April 2003

Report to Murraylink Transmission Company

Application for Conversion of Murraylink to a Prescribed Service

Commentary on the Economic Issues

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Table of Contents

1. Introduction and Overview

The Allen Consulting Group has been engaged by Murraylink Transmission Company (MTC) to provide commentary on the economic issues that were raised in the submissions from interested parties to MTC's application for the services provided by the Murraylink project to be converted to a prescribed service,[1] and for the maximum allowable revenue for those services to be determined. The report was prepared by Jeff Balchin, Director, from the Group's infrastructure regulation practice.

The most important of the economic issues raised in submissions relate to the determination of a regulatory value for Murraylink on its conversion to a regulated interconnector. MTC applied the 'optimised deprival value' methodology (ODV) to determine the regulatory value for the Murraylink asset, consistent with Chapter 6 of the National Electricity Code, the Australian Competition and Consumer Commission's draft Statement of Regulatory Principles, and the Commission's statements about how it would set the regulatory value for an interconnector that converts into a regulated interconnector.

A major concern expressed in submissions with the valuation methodology employed for the Murraylink asset was that an ODV methodology is not the most appropriate methodology for deriving the regulatory asset value of an interconnector that is converting to a regulated interconnector. Instead, it was argued that the regulatory value for such a project should – in effect – be set such that all market participants would be made better off as a result of the conversion.[2] This valuation methodology is referred to below as the 'incremental benefits' valuation methodology.

An implicit assumption in the suggested use of the 'incremental benefits' valuation methodology is that the Commission is starting with a 'clean sheet of paper' and that any asset value the Commission assigns is equally valid and – as the Murraylink asset is sunk – has no implications for economic efficiency.

In contrast, as noted already above, the Commission has made a number of statements about the method it would apply to determine the regulatory value of electricity transmission assets in general, as well as specific statements about how it would derive a value for an interconnector that converted from a market network service to a regulated interconnector. One of the purposes of such statements is to provide investors with the degree of certainty about future regulatory decisions required to attract capital into the industry – the future regulatory valuation of assets of key importance. In the face of such commitments, it is not valid for these submitters to assume that all options are open and that there are no efficiency implications associated with alternative asset valuation methodologies.[3] This matter is discussed in section 2.

In addition, when analysed further, the 'incremental benefits' asset valuation methodology is also found to have implications that are unreasonable to the owners of Murraylink, and may also undermine the rationale for permitting a conversion of an interconnector into a regulated interconnector. This matter is discussed in section 3.

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[1] The terms 'prescribed service' and 'regulated interconnector' are used interchangeably in this report.

[2] NERA, Comments on Murraylink's Application for Conversion to Regulated Status, January 2003, p.10.

[3] As noted in section 2, the Commission has been careful to acknowledge its previous statements on this matter.

Regarding the asset valuation methodology applied by MTC, the most important of the criticisms was that the valuation methodology adopted by MTC was inconsistent with the Commission's 'regulatory test'.[4] At least three reasons were provided for this inconsistency, which were that:

- only the cost of alternative projects were considered, rather than the benefits – and in particular, the relative net benefits of alternative projects;
- related to the previous point, it was argued that the alternative projects to Murraylink were defined too tightly, which precluded analysis of similar (but not identical) options and possibly included 'gold-plating'; and
- sufficient market development scenarios were not analysed when calculating the market benefits created by Murraylink.

A threshold issue for the Commission that is raised by these comments is whether all of the parallels with the conduct of the 'regulatory test' necessarily are relevant – or appropriate – to the determination of asset values for regulatory purposes. Any methodology for valuing assets – and revaluing assets over time – needs to achieve predictability of operation, as well as a reasonable degree of administrative cost. The types of analysis required to satisfy the criticisms summarised above would imply a degree of subjectivity – and new analysis – that would be unlikely to satisfy either of these objectives. This matter is discussed in section 4.

Lastly, a concern at the centre of many of the comments of market participants – or their representatives – was that Murraylink's conversion could lead to market participants 'paying twice' (through regulated transmission use of system charges) for part or all of the service potential that is created by Murraylink. Market participants can form their own views about whether such duplication is likely to occur in practice. However, even should such duplication occur, whether the costs recovered from market participants (through TUOS charges) increase as a result would depend upon how the Commission applies a ODV valuation to assets that – in combination – are excess to requirements. This matter is discussed in section 5.

Section 6 then comments on a number of miscellaneous regulatory issues, which include:

- *the 'commercial discount rate'* – out of the alternative 'commercial discount rates' that have been proposed, the estimate used by MTC appears to have been the only one derived from objective capital market information, which is the information relevant to cost of capital estimation; and
- *the assumptions reflected in the regulatory WACC for Murraylink and regulatory period* – consistency with its previous regulatory decisions would imply the Commission using a 10 year bond rate as the risk free rate (reflecting the length of the regulatory period), and the merits (and provisos) identified in the NERA submission with the use of a 10 year regulatory period are supported.[5]

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[4] Australian Competition and Consumer Commission, Regulatory Test for New Interconnectors and Network Augmentations, December 1999.

[5] NERA, op cit, p.26.

As noted above, this report focuses on the main economic issues that were raised in submissions on MTC's application. A number of comments have been made in submissions on the detailed implementation of the ODV asset valuation methodology to Murraylink, including on the cost of alternative projects and related matters like the extent of undergrounding required, the assumptions reflected in MTC's modelling of the market benefits of Murraylink as well as on technical matters, such as the expected power flows from the use of the Murraylink asset and the appropriate reliability targets. It is understood that these matters either have been – or will be – addressed in other submissions by MTC, and are not the subject of this report.

2. Guiding Principles for Asset Valuation

2.1 Efficiency and Asset Valuation

An overarching objective of all of the reforms to Australia's utility industries under the broad framework of national competition policy is the promotion of economic efficiency. Indeed, in its recent report on the operation of Part IIIA of the *Trade Practices Act 1974* (the 'national' access regime), the Productivity Commission recommended that the relevant legislation be amended to clarify that economic efficiency is the primary objective. The Commission itself has recognised the importance of economic efficiency as the guide for regulatory decisions, a position it has taken consistently across all industries.

Economic analysis takes as given that we have only limited resources available, and the goal of an economy – economic efficiency – is to use those limited resources in a manner that maximises the net benefit to society. While there are a number facets of economic efficiency – which include that only goods and services sought by customers are produced, that they are produced for least cost, and that these conditions continue to be met over time in the face of changing tastes and technology – the underlying requirement is that an economy makes best use of the resources it has. Applied to Murraylink – given this asset already exists (and cannot be reversed), the relevant objective is to use it in a manner that maximises economic efficiency.

A relevant question for the Commission – and one not expressly addressed in the submissions to MTC's application – is whether its conversion (and the terms of that conversion) from a market network service to a regulated interconnector would advance economic efficiency – that is, whether its conversion (and the terms of that conversion) would be good for the economy overall.

When analysed objectively, it is difficult to see how Murraylink's conversion to a regulated service could reduce economic efficiency, and indeed the arguments made in related matters would suggest that Murraylink's conversion may provide substantial efficiency improvements. There are two routes through which efficiency may be advanced.

First, it has been argued that, when operated as a market network service, MTC may have an incentive to withhold part of Murraylink's capacity.[6] If true, then in times of constraint between regions, more expensive generation than required would be used, and a loss of efficiency would result. While MTC disputes the magnitude of this incentive – and no independent view of this matter is provided here – its conversion to a regulated interconnector would remove any incentive or ability to withhold its capacity from the market, and so preclude any such inefficiency.

[6] MTC's (or any other MNSP's) incentives with respect to the withholding of capacity are complex, and not independent of the regulatory framework within which they operate. To the extent that an MNSP negotiates hedging contracts with other market participants, it would have an incentive to place the corresponding amount of capacity onto the market (at least in the circumstances where withholding capacity may affect efficiency). However, its ability to sign hedging contracts with other market participants is dependent upon those other participants' expectations about future price differentials between regions, which in turn are dependent upon expectations of the implications of the regulatory arrangements for new developments between regions (in particular, the application of the 'regulatory test').

Secondly, operating Murraylink on an open access basis may also provide for a more certain environment for the planning of the national electricity grid. This reflects the fact that all of Murraylink's capacity (subject to the relevant power system constraints) would be available for the independent operator to use in a manner consistent with the solution to the (known) system optimisation algorithms, rather than the available capacity being determined by MTC's bidding behaviour. Indeed, the arguments of other parties to other related matters would suggest that Murraylink's conversion to a prescribed service may remove a barrier to efficient investment proceeding.

- The National Electricity Tribunal summarised TransGrid's concern about the commercial feasibility of the unbundled SNI project (USNI) as follows:[7]

  > TransGrid's reason for not undertaking USNI is that it would lead to a risk of "asset stranding". It has declined to be a proponent. Its stated fear is that Murraylink, as an unregulated interconnector undertaking its activities by way of arbitrage, might so conduct itself that TransGrid's investment in USNI could become stranded. It contends that USNI would be dependent on the flow of power over Murraylink, and that Murraylink would have the capacity and the financial incentive to withhold flow, which would have as a consequence the possible stranding of USNI.

- This perceived 'stranded asset risk' – and hence TransGrid's concerns about the commercial viability of the more efficient unbundled SNI project – presumably would disappear with Murraylink's conversion from a market network service to a regulated interconnector.

Accordingly, the conversion of Murraylink to a regulated interconnector may enhance efficiency, and potentially enhance efficiency substantially, if the arguments that other parties have made in related proceedings are correct. These efficiency benefits would flow irrespective of the terms of Murraylink's conversion (that is, irrespective of its regulatory asset value). The main issues of contention with the MTC application, therefore, come down to the distribution of the benefits that are provided by the Murraylink interconnector between MTC and other market participants.

If *static efficiency* alone is considered, the distribution of the benefits of Murraylink – to a large extent – is unlikely to affect efficiency. That is, they relate to transfers between the respective parties, the 'sharing of the cake' rather than the 'size of the cake'. However, the valuation methodology adopted by the Commission is likely to have implications for dynamic efficiency, which is discussed below.

2.2 The Importance of Acting Reasonably and Adhering to Commitments

As the Commission is well aware, potential investors in irreversible investments make decisions based upon perceptions of future regulatory decisions, and objectives such as 'fairness' or 'reasonableness of treatment' – which have little to do with *static* efficiency – can have a profound impact on new investment, and hence with the achievement of economic efficiency over time. Indeed, the Commission explicitly recognised the implications for dynamic efficiency of acting reasonably in its very first consideration of regulatory asset valuation for energy utilities, where it commented as follows:[8]

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[7] *In the Matter of an Application for Review of a NEMMCO Determination on the SNI Interconnector Dated 6 December 2001*, per Cripps and Williamson, pp.49-50.

[8] Australian Competition and Consumer Commission, Final Decision: Access Arrangements for Transmission Pipelines Australia, October 1998, p.32. The Commission referenced this discussion of asset valuation in its draft Statement of Regulatory Principles (p.x).

> This discussion [on static efficiency considerations] assumes, however, that the treatment of existing assets can be separated from the treatment of new assets. One consideration for dynamic efficiency is that the price set for existing assets may influence the expectations of investors as to the regulator's treatment of future investment. While the Victorian Access Code clearly separates the treatment of existing assets from new assets, industry participants are likely to see the regulator's treatment of existing assets as setting a precedent for how it will exercise its (generally wide) discretion when making other decisions under the Victorian Access Code in the future. Therefore, opportunistic behaviour by the regulator with respect to existing assets may dampen the incentives for investment in the industry.

One of the means that regulators use to limit the uncertainty with respect to a regulator's potential future decisions is to make statements about how they are likely to exercise that discretion. A dominant purpose of such statements is to provide the degree of confidence about future regulation – and hence future revenue – required for investors to fund large projects where the costs are (economically) sunk.[9]

The Commission has made a number of statements about the valuation of assets that are relevant to this application. The draft Statement of Regulatory Principles proposes the use of a depreciated optimised replacement cost (DORC) methodology for valuing and revaluing regulated assets together with the ability to write-down assets to below the DORC value where this exceeds its economic value.[10] These two valuation rules combined amount to what is normally referred to as an optimised deprival value methodology (ODV), consistent with clause 6.2.3(d)(4)(iv)(A) of the National Electricity Code. The Commission has noted that the same principles should apply to the determination of a regulatory asset value for an asset converting to a regulated interconnector:[11]

> The Commission will consider any applications to convert from market to prescribed status on a case by case basis. However, the *Draft Regulatory Principles* clearly set out the process that incumbent NSPs must follow at each regulatory review [for setting revenue caps] and applicants for conversion of network services to prescribed status will have to follow the same process. The Commission will develop the *Draft Regulatory Principles* to set out the process and guidelines needed to formalise the conversion arrangements.
>
> Further the *Draft Regulatory Principles* set out that a DORC valuation will be used to value (or revalue) the asset base of the NSP. The Commission considers that the DORC valuation allows for consideration of all possible options for replacing existing network services, as well as consideration of current and future utilisation rates. The effect of a DORC valuation will be that the network is valued to reflect the least cost solution to resolve any demand and supply imbalance needing to be addressed. Thus the process of changing status of network services requires the NSP to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test. The processes set out in the *Draft Regulatory Principles* may be simpler than the regulatory test processes but the Commission considers that no material advantage will accrue to NSPs converting from market to prescribed status through bypass of the regulatory test.

[9] The term 'sunk cost' implies that the related asset has no practicable alternative use. In such a situation, it is not possible for the asset owner to withdraw the physical asset from one activity and use it in another if the profitability of the first activity falls.

[10] Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, Proposed Statements S4.2 and S4.3, p.53.

[11] Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138.

It is reasonable to interpret this statement as confirming that the Commission would apply the same process and rules for setting revenue caps – and most importantly for the matter at hand, for deriving regulatory asset values – to all regulated networks, irrespective of whether the relevant network was an existing regulated network, or the revenue caps were being determined in the context of an asset converting to a regulated asset. The additional guidance the Commission provided was that it considered that a DORC valuation methodology would be consistent with the application of the regulatory test for prospective new projects.[12]

As discussed in section 4 below, the Commission's statement about the equivalence of the regulatory test and ODV is true, provided the *economic value* constraint in the ODV valuation is calculated in a manner consistent with the calculation of market benefits in the regulatory test. The asset valuation methodology adopted by MTC has adopted *market benefits* calculated in accordance with the 'regulatory test' as the measure of the economic value of the Murraylink asset, reflecting the intent of the Commission.

The Commission's Issues Paper on the MTC application demonstrates its awareness of the statements and reasonable expectations that it has made regarding the setting of revenue caps in general and the regulation of interconnectors converting to regulated assets in particular, and implicitly of the importance of acting in a manner that is consistent with its previous statements.[13] Moreover, in other relevant matters, the Commission has been careful to act in accordance with its previous statements in circumstances where it is reasonable for those statements to have been acted upon.

The alternative asset valuation methodology that has been proposed – that is, to determine the value for Murraylink such that all market participants benefit from its conversion to a regulated interconnector – is not consistent with the previous guidance the Commission has provided on this matter. As the Commission has provided guidance as to how it would deal with interconnectors that convert to regulated interconnectors – long term efficiency considerations dictate that its previous guidance should be applied, and the ODV methodology applied to determine the regulatory value for the Murraylink asset.

Irrespective of the Commission's previous commitments, however, it is considered that there are a number of weaknesses with the proposed alternative valuation methodology. These issues are addressed in section 3 below. First, however, a number of comments about the rational for permitting an MNSP to convert to a regulated interconnector are addressed.

2.3 Rationale for the NEC Conversion Provisions

A number of submissions have implied that it is undesirable for the Commission to permit the Murraylink asset to convert to a regulated interconnector as this would permit it to escape from the commercial risk that it took when it committed to the project. TransGrid comments that:[14]

> [t]he conversion process should not under any circumstances be allowed to be used merely to bail out bad commercial decisions.

[12] It is assumed in this discussion that the Commission intended to apply the ODV methodology to converting interconnectors – that is, to retain the discretion to value assets at less than DORC if the economic value constraint was met – reflecting its proposed treatment of other regulated assets.

[13] Australian Competition and Consumer Commission, Issues Paper: Murraylink Transmission Partnership – Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue, February 2003.

[14] TransGrid, Murraylink Transmission Company Application for Conversion of Murraylink to Prescribed Services, March 2003, p.1.

The ability for a market network service to convert to a regulated interconnector – including the reference to the Chapter 6 revenue setting principles – was included in the National Electricity Code prior to Murraylink's construction, and the Commission's statements as to how it would apply Chapter 6 to value assets in general already had been made. It is reasonable to expect that MTC's assessment of the commercial viability of the Murraylink investment took account of the 'escape clause' in the NEC, and that the existence of the clause influenced its decisions of whether to proceed with the project. Accordingly, it is difficult to maintain that the 'escape clause' in clause 2.5.2 of the NEC is being used by MTC in a manner that was not envisaged when the relevant clause was inserted in the NEC.

A more general question is whether such an 'escape clause' as exists in clause 2.5.2 is appropriate.

The ability for a market network service provider to capture the market benefits that it provides to the market – and hence the profitably of these projects – depends critically on both the efficiency of the NEC provisions and the administration of those provisions. Indeed, it is difficult to imagine any other activities for which the design and administration of the market and regulatory arrangements can have a greater effect on a project's viability. Without some protection against unfavourable regulatory developments that affect their ability to capture the benefits created, it may well be that investment in unregulated interconnectors would seldom be financially viable. Indeed, the dependence of the ability of MNSPs to capture the benefits they create on the efficiency of the national electricity market was recognised by the NECA Working Group that developed the 'safe harbour' provisions for MNSPs:[15]

> As already noted, the concept of a non-regulated interconnector is still somewhat experimental. It might be argued that as well as the usual commercial risks, the proponent of a non-regulated interconnector may face additional risks related to market design deficiencies that may only become apparent once the first interconnectors are operational.
>
> Providing a right to apply for regulated status may help ensure that investment is not inefficiently inhibited by such non-commercial market design risks. However it is important that the conversion option should not shield the proponent from normal commercial risks, e.g. the risk of having over-judged the future demand for the interconnection service. It is therefore essential that the regulated revenue entitlement is based on the assessed need for the facility at the time of the application, rather than guaranteeing a return on the original capital cost.

In light of these concerns, the Working Group's recommendation was that the 'safe harbour' provisions to be inserted in the National Electricity Code be drafted so that '[t]he interconnect owner can apply to convert to regulated status at any time'.[16]

The administration of the relevant market rules – as well as the rules themselves – can have a substantial impact on a project's viability. Clearly, an important factor that will affect the viability of any MNSP is the application of the 'regulatory test', which remains subject to substantial uncertainty. Moreover, uncertainty with respect to the 'regulatory test' may affect an MNSP's ability to extract the benefits it creates well before any duplication occurs as this uncertainty will affect the propensity for participants to sign contracts for the benefits they receive.

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[15] NECA Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors, Entrepreneurial Interconnectors: Safe Harbour Provisions, November 1998, p.9.

[16] NECA Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors, Entrepreneurial Interconnectors: Safe Harbour Provisions, November 1998, p.9.

It is also possible that investors may make decisions based upon assumptions that the relevant market rules would change – and in particular, that changes that enhance economic efficiency – would be made. There are also a number of improvements to the national electricity market rules that a reasonable person may have expected to have occurred, and which would affect the capacity of MNSP's to capture the benefits that they create. These include:

- *Value of Lost Load (VOLL)* – NECA's recommendation to increase VOLL to $20,000 has not been implemented, notwithstanding the Commission's acceptance that such a value would be more efficient. The lower VOLL constrains the value of the services MNSP's provide to below efficient levels.
- *Nodal pricing* – despite numerous recommendations for the increasing the locational signals in the market, there has been little movement in this direction.
- *Settlements* – while prices are calculated in the national electricity market for each five minute interval settlement is conducted for 30 minute time intervals, with the prices calculated as a simple average of the five minute prices. In addition, settlements assume that flow along interconnectors proceeds in only on direction during the 30 minute settlement period, whereas energy can flow in both directions during this period. Both of these rules reduce the efficiency of pricing in the national electricity market – and limit the extent to which MNSP's can capture the benefits that they create.

Given the risk associated with changes to the national electricity market rules, failures to change the rules as expected, and with the administration of those rules, it is not unreasonable for an 'escape clause' to exist for MNSP's. Indeed, without such a clause, it may well be that such investments could not be justified.

3. Application of the 'Incremental Benefits' Asset Valuation Methodology

As discussed above, it is considered that the 'incremental benefits' valuation methodology – as described in the NERA submission and reflected in other submissions – is not the correct methodology to apply to determine the regulatory asset value for the Murraylink asset. The Commission described the manner in which it would value assets converting from market network services to prescribed services in its draft Statement of Regulatory Principles – which reflects the methodology described in Chapter 6 of the National Electricity Code – and upon which expectations, substantial investments have been committed. As the ACCC is well aware, resiling from commitments that it has given – and given for the sole purpose of providing investors with guidance about how the Commission will exercise its discretion in the future – is unlikely to promote economic efficiency or any of the other objectives of the national market.

Even if the Commission's assessment of the MTC application was not guided by the relevant legislation and the Commission's own statements on the matter, however, it is not clear that significant weight should be accorded the 'incremental benefits' methodology.

On the face of it, the 'incremental benefits' valuation methodology has some appeal – it would ensure that other market participants could not be made worse off (as a group) as a result of the conversion of a market network service into a prescribed service. Although, as always, some individual market participants could be made worse off, provided that others were made correspondingly better off. When analysed more closely, however, it is patently unreasonable.

The formula for the 'incremental benefits' methodology implies a regulatory cost for the prescribed services consistent with the minimum between:

- the lifecycle capital and operating cost of Murraylink; or
- the expected revenue from Murraylink if it continued to act as an MNSP (denoted below as Revenue [MNSP]) plus the net market benefit associated with Murraylink's conversion to a regulated interconnector.

The first constraint is identical to that proposed by MTC, as discussed above. The relevant constraint for the purposes of this discussion is the second – and will provide a different answer to a standard DORC/ODV methodology to the extent that the amount calculated under this constraint differs to the gross market benefit provided by Murraylink.

The *net market benefit* associated with Murraylink's conversion from an MNSP to a regulated interconnector is simply the difference between:[17]

- the market benefit provided by Murraylink as a regulated interconnector (denoted below as Benefit [Reg]); and
- the market benefit provided by Murraylink as an MNSP (denoted below as Benefit [MNSP]).

[17] It is assumed for the purpose of this discussion that the incremental cost of converting from MNSP to regulated interconnector is negligible.

Accordingly, the second constraint of the 'incremental benefits' valuation methodology can be expressed as:

- *Regulatory Cost* = *Revenue [MNSP] + Benefit [Reg] – Benefit [MNSP]*
  = *Benefit [Reg] – (Benefit [MNSP] – Revenue [MNSP])*

The first of the terms in the expression above is the constraint imposed by the ODV methodology, as discussed above. Accordingly, an implication of the 'incremental benefits' methodology is that the regulatory cost for Murraylink would be set at the ODV, *minus* the benefits that Murraylink creates as an MNSP that it is unable to capture (as revenue). That is, the ODV would be adjusted downwards by the amount of benefits created by Murraylink as an MNSP that other market participants are able to enjoy at no cost (that is, the benefits that they are able to 'free ride' upon).

When expressed in this way, it is difficult to argue that the 'incremental benefits' valuation methodology that is advanced in the submissions results in a regulatory cost for Murraylink that could be considered reasonable.

The justification for an 'escape clause' for an MNSP stems from the fact that the rules for the national electricity market and their administration have a profound effect on the capacity of MNSP to capture the benefits that they create. The purpose of the 'escape clause' is to provide the ability to convert to a regulated interconnector should either the rules – or the administration of the rules – change or fail to change as expected and so affect the extent to which the benefits created can be captured.

Against this background, it would appear counter-intuitive to set a regulatory value for a converting MNSP which had the effect of compensating it for *all* of the market benefits it creates *except* for those it was unable to capture as an MNSP.

More generally, the 'incremental benefits' valuation methodology has the effect of giving market participants a right to continue to receive for free benefits that technically they are 'free-riding' upon.[18] While the parties (and their representatives) who receive benefits at no cost would be expected to support the continuation of such a situation, there is no strong economic or public policy reason for preserving the status quo. Rather, the appropriate response in the face of a market failure such as 'free-riding' is to seek to correct that market failure – or to apply any rules that were put in place to address such a market failure should it arise. Clause 5.2.5 of the National Electricity Code and the Commission's statements in the draft Statement of Regulatory Principles were designed to deal with this potential for free-riding, and should be applied.

[18] 'Free riding' refers to the situation whereby agents cannot be excluded from consuming the relevant good or service (referred to as non-excludable) and so are able to receive the good or service without paying for it (insert ref). Goods or services from which agents cannot be excluded (such as national defence) are unlikely to be provided (or provided in optimal quantities) in a market, and some form of government intervention may be justified.

4. Application of the ODV Asset Valuation Methodology

4.1 MTC's Asset Valuation Methodology

Consistent with the Commission's guidance on the matter, MTC has adopted an optimised deprival value (ODV) methodology for deriving a regulatory value for the Murraylink asset. Under ODV, the regulatory value of an asset would be defined as the lesser of:

- the *depreciated optimised replacement cost* (DORC) of the asset; and
- the *economic value* of the asset.

As the Commission has noted previously, the derivation of the *economic value* of an asset – and the use of that value as a regulatory value – can be problematic, given that the regulatory settings determine the value of an asset to its owner, implying a degree of circularity.[19] However, in its application, MTC has broken the circularity by defining economic value in a manner consistent with the estimation of market benefits under the Commission's 'regulatory test'. As discussed further below, this definition of economic value also creates consistency between the Commission's 'regulatory test' and the valuation and ongoing re-valuation of regulated assets, consistent with the intent of the Commission.[20]

In contrast, the objective of a DORC valuation of an asset is well-defined – at least in theory. In principle, a DORC valuation seeks to estimate the maximum price that a person would be willing to pay for an asset against the alternative of constructing a new asset – in effect, an estimate of the price that an asset would sell for if that asset was traded in a liquid second-hand market (like used cars). Accordingly, the value of the old asset would reflect the cost of the new – and optimum – asset, adjusted to reflect differences between the old asset and the new asset (for example, to reflect higher maintenance and renewals capital expenditure of old assets, differences in service potential, etc).[21] In practice, however, a number of administrative simplifications are reflected in DORC valuations – and for good reason, as discussed below.

The dominant criticism of the asset valuation methodology employed by MTC was that it was inconsistent with the Commission's 'regulatory test'. Three specific concerns were raised, which were that:

- only the cost of alternative projects were considered, rather than the benefits – and in particular, the relative net benefits of alternative projects;
- related to the previous point, it was argued that the alternative projects to Murraylink were defined too tightly, which precluded analysis of similar (but not identical) options; and

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19 Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, p.39.

20 Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138.

21 The Commission has discussed the theoretical foundations of the DORC valuation in similar terms: Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, pp.39-40.

- sufficient market development scenarios were not analysed when estimating the market benefits created by Murraylink.

On a related matter, it was also suggested that the asset value included costs in respect of 'non-prescribed services', which should be removed.

A threshold issue for the Commission is the extent to which it is appropriate for the lessons from the application of the 'regulatory test' to be carried over into the Commission's approach to valuing – and re-valuing – assets in the context of periodic revenue cap reviews. This issue is discussed first, followed by the specific criticisms of the MTC asset valuation methodology.

4.2 Regulatory Test vs Asset Valuation (and Re-Valuation)

It is important to understand the specific – and different – contexts of the application of the 'regulatory test' and the valuation and re-valuation of assets for regulatory purposes.

- The 'regulatory test' is applied at a time prior to investment being undertaken (and expenditure sunk). The objective of the 'regulatory test' is to rank the desirability of a particular project against possible alternatives (including the alternative of doing nothing, or doing the same thing at a different time), and the particular project need not rank ahead of alternatives in all of the future scenarios modelled. The benefits and costs assumed in the application of the test have no continuing relevance after the conduct of the test – the value of the new asset will be set at its DORC value (which should reflect its actual cost in the first instance) and then get re-valued at DORC over time.

- Asset valuation methodologies are applied – and reapplied over time – to assign a regulatory value for the relevant network asset. This regulatory value, in term, is used as an input to derive the revenue that the network service provider is permitted to receive from the sale of the services provided by means of that asset. A substantial portion of the allowed revenue for transmission assets reflects capital related costs (typically in excess of 70 per cent), of which the regulatory value is a key input. Investors will only be willing to devote their funds to these projects if the expected return over the life of the project (taking account of the regulator's future decisions) exceeds their required returns.

For the application of the 'regulatory test, it is appropriate that the widest set of alternative options and market development scenarios be considered, given that all options at that stage – literally – are open, and because the only result required of the analysis is either a 'yes – the project passes the test' or 'no – the project does not pass the test'.

In contrast, the methodology that is used to assign a value to assets for regulatory purposes will have a significant effect on the returns available to investors, and hence the expectations about how assets will be re-valued in the future are likely to have a significant effect on the preparedness of investors to devote their funds to the regulated activity. Given the importance of the future asset valuation methodology to investors, it is imperative that the outcomes of that methodology have a degree of *predictability of operation*.

In addition, the Commission has foreshadowed that it may re-set the regulatory value of assets at each revenue cap review, which have typically been at intervals of approximately five years. Where the asset valuation is to be reapplied at such frequent intervals, there is also likely to be merit in standardising relevant aspects of the methodology to *reduce the costs of administering* the relevant methodology.

The full implications of the parallels of the 'regulatory test' for asset valuation – as discussed in the submission by NERA (and reflected in other submissions) – while arguably theoretically correct, are likely to result in an asset valuation methodology that would generate not predictability of operation and involve unreasonable cost of administration. In addition, it is not clear that the adoption of that additional analysis would change the valuation calculated in the current matter. This matter is discussed next.

4.3 Implications of the 'Regulatory Test' for Asset Valuation

Practical Implications of the 'Regulatory Test' DORC

NERA's comments about the asset valuation methodology employed by MTC are phrased in terms of whether the methodology results in a regulatory asset value that passes the 'regulatory test', noting for example:

> In order to ensure that a RAV is chosen for Murraylink such that it passes the regulatory test …

As noted above, however, the matter for the Commission is not the administration of the 'regulatory test', but the determination of a regulatory value for the Murraylink asset. That said, the comments about the consistency of MTC's valuation methodology with the 'regulatory test' can be reinterpreted as a comment on how MTC has applied ODV to its asset.

The key concern that submitters expressed with MTC's asset valuation methodology is that it failed to consider similar – but not identical – projects, and also failed to consider the market benefits of the alternative (similar) projects as well as the costs. It was noted that the 'regulatory test' requires attention to be focussed on 'net market benefits'.[22]

These considerations are equally valid when considering how to apply a DORC valuation methodology in a manner consistent with its theoretical foundations. When the notional purchaser is considering buying the second-hand (sunk) asset, they would be expected to take account of the price – as well as service potential – of similar but not identical assets.

- If there was an alternative asset that cost more than a 'standard' asset – but generated benefits that exceeded the extra cost – then the price the notional purchaser would be prepared to pay for the standard asset would be lower than had the alternative (higher service) asset not existed. The price of the standard asset would fall by the difference between the incremental benefits and incremental cost associated with obtaining the higher service asset. This reduction in the price the notional purchaser would be prepared to pay for the existing asset would reflect the fact that the standard service asset implies that the net benefits associated with buying the higher service asset are sacrificed.

[22] As noted below, MTC was careful to select projects that delivered the same service potential, and so it would be reasonable to assume that the benefits from the alternatives are similar.

- Stated alternatively, the optimum replacement for a particular asset may be one that has a higher level of service potential – which, in theory at least, should be taken into account when deriving the DORC estimate.

The numerical implications of the 'theoretically correct' DORC valuation described above are identical to those derived by NERA in its discussion of the 'regulatory test'.[23] Where the optimum replacement for the current project is one that provides a different level of benefit – for example, a 'higher benefit' project is optimal – the DORC value for the existing asset would be calculated as:[24]

$$DORC_{Standard} = ORC_{Higher\ Service} - \Delta Benefit$$

where $\Delta Benefit$ is the difference in the benefit between the standard and higher service option.

This expression can be rearranged to yield:

$$DORC_{Standard} = ORC_{Standard} - Net\ Benefit$$

where Net Benefit is the change in net benefit from moving from the standard service asset to the higher service asset, which is the difference between the incremental benefits and incremental costs associated with the change in service.

The second of the above formulae is consistent with the formulae employed by NERA.[25]

Before endorsing the refined DORC valuation approach implied by the discussion above for the valuation of transmission network assets, however, the Commission needs to understand the full implications of the change in methodology.

The standard approach to DORC valuation – as applied by MTC – is to fix the level of service required and to derive an estimate of the efficient cost of replacing that service element using current technology.[26] The optimisation step normally takes as given the existing network architecture, and merely asks whether a lower capacity network asset would suffice to meet current demand (for example, this may involve asking whether the demand served by a transmission line rated to 500 kV could be met with a transmission line rated to 330 kV).

In contrast, the application of the service-adjusted DORC valuation would require far more analysis.

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[23] NERA, op cit, pp.3-4. This equivalence between the implications of the 'regulatory test' as derived by NERA and the 'theoretically correct' DORC valuation as discussed above implies that the Commission's intuition that the regulatory test and DORC valuation should produce similar results was correct (Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138).

[24] It is assumed here that the only role for the 'depreciation' step of the DORC valuation is to adjust for the difference in the net benefits associated with alternatives with different service potential. In practice, the 'depreciation' step also adjusts for the difference in the forward-looking cost of operating the old asset compared to the optimal replacement.

[25] NERA, op cit, p.4, table 2.3.

[26] A number of other simplifying assumptions are also typically made when applying the DORC valuation methodology in practice. As an example, as noted in footnote 22, one role of the 'depreciation' step in the DORC valuation is to allow for differences between the forward-looking cost of operating, maintaining and replacing the 'old' (ie existing) asset compared to that of a 'new' asset (in discounted terms). Notwithstanding the theory, it has become standard practice merely to apply straight-line depreciation to the ORC value to derive the estimate of DORC.

- First, all alternatives for providing some or all of the existing service potential *of each network element* would need to be identified and costed (that is, the class of *similar* but not necessarily *equivalent* projects).
- Secondly, the market benefits associated with all of the different options for each of the network elements would need to be estimated (and with a number of market development scenarios run to ensure that the estimated benefits were robust).
- Thirdly, a comparison of the benefits and costs associated with the various alternatives would find the project that was the optimal replacement for the current asset (which is equivalent to the asset that maximises the 'net market benefits'). The service-adjusted DORC would then be calculated using either of the equations – so that if the optimal replacement provided a higher level of benefit than the current asset, DORC value would be adjusted downwards.

Clearly, the level of analysis required to apply the service-adjusted DORC valuation methodology is significant, and the application of such an approach *uniformly across all transmission network service providers* – consistent with the relevant Code provisions and the Commission's previous statements – would require significant resources, particularly as the analysis would need to be applied across all network elements individually. Moreover, the outcomes of such an analysis are unlikely to be predictable – particularly as the class of 'similar but not equivalent assets' is broadened. Thus, the service-adjusted DORC valuation methodology is unlikely to meet either of the objectives noted above of *predictability* and involving *reasonable administrative costs*.

We are unaware of the Commission or any other energy regulator having applied such an approach for estimating a DORC value.

A Reasonable Approximation

As noted above, the approach adopted by MTC is to decide upon and fix the level of service, and then to determine the least-cost means of providing that service potential, which follows standard practice – a point acknowledged by the Commission.[27]

As MTC has fixed the level of service potential to be provided by the asset, a reasonable assumption would be that the market benefits associated with alternative projects are similar, and thus unlikely to have a significant effect on the valuation determined. Indeed, the difficulty with quantifying the market benefits associated with different options provides a good rationale for being careful to have regard to only projects that have very similar functions when undertaking a DORC valuation.

Lastly, it needs to be noted that the relative market benefits associated with alternative projects are only relevant to the extent that those alternative projects are likely to provide 'net market benefits'. Under the ODV approach, alternative projects only affect the DORC valuation – and so a change to the DORC valuation would only affect the ODV of an asset in instances where the *economic value* constraint is not binding.

[27] Australian Competition and Consumer Commission, Issues Paper: Murraylink Transmission Partnership – Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue, February 2003, p.4.

The operative constraint on the ODV for the Murraylink asset is the economic value, rather than its estimated DORC value. Accordingly, any change to the DORC value on account of providing different levels of service would only affect the ODV to the extent that it was sufficient to change the relativity between economic value and the DORC value.

4.4 Market Development Scenarios

As noted above, MTC's ODV estimation was also criticised for not undertaking sufficient 'market development scenarios'. The assumed market development scenarios are of prime importance to MTC's estimation of the economic value associated with the Murraylink asset – although the (theoretically-correct) service-adjusted DORC value discussed in section 4.3 would also be affected by different scenarios.

It is understood that MTC has provided the Commission modelling results that are implied by the different market development scenarios, which provides an indication of the sensitivity of the estimated market benefits to different market development scenarios. This report comments only on the conceptual issue of how the Commission should use the different scenarios.

In the context of applying the 'regulatory test' – at which time no capital has been sunk and 'all options are open' – it is appropriate for a large number of market development scenarios to be tested. As discussed already, all the analysis is required to produce is an indication that a particular project is superior to all other options in most but not all cases, and a wide array of plausible scenarios – if interpreted carefully – can only assist with this decision.

However, where market benefits are calculated for the purpose of applying the ODV methodology, the output required by the analysis is a single number – not a range. To the extent that it was possible to assign the probability associated with different scenarios on an objective basis, then adding scenarios can assist – the appropriate number would be the expected (probability-weighted) value of the scenarios. In practice, however, it is unlikely that there could be any objective basis for assigning probabilities to the different scenarios, making it unclear whether expanding the number of scenarios improves the information set available.

Rather, a more robust estimate of the market benefits associated with a project – and hence the estimated economic value of the project, as required for the application of ODV – would come from undertaking only a limited number of market development scenarios – or, preferably, only one scenario – and focussing instead on the assumptions reflected in that scenario.

Moreover, if the Commission adopts the approach used by MTC to estimate the *economic value* of assets when applying the ODV to other transmission network service providers, it is likely that some form of standardisation of the calculation of economic value would be warranted. The easiest means of standardising this calculation would be for the Commission to prescribe one or a small number of market development scenarios for any particular asset revaluation.

5. Impact of Conversion on Customers and Other Market Participants

One of the key concern of market participants or their representatives is that the conversion of Murraylink to a prescribed service risks them 'paying twice for interconnection through the Riverland corridor'.[28] An implicit assumption behind this is that a project that duplicates the service provided by Murraylink may be built and also recovered (as a prescribed service) through TUOS charges.

Whether duplicate investments occur will depend upon the decisions of the relevant network provider or providers, and participants can form their own opinions as to whether such actions will eventuate.[29]

However, even if duplication of Murraylink's service did occur, it is not certain that customers could 'pay twice' for that or a similar service.[30]

To date, the Commission has not stated that it will not re-optimise an asset that passes the regulatory test. Moreover, even if the full value of an asset that passed the 'regulatory test' were to be reflected in TUOS charges immediately, the Commission has made it clear that it will re-optimise all investments at future reviews – irrespective of whether they historically had passed the regulatory test.

A standard application of the ODV methodology discussed above would imply that the assets reflected in the regulatory asset base for any entity would be optimised to the asset required to serve the demand. To the extent that a service was duplication – and there was insufficient demand to justify that duplication – it would be expected that value ascribed to one or both of the 'duplicating' assets would be written down to reflect that required for current and forecast demand.

- In the case of duplicated service potential, it would be expected that the Commission would write-down the value of the second of the assets constructed to that of an asset required to serve the incremental demand. This approach would imply that any provider who duplicated existing service potential would face substantial stranded asset risk – which would reduce the likelihood that unnecessary duplication would occur.

The effect would be that customers and other market participants would only pay once for the assets used to provide prescribed services.

[28] ESPIC, 'Planning Council Submission – Murraylink's Application for Conversion', 28 February 2003, p.6.

[29] As discussed in section 2.1, concerns expressed by parties in a related matter about the uncertainty (or, more particularly, potential stranded asset risk) arising from Murraylink's operation as a market network service would suggest that Murraylink's conversion from a market network service to a prescribed service may remove a barrier to more efficient network investment. This reduction in uncertainty would be expected to reduce the likelihood that part or all of Murraylink's service potential will be duplicated (at least prior to the time at which demand would be sufficient to warrant the duplication).

[30] Note that it is unlikely that a duplicate project would provide all of the services provided by Murraylink, as some of the benefits it provides reflect its unique technology.

6. Other Issues

6.1 Commercial Discount Rate

A number of submissions have noted that the discount rate applied by MTC to derive the present value of its future market benefits differs from the discount rates that have been applied in other applications of the regulatory test, and in particular, that the rate used is lower than that previously applied.[31] The comments in submissions noted that use of a lower discount rate would raise the present value of the market benefits.

It would appear to be widely accepted that the discount rate should reflect the cost of capital associated with an investment in unregulated activities in the electricity supply industry (referred to as a 'commercial discount rate'), and no comment is made on this view.

While other studies have used higher discount rates than that employed by MTC when applying the regulatory test, it is not clear how those discount rates have been calculated.

The cost of capital associated with an activity is equivalent to a price that investors require to devote their investment funds to an activity. However, unlike prices for most goods and services, the cost of capital cannot simply be observed, but *can only be estimated* from the available capital market information, interpreted through a well-accepted financial model.

- The *cost of capital* associated with an activity – which is unobservable – must be distinguished from other discount rates that can be observed – such as investor hurdle rates. At best, hurdle rates reflect those investors' estimates of the cost of capital associated with the relevant activity. More likely, the hurdle rates also embody other management objectives – such as a tool for capital rationing, or for offsetting 'optimism bias' in managers – that would cause the hurdle rate to overstate the firm's estimate of the cost of capital associated with the activity.

Consistent with the discussion above, the estimate of the 'commercial discount rate' by MTC is based upon available capital market information, interpreted through a well-accepted financial model. The capital asset pricing model was used, which is probably the most widely used model for estimating costs of capital in the world. The comments in submissions have not directed the Commission to alternative and superior estimates of the cost of capital associated with the relevant activities that reflect capital market information interpreted through a well-accepted financial model.

[31] NERA (NERA, op cit, pp.17-19) also raised a number of technical issues associated with MTC's derivation of the commercial discount rate from the relevant parameter estimates. It is understood that Deloitte Touche Tohmatsu has addressed these comments in a separate report, and so these matters are not discussed here. It is also understood that the adjustments implied by NERA's comments did not have a material effect on the estimate of the commercial discount rate.

In addition, most financial models – the capital asset pricing model included – requires continuous observation of economic returns, which inevitable constrains the set of firms that can be used to estimate the cost of capital associated with a relevant activity to those listed on the stock exchange. Moreover, as there are problems with comparing information derived from capital market information across countries – the most relevant piece of information being the estimate of the equity beta – it is highly desirable that those firms that are used to estimate the cost of capital associated with the relevant activity be Australian firms.

A key feature of the Australian capital market is the recent growth in the number of energy-sector entities that are listed on the Australian Stock Exchange, both in regulated and unregulated activities. In general, as there is substantial estimation error in estimating equity betas – an input into the capital asset pricing model – the largest possible set of entities whose activities are considered comparable to the activity in question – should be used. In addition, it is generally considered that about four or five years of capital market observations are required to obtain stability in beta estimates.

The recent growth in the amount of relevant information available from the Australian capital market for estimating a commercial discount rate would suggest that the latest beta estimates of the relevant parameters would be superior – reflecting both additional entities in the set of comparable entities, and a longer time series of observations. This would suggest that historical estimates of the commercial discount rate may be less valid than more recent estimates of the commercial discount rate.

6.2 Regulatory WACC and Regulatory Period for Murraylink

In its submission, NERA offers a number of comments about the inputs that MTC has used to estimate its cost of capital for regulatory purposes (regulatory WACC). NERA notes that MTC has used a 10 year bond rate, which differs from the Commission's practice of using the yield on 5 year bond rate.[32]

NERA's comment about the Commission's practice with respect to the term of the bond that is used in the estimation of the regulatory WACC is not correct. The Commission's policy has been to align the term of the bond rate used for this purpose with the term of the regulatory period. As MTC has proposed a 10 year regulatory period, it would be consistent with the Commission's standard practice to use a 10 year bond rate as the proxy for the risk free rate.

It is noted that NERA would appear to support the use of a 10 year regulatory period rather than a 5 year period for Murraylink on the basis that the magnitude of any efficiency gains are likely to be low, and that periodic reviews impose administrative costs, subject to any cost pass-throughs being better defined and symmetric in operation.[33] We also see merit in permitting a 10 year regulatory period, and also support the provisos noted by NERA.

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[32] NERA, op cit, p.24.

[33] NERA, op cit, 25-26.

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4 April 2003

The Directors
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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"). MTP's application was provided to the Australian Competition and Consumer Commission ("ACCC") on 18 October 2002.

As part of this application Deloitte provided a letter to MTP titled "Regulatory Test – Murraylink Discount Rate", dated 16 October 2002, which developed 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 (the "Regulatory Test Discount Rate"). An estimate was also required of the low and high case scenarios around this base discount rate. The following table summarises the discount rates calculated (the discount rates are a real, pre-tax weighted average cost of capital ("WACC"):

Discount Rate	
Low	7.76%
Base	9.25%
High	10.40%

Subsequently, MTP's application has been subject to a public submissions process and a number of submissions have been made that refer to the Regulatory Test Discount Rates estimated.

As a result, MTP has requested Deloitte to perform the following agreed upon procedure:

1. Provide a response on the matters raised in submissions relating to the Regulatory Test Discount Rate. In particular, National Economic Research Associates ("NERA") has provided the only substantive comments in relation to the Regulatory Test Discount Rate in its report commissioned by TransGrid and Deloitte should refer specifically to section 3.1.4 of this report.

This letter reports our findings in relation to this agreed-upon procedure.

Deloitte
Touche
Tohmatsu

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 of MTP 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.

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.

We note that we have not been requested to update our analysis for changes in the parameters underlying the Regulatory Test Discount Rate as a result of changes in markets (for example, movements in the market's expectation of future inflation or the current level of risk-free interest rates or debt margins). It is expected that these parameters will be updated at the time of the ACCC making its final decision.

RESPONSE TO NERA COMMENTS

TransGrid commissioned NERA to provide a report on MTP's application. NERA produced a report titled "Comments on Murraylink's Application for Conversion to Regulated Status: A Report for TransGrid", dated January 2003 (the "NERA Report"). Section 3.1.4 of the NERA Report specifically discusses a number of issues regarding the Regulatory Test Discount Rate.

The NERA Report is the only submission to the ACCC regarding MTP's application that discusses the discount rate in detail[1]. The key issues raised in the NERA Report were:

- 9.25% base discount rate is significantly below previous applications of the regulatory test that used a central estimate of 11%
- The parameters used in deriving the discount rate estimates are more applicable for a regulated business rather than a commercial business
- Lack of rationale for the 'low' discount rate
- Whether the Intelligent Energy Systems ("IES") parameters are nominal or real
- Whether the 'high' discount rate is pre or post tax
- Calculation of the equity beta for the 'base' discount rate

[1] The only other major comment was made by ElectraNet SA in paragraph 5.48 of its submission titled "Submission to ACCC Re Murraylink Transmission Partnership's Application for Conversion to a Prescribed Service and Maximum Allowable Revenue", March 2003. The issues raised by ElectraNet SA are covered in the discussion of the NERA Report issues.

Deloitte Touche Tohmatsu

- Inconsistency in the return on equity between the 'base' and 'high' discount rates
- Conversion from nominal to real using the Fisher Equation

Each of these key issues is discussed below.

Comparison of 9.25% to 11% discount rate

NERA indicates that the 9.25% discount rate used in MTP's application is lower than previous discount rates used of 11%:

> "*The 9.25% discount rate used by [MTP] is significantly below the central estimate of 11% used in other recent applications of the regulatory test.*"[2]

Further they go on to state:

> *"The IRPC used a real pre-tax commercial discount rate of 11% in its assessment of SNOVIC 400 and SNI.*
> *…*
> *The commercial discount rate has proved to be a relatively uncontroversial parameter in the regulatory test assessment. However, it should be noted that the IRPC was only required to* rank *alternative projects under the regulatory test, with the absolute values not being relevant. As such, to the extent that changes in the commercial discount rate do not change the rankings of alternative projects, the choice of discount rate would not be expected to be overly controversial. In contrast, [MTP's] choice of the discount [rate] will have a direct impact on the RAV derived for Murraylink."*[3]

In discussing this issue we wish to note the following key points:

- The "central estimate of 11%" appears to have limited supporting variables for its calculation.
- The 9.25% discount rate used by MTP is within the range of 8% to 11%, which is the range of base discount rates used in recent applications of the regulatory test.

These points are further developed below.

In determining an appropriate discount rate for MTP, Deloitte researched previous discount rates used in applications of the regulatory test. It soon became apparent that whilst the 11% discount rate used by IRPC appeared to be the benchmark rate, there was little or no supporting documentation or analysis on to the derivation of that discount rate[4]. As such, it became clear that this discount rate was only being used for the purposes of ranking alternative projects, and as NERA notes, as a result it would be a non-controversial parameter in the analysis.

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[2] Page 17 of the NERA Report.
[3] Pages 17 and 18 of the NERA Report.
[4] NERA do not make any reference in their report to any applications/submissions/literature that indicates the underlying parameters to the estimate of 11%. This may indicate that NERA had the same difficulty as Deloitte in sourcing information on the basis of the 11%.

For MTP the discount rate will have greater significance, as it will be used to derive their regulated asset value. Hence greater analysis was put into the parameters underlying the discount rate to be used. In performing this more detailed analysis, it became apparent that the supposed parameters underlying 11% (we refer to further discussion below on the IES parameters) are not appropriate for the current market situation.

The "rationale for deviating from the 11% commercial discount rate used in previous applications of the regulatory test" was that this base rate of 11% had little supporting evidence and that just because this rate was used in the past does not necessarily mean that this is the right rate to use for MTP's application.

In addition the discount rate determined for MTP was in the range used by VENCorp and IRPC of 8% to 11%. NERA has not provided reasons as to why they do not discuss the VENCorp discount rate, however the 9.25% used by MTP is not significantly different to the mid point of the range 8% to 11%, which is 9.5%, indicating that the base discount rate used is within an appropriate range.

Regulated parameters versus commercial parameters

The NERA Report indicates that:

> *"DTT's analysis uses parameters which are appropriate for a* regulated *business rather than a* commercial *business, and contains a number of unsupported assumptions.*
> …
> *DTT has again used the WACC/CAPM variables applicable to a* regulated *monopoly business, such as the debt equity ratio and debt premium (based on a regulated return), to derive a* commercial *discount rate."*[5]

In discussing this issue we wish to note the following key points:

- Regulators set regulated WACC's as a surrogate for commercial returns, and hence regulated WACC's are a relevant starting point for determining commercial discount rates
- To the extent that regulated and commercial discount rates will differ, this has been reflected in the adjustment made to the equity beta, with no adjustment to the debt margin and gearing ratio

These points are further developed below.

In the ACCC's report titled "Regulatory Test for New Interconnectors and Network Augumentations" dated 15 December 1999 (the "ACCC Guidelines") indicates that:

> *"The net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector."*[6]

The discussion in the ACCC Guidelines further states:

[5] Pages 17 and 19 of the NERA Report.
[6] Page 21 of the ACCC Guidelines.

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"In order to ensure that regulated network investments are undertaken in a competitively neutral way in comparison to generation and non-regulated investments, the [ACCC] has accepted the argument that a commercial discount rate should be used."[7]

One of the principles underlying the determination of WACC's by regulators is to provide infrastructure holders with a competitive market return. For example, the ACCC has stated:

"It is important that the rate of return be set at an appropriate level which reflects a commercial return for the regulated businesses."[8]

The Office of the Regulatory-General, Victoria (the "ORG") has also indicated:

The specific objectives of the regulatory framework and the role of the [ORG] within it, is to act as a surrogate for the rewards and disciplines normally provided by a competitive market."[9]

Hence one would expect that many of the underlying parameters between a regulated and a commercial return would be similar, otherwise one should question whether regulators are getting their estimates of WACC correct.

There will, however, be differences due to risk profiles as regulated businesses have revenue streams that are more certain, whilst purely commercial businesses have greater risk.

The different risk profiles between commercial and regulated projects will see different equity betas, debt premiums and gearing ratios applied when calculating an appropriate WACC for the different projects. However, there are also some parameters that will not change between the two, for example the market risk premium and the real risk free rate.

For those parameters that could potentially be different between commercial and regulated projects (the equity beta, debt premium and gearing ratio), these are discussed below.

The equity beta has been adjusted and is discussed further below.

In relation to the debt premium, the question arises as to whether a commercial discount rate should include a higher debt premium than assumed in the Officer Paper[10]. In relation to the debt margin, the regulated WACC assumed in the Officer Paper is based on a BBB+ rated company, which provides a debt margin of 150 basis points. Analysing current credit ratings of generation companies in Australia indicates that their credit ratings are in the range of BBB to AA-[11].

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[7] Page 5 of the ACCC Guidelines.
[8] Page 71 of the ACCC's "Statement of Principles for the Regulation of Transmission Revenue", dated 27 May 1999.
[9] Page 3 of the ORG's "Electricity Distribution Price Review: Cost of Capital Financing - Consultation paper number 4" dated May 1999.
[10] The Officer Paper is contained in Appendix G of MTP's application.
[11] Standard & Poors Australian and New Zealand Utilities Report, October 2002.

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Company	Credit Rating
Delta Electricity	AA-
Edison Mission Energy	BBB
Snowy Hydro	BBB+

Regarding the gearing ratio the regulated gearing ratio of 60% has been used as it was seen to be slightly more conservative than the 65% used as part of the IES Parameters (refer to comments below). As the 65% was used in support of the 11% benchmark Regulatory Test Discount Rate, the lower rate of 60% (which causes the discount rate to be higher as it includes a greater proportion of the higher equity cost) was seen to provide a more appropriate discount rate.

Rationale for the 'low' discount rate

NERA indicates that:

> *"DTT does not provide any rationale for why this regulated return is a good proxy for a low commercial discount rate."*[12]

In discussing this issue we wish to note the following key point:

- As regulators set regulated WACC's as a surrogate for commercial returns, the regulated WACC's is considered an appropriate starting point for the low point of sensitivity analysis

As discussed above, regulators can set the regulated WACC at a level whereby it acts as a surrogate for the return received in a competitive market. Also, as noted above, there will be differences between the returns of a regulated business and a fully commercial business even though many of the underlining parameters will be the same. To that extent the regulated WACC as proposed in the Officer Paper has been used as the low end of the discount rate range on the basis that the regulated WACC is an appropriate surrogate for the commercial discount rate.

IES parameters

The IES report titled "Application of the ACCC Regulatory Test to SNI: Report to TransGrid" dated 27 November 2000 (the "IES Report") makes the following comments in relation to the 11% discount rate:

> *The ACCC test specifies that discount rates applicable to private enterprise investment be used in the NPV calculation. The discount rates used were 9%, 11% and 13% (pre-tax real). A 11% discount rate is consistent with the discount rate for a 65% geared project in which debt and equity rates are about 9% and 18% respectively. Such values are typical of many utility-based projects. The 9% and 13% discount rates represent a likely range about this rate."*[13]

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[12] Page 18 of the NERA Report.
[13] Page 14 of the IES Report.

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NERA indicate that:

> *"It is not readily apparent that the figures reported by IES are nominal rather than real: DTT's assumption that they are real decreases the discount rate by around 2.2%."*[14]

In discussing this issue we wish to note the following key points:

- The IES 11% discount rate is a real discount rate
- It is not clear from the IES Report whether the 9% and 18% debt and equity rates respectively are real or nominal
- It has been assumed that the rates are nominal, as to assume that they are real would imply unrealistic rates when compared to current market rates

These points are further developed below.

It is readily apparent that the 11% discount rate used by IES was a real discount rate, however it is unclear as to whether the 9% and 18% debt and equity rates respectively are real or nominal. Assuming that the 9% and 18% are quoted on the same basis (that is, they are either both real or both nominal rates), we examined the debt rate of 9% and determined that if this was a real debt rate and if inflation was added, it would imply a nominal cost of debt of around 11.2%. This provides an unrealistic cost of debt when compared to current market rates of debt of approximately 6.9%.

The IES Parameters were used to derive the high discount rate for MTP as these were the only previously reported parameters underlying a Regulatory Test Discount Rate, however, as noted above, they were considered too high to form parameters of the base discount rate when compared to current market rates. This gives these parameters support for sensitivity purposes (as the high-end scenario), but not as the base discount rate.

Pre or post-tax high discount rate

The NERA Report states:

> *"DTT's calculation of the high discount rate does not include any compensation for tax, resulting in the 10.4% derived being a post-tax rather than pre-tax discount rate."*[15]

In discussing this issue we wish to note the following key point:

- The assumptions are clearly noted in our letter dated 16 October 2002 as being pre-tax

It is unclear why NERA have interpreted the high discount rate provided as being post-tax. As the table on page 3 of our letter dated 16 October 2002 indicates, the inputs to the high discount rate are on a nominal pre-tax basis, which are then adjusted by inflation to derive the real pre-tax parameters.

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[14] Page 18 of the NERA Report.
[15] Page 18 of the NERA Report.

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One possible source for NERA's comment is that they have interpreted the IES parameters of 9% and 18% as being on a post-tax basis. The extract from the IES Report above does not indicate whether the debt and equity rates are pre or post tax (although if the figures are consistent with the comments made regarding the 11% base figure, they are on a pre-tax basis). However, if we assume that the debt rate of 9% is post-tax, this would imply that the pre-tax rate is 10.8%[16], once again a value that is high when benchmarked against current market debt rates indicating that the more accurate interpretation is that the 9% discount rate is a pre-tax rate to begin with.

Base discount rate equity beta

The NERA Report indicates that the equity beta is incorrectly calculated as the equity betas had not been unlevered and then relevered to the assumed gearing ratio for the base discount rate. Correcting for this issue results in the following adjustments:

	Previous Analysis		Relevered Equity Beta		
Company	**Equity Beta**	**Included**	**Equity Beta**	**Excluding Outliers**	**Including Outliers**
Energy Developments	0.74	Yes	1.05	Yes	Yes
Energy World	2.49	Yes	2.13	Yes	Yes
Pacific Energy	1.67	Yes	0.29	No	Yes
Pacific Hydro	2.16	Yes	4.49	No	Yes
Origin Energy	1.16	Yes	1.98	Yes	Yes
Horizon Energy	0.36	No[17]	0.24	No	Yes
Simple average		**1.644**		**1.715**	**1.694**

Using the higher of the two new equity betas of 1.715[18], this increases the base discount rate from 9.25% to 9.46%.

These adjustments to the base discount rate's equity beta will have no impact on the low or high discount rates.

Consistency between base and high discount rates

On page 19 of the NERA Report it is noted:

> *"There is inconsistency in the return on equity presented in the base case. The high discount rate uses a return on capital of 18% which DTT comment is a "high-end scenario" - however the base discount rate is based on an 18.28% return on equity, which is* greater *than the high-end scenario."*[19]

[16] Assuming a tax rate of 30% and value of imputation credits of 50%.
[17] Horizon Energy was previously excluded as an outlier.
[18] The equity beta excluding outliers has been used to be consistent with the methodology used in our letter of 16 October 2002 of excluding outliers in the analysis.
[19] Page 19 of the NERA Report.

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The low, base and high discount rate were chosen on a particular scenario for each individual WACC as opposed to looking at a range of outcomes for each particular parameter of the WACC. This does lead to this minor inconsistency. To adjust the high-end discount rate return on equity to be above or consistent with the base case, would then make that return on equity inconsistent with the other parameters used for the high WACC scenario. In addition the high-end scenario WACC is used for sensitivity purposes only and greater emphasis should be placed on the base discount rate.

Nominal to real conversion

We acknowledge NERA's points in relation to the application of the Fisher equation and agree that the Fisher transformation is the accepted methodology for converting a discount rate from nominal to real (or vice-versa). As noted in our previous letter the conversion was calculated to ensure consistency between the calculation of the market discount rate and the calculations contained in the Officer Paper. Adjusting the calculation to the Fisher equation results in the discount rate decreasing from 9.25% to 9.05%, or alternatively taking into account the adjusted calculation of the equity beta would decrease the base discount rate from 9.46% to 9.25%.

Likewise the low discount rate would decrease from 7.76% to 7.59% and the high discount rate from 10.40% to 10.18%.

SUMMARY

In summary the low, base and high discount rates should be adjusted to the following:

	Low	Base	High
Deloitte Letter dated 16 October 2002	7.76%	9.25%	10.40%
Adjustment to equity betas	7.76%	9.46%	10.40%
Adjustment for Fisher Equation	7.59%	9.25%	10.18%
Update Discount Rates	**7.59%**	**9.25%**	**10.18%**

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

Yours sincerely

Deloitte Touche Tohmatsu

Peter Thornely
Partner

Further Comments on Murraylink Reliability Benefits and Other Modelling Issues

Prepared for

Murraylink Transmission Company

By

TransÉnergie US Ltd.

April 4, 2003

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Contents

1 Introduction

A number of submissions have been made to the Australian Competition and Consumer Commission in relation to Murraylink Transmission Company's (MTC's) application of October 18, 2002 and TEUS' report contained in Appendix D of the application.

Some of these submissions have observed that the method TEUS used to calculate Murraylink's reliability benefits is different from the method used by the Inter-regional Planning Committee for SNI, that TEUS has not explicitly modeled reliability entry plant, and that the inclusion of reliability plant would provide a lower level of unserved energy. This paper explains why TEUS believes the method it has used is more appropriate, and, simply for the purpose of comparison, how its results would be different if TEUS had used a method that explicitly incorporated reliability entry plant.

This paper also deals with a range of other issues that were raised by stakeholders in relation to market modeling and the calculation of Murraylink's market benefits.

2 Reliability Benefits

2.1 The Unserved Energy Standard and Reliability Entry Plant

The NECA Reliability Panel recommends a maximum level of unserved energy (USE) less than or equal to 0.002% of annual energy consumed. Active enforcement of this reliability standard presumes that:

- the National Electricity Code (Code) will continue to enable NEMMCO to procure reserve contracts for any additional capacity resources[1] (referred to generally as "reliability entry plant"); and
- NEMMCO will determine to enter into reserve contracts for the provision of reserve to ensure that the reliability of supply in a region meets the reliability standard.

For a previous studies conducted by NEMMCO in which reliability benefits of a new interconnector have been calculated, an estimate has been made of the change in the amount of reliability entry plant that NEMMCO would procure if the interconnector is in place. The reliability benefit was the economic benefit of avoiding investment in that plant.

[1] The additional resources could be supply-side (i.e. new generation), or demand-side (i.e. interruptible load).

2.2 The TEUS Method

In the estimate of Murraylink's Gross Market Benefits prepared by TEUS and submitted to the Commission with MTC's application in October 2002, TEUS estimated Murraylink's reliability benefits by measuring the expected change in unserved energy attributable to Murraylink's operation, and valued at the current VoLL of $10,000/MWH as described in Appendix D of Murraylink Transmission Company's Application for Conversion to regulated status..

2.3 Most Appropriate Method

TEUS strongly believes its method remains the best approach to estimating the true value of an interconnector's reliability benefits.

The points described in section 2.1 of this paper are the essential features of NEMMCO's reserve trader function and are designed to deal with circumstances in which market forces fail to bring forth the necessary generation investment during the period in which the NEM matures[2]. To date, no such reserve contracts have been written. Currently, the Code specifies that NEMMCO's reserve trader function will come to an end on 1 July 2003. NECA has applied to the Commission seeking authorization of Code changes that could extend NEMMCO's reserve trader functions until July 2005, and the Commission's decision is pending.

TEUS's method is fully consistent with the National Electricity Code and the expectation that, even if NEMMCO's reserve trader functions are extended until July 2005, there is less chance that it will be extended beyond that time given the extent to which the market had matured already and the potential for the very existence of the reserve trader Code provisions to distort on-going market outcomes. In any case, given the lead times necessary to bring on new generation plant and the uncertainties of load forecasting, there are real practical impediments to the effectiveness and precision with which NEMMCO, as the reserve trader, can achieve its objective.

The TEUS methodology presumes only that VoLL represents the appropriate value of USE, and that market forces will continue to determine future market entry.

In fact, by relying on a value of VoLL of $10,000/MWh even in real terms, TEUS may actually underestimate the true benefit, when one considers that VENCorp is proposing to use a value of $29,600/MWh for transmission planning purposes[3].

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[2] NECA 19 September 2002, Letter to ACCC seeking authorisation of Code changes that could extend NEMMCO's reserve trader functions until July 2005.
[3] VENCorp 25 March 2003, *Response to submissions: The value of unserved energy to be used by VENCorp for electricity transmission planning*.

3 Results Incorporating Reliability Entry Plant

To the extent that NEMMCO's reserve trader functions operate actively in the future, additional reliability entry plant would be added in amounts and locations as necessary to ensure that annual expected USE in each region will remain less than or equal to 0.002% of the energy consumed in the region.

Using the TEUS method, in some instances of the MARS reliability simulations in the year 2009 and beyond, expected levels of USE did slightly exceed the 0.002%. To determine the reliability plant that NEMMCO, as the reserve trader, would have to procure to achieve the unserved energy standard, TEUS used the MARS reliability simulation model and added reliability entry plant to the Base Case merchant entry schedule in regions and years where USE exceeded 0.002%. The simulations were repeated, adding progressively more reliability entry plant, until all regions satisfied the criterion in all years. In response to comments made to the ACCC by Saha Energy International Ltd. (SEIL) in its January 2003 report that extending the modeling horizon would provide a more robust view of long term market benefits, the simulations were carried out through 2018 using the Extended Base Case prepared by TEUS and described in the TEUS report included in MTC's March 17, 2003 submission.[4]

The Extended Base Case merchant entry schedule and the resulting reliability entry plant schedule are shown below in Table 1.

Table 1

Merchant Entry Plant and Reliability Entry Plant (MW)

	Base Case Merchant Entry			Reliability Entry Plant			Total Deferred Plant
	Without Murraylink	With Murraylink	Deferred Merchant Entry	Without Murraylink	With Murraylink	Deferred Reliability Entry	
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	50	0	50	50
2009	50	0	50	250	250	0	50
2010	300	150	150	350	350	0	150
2011	700	500	200	350	350	0	200
2012	900	750	150	450	500	-50	100
2013	1300	1050	250	450	500	-50	200
2014	2050	1800	250	400	550	-150	100
2015	3000	2550	450	400	650	-250	200
2016	3750	3450	300	500	650	-150	150
2017	4450	4000	450	600	750	-150	300
2018	5250	5050	200	650	650	0	200

[4] See the discussion of Sensitivity Tests on page 4 of the report titled "Further Comments on Murraylink Market Benefits".

All reliability entry plant additions are assumed to be Open Cycle Gas Turbines, as described in the IRPC's SNI Stage 1 Report. The difference in required levels of reliability entry plant is valued in the same manner as deferred merchant entry has been valued in the original TEUS analysis. As can be seen from Table 1, the With Murraylink case in 2012 requires 50 MW more reliability entry plant than the Without Murraylink case. As Murraylink defers 150 MW of combustion turbine market entry, this results in a total deferral of combustion turbine capacity of 100 MW (= +150 MW Merchant Entry Deferral – 50 MW Reliability Entry Plant Deferral).

In 2018, the same amount of reliability plant must be added to both the With and Without cases to achieve the 0.002% criterion, resulting in deferred reliability entry plant. The total deferral is just the 200 MW of deferred merchant entry plant. In the years 2013-2017, higher amounts of merchant entry in the Without Murraylink case reduce the need for reliability plant, resulting in total deferred plant levels of approximately 200 MW.

Murraylink's estimated impact on any remaining unserved energy (which will be smaller than in the Base Case because of the additional reliability entry plant in both the With and Without Murraylink simulations) is calculated in exactly the same manner as for the original Base Case gross market benefits estimate, and as described in the October 2001 submission.

This analysis indicates a Gross Market Benefit of $172m when reliability entry plant is included to achieve the NECA 0.002% unserved energy standard.

Note that the energy benefits and Riverland Deferral benefits are unchanged by the addition of reliability plant. However, Deferred Capacity Benefits (including both Merchant Entry and Reliability Entry) and Reliability Benefits are decreased. The reliability benefits of adding Murraylink or, for that matter, any other generator or transmission augmentation, to an already highly reliable system, will be less than the benefits of making the same addition to a system where reliability is determined only by market forces and VoLL of $10,000/MWh.

4 Other Market Benefits Modelling Issues

4.1 Riverland Deferral Benefits

TEUS notes that some stakeholders queried the manner in which TEUS determined Murraylink's Riverland deferral benefits. While TEUS understands the uncertainty associated with any load forecast, TEUS determined Murraylink's Riverland deferral benefits using the best available information from valid public sources such as the South Australian ESIPC. As such it stands by its original determination set out in its report contained in MTC's Application.

4.2 Snowy Hydro Dispatch

Two submissions made to the ACCC comment that particular assumptions about Snowy Hydro dispatch may be necessary to support high Murraylink transfer levels under certain conditions.

TEUS notes that for its market benefits modeling, a) the Snowy Hydro generation has been assumed to operate as peaking generation, b) the SnoVic interface limit used is the present 1900 MW, not the higher limit of 2010 MW that might require a directed Snowy dispatch, and c) if higher transfers were necessary to preserve system reliability and such transfers could be achieved by NEMMCO issuing specific dispatch instructions to certain generators, then it can reasonably be assumed that NEMMCO would take the required actions. This is no different than assuming that available generators would be directed to operate by NEMMCO, and would actually generate when unserved energy would otherwise result.

4.3 Double-counting Deferred Merchant Entry Benefits and Reliability Benefits

One submission suggests that the TEUS methodology has the potential to double-count deferred merchant entry benefits and reliability benefits.

As explained in the original TEUS report (Appendix D of MTC's application), we have endeavored to keep these issues separate. The estimation of deferred market entry plant is calculated using the PROSYM model, based on energy market economics of the NEM with and without Murraylink. The MARS model is then used to estimate the expected of Murraylink on unserved energy in both the With and Without Murraylink cases. This becomes the separate estimate of Murraylink's reliability benefit.

4.4 Lightning Detection Equipment on the Heywood Interconnector

ElectraNet has argued that the installation of lightning detection equipment on the Heywood interconnector may significantly reduce the number of hours per year in which Heywood transfer capability into South Australia must be derated to 250 MW. TEUS has tested the sensitivity of this assumption and found that, with no lightning-related forced outages on the Heywood interconnector, Murraylink's base case market benefits would decline by $3m to $211m. Conversely, the Heywood constrained limit into South Australia for the six months ending February 28, 2003, was at or near 250 MW approximately 12% of the time. The constraints are attributable to a range of factors, including electrical storms. As an upper bound on the impact of Heywood outages, a 12% Heywood forced outage rate produces an estimate of $251m for Murraylink's base case gross market benefits. This range of estimates ($211-251m) indicates that TEUS' original estimate of $214m is reasonable and well within the range of uncertainty associated with electrical storm activity, despite the addition of lightning detection equipment.

ElectraNet notes that during hours when the Heywood interconnector is constrained to transfer levels below 500 MW, the constraints are not necessarily binding. TEUS agrees, but notes also that no Heywood derates or outages were assumed for any of the PROSYM modeling used to estimate energy benefits and deferred merchant entry. The PROSYM modeling has been conservative in this regard.

4.5 Intraregional Constraints

ElectraNet suggests that the use of thermal limits to model certain intraregional constraints is inappropriate. TEUS notes that the more traditional approach of modeling only interregional constraints effectively assumes away the existence of intraregional constraints. The application of intraregional thermal constraints clearly adds additional conservatism to the MARS reliability analysis.

4.6 Modelling of Murraylink Limits in PROSYM

One stakeholder observed that TEUS modeled the Murraylink transfer limits from Victoria to South Australia in PROSYM by assuming a constrained transfer capability during February afternoon weekdays and July-August morning and afternoon peak periods. These time periods were based on historical interface flows during 1999-2001, and it is suggested that this historical period may not reflect future conditions. TEUS now believes that it was unnecessary to include the time-period based Murraylink constraints in the original PROSYM modeling, as the PROSYM dispatch engine will automatically enforce an appropriate constraint. In other words, PROSYM will not export power from Victoria to South Australia unless there is surplus power available in Victoria. Under these conditions, Murraylink would be able to use its full rated capacity.

During periods when the SnoVic interface is fully loaded and no surplus capacity exists in Victoria, PROSYM will not export power over Murraylink. TEUS believes the time-period based limits were overly conservative. Removing the limits increases the base case gross market benefit by slightly over $5m to $219.5m.

TransÉnergieUS
Member of the Hydro-Québec group

Memorandum

To	Date	Doc ID	Page
Murraylink Transmission Company	March 19, 2003		1 of 4

Cc	Issued by
	J. J. Miller, B.D. Railing, J. B. Lowell

Replaces	Subject
	Treatment of Murraylink Losses in the Calculation of Market Benefits and A Comparison to Estimated Losses for AC Alternative 3

Background

At the request of Murraylink Transmission Company (MTC), this memorandum reviews the treatment of Murraylink Losses in the estimation of Gross Market Benefits prepared by TransEnergie US, and presents an estimate of transmission power losses associated with an AC transmission interconnection as an alternative to the Murraylink HVDC project.

Murraylink losses can impact the estimated energy benefits and reliability benefits that Murraylink provides to the NEM. As discussed in more detail below, TransÉnergie US (TEUS) has appropriately accounted for these impacts in the PROSYM and MARS simulation models used to estimate market benefits.

Some submissions made to the ACCC incorrectly characterize Murraylink losses as significantly higher than alternative AC designs. This memorandum estimates the losses for BRW's Alternative Project 3, an AC line between Red Cliffs and Monash, as described in Appendix F of MTC's Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12, dated 18 October 2002, and shows that during important high load periods, losses over Murraylink will be less than losses over Alternative Project 3.

AC Alternative 3 was identified by BRW as the lowest cost in the MTC application that offers a level of service near equal to the Murraylink project. AC Alternative 3 also interconnects between the same ac network substation locations as the Murraylink project, therefore, AC Alternative 3 provides a sound basis for a comparison of losses to Murraylink. A curve of estimated transmission losses versus AC delivered power over AC Alternative 3 (AC Alt. 3) has been established by TEUS and is presented in the attached Figure 1. For comparison, the Murraylink estimated transmission loss curve (Murraylink Est.) and the Murraylink actual transmission loss curve (Murraylink Actual) are provided on Figure 1.

Treatment of Losses in Estimation of Market Benefits

The estimation of Murraylink's market benefits involves modeling of the Austrailian NEM in two stages:

1. estimation of market entry, generator dispatch and interregional flows with and without Murraylink using the PROSYM model
2. estimation of Murraylink's reliability benefits (reduction in unserved energy) using the MARS model

Losses over Murraylink and other interconnectors have been accounted for in both models, as described in the TEUS report, "Estimation of Murraylink Market Benefits", included as part of Murraylink Transmission Company's submission to the ACCC in October 2002. The PROSYM model also incorporates the impact of intraregional loss factors on generator dispatch.

Consequently, all estimates of Murraylink's market benefits prepared by TEUS reflect the change in system operation and system cost caused by differences in system losses with and without Murraylink.

More specifically, losses are incorporated into the PROSYM model in two ways. First, PROSYM allows quadratic loss equations (where losses are a quadratic function of flow) to be specified for each of the links between the five regions in the NEM. The model inputs describing these equations were developed from the interregional dynamic loss equations published in the IRPC's SNI Stage 1 Report. Separate loss equations for flows in each direction are specified, as necessary. Murraylink loss parameters were developed from an estimated loss function prepared by TEUS and were based on preliminary technical specifications provided by the equipment manufacturer.

Secondly, short run marginal costs for each generator have been adjusted by the generator's marginal loss factor to develop the bid price for the generator used by PROSYM to calculate hourly generator dispatch.

The MARS model does not provide a direct means of accounting for interregional losses, because it does not perform an economic system dispatch. Interconnector losses effectively consume capacity that otherwise would be available to reduce unserved energy. Accounting for the capacity consumed by losses is therefore important when measuring changes in unserved energy. TEUS has addressed this by making hourly adjustments to the load traces used by MARS to account for the capacity required to meet losses. Hourly flows between regions are provided by the PROSYM simulations. The hourly flows are used in conjunction with the interregional loss equations were used to calculate hourly losses in each direction over each link. The estimated hourly losses are then added to the hourly load at the sending end of the transmission link. This preserves the locational impact of losses on unserved energy in each of the nine regions simulated in the MARS model.

Murraylink's losses include losses related to the level of power being transmitted, and losses related to the status ("blocked" or "deblocked") of the converter terminals. When the terminals are "blocked", Murraylink incurs only 0.39 MW of losses at each terminal and is unable to transmit power. When the terminals are "deblocked", Murraylink incurs no-load losses of approximately 3.76 MW, plus any flow-related losses. The calculation of losses for the MARS simulation assumes that in hours when PROSYM indicates flows of less than 5 MW, Murraylink would be "blocked" and would incur only 0.39 MW of losses at the SA and Vic terminals. In all other hours, the 3.76 MW of no-load losses are incurred.

The estimated Murraylink loss equation used in the market benefits modeling is:

$$\textbf{Losses} = \mathbf{3.76 + .00017 \times Flow + .00008 \times Flow^2}$$

Loss measurements made after Murraylink began operations in 2002 have shown that actual losses are significantly lower than the estimated losses used in the market benefits modeling (see Figure 1 below). Consequently, the TEUS estimate of Murraylink market benefits is conservative. The benefit calculations have incorporated the impacts of intraregional and interregional losses in a consistent manner throughout. The losses ascribed to Murraylink are conservatively high, which will act to understate the total gross market benefits.

Estimated Losses for AC Alternative 3

Description of Alternative 3
As outlined in Appendix F of the MTC application, AC Alternative 3 consists of the following primary components:

- 220 kV AC interconnection between the Redcliffs 220 kV substation in Victoria and the Monash 132 kV substation in South Australia.
- 25 km section of interconnection assumed to be underground cable with the remainder over head transmission.
- 220-132 kV Phase Shifting Transformer (PST) at Monash end of interconnection.
- -110 to +120 MVAr Static Var Compensator (SVC) at Monash
- 30 MVAr switched shunt reactors at Red Cliffs.

Calculations
AC Alternative 3: Estimated losses where calculated using the PSS/E Power Flow package with the following assumptions:

- 1 per unit voltage held at Red Cliffs 220 kV and Monash 132 kV
- Power transfer direction from Red Cliffs to Monash
- Impedance for 153 km overhead transmission segment based on data taken from Australian PSS/E database for 220 kV line between Red Cliffs and Horsham, R = 10.67 ohms/phase, Normal rating = 267 MVA
- 25 km of 220 kV underground cable - 1000 mm2 Aluminum conductor, R = 1.12 ohms/phase including estimate of screen conductor influence
- 132-220 kV PST at Monash, R = 0.0027 per unit on 100 MVA base
- 400 KW stand-by losses on Monash SVC assumed based on recent SVC installation data
- No load losses are due to charging current, cable dielectric loss representation, PST magnetization and SVC stand-by losses.

Murraylink (Estimated): Prior to the construction and commissioning of Murraylink, an estimated transmission loss curve for the Murraylink project was established by TEUS based on calculated data provided by the equipment manufacturer. The estimated transmission loss curve is for all losses between the 220 kV ac bus at Red Cliffs to the 132 kV ac bus at Monash, including the auxiliary power losses. An estimated loss curve was provided to NEMMCO in July, 2001. This loss data (Murraylink Est.) is presented in the memo for comparison to the estimated losses over AC Alternative 3 and the actual losses measured on Murraylink.

Murraylink (Actual): During commissioning of the Murraylink project, test block TRANS-8 was performed during Sept 14-16, 2002 to verify transfer capability and losses. All of the auxiliary power was provided by the Murraylink power transformer tertiary windings during this test block. The cooling systems for the IGBT valves, phase reactors, building areas and power transformers were operated at maximum during TRANS-8 to simulate cooling load at 40ºC dry-bulb air temperature. The actual loss curve was created by using the actual MW values from the 220 kV and 132 kV utility revenue meters.

Results
Figure 1 illustrates the results of the calculations summarized above. For each option, the corresponding curve shows transmission losses (MW) versus AC delivered end power (MW). The flow direction is from Victoria to South Australia, therefore, the delivered power is at the Monash 132 kV bus. Sending end power at the Red Cliffs 220 kV bus can be calculated by adding the transmission loss to the delivered power at any point on a given curve. As shown, the actual measured losses over the Murraylink project are significantly less then the initial estimated losses, especially for higher power transfer levels. This is primarily due to lower actual converter station losses as compared to the estimated values provided by ABB.

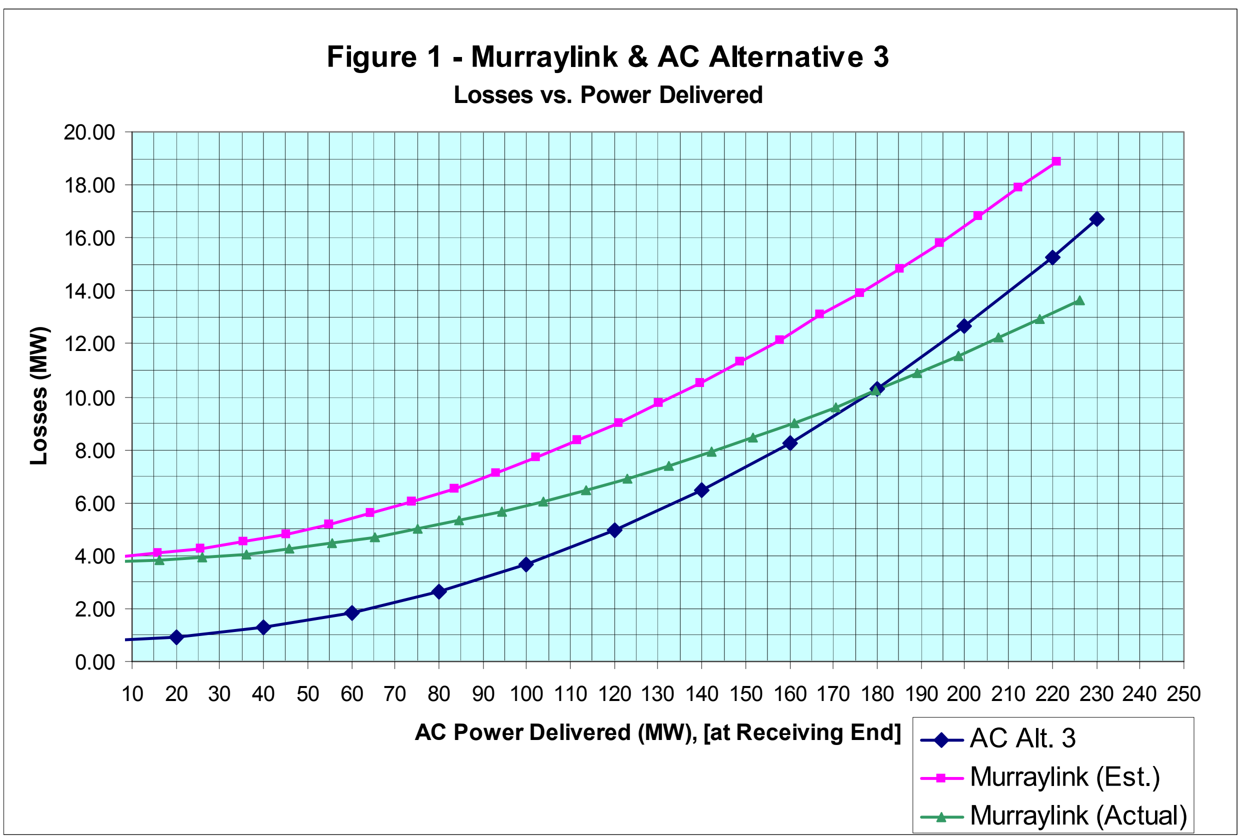
In comparing the estimated AC Alternative 3 losses to the actual Murraylink losses, the AC alternative losses are less at low power levels, however, for high power transfers, the losses are less for Murraylink. The crossover level for equivalent losses between the two options is approximately 176 MW of delivered power. At 220 MW delivered, AC Alternative 3 estimated losses are 16% higher than the actual calculated losses over Murraylink. During periods of high power transfer over the interconnector, where network reliability will often be most crucial, incremental transfers over Murraylink will incur less loss as compared to AC Alternative 3.

During periods of zero or low transfers over Murraylink where the cost of losses may out weigh the benefit of transferring power, Murraylink can simply block power transfer and go into stand-by mode. Losses associated with stand-by mode are estimated to be 778 kW. The stand-by condition for Murraylink is defined as:

1. Red Cliffs Converter Station is connected to the 220 kV ac bus at Red Cliffs Substation but the IGBT valves are "blocked" from switching. Auxiliary power is supplied to the converter station via the tertiary winding on the converter power transformer.

2. Berri Converter Station is connected to the 132 kV ac bus at Monash Substation but the IGBT valves are "blocked" from switching. Auxiliary power is supplied to the converter station via the tertiary winding on the converter power transformer.

3. The dc transmission cables are connected at both converter stations, and are energized to about 276 kV dc.



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power & water expertise

2 April 2003

REF: 024/45003

Murraylink Transmission Company
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BRISBANE QLD 4001

Attention: Stéphane Mailhot
Chief Executive Officer

RE: MURRAYLINK ACCC ISSUES PAPER

Dear Stéphane

Burns and Roe Worley (BRW) is pleased to provide the following responses to issues raised in submissions to the ACCC regarding Murraylink Transmission Company's application for conversion to a prescribed service.

1 The Type of Alternative Projects to be considered

Response

The methodology used by BRW in assisting the Murraylink Transmission Company (MTC) to propose the opening regulatory asset value (RAV) was "to select and assess alternative projects that offer the same technical service (and hence, the same market benefits) as Murraylink". Alternatives having system characteristics different to those of Murraylink were not pursued.

As indicated in the Executive Summary of BRW's report *TransÉnergie – Murraylink Selection and assessment of alternatives* (16 October 2002), the technical service identified included the following:

- 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") interconnector 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 Code1, 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.

Submissions to the ACCC have proposed a number of alternative projects and these have been assessed against the above technical services as follows:

Alternative	**220MW injection in South Australian Region (from Victoria)**	**Maintains power transfer capability during times when Heywood is constrained**	**220MW injection into Victorian Region (from Sth Australia)**	**"Smooth" reactive support**	**Additional transmission Infeed into Monash substation**
SNI	No [1]	No	No	No	No [2]
Heywood A + Robertstown Monash	No [3]	No	No	No	Yes
Horsham A + Robertstown Monash	Yes	No	Yes [4]	No	Yes
NEWVIC 2500	No	Yes	Yes [5]	No	No
SA/VIC 150MW Upgrade [6]	See note 6	See note 6	See note 6	See note 6	See note 6
SNOVIC800	No	Yes	Yes [5]	No	No
Synergen	See note 7	See note 7	See note 7	See note 7	See note 7

Notes

1. With reference to *NEMMCO 5.6.6(b) Assessment of SNI, September 2001*, page 10, figure 4, the SNI project can deliver only 180MW to South Australia and 70MW to Victoria, for a total of a 250MW increase to the combined SA and Victoria regions.
2. SNI project, as defined in the document *IRPC – SNI Stage 2 Report Version 7.0, 26 October 2001*, does not provide for a transmission infeed to the Monash substation.
3. Heywood A, as defined in *Interconnection Options Working Group – Technical Issues and Costs of Interconnection Options for South Australia* increases transfer by only 130MW.

4. No detailed analysis has been undertaken by BRW to confirm that a 220MW transfer from Sth Australia to Victoria is achievable, and publicly available documentation confirming that such a transfer is possible has not been identified.

5. Increase in transfer is between Snowy/NSW and Victoria, not South Australia and Victoria.

6. BRW is unaware of a SA/VIC 150MW transfer increase project, unless this is referring to Heywood A option which is discussed in note 2 above.

7. With reference to Section 4.7.1 of BRW's report dated 16 October 2002, "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." (BRW notes the recent generation constraints incurred in South Australia due to reduced availability of the Moomba gas pipeline.) "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."

2 Reason for inclusion of SVC/voltage control

Response

BRW has included SVC's in the alternative projects to provide a level of performance equivalent to that of Murraylink.

However, beyond this requirement there is a system need for fast acting automatic voltage control within the local system network around Red Cliffs and Monash.

Specifically for Alternatives 1 and 3, fast voltage control is required to control system voltage in the event that the link must be tripped. In most situations, Murraylink need not be tripped but it may be required to rapidly reduce power transfer ie: to provide fast runback. Without fast voltage control, the voltage at Monash substation may collapse under some situations. Red Cliffs substation may experience very high voltages under similar situations.

For strict equivalence with Murraylink, two SVCs should be costed for Alternatives 1 and 3 - one at Red Cliffs (or at Buronga) and one at Monash. Given that SVCs already exist at Kerang and Horsham which will provide limited voltage control for the Red Cliffs area. Consequently, BRW has only costed one SVC (at Monash) even though this does not strictly provide an equivalent service to that of Murraylink.

It is important to note, that in similar situations, SVCs have been installed for similar reasons or simply used to reduce losses during power transfers. For example, the SVC's at South East (2 SVC from +80 MVAr to –50 MVAr) are used to provide fast automatic voltage regulation for the existing link between Victoria and South Australia. There are also SVC's at Bremar and Armidale associated with the QNI interconnection between Queensland and NSW. They are very common in the USA and Europe wherever long interconnections between power systems occur. In some cases, it could be argued that SVCs are not required - but their absence would place greater restrictions on the operation of the system, and lead to a lower quality of power supply sometimes leading to voltage collapse conditions. It would also reduce the market benefits of any scheme.

3 *Component costings are excessive*

Response

BRW notes that in TransGrid's analysis of the alternatives, a number of detailed observations are made, particularly in its Appendix (*Analysis of Proposed Alternative Projects*). Each issue has been addressed below.

Alternative 1

(a) TransGrid states "Two 275/132kV transformers are provided at Monash with a spare. In reality one transformer is required at Monash with a spare if necessary";

BRW notes that 2 x 160MVA transformers are proposed to achieve the 220MW transfer into Monash. This is based on good engineering principles in that it allows for interchangability with existing ElectraNet 275/132kV transformers (which are typically sized at 160MVA). One transformer could have been installed but would have required a higher MVA rating at a greater cost (and would not be suitable for other ElectraNet substations). TransGrid appears not to have considered the size of the transformer when making this statement.

(b) TransGrid states the "provision of a spare phase shifting transformer appears unnecessary".

BRW notes that in the absence of this device, failure of the unit would cause the 220MW transfer to be unavailable for an extended period until the unit could be repaired or a new unit manufactured. BRW has applied good engineering principles in ensuring a suitable spare is available for this critical plant item.

(c) TransGrid states "the line and cable cost is given as $88M compared to an overhead line of the order of $30M";

BRW agrees with TransGrid. An AC cable is an expensive item, but tactical undergrounding is likely to be necessary to abide by the likely outcome of statutory environment approval processes.

(d) TransGrid states "An SVC is included at Monash at a cost of $19M, however, in early TransGrid/ETSA studies on network development similar to this option, an SVC was not required";

Refer to item 2 above.

(e) TransGrid states "the 132 kV connection cost at Monash is stated as $10M but TransGrid considers this is more likely to be of the order of $2M. A detailed engineering review is required to estimate the cost of the works";

BRW believes TransGrid has misinterpreted the basis for including this cost. $A10.4M is the estimated cost of a new 132kV injection point into the Riverland area of South Australia. This injection point became known as the Monash Substation which was substantially paid for, and built by MTC as part of the Murraylink interconnection project. In the absence of Murraylink, any alternative would be required to develop the Monash substation for connection to the South Australian system.

(f) TransGrid states "BRW quote the total cost of transformers (without spare) and connection at Monash to be in the order of $20M whereas, in the context of the SNI project, TransGrid considers that a cost of less than $10M would be incurred for connecting SNI at Monash with a single transformer";

With reference to the Base Cost Estimates contained in Section 3, Appendix 5 of BRW's report dated 16 October 2002, the total cost of switchyard works, not including SVC, PST and Monash connection costs noting this the cost of the substation alone, prior to any 275kV interconnection) are approximately $A30M which includes;

- 2 x 160MVA 275/132kV transformers
- 2 x 220kV CBs and 1 x 30MVAr reactor at Buronga
- 4 x 275kV and 1 x 132kV CBs at Monash
- Augmentation of existing plant due to impact of new interconnection (ie: switchgear replacements due to increased fault levels)

$A10M to connect SNI at Monash using a single transformer does not appear inconsistent with our estimate for substation works; however, a full scope of works proposed by TransGrid would be necessary before BRW could comment on such costs.

(g) TransGrid states "mention is made of "Augmentation of existing plant due to impact of new interconnection with increased fault levels". No details seem to be provided and these details are required to provide further comment";

Without detailed access to plant characteristics, available only to SPI Powernet and TransGrid, BRW is unable to determine what, if any network augmentations may be required due to the interconnection. However, it is not unreasonable to expect such work to be necessary. For example, in *NEMMCO 5.6.6(b) Assessment of SNI – Appendix C – VENCorp Report September 2001*, pages 3 and 4 approximately ten 22kV CBs at Red Cliffs may require to be replaced, and two 220kV CBs at Mount Beauty as a result of the SNI project. Similar works may be required as a result of Alternative 1.

(h) TransGrid states "no communications development costs appear to be included".

BRW would expect these costs to be included in the above augmentation costs discussed in (g) above.

Alternative 2

(a) TransGrid states "Spare converter transformers are included for each end of the link. It is not known whether such spares were purchased for Murraylink. In TransGrid's view only one dual voltage spare converter transformer is needed for Murraylink on the basis that it has three single-phase converter transformers at either end".

One spare transformer with multiple tappings (to allow for connection at either end of the HVDC line) is included in the estimate. BRW understands that MTC purchased two spare single phase units, with a unit located at either end of the link.

(b) TransGrid states "The cost breakdown of Appendix 5 of MTC's Application indicates that the Red Cliffs - Monash line and cable section would cost in the order of $53 million. The HVDC overhead line should cost of the order of $150k per km, with a total of the order of $23M based on 180 km route length that includes a 25 km underground section. Hence the 25 km of underground cable is costed at the order of $30M. TEA has often stated that undergrounding costs less than an overhead line. The cabling appears to cost of the order of $1.2M per km. Even if the line cost $200k per km or $31M this leaves 25 km of cable costing $22M or $0.9M per km. As a result, it is difficult to understand the costs of this option."

BRW's costs were based on in-house databases and quotations from suppliers. The assumed cost for an overhead DC transmission line is approximately $A140k/km (which is lower than the assumed value of approximately $A170k/km for an overhead AC line as less conductor is required and smaller towers). The DC cable costs are assumed to by 67% of the cost (both for supply and installation) of an equivalent AC cable.

Alternative 3

(a) With respect to power transfer TransGrid states "It appears that BRW has not taken into account the fact that operation of this new line with power flow of the order of 200 MW would significantly stress the NSW 220 kV system."

In the detailed costings provision is made for augmentations back within the SPI and TransGrid systems. Whilst acknowledging the differing reactive requirements, BRW would expect that if 220MW can be currently transferred across Murraylink from Red Cliffs, this should be achievable utilising AC transmission and phase shifting transformers.

It is important to note that with the existing system intact a 220MW transfer can easily be supported. The immediate post-contingent situation however is the major determinant in power transfer capability. In this regard Murraylink capability is facilitated by the use of automatic runback to alleviate post-contingent overloads and in some cases voltage violations. For an AC link an analogous automatic response is also required (in lieu of major augmentations). For SNI it was proposed to simply 'trip' the link between Buronga and Robertstown for certain contingencies in the south west NSW and Vic state grid network. BRW assumed its AC alternatives would also be tripped during such a contingency.

The advantage of the "runback" feature inherent in Murraylink is that it leaves the network intact with the VSC converter stations providing reactive support at each connection point, where as in the case of SNI tripping the Buronga to Robertstown lines, the system is "de-meshed", raising the impedance between points, increasing generator angle and potentially impacting on angle stability. With appropriate runback control an HVDC link can better utilise existing upstream network assets without the need for major augmentations and/or tripping of major components of an AC interconnector (as is proposed for SNI and any other AC link providing equivalent service level).

Alternative 4

(a) TransGrid states "BRW give the cost of the 275 kV from Heywood to South East Line as $38M. The IOWG estimated $150k per km over 80km, that is at $12M. TransGrid considers the BRW cost very high."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A38M reflects the cost of the 130km 275kV line section between Robertstown and Monash, and the 80km 275kV line section between Heywood and South East.

(b) TransGrid states "BRW estimate $6.4M for the series capacitors, while the IOWG estimated $24M for these works although it is possible that BRW has included part of the series capacitor cost in the switchgear cost."

BRW acknowledges the discrepancy. The estimate of $A6.4M reflects only the plant costs. Installation costs, civil works and associated switchgear costs have not been included.

(c) TransGrid states "BRW estimate the cost of switchgear at $22M. The IOWG estimated the switchgear costs would be in the order of $12M."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A22M reflects the cost of switchgear for works at Robertstown, Monash, South East and Heywood.

(d) TransGrid states "BRW estimate the cost of the transformer as $10.6M and the IOWG estimate for this is $9M."

The IOWG estimate is based on costs in 1997 dollars. Escalating the IOWG value would give a cost for the transformer to within 10% of BRW's estimate.

(e) In the context of the inclusion of the phase shifting transformer, TransGrid states "With a new third line in place the interconnector could then be rated at a higher secure level during storms. This may be above 500 MW depending on the rating of the new plant. As a result, the phase shift transformer is probably redundant – there is no need to provide power flow control given adequate rating on the other plant. The Heywood transformer is rated at 600 MVA and the line rating should not present any difficulty."

BRW notes that with a third line operating between Heywood and South East, there will be the existing double circuit line, and a third single circuit line. During periods of storm activity, the existing double circuit line is derated to 250MW (from a pre storm activity rating of 500MW). This derating would likely remain in place when the third line is placed in service. As there would be three lines in parallel (with essentially the same electrical characteristics), a reduction in the double circuit transfer to 250MW would also reduce the transfer in the single circuit line of 50% (or 110MW is the pre storm activity transfer was 220MW). To maintain the pre storm activity transfer of 220MW on the third line a phase shift transformer would be required.

Note that BRW understands the Heywood transformers have a firm rating of only 370 MVA, and an emergency rating of 525MVA.

(f) TransGrid states "The Monash works include a new 275/132 kV transformer and an SVC. The cost of transformers is given as $10.6M. It appears that this would cover two transformers. The system would be secure for loss of a transformer hence the reason for a spare is not clear."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A10.6M reflects the cost of a 500/275kV transformer at Heywood, and a 275/132kV transformer at Monash.

(g) TransGrid states "An SVC is included at Monash at a cost of $19M. In the ElectraNet and ESIPC work on the Riverland reinforcement there was no need for an SVC in addition to the 275 kV line. Presumably BRW seeks to provide the same level of voltage control as provided by Murraylink."

Refer to item 2 earlier detailing the reasoning for inclusion of SVC's.

(h) TransGrid states "the 132 kV connection cost at Monash is stated as $10M but TransGrid considers this is more likely to be of the order of $2M. A detailed engineering review is required to estimate the cost of the works";

As noted in item (e) for comments relating to Alternative 1, BRW believes TransGrid has misinterpreted the basis for including this cost. $A10.4M is the cost of a new 132kV injection point into the Riverland area of South Australia. This injection point became known as the Monash Substation which was substantially paid for, and built by MTC as part of the Murraylink interconnection project. In the absence of Murraylink, any alternative would be required to develop the Monash substation for connection to the South Australian system.

General comment on Costs

On page 21 of TransGrid's submission, costings are provided for various interconnection projects. The main source for these costs is the IOWG report *Technical Issues and Costs Of Interconnection Options for South Australia*. BRW notes that all estimates are quoted in 1997 dollars.

BRW also has a number of concerns with respect to the accuracy of these estimates, particularly the $A110M figure being quoted for the SNI project. This project has changed considerably in scope since the report above was published (ie: the above estimate does not include costs for the Jindera phase shifting transformer). It is also noted that the original estimate had no provision for many of the components critical to achieving the nominal 220MW transfer proposed for the SNI interconnection (such as line uprating works in south west NSW). BRW believes a thorough review of the SNI scope of works, including itemised cost estimates for all peripheral works be undertaken before credence be given to the $A110M estimate for this project.

4 Reason for profit and overhead

Response

BRW's original cost estimate assumed an EPC (Engineer, Procure and Construct) contractor would manage the switchyard and transmission line works as a total project. The BRW cost estimate has been derived from a "bottom-up" process. This involves obtaining quantities and cost estimates for plant and equipment from suppliers, estimating material quantities and labour hours, including detailed engineering and project management on an at cost basis, then applying profit and overhead margins. This estimating process simulates the development of an all-inclusive EPC cost to deliver a total project.

Yours sincerely
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