLTS	66	39107*	BLTS/D8	66	203.4	159	127.9
36160*	CLPS	66	36460	MBTS	66	22.6	20	112.8
36200	ERTS	66	39202*	ERTS/D3	66	171.3	150	114.2
36680*	RWTS	66	39682	RWTS/D3	22	42.5	41	103.6
36841*	TTS/B12	66	39841	TTS/D1	66	214.2	173	123.8
37680	RWTS	22	39680*	RWTS/D1	22	73.9	57	129.6

220 MW DISPATCH - RATE A								
BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
30449*	DUMGEN	20	35440	LYPS	500	520.1	300	173.4
32010*	ATS	220	39010	ATS/D1	66	185.2	171	108.3
32100*	BLTS	220	39107	BLTS/D8	66	250.2	159	157.4
32620	RCTS	220	32621	RCLFVSC	165	275.5	265	104
32680*	RWTS	220	39680	RWTS/D1	22	80.5	57	141.2
32841*	TTS/B1	220	39841	TTS/D1	66	261.3	173	151
36100	BLTS	66	39107*	BLTS/D8	66	214	159	134.6
36160*	CLPS	66	36460	MBTS	66	22.5	20	112.7
36200*	ERTS	66	39202	ERTS/D3	66	171.1	150	114.1
36680*	RWTS	66	39682	RWTS/D3	22		NO VIOLATION	
36841	TTS/B12	66	39841*	TTS/D1	66	215.4	173	124.5
37680	RWTS	22	39680*	RWTS/D1	22	75.1	57	131.8

180 MW DISPATCH - RATE A								
BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
30449*	DUMGEN	20	35440	LYPS	500	520.3	300	173.4
32010*	ATS	220	39010	ATS/D1	66	187.6	171	109.7
32100*	BLTS	220	39107	BLTS/D8	66	244.9	159	154
32620	RCTS	220	32621	RCLFVSC	165		NO VIOLATION	
32680*	RWTS	220	39680	RWTS/D1	22	80.5	57	141.1
32841*	TTS/B1	220	39841	TTS/D1	66	260.6	173	150.6
36100	BLTS	66	39107*	BLTS/D8	66	211	159	132.7
36160*	CLPS	66	36460	MBTS	66	22.6	20	112.8
36200	ERTS	66	39202*	ERTS/D3	66	171.3	150	114.2
36680*	RWTS	66	39682	RWTS/D3	22		NO VIOLATION	
36841	TTS/B12	66	39841*	TTS/D1	66	214.9	173	124.2
37680*	RWTS	22	39680	RWTS/D1	22	75.1	57	131.7

In the subsequent contingency analyses, any violations on the elements listed above are ignored.

2.3 Linear Analysis (TLTG)

This analysis identifies limiting transfers based on thermal ratings. For normal conditions and each contingency the analysis identifies the incremental transfers across Murraylink assuming a beginning condition with zero dispatch over Murraylink.

For each contingency the output from the analysis shows the network elements which are most limiting, in increasing order of transfer, and indicates the contingency involved. The results show that for most contingencies, the transfer limit is well over 220 MW (from the point of view of the network). There are some contingencies for which Murraylink has to be constrained to below 220 MW to avoid element overloads. Table 2.3 below shows a summary of the critical contingencies.

Table 2.3 -- TLTG EXPORT LIMITS - OUTPUT FOR BASE CASE WITH VICTORIA SWING BUS

LOADINGS AT OR ABOVE 100 % OF RATING ARE MARKED WITH *

			<------------BASE CASE					------------>
<----- FROM ----->	<------ TO ------>	CKT	INCR. TRANS CAPAB	RATING A	PRE-SHIFT MW	POST-SHIFT MW	LIMIT CASE MW	DISTR. FACTOR
20079 DLPT220A 220	20082 BLND220A 220	1	349.9	294	193.6	308.9*	294.5*	0.28818
32080 BETS 220	32700 SHTS 220	1	392.4	317	-249	-318.6*	-309.9	-0.17393
36041 BAN 66 66.0	36042 ART 66 66.0	1	406.7	19	10.5	19.2	18.1	0.0219
20080 BURO220A 220	20082 BLND220A 220	1	428.3	294	-170.9	-286.1	-271.7	-0.28818
32380 KGTS 220	32620 RCTS 220	1	507	190	3.2	150.8	132.3	0.36905
CONTINGENCY SNOVIC-2.1	OPEN BRANCH FROM 20001 [MSS 330A] TO 33181 [DDTS/D 330] OPEN BRANCH FROM 33181 [DDTS/D 330] TO 33180 [DDTS 330]							
20003 LTSS330A 330	20014 WAGG330A 330	1	$\boxed{191.3}$	1097	1057.6	1141.0*	-20592*	0.20845
CONTINGENCY NSW-4.4	OPEN BRANCH FROM 20014 [WAGG330] TO 20015 [DLPT 330] OPEN BRANCH FROM 20079 [DLPT 220A] TO 20082 BLND 220A]							
32080 BETS 220	32700 SHTS 220	1	$\boxed{129.4}$	352	-316.5	-426.2*	15268.*	-0.27432
32380 KGTS 220	32620 RCTS 220	1	160.7	190	106.3	315.3*	-29581*	0.52255
CONTINGENCY VIC-5.1	OPEN BRANCH FROM 32040 [BATS 220] TO 32280 [HOTS 220]							
36041 BAN 66 66.0	36042 ART 66 66.0	1	$\boxed{66.8}$	26	21.1	52.2*	-8073.*	0.07786
20079 DLPT220A 220	20082 BLND220A 220	1	205.1	294	213.7	371.3*	-40739*	0.39395
CONTINGENCY VIC-5.3	OPEN BRANCH FROM 32080 [ETS 220] TO 32380 [KGTS 220]							
20079 DLPT220A 220	20082 BLND220A 220	1	$\boxed{171.2}$	294	217.9	396.8*	-46234*	0.44725
CONTINGENCY VIC-5.6	OPEN BRANCH FROM 32080 [BETS 220] TO 32700 [SHTS 220]							
32040 BATS 220	32480 MLTS 220	2	$\boxed{189.4}$	311	-246.7	-383.6*	21126.*	-0.34224
20079 DLPT220A 220	20082 BLND220A 220	1	192.8	294	233.5	360.0*	-19503*	0.31605
CONTINGENCY 3.2:	OPEN BRANCH FROM 35640 [ROTS500] TO 35720 [SMTS500] CKT 3							
32643 ROTS/A1 220	39641 ROTS/D 220	1	$\boxed{49.1}$	966	-958.1	-1021.*	13182.*	-0.15612
CONTINGENCY NSW-4.2	OPEN BRANCH FROM 20080 [BURO220] TO 20082 [BLND 220A]							
32080 BETS 220	32700 SHTS 220	1	$\boxed{158.3}$	352	-308.6	-418.3*	28311.*	-0.27432
32380 KGTS 220	32620 RCTS 220	1	183.9	190	94.2	303.2*	-54423*	0.52255
CONTINGENCY NSW-4.3	OPEN BRANCH FROM 20082 [BLND22OA 220] TO 20079 [DLPT220A]							
32080 BETS 220	32700 SHTS 220	1	$\boxed{129.4}$	352	-316.5	-426.2*	15268.*	-0.27432
32380 KGTS 220	32620 RCTS 220	1	160.7	190	106.3	315.3*	-29581*	0.52255

- Contingencies in red do not converge in an AC solution in the "do nothing" scenario
- Limiting transfers/dispatches shown in boxes
- Pre-shift flow is flow on the limiting element before Murraylink dispatch is increased from zero
- Distribution factor is the fraction of Murraylink flow which flows on the network element
- Results ignore elements overloaded in base cases
- Rate A for base conditions
- Rate B for contingency conditions
- **Results are linear approximations**

2.4 AC Contingency Analysis (ACCC)

Initial results from the TLTG analysis have indicated contingencies and network elements which would limit Murraylink flow to the levels shown, (i.e. without the provision of some automatic Runback scheme).

The results are not indicative of full AC solutions and, as the previous table shows, some of the contingencies tested, as is seen in the following sections, did not converge in a full AC solution with 220 MW dispatched on Murraylink. This does not indicate that the contingencies would not converge at the thermally limiting levels shown in Table 2.3; in fact the cases showing significantly low thermal limits (e.g contingencies Vic 5.1 and 3.2) probably would converge without additional voltage support at those limited levels. Table 2.3 merely indicates that these are critical contingencies at elevated transfer levels although this was not known until the analysis of Section 2.5 was complete.

The results are useful, however, in early identification of limiting elements and the extent to which they would be affected by Murraylink's flow (see the distribution factors). Note that the incremental flow limits shown previously are equivalent to the limiting Murraylink dispatch since they are incremental to an initial flow of zero on Murraylink for this analysis.

At this point, in the analysis, an AC solution was used to better identify the performance of the network under specific Murraylink transfer levels. The ACCC analysis was used to test the contingency set in order to show thermal and voltage violations. It will be seen that:

- Some contingencies solve without problem and show no thermal or voltage violations. (These do not appear in the summary output reports).
- Some contingencies converge but show either thermal or voltage violations or both.
- Some contingencies do not converge, indicating the requirement for additional voltage support to avoid voltage collapse with constant MVA loads.

It should be noted that failure to converge a load-flow model with constant MVA loads is not necessarily indicative of voltage collapse. This is because loads are voltage sensitive and are immediately reduced, following a disturbance, because the voltages in the system have fallen. The load-flow model does not assume this load reduction and attempts to meet the constant MVA load with low network voltages. A dynamic solution can verify whether or not a voltage collapse condition really exists or whether time is available to adjust voltage support before the loads recover from their reduced level to their "constant" MVA levels which existed before the contingency occurred. (Note that the loads will not recover completely to pre-contingency levels until their local voltages recover completely).

2.4.1 Results Summary

The AC contingency analysis was performed for the three scenarios previously examined, those are with zero Murraylink flow and with levels of 180 MW and 220 MW.

It will be seen that even with zero flow on Murraylink, there are voltage and thermal violations. It will be seen further that with both a 180 MW and a 220 MW flow some contingencies indicate possible voltage collapse if these flow levels are not reduce by run-back.

Tables 2.4 a, b and c (Appendix B) show a combined summary of **thermal** contingency failures for the three Murraylink transfer levels. The Tables show only those contingencies which converged with 220 MW on Murraylink, without additional capacitor support. Some contingencies in the Tables are indicated with a pink background. These did not converge and their results cannot be shown in the Tables. Others results are marked with a yellow background. This indicates that the contingency resulted in both thermal and voltage violations.

It will be seen in the Table 2.4 b that, for the 180 MW transfer case, some cases show results but are indicated to be cases which did not converge. It needs to be explained that this transfer level was tested with the additional shunt capacitors identified by TEA. The contingencies indicated failed to converge without this additional capacitive support but converged with it. The results for the 220 MW transfer cases did not assume any additional voltage support.

To clarify, Tables 2.4a, 2.4b and 2.4c show results for the conditions summarized in Table 2.4d below. The failures indicated are failures to comply with thermal limits.

The thermal failures indicated are based on RATE A for the Base Case and on RATE B for the contingency cases.

Table 2.4 d - Summary of Voltage Support Conditions for ACCC Test Cases

Results Table	MLINK Dispatch	Reactive Support
2.4 (a)	0	As per base case
2.4 (b)	180	As per TEA recommendation (add 150MVA)
2.4 (c)	220	As per base case

Table 2. 5, (Appendix B) shows those contingencies which converged but failed to comply with voltage criteria. The study conditions are **without** additional capacitor support.

2.4.2 Comments on Results of ACCC Analysis

- The case with a zero flow on Murraylink shows thermal violations in several contingencies and in accordance with Table 2.5 show the same voltage violations as the case with a 220 MW flow on Murraylink.

- Table 2.4(c) has two additional columns at the right. These show the difference in flow percentages between the Zero flow condition and the 180 MW and 220 MW flow condition on Murraylink. It can be seen that the differences are small, indicating that the network has fundamental flow limits independent of the Murraylink flows.

- Table 2.5 shows voltage weakness in the system without flow on Murraylink. The dispatch at 220 MW on Murraylink merely extends the area of the network affected by low voltage on the same contingencies. An additional contingency (# 4.5) shows voltage violations with 220 MW flow that do not occur with a Zero flow. However, the violations are marginal.

- In Table 2.5, violations are designated as "Range" or "Deviation". The first means that the failure is a result of voltages falling below the limit level of 0.9 pu. The second means that the voltage at the buses indicated dropped by more than 10% as a result of the contingency.

- The system with 180 MW flow on Murraylink shows failure to converge (see colour coding in Table 2.4 (b)), **without** additional capacitor support. With the small amount of added shunt capacitive support suggested by TEA these cases converge and show thermal violations of limited degree over the Zero flow case. Further, with the additional voltage support, there are **no voltage** violations indicated for these same contingencies.

- Table 2.4 c) indicates failures to converge not seen with a Zero Murraylink flow (similar to the 180 MW flow condition). These are caused by lack of voltage support and are studied in more detail.(See discussions below in Section 2.5).

2.5 Resolving Critical Contingencies

The previous results showed that at a level of 180 MW flow on the Murraylink, some contingency conditions would not sustain a load-flow solution. Additional capacitance, suggested by TEA, proved to resolve these issues.

For the 220 MW dispatch on Murraylink, the same phenomenon exists.

What is important for operation is to identify flow limits on Murraylink, which will not result in apparent voltage collapse. If contingencies result in network element overloads it is clear that a reduction in Murraylink's flow can resolve this problem (or a generation redispatch). If the network voltage collapses rapidly, however, an operational result may not solve the problem.

The studies reported here attempt to identify the Murraylink flow which are sustainable with a limited amount of additional voltage support and which will not result in immediate voltage collapse. While a detailed study could identify the level and location of voltage support which would serve to maintain an initial dispatch of 220 MW on Murraylink, this work is intended to assist in verifying that the TEA analysis makes sense and is producing accurate results. The work performed here, has that as the objective rather than performing a detailed planning study of equipment requirements for a 220 MW dispatch.

To that end, the "critical" contingencies have been studied in more detail. The "critical" contingencies are nominated as those which failed to converge in an AC solution in the ACCC analysis, or are interesting in that they have displayed low transfer limits. They are shown below in Table 2.6.

The intention in studying these critical contingencies is to confirm that a Murraylink transfer of at least 180 MW is possible with minimal additional voltage support, as demonstrated by the TEA studies.

To clarify, the cases shown to fail, in Table 2.6, were based on a base case condition **without** additional voltage support.

TABLE 2.6 - CONTINGENCIES FAILING TO CONVERGE WITH 220 MW DISPATCH

CONTINGENCY 3.2 (CONVERGED WITH A LOW TRANSFER LIMIT)
OPEN BRANCH FROM BUS 35640 [ROTS500 500] TO BUS 35720 [SMTS 500] CKT 3

CONTINGENCY 4.1
OPEN BRANCH FROM BUS 20080 [BURO220A220.00] TO BUS 32620 [RCTS 220.00]

CONTINGENCY 4.2+ 4.3
OPEN BRANCH FROM BUS 20080 [BURO220A220.00] TO BUS 20082 [BLND220A220.00]
OPEN BRANCH FROM BUS 20082 [BLND220A220.00] TO BUS 20079 [DLPT220A220.00]

CONTINGENCY 4.4
OPEN BRANCH FROM BUS 20014 [WAGG330A330.00] TO BUS 20015 [DLPT330A330.00]
OPEN BRANCH FROM BUS 20079 [DLPT220A220.00] TO BUS 20082 [BLND220A220.00]

CONTINGENCY VIC-5.1
OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32280 [HOTS 220.00]

CONTINGENCY VIC-5.2
OPEN BRANCH FROM BUS 32280 [HOTS 220.00] TO BUS 32620 [RCTS 220.00]

CONTINGENCY VIC-5.3
OPEN BRANCH FROM BUS 32080 [BETS 220.00] TO BUS 32380 [KGTS 220.00]

CONTINGENCY VIC-5.4
OPEN BRANCH FROM BUS 32380 [KGTS 220.00] TO BUS 32620 [RCTS 220.00]

CONTINGENCY VIC-5.6
OPEN BRANCH FROM BUS 32080 [BETS 220.00] TO BUS 32700 [SHTS 220.00]

CONTINGENCY VIC-5.8
OPEN LINE FROM BUS 39481 [MLTS/D 220.00] TO BUS 32480 [MLTS 220.00]
OPEN LINE FROM BUS 39481 [MLTS/D 220.00] TO BUS 35480 [MLTS 500.00]

Contingency 3.2

This case was not problematic from a voltage support viewpoint. The linear analysis, however, indicated that Murraylink would need to operate at less than 100 MW to avoid overloading the ROTS transformer under this contingency. In the ACCC analysis, this contingency showed the overload condition existed only with 220 MW on Murraylink. The a c solution shows the following element overloads with a 220 MW transfer on Murraylink and without additional capacitors.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
32643*	ROTS/A1	220	39641	ROTS/D	220	1003.1	1000	100.3
35640*	ROTS500	500	39641	ROTS/D	220	1023.5	1000	102.4

The transformer is close to full load under the Zero dispatch condition on Murraylink. The overloads shown are sensitive to reactive flow on the transformer and in reality show no significant problem with a 220 MW transfer on Murraylink.

Contingency 4.1

This contingency opens up the tie from Buronga to Red Cliffs and fails to converge without additional voltage support. With added capacitors suggested by the TEA study, the case converges with 220 MW flow on Murraylink but shows overload conditions which confirm TEA study results.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
32080	BETS	220	32700*	SHTS	220	371.6	352	105.6
32380*	KGTS	220	32620	RCTS	220	212.5	194	109.6

With a 180 MW transfer on Murraylink, these overloads do not appear.

Contingency 4.2+4.3

With the added capacitors suggested by TEA this case will converge with a 180 MW flow on Murraylink. An OPF solution shows an addition of 131MVAr of capacitors at appropriate locations will resolve this contingency. This level of support broadly matches the TEA solution. With a 180 MW flow the contingency shows the following overloads..

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
32080	BETS	220	32700*	SHTS	220	376.7	352	107
32380*	KGTS	220	32620	RCTS	220	212.3	194	109.4

A flow of 200 MW would be feasible assuming higher levels of investment in voltage support equipment.

Contingency 4.4

This contingency will limit Murraylink flow to 180 MW assuming the capacitor additions suggested by TEA. Again the OPF suggests an addition of capacitor support in the order of 130 MVAr at BETS. Both voltage support solutions function to provide convergence but, as for the previous contingency, the BETS-SHTS and KGTS-RCTS lines suffer overloads at this Murraylink flow level, as shown in the TEA study..

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
32080	BETS	220	32700*	SHTS	220	378.6	352	107.6
32380*	KGTS	220	32620	RCTS	220	216.7	194	111.7

Contingency 5.1

Previous linear contingency analysis indicated that this contingency would limit the Murraylink flow to about 70 MW to avoid thermal overloads on the BAN-ART 66 kV line. Checking the result with an ac solution shows a limit on Murraylink in the order of 83 MW.

For this case to converge, Murraylink flow is limited to 180 MW with the additional voltage support suggested by the TEA study. With a Murraylink flow of 180 MW, slow runback is required to return line thermal loadings to acceptable levels.

Contingency 5.2

This study confirms that the voltage support suggested by the TEA study will result in convergence of this case with a 220 MW flow on the Murraylink and without showing any overload conditions.

Contingency 5.3

Using the additional capacitor support suggested by the TEA study, this analysis shows a need to limit the flow on the Murraylink to 180 MW (TEA suggested 190 MW) to obtain a secure convergence. The loading conditions however, in agreement with the TEA result show overloads in the DLPT to BURO sections.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
20079*	DLPT220A	220	20082	BLND220A	220	318.2	296	107.5
20080	BURO220A	220	20082*	BLND220A	220	307.6	296	103.9

Contingency 5.4

Using the voltage support suggested by TEA, the case will converge with a 220 MW flow on the Murraylink. The tests also confirm the post contingency loading condition on the DLPT- BURO section being marginally over rating.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
20079*	DLPT220A	220	20082	BLND220A	220	302.5	296	102.2

Contingency 5.6

The tests performed here indicated successful post contingency convergence with a 180 MW flow on Murraylink, using the capacitive support suggested by TEA. Higher loadings were unsuccessful. With capacitive support suggested by the OPF (~100 MVAr at BLND) the case was successfully converged with a 220 MW flow on Murraylink. Overloading occurs in the DLPT-BURO sections but not in the BATS lines as suggested in the TEA summary document.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
20079*	DLPT220A	220	20082	BLND220A	220	318.2	296	107.5
20080	BURO220A	220	20082*	BLND220A	220	307.6	296	103.9

Contingency 5.8

Using the capacitive support suggested by TEA was sufficient to obtain post contingency convergence with a flow of 220 MW on Murraylink. Using a suggested modification to the SVC set points, from the OPF, was equally successful. Overloads are found as shown below; confirming the TEA findings.

BUS	NAME	BSKV	BUS	NAME	BSKV	LOADING	RATING	PERCENT
32080	BETS	220	32700*	SHTS	220	367	352	104.3
32260	GTS	220	32403*	KTS/B3	220	345.2	325.2	106.2

2.6 Summary Comments

- Given the level of additional voltage support suggested by TEA, the supportable level of flow on Murraylink is in the order of 180 MW under the peak load condition studied. PTI's studies and those of TEA support this conclusion.

- This limit indicates a level which should allow any of the contingencies studied to occur without the system voltage collapsing at pre-contingency peak loading levels. The interpretation of "failure to converge a load-flow solution" has been taken as a "voltage collapse" condition.

- With a pre-contingency flow of 180 MW on the Murraylink (assuming the limited amount of voltage support suggested by TEA) it should be possible to allow a “slow” run back of the Murraylink dispatch in order to bring loading levels to within ratings subject to the operation of thermal overload protection in cases such as the BAN-ART 66 kV line.

- Specifically, contingency 5.1 results in a 40% overload on the BAN-ART 66 kV line. That overload is in the order of only 10 MW. In order to bring loading within the line rating, however, Murraylink would have to back off about 120 MW. This is because the “distribution factor” is very small for this line. See Table 2.3. For other lines’ overloading relief, Murraylink would need to back off much less because of much higher distribution (or participation) factors.

- PTI has done some work with the OPF to identify minimum capacitive support requirements for convergence in the critical cases. In general, the level of support agrees with the TEA suggestion but it has indicated different locations for the support. A broader study, that considers other dispatch conditions, could determine a precise set of equipment requirements.

- The system with Zero flow on Murraylink shows failures in complying with loading criteria for both base case and contingency conditions (See Table 2.4a). With up to 220 MW on Murraylink, those same failures occur but without significant increase in severity. In some instances the loading is seen to reduce.

- A flow up to 220 MW on the Murraylink could be sustained under all contingency conditions, but higher levels of voltage support would be required. It is not clear from these studies if that increased level of voltage support could comprise only static elements rather than active elements such as SVCs.

- Although not specifically analysed by TEA or PTI, it is reasonable to assert that Murraylink could transfer power securely from Victoria to SA at levels above the limits discussed in this report during off-peak network conditions. In particular, load levels in western Victoria are a key factor in identification of Murraylink transfer limits.

Section
3

New South Wales Swing Bus Analysis

3.1 Input Information

At study initiation, TEA provided three base case load-flows.

TEA's first (Case 1) was a "do nothing" case, representing the existing system with the SNOVIC 400 Project reactive support projects and line upgrades. For this case, TEA determined a limit on the Murraylink at 20 MW.

The second (Case 2) assumed additional capacitors to relieve undervoltage conditions and adjust Snowy hydro generation to maximize SNOVIC capability. For this case a limit of 45 MW on the Murraylink was identified. This limit was governed by loading on the Murray-Dederang and the LTSS-WAGGA lines following loss of a Murray-Dederang circuit, (Contingency 2.1).

The third (Case 3) assumed a higher rating on the LTSS-WAGGA 330 kV line (increased from 1100 MVA to 1160 MVA) and additional capacitors.

Case 2 capacitors

- Wagga 330 bus 50 MVAr
- Dederang 330 bus 80 MVAr
- Balranald 220 bus 30 MVAr
- Deniliquin 132 bus 5 MVAr
- Kerang 220 bus 0 MVAr

Case 3 capacitors

- Wagga 330 bus 160 MVAr
- Dederang 330 bus 160 MVAr
- Balranald 220 bus 30 MVAr
- Deniliquin 132 bus 5 MVAr
- Kerang 220 bus 25 MVAr

3.2 Study Approach

PTI's work for the NSW swing bus case was based on the same approach as for the Victoria swing bus case, using the same software activities. For the NSW swing bus case, however, two Murraylink conditions were selected; a Zero flow and a 110 MW flow. The TEA studies have identified a Murraylink limit in the order of 90 MW under peak load conditions, implying a SNOVIC interconnector transfer of 110 MW. For the purpose of testing a limiting condition in the PTI studies, the 110 MW was assumed on Murraylink itself.

3.3 Linear Analysis (TLTG)

The process used for the NSW swing bus case mirrors that used for the Victoria swing bus case. In the NSW swing bus case, the power system was tested by shifting power to the Murraylink from the NSW swing bus # 20201 ERAR. The TLTG analysis identifies limiting, incremental thermal conditions as power is increased from Zero to the DC inverter. Since the initial DC power is Zero, any incremental power is equal to absolute power on Murraylink.

Table 3.1 below shows allowable flows on Murraylink as a function of thermally bound network elements for the contingencies shown. It should be noted that the full complement of contingencies used for the Victoria swing bus case were used here. The Table shows only those limiting elements which are not already exceeding thermal limits in the base case with Zero flow on Murraylink.

It should be remembered that the incremental flows shown are not exact because of the linearization. If actual voltages are low (away from nominal) the TLTG incremental flows will be higher than actual.

TABLE 3.1 - LIMITING MURRAYLINK LOADING

DELTA-P	LIMITING ELEMENT							DIST	CONTINGENCY
MW	BUS	NAME	KV	BUS	NAME	KV	CKT	FACTOR	DESCRIPTION
72	*20001	MSS 330A	330	33181	DDTS/D	330	2	0.43527	**CONTINGENCY SNOVIC-2.1:** OPEN 20001 [MSS_330A 330] TO 33181 [DDTS/D OPEN 33181 [DDTS/D 330] TO 33180 [DDTS
91.4	*36041	BAN 66	66	36042	ART 66	66	1	0.07002	**CONTINGENCY VIC-5.1:** OPEN 32040 [BATS 220] TO 32280 [HOTS
112.5	*32080	BETS	220	32700	SHTS	220	1	-0.34825	**CONTINGENCY NSW-4.4:** OPEN 20014 [WAGG330A 330] TO 20015 [DLPT330A OPEN 20079 [DLPT220A 220] TO 20082 [BLND220A
126.9	*20003	LTSS330A	330	20014	WAGG330/	330	1	0.44045	**CONTINGENCY SNOVIC-2.1:** OPEN 20001 [MSS_330A 330] TO 33181 [DDTS/D OPEN 33181 [DDTS/D 330] TO 33180 [DDTS
167.6	*32380	KGTS	220	32620	RCTS	220	1	0.53263	**CONTINGENCY NSW-4.4:** OPEN 20014 [WAGG330A 330] TO 20015 [DLPT330A OPEN 20079 [DLPT220A 220] TO 20082 [BLND220A
167.8	*20079	DLPT220A	220	20082	BLND220A	220	1	0.4919	**CONTINGENCY VIC-5.3:** OPEN 32080 [BETS 220] TO 32380 [KGTS
212.6	*20080	BURO220/	220	20082	BLND220A	220	1	-0.4919	**CONTINGENCY VIC-5.3:** OPEN 32080 [BETS 220] TO 32380 [KGTS
230.8	*32040	BATS	220	32480	MLTS	220	2	-0.31157	**CONTINGENCY VIC-5.6:** OPEN 32080 [BETS 220] TO 32700 [SHTS
251.2	*32040	BATS	220	32080	BETS	220	1	0.30209	**CONTINGENCY VIC-5.6:** OPEN 32080 [BETS 220] TO 32700 [SHTS

The left hand column shows the flow which would appear on Murraylink when the "limiting elements" reach rating (B).

These results, while not exact, confirm TEA's findings which identify contingency 2.1 as the limiting condition when the MSS-DDT and the LTSS-WAGG lines reach there respective thermal limits.

It is interesting to note that the distribution factors for the limiting elements are high. That is when the Murraylink flow increases, they pick up a significant part of that flow. The exception, as for the Victoria swing bus case, is the BAN-ART 66 kV line which has a very low distribution factor implying that in order to unload the line, the Murraylink flow would have to be reduced substantially.

3.4 AC Contingency Analysis (ACCC)

As for the Victoria swing scenario, this automatic contingency analysis was used to test for thermal and voltage violations using a non-linear AC solution. In this case the tests were performed with Zero flow and a 110 MW flow on Murraylink.

Table 3.2 (Appendix C) shows the thermal violations with a Zero flow on Murraylink. Table 3.3 (Appendix C) shows the same information with 110 MW on Murraylink. In addition, this table shows the differences in percentage loading on the overloaded elements when Murraylink flow changes from Zero to 110 MW.

In general, the loading conditions with 110 MW on Murraylink are very similar to the condition with Zero flow. The right-hand column shows the difference.
Notable are:

- The contingency 5.1 overloads the BAN-ART line, as expected. A reduction of about 40 MW flow on Murraylink would be needed to unload this line.
- Contingencies 24 and 25 at TBTS cause new overloads in that region. It is not clear what those elements are.
- Some overloads occur with Zero flow which do no appear with a 110 MW flow.
- The limiting contingency 2.1 does not show the overloaded MSS-DDTS line. It appears that the ACCC analysis misses it. This is probably because the line is in two "Areas"

3.4.1 Voltage Violations

As for the Victorian swing bus case, the converged contingency cases show few voltage violations in terms of the number of contingencies showing problems. (See Table 3.4 in Appendix C). The same contingencies are problematic; those being loss of ERTS-TBTS 220 (contingencies 24 and 25) and loss of HYTS-MLTS 500 (contingencies 123 and 125). These create problems with Zero flow too.

No voltage support solutions have been specifically tested in this analysis of voltage conditions. The additional capacitors, selected by TEA for the 90/110 MW situation (Case 3) were not used here. Rather the objective is to identify the differenc es between a loaded and unloaded condition on Murraylink.

3.5 Resolving Critical Contingencies

Several contingencies failed to converge in the ACCC analysis, with a Murraylink flow of 110 MW. The assumption was that this is due to lack of voltage support. These contingencies have been tested separately together with the limiting contingency (2.1).

Contingency 3.2+4.2
This contingency considers the loss of line elements 20080 to 20082 and line 20082 to 20079 between DLPT and BURO.

With only 25 MVAR added at KG, this case supports a 110 MW Murraylink flow without voltage violations but the BETS-SHTS line circuit loading is 104%. A reduction of Murraylink flow to 90 MW resolves this overload.

Contingency 4.4
This contingency considers the loss of the WAGG-DLPT line. The 220 kV line from DLPT to Balranald is tripped to unload the 132 kV network.

Using the OPF, this contingency passed without additional voltage support. Using a conventional solution with only 25 MVAr at KG the case passes with a 110 MW loading on Murraylink.

If the DLPT-BLND line is not tripped it will suffer a 3.5% overload with 110 MW on Murraylink. Lowering Murraylink flow to 90 MW removes the overload on DLPT-BLND.

Contingency 4.5
This contingency considers the loss of the LTSS-WAGG 330 kV line.

An OPF solution indicated the need for minimum voltage support as follows:

- 48 MVAr at 26169 Darlington
- 25 MVAr at KG
- 15 MVAr at SHTS

With this support the contingency passes with 110 MW on Murraylink, without overloads and voltage violations.

Contingency 76
This contingency considers the loss of a 220/66 kV transformer in the MBTS area. The case does not solve with any level of Murraylink loading, including zero, and thus appears to indicate a local support problem. This contingency was not pursued further.

Contingency 2.1
This contingency considers the loss of one of the MSS-DDTS 330 kV lines and is the most critical contingency from the point of view of loading the EHV network. Linear analysis shows that this contingency will limit Murraylink flow to around 70 MW or less to avoid overloading the other MSS-DDTS 330 kV circuit under peak load conditions.

- The contingency solves with 110 MW on Murraylink with only marginal voltage violations in the Deniliquin and Finley stations; where TEA has proposed to add capacitive support. Under this condition, the MSS-DDTS remaining circuit is overloaded in the order of 100 MW (107)

- An AC solution was run on this case to confirm that a reduction of Murraylink flow from 110 MW down to 50 MW would be required to maintain the MSS-DDTS circuit within thermal limits.

- It was suggested by TEA that loading relief of the MSS-DDTS line could be achieved by redispatching the Snowy hydro generation. PTI found that the redispatch which works requires a significant increase in output from Lower Tumut (600 MW) and a marginal decrease in Murray (MSS –182 MW). Testing this dispatch confirmed that Murraylink could operate at 90 MW without violating the MSS-DDTS thermal limits during this contingency.

- Separate testing of a redispatch only at MSS and the swing bus was unsuccessful in resolving this loading problem. Further, it is to be expected that shifting generation north would not be successful. The advantage of redispatching Lower Lumut is that it lies directly on the electrical route to WAGG.

- With only three links between the Victoria and the NSW regions, it is difficult to see alternative solutions to this limit. Flow control devices would probably be limited in scope since not only is the DLPT route limited but the contingency analysis showed that the BETS-SHTS circuit would quickly be a limiting element.

Section
4

Use of Transfer Limits

PTI, in conjunction with its parent firm, Stone and Webster Consultants (SWC), has reviewed documents prepared by TEUS: "Incorporating the findings of Murraylink Load Flow Analysis into Prosym Transmission Limits" (contained in Appendix B) and "Incorporating the Findings of a Murraylink Load Flow Analysis in MARS Regional Interface Limits" (contained in Appendix C). These documents describe the methodology by which TEUS will use the power transfer limits calculated by TEA as inputs

The methodology developed by TEUS is very good and entirely consistent with what PTI would do. The use of dummy transmission areas is a clever modeling technique to allow focus on the transmission line of interest. The loading issues associated with the line are handled via ratings changes by time periods and this is quite sufficient. It was evident from the telephone conversations between PTI, SWC and TEUS that the TEUS personnel involved are very knowledgeable in that respect

If, for some reason it becomes necessary to expand the level of detail, it is possible to model outages/maintenance on transmission lines, but this is normally not worth the effort because of the small impact. Neither of these can be modeled directly but would need to be done via RULEGROUPS and PROXY STATIONS. In SWC's opinion, what has been done is completely satisfactory and getting into these "Rules of Existence" is not recommended.

Appendix

A

Contingency List

CONTINGENCY REFERENCES	
LABEL	EVENTS
SNOVIC-2.1	OPEN BRANCH FROM BUS 20001 [MSS_330A330.00] TO BUS 33181 [DDTS/D 330.00]
	OPEN BRANCH FROM BUS 33181 [DDTS/D 330.00] TO BUS 33180 [DDTS 330.00]
NSW-4.4	OPEN BRANCH FROM BUS 20014 [WAGG330A330.00] TO BUS 20015 [DLPT330A330.00]
	OPEN BRANCH FROM BUS 20079 [DLPT220A220.00] TO BUS 20082 [BLND220A220.00]
SNOVIC-2.2	OPEN LINE FROM BUS 33721 [SMTS/SC1330.00] TO BUS 33181 [DDTS/D 330.00] CKT 1
	OPEN LINE FROM BUS 33721 [SMTS/SC1330.00] TO BUS 33720 [SMTS 330.00] CKT 1
VIC-5.7	OPEN LINE FROM BUS 39341 [HYTS/D1 275.00] TO BUS 34341 [HYTS/T1 275.00] CKT 1
	OPEN LINE FROM BUS 39341 [HYTS/D1 275.00] TO BUS 35341 [HYTS/B1 500.00] CKT 1
VIC-5.8	OPEN LINE FROM BUS 39481 [MLTS/D 220.00] TO BUS 32480 [MLTS 220.00] CKT 1
	OPEN LINE FROM BUS 39481 [MLTS/D 220.00] TO BUS 35480 [MLTS 500.00] CKT 1
1	OPEN BRANCH FROM BUS 20001 [MSS_330A330.00] TO BUS 33181 [DDTS/D 330.00] CKT 2
2	OPEN BRANCH FROM BUS 20013 [JIND330A330.00] TO BUS 33900 [WOTS 330.00]
3	OPEN BRANCH FROM BUS 20080 [BURO220A220.00] TO BUS 32620 [RCTS 220.00]
4	OPEN BRANCH FROM BUS 32010 [ATS 220.00] TO BUS 32100 [BLTS 220.00]
5	OPEN BRANCH FROM BUS 32010 [ATS 220.00] TO BUS 32401 [KTS/B1 220.00]
7	OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32080 [BETS 220.00]
VIC-5.1	OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32280 [HOTS 220.00]
VIC-5.5	OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32480 [MLTS 220.00]
8	OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32480 [MLTS 220.00] CKT 2
9	OPEN BRANCH FROM BUS 32040 [BATS 220.00] TO BUS 32800 [TGTS 220.00]
VIC-5.3	OPEN BRANCH FROM BUS 32080 [BETS 220.00] TO BUS 32380 [KGTS 220.00]
VIC-5.6	OPEN BRANCH FROM BUS 32080 [BETS 220.00] TO BUS 32700 [SHTS 220.00]
10	OPEN BRANCH FROM BUS 32100 [BLTS 220.00] TO BUS 32220 [FBTS 220.00]
11	OPEN BRANCH FROM BUS 32100 [BLTS 220.00] TO BUS 32401 [KTS/B1 220.00]
12	OPEN BRANCH FROM BUS 32100 [BLTS 220.00] TO BUS 32540 [NPS 220.00]
13	OPEN BRANCH FROM BUS 32120 [BTS 220.00] TO BUS 32660 [RTS 220.00]
14	OPEN BRANCH FROM BUS 32120 [BTS 220.00] TO BUS 32842 [TTS/B2 220.00]
15	OPEN BRANCH FROM BUS 32120 [BTS 220.00] TO BUS 32843 [TTS/B3 220.00]
17	OPEN BRANCH FROM BUS 32180 [DDTS 220.00] TO BUS 32240 [GNTS 220.00]
18	OPEN BRANCH FROM BUS 32180 [DDTS 220.00] TO BUS 32240 [GNTS 220.00] CKT 3
19	OPEN BRANCH FROM BUS 32180 [DDTS 220.00] TO BUS 32460 [MBTS 220.00]
20	OPEN BRANCH FROM BUS 32180 [DDTS 220.00] TO BUS 32460 [MBTS 220.00] CKT 2
21	OPEN BRANCH FROM BUS 32180 [DDTS 220.00] TO BUS 32700 [SHTS 220.00] CKT 2
22	OPEN BRANCH FROM BUS 32200 [ERTS 220.00] TO BUS 32641 [ROTS/B1 220.00]
23	OPEN BRANCH FROM BUS 32200 [ERTS 220.00] TO BUS 32641 [ROTS/B1 220.00] CKT 2
24	OPEN BRANCH FROM BUS 32200 [ERTS 220.00] TO BUS 32781 [TBTS/B1 220.00]
25	OPEN BRANCH FROM BUS 32200 [ERTS 220.00] TO BUS 32782 [TBTS/B2 220.00]
26	OPEN BRANCH FROM BUS 32210 [EPS 220.00] TO BUS 32460 [MBTS 220.00]
27	OPEN BRANCH FROM BUS 32210 [EPS 220.00] TO BUS 32460 [MBTS 220.00] CKT 2
28	OPEN BRANCH FROM BUS 32210 [EPS 220.00] TO BUS 32842 [TTS/B2 220.00]
29	OPEN BRANCH FROM BUS 32220 [FBTS 220.00] TO BUS 32540 [NPS 220.00]
30	OPEN BRANCH FROM BUS 32220 [FBTS 220.00] TO BUS 32880 [WMTS 220.00]
31	OPEN BRANCH FROM BUS 32220 [FBTS 220.00] TO BUS 32880 [WMTS 220.00] CKT 2
32	OPEN BRANCH FROM BUS 32240 [GNTS 220.00] TO BUS 32700 [SHTS 220.00]
33	OPEN BRANCH FROM BUS 32240 [GNTS 220.00] TO BUS 32700 [SHTS 220.00] CKT 3
34	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32403 [KTS/B3 220.00]
35	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32403 [KTS/B3 220.00] CKT 2
36	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32403 [KTS/B3 220.00] CKT 3

CONTINGENCY REFERENCES - CONTINUED	
LABEL	EVENTS
37	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32480 [MLTS 220.00]
38	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32480 [MLTS 220.00] CKT 2
39	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32600 [PTH 220.00]
40	OPEN BRANCH FROM BUS 32260 [GTS 220.00] TO BUS 32600 [PTH 220.00] CKT 2
VIC-5.2	OPEN BRANCH FROM BUS 32280 [HOTS 220.00] TO BUS 32620 [RCTS 220.00]
41	OPEN BRANCH FROM BUS 32300 [HTS 220.00] TO BUS 32740 [SVTS 220.00]
42	OPEN BRANCH FROM BUS 32300 [HTS 220.00] TO BUS 32740 [SVTS 220.00] CKT 2
43	OPEN BRANCH FROM BUS 32311 [HWTS/T1 220.00] TO BUS 32322 [HWPS/B2 220.00]
44	OPEN BRANCH FROM BUS 32311 [HWTS/T1 220.00] TO BUS 39324 [HWTD/D4 220.00]
45	OPEN BRANCH FROM BUS 32312 [HWTS/T2 220.00] TO BUS 32321 [HWPS/B1 220.00]
46	OPEN BRANCH FROM BUS 32312 [HWTS/T2 220.00] TO BUS 39323 [HWTD/D3 220.00]
47	OPEN BRANCH FROM BUS 32313 [HWTS/T3 220.00] TO BUS 32323 [HWPS/B34220.00]
48	OPEN BRANCH FROM BUS 32313 [HWTS/T3 220.00] TO BUS 39322 [HWTD/D2 220.00]
49	OPEN BRANCH FROM BUS 32314 [HWTS/T4 220.00] TO BUS 32323 [HWPS/B34220.00]
50	OPEN BRANCH FROM BUS 32314 [HWTS/T4 220.00] TO BUS 39321 [HWTD/D1 220.00]
52	OPEN BRANCH FROM BUS 32321 [HWPS/B1 220.00] TO BUS 32360 [JLTS 220.00]
53	OPEN BRANCH FROM BUS 32322 [HWPS/B2 220.00] TO BUS 32641 [ROTS/B1 220.00]
55	OPEN BRANCH FROM BUS 32323 [HWPS/B34220.00] TO BUS 32360 [JLTS 220.00]
56	OPEN BRANCH FROM BUS 32323 [HWPS/B34220.00] TO BUS 32360 [JLTS 220.00] CKT 2
57	OPEN BRANCH FROM BUS 32323 [HWPS/B34220.00] TO BUS 32500 [MPS 220.00]
58	OPEN BRANCH FROM BUS 32325 [HWPS/B56220.00] TO BUS 32327 [HWTS T 220.00] CKT 2
59	OPEN BRANCH FROM BUS 32325 [HWPS/B56220.00] TO BUS 32641 [ROTS/B1 220.00]
60	OPEN BRANCH FROM BUS 32325 [HWPS/B56220.00] TO BUS 32641 [ROTS/B1 220.00] CKT 2
61	OPEN BRANCH FROM BUS 32325 [HWPS/B56220.00] TO BUS 32940 [YPS 220.00]
62	OPEN BRANCH FROM BUS 32327 [HWTS T 220.00] TO BUS 32940 [YPS 220.00] CKT 2
VIC-5.4	OPEN BRANCH FROM BUS 32380 [KGTS 220.00] TO BUS 32620 [RCTS 220.00]
66	OPEN BRANCH FROM BUS 32401 [KTS/B1 220.00] TO BUS 32403 [KTS/B3 220.00]
67	OPEN BRANCH FROM BUS 32401 [KTS/B1 220.00] TO BUS 39401 [KTS/D1 220.00]
68	OPEN BRANCH FROM BUS 32402 [KTS/B2 220.00] TO BUS 32842 [TTS/B2 220.00]
69	OPEN BRANCH FROM BUS 32402 [KTS/B2 220.00] TO BUS 32843 [TTS/B3 220.00]
70	OPEN BRANCH FROM BUS 32402 [KTS/B2 220.00] TO BUS 32880 [WMTS 220.00]
71	OPEN BRANCH FROM BUS 32402 [KTS/B2 220.00] TO BUS 32880 [WMTS 220.00] CKT 2
72	OPEN BRANCH FROM BUS 32402 [KTS/B2 220.00] TO BUS 39402 [KTS/D2 220.00] CKT 2
73	OPEN BRANCH FROM BUS 32403 [KTS/B3 220.00] TO BUS 39403 [KTS/D3 220.00]
76	OPEN BRANCH FROM BUS 32460 [MBTS 220.00] TO BUS 39460 [MBTS/D 220.00]
77	OPEN BRANCH FROM BUS 32480 [MLTS 220.00] TO BUS 32800 [TGTS 220.00]
78	OPEN BRANCH FROM BUS 32480 [MLTS 220.00] TO BUS 39481 [MLTS/D 220.00]
79	OPEN BRANCH FROM BUS 32500 [MPS 220.00] TO BUS 32503 [MWTS 220.00]
80	OPEN BRANCH FROM BUS 32520 [MTS 220.00] TO BUS 32642 [ROTS/B2 220.00]
81	OPEN BRANCH FROM BUS 32520 [MTS 220.00] TO BUS 32642 [ROTS/B2 220.00] CKT 2
83	OPEN BRANCH FROM BUS 32641 [ROTS/B1 220.00] TO BUS 32660 [RTS 220.00]
84	OPEN BRANCH FROM BUS 32641 [ROTS/B1 220.00] TO BUS 32660 [RTS 220.00] CKT 2
85	OPEN BRANCH FROM BUS 32641 [ROTS/B1 220.00] TO BUS 32841 [TTS/B1 220.00]
86	OPEN BRANCH FROM BUS 32641 [ROTS/B1 220.00] TO BUS 32940 [YPS 220.00]
87	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32643 [ROTS/A1 220.00]
88	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32680 [RWTS 220.00]
89	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32740 [SVTS 220.00]
90	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32740 [SVTS 220.00] CKT 2

CONTINGENCY REFERENCES - CONTINUED	
LABEL	EVENTS
91	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32820 [TSTS 220.00]
92	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32940 [YPS 220.00] CKT 2
93	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32940 [YPS 220.00] CKT 3
94	OPEN BRANCH FROM BUS 32642 [ROTS/B2 220.00] TO BUS 32940 [YPS 220.00] CKT 4
95	OPEN BRANCH FROM BUS 32643 [ROTS/A1 220.00] TO BUS 39641 [ROTS/D 220.00]
96	OPEN BRANCH FROM BUS 32680 [RWTS 220.00] TO BUS 32841 [TTS/B1 220.00]
97	OPEN BRANCH FROM BUS 32721 [SMTS/B1 220.00] TO BUS 32843 [TTS/B3 220.00]
98	OPEN BRANCH FROM BUS 32721 [SMTS/B1 220.00] TO BUS 39720 [SMTS/D1 220.00]
99	OPEN BRANCH FROM BUS 32722 [SMTS/B2 220.00] TO BUS 32841 [TTS/B1 220.00]
100	OPEN BRANCH FROM BUS 32722 [SMTS/B2 220.00] TO BUS 39721 [SMTS/D2 220.00]
101	OPEN BRANCH FROM BUS 32820 [TSTS 220.00] TO BUS 32841 [TTS/B1 220.00]
102	OPEN BRANCH FROM BUS 32842 [TTS/B2 220.00] TO BUS 39842 [TTS/D2 220.00]
103	OPEN BRANCH FROM BUS 33180 [DDTS 330.00] TO BUS 33181 [DDTS/D 330.00]
104	OPEN BRANCH FROM BUS 33180 [DDTS 330.00] TO BUS 33900 [WOTS 330.00]
105	OPEN BRANCH FROM BUS 33180 [DDTS 330.00] TO BUS 39181 [DDTS/D1 330.00]
106	OPEN BRANCH FROM BUS 33180 [DDTS 330.00] TO BUS 39182 [DDTS/D2 330.00] CKT 2
107	OPEN BRANCH FROM BUS 33180 [DDTS 330.00] TO BUS 39183 [DDTS/D3 330.00] CKT 3
109	OPEN BRANCH FROM BUS 33181 [DDTS/D 330.00] TO BUS 33721 [SMTS/SC1330.00]
110	OPEN BRANCH FROM BUS 33181 [DDTS/D 330.00] TO BUS 33722 [SMTS/SC2330.00] CKT 2
111	OPEN BRANCH FROM BUS 33720 [SMTS 330.00] TO BUS 33721 [SMTS/SC1330.00]
112	OPEN BRANCH FROM BUS 33720 [SMTS 330.00] TO BUS 33722 [SMTS/SC2330.00]
113	OPEN BRANCH FROM BUS 33720 [SMTS 330.00] TO BUS 39722 [SMTS/D3 330.00]
114	OPEN BRANCH FROM BUS 34341 [HYTS/T1 275.00] TO BUS 34343 [HYTS/T3 275.00]
115	OPEN BRANCH FROM BUS 34341 [HYTS/T1 275.00] TO BUS 39341 [HYTS/D1 275.00]
116	OPEN BRANCH FROM BUS 34341 [HYTS/T1 275.00] TO BUS 53900 [SEAS 275.00]
117	OPEN BRANCH FROM BUS 34342 [HYTS/T2 275.00] TO BUS 34343 [HYTS/T3 275.00]
118	OPEN BRANCH FROM BUS 34342 [HYTS/T2 275.00] TO BUS 39342 [HYTS/D2 275.00]
119	OPEN BRANCH FROM BUS 34342 [HYTS/T2 275.00] TO BUS 53900 [SEAS 275.00]
120	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35440 [LYPS 500.00]
136	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35440 [LYPS 500.00] CKT 2
121	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35440 [LYPS 500.00] CKT 3
3.1	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35640 [ROTS500 500.00] CKT 4
3.3	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35720 [SMTS 500.00]
122	OPEN BRANCH FROM BUS 35310 [HWTS 500.00] TO BUS 35720 [SMTS 500.00] CKT 2
123	OPEN BRANCH FROM BUS 35341 [HYTS/B1 500.00] TO BUS 35480 [MLTS 500.00]
124	OPEN BRANCH FROM BUS 35341 [HYTS/B1 500.00] TO BUS 35580 [APD 500.00]
125	OPEN BRANCH FROM BUS 35342 [HYTS/B2 500.00] TO BUS 35480 [MLTS 500.00] CKT 2
126	OPEN BRANCH FROM BUS 35342 [HYTS/B2 500.00] TO BUS 35580 [APD 500.00] CKT 2
127	OPEN BRANCH FROM BUS 35400 [KTS 500.00] TO BUS 35720 [SMTS 500.00]
128	OPEN BRANCH FROM BUS 35400 [KTS 500.00] TO BUS 35760 [SYTS 500.00]
129	OPEN BRANCH FROM BUS 35480 [MLTS 500.00] TO BUS 35760 [SYTS 500.00]
130	OPEN BRANCH FROM BUS 35480 [MLTS 500.00] TO BUS 35760 [SYTS 500.00] CKT 2
131	OPEN BRANCH FROM BUS 35580 [APD 500.00] TO BUS 39581 [APD/D1 500.00]
133	OPEN BRANCH FROM BUS 35580 [APD 500.00] TO BUS 39583 [APD/D3 500.00] CKT 3
3.2	OPEN BRANCH FROM BUS 35640 [ROTS500 500.00] TO BUS 35720 [SMTS 500.00] CKT 3
134	OPEN BRANCH FROM BUS 35720 [SMTS 500.00] TO BUS 35760 [SYTS 500.00]
135	OPEN BRANCH FROM BUS 35720 [SMTS 500.00] TO BUS 35760 [SYTS 500.00] CKT 2
NSW-4.2	OPEN BRANCH FROM BUS 20080 [BURO220A220.00] TO BUS 20082 [BLND220A220.00]
NSW-4.3	OPEN BRANCH FROM BUS 20082 [BLND220A220.00] TO BUS 20079 [DLPT220A220.00]
NSW-4.5	OPEN BRANCH FROM BUS 20014 [WAGG330A330.00] TO BUS 20003 [LTSS330A330.00]

Appendix

B

Tables from Section 2

TABLE 2.4 (a) - ACCC CONTINGENCY THERMAL FAILURES WITH ZERO DISPATCH

MONITORED ELEMENT		CONTINGENCY	RATE	FLOW	%
30449*DUMGEN 20	35440 LYPS 500	BASE CASE	300	518.7	172.9
32010*ATS 220	39010 ATS/D1 66	BASE CASE	171	201.9	118
32100*BLTS 220	39107 BLTS/D8 66.0	BASE CASE	159	234.2	147.3
32680*RWTS 220	39680 RWTS/D1 22	BASE CASE	57	79.1	138.8
32841*TTS/B1 220	39841 TTS/D1 66	BASE CASE	173	259.8	150.2
36100 BLTS 66	39107*BLTS/D8 66.0	BASE CASE	159	203.4	127.9
36160*CLPS 66	36460 MBTS 66	BASE CASE	20	22.6	112.8
36200ERTS 66	39202*ERTS/D3 66.0	BASE CASE	150	171.3	114.2
36680*RWTS 66	39682 RWTS/D3 22	BASE CASE	41	42.5	103.6
36841*TTS/B12 66.0	39841 TTS/D1 66	BASE CASE	173	214.2	123.8
37680 RWTS 22	39680*RWTS/D1 22	BASE CASE	57	73.9	129.6
		VIC-5.8			
		VIC-5.8			
		VIC-5.8			
		VIC-5.1			
		VIC-5.1			
		VIC-5.5			
		VIC-5.3			
		VIC-5.3			
		VIC-5.6			
		VIC-5.6			
		VIC-5.6			
32200*ERTS 220	32641 ROTS/B1 220	22	686	816	119.8
32200*ERTS 220	32641 ROTS/B1 220	23	686	816	119.8
		24			
36780*TBTS 66.0	39782 TBTS/D2 66.0	24	225	233.9	114.3
36780*TBTS 66.0	39781 TBTS/D1 66.0	25	225	233.9	114.4
		25			
32300*HTS 220	32740 SVTS 220	41	381	379.1	102.3
32300*HTS 220	32740 SVTS 220	42	381	379.1	102.3
32120 BTS 220	32660*RTS 220	53	450	454	102.9
36160 CLPS 66.0	36460*MBTS 66.0	76	40	21.4	130.3
36241 WN 66 66.0	36462*MYT 66 66.0	76	49.2	34.3	140.1
32120 BTS 220	32660*RTS 220	87	450	520.7	117.6
32722*SMTS/B2 220	32841 TTS/B1 220	87	746.4	786.8	111.7
32722 SMTS/B2 220	39721*SMTS/D2 220	87	700	801.5	119.1
32842*TTS/B2 220	39842 TTS/D2 220	87	206	211.1	103.2
		87			
32120 BTS 220	32660*RTS 220	95	450	520.7	117.6
32722*SMTS/B2 220	32841 TTS/B1 220	95	746.4	786.8	111.7
32722*SMTS/B2 220	39721 SMTS/D2 220	95	700	786.8	119.1
32842 TTS/B2 220	39842*TTS/D2 220	95	206	205.2	103.2
		95			
		99			
		99			
		100			
		100			
		123			
35342*HYTS/B2 500	35580 APD 500	123	693	854.7	133.7
35342*HYTS/B2 500	35580 APD 500	124	693	716.5	101.9
		125			
35341*HYTS/B1 500	35580 APD 500	125	693	854.7	133.7
35341*HYTS/B1 500	35580 APD 500	126	693	716.5	101.9
		133			
35580*APD 500	39581 APD/D1 500	133	500	716.4	142.6
		3.2			
		NSW -4.3			
		NSW -4.3			
		NSW -4.3			
		NSW -4.3			
22359*YASSTX1^ 330	23100 YASS132A 132	NSW-4.5	165	194.8	118.1
22360*YASSTX2^ 330	23100 YASS132A 132	NSW-4.5	165	194.8	118.1
		NSW-4.5			
		NSW-4.5			

TABLE 2.4 (b) - ACCC CONTINGENCY THERMAL FAILURES WITH 180 MW DISPATCH

MONITORED ELEMENT		CONTINGENCY	RATE	FLOW	%
30449* DUMGEN 20	35440 LYPS 500	BASE CASE	300	520.3	173.4
32010*ATS 220	39010 ATS/D1 66	BASE CASE	171	187.6	109.7
32100*BLTS 220	39107 BLTS/D8 66.0	BASE CASE	159	244.9	154
32680*RWTS 220	39680 RWTS/D1 22	BASE CASE	57	80.5	141.1
32841*TTS/B1 220	39841 TTWS/DD1 66	BASE CASE	173	260.6	150.6
36100*BLTS 66.0	39107 BLTS/D8 66.0	BASE CASE	159	211	132.7
36160* CLPS 66	36460 MBTS 66	BASE CASE	20	22.6	112.8
36200*ERTS 66.0	39202 ERTS/D3 66.0	BASE CASE	150	171.3	114.2
		BASE CASE			
36841*TTS/B12 66.0	39841 TTS/D1 66.0	BASE CASE	173	214.9	124.2
37680*RWTS 22	39680 RWTS/D1 22	BASE CASE	57	75.1	131.7
32080 BETS 220	32700*SHTS 220	VIC-5.8	352	349.9	100.2
32260 GTS 220	32403*KTS/B3 220	VIC-5.8	325.2	333.7	102.4
32260 GTS 220	32403*KTS/B3 220	VIC-5.8	325.2	333.9	102.5
20079*DLPT220A 220	20082 BLND220A 220	VIC-5.1	296	298.4	101.8
36041*BAN 66 66.0	36042 ART 66 66.0	VIC-5.1	26.3	37.5	141.9
32040 BATS 220	32480*MLTS 220	VIC-5.5	312	321.5	101.9
20079*DLPT220A 220	20082 BLND220A 220	VIC-5.3	296	311.1	107.5
20080 BURO220A 220	20082*BLND220A 220	VIC-5.3	296	290.3	103.9
20079*DLPT220A 220	20082 BLND220 A 220	VIC-5.6	296	296.7	100.3
32040*BATS 220	32080 BETS 220	VIC-5.6	270	278.5	106
32040 BATS 220	32480*MLTS 220	VIC-5.6	312	339.2	109.5
32200*ERTS 220	32641 ROTS/B1 220	22	686	816	119.8
32200*ERTS 220	32641 ROTS/B1 220	23	686	816	119.8
		24			
36780 TBTS 66.0	39782*TBTS/D2 66.0	24	225	235.1	114.3
36780 TBTS 66.0	39781*TBTS/D1 66.0	25	225	234.9	114.4
		25			
32300*HTS 220	32740 SVTS 220	41	381	379.2	102.5
32300*HTS 220	32740 SVTS 220	42	381	379.2	102.5
32120 BTS 220	32660*RTS 220	53	450	444.8	100.9
36160 CLPS 66.0	36460*MBTS 66.0	76	40	21.4	131.6
36241 WN 66 66.0	36462*MYT 66 66.0	76	49.2	34.5	140.9
32120 BTS 220	32660*RTS 220	87	450	511.9	115.6
32722*SMTS/B2 220	32841 TTS/B1 220	87	746.4	783.6	111.1
32722*SMTS/B2 220	39721 SMTS/D2 220	87	700	783.6	118.5
32842*TTS/B2 220	39842 TTS/D2 220	87	206	210.7	102.9
		87			
32120 BTS 220	32660*RTS 220	95	450	511.9	115.6
32722*SMTS/B2 220	32841 TTS/B1 220	95	746.4	783.6	111.1
32722*SMTS/B2 220	39721 SMTS/D2 220	95	700	783.6	118.5
32842*TTS/B2 220	39842 TTS/D2 220	95	206	210.7	102.9
		95			
32643*ROTS/A1 220	39641 ROTS/D 220	99	1000	1031	103.2
		99			
32643*ROTS/A1 220	39641 ROTS/D 220	100	1000	1031	103.2
		100			
		123			
35342*HYTS/B2 500	35580 APD 500	123	693	858.6	138.6
35342*HYTS/B2 500	35580 APD 500	124	693	716.7	102.6
35341*HYTS/B1 500	35580 APD 500	125	693	858.6	138.6
35341*HYTS/B1 500	35580 APD 500	126	693	716.7	102.6
		133			
35580 APD 500	39581*APD/D1 500	133	500	669.6	143.9
		3.2			
32040*BATS 220	32480 MLTS 220	NSW -4.3	312	305.2	103.9
32080*BETS 220	32380 KGTS 220	NSW -4.3	312	291.2	102.8
32080 BETS 220	32700*SHTS 220	NSW -4.3	352	367.4	110.6
32380*KGTS 220	32620 RCTS 220	NSW -4.3	194	219.4	117
22359*YASSTX1^ 330	23100 YASS132A 132	NSW -4.5	165	198.5	120.3
22360*YASSTX2^ 330	23100 YASS132A 132	NSW -4.5	165	198.5	120.3
36841*TTS/B12 66.0	39841 TTS/D1 66.0	NSW -4.5	206	223.7	105.8
		NSW -4.5			

Did not converge without additional capacitors

TABLE 2.4 (C) -- ACCC CONTINGENCY THERMAL FAILURES WITH 220 MW DISPATCH

MONITORED ELEMENT	CONTINGENCY	RATE	FLOW	%	DELTA 180	DELTA 220
30449*DUMGEN 20 35440 LYPS 500	BASE CASE	300	520.1	173.4	0.5	0.5
32010* ATS 220 39010 ATS/D1 66	BASE CASE	171	185.2	108.3	-8.3	-9.7
32100*BLTS 220 39107 BLTS/D8 66.0	BASE CASE	159	250.2	157.4	6.7	10.1
32620 RCTS 220 32621* RCLFVCS 165	BASE CASE	265	275.5	104		
32680*RWTS 220 39680 RWTS/D1 22.0	BASE CASE	57	80.5	141.2	2.3	2.4
32841*TTS/B1 220 39841 TTS/D1 66.0	BASE CASE	173	261.3	151	0.4	0.8
36100*BLTS 66.0 39107 BLTS/D8 66.0	BASE CASE	159	214	134.6	4.8	6.7
36160* CLPS 66 36460 MBTS 66	BASE CASE	20	22.5	112.7	0	-0.1
36200*ERTS 66.0 39202 ERTS/D3 66.0	BASE CASE	150	171.1	114.1	0	-0.1
36841*TTS/B12 66.0 39841 TTS/D1 66.0	BASE CASE	173	215.4	124.5	0.4	0.7
37680*RWTS 22.0 39680 RWTS/D1 22.0	BASE CASE	57	75.1	131.8	2.1	2.2
	VIC-5.8					
	VIC-5.8					
	VIC-5.8					
	VIC-5.1					
	VIC-5.1					
32040 BATS 220 32480*MLTS 220	VIC-5.5	312	346.9	110.5	> 2.	> 10
	VIC-5.3					
	VIC-5.3					
	VIC-5.6					
	VIC-5.6					
	VIC-5.6					
32200*ERTS 220 32641 ROTS/B1 220	22	686	815.9	119.7	0	-0.1
32200*ERTS 220 32641 ROTS/B1 220	23	686	815.9	119.7	0	-0.1
32782*TBTS/B2 220 39782 TBTS/D2 66.0	24	225	259.4	115.3		
36780*TBTS 66.0 39782 TBTS/D2 66.0	24	225	233.9	114.4	0	0.1
32781*TBTS/B1 220 39781 TBTS/D1 66.0	25	225	259.6	115.4	0	1
36780*TBTS 66.0 39781 TBTS/D1 66.0	25	225	233.9	114.4		
32300*HTS 220 32740 SVTS 220	41	381	379.5	102.6	0.2	0.3
32300*HTS 220 32740 SVTS 220	42	381	379.5	102.6	0.2	0.3
	53					
36160 CLPS 66.0 36460*MBTS 66.0	76	40	21.4	130	1.3	-0.3
36241 WN 66 66.0 36462*MYT 66 66.0	76	49.2	34	139.1	0.8	-1
32120 BTS 220 32660*RTS 220	87	450	509.4	115.1	-2	-2.5
32722*SMTS/B2 220 32841 TTS/B1 220	87	746.4	784	111.1	-0.6	-0.6
32722*SMTS/B2 220 39721 SMTS/D2 220	87	700	784	118.4	-0.6	-0.7
32842*TTS/B2 220 39842 TTS/D2 220	87	206	210.4	102.7	-0.3	-0.5
33720 SMTS 330 39721*SMTS/D2 220	87	700	799.2	114.2		
32120 BTS 220 32660*RTS 220	95	450	509.4	115.1	-2	-2.5
32722*SMTS/B2 220 32841 TTS/B1 220	95	746.4	784	111.1	-0.6	-0.6
32722*SMTS/B2 220 39721 SMTS/D2 220	95	700	784	118.4	-0.6	-0.7
32842*TTS/B2 220 39842 TTS/D2 220	95	206	210.4	102.7	-0.3	-0.5
33720 SMTS 330 39721*SMTS/D2 220	95	700	799.2	114.2		
32643*ROTS/A1 220 39641 ROTS/D 220	99	1000	1032.9	103.4		
35640*ROTS500 500 39641 ROTS/D 220	99	1000	1073.3	107.3		
32643*ROTS/A1 220 39641 ROTS/D 220	100	1000	1032.9	103.4		
35640*ROTS500 500 39641 ROTS/D 220	100	1000	1073.2	107.3		
30820*TSTS/SC122.0 36821 TSTS/B1 66.0	123	111	125	112.6		
35342*HYTS/B2 500 35580 APD 500	123	693	873.7	152.2	4.9	18.5
35342*HYTS/B2 500 35580 APD 500	124	693	716.8	102.9	0.7	1
30820*TSTS/SC122.0 36821 TSTS/B1 66.0	125	111	125	112.6		
35341*HYTS/B1 500 35580 APD 500	125	693	873.7	152.2	4.9	18.5
35341*HYTS/B1 500 35580 APD 500	126	693	716.8	102.9	0.7	1
32580 APD 220 39581*APD/D1 500	133	500	669.6	133.9		
35580 APD 500 39581*APD/D1 500	133	500	669.6	144.4	1.3	1.8
35640*ROTS500 500 39641 ROTS/D 220	3.2	1000	1030.8	103.1		
	NSW-4.3					
	NSW-4.3					
	NSW-4.3					
	NSW-4.3					
22359*YASSTX1^ 330 23100 YASS132A 132	NSW-4.5	165	199.1	120.7	2.2	
22360*YASSTX2^ 330 23100 YASS132A 132	NSW-4.5	165	199.1	120.7	2.2	
	NSW-4.5					
32860 WKPS 220 38860*WKPS/T1 11.5	NSW-4.5	66	68	103.1		

	Did not converge
	Failed to pass Voltage Criteria

TABLE 2.5 - VOLTAGE VIOLATIONS FOR ZERO AND 220 MW MURAYLINK DISPATCHES

CONTINGENCY	BUS	V-CONT	V-INIT	V-MIN	CONTINGENCY	BUS	V-CONT	V-INIT	V-MIN
RANGE 24/25	32351 JLA/B1 220	0.8125	0.9796	0.9	RANGE 24/25	32351 JLA/B1 220	0.812	0.9796	0.9
RANGE 24/25	32781 TBTS/B1 220	0.8132	0.9802	0.9	RANGE 24/25	32781 TBTS/B1 220	0.8127	0.9801	0.9
DEVIATION 24/25	32351 JLA/B1 220	0.8125	0.9796	0.1	DEVIATION 24/25	32351 JLA/B1 220	0.812	0.9796	0.1
DEVIATION 24/25	32781 TBTS/B1 220	0.8132	0.9802	0.1	DEVIATION 24/25	32781 TBTS/B1 220	0.8127	0.9801	0.1
DEVIATION 24/25	36780 TBTS 66.0	0.9097	1.0363	0.1	DEVIATION 24/25	36780 TBTS 66.0	0.909	1.0359	0.1
DEVIATION 24/25	39781 TBTS/D1 66.0	0.9081	1.0371	0.1	DEVIATION 24/25	39781 TBTS/D1 66.0	0.9074	1.0367	0.1
DEVIATION 24/25	39782 TBTS/D2 66.0	0.9144	1.0372	0.1	DEVIATION 24/25	39782 TBTS/D2 66.0	0.9137	1.0369	0.1
RANGE 76	30161 CLPS/G 11.0	0.4696	0.9695	0.9	RANGE 76	30161 CLPS/G 11.0	0.4705	0.9695	0.9
RANGE 76	36160 CLPS 66.0	0.4401	1.0471	0.9	RANGE 76	36160 CLPS 66.0	0.4411	1.0451	0.9
RANGE 76	36241 WN 66 66.0	0.8552	0.9859	0.9	RANGE 76	36241 WN 66 66.0	0.8518	0.984	0.9
RANGE 76	36460 MBTS 66.0	0.4112	1.0379	0.9	RANGE 76	36460 MBTS 66.0	0.4122	1.0354	0.9
RANGE 76	36461 BRT 66 66.0	0.3981	0.9889	0.9	RANGE 76	36461 BRT 66 66.0	0.3988	0.9861	0.9
RANGE 76	36462 MYT 66 66.0	0.4972	0.9555	0.9	RANGE 76	36462 MYT 66 66.0	0.4966	0.9526	0.9
RANGE 76	36468 TEE 66 66.0	0.3989	0.9894	0.9	RANGE 76	36468 TEE 66 66.0	0.3996	0.9866	0.9
RANGE 76	39460 MBTS/D 220	0.3892	0.9809	0.9	RANGE 76	39460 MBTS/D 220	0.3901	0.9788	0.9
DEVIATION 76	30161 CLPS/G 11.0	0.4696	0.9695	0.1	DEVIATION 76	30161 CLPS/G 11.0	0.4705	0.9695	0.1
DEVIATION 76	36160 CLPS 66.0	0.4401	1.0471	0.1	DEVIATION 76	36160 CLPS 66.0	0.4411	1.0451	0.1
DEVIATION 76	36241 WN 66 66.0	0.8552	0.9859	0.1	DEVIATION 76	36241 WN 66 66.0	0.8518	0.984	0.1
DEVIATION 76	36460 MBTS 66.0	0.4112	1.0379	0.1	DEVIATION 76	36460 MBTS 66.0	0.4122	1.0354	0.1
DEVIATION 76	36461 BRT 66 66.0	0.3981	0.9889	0.1	DEVIATION 76	36461 BRT 66 66.0	0.3988	0.9861	0.1
DEVIATION 76	36462 MYT 66 66.0	0.4972	0.9555	0.1	DEVIATION 76	36462 MYT 66 66.0	0.4966	0.9526	0.1
DEVIATION 76	36468 TEE 66 66.0	0.3989	0.9894	0.1	DEVIATION 76	36468 TEE 66 66.0	0.3996	0.9866	0.1
DEVIATION 76	39460 MBTS/D 220	0.3892	0.9809	0.1	DEVIATION 76	39460 MBTS/D 220	0.3901	0.9788	0.1
RANGE 113	30100 BLTS/SC114.5	0.8853	0.9756	0.9					
DEVIATION 113									
RANGE 123/125	38581 APD/B1 33.0	0.8826	0.9962	0.9	RANGE 123/125	32580 APD 220	0.8179	1.0355	0.9
RANGE 123/125	38583 APD/B3 33.0	0.8826	0.9962	0.9	RANGE 123/125	34341 HYTS/T1 275	0.8825	1.0723	0.9
RANGE 123/125	39581 APD/D1 500	0.8826	0.9962	0.9	RANGE 123/125	34342 HYTS/T2 275	0.8825	1.0723	0.9
RANGE 123/125	39583 APD/D3 500	0.8826	0.9962	0.9	RANGE 123/125	34343 HYTS/T3 275	0.8825	1.0723	0.9
					RANGE 123/125	35341 HYTS/B1 500	0.821	1.019	0.9
					RANGE 123/125	35342 HYTS/B2 500	0.8284	1.019	0.9
					RANGE 123/125	35580 APD 500	0.8159	1.0118	0.9
					RANGE 123/125	36042 ART 66 66.0	0.8826	0.9648	0.9
					RANGE 123/125	36281 STL 66 66.0	0.8992	0.9769	0.9
					RANGE 123/125	38581 APD/B1 33.0	0.78	0.9864	0.9
					RANGE 123/125	38582 APD/B2 33.0	0.8159	1.0118	0.9
					RANGE 123/125	38583 APD/B3 33.0	0.78	0.9864	0.9
					RANGE 123/125	39341 HYTS/D1 275	0.8846	1.0735	0.9
					RANGE 123/125	39342 HYTS/D2 275	0.8843	1.0735	0.9
					RANGE 123/125	39581 APD/D1 500	0.78	0.9864	0.9
					RANGE 123/125	39582 APD/D2 500	0.8159	1.0118	0.9
					RANGE 123/125	39583 APD/D3 500	0.78	0.9864	0.9
DEVIATION 123/125	32580 APD 220	0.9187	1.0375	0.1	DEVIATION 123/125	32580 APD 220	0.8179	1.0355	0.1
DEVIATION 123/125	35341 HYTS/B1 500	0.918	1.0283	0.1	DEVIATION 123/125	34341 HYTS/T1 275	0.8825	1.0723	0.1
DEVIATION 123/125	35342 HYTS/B2 500	0.9225	1.0283	0.1	DEVIATION 123/125	34342 HYTS/T2 275	0.8825	1.0723	0.1
DEVIATION 123/125	35580 APD 500	0.9123	1.0212	0.1	DEVIATION 123/125	34343 HYTS/T3 275	0.8825	1.0723	0.1
DEVIATION 123/125	38581 APD/B1 33.0	0.8826	0.9962	0.1	DEVIATION 123/125	35341 HYTS/B1 500	0.821	1.019	0.1
DEVIATION 123/125	38582 APD/B2 33.0	0.9123	1.0212	0.1	DEVIATION 123/125	35342 HYTS/B2 500	0.8284	1.019	0.1
DEVIATION 123/125	38583 APD/B3 33.0	0.8826	0.9962	0.1	DEVIATION 123/125	35580 APD 500	0.8159	1.0118	0.1
DEVIATION 123/125	39581 APD/D1 500	0.8826	0.9962	0.1	DEVIATION 123/125	38581 APD/B1 33.0	0.78	0.9864	0.1
DEVIATION 123/125	39582 APD/D2 500	0.9123	1.0212	0.1	DEVIATION 123/125	38582 APD/B2 33.0	0.8159	1.0118	0.1
DEVIATION 123/125	39583 APD/D3 500	0.8826	0.9962	0.1	DEVIATION 123/125	38583 APD/B3 33.0	0.78	0.9864	0.1
					DEVIATION 123/125	39341 HYTS/D1 275	0.8846	1.0735	0.1
					DEVIATION 123/125	39342 HYTS/D2 275	0.8843	1.0735	0.1
					DEVIATION 123/125	39581 APD/D1 500	0.78	0.9864	0.1
					DEVIATION 123/125	39582 APD/D2 500	0.8159	1.0118	0.1
					DEVIATION 123/125	39583 APD/D3 500	0.78	0.9864	0.1
					RANGE NSW-4.5	26169 DENL132A 132	0.8937	0.9956	0.9
					DEVIATION NSW-4.5	26169 DENL132A 132	0.8937	0.9956	0.1
					DEVIATION NSW-4.5	26170 FNLY132A 132	0.9017	1.005	0.1

Appendix

C

Tables from Section 3

TABLE 3.2 - VIOLATIONS WITH ZERO DISPATCH ON MURRAYLINK

MONITORED ELEMENT							
FROM		TO		CONTY	RATE	FLOW	%
30161 CLPS/G	11	36160*CLPS	66	BASE	26	27.8	106.8
30211*EPS/G1	11	32210 EPS	220	BASE	67	69.2	103.4
30212*EPS/G2	11	32210 EPS	220	BASE	67	69.2	103.3
32010*ATS	220	39010 ATS/D1	66	BASE	193	251.7	130.4
32100*BLTS	220	39107 BLTS/D8	66	BASE	185	204.9	110.7
32680*RWTS	220	39680 RWTS/D1	22	BASE	70	77.9	111.3
32841*TTS/B1	220	39841 TTS/D1	66	BASE	206	253.3	123
36200 ERTS	66	39202*ERTS/D3	66	BASE	150	178.4	113.8
36841*TTS/B12	66	39841 TTS/D1	66	BASE	206	219.5	103.3
37680 RWTS	22	39680*RWTS/D1	22	BASE	70	75.8	105.3
				VIC-5.1			
32200*ERTS	220	32641 ROTS/B1	220	22	686	813.5	119.4
32200*ERTS	220	32641 ROTS/B1	220	23	686	813.5	119.4
32782*TBTS/B2	220	39782 TBTS/D2	66	24	225	259.8	115.5
				24			
32781*TBTS/B1	220	39781 TBTS/D1	66	25	225	260.1	115.6
				25			
32120 BTS	220	32660*RTS	220	53	450	460.5	104.3
32120 BTS	220	32660*RTS	220	87	450	529.4	119.6
32722*SMTS/B2	220	32841 TTS/B1	220	87	746.4	789.5	112.3
32722*SMTS/B2	220	39721 SMTS/D2	220	87	700	789.5	119.7
32842 TTS/B2	220	39842*TTS/D2	220	87	206	206.3	103.8
33720 SMTS	330	39721*SMTS/D2	220	87	700	804.2	114.9
32120 BTS	220	32660*RTS	220	95	450	529.4	119.6
32722*SMTS/B2	220	32841 TTS/B1	220	95	746.4	789.5	112.3
32722 SMTS/B2	220	39721*SMTS/D2	220	95	700	804.2	119.7
32842 TTS/B2	220	39842*TTS/D2	220	95	206	206.2	103.8
33720 SMTS	330	39721*SMTS/D2	220	95	700	804.2	114.9
32643*ROTS/A1	220	39641 ROTS/D	220	99	1000	1028.9	102.9
35640*ROTS500	500	39641 ROTS/D	220	99	1000	1076.2	107.6
32643*ROTS/A1	220	39641 ROTS/D	220	100	1000	1028.9	102.9
35640*ROTS500	500	39641 ROTS/D	220	100	1000	1076.1	107.6
				113			
30020*APS/G1	13.8	32020 APS	220	123	160	162	101.2
35342*HYTS/B2	500	35580 APD	500	123	693	854.5	133.5
35342*HYTS/B2	500	35580 APD	500	124	693	716.6	102.1
30020*APS/G1	13.8	32020 APS	220	125	160	162	101.2
35341*HYTS/B1	500	35580 APD	500	125	693	854.5	133.5
				126			
32580 APD	220	39581*APD/D1	500	133	500	669.6	133.9
35580*APD	500	39581 APD/D1	500	133	500	716.6	142.8
22359*YASSTX1	^ 330	23100 YASS132	A 132	NSW-4.5	165	198.8	120.5
22360*YASSTX2	^ 330	23100 YASS132	A 132	NSW-4.5	165	198.8	120.5

TABLE 3.3 - VIOLATIONS WITH 110 MW DISPATCH ON MURRAYLINK											
MONITORED ELEMENT											
FROM			TO			CONTY	RATE	FLOW	%	DIFF	
30161	CLPS/G	11	36160*	CLPS	66	BASE	26	27.8	106.7	-0.1	
30211*	EPS/G1	11	32210	EPS	220	BASE	67	69.8	104.2	0.8	
30212*	EPS/G2	11	32210	EPS	220	BASE	67	69.8	104.1	0.8	
32010*	ATS	220	39010	ATS/D1	66	BASE	193	251.8	130.5	0.1	
32100	BLTS	220	39107	BLTS/D8	66	BASE					
32680*	RWTS	220	39680	RWTS/D1	22	BASE	70	78	111.4	0.1	
32841*	TTS/B1	220	39841	TTS/D1	66	BASE	206	253.2	122.9	-0.1	
36200*	ERTS	66	39202	ERTS/D3	66	BASE	150	178	113.6	-0.2	
36841	TTS/B12	66	39841*	TTS/D1	66	BASE	206	220.3	103.3	0	
37680*	RWTS	22	39680	RWTS/D1	22	BASE	70	75.7	105.4	0.1	
36041*	BAN 66	66	36042	ART 66	66	VIC-5.1	26.3	29.5	111.3		
						22					
32200*	ERTS	220	32641	ROTS/B1	220	23	686	813.3	119.4	0	
32782*	TBTS/B2	220	39782	TBTS/D2	66	24	225	259.4	115.3	-0.2	
36780*	TBTS	66	39782	TBTS/D2	66	24	225	233.4	114.8		
32781*	TBTS/B1	220	39781	TBTS/D1	66	25	225	259.6	115.4	-0.2	
36780	TBTS	66	39781*	TBTS/D1	66	25	225	234.4	114.9		
						53					
32120	BTS	220	32660*	RTS	220	87	450	525.5	118.8	-0.8	
32722*	SMTS/B2	220	32841	TTS/B1	220	87	746.4	798.1	113.6	1.3	
32722*	SMTS/B2	220	39721	SMTS/D2	220	87	700	798.1	121.1	1.4	
32842*	TTS/B2	220	39842	TTS/D2	220	87	206	211.8	103.5	-0.3	
33720	SMTS	330	39721*	SMTS/D2	220	87	700	814.1	116.3	1.4	
32120	BTS	220	32660*	RTS	220	95	450	525.5	118.8	-0.8	
32722*	SMTS/B2	220	32841	TTS/B1	220	95	746.4	798.1	113.6	1.3	
32722*	SMTS/B2	220	39721	SMTS/D2	220	95	700	798.1	121.1	1.4	
32842*	TTS/B2	220	39842	TTS/D2	220	95	206	211.8	103.5	-0.3	
33720	SMTS	330	39721*	SMTS/D2	220	95	700	814.1	116.3	1.4	
32643	ROTS/A1	220	39641*	ROTS/D	220	99	1000	1024	102.5	-0.4	
35640*	ROTS500	500	39641	ROTS/D	220	99	1000	1068.7	106.9	-0.7	
						100					
35640*	ROTS500	500	39641	ROTS/D	220	100	1000	1068.6	106.9	-0.7	
32100*	BLTS	220	39107	BLTS/D8	66	113	185	195.2	105.5		
						123					
35342*	HYTS/B2	500	35580	APD	500	123	693	855.3	136.1	2.6	
35342*	HYTS/B2	500	35580	APD	500	124	693	716.7	102.6	0.5	
						125					
35341*	HYTS/B1	500	35580	APD	500	125	693	855.3	136.1	2.6	
35341*	HYTS/B1	500	35580	APD	500	126	693	716.7	102.6		
32580	APD	220	39581*	APD/D1	500	133	500	669.6	133.9	0	
35580*	APD	500	39581	APD/D1	500	133	500	717.6	143.9	1.1	
NOT CONVERGED						NSW-4.5 NSW-4.5					

TABLE 3.4 - VOLTAGE VIOLATIONS

ZERO FLOW ON MURRAYLINK

SYSTEM	FAILURE	CONTY	BUS			V-CONT	V-INIT
AREA 2	DEVIATION	NSW-4.4	22310	DLPTTX3^	220	0.975	1.0863
AREA 2	DEVIATION	NSW-4.4	22311	DLPTTX4^	220	0.975	1.0862
AREA 2	DEVIATION	NSW-4.4	26792	DLPT033A	33	0.975	1.0863
AREA 2	DEVIATION	NSW-4.4	26793	DLPT033B	33	0.975	1.0862
AREA 3	RANGE	24/25	32351	JLA/B1	220	0.8081	0.9795
AREA 3	RANGE	24/25	32781	TBTS/B1	220	0.8088	0.9801
AREA 3	RANGE	24/25	36780	TBTS	66	0.8998	1.0287
AREA 3	RANGE	24/25	39781	TBTS/D1	66	0.8982	1.0295
AREA 3	DEVIATION	24/25	32351	JLA/B1	220	0.8081	0.9795
AREA 3	DEVIATION	24/25	32781	TBTS/B1	220	0.8088	0.9801
AREA 3	DEVIATION	24/25	36780	TBTS	66	0.8998	1.0287
AREA 3	DEVIATION	24/25	39781	TBTS/D1	66	0.8982	1.0295
AREA 3	DEVIATION	24/25	39782	TBTS/D2	66	0.9047	1.0297
AREA 3	RANGE	85	30642	ROTS/SV2	10.5	0.898	0.9129
AREA 3	RANGE	123/125	38581	APD/B1	33	0.8838	0.994
AREA 3	RANGE	123/125	38583	APD/B3	33	0.8838	0.994
AREA 3	RANGE	123/125	39581	APD/D1	500	0.8838	0.994
AREA 3	RANGE	123/125	39583	APD/D3	500	0.8838	0.994
AREA 3	DEVIATION	123/125	32580	APD	220	0.92	1.0352
AREA 3	DEVIATION	123/125	35341	HYTS/B1	500	0.9192	1.0262
AREA 3	DEVIATION	123/125	35342	HYTS/B2	500	0.9236	1.0262
AREA 3	DEVIATION	123/125	35580	APD	500	0.9135	1.0191
AREA 3	DEVIATION	123/125	38581	APD/B1	33	0.8838	0.994
AREA 3	DEVIATION	123/125	38582	APD/B2	33	0.9135	1.0191
AREA 3	DEVIATION	123/125	38583	APD/B3	33	0.8838	0.994
AREA 3	DEVIATION	123/125	39581	APD/D1	500	0.8838	0.994
AREA 3	DEVIATION	123/125	39582	APD/D2	500	0.9135	1.0191
AREA 3	DEVIATION	123/125	39583	APD/D3	500	0.8838	0.994

110 MW FLOW ON MURRAYLINK

SYSTEM	CHECK	CONTY	BUS			V-CONT	V-INIT
AREA 2	RANGE	SNOVIC-2.1	26169	DENL132A	132	0.8834	1.0057
AREA 2	RANGE	SNOVIC-2.1	26170	FNLY132A	132	0.8948	1.0147
AREA 2	DEVIATION	SNOVIC-2.1	26169	DENL132A	132	0.8834	1.0057
AREA 2	DEVIATION	SNOVIC-2.1	26170	FNLY132A	132	0.8948	1.0147
FAILED TO CONVERGE							
AREA 3	RANGE	24/25	32351	JLA/B1	220	0.8096	0.9795
AREA 3	RANGE	24/25	32781	TBTS/B1	220	0.8103	0.9801
AREA 3	DEVIATION	24/25	32351	JLA/B1	220	0.8096	0.9795
AREA 3	DEVIATION	24/25	32781	TBTS/B1	220	0.8103	0.9801
AREA 3	DEVIATION	24/25	36780	TBTS 6	6	0.9033	1.0314
AREA 3	DEVIATION	24/25	39781	TBTS/D1 6	6	0.9016	1.0322
AREA 3	DEVIATION	24/25	39782	TBTS/D2 6	6	0.9081	1.0324
AREA 3	RANGE	85	30642	ROTS/SV21	0.5	0.8978	0.9154
AREA 3	RANGE	113	30100	BLTS/SC1	4.5	0.8914	0.9759
AREA 3	RANGE	123/125	35580	APD	500	0.8964	1.0142
AREA 3	RANGE	123/125	38581	APD/B1 3	3	0.8659	0.9889
AREA 3	RANGE	123/125	38582	APD/B2 3	3	0.8964	1.0142
AREA 3	RANGE	123/125	38583	APD/B3 3	3	0.8659	0.9889
AREA 3	RANGE	123/125	39581	APD/D1	500	0.8659	0.9889
AREA 3	RANGE	123/125	39582	APD/D2	500	0.8964	1.0142
AREA 3	RANGE	123/125	39583	APD/D3	500	0.8659	0.9889
AREA 3	DEVIATION	123/125	32580	APD	220	0.9082	1.0379
AREA 3	DEVIATION	123/125	34341	HYTS/T1	275	0.9724	1.0779
AREA 3	DEVIATION	123/125	34342	HYTS/T2	275	0.9724	1.0779
AREA 3	DEVIATION	123/125	34343	HYTS/T3	275	0.9724	1.0779
AREA 3	DEVIATION	123/125	35341	HYTS/B1	500	0.9022	1.0214
AREA 3	DEVIATION	123/125	35342	HYTS/B2	500	0.9068	1.0214
AREA 3	DEVIATION	123/125	35580	APD	500	0.8964	1.0142
AREA 3	DEVIATION	123/125	38581	APD/B1 3	3	0.8659	0.9889
AREA 3	DEVIATION	123/125	38582	APD/B2 3	3	0.8964	1.0142
AREA 3	DEVIATION	123/125	38583	APD/B3 3	3	0.8659	0.9889
AREA 3	DEVIATION	123/125	39341	HYTS/D1	275	0.9746	1.0791
AREA 3	DEVIATION	123/125	39342	HYTS/D2	275	0.9745	1.0791
AREA 3	DEVIATION	123/125	39581	APD/D1	500	0.8659	0.9889
AREA 3	DEVIATION	123/125	39582	APD/D2	500	0.8964	1.0142
AREA 3	DEVIATION	123/125	39583	APD/D3	500	0.8659	0.9889

Appendix
D

Incorporating the Findings of a Murraylink Load Flow Analysis in Prosym Transmission Limits

Background

Prosym is a chronological production cost model that simulates the operation of a multi-area generation and transmission system, reflecting the operation, maintenance and forced outage characteristics of generators, transmission interconnections between the areas, and the projected hourly loads of the areas. The topology of the multi-area system, including the limits on flows between areas is an important determinant of the simulated operation of the system.

Load flow analysis using summer peak conditions has been done to establish the likely operating limits of the Murraylink facility when exporting power from Victoria to South Australia. Murraylink provides the technical capability to flow 220 MW from Victoria to South Australia, or from South Australia to Victoria. However, under summer peak conditions when imports from Snowy to Victoria are at 1900 MW, the load flow analysis found that:

- When additional supply is available from generation sources in Victoria (referred to in the load-flow analysis as the “Victoria Swing-Bus Case”), Murraylink can safely operate at 180 MW with the installation of moderate amounts of voltage support at several locations in Victoria.

- With more substantial installations of voltage support in Victoria, the Murraylink limits could be raised to 220 MW.

- When additional supply is available in New South Wales, but not Victoria (referred to in the load flow analysis as the “New South Wales Swing-Bus Case”), Murraylink dispatch would be limited to 110 MW.

These results have been characterized as conservative, and are likely to apply only under the highly stressed conditions represented by the summer peak load flow.

Network Topology

The Australian National Electricity Market (NEM) is configured in five regions: Queensland, New South Wales, Snowy Mountains, Victoria, and South Australia. Each region represents a separate market with a separate market clearing price for each half hour dispatch period. The NEM topology, plus the addition of a sixth artificial region, “Riverland”, is illustrated in Figure 1 as it is incorporated into the Prosym modeling. Prosym, by default, is only capable of representing a single transmission link between any two regions. The Riverland region has been introduced as a modeling device to enable power transfers over the Heywood Interconnector and Murraylink to be separately observed. Riverland is modeled with no load and no generation, and the two links, SA-Riverland and Riverland-Victoria, together represent the Murraylink facility.

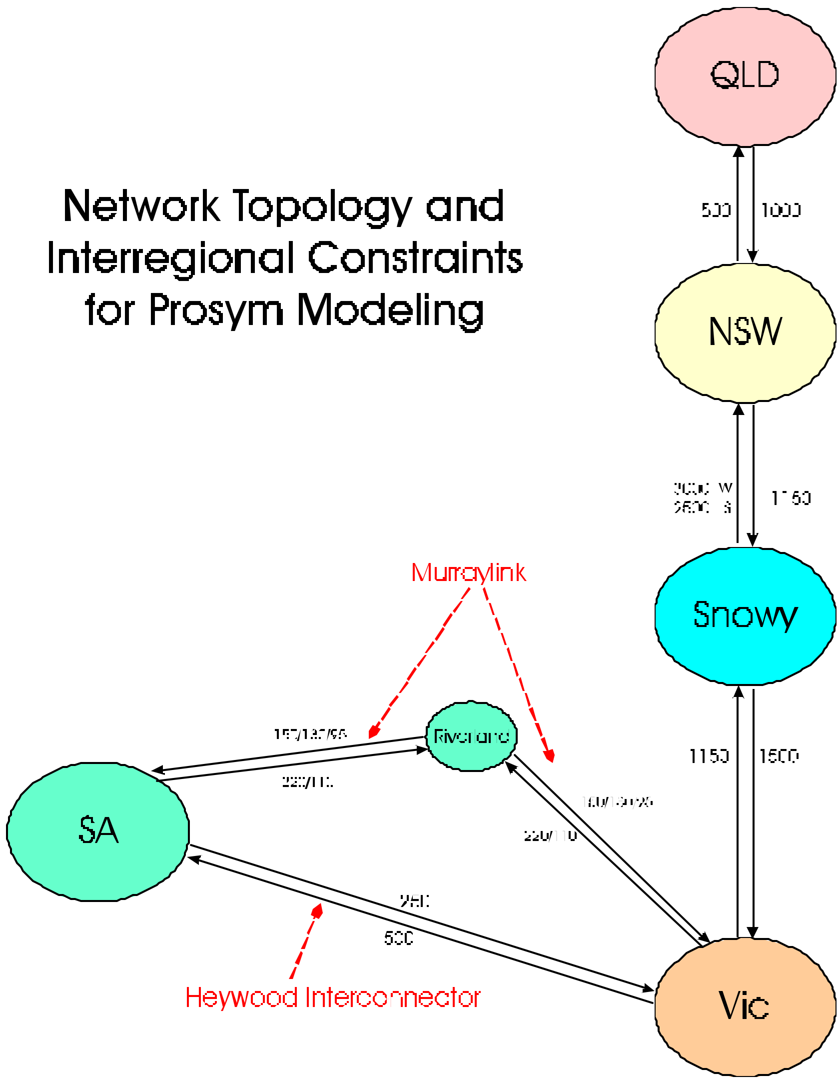

Figure 1

Modeling Interface Limits in Prosym

Interface limits between the five NEM regions have been determined in studies completed by or for the IOWG[4] as part of the recent evaluation of the proposed SNI interconnector, and are published on the NEMMCO[5] web site as Appendices to the IOWG "Report on Additional Interconnection Augmentation Scenarios for SNI and SNOVIC Economic Assessments, October 2001".

The Prosym model provides flexibility to model transmission limits that change cyclically over time (i.e. seasonally, by time of day, by day of week), but it does not provide a means of implementing dynamic constraints that change as a function of load or generation. The conservative Murraylink limits developed through the load flow analysis using summer peak stressed system conditions are appropriate for only a limited number of hours per year. At other times, Murraylink will be capable of operating at its full rated capacity of 220 MW.

[4] Interconnection Options Working Group
[5] National Electricity Market Management Company, Ltd., www.nemmco.com

The Prosym modeling is an hourly simulation of the ten year period 2003-2012 on a pre-contingent, or "all lines in" basis. Furthermore, we have assumed that additional voltage support and appropriate runback schemes will be implemented as necessary to support the maximum transfer levels identified in the load flow analysis. Transmission maintenance is assumed to be planned for periods when it would not have reliability impacts. Prosym does not provide a direct means of simulating transmission outages.

Murraylink Limits – Victoria to South Australia

As a proxy for dynamic limits that change with grid loading, we have reviewed three years of historical NEM operation, 1999-2001, to determine the number of past occurrences by month of "max flow" events, where flow from Snowy to Victoria came within 100 MW of the 1500 MW Snowy-Vic maximum flow limit. The historical data shows 134 half-hour dispatch intervals that approached "max flow" during 1999-2001, or 0.25% of the time.

Most occurrences happened during 3pm-6pm in February months, and 9am-10am plus 6pm-8pm in July and August months. These periods account for 62% of the total number of events.

This information has been modeled in Prosym by using the following Murraylink Victoria? South Australia limits:

February 3pm-6pm weekdays	110 MW
July & August 9am-10am weekdays	110 MW
July & August 6pm-8pm weekdays	110 MW
All Other Hours weekdays	220 MW

Together, the hours constrained to 110 MW account for approximately 2.2% of the hours in a year, nearly ten times the historical incidence of "max flow" events, and they include the periods most likely to have conditions that might lead to future "max flow" events. As such, they represent a reasonably conservative approach to simulating dynamic limits within Prosym.

Murraylink Limits – South Australia to Victoria

Different factors potentially constrain the operation of Murraylink when flowing power from South Australia to Victoria. Voltage support considerations are likely to limit flows to no more than 150 MW during most hours. This is reflected in Prosym as a absolute limit on South Australia? Victoria flow of 150 MW for any hour.

Thermal limitations from Robertstown to North West Bend will constrain Murraylink flows to 222 MW less the Riverland area load in the summer, and to 280 less Riverland load in the winter. Forecast hourly Riverland loads for 2012, the last year modeled, were used to calculate the appropriate hourly limits by hour-of-day for the summer (December-February) and hour-of-day for the winter (March-November) based on the maximum load forecast to occur during each hour of the day.

Summer hours were divided into two periods with appropriate limits for the maximum demand expected to be seen during the period:

10am-8pm	95 MW limit
8pm-10am	130 MW limit

Winter limits, based on the 280-Riverland load formula, always exceeded 150 MW, the limit attributable to voltage support requirements. Consequently, a limit of 150 MW was used for all winter hours.

We believe this seasonal time-of-day limit structure incorporates an appropriate degree of conservatism. It is based on expected loads in the final year of analysis, which are higher than the earlier years, and the limits for all summer hours are low enough to accommodate the highest forecast demand in any summer hour.

Appendix

E

Incorporating the Findings of a Murraylink Load Flow Analysis in MARS Regional Interface Limits

Background

GE-MARS is a Monte Carlo simulation model that evaluates the reliability performance of a multi-area transmission system, reflecting the operations, maintenance and forced outage characteristics of generators and the projected hourly loads of the several connected areas. The topology of the multi-area system, including the limits on flows between areas is an important determinant of the reliability performance of the system.

Load flow analysis using summer peak conditions has been done to establish the likely operating limits of the Murraylink facility when exporting power from Victoria to South Australia. Murraylink provides the technical capability to flow 220 MW from Victoria to South Australia, or from South Australia to Victoria. However, under summer peak conditions when imports from Snowy to Victoria are at 1900 MW, the load flow analysis found that:

When additional supply is available from generation sources in Victoria (referred to in the load-flow analysis as the "Victoria Swing-Bus Case"), Murraylink can safely operate at 180 MW with the installation of moderate amounts of voltage support at several locations in Victoria.

With more substantial installations of voltage support in Victoria, the Murraylink limits could be raised to 220 MW.

When additional supply is available in New South Wales, but not Victoria (referred to in the load-flow analysis as the "New South Wales Swing-Bus Case"), Murraylink dispatch would be limited to 110 MW.

These results have been characterized as conservative, and are likely to apply only under the highly stressed conditions represented by the summer peak load-flow.

Network Topology

The diagram in Figure 1 illustrates the network topology assumed in the MARS analysis. It is consistent with the five regions presently defined in the NEM, but incorporates additional detail by subdividing three of the regions into several subregions.

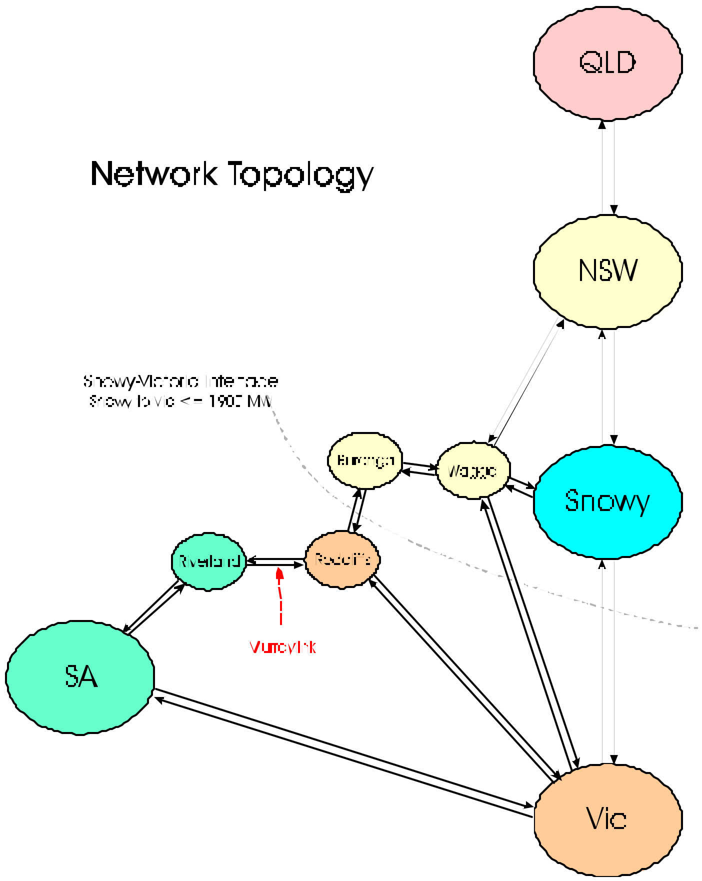

Figure 1.

Modeling Limits in MARS

Interface limits between the five NEM regions have been determined in studies completed by or for the IOWG[6] as part of the recent evaluation of the proposed SNI interconnector, and are published on the NEMMCO[7] web site as Appendices to the IOWG "Report on Additional Interconnection Augmentation Scenarios for SNI and SNOVIC Economic Assessments, October 2001". Limits on interfaces between subregions that do not correspond to published limits were developed using the thermal capacity of the links as represented in the summer peak load flow. Table 1 provides a summary of the limits used in the MARS analysis.

[6] Interconnection Options Working Group
[7] National Electricity Market Management Company, Ltd., www.nemmco.com

From	To	Positive Direction	Negative Direction
Queensland	New South Wales	1000	500
New South Wales	Wagga	300	300
New South Wales	Snowy	1150	2000
Wagga	Buronga	296	296
Wagga	Snowy	1050	1050
Wagga	Victoria	817	817
Buronga	Redcliffs	265	265
Snowy	Victoria	1500	1150
Victoria	Redcliffs	461	461
Victoria	South Australia	500	250
Redcliffs	Riverland	220	150
Riverland	South Australia	255	255

Table 1

The MARS model provides several capabilities that allow limits to be modeled with a dynamic or changing representation. These include, but are not limited to, a) creating composite limits that constraint the total simultaneous flow over several interfaces to be less than or equal to a specified value, b) allowing limits to change with time, (for example, seasonal limits, or limits that grow or decline year by year), c) tighter limits that apply when certain conditions are met, such as the unavailability of specific generators or area load in excess of a target level, and d) restricting exports from an area when insufficient resources are available within the area.

The MARS modeling is an hourly simulation of the ten year period 2003-2012 on a pre-contingent, or "all lines in" basis. Furthermore, we have assumed that additional voltage support and appropriate runback schemes will be implemented as necessary to support the maximum transfer levels identified in the load flow analysis. Transmission maintenance is assumed to be planned for periods when it would not have reliability impacts. With the exception of derates of the Heywood Interconnector between Victoria and South Australia for electrical storm activity, information on the frequency and duration of transmission outages is not available and is assumed to have a diminimus impact on Murraylink's contribution to total system reliability because of the low probability of an outage that would affect Murraylink's transfer capability happening during the few hours over the ten year period having conditions similar to those represented in the summer peak load flow analysis. During hours when Heywood is heavily loaded, Heywood outages will increase the reliability benefit of Murraylink by increasing the number of hours with area capacity shortfalls that Murraylink's capability can mitigate.

Murraylink Limits – Victoria to South Australia

Murraylink operating limits have been modeled using a combination of methods "a" and "d". The Victoria subregion is assigned highest reserve priority. This prevents power from being exported within the MARS simulation unless surplus capacity (generation plus imports) exists within the subregion. Additionally, a composite constraint is established that restricts the combined flows from Snowy? Vic, Wagga? Vic, and Buronga? Redcliffs to less than or equal to 1900 MW. This reflects the limits on the Snowy-Vic interface after completion of the committed SnoVic400 transmission upgrade project. In addition, a maximum limit of 220 MW over Murraylink from Victoria to South Australia is also imposed.

The simultaneous operation of these constraints within MARS will have the following effects:

- When conditions that would limit flows to 110 MW apply (no surplus generation in Victoria, Snowy imports at 1900 MW), MARS will effectively restrict Murraylink flow to 0 MW, since the only other source of power would be from South Australia via the Heywood connector. Such a flow would offset and cancel the reliability impact of

Murraylink flows into South Australia, and would be unnecessary if available capacity existed in South Australia.

- Every 1 MW reduction in Snowy imports will effectively create an additional 1 MW flow capability over Murraylink from Victoria to South Australia.

- Every MW of available generation in Victoria will create an additional MW of flow capability over Murraylink fro Victoria to South Australia.

These constraints are somewhat more conservative than the limits established by the load-flow analysis, in that they will result in effective limits of less than 110 MW under the conditions in which the load-flow analysis indicates a flow of 110 MW would be feasible without jeopardizing system reliability.

Murraylink Limits – South Australia to Victoria

Different factors potentially constrain the operation of Murraylink when flowing power from South Australia to Victoria. Voltage support considerations are likely to limit flows to no more than 150 MW during most hours. This is reflected in MARS as an absolute limit for all hours.

Thermal limitations from Robertstown to North West Bend will constrain Murraylink flows to 222 MW less the Riverland area load in the summer, and to 280 MW less Riverland load in the winter. This constraint is implemented in the MARS model using method "c" with a series of constraints based on 5 MW increments of Riverland load and the conservative summer Robertstown-NSW rating. At Riverland load below 70 MW, the 150 MW stability limit dominates. For loads greater than or equal to 70 MW, the Murraylink transfer limits are shown in Table 2 below.

Riverland Load MW	Murraylink Limit MW
10	150
75	147
85	137
95	127
105	117
115	107
120	102
125	97
130	92
135	87
140	82
145	77
150	72
155	67
160	62
165	57
170	52
175	47
180	42
185	37

Table 2

Over the ten year study horizon, maximum forecast Riverland load does not exceed 185 MW. In each simulated hour, MARS will examine the Riverland load and apply the appropriate limit. This approach is conservative, in that the summer formulation (222 – R.L.) is used year-round, and winter limits would result in higher values.

Appendix C: Letter - Deloitte Touche Tohmatsu – Commercial Discount Rate

16 October 2002

The Directors
Murraylink Transmission Partnership
Level 11
77 Eagle Street
Brisbane QLD 4000

Dear Sirs

REGULATORY TEST – MURRAYLINK DISCOUNT RATE

SCOPE AND BASIS OF REVIEW

Deloitte Touche Tohmatsu ("Deloitte") has been engaged by Murraylink Transmission Partnership ("MTP") to provide accounting and financial advice and support services to assist with the preparation of a regulatory application for the Murraylink transmission project ("Murraylink").

As part of this consultancy, MTP has requested Deloitte to perform certain agreed upon procedures as follows:

1. Develop an estimate of the base discount rate to be applied by MTP in performing the ACCC regulatory test as part of the process to obtain regulatory approval for Murraylink ("Regulatory Test Discount Rate").
2. Provide an estimate of a 'high' and a 'low' value of the Regulatory Test Discount Rate.

This letter reports our findings in relation to these agreed-upon procedures.

Declarations and restrictions

The scope of our work is limited to the matters set out above and governed by the terms set out in our Consultancy Agreement with TransÉnergie Australia Pty Limited dated 2 July 2002.

Our procedures and enquiries did not include verification work nor constitute an audit in accordance with Australian Auditing Standards ("AUS"), nor do they constitute a review in accordance with AUS 902 applicable to review engagements. Consequently, no assurance is expressed.

This report is for the sole use in accordance with the terms of reference established by you and as such cannot be relied upon or used for any other purpose without our express written permission. We accept no responsibility to any other person in relation to the contents of this report and no other person should rely upon any statement made in this report for any purpose.

Deloitte Touche Tohmatsu

Statements and opinions contained in this letter are given in good faith but, in the preparation of this letter, Deloitte has relied upon the information provided by MTP which Deloitte believes, on reasonable grounds, to be reliable, complete and not misleading. We have not corroborated the information received. Deloitte does not imply, nor should it be construed that it has carried out any form of audit or verification on the information and records supplied to us.

REGULATORY TEST DISCOUNT RATE

In determining an appropriate discount rate we referred to the ACCC's guidance, previous Regulatory Tests performed and cost of capital estimation practice.

The ACCC guidelines indicate that:

> *"the net present value calculation should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector"*[1]

The ACCC does not give any further guidance as to the method of estimating this 'discount rate' or whether the discount rate should be a weighted average cost of capital ("WACC") or equity return, on a pre-tax or post-tax basis, or in nominal or real terms.

The first guiding principle in selecting a discount rate is that the discount rate used should be consistent with the cash flows being discounted. For example if the cash flows are in real dollars (that is, not inflated) then the discount rate should be a real (as opposed to nominal) discount rate. As the market benefits being discounted are before debt and interest payments, exclude taxation impacts and are in real 1 May 2003 dollar terms, the discount rate that should be applied in calculating a net present value of the market benefits should be:

- a WACC
- pre-tax
- real.

The discount rate determined below is therefore a real, pre-tax WACC.

The second guiding source is previous applications of the Regulatory Test. There have been a limited number of previous applications of the Regulatory Test, as follows:

- South Australia – New South Wales Interconnector ("SNI")
- Upgrade of the Snowy to Victoria Transmission Capacity ("SNOVIC"), analysis undertaken by VENCorp
- Upgrade of the Snowy to Victoria Transmission Capacity, analysis undertaken by the Inter Regional Planning Committee
- Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity, analysis undertaken by VENCorp
- Upgrade of the Heywood interconnector between Victoria and South Australia, analysis undertaken by ElectraNet SA.

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[1] Page 21, ACCC "Regulatory Test for New Interconnectors and Network Augmentations", 15 December 1999.

Deloitte Touche Tohmatsu

Each of these regulatory tests have stated the discount rate that has been used but no supporting information has been provided as to the derivation of the stated discount rate. The only additional supporting information sighted was in relation to the SNI Regulatory Test, whereby Intelligent Energy Systems provided the gearing ratio, debt rate and equity rates in a report to TransGrid[2].

A comparison of the discount rates used in previous regulatory tests to the Murraylink WACC derived by Bob Officer (the "Officer WACC") for determining the regulated revenue stream and the market discount rates (low, high and base) determined below are contained in the following table.

	Murraylink (Officer)	VENCorp	IRPC	ElectraNet SA	Murraylink - Low	Murraylink - High	Murraylink - Base
Variable	**Regulatory**	**Market Benefits**	**Market Benefits**	**Market Benefits**	**Market Benefits**	**Market Benefits**	**Market Benefits**
Expected Inflation Rate	2.20%	n/a	n/a	n/a	2.20%	2.20%	2.20%
Nominal Risk-Free Rate	5.40%	n/a	n/a	n/a	5.40%	n/r	5.40%
Nominal Cost of Debt	6.90%	n/a	n/a	n/a	6.90%	9.00%	6.90%
Real Cost of Debt	4.7%	n/a	9%	n/a	4.7%	6.8%	4.7%
Equity Beta	1.13	n/a	n/a	n/a	1.13	n/r	1.644
Market Risk Premium	6.00%	n/a	n/a	n/a	6.00%	n/r	6.00%
Nominal Post Tax Return on Equity	12.15%	n/a	n/a	n/a	12.15%	n/r	15.26%
Corporate Tax Rate	30%	n/a	30%	n/a	30%	n/r	30%
Value of Imputation Credits	45%	n/a	50%	n/a	45%	n/r	45%
Nominal Pre Tax Return on Equity	14.55%	n/a	n/a	n/a	14.55%	18.00%	18.28%
Real Pre Tax Return on Equity	12.35%	n/a	18%	n/a	12.35%	15.80%	16.08%
Debt Funding	60%	n/a	65%	n/a	60%	60%	60%
Real, pre-tax WACC (discount factor)	**7.76%**	**8.0%**	**11.0%**	**13.0%**	**7.76%**	**10.40%**	**9.25%**

Notes:
n/a: not available
n/r: not required
VENCorp discount rate was used for both SNOVIC and the Latrobe Valley to Melbourne analysis
IRPC discount rate was used for both SNOVIC and SNI analysis

[2] Refer to the paper "Application of the ACCC Regulatory Test to SNI: Report to TransGrid" by Intelligent Energy Systems, dated 27 November 2000.

Deloitte
Touche
Tohmatsu

The table below discusses each of the variables used to derive the Murraylink low, high and base case market benefits discount rate. However, the low, high and base case have essentially been derived from the following sources:

- the **Low** case is based on the Officer WACC
- the **High** case is based on the reported variables underlying the SNI discount rate, however it assumes that the SNI figures were in fact nominal, not real as indicated, and gearing of 60%
- the **Base** case is based on the Officer WACC for all variables except for the equity beta, which is based on the more relevant equity betas from Officer's paper.

Variable	Values / Calculation	Comments
Expected Inflation Rate	Low: 2.2% High: 2.2% **Base: 2.2%**	Expected inflation rate sourced from the Officer WACC to ensure consistency between the regulatory WACC and the market discount rate, as expected inflation should be consistently applied.
Nominal Risk-Free Rate	Low: 5.4% High: n/r **Base: 5.4%**	Nominal risk free rate sourced from the Officer WACC to ensure consistency between the regulatory WACC and the market discount rate, as the nominal risk-free rate should not change between the two. The nominal risk-free rate is not required for the high case as the nominal cost of debt and the nominal pre-tax return on equity (both below) are treated as the inputs for the high case.
Nominal Cost of Debt	Low: 6.9% High: 9.0% **Base: 6.9%**	Low and base nominal cost of debt sourced from the Officer WACC, being reflective of the current cost of debt for a utility business. High rate of 9.0% sourced from SNI analysis, however where the SNI analysis indicates that the 9.0% is a real rate this has been considered too high a cost of debt (this would imply a nominal cost of debt of around 11.2%). Therefore it was considered that the SNI rate of 9.0% would be applicable as a high-end scenario for the nominal, not real, cost of debt.
Real Cost of Debt	= Nominal Cost of Debt – Expected Inflation Rate	Calculation consistent with Officer WACC calculation[3] of subtracting inflation rather than using the Fisher Equation method.

[3] Refer to Appendix 1 of the Officer paper "A Cost of Capital for Murraylink"

Deloitte Touche Tohmatsu

Variable	Values / Calculation	Comments
Equity Beta	Low: 1.13 High: n/r **Base: 1.644**	Low equity beta sourced from Officer WACC. High equity beta not required as nominal pre-tax return on equity treated as the input for the high case. Base equity beta based on a simple average of the following equity betas sourced from Officer's paper[4]: • Energy Developments 0.74 • Energy World 2.49 • Pacific Energy 1.67 • Pacific Hydro 2.16 • Origin Energy 1.16
Market Risk Premium	Low: 6% High: n/r **Base: 6%**	Market risk premium sourced from the Officer WACC to ensure consistency between the regulatory WACC and the market discount rate, as the market risk premium should not change between the two. The market risk premium is not required for the high case as the nominal pre-tax return on equity is treated as the input for the high case.
Nominal post-tax return on equity	Low: 12.15% High: n/r **Base:** = nominal risk-free rate + equity beta * market risk premium	Low value sourced from Officer WACC. The nominal post-tax return on equity is not required for the high case as the nominal pre-tax return on equity is treated as the input for the high case. The base value is calculated according to the Capital Asset Pricing Model ("CAPM").
Corporate Tax Rate	Low: 30% High: n/r **Base: 30%**	The corporate tax rate is the current Australian corporate tax rate. The corporate tax rate is not required for the high case as the nominal pre-tax return on equity is treated as the input for the high case.
Value of Imputation Credits	Low: 45% High: n/r **Base: 45%**	The value of imputation credits is sourced from the Officer WACC to ensure consistency between the regulatory WACC and the market discount rate, as the value of imputation credits should not change between the two. The value of imputation credits is not required for the high case as the nominal pre-tax return on equity is treated as the input for the high case.

[4] As a commercial discount rate (that is a discount rate for a non-regulated business) is required the following entities listed in Officer's paper were excluded as part of their operations included regulated businesses – AGL, United Energy and Envestra. Horizon Energy was excluded as an outlier.

Deloitte Touche Tohmatsu

Variable	Values / Calculation	Comments
Nominal Pre-Tax Return on Equity	Low: = nominal post-tax return on equity * (1 – Corporate Tax Rate * (1 – Value of Imputation Credits)) High: 18.0% **Base:** = nominal post-tax return on equity * (1 – Corporate Tax Rate * (1 – Value of Imputation Credits))	Low and base case calculated from other variables as indicated. High rate of 18.0% sourced from SNI analysis, however where the SNI analysis indicates that the 18.0% is a pre-tax, real rate this has been considered too high a cost of equity (this would imply a nominal cost of equity of around 20.2%). Therefore it was considered that the SNI rate of 18.0% would be applicable as a high-end scenario for the nominal, pre-tax cost of equity.
Real Pre-Tax Return on Equity	= Nominal Pre-Tax Return on Equity – Expected Inflation Rate	Calculation consistent with Officer WACC calculation[5] of subtracting inflation rather than using the Fisher Equation method.
Debt Funding	Low: 60% High: 60% **Base: 60%**	Debt funding variable sourced from the Officer WACC to ensure consistency between the regulatory WACC and the market discount rate, as the debt funding rate should not change between the two.
Real, Pre-Tax WACC (discount factor)	= Real Cost of Debt * Debt Funding + Real Pre-Tax Return on Equity * (1 – Debt Funding)	

[5] Refer to Appendix 1 of the Officer paper "A Cost of Capital for Murraylink"

Deloitte Touche Tohmatsu

CONCLUSION

Based on the analysis undertaken for comparable investments, we consider an appropriate real, pre-tax discount rate for the analysis of a private enterprise investment in the electricity sector to be in the range of 7.76% to 10.40%.

Accordingly, we consider a discount rate of 9.25% to be reasonable for MTP to apply in performing the ACCC regulatory test in relation to Murraylink.

	Base	**Low**	**High**
Regulatory Test Discount Rate	9.25%	7.76%	10.40%

Should you have any queries or require any additional information please do not hesitate to contact Tim Emonson or myself of this office.

Yours faithfully

Deloitte Touche Tohmatsu

Peter Thornely
Partner

Appendix D: Report – Report on the Estimation of Murraylink Market Benefits – TransÉnergie US Ltd

Estimation of Murraylink Market Benefits

Prepared for

Murraylink Transmission Company

ACN 089 875 080

By

TransÉnergie US Ltd.

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Contents

Executive Summary

Murraylink is an HVDC Light transmission interconnector between the Monash substation in the Riverland region of South Australia and the Red Cliffs substation in north-western Victoria. It is capable of delivering up to 220 MW in either direction under normal (e.g. "all lines in") system conditions. The Murraylink facility will provide several significant benefits to those who produce, consume or distribute electricity within the National Electricity Market (NEM):

- Lower total energy costs (both lower generation fuel and variable operations and maintenance (O&M) costs and lower costs associated with activation of voluntary load interruption);
- Improved reliability;
- Deferral of new market entry generation;
- Deferral of transmission augmentations otherwise necessary to support electrical load in the Riverland.

This report describes the assumptions, methodology and input data sources used to calculate monthly cashflows representing these gross market benefits over a 39.5 year horizon beginning on May 1, 2003, and provides an estimate of the gross market benefit cashflows under several load growth scenarios.

In general, the input data, assumptions and methodology are consistent with those used in the Inter Regional Planning Committee's (IRPC) November 2001 economic evaluation of the proposed SNI interconnector. Those assumptions and methodology are discussed in detail in the main body of this report, including those areas where differences have been incorporated.

Energy benefits are estimated by taking the difference between energy costs in a "Without Murraylink" scenario and a "With Murraylink" scenario, simulated using the PROSYM chronological production cost simulation model. The PROSYM model is also used to develop schedules of merchant entry plant by region, assuming that new plants will enter the market when regional prices allow all such entry to be profitable on a sustained basis.

Reliability benefits are estimated by measuring the difference in total expected unserved energy (USE) throughout the NEM between the Without and With Murraylink scenarios, using the General Electric's Multi-Area Reliability Simulation model (MARS). MARS is a chronological Monte Carlo simulation tool specifically designed to measure reliability in multi-area systems such as the NEM.

The benefits of deferring Riverland transmission augmentations is derived from studies in 2001 and 2002 conducted by or for the Electricity Supply Industry Planning Council (ESIPC), recently updated load forecasts for the Riverland, and submittals and publications associated with ESIPC's review of Riverland requirements. These documents indicate that Murraylink can defer the need for additional voltage support until summer 2007–08, and can defer the need for thermal upgrades of lines in the Robertstown-North West Bend-Monash area until 2012–13.

The results of TransÉnergie US Ltd's (TEUS's) study of Murraylink gross market benefits indicates a best estimate cumulative present worth of $214.2m (2003 A$ discounted to May 1, 2003 at 9.25%[1]). The additional sensitivity results are shown in table ES-1:

Cumulative Present Worth of Gross Market Benefits

Discounted to May 1, 2003 at 9.25%

Scenario	Gross Market Benefits ($000)
Base	214,240
Low Growth	135,514
High Growth	225,589

Table ES-1

[1] The derivation of the 9.25% discount rate is discussed in a letter from Peter Thornely of Deloitte Touche Tohmatsu, to the Murraylink Transmission Partnership (MTP), in which Mr. Thornely discusses appropriate discount rates for use in applications of the Australian Competition and Consumer Commission's Regulatory Test.

1 Background and Context

1.1 Purpose of the Report

The purpose of this report is to articulate the total gross market benefits of Murraylink to all those who produce, distribute and consume electricity in the NEM and to explain the manner in which these total gross market benefits have been calculated.

The total gross market benefits, calculated by TEUS and documented in this report, will be used as an input for the application of the Australian Competition and Consumer Commission's (ACCC's) *Regulatory Test for New Interconnectors and Network Augmentations* (Regulatory Test) to the Murraylink transmission asset.

The costs of Murraylink, the resulting net market benefits, and the extent to which Murraylink satisfies the ACCC's Regulatory Test are not addressed in this report. These topics are the subject of other reports incorporated into Murraylink Transmission Company's submission to the ACCC.

1.2 History

Murraylink is a 180 kilometer underground transmission facility using HVDC Light technology that interconnects Victoria and South Australia. It was placed into commercial operation in October 2002. HVDC Light technology incorporates sophisticated power control electronics and advanced cable technologies in a single transmission system. This technology provides several significant technical capabilities:

- Direction and magnitude of power flows can be fully controlled.

- Voltage source converter technology requires less filtering than conventional HVDC technology, which leads to higher reliability and a more compact design.

- AC system voltage or reactive power exchange with the local AC network can be readily controlled.

- The undergrounding of the cables along with the system's near instantaneous controllability allows Murraylink to operate without derates during electrical storm activity, as is the case for the Heywood AC interconnector between South Australia and Victoria.

Active power transfer over HVDC facilities is directly controlled by electronic valves at converter stations at each end of the Murraylink facility. The valves convert AC electrical energy into DC electrical energy (and vice versa) and control the power flow between the converter stations. The firing control for each valve allows for the rapid control of power transfers and fast response to changing AC system conditions.

Murraylink Transmission Company (MTC) is applying to the ACCC for the network services provided by Murraylink to be classified as prescribed network services, and for the ACCC to determine a revenue cap for MTC. MTC has engaged TEUS to calculate the total gross market benefits of Murraylink.

1.3 Description of Murraylink's Technical Service

Murraylink provides economic benefits to the NEM as a result of its basic technical service that includes:

- An additional 220 MW injection capability into South Australia (dependant on the Victorian state grid load);

- An additional 220 MW injection capability into Victoria from South Australia (dependant on the Riverland load);

- Reactive support and regulation of the voltage profile of the AC networks at both ends of the link; and

- An additional transmission in-feed into the Monash substation 132 kV bus that relieves an existing non-compliance with the Code under an N-1 contingency.

TransÉnergie Australia (TEA) has confirmed the ability for Murraylink to provide this basic technical service, and Power Technologies Inc. has verified TEA's calculations.

1.4 Market Benefits

Under the Regulatory Test:

> "market benefit" means the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the NEM. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios [emphasis added].

Four specific market benefits have been identified and evaluated in this report:

1. Reduced energy costs (reduced fuel and variable O&M, and reductions in the frequency and level of voluntary load interruptions).
2. Deferred market entry of new merchant generation.
3. Increased reliability measured as the reduction in expected USE throughout the NEM.
4. Deferred cost of transmission upgrades necessary to provide reliable service to the Riverland region.

Murraylink can also provide other market benefits whose value is difficult to quantify, and which have not been considered in this analysis (thus understating the market benefits provided by Murraylink). These additional market benefits include:

- The ability of Murraylink to provide frequency control ancillary services, by operating in frequency control mode; and
- The ability of Murraylink to automatically control AC voltages while simultaneously providing real power transfer capability.

1.5 Modeling Software Used to Estimate Gross Market Benefits

Two different commercially available electric system simulation models are used to calculate the projected energy, reliability, and deferred market entry benefits that Murraylink provides.

1.5.1 PROSYM

The PROSYM Chronological Production Modeling System is a comprehensive modeling package specifically designed for the estimation of energy costs and electricity prices in large, complex markets. The software has been licensed by TEUS from Henwood Energy Systems, a consulting firm with offices in both the United States and Australia and with experience in modeling the Australian NEM.

PROSYM is a chronological production cost model that simulates the operation of a multi-area generation and transmission system, reflecting the operation, maintenance and forced outage characteristics of generators, transmission interconnections between the areas, and the projected hourly loads of the areas. It provides the capability to model the cost and operating characteristics of individual generators within several interconnected regions, and is well suited for use within the five-region structure of the NEM. Seasonal limitations on the transfer of power between regions are specified. On an hour-by-hour basis, PROSYM dispatches the generators in each region to serve the region's load in a manner that minimizes the total cost of electricity production—importing power from adjacent regions when that power is less expensive than local generation or exporting power when local generation can displace more expensive generation in neighboring regions. The model simulates the impact of maintenance requirements and forced outages, and the specific operating limitations of each generating facility. The dispatch of generation and interregional transfers are simultaneously optimized across the five regions

1.5.2 MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a commercially available reliability planning tool licensed by TEUS from General Electric's Power Systems Engineering Consulting group in Schenectedy, New York. MARS provides sophisticated capabilities to model uncertain load forecasts, generator outage and availability characteristics, maintenance schedules, capacity contracts and reserve sharing agreements. MARS provides more than enough flexibility to model the operation of the NEM—a single integrated system with multiple regions, all operating under a common set of rules.

MARS is a stochastic simulation model that uses a Monte Carlo approach to estimating reliability parameters. Each year is simulated chronologically for a number of samples, using randomly determined generator outages. The reliability indicators, including the total system unserved energy, are calculated for each sample. By averaging the unserved energy from a large number of randomly generated samples, the expected unserved energy, also known as the loss of energy expectation (LOEE) is determined. This is the primary reliability indicator used in the Murraylink analysis. It directly and transparently captures reliability impacts throughout the entire NEM valuing unserved energy in any region equally, and implicitly incorporates both the size and duration of capacity shortfalls.

The MARS model implements a stochastic reliability simulation methodology that is quite similar to approaches used previously in the NEM. The NECA Reliability Panel used a similar modeling approach in 1999 to develop the reserve trigger levels used as part of the reserve trader mechanism. More recently, the same approach has been used by TransGrid to develop optimal reserve margins for NSW and other NEM states.

1.6 Report Structure

The report presents a detailed description of the assumptions and methodology used to calculate Murraylink's gross market benefits, and an estimate of those benefits under several different economic growth scenarios. The information is presented in several sections:

- Energy benefits and deferred market entry
- Reliability benefits
- Riverland deferral benefits
- Scenarios and results.

Three appendices provide detailed results, a summary of generator characteristics, and a summary of the load forecasts used in the three scenarios analyzed. Following the appendices, a list of benefit calculations and a list of references are provided.

2 Energy Benefits and Deferred Market Entry

The addition of a 220 MW interconnector between SA and Vic increases the opportunities to displace more expensive generation in one region with less expensive generation in another region. When energy flows over Murraylink in response to such opportunities, total system fuel costs are reduced, providing important market benefits to the NEM.

This subset of Murraylink's benefits has been quantified for several scenarios using the methodology and assumptions recently established by the IRPC in its document *IRPC Stage 1 Report: Proposed SNI Interconnector, Version V014*, published on October 26, 2001. This methodology measures the fuel cost reductions associated with a new interconnector by simulating over a 10 year horizon the fuel and variable operating costs of NEM generators as they are dispatched to serve load. By simulating the Without Murraylink and With Murraylink cases, the fuel cost savings of Murraylink can be calculated. To best measure total fuel cost benefits to all market participants, including electricity producers and consumers, generators are priced at their short run marginal cost (SRMC), as estimated by the IRPC. New generators are assumed to enter the market when prices, driven by load growth, rise to a level that fully compensates the new facilities for their fixed costs (capital and fixed O&M) and variable operating costs.

This simulation process will also measure the benefits attributable to Murraylink from reducing the amount of voluntary interruptible load actually interrupted. For simplicity, the total benefits associated with (a) reductions in fuel costs through the NEM, and (b) reductions in the cost of activating interruptible loads are both included in the definition of "energy benefits".

2.1 Inputs, Assumptions, and Information Sources

The PROSYM model requires detailed assumptions regarding loads, generator characteristics, fuel costs, bidding behavior, and simplified transmission network topology and constraints. The primary source of information and assumptions has been the IRPC Stage 1 Report. Other significant sources are as noted below.

PROSYM provides the capability for detailed modeling of fuel prices and generator performance characteristics such as heat rate curves, maintenance schedules, startup costs, and variable O&M costs. However, the IRPC has provided only aggregated maintenance information (maintenance days per year by generator type) and "all-in" estimates of each generator's fuel and variable operating cost in the form of estimated (SRMC) expressed in $/MWh.

2.1.1 Evaluation Time Horizon

Murraylink was placed into service in early October 2002, and is currently operating as a market network service provider within the

NEM. Murraylink's design life is 40 years, indicating a retirement date of September 30, 2042. This analysis considers the period from May 1, 2003 through September 30, 2042, a 39.5 year period. In all likelihood, Murraylink's actual operational life will be greater than 40 years, so this assumption of Murraylink retirement as September 30, 2042 is conservative. The PROSYM modeling covers calendar years 2003–2012 (modeled monthly). By 2012, the NEM is anticipated to have reached a long run equilibrium status. Energy results for calendar years 2013–2042 are assumed to replicate 2012 results on a monthly basis.

2.1.2 Inflation and Discount Rates

All cost and financial assumptions are derived from the IRPC Stage 1 Report released in late 2001, and are therefore considered to be in September 2000 dollars. Model results have been inflated from September 30, 2002 to May 1, 2003 using the Australian "All Cities" consumer price index for September 2000 and June 2002, plus 10 months at an annual inflation rate of 2.2%. The projected inflation rate of 2.2% was developed for MTC by Prof. Robert Officer as part of the development of a weighted average cost of capital for MTC. Combined, this results in a 7.04% inflation adjustment applied to all IRPC Stage 1 Report cost estimates.

In calculating the net present value (NPV) numbers shown in the Executive Summary, an annual discount rate of 9.25% was used, as indicated to MTC by Peter Thornely of Deloitte Touche Tohmatsu in his letter to MTC.

2.1.3 Network Topology and Constraints

The topology of a multi-area transmission system, including the limits and constraints on flows between areas is an important determinant of the simulated operation of the system. The existing five-region structure of the NEM, as shown in Figure 2.1, is represented within the PROSYM model. The PROSYM representation includes a sixth "artificial" region (i.e. a region not defined in the NEM's current configuration). PROSYM, by default, is only capable of representing a single transmission link between any two regions. This artificial region has been introduced as a modeling device to enable power transfers over the Heywood interconnector and Murraylink to be separately observed. The artificial region is modeled with no load and no generation, and the two links, SA-Artificial Region and Artificial Region-Victoria, together represent the Murraylink facility.

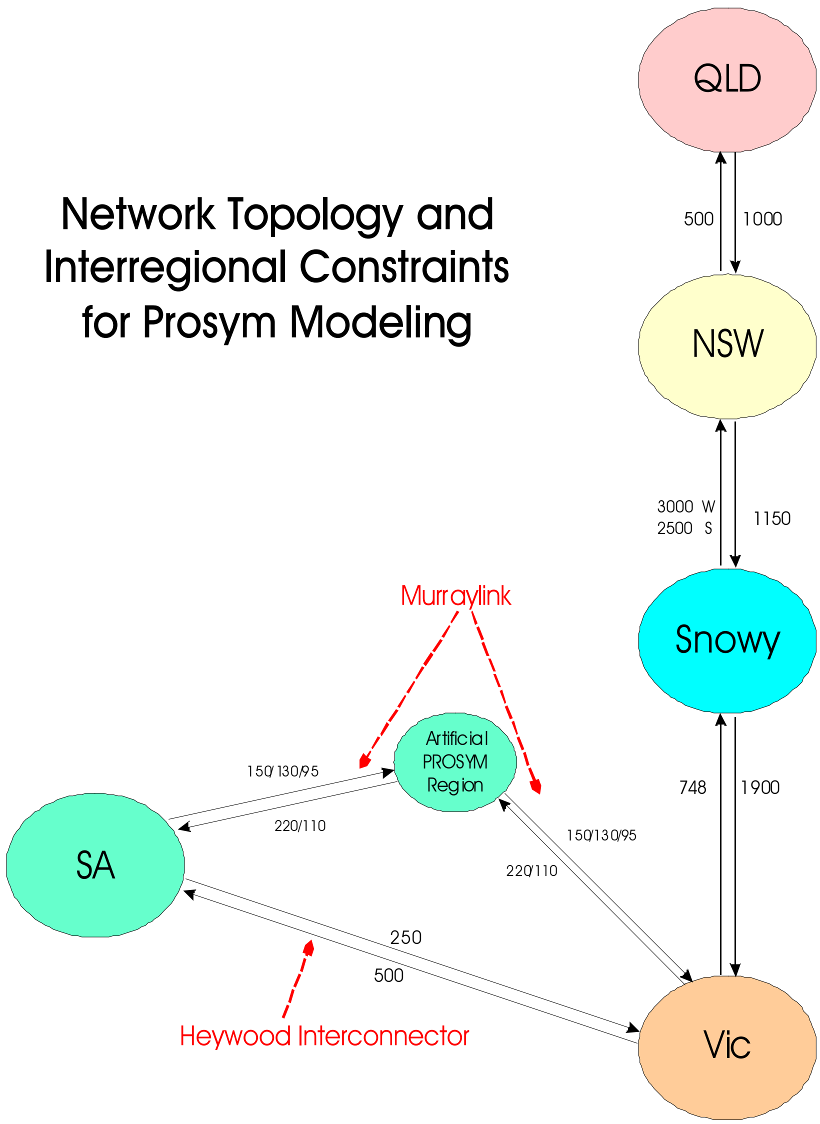

Figure 2.1

The NEM operates using detailed "constraint equations" that define limits on interconnector flows in relation to load and generation patterns that will ensure the transmission system will operate reliably. The detailed constraint equations have been represented within the PROSYM model with seasonal interface limits. This modeling technique was used in the IRPC's review of SNI. The relevant constraints have been developed from two sources:

1. Studies completed by or for the Interconnection Options Working Group (IOWG) as part of the recent evaluation of the proposed SNI interconnector, and published on the NEMMCO web site[2] as appendices to the IOWG *Report on Additional Interconnection Augmentation Scenarios for SNI and SNOVIC Economic Assessments*, October 2001.

[2] National Electricity Market Management Company Ltd., www.nemmco.com

2. Load flow studies prepared by TEA and presented in the TEA report *Murraylink Transfer Capability Studies* (the TEA Report), and as reviewed and summarized by the PTI report, *Due Diligence on Power Transfer Studies*.

The PROSYM model provides flexibility to model transmission limits that change cyclically over time (i.e. seasonally, by time of day, by day of week), but it does not provide a means of implementing dynamic constraints that change as a function of load or generation. The conservative Murraylink limits developed through the load flow analysis using summer peak stressed system conditions are appropriate for only a limited number of hours per year. At other times, Murraylink will provide its full rated power transfer capacity of 220 MW.

The PROSYM modeling is an hourly simulation of the 10 year period 2003–2012 on a pre-contingent, or “all lines in” basis. TEUS has assumed that AC network augmentations will be implemented as necessary to achieve the power transfer levels identified in the TEA Report. Transmission maintenance is assumed to be planned for periods when it would not have meaningful impacts on NEM reliability or NEM energy costs. PROSYM does not provide a direct means of simulating unplanned transmission outages.

2.1.3.1 Murraylink Limits – Victoria to South Australia

As a proxy for dynamic limits that change with grid loading, TEUS has reviewed three years of historical NEM operation, 1999–-2001, to determine the number of past occurrences by month of “max flow” events, where flow from Snowy to Victoria came to within 100 MW of the 1500 MW Snowy-Vic maximum flow limit applicable during that period. The historical data shows 134 half-hour dispatch intervals that approached “max flow” during 1999–-2001, or 0.25% of the time.

Most occurrences happened during 3–6 pm in February months, and 9–10 am plus 6–8 pm in July and August months. These periods account for 83 of these events, or 62% of the total number.

This information has been incorporated into the PROSYM modeling by using the following limits to flows on Murraylink from Victoria to South Australia:

February 3–6 pm weekdays	110 MW
July & August 9–10 am weekdays	110 MW
July & August 6–8 pm weekdays	110 MW
All Other Hours	220 MW

Together, the hours constrained to 110 MW account for approximately 2.2% of the hours in a year, nearly 10 times the historical incidence of “max flow” events, and they include the periods most likely to have conditions that might lead to future "max flow" events. As such, they represent a reasonably conservative approach to simulating dynamic limits within PROSYM.

2.1.3.2 Murraylink Limits – South Australia to Victoria

Different factors potentially constrain the operation of Murraylink when flowing power from South Australia to Victoria. Voltage support considerations are likely to limit flows to no more than 150 MW during most hours. This is reflected in PROSYM as an absolute limit to flows on Murraylink from South Australia to Victoria of 150 MW at any time.

The TEA Report indicates that thermal limitations from Robertstown to North West Bend will constrain Murraylink flows to 222 MW less the Riverland area load in the summer, and to 280 MW less Riverland load in the winter. Forecast hourly Riverland loads for 2012 (the last year modeled) were used to calculate the appropriate hourly limits by hour-of-day for the summer (December–February) and winter (March–November) based on the maximum load forecast to occur during each hour of the day.

Summer hours were divided into two periods with appropriate limits for the maximum demand expected to be seen during the period:

10 am–8 pm	95 MW limit
8 pm–10 am	130 MW limit

Winter limits, based on the "280 MW – Riverland load" formula, always exceeded 150 MW, the limit attributable to voltage support requirements. Consequently, a limit of 150 MW was used for all winter hours for transfers over Murraylink from South Australia to Victoria.

This seasonal time-of-day limit structure incorporates a significant degree of conservatism. These limits are based on expected loads in the final year of analysis, (which are higher than the earlier years), and the limits for all summer hours are low enough to accommodate the highest forecast demand in any summer hour.

2.1.4 Load Traces

A total of nine half-hourly load traces were developed by Roam Consulting for the SNI evaluation for the three economic growth scenarios (high, mid, and low), and for the three probability of exceedence (POE) values (90%, 50%, and 10%). For the PROSYM analysis TEUS developed hourly load traces for each economic growth scenario by simply averaging the appropriate half-hourly load traces for the 50% POE demands for that economic growth scenario. A summary of the annual peak demands and energies for each economic growth scenario is provided in Appendix 3.

2.1.5 Market Entry Generation

Based on information published in the IRPC Stage 1 Report, four types of market entry new generation were considered. Not all types of generation are available in all regions.

Potential Merchant Plant Entry

	Open Cycle Gas Turbine	Combined Cycle Gas Turbine	Black Coal	Brown Coal
Queensland	X	X	X	
New South Wales	X	X	X	
Victoria	X	X		X
South Australia	X	X		

The different types of generation are assumed to have the cost structures published by the IRPC:

Technology	Capital Cost $/KW	Annualized Capital Cost $/KW-Yr	SRMC $/MWH	Size MW
Combined Cycle Gas Turbine	1031	165	22	180
Open Cycle Gas Turbine	500	80	40	50
Brown Coal	1500	240	5	500
Black Coal	1200	192	8	450

The amount, type, and location of new generation was not assumed, but was determined through the modeling process, as described in Section 2.2.1.

2.1.6 Existing and Committed Generation Characteristics

The characteristics of existing and committed generators required by the PROSYM and MARS models have been taken from the IRPC Stage 1 Report. The characteristics include:

- Region
- Seasonal maximum capacity ratings (winter ratings March–-November, summer ratings December–-February)
- In-service and retirement dates
- Marginal loss factor
- Forced outage rate

- Annual maintenance requirement
- Mean time to repair
- Short run marginal cost.

TEUS adopted the IRPC's SRMC estimates as each generator's bid price, which is used by PROSYM to select which units will operate to serve the load, and as the best estimate of each generator's actual fuel and operating cost. For several of the larger baseload generators, an initial block of the generator's maximum capacity is bid at $0/MWh to simulate minimum loading requirements for these facilities. The size of the initial block is 65% in Victoria and 40% in the other NEM regions.[3]

The specific values used for each generator are summarized in Appendix 2.

2.1.7 Bidding Behavior

Generators are assumed to bid their SRMC, as defined by the IRPC in the Stage 1 Report. These costs represent the fuel cost plus variable O&M cost for each generator.

Murraylink is assumed to operate as a regulated interconnector in this analysis, and hence, does not bid transport capacity into the market. Instead, Murraylink simply follows dispatch instructions from NEMMCO with no "transport charge". The NEMMCO dispatch then minimizes the total energy cost of dispatched generation and interruptible load, recognizing the generating unit capacities, hourly demands, interconnector losses, and transmission constraints.

2.1.8 Losses

The PROSYM model allows quadratic loss equations (where losses are a function of flows) to be specified for each interconnector. These equations were developed from the interregional dynamic loss equations described in the IRPC Stage 1 Report.

Electrical losses over Murraylink were based on the measured electrical losses that have been reported to NEMMCO, and fitted to the quadratic equation format required in PROSYM.

2.1.9 Hydro Information

The Stage 1 Report provided basic information on hydro generation capacity and monthly production profiles for Snowy hydro. Information on Southern Hydro monthly production was obtained from the NEMMCO web site (www.nemmco.com).

[3] IRPC Stage 1 Report, p. 44.

2.1.10 Heywood Derating

The Heywood interconnector is vulnerable to outages caused by electrical storm activity. To avoid unacceptable consequences of a lightning strike, the interconnector is often derated. A discussion paper by the South Australian Independent Industry Regulator (SAIIR) provided historical data regarding the causes and frequency of derates of the Heywood interconnector. The paper titled *Transmission Line Performance in South Australia & the SA Transmission Code* was published in December 2001. However, the PROSYM model does not provide a direct means of modeling transmission outages, and the modeling of energy benefits does not reflect Heywood outages. Hence, the energy benefits of Murraylink are understated, since TEUS assumed the existing Heywood interconnector to be available at full capacity at all times.

2.1.11 Demand-Side Impacts

The PROSYM modeling incorporates two forms of demand-side response during periods of tight supply—voluntary load reduction and USE (which is equivalent to involuntary load reduction, or “lost load”). The IRPC has estimated the amount of voluntary load reduction available in the NEM dispatch as a function of the forecast maximum regional demand and the price level. At higher price levels, greater amounts of voluntary load reduction become available. In total, the voluntary load reduction capability within each region is assumed equal to 3% of the 10% POE load forecast, with the following costs:

Pool Price	Voluntary Load Reduction Participation
$500/MWh	0.45 %
$1000/MWh	0.60 %
$3000/MWh	0.90 %
$5000/MWh	1.05 %

Reductions in the extent of voluntary load reductions represent a market energy benefit not captured by the change in fuel consumption by generators. Section 2.2.4 discusses the calculation of this benefit.

2.1.12 Maintenance

Maintenance schedules are developed by PROSYM for each year using a “distributed maintenance levelized loss of load probability” algorithm. Annual maintenance rates for each unit are developed from the IRPC Stage 1 Report information.

2.1.13 Unserved Energy

Unserved energy (USE) results when either (a) the installed generation capacity is unable to provide enough energy to serve all of the NEM load at some point in time and/or (b) transmission constraints prevent energy available at a generating unit from being delivered to the point of consumption. Even when sufficient generating capacity is installed to meet regional required reserve levels, USE can still occur due to generation or transmission forced outages or non-interruptible demands that unexpectedly exceed the forecast demand. Although a reduction in USE can be viewed as an energy benefit, the value of reductions in USE has not been included in the calculation of energy benefits, but instead is modeled in much greater detail as part of the calculation of reliability benefits[4].

2.2 Methodology

The PROSYM modeling of energy benefits follows several steps:

- Development of a long run market equilibrium with Murraylink in service based upon market entry of merchant generation in response to regional prices[5] resulting from short run marginal cost bidding behavior for each generator.
- Development of a similar long run equilibrium with Murraylink not in service
- Quantification of the market benefits of deferral of market entry generation resulting from the presence of Murraylink.
- Quantification of the difference in variable generation costs (fuel plus variable O&M) on a monthly basis between the With and Without Murraylink simulations.
- Quantification of the difference in voluntary load reductions (also referred to as interruptible load or dispatchable demand) on a monthly basis between the With and Without Murraylink simulations.

2.2.1 Required Simulations

The development of the market equilibrium simulation is an iterative process, the purpose of which is to determine the amount, timing, and location of new market entry generation that can be expected in a competitive bid-based electricity market. New entry will be determined by the perceived profitability of new generation. If

[4] Note that although the PROSYM market simulations calculated some level of USE in a much less sophisticated fashion, the USE estimated by PROSYM was not included in the total energy cost calculations, to avoid double counting the benefits from reducing the amount of USE.
[5] For developing regional prices (used solely to determine the timing of market entry generation), any USE forecasted by PROSYM was priced at $10,000/MWh. As noted earlier, however, reductions in USE in the PROSYM simulations were not considered as part of either the energy benefits or the reliability benefits.

market prices are high, new entrants will be attracted. If prices are low, entry will be deterred. Equilibrium is reached each year when the amount of new entry results in prices that are sufficiently high to compensate the selected new entrants for their fixed and variable costs, but not so high as to merit the entry of another new generator.

TEUS developed the schedules of market entry generation by modeling each year with PROSYM, and calculating the total energy margin being earned by each new entrant generator, assuming the generic costs for each generator type identified by the IRPC.[6] If, for example, the total energy margin for a baseload combined cycle plant exceeded its annualized fixed cost, additional plant is added and the year is re-simulated in the PROSYM model to test whether the new entrants are still profitable after the addition of the last unit. Similarly, if the included generic baseload plants are earning less than their annualized fixed cost, capacity is removed and the year is re-simulated. The same process is applied simultaneously for each type of generic new generation. The iterative process continues until the added merchant capacity is at least breaking even (earning energy margins greater than or equal to annualized fixed costs), but another new entrant of any type would be unprofitable.

Generating plants of each of the four different types (open cycle gas turbine, combined cycle gas turbine, black coal, brown coal) were considered in this manner.

The same market equilibrium modeling approach has been used for all scenarios analyzed.

2.2.2 Forecast of Electrical Losses

After the PROSYM simulations are completed, interconnector flows are analyzed to calculate interregional losses. These losses are calculated using the quadratic loss equations applicable to each regional interface. Since electrical losses must be input into MARS directly, the losses calculated internally by PROSYM are used as inputs into the MARS model.

2.2.3 Simulation Outputs

The PROSYM model provides an extensive range of output information. We have relied upon the two standard output reports, the *annual station revenue report* and the *monthly station revenue report*, augmented by customized reports showing hourly load and price by region, to provide the information required to determine the profitability of new generation. The station revenue report shows the total generation (GWh), total revenue ($k), and total fuel and variable O&M cost ($k) for each generator.

Once the market entry schedule is finalized, a customized report showing interconnector flows is created and used to calculate

[6] Stage 1 Report, November 1, 2001, p. 27.

interregional losses. Losses are handled internally by PROSYM, but must be estimated externally for incorporation into the MARS model.

2.2.4 Calculation of Energy Benefits

The market entry equilibrium balancing process is conducted separately for both the Without Murraylink and With Murraylink cases. Calculation of differences between the two simulations will capture changes in:

1. energy costs, caused by changes in the NEM's dispatch order due to increased interface capability between regions;
2. fuel costs caused by different market entry schedules;
3. voluntary load reduction; and
4. USE.

The first three items represent energy benefits and are calculated directly from the PROSYM modeling results. The USE estimated by PROSYM is not used, in deference to the more accurate estimate provided by the MARS model.

Fuel cost benefits (items 1 and 2 above) are calculated monthly by summing the fuel and variable O&M costs for all generators for the With Murraylink and Without Murraylink simulations and taking the difference between the two cases.

TEUS valued the changes in voluntary load reduction at the appropriate price level for each voluntary load reduction block, as discussed in Section 2.1.11.

The annual energy benefit cashflows for each scenario are shown in Appendix 1.

2.2.5 Calculation of Deferred Market Entry Benefits

The addition of Murraylink changes prices in each NEM region, but particularly in South Australia and Victoria. The resulting prices are generally lower, both on an all-hours annual basis and an on-peak basis, particularly in South Australia. Lower prices are less profitable for new generation. This price reduction causes entry of new merchant generation to be deferred until there is sufficient load growth to offset Murraylink's impact on prices. The deferral of capital spending and fixed O&M for new merchant entry plant represents a market benefit, and was recognized as such in the IRPC's evaluation of SNI.

The deferred capital cost benefit is calculated as avoided capital cost spending in January of the year from which the generation is deferred. The deferred O&M benefit is similarly the avoided O&M costs for the deferred generating units.

The deferred merchant entry benefits for each scenario are shown on an annual basis in Appendix 1.

3 Reliability Benefits

Murraylink allows generation capacity in the NEM to be shared more efficiently, thus reducing the underutilization of that capacity. Limits to the transmission system that prevent the natural diversity in peak demands between regions from being fully captured is one contributor to underutilization. The unpredictability of forced outages is another. Higher reserve levels are necessary to provide adequate reliability when a region is unable to share available reserves in adjacent regions. Increased transfer capability between regions, such as Murraylink provides, makes this reserve sharing possible and thus increases system reliability for a given investment in generating plant. TEUS has modeled the benefits of such increased reliability (reliability benefits); this section of the report discusses that modeling process.

Reliability benefits are estimated by measuring the change in USE between two otherwise identical simulations, one of which includes Murraylink, and one which does not. The impact of Murraylink will vary, however, as the level of generation reserves in the simulation varies. For this reason, two estimates of Murraylink's impact on USE were made: (1) using the market equilibrium developed with the PROSYM model with Murraylink in service; and (2) using the market equilibrium developed with the PROSYM model with Murraylink not in service.

Typically, a With Murraylink balanced equilibrium scenario will have less market entry than the corresponding Without Murraylink scenario. As a result, the change in USE is greater when Murraylink is removed, than when Murraylink is added. To eliminate this asymmetry, an average change in USE is calculated using both results. The annual reliability benefit is calculated as the average change in USE multiplied by $10,000/MWh, the value of lost load. The benefit in 2012 is assumed to apply for the remainder of the analysis horizon. In the early years, when reserves are high and USE is low, Murraylink makes a small but noticeable decrease in annual USE. Over time, the level of USE increases, and the reduction in annual USE due to Murraylink is significantly greater. The total reliability benefit is the cumulative present worth of the stream of annual USE reduction benefits.

An accurate estimate of USE requires a sophisticated stochastic simulation approach that can explicitly address complex interconnector constraints. For that reason, TEUS selected the MARS model, a stochastic multi-area reliability simulation model that accurately captures the impacts of reserve sharing between interconnected regions with diverse load patterns and generation portfolios.

This modeling technique directly measures and values the increased reliability that Murraylink provides, rather than using a shadow valuation technique such as "installed capacity margins" that attempts to (indirectly) mimic the valuation process. By directly valuing the benefits of reducing expected USE in the NEM, the sole issues are (a) the calculation of such reductions in MWh of USE and (b) the value of reducing USE (valued here at $10,000 per MWh).[7]

[7] Note that although the PROSYM market simulations calculated some level of unserved energy in a much less sophisticated fashion, the USE estimated by PROSYM was **not** included in the total energy costs calculations, to avoid double counting the benefits from reducing the amount of USE.

The MARS modeling process is described in greater detail in section 1.5.2.

3.1 Inputs, Assumptions, and Information Sources

The MARS model requires detailed input data regarding hourly loads, generator capacity and availability, simplified network topology and constraints. The primary source of information and constraints has been the IRPC Stage 1 Report. Other significant sources include load flow analyses conducted by TEA and the review and summary of those studies by Power Technologies Inc.[8]. Other sources are as noted below.

3.1.1 Evaluation Time Horizon

The reliability benefits were calculated using the same analysis horizon used in the calculation of the energy benefits. The reliability benefits calculated for the calendar year 2012 were replicated for the remainder of the analysis horizon. Section 2.1.1 describes the analysis horizon in more detail.

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3.1.2 Inflation and Discount Rates

Section 2.1.2 describes the inflation and discount rate parameters that were used in the analysis of energy benefits. The same inflation and discount rate parameters were used in the calculation of the reliability benefits.

3.1.3 Generator Characteristics

The operating characteristics of generators modeled in MARS have been developed from the IRPC Stage 1 Report, and are fully consistent with the assumptions used in the PROSYM modeling. These characteristics are listed in Appendix 2, and include:

- Location/subregion (see section 3.1.5)
- Seasonal maximum capacity (winter ratings March–November, summer ratings December–February)
- Forced outage rates
- Annual maintenance requirements
- Marginal loss factors[9].

MARS requires maintenance to be specified as an integral number of weeks. IRPC-specified maintenance requirements in days/year

[8] *Due Diligence on Power Transfer Studies*, Power Technologies Inc., September 2002.
[9] Generator capacity ratings were adjusted by the generator-specific marginal loss factor to provide input capacity ratings to the MARS model.

have been rounded to the nearest integral number of weeks/year. Annual maintenance schedules are developed by the MARS model on a regional basis considering the regional load and generation in a manner that will levelize each region's reserves over the year.

The MARS model provides the capability to represent unit outages in terms of outage states that may include partial outages as well as full outages. When the probabilities of moving from one outage state to another or outage frequency and duration data are not available, MARS imputes appropriate transition probabilities from the forced outage rates and an estimate of the number of annual outages. The IRPC Stage 1 Report does not provide outage state transition probabilities, but does provide forced outage rates (FOR) and mean time to repair (MTTR). The forced outage rates are used directly. The number of annual outages are calculated as:

$$\text{Annual outages} = 8760 \times \text{FOR} / \text{MTTR}$$

3.1.4 Demand-Side Impacts

Voluntary load curtailment (dispatchable load) is included by region in the MARS model as generators of last resort that can be called upon to avoid or reduce the amount of USE within the NEM. The total amounts of available voluntary load reduction are calculated in the same manner as previously described in section 2.1.11, although there is no need in the reliability modeling to separate blocks by price band.

3.1.5 Network Topology and Constraints

As discussed previously, MARS is a Monte Carlo simulation model that evaluates the reliability performance of a multi-area transmission system, reflecting the operations, maintenance and forced outage characteristics of generators and the projected hourly loads of the several connected areas. The topology of the multi-area system, including the limits on flows between areas is an important determinant of the reliability performance of the system.

Load flow analysis performed by TEA using summer peak conditions has established the likely operating limits of the Murraylink facility when exporting power from Victoria to South Australia. Murraylink provides the technical capability to flow 220 MW from Victoria to South Australia, or from South Australia to Victoria. However, under summer peak conditions (when imports from Snowy/NSW to Victoria are assumed to be at 1900 MW), the load flow analysis found that:

- When additional supply is available from generation sources in Victoria (referred to in the load flow analysis as the Victoria swing-bus case), Murraylink can safely operate at 180 MW with the installation of moderate amounts of voltage support in Victoria.

- With installations of additional voltage support in Victoria, and an appropriate runback scheme, the Murraylink limits could be raised to 220 MW[10].
- When additional supply is available in New South Wales, but not in Victoria (referred to in the load flow analysis as the New South Wales swing-bus case), Murraylink dispatch would be limited to 110 MW.

These results have been characterized as conservative, and are likely to apply only under the highly stressed conditions represented by the summer peak load flow.

3.1.5.1 Network Topology

The diagram in Figure 3.1 illustrates the network topology assumed in the MARS analysis. It is consistent with the five regions presently defined in the NEM, but incorporates additional detail by subdividing three of the regions into several subregions.

[10] As with the calculation of the energy benefits, these additional network augmentations were reflected in the calculation of the reliability benefits.

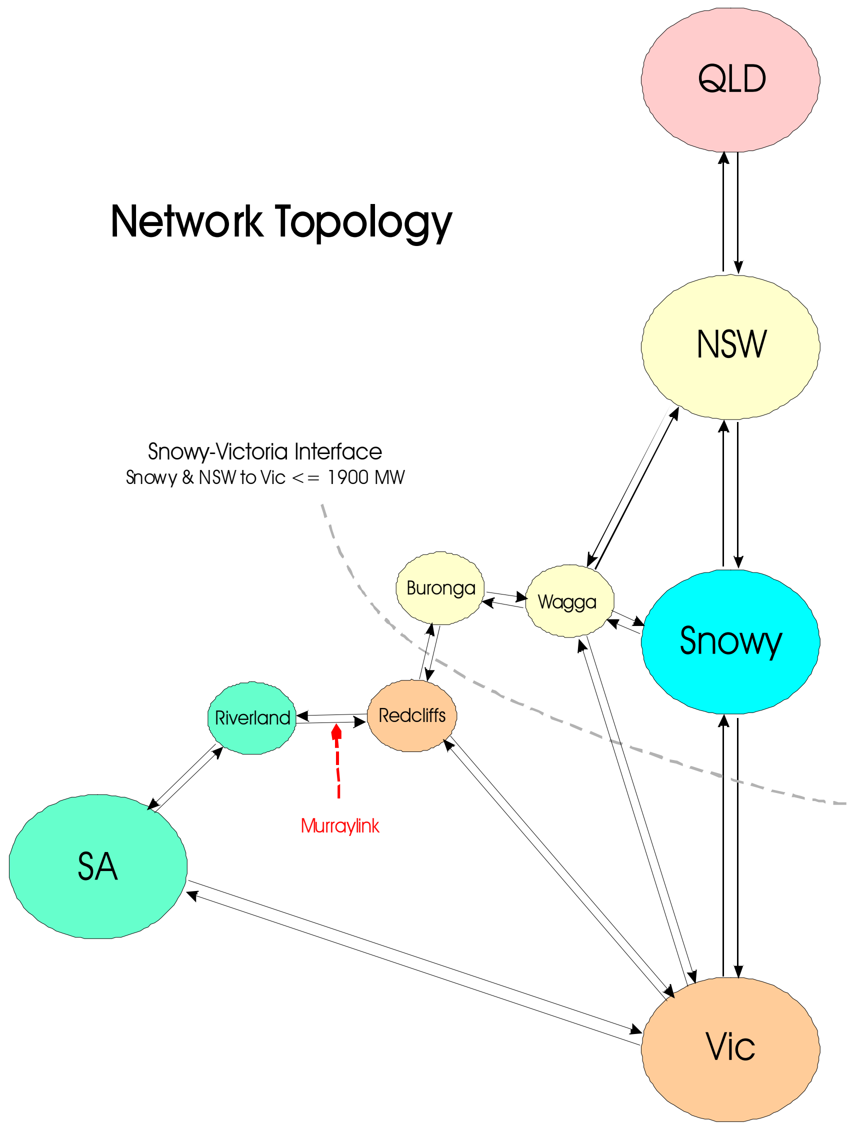

Figure 3.1

3.1.5.2 Modeling Limits in MARS

Interface limits between the five NEM regions have been determined in studies completed by or for the IOWG as part of the recent evaluation of the proposed SNI interconnector. These studies are published on the NEMMCO web site as appendices to the IOWG *Report on Additional Interconnection Augmentation Scenarios for SNI and SNOVIC Economic Assessments*, October 2001. Limits on interfaces between subregions that were not evaluated in the IOWG reports were developed using the thermal capacity of the links as represented in the summer peak load flow. Table 3.1 provides a summary of the limits used in the MARS analysis.

				Limits Adjusted to Approximate Losses	
From	To	Positive Direction	Negative Direction	Positive Direction	Negative Direction
Queensland	New South Wales	1000	500	912	475
New South Wales	Wagga	300	300	300	300
New South Wales	Snowy	1150	2000	1061	1894
Wagga	Buronga	296	296	296	296
Wagga	Snowy	1050	1050	969	994
Wagga	Victoria	817	817	773	792
Buronga	Redcliffs	265	265	251	257
Snowy	Victoria	1500	748	1419	726
Victoria	Redcliffs	461	461	461	461
Victoria	South Australia	500	250	468	243
Redcliffs	Riverland	220	150	207	141
Riverland	South Australia	255	255	255	255

Table 3.1

MARS provides several capabilities that allow limits to be dynamically modeled and composite multi-interface limits to be represented. These include, but are not limited to: (a) creating composite limits that constrain the total simultaneous flow over several interfaces to be less than or equal to a specified value; (b) allowing limits to change with time (for example, seasonal limits, or limits that grow or decline year by year); (c) different limits that apply when certain conditions are met, such as the unavailability of specific generators or area load in excess of a target level; and (d) restricting exports from an area when insufficient resources are available within the area. These capabilities are referred to as Methods a, b, c, and d in the discussion in Section 3.1.5.3.

The MARS modeling is an hourly simulation of the 10 year period 2003–-2012 on a pre-contingent, or “all lines in” basis. Transmission maintenance is assumed to be conducted in periods in which it would have *de minimus* reliability impacts. Only derates of the Heywood interconnector between Victoria and South Australia for electrical storm activity were modeled as transmission outages.

3.1.5.3 Murraylink Limits – Victoria to South Australia

Murraylink operating limits have been modeled using a combination of methods “a” and “d” as described in Section 3.1.5.2. The Victoria region (Vic and Red Cliffs in Figure 3.1 above) is assigned highest reserve priority within MARS. This priority prevents energy from being exported from Victoria unless surplus capacity (generation plus imports) exists within the Victoria region. Additionally, a composite constraint is established that restricts the combined flows from Snowy-to-Vic, Wagga-to-Vic, and Buronga-to-Red Cliffs to less than or equal to 1900 MW. This composite constraint reflects the limits on the overall Snowy-Vic interface after completion of the committed SnoVic400 transmission upgrade project. In addition, a maximum limit of 220 MW over Murraylink from Victoria to South

Australia is also imposed. A summary of the composite constraints is shown in Table 3.2[11].

Composite Constraint Limits

Composite Constraint	Elements						Positive Direction	Negative Direction
SnoVic Composite	SNWY-VIC	+	WAG-VIC	+	BUR-RED	<=	1900	748
NSW-Snowy Comosite	NSW-SNWY	+	WAG-SNWY			<=	1150	2500 S 3000 W

Table 3.2

The simultaneous application of these constraints and the regional prioritization within MARS will have the following effects:

- When conditions apply that would otherwise limit flows on Murraylink from Red Cliffs to the Riverland to 110 MW (no surplus generation in Victoria, and no ability to increase imports into Victoria from Snowy/NSW), MARS will effectively restrict Murraylink flow to 0 MW.

- Every MW of available generation in Victoria will create an additional MW of flow capability over Murraylink from Victoria to South Australia.

- Every 1 MW reduction in Snowy/NSW imports into Victoria will effectively create an additional 1 MW flow capability over Murraylink from Victoria to South Australia, as such reductions in imports into Victoria have the same reliability impact as additional generation in Victoria.

These constraints are more conservative than the limits established in the TEA Report, since the TEA Report indicated that some energy could be transferred directly over Murraylink from NSW to South Australia. The MARS analysis is quite conservative by completely neglecting this additional pathway for energy from NSW to directly reach South Australia.

3.1.5.4 Murraylink Limits – South Australia to Victoria

Different factors potentially constrain the operation of Murraylink when flowing power from South Australia to Victoria. Voltage support considerations are likely to limit flows to no more than 150 MW during most hours. This is reflected in MARS as an absolute limit for all hours.

Thermal limitations from Robertstown to North West Bend will constrain Murraylink flows to 222 MW less the Riverland area load in the summer, and to 280 MW less the Riverland load in the winter. This constraint is implemented in the MARS model using method “c”

[11] VIC-SA, VIC-SA2 and VIC-SA3 represent the Heywood interconnector modeled in three parts to facilitate treatment of Heywood outages (see Section 3.1.6). The composite constraint limits were derived from IOWG reports conducted for the SNI and SnoVic400 economic evaluations.

with a series of constraints based on small increments of Riverland load and the conservative summer Robertstown-NSW rating. At Riverland load below 75 MW, the 150 MW voltage limit dominates. For loads greater than or equal to 75 MW, the Murraylink transfer limits are shown in Table 3.3.

Riverland Load MW	Murraylink Limit MW
10	150
75	147
85	137
95	127
105	117
115	107
120	102
125	97
130	92
135	87
140	82
145	77
150	72
155	67
160	62
165	57
170	52
175	47
180	42
185	37

Table 3.3

Over the 10 year study horizon, maximum forecast Riverland load does not exceed 185 MW. In each simulated hour, MARS will examine the Riverland load and apply the appropriate limit. This approach is conservative, in that the summer formulation (222 MW – Riverland load) is used year-round, and winter limits would result in higher values.

3.1.6 Interconnector Outages

Maintenance and forced outages on interconnectors have the potential to affect reliability in the NEM. We make the assumption that planned maintenance would be undertaken only during periods when it would not jeopardize network reliability. Transmission forced outage rates are typically very low, and we have assumed them to be zero, with one exception. The Heywood interconnector is frequently subject to derates of up to 50%, caused primarily by the threat of nearby electrical storm activity. A report by SAIIR[12] provides information on the size, duration, and frequency of these outages. To incorporate this information, the Heywood interconnector is modeled as three components:

[12] *Transmission Line Performance in South Australia & the SA Transmission Code*, South Australian Independent Industry Regulator, December 2001.

- 50% of total capacity with an outage rate of 1.36% for lightning outages (VIC-SA)
- 10% of total capacity with an outage rate of 4.3% for “other” outages (VIC-SA2)
- 40% with a zero outage rate (VIC-SA3).

3.1.7 Reserve Sharing

The NEM operates as an integrated system under centralized dispatch control. Therefore, generation resources in any region are assumed to be available to meet demands in any other region, subject to transfer limitations. The internal algorithm used by MARS to solve the multi-area reliability problem requires that a priority order be assigned to all regions. The priority order used for this analysis is: Vic (excluding Red Cliffs), Red Cliffs, Riverland, SA (excluding Riverland), Buronga, Wagga, NSW (excluding Buronga and Wagga), Qld, Snowy. When USE occurs, the priority order could affect the region in which the USE appears, but because full reserve sharing is modeled, it will not affect the level of total system USE. The two Victorian regions, Vic (excluding Red Cliffs) and Red Cliffs, are placed highest on the priority list only to facilitate the accurate modeling of Murraylink limits into South Australia, as described above. Effectively, this priority ordering will only allow Murraylink to export power to South Australia when that power is not required in either Red Cliffs or Victoria. (So, this only allows power to flow over Murraylink when that power can either be (a) generated in Victoria or (b) transmitted from Snowy/NSW to Victoria without exceeding the overall 1900 MW composite interface limit).

3.1.8 Chronological Load Traces and Load Uncertainty

The 50% probability of exceedence (POE) chronological half-hourly load traces for the high, medium, and low economic growth load forecasts, as developed by Roam Consulting for the SNI evaluation, have been adapted for use in the MARS analysis. The MARS model utilizes hourly data. Hourly load traces were prepared by averaging the demands for each pair of half-hours in the Roam traces.

The Roam traces were prepared for four of the existing NEM regions: Qld, NSW, Vic, and SA. (Snowy is presumed to have generation but negligible load). To create traces for the modified regions used in the MARS analysis, subregional factors were developed to allocate the total regional load to each of the subregions on an hourly basis. For example, NSW load was proportioned out to the Buronga, Wagga, and NSW (excluding Buronga and Wagga) subregions. The allocation factors were developed using a 2003–4 summer peak load flow for NSW, Vic, and SA. The load flow identifies the load at each bus within the region. The buses were allocated to subregions, and then loads were summed by subregion. The allocation factors were calculated as the total subregional loads divided by total regional load. This method preserves the regional load diversity present in the original Roam load traces, although it may not capture any additional subregional load diversity that might exist outside of the summer peak hours. Constructing detailed load traces for the subregions would have required access to commercially proprietary information.

Load Allocation Factors	
NSW_N	95.6%
Wagga	3.9%
Buronga	0.5%
Vic_S	96.9%
Redcliffs	3.1%
SA_W	97.2%
Riverland	2.8%

The IRPC addressed the uncertainty in load forecasts due to weather and other factors unrelated to long term economic growth by developing alternative load shapes for 10%, 50%, and 90% POE forecasts. MARS allows the impact of load uncertainty to be handled through the specification of up to 10 load uncertainty bands, their associated probabilities and load scaling factors for each band. During the chronological stochastic simulation, reliability measures are calculated each hour for each load uncertainty band (i.e. load is adjusted up or down by the appropriate scale factor for each band), and the results are weighted by the band probabilities.

For each year, the widths and probabilities for the lower five bands and the upper five bands were developed by assuming that (a) the 50% POE and 90% POE forecast peak demands defined one side of a normal distribution, and (b) the 50% POE and 10% POE forecast peak demands defined the other side of a normal distribution with a different variance. Load scaling factors were calculated for each band such that each of the five lower bands would represent 1%, 4%, 5%, 20%, and 20% of the total probability, respectively, consistent with a normal probability distribution with a variance given by the 90% POE and the 50% POE forecast.

Similarly, probabilities and widths were developed for the five upper load uncertainty bands by assuming the 50% POE and 10% POE forecast peak demands defined the upper side of a similar, but different, normal distribution.

3.1.9 Losses

The MARS model does not provide a direct means of modeling dynamic losses on interconnectors. The effect of these losses was represented by using the hourly interconnector losses projected by the appropriate PROSYM run for the same period, and adding the losses to the load of the sending region. This has the effect of forcing MARS to account for the energy lost due to electrical losses at the correct location in the grid.

3.2 Methodology

The MARS model was used to measure Murraylink's reliability impact when interconnector limits (including Murraylink's limits), load diversity, generator maintenance and outage rates are simultaneously considered in a stochastic simulation. Murraylink's reliability benefits are measured as the decrease in annual USE that results when Murraylink is added to a "Without Murraylink" simulation.

3.2.1 Required Simulations

Specifically, this is accomplished in several steps:

1. With and Without Murraylink balanced equilibrium merchant entry schedules are developed as part of the energy benefits analysis using the PROSYM model.

2. Four MARS cases are run using the competitive equilibrium merchant entry planting schedules:

Run	Network Topology	Balanced Equilibrium
1	With Murraylink	With Murraylink
2	With Murraylink	Without Murraylink
3	Without Murraylink	With Murraylink
4	Without Murraylink	Without Murraylink

3. Murraylink's impact on USE is calculated by subtracting month by month, the USE in run 1 from run 3, and the USE in run 2 from run 4. The impact of Murraylink is generally greater when reserve margins are lower, as is the case in runs 1 & 3 because of lower merchant entry. Similarly, the impact is generally lower for runs 2 & 4, which typically have higher reserve margins.

4. To avoid an estimate biased towards the high or low impacts, the USE impacts of both pairs of runs (3 – 1 and 4 – 2) are averaged.

5. The average change in USE month by month is valued at $10,000/MWh.

The MARS analysis is used to directly calculate Murraylink's reliability benefits in the manner described above for the 2003–2012 period. By 2012, the system has converged to a long run economic equilibrium, and USE levels in 2013 and beyond are assumed to remain constant at their 2012 values.

3.2.2 Simulation Outputs

The MARS model calculates several standard reliability statistics for each region in the multi-area system being studied, including expected loss of load (LOLE) in days/year and hours/year, expected loss of energy (LOEE, referred to in this report as unserved energy or USE), loss of load frequency (outages/year), and loss of load duration (hours/outage).

Unserved energy (LOEE or USE) was selected as the most appropriate measure of reliability impacts because:

- It is consistent with the metrics used by the NECA Reliability Panel in its reviews of NEM reliability standards.
- It directly captures impacts across the entire NEM consistently, without requiring adjustments to make outage frequency in a region with relatively large load, such as NSW, comparable to the outage frequency in a smaller load region, such as SA.
- It provides a direct indication of the magnitude of the customer impact of reliability problems.

The MARS simulation runs chronologically on an hourly basis, and reliability statistics are reported on a monthly and annual basis.

3.2.3 Calculation of Benefits

Monthly USE is summed across all regions and valued at $10,000/MWh for each of the four runs identified in section 3.2.1. Monthly differences are calculated between the With and Without Murraylink runs for both pairs of reliability simulations (runs 1 & 3 and runs 2 & 4). The pairs of differences for each month are averaged to develop the best estimate of the Murraylink-induced change in USE for the month.

The total reliability benefit is the cumulative present worth of the monthly USE estimated changes.

Figure 3.2 shows monthly estimates of USE for the medium economic growth scenario. The seasonal patterns and a long term trend that is increasing to the long run equilibrium are clearly visible.

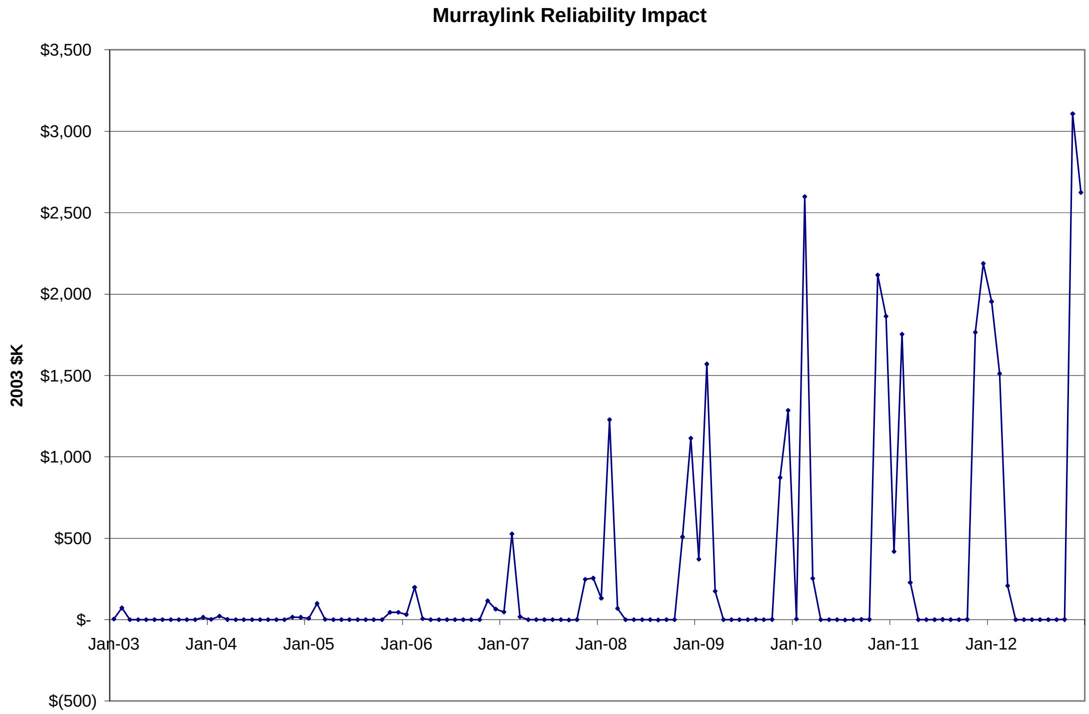
Murraylink Reliability Impact
2003 $K
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$-
$(500)
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12

Figure 3.2

4 Riverland Deferral Benefits

From the summer of 2002–03, Murraylink provides additional supply capacity to the Riverland area, deferring the need for major transmission augmentation up to 2012–13.

In its 2001 Riverland Augmentation Report[13], the South Australian Electricity Supply Industry Planning Council (ESIPC) confirmed that Murraylink has sufficient power transfer capability to satisfy the Riverland supply requirements until at least 2007–08 provided that it is operated in conjunction with a Riverland support facility[14].

If Murraylink is operated as a regulated network asset, services that would have been provided under a network support agreement would be provided as a prescribed service, and a network support agreement will be unnecessary.

The ESIPC[15] also found that scope exists to extend the adequacy of the current transmission system to the Riverland past 2007–08, if some additional static capacitors are installed in the Riverland system for voltage support. If a new transmission line to the Riverland is required in later years, it is reasonable to assume that the static capacitors can be easily disconnected and used in another location.

In its 2002 Annual Planning Review[16], the ESIPC revised its load forecasts. The load forecasts for the Riverland region have been adjusted downwards compared to those upon which the Riverland Augmentation Report was based[17]. The consequence of these adjustments is that Murraylink, in conjunction with the existing transmission lines, meets all Riverland loads until at least 2009–10[18]. Given these more up-to-date forecasts and that the peak load occurs in the summer, the need for additional transmission augmentation to the Riverland is not expected until the summer of 2010–11—three years later than previously estimated by the ESIPC.

In summary, the combination of lower Riverland demand forecasts, the operation of Murraylink as a regulated transmission asset, and the use of static capacitors for enhanced reactive support, means that the need for major transmission augmentation to the Riverland is deferred to at least 2012–13. This deferral of major capital expenditure results in economic benefits to the NEM, described in this report as "Riverland deferral benefits".

[13] *Riverland Augmentation Final Technical Report*, ESIPC, 2001, p. 8.
[14] A "Riverland support facility" might be a network support agreement with MTP, a specific control system, or another scheme that adequately manages Murraylink's operating set point in relation to the Riverland power system characteristics and demand.
[15] *Riverland Augmentation Final Technical Report*, ESIPC, 2001, pp. 17–-8.
[16] *Annual Planning Review*, ESIPC, 2002, pp. 136–7.
[17] *Discussion Paper on Riverland Augmentation*, ESIPC, 2001, p. 22.
[18] In effect, the load levels that previously occurred in 2007–08 do not now occur until after the summer of 2009–10.

4.1 Information Sources

Information on the timing and scope of required augmentations in the Riverland regions come from the ESIPC report *Riverland Augmentation Final Technical Report*, December 2001, p. 11; a submission to the ESIPC from TransGrid titled *Submission to Electricity Supply Industry Planning Council (ESIPC) on 'Discussion Paper on Riverland Augmentation'*, July 27, 2001, p. 2; and ESIPC's June 2002 *Annual Planning Report*.

These documents are available on the ESIPC web site at:

http://www.esipc.gov.sa.au/

Additional information on the cost of transmission upgrades to prevent thermal overload problems was obtained from the report prepared by Burns and Roe Worley, *Murraylink Regulatory Asset Base Valuation*, which is included as one part of the Murraylink Revenue Cap Application, and from a TEA letter to the ACCC dated August 9, 2002.

4.2 Methodology

The ESIPC confirms that the existing transmission network with no augmentations will exhibit inadequate voltage performance beyond 2003–04 conditions, and the risk of thermal overloads on existing transmission lines under N-1 contingency conditions are already present. Murraylink's ability to provide reactive support to the Riverland region will defer the need for additional Riverland voltage support until 2008. Murraylink's power transfer capability from Victoria into the Riverland region will similarly defer the need for additional or larger transmission lines until 2014.

TEUS estimates the cost of the capacitor banks necessary to provide the needed voltage support at $0.5m. The transmission line upgrades (a 275 kV line from Monash to Robertstown) are estimated to cost $40m. Murraylink provides a Riverland deferral benefit equal to the present value of deferring these construction costs until 2008 for the reactive support, and 2013 for the thermal upgrades in the base case. In the low growth case, the thermal upgrades are deferred until 2018. In the high growth case, the thermal upgrade deferral is only until 2011.

5 Scenarios and Results

5.1 Description of Scenarios

TEUS has evaluated three scenarios, based on the 50% POE load forecasts for the low, medium and high economic growth scenarios established by the IRPC in the Stage 1 Report, with load uncertainty as implied by the 10% and 90% POE load forecasts for each economic growth scenario.

5.2 Summary of Results

Table 5.1 below provides the cumulative present worth at May 1, 2003 of gross market benefits for the base, low, and high economic growth scenarios using a 9.25% discount rate. Table 5.2 provides the annual gross market benefits cashflow streams upon which these values are based for the base, low and high economic growth scenarios. Detailed results are provided in Appendix 1.

Cumulative Present Worth of Gross Market Benefits

Discounted to May 1, 2003 at 9.25%

Scenario	Gross Market Benefits ($000)
Base	214,240
Low Growth	135,514
High Growth	225,589

Table 5.1

Gross Market Benefits Annual Cashflow

Date	Base	Low	High
2003	44,016	43,710	43,739
2004	6,290	5,657	6,169
2005	6,253	5,388	7,371
2006	6,987	5,501	9,555
2007	8,381	5,727	66,662
2008	10,970	5,781	11,120
2009	41,009	7,404	(90,303)
2010	70,564	7,714	69,940
2011	39,656	10,275	(156,558)
2012	(8,660)	13,267	569,336
2013	(22,188)	13,267	(13,283)
2014	17,812	13,267	(13,283)
2015	17,812	13,267	(13,283)
2016	17,812	13,267	(13,283)
2017	17,812	13,267	(13,283)
2018	17,812	(26,733)	(13,283)
2019	17,812	13,267	(13,283)
2020	17,812	13,267	(13,283)
2021	17,812	13,267	(13,283)
2022	17,812	13,267	(13,283)
2023	17,812	13,267	(13,283)
2024	17,812	13,267	(13,283)
2025	17,812	13,267	(13,283)
2026	17,812	13,267	(13,283)
2027	17,812	13,267	(13,283)
2028	17,812	13,267	(13,283)
2029	17,812	13,267	(13,283)
2030	17,812	13,267	(13,283)
2031	17,812	13,267	(13,283)
2032	17,812	13,267	(13,283)
2033	17,812	13,267	(13,283)
2034	17,812	13,267	(13,283)
2035	17,812	13,267	(13,283)
2036	17,812	13,267	(13,283)
2037	17,812	13,267	(13,283)
2038	17,812	13,267	(13,283)
2039	17,812	13,267	(13,283)
2040	17,812	13,267	(13,283)
2041	17,812	13,267	(13,283)
2042	11,257	9,295	(14,268)

Table 5.2

5.3 Commentary

Across the scenarios, annual energy benefits remain fairly constant until load increases sufficiently to raise prices (based on assumed short run marginal cost bidding strategies) to a level that begins to support new merchant entry. In the base case, this occurs in 2009. In the high case, merchant plants first become viable in 2006. In the low case, prices do not rise high enough until sometime after 2012, the last year modeled with PROSYM and MARS.

When new plant begins to enter the market, there will be a relative shift of benefits from the energy category to the capacity deferral and reliability categories, and the overall level of annual benefits increases. The low case, because it does not reach market equilibrium by 2012 and because results for years 2013–2042 are extrapolated from 2012, is likely to understate the capacity deferral and reliability benefits in the later years.

The high case sees loads rising high enough to make new baseload coal plants attractive in both the With and Without Murraylink analyses, although Murraylink acts to defer several hundred MW of coal capacity. This creates a large capacity deferral benefit that is partially offset by the loss of low cost energy that the coal plants would provide.

Murraylink will defer the need for certain Riverland transmission network augmentations. The length of the deferral is dependent on the time it takes for Riverland load growth to exceed the capabilities of the existing transmission system as augmented by Murraylink. In the low growth case, this is anticipated to happen in 2018, resulting in a higher Riverland deferral benefit. In the high case, the significant augmentations can only be deferred until 2011 producing a lower benefit.

Appendix 1: Results Detail

The publication of the detailed calculation of monthly results for three economic growth scenarios and three discount rate sensitivities would be quite voluminous. This appendix therefore provides annual gross market benefits cashflow detail for the 40-year study horizon 2003–2042.

Base Case Gross Market Benefit Annual Cashflow							
Date	Energy Savings	Merchant Entry Capital Deferral	Avoided Merchant Entry O&M	Reliability Benefit	Riverland Capital Deferral	Riverland O&M Deferral	Total
2003	3309	0	0	15	40500	192	44016
2004	5946	0	0	55	0	288	6290
2005	5765	0	0	199	0	288	6253
2006	6283	0	0	415	0	288	6987
2007	7000	0	0	1092	0	288	8381
2008	8132	0	0	3050	-500	288	10970
2009	9418	26760	268	4275	0	288	41009
2010	9119	53520	803	6835	0	288	70564
2011	5183	26760	1070	6355	0	288	39656
2012	7602	-26760	803	9407	0	288	-8660
2013	7602	0	803	9407	-40000	0	-22188
2014	7602	0	803	9407	0	0	17812
2015	7602	0	803	9407	0	0	17812
2016	7602	0	803	9407	0	0	17812
2017	7602	0	803	9407	0	0	17812
2018	7602	0	803	9407	0	0	17812
2019	7602	0	803	9407	0	0	17812
2020	7602	0	803	9407	0	0	17812
2021	7602	0	803	9407	0	0	17812
2022	7602	0	803	9407	0	0	17812
2023	7602	0	803	9407	0	0	17812
2024	7602	0	803	9407	0	0	17812
2025	7602	0	803	9407	0	0	17812
2026	7602	0	803	9407	0	0	17812
2027	7602	0	803	9407	0	0	17812
2028	7602	0	803	9407	0	0	17812
2029	7602	0	803	9407	0	0	17812
2030	7602	0	803	9407	0	0	17812
2031	7602	0	803	9407	0	0	17812
2032	7602	0	803	9407	0	0	17812
2033	7602	0	803	9407	0	0	17812
2034	7602	0	803	9407	0	0	17812
2035	7602	0	803	9407	0	0	17812
2036	7602	0	803	9407	0	0	17812
2037	7602	0	803	9407	0	0	17812
2038	7602	0	803	9407	0	0	17812
2039	7602	0	803	9407	0	0	17812
2040	7602	0	803	9407	0	0	17812
2041	7602	0	803	9407	0	0	17812
2042	6981	0	602	3674	0	0	11257

Low Case Gross Market Benefit Annual Cashflow							
Date	Energy Savings	Merchant Entry Capital Deferral	Merchant Entry O&M Deferral	Reliability Benefit	Riverland Capital Deferral	Riverland O&M Deferral	Total
2003	3207	0	0	4	40500	192	43710
2004	5643	0	0	14	0	288	5657
2005	5345	0	0	43	0	288	5388
2006	5407	0	0	95	0	288	5501
2007	5541	0	0	186	0	288	5727
2008	5894	0	0	388	-500	288	5781
2009	6703	0	0	701	0	288	7404
2010	6472	0	0	1242	0	288	7714
2011	7960	0	0	2316	0	288	10275
2012	9039	0	0	4228	0	288	13267
2013	9039	0	0	4228	0	288	13267
2014	9039	0	0	4228	0	288	13267
2015	9039	0	0	4228	0	288	13267
2016	9039	0	0	4228	0	288	13267
2017	9039	0	0	4228	0	288	13267
2018	9039	0	0	4228	-40000	0	-26733
2019	9039	0	0	4228	0	0	13267
2020	9039	0	0	4228	0	0	13267
2021	9039	0	0	4228	0	0	13267
2022	9039	0	0	4228	0	0	13267
2023	9039	0	0	4228	0	0	13267
2024	9039	0	0	4228	0	0	13267
2025	9039	0	0	4228	0	0	13267
2026	9039	0	0	4228	0	0	13267
2027	9039	0	0	4228	0	0	13267
2028	9039	0	0	4228	0	0	13267
2029	9039	0	0	4228	0	0	13267
2030	9039	0	0	4228	0	0	13267
2031	9039	0	0	4228	0	0	13267
2032	9039	0	0	4228	0	0	13267
2033	9039	0	0	4228	0	0	13267
2034	9039	0	0	4228	0	0	13267
2035	9039	0	0	4228	0	0	13267
2036	9039	0	0	4228	0	0	13267
2037	9039	0	0	4228	0	0	13267
2038	9039	0	0	4228	0	0	13267
2039	9039	0	0	4228	0	0	13267
2040	9039	0	0	4228	0	0	13267
2041	9039	0	0	4228	0	0	13267
2042	6696	0	0	2599	0	0	9295

High Case Gross Market Benefit Annual Cashflow							
Date	Energy Savings	Merchant Entry Capital Deferral	Merchant Entry O&M Deferral	Reliability Benefit	Riverland Capital Deferral	Riverland O&M Deferral	Total
2003	2991	0	0	56	40500	192	43739
2004	5665	0	0	215	0	288	6169
2005	6311	0	0	772	0	288	7371
2006	7408	0	0	1859	0	288	9555
2007	9139	52965	530	3740	0	288	66662
2008	4931	0	530	5871	-500	288	11120
2009	9387	-105931	-530	6483	0	288	-90303
2010	5557	52965	0	11129	0	288	69940
2011	74849	-201269	-2013	11875	-40000	0	-156558
2012	-24886	582620	3814	7790	0	0	569336
2013	-24886	0	3814	7790	0	0	-13283
2014	-24886	0	3814	7790	0	0	-13283
2015	-24886	0	3814	7790	0	0	-13283
2016	-24886	0	3814	7790	0	0	-13283
2017	-24886	0	3814	7790	0	0	-13283
2018	-24886	0	3814	7790	0	0	-13283
2019	-24886	0	3814	7790	0	0	-13283
2020	-24886	0	3814	7790	0	0	-13283
2021	-24886	0	3814	7790	0	0	-13283
2022	-24886	0	3814	7790	0	0	-13283
2023	-24886	0	3814	7790	0	0	-13283
2024	-24886	0	3814	7790	0	0	-13283
2025	-24886	0	3814	7790	0	0	-13283
2026	-24886	0	3814	7790	0	0	-13283
2027	-24886	0	3814	7790	0	0	-13283
2028	-24886	0	3814	7790	0	0	-13283
2029	-24886	0	3814	7790	0	0	-13283
2030	-24886	0	3814	7790	0	0	-13283
2031	-24886	0	3814	7790	0	0	-13283
2032	-24886	0	3814	7790	0	0	-13283
2033	-24886	0	3814	7790	0	0	-13283
2034	-24886	0	3814	7790	0	0	-13283
2035	-24886	0	3814	7790	0	0	-13283
2036	-24886	0	3814	7790	0	0	-13283
2037	-24886	0	3814	7790	0	0	-13283
2038	-24886	0	3814	7790	0	0	-13283
2039	-24886	0	3814	7790	0	0	-13283
2040	-24886	0	3814	7790	0	0	-13283
2041	-24886	0	3814	7790	0	0	-13283
2042	-21550	0	3178	4104	0	0	-14268

Appendix 2: Characteristics of Existing and Committed Generation

Generator	Region	Summer Max MW	Winter Max MW	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Maint (Days)	Mean Time to Repair (Hours)	SRMC Bid $/MWH
Anglesea	VIC_S	160		1/1/2000	12/31/2099	1.0141	0.0186	10	24	9.4
Bairnsdale	VIC_S	31	43	1/1/2000	12/31/2099	0.9850	0.0100	0	24	40
Barcaldine	QLD	55	57	1/1/2000	12/31/2099	0.7069	0.0446	0	34	34
Barron Gorge 1	QLD	30		1/1/2000	12/31/2099	1.1616	0.0012	0	24	0
Barron Gorge 2	QLD	30		1/1/2000	12/31/2099	1.1616	0.0012	0	24	0
Bayswater 1	NSW_N	660		1/1/2000	12/31/2099	0.9595	0.0261	17	37	12.6
Bayswater 2	NSW_N	660		1/1/2000	12/31/2099	0.9595	0.0261	17	37	12.6
Bayswater 3	NSW_N	660		1/1/2000	12/31/2099	0.9595	0.0261	17	37	12.6
Bayswater 4	NSW_N	660		1/1/2000	12/31/2099	0.9595	0.0261	17	37	12.6
Bendeela	NSW_N	80		1/1/2000	12/31/2099	1.0000	0.0117	0	37	0
Blowering	SNOWY	80		1/1/2000	12/31/2099	0.9898	0.0000	0	0	0
Callide A 1	QLD	30		1/1/2000	12/31/2099	0.8810	0.0500	19	37	16.4
Callide A 2	QLD	30		1/1/2000	12/31/2099	0.8810	0.0500	19	37	16.4
Callide A 3	QLD	30		1/1/2000	12/31/2099	0.8810	0.0500	19	37	16.4
Callide A 4	QLD	30		1/1/2000	12/31/2099	0.8810	0.0500	19	37	16.4
Callide B 1	QLD	350		1/1/2000	12/31/2099	0.9030	0.0500	19	37	11.89
Callide B 3	QLD	350		1/1/2000	12/31/2099	0.9030	0.0500	19	37	11.89
Callide C 3	QLD	420		1/1/2000	12/31/2099	0.9010	0.0500	19	37	10.65
Callide C 4	QLD	420		1/1/2000	12/31/2099	0.9010	0.0500	19	37	10.65
Collinsville A 1	QLD	30		1/1/2000	12/31/2099	1.0604	0.0500	19	37	22.1
Collinsville A 2	QLD	30		1/1/2000	12/31/2099	1.0604	0.0500	19	37	22.1
Collinsville A 3	QLD	30		1/1/2000	12/31/2099	1.0604	0.0500	19	37	22.1
Collinsville A 4	QLD	30		1/1/2000	12/31/2099	1.0604	0.0500	19	37	22.1
Collinsville B	QLD	66		1/1/2000	12/31/2099	1.0604	0.0500	19	37	20.7
Dry Creek 1	SA_W	45	52	1/1/2000	12/31/2099	1.0021	0.0446	0	34	43.2
Dry Creek 2	SA_W	45	52	1/1/2000	12/31/2099	1.0021	0.0446	0	34	43.2
Dry Creek 3	SA_W	45	52	1/1/2000	12/31/2099	1.0021	0.0446	0	34	43.2
Energy Brix Complex 1	VIC_S	20		1/1/2000	12/31/2099	1.0000	0.0186	10	24	14.2
Energy Brix Complex 2-01	VIC_S	30		1/1/2000	12/31/2099	1.0000	0.0186	10	24	14.2
Energy Brix Complex 2-02	VIC_S	30		1/1/2000	12/31/2099	1.0000	0.0186	10	24	14.2
Energy Brix Complex 2-03	VIC_S	30		1/1/2000	12/31/2099	1.0000	0.0186	10	24	14.2
Energy Brix Complex 3	VIC_S	60		1/1/2000	12/31/2099	1.0000	0.0186	10	24	12
Eraring 1	NSW_N	660		1/1/2000	12/31/2099	0.9841	0.0261	17	37	17.07
Eraring 2	NSW_N	660		1/1/2000	12/31/2099	0.9841	0.0261	17	37	17.07
Eraring 3	NSW_N	660		1/1/2000	12/31/2099	0.9841	0.0261	17	37	17.07
Eraring 4	NSW_N	660		1/1/2000	12/31/2099	0.9841	0.0261	17	37	17.07
Gladstone 1	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Gladstone 2	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Gladstone 3	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Gladstone 4	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Gladstone 5	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Gladstone 6	QLD	280		1/1/2000	12/31/2099	0.9181	0.0500	19	37	16.23
Guthega	SNOWY	60		1/1/2000	12/31/2099	0.9671	0.0000	0	0	0
Hazelwood 1	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 2	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 3	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 4	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 5	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 6	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 7	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hazelwood 8	VIC_S	200	205	1/1/2000	12/31/2099	0.9614	0.0186	10	24	6.6
Hume-NSW	NSW_N	29	0	1/1/2000	12/31/2099	0.9965	0.0000	0	0	0
Hume-Vic	VIC_S	29	0	1/1/2000	12/31/2099	1.0038	0.0000	0	0	0
Hunter Valley 1	NSW_N	22	25.5	1/1/2000	12/31/2099	0.9612	0.0117	0	37	224
Hunter Valley 2	NSW_N	22	25.5	1/1/2000	12/31/2099	0.9612	0.0117	0	37	224
Jerralang A 1	VIC_S	52	55.5	1/1/2000	12/31/2099	0.9577	0.0115	0	24	44.14
Jerralang A 2	VIC_S	52	55.5	1/1/2000	12/31/2099	0.9577	0.0115	0	24	44.14
Jerralang A 3	VIC_S	52	55.5	1/1/2000	12/31/2099	0.9577	0.0115	0	24	44.14
Jerralang A 4	VIC_S	52	55.5	1/1/2000	12/31/2099	0.9577	0.0115	0	24	44.14
Jerralang B 1	VIC_S	76	81	1/1/2000	12/31/2099	0.9577	0.0115	0	24	42.58

Generator	Region	Summer Max MW	Winter Max MW	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Maint (Days)	Mean Time to Repair (Hours)	SRMC Bid $/MWH
Jerralang B 2	VIC_S	76	81	1/1/2000	12/31/2099	0.9577	0.0115	0	24	42.58
Jerralang B 3	VIC_S	76	81	1/1/2000	12/31/2099	0.9577	0.0115	0	24	42.58
Kangaroo Valley 1	NSW_N	80		1/1/2000	12/31/2099	1.0000	0.0000	0	0	0
Kangaroo Valley 2	NSW_N	80		1/1/2000	12/31/2099	1.0000	0.0000	0	0	0
Kareeya 1	QLD	18		1/1/2000	12/31/2099	1.1146	0.0012	0	24	0
Kareeya 2	QLD	18		1/1/2000	12/31/2099	1.1146	0.0012	0	24	0
Kareeya 3	QLD	18		1/1/2000	12/31/2099	1.1146	0.0012	0	24	0
Kareeya 4	QLD	18		1/1/2000	12/31/2099	1.1146	0.0012	0	24	0
Ladbroke Grove 1	SA_W	36	43	1/1/2000	12/31/2099	0.9225	0.0444	0	24	12.8
Ladbroke Grove 2	SA_W	36	43	1/1/2000	12/31/2099	0.9225	0.0444	0	24	12.8
Liddell 1	NSW_N	500		1/1/2000	12/31/2099	0.9612	0.0261	17	37	12.43
Liddell 2	NSW_N	500		1/1/2000	12/31/2099	0.9612	0.0261	17	37	12.43
Liddell 3	NSW_N	500		1/1/2000	12/31/2099	0.9612	0.0261	17	37	12.43
Liddell 4	NSW_N	500		1/1/2000	12/31/2099	0.9612	0.0261	17	37	12.43
Loy Yang A 1	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.29
Loy Yang A 2	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.29
Loy Yang A 3	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.29
Loy Yang A 4	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.29
Loy Yang B 1	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.37
Loy Yang B 2	VIC_S	500		1/1/2000	12/31/2099	0.9639	0.0186	10	24	5.37
Mackay GT	QLD	30	34	1/1/2000	12/31/2099	1.0547	0.0446	0	34	216
Middle Ridge	QLD	44	52	1/1/2000	12/31/2099	0.9929	0.0446	0	34	224
Millmerran 1	QLD	426	431.5	1/1/2000	12/31/2099	0.9774	0.0500	19	37	6.05
Millmerran 2	QLD	426	431.5	1/1/2000	12/31/2099	0.9774	0.0500	19	37	6.05
Mintaro	SA_W	76	90	1/1/2000	12/31/2099	0.9859	0.0100	0	24	41
Mt Piper 1	NSW_N	660		1/1/2000	12/31/2099	0.9718	0.0261	17	37	15.6
Mt Piper 2	NSW_N	660		1/1/2000	12/31/2099	0.9718	0.0261	17	37	15.6
Mt Stuart 1	QLD	144	152	1/1/2000	12/31/2099	1.1291	0.0446	0	34	147.2
Mt Stuart 2	QLD	144	152	1/1/2000	12/31/2099	1.1291	0.0446	0	34	147.2
Munmorah 3	NSW_N	300		1/1/2000	12/31/2099	0.9917	0.0261	17	37	19.82
Munmorah 4	NSW_N	300		1/1/2000	12/31/2099	0.9917	0.0261	17	37	19.82
Murray 1-01	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-02	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-03	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-04	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-05	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-06	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-07	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-08	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-09	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 1-10	SNOWY	95		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 2-01	SNOWY	138		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 2-02	SNOWY	138		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 2-03	SNOWY	138		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Murray 2-04	SNOWY	138		1/1/2000	12/31/2099	1.0010	0.0000	0	0	0
Newport	VIC_S	500	510	1/1/2000	12/31/2099	0.9918	0.0115	10	24	27.56
Northern NSW 1	NSW_N	22	25	1/1/2000	12/31/2099	0.9823	0.0117	0	37	232
Northern NSW 2	NSW_N	22	25	1/1/2000	12/31/2099	0.9823	0.0117	0	37	232
Northern SA 1	SA_W	260		1/1/2000	12/31/2099	0.9802	0.0188	32	39	12.5
Northern SA 2	SA_W	260		1/1/2000	12/31/2099	0.9802	0.0188	32	39	12.5
Oakey 1	QLD	160	172	1/1/2000	12/31/2099	0.9945	0.0446	0	34	160.1
Oakey 2	QLD	160	172	1/1/2000	12/31/2099	0.9945	0.0446	0	34	160.1
Osborne A	SA_W	175	190	1/1/2000	12/31/2099	0.9993	0.0444	0	24	20.04
Pelican Point 1	SA_W	150	162.3333	1/1/2000	12/31/2099	1.0000	0.0444	0	24	18.72
Pelican Point 2	SA_W	150	162.3333	1/1/2000	12/31/2099	1.0000	0.0444	0	24	18.72
Pelican Point 3	SA_W	150	162.3333	1/1/2000	12/31/2099	1.0000	0.0444	0	24	18.72
Playford 1	SA_W	53	45	1/1/2000	12/31/2099	0.9762	0.0446	32	34	26
Playford 2	SA_W	53	45	1/1/2000	12/31/2099	0.9762	0.0446	32	34	26
Playford 3	SA_W	53	45	1/1/2000	12/31/2099	0.9762	0.0446	32	34	26
Playford 4	SA_W	53	45	1/1/2000	12/31/2099	0.9762	0.0446	32	34	26

Generator	Region	Summer Max MW	Winter Max MW	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Maint (Days)	Mean Time to Repair (Hours)	SRMC Bid $/MWH
Port Lincoln 1	SA_W	20	25	1/1/2000	12/31/2099	1.0122	0.0446	0	34	216
Port Lincoln 2	SA_W	20	25	1/1/2000	12/31/2099	1.0122	0.0446	0	34	216
Redbank	NSW_N	150		1/1/2000	12/31/2099	0.9603	0.0261	17	37	22
Roma 7	QLD	30	37	1/1/2000	12/31/2099	0.9360	0.0012	0	24	57
Roma 8	QLD	30	37	1/1/2000	12/31/2099	0.9360	0.0012	0	24	57
SA-GT 1	SA_W	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
SA-GT 2	SA_W	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
SA-GT 3	SA_W	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Smithfield	NSW_N	166	179	1/1/2000	12/31/2099	1.0020	0.0261	17	37	31.75
Snuggery 1	SA_W	15	21	1/1/2000	12/31/2099	0.9751	0.0446	0	34	216
Snuggery 2	SA_W	15	21	1/1/2000	12/31/2099	0.9751	0.0446	0	34	216
Snuggery 3	SA_W	15	21	1/1/2000	12/31/2099	0.9751	0.0446	0	34	216
Stanwell 1	QLD	350		1/1/2000	12/31/2099	0.9106	0.0500	19	37	13.87
Stanwell 2	QLD	350		1/1/2000	12/31/2099	0.9106	0.0500	19	37	13.87
Stanwell 3	QLD	350		1/1/2000	12/31/2099	0.9106	0.0500	19	37	13.87
Stanwell 4	QLD	350		1/1/2000	12/31/2099	0.9106	0.0500	19	37	13.87
Southern Hydro	VIC_S	451		1/1/2000	12/31/2099	1.0000	0.0000	0	0	0
Swanbank A 1	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank A 2	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank A 3	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank A 4	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank A 5	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank A 6	QLD	68		1/1/2000	12/31/2099	0.9988	0.0500	19	37	17.92
Swanbank B 1	QLD	125		1/1/2000	12/31/2099	1.0015	0.0500	19	37	14.56
Swanbank B 2	QLD	125		1/1/2000	12/31/2099	1.0015	0.0500	19	37	14.56
Swanbank B 3	QLD	125		1/1/2000	12/31/2099	1.0015	0.0500	19	37	14.56
Swanbank B 4	QLD	125		1/1/2000	12/31/2099	1.0015	0.0500	19	37	14.56
Swanbank C	QLD	25	28	1/1/2000	12/31/2099	1.0017	0.0446	0	34	216
Swanbank D	QLD	32	37	1/1/2000	12/31/2099	1.0017	0.0446	0	34	177
Swanbank E	QLD	355	385	1/1/2000	12/31/2099	1.0015	0.0100	14	24	22
Tarong 1	QLD	350		1/1/2000	12/31/2099	0.9755	0.0500	19	37	13.32
Tarong 2	QLD	350		1/1/2000	12/31/2099	0.9755	0.0500	19	37	13.32
Tarong 3	QLD	350		1/1/2000	12/31/2099	0.9755	0.0500	19	37	13.32
Tarong 4	QLD	350		1/1/2000	12/31/2099	0.9755	0.0500	19	37	13.32
Tarong North	QLD	450		1/1/2000	12/31/2099	0.9755	0.0500	19	37	11.81
Torrens A 1	SA_W	120		1/1/2000	12/31/2099	0.9997	0.0444	0	24	24.2
Torrens A 2	SA_W	120		1/1/2000	12/31/2099	0.9997	0.0444	0	24	24.2
Torrens A 3	SA_W	120		1/1/2000	12/31/2099	0.9997	0.0444	0	24	24.2
Torrens A 4	SA_W	120		1/1/2000	12/31/2099	0.9997	0.0444	0	24	24.2
Torrens B 1	SA_W	200		1/1/2000	12/31/2099	0.9997	0.0188	32	39	22.11
Torrens B 2	SA_W	200		1/1/2000	12/31/2099	0.9997	0.0188	32	39	22.11
Torrens B 3	SA_W	200		1/1/2000	12/31/2099	0.9997	0.0188	32	39	22.11
Torrens B 4	SA_W	200		1/1/2000	12/31/2099	0.9997	0.0188	32	39	22.11
Townsville GT	QLD	165	174	1/1/2000	12/31/2099	1.1291	0.0446	0	34	148.4
Tumut 1-01	SNOWY	82		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 1-02	SNOWY	82		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 1-03	SNOWY	82		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 1-04	SNOWY	82		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 2-01	SNOWY	72		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 2-02	SNOWY	72		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 2-03	SNOWY	72		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 2-04	SNOWY	72		1/1/2000	12/31/2099	1.0018	0.0000	0	0	0
Tumut 3-01	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.9990	0	8760	0
Tumut 3-02	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.0000	0	0	0
Tumut 3-03	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.0000	0	0	0
Tumut 3-04	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.0000	0	0	0
Tumut 3-05	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.0000	0	0	0
Tumut 3-06	SNOWY	250		1/1/2000	12/31/2099	1.0053	0.0000	0	0	0
Vales Point 5	NSW_N	550	660	1/1/2000	12/31/2099	0.9891	0.0261	17	37	16.2
Vales Point 6	NSW_N	550	660	1/1/2000	12/31/2099	0.9891	0.0261	17	37	16.2

Generator	Region	Summer Max MW	Winter Max MW	Assumed In-Service	Assumed Retire Date	Marginal Loss Factor	FOR	Annual Maint (Days)	Mean Time to Repair (Hours)	SRMC Bid $/MWH
Vic-GT 1	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 2	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 3	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 4	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 5	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 6	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 7	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Vic-GT 8	VIC_S	50		1/1/2000	12/31/2099	1.0000	0.0100	0	24	40
Wallerawang 7	NSW_N	500		1/1/2000	12/31/2099	0.9720	0.0261	17	37	15.88
Wallerawang 8	NSW_N	500		1/1/2000	12/31/2099	0.9720	0.0261	17	37	15.88
Wivenhoe 1	QLD	250		1/1/2000	12/31/2099	0.9955	0.0012	0	24	0
Wivenhoe 2	QLD	250		1/1/2000	12/31/2099	0.9955	0.0012	0	24	0
Yallorn W 1	VIC_S	350		1/1/2000	12/31/2099	0.9567	0.0186	10	24	7.35
Yallorn W 2	VIC_S	350		1/1/2000	12/31/2099	0.9567	0.0186	10	24	7.35
Yallorn W 3	VIC_S	375		1/1/2000	12/31/2099	0.9567	0.0186	10	24	7.25
Yallorn W 4	VIC_S	375		1/1/2000	12/31/2099	0.9567	0.0186	10	24	7.25

Appendix 3: Summary of Load Forecasts

	Base Case - Medium Economic Growth							
	Annual Energy (GWH)				Peak Demand (MW)			
Year	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2003	73,991	38,117	13,688	49,538	12,560	6,362	3,131	8,792
2004	76,164	39,931	14,106	50,747	12,782	6,646	3,085	9,070
2005	77,523	41,530	14,421	51,728	12,904	6,895	3,174	9,321
2006	79,027	43,155	14,737	52,689	13,054	7,163	3,259	9,559
2007	80,117	44,811	14,999	53,464	13,215	7,436	3,335	9,784
2008	81,377	46,336	15,258	54,420	13,411	7,615	3,410	10,015
2009	82,457	47,657	15,455	55,037	13,673	7,894	3,503	10,265
2010	83,581	49,499	15,795	55,764	13,894	8,205	3,607	10,502
2011	84,555	51,395	16,217	56,464	14,119	8,442	3,714	10,745
2012	85,919	53,539	16,707	57,360	14,347	8,706	3,824	10,994

	High Economic Growth							
	Annual Energy (GWH)				Peak Demand (MW)			
Year	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2003	75,562	39,863	14,196	50,826	12,925	6,753	3,255	9,029
2004	78,189	42,424	14,779	52,244	13,166	7,195	3,207	9,354
2005	80,050	45,013	15,210	53,422	13,378	7,706	3,316	9,659
2006	82,082	47,864	15,628	54,716	13,600	8,185	3,424	9,979
2007	83,733	50,847	16,038	55,895	13,981	8,703	3,530	10,284
2008	85,713	53,687	16,427	57,261	14,243	9,116	3,630	10,602
2009	87,437	56,220	16,737	58,259	14,515	9,649	3,753	10,928
2010	89,151	59,520	17,203	59,437	14,726	10,290	3,882	11,259
2011	90,695	63,089	17,733	60,681	14,940	10,666	4,016	10,788
2012	92,662	66,922	18,342	62,192	15,158	11,164	4,155	11,600

	Low Economic Growth							
	Annual Energy (GWH)				Peak Demand (MW)			
Year	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2003	72,381	36,459	13,219	48,629	12,273	6,008	3,021	8,613
2004	74,203	37,533	13,531	49,517	12,484	6,143	2,976	8,815
2005	75,172	38,214	13,777	50,163	12,546	6,275	3,045	8,992
2006	76,211	38,967	13,982	50,753	12,627	6,331	3,111	9,155
2007	76,740	39,857	14,150	51,093	12,698	6,464	3,172	9,287
2008	77,372	40,568	14,316	51,577	12,650	6,582	3,229	9,423
2009	77,806	41,086	14,376	51,772	12,941	6,605	3,290	9,571
2010	78,355	42,107	14,500	52,162	13,172	6,743	3,357	9,730
2011	78,768	43,238	14,666	52,607	13,407	6,880	3,425	9,329
2012	79,540	44,575	14,891	53,279	13,646	6,959	3,495	9,892

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15. *Regulatory Test – Murraylink Discount Rate*, letter from Mr. Peter Thornely of Deloitte Touche Tohmatsu to MTC, October 11, 2002.

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Appendix E: Report – Review of TEUS Market Benefits Report - Charles River Associates (Asia Pacific)

FINAL

Assessment of Murraylink Market Benefits

Comments on TransEnergie US Study

Submitted to

Murraylink Transmission Partnership
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11 October 2002

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EXECUTIVE SUMMARY

This report summarises my review of the report prepared by TransEnergie US (TEUS) titled "The Estimation of Murraylink Market Benefits" dated October 11, 2002. I have focussed primarily on:

- The methodology and the models adopted to implement the methodology;
- Compliance of the methodology to estimate market benefit of an interconnector with the intent of the regulatory test promulgated by the Australian Competition and Consumer Commission (ACCC); and
- A broad review of the assumptions that have been used in the study and the model results as presented in the TEUS report.

SCOPE OF THE REVIEW

The TEUS study employed a combination of market and reliability models to estimate the full range of market benefits that can be attributed to Murraylink. This review specifically focuses on the methodological approach, the models employed, a broad review of the inputs and assumptions and the results obtained from the models as presented in the TEUS study report.

I have also commented on whether the assessment of Murraylink market benefit complies with the requirements of the regulatory test promulgated by ACCC. However, it is not the intent of the TEUS report, and hence this review, to consider all the requirements of the regulatory test and in particular those pertaining to the consideration of alternative projects.

SUMMARY OF CONCLUSIONS

TEUS study has adopted a definition of market benefit that comprises four primary components, namely:

- "Energy benefits" i.e., the benefits that accrue due to economy power exchanges over the interconnector leading to savings in fuel, other variable O&M costs as well as reduction in voluntary load curtailments;
- "Capacity deferral benefits" or the fact that an interconnector allows more efficient sharing of reserve and energy production capacity across interconnected regions which imply lower new capacity requirements in the long run to meet the reliability and energy needs of the system as a whole;

- "Reliability benefits" – unforeseen events such as forced outages of generators and transmission lines and/or unusually high demand may lead to unserved energy for the system. The presence of a new interconnector equips the system better to handle such contingencies and consequently lower the amount of expected unserved energy or USE; and finally

- "Riverland deferral benefits" due to the deferral of planned transmission augmentation in the Riverland area.

This definition of market benefit is appropriate. There are a few critical issues that forms the basis of estimating market benefit, namely:

1. Bidding behaviour by generators: TEUS have assumed a short run marginal cost based bidding behaviour which effectively means generators do not exercise market power. This is consistent with the methodology put forward by IRPC in a prior study for SNI evaluation[1] and meant to provide a conservative estimate of the market benefits related to fuel cost savings;

2. New entry: TEUS use a profitability test to determine if new market entry should occur i.e., additional MW entry occurs only if the post-entry market prices can cover the fixed costs over and above variable costs. This is a reasonable assumption and a very similar approach was adopted by IRPC for evaluation of SNI;

3. Reliability: TEUS have adopted a detailed reliability simulation approach to estimate the reliability impacts of adding a new interconnector. The differential USE (i.e., USE without and with Murraylink in place) is valued at VoLL (value of lost load). This seems to be a reasonable approach to capture the impact of unforeseen outage and high load events;

4. Transmission: TEUS have considered a zonal representation of the system which is consistent with both IRPC's approach for SNI and the NEM dispatch realities. The MW transfer limits have been obtained using an AC load flow.

My review of the general methodological approach adopted by TEUS suggests that it is broadly reasonable for the purpose of evaluation of benefit associated with an interconnector.

The models used by TEUS to implement the methodology are summarised as follows:

1 Inter Regional Planning Committee (IRPC), Stage 1 Report – Proposed SNI Interconnector, Version No. V014, October 26, 2001.

1. Henwood's PROSYM model has been employed as the central analytic tool that performs a chronological hourly dispatch for multiple years taking into account a "transportation type" transmission model. This directly provides an accurate estimate of the system cost to meet energy requirement. TEUS assume a conservative short run marginal cost bidding behaviour that forms the basis for generator cost representation in PROSYM. Difference between the total system cost without and with the interconnector under study provides an estimate of the energy cost savings benefit;

2. A profitability test around PROSYM is used to determine the quantum of new entry in each year. This is an iterative process that involves running PROSYM repeatedly with different new (market) entry profiles and the difference between the quantum of new entry without and with the interconnector provides an estimate of the capacity deferral benefits;

3. General Electric's MARS model has been employed as a detailed reliability indices calculation tool. MARS is also a chronological hourly model that performs a detailed sequential Monte Carlo simulation of generator/transmission line outages and enables a scenario representation of load uncertainties. TEUS have also endeavoured to maintain a high degree of consistency across PROSYM and MARS. Difference between the USE without and with the new interconnector provides an estimate of the reliability benefit attributable to the interconnector. This is valued at the cost of unserved energy or value of lost load (VoLL); and finally,

4. PTI's Power System Simulator for Engineers (PSS/E) is used to perform an AC load flow analysis. Although the TEUS study did not directly perform load flow analyses, it relied upon transfer limits developed by TransEnergie Australia (TEA) and confirmed by Power Technologies, Inc. (PTI). TEA and PTI used PTI's load flow analysis model Power System Simulator for Engineers (PSS/E) to perform the AC load flow analysis. This analysis is used to primarily calculate the MW transfer limits under different loading conditions and network augmentation scenarios.

This implementation scheme is broadly appropriate and consistent with the methodology.

I have also reviewed the data sources and assumptions as presented in the TEUS report and conclude that these are broadly reasonable and consistent wherever possible with those used in the IRPC study for SNI evaluation.

Finally, the regulatory test promulgated by ACCC states:

"A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the <u>*market benefit*</u> having regard to a number of different <u>alternative projects</u>, <u>timing</u> and <u>market development scenarios</u>;" [*italics* as in original, <u>underline added</u>]

Consideration of alternative projects has clearly been identified as a major requirement in the test. However, as I have mentioned before, the TEUS study concerns the estimation of market benefit for Murraylink only or for that matter any other interconnector/network augmentations that provides a similar level of power transfer capability on a stand alone basis. Hence, this review also focuses solely on the appropriateness of the market benefit assessment process. I understand that there are separate studies being undertaken by Murraylink Transmission Company (MTC) and/or its consultants to address the issue relating to alternative projects.

Based on the definition of market benefit, methodology and the specific implementation scheme adopted and taking into account the definition of the regulatory test as well as various practical considerations, I conclude that the TEUS analysis complies with the intent of the regulatory test.

In summary, I conclude that:

- The definition of market benefit and the methodology to calculate the four major components therein, namely, operating cost savings, capacity deferral, reliability and all other benefits including the deferral of transmission augmentation, is appropriate, reasonably accurate and robust. The different elements of the benefits can be calculated using this methodology in a coherent manner free from any distortions due to double counting and inconsistency;

- The methodology complies with the intent of the regulatory test; and

- The assumptions that have been used to obtain the numerical estimates of the market benefits are consistent with those used in a prior study by the Australian Inter Regional Planning Committee (IRPC) on SNI interconnection benefits.

1. INTRODUCTION

This report summarises my review of the draft report prepared by TransEnergie US (TEUS) titled "The Estimation of Murraylink Market Benefits" dated October 11, 2002. I have focussed primarily on:

- The methodology adopted and the models adopted to implement the methodology;
- Compliance of the methodology to estimate market benefit of an interconnector with the intent of the regulatory test promulgated by the Australian Competition and Consumer Commission (ACCC); and
- A broad review of the assumptions that have been used in the study and the model results as presented in the TEUS report.

1.1. SCOPE OF THE REVIEW

The TEUS study has employed a set of market and reliability models to estimate the full range of market benefits that can be attributed to Murraylink. This review specifically focuses on the methodological approach, the models employed, a broad review of the inputs and assumptions and the results obtained from the models as presented in the TEUS study report.

I have also commented on whether the assessment of Murraylink market benefit complies with the requirements of the regulatory test promulgated by ACCC. However, it is not the intent of the TEUS report, and hence this review, to consider all the requirements of the Regulatory Test and in particular those pertaining to the consideration of alternative projects.

1.2. ORGANISATION OF THE REPORT

I have organised this report in the following way:

- Section 2 deals with comments on the methodology and models;
- Section 3 briefly discusses the compliance of the methodology with the regulatory test;
- Section 4 discusses the critical data and assumptions issues; and
- Section 5 provides an overview of the model results.

1.3. MATERIALS REVIEWED

I reviewed the relevant parts of the following reports in addition to the TEUS study:

- ACCC, Regulatory Test for New Interconnectors and Network Augmentation, 15 December 1999, 1999;
- Inter Regional Planning Committee (IRPC), Stage 1 Report – Proposed SNI Interconnector, Version No. V014, October 26, 2001;
- NEMMCO Statement of Opportunity 2001 and 2002;
- Report by Intelligent Energy Systems titled "Application of the ACCC Regulatory test to SNI: Report to TransGrid" dated 27 November 2000;
- Report by ROAM Consulting titled "NEM Forecasting - Optimised timing of SNI and SNOVIC: Report to NEMMCO" 4 December 2001; and
- The Office of the South Australian Independent Industry Regulator (SAIIR), Transmission Line Performance in South Australia and the SA Transmission Code, Discussion Paper, December 2001.

2. COMMENTS ON THE METHDOLOGY AND MODELS

2.1. OVERVIEW

Market benefit due to a (regulated) interconnector has several distinct components and TransEnergie US (TEUS) study has considered the following components:

- "Energy benefits" i.e., the benefits that accrue due to economy power exchanges over the interconnector leading to savings in fuel, other variable[2] O&M costs as well as reduction in voluntary load curtailments;

- "Capacity deferral benefits" or the fact that an interconnector allows more efficient sharing of reserve and energy production capacities across interconnected regions which imply lower new capacity requirements in the long run to meet the reliability and energy needs of the system as a whole;

- "Reliability benefits" – even for the case when there is sufficient installed capacity to meet the peak MW requirement in a given year, unforeseen events such as forced outages of generators and transmission lines and unusually high demand may lead to unserved energy for the system. The presence of a new interconnector equips the system better to handle such contingencies and consequently lower the amount of expected unserved energy or USE; and finally

- "Riverland deferral benefits" due to the deferral of planned transmission augmentation in the Riverland area. There may potentially be other benefits that may include a range of items such as the deferral of any other transmission augmentation, more reliable performance of the interconnector, ability of the interconnector to contribute to frequency control, voltage control, and preventing catastrophic events such as voltage collapse. The TEUS study takes into account the planned transmission augmentation deferral issues and the technical benefits such as reliability/performance, frequency/voltage control are outside the scope of the this TEUS study and hence this review.

This definition of market benefits provides a comprehensive view of the full range of benefits that an interconnector brings forth. While this is true, it is anything but easy to estimate these benefits in an accurate and robust manner consistent with the regulatory framework. There are several issues that need to be addressed in the choice of methodology. Table-1 below presents these issues and also how TEUS have dealt with them in their selection of methodology.

[2] Fixed O&M costs have not been included in the study. This is not a limitation of the modelling framework, rather one of maintaining consistency with the available data and previous studies in the NEM.

Table 1: Methodological Issues: An overview

Issue	Comments on TEUS Approach
Gaming by the generators	This is a relevant but extremely complex issue that also entails a highly questionable subjective element of predicting expected behaviour of generators in the long term. It is well known that most electricity markets worldwide exhibit some form of gaming by the generators to effectively withdraw capacity to raise prices above marginal cost. However, there is hardly any agreement on the methodology and much less on the extent to which generators exercise market power. Australian national electricity market (NEM) is arguably no exception. TEUS have virtually assumed that the generators do not exercise market power and hence used marginal cost bidding behaviour by the generators. This may generally underestimate the market benefit for both energy cost savings related benefits as well as capacity deferral benefits. In my view, this is not an unreasonable assumption especially in view of the fact that there is neither a universally agreed theoretical framework to estimate market power, nor enough empirical evidence to quantify/calibrate any of the existing theoretical models. A marginal cost bidding approach is likely to yield a good estimate of the fuel cost savings which may be viewed as a lower bound on the likely range of energy supply cost reduction in the NEM.
New generation entry and generation capacity deferral	Appropriate treatment of new entry in the long run is an integral part of the benefit assessment framework. Ideally, the methodology should consider the optimal new entry taking into account the short-term dispatch aspects in an integrated framework. However, this is confronted with the computational difficulties. TEUS have adopted a reasonable compromise by using a "profitability test" around detailed dispatch model (i.e., PROSYM). This profitability test is essentially an exogenous decision variable estimated in an iterative way to check if an incremental unit addition is likely to recover the capital investments. This also partly relates to the bidding assumption and TEUS assumes all the generators – existing and new entrants - bid at marginal cost. Finally, the TEUS treatment of new entry is consistent with the methodology adopted by IRPC/ROAM for evaluation of SNI.
Reliability consideration	A new interconnector reduces the possibility of unserved energy under extreme contingencies in the short run and further, avoids investment in demand side management (e.g., interruptible load programme) and supply (e.g., building peaking plants) side options to maintain reliability in the long run. Ideally, the methodology should capture all short and long term aspects in a unified framework but again there are both theoretical and computational limits. TEUS have adopted a two-tier approach with a combination of a detailed reliability simulation and a detailed production costing simulation

Issue	Comments on TEUS Approach
	model. This is a reasonable approach. A reliability simulation framework can deal with the detailed simulation of outage/load contingencies without regard to the economic operational aspects and complement the economic analysis with an estimate of the unserved energy. The economic analysis on the other hand need not be crowded with a detailed consideration of outage/load contingencies.
Transmission	Transmission issues cover not merely the representation of the market network and the MW transfer limits but also include reactive power, voltage and stability considerations in the short and long run. The complexity of the latter issues can only be fully addressed using a detailed AC load flow analysis. A complete integration of these issues in a long term market benefit assessment framework is undoubtedly a very complex issue and, while theoretically desirable, is not practical with the analytical and computational methods available today. TEUS have utilised a series of load flow studies undertaken by TransEnergie Australia (TEA) that are further verified and confirmed to be accurate by Power Technologies, Inc. (PTI). I have discussed elsewhere before[3] that the treatment of the MW transfer limits from a load flow model has been appropriately dealt in the market benefit and reliability estimation. There is also a related transmission issue namely, whether the new interconnector can defer, or eliminate, the need for an already planned network augmentation. This also requires an in-depth technical analysis i.e., load flow analysis. Again, I believe TEA has undertaken such analysis to identify the network augmentation components that can be deferred. I note however that a MW limit does not satisfactorily represent the reactive power, voltage and voltage stability considerations especially for a HVDC interconnector that can offer substantial relief in these terms under stressed system conditions. By excluding these issues from the market benefit assessment framework, TEUS is likely to underestimate the transmission related benefits. However, it is possible that such benefits are of minor significance.

3 See Appendix-2. Letter from Deb Chattopadhyay (CRA-Asia Pacific Ltd.) to Louis Grenier (TEA) dated August 19, 2002.

Table-1 above is not intended to be an all-inclusive list of all methodological issues – rather it attempts to focus on the core issues and the interlinkages among them. In theory, there are potentially many more issues that could be considered including both macro considerations such as electricity vs. other energy commodity markets, and energy-economy interactions, as well as micro issues such as generator ramping, ancillary services co-optimisation etc at the other end of the spectrum. In most instances, TEUS have not dealt with these macro and micro issues and this is entirely consistent with the assumptions made by IRPC/ROAM for evaluation of SNI. In my review of the TEUS analysis, I have limited my discussion on these peripheral issues. The complete range of issues is, however, described in Appendix-A together with a comparison of what the previous IRPC study considered in their analysis of SNI benefits.

My review of the general methodological approach adopted by TEUS suggests that it is broadly reasonable for the purpose of evaluation of benefit associated with an interconnector.

2.2. THE MODELS EMPLOYED FOR ANALYSIS

Figure 1 below presents a schematic representation of the market benefit analysis framework which comprises of the following elements:

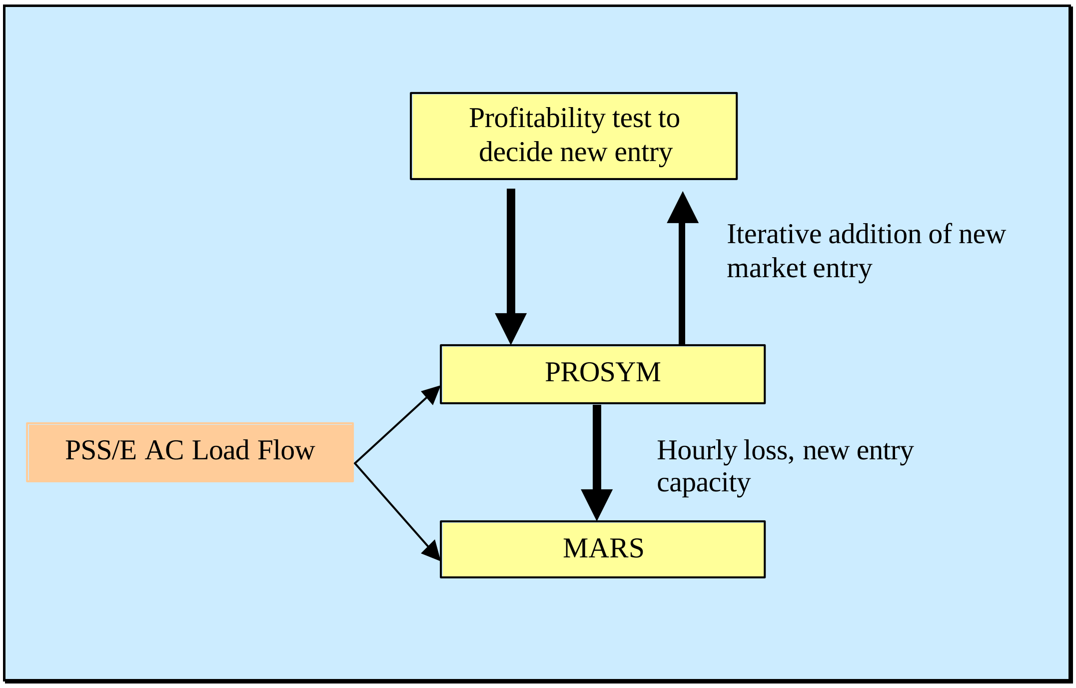
1. Henwood's PROSYM model has been employed as the central analytic tool that performs a chronological hourly dispatch for multiple years taking into account a simplified transmission model. This directly provides an accurate estimate of the system cost to meet energy requirement. As already discussed, TEUS assumes a short run marginal cost bidding which forms the basis for generator cost representation in PROSYM. Difference between the total system cost without and with the interconnector under study provides an estimate of the energy cost savings benefit;

2. A profitability test around PROSYM is used to determine the quantum of new entry in each year. This is an iterative process that involves running PROSYM repeatedly with different new (market) entry profile – the process stops when the next incremental new entrant stops being profitable. Difference between the quantum of new entry without and with the interconnector provides an estimate of the capacity deferral benefits;

3. General Electric's MARS model has been employed as a detailed reliability indices calculation tool. MARS is also a chronological hourly model that performs a Monte Carlo simulation of generator and transmission line outages. MARS also allows a deterministic/scenario representation of load uncertainties by specifying different levels of loads with associated probabilities. TEUS have also endeavoured to maintain a high degree of consistency across PROSYM and MARS in terms of transmission loss and new entry profile. Difference between the USE without and with the new interconnector provides an estimate of the reliability benefit attributable to the interconnector. This is valued at the cost of unserved energy or value of lost load (VOLL); and finally,

4. PTI's Power System Simulator for Engineers (PSS/E) is used to perform an AC load flow analysis. Although the TEUS study did not directly perform load flow analyses, it relied upon transfer limits developed by TransEnergie Australia (TEA) and confirmed by Power Technologies, Inc. (PTI). TEA and PTI used PTI's load flow analysis model Power System Simulator for Engineers (PSS/E) to perform the AC load flow analysis. This analysis is used to primarily calculate the MW transfer limits under different loading conditions and network augmentation scenarios. This analysis is used among other things to calculate the MW transfer limits under different loading conditions and network augmentation scenarios.

Figure 1: Models employed to estimate the market benefits



2.2.1. PROSYM Model

PROSYM has the following features:

- It performs a chronological hourly dispatch which is analogous to a half-hourly pre-dispatch performed in several markets including the Australian NEM except that PROSYM's dispatch extends over multiple years. The hourly details of demand and supply renders it a high level of accuracy although it is obviously a function of the accuracy of the inputs;

- PROSYM can deal with a fair degree of short term operational details such as generator ramping, commitment constraints, heat rate curve, etc as well as other mid/long term considerations such as generator outages, hydro energy limits etc[4]. Further, it can represent demand side response much in the same manner as the Australian NEM clears dispatchable loads;

- It co-optimises the transmission flows over interconnectors together with the generation dispatch. This closely resembles the zonal market dispatch performed in Australian NEM. Further, it deals with piecewise linear loss functions and MW transfer limits much in the same fashion as the Australian market clearing process;

- Prices produced by PROSYM reflect the marginal cost of providing an additional MWh of electricity at a node – this is consistent with the way prices are determined in real-time in Australian NEM;

- Although PROSYM can treat spinning reserve constraints, I note that IRPC/ROAM have not considered ancillary services related benefits to be a major issue in its evaluation of interconnectors. TEUS analysis has not accordingly considered spinning reserve and related benefits. This is likely to underestimate the market benefits – however, IRPC/ROAM study noted that this is likely to be a negligible component;

- PROSYM does not *per se* optimise the new entry decision – however, as I have mentioned before, it can be augmented with a profitability test to approximately estimate the quantum of economic new market entry. TEUS have adopted such a profitability test and I think this to be a reasonable approach to determine new entry; and

- PROSYM essentially uses a linear program (LP) model to determine the optimal generation-transmission dispatch for each hour – thus it based on the same optimisation principles adopted in the Australian market clearing process.

In view of the above, I think the choice of PROSYM as a tool for analysis of energy cost savings and capacity deferral is appropriate in the present context.

[4] . The SRMC bidding assumptions and the availability of data in the public domain (e.g. published in the IRPC Stage 1 report, etc) meant that not all of these features were necessarily used in the TEUS analysis. However, TEUS have complied with all the modelling requirements that the IRPC Stage 1 report laid out.

2.2.2. MARS Model

While PROSYM in theory has the capability to perform Monte Carlo simulation, it is computationally very expensive to run the dispatch optimisation numerous times for randomly selected samples simply because the number of such samples in a relatively naïve Monte Carlo sampling procedure can run into several thousands. Combining the power of optimisation together with the computational burden of a Monte Carlo simulation is, therefore, anything but trivial. PROSYM of course provides access to a number of reasonably advanced sampling techniques. Nevertheless, it is not clear if a sufficiently high degree of confidence can be derived from a very limited number (e.g., 10) of samples however much sophisticated the underlying sampling process is.

TEUS have adopted the MARS model which is a sequential Monte Carlo simulation model. MARS deals exclusively with generation and transmission capacity and hourly demand to simulate the impact of generator/transmission random outages. This impact may be measured in various alternative terms including the expected unserved energy. It does not perform a dispatch optimisation and hence can run a much larger number of samples as compared to PROSYM.

MARS is also fairly detailed in terms of its ability to represent the power system realities including time varying generation/transmission limits, energy limited plants, dispatchable loads, etc which are all quite relevant in the Australian context.

MARS is able to represent the nodal/zonal characteristic of the market by virtue of its transmission model and hence able to capture the impact a new interconnection may have in terms of improving the reliability benefit to the system. It calculates a few reliability indices including the Loss of Energy Expectation (LOEE) which is analogous to USE index used in Australia.

In my opinion, the choice of MARS as a simulation tool is appropriate in the Australian context and it complements the PROSYM capabilities in terms of providing the USE reliability benefits that a new interconnector brings forth.

2.2.3. Interaction Between PROSYM and MARS

Last but not the least, PROSYM and MARS should be used in a consistent manner so that the reliability benefits estimated using MARS reflects the market dispatch and new entry predicted by PROSYM in the long run.

While MARS has superior computational advantages to perform a more detailed Monte Carlo simulation, it does not consider market economics and cannot forecast the new entry. PROSYM in conjunction with the profitability test enables predicting the long term market entry. This information needs to be provided to MARS for it to simulate the future years to estimate the expected unserved energy.

Also, an issue possibly of secondary importance– MARS does not have the ability to represent the transmission losses directly and therefore the hourly losses calculated by PROSYM is added on to the load at the exporting end. This enables consistent treatment of loads and losses across MARS and PROSYM.

Overall, I conclude that the implementation scheme using MARS-PROSYM is broadly appropriate and consistent with the methodology.

3. COMPLIANCE WITH THE REGULATORY TEST

3.1. OVERVIEW

The regulatory test is essentially a standard cost-benefit analysis adopted for the specific purpose of assessing the cost-effectiveness of new interconnection and network augmentation arrangements by the Australian Competition and Consumer Commission (ACCC).

3.1.1. Principles

There are two fundamental principles that ACCC have stated to have formed the basis of the test, namely,

1. Economic efficiency i.e., the fact that regulated investment should not be "gold plated"; and

2. Foster unregulated investment wherever such options promise efficient utilisation of resources.

3.1.2. The Regulatory Test

The test states:

"A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the <u>*market benefit*</u> having regard to a number of different <u>alternative projects</u>, <u>timing</u> and <u>market development scenarios</u>;" [*italics* as in original, <u>underline added</u>]

Consideration of alternative projects has clearly been identified as a major requirement in the test. However, as I have mentioned before, the TEUS study concerns the estimation of market benefit for Murraylink or for that matter any other network augmentations that provide a similar level of power transfer capability on a stand alone basis. Hence, this review also focuses solely on the appropriateness of the market benefit assessment process. I understand that there are separate studies being undertaken by MTC and its other consultants to address the issue of alternative projects.

3.1.3. Ramifications of the Public Debate on the Regulatory Test

Although it appears that the intent and hence application of the test should be straight-forward, there has been considerable amount of confusion and public debate around the test in Australia although some of the issues have been resolved in the process and the application issues are more rigorously defined today than it was a year ago.

If I consider the basic principles and a direct interpretation of the test together with the debates and responses that have transpired from NEMMCO/IRPC etc, it seems there are several practical implications of the test that become paramount in any discussion of the compliance. This is simply because these issues have been significant in the past and are likely to emerge in the course of future public discussion.

- **Alternative projects – what ought and ought not be considered**

  Alternative projects may include other proposed interconnections as well as generation and demand-side alternatives. Consideration of alternative projects that are both technically and commercially feasible has been a source of confusion and debate in the recent past. However, as already discussed, these issues are not subject of the present review.

- **Costs and benefits that qualify and those that do not**

  As typical of any practical cost-benefit analysis, the definition of cost and benefit itself requires careful attention – firstly, the term "market benefit" merits special attention – it includes both consumer and producer surplus. In other words, the market benefit analysis framework should be broad enough to encompass not merely the production cost savings related benefits but also the price reduction benefits that consumers enjoy as a direct consequence of the new interconnector. Secondly, only the relevant costs and benefits that apply to a specific project should be considered. The relevant set of costs and benefits may vary across different projects and this is entirely appropriate. Finally, if there are additional costs/benefits that cannot be measured in financial terms, or do not relate to producer/consumer surplus, such costs/benefits do not qualify to be included in the test. This may relate both to technical issues as much as to commercial issues; and

- **Scenarios to capture impact of uncertainties only**

  First and foremost, scenarios are intended to test the variation of a baseline estimate in view of significant uncertainties that may prevail in a particular market – these are specific to both the market and to the project itself. A balanced selection of scenarios is an essential part of the regulatory test to capture the uncertainties in market development over the long run. These may include virtually all aspects of market that may have a sizable impact on the interconnector benefits – however the fundamental principles of completeness, materiality and balance are critical. A biased selection of scenarios that work in favour or against a particular project should not be undertaken and having too many scenarios that are unlikely to have any significant effect at the cost of omitting important ones should also be avoided. In addition to "scenarios", a range of sensitivities for critical parameters is useful to check the robustness of the estimates i.e., whether a small change in the parameter values lead to a significant swing in the benefit estimates.

3.2. DOES THE TEUS ANALYSIS ALIGN WITH THE INTENT OF THE TEST?

In the backdrop of the above discussion on the basic principles and the practical aspects of the test, I consider that the TEUS methodology and models used to estimate the market benefits align well with the intent of the regulatory test. I have included detailed remarks on the specifics of the methodology and also how it aligns with the IRPC methodology in Appendix-1. I summarise the key points below:

1. Consideration of existing supply of generation is consistent with NEM realities and their representation in MARS and PROSYM models is appropriate;

2. Consideration of new generation alternatives is consistent with the norms laid out by IRPC;

3. Representation of transmission in MARS/PROSYM is consistent with the NEM realities;

4. There is appropriate consideration of uncertainties in generation/transmission outages as well as alternative load growth scenarios performed;

5. The methodology for calculation of market benefits for energy savings using the PROSYM methodology is sufficiently detailed and matches the intent of the regulatory test;

6. The methodology for calculation of capacity deferral benefits using a profitability test is reasonably accurate and matches the intent of the regulatory test;

7. The methodology for calculation of reliability benefits using the MARS model is accurate and captures the inherent physical uncertainties well which is consistent with the NEM planning process and the intent of the regulatory test; and

8. Externalities including environmental externalities and ancillary services cost issues are not considered in the analysis which are consistent with the treatment of these issues in the prior IRPC[5]/ROAM study[6];

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5 IRPC Stage 1 report, p.34 suggests that externalities are not to be included and specifically mentions the future environmental costs are “poorly defined” at the moment.

6 ROAM Consulting, Main Report dated October 26, 2001, p.24 commented that various alternative interconnection arrangements are unlikely to yield any significant changes in the ancillary services costs and hence these could be ignored.

4. COMMENTS ON DATA AND ASSUMPTIONS USED

4.1. Overview

I have already discussed the key methodological issues and presented them in Table-1. The data/assumptions relate to these issues as well as other areas that I discuss below.

- Macroeconomic assumptions:
  - Demographic factors that influence load growth;
  - Exchange rates; and
  - Fuel prices.
- Optimisation timeframe and assumptions relating to the residual value of benefit beyond the optimisation timeframe.
- Physical system representation:
  - Generator capacity;
  - Regional load distribution and time profile;
  - Representation of transmission constraints and losses;
  - Representation of contingencies; and
  - Operational system security criteria.
- Behavioural assumptions:
  - Generator bidding strategy; and
  - New entrant cost and bidding assumptions.
- Assumptions on alternative projects and market development scenarios.
- Issues pertaining to additional benefit that relate to network augmentation deferral.

4.2. Data Sources and Assumptions

I have reviewed the relevant data and assumptions during the course of the TEUS study and the following comments are in order.

- The optimisation timeframe has been set as 2003-2012 and the residual values have been calculated on an additional 30 years timeframe beyond 2012 (i.e., until 2042). The residual value calculation assumptions seem appropriate.

- The primary source of the data on most of the physical system is the IRPC Stage 1 report. The following items have specifically been obtained from the IRPC report:

  - Generator summer and winter ratings;
  - Generator forced and planned outage rates;
  - Interconnector capacity, and loss equations[7];
  - Snowy hydro energy availability;
  - Operational regional reserve requirements;
  - Short run marginal cost of generation by plant; and
  - Committed projects and cost of building new CCGT/OCGT/coal plants.

- Both the existing and new entrants are assumed to bid at SRMC level for all hours. This is unlikely to be a realistic representation of the NEM but as I have discussed before this is likely to yield a conservative estimate of the market benefit in light of the specific methodology that TEUS have adopted with regard to estimation of reliability benefits. The SRMC assumptions do not change over the years and therefore obviate the need for any fuel price projections.

- Hourly load traces are obtained from a previous study undertaken by ROAM Consulting for IRPC/NEMMCO SNI evaluation. Peak load and energy forecasts are obtained from NEMMCO Statement of Opportunity (SOO) 2001. The specific assumptions that have gone into developing the load traces and the peak/energy forecasts are documented in the relevant background documents. I also believe that much of the macro-economic assumptions on demographic factors etc are underlying in the load growth assumptions and hence are not directly relevant for TEUS analysis.

- Selection of alternative projects encompasses both generation and demand-side projects – TEUS have considered a range of generic generation alternatives of various types in all NEM regions.

7 Murraylink transfer capabilities are developed using a detailed AC load flow analysis by TEA as discussed later.

- Market development scenarios as indicated in the regulatory test imply varying critical uncertain parameters. TEUS have considered a variation in load growth as a consequence of higher and lower economic growth around the baseline scenario. In addition, TEUS have also considered sensitivity of the results to discount rates.

- Murraylink (seasonal) transfer capabilities are estimated using PSS/E load flow analysis. I have not reviewed the inputs to PSS/E but can confirm that the output have been appropriately incorporated as inputs to PROSYM and MARS analyses.

- Transmission outage rates for Heywood alone has been used in MARS – these outage rates are derived from the SAIIR Discussion Paper on transmission line performance (p.11).

- TEUS assumes that Murraylink is capable of deferring Riverland augmentation from 2003 to 2013. I have not attempted to confirm this independently, but I understand TEA have undertaken appropriate analysis to suggest that the presence of Murraylink provide the requisite relief to the Riverland area for several years.

5. COMMENTS ON RESULTS

5.1. COMPOSITION OF BENEFIT

Table-2 below shows the composition of the annual benefit both in terms of the four components and how these components evolve over time.

Table 2: Annual benefits (undiscounted)for 2003-12 (Base case)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Fuel cost savings	3309	5946	5765	6283	7000	8132	9418	9119	5183	7602
Capacity deferral	0	0	0	0	0	0	27028	54323	27830	-25957
Reliability	15	55	199	415	1092	3050	4275	6835	6355	9407

There are a few things to observe:

- The fuel cost savings (discounted at 9.25%) averages at around $4.1m over the years, albeit slightly declining as the demand-supply situations in all regions tighten with increase in demand. In order to develop some insight about the magnitude of benefit, this is roughly equivalent to $3-$4/MWh price differential across Victoria and South Australia – historically, the price differential has been significantly higher than this level. It may be reasonable, therefore, to view this benefit as a relatively conservative estimate of fuel cost savings. If, for instance, a generator bidding behaviour above SRMC were to be considered, this will in general have an effect of increasing prices and quite possibly the price differential especially during the hours when the link is congested;

- Capacity deferral benefits occur once the existing generation-demand side resources cease to be adequate and/or economic and hence Murraylink is able to successfully defer addition of new merchant peaking capacity – the first instance of capacity deferral occurs as late as 2009. As the supply-demand gap reduces over the years, Murraylink is able to defer a reasonable MW quantum of market entry although part of the capacity requirement can only be deferred by a few years and cannot be eliminated permanently as I discuss further later; and

- Reliability benefits are almost negligible during the initial years but become very significant as demand grows and hence the probability that Murraylink will be useful in sharing reserve across the regions become more and more significant.

Figure 2: Percentage share of annual benefit 2004-2013 and 2030[8]

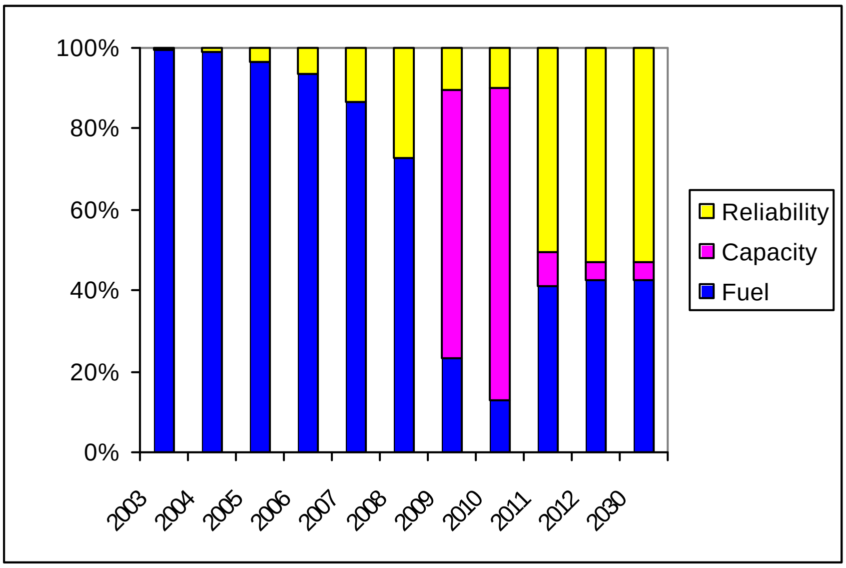


Figure 2 presents the relative share of benefit over the years. Figure 2 shows clearly, however, that the relative contribution of fuel cost savings decline over the years and capacity deferral and reliability components become more and more prominent especially as the demand supply situation tightens around 2009-10. However, an interconnector has only limited ability to defer all of the capacity permanently and hence part of the deferred generation capital is eventually needed in 2012. This is a sensible outcome – one should expect capacity deferral benefits to become significant over the years although there may be a limit till which an interconnector is able to defer building new generators. It also makes sense that the interconnector contributes to significant reliability benefits during the later years. The reliability and capacity deferral benefits occur almost in unison which are indicative of an equilibrium demand-supply situation.

Further, the composition of benefit is likely to be quite sensitive to the underlying system conditions e.g., demand level. This is particularly true for the capacity deferral and reliability benefits. I present the 40 year NPV results for the base and the low economic growth cases in Table-3.

[8] For the ease of exposition, I have ignored the one year deferral of capacity benefit of $26.7m from 2011 to 2012.

Table 3: Comparison of composition of benefits for the base and low scenarios (40 year NPV in million $ at 9.25% discount rate)

	Fuel costs	Capacity deferral	Reliability	Riverland Deferral	Total
Base	79.2	51.9	58.0	25.0	214.2
Low growth	80.2	0	23.6	31.6	135.5

As the comparison clearly shows, capacity deferral benefits diminish rapidly with lower demand[9]. It may also be expected that the reliability benefit would also go down with lower demand[10]. It should be noted though that the total capacity and reliability benefit goes down with lower demand. The Riverland deferral benefits remain relatively constant although it has been assumed in the TEUS study that the Riverland deferral lasts longer in the low demand scenario. However, the fuel cost saving grows significantly. There is more economic transfer across Murraylink in the absence of new entry because demand is not high enough to sustain such additional new entry[11]. This is a reasonable outcome.

Finally, although the majority of the benefits occurs during the first 10 years, the residual values could account for a significant share of the total benefits. I note that the relative share of the benefits stabilise over the years and remain nearly constant from 2011 onwards- this signifies the demand-supply scenarios at the two ends of the interconnector (and possibly in other regions) have equilibrated. This also implies the assumptions underlying the planning horizon are sensible. I have compared the share of benefits in 2030 with that of 2011-12 and they match very closely – this is a good indication of the fact that the PROSYM/MARS modelling horizon was not arbitrarily cut off before a stable demand-supply situation was achieved.

[9] It may be worthwhile to add that the opposite trend may be expected with a higher demand growth i.e., the capacity deferral benefit will be higher and the energy benefit will go down especially if the exporting region's demand grows more rapidly because it will reduce the opportunity of economy power exchanges. In an extreme case, the energy benefit may even be negative if the addition of interconnector actually defers part of the capacity addition that was contributing significantly to meet energy requirements which now needs to be met from relatively expensive sources of generation. Another issue which may add to lower/negative energy benefit is the "lumpy" nature of capacity addition – because new generators will be added to the system in relatively large chunks of MW, it is possible that addition of an interconnector will get rid of a similarly large block of capacity – thereby earning a large capacity deferral benefit, but possibly a lower/negative energy benefit that the displaced/deferred generator was contributing to. The interconnector would however be able to obtain a higher overall market benefit because capacity deferral benefits would typically supersede the decrease in energy benefits.

[10] However, it is possible that the supply-demand gap in the lower demand during the future years actually reduce because lower demand (and hence prices) does not attract sufficient new market entry. It is therefore not impossible for the reliability benefit in the low growth case to be higher than the base case.

[11] This does not imply though that the new entry schedule for the low case is sub-optimal. It simply means that the trade-off between investment and operating costs leans in favour of the latter if demand is not high enough. The overall cost (i..e, investment and operational costs) is minimised for the low growth case.

APPENDIX A: DETAILED COMMENTS ON METHODOLOGY AND ASSUMPTIONS AND COMPARISON WITH IRPC STUDY

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
General		
Guiding principle	ACCC regulatory test	Yes
Time period of study	2003-2012	Yes.
Treatment of benefit beyond planning horizon	Assumes end year benefits to accrue till 2042.	Yes but IRPC assumes end year benefits to accrue as a perpetuity
Market development scenarios	Economic growth rate	A number of additional scenarios including different interconnector, variation of cost, etc considered.
Interlinkages to other physical energy markets e.g., gas	Not considered	Not considered
Interlinkages to financial markets	Not considered	Not considered
Demand		
Representation of load	Chronological hourly load curve for both MARS reliability calculations and PROSYM energy cost savings estimation. Data source: ROAM Consulting Website	Yes. But ROAM model uses half-hourly load and time steps.
Demand elasticity	Ignored	Yes. Ignored in ROAM analysis. Although ROAM had considered it in a scenario,

12 IRPC Stage 1 Report on "Proposed SNI Interconnection" October 2001.

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
		this was not included in the final analysis.
Demand side participation	DSP response modelled as dispatchable load in several price band. Data source: IRPC report.	Yes
Interruptible load	Considered	Yes
Unserved demand/energy	Both MARS and PROSYM treat unserved demand as MW deficit. There is no explicit limit imposed on USE. All USE valued at $10,000/MWh to obtain the reliability benefits.	Yes ROAM model treats unserved demand as "VOLL generators" that offer energy at $10,000/MWh and this is equivalent to MARS/PROSYM's treatment. Although there are transmission loss implications, as long as VOLL generators are put in all regions (as ROAM presumably does), this is not an issue.
Load uncertainty	Longer term load growth uncertainty captured via scenarios in PROSYM. Reliability impact of shorter term intra-year variations due to weather etc captured in MARS using probability distributions and then looking at scenarios associated with *x%* probability of exceedance or cumulative probability distribution of hourlyloads. MARS has slightly different way of treating load uncertainty in a deterministic fashion – it allows a fixed number of	Yes. ROAM methodology is limited to deterministic scenario based approach for both reliability entry and cost savings estimation. It does not do a probabilistic estimation of reliability benefit as MARS does.

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
	bands for variation of load with probability of occurrence of each load band. Long term growth and short term weather related hourly load scenarios/traces are based on IRPC report. MARS load uncertainty data has 10 blocks and this is developed using the same normal distribution as followed by IRPC.	
Generation		
Capacity	Different ratings for summer and winter are used. Data source: IRPC report	Yes
Bidding	Entire available capacity is offered at SRMC. Data source: IRPC report	Yes. ROAM uses a LRMC bidding scenario as well as other scenarios based on variation of fuel prices (high SA gas price, lower NSW coal plant SRMC)
Strategic capacity withdrawal and other market power considerations	Not considered	Not considered
Generation contracts	Not considered	Not considered

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
Planned maintenance	MARS schedules maintenance on a levelised regional reserve basis. PROSYM can schedule maintenance on the same basis or other criteria. Maintenance plan used consistently across PROSYM and MARS. Maintenance of new entry plants is modelled as per the norms specified in IRPC report. Maintenance days for generators in each region is based on IRPC report.	ROAM does not specify any specific criterion that was adopted. However, IRPC guidelines (Stage 1, section 4.3.6) seem to suggest maintenance for all units should be done on a similar basis i.e., distribute maintenance within a region to lower demand periods.
Forced outages	Both MARS and PROSYM use Monte Carlo simulation to sample random generator outages and performing the respective calculation of reliability MW and energy cost savings on this basis. The specific details of the sampling method varies across MARS and PROSYM though – in the latter case a convergent sampling technique is used to reduce the number of iterations required. However, in theory, the difference is not a material issue here as they both are expected to produce the same level of convergence and PROSYM's method does so more efficiently. Forced outage data: IRPC report.	Yes, but description of ROAM methodology makes it unclear what specific form of outage sampling was used and how it fits into the dispatch optimisation.

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
New market entry	Includes the committed plants per IRPC schedule. PROSYM relies on a profitability test outside the model to determine additional new market entry based on a capital cost assumption and then incrementally add capacity till such increment ceases to be profitable. MARS uses the planting schedule determined by PROSYM	Yes. ROAM uses a similar "market opportunity assessor" to post-optimally determine if a new entrant would earn *sufficient* premium to be in the market.
Hydro generation	Treated as energy constrained units. Energy constraints for each month is specified for a group of generators and an SRMC of zero apply to all hydro generation. Energy limits are based on those reported in IRPC report.	Yes
Minimum MW loading or "self-dispatch"	Modelled through bidding the minimum number of MW at $0/MWh so that the unit is dispatched at least to the minimum MW level. Data source for regional self-dispatch level: IRPC report.	Yes
Ramp rates	Not used/activated	Not used
Minimum up and down time constraints	Not used/activated	Not used

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
Co-optimisation of spinning reserve	Not modelled	Not modelled
Co-optimisation of regulation response	Not modelled	Not modelled
Excess generation	Valued at 0 dump price	No excess generation condition reported anywhere.
Emissions/Environmental impacts	Not modelled.	Not modelled
Heat rate curves	Not used/activated.	Not used
Ancillary services	Not considered	Not considered
Pump storage plants	Not modelled.	Not modelled
Fuel contracts, limits etc	Not modelled	Not modelled
Transmission		
Representation of the system	Total 9 regions for MARS: NSW subdivided into NSW, Wagga, and Buronga Victoria subdivided into Vic and Redcliffs South Australia subdivided into SA and Riverland PROSYM uses 5 market reference nodes or NEM regions to be consistent with NEM dispatch/pricing regime.	Yes. Five NEM regions with new interconnectors lumped together with any existing ones.
Inter-regional Transfer limits	Simple bounds on transfers each way Data source: IRPC report	Yes

Issue	TEUS methodology and assumptions	Is TEUS methodology and assumption consistent with IRPC study[12]?
Inter-regional Transmission flows	Treated as flows in a transportation network for both MARS and PROSYM. PROSYM co-optimises the flows together with generation dispatch.	Yes. However, ROAM model has a simpler treatment of flows – flows are not co-optimised with generation.
Intra-regional flow limits	Not modelled	Not modelled
Inter-regional transmission losses	Linear and quadratic loss factors are used in PROSYM as per the IOWG constraint equations. MARS derates the transfer capacity of the interconnectors. Data Source: NEMMCO document and IRPC Stage 1 Appendix B	Yes
Intra-regional transmission losses	Modelled using static marginal loss factors. Data source: IRPC report	Yes
Generic security constraint	Not modelled	Not modelled
Transmission expansion scenarios	This is outside the scope of the TEUS report but alternative transmission projects will be considered in a separate study.	IRPC considers a few alternative scenarios of transmission expansion.

APPENDIX B: LETTER ON MURRAYLINK FLOW LIMITS

August 19, 2002

Mr Louis Grenier
Chief Financial Officer
Murraylink Transmission Company
Level 11, 77 Eagle Street
BRISBANE
QLD 4001

RE: MURRAYLINK FLOW LIMITS IN MARKET BENEFIT ANALYSIS

Dear Mr Grenier

Ms Sandra Gamble, Director of DGJ Projects Pty Ltd, asked me to review the following reports prepared by TransEnergie U.S. Limited:

1. Incorporating the findings of a Murraylink load flow analysis in MARS regional interface limits; and

2. Incorporating the findings of a Murraylink load flow analysis into Prosym transmission limits.

I have been asked to provide an opinion on whether the results of the load flow analysis have been appropriately incorporated in the market benefit analysis being performed by TransEnergie U.S. More specifically, Ms. Gamble has asked me to answer the following question:

<u>Is the methodology expressed in the reports (1)-(2) above appropriate?</u>

I understand that,

- TransEnergie U.S. is using the MARS model to evaluate the reliability benefit from Murraylink and the Prosym model for evaluating the reduction in energy costs in the Australian national electricity market (NEM);

- TransEnergie Australia (TEA) have conducted a detailed load flow analysis using the PSS/E software of Power Technologies, Inc. (PTI), to estimate the power transfer capability of Murraylink. I have not reviewed the detailed load flow analysis and consider this to be outside the present scope of work; and

- The reports (1)-(2) are intended to reflect appropriate usage of the transfer limits obtained from the load flow studies for the purpose of reliability benefit estimation using the MARS model and energy cost reduction benefits using the Prosym model consistent with the NEM realities as relevant in the context of the long term reliability and energy supply planning.

<u>Based on my understanding as above and a review of the reports (1)-(2), I conclude that TransEnrgie have correctly interpreted and incorporated the Murraylink transfer limits in their MARS and Prosym modelling.</u>

Some of the specific details of the MARS and Prosym modelling may, however, be noteworthy in this context in so far as these are inherent inflexibilities in these models rather than a misinterpretation of the load flow study results:

- Both MARS and Prosym use relatively simplistic representation of transmission and the time/season varying MW limits are the only means to represent the transfer capability in both these models. I note however though that a simplification of the transmission representation is essential for a long term reliability/dispatch model to be computationally tractable;

- The network security constraints also referred as the "generic constraints" in the NEM context cannot be adequately represented in either model. While this is a limitation of the MARS/Prosym modelling approach, I understand the transfer capability estimated by the detailed load flow studies would capture the essence of the generic security limits in the longer term. It is also my opinion that no long term planning analysis can satisfactorily deal with the intricate short term security details captured by some of the generic constraints;

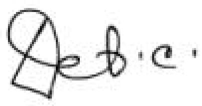
- MARS is able to represent interface limits i.e., a composite limit on a group of interconnectors as well as limits contingent on load/generation. MARS uses the hourly losses estimated by PROSYM – the latter treats losses as a function of flow which is consistent with the NEM dispatch process; and

- Prosym is not able to represent the dynamic limits directly but TransEnergie have examined the historical NEM operation data and set the limits conservatively so that there are as much as 10 times the number of hours when the most conservative limit on Murraylink applies as compared the historical incidence of events that lead to such conservative. Not withstanding the inherent limitation of Prosym transmission model, I therefore opine that the energy cost reduction is likely to err on the side of conservatism.

Finally, I would like to highlight the fact that TransEnergie's market modelling basically assumes that the voltage support and appropriate runback schemes will be implemented to achieve the maximum transfer capability reflected in the load flow analysis. While this seems appropriate to me, it is important that any change in these underlying assumptions must be reflected in the MW transfer capability because the transfers can potentially be as low as zero (or, even negative) if some of the additional network augmentations are not implemented.

Please feel free to contact me if you have any questions regarding this letter.

Yours sincerely



Deb Chattopadhyay
Principal

Appendix F: Report – Selection and Assessment of Alternative Projects – Burns and Roe Worley

TransÉnergie Australia

TransÉnergie - Murraylink
Selection and assessment
of alternatives

16 October 2002

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
2	024/45003	Final Report	AR/ BM/TC	Graham Bennett	Rod Touzel

Burns and Roe Worley Pty Ltd
ABN 98 000 886 313

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Brisbane: **Level 6 80 Albert Street Brisbane QLD 4000 (PO Box 81 Albert Street Brisbane QLD 4002) Tel 61 7 3221 2347 Fax 61 7 3221 7791**

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EXECUTIVE SUMMARY

Murraylink Transmission Partnership ("MTP") is applying to the Australian Competition and Consumer Commission ("ACCC") for a regulatory determination regarding the Murraylink DC interconnector between the Victorian 220 kV transmission network at Red Cliffs substation and the South Australian 132 kV transmission network at Monash substation.

On behalf of MTP, TransÉnergie Australia ("TEA") engaged Burns & Roe Worley ("BRW") to prepare a report to select and assess alternative projects that offer the same technical service (and hence, the same market benefits) as Murraylink. This report is intended to assist MTP to propose the opening regulatory asset value ("RAV") for Murraylink.

Kellog Brown and Root Pty Ltd ("KBR") was also engaged by TEA to provide BRW with an environmental assessment of the alternative projects. Its assessment has been included in Appendix 1.

Murraylink is a transmission interconnection using ABB's HVDC Light technology that connects the Victorian 220 kV transmission system at the Red Cliffs substation in north-west Victoria, to the South Australian 132 kV transmission system at Monash substation in the Riverland region, north-east of Adelaide. The AC/DC converter stations have been established at Red Cliffs and Monash, and the DC link between Red Cliffs and Monash has been constructed using two underground cables.

Murraylink delivers the following services to the South Australian and Victorian electricity networks:

- Provides an additional 220 MW injection capability into the South Australian region during moderate and light load periods, and it can also provide at least an additional 110 MW injection capability into the South Australian region during peak load periods. This can occur even in the worst case when Victorian generation is constrained and excess generation must be sourced from the New South Wales region, subject to a prudent level of additional voltage support.
- Maintains a power transfer capability from the Victorian to South Australian regions even during times when the Heywood to South East substation ("SESS") inter-connector is constrained.
- Provides an additional 220 MW injection capability into Victoria from South Australia subject to constraints related to Riverland load and generation capacity in the South Australian region. During times of heavy Riverland load, Murraylink will be constrained to lower levels to prevent overloading the 132 kV circuits between Robertstown and Monash substations.
- Provides reactive support and assists with regulating the voltage profile of the AC networks at both the sending and receiving ends of the link. The reactive support is provided in a controlled manner, with minimal delay time and without incremental block changes. This reactive control is classified as an ancillary service within the National Electricity Market.
- Provides an additional transmission in-feed into the Monash substation 132 kV bus that relieves a potential future non-compliance with the SA Transmission Code, which defines the Riverland as a category 3 connection point. Such substations

require all customer loads to be supplied upon a single element contingency without load shedding. This issue is expanded in section 3.3.2.

In developing the alternatives, each project was designed to provide the same services as Murraylink. This required AC transmission alternatives to include both phase shifting transformers (“PST”) and static var compensators (“SVC”). In addition to providing power flow control, the PST is essential to achieve the nominal 220 MW transfer capability (due to relative system impedances) and to avoid overloading of other plant. An SVC provides the reactive control offered by Murraylink which is continuous, rather than discrete (as would be offered by shunt reactors and capacitor banks).

Murraylink also has a small environmental footprint because the cable has been installed underground. In developing the alternatives, consideration was also given to the likely environmental and community issues that surround the siting of a transmission line. As a consequence, provision was made for tactical undergrounding of transmission lines in environmentally or community sensitive areas.

BRW considered six equivalent or near equivalent alternatives to Murraylink. They were:

1. Buronga to Monash 275 kV AC, mostly overhead transmission line initially operating at 220 kV, with substation augmentations at Buronga and Monash;
2. Red Cliffs to Monash 140 kV DC, mostly overhead transmission line with substation augmentations at Red Cliffs and Monash;
3. Red Cliffs to Monash 220 kV AC, mostly overhead transmission line with substation augmentations at Red Cliffs and Monash;
4. Robertstown to Monash 275 kV AC overhead transmission line and Heywood to South East substation 275 kV AC overhead transmission line, with substation augmentations at Robertstown, Monash, Heywood and South East substation, and series capacitors at Tailem Bend;
5. Generation in South Australia and the Riverland; and
6. Demand side management.

BRW examined alternatives 5 and 6 for completeness as they represented possible alternatives for meeting the Riverland load requirements. However, in all other respects, they were not equivalent to Murraylink, and they were discarded early in the analysis.

For the remaining alternatives, a detailed base estimate was developed for the assets' capital, operating and maintenance costs. The base estimates were further subjected to a quantitative analysis of the cost risks so as to determine an appropriate contingency for each alternative. The contingency plus base estimates were used as the capital cost base for the project alternatives and a net present cost of annual operating and maintenance (O&M) over a forty-year period was added to develop a total net present cost of each of the alternative projects.

The summary level results are illustrated in the following table:

Attribute	***Alternative 1***	***Alternative 2***	***Alternative 3***	***Alternative 4***
Technical equivalence	Provides slightly lesser service than M/L.	Equal to M/L	Provides slightly lesser service than M/L	Provides lesser service than M/L and other alternatives.
Base cost including IDC	\$235.5 m	\$190.2 m	\$189.4 m	\$194.9 m
Contingency	\$10.4 m	\$16.1 m	\$12.2 m	\$7.1 m
Total capital cost	*\$245.9 m*	*\$206.3 m*	*\$201.6 m*	*\$202 m*
O&M costs	\$3.6 m per annum	\$3.4 m per annum	\$3.5 m per annum	\$3.6 m per annum
O&M net present costs over 40 years	*\$39.9 m*	*\$37.7 m*	*\$38.8 m*	*\$39.9 m*
Total net present cost	**\$285.8 m**	**\$244 m**	**\$240.4 m**	**\$241.9 m**
Uncertainty ranking 1 – least 4 – most	3	4	2	1

The cost analyses revealed the following:

- Alternatives 2, 3 & 4 had similar likely net present costs which were substantially less than the cost of Alternative 1.
- Alternative 4 would provide slightly less technical benefits compared to alternatives 1,2 and 3.
- Alternative 2 had a higher level of uncertainty with respect to capital cost than Alternative 3.

On the basis of the above, Alternative 3 represents the lowest cost alternative to Murraylink although the differences between the alternatives 2, 3 and 4 are marginal.

The RAV process provides that the opening value of an asset is determined by considering the following:

1. The equivalent cost of the optimised alternative that provides the same benefit; or
2. In the event that the cost of the equivalent is greater than the market benefit, the RAV will be determined as the actual cost of the built asset subject to there being a net market benefit.

Subject to the regulatory restrictions imposed by item 2 above, BRW recommends that the upper limit be placed on the valuation of Murraylink, such that the total net present cost of Murraylink, inclusive of lifecycle O&M costs, does not exceed the total net present cost of Alternative 3 of \$240.4 m.

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ATTACHMENTS

1 CLIENT BRIEF

Murraylink Transmission Partnership ("MTP") is applying to the Australian Competition and Consumer Commission ("ACCC") for a regulatory determination regarding the Murraylink DC interconnector between the Victorian 220 kV transmission network at Red Cliffs substation and the South Australian 132 kV transmission network at Monash substation.

On behalf of MTP, TEA engaged Burns & Roe Worley ("BRW") to prepare a report to select and assess alternative projects that offer the same technical service (and hence, the same market benefits) as Murraylink. This report is intended to assist MTP to propose the opening regulatory asset value ("RAV") for Murraylink in accordance with the *National Electricity Code* ("NEC"), the ACCC's *Draft Statement of Principles for the Regulation of Transmission Revenue* ("Draft Regulatory Principles"), and the ACCC's *Regulatory Test for New Interconnectors and Network Augmentations* ("Regulatory Test").

Kellog Brown and Root Pty Ltd ("KBR") was also engaged by TEA to provide BRW with an environmental assessment of the alternative projects. Its assessment has been included in Appendix 1.

2 ISSUES AND METHODOLOGY

An application for regulated status for Murraylink is dependant on a unique blend of technical, legal and commercial factors as described below:

1. Murraylink is a transmission augmentation which has already been commissioned by a new market entrant with no pre-existing regulated asset value. This is unique in the Australian National Electricity Market.
2. Murraylink makes use of relatively new HVDC technology. This technology has only recently been developed and its functionality can only be provided for by a combination of other existing technologies.

Consequently, there are issues associated with other market participants' potential use of their established arrangements to create non-economic outcomes, and benefitting from the technical services provided by Murraylink without affording due recognition.

The National Electricity Code ("NEC"), Regulatory Test and Draft Regulatory Principles give guidance as to what is required for Murraylink to become a regulated asset. However, there needs to be an appropriate and consistent approach to regulatory valuations. These valuations should not only include the benefit associated with Murraylink's ability to transmit electrical power, but should also consider the less tangible benefits associated with features such as system voltage control and rapid re-dispatch.

The methodology adopted for this Murraylink RAV involved steps that were undertaken by different parties assisting MTP. The party responsible for undertaking these steps is shown in brackets.

1. Review of the principles determined by the ACCC and the NEC that concern the RAV of an interconnector so as to develop a coherent methodology for arriving at the final RAV of Murraylink. (DGJ Projects)
2. Develop an understanding of the services delivered by Murraylink, as a basis for defining firm technical capabilities for alternative projects to be used for the RAV. (BRW)
3. Identify alternative projects that deliver services as close as possible to Murraylink, including the ancillary benefits provided by Murraylink. (BRW)
4. Investigate potential environmental and social impacts, possible mitigating measures and easement/property issues associated with similar interconnection projects and consider their impact when developing the alternative to Murraylink. (BRW/KBR)
5. Carry out any necessary system studies to confirm that the alternative projects provide the same level of technical service as Murraylink. (BRW)
6. Analyse the project risk profiles for the various project alternatives in relation to commercial, environmental and probable operational constraints. (BRW)
7. Prepare capital and operating cost estimates for each alternative over the life of Murraylink. These estimates are to consider all costs associated with the development of an asset including such items as easement and land costs, costs for environmental impact mitigation, etc. A probabilistic model is used to capture and assess the cost risks associated with each of the short-listed alternatives. Key risks considered

include factors such as market driven changes in the capital price of the equipment and materials and the cost risks associated with constructing the asset. The model is used to quantify the costs associated with these risks and provide a measure of uncertainty for each equivalent alternative. (BRW)

8. Carry out net present value evaluation of alternatives over a whole operational life of 40 years. (BRW)
9. Determine the gross market benefit provided by Murraylink. (TransÉnergie US)
10. Determine the Murraylink opening RAV at the regulatory period such that the value shall be no more than the equivalent valuation of any of the technically equivalent alternatives identified; or (DGJ Projects)
11. In the event that none of the identified alternatives provide a net market benefit, determine the RAV at the commencement of the regulatory period which is equivalent to the gross market benefit less the present value cost of operating and maintaining Murraylink. (DGJ Projects)

3 SELECTION AND ASSESSMENT OF ALTERNATIVE PROJECTS

3.1 Description of Murraylink

3.1.1 Technical components of Murraylink

Murraylink is a HVDC Light interconnection that connects the Victorian 220 kV transmission system at Red Cliffs substation in the north-west corner of Victoria, to the South Australian 132 kV transmission system at Monash substation in the Riverland region to the north-east of Adelaide. The AC/DC converter stations have been established at Red Cliffs and Monash, and the DC link between Red Cliffs and Monash has been constructed using two underground cables. Murraylink will normally operate at up to 220 MW.

The project works include the following:

Table 3.1.1.a Breakdown of Murraylink Project Works

Item	*Details*
Generation	N/A
Lines	An underground cable is constructed between Monash substation and Red Cliffs substation
Substations	Red Cliffs – switchgear and secondary system modifications to allow for connection of Murraylink Monash – switchgear and secondary system modifications to allow for connection of Murraylink
Control & communications equipment	Rapid run-back of DC link to cater for possible trips on sections of the interconnecting grid networks. eg Ballarat to Horsham 220 kV line
Spare equipment	1 x single-phase unit for each of the converter transformers located at Monash and Red Cliffs respectively. Miscellaneous spares associated with the converter stations to ensure rapid repair following failure of plant (eg: smoothing reactor)
Other network augmentations	South Australia – upgrades of current transformer circuitry and wave traps Victoria – minor upgrades of secondary protection systems
Other equipment	Converter stations near Red Cliffs and Monash

3.1.2 Technical services delivered by Murraylink

Murraylink delivers the following services to the South Australian and Victorian electricity networks:

- Provides an additional 220 MW injection capability into the South Australian region during moderate and light load periods. It can also provide at least an additional 110 MW injection capability into the South Australian region during peak load periods. This can occur even when Victorian generation is constrained and excess generation must be sourced from the New South Wales region, subject to a prudent level of additional voltage support.

- Maintains a power transfer capability from the Victorian to South Australian regions even during times when the Heywood to South East substation ("SESS") inter-connector is constrained. For example during times of lightning activity in the south-east region, Heywood transfer is reduced from 500 MW to 250 MW.
- Provides an additional 220 MW injection capability into Victoria from South Australia subject to constraints related to Riverland load and generation capacity in the South Australian region. During times of heavy Riverland load, Murraylink will be constrained to lower levels to prevent overloading the 132 kV circuits between Robertstown and Monash substations.
- Provides reactive support and assists with regulating the voltage profile of the AC networks at both the sending and receiving ends of the link. The reactive support is provided in a controlled manner, with minimal delay time and without incremental block changes as would otherwise be offered by shunt reactors and capacitor banks. Previously synchronous condensers provided this form of "smooth" reactive support, though the modern equivalent is an SVC. This reactive control is classified as an ancillary service and ranges from –110 MVAr to +140 MVAr during rectifier operation and –125 MVAr to +120 MVAr during inverter operation.
- Provides an additional transmission in-feed into the Monash substation 132 kV bus that relieves a potential future non-compliance with the SA Transmission Code[1], which defines the Riverland as a category 3 connection point. Such substations require all customer loads to be supplied under a single element contingency without load shedding. This issue is expanded in section 3.3 and Appendix 4.

3.1.3 Development, approval and construction issues for Murraylink

Murraylink obtained the necessary development approvals to allow construction to commence within 10 months of appointing an environmental consultant to the project, primarily because a full environmental impact assessment was not required. This was largely because of the following features:

- all transmission lines are underground; and
- the transmission lines are located along existing easements.

Typically, the development approval would take a lot longer and is the longest lead approval in the development process of a transmission asset.

3.2 Criteria for selection of alternatives

3.2.1 Alternatives to provide the same level of technical services

Implicit in the determination of an alternative project is the requirement that it achieve the same technical service offered by Murraylink. However, in using ABB's HVDC Light technology, Murraylink is taking advantage of the latest engineering technology, and no single alternative technology would be able to replicate Murraylink's performance.

[1] SAIIR, SA Transmission Code, 1 July 2001

Alternatives have been developed using proven technologies, which deliver services and ancillary benefits as similar as possible to Murraylink. Table 3.2.1.a provides details of these services and the possible alternative technologies.

Table 3.2.1.a General comparisons between Murraylink and conventional alternatives

Murraylink	***Alternatives***
Provides an additional 220 MW injection capability into the South Australian region during moderate and light load periods, and it can also provide at least an additional 110 MW injection capability into the South Australian region during peak load periods.	AC links can provide similar facilities, but are heavily dependent on the order of generation dispatch. Power flow control can be achieved with phase shifting transformers. More recently, thyristor controlled series capacitors ("TCSC") have been developed which provide a similar service, though such devices are generally cost effective only for large transmission interconnections (>500 MW) and are therefore not considered herein.
Provides an additional 220 MW injection capability into Victoria from South Australia.	Same comment as above.
Provides reactive support and assists with regulating the voltage profile of the AC networks at both the sending and receiving ends of the link	In general AC links cannot supply this service and under some system conditions this would constrain the operation of the interconnection. SVC technology (using thyristor switched capacitors and thyristor controlled reactors) has been available for almost two decades now to achieve "smooth" reactive compensation and voltage control. More recently, STATCOM devices using voltage source converter technology have become available which have an even greater range of operation than existing SVCs. These devices are, however, more expensive than conventional SVCs and have not been considered as an appropriate technology to be included in any of the alternatives.
Provides an additional transmission in-feed into the Monash substation 132 kV bus that relieves an existing non-compliance with the SA Transmission Code which defines the Riverland as a category 3 connection point.	AC links can also provide this service.
Provides a small environmental footprint because the cable is underground.	A similar level of environmental performance is achievable by undergrounding sections of the line that pass through sensitive areas.

For completeness, generation and demand side management (DSM) alternatives have also been briefly considered although they provide a substantially different level of service compared with Murraylink.

3.2.2 Alternatives to commence/cease operations at the same time

To compare the alternatives to Murraylink, a common project operation date of the 1 May 2003 has been used. This is based on the assumption that the alternatives would have been identified and works commenced in sufficient time to ensure commercial operation by this date. The operational life of each of the alternatives shall be 40 years and TransÉnergie US (TEUS) has calculated gross market benefits on this basis. Summer 2002–03 has been used as the base year for the system studies and all costs are escalated to reflect the 1 May 2003 costs.

3.2.3 Stand alone new entrant as alternative project developer

The RAV approach reflects the actual costs incurred by a potential new entrant in developing and operating the transmission asset on a stand-alone basis. In assessing costs for the alternative projects, it has therefore been necessary to include all of the business costs without regard to any cost sharing that may be available if a TNSP had many other assets from which to share spares, administration expenses, etc. In this evaluation, all the costs associated with developing and operating the single transmission link have been considered within the project estimate. As a stand-alone facility, the costs also include an allowance for the support infrastructure associated with ensuring adequate system reliability.

The SA Transmission Code requirements for category 3 connection point state inter alia "transmission entities will keep in stock at least one spare transformer capable of replacing installed transformer capacity. In the event of a transformer failure, a transmission entity will use its best endeavours to repair the installed transformer or install a replacement transformer within 4 days of the failure". Continuing with this requirement, critical spares, ranging from insulators to circuit breakers, are also required, so that in the event of line failure, the system can be quickly returned to service. For transmission alternatives, this criterion has been applied to ensure that relevant total costs are captured.

3.2.4 Environment permitting and approval impacts

To develop credible alternatives, it is necessary to consider current trends in the environmental management of transmission line assets. Any decision on both the route and the extent of undergrounding (if any) needs to consider this.

The recent Basslink assessment gives some indication of these trends and their underlying rationale. In the assessment, areas considered to be of state and/or national significance required undergrounding, while those of only local significance did not.

KBR, the study's environmental adviser, has assessed the impact of these trends on each of the alternative transmission projects. These impacts have been included in the cost assessment for each alternative. (See Appendix 1.)

3.3 Network augmentations

3.3.1 Recent augmentations of the Riverland region

The supply to the Riverland region has recently been augmented by the following two projects:

- A new Monash substation complete with 4 x 132 kV feeder bays and 2 x 132 feeder breakers, a 132/66 kV transformer to feed into the Berri substation 66 kV bus and two 18 MVAr capacitors. The capital cost of the 132/66 kV transformer and capacitors (only) was borne by ElectraNet SA. The remaining costs were borne by MTP.
- Minor augmentations to the 132 kV system feeding into Riverland, including modifications to 132 kV wave traps at North West Bend ("NWB") and Berri substations, changes to 132 kV current transformer ("CT") settings, and replacement of 132 kV CTs at NWB and Robertstown substations. The scope of these works and the circuit ratings prior to and after the augmentations has been advised by TEA on behalf of MTP[2].

The need for, and the scope of, these connection point augmentation works were determined by the IOWG[3] during the Murraylink review process. Both of these augmentations have been funded by Murraylink and form part of the Murraylink project (though the assets are the property of ElectraNet), and are assumed to be required as part of each alternative.

3.3.2 Ongoing capacity of transmission networks

Murraylink and all the alternatives depend on available capacity within the NSW, Victorian and SA transmission networks at their connection points and in the network behind those connection points for their performance. Over time it can be expected that load growth and other factors will vary the available capacity of the networks in each region.

For the purposes of this study, it has been assumed that those authorities responsible for the networks in each region will be obliged to continually 'make good' the transmission network capacity to that prevailing at the original date. In other words, no consideration has been given to future augmentations in the NSW, Vic and SA transmission networks (beyond those considered in the Riverland as discussed in the following section) that are required to support the proposed alternative project transfer capacity.

3.3.3 Future Riverland augmentations

ESIPC has provided 10-year load predictions for the Riverland area. These have been extended to summer 2017–18 to determine the next stages of augmentation for each of the alternatives. Load-flow studies have shown that each of the alternatives are to all intents and purposes equal in this matter (refer Appendix 4). These studies also confirm the likely timing of future augmentations which is consistent with the market benefit analysis carried out by TEUS concerning deferral benefits.

3.4 Baseline costing and net present value costs

Works' estimates have been built up on the basis that the project proponent is both the developer; the engineer, procure and construct ("EPC") contractor; and the operator. In this way, it has been possible to consider and account for the cost elements associated with all phases of the project.

[2] TransÉnergie Australia submission to ESIPC dated 30 July 2001

[3] NEMMCO 5.6.6(b) Assessment of Murraylink, August 2001 pp.16

Base costs have been derived using BRW's own internal cost databases supplemented by the following:

- quotes obtained from key electrical equipment vendors;
- cost data from other similar transmission line projects; and
- TNSP's replacement cost data which is available in the public domain.

Elements considered include development costs, easement costs, and EPC contract costs inclusive of the contractor profit. The contractor will also likely provide the strategic spares and this cost has been included.. Interest during construction ("IDC") has also been considered in the total capital cost. This amount has been calculated using a discount rate that is consistent with the rate used by TEUS in assessing market benefits for Murraylink. A generic expenditure profile based on a five-year project timeline from inception to operation has been developed for each alternative to assist in the determination of IDC costs.

Annual operation and maintenance costs have also been established for each alternative. In addition to these costs, a provision has been included within the estimate amount to cover expenditure of a capital nature over the expected life of the alternative.

The total net present cost of each alternative therefore is made up of total operation and maintenance costs plus capital expenditure for the life of the asset.

3.5 Probabilistic risk assessment

There is significant uncertainty in pricing any alternative. Risk arises from several areas. The main one is uncertainty in the information contained in the base estimate itself; authors of the estimate can use their skill and experience to make 'best guess' estimates for a range of parameters, but these may turn out to be incorrect. For example, information on the Basslink project, recently released into the public domain, includes costs for an underground cable that varies markedly depending on the source data. Market forces are such that the price of discrete capital items such as transformers, etc, also varies significantly depending on issues such as order backlog, etc.

These uncertainties have been modelled by replacing a single deterministic value with a range of values, each with an associated probability. The end output of this process is a probabilistic curve of cost against probability.

The structured approach to risk analysis and management used for this assignment was based on the first part of the Worley risk management process—a general risk management methodology of risk identification, risk assessment and appraisal, and risk control. The cost risk model was developed in @Risk for Excel (version 4.0.5), a risk analysis tool for spreadsheets. The model contains 31 risk factors, all of which were assigned risk variables describing a continuous range of uncertainty. Table 3 illustrates some of the major uncertainties catered for by the model.

Table 3.3.3.a Cost model uncertainties

Cost Element	***Uncertainty***	***Rationale***
Environmental approvals Alternatives 1,2 & 3 Alternative 4	 -40%, +60% -20%, +10%	The environmental approvals process and the extent of effort (and hence costs) required to prepare the necessary environmental assessments is inter-related to the extent of consultation required and the process duration which has significant risk of delay. For Alternative 4, this cost uncertainty is considered less as the routes for the two lines which make up Alternative 4 run parallel to existing lines.
Major equipment costs SVC, PST DC converter station	 -10%, +25% -20%, +40%	The cost of major equipment is subject to significant uncertainty largely as a result of market forces. BRW has over time determined that initial budget prices quoted are often lower than actual costs at purchase time due to specification refinements. Hence a wider upward variation was predicted. Competition amongst suppliers was assessed as the main driver of possible price reduction.
Undergrounding of cable Supply Installation	-20%, +10% -25%, +15%	Budget prices obtained from suppliers/contractors to carry out these works varied significantly both in terms of supply and installation. With regard to installation, the price is heavily dependent on the ground conditions and the extent of vegetation removal, etc which has not been specifically investigated and therefore has a proportionately higher level of uncertainty.
Labour productivity	-10%,+45%	Line estimates were derived using unit rates for foundations, tower erection and stringing. Typically these historically-based estimates are optimised with little likelihood for improvement but there can be significant chance of overrun due to the impact of industrial relations issues, etc.

Other elements had uncertainty limits assigned which were within a +/-15% band. These cost elements included tower foundation, number of towers (due to variation in tower spacing), tower fabrication costs, tower tonnage, line hardware and conductor supply. A full listing of uncertainty provisions along with additional explanatory information regarding the process undertaken and simulation results is contained in Appendix 5.

3.6 Assessment of cost contingency criteria

The primary purpose of undertaking this analysis was to determine the uncertainty associated with the alternative project base estimates and from this assign an appropriate contingency amount to be considered as part of the total alternative project cost.

For a major organisation, a contingency criterion is normally selected such that there is an equal probability of underrun verses overrun of the budgeted amount. This is because the large developer has a portfolio of assets and development activities and in these circumstances, the criterion referred to as the P50 contingency is appropriate. For a new market entrant in the smaller Australian market, it is likely that the proponent would derive a large proportion of its income from the single project. In this instance, a contingency criterion of P50 represents a risk level that is unacceptably high.

In carrying out bankers due diligence for new projects, the criteria for assessing the appropriateness of the contingency amount is largely dictated by the allocation of risk in the proposed EPC contract. A P50 or lower range contingency criteria is only acceptable in instances where the developer has transferred all significant technology and program risk. Within the construction industry, contingency for a lump sum project is often assessed at the P75 level, i.e. at this level, a project has a likelihood of 25% of overrunning the budget estimate. For guaranteed maximum price arrangements, this criterion can be as high as P85. In the analysis of Murraylink alternatives, the estimate assumes the proponent was both the developer and the EPC contractor. Accordingly, BRW considers that a criterion of between P75 and P85 is appropriate and has taken the lower number in assessing the total budgeted capital costs. As the lower criterion will yield a lower net cost, BRW considers this criterion to be conservative.

4 THE ALTERNATIVE PROJECTS

4.1 Summary of alternative projects

BRW considered six equivalent alternatives to Murraylink in order to assess the asset. They were:

1. Buronga to Monash 275 kV AC, mostly overhead transmission line initially operating at 220 kV, with substation augmentations at Buronga and Monash;
2. Red Cliffs to Monash 140 kV DC, mostly overhead transmission line with substation augmentations at Red Cliffs and Monash;
3. Red Cliffs to Monash 220 kV AC, mostly overhead transmission line with substation augmentations at Red Cliffs and Monash;
4. Robertstown to Monash 275 kV AC overhead transmission line and Heywood to South East substation 275 kV AC overhead transmission line, with substation augmentations at Robertstown, Monash, Heywood and South East substation, and series capacitors at Tailem Bend;
5. Generation in South Australia and the Riverland; and
6. Demand side management.

BRW examined alternatives 5 and 6 for completeness as they represented possible alternatives for meeting the Riverland load requirements. However in all other respects they were not equivalent to Murraylink, and they were discarded early in the analysis for reasons given in sections 4.7 and 4.8 respectively.

4.1.1 Routes for the transmission lines

The preferred routes for the transmission lines were determined by BRW with input from KBR, the environmental consultant.

The following routes were selected.

- For the Monash to Buronga routes, the selected route is similar to that published in the environmental impact statement for the SNI project but with some tactical undergrounding to reduce environmental impacts in the Bookmark biosphere area. (Alternative 1)
- For the Monash to Red Cliffs route, the route is similar to the constructed Murraylink project, but crosses private land instead of road reserves with tactical undergrounding for several kilometres either side of the Lyrup and Red Cliffs settlements. (Alternatives 2 & 3)
- For the Heywood to South East substation route, the selected route runs parallel to the existing Heywood to South East substation transmission line. (Part of Alternative 4)
- For the Robertstown to Monash route, the selected route runs parallel to the existing 132 kV line. (Part of Alternative 4).

A diagram illustrating the selected routes is included in appendix 1.

4.2 Assessment of alternatives' technical service delivery

The subsequent section provides an overview of the alternatives. An engineering review containing an assessment of the technical services of each selected alternative and load-flow analyses is presented in Appendix 2. As identified in Table 3.2.1.a, an AC alternative will require a PST to achieve the nominal MW transfer due to relative system impedances, while an SVC and shunt reactor is required to achieve the voltage regulation and reactive support offered by Murraylink.

4.3 Alternative 1 – Buronga to Monash AC 275 kV transmission line

4.3.1 Scope of capital works for Alternative 1

Alternative 1 is based on an AC connection between Buronga substation in south-west NSW and Monash substation. This line would be constructed for 275 kV operation, but would initially be operated at 220 kV. Such an approach is consistent with that applied to the existing Darlington Point to Buronga transmission line. It also defers the need for a major upgrade of the Buronga site.

The capital works include the following:

Table 4.3.1.a Equipment requirements of Alternative 1

Item	***Details***
Lines	275 kV overhead line between Monash and Buronga substations (operated at 220 kV) with 30 km of undergrounding in the bookmark biosphere area.
Substations	***MONASH*** Switchgear and secondary system modifications to allow for connection of alternative 2 x 275/132 kV 160 MVA transformers (with 220 kV taps) 1 x 275/275 kV 350 MVA phase shift transformer 1 x +120 / -110 MVAr SVC ***BURONGA*** Switchgear and secondary system modifications to allow for connection of alternative30 MVAr switched shunt reactors
Control & communications equipment	Control systems as required to prevent system overloads following loss of a critical circuit (similar to that used in conjunction with Murraylink "runback" scheme). Typical line protection communication systems
Spare equipment	1 x 350 MVA 275/275 kV phase shifting transformer (to be located at Monash) 1 x 160 MVA 275/132 kV autotransformer with additional 220 kV tapping (to be located at Monash) Substation spares (at 6% of substation electrical costs) Transmission line spares (considered within O&M budget)
Other network augmentations	Augmentations of existing plant due to impact of new interconnection with increased fault levels.

4.3.2 Technical services delivered by Alternative 1

Alternative 1 can provide almost the same technical service that Murraylink provides subject to the following differences:

- Murraylink provides full control of power over the interconnection. Alternative 1 has only partial control affected by generation dispatch and phase shifting transformer tap changing.
- Murraylink provides reactive support independently at Red Cliffs and Monash. Alternative 1 provides reactive support at Monash, which is considered adequate to control the Red Cliffs region as well.

The full details of the technical service performance of this alternative are presented in Appendix 3.

4.3.3 Development, approval and construction issues for Alternative 1

The route for this transmission line traverses the Bookmark biosphere area and KBR has advised that tactical undergrounding in the Ramsar wetland area (a 30 km wide area which forms part of the Bookmark biosphere) would likely be required to meet the environmental management objectives. Even if this amount of undergrounding was not found to be strictly necessary, a totally above ground alternative would likely suffer delay in gaining approval. To be consistent with Murraylink's approach and ensure that the alternative system is operational within the required timeframe, it is appropriate to include within the base estimate an allowance for 30 km of undergrounding.

4.3.4 Base costs and contingent costs of capital works for Alternative 1

The base capital estimate for developing this project is $235.5 m. This estimate includes costs as discussed in Section 3.4. As a result of uncertainty associated with the estimate, a contingent amount of $10.4 m (P75 level) has been added to the base. For valuation purposes therefore, the total budgeted amount for Alternative 1 has been assessed at $245.9 m.

The major contributors to this contingency are as follows:

- underground costs – supply and installation
- PST and SVC costs – supply only
- labour productivity.

Details of the capital price breakdown is contained within Appendix 5 along with a complete listing of the contingency cost drivers. The relative impact of these cost drivers is also contained in the sensitivity analysis which is a deliverable of the cost risk process.

4.3.5 Operating and maintenance costs of Alternative 1

Operation and maintenance costs for Alternative 1 were estimated at $3.6 m per annum. These costs are higher than the large TNSP's on a per km basis because the new entrant proponent does not operate with the same economies of scale.

4.3.6 Net present value cost of Alternative 1

Based on a discount rate of 9.25% which has been used for the market benefit analysis, the total net present operation and capital costs of this asset inclusive of contingency on capital has been assessed at $284.3 m. This is inclusive of $39.9 m in net present terms for 40 years of operation and maintenance.

4.4 Alternative 2 – Red Cliffs to Monash 140 kV DC transmission line

4.4.1 Scope of capital works for Alternative 2

This alternative would provide the same benefits as the actual Murraylink project, but would include a predominantly above-ground 140 kV DC bi-polar transmission line from Red Cliffs to Monash.

The capital works include the following:

Table 4.4.1.a General equipment requirements of Alternative 2

Item	***Details***
Lines	HVDC overhead line between Monash and Red Cliffs substations with a total of 25 km of undergrounding where the route passes through or near the townships of Red Cliffs and Lyrup.
Substations	***MONASH*** Switchgear and secondary system modifications to allow for connection of alternative HVDC converter station, including converter transformer ***RED CLIFFS*** Switchgear and secondary system modifications to allow for connection of alternative HVDC converter station, including converter transformer
Control & communications equipment	Control systems as required to prevent system overloads following loss of a critical circuit (similar to that used in conjunction with Murraylink “runback” scheme).
Spare equipment	1 x converter transformer located at Monash) 1 x converter transformer located at Red Cliffs Converter station spares (particular large items such at smoothing reactors, etc). Substation spares (at 6% of substation electrical costs) Transmission line spares (considered within O&M budget)
Other network augmentations	Augmentations of existing plant due to impact of new interconnection with increased fault levels

4.4.2 Technical services delivered by Alternative 2

The technical services provided by Alternative 2 are identical to Murraylink.

4.4.3 Development, approval and construction issues for Alternative 2

The route for this transmission line traverses the townships of Lyrup and Red Cliffs. Advice obtained from KBR recommends that tactical undergrounding within and around these townships would significantly reduce the environmental impact associated with this alternative. This improvement in environmental performance would assist in ensuring that the environmental approvals process for this asset would not suffer undue delay. This is consistent with Murraylink’s approach to ensure that the system is operational within the required timeframe. The base estimate therefore contains an allowance for 25 km of undergrounding – 12.5 km at each end.

4.4.4 Base costs and contingent costs of capital works for Alternative 2

The base estimate for developing this project is $190.2 m. As a result of uncertainty associated with the estimate, a contingent amount of $16.1 m (P75 level) is required to be added to this base. For valuation purposes therefore, the total budgeted amount for Alternative 2 has been assessed at $206.3 m.

The major contributors to this contingency are as follows:

- DC converter station costs – supply only
- Underground costs – supply and installation
- PST and SVC costs – supply only.

Because of the additional uncertainty in the costs of the converter station, the contingency amount is higher than Alternative 1 notwithstanding that the base capital price is lower. Details of the capital price breakdown is contained within Appendix 5 along with a complete listing of the contingency cost drivers. The relative impact of these cost drivers is also contained in the sensitivity analysis which is a deliverable of the cost risk process.

4.4.5 Operating and maintenance costs of Alternative 2

Operation and maintenance costs for alternative 2 were estimated at $3.4 m per annum. This is $0.2 m per annum less than Alternative 1 due to the reduced length of line and reduced quantum of cable, insulators etc associated with the HVDC technology.

4.4.6 Net present value cost of Alternative 2

Based on the discount rate of 9.25% which has been used for the market benefit analysis, the total net present operation and capital costs of this asset inclusive of contingency on capital has been assessed at $243.6 m. This is inclusive of $37.7 m in net present terms for 40 years of operation and maintenance.

4.5 Alternative 3 – Red Cliffs to Monash AC 220 kV transmission line

4.5.1 Scope of capital works for Alternative 3

This project would provide similar benefits to the existing Murraylink project, and consists of a 220 kV AC transmission line from Red Cliffs to Monash. This alternative is similar to Alternative 1 but takes a different route which is 30 km shorter than Alternative 1.

The capital works include the following:

Table 4.5.1.a General Equipment requirements for Alternative 3

Item	***Details***
Lines	220 kV single circuit transmission line between Red Cliffs and Monash with a total of 25 km of undergrounding where the route passes through, or near, the townships of Red Cliffs & Lyrup.
Substations	***MONASH***

Item	*Details*
Substations (con't)	Switchgear and secondary system modifications to allow for connection of alternative 1 x 220/132 kV phase shift transformer [4] 1 x +120 / -110 MVAr SVC ***RED CLIFFS*** Switchgear and secondary system modifications to allow for connection of alternative 30 MVAr switched shunt reactors
Control & communications equipment	Control systems as required to prevent system overloads following loss of a critical circuit (similar to that used in conjunction with Murraylink "runback" scheme). Typical line protection communication systems
Spare equipment	1 x 220/132 kV phase shift transformer Substation spares (at 6% of substation electrical costs) Transmission line spares (considered as part of O&M budget)
Other network augmentations	Augmentations of existing plant due to impact of new interconnection with increased fault levels

4.5.2 Technical services delivered by Alternative 3

Alternative 3 can provide almost the same technical service as Murraylink except for the following differences:

- Murraylink provides full control of power over the interconnection. Alternative 3 has only partial control affected by generation dispatch and phase shifting transformer tap changing.
- Murraylink provides reactive support independently at both Red Cliffs and Monash. Alternative 3 provides reactive support at Monash only. A switched shunt reactor at Red Cliffs has also been provided to prevent severe overvoltages following a sudden disconnection of the 220 kV interconnection.

Alternative 3 provides the best match of an equivalent AC connection to Murraylink of all the alternatives considered.

4.5.3 Development, approval and construction issues for Alternative 3

The route for this transmission line is the same as Alternative 2 and the same extent of undergrounding has been assumed.

[4] For Alternative 1 and 4, a 275/275 PST has been nominated, yet for Alternative 3, a voltage transformation is also included (220/132 kV). This has been done because a 220 kV bus is unlikely to ever be established at Monash. Note also the greater angle tap requirements for the 220/132 kV phase shift transformer.

4.5.4 Base costs and contingent costs of capital works for Alternative 3

The base estimate for developing this project is $189.4 m with a contingent amount of $12.2 m. For valuation purposes therefore, the total budgeted amount for Alternative 3 has been assessed at $201.6 m.

The major contributors to this contingency were as per Alternative 1 (refer section 4.3.4). Cost details are contained in Appendix 5.

4.5.5 Operating and maintenance costs of Alternative 3

Operation and maintenance costs for Alternative 3 were estimated at $3.5 m per annum. This is lower than the estimated costs of Alternative 1 due to the shorter line route.

4.5.6 Net present cost of alternative 3

Based on the discount rate of 9.25%, the total net present operation and capital costs of this asset inclusive of contingency on capital has been assessed at $240.4 m. This is inclusive of $38.8 m in net present terms for 40 years of operation and maintenance.

4.6 Alternative 4 - Robertstown to Monash 275 kV project + Heywood B Interconnector

4.6.1 Scope of capital works for Alternative 4

This alternative is a combination of two projects; the Robertstown – Monash 275 kV line with 275/132 kV transformation at Monash and the Heywood B interconnection. The new Robertstown to Monash line would provide for re-enforcement of the existing Riverland network, while the Heywood upgrade would provide for increased transfer capacity between the Victorian and South Australian region. A 275 kV PST is also included at Heywood to ensure a full 220 MW transfer is available across the new Heywood to Robertstown 275 kV line, even when the existing 275 kV double circuit between Heywood and South East Substation is constrained (as occurs during times of lightning activity in south-east South Australia).

The capital works include the following:

Table 4.6.1.a General equipment requirements for Alternative 4

Item	***Details***
Lines	275 kV single circuit overhead transmission line between Robertstown and Monash substations 275 kV single circuit transmission line between Heywood and South East substations
Substations	***MONASH*** Switchgear and secondary system modifications to allow for connection of alternative 1 x 275/132 kV 160 MVA transformer 1 x +120 / -110 MVAr SVC ***ROBERTSTOWN*** Switchgear and secondary system modifications to allow for connection of alternative 30 MVAr switched shunt reactors

Item	Details
	HEYWOOD Switchgear and secondary system modifications to allow for connection of alternative 1 x 500/275 kV 600 MVA transformer 1 x 275 kV 350 MVA phase shift transformer ***SOUTH EAST*** Switchgear and secondary system modifications to allow for connection of alternative ***TAILEM BEND*** Series capacitors with 50% compensation of existing Tailem Bend to South East lines.
Control & communications equipment	Typical line protection communication systems.
Spare equipment	1 x 220/132 kV phase shift transformer Substation spares (at 6% of substation electrical costs) Transmission line spares (considered as part of O&M budget)
Other network augmentations	Augmentations of existing plant due to impact of new interconnection with increased fault levels

4.6.2 Technical services delivered by Alternative 4

Alternative 4 can provide almost the same technical service that Murraylink provides subject to the following differences:

- Murraylink provides full control of power over the interconnection. Alternative 4 has only partial control affected by generation dispatch and phase shifting transformer tap changing.
- Murraylink provides reactive support to the Vic/NSW transmission system whereas Alternative 4 cannot provide any such support.
- Murraylink injects power into the Riverland region whenever importing power into South Australia. Alternative 4 injects power into the southeast region, which means that the constraints on Alternative 4 are different to the constraints on Murraylink. Specifically, Alternative 4 partially relieves bottlenecks that currently occur between Victoria and South Australia. However, bottlenecks will still exist between South East and Tailem Bend substations that can be more constraining than the bottleneck between Victoria and South Australia,[5] particularly if wind farm development occurs in the south-east region. For the purposes of this analysis, BRW has ignored these issues and taken the simplistic view that transmission of power from Victoria to South Australia is improved regardless of transmission bottlenecks within the South Australian system.

[5] ESPIC, BRW, South Eastern Transmission Development concept Plan, 19 April 2002

Alternative 4 provides the necessary support to the Riverland and it allows additional power transfers between Victoria and South Australia. However, it is not a close equivalent because it is subject to differing constraints and cannot provide voltage support to the south-west NSW transmission system. The power flow studies also indicate that the other alternatives can derive more flow from the south-west NSW region which is not the case for Alternative 4.

4.6.3 Development approval and construction issues for Alternative 4

The approvals process for this alternative was assessed as having a lower risk than other alternatives. The two lines that make up this alternative will be run in parallel with existing lines. The environmental constraints associated with this alternative have therefore been assessed as being less subject to risk of delay or risk of non-compliance with anticipated environmental performance requirements. Accordingly, no undergrounding has been considered for the base case.

4.6.4 Base costs and contingent costs of capital works for Alternative 4

The base estimate for developing this project is $194.9 m with a contingent amount of $7.1 m. The lower contingency is largely due to the fact that this alternative has no requirement for strategic undergrounding. For valuation purposes therefore, the total budgeted amount for Alternative 4 has been assessed at $202 m.

The top three contributors to this contingency were as follows:

- PST and SVC costs – supply only
- Labour productivity
- Suspension tower costs.

The increased line length of Alternative 4 means that the cost estimate is more heavily impacted by cost elements associated with the overhead line construction. In terms of contingency, therefore, a reasonable proportion is associated with the tower costs.

Further details on costs are contained in Appendix 5.

4.6.5 Operating and maintenance costs of Alternative 4

Operation and maintenance costs for Alternative 4 were estimated at $3.6 m per annum. This is the same as Alternative 1 notwithstanding that it is a longer line. This is because the easements and consequent costs of easement maintenance would likely be shared with existing lines. However, this assumption is predicated on the incumbent TNSP and the new entrant entering into an appropriate commercial arrangement.

4.6.6 Net present cost of Alternative 4

Based on the discount rate of 9.25% which has been used previously, the total net present operation and capital costs of this asset inclusive of contingency on capital has been assessed at $241.9 m. This is inclusive of $39.9 m in net present terms for 40 years of operation and maintenance.

4.7 Alternative 5 – Generation in South Australian and the Riverland

4.7.1 Gas turbine open cycle or combined cycle generating plant

Capital costs for open cycle gas turbine plant varies between $400 – $700 per kW depending on unit size, market conditions and the prevailing exchange rate. Taking the mid-range costing, the total capital cost for 220 MW of open cycle gas turbine is around $121 m. For combined cycle plant, the mid-range capital costs on a per MW basis has been assessed at $1000 per kW, or $220 m for a 220 MW facility. These costs exclude the operation and maintenance costs associated with generation alternatives and any augmentation that may be required to supply gas to the region.

Even at low levels of generation, when these costs are included in any net present cost analysis, the total cost associated with these alternatives is in excess of the transmission alternatives. That portion of market benefit associated with the transfer of power from the lower marginal cost regions is also not realised in the generation alternatives.

4.7.2 Technical services delivered by Alternative 5

Alternative 5 could support the Riverland area during peak loads and also provide continuous reactive support for the Riverland system when the generator is on line.

The main services that Alternative 5 cannot supply are transfer of power from NSW/Vic to South Australia or transfers in the other direction. This has market implications because it means that the present constraints between different market areas would remain.

Alternative 5 is also unable to provide any voltage support to NSW or Victoria.

As a result of these factors, the generation alternative has not been considered further in this assessment.

4.8 Alternative 6 – Demand side management

NEMMCO[6] has provided the following estimates of the possible extent of DSM programs in Victoria and SA. Approximately 2.4% of the combined Victorian and South Australian peak demand for the summer of 2001–02, has been identified as being able to provide a committed demand side response. This amounts to 286 MW. NEMMCO is aware that there can be technical difficulties associated with demand reduction for any particular system condition. To this end, NEMMCO has decided that only 50% of the demand side response indicated should be included in the supply/demand assessment in order to avoid an overly optimistic outlook. This would mean that only 143 MW of demand side response will be included in the supply/demand assessment for Victoria and South Australia combined. In order to provide separate levels of demand side for the individual assessment of these regions in the supply/demand balance, it was arbitrarily assumed that the ratio between demand side participation ("DSP") in Victoria and South Australia will closely follow the ratio between Victorian and South Australian demands. This ratio is approximately 3:1 and would indicate an assumed DSP level of:

- 107 MW in Victoria, and
- 36 MW in South Australia.

[6] NEMMCO 2001 Statement of Opportunities

The South Australian Electricity Supply Industry Planning Council (ESIPC) report[7] noted that '*a significant component of Riverland demand is water pumping associated with SA Water's Morgan to Whyalla pipeline, and that the water pumping schedules typically restrict substantial pumping to off-peak hours during high Riverland demand over summer. Also, that pumping demand reduces substantially in response to high South Australian electricity pool prices. The load predictions that are used to determine the augmentations to the supply to the Riverland region have been adjusted to take account of these pumping regimes.*

A significant portion of Riverland demand is associated with irrigation and industrial processing associated with fresh produce, fruit and grape growing. The Riverland demand profile exhibits a shape during summer that is relatively flat over a period extending from early morning to evening. It is significantly different from the overall South Australian power system peak demand profile which exhibits a short duration peak in early afternoon.'

ESIPC concluded that the nature of usage electricity in the Riverland region offer little scope for further substantial modification of customer demand. BRW are in general agreement with the ESIPC report and as such have not investigated this alternative any further.

4.9 Transmission Alternatives Summary

Table 4.7.2.a provides a summary of the transmission alternatives considered in this study.

Table 4.7.2.a Summary of alternatives attributes

Attribute	***Alternative 1***	***Alternative 2***	***Alternative 3***	***Alternative 4***
Technical equivalence	Provides slightly lesser service than M/L.	Equal to M/L	Provides slightly lesser service than M/L	Provides lesser service than M/L and other alternatives.
Base cost	$235.5 m	$190.2 m	$189.4 m	$194.9 m
Contingency	$10.4 m	$16.1 m	$12.2 m	$7.1 m
Total capital cost	*$245.9 m*	*$206.3 m*	*$201.6 m*	*$202 m*
O&M costs	$3.6 m per annum	$3.4 m per annum	$3.5 m per annum	$3.6 m per annum
O&M net present costs over 40 years	*$39.9 m*	*$37.7 m*	*$38.8 m*	*$39.9 m*
Total net present cost	**$285.8 m**	**$244 m**	**$240.4 m**	**$241.9 m**
Uncertainty ranking 1 – least 4 – most	3	4	2	1

[7] ESIPC Riverland Augmentation Report, December 2001

As can be seen from the summary of alternatives, projects 2, 3 and 4 are similar in terms of net present cost. As discussed earlier, Alternative 4 provides a slightly lesser service than Alternatives 2 and 3 and on the basis that the pricing is similar, this alternative was discounted.

To distinguish between Alternatives 2 and 3, it is necessary to consider the risk profiles of each project. Figure 4.9 (a) illustrates the probabilistic estimate for project costs inclusive of operation and maintenance.

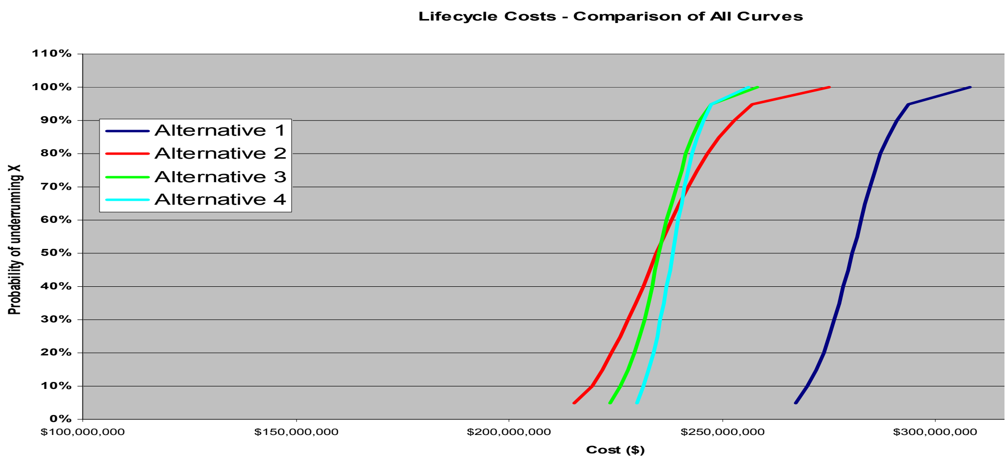

Figure 4.9a: Probabilistic cost curve for transmission alternatives

From the curves, it is apparent that Alternatives 3 and 4 have less uncertainty than Alternative 2. This is largely because of the increased uncertainty surrounding the converter station estimate in Alternative 2. It is a subjective determination as to whether the superior technical service associated with Alternative 2 outweighs the additional risk associated with this alternative.

Therefore, on the basis of the risk profile and net present cost, BRW considers that Alternative 3, the 220 kV line between Monash and Red Cliffs presents the lowest cost alternative to Murraylink.

5 RAV IMPACTS

Of the alternatives considered by BRW that provide services equivalent to Murraylink, Alternative 3, the 220 kV AC transmissions link from Red Cliffs to Monash, presents the lowest net present cost at $240.4 m inclusive of contingency at the P75 level. Based on the uncertainty simulations carried out on the alternatives, the accuracy of this alternative is also the best.

On this basis, BRW recommends that the upper limit be placed on the valuation of Murraylink such that the total net present cost of Murraylink does not exceed $240.4 m which is the estimated total cost inclusive of all capital and operation and maintenance costs for Alternative 3.

6 REFERENCES

I. ElectraNet SA submission to ESIPC, Riverland Region Reinforcement, 31 July 2001

II. ESIPC, Annual Planning Report, 2002

III. ESIPC, Riverland Augmentation Report, December 2001

IV. ESIPC, BRW, South Eastern Transmission Development concept Plan, 19 April 2002

V. GTW Handbook 2001

VI. Interconnection Options Working Group draft paper, Technical Issues and Costs of Interconnection Options for South Australia, 11 May 1999

VII. NEMMCO, Statement of Opportunities, 2001

VIII. NEMMCO, 5.6.6(b) Assessment of Murraylink, August 2001

IX. SAIIR, SA Transmission Code, 1 July 2001

X. TransÉnergie Australia submission to ESIPC, 30 July 2001

ATTACHMENTS

Appendix 1 – Environmental Design considerations

Appendix 2 – Alternative projects

Appendix 3 – Technical assessment of alternative projects

Appendix 4 – Future Riverland augmentations

Appendix 5 – Quantitative risk analysis of interconnector alternatives

Appendix 1 - Environmental design considerations

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MEN254-C-S65
JB

16 October 2002

Mr T Clark
Senior Project Manager
Burns and Roe Worley Pty Ltd
PO Box 293
Collins Street West
MELBOURNE VIC 8007

Dear Tony

MURRAYLINK - ENVIRONMENTAL ASSESSMENT OF ALTERNATIVES

We have examined the four transmission line alternatives proposed in order to provide advice on potential undergrounding requirements to address environmental and social issues, and to achieve the required statutory approvals from each State and the Commonwealth.

It is generally accepted that undergrounding of a transmission line will assist in reducing the impacts of its construction and maintenance, particularly in comparison to overhead transmission lines, and therefore is an accepted environmental mitigation measure. However, this does not remove the need for consideration of environmental management of issues associated with underground construction, particularly in sensitive or unstable areas such as creek and river crossings.

Other than a requirement for undergrounding of electrical services in subdivisions, there are no statutory, regulatory or policy positions that we are aware of for the undergrounding of high voltage transmission lines as a standard requirement. As such, it is very difficult to determine the extent of undergrounding, if any, that would be required for any of the alternatives proposed to achieve environmental and planning approvals.

It is our view that in the current political climate, the government agency or Ministerial decision makers would balance the decision on environmental management objectives and requirements against the cost and commercial feasibility of undergrounding the transmission line. That is, if the environmental management objective is strongly held, then decision makers are likely to determine either that some undergrounding should be undertaken, or that the transmission line route should be altered to protect the environmental values identified. It is highly unlikely that they would require undergrounding of the entire transmission line to address environmental and social issues as proponents would probably successfully argue that this would adversely affect project feasibility for little environmental and social gain.

A recent example to support this advice is the assessment of the Basslink interconnector between Tasmania and Victoria, proposed by Basslink Pty Ltd (BPL). The Victorian community in the region of the transmission line route strongly advocated for the undergrounding of the entire transmission line route in Victoria. The main reason the community pursued undergrounding of the route was to address social, landscape and perceived health issues.

The Joint Advisory Panel (JAP), appointed by the Commonwealth, Victorian and Tasmanian governments to assess the project reviewed the environmental implications of the preferred overhead route in Victoria, and considered whether undergrounding of the transmission line in whole or in part would be required for the project to be regarded as environmentally acceptable.

The JAP determined that as a general principle, the use of overhead transmission lines is acceptable, subject to environmental analysis. The JAP identified a set of key principles to provide guidance for situations where the use of overhead transmission lines may be inappropriate:

> *"instances where the proposed transmission line passes close to residence so that the accepted buffer values that relate to EMFs are not achieved. Normally the designer of the proposed transmission line route will avoid this, but should it arise, the usual practice is to purchase the property and remove or relocate the residence, or alternatively revisit the design of the transmission line route;*

- *instance where a highly valued heritage attribute may exist and the presence of an overhead transmission line could detract from the character of the attribute*
- *an inappropriate relationship would result with exiting infrastructure or operations whereby its primary function and role would be threatened*
- *flora and fauna impacts occur in areas recognised for natural values under State and Commonwealth statute or policies; and*
- *planning controls as may be expressed in environmental overlays or strategic policy statements and associated local planning policies that raise issues that may justify a possible need for undergrounding.*

The issue raised by submitters to the JAP suggested that a further category could have been included:

- *adverse social impacts that may result in communities experiencing a perceived sense of dominance in their every day living patterns because of a claimed highly visible presence of overhead powerlines within the area or region.*

However, the JAP considered that this final category did not require a specific measure that must lead to undergrounding. (Page 76 of the Final JAP report, June 2002).

The JAP reviewed the Basslink project in the context of these principles, and recommended that the route of the transmission line be changed to lower the impact on high value conservation areas, and also recommended the need for extra undergrounding on the coastal plain. This was based on:

- *"avoidance of the presence of pylons and overhead transmission lines and possible associated bird strike in a wetlands area that was subject to overseas agreements (CAMBA*

- *and JAMBA) in regard to migratory birds, native waterfowl and the orange bellied parrot, ensuring that no constraint existed for birds approaching and taking off from lake waters."*
- *to continue undergrounding to a point where a transition station could be located to provide partial visual screening of the proposed overhead transmission line by existing vegetation;*
- *to minimise any possible impact on the Victorian Flora and Fauna Guarantee Act listed South Gippsland Plains Grassland that exists in a portion of Stringy Bark Lane"* (Page 76 of the Final JAP report, June 2002).

Following examination of the JAP's assessment report and recommendations, the Victorian Minister for Planning determined in her assessment report that the undergrounding of the transmission line be considered in the context of:

- the feasibility of achieving a commercially viable underground link; and
- the landscape justification for requiring undergrounding, in conjunction with any other benefits.

The Minister states in her report:

"the possibility of requiring complete undergrounding would only be relevant if the landscape values affected by BPL's Basslink proposal were of such significance that in combination with other considerations - the project warranted refusal of statutory approval. I am satisfied that the landscape values of the Merriman Creek valley and West Giffard coastal plain are of local or perhaps regional significance, but not State significance." (page 6 of the Minister for Planning's Assessment Report, September 2002).

Although the Minister did not support undergrounding across the Merriman Creek Valley, she did require that poles be used across the valley instead of towers, and she supported the Joint Advisory Panel's recommendation for a different route to that proposed by BPL and extra undergrounding on the coastal plain.

Another example of a project assessment that resulted in a recommendation for a transmission line to be undergrounded is the transmission line proposed by the State Energy Commission (SEC) in Western Australia to connect the Beenyup Mineral Sands Mine to the Manjimup substation. In 1991, the SEC proposed a route for the 132kV transmission line that crossed high value Karri forest. The Environment Protection Authority and the Minister for the Environment accepted this route on the basis that 6.2km through the Karri forest would be placed underground to protect the forest's conservation values. The SEC responded that undergrounding the transmission line would render the project unviable, and in 1993 put forward for assessment an alternative route for the transmission line that avoided the Karri forest. The Environment Protection Authority assessed the re-routed overhead transmission line as being environmentally acceptable (Environment Protection Authority Western Australia, Bulletin numbers 603 and 707).

It should be noted that there are also instances where proponents have responded to the difficulties associated with locating over head and underground transmission lines and have varied the proposals in order to minimise potential environmental or community conflicts. An example of this is the Brunswick to Richmond (Victoria) high voltage transmission line. Despite this proposal gaining approval to be constructed as an overhead transmission line, the SECV chose to underground the transmission line in response to community concerns.

Another example of a voluntary decision to underground a transmission line is the Murraylink project. The decision by the proponent to underground the transmission line significantly decreased community concerns and also assisted in addressing key environmental issues such as minimisation of direct impacts on remnant vegetation and habitat values. This resulted in the gaining of environmental and planning approvals for the project in both South Australia and Victoria within ten months of our company being appointed to undertake the necessary studies and lodge and obtain the statutory approvals (1999 – 2000). As a contrasting example to this experience, the Basslink project formally commenced assessment in early 1999 (having already been progressed by the Basslink Development Board which commenced work on the project in early 1998). The final statutory planning and environmental approval for this project was granted in October 2002.

It should also be noted that Murraylink has won environmental excellence awards and commendations for its design and construction from the Royal Australia Planning Institute (South Australian Division) and the Case Earth Awards (Victorian and National).

On this basis, our specific advice regarding undergrounding for the alternative options is, based on a categorisation of lowest requirement, most likely requirement, and potentially highest requirement for undergrounding in terms of kilometres of transmission line route are:

Option 1:

- Low (0km) - it is still possible that governments will accept full overhead transmission lines, especially where they are remote from settlements.
- Most Likely (30km) - this is based on a need for tactical undergrounding past the Ramsar wetland within the Bookmark Biosphere reserve in South Australia. Ramsar wetlands, migratory species, and nationally threatened species and ecological communities are all matters of national environmental significance under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). These are strong environmental values which would provide sufficient impetus for decision-makers to consider tactical undergrounding to achieve environmental management objectives, despite increased cost.
- High (60km) - estimated as the distance required to traverse the Bookmark Biosphere reserve. This outcome could eventuate if the decision making governments take a holistic view of the environmental and social values of the area.

Options 2 & 3:

- Low (0km) – same reasons as given for Option 1.
- Most Likely (25km) - based on traversing the settlements at Red Cliffs (Victoria) and Lyrup (South Australia), to minimise social and environmental impacts and community reaction/opposition to the proposal..

Options 2 & 3 continued

- High (40km) - based on traversing the settlements at Red Cliffs and Lyrup and the Sunset National Park (Victoria). Re-routing the transmission line so that it does not cross the national park is not an option given the size and location of the park. Consequently, the only mitigation measure available (if overhead transmission line is deemed to be unacceptable due to environmental impacts), is to underground the route through the national park.

Option 4:

- High (10km) - based on traversing a segment of the Bookmark Biosphere reserve located along the route between Monash and Robertstown (not the same as that affected by Option 1).

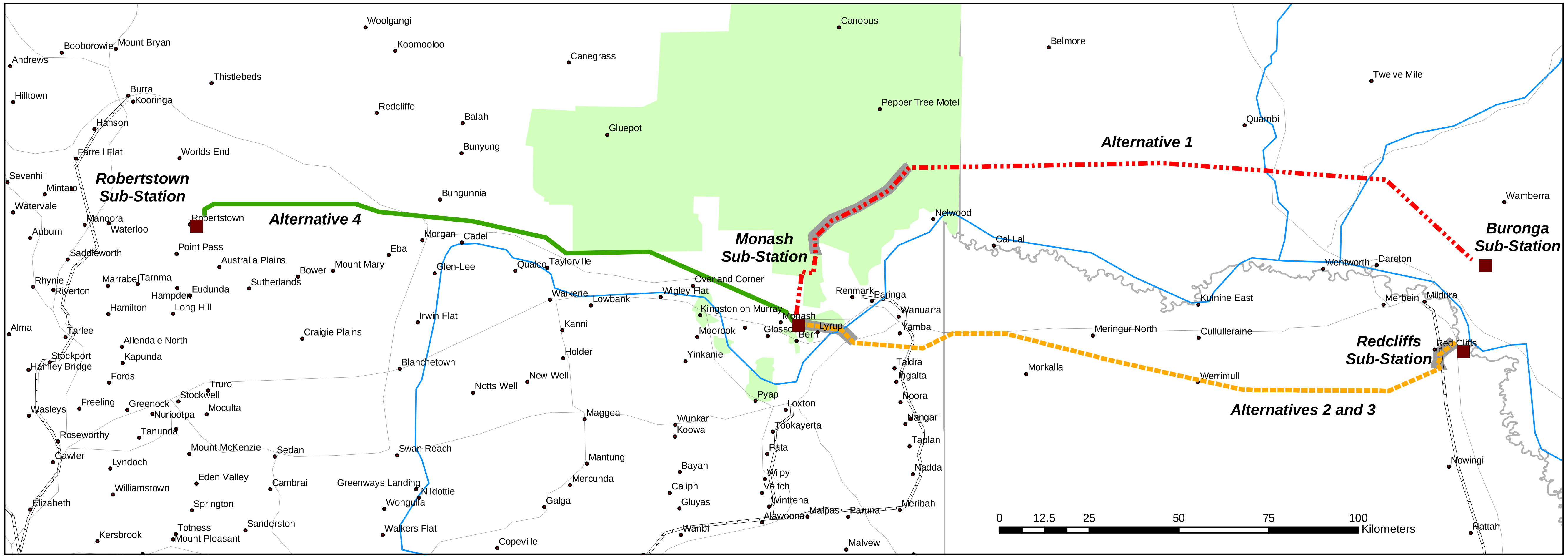
We have attached a map indicated the approximate area and length of the most likely undergrounding required for each option (MEN255-WD-001, Rev B).

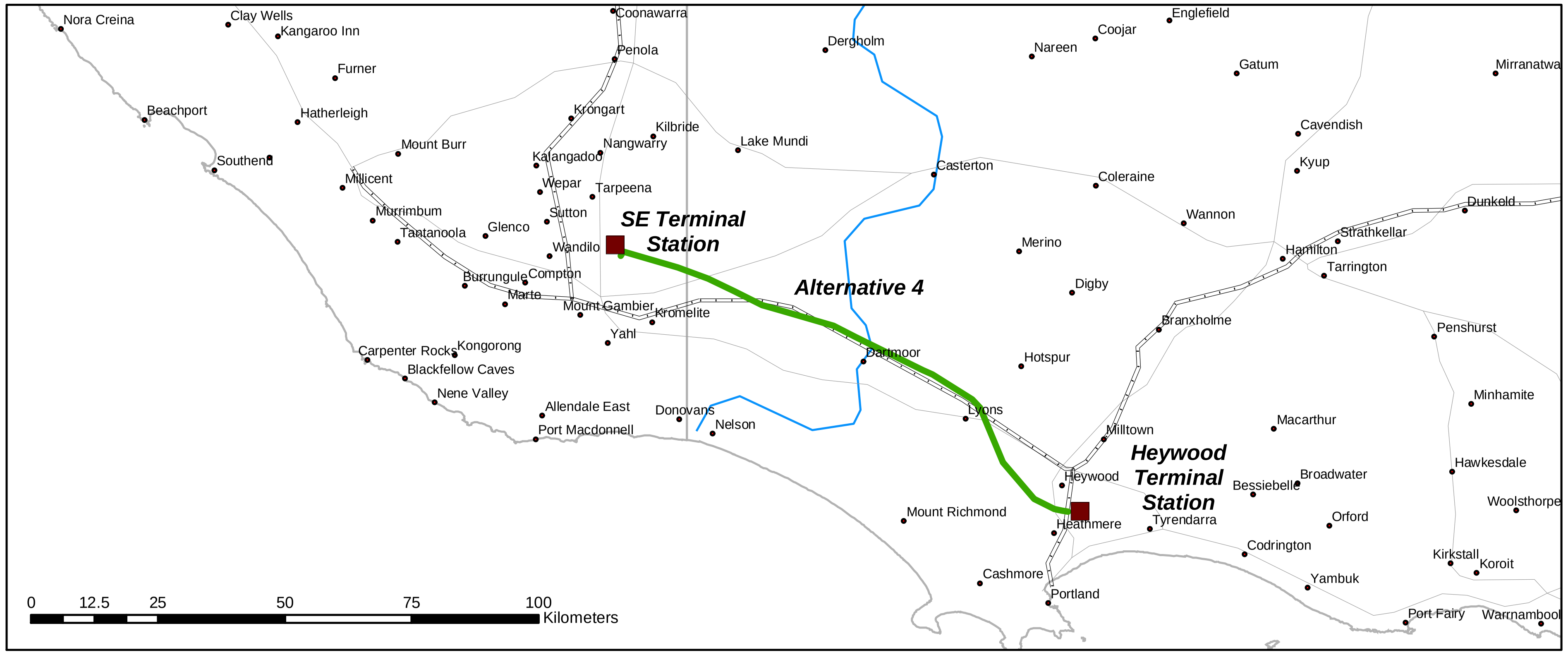
We trust that this information will be of assistance to you in your review of alternative options.

Yours sincerely

Jackie Boyer

Principal Environmental Scientist





FINAL APPROVALS			
ENGINEERING APPR.	DATE	PROJECT APPR.	DATE
TECHNICAL APPR.	DATE	CLIENT APPR.	DATE

LEGEND

- Alternative 1
- Alternative 2 and 3
- Alternative 4
- Towns
- Railways
- Major roads
- Rivers
- Water bodies
- State borders
- Approximate location of Bookmark Biosphere
- Approximate location of undergrounding

DATA SOURCE: Auslig

KBR

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TITLE: ALTERNATIVE OPTIONS

DRAWING NO.: MEN255-WD-001

REVISION: B

TransÉnergie Australia

TransÉnergie - Murraylink
Selection and assessment
of alternatives

APPENDIX 2
Alternative projects

14 October 2002

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
0	024/45003	Final Report	Andrew Robertson	Tony Clark	Rod Touzel

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Brisbane: **Level 6 80 Albert Street Brisbane QLD 4000 (PO Box 81 Albert Street Brisbane QLD 4002) Tel 61 7 3221 2347 Fax 61 7 3221 7791**

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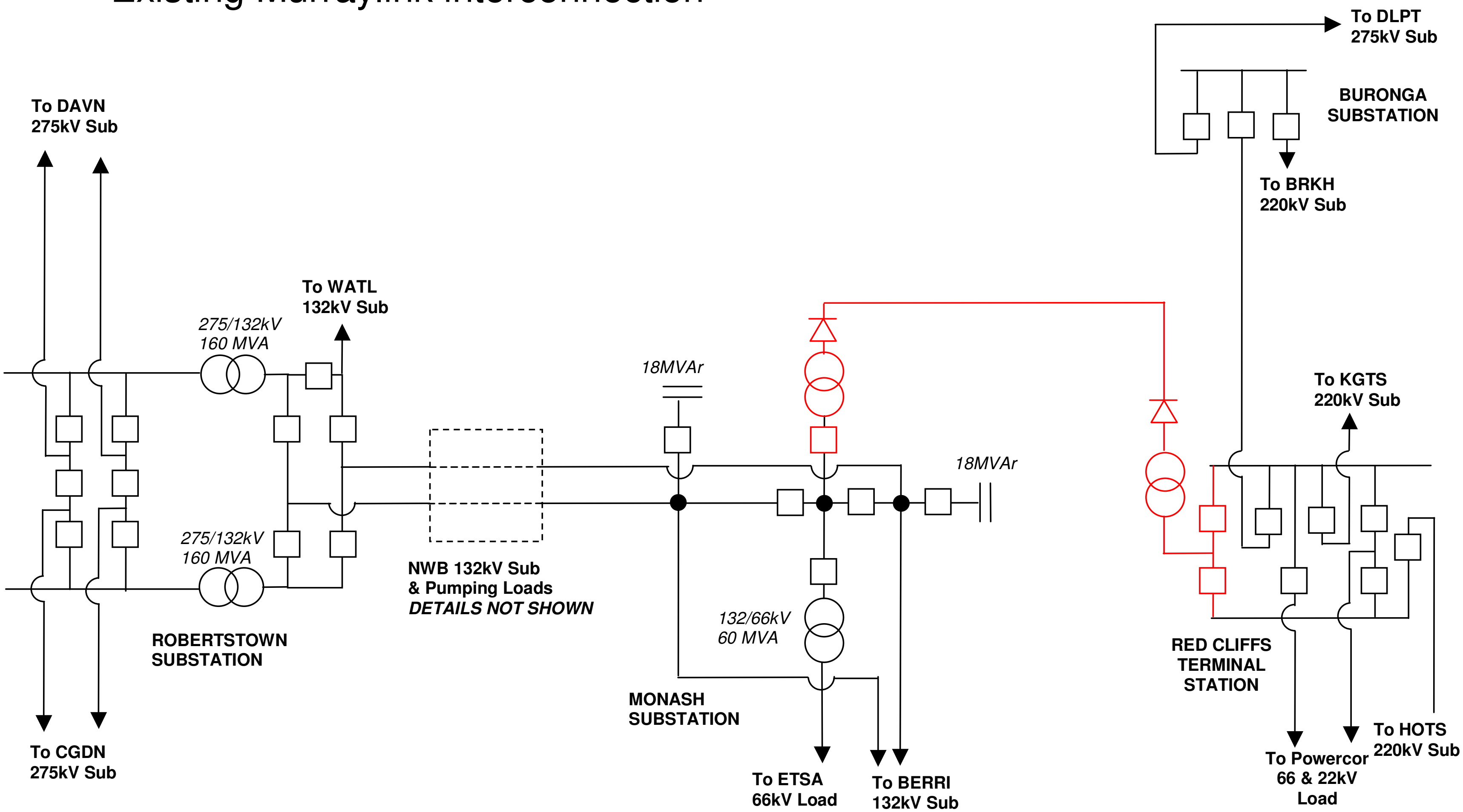
Introduction

This appendix contains single line diagrams of the alternatives.

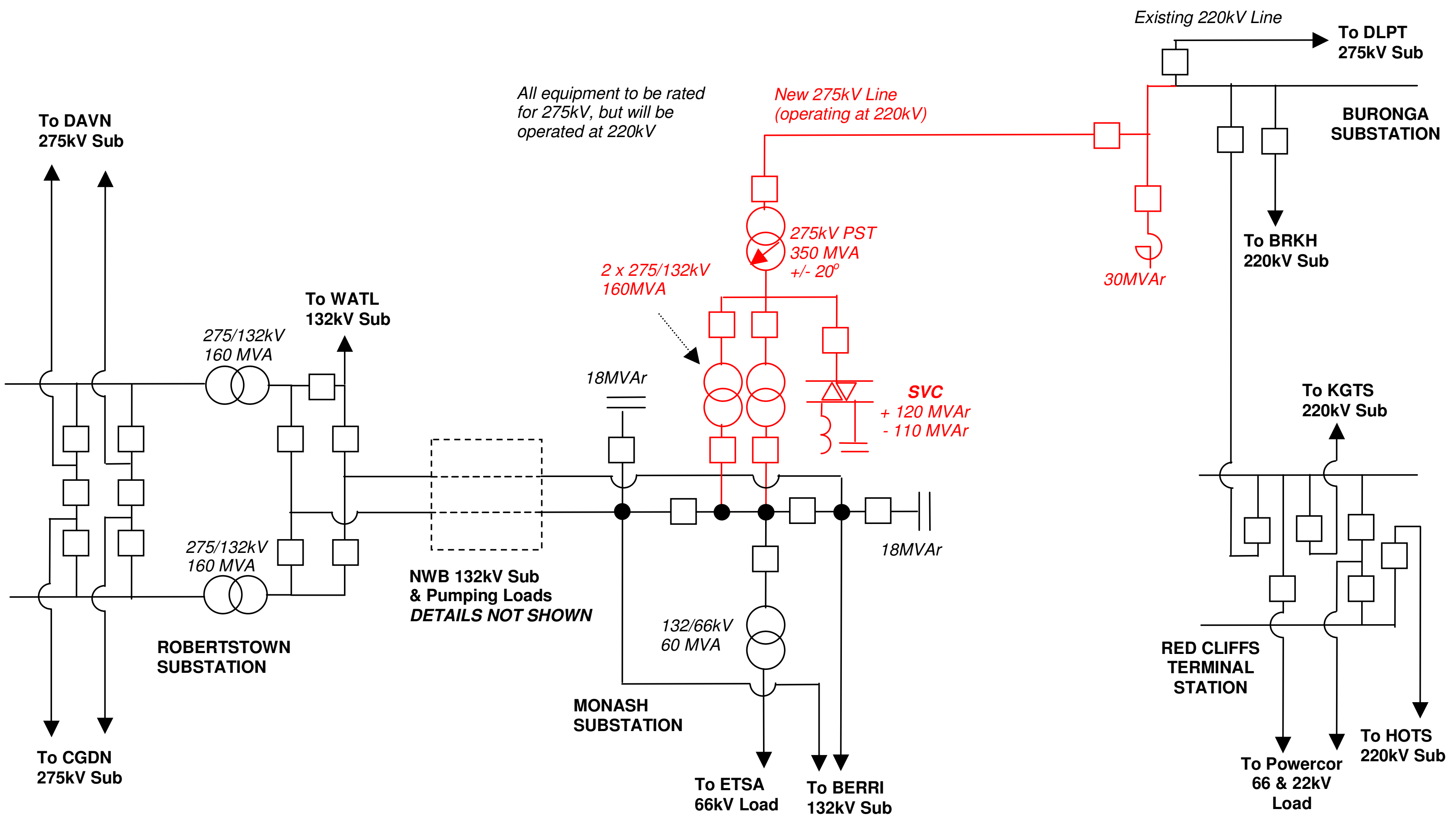
The following specific diagrams are provided:

- Single line diagram of existing Murraylink interconnection
- Single line diagram of Alternative 1 – NSW to SA 275 kV interconnection
- Single line diagram of Alternative 2 – Vic to SA HVDC interconnection with overhead (OH) line
- Single line diagram of Alternative 3 – Vic to SA 220 kV interconnection
- Single line diagram of Alternative 4 – Heywood upgrade and Riverland augmentation

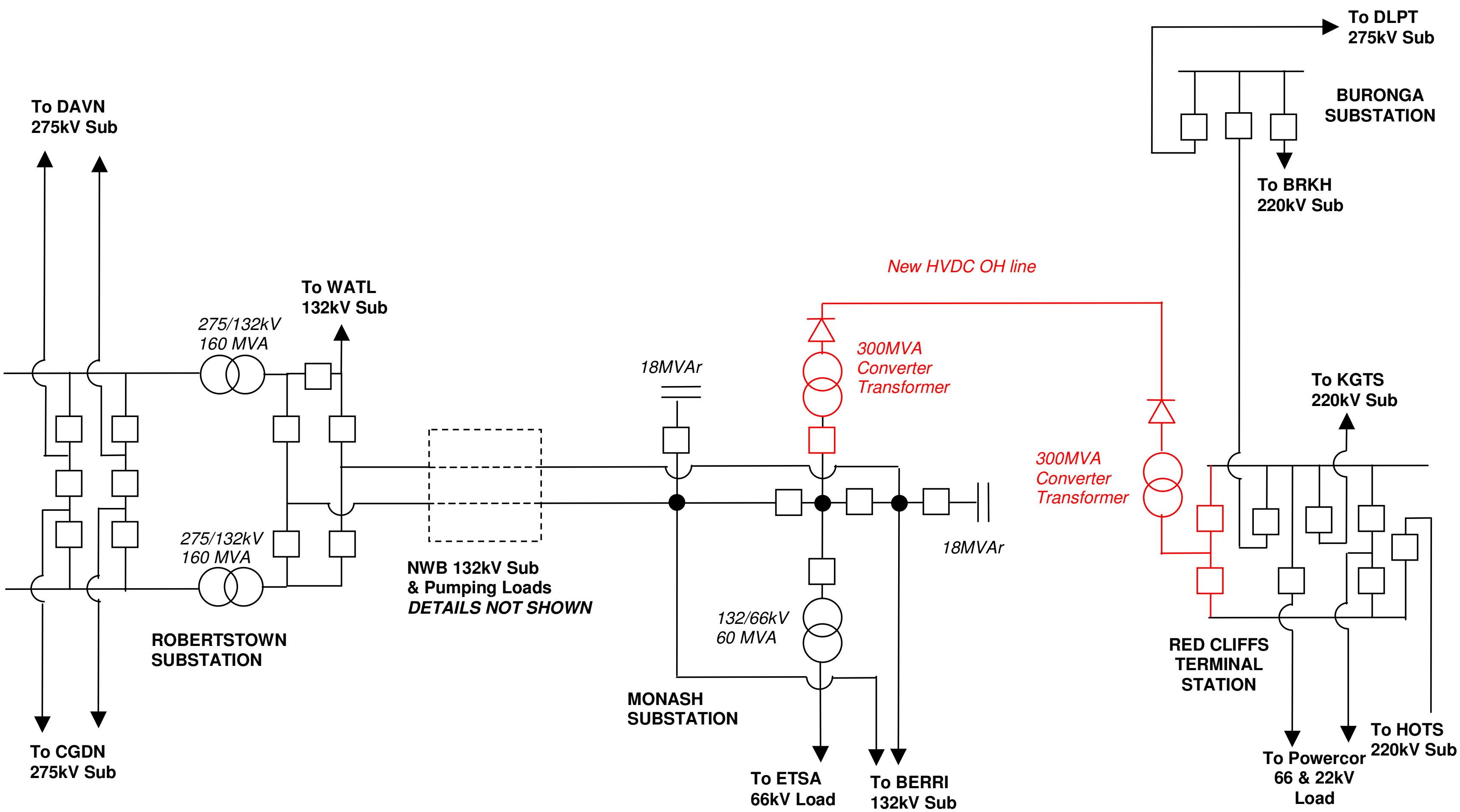
Existing Murraylink interconnection



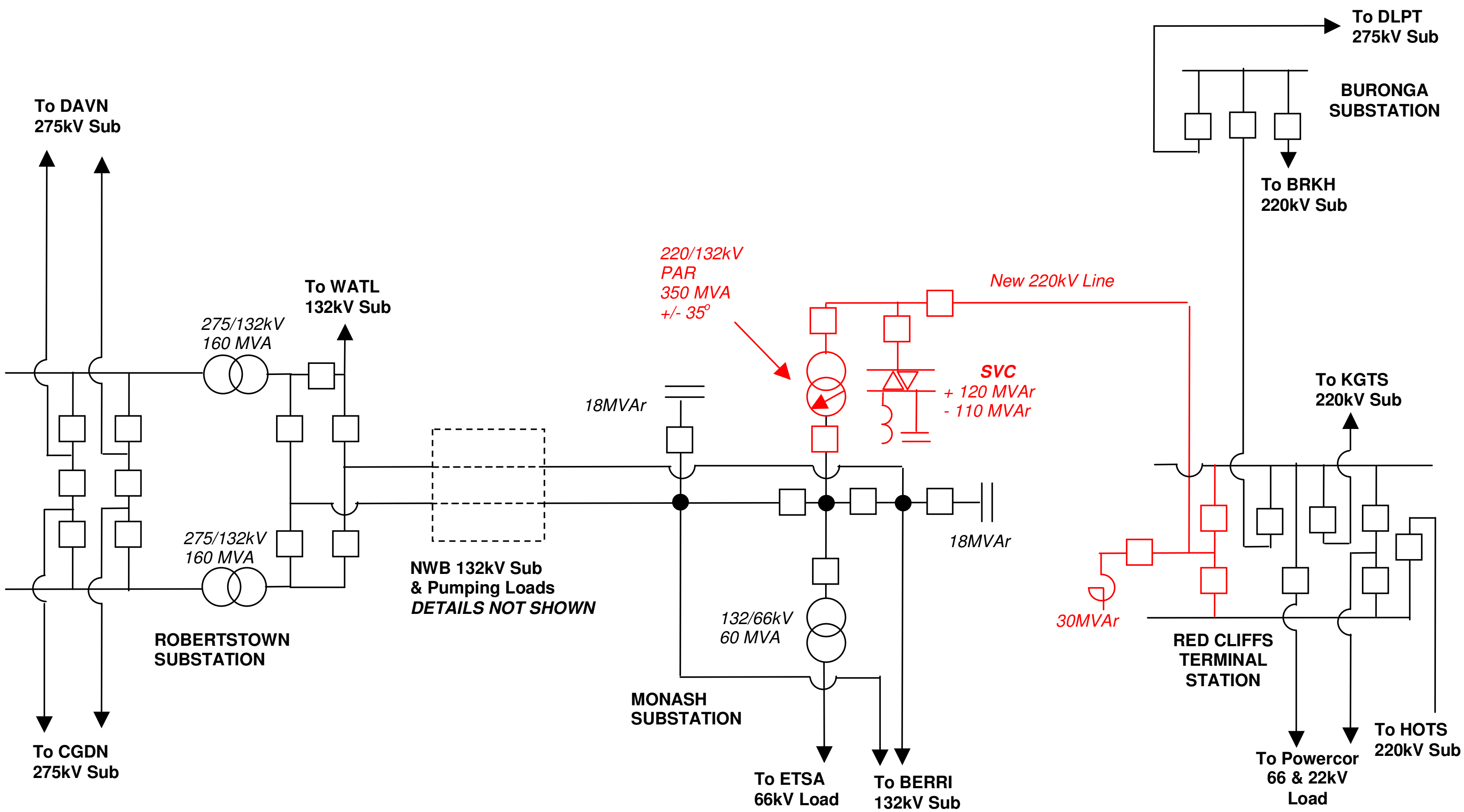
ALTERNATIVE 1 – NSW-SA 275 kV interconnection



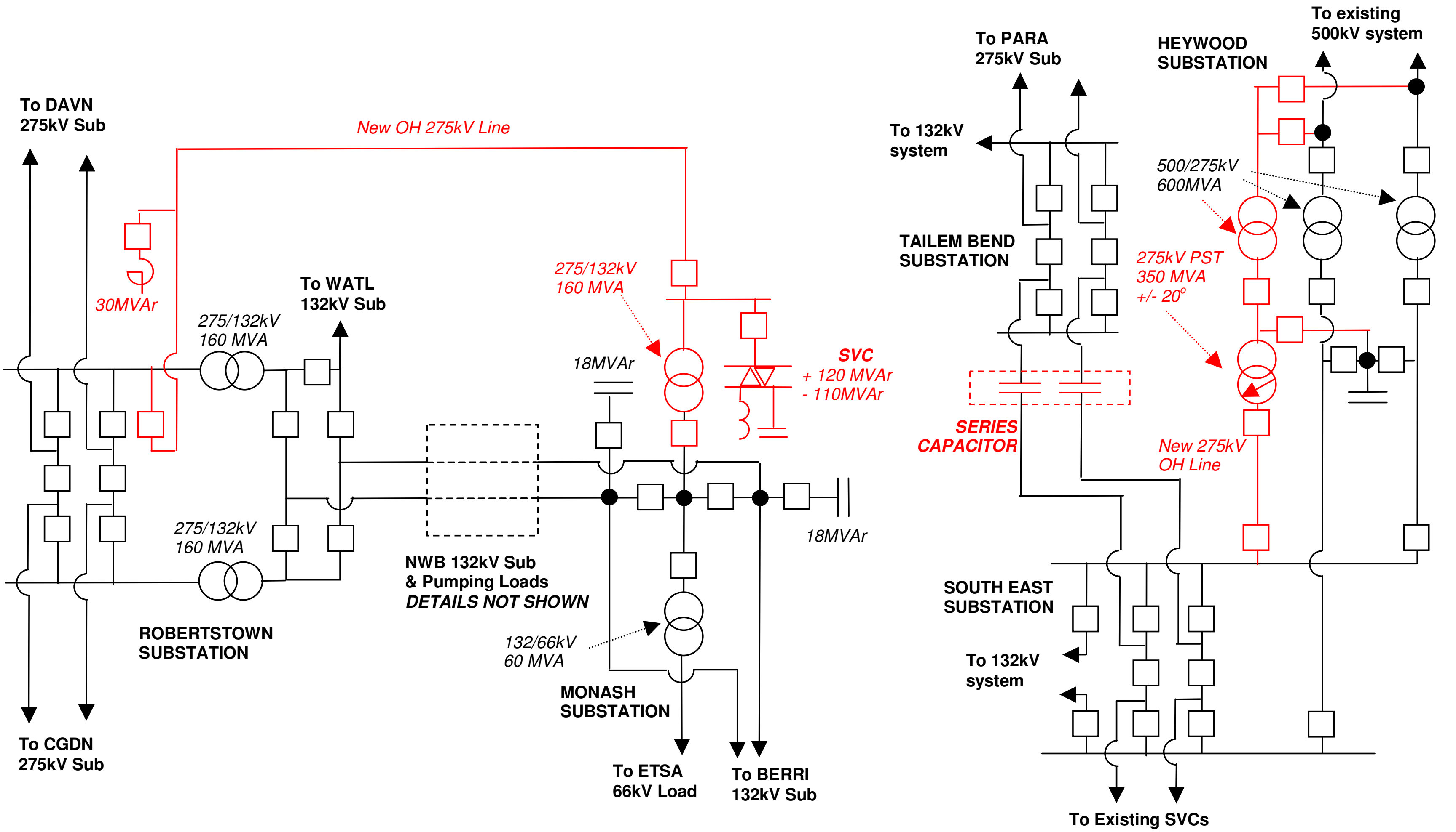
ALTERNATIVE 2 – Vic to SA HVDC interconnection with OH line



ALTERNATIVE 3 – Vic to SA 220 kV interconnection



ALTERNATIVE 4 – Riverland augmentation and Heywood upgrade



TransÉnergie Australia

TransÉnergie - Murraylink

Selection and assessment

of alternatives

APPENDIX 3 –

Technical assessments of alternative projects

14 October 2002

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
0	024/45003	Final Report	Bruce Miller	Andrew Robinson	Rod Touzel

Burns and Roe Worley Pty Ltd

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Brisbane: **Level 6 80 Albert Street Brisbane QLD 4000 (PO Box 81 Albert Street Brisbane QLD 4002) Tel 61 7 3221 2347 Fax 61 7 3221 7791**

Technical analyses of alternatives

Burns and Roe Worley (BRW) has carried out the following technical analyses to ascertain the power system constraints for each of the alternatives.

This analysis is not a full and complete determination of all of the constraint equations that may apply to Murraylink or any of the other alternatives. Rather it represents an exploration of the issues likely to constrain the operation of the proposed interconnections.

The main constraints are:

1. Thermal limitations on individual network elements (transmission lines, transformers, etc).
2. Limitations imposed because of insufficient voltage regulation or the possibility of voltage collapse.
3. Limitations imposed because of dynamic instability (so called oscillatory instability).
4. Limitations imposed because of transient instability – i.e. the onset of generator pole slipping after a system fault has been cleared.

Detailed system studies are required to determine each of these limits in turn. BRW has not performed these studies as the excessive time and resources required are not warranted for projects that are never likely to be built. Instead, BRW has performed simplified load-flow studies and used these to deduce the characteristics of the main system components involved and the probable constraints that exist in the transmission system for each of the Alternatives.

System representation

To avoid undue complexity the transmission system is modelled with the following boundary substations, which were taken to be infinite buses:

- South Australia – Robertstown, Tailem Bend 275kV
- Victoria – South Morang 330 kV
- New South Wales – Wagga 330kV

The system between these locations was then modelled to investigate the impact of Murraylink and the alternatives. For reasons of clarity, some circuit elements (such as the pumping stations in South Australia, and Sydenham Terminal station in Victoria) have been omitted even though they are inside the area of consideration. Equivalent loads were inserted in order to provide a realistic load-flow calculation.

System impacts of Murraylink

To enable direct comparison of the alternatives with Murraylink, it is necessary to establish a benchmark of how Murraylink could operate to the benefit of the market.

Relative contributions from Victoria and NSW (Murraylink)

Figure 1 and Figure 2 show two possible operating conditions for Murraylink: 220 MW transfer from RedCliffs to Monash and 0 MW transfer respectively. The most salient point derived from this study is that reducing the transfer by 220 MW (and simultaneously maintaining the Vic-SA Heywood interconnection flow) reduces the contribution from NSW by only about 55 MW, whereas the contribution from Victoria changes by approximately 155 MW.

Murraylink affects the power flows in Victoria to a greater extent than in New South Wales.

Reactive power requirements (Murraylink)

When changing the power flow of Murraylink from 220 MW to 0 MW, in order to maintain voltage support for the Riverland region the reactive output of Murraylink changes from 20.1 MVar to 92.1 MVar. Similarly, the reactive support for Red Cliffs must change from 88 MVar to –42.8 MVar to prevent a system over voltage condition. This is within the technical capabilities of Murraylink.

Murraylink can maintain a flat voltage profile at Red Cliffs and Monash for most of its active power range.

Effect on the Victorian system (Murraylink)

Figure 3 and Figure 4 show typical representations of the Victorian system for a Murraylink dispatch to South Australia of 220 MW and 0 MW respectively. The power flow from Horsham to Red Cliffs changes by approximately 100 MW, whereas the power flow from Kerang to Red Cliffs changes by approximately 70 MW. The reactive support at Horsham changes from 11.6 MVar to –16.8 MVar whereas the reactive change at Kerang is not established in these simulations because the SVC at Kerang is assumed to be at its limit.

Summary of Murraylink system impacts

The system studies indicate the following impacts of Murraylink:

1. Changes in the power dispatch of Murraylink are reflected mainly in the Victorian system (~75%) relative to the NSW system (~25%).
2. Within the Victorian system the Horsham to Red Cliffs circuit alters the most (~ 60%) relative to the Kerang to Red Cliffs circuit (~40%).
3. The reactive power management facilities of Murraylink are adequate to support the system voltage in the Riverland area of South Australia and simultaneously hold the voltage constant at Red Cliffs.

Points 1 and 2 above are a direct consequence of the connection of Murraylink between Red Cliffs and Monash substations and the relative system impedances of the NSW and Victorian systems. Alternatives 1,2 and 3 display similar behaviours, so long as a combination of generation dispatch and power control on the interconnection can maintain the Heywood connection (Vic-SA) at a constant power transfer level. Alternative 1 has slightly differing power flow behaviour due to the connection to Buronga in preference to Red Cliffs. When the existing 220 kV circuits between Buronga and Darlington Point are upgraded to 275 kV, one would expect this difference to be enhanced.

The reactive power impacts will be different for all alternatives considered, but all alternatives must be able to adequately control the voltage at Red Cliffs and Monash substations for a variety of interconnection power flows.

Technical requirements of alternatives

The alternative interconnections to Murraylink must satisfy the following technical requirements in order to deliver equivalent market benefits.

The alternative must be capable of delivering to South Australia 220 MW of power, sourced from the Victorian, Snowy or New South Wales region, and do so under the same conditions as Murraylink.

The flow across the interconnection must be directly controllable within a suitably defined range. This has the market benefit of being able to transfer more power across the alternative whenever existing interconnections at Heywood are at their maximum limits.

The interconnections must be able to adequately control the voltage at Red Cliffs and Monash to prevent voltage sag or surge conditions. This has the market benefit of maintaining a high quality electrical supply to the rural communities in the Riverland region of South Australia and the Western districts of Victoria and New South Wales—particularly when network elements (transformers or lines) suddenly fail.

The alternative interconnections must be able to relieve the congestion in the South Australian network connection to the Riverland.

In determining the various interconnection alternatives using available technology, the points listed above are met as follows:

- All AC interconnections include phase angle regulators to enable partial direct control of the flow of power through the interconnection. They are required to direct power along the AC alternatives due to system relative impedances (whereby the parallel Heywood connection is “stronger” than the AC interconnection of Alternatives 1 and 3). Note that the PAR is included in Alternative 4 to ensure a 220 MW transfer is achievable when the existing Heywood interconnection is limited to 250 MW transfer (as occurs during times of lightning activity in south-east South Australia).

  Phase angle regulation does not allow the same degree of control as a DC link but the envisaged market benefits are very similar. This is because phase angle regulation can be used to prevent overloading the existing Heywood–South-East interconnection. Overloading that would otherwise occur if there was total reliance on generation dispatch to effect transfers between Victoria and South Australia.

- All AC interconnections include fast response static var compensators (SVCs) to ensure that voltage in the Monash/Buronga and RedCliffs region is adequately controlled in the event of changes in interconnection flows or sudden failure of system components.

If any of the alternatives were to be built, detailed system studies would be required in order to establish the most economical arrangements and ratings of the major system components. BRW has not attempted to carry out detailed rating studies. The sizing of equipment has been chosen to reflect the existing capabilities of Murraylink.

The studies presented herein are used to determine the overall characteristics of the various alternatives. Budgetary estimates with probabilistic modelling produce the costing of the various alternatives. In particular the probabilistic modelling was used to estimate the possible cost savings/cost overruns that may occur during detailed design studies.

In BRW's modelling, Alternatives 1 and 3 are considered to be equivalent, as they are both 220 kV links (noting that Alternative 1 is constructed for future upgrading to 275 kV) operating from essentially the same electrical point.

Alternatives 1 & 3

Relative contributions from Victoria and NSW (Alternative 3)

Figure 5 and Figure 6 show two possible operating conditions of Alternatives 1 & 3: 220 MW transfer from Buronga to Monash and 0 MW transfer respectively. The relative contributions from NSW and Victoria are the same as Murraylink.

Reactive power requirements (Alternative 3)

In order to maintain voltage support for the Riverland region the reactive output of the SVC connected at Monash changes by 70 MVAr when the power flow over the link changes by 220 MW.

Effect on the Victorian and NSW system (Alternative 3)

The power flow impact on the Victorian and NSW systems is the same as Murraylink.

Summary of Alternatives 1 & 3 system impacts

The system studies indicate the following impacts of Alternative 1 & 3.

- Changes in the power dispatch of Alternative 1 & 3 are reflected mainly in the Victorian system (~75%) relative to the NSW system (~25%), which is the same as Murraylink.
- Within the Victorian system the Horsham to Red Cliffs circuit alters the most (~ 60%) relative to the Kerang to Red Cliffs circuit (~40%) as is the case for Murraylink.

The reactive power management facilities of Alternatives 1 & 3 are adequate to control the system voltage in the Riverland area of South Australia and simultaneously hold the voltage constant at RedCliffs so long as the link is in operation.

Alternative 2

Alternative 2 is technically the same as Murraylink so it is not specifically considered in the system studies. Note that Alternative 2 has a different cost structure to Murraylink because it involves strategic undergrounding of the cable connection as compared to total underground installation used by Murraylink.

Alternative 4

Alternative 4 is a departure from the general approach adopted by Murraylink and Alternatives 1,2 and 3 in that the two main requirements:

- support for the Riverland region, and
- increase in interstate transfer capacity

have been separated into two different technical approaches.

Figure 7 shows how an additional 275 kV line between Robertstown and Monash may support the Riverland area.

Figure 8 shows the general effects on the Victorian system of increasing power flows to South Australia from 500 MW (compare with Figure 3) to approximately 700 MW.

Figure 9 shows the changes in system flows in the south-East system of South Australia (neglecting the effects of the 132 kV system) with the additional augmentations.

Effect on the Victorian system (Alternative 4)

The Victorian system has ample capacity to accommodate Alternative 4 so long as there is adequate generation within Victoria. In practice this alternative may be limited by the coincidence in load curves between South Australia and Victoria.

The market benefit of Alternative 4 relative to the other benefits is different because of differing constraints.

Effect on the South Australian system (Alternative 4)

With existing load profiles and line/transformer ratings – an upgrade of the Heywood to South East interconnection will give much benefit to the South Australian system. However, if extensive generation is connected to the south eastern system then many of the expected market benefits will be dissipated because of the constraints imposed by the South East to Tailem Bend portion of the system (refer to the ESIPC, BRW, South Eastern Transmission Development concept Plan, 19 April 2002 for further details).

Summary of Alternative 4 system impacts

Alternative 4 meets most of the requirements that Murraylink currently addresses but can be affected by system developments that have no impact on Murraylink.

Conclusion of technical analyses

The system studies presented herein demonstrate the equivalences between Murraylink and the various alternatives. In summary:

Alternatives 1 & 3 affect the NSW and Victorian systems in a similar fashion to Murraylink and hence will be subject to very similar constraints.

Alternative 4 solves the main issues that Murraylink solves, but is subject to very different system constraints. This in turn will cause differing market benefits.

Alternatives 1 and 3 differ from Murraylink mainly in their ability to control system voltage at Monash, Buronga and Red Cliffs. Each of the alternatives has differing reactive power requirements, which would need to be optimised if the projects were ever to be built. A strict technical equivalent of Murraylink would have an SVC at both Red Cliffs and Monash. BRW has not considered this option as it would not be considered a practical project in the existing electrical industry environment. However, in practice for Alternatives 1 and 3 additional switched units will be required in order to adequately control the voltage in this weak area of the transmission network. BRW has included costs for these components.

To obtain the same market benefit as Murraylink, Alternatives 1 and 3 include phase shift transformers in order to partially control power flows across the interconnection. This is necessary to ensure that the Heywood Interconnection still transfers 500 MW to SA whilst 220 MW is being transmitted over the alternative.

Alternative 4 does not have any specific voltage control issues except during ‘N-1’ contingencies. Series capacitor compensation is included in the South East to Tailem Bend lines to cater for voltage drop issues across these lines (as proposed in upgrades to the existing Heywood interconnection proposed by both TransÉnergie and ElectraNet SA).

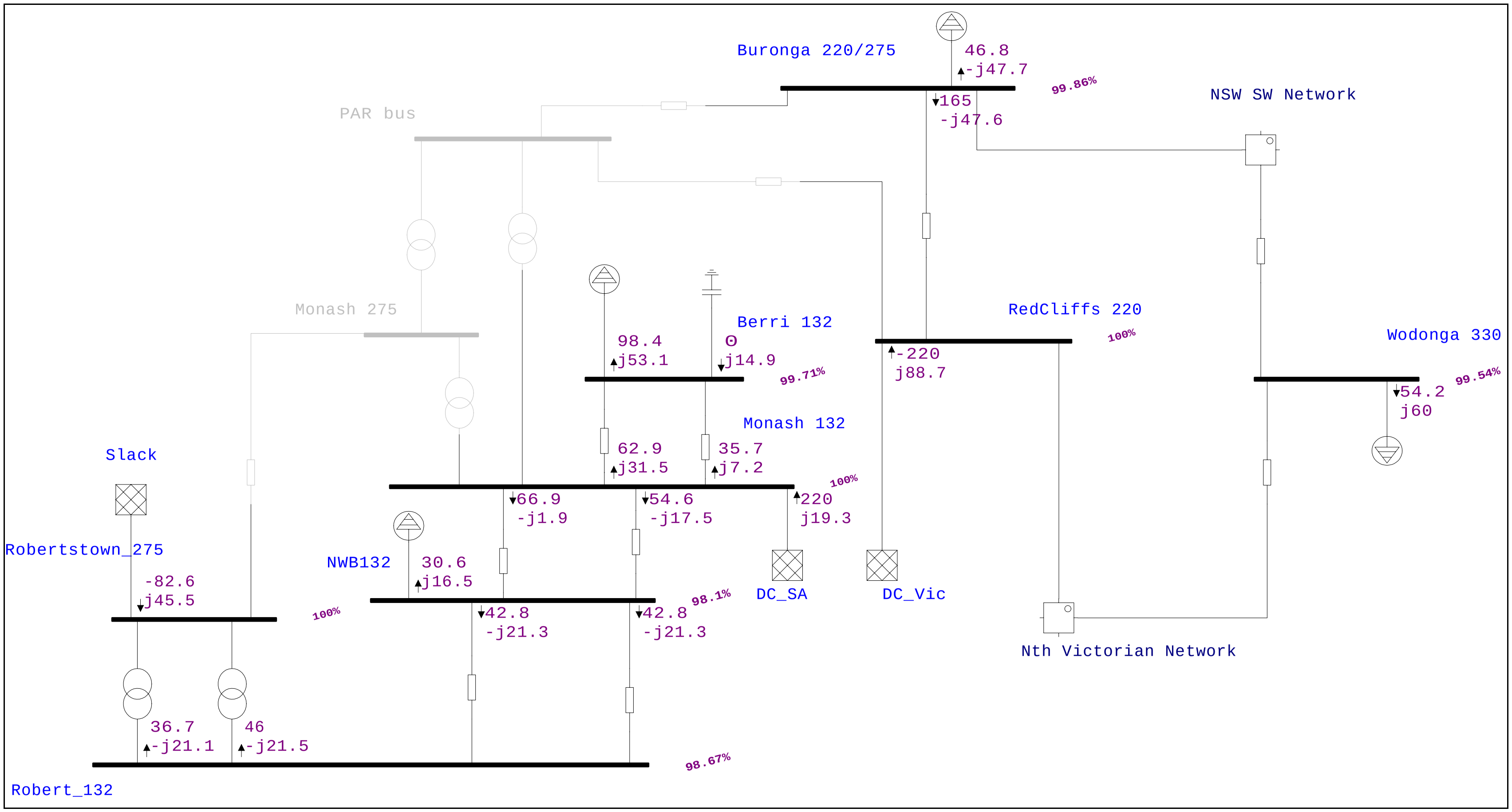

Figure 1 Typical system loadflow showing a transfer of 220 MW from Red Cliffs to Monash using Murraylink

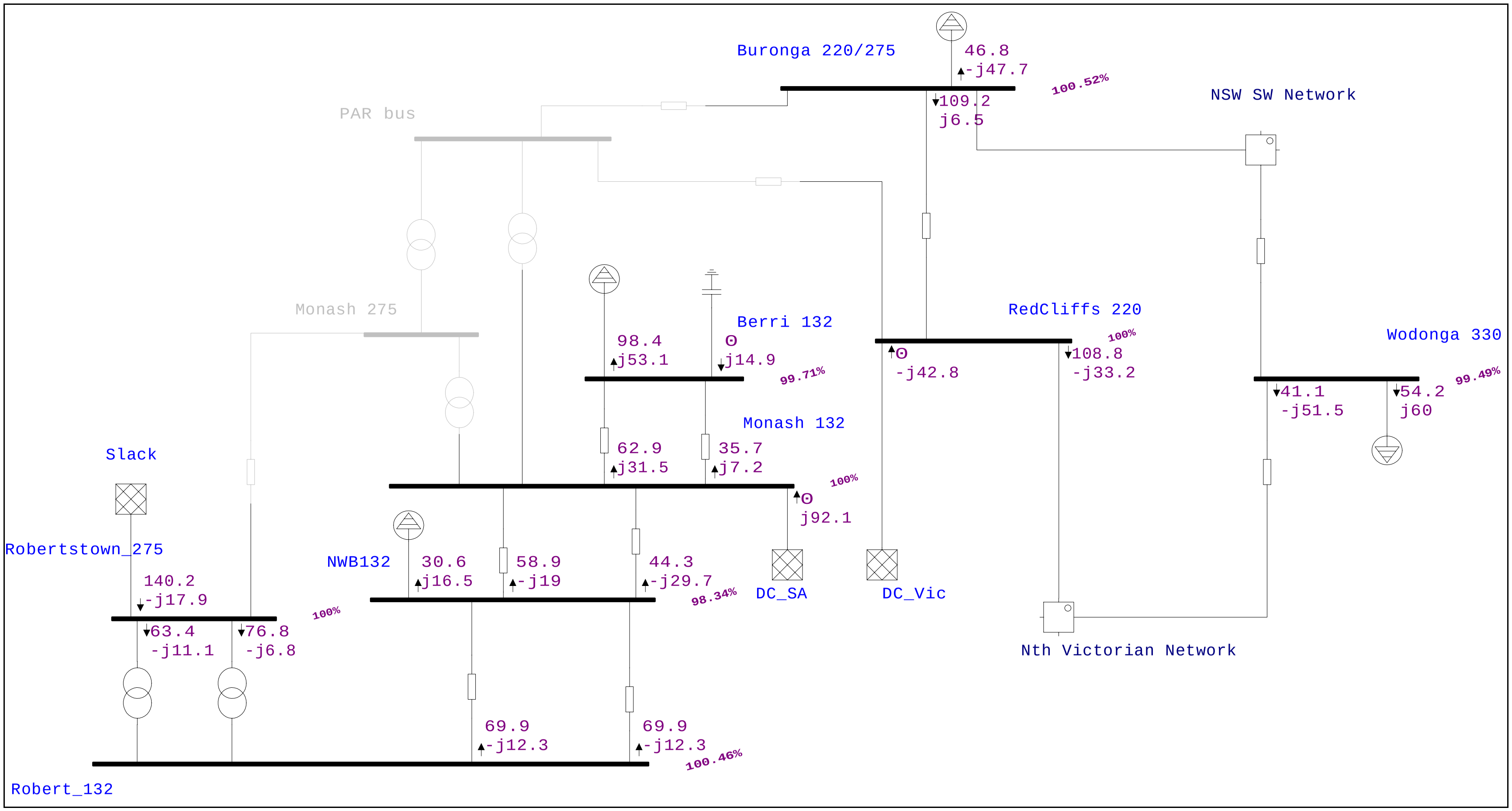

Figure 2 Murrraylink transfer of 0 MW between Victoria and South Australia

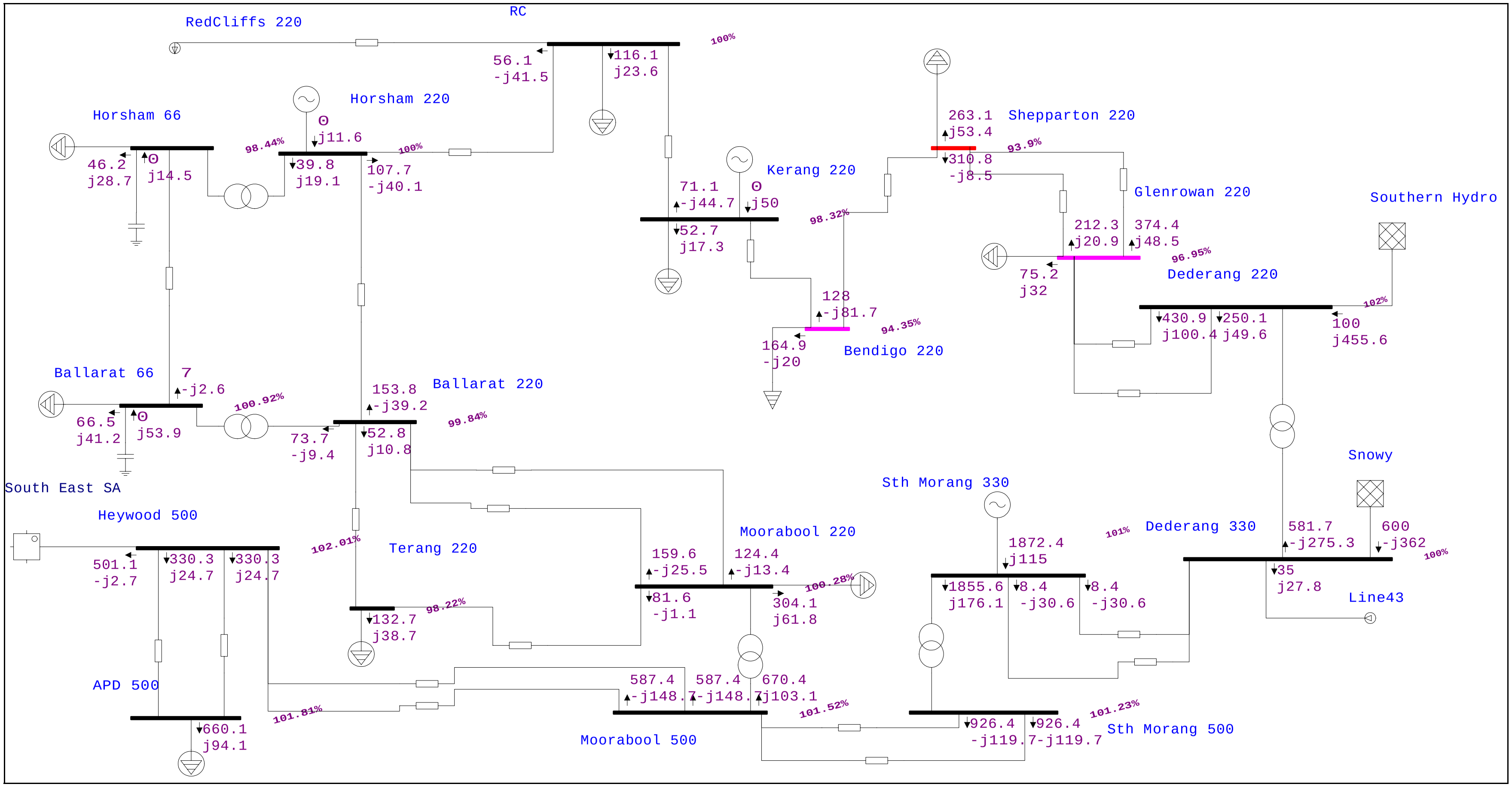

Figure 3 Typical representation of the Victorian system when Murraylink is transferring 220 MW to South Australia

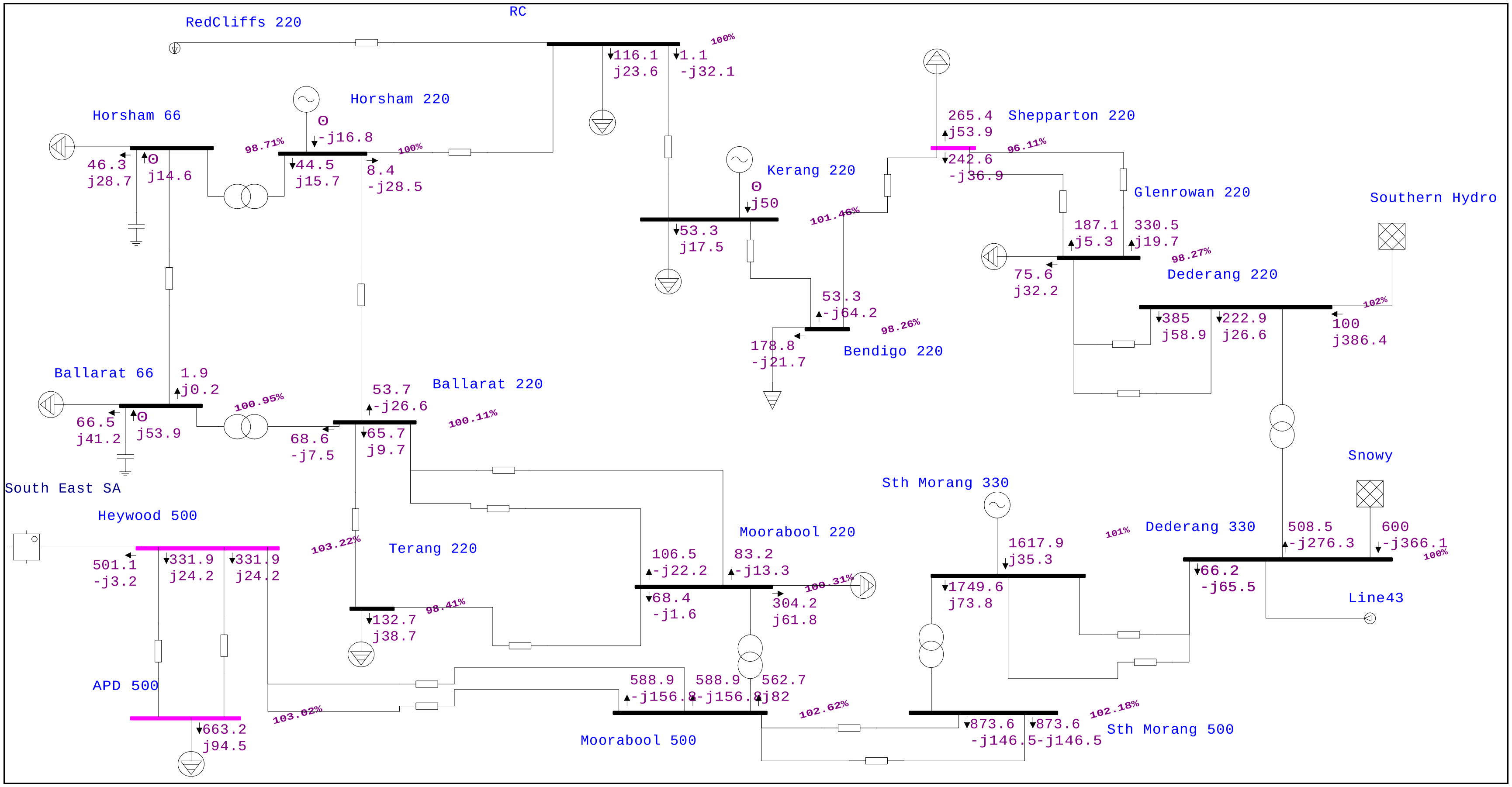

Figure 4 Typical representation of the Victorian system when Murrayink is transferring 0 MW

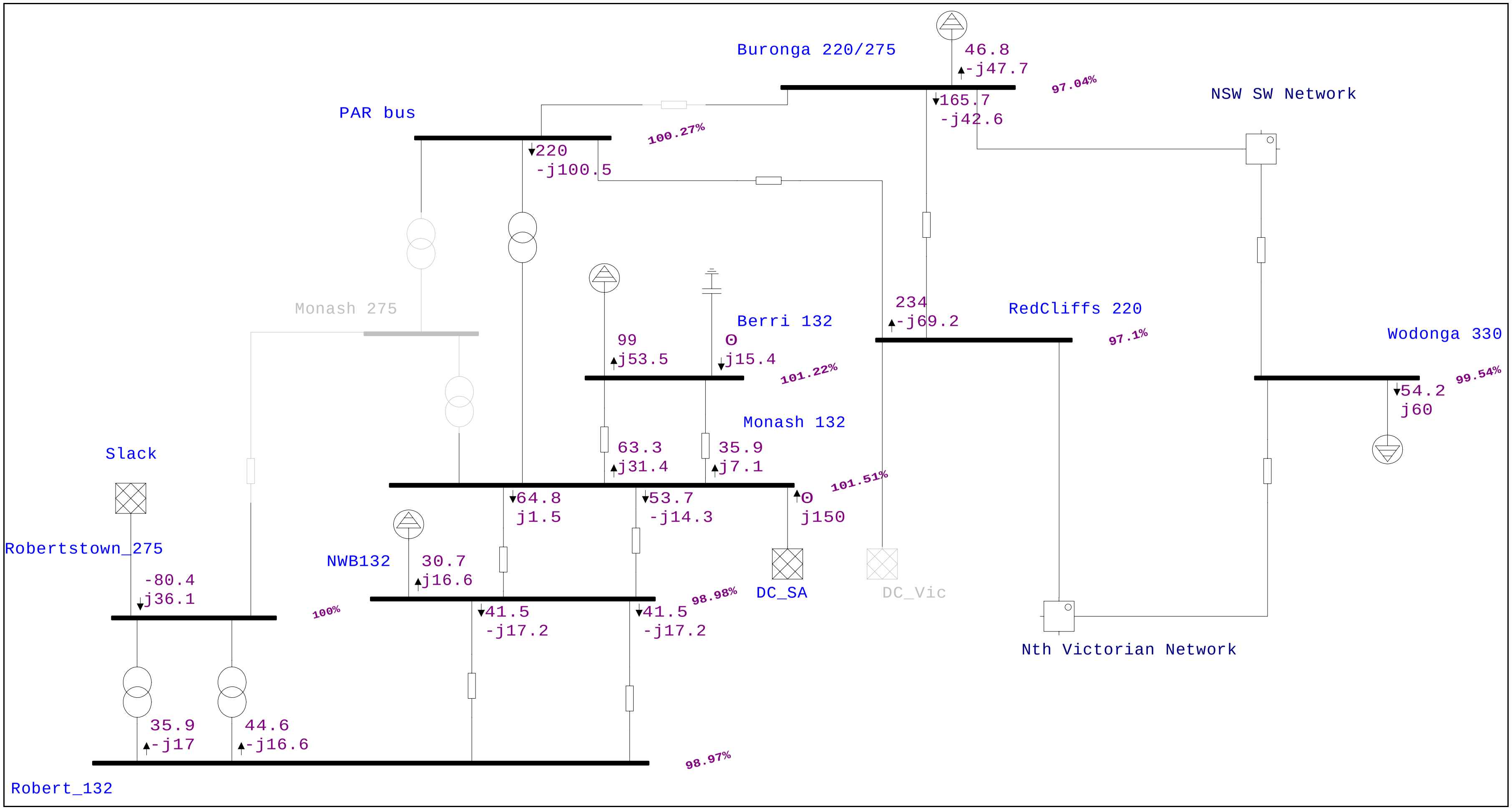

Figure 5 Transfer of 220 MW using Alternatives 1 & 3

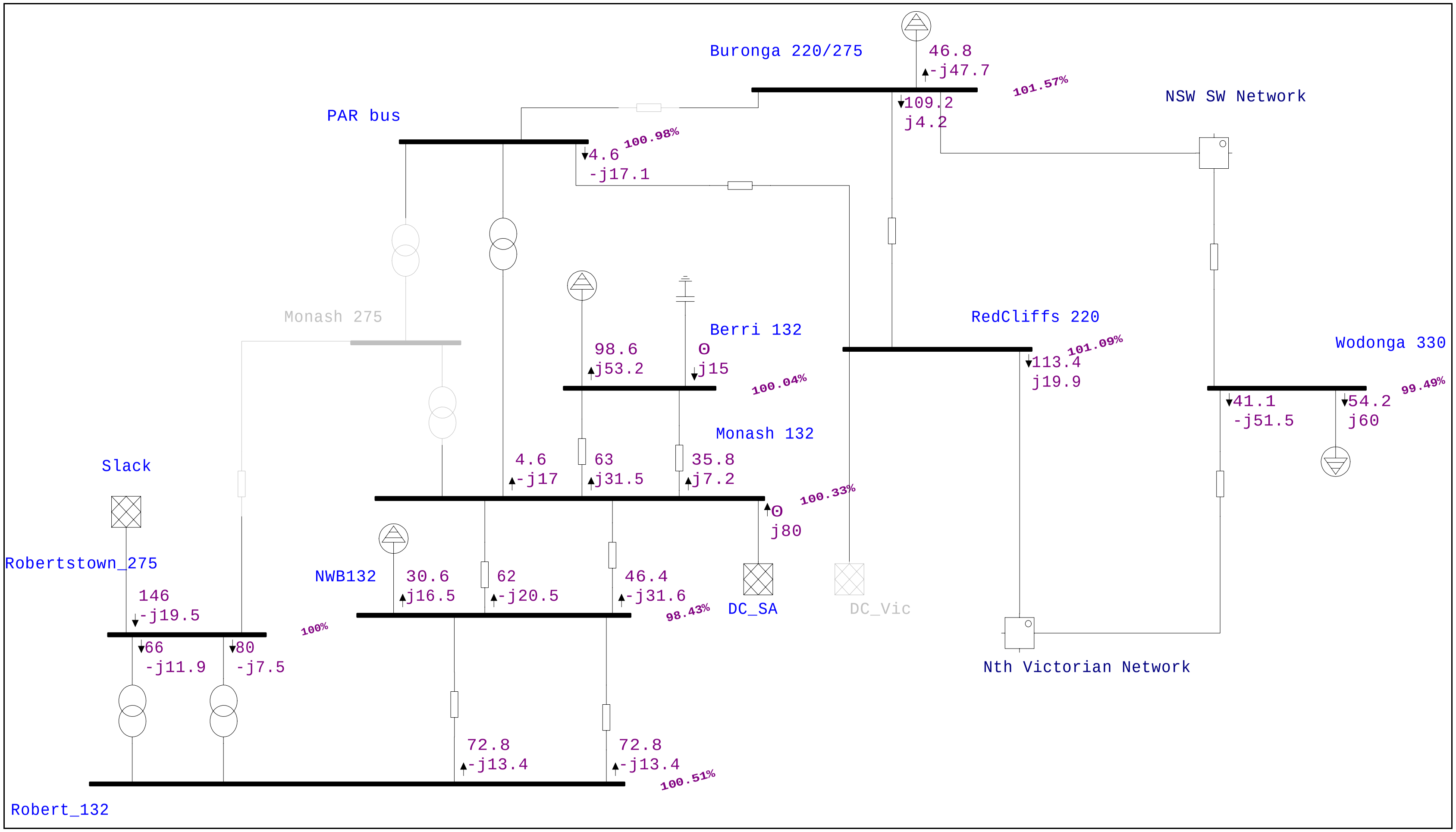

Figure 6 Transfer of 0 MW using Alternatives 1 & 3

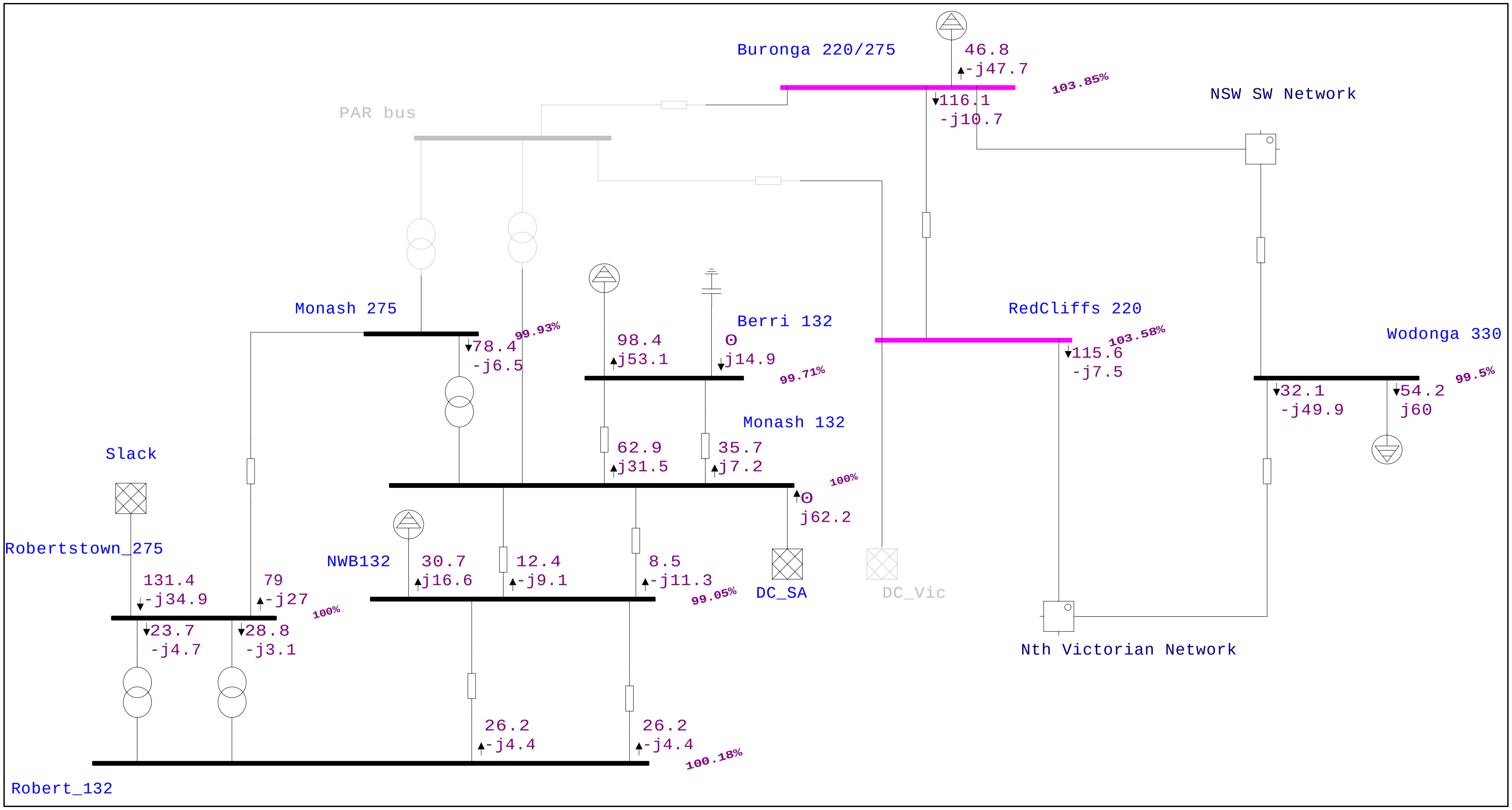

Figure 7 Transfer of 220 MW using Alternative 4

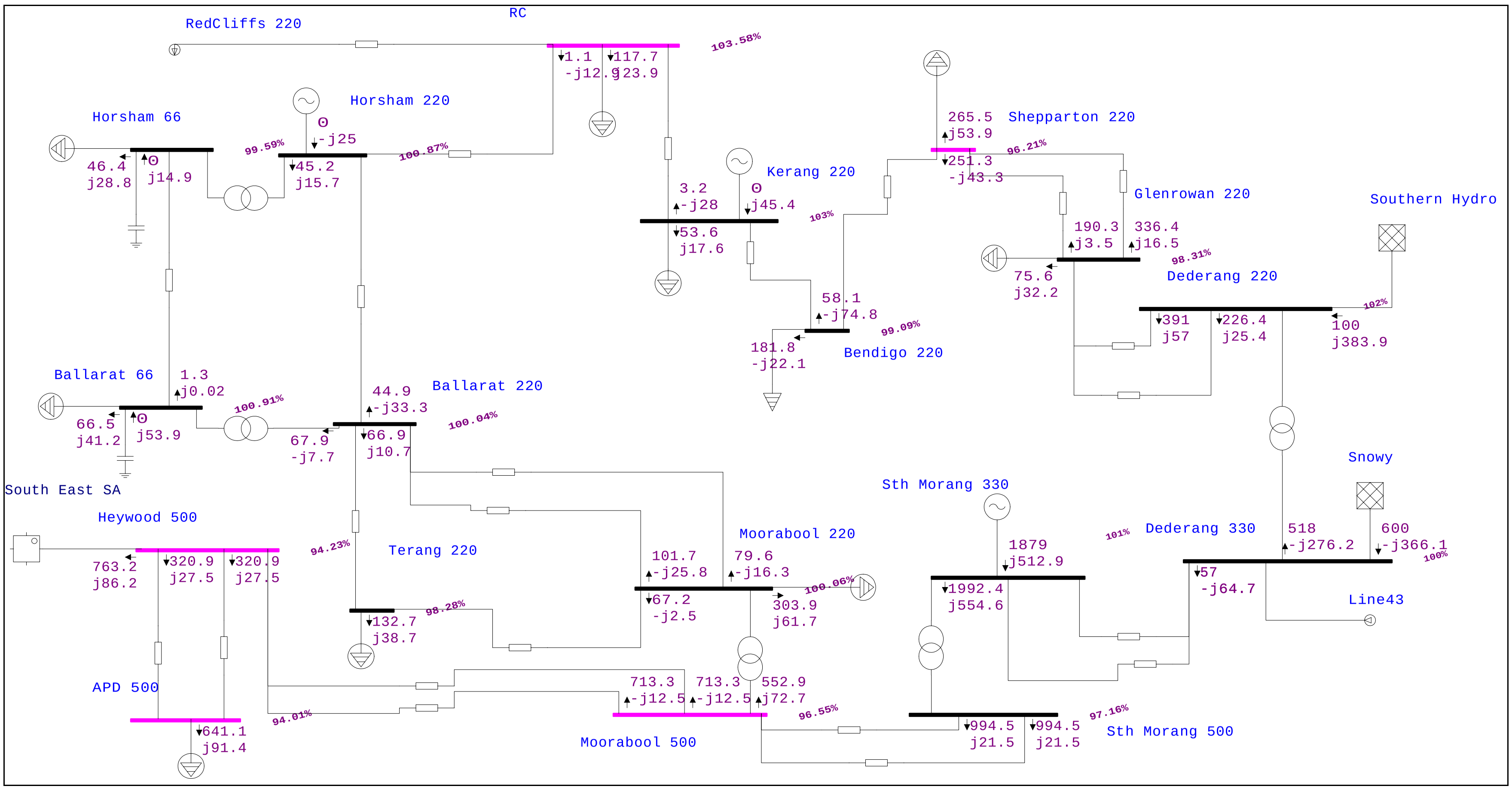

Figure 8 Typical representation of the Victorian system when transferring an additional 220 MW using Alternative 4

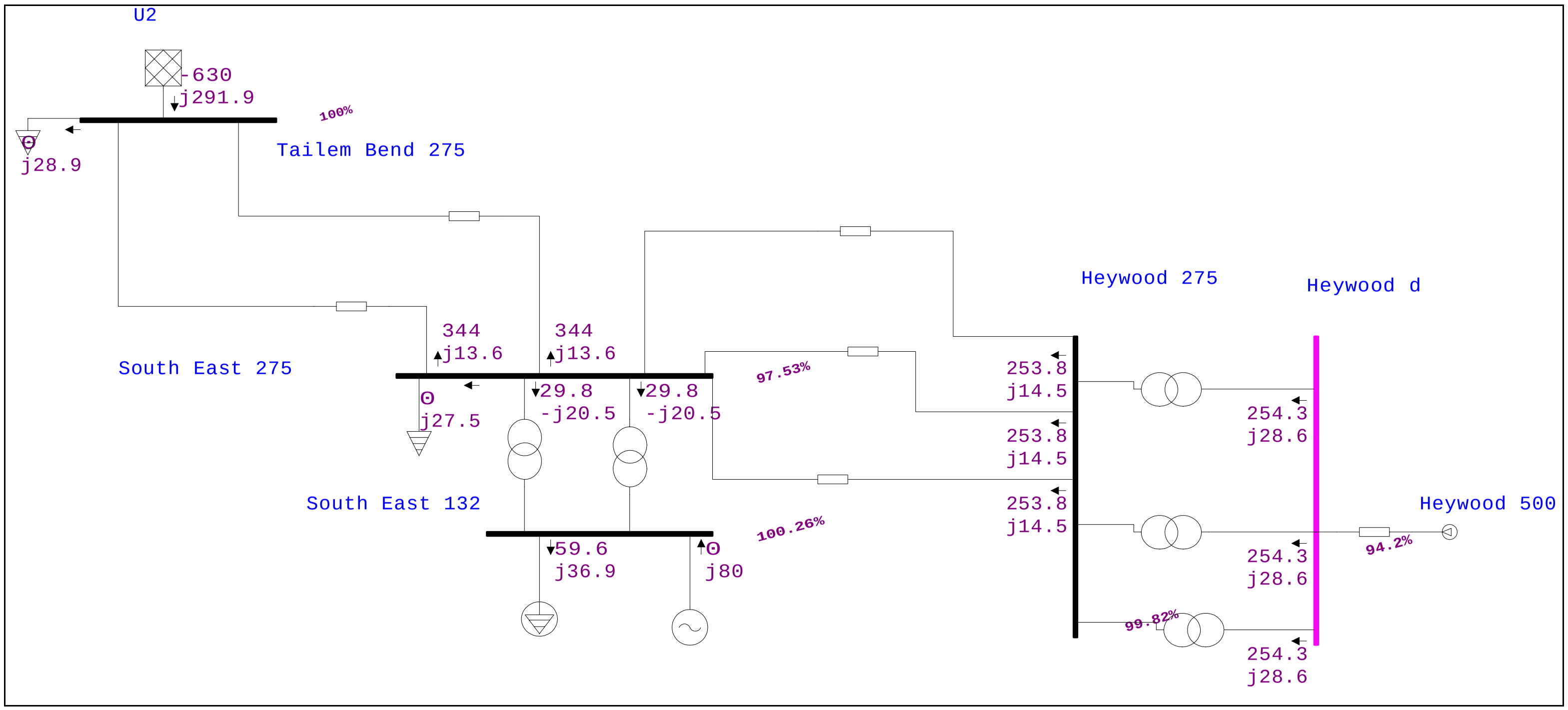

Figure 9 Simplified representation of the south-east South Australian system with Alternative 4

TransÉnergie Australia

TransÉnergie - Murraylink
Selection and assessment
of alternatives

APPENDIX 4
Future Riverland augmentations

14 October 2002

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
0	024/45003	Final Report	Andrew Robertson	Tony Clark	Rod Touzel

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Introduction

This appendix details BRW's methodology in assessing future augmentations for the Riverland network for each of the alternative projects considered as part of the regulatory asset valuation (RAV) study detailed in the document "Murraylink – Selection and assessment of alternatives".

Future augmentations of the Riverland region

Each alternative alone will not support the Riverland load over this period (during N-1 contingency conditions) without additional augmentations (based on existing projected load growth).

For this evaluation, the projected Riverland loads are assessed against the capacity of the successive stages of augmentation to determine their dates and costs?. The study period has been taken to be the 2014–2015 summer. After this time, uncertainties surrounding load forecasts make any detailed planning assessment unreliable.

All alternatives, including Murraylink, essentially offer the same augmentation benefits and are compared with the "do nothing" scenario which is the existing Riverland system without a 220 MW (and reactive support) injection.

Augmentation building blocks

For reinforcement of the supplies to the Riverland region, ElectraNet SA has used voltage level building blocks of 132 kV and 275 kV to provide for the existing transmission network and also for proposals for future network augmentation. A standard size of 160 MVA for 275/132 kV transformers is also used in the ElectraNet system. BRW has assessed that future augmentations to the Riverland transmission network should utilise 275 kV transmission with 160 MVA transformation.

Murraylink or alternative support for the Riverland Region

Prior to the completion of the Murraylink interconnector, ESIPC[1] had provided a summary of the supply performance to the Riverland region with no augmentations and with Murraylink. The report made the following conclusions.

[1] ESIPC Riverland Augmentation Report, December 2001

With no further augmentations:

- For (N condition) no 132 kV line outage, the network would have been adequate for summer 2002–03, but not for summer 2003–04 onwards.
- For (N-1 condition loss of the most critical 132 kV line), the existing network would not be adequate as it would suffer from excessively low voltages and thermal overloads of the 132 kV lines.

With the network augmented by Murraylink:

- For no 132 kV line outages (N condition), the network would have been adequate in the planning horizon of the study (summer of 2010–11)
- For (N-1 condition) or loss?? Murraylink, the network would have been adequate for summer 2006–07, but not for summer 2007–08 onwards due to excessively low voltages (assuming no additional reactive support is installed).

Summary of findings

The projected Riverland loads used in the original report have subsequently been revised downwards[2]. For the purpose of this study, BRW has used both the revised load growth figures and the power factors for the NWB and Berri connection points as listed within the ESIPC planning study report.

Without Murraylink (or an alternative) in service providing 220 MW injection capability into the Riverland at the Monash 132 kV bus:

- An additional transmission injection into the Riverland region (in the form of a 275 kV line between Robertstown and Monash) is required by the summer of 2002–03 should an N-1 contingency condition occur, such as the loss of a critical 132 kV circuit.
- Assuming a prudent level of voltage support (such as a third 18 MVAr capacitor bank located at Monash substation in service by 2008–2009) a second transmission injection into the Riverland would be required by 2011–12.
- These capacitor banks could be relocated to alternative sites within the ElectraNet system following construction of the second 275 kV transmission line.

With Murraylink (or an alternative) in service providing 220 MW injection capability into the Riverland at the Monash 132 kV bus:

- Assuming a prudent level of voltage support (such as a third 18 MVAr capacitor bank located at Monash substation) an additional transmission injection into the Riverland would be required by 2014–15 (based on a 4% per annum load growth from the 2011–12 load, which is the last year in the review to have its load forecast).

[2] ESIPC, Annual Planning Report, 2002

- The additional 18 MVAr capacitor bank would be required to be in service by 2012–13.

These capacitor banks could be relocated to alternative sites within the ElectraNet system following construction of the second 275 kV transmission line.

The power factors considered in the 2001 report are lower than the revised 2002 report. If the lower power factors were used in the analysis, the capacitor bank would be required to be in service by 2008–2009 and the new transmission capacity would be required by 2011–2012 some two years earlier. An estimate of the future power factors at Berri and NWB is subject to significant uncertainty and hence the timing of the augmentations is similarly impacted.

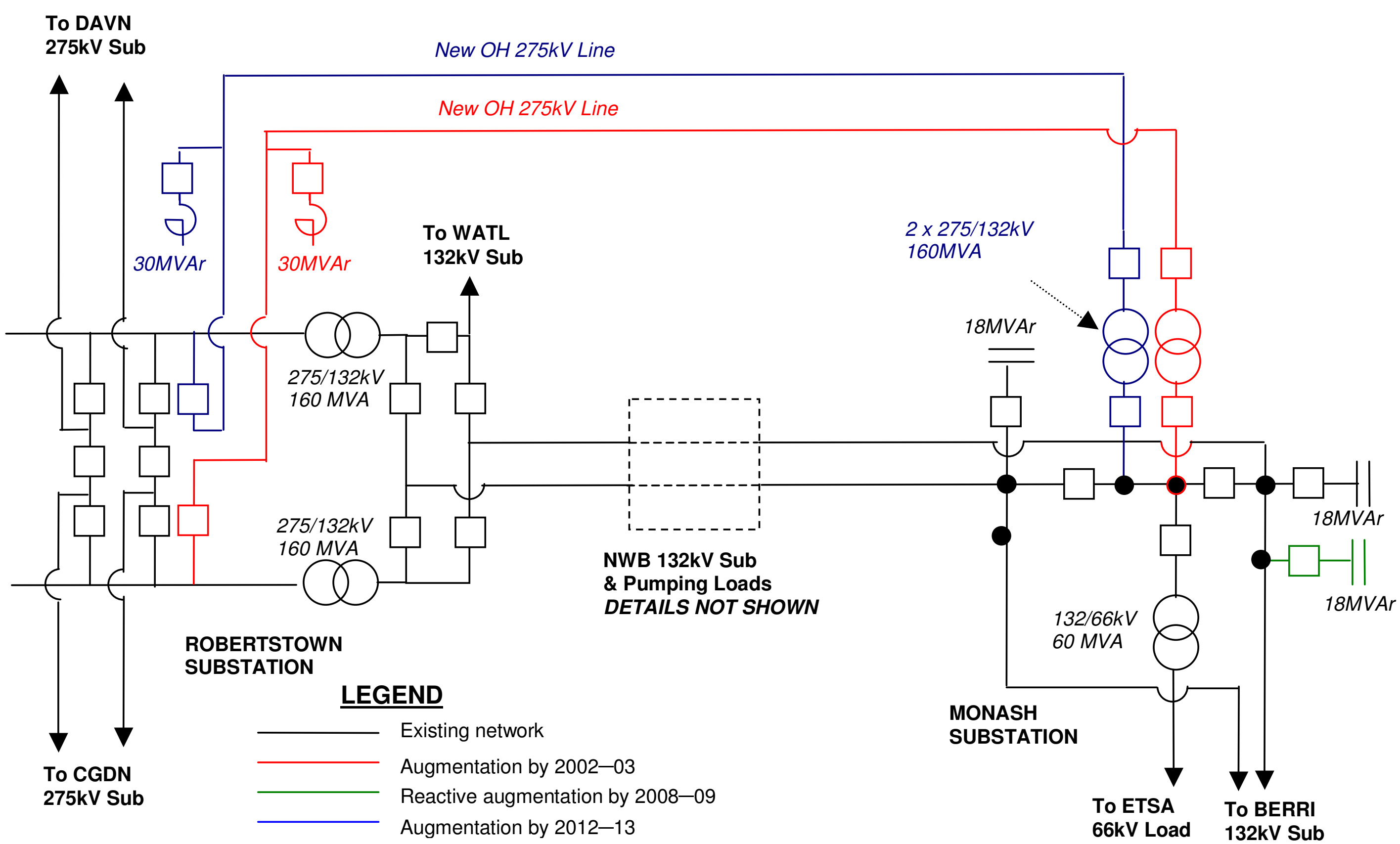
The table below illustrates the sensitivity to power factor projections.

Augmentation	**Timing of augmentations**			
	Without Murraylink	Murraylink (based on 0.97 power factor at Berri)	Murraylink (based on 0.92 power factor at Berri)	TransÉnergie market benefit timing
18 MVAr capacitor bank	2008–09	2012–13	2008–09	2010–11
Additional 275 kV transmission line from Robertstown to Monash	2002–03	2014–15	2011–12	2012–13

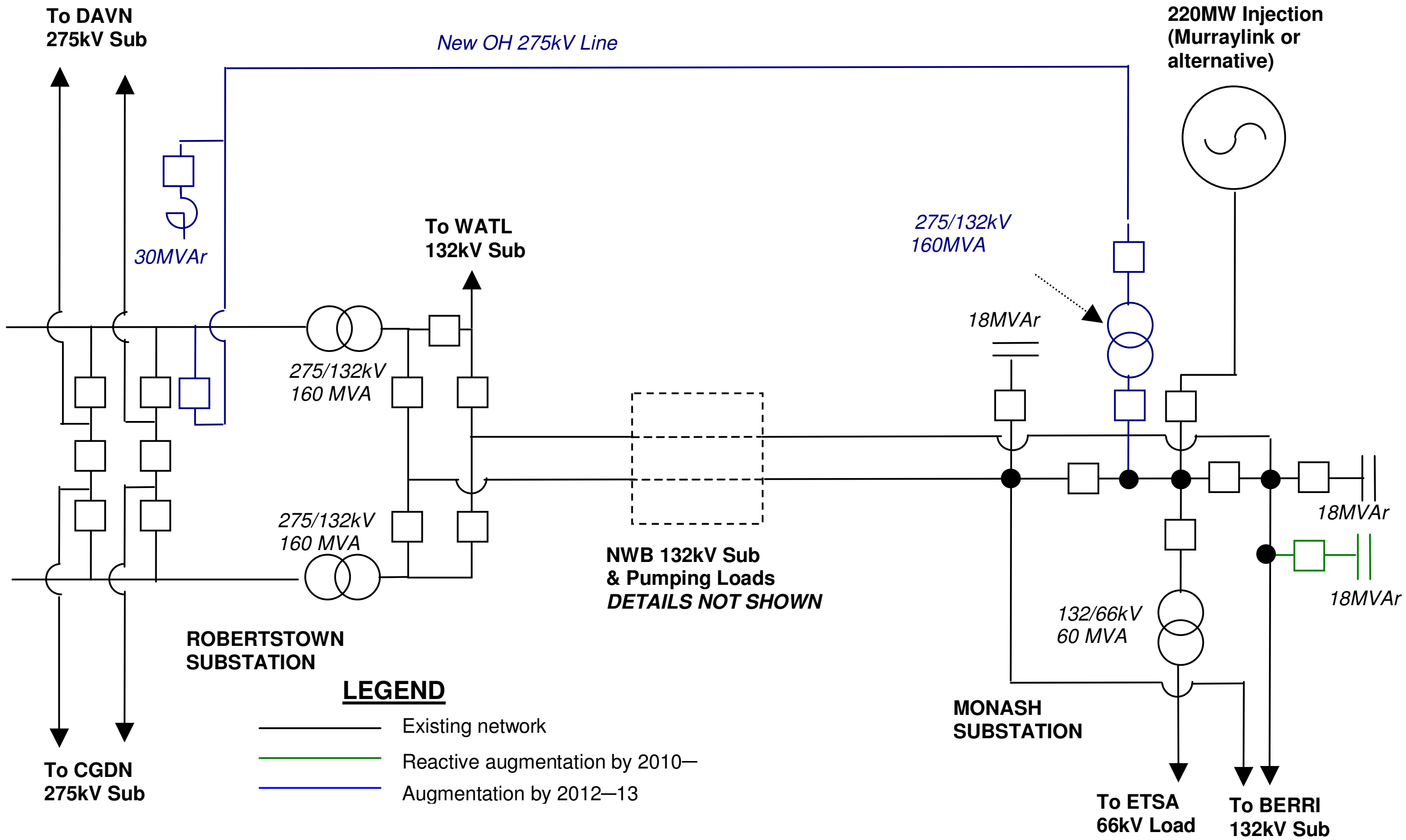
In the market benefit analysis, TransÉnergie has assumed a mid-range position in the augmentation timing. Given the uncertainty on both load growth projections and the forecast power factor, BRW considers that these assumptions are reasonable.

Diagrams showing future augmentations are provided on the following pages.

EXISTING network (without Murraylink or alternative) with future augmentation



MURRAYLINK/ALTERNATIVE interconnection with future augmentation



TransÉnergie Australia

TransÉnergie - Murraylink
Selection and assessment
of alternatives

APPENDIX 5

Quantitative risk analysis of interconnector alternatives

14 October 2002

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
0	024/45003	Final Report	AT / BM / TC	Neil Johnson	Rod Touzel

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TABLE OF CONTENTS

1 INTRODUCTION

Risk exists in all project estimates. Typically this risk is accounted for within the estimate as a contingency. This appendix deals with the assessment of cost risk for the four alternative transmission projects developed by BRW as part of the Murraylink RAV study.

Risk arises from two main areas:

1. Uncertainty in the information in the base estimate itself: i.e. the authors of the estimate use their skill and experience to make ‘best guess’ estimates for a range of parameters, but these may turn out to be incorrect. For example, the estimate may use a labour rate of $30/hwhich turns out to be $32/h due to availability in the local labour market. This uncertainty is modelled by replacing a single deterministic value with a range of values, each with an associated probability. The end output of this process is a probabilistic curve of cost against probability.
2. Adverse events *which may or may not occur*. Examples are weather conditions, an earthquake, labour disputes or utility interruptions. These have to be modelled separately from the uncertainty items described above. By assigning a probability to these events, they can be incorporated into a probabilistic model.

2 METHODOLOGY

The structured approach to risk analysis and management used here is from the Worley risk management process, which is based on a general risk management methodology of risk identification, risk assessment and appraisal, and risk control. The following CAPEX analyses are based on the first part of this process**Stage 1 - Initiation and Data Gathering**

In the first stage, the objectives of the risk analysis exercise are identified and the process adjusted to accommodate project needs. In this case, the four alternative transmission line projects have all been technically specified at concept level and a base cost estimate has been developed.

Stage 2 - Qualitative Assessment

In the second stage, the project risk drivers are identified and expressed in terms of their likelihood of occurrence and severity of impact. This is achieved with brainstorming techniques and by drawing on the expert team's experience. Identified risk drivers are screened to focus attention and resources on the significant few risks as opposed to the insignificant many. The screened risks are tabulated into a risk register, which contains a description of the risk and its associated likelihood.

Stage 3 – Quantitative Analysis

In the third stage, the risks are quantified through interviews with project representatives. Interviews cover the methods or approach used to derive the base estimate and concerns these project representatives may have. The uncertainty range on risk drivers is described using three estimates: the least likely minimum (P10 value), the most likely case (median value), and the least likely maximum (P90). The cost risk model is developed using the spreadsheet package @Risk for Excel. Then the quantitative risk model is analysed using Monte Carlo simulations and the results interpreted and sensitivity studies performed on the cost analysis.

3 RISK ASSESSMENT

3.1 Quantitative Risk Assessment

The quantitative risk assessment was conducted on 3 and 4 September 2002 with a team of BRW staff and external specialists. The purpose of the sessions was two-fold:

- to verify and agree the base models for cost of each of the four options and agree that these models represented a fair 'most likely' scenario'; and
- to identify crucial cost risk factors.

The base case estimate for each of the four transmission alternatives is illustrated below.

Item No.	BASE COST ESTIMATES MURRAYLINK ALTERNATIVES Item Description	Alternative 1 275kV AC O/H Line Interconnection Base Cost ('000s)	Alternative 2 150kV DC O/H Line Interconnection Base Cost ('000s)	Alternative 3 220kV AC O/H Line Interconnection Base Cost ('000s)	Alternative 4 275kV AC O/H Line Plus Heywood B Interconnect Base Cost ('000s)
A	**DEVELOPMENT WORKS**				
	Project Management	$ 2,200	$ 2,200	$ 2,200	$ 2,200
	Feasibility Consultants - Legal, Market, Technical. Environ.	$ 1,276	$ 1,276	$ 1,276	$ 1,276
B	**APPROVALS**	$ -	$ -	$ -	$ -
	Approvals - Planning & Environment	$ 2,500	$ 2,000	$ 2,000	$ 2,500
	Approvals - NECA, ACCC, Transmission licences, etc	$ 2,293	$ 2,293	$ 2,293	$ 2,293
	Other - easements,licences, financiers,insurance etc.	$ 7,500	$ 5,400	$ 5,800	$ 6,800
		$ -	$ -	$ -	$ -
	TOTAL DEVELOPMENT COSTS	**$ 15,769**	**$ 13,169**	**$ 13,569**	**$ 15,069**
		$ -	$ -	$ -	$ -
C	***TRANSMISSION LINE WORKS***	$ -	$ -	$ -	$ -
C1	Design	$ 194	$ 174	$ 174	$ 259
C2	Construction	$ 34,636	$ 20,487	$ 29,074	$ 6,280
C3	Fabrication	$ 6,767	$ 4,702	$ 5,767	$ 9,235
C4	Erection	$ 3,929	$ 2,730	$ 3,349	$ 5,319
C5	Stringing	$ 3,600	$ 2,635	$ 3,100	$ 4,840
C6	Material Supply	$ 38,969	$ 22,302	$ 33,184	$ 11,991
	SUB-TOTAL	$ 88,095	$ 53,029	$ 74,647	$ 37,923
C8	Project Management	included above	included above	included above	included above
		$ -	$ -	$ -	$ -
	TOTAL TRANSMISSION LINE COST	**$ 88,095**	**$ 53,029**	**$ 74,647**	**$ 37,923**
		$ -	$ -	$ -	$ -
D	***SWITCHYARD WORKS***	$ -	$ -	$ -	$ -
D1	Design	$ 2,152	$ 561	$ 1,007	$ 2,889
D2	Construction (site labour and supervision)	$ 5,320	$ 1,470	$ 2,580	$ 6,787
D3	Plant (elec prim & sec, civil)	$ 14,855	$ 3,807	$ 6,886	$ 21,261
D4	Commissioning	$ 557	$ 112	$ 220	$ 728
D5	Project Management	$ 784	$ 216	$ 379	$ 998
D6	Phase Shift Xmfrs	$ 19,080	$ -	$ 19,080	$ 19,080
D7	Static Var Compensators	$ 19,080	$ -	$ 18,020	$ 19,080
D8	Transformers	$ 6,360	$ 15,900	$ -	$ 10,600
D9	Series Cap / DC Converter Stations	$ -	$ 48,720	$ -	$ 6,360
D10	Monash 132kV Connection Costs	$ 10,400	$ 10,400	$ 10,400	$ 10,400
		$ -	$ -	$ -	$ -
	TOTAL SWITCHYARD COST	**$ 78,588**	**$ 81,186**	**$ 58,572**	**$ 98,183**
		$ -	$ -	$ -	$ -
	TOTAL EPC PROJECT COST incl 10% contractor profit & O/H	**$ 183,352**	**$ 147,637**	**$ 146,541**	**$ 149,716**
E	Interest during construction	$ 36,373	$ 29,374	$ 29,247	$ 30,101
	TOTAL PROJECT COST	**$ 235,493**	**$ 190,179**	**$ 189,357**	**$ 194,886**

Clarifications/ Assumptions in cost estimate

(a) Major plant spares assummed in total cost.

(b) Testing and commissioning set to 20% of electrical labour hours (ie: for switchgear and miscellaneous installation, but not civil works installation)

(c) Detailed design set to 10% of total swyd project cost (including switchyard pant, labour, testing and commisioning but not major plant items ie: SVCs, transformers, converter stations).

(d) Project Management set to 10% of total labour costs (site and supervision labour, testing and commissioning)

(e) Major plant items are cost turn key project (Installation included. Commissioning of DC converter station, series capacitors, phase angle tranformers, tranformers). Additional 6% delivery charge assumed

(f) Switchyard spares set to 6% of total switchyard costs.

(g) External augmentations set to 1/ Plant $ = 50% of switchyard costs (not including civil costs) 2/ Labour $ = 20% of switchyard labour costs (not including civil labour) 3/Test and commissioning $ = 20% Test and commissioning costs 4/ Proj Management $ = 10% of sum 1/ , 2/ , 3/

* Option 1 requires upgrade of 330&132kV lines in south west NSW and fault level
* 220kV Red Cliffs interconnector has fault level impacts in Victorian 66&22kV system
* Heywood / Riverlands augmentation option has fault level impacts in South Australian

(h) IDC calculated at discount rate assuming a 5 year project timeframe with costs distributed as follows:

Year 1 - 5%
Year 2 - 5%
Year 3 - 30%
Year 4 - 40%
Year 5 - 20%
All annual costs were allocated using a mid year convention.

4 RISK MODEL

The cost risk model was developed in @Risk for Excel (version 4.0.5), a risk analysis tool for spreadsheets. The model contains 31 risk factors, all of which were assigned risk variables describing a continuous range of uncertainty.

The risk factors covered uncertainties associated with the work scope such as rates for labour and permanent materials, specialist plant cost, complexity and productivity.

The risk variables were modelled as triangular distributions, using a 3-point estimate of their likely range of uncertainty. Thus, the least likely minimum (P10), the most likely (P50), and the least likely maximum (P90) were identified.

The @Risk model was analysed using Monte Carlo simulation (5,000 simulation runs were performed). The results of the simulation are shown in Attachment A as the cumulative frequency distribution of the project net total cost inclusive of all capital, and operation and maintenance costs for the whole-of-life of the asset.

Using risk analysis, a capital cost contingency was determined with reference to the base estimate. This contingency amount was defined as the provisional sum required to bring the base estimate to the P75 probability. That is, the contingency was added to the base estimate so that the total cost budget has a 25% chance of overrunning and a 75% chance of underrunning. This level of contingency is typical of that used by contractors in formulating an EPC price in a balanced market.

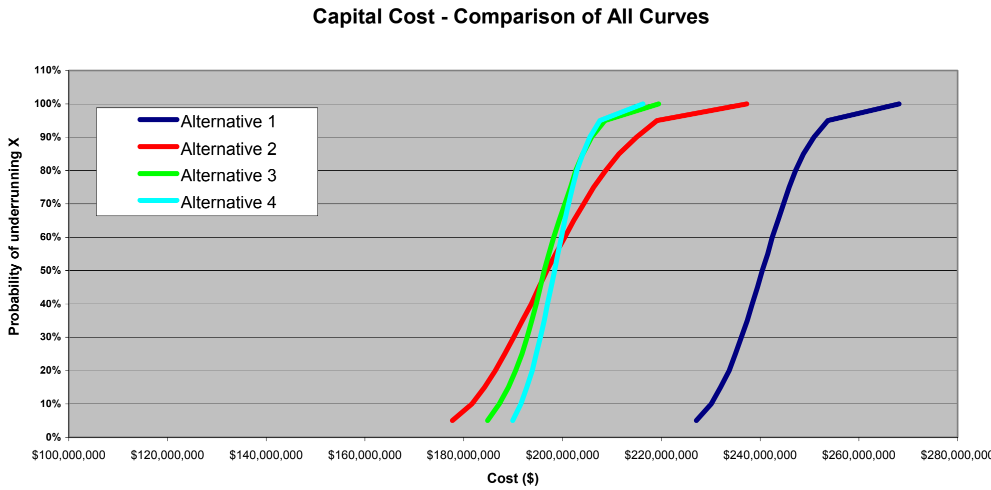
The accuracy of the estimate was then defined as the P10 and P90 points on the cumulative curve, meaning that there is an 80% chance that the project capital cost would fall within that range.

To produce a register of ranked cost risk factors, sensitivity analysis was performed on the risk factors by ranking the factors in terms of contribution to the overall contingency. A summary report on each of the alternatives is contained in Attachment B.

COST RISK FACTORS		ALTERNATIVE 1				ALTERNATIVE 2				ALTERNATIVE 3				ALTERNATIVE 4			
		Minimum	Most Likely	Maximum	RISK	Minimum	Most Likely	Maximum	RISK	Minimum	Most Likely	Maximum	RISK	Minimum	Most Likely	Maximum	RISK
APPROVALS PROCESS																	
A-1	Planning and environment	60%	100%	160%	109%	60%	100%	160%	109%	60%	100%	160%	109%	80%	100%	111%	96%
A-2	NECA	80%	100%	140%	109%	80%	100%	140%	109%	80%	100%	140%	109%	80%	100%	140%	109%
A-3	ACCC	80%	100%	140%	109%	80%	100%	140%	109%	80%	100%	140%	109%	80%	100%	140%	109%
TRANSMISSION LINE																	
T-1	Tower Spacing	95%	100%	105%	100%	95%	100%	105%	100%	95%	100%	105%	100%	95%	100%	105%	100%
T-2	Mass Suspension Towers	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%
T-3	Mass Light Strain Towers	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%
T-4	Mass Heavy Strain Towers	95%	100%	110%	102%	95%	100%	110%	102%	95%	100%	110%	102%	95%	100%	110%	102%
T-8	Mobilisation/Site Facilities	90%	100%	130%	109%	90%	100%	130%	109%	90%	100%	130%	109%	90%	100%	130%	109%
T-9	Construct Access Track/Tower Survey	90%	100%	130%	109%	90%	100%	130%	109%	90%	100%	130%	109%	90%	100%	130%	109%
T-10	Tower Fabrication	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%	95%	100%	115%	104%
T-11	Tower Footings	90%	100%	120%	104%	90%	100%	120%	104%	90%	100%	120%	104%	90%	100%	120%	104%
T-12	Tower Stringing	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%
T-13	Install New 275kV Insulators	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%
T-14	Supply Conductors	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%
T-15	Supply Ground Wire	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%
T-16	Supply Line Hardware	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%	90%	100%	110%	100%
T-17	Tower/cable Labour Productivity Factor	90%	100%	145%	115%	90%	100%	145%	115%	90%	100%	145%	115%	90%	100%	145%	115%
T-18	Underground cable material cost	80%	100%	110%	96%	80%	100%	110%	96%	80%	100%	110%	96%				
T-19	Underground cable installation cost	75%	100%	115%	96%	75%	100%	115%	96%	75%	100%	115%	96%				
SWITCHYARD WORKS																	
S-01	PSTs total cost, including spares	85%	100%	125%	104%					85%	100%	125%	104%	85%	100%	125%	104%
S-02	Transformers total cost, including spares	90%	100%	110%	100%	90%	100%	115%	102%	90%	100%	110%	100%	90%	100%	110%	100%
S-03	SVC total cost, including spares	85%	100%	125%	104%					85%	100%	125%	104%	85%	100%	125%	104%
S-04	Series capacitors total cost													95%	100%	108%	101%
S-05	DC convertor station total cost					80%	100%	140%	109%								
S-06	External augmentation cost (delivery 6%)	95%	100%	108%	101%	95%	100%	108%	101%	95%	100%	108%	101%	95%	100%	108%	101%
S-07	Substation land/ civil works	95%	100%	108%	101%	95%	100%	108%	101%	95%	100%	108%	101%	95%	100%	108%	101%
S-08	Substation productivity factor	90%	100%	145%	115%	90%	100%	145%	115%	90%	100%	145%	115%	90%	100%	145%	115%
S-09	Miscellaneous network costs	90%	100%	120%	104%	90%	100%	110%	100%	90%	100%	115%	102%	90%	100%	120%	104%

ATTACHMENT A – COST SIMULATION RESULTS

Cumulative frequency distribution of the project capital cost.



Capital cost contingency and distribution

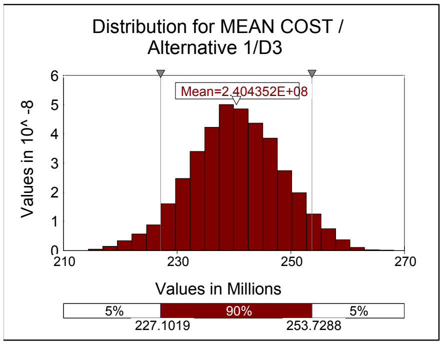
	Alternative 1	Alternative 2	Alternative 3	Alternative 4
MEAN COST	$ 240,436,778	$ 197,549,694	$ 196,537,156	$ 198,460,373
Base estimate	$ 235,493,046	$ 190,179,431	$ 189,356,996	$ 194,885,962
P75 price	$ 245,906,230	$ 206,308,262	$ 201,608,476	$ 202,014,701
P75 Contingency	$ 10,413,184	$ 16,128,831	$ 12,251,480	$ 7,128,738
Contingency %	4.42%	8.48%	6.47%	3.66%
Accuracy	8%	16%	9%	7%
Accuracy above	2%	4%	2%	2%
Accuracy below	6%	12%	7%	5%

Cost distribution details

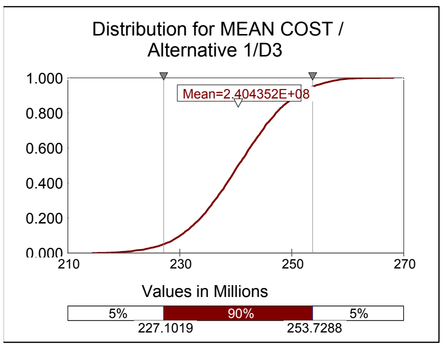
		Alternative 1	Alternative 2	Alternative 3	Alternative 4
	5%	$ 227,101,905	$ 177,688,772	$ 184,794,095	$ 189,908,046
==>	10%	$ 230,079,581	$ 181,613,588	$ 187,169,978	$ 191,548,617
	15%	$ 232,011,196	$ 184,228,916	$ 189,066,908	$ 192,794,453
	20%	$ 233,759,275	$ 186,387,093	$ 190,505,481	$ 193,863,482
	25%	$ 235,008,400	$ 188,272,832	$ 191,807,058	$ 194,699,238
	30%	$ 236,196,741	$ 190,103,447	$ 192,822,169	$ 195,541,909
	35%	$ 237,373,068	$ 191,831,052	$ 193,761,807	$ 196,307,827
	40%	$ 238,382,867	$ 193,673,594	$ 194,677,771	$ 196,946,018
	45%	$ 239,454,879	$ 195,229,635	$ 195,465,431	$ 197,686,616
	50%	$ 240,415,624	$ 196,854,360	$ 196,271,072	$ 198,399,233
	55%	$ 241,523,131	$ 198,579,398	$ 197,232,770	$ 199,054,533
	60%	$ 242,468,287	$ 200,455,418	$ 198,192,095	$ 199,757,580
	65%	$ 243,602,451	$ 202,266,218	$ 199,307,753	$ 200,457,648
	70%	$ 244,734,955	$ 204,278,710	$ 200,494,925	$ 201,193,529
==>	75%	$ 245,906,230	$ 206,308,262	$ 201,608,476	$ 202,014,701
	80%	$ 247,181,456	$ 208,748,389	$ 202,669,951	$ 202,908,801
	85%	$ 248,799,539	$ 211,422,751	$ 204,085,189	$ 204,086,842
==>	90%	$ 250,882,325	$ 214,957,030	$ 205,853,524	$ 205,537,623
	95%	$ 253,728,839	$ 219,135,944	$ 208,572,096	$ 207,548,488
	100%	$ 268,151,155	$ 237,283,896	$ 219,463,620	$ 216,284,220

ATTACHMENT B – CAPITAL COST SENSITIVITY ANALYSES

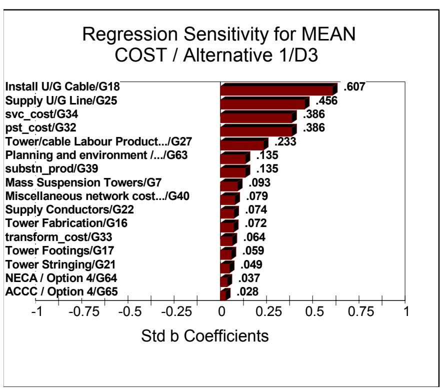
Simulation Results for
MEAN COST / Alternative 1 / D3



Summary Information	
Workbook Name	cost risk model rev4a- stategic undergrounding.xls
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	204
Number of Outputs	12
Sampling Type	Latin Hypercube
Simulation Start Time	13/10/2002 14:04
Simulation Stop Time	13/10/2002 14:09
Simulation Duration	00:04:21
Random Seed	773279581

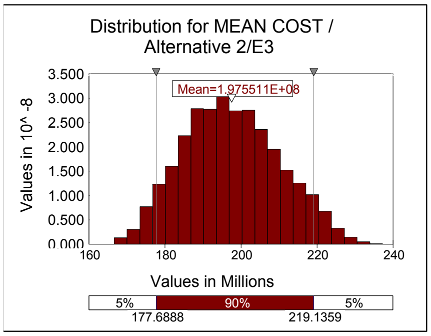


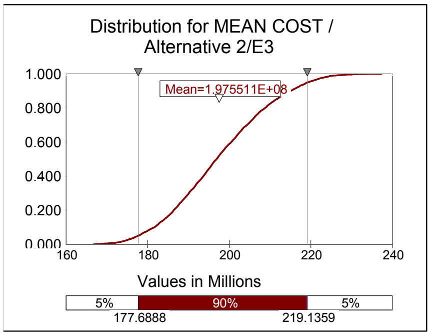
Summary Statistics			
Statistic	**Value**	**%tile**	**Value**
Minimum	$ 214,345,584	5%	$ 227,101,904
Maximum	$ 268,151,152	10%	$ 230,079,584
Mean	$ 240,435,238	15%	$ 232,011,200
Std Dev	$ 8,049,934	20%	$ 233,759,280
Variance	6.48014E+13	25%	$ 235,008,400
Skewness	-0.045026495	30%	$ 236,196,736
Kurtosis	2.883202305	35%	$ 237,373,072
Median	$ 240,415,632	40%	$ 238,382,864
Mode	$ 230,743,888	45%	$ 239,454,880
Left X	$ 227,101,904	50%	$ 240,415,632
Left P	5%	55%	$ 241,523,136
Right X	$ 253,728,832	60%	$ 242,468,288
Right P	95%	65%	$ 243,602,448
Diff X	$ 26,626,928	70%	$ 244,734,960
Diff P	90%	75%	$ 245,906,224
#Errors	0	80%	$ 247,181,456
Filter Min		85%	$ 248,799,536
Filter Max		90%	$ 250,882,320
#Filtered	0	95%	$ 253,728,832

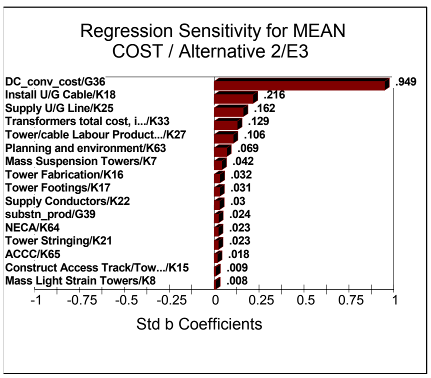


Sensitivity			
Rank	**Name**	**Regr**	**Corr**
#1	Install U/G Cable / G18	0.606	0.594
#2	Supply U/G Line / G25	0.456	0.447
#3	pst_cost / G32	0.387	0.370
#4	svc_cost / G34	0.384	0.371
#5	Tower/cable Labour Produ	0.231	0.218
#6	Planning and environment	0.136	0.126
#7	substn_prod / G39	0.136	0.141
#8	Mass Suspension Towers	0.094	0.087
#9	Miscellaneous network co	0.080	0.076
#10	Supply Conductors / G2	0.074	0.072
#11	Tower Fabrication / G16	0.072	0.053
#12	transform_cost / G33	0.065	0.053
#13	Tower Footings / G17	0.058	0.074
#14	Construct Access Track/T	0.017	0.045
#15	Mass Heavy Strain Towers	0.000	-0.043
#16	Underground cable installa	0.000	0.049

Simulation Results for
MEAN COST / Alternative 2 / E3







Summary Information	
Workbook Name	cost risk model rev4a- stategic undergrounding.xls
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	204
Number of Outputs	12
Sampling Type	Latin Hypercube
Simulation Start Time	13/10/2002 14:04
Simulation Stop Time	13/10/2002 14:09
Simulation Duration	00:04:21
Random Seed	773279581

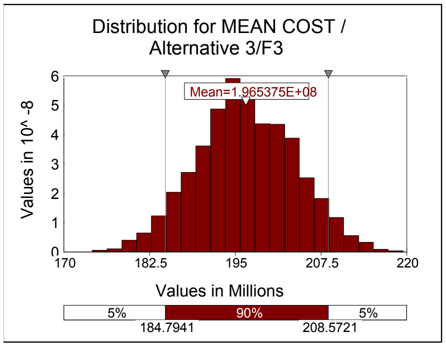
Summary Statistics

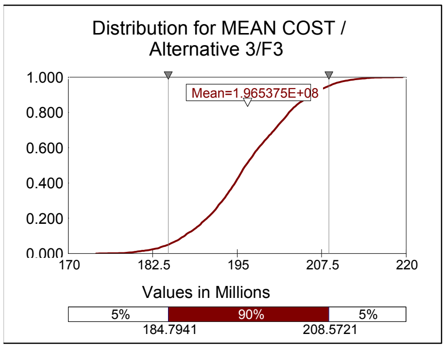
Statistic	Value	%tile	Value
Minimum	$ 166,673,904	5%	$ 177,688,768
Maximum	$ 237,283,904	10%	$ 181,613,584
Mean	$ 197,551,065	15%	$ 184,228,912
Std Dev	$ 12,552,952	20%	$ 186,387,088
Variance	1.57577E+14	25%	$ 188,272,832
Skewness	0.176762075	30%	$ 190,103,440
Kurtosis	2.500631163	35%	$ 191,831,056
Median	$ 196,854,368	40%	$ 193,673,600
Mode	$ 187,067,888	45%	$ 195,229,632
Left X	$ 177,688,768	50%	$ 196,854,368
Left P	5%	55%	$ 198,579,392
Right X	$ 219,135,936	60%	$ 200,455,424
Right P	95%	65%	$ 202,266,224
Diff X	$ 41,447,168	70%	$ 204,278,704
Diff P	90%	75%	$ 206,308,256
#Errors	0	80%	$ 208,748,384
Filter Min		85%	$ 211,422,752
Filter Max		90%	$ 214,957,024
#Filtered	0	95%	$ 219,135,936

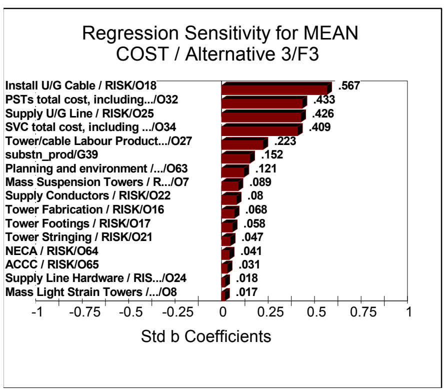
Sensitivity

Rank	Name	Regr	Corr
#1	DC_conv_cost / G36	0.949	0.941
#2	Install U/G Cable / K18	0.216	0.194
#3	Supply U/G Line / K25	0.162	0.140
#4	Transformers total cost, includi	0.128	0.085
#5	Tower/cable Labour Productivit	0.107	0.101
#6	Planning and environment / K	0.068	0.060
#7	Mass Suspension Towers / K	0.043	0.060
#8	Tower Fabrication / K16	0.032	0.043
#9	Supply Conductors / K22	0.031	0.036
#10	NECA / K64	0.024	0.035
#11	Tower Stringing / K21	0.023	0.046
#12	Tower Stringing / RISK / O17	0.000	-0.038
#13	Underground cable material co	0.000	-0.032
#14	Mass Light Strain Towers / RIS	0.000	0.033
#15	transform_cost / G33	0.000	-0.048
#16	SVC total cost, including spare	0.000	-0.033

**Simulation Results for
MEAN COST / Alternative 3 / F3**





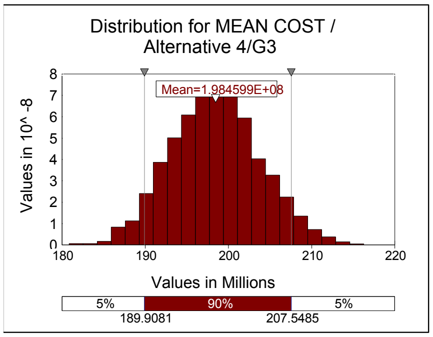


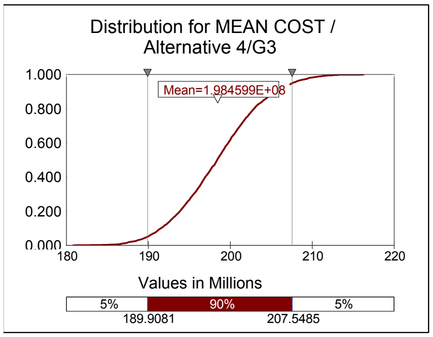
Summary Information	
Workbook Name	cost risk model rev4a- stategic undergrounding.xls
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	204
Number of Outputs	12
Sampling Type	Latin Hypercube
Simulation Start Time	13/10/2002 14:04
Simulation Stop Time	13/10/2002 14:09
Simulation Duration	00:04:21
Random Seed	773279581

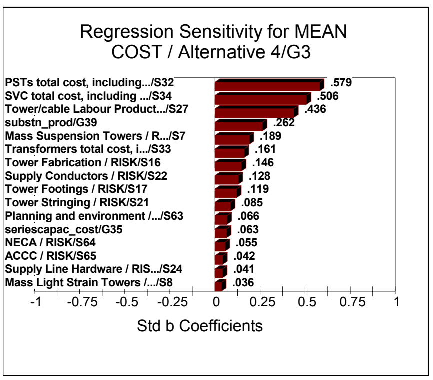
Summary Statistics					
Statistic		**Value**	**%tile**		**Value**
Minimum	$	174,136,832	5%	$	184,794,096
Maximum	$	219,463,616	10%	$	187,169,984
Mean	$	196,537,456	15%	$	189,066,912
Std Dev	$	7,173,952	20%	$	190,505,488
Variance		5.14656E+13	25%	$	191,807,056
Skewness		0.018349343	30%	$	192,822,176
Kurtosis		2.794477329	35%	$	193,761,808
Median	$	196,271,072	40%	$	194,677,776
Mode	$	186,538,544	45%	$	195,465,424
Left X	$	184,794,096	50%	$	196,271,072
Left P		5%	55%	$	197,232,768
Right X	$	208,572,096	60%	$	198,192,096
Right P		95%	65%	$	199,307,760
Diff X	$	23,778,000	70%	$	200,494,928
Diff P		90%	75%	$	201,608,480
#Errors		0	80%	$	202,669,952
Filter Min			85%	$	204,085,184
Filter Max			90%	$	205,853,520
#Filtered		0	95%	$	208,572,096

Sensitivity			
Rank	**Name**	**Regr**	**Corr**
#1	Install U/G Cable / RISK / $	0.566	0.550
#2	PSTs total cost, including s	0.431	0.437
#3	Supply U/G Line / RISK / $	0.426	0.424
#4	SVC total cost, including sp	0.408	0.419
#5	Tower/cable Labour Produ	0.223	0.218
#6	substn_prod / G39	0.152	0.153
#7	Planning and environment	0.122	0.130
#8	Mass Suspension Towers /	0.089	0.116
#9	Supply Conductors / RISK	0.079	0.100
#10	Tower Fabrication / RISK /	0.068	0.039
#11	Tower Footings / RISK / $O	0.060	0.077
#12	NECA / RISK / O64	0.041	0.075
#13	ACCC / RISK / O65	0.032	0.032
#14	Supply Line Hardware / RIS	0.002	-0.030
#15	Tower/cable Labour Produ	0.002	0.039
#16	extaug_cost / G37	0.000	-0.038

Simulation Results for
MEAN COST / Alternative 4 / G3







Summary Information	
Workbook Name	cost risk model rev4a- stategic undergrounding.xls
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	204
Number of Outputs	12
Sampling Type	Latin Hypercube
Simulation Start Time	13/10/2002 14:04
Simulation Stop Time	13/10/2002 14:09
Simulation Duration	00:04:21
Random Seed	773279581

Summary Statistics

Statistic	Value	%tile	Value
Minimum	$ 180,850,272	5%	$ 189,908,048
Maximum	$ 216,284,224	10%	$ 191,548,624
Mean	$ 198,459,867	15%	$ 192,794,448
Std Dev	$ 5,360,756	20%	$ 193,863,488
Variance	2.87377E+13	25%	$ 194,699,232
Skewness	0.100848479	30%	$ 195,541,904
Kurtosis	2.837097467	35%	$ 196,307,824
Median	$ 198,399,232	40%	$ 196,946,016
Mode	$ 191,162,432	45%	$ 197,686,608
Left X	$ 189,908,048	50%	$ 198,399,232
Left P	5%	55%	$ 199,054,528
Right X	$ 207,548,480	60%	$ 199,757,584
Right P	95%	65%	$ 200,457,648
Diff X	$ 17,640,432	70%	$ 201,193,536
Diff P	90%	75%	$ 202,014,704
#Errors	0	80%	$ 202,908,800
Filter Min		85%	$ 204,086,848
Filter Max		90%	$ 205,537,616
#Filtered	0	95%	$ 207,548,480

Sensitivity

Rank	Name	Regr	Corr
#1	PSTs total cost, including	0.580	0.575
#2	SVC total cost, including	0.506	0.497
#3	Tower/cable Labour Prod	0.436	0.431
#4	substn_prod / G39	0.261	0.261
#5	Mass Suspension Towers	0.190	0.196
#6	Transformers total cost, i	0.160	0.137
#7	Tower Fabrication / RISK	0.145	0.136
#8	Supply Conductors / RISI	0.127	0.135
#9	Tower Footings / RISK / $	0.119	0.092
#10	Tower Stringing / RISK /	0.085	0.085
#11	Planning and environmer	0.065	0.076
#12	seriescapac_cost / G3	0.064	0.067
#13	NECA / RISK / S64	0.055	0.047
#14	ACCC / RISK / S65	0.040	0.046
#15	Construct Access Track/	0.035	0.044
#16	Miscellaneous network cc	0.000	0.043

Appendix G: Report – A Cost of Capital for Murraylink – Professor Robert Officer

A Cost of Capital for Murraylink

R.R.Officer

1-10-02

Summary and Conclusions

In order to determine the required rate of return on the regulated asset base for Murraylink, the equivalent of a weighted average cost of capital (WACC) is needed. The approach that is adopted in this report is to estimate the cost of capital for the asset or industry type i.e. a Transmission Network Service Provider (TNSP). The estimate was made using the CAPM where the expected or required return was estimated for the asset class. This approach is different but is logically consistent with estimating a WACC by separately estimating the cost of equity and debt and then weighting them by their respective values in the balance sheet. The estimate is consistent with a WACC that is a post tax nominal estimate of this required return or colloquially known as the "Vanilla" WACC equation. Further, by "reverse engineering" the asset cost of capital given the leverage and cost of debt, we can provide estimates of the various components of the WACC even though the estimate was not made directly as a WACC.

Differences in the cost of capital or WACC, at any point in time, reflect differences in the risks associated with the cash flows being generated by the assets. In the context of capital market theory, only non-diversifiable or systematic risks are accounted for in the cost of capital estimates. This does not imply that diversifiable or non-systematic risks are not relevant to a valuation decision or the problem of determining revenue caps in a regulatory setting. Such diversifiable risks are, typically, accounted for in the net cash flows being generated by the assets. This paper outlines the procedures for taking account of such risk but it is beyond the mandate of the paper to do the calculations.

Ultimately, it is risk that determines the size of the cost of capital or WACC. The assessment of the cost of capital or the required return on the assets of the entity in this paper will be estimated using the capital asset pricing model (CAPM).

The CAPM has a number of parameters whose value will be estimated from the available evidence, as at the date of the report, to arrive at the appropriate cost of capital. The most important and potentially controversial estimate is that of the beta; various sources for the estimates of beta or non-diversifiable risks are identified to arrive at an estimate. An examination is made of off-shore company betas, domestic sources for the estimation of beta including those provided by regulators and some separately calculated betas.

The determination of an appropriate beta for the asset class (electricity transmission) is not definitive and must be based on empirical evidence and inevitably subjective

Professor R.R.Officer
Initials:

judgments about the weight to place on the evidence. The examination leads me to conclude that an ***asset beta of around 0.6*** *is justified.*

All of the estimates of the parameters required for a cost of capital estimate for Murraylink are shown in the Table below.

Parameter Name	**Value**
Nominal Risk Free Interest Rate (R_f)%	5.4%
Expected Inflation Rate %	2.2%
Debt margin (over R_f) %	1.50%
Cost of debt R_d = R_f + debt margin %	6.90%
Market Risk Premium (R_m-R_f) %	6.00%
Debt Funding (D/V) %	60%
Value of imputation credits *g*	45%
Asset Beta β_a	0.60
Debt Beta Equity Beta	0.20 1.13
Nominal Post Tax Return on Equity	12.15%
Post Tax Nominal WACC – As used by ACCC[1]	6.97%
Vanilla WACC[2]	**9.00%**
Pre Tax Nominal WACC[3]	9.96%
Pre Tax Real WACC[4]	7.76%

[1] See Equation 2, in Appendix 1.
[2] See Equation 5, in Appendix 1.
[3] See Equation 1, in Appendix 1.
[4] See Equation 1a, in Appendix 1.

Introduction[5]

Murraylink Transmission Corporation (MTC) has been established for the sole purpose of constructing, owning and operating the Murraylink transmission project. MTC is a company owned equally by Murraylink HQI Australia Pty Limited and SNC-Lavalin Investment Australia Pty Ltd.

The Murraylink project is a privately funded electricity project that includes the installation of the world's longest underground power cable (180km) to connect the Victorian and South Australian electricity grids as an innovative solution to the electricity supply requirements of these two regions. Murraylink has the capacity to deliver at least 200 MW into either of the Victorian and South Australian electricity grids and is scheduled to come into operation during the second quarter of 2002.

Murraylink involves the laying of two underground electric cables buried at a depth of approximately 1.2 meters along the entire route between Red Cliffs in Victoria and Berri in South Australia. The Murraylink route is situated along existing rights-of-way, and did not require any new rights-of-way, easements or resumptions involving private land holdings. Murraylink utilises the HVDC Light electricity transmission technology developed by the Swedish company ASEA Brown Boveri. This technology has been specifically designed to meet both high reliability and technical standards and has been used previously in Australia and Sweden.

Initially, MTC will be a registered as a market network service provider ("**MNSP**") in the National Electricity Market ("**NEM**"). The transmission services provided by Murraylink as a MNSP to the NEM are best compared to a simultaneous load-generator pair operating in two markets. MTC will be eligible to bid 'transport' capacity into the NEM, and will be entitled to spot market and ancillary service revenues from the NEM based on the services provided.

[5] Much of this the Introduction has been abstracted from the Information Memorandum supplied by DGJ Projects Pty Ltd.

However, MTC is applying to the ACCC to become a regulated transmission asset, a transmission network service provider **(TNSP)**, under clause 2.5.2(c) of the National Electricity Code.

> 2.5.2(c) *If an existing network service ceases to be classified as a market network service it may at the discretion of the Regulator or Jurisdictional Regulator (whichever is relevant) be determined to be a prescribed service or prescribed distribution service in which case the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with chapter 6 to include to an appropriate extent the relevant network elements which provided those network services.*

The purpose of this consultancy is to calculate the optimal cost of capital and other related financial indicators for Murraylink that will be accepted by the Australian Competition and Consumer Commission ("**ACCC**") for the purposes of determining a regulated revenue path for the Murraylink Transmission Corporation under Chapter 6 of the National Electricity Code.

The ACCC has recently issued a *Statement of Principles for the Regulation of Transmission Revenues: Information Guideline Requirements,* dated 5th June, 2002. In Appendix A to that Statement a set of "minimum mandatory statements required by [the] this guideline" is set out. The requirements for the "Rate of Return" (WACC) or weighted average cost of capital is attached as Appendix 2 to this report. This report will provide the relevant estimates for Murraylink to fulfill the WACC data requirements as outlined in the *Statement of Principles* of the ACCC. However, it should be noted that the *Statement of Principles* although requiring the estimation of a post tax nominal WACC, the *Statement* does not define which of the alternative post tax nominal WACC equations should be used.

The Principles for Estimating A WACC

The requirement under chapter 6 of the National Electricity Code is for the ACCC to set a new revenue cap with a minimum tenure of 5 years. It has been the approach of the ACCC's in recent decisions e.g. Snowy Mountains Hydro Electric Authority (7th February,2001) and Queensland Transmission Network (1st November 2001) to use a post-tax nominal WACC when setting the revenue cap.

At any point of time, the cost of capital is determined by the intersection of the demand and supply curves for capital. The difference between investments', projects' or companies' costs of capital reflect differences in their risk class. Higher risk requiring greater compensation and therefore a greater cost of capital, and conversely. Across time, adjusting for risk differences, the differences in rates reflect the "time rate of discount" or the "risk-free rate".

In a fully informed market, in equilibrium, it is the nature of the risk associated with the cash flows generated by the assets and not the assets per se nor the source of capital, which determines the cost of capital. The source of capital simply determines the ordering of claims on the cash flows and, in the event of liquidation, the claim on assets. Therefore, it is the assets (the Asset side of the Balance Sheet) or more accurately the cash flows generated by those assets which distinguishes the cost of capital between projects, investments or companies. The source of capital (the Financial Obligations side of the Balance Sheet) simply determines the "packaging" of the cash flows and associated risks amongst the providers of funds. The assets generate these cash flows and their associated risks.

This raises the question of why is the cost of capital typically estimated by way of a WACC that reflects the weighted average of the equity costs and debt costs of capital? The reason for this is that we can only access the costs of capital from the Financial Obligations side of the Balance Sheet. It is rare that a single source of capital is dedicated to and is the sole collateral of a specific asset or investment that would enable us to directly assess the required return for that asset or investment. Moreover, sources of finance are usually backed by a variety of assets (a "floating charge"), therefore, we must rely on an average, or more accurately a WACC. The WACC reflects the average cost of capital for the assets that support the various classes of capital and estimated as a weighted average (by value) of the types of capital.

The Weighted Average Cost of Capital (WACC)

The cost of various components of the firm's capital structure, in broad terms debt and equity, weighted by their proportion to the firm's total assets is the firm's weighted cost of capital.

The purpose in estimating a WACC is to estimate the cost of capital for the assets of the assets or entity over which the declared services are provided. The WACC is often the only way to obtain such an estimate. The capital structure is only relevant to the extent that we have to estimate the WACC via the "titles" (securities) to the assets. The relationship of the firm's cost of capital with its capital structure is such that it is assumed that the capital structure of the firm is optimal or does not affect the cost of capital. That is, we are assuming that the market-place expects that the firm will maintain the capital structure for which we are deriving the cost of capital and moreover, there is no alternative capital structure that is likely to make the firm more valuable.

Consistency in Estimating the WACC with the Net Cash Flows

It is important that the definition of the weighted average cost of capital (WACC) is consistent with the net cash flows that are allowed as a return to capital. The most obvious examples are where an after-tax definition of cash flows is to be used then an after-tax definition, as distinct from a before-tax definition, of the cost of capital should be used. However, obvious inconsistencies are not the most common source of error amongst practitioners; the more common errors are more subtle, insofar as there are a number of after-tax definitions of the WACC that could be used and therefore a variety of definitions of net cash flow. The most common error is to mix these definitions of the after-tax WACC with an inappropriate definition of the after-tax net cash flow.

There are a variety of WACC that could be used and the most commonly used formulae for the WACC and the appropriate definition of net cash flows, given the WACC, are defined in Appendix 1.

The Appropriate Definition of WACC

The definition of WACC that has been favoured by the ACCC in its recent regulatory decisions[6] is a particular definition of a post tax nominal WACC colloquially known as the "Vanilla WACC", it is defined as:

$$WACC = r_e.\frac{S}{V} + r_d.\frac{D}{V} \quad \cdots(1)$$

where:

r_e is (post-tax) return on equity;
r_d is the return on debt;
D/V is the debt to value ratio; and
S/V is the equity to value ratio.

The ACCC have also required the estimation of a WACC equation which they call the post tax nominal WACC.[7], which is defined as:

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[6] **"**In the draft *Regulatory Principles* the Commission outlines its view on the appropriate expression of the return on equity that is to be achieved, and how it is to be used for deriving the regulated revenues. This view is summarised in the proposed statement 6.3:

The Commission will apply the nominal post-tax return on equity as a benchmark. The revenues will be calculated on the basis of the cash-flows associated with the regulatory accounts necessary to deliver this return after taking into account liabilities and the assessed value of franking credits based on existing tax provisions and foreshadowed tax changes due to occur during the regulatory period.[1]

For this decision, the Commission has chosen to adopt the cash flow modelling approach as specified in the code and outlined in the draft *Regulatory Principles*. This approach extracts the parameters relating to business income tax from the WACC formula. In doing so, the Commission explicitly models the impact of tax and franking credits on the required post-tax distributions in the cash flows. The remaining WACC formula, which has been termed the vanilla WACC, is merely the weighted average of the gross post-tax returns on debt and equity." P. 8, of the ACCC decision in the Queensland Transmission Network Revenue Cap, 1st November,2001.

[7] The equation is also defined in Appendix 1 along with a number of other WACC equations

$$WACC = r_e . \frac{S}{V} . \frac{(1-T)}{(1-T(1-g))} + r_d . \frac{D}{V}(1-T) \quad . . . \text{(Equation 2)}$$

where:

r_e is (post-tax) return on equity;
r_d is the return on debt;
D/V is the debt to value ratio;
S/V is the equity to value ratio;
T is the effective company tax rate and
? is the value of franking credits as a proportion of their face value of $1.

The appropriate definition of cash flows to be discounted by this definition of WACC is:

$$X_0(1 - T)$$

where:

X_o are operating net cash flow before interest and taxes.

The above equation is sometimes referred to as the Officer Equation because I derived the equation to give a WACC that could be used to discount net cash flows that were equivalent to the standard text book definition of WACC under a Classical System of company tax. However, it is not the equation that I would recommend using as it has a number of deficiencies quite apart from the complex looking formula.

The equation I recommend using is the "Vanilla" WACC because of its simplicity (it is a plane vanilla equation). This equation (1) is less prone to error and confusion relative to other equations or formulae. For example, the absence of a tax parameter in the WACC - taxes are taken account of in the definition of cash flows - makes the effect of taxes less prone to error when this definition is used. Also, when finite life investments are to be valued the various equations for the WACC (see Appendix 1) can give different answers to the value of the capitalized net cash flows. This problem arises because of the problem of confounding tax rates and depreciation in the cost of capital. The above equation (equation 1) does not have this problem because taxes are separately estimated in the net cash flows. Also, the values are more readily identified with observations of capital market rates and therefore easier to comprehend.

In summary, the reason for arguing that the "Vanilla" WACC is the most appropriate is that all the adjustments for taxes, imputation credits and the like occur in the net cash flows. This has the advantage of being able to clearly identify when these taxes are paid (also, it clearly recognises the difference between economic depreciation and tax depreciation). In addition, this simple WACC or "Vanilla WACC" is much easier for lay people to understand because it bears a closer resemblance to observable market rates.

The definition of net cash flow that is applicable to the "Vanilla" WACC is the cash or cash equivalent that is available to "service" the equity and debt after company tax but before personal taxes. It is simply the interest on debt finance and the earnings that are attributable to equity after company tax but before personal tax, because imputation tax credits are a withholding of personal taxes at the company level they are added back. In the context of the equations defined in Appendix 1, the appropriate definition of the net cash flows is:

$$x_o - x_g^{'} = x_o - T(x_o - x_d) + gT(x_o - x_d)$$

where:

x_o = economic operating profit ($\equiv$ earnings before interest and taxes);

x'_g = the government's share of the net cash flows or the tax collected from the company by way of "company tax" i.e. the company tax liabilities arising from the net cash flows;

$T(x_o-x_d)$ = company tax with interest (x_d) as a tax deduction;

$\gamma.T(x_o-x_d)$ = the value of franking credits added back because these are really a withholding of personal taxes at the company level.

This definition of net cash flows is also closer to what most would consider net of tax cash to providers of capital (relative to the implied definitions of net cash flow of other WACC equations) insofar as it includes the effect of the tax shield afforded by debt.

Capital Structure.

Restating some of the principles that have been outlined above:

- It is the nature of the risks associated with the net cash flows that determine the capital structure and therefore the assets which generate those cash flows reflect the cost of capital associated with the company or the enterprise.
- It is the WACC that reflects the cost of capital associated with the assets but the estimates of that WACC are provided by the required return to debt and equity.
- Further, the return required to service debt and equity is not only a function of the nature of the risk associated with the cash flows but also the relative gearing or capital structure associated with the funding (debt and or equity) which will affect where the cash flows are directed between debt and equity.

An implied assumption in the estimation of any WACC is that the capital structure from which the WACC is estimated is optimal or, equivalently, the Modigliani and Miller Proposition (I) holds.[8] The Proposition (I) says, in effect, that because the assets generate the cash flows and they in turn when capitalized reflect the value of the enterprise then the source of capital does not affect the value but simply how that value is distributed amongst the various providers of capital. However, this does not mean that the gearing or capital structure does not affect the required return by providers of equity capital or debt capital.

It was Modigliani and Miller's second proposition (Proposition II) which illustrates the effect of alternative gearing or capital structures on the relative cost of debt and equity. The proposition, expressed simply, states that as the gearing or the proportion of debt in the capital structure increases so will the required return to equity and debt holders because both classes of capital are subject to greater risk as the proportion of debt increases. The proposition is not inconsistent with the first proposition, that the capital structure does not affect the cost of capital or value of the enterprise. Both the cost of debt and equity can increase with increasing gearing and yet the weighted average cost of capital (WACC) does not change. Mathematically this occurs because the increasing

[8] The proposition is clearly illustrated in any basic text of Corporate Finance e.g.Brealey, Myers, Partington and Robinson. Principles of Corporate Finance, 1st Australian Edition, McGraw Hill, 1999, p.497.

proportion of capital is being weighted by the cost of debt and the decreasing proportion of the cost of equity such that the weighted average of the two, even though the cost of debt and equity are increasing, remain constant.

The Modigliani and Miller propositions are explicitly or implicitly employed when the cost of capital for an enterprise is being estimated making use of estimates of the cost of capital from similar enterprises or activities. For example, the costs of equity capital are typically derived from estimates of listed companies equity costs where these companies are involved in similar activities or at least have similar risks associated with their net cash flows as the enterprise for which the cost of capital is to be determined. The various companies from which estimates will be obtained for the cost of equity will have, typically, different gearing even though they may be all involved in similar activities. The different gearing or capital structure will mean that the costs of equity will vary even though the underlying cost of capital of the enterprises or the WACC of the enterprises are comparable.

To adjust for the differential effects of gearing on estimates of equity capital, the WACC of the various enterprises must be "de-geared" i.e. equity cost of capital of the enterprise is estimated assuming no debt or gearing which implies that the cost of equity will be equivalent to the WACC. Such a practice of estimating the WACC from de-geared costs of equity invokes the Modigliani and Miller propositions. For example, the weighted average of the cost of capital is equal to a de-geared equity cost of capital; in the case of the "Vanilla" WACC this implies that the de-geared equity is equal to the WACC i.e.

$$r_{WACC} = r_e.\frac{S}{V} + r_d.\frac{D}{V} \quad \cdots(1)$$

In some cases, typically because the before tax cost of capital is to be estimated, the WACC is used to estimate a relevant "geared" equity for the enterprise. Once again, such an estimate embraces the Modigliani and Miller propositions and where the

"Vanilla" WACC is implied, the relevant equation for estimating a "geared" equity for the enterprise shown below[9]:

$$r_e = r_{WACC} + \frac{D}{S}(r_{WACC} - r_d) \quad \ldots(3)$$

A WACC for Murraylink

Murraylink or the operating company MTC is not listed, it is a company owned equally by Murraylink HQI Australia Pty Limited and SNC-Lavalin Investment Australia Pty Ltd., whose ultimate owners are overseas corporations with many businesses. The means by which the partners have financed the assets of Murraylink are largely irrelevant to the assessment of the risk of the Murraylink investments; moreover the costs of the sources of finance would be "hopelessly" confounded with the assets of the parent companies and of no value in trying to assess the risk class of Murraylink. The consequence is that the estimate of the cost of capital for Murraylink will have to be derived by examing the risk class of companies managing comparable assets. Similarly, the other parameters to the WACC such as gearing and the debt premium will also have to be derived from companies managing comparable assets.

Ultimately, it is risk that differentiates required returns or costs of capital at any point in time. The most popular model or approach for estimating the risk of securities or assets which have no contractual required rate of return or where it is not possible to obtain direct market measures of the cost of capital is the capital asset pricing model (CAPM). Once an estimate of the risk appropriate for the CAPM is assessed the rest of the procedure to obtain an estimate of the cost of capital is fairly straight forward.

[9] In a number of decisions the ACCC quote that they use the "Monkhouse formula" for the degearing for example see the Snowy Mountains Hydro-Electric Authority decision, page 17. In the Queensland Transmission Network decision the ACCC say they used this formula in the context of "deriving a value for the effective tax rate" p.27 and footnote 10. I do not follow the logic in this latter quotation, nonetheless, the formula is the wrong formula for the approach adopted by the ACCC. It is easily proved that equation 2 above is the correct formula. The consequence of the ACCC's use of the "Monkhouse formula" in their decisions is unclear, in fact it is not clear that they used the formula since their results indicate that if they relied on it, it was not directly used to calculate the WACC.

The risk of the CAPM is known as non-diversifiable risk, there is also diversifiable risk. Both risks will have an impact on the value of an entity or more specifically on the asset values of the entity. These two types of risk and how they affect values are often a source of confusion and error in valuations and in exercises involving establishing assets' cost of capital. The next section describes the differences between the two types of risk and how they affect values. The distinction between the two types of risk is important for this report which is essentially only concerned with non-diversifiable risk used in the context of CAPM.

Risk *(Comprising Non-Diversifiable (ß) and Diversifiable (non- ß) Risk)*

1. Non-diversifiable Risk

This risk is also known as:

- Systematic risk
- Market risk
- Covariance risk
- Beta risk

Because the risk ß is non-diversifiable it commands a risk premium, known as the market risk premium (MRP), which is defined as [$E(R_m) – R_f$]. The MRP is the premium a market portfolio of assets or securities (R_m) is expected to earn above the risk-free rate (R_f).

The effect of non-diversifiable risk is captured through such models as the Capital Asset Pricing Model (CAPM):

$$R_j = R_f + b_j[R_f - R_m]$$

$$R_j = R_f + b_j.MRP \qquad \ldots (4)$$

Where,

R_j is the expected return on asset (security) j or its required return or cost of capital.

R_f is the risk-free rate of return.

ßj is the non-diversifiable risk associated with asset j and because of the market risk premium (MRP = the difference between the market's return R_m and the R_f) this ßj component of risk increases the discount rate or cost of capital in an NPV analysis.

The CAPM is the standard approach to estimate the required return (cost of capital) of equity (R_e) where unlike debt there is no contractual rate set for the return. However, this does not mean that the concept and the measure of a ß is restricted to equity, we use it in the context of debt and the assets (the sum of debt and equity) in the current paper. Risk is taken into account in the ß in the above CAPM and this risk is known as non-diversifiable risk for which the capital market pays a market risk premium (MRP).

In the case of debt, we typically use the yield on debt to estimate the cost of debt (R_d). Such a yield includes both non-diversifiable risk and diversifiable risk. The latter is usually included when estimating a company's WACC or asset cost of capital, although logically the diversifiable risk should not be included but for major companies it is so low the bias is judged to be not consequential.

In the current matter we will be using the CAPM to obtain an estimate of the Murraylink assets' cost of capital, i.e. the $ß_a$ of the assets will be critical to the assessment of the cost of capital. Once the $ß_a$ is estimated and the $ß_d$ derived from the debt margin the implied $ß_e$ can be calculated. In contrast, for many of the comparable companies a WACC will be estimated from both equity and debt issued by the companies and from such estimates an implied $ß_a$ of the assets can be derived.

One of the benefits in using the CAPM and the associated ß's is the property of additivity. For example, when the "Vanilla" WACC equation is used the ß's can be expressed in the same form i.e.

$$r_{WACC} = r_e.\frac{S}{V} + r_d.\frac{D}{V} \quad \cdots (1) \qquad \text{"Vanilla " WACC}$$

$$b_a = b_e.\frac{S}{V} + b_d.\frac{D}{V} \quad \ldots(5)$$

In effect, knowledge of any two of the three ß's enables calculation of the third using the above equation (5).

2. Diversifiable Risk

The diversifiable risk is typically taken into account in the expected net cash flows that are to be discounted. Diversifiable risk is also known as:

- Non-systematic risk
- Non-market risk
- Non ß risk
- Idiosyncratic risk
- Residual risk
- Insurable risk

Diversifiable risk can be diversified away because it is uncorrelated with other risks or variations in net cash flows and as such it does not command a premium in the sense that non-diversifiable risk commands a premium. However, this does not mean that it has no effect on values or that it can be ignored in a discounted cash flow analysis.

As one of the names for it suggests, the cost of diversifiable risk is akin to an insurance premium, to the extent that insurance represents those events which can be diversified.

The "charge" against cash flows should be the actuarial estimate of the event, i.e. the product of the probability of the event occurring times the effect on net cash flows of the event. Therefore, the standard (textbook) approach to handling risk in a valuation (NPV) problem is to account for non-diversifiable risk in the discount rate and diversifiable risk in the net cash flows.

An Example

Suppose we have a three period investment whose net cash flows are at the left of the column and the expected value is on the right of each column:

Table 1

Probability	Period 1		Period 2		Period 3	
	Outcome	Expected	Outcome	Expected	Outcome	Expected

Event 1	0.3	$10m	$3m	$15m	$4.5m	$20m	$6m
Event 2	0.5	$40m	$20m	$50m	$25m	$50m	$25m
Event 3	0.2	$60m	$12m	$65m	$13m	$60m	$12m
			E($35m)		**E($42.5m)**		**E($43m)**

The expected or actuarial flows for each period are respectively $35m, $42.5m and $43m. The "**normal**" cash flows are $40m, $50m and $50m.

(i) Applying a WACC of 10% to the expected net cash flows gives a value of :

$$NPV = \frac{35}{1.1} + \frac{42.5}{(1.1)^2} + \frac{43}{(1.1)^3}$$
$$= 99.25$$

This is the textbook or regulatory approach for handling risk.

The "business approach" is often different. Practitioners often take expected net cash flows to mean "normal" cash flows which is what they expect and not the actuarial expectation. The result is they adjust the discount rate for diversifiable risk as well as non-diversifiable risk.

Consider our previous example, "normal" cash flows per period are:

40, 50, 50

which when discounted by a 18.6% instead of 10% we get the same value for the project, i.e.

$$99.25 = \frac{40}{1.186} + \frac{50}{(1.186)^2} + \frac{50}{(1.186)^3}$$

The 18.6% includes an adjustment for both the non-diversifiable and the diversifiable risk.

The problem with the "business approach" is how to get a measure for the diversifiable risk contribution to the discount rate. Unless there are a number of sales in the asset class, there is no corroborating evidence for the discount rate. In these circumstances (of unique asset classes), adjusting the discount rate for diversifiable risk is usually ad hoc.[10] The alternative is to first solve for the value using the "textbook" approach and then plug in the "normal" net cash flows and solve for the internal rate of return to get an appropriate discount rate that incorporates both diversifiable and non-diversifiable risk.

The approach used in this report will be that which is adopted by the regulators, it is assumed that the WACC only reflects β or non-diversifiable risk. It is assumed that account will be taken of diversifiable risk in the estimates of net cash flows.

Betas for Comparable Assets (Companies)

It is the nature of the cash flows generated by the assets that determine the risk class of a company and therefore the activities of the company. "When Murraylink becomes a regulated interconnector, the level of power flow across it will be determined by NEMMCO as an outcome of its merit-order dispatch and system operation processes. That is, it will be used as part of the normal grid." (Communication with DGJ Projects Pty Ltd, 19-7-02). In short, Murraylink should be assessed as a TNSP.

1. Domestic Companies

It is not only measurement errors that may cause problems with estimation of appropriate betas. The assumptions explicitly or implicitly employed, using the CAPM, in relation to gearing and the beta of debt to estimate the cost of capital can also have a significant effect on the outcome.

Beta estimates are usually restricted to traded securities in deep and well informed capital markets. The trade in securities amongst the world capital markets is dominated by

[10] Where there are many comparable assets being sold e.g. apartments, the "practioner's" approach is better than the "textbook" approach because it will implicitly encompass risks that the CAPM does not take account of.

equities issued by companies and debt issued by governments, with some limited amount of corporate debt. This means that the beta estimates have to be derived from the equities of the companies that are operating in the same industry class or reflect the same asset composition of the company whose beta has to be estimated.

One of the variables causing differences in beta estimates for companies in the same industry class with the same assets is the differential gearing or average between companies. The greater the level of gearing, the greater the risk of both debt and equity, however over reasonable ranges, the risk of the total assets does not change. This is because the change in the weighting of capital from equity to debt maintains a constant risk level for the assets as a whole even though the beta measures of both debt and equity will increase.[11]

The ß of Debt

An approach to estimate a general debt risk margin appropriate for corporations who issue or might be expected to issue 'A' rated debt is to use data from the Reserve Bank of Australia's Monthly Bulletin. For example, Table S49 of the August 2002 issue of the Bulletin indicates a "risk premium" of 85 basis points (bp) for July 2002 of A-rated corporate debt[12] relative to Commonwealth securities of the same maturity (two to four years). This "risk premium" when added to a "maturity premium" of about 50 bp, the difference between three year and ten year Commonwealth securities (Table S48), implies a corporate debt margin of 135 bp over the "risk-free rate (the 10 year government bond rate). In contrast, the figures for the end of December, 2001 are respectively, 76 and 91 bp, implying a debt margin of 167 bp. The margin has been narrowing because the yield curve has become "flatter".

A more up-to-date and complete series on corporate bond yields is provided by the CBA Spectrum Service. The service gives an estimate of the spreads for the various corporate bond ratings over the full term structure out to 10 years. The current spread for 'A' rated

[11] This was discussed above in the context of the Modigliani and Miller Propositions.
[12] It is my assessment that companies of the type of Murraylink (TNSP's) with the typical gearing of 60% debt could issue debt at an 'A' rating.

debt is 142 bp and for 'BBB+' debt which ElectraNet indicated was their rating it is 160 bp. Appendix 4 shows the CBA Spectrum Series. The rating for the a company such as Murraylink with 60% debt in its capital structure could be expected to be rated between 'A' and 'BBB+' and in these circumstances a reasonable debt margin would be 150 bp.

Adopting the debt margin implied by the most recent figures of 150 basis points implies[13] a beta of about 0.25. I am rounding this estimate of the corporate debt beta to 0.2 because any further decimal points gives a spurious impression of accuracy. Further, although a debt beta of 0.2 implies a debt margin of 120 basis points not all the debt margin is going to reflect non-diversifiable risk, some of the margin will reflect diversifiable risk. In the recent (11th September,2002) Draft Decision of the ACCC in the South Australian Transmission Network Revenue Cap ("The ElectraNet draft Decision"), the ACCC used a debt margin of 130 basis points whereas ElectraNet argued for 172 bp. Both these numbers could be consistent with a debt beta of 0.2, the difference between the margin implied by the beta of 120bp and a higher number could be explained by diversifiable risk.

Asset ß's

Table 2 below presents estimates of equity and asset betas for various companies provided in the recent decision of the Queensland Competition Authority on Regulation of Electricity Distribution, May 2001. The asset beta of the companies listed averages around 0.62 for the reported asset betas and 0.68 if the debt beta in the WACC is assumed to be 0.20.

Table 2
Beta estimates from Queensland Electricity Distribution Price Review

Firm	Primary Business	Equity Beta	Leverage	Asset Beta*	Asset Beta**

[13] The estimate of ß is made through "reverse engineering" the CAPM, i.e.
$R_j = R_f + b_j . MRP$ so that $b_j = (R_j - R_f) / MRP$.

			(%)		
United Energy Ltd	Electricity distribution	0.84	53	0.42	0.48
Pacific Energy Limited Pacific Hydro Limited	Electricity generation Electricity generation	2.03 1.00	29 45	1.42 0.66	1.56 0.64
Energy Developments Ltd	Electricity generation	1.17	25	0.92	0.94
Allgas Energy Limited	Gas distribution and retailing	0.50	17	0.47	0.43
Australian Gas Light Ltd	Gas distribution and retailing	0.62	30	0.44	0.47
Envestra Ltd	Gas distribution and retailing	0.48	80	0.00	0.17
Simple Averages		**0.95**	**40**	**0.62**	**0.67**

* Asset beta as reported.
** Asset beta calculated with a debt beta of 0.20.
Source: Queensland Competition Authority, May 2001

Table 3 below sets out the estimates cited by the Victorian Office of the Regulator-General (ORG) in its decision for Electricity Distribution. The results give a consistently lower WACC than the QCA estimates which may simply reflect the time at which the estimates were made and indicate the variability of betas over time. It is worth noting that the ORG used a debt beta of 0.2 for its estimates of the appropriate WACC.

Table 3
Beta estimates from Victorian Electricity Distribution Price Review

Firm	Primary Business	Equity Beta	Leverage (%)	Asset Beta*
United Energy Ltd	Electricity distribution	0.46	54	0.32
AGL	Gas distribution and retailing	0.57	25	0.48
Envestra	Gas distribution and retailing	0.50	78	0.27

* Asset beta as reported
Source: Office of Regulator General, Victoria, September 2000

The ß estimates in Table 4 are based on the Australian Graduate School of Management's latest (March 2002) Risk Measurement Service estimates and the values for debt and equity are taken from the latest annual reports of the companies. The results indicate an asset beta for the group of around 0.6 for a debt beta assumption of 0.2. The presence of

AGL and United Energy significantly reduced the size of the estimates as weighted (by value) averages of the asset ß's.

Table 4

Australian Electricity & Energy Companies

Australian Electricity & Energy Companies

Company	Beta Assets	Beta Equity	Beta Debt
Australian Gas & Light (AGL)	0.362	0.47	0.20
Energy Developments	0.538	0.74	0.20
Energy World	0.970	2.49	0.20
Pacific Energy	0.235	1.67	0.20
Pacific Hydro	1.916	2.16	0.20
United Energy	0.294	0.39	0.20
Envestra	0.301	0.65	0.20
Origin Energy	0.910	1.16	0.20
Horizon Energy	0.216	0.36	0.20
Simple Averages	0.638	1.121	0.200
Weighted Averages	0.627	0.999	0.200
Weighted Averages without AGL	0.929	1.883	
Weighted Averages without Origin	0.902	1.656	

Company	Equity $m (E)	Debt $m (D)	Total Assets $m (V)	Leverage (D/V)
Australian Gas & Light (AGL)	$4,041.90	$2,682.10	$6,724.00	40%
Energy Developments	$378.39	$ 226.01	$604.40	37%
Energy World	$47.20	$ 93.68	$141.10	66%
Pacific Energy	$0.38	$ 15.74	$16.12	98%
Pacific Hydro	$430.67	$ 61.14	$491.81	12%
United Energy	$963.86	$ 989.65	$1,953.51	51%
Envestra	$599.47	$2,074.39	$2,673.86	78%
Origin Energy	$2,111.77	$ 743.08	$2,854.85	26%
Horizon Energy	$36.85	$ 329.80	$366.65	90%
Simple Averages	$956.746	$801.732	$1758.478	0.553
Weighted Average				0.456

Source: Equity ß's AGSM, company accounts for asset and funding values.

Table 5

Recent Regulatory decisions on Betas for Electricity and Gas

Matter	**Industry**	**Equity Beta**	**Leverage (%)**	**Asset Beta***	**Asset Beta****
ORG, Price Determination	Electricity Distribution	1.00	60	0.40	0.52
ACCC, Snowy Mountains	Electricity Transmission	1.00	60	0.40	0.52

ACCC, NSW & ACT	Electricity Transmission	0.78-1.25	60	0.35-0.50	0.43-0.62
IPART, Elect. DB's	Electricity Distribution			0.35-0.50	0.43-0.62
QCA, Price Determination	Electricity Distribution	0.71	60	0.45	0.40
ACCC, Powerlink	Electricity Distribution	1.00	60	0.4	0.52
ACCC, EAPL	Gas Pipeline	1.16	60	0.5	0.58
ACCC, AGL	Gas Pipeline	1.50	60	0.6	0.72

*Asset beta as reported

** Asset beta calculated with a debt beta of 0.20

Table 5 summarises recent regulatory decisions in the electricity and gas transmission and distribution. The results are consistent with those already discussed and the β estimates are no more definitive. The asset betas are between 0.4 and 0.6 for the decisions but up to 0.72 in the case of the ACCC's decision with respect to the AGL pipeline if a debt beta of 0.20 is used. Overall, an estimate of 0.5 to 0.6 appears to be most realistic when taking into account the ß of debt implied by the debt margin and estimating the asset ß using this estimate of debt (see equation 5 above). The omission of a debt ß or the implication that it is zero in the regulatory decisions is flawed, in my opinion, and inconsistent with the use of a debt margin. The assumption of a debt ß of zero by the regulators causes a downward bias' in their estimates.

It is difficult to find any conclusive evidence for a specific asset beta for electricity distribution. The regulators have opted for a number between 0.4 and 0.6 with most around 0.4. Empirical evidence from the industry (see Table 4) and recognizing risky debt (a positive implied ß of debt) would suggest an asset beta of around 0.6. On the basis of this Australian data it is my opinion that such an estimate ($ß_{Asset}$ = 0.60) is the most realistic for Murraylink. However, there are examples of overseas ß estimates being used to derive an Australian estimate and an examination of these estimates should be made before reaching a conclusion.

2. Overseas Companies

Australia has relatively few privatized electricity and gas companies. Moreover, nearly all of them have only been privatized in recent years. This means that there is a paucity of data on the risk characteristics of the companies and the industries. In such circumstances it would seem obvious to examine the risk characteristics of comparable companies and industries in countries that have been around for a much longer time, to supplement the limited observations on the Australian companies. However, such an approach is hazardous because of different economic and regularity conditions in foreign countries. Nonetheless, providing caution is exercised in interpreting the relevance of the offshore results for Australia, some information can be usefully gleaned from such an examination.

The CAPM is the most popular procedure for estimating the required returns for assets or securities (equity) where there is no contractual right for a particular amount of return to the capital providers. The risk that is accounted for in the CAPM is non-diversifiable or beta-risk; it was described in the previous section. A domestic beta, i.e. the covariance risk of an asset or a company with its domestic share market, reflects the relative risk of that asset relative to the domestic market. A beta for an electricity company in the US or UK measures the risk of that company relative to those markets. Further, although such a beta may be indicative of the type of relative risk experienced by an Australian electricity company, certain conditions must apply before one can derive an Australian electricity beta from a US or UK beta.

As long as the component of the return on the Australian market that is uncorrelated with the return on the US market is also uncorrelated with the return on stock i,[14] then it follows that:

$$\beta_{i,Aus} = \beta_{US,Aus} \times \beta_{i,US}. \quad \dots \quad (3)$$

where:

> $\beta_{i,Aus}$ is the domestic beta of an Australian company;
>
> $\beta_{US,Aus}$ is the beta of the US index regressed against an Australian index;
>
> $\beta_{i,US}$ is the domestic beta of the US company.

[14] In effect, this component of a stock's return is idiosyncratic to the company, it does not relate to returns of either market.

On the basis of data from Datastream (a financial data service which is division of Thomson Publishing) the average beta ($\beta_{i,US}$) for US electricity companies is about 0.35. In addition, it is estimated that the beta $\beta_{US,Aus}$ over recent years is about 0.5. This implies an Australian $\beta_{i,Aus}$ of 0.18 – a very low number. A comparable analysis (also based on Datastream) for using UK electricity companies gave a $\beta_{i,UK}$ for UK electricity companies is also about 0.4, a $\beta_{UK,Aus}$ of 0.70, which using the relationship defined above implies a $\beta_{i,Aus}$ of about 0.28 which is also a very low number.

The problem is that the assumption underlying the relationship between domestic and offshore betas implies that the respective capital markets are fully integrated, such that any idiosyncrasies of the Australian market reduce the β-risk for an offshore investor and accordingly make investment in an Australian electricity company look attractive. Also, measurement errors can make the domestic market look attractive from a β-risk perspective. In the circumstances, I believe it is unwise to simply adopt the implied β-risks for Australian from offshore companies at face value. Nonetheless, an examination of the consistency or otherwise of the β-risks amongst the different type of energy companies can be instructive. It is for this reason the table below setting out the β-risks for offshore companies is shown.

Table 6

Estimates of Overseas Betas

Industry Name	*Source*	*Number of Firms*	*Average Equity Beta*	*Market D/E Ratio (%)*	*Asset Beta*
US					
Electric Util. (Central)	DNYU	28	0.53	118.35	0.29
Electric Utility (East)	DNYU	34	0.55	83.4	0.35
Electric Utility (West)	DNYU	17	0.56	150.22	0.27
Electricity Integrated	QCA	53	0.45 (0.26-0.9)	NA	0.32 (0.22-0.78)
Electricity Distributors	Datastream	12	0.27	NA	NA
Natural Gas (Distrib.)	DNYU	33	0.59	82.35	0.38
Natural Gas(Diversified	DNYU	37	0.72	45.95	0.54
Gas Distribution	Datastream	16	0.33	NA	NA
UK					

Electricity	QCA	4	0.68 (0.48-1.00)	NA	0.52 (0.41-0.72)
Electricity	ORG Bloomberg	5	0.32 (0.18-0.47)	32	0.29 (0.17-0.40)
Electricity	ORG Lond. Bus.S.	5	0.59 (0.51-0.65)	32	0.47 (0.34-0.56)
Electricity	Datastream	6	0.24	NA	NA
NZ					
Electricity	Datastream	4	0.54	NA	NA
Gas	Datastream	1	1.00	NA	NA

(DNYU=http://www.stern.nyu.edu/~adamodar/New_Home_Page/datafile/Betas.html)

An examination of the β-risks in the table indicate they are all relatively low, significantly lower than the β of the average investment, whose β=1.0. The asset betas have been calculated with the assumption of a debt beta of zero and often using a more conventional after tax WACC and not the "Vanilla" WACC assumption. The net effect is to downward bias the estimate of the asset or WACC beta.

An independent check of 24 US electricity companies and 5 UK electricity companies, using the “Vanilla” WACC equation and a debt beta of 0.2 confirm the relatively low asset betas of the overseas companies in the data above in Table 6.

Overall, I do not think much weight can be put on estimates of an appropriate ß for the assets of a TNSP based on the overseas data. There are too many differences between the operating environment and the adjustment for some of these differences is too “blunt” an instrument to correct for the problem. Therefore, I conclude that the best estimate for an Australian TNSP is an asset beta of 0.6.

Parameter Values for the CAPM – Assessing Murraylink’s Cost of Capital

It has already been pointed out that because Murraylink is not listed, it is ultimately owned by two large overseas companies and therefore its financing and capital structure are of little use in establishing the cost of capital of its activities (delivered by the assets).

The best approach to a cost of capital in these circumstances is to estimate it for the asset class that Murraylink belongs to using the CAPM.

Beta (ß)

The Australian evidence and discussion above established that the "best" estimate of an appropriate ß for Murraylink (a TNSP) was a ß = 0.6. The difficulties in clearly defining a ß reflects the general difficulties one normally encounters in estimating this critical parameter. Arguments could be advanced for increasing or decreasing the size of this ß but on balance I believe ß = 0.6 is a defensible and appropriate estimate of the ß for the assets of Murraylink.

The Risk-free Rate (R_f)

There has been some debate about what is the appropriate risk free rate to use in the CAPM. The debate has not concerned the source of the surrogate "risk free" rate which is a Commonwealth Government Issued security. The debate, to the extent that it exists, concerns the duration or term of such a security together with the sampling method used for determining an estimate.

The CAPM is a single period model of no fixed duration and various governments securities from government bills to long term government bonds have been used as a surrogate rate. In the context of CAPM theory there is no reason to pick one duration over another. However, ideally the duration of the CAPM should be the duration of the planning period for which the CAPM is to be used to estimate an expected or required return. This means that if the planning horizon is a long term investment then a long term government bond is the appropriate duration to use.

Further, it has been conventional in Australia to use 10 year Commonwealth Bond Yields as the proxy of the risk free rate as it is a highly liquid security which provides a good reflection of the expected yield on a long term government security. The data bases that have been assembled typically use such a bond as the surrogate risk free rate and, therefore, measures of market risk premium and the like are more readily available where a 10 year commonwealth bond rate has been used. To the extent that a shorter rate has been used in electricity regulation (refer to Table 10), it has only been by ACCC, to my knowledge, in relation to Snowy Mountains and more recently Powerlink. In these two decisions a 5 year rate was used on the grounds that this was consistent with the period of the regulatory decision.

However, even in these circumstances, if the planning period of the company is longer than the periods between regulatory decisions, it is a mistake to use the 5 year rate as distinct from a longer term rate such as the 10 year rate. The longer term will better reflect the investment horizon of the company which is the relevant term and not that of the regulators. A moving 10 year rate should be used if regulatory periods are considerably shorter than the 10 year period. In short, there is no sound justification for the use of a five year rate.

The argument for a term consistent with the regulatory period would be correct if the entity, at the time they purchased the assets, were guaranteed that they would get compensation for the required return based on a five year benchmarked fixed interest security and at the end of the five years, if they choose to walk away from the asset, they would be fully compensated. In these circumstances, from the perspective of the owner of the asset, it is a five year asset even though its economic life might be greater.

Electricity companies are not in this position. When a company commits funds to purchase an asset, it is typically long-term, for infrastructure assets probably considerably longer than the term of the ten year Government Bond that is used for a surrogate risk-free rate that I and others advocate as an appropriate benchmark. When it makes the purchase, it has to consider making the purchase of that asset or the opportunity cost of investing in other assets of comparable risk and duration, or where the risk and duration has adequate compensation for the alternative investments. Even though it knows that the allowed rate of return on the asset will be reset at regular periods, it does not have the luxury of having those rates prescribed to it at the time of the purchase of the asset. Nor does it have the luxury of knowing that it can walk away from the asset if it finds such compensation unsatisfactory. The risk to the infrastructure owner is the risk faced by the purchaser of a long-term asset. The nature of the risk may be affected by the regulatory regime but nonetheless it is still committed to the asset unless it is offered full compensation should they choose to walk away or sell the asset. For these purposes a full compensation implies at least the replacement cost of the asset or its optimal deprival value under the same set of conditions i.e., the same regulatory regime that was expected at the time the asset was purchased.

Therefore, the 10 year rate of return on a Commonwealth Bond has been chosen as the appropriate risk-free rate of return which is currently (31-09-02) 5.4%.

Table 7

Risk-free rate parameters adopted in regulatory decisions

Entity/Author	Industry	Benchmark bond	Estimation factor
QCA (2001)	Electricity distribution	10 year Commonwealth	20-day average
ORG (2000a)	Electricity distribution	10-year inflation indexed Commonwealth	20-day average
ACCC (1999a)	Electricity transmission	5-year Commonwealth	40-day average
ACCC (2000a)	Electricity transmission	10-year Commonwealth	40-day average
IPART (1999c)	Electricity distribution	10-year Commonwealth	20-day average
IPART (1999d)	Electricity distribution	10-year Commonwealth	20-day average
OTTER (1999) OFGEM (1999)	Electricity distribution Electricity distribution	10-year Commonwealth (UK) A range, with particular weight on the 10-year Gilt	12-month average A range, on the 10 year Gilt
ACCC/ORG (1998)	Gas transmission	10-year Commonwealth	12-month range
ORG (1998b)	Gas distribution	10-year Commonwealth	2-month average
IPART (1999b)	Gas distribution	10-year Commonwealth	20-day average

Source: Queensland Competition Authority, Electricity Distribution Decision, May 2001, page 78

Another issue, that has been contentious, is at what point (date) should the redemption yield on a government security (the 10 year Commonwealth Bond) be used. Typically regulators have used an average rate running from 12 months down to 20 days. The argument is that these averages remove potential "spikes" which may be reflected in the rates due to some short term uncertainty. The justification for using an average of rates is that it will reduce the volatility in the estimate. However, offsetting this reduction in volatility is the less emphasis is placed on contemporary information contained in the current rate. If the only information available is historical rates, then the changes in redemption yields behave as a random walk, which implies that the best forecast of future rates is the last observed rate. By taking an average of the last 20 days or longer simply lessens the information content in the last rate about expected future rates.

Therefore, it is recommended that the "latest" available rate on a 10 year Commonwealth Government bond be used as the surrogate for the risk-free rate when the required or expected return is estimated using the CAPM or a short period average such as five days might be used to reduce the volatility of the estimate.

The Market Risk Premium (MRP)

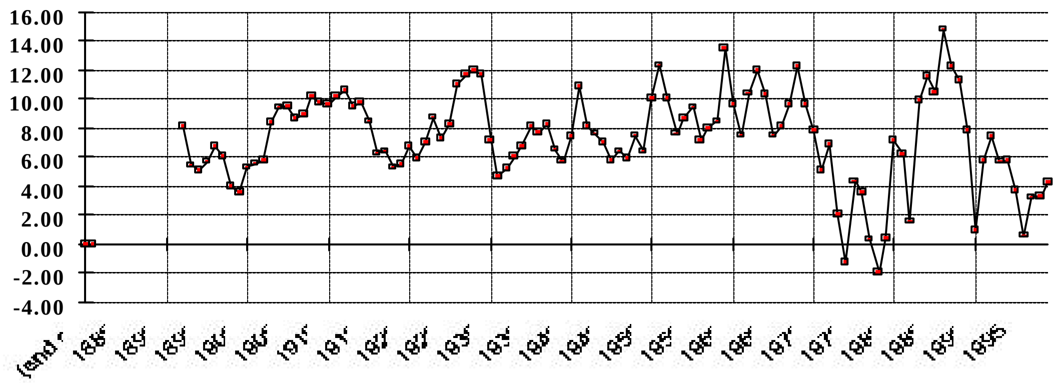
The market risk premium (MRP) arises out of the capital asset pricing model (CAPM). The MRP is the stock market's price of risk relative to a risk-free rate of return such as the yield on 10-year Government bonds. The MRP is a real measure of risk as distinct from a nominal measure, i.e. although both R_f and R_m are nominal numbers (they include expected inflation) but because one is subtracted from the other, the resulting MRP is a real number, the effect of inflation is omitted but in the context of the CAPM it is incorporated in the intercept term R_f.

The rationale for using historical data as a measure of the ex-ante MRP is that investors' expectations will be framed on the basis of their past experience. Historically, the MRP tends to be mean reverting although there have been long periods e.g. 10-years, when the returns from equities have been below the yield of 10-year bonds which is clearly not expected. Therefore, some care is needed in interpreting historical data to reach a conclusion about a current MRP. The MRP should be an expected number, reflecting what investors expect to get or require as a premium from an investment in the "average equity" relative to the "risk-free" rate (the 10 year bond rate).

A figure of 6% is commonly used in Australia and the US by regulators and academics, although some market participants use more recent data and subjective measures to justify using a lower MRP figure. When calculating ex-post MRP figures as a basis for determining the ex-ante MRP, the use of arithmetic average stock returns is favoured over the geometric measure because arithmetic average returns are probably a closer proxy for what are expected by investors or how expectations are framed by investors. The Australian historical MRP data has been reasonably consistent with that of the US, UK and New Zealand.

The graphs below demonstrate a justification for a MRP of 6%. The ten year moving average has a mean of about 6% although in any ten year period the average could be well below or above this average but this does not mean expectatio ns will be framed on any one ten year period.

Figure 2
Ten year MRP



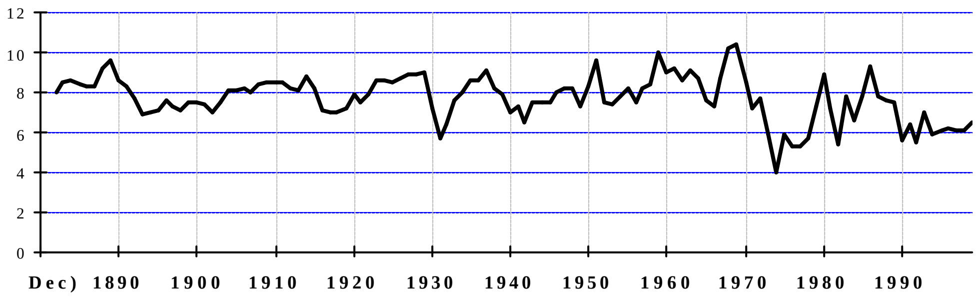
Source: The author

The Exponential Moving Series is also trending towards 6%, such a series places greater weight on more recent observations, the equation is defined as:

$$SMRP(t) = \alpha . MRP(t) + (1-\alpha) . SMRP(t-1)$$

Figure 3

Simple exponential smoothing of the MRP, alpha=0.5



Source: The author

A Jardine Fleming Capital Partners survey of professional market participants' MRP expectations found that on average these participants thought the historic MRP for Australia was 5.87%. Their expectation for the future MRP is about 1% below this figure. However, there was a high co-efficient of variation in these expectations reflecting a significant amount of uncertainty. Also, a survey of brokers' forecasts of stocks' future earnings related to their current share price showed an implied MRP of about 6% - see the table below:

Table 8
Implied MRP from brokers' forecasts

Company	IRR perpetuity	Start Date	Prices at this date	Risk-free Rate	Beta	(Rm-Rf)	Implied MRP
Southcorp	10.892%	30-Jun-00	$4.82	6.16	0.82	4.73%	5.77%
Adcorp	9.901%	6/30/2000	$1.64	6.16	1	3.74%	3.74%
Amcor	9.919%	6/30/2000	$5.84	6.16	1.29	3.76%	2.91%
Aristocrat	22.283%	12/31/1999	$4.32	6.96	0.47	15.32%	32.60%
Baycorp	7.848%	6/30/2000	$8.40	6.16	1	1.69%	1.69%
Brambles	7.017%	6/30/2000	$51.34	6.16	0.82	0.86%	1.04%
Coles Myer	9.928%	7/30/2000	$6.59	6.96	0.43	2.97%	6.90%
Cochlear	3.740%	6/30/2000	$28.76	6.16	0.63	-2.42%	-3.84%
Computershare	15.641%	6/30/2000	$8.59	6.16	1.73	9.48%	5.48%
CSL	8.042%	6/30/2000	$33.03	6.16	0.55	1.88%	3.42%
Ci Technologies	6.540%	12/31/1999	$8.10	6.96	1.12	-0.42%	-0.37%
Data Advantage	8.269%	6/30/2000	$4.58	6.16	1.79	2.11%	1.18%
Energy Developments	10.197%	6/30/2000	$9.75	6.16	1.57	4.04%	2.57%
Foster's	7.069%	6/30/2000	$4.70	6.16	0.6	0.91%	1.52%
Hansen Technologies	5.480%	6/30/2000	$1.80	6.16	1	-0.68%	-0.68%
Harvey Norman	16.258%	6/30/2000	$3.76	6.16	0.95	10.10%	10.63%
MYOB	24.856%	12/31/1999	$3.22	6.96	1	17.90%	17.90%
News Corp	7.362%	6/30/2000	$23.00	6.16	0.86	1.20%	1.40%
Seven	8.774%	6/30/2000	$7.09	6.16	0.95	2.61%	2.75%
Sonic Healthcare	11.779%	6/30/2000	$6.88	6.16	1.13	5.62%	4.97%
Howard Smith	13.107%	6/30/2000	$8.16	6.16	1.16	6.95%	5.99%
Tabcorp	11.850%	6/30/2000	$9.60	6.16	1	5.69%	5.69%
Wesfarmers	8.183%	6/30/2000	$13.30	6.16	0.95	2.02%	2.13%
Woolworths	7.187%	6/30/2000	$6.16	6.16	0.25	1.03%	4.11%
Westfield Holdings	5.996%	6/30/2000	$11.48	6.16	1.2	-0.16%	-0.14%
Cable&Wireless	5.459%	6/30/2000	$4.98	6.16	1	-0.70%	-0.70%
Frucor	20.384%	6/30/2000	$1.71	6.16	1	14.22%	14.22%
Telstra	7.591%	6/30/2000	$6.78	6.16	1.05	1.43%	1.36%
BHP	11.280%	5/30/2000	$19.75	6.27	1.2	5.01%	4.18%
MIM	32.041%	6/30/2000	$0.90	6.16	1.95	25.88%	13.27%
North Broken Hill	12.005%	6/30/2000	$3.95	6.16	2.25	5.84%	2.60%
Rio Tinto	18.232%	12/31/1999	$32.72	6.96	1.77	11.27%	6.37%
Western Mining	10.592%	12/31/1999	$8.40	6.96	1.7	3.63%	2.14%
Woodside	9.231%	12/31/1999	$11.25	6.96	0.9	2.27%	2.52%
Qantas	14.913%	6/30/2000	$3.38	6.16	0.23	8.75%	38.06%
TOTALS	399.849%			221.31		178.54%	203.38%
AVERAGES	11.42%			6.32%		**5.10%**	**5.81%**

Source: JF Capital Partners, Trinity Best Practices Committee.

Finally, The Millennium Book: A Century of Investment Returns, shows in the table below that the Australian results are consistent with countries such as the US, UK and Canada whose capital markets are very similar to Australia. The arithmetic rates are more likely to be reflected in investors' expectations than the geometric rates, which over the period represent 10 year rates, whereas the arithmetic represent annual rates.

Table 9
Market Risk Premium

Equity Premium	Arithmetic Mean (%)	Geometric Mean (%)
Australia	7.6	5.9
Canada	6.1	4.6
Denmark (from 1915)	3.6	2.5
France	7.0	5.0
Germany (ex1922/3)	10.1	6.9
Italy	8.5	5.0
Japan (from 1914)	10.9	6.4
Netherlands	6.8	4.8
Sweden	8.0	5.8
Switzerland (from 1911)	4.3	2.8
USA	7.2	5.3
UK	5.8	4.6

Source: The Millennium Book: A Century of Investment Returns

In conclusion, the evidence from a moving average of historical series, a similar process using an exponential series, and the implied forward rate of securities analysts' and the rate used by regulators, all point to an estimate of the MRP of 6% as the most defensible. I have seen no evidence that would cause me to change this estimate although acknowledging the difficulty in arriving with any precision at an estimate.

Debt Margin and Leverage (D/V)

The debt margin was discussed above when estimating asset ß's from comparable companies. In Table 4 the simple average leverage (debt to total value) was 55% for the companies listed there. The regulators, see Table 5, have universally adopted a figure of 60%. The relative stability of cash flows for electricity transmission companies means that the companies can take on much higher levels of debt relative to most companies. On this basis a figure of a 60% leverage was considered a reasonable estimate for a TNSP such as Murraylink. In the context of the stability of cash flows and the leverage it is considered that TNSP could issue debt at an 'A' rating – the recent ElectraNet Draft Decision, suggested BBB+ would be a better reflection of the rating. Such a bond rating currently implies a debt margin over the risk free rate of about 150 bp – see above, p. 19 and Appendix 4, which, as discussed above, is consistent with a ß = 0.2 for debt.

Tax and Imputation Credits

One of the advantages of the "vanilla" WACC is that all the tax is accounted for in the cash flows, which in the context of a revenue determination requires separate compensation for tax (see Equation 1 above). This raises the issue of what is the company tax that is appropriate with the definition of the net cash flows and the WACC; it is not the net cash flows multiplied by the statutory tax rate.

The amount of tax paid by a company reflects the tax assessable income which is unlikely to coincide with the net cash flows, and the "effective" tax rate. Under an imputation tax system not all the tax collected from the company is really company tax. To the extent that part or all of the tax collected is redeemable against personal tax liabilities it represents personal tax. The company is collecting that proportion of the tax that is redeemable but it is tax that would otherwise be paid by the shareholder as personal tax. Therefore the "effective" tax rate for the company must take into account that amount of the tax paid by the company that is later redeemed by shareholders as a payment of personal tax. The issue is to assess what proportion of the tax collected from the company is not company tax but a pre-payment of personal tax.

There are two basic methods[15] of estimating the average amount of company tax that is redeemed as imputation tax credits against personal tax:

- through the official tax statistics of the amount of company tax paid that is redeemed and
- dividend drop-off studies.

The most comprehensive study to date, using both methods, is by Hathaway and Officer. The work is currently being up-dated but the results, to date, are broadly consistent with earlier studies by the authors and others.

[15] There is a third mechanism but it requires warrants to be listed on the shares which severely limits the sample of companies for which an estimate of the value of the credits can be assessed.

The introduction of imputation tax in July l987 substantially reduced the previous position of double tax on company earnings; company tax followed by personal tax on dividends. Shareholders now pay personal tax on the gross of dividends and imputation tax (company tax) credits and obtain credit for the company tax paid. There are three milestones in the life of franking credits; they are created when company tax is paid, they are distributed along with dividends and they are redeemed when shareholders claim them against personal tax liabilities. Two issues thus arise; how many credits are issued (access) and how many of these distributed credits are redeemed (utilisation)? The study found that the access factor is 80% and increasing (an increasing amount of company tax is being distributed as credits) and about 60% of distributed credits are being redeemed. Overall, 48% of company tax is actually pre-payment of personal tax.

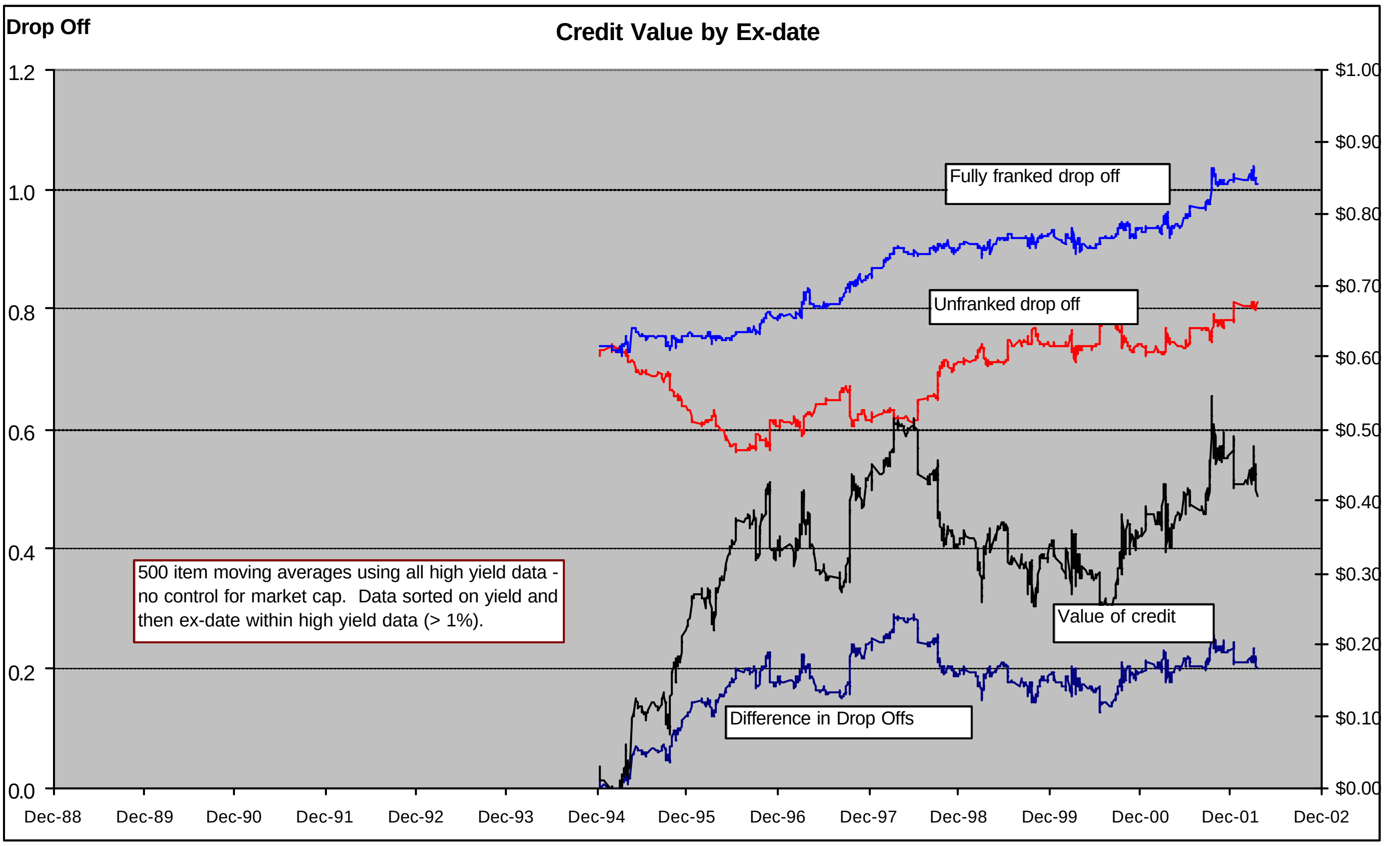
The study of official tax statistics indicate that a large proportion (48%) of the tax that "masquerades" as company tax is personal tax collected (withheld) at the company level. This means that the effective company tax rate in Australia during the period of the study was much closer to 18% than the statutory rate of 36%.

A company that pays a dividend, other-things-being-equal, is expected to drop in value by the value of the dividend being paid. By examining the amount of cash dividends and, separately, the amount of imputation credits we are able to assess the implied market value of the credits for the extent that the share price drops as the credit is being paid. The dividend drop-off study showed slightly greater value to the franking credits about 62% which may reflect the sample which was based on listed companies whereas the tax statistics include all companies. The main data set analysed consisted of all closing share prices for the period January 1 1985 to June 30 1995, although only a subset of this data was suitable for analysis.

As a result of these studies[16] and preliminary analysis of an up-dated version of these studies suggest that an estimate of 50% of the "face value" of the imputation tax credits is reasonable for attributing this to personal taxes. There is considerable variance between

[16] The paper which reports these studies is shown as Appendix 3.

individual company estimates of the value of these credits and the 50% is only an average or "benchmark" estimate. However, there is ongoing research to update the period of the analysis and this may have some effect on the conclusion as to the average value of franking credits. The latest research results are shown below:



Source:N.Hathaway, Invesco Ltd.

The above figure gives a moving average of the implied value of franking credits from an update of the dividend drop-off study. This study concludes in March 2002, although the graph's final point at March, 2002 reflects an average of dividends over the year March 2001 to March 2002 – the whole series are a moving average of typically a sample of 500 dividend payments with a minimum yield of greater than 1 %. The value of the credits is sensitive to the size of the dividend payment or yield and the size of the company issuing the dividend. The results of the above graph reflect, in part, sample differences to the previous study where in the current study there is a greater variation in the sample, particularly with respect to the size of the company.

On the basis of the most recent study a value of 40 cents per dollar of franking credits would appear to be more reasonable than the 50 cents implied by the previous study. However, there are differences in the sample of dividends between the two studies and the current study includes smaller companies which we would expect to lead to a greater variability in the estimate and a slightly lower estimate, other-things-being-equal. The possibility of significant "measurement errors" means that we could not be emphatic that there has been any change in the value of the credits, all we can be sure of is the credits have value and for large, higher dividend paying stock it is likely to average between 40 and 50 cents in the dollar. A compromise estimate would be 45 cents.

Expected Inflation

The expected level of inflation comes into a regulatory decision on prices when an inflation adjustment is required for forecasting net cash flows. It is important in such circumstances that the inflation adjustment made with respect to net cash flows is consistent with the implied rate of inflation embedded in the cost of capital. The CAPM takes account of expected inflation in the risk free rate and, to the extent that this is a 10 year bond, then the embedded inflation is the expected annual geometric mean inflation over the 10 years of the bond. An alternative approach would be to estimate the risk free rate in real terms. In this circumstance a 10 year capital indexed bond rate would be appropriate. The rates then would require simply forecasting net cash flows at current prices and then adjusting for any inflation forecast.

The difference between a Commonwealth Government capital index bond and a Commonwealth Government nominal index bond of the same duration, will reflect the expected inflation over the period of the duration. Also, there are regular forecasts by economists of expected inflation rates for, typically 12 month periods, which could be used as a measure of expected inflation for the period of the forecast.

I would recommend using the difference between a capital indexed bond and the government bond of the same duration to estimate expected inflation over the period of the chosen duration. This would mean the other parameters of the model including the cost of capital would need to be estimated in real terms in the first instance and then adjusted for the expected inflation over the duration of the regulatory decision. The current (30-09-02) yield on a 10 year commonwealth bond is 5.4% and the yield on an indexed bond of approximately the same time period is about 3.2%[17]. These results imply over the ten year period the current expected annual inflation is approximately 2.2%, on the basis of the difference in yields between indexed bonds and nominal bonds.

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[17] Reserve Bank of Australia, Daily Statistical Release of indicative mid rates on selected Commonwealth securities.

APPENDIX 1

Definitions of WACC

There are a variety of WACC that could be used and the most commonly used formulae for the WACC and the appropriate definition of net cash flows, given the WACC, are given below. The proof of these definitions can be found in Officer, R.R. [1994], "The Cost of Capital of a Company Under an Imputation Tax System". *Accounting and Finance*, Vol. 34, No. 1, pp. 1-17.

Definitions

X_0	represents operating net cash flows, i.e. the net cash flows that are distributed to shareholders, debt holders and the government through taxation i.e. $\mathbf{X_o = X_e + X_d + X_g}$
X_e	is the net cash flows that are attributable to shareholders.
X_d	is the net cash flows that are attributable to debt holders
X_g	is the net cash flows that are attributable to government through taxation
T	is the effective tax rate
γ	is the value of imputation tax credits as a proportion of the tax credits paid
r_e	is the required return to equity holders
r_d	is the required return to debt holders
S	is the value of shares or equity
D	is the value of debt
V = S + D	is the value of the assets of the company

Before tax Cost of Capital

Definition of cash flows:

$$X_0 = X_e + X_d + X_g$$

Cost of capital:

$$r_0 = \frac{r_e}{(1 - T(1 - \gamma))} \cdot \frac{S}{V} + r_d \cdot \frac{D}{V} \quad \text{… Equation 1}$$

The above estimate is a nominal before tax cost of capital, to convert this to a real estimate (r_r) the expected inflation E(I) has to be subtracted from $\mathbf{r_0}$, i.e

$$r_r = r_0 - E(I) \quad \text{… Equation 1a}$$

After tax Cost of Capital

1. Definition of cash flows:

$$X_0(1 - T)$$

Cost of capital:

$$r_i = r_e \cdot \frac{S}{V} \cdot \frac{(1 - T)}{(1 - T(1 - \gamma))} + r_d \cdot \frac{D}{V}(1 - T) \quad \text{(Equation 2)}$$

2. Definition of cash flows:

$$X_0(1 - T(1 - \gamma))$$

Cost of capital:

$$r_{ii} = r_e \cdot \frac{S}{V} + r_d(1 - T(1 - \gamma)) \cdot \frac{D}{V} \quad \text{(Equation 3)}$$

3. Definition of cash flows:

$$X_0(1 - T) + \gamma \cdot T(X_0 - X_d)$$

Cost of capital:

$$r_{iii} = r_e \cdot \frac{S}{V} + r_d \cdot \frac{D}{V} \cdot (1 - T) \quad \text{(Equation 4)}$$

4. Definition of cash flows:

$$X_0 - X'_g = X_0 - T(X_0 - X_d)(1 - \gamma)$$

Cost of capital (the "Vanilla" WACC):

$$r_{iv} = r_e \cdot \frac{S}{V} + r_d \cdot \frac{D}{V} \qquad \text{(Equation 5)}$$

APPENDIX 2

Appendix A to:
Statement of Principles for the Regulation of Transmission Revenues: Information Guideline Requirements,
Published by ACCC, dated 5th June, 2002.

Setting the Revenue Cap Forecast - Rate of Return ("WACC")

Notes for the preparation of information on this proforma:

1. The proforma sets out the minimum inputs required by the ***Commission*** to model a ***TNSP's*** estimate of WACC.

2. The minimum inputs set out in the proforma are averages for the five-year regulatory period.

3. A post-tax nominal WACC framework involves the use of a cash flow modelling approach to derive the revenue requirement.

4. A ***TNSP*** shall provide to the ***Commission:***
   (a) an estimate of its post-tax nominal return on equity; post-tax nominal WACC; and pre-tax real WACC.
   (b) the assumptions underlying the estimation.
   (c) full and detailed explanations of the basis of any calculations.
   (d) references to any sources of information or precedents.

Setting the Revenue Cap Forecast - Rate of Return ("WACC")

TNSP: ______________________ Reporting date: ______________

	Lower range %	*Upper range* %	*Proposed value* %
Nominal risk free rate			
Expected inflation rate			
Debt as a long term proportion of total funding			
Cost of debt margin over the risk free rate			
Market risk premium			
Corporate tax rate			
Effective tax rate for equity			
Proportion of franking credits attributed to shareholders			
Asset beta			
Debt beta			
Equity beta			
Post-tax nominal return on equity			
Post-tax nominal WACC			
Pre-tax real WACC			

THE VALUE OF IMPUTATION TAX CREDITS

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ABSTRACT

A large proportion (48%) of the tax that "masquerades" as company tax is personal tax collected (withheld) at the company level. This means did the effective company tax in Australia is much closer to 19% than the statutory rate of 36%. This is because the introduction of imputation tax in Julyl987 substantially reduced the previous position of double tax on company earnings; company tax followed by personal tax on dividends. Shareholders now pay personal tax on the gross of dividends and imputation tax (company tax) credits and obtain credit for the company tax paid. There are three milestones in the life of franking credits; they are created when company tax is paid, they are distributed along with dividends and they are redeemed when shareholders claim them against personal tax liabilities. Two issues thus arise; how many credits are issued (access) and how many of these distributed credits are redeemed (utilisation)? We find that the access factor is 80% and increasing (an increasing amount of company tax is being distributed as credits) and about 60% of distributed credits are being redeemed. Overall, 48% of company tax is actually pre-payment of personal tax.

NOTE

The results of this paper were first presented at a Pacific Basin Finance Conference in New York in December 1991. There have also been a number of presentations at seminars in Sydney, Brisbane and Melbourne during 1992, 1993 and 1995. 'The paper has benefited from comments at these seminars. The authors acknowledge the invaluable assistance of the Australian Stock Exchange (Melbourne Office) and Knight Ridder/Equinet in giving us access to the data. Funding by Esso for the extension of the study in 1993 is gratefully acknowledged. The authors are also indebted to Professor Frank Finn for insightful comments on the Study.

1. Introduction

Imputation credits are valuable but how valuable depends on dividend policy and the tax status of the recipient shareholder. (Do they pay Australian taxes?) Unfortunately, tax laws prevent the trade in imputation tax credits and therefore there is no open market to observe the value of the credits. The consequence is that an implicit value of the credits has to be estimated indirectly. This paper, which is a "cut down" version of a more comprehensive (academic) paper, is a study of the value of imputation tax credits.

The introduction of the imputation tax system for companies in 1987 has partially eliminated the double taxation of the classical company tax system that prevailed before 1st July 1987. Under the classical tax system, company tax was charged on a company's profit and then personal tax was charged on dividends distributed from after-tax company profits. Under the imputation tax system, tax is first collected as "company tax" and then when shareholders receive (franked) dividends they are credited with these "company tax" payments, called imputation credits, for use against their personal tax liabilities on the grossed up (for tax credits) dividends. Shareholders aggregate the cash dividends received and the credits allowed and are liable for personal tax on this total. 'Me imputation credits (company tax collections) are credited against this personal tax liability and the shareholder pays the net liability or, in the case of an excess of imputation credits over personal tax liability, receives a net credit that can be applied against other tax liabilities in that year. No cash refund of excess credits is allowed and credits cannot be carried across tax years by personal investors.

Most countries have some form of imputation tax system that credits some proportion of company tax against personal tax liabilities. There are only a handful of OECD countries still applying the classical tax system, with the USA the most noteworthy. However, the USA is known to be considering introducing some form of crediting system.

Under the imputation tax system, the much of the money collected as "company tax" is really a withholding of personal tax. If shareholders could access all company tax payments as imputation credits and all such credits could be redeemed as pre-payment of personal tax liabilities, then there would be no company tax. The only tax liability would be the personal tax liability. In practice, this extreme case of zero company tax is not achieved. Not all company tax payments are distributed as credits and of those credits that are distributed, not all can be utilised by the recipients. Companies rarely have a policy of 100% payout of earnings so some credits are not accessible by shareholders. In turn, some recipients are not liable for Australian tax (noticeably, foreign shareholders and Australian tax-exempts, such as charitable funds and universities) and so they do not have a tax liability against which they can utilize the credits. There has been some "trading" in tax credits between taxable and tax-exempt shareholders but the Australian Tax Office (ATO) has actively sought to curtail this activity with considerable success.

In summary, we find the following overall results:

1. *access* - 80% of company tax payments are distributed as imputation credits, and
2. *utilisation* - 60% of the distributed credits are redeemed by taxable investors.

These are *two factors* which, when compounded, indicate that statutory company tax rate is reduced by 48%. Effectively, company tax is substantially less than the statutory rate of 36% and much closer to an effective rate of 19%. It must be emphasised that these are Australia-wide **average** results and market sectors or individual companies may experience substantial variations from the average. A different payout ratio and a different shareholder tax status would be obvious reasons for a deviation from the average. As we will see below, the *access* factor has been increasing over time. An increasing proportion of the credits are becoming available to shareholders. The effective company tax rate, as distinct from the statutory rate, is declining.

There are three milestones in the life of imputation credits:

1. They are **created** when company tax is paid.

2. They are **distributed** when franked dividends are paid to shareholders.

3. They are **redeemed** when shareholders lodge their personal tax claims.

These three events are analysed in order to establish the value of franking credits.

We derive our results in two ways. Firstly, we examine the national tax statistics from which we derive the overall average results as imputation credits are redeemed. However, when tax statements are lodged by taxpayers, there is no requirement to identify the source of the credits claimed, but rather just the aggregate of tax, dividends and credits. Hence we can only obtain broad results from the taxation statistics. For example, we cannot use them to distinguish between credits paid and received by resources versus industrial stocks. To overcome this problem, we also analyse the ex-dividend behaviour of stock prices.

When stocks go ex-dividend, the share price typically drops because the assets, in the form of dividends and franking credits, are being distributed. The drop in the share price reflects the market's value of the dividend and credit being paid out. If shareholders value the associated imputation credits, then the share price should drop further to reflect the trade-off between capital value and dividend cash plus credits. This is indeed what happens. Share prices of fully-franked dividends fall further, as shares go ex-dividend, than shares which pay out unfranked dividends. We analyse the ***extra*** drop-off in the share price that is attributable to the credits as distinct to the drop-off attributable to the dividend alone.

This method of valuing the credits has the advantage that separate valuations of tax credits can be made for market sectors and even individual companies.. However, much caution should be exercised when interpreting such sub-sector valuations because there is considerable "noise!' in the individual results. Consistent with our taxation statistics results, we find that the **average** drop-off value of the credits is between 50% - 60% of their face value.

Ex-dividend drop-off statistics can only address the *second* factor, **distribution**, associated with company tax and imputation credits. Drop-off analyses (and any other valuation based on dividend events) can only value the tax credit attached to a dividend when it (the franked dividend) is paid. This happens after the company makes its decision about how much of the profit, after-company tax, to distribute as a franked dividend. The value of credits derived from drop-off analyses indicates the market value of credits, not the redemption value. In theory, we would expect the drop-off valuations to be less then the redemption valuations in order to allow for the time value of money between the payment of the franked dividend and the redemption of the franking credit.. In practice, the "noise" in the data may mask any such finessing of the results.

Before proceeding to the results, there are two issues that should be cleared away. These are issues that we find are frequently raised and represent some confusion in the minds of some people.

The first such issue is that the personal taxation rate (as distinct from the tax status) of the shareholder recipient of the dividend is irrelevant. The only fact that matters is that the shareholder has an Australian taxation liability against which the imputation credits can be applied. Whether that tax liability was incurred at a marginal tax rate of 15% or 48% is immaterial. To see the veracity of this statement, simply ask yourself the question "if they could sell their imputation credits, what would two taxpayers, one on a 15 % and the other on a 48% rate, want as monetary compensation for their imputation credits paid from a company on 36% corporate rate?" To make this concrete, suppose each received a $0.64 fully franked dividend. 'Men each would be liable for personal tax on the grossed up amount of $1.00 ($0.64 cash dividend plus $0.36 imputation credit). The answer is that ***both*** would want $0.36 cents for their imputation credit. In this case alone, they would end up with $1.00 cash and their personal tax position would remain unaltered. The fact that they are on two separate marginal personal tax rates is immaterial Being able to both access and utilize the credits are the important aspects of the value of imputation credits.

The second major issue of confusion is that foreign investors (indeed, non-taxpayers in general) would not pay anything for the value of future imputation credits impounded in Australian share prices. But this would only be true if tax-exempt shareholders always traded their shares with other tax-exempt shareholders. In this case, none of the future credits would ever be used so they would indeed be valueless (assuming some mechanism is not invoked to trade credits with taxpayers). However this is very unrealistic. The Australian Stock Market turns over about 50% of its aggregate market capitalisation each year. So, on average, each share is traded every two years. Even if foreign investors held their Australian shares for this average of two years, they would only lose value for the imputation credits paid out over the two year holding period. When they sell out of their shares, they are selling into a market that does place value on the credits. Our result, that distributed credits are valued at about 60% of face value reflects a market of investor, some of whom place no value on the credits and some of whom place a high value on the credits.

To avoid paying for something you cannot use, we would expect that shareholders arrange their affairs to be the most tax efficient. Presumably, taxable investors would be attracted to shares with fully franked dividends and, insofar as these shares reflect some value in the franking credits, non-taxpayers would be attracted to shares with unfranked dividends, all else being the same. There is certainly strong evidence that this clientele effect is occurring. We will present the results below. However, it is difficult to avoid franking credits when buying shares because the vast majority of dividends are franked and of the franked dividends, the vast majority are fully franked.[1] All up, 83% (by value) of the dividends paid out are franked dividends. These franked dividends are, on average, 96% franked; 92% are fully franked and the other 8% are on average 50% franked, giving an overall average of 96% franking. So while there is a theoretical argument for market segmentation, there are practical limits on how far this segmentation can go.

We now turn to presenting our empirical results. Section 2 presents the Australian Tax Office (ATO) data and the associated analyses. In Section 3 we present the ex-dividend drop-off events. We present only the main results and only sufficient detail to understand the analyses and the results. We make some concluding remarks in Section 4, as well as some precautionary dictates on using these results in practical valuation exercises. 'Me authors have been involved in quite a wide range of projects that involve applying these results and have made some deductions about their practical implementation.

2. REDEMPTION VALUE OF CREDITS (ATO DATA)

We extracted data on dividends paid, company tax payments, credits issued and credits claimed by taxable claimants. This data set describes the *creation* of credits (i.e. company tax payments), the *distribution* of credits (i.e. franked dividend payments) and the *redemption* of credits (i.e. taxpayer claims of credits, including individuals, superfunds and some financial companies). The proportion of credits claimed

[1] Dividends are either 100% franked or unfranked (0%) but a company can payout a mixture of franked and unfranked dividends. We include those dividends paid out as a mixture in our figures on “franked” dividends unless otherwise stated.

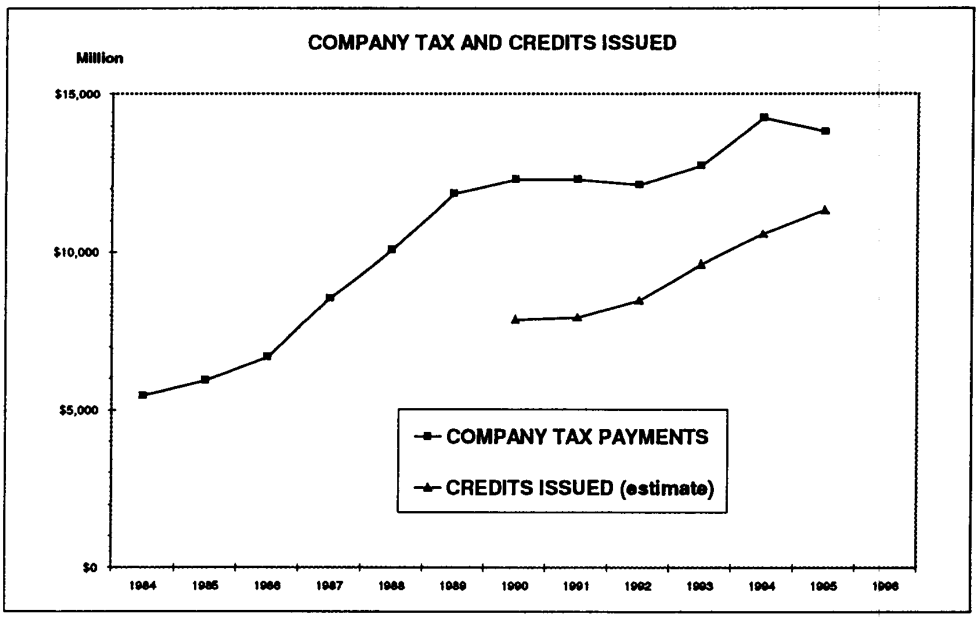
(redeemed) and thus the dollar value of the credits to the ultimate users of the credits can be derived from this ATO data.

2.1 Creating Imputation Credits (ATO Data)

The source of credits is company tax collections. Figure 1 illustrates these data over the 13 financial years 1984 to 1996. There have clearly been some major events in company tax collections, including the hiatus from the recession in the early 1990t plus a sudden downturn in 1995, notwithstanding th3l company profits and tax payments appeared by then to have recovered from the recession. However, dividends and credits can be issued from retained earnings, within the confines of a company's Franking Account Balance (FAB), which means that the credits issued need not directly correlate with current year tax collections.

The *ATO* only began to report data on credits from the 1990 financial year.

Figure 1: CREDIT CREATION



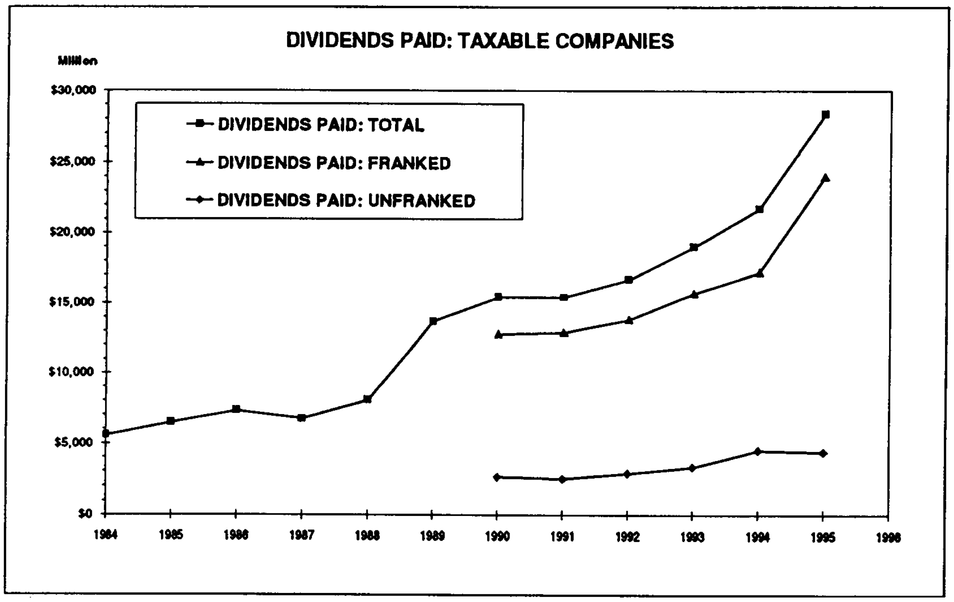
Ultimately, any downturn in company tax payments must be reflected in the distribution of future credits as any pool of undistributed credits is exhausted.

2.2 Distributing Credits (ATO Data)

Credits are distributed to the ultimate users (credit redeemers, which include personal taxpayers, superfunds and some finance companies), either directly by the taxable companies which create the credits or passed through other entities such as taxable and non-taxable companies, and partnerships and trusts. In the case of trusts, the dividend is passed on as a cash distribution and the credits (and therefore their value) received by a trust can be passed on to the trust recipients. The ATO data distinguishes between credits received by investors in their own right (*primary credits*) and credits received via these intervening trusts (*secondary credits*).

The ATO have published data on the amount of dividends paid (franked and unfranked) since the 1990 financial year. The amount of franking of dividends has averaged about 83% of total dividends. These results are seen in Figure 2: distribution of credits via taxable companies (distribution of credits via non-taxable companies are not presented here. The ATO data have two years missing for data). Obviously the nontaxable companies are distributing credits from their FAB account received as investment income from franked dividends. These non-taxable companies are not creating any tax credits of their own (after all, they do not pay company tax) but are just passing such credits through to their shareholders. Another way that credits are passed through to the ultimate redeemers of the credits is via trusts. This data is described in Figure 3: distribution of credits via trusts. 'Me franking credits accompanying the franked dividend income of trusts is distributed to trust beneficiaries as their *secondary imputation credits*.

Figure 2: DISTRIBUTION VIA TAXABLE COMPANIES



We have estimated the credits issued from the franked dividends paid data. We had previously established that franked dividends averaged a 96% franking level. We used this calculation and the contemporaneous company tax rate to estimate the amount of credits issued from the amount of franked dividends distributed. Any credits issued that were created under a previous company tax rate will cause an overestimate (underestimate) to the amount of credits issued if that tax rate was lower (higher) than the contemporaneous tax rate. Figure 1 contains this estimate plotted against company tax payments. We are now in a position to estimate the first or access factor of imputation credits. This is the proportion of credits issued as a percentage of company tax paid. This is plotted within Figure 4.

Figure 3: DISTRIBUTION VIA TRUSTS

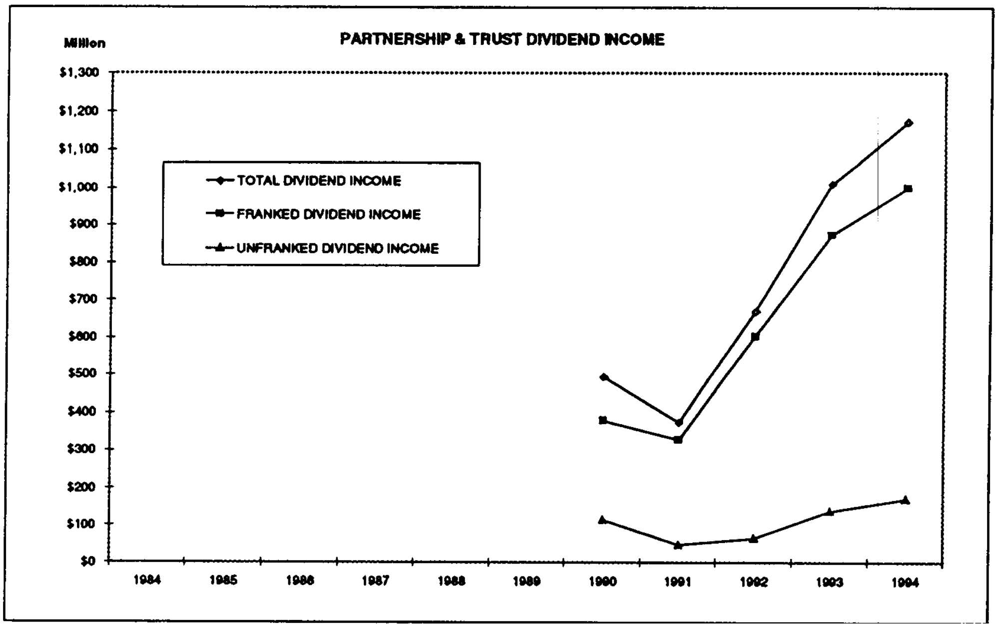
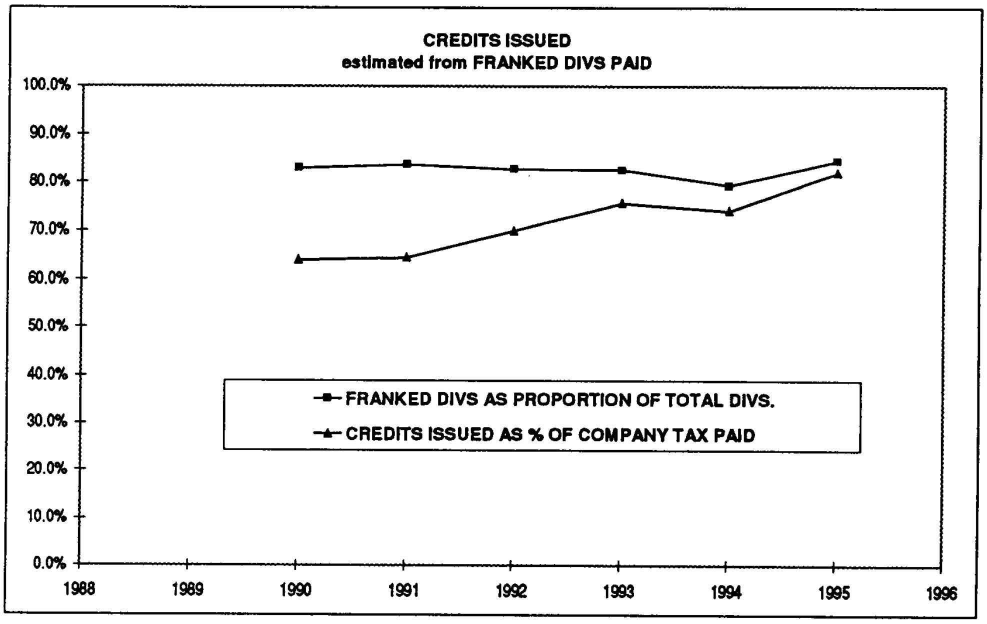


Figure 4: CREDIT ACCESS



2.3 Redemption of Credits

We next estimate the credits redeemed (claimed) by the ultimate consumers of the tax credits. These include taxable and non-taxable individuals, superfunds and some finance companies. The imputation credits that are redeemed by (1) taxable individuals are shown in Figure 5 (non-taxable individuals are not shown: these credits are lost as non-claimed credits cannot be held over once received by shareholders), (2) superfunds are shown in Figure 6 and by (3) some finance companies are shown in Figure 7.

Figure 5: CREDITS REDEEMED BY TAXABLE INDIVIDUALS

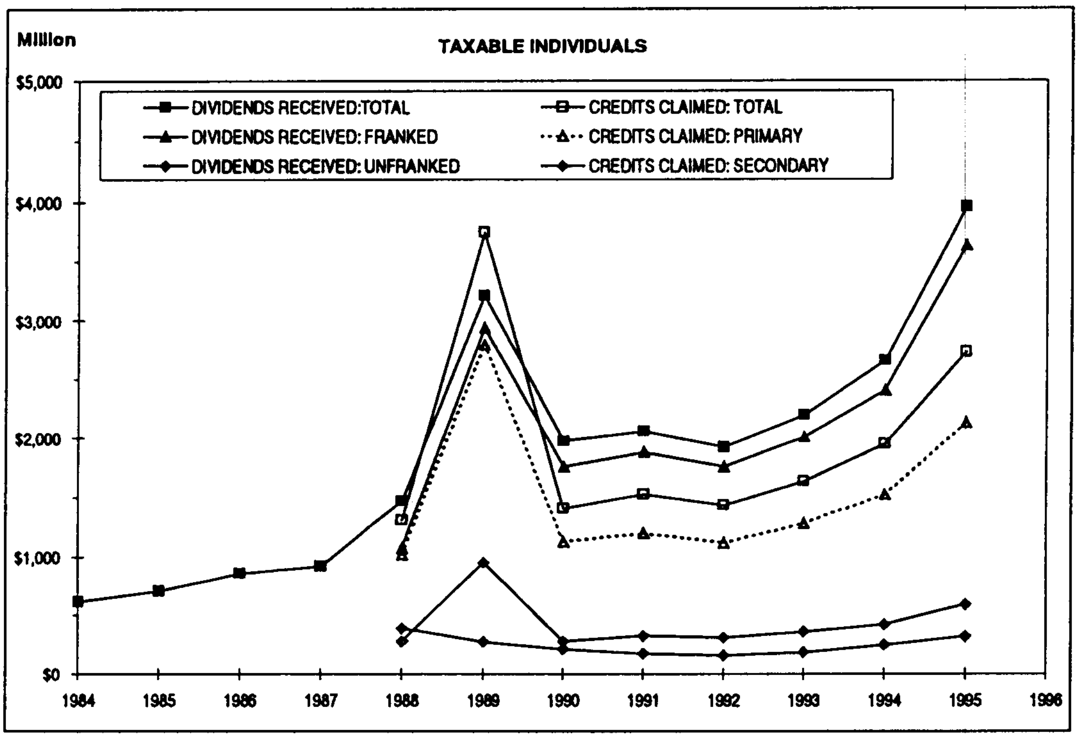
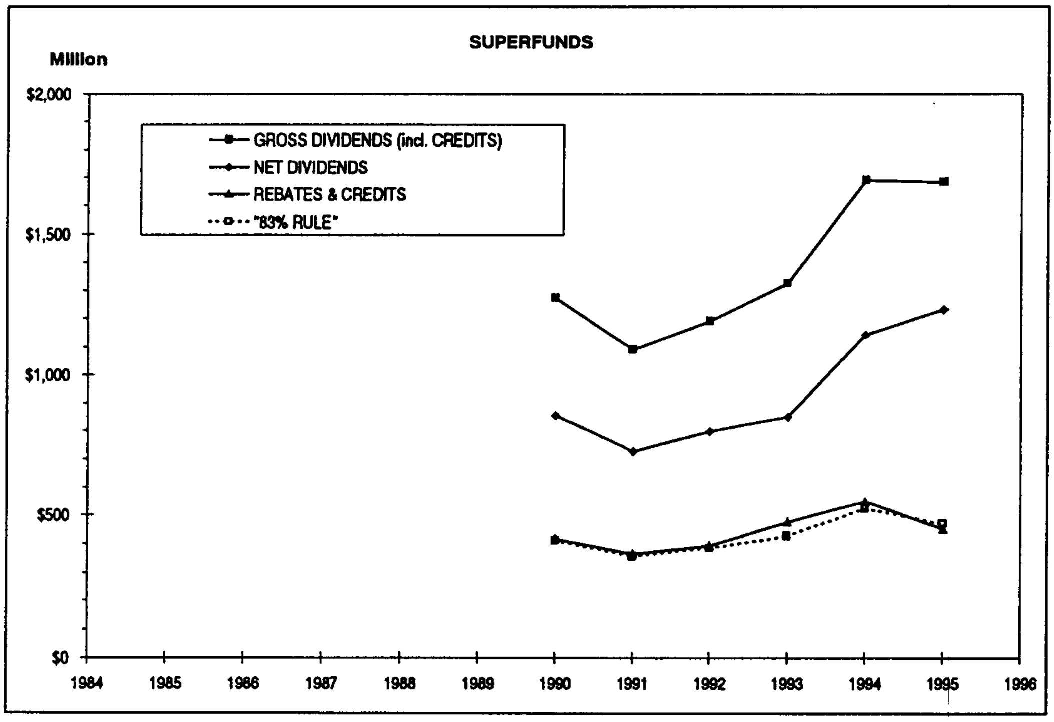


Figure 6: CREDITS REDEEMED BY SUPERFUNDS



Superfund dividend receipts are not reported as franked or unfranked. Instead, the grossed-up dividend (credit plus cash) is reported as well as net dividends and aggregate rebates and credit claims. These credit claims include items other than just dividend imputation credits. We cannot assume that all dividends are domestic sourced dividends so the proportions developed above for franked and unfranked dividends may be in error for superfunds. Accordingly, we plotted the theoretical credit amount assuming the superfunds received credits in the same overall proportion as the complete market for that year. Incidentally, this has averaged 83% of franked dividends so we call this assumption the "83% rule". The superfunds' actual claims for rebates and credits very closely follows the theoretical amount. Accordingly, we assume that the aggregate rebates and credits claim by superfunds are all redeemed franking credits. Any error in this assumption means we are overstating the amount of credits redeemed by superfunds.

Redemptions by finance companies were considered in detail. Many credits are claimed by the superfund subsidiary of a finance (holding) company which appears in the ATO statistics as a **company** redemption instead of as a superfund. The vast majority of dividends paid by Australian companies are paid to other companies, and finance companies (as defined by the ATO) receive the bulk of these company dividends. Some finance companies can redeem the credits. To explore this important source of credit redemption, we plotted by industry sector the gross dividends received, the rebates and credits claimed and the theoretical credits that would accompany the dividends (assuming the "83% rule" of franked versus unfranked dividends). We did this for taxable and non-taxable finance companies across a number of years. An example is shown for taxable finance companies in 1993-94 (Figure 7).

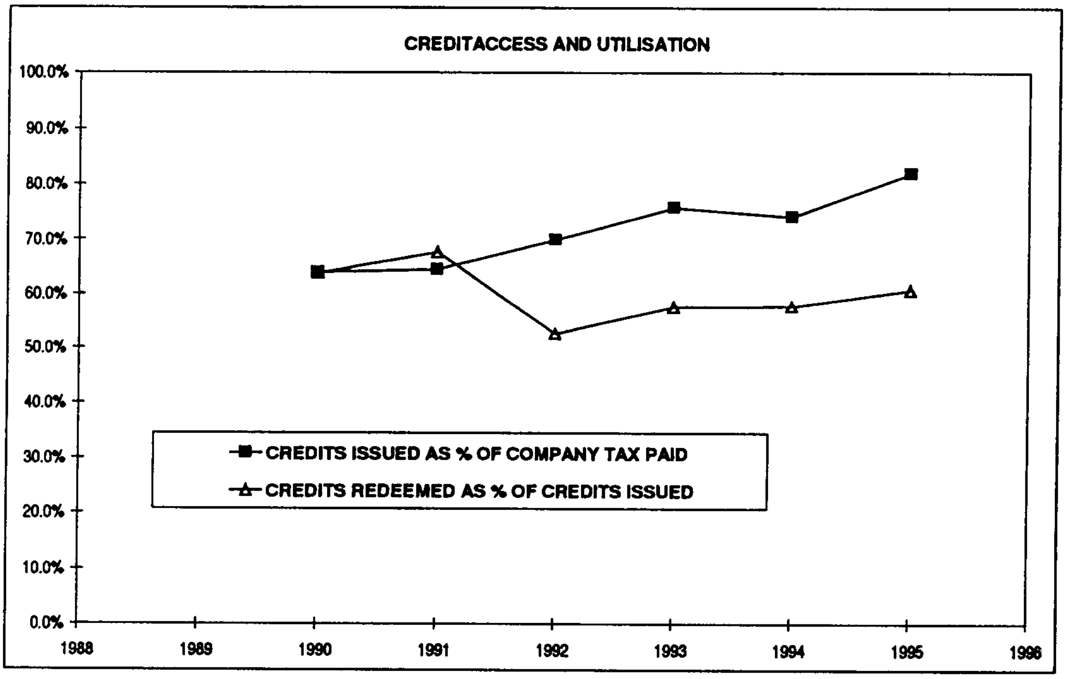
Just as for superfunds, we are forced to assume that all the claim for rebates and credits were actually claims for imputation tax credits. If the dividend income was all domestic, we would expect dividends to be franked in line with the overall Australian average for that year- the "83% rule". The imputation credits would then be derived from the grossed-up amount of that dividend. These theoretical credits are calculated and compared to the actual credits claimed by ATO records. In 1994 the theoretical credits are generally too high compared to what was claimed by finance companies, particularly for finance companies not elsewhere classified (n.e.c.), indicating we are grossing up dividends that actually have less franking than the Australian average. We have no means of correcting each estimate so we make the assumption that the finance company credit and rebate amounts are all the redemption of franking credits. To the extent that some finance companies derive overseas dividend income which does not have any attached franking credits, our estimates will overstate the redemption of imputation credits by these companies. In other years the error was in the opposite direction We can only hope that with sufficient years of data, the errors will cancel out.

The redemption of franking credits by *taxable investors* is our overall measure of the redemption value of credits. This fraction is the ratio of the aggregate credits redeemed by taxable individuals, taxable finance companies and superfunds to the aggregate credits issued by taxable companies. If we included credits of nontaxable companies we would certainly be double counting. Most dividends received by non-taxable companies are passed through. Over the five years 1990-96, non-taxable companies received aggregate dividends of $45.616 billion and paid out aggregate dividends of $43.532 billion, a 95% pass-through ratio.

We have now established the two important factors for imputation tax credit valuation These are an increasing access to credits (now standing at 82%) and a redemption factor of 60% for distributed credits.

The aggregate redemption (*utilisation*) fraction of imputation credits by taxable claimants is plotted in Figure 8, along with the other important factor of the access rate. The utilisation fraction has fluctuated around 60%. On the basis of these data and our assumptions, we estimate the redemption value of credits to average 60 cents per $1 of issued credit.

Figure 8: CREDIT ACCESS AND UTILISATION

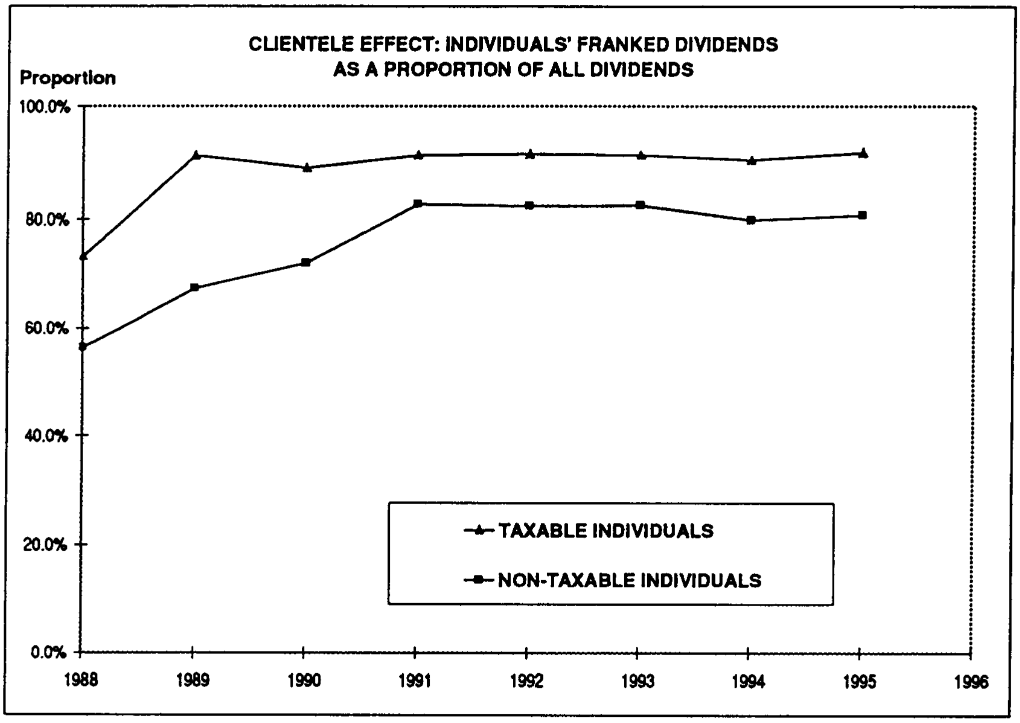


We have now established the two important factors for imputation tax credit valuation. These are an increasing access to credits (now standing at 82%) and a utilisation factor of 60% for distributed credits.

2.4 Clientele Effects

In the above analysis, it is observed that franked dividends are pervasive. This does not mean however that all investors hold equal weightings of shares paying franked versus unfranked dividends. There is the opportunity for clientele effects which we observe in the data. Figure 10 plots a clientele effect among individual taxpaying investors. We observe that there has emerged a rather steady difference of 10% in the proportion of franked dividend income to total dividend income between taxable and non-taxable investors and since imputation commenced in June 1987, it took four years for this difference to become stable. Also of interest is the quick emergence (two years) of a stable fraction of franked dividends to total dividends in taxable investors' portfolios. Equilibrium appears to have been reached rather quickly which suggests that the clientele effect has little further progress to make.

Figure 9: CLIENTELE EFFECT



3. VALUING IM[PUTATION CREDITS BY DIVIDEND DROP-OFFS (Listed Companies)

We now turn to the measurement of the value of imputation tax credits by examining dividend drop-offs which are the change in value of a share price when stocks go ex-dividend. Only the overall results and a brief outline of the method will be presented here.

If a stock pays a dividend of $0.64 that is fully franked at the rate of 36% (i.e. a franking credit of $0.36) then one might think that the stock price will fall by $ 1.00, thus M impact of the cash and the crediL To establish the amount of the franking credit, the dividend is first grossed-up to a pre-tax amount (divided by 0.64) and then the tax component of this gross amount is calculated (multiplied by the tax rate, 0.36). This establishes the amount of a fully franked dividend. If the dividend is not fully franked then the tax credit component is scaled down by the franking percent factor.

$$\Delta P \quad = \quad Div + FC$$

A more general statement of this is as follows;

$$\Delta P \quad = \quad Div \quad + \quad Div.[t/(l\text{-}t)]f \qquad \text{.... (1)}$$

where *DP* = share price change over the dividend event, *FC* = franking credit amount, *Div* = cash dividend amount, *t* = company tax rate, and *f* = franking proportion of the imputation tax credit (*f* = 1 for a fully franked dividend). If we eliminate the scale effect of the cash dividend, then equation (1) becomes simply

$$\Delta P/ Div \quad = \quad 1 \quad + \quad [t /(1\text{-}t)]f \qquad \text{.... (2)}$$

We estimate (2) by running the regression equation

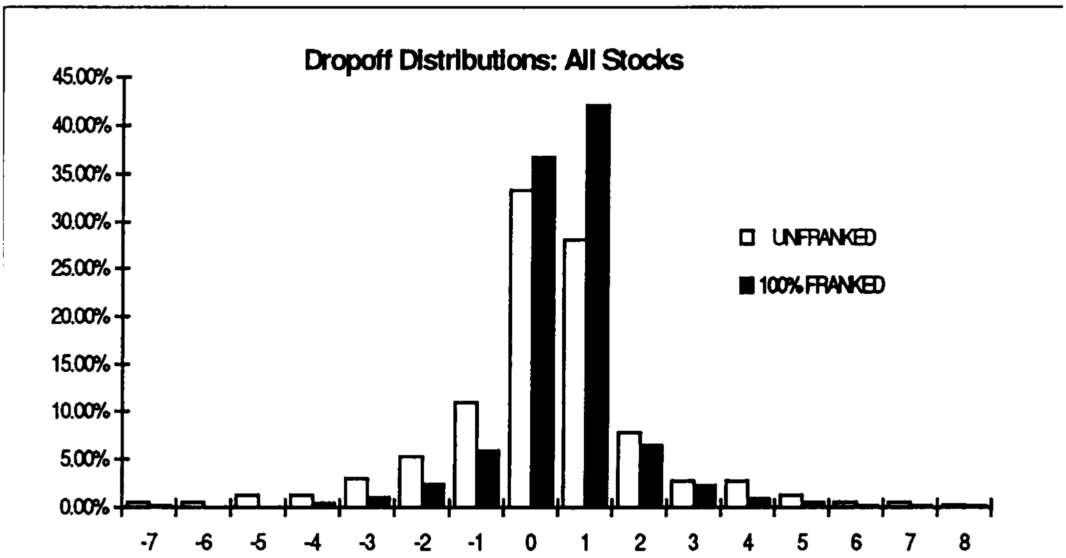
$$\Delta P/ Div \quad = \quad a + b.f \qquad \text{.... (3)}$$

The interpretation of a is the drop-off proportion due to the cash component of the dividend and the interpretation of b is the extra drop-off proportion due to the franking component. We are particularly interested in this imputation factor.

The main data set analysed consisted of all closing share prices for the period January 1 1985 to June 30 1995. This data set contained 6179 dividends and associated stock drop-offs. There were enough data points to enable sub groups to be analysed. Only the broad results will be presented here. We confined the analyses to fully paid ordinary stocks which reduced the relevant dividend events to 4355. A drop-off calculated from non-consecutive closing price data is at risk of being influenced by extraneous information Attempting to control for this by a4justing drop-offs for market moves is unlikely to make the drop-off more reliable estimates. In any event, we also conducted the analysis with the drop-offs a4justed for market moves. We found no consistent nor significant differences in the results.

We eliminated any zero drop-offs and confined our analysis to either zero franked or 100% franked dividends. The difference in means of the drop-offs for zero franked and 100% franked dividends is a measure of the extra drop-off due to the credits. Our final sample size was 1482 dividend events, with the following break down. These drop-off data were plotted as histograms and then subjected to statistical analysis as before. Only the histogram for the entire set of 1482 drop-offs is presented in Figure 10. This histogram demonstrates a clear move to the right for 100% franked stocks compared to unfranked stocks, that is, fully franked stocks drop-off more than the unfranked stocks.

Figure 10: DROP-OFF DISTRIBUTION



This extra drop-off is quantified in Table 1 for various sectors of stocks.

Table 1: RESULTS OF THE RGRESSION EQUATION (3)

$$\Delta P/D = a + b.f$$

SECTOR	MKT CAP < $500m			MKT CAP >= $500m			ALL		
	a	b	N	a	b	N	a	b	N
INDUSTRIALS	0.86 -7.14	0.11 -0.79	676	0.8 -6.23	0.31 -2.11	456	0.83 -9.47	0.19 -1.94	1032
RESOURCES	0.55 -3.43	0.45 -1.64	167	0.72 -3.71	0.28 -1.13	183	0.61 -5.01	0.39 -2.22	350
ALL STOCKS	0.71 -7.23	0.26 -2.48	843	0.77 -7.23	0.31 -2.48	639	0.74 -10.56	0.28 -3.44	1482

The company tax rate during the period of the analysis varied from 49% to 39% and finally for the last twelve months (July 1994 to June 1995) it was 33%. The bulk of the data cover the 39% regime. Attempts to discern any difference in means of drop-offs at the different tax rates provd inconclusive - there were insignificant differences in mean drop-offs.

Interpretation

The theoretical value for the drop-off fraction due to the credit component of a fully franked dividend is t_c ($1t_c$). As most of the data covers the 39% tax regime, we take this ratio to be 0.39/0.61 = 0.64. Then, for example, a drop-off fraction for the credit of 0.31 (big industrials) means that those credits are being priced at 49% of their face value i.e. they are being priced at 49 cents per $1 of credit. Table 2 describes the full set of these results.

TABLE 2: VALUE OF THE CREDITS
(COMPANY TAX RATE = 39%)

SECTOR	MKT CAP < $500m		MKT CAP >= $500m		ALL	
	B	Value	b	Value	b	Value
INDUSTRIALS	0.11	17%	0.31	49%	0.19	30%
	-0.79		-2.11		-1.94	
RESOURCES	0.45	70%	0.28	44%	0.39	61%
	-1.64		-1.13		-2.22	
ALL STOCKS	0.26	41%	0.31	49%	0.28	44%
	-2.48		-2.48		-3.44	

The results for the Small Stocks appear erratic which in turn effects the results for AR Stocks. There is no logical reason why the credits of Small Resource are priced at 70 cents per $1 of credit whilst the credits of Small Industrials are priced at just 17 cents per $1 of credit. If small listed companies are similar to private companies in that their share holdings are dominated by Australian taxpaying shareholders then we would expect their credits to be more highly valued. Hence the 17% value for Small Industrials' credits appears to be the anomalous result.

All Big Stocks have their credits priced at 49 cents per $1 of credit. The tax redemption value across all companies gives a value of about 60 cents per $1 of credit. Of course this redemption value should exceed the market-derived values because the market value must be a time discounted value of the redemption value. In addition, the redemption value is necessarily a capitalisation weighted average over all companies (tax data only show the aggregate amounts collected), both listed (big and small) and private companies. Presumably the private company derived credits are more highly valued than credits from listed companies because the latter have non-Australian taxpayers as shareholders whereas the private companies would be dominated by Australian taxpaying shareholders.

In summary, we find broadly consistent values of imputation credits from two quite different analyses: one based on taxation statistics and one based on market values from dividend drop-offs.

4. Observations

Clearly our analyses demonstrate that imputation credits have a significant value. However, a word of caution. Both measures of credit value are taken after the company has announced the payment of the dividend and the credits. This means there is no uncertainty about the timing and the amount of the credit within the measures we obtain for the value of credits. Credits cannot be redeemed until paid with accompanying dividends and stocks cannot be traded cum-dividend until dividends are declared. Hence both methods of valuing the credits give conditional valuations: the value of the credits conditions on the company deciding to pay a franked dividend. Neither method accurately values the credits which remain locked inside the company. Typically there is uncertainty about when such credits will be paid out and he amount of the credits to be issued. For this case, we would have to apply a discount rate to allow for :he uncertainty in accessing the credits. The exact discount rate remains obscure.

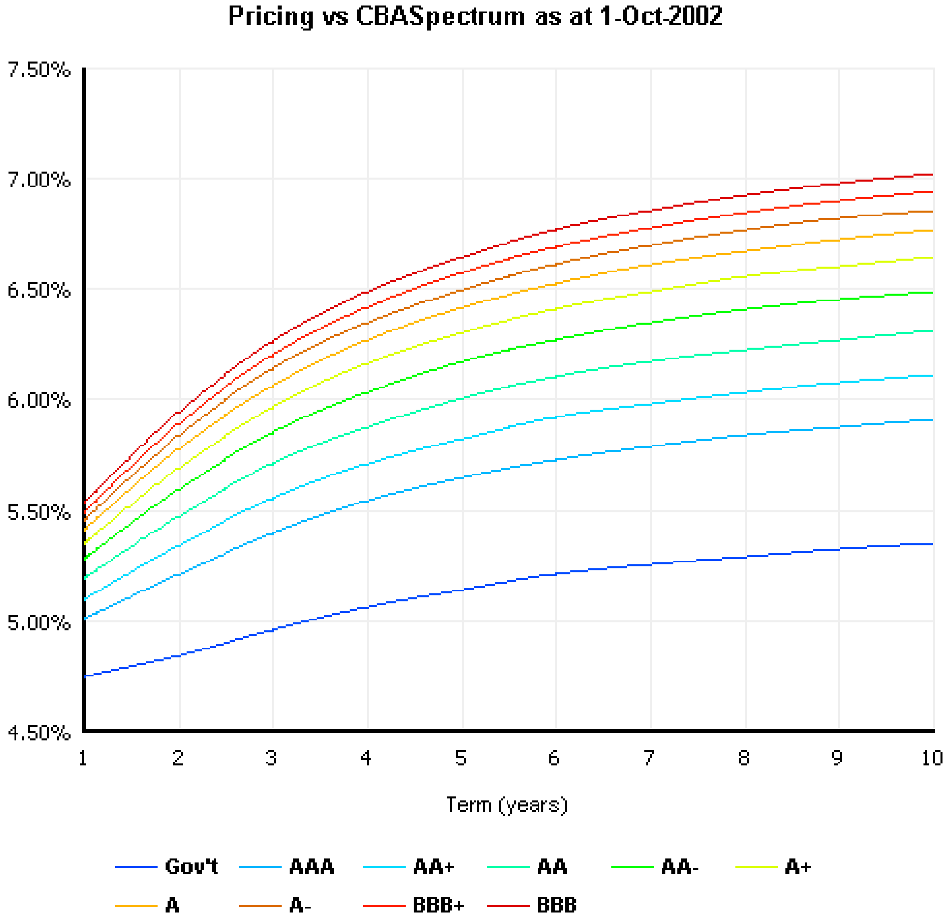
After applying the above measures in many discounted cash flow valuation exercises, we much prefer keeping imputation effects quarantined in the cash flow factors and not adjust the discount factor to allow for imputation. Certainly any combination of discount rate and cash flow can be derived to give consistent valuation results. However, allowing for franking credits in the discount rate poses practical issues that can be very difficult to solve. Valuations are usually done after company tax but before personal tax. As shareholders pay personal tax on the aggregate of dividends and imputation credits, an allowance for the value of imputation credits has to be added back. This is easier to add back into the cash flows.

Imagine a project with a cash flow stream that has a large lumpy capital expenditure that causes temporary large deductions before tax, maybe even sufficient to eliminate tax payments for a number of years (e.g. Pay TV and its cabling expenditure). This reduces company tax payments and hence reduces the creation of credits. Adding back a proportion (e.g. 50%) of company tax payments each year as a stream of credits automatically accommodates these lumpy events. Trying to apply franking credits by modifying the cost of capital requires forming some geometric average of the annual franking credit value is very difficult, if not impossible, without first knowing the project value! There is an academic "cottage industry" in deriving new models of the costs of capital that incorporates the value of franking credits. It leads to some complicated models which are unnecessary.

We would be the first to admit that the value of imputation credits is not measured with any precision, but neither are many attributes of investment decisions which, by definition, must depend on future outcomes. Notwithstanding this lack of precision, ignoring them is tantamount to assuming a zero value for credits and this certainly is a gross error.

APPENDIX 4

CBA SPECTRUM YIELD SPREADS AT 1/10/02



	CBASpectrum Yield									
S&P Rating	1	2	3	4	5	6	7	8	9	10
Gov't	4.74 %	4.84 %	4.96 %	5.06 %	5.14 %	5.20 %	5.25 %	5.29 %	5.32 %	5.34 %
AAA	5.01 %	5.21 %	5.39 %	5.54 %	5.65 %	5.73 %	5.79 %	5.84 %	5.87 %	5.91 %
AA+	5.10 %	5.34 %	5.55 %	5.71 %	5.82 %	5.91 %	5.98 %	6.03 %	6.07 %	6.11 %
AA	5.19 %	5.47 %	5.70 %	5.88 %	6.00 %	6.10 %	6.17 %	6.23 %	6.27 %	6.31 %
AA-	5.28 %	5.59 %	5.85 %	6.03 %	6.17 %	6.27 %	6.34 %	6.40 %	6.45 %	6.49 %
A+	5.35 %	5.69 %	5.96 %	6.16 %	6.30 %	6.41 %	6.49 %	6.55 %	6.60 %	6.64 %
A	5.41 %	5.77 %	6.06 %	6.26 %	6.41 %	6.52 %	6.60 %	6.67 %	6.72 %	6.76 %
A-	5.45 %	5.84 %	6.13 %	6.34 %	6.50 %	6.61 %	6.69 %	6.76 %	6.81 %	6.86 %
BBB+	5.49 %	5.89 %	6.19 %	6.41 %	6.57 %	6.68 %	6.77 %	6.84 %	6.89 %	6.94 %
BBB	5.53 %	5.94 %	6.26 %	6.48 %	6.65 %	6.76 %	6.85 %	6.92 %	6.98 %	7.02 %