TransGrid

ABN 19 622 755 774

201 Elizabeth Street (cnr Park St)
PO Box A1000 Sydney South
New South Wales 1235 Australia
Facsimile (02) 9284 3456
Telephone (02) 9284 3000
Web http://www.transgrid.com.au
DX1122 Sydney

Mr John Tamblyn
Chairman
Australian Energy Market Commission
Level 16
1 Margaret Street
SYDNEY NSW 2001

Dear Mr Tamblyn

AEMC Transmission Pricing Issues Paper

Thank you for the opportunity to comment on this issues paper. TransGrid attaches a specific response to each of the questions raised in the issues paper. TransGrid is also party to a joint submission from the NEM transmission owners, provided under separate cover, and generally supports that submission.

TransGrid considers that transmission pricing arrangements in the NEM have supported the long term interests of customers in efficient and stable pricing outcomes. In this regard the form of pricing that is prescribed, and the extent to which transmission pricing requirements are set out in the Rules, appear to be working well. Specifically, TransGrid believes that there is a weak case for major changes to current transmission pricing arrangements, and that the challenge for the Commission is to focus on those aspects of the current arrangements where, on balance, it is considered that a changed approach would deliver material economic benefits.

There are three particular aspects of the current arrangements that may benefit from further examination. There may be scope to simplify the methodology for allocating the costs associated with the shared transmission network (CRNP), to improve arrangements for signalling the economic benefits of network investment deferral to existing and prospective network support generators, and to develop workable arrangements for participant funded augmentations to the shared network.

TransGrid's position is set out in more detail on each of these matters in this letter as well as in the attached responses to the individual questions raised in the AEMC's issues paper.

<u>Framework for Transmission Pricing in the NEM</u>

It is worth considering current transmission pricing arrangements within the wider context of the NEM.

The vast majority of transmission investment is driven by transmission reliability requirements and, as such, is to the benefit of electricity consumers[1]. Even when investment is undertaken to remove uneconomic congestion, consumers benefit significantly from access to the most competitive generation sources. Generators, on the other hand, receive no assurance of access rights from regulated investment in the shared network. Taken together, these factors suggest that the current recovery of shared transmission network charges from consumers rather than generators is appropriate.

[1] In this submission TransGrid uses the term 'consumer' to mean the end-consumer of electricity; e.g. a household or business user. The term 'customer' is used for electricity distributors; end-consumers that are directly connected to the transmission network, e.g. some aluminium smelters; and generators that are directly connected to the transmission system.

Within this overall charging approach, the costs of connection assets are directly allocated to the relevant grid users, whereas the CRNP charge is intended to reflect broad cost trends of taking supply from different parts of the network. Although CRNP has not been without its detractors, its key advantage over other dynamic charging approaches is that it provides a stable and predictable locational price signal to consumers, and is based on a methodology that is now reasonably well-understood.

The greater part of the costs of investing in and maintaining the shared transmission network are recovered from electricity customers on a postage stamped basis; TransGrid submits that this is both efficient and practicable. Cost attribution in electricity networks is tenuous at best, and this applies, above all, to customer-driven reliability investment – the overwhelming majority of investment undertaken by TransGrid – which benefits all consumers, largely irrespective of their location. The current pricing structure then provides customers with pricing signals that are both predictable and transparent, while reflecting the overall cost of providing reliable network services via the shared network.

Furthermore, the NEM Rules provide for a flexible framework that enables some modifications to the existing framework where this would support efficient operational and investment decisions. Most important of these is the mechanism for negotiating transmission charging discounts where it can be shown that uneconomic network bypass can be avoided as a result of a 'discount' to a price sensitive customer. Other mechanisms include the option to adopt modified CRNP for a region. Specifically in relation to large, price-sensitive customers, the Rules also provide a flexible approach to the fixed charges (Common Service and General Charges) whereby customers have a choice in relation to the charging basis.

It is also worth noting that for the overwhelming majority of consumers, transmission charges constitute a small proportion (around five percent) of electricity bills and are 'rolled into' energy charges. Accordingly, the structure and allocation of transmission charges will have little impact on the majority of consumers' consumption and investment decisions. In addition, due to the process of incorporating transmission charges into distribution use of system pricing the transmission locational signal may not be fully reflected to end consumers. This raises real questions about the merits of developing an increasingly sophisticated approach to transmission pricing when the effect of these prices is unlikely to be material for the bulk of consumers.

Finally, transmission pricing must be integrated with other features of the electricity market, such as pricing arrangements in the spot market, and regulatory arrangements for transmission investment, in this case the Regulatory Test. In the context of the NEM, generators receive clear and appropriate signals regarding current and future network congestion. Regional price differences value the majority of network congestion for operational purposes. Loss factors also provide an indicator of the marginal cost of transmission losses. Annual planning statements by TNSPs and NEMMCO, together with Regulatory Test consultations and project announcements, allow generators to predict future transmission capability and congestion outcomes when making investment decisions.

TransGrid believes that, taken in their entirety, these elements deliver a sound framework that supports efficient operational and investment decisions within the NEM.

Transmission Pricing Framework In Context

This review of transmission pricing by the Commission follows a number of previous investigations, commencing with the work by the National Grid Management Council in the early 1990s and followed by later work by NECA and the ACCC. In the course of the various reviews, a wide range of models for setting transmission prices have been examined, including approaches used in other jurisdictions. Some improvements have been identified and implemented as a result of these reviews.

A reasonable conclusion from these various reviews is that there is no perfect system for transmission pricing. Both in theory and in practice, transmission pricing requires a trade-off between multiple and competing objectives. These trade-offs must be recognised in order to develop a stable approach that serves the long term interests of customers, as well as ensuring that TNSPs are able to recover efficient costs. In practice, all transmission pricing regimes would be expected to result in some price anomalies, and the discounting arrangements referred to above ensure that price outcomes are efficient.

TransGrid therefore submits that the current charging structure represents a workable compromise between:

- Efficiency – cost signalling – objectives that can realistically be achieved in relation to transmission pricing;
- The interests of both grid users and TNSPs in a stable and predictable pricing framework; and
- A transparent methodology that is directly linked to the costs of the underlying assets.

The challenge for the Commission is to identify and address those aspects of the current transmission pricing framework where, on balance, it is considered that the current approach is materially flawed, and where a changed approach would deliver demonstrable net benefits in terms of the NEM Objective.

Prescribing Pricing Arrangements in the Rules

Current provisions in the Rules set out in some detail the transmission pricing approach that should be adopted by TNSPs, the methodology that should be applied and where there is scope for regional variation. TransGrid submits that this degree of prescriptiveness is appropriate, and supports the long term interest of consumers in a stable transmission pricing regime that can be administered by TNSPs in an even-handed and transparent manner.

While the focus of regulators has been on the monopolistic nature of transmission services, the essential nature of this service to consumers and regional economies also significantly constrains TNSPs in any negotiating situation. In addition, for shared network services there are invariably multiple users of this service raising material 'free rider' issues and difficulties quantifying the service benefits for individual users. Furthermore, unlike in the gas industry, there is minimal scope for separate arrangements to fund incremental private augmentation of the shared transmission network, and virtually all transmission investment must be funded from regulated transmission prices charged to customers.

The consequence is that greater discretion in relation to transmission pricing – either in relation to how individual charges would be determined or with respect to targeting specific groups of users or 'beneficiaries' – would almost certainly increase the scope for disputes. Such disputes are inherently intractable and costly, and the costs would eventually be borne by all consumers. Significantly, arrangements to fund new investment would be difficult to conclude leading to both delays in delivering vital network capability and the real risk of under investment.

Specific Areas for Review

Given the current framework set out in the Rules, there are a number of discrete areas where some change is justified to improve clarity and provide additional certainty for both TNSPs and market participants. In particular, the following aspects appear to offer scope for improvement:

- There may be scope to adopt simpler methodologies than CRNP for allocating shared network costs without a significant loss in the quality of locational signals provided to customers. The economic outcomes of the current pricing regime appear to owe more to the ability to be flexible in pricing to price sensitive customers, locational signals arising out of the wholesale market, and administrative arrangements such as the Regulatory Test than to CRNP per se. With this in mind simpler more approximate arrangements for allocating shared network may work just as well, However, regardless of the method adopted clear prescription within the Rules would still be required, together with arrangements to assure transmission investors of the full recovery of efficient costs.

- The current Rules are characterised by an apparent overlap and the absence of a clear distinction in the classification of services – as being prescribed, negotiable, or contestable. An unambiguous definition of these categories would serve to clarify the respective rights and obligations of TNSPs and market participants, although TransGrid notes that the *functional* role of specific assets – for instance, whether they are part of the shared network and must therefore remain within the operational control of TNSPs – should be a key determinant in this regard.

- The current Rules also lack a coherent regulatory and pricing framework in relation to the treatment of alternatives to network investment as reflected in TUOS rebates and network support arrangements, and specifically how operational and funding responsibilities by transmission and distribution NSPs should be coordinated. Clarifying these arrangements would provide greater certainty to generation investors, as well as defining the respective responsibilities of TNSPs and DNSPs.

- Finally, there is some concern that the absence of workable arrangements to enable (participant) funded augmentations of the shared network may prevent generation investment taking place in the NEM. While it is recognised that such augmentations raise a number of complex questions, TransGrid considers that there is merit in this approach to investment in the shared network in certain circumstances, and would welcome guidance on the corresponding regulatory treatment of such augmentations.

<u>Summary</u>

The transmission pricing arrangements set out in the Rules balance efficiency, stability and transparency objectives, and provide TNSPs with appropriately limited flexibility to address specific circumstances. The current level of prescriptiveness is likely to reduce the costs associated with disputes, and support efficient investment in the NEM in the longer term. Within this broader framework, some ambiguity remains in the Rules, and TransGrid has highlighted these areas in its responses to the specific questions raised in the Issues Paper.

All TNSPs have devoted considerable resources to setting up the current price setting systems. If alternatives are proposed, the time, resources and cost required to develop the methodology and to set up new processes should not be under estimated. TransGrid would expect that these costs would be treated as a pass through by the Australian Energy Regulator, given that no changes were contemplated at the time of TransGrid's revenue determination.

TransGrid staff would be pleased to discuss the issues in this submission with the Commission. In this regard please feel free to contact me on telephone 9284 3537 to make the necessary arrangements.

Yours sincerely

Kym Tothill

30/12/2005

Kym Tothill
General Manager/Corporate Development

AUSTRALIAN ENERGY MARKET COMMISSION

TRANSGRID RESPONSES TO THE QUESTIONS IN THE TRANSMISSION PRICING ISSUES PAPER

Introduction

TransGrid's submission in response to the Commission's Consultation on TNSPs' Revenue Requirements emphasised the importance of a regulatory framework that creates a stable and predictable regulatory environment, and the need for transmission regulation to reflect the specific characteristics of transmission. These themes are also central to TransGrid's submission in relation to the transmission pricing approach that should be adopted in the NEM.

TransGrid considers that transmission pricing arrangements in the NEM have supported the long term interests of customers in efficient and stable pricing outcomes. In this regard the form of pricing that is prescribed, and the extent to which transmission pricing requirements are set out in the Rules, appear to be working well. Specifically, TransGrid believes that there is a weak case for major changes to current transmission pricing arrangements, and that the challenge for the Commission is to focus on those aspects of the current arrangements where, on balance, it is considered that a changed approach would deliver material benefits.

There are three particular aspects of the current arrangements that may benefit from further examination. There may be scope to simplify the central methodology for allocating the costs associated with the shared transmission network (CRNP), to improve arrangements for signalling the economic benefits of network investment deferral to existing and prospective network support generators, and to develop workable arrangements for participant funded augmentations to the shared network.

The Overall Efficiency of Current Arrangements

TransGrid believes that, taken in their entirety, current transmission arrangements deliver a sound framework that supports efficient operational and investment decisions within the NEM.

The vast majority of transmission investment is driven by transmission reliability requirements and, as such, is to the benefit of electricity consumers. Even when investment is undertaken to remove uneconomic congestion, end consumers benefit significantly from access to the most competitive generation sources. Generators, on the other hand, receive no assurance of access rights from regulated investment in the shared network. Taken together, these factors suggest that the current recovery of shared transmission network charges from consumers rather than generators is appropriate.

Within this overall charging approach, the costs of connection to the network are signalled to grid users where this is directly possible, while the CRNP charge is intended to reflect broad cost trends in different parts of the network. Although CRNP pricing has not been without its detractors, its key advantage over other dynamic charging approaches is that it provides a stable and predictable locational price signal to consumers, and is based on a methodology that is now well-understood.

The greater part of the costs of investing in and maintaining the shared transmission network are recovered from customers on a postage stamped basis; TransGrid submits that this is both efficient and practicable. Cost attribution in electricity networks is tenuous at best, and this applies above all to customer-driven reliability investment – the overwhelming majority of investment undertaken by TransGrid – which benefits all customers, largely irrespective of their location. The current pricing structure then provides customers with pricing signals that are both predictable and transparent, while reflecting the overall cost of providing reliable network services via the shared network.

Furthermore, the NEM Rules provide for a flexible framework that enables some modifications to the existing framework where this would support efficient operational and investment decisions. Most important of these is the mechanism for negotiating transmission charging discounts where it can be shown that uneconomic network bypass can be avoided as a result of a 'discount' to a price sensitive customer. Other mechanisms include the option to adopt modified CRNP for a region. Specifically in relation to large, price-sensitive customers, the Rules also provide a flexible approach to the fixed charges (Common Service and General Charges) whereby customers have a choice in relation to the charging basis.

It is also worth noting that for the overwhelming majority of electricity consumers, transmission charges constitute a small proportion (around five percent) of electricity bills and are ‘rolled into’ energy charges. Accordingly, the structure and allocation of transmission charges will have little impact on the majority of consumer consumption and investment decisions. This raises real questions about the merits of developing an increasingly sophisticated approach to transmission pricing when the effect of these prices is unlikely to be material for the bulk of consumers.

Finally, transmission pricing must be integrated with other features of the electricity market, such as pricing arrangements in the spot market, and regulatory arrangements for transmission investment, in this case the Regulatory Test. In the context of the NEM, generators receive clear and appropriate signals regarding current and future network congestion. Regional price differences value the majority of network congestion for operational purposes. Loss factors also provide an indicator of the marginal cost of transmission losses. Annual planning statements by TNSPs and NEMMCO, together with Regulatory Test consultations and project announcements, allow generators to predict future transmission capability and congestion outcomes when making investment decisions.

This analysis demonstrates the challenges inherent in developing theoretically ‘pure’ pricing arrangements, and the need to balance the benefits of such a solution against the corresponding complexity and costs. The next section of this submission provides background as to some of the complicating factors that would lead to such complexity by way of context to TransGrid’s responses to the individual questions raised in the AEMC’s Issues Paper.

Transmission Networks and Transmission Pricing

TransGrid’s comments in response to the questions raised by the Commission reflect the specific economics of transmission networks and the corresponding implications for transmission pricing.

Unlike a road system where users can elect which conduit to use, electricity moves across a network by following the path of least resistance. This creates extensive ‘loop flow’ externalities in ‘shared’ networks, since flows in one part of the network – reflecting consumption and generation patterns – affect flows elsewhere. Moreover, network flows and the extent to which individual transmission assets are used change continuously during the day and over time as demand and generation patterns change, but also whenever infrastructure is added (or removed) from the shared network. The existence of strong network effects has an important implication for this review: it severely limits the extent to which the costs of the transmission network can meaningfully be attributed to individual users or beneficiaries. Put in another way, averaging is inherent in the design of transmission prices for the shared transmission network, and transmission prices can at best only signal an approximation of costs.

Even in the absence of such loop flows, allocating transmission costs to derive prices is problematic. Transmission infrastructure consists of substantial, long-lived assets that can only be built in discrete, large increments, rather than tailored to a desired size. The cost of providing transmission services is largely fixed: that is, invariant to quantities of network flows.

Moreover, transmission is characterised by significant economies of scale and scope: the average cost of capacity declines with the magnitude of the investment, and combinations of transmission projects can deliver wider benefits, for instance from a reliability perspective. All of these factors complicate notions of causality or beneficiaries that would conventionally be applied to determine prices.

Finally, differing objectives can result in different transmission pricing outcomes. Once built, transmission assets are generally regarded as 'sunk', meaning that they have no alternative use if projections supporting the case for an investment turn out to be wrong. How the costs of sunk assets should be recovered is a problem similar to the question of optimal taxation that is solved by 'Ramsay pricing'. However, such an approach is in direct conflict with dynamic pricing objectives, where charges are set with the intent of changing the actions of grid users to as to minimise the costs of future investment. These conflicting objectives are an indication of the controversy that accompanies the design of transmission pricing arrangements in practice. As noted above, the current arrangements appear to achieve an appropriate outcome without the need for substantial additional complexity.

Transmission pricing in the NEM

To different degrees, the varying and sometimes conflicting considerations described above are currently reflected in transmission pricing arrangements in the NEM. The structure and design of transmission prices reflects the fact that in transmission, cost attribution is highly problematic, and that many of the benefits of transmission – for instance, in terms of reliability – accrue to all customers. Overall, this charging design has remained broadly stable since the inception of the NEM, an important factor for all customers.

The current charging structure appears to meet efficiency, certainty, and transparency objectives. It is a corollary of the above discussion that while it is usually possible to think of improvements to transmission pricing, such improvements come at a cost, in terms of predictability and, in most instances, complexity for customers, or greater risks for TNSPs. That is, the onus should be on proponents of change to demonstrate that the current transmission pricing structure is flawed and could be materially improved.

2. Requirement for Regulation

1. Should transmission prices be regulated and why?

Transmission prices associated with shared network services need to be regulated and these pricing arrangements need to be prescribed in the Rules.

Need for Regulation of Prices

Strong scale and scope economies imply that transmission has the characteristics of a natural monopoly: it is always cheaper for a single firm to supply the entire market. In the absence of regulation, TNSPs would be accused of exploiting their market power to raise prices to users, or to deliver poor quality outcomes. In contrast, a transparent and predictable regulatory framework defines the regulatory compact, and clarifies the rights and obligations of all parties.

NEM TNSPs are also subject to a broad range of obligations beyond those set out in the National Electricity Market Rules ("the Rules"), and to a corresponding degree of scrutiny. In theory, if TNSPs were unfettered by other constraints they would have considerable market power and this would be a good reason to regulate transmission prices. In practice, however, the essential nature of the service provided to customers and the central role of electricity in regional economies is such that TNSPs are not in a position to dictate terms to their customers, let alone disconnect them. For example, TNSPs are normally not able to refuse service except in extreme circumstances and are subject to extensive reliability obligations.

The arguments in favour of regulating the provision of transmission services overall also apply to the regulation of transmission prices.

Need to Prescribe Pricing Arrangements in the Rules

Regulation of pricing, particularly relatively prescriptive pricing rules as apply at present, ensure consistent and certain outcomes for customers. As such, regulated transmission prices are likely to support the investment decisions of customers connecting to the transmission network, and, in turn, long term transmission planning process.

If electricity transmission pricing rules were not 'laid out' in the Rules then TNOs would be required to negotiate prices that delivered their entire regulated revenue entitlement. This contrasts with many gas network investments that are largely underwritten in the first instance by negotiated foundation contracts. The increased negotiation and disputations that are likely to arise from this would add to overall costs with no corresponding real benefits to society, since any costs not recovered from one customer would need to be recovered from the remainder.

Any approach to transmission pricing which is centred on negotiation would need to address the problems of 'free riders' and the difficulties of resolving who pays for the shared network among multiple users when the value of transmission services from a particular investment to individual users is hard to define and varies over time. These basic problems would render an approach to transmission pricing based on negotiation impracticable and, in many cases, lead to delays in the delivery of much needed investment.

2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?

The current degree of prescriptiveness in the Rules with respect to transmission pricing is broadly appropriate, since it supports certainty, clarity and consistency in pricing. Less prescriptive regulation will result in greater divergence of pricing structures across the NEM, increase pressure on TNSPs to lower transmission prices to some customers at the expense of higher prices to others, and will add to TNSP and participant costs overall by increasing the scope for negotiations and disputes.

Paradoxically, there is also likely to be a trade off between the degree of prescriptiveness and the "regulatory burden" overall. A less prescriptive approach may require the AER to set up price monitoring or even price approval processes. These would add to the workload for the AER and TNSPs for no demonstrable gain.

It could be argued that prescriptive transmission prices risk being the source of future inefficiencies, as technologies and network cost drivers change, and transmission prices are increasingly removed from underlying cost trends. This is unlikely to be the case here. The technology for delivering shared transmission services has evolved relatively slowly over time, and the cost structure of transmission – significant fixed costs characterised by substantial economies of scale and scope – has largely stayed unchanged. As we comment below, existing discounting provisions in the Rules also assist TNSPs where current pricing arrangements are not sufficiently flexible. Furthermore, the Rules in relation to locational pricing permit TNSPs some leeway to address specific (regional) network conditions.

The process of determining transmission pricing in the NEM is already relatively transparent. Transmission prices are published each year, providing a reasonable degree of transparency and allowing customers the opportunity to track price changes over time. Where customers consider charges to be commercially sensitive, TransGrid does not publish some specific prices.

Given these overall comments, TransGrid has identified a number of areas where there is scope to reduce ambiguity in the current Rules. These are highlighted in TransGrid's responses to subsequent questions, and specifically relate to:

- The classification of assets as 'connection' or 'shared network' assets, and the distinction between prescribed, non-prescribed, as well as non-contestable and fully contestable services (Questions 6, 14ff.);
- The regulatory and pricing framework for alternatives to network investment as reflected in TUOS rebates and network support arrangements (Question 14); and
- The meaning and implications of negotiated generator/MNSP use of system charges, and the role of funded augmentations more generally (Question 8).

3. What role, if any, should the AER have in determining the nature and form of price regulation?

The governance model adopted by the Ministerial Council on Energy (MCE) was designed to achieve a separation between the development of energy market rules, on the one hand, and industry regulation on the other. As such, the MCE transferred responsibility for rule-making and market development to the AEMC, and requires the AEMC to amend the nature and form of price regulation in the National Electricity Rules. The role of the AER, in contrast, is to undertake the economic regulatory and enforcement functions.

Accordingly, the degree of discretion afforded to the AER should be limited, and relate to the practical interpretation of the Rules, subject to the principles and guidance set out in the Rules by the AEMC. The AER's discretion in relation to transmission pricing arrangements should therefore be limited to areas, such as:

- Approvals for recovery of the costs of TUOS discounts;
- The use of the modified CRNP methodology (Clause 6.4.3(B)(c)(1)); and
- The use of current energy data (Clause 6.5.4A(e)(1)(I)(B)).

See also the comment on Question 2.

3. Context and Objectives for the Review [price shocks, certainty, consistency]

4. Bearing in mind the NEM objective, should economic efficiency of the Rules be the focus or should it also have regard to the distributional consequences of Rule changes?

In TransGrid's view, such considerations are a matter for policy makers, as reflected in the drafting of the NEL We have confidence that the AEMC is able to interpret its charter in this regard.

It is worth noting that the transitionary arrangement (2 % limit rule) in Section 6.5.5 of the Rules may be appropriate from an efficiency perspective even though it has short to medium term distributional implications. On this basis the application of clause 6.5.5 could be extended to restrict levels of price changes from year to year so that no connection point is exposed to price changes that differ materially from the average change. An important exception to this would be where there has been a significant change in the services provided at that connection point (e.g. to service a new customer load).

5. If the NEM objective should have regard to distributional consequences of Rules changes, how should these be taken into account?

As noted in response to Question 4, there may be efficiency benefits in broad price stability for the benefits of customers, and there may be some benefit to permitting transitional mechanisms to mitigate the effects of sudden price changes.

4. Current Transmission Pricing Regime

6. Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate? If not, how could it be improved?

The NEM Rules apply a 'shallow' definition of connection charges to include only the costs of assets in the immediate vicinity of the connected party. The advantage of this distinction is that it broadly corresponds to the distinction between 'shared' network elements, which are characterised by loop flow externalities, and where cost-reflective pricing objectives are difficult to implement, and 'radial' elements where this is not the case. At the level of connections, 'users' can easily be identified, and as a general rule, attributing these costs to a specific user is both possible and efficient.

However, that there are circumstances where the categorisation of assets under Schedule 6.2 requires further clarification. While the definitions in Schedule 6.2 are broadly appropriate, they do not address instances where the function of an asset changes over time, for instance where an asset that would originally be considered a connection asset effectively becomes part of the shared network.[1] The purpose of aligning the definition of an asset with its function in the network then extends beyond cost attribution objectives in a transmission pricing context to reflect operational responsibilities. As a TNSP with responsibility for maintaining reliable network services to its customers, TransGrid must be in a position to control the operation of those assets, which may affect the operation of the shared network. TransGrid would therefore insist on controlling some assets (for instance, certain circuit breakers), which may be classified formally as a connection asset under Schedule 6.2., but which directly impact on TransGrid's ability to meet overall service obligations including reliability obligations.

[1] For instance, this may be relevant for capacitor banks that may have originally been installed to support a connection, but may subsequently be required to maintain network voltages.

TransGrid understands that the Transmission Network Owners intend to provide details of useful clarifications to the AEMC at a later stage in this review and will be contributing directly to this process.

Furthermore, a number of broader questions emerge in categorising services into prescribed, non-prescribed, as well as non-contestable and fully contestable services. TransGrid addressed these in its submission on the Revenue Requirements Issues Paper (see Question 30 and related questions). Various definitions of service are currently used in the Rules, and represent a considerable source of confusion. While the original intention in drafting the Rules may have been to define three classes of service – prescribed, negotiable, and fully contestable services – these definitions and distinctions, and how they relate to connection versus shared network assets – have not been clarified.

The Issues Paper notes that the Rules appear to indicate that since NEM start, connection charges should be negotiated rather than set under the Rules methodology. By extension, it has been argued that all connection assets and services established since NEM start should be non-prescribed. However, it is not clear that this particular distinction was intended in the Rules. TransGrid's view is that it is appropriate to negotiate connection charges for new connections to generators or directly connected customers. However, there is a reasonable case to continue with prescribed charges (and for assets to be treated as prescribed) where there is a new connection between a TNSP and another regulated NSP, or where there is a minor augmentation to an existing connection to a generator or customer that was established pre-NEM.

7. Should a common service charge be maintained or should these costs be incorporated into another charge? If not, how should common service costs be allocated or incorporated into other charges?

Entry, Exit and Usage charges are customer or location specific charges. Common Service charges relate to the costs of providing services that benefit all network users, irrespective of their location, for instance in the provision of stability and reliability services. Therefore there is merit in a charge that is 'postage stamped' forming part of a fixed charge in a two part (fixed/variable) pricing regime, as discussed in section 8.3.1 of the Issues Paper.

As noted in section 4.2.3.1 of the Issues Paper, it can be unclear under the Rules whether reactive plant should be considered as a connection asset or as common service. This reflects the fact that capacitor banks installed for the benefit of a DNSP may also provide wider system benefits and, over time, their prime function may become a system role rather than a customer requirement. TransGrid's interpretation of the Rules is that such assets are classified as common service unless it is clear that their purpose is almost solely for the customer. Some assets will therefore change classification over time. This has flow on implications for metering location. If the capacitor bank is a connection asset then any losses associated with it may reasonably be treated as part of the customer load. If it is common service asset then the losses are system losses.

8. Should generator and MNSP use of system charges remain a matter for negotiation with the TNSP or should they be prescribed in the Rules?

The current NEM Rules appear to envisage a number of ways in which generators would contribute to the cost of the shared transmission network:

1. Through negotiated use of system charges towards the cost of prescribed assets;
2. Through negotiated payments outside the revenue cap for access services to a higher standard;
3. Through negotiated payments to provide a funded augmentation; and
4. Through calculated charges to generators for the cost of new investment (the beneficiary pays charges which are included in the Rules but set to zero for generators under Schedule 6.8).

This is an area where the Commission could usefully clarify the policy intent to provide a simple set of rules. The first of these options is theoretically possible, but not feasible in practice. Generators are under no obligation in the Rules to make use of system payments. It is therefore most unlikely that they would ever agree to a negotiated use of system payment where that payment would go towards prescribed revenue, given that prescribed shared network assets are funded by customers. But where an augmentation is required to the shared network in order for a generator to connect, or to increase its output, then that augmentation has to be paid for. If the augmentation does not pass the regulatory test to become prescribed assets, then the only practical mechanism is a funded augmentation. Funded augmentations may also be required to meet the specific commercial objectives of a generator/MNSP for market access,

As noted in TransGrid's response to Questions 22 ff., the difficulty posed by these funded augmentations is that, to the extent that they have not met the criteria of the Regulatory Test, they would need to be paid for by the proponent. This may be feasible where the cost is relatively small, for example a change to an existing tripping scheme. However, in the absence of meaningful access rights in return for such funding, large-scale investment in the shared network are most unlikely to proceed on the basis of participant-funding. (The international experience suggests that even with access rights, participant funding for large-scale investment is unlikely.).

The issue therefore is a broader one – what role should funded augmentations play and what Rules are needed to make that role effective. The Rules are currently unclear on this issue. By definition, these are not prescribed, although, given their location in the shared network, they often do in fact provide prescribed services.

More generally, as highlighted in TransGrid's response to the AEMC's TNSP Revenue Regulation consultation, a number of broader questions arise in the context of funded augmentations:

- Whether and under what circumstances these assets should be eligible for inclusion in the TNSP's prescribed asset base;
- Whether the cost of maintaining and operating these assets should be included in the MAR (including any operational risk or component failure risk); and
- How these assets should be treated in setting transmission prices.

9. If a modified CRNP usage charge is to remain an option:

- **should the Rules prescribe the criteria for the AER to accept implementation of modified CRNP?; and**
- **should any network customer (rather than just the TNSP) be able to request that the modified CRNP methodology be implemented?**

At present, standard CRNP is the default methodology, and the Rules specify how the methodology is to be applied. The Rules provide only general principles for the alternative modified CRNP and require that, if a TNSP wants to use this methodology, it must submit its detailed methodology to the AER for approval. This arrangement permits a TNSP to modify the basic methodology to reflect network conditions, for instance if the resulting price signal was found to be distorting customers' operation and investment decisions.

TransGrid's response to Questions 1ff. highlights the importance of relatively prescriptive guidelines in reducing the scope for disputes and delivering greater clarity of outcomes. To ensure that the CRNP methodology is applied in a transparent and predictable manner, the Rules should therefore include a set of criteria under which the AER can grant approval of the modified CRNP methodology, as well as guidelines setting out its application.

Furthermore, the standard and modified CRNP methodologies need to be applied across the whole region, or regions, for which the pricing allocation is being made, not simply to a single connection point. The Rules currently recognise this. Accordingly, a decision on which methodology to use should rest with the TNSP (and with the AER if use of modified CRNP is proposed), not with an individual customer seeking commercial advantage from a change in the methodology.

10. How well do the CRNP and modified CRNP methodologies accord with efficient pricing principles? Could simpler approaches be applied to produce similar outcomes?

As already noted, TransGrid's experience is that the actual pricing methodology adopted for the shared network does not impact greatly on the consumption and investment decisions of network users. As such it may be possible to consider a simpler approach than CRNP for allocating shared network costs without undermining efficiency objectives significantly.

The CRNP methodology was adopted following a lengthy process of review, which considered all available options. This review was conducted under the auspices of the National Grid Management Council and substantial documentation would be available of the alternative methods assessed and the findings from the review. CRNP was adopted as the best option identified from this process. Subsequent reviews of the transmission pricing regime applicable in the NEM have also recognised the broad benefits of the CRNP pricing methodology as a mechanism for approximately estimating the distance and asset related costs associated with a particular network location.

As a general matter, all locational pricing approaches in transmission networks can provide, at best, an indicative signal to grid users of the cost that their locational or operational decisions impose on the network. Furthermore, a number of tradeoffs must invariably be made, and the international experience with locational transmission charges is instructive in this respect: the more 'precise' a locational signal is intended to be, the more complex and non-transparent its calculation, and the greater the risk that it will no longer in fact be 'accurate'. Locational transmission prices, specifically those incorporating some form of LRMC signal, are then potentially volatile, a fact that tends to undermine their signalling function. In this context, the CRNP charge could be considered as a workable compromise that provides customers with a limited cost signal, but avoids a situation in which all network costs are simply averaged, irrespective of the particular location of a customer.

CRNP then appears to provide a reasonable approximation to the cost in the longer term of augmenting the network. For the NSW transmission network, a review of CRNP prices indicates that the pattern is broadly that which would be expected – lower prices close to major generation and load centres and higher prices in the more electrically remote areas.

However, CRNP, in common with all the pricing methodologies reviewed, does not provide reasonable LRMC reflective prices at all locations, as noted in the Issues Paper. In particular, prices on radial lines may appear unduly high where the radial line has substantial surplus capacity. This is to be expected, given the economics of transmission: the need to commission capacity in substantial, 'lumpy' increments. That is, it may not have been feasible to install a lower capacity line, or there may have been a trade off between reduced losses and higher capital cost.

Nonetheless, it is very doubtful whether an alternative LRMC based transmission pricing methodology would deliver improved outcomes. As highlighted in TransGrid's response to Question 17, the cost of moving to an increasingly 'accurate' pricing signal takes the form of a significant increase in complexity, lack of transparency and price volatility for customers. Indeed, LRMC calculation for transmission networks relies on a range of assumptions about future network developments. These assumptions are subject to change, particularly in relation to possible projects beyond the medium term (4 –5 years). In practice LRMC assessments are highly sensitive to these assumptions and open to dispute.

It should be emphasised instead that the Rules now provide two important mechanisms for dealing with anomalies that may arise in practice. First, if there are many locations where the CRNP prices provide grid users with inappropriate incentives, the TNSP can choose to adopt the modified CRNP methodology. As noted in the Issues Paper, this methodology modifies prices to reflect the actual level of usage of a line and may therefore result in prices that are more reflective of the LRMC of an augmentation at that location. However, in certain instances, this formulation can also be problematic. Where a line is appropriately sized for its load and where there is no prospect of significant load growth, high prices will result. In effect, the customer is penalised for connecting to a line that is well matched to its load.[2]

The second important mechanism is the discount provision. Where a customer faces transmission prices, which demonstrably exceed those of alternative connection arrangements – effectively, if the customer can bypass certain parts of the transmission network – that customer can seek a TUOS discount. While the locational price itself (the Usage Charge) cannot be discounted, a reduction in the Common Service and General Charges can achieve the same effect of reducing the price anomaly. In effect, the transmission pricing approach then corresponds to the Ramsay pricing rule, so that customers who can demonstrably avoid a transmission charge will receive a discount.

Setting up the CRNP or modified CRNP approaches and related systems to set prices under the current methodology and price structure was a lengthy process for each of the TNSPs. All TNSPs now have systems in place so that the annual pricing reset is a well understood, established process, as noted in the Issues Paper (section 7.2.1.2). Given this, it is hard to envisage that setting up any alternative, other than basic postage stamping, could be simpler than continuing with the current approach. Given the distances that TNSPs' networks must cover in the NEM this would also raise the question whether a transmission pricing approach with no locational signal would be appropriate. In any case it should be noted that any change to the current process will require substantial time, resources and cost with uncertain outcomes for customers.

In summary, it is worth reiterating that in transmission networks all locational charging approaches are inherently problematic; the challenge is to design an approach that is broadly stable, and in general terms reflects the underlying costs at different points of the network. In broad terms, the CRNP methodology appears to meet this objective, and the international experience with other forms of locational charging would suggest that the difficulties that are occasionally encountered are magnified under alternative locational pricing schemes.

11. If the CRNP and/or modified CRNP methodologies were to be retained are the descriptions of the methodologies in the Rules sufficiently detailed and clear? If not, how could they be clarified?

The CRNP methodology is described well in the Rules. TransGrid understands that the Transmission Network Owners intend to provide details of some minor suggested changes to the AEMC at a later stage in this review.

2 Again, this is a reflection of the inherent difficulties in designing a transmission pricing methodology that delivers the 'right' outcome in all circumstances.

12. Is it appropriate to provide scope for TUOS discounting in the Rules?

As noted in TransGrid's response to Question 10, discounting is appropriate and efficient within certain defined circumstances. Discounts are only applicable where the customer has a genuine alternative which, if adopted, would lead to higher transmission charges for other customers. The discounting regime thus provides benefits for all customers. No system of pricing is perfect, and the discount provisions provide an essential 'safety valve' to deal with anomalies that would otherwise result in uneconomic bypass. TransGrid comments further on this issue in the response to Question 30.

13. If so, could the existing arrangements be refined and how?

TNSPs could benefit from greater certainty in relation to discounting by the ability to gain regulatory approval in the course of such negotiations. When the regime was initially established, the ACCC reviewed and approved each case as it arose. However, once the Guidelines were finalised, the regulator no longer had that power under the Code and could only approve discounts at the time of the next regulatory reset. It may have been thought at the time that many such cases would arise, and that the workload on the regulator would be excessive. However, this has not been the case, and there have been relatively few cases of genuine bypass.

There would be definite advantages for both the TNSP and the customer seeking a discount if the AER had the power and responsibility to consider and approve or reject the recovery by the TNSP of the cost of a discount at the time when the discount is proposed. Such discounts are normally sought for large industrial projects where long term contracts are required; the risk for TNSPs and/or the relevant customers is that any discounting agreements are overturned at a later point in time. The AER should therefore have the power to approve discounts for the life of the contract, e.g. up to 20 years. These changes would provide certainty and avoid the need for complex contractual arrangements required at present to manage regulatory risk.

14. Is it appropriate to prescribe arrangements for TUOS rebates in the Rules? If so, could the existing arrangements be refined and how?

TUOS rebates are essentially a matter between Distribution Network Service Providers (DNSPs) and generators embedded in their networks. As such, they do not involve TNSPs. The only issue relevant to this review, therefore is whether the existing transmission prices, when applied by a DNSP to calculate an avoided TUOS rebate, are providing any useful locational signals to intending embedded generators.

TUOS rebates should be seen as one element in an overall regulatory framework that provides for scope for substitution between network and generation investment, and which also includes network support arrangements. Avoided TUOS rebates are intended as a (fairly crude) locational price signal for embedded generators. Their rationale is that they encourage generation to locate in the vicinity of loads, and may, at some future time, result in a network investment being avoided.[3] However, it should be clarified that there is no direct linkage between the avoided TUOS payments and any particular network augmentation. In some circumstances, no augmentation may be needed for many years, and the generator simply reduces load on an unconstrained system. In effect, the avoided TUOS payment reflects an act of faith in a reduction in costs at some future time.

Network support arrangements, on the other hand, are a direct alternative to a specific planned augmentation of the network. The transmission network is designed mainly to meet defined reliability standards for customers. To maintain those standards, TNSPs and DNSPs from time to time must undertake augmentations of their network or adopt an alternative which results in meeting the standard. NSPs apply the Regulatory Test and select the option

3 There may also be benefits in reduction of losses but these are captured in the energy market.

which meets the test. Where this option is generation or demand side measures, network support payments can be made as an alternative to building additional network. It follows that if the TNSP and/or DNSP have a capital allocation from the regulator to fund an augmentation, then the network support payments should be funded from, and seen as an alternative to, the capital funding for the augmentation.

If the generator or DSM is embedded in the DNSP's network, then it is appropriate that the DNSP contract with the provider for the network support. Both the TNSP and DNSP could provide funding for the network support, if both had capital allocations for augmentations that are deferred or avoided. However, it must be recognised that once a DNSP has contracted for network support, this becomes part of its load management obligation. The load as 'seen' by the TNSP is reduced and the TNSP no longer needs to undertake an augmentation to meet its reliability responsibilities to the DNSP. Accordingly, at the next regulatory reset, other things being equal, the TNSP should not need to seek funding for the original augmentation or its replacement – the network support. The ongoing responsibility to fully fund any ongoing network support then rests only on the DNSP.

The Rules do not currently provide a fully coherent framework for network support arrangements, and the current review should address this issue, together with avoided TUOS payments. Specifically, greater clarification is required in relation to ensuring that:

- Network alternatives are appropriately compensated for any cost savings their locational and operational decisions confer on the network; but equally
- Operational and funding responsibilities by TNSPs and DNSPs are coordinated, so as to minimise the costs of network support services to customers overall.

15. Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?

As noted under TransGrid's response to Question 14, the current Rules provide for payments to alternatives that avoid or postpone the need for network investment. Nonetheless, there is a question in relation to which cost pool such payments should be attributed. The Rules specify that where a TNSP adopts a generation option as an alternative, the cost of that service is included in the General Charge. No equivalent provision applies for a demand side option, leaving recovery via the (non-asset related) Common Service Charge as the most likely option. In either case the cost of the alternative is included in a transmission charge, which is postage stamped across all customers, rather than being a location-specific charge as would apply to the network alternative. Given that in the majority of cases, the network alternative would support network operations at a specific location, inclusion of this cost within the locational charging framework would seem appropriate.

Developing a mechanism to apply the cost of a generation or DSM network support project as a locational charge is not simple. TransGrid would be pleased to work with the AEMC in developing a suitable proposal for inclusion in the Commission's planned Options Paper.

16. Should TUOS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options? Does this depend on whether generators generally pay shared transmission costs?

As noted in TransGrid's response to Question 14, this question should be considered in the development of a clarified and coherent framework for network support.

5. Efficiency and Transmission Pricing – Key Concepts

17. Should transmission pricing arrangements principally seek to promote efficiency in the short or long run?

The NEM objective appears to have a clear emphasis on long term considerations. TransGrid has highlighted in its earlier responses that the existing CRNP charge (or its modified version) represents a relatively stable locational cost signal to customers. A number of commentators have proposed moving towards a more explicit LRMC charging arrangement as a way of directly signalling the costs of network expansion arising from a user's locational decision.

The question is therefore whether prices for the shared transmission network can be designed in a way so as to provide locational signals for new generation and loads, perhaps by incorporating some version of LRMC. For instance, locational transmission charges could be set to discourage the location of new generators in those parts of the grid where significant new costs would arise as a result of a new connection.

As a general matter, it should be recognised that even LRMC transmission prices can only ever transmit an approximate signal; for instance, the network investment required to accommodate different types and sizes of customers (or generators) may in practice differ significantly.[4] Beyond this, transmission prices that seek to achieve dynamic pricing objectives are problematic, both in theory and in practice, and are typically associated with a considerable increase in complexity. Paradoxically such charges tend to be highly variable, which tends to undermine their effectiveness as an investment signal.

There are various reasons for this. Network flows and network constraints change over time, as demand and generation patterns evolve, but in particular following the locational decision of a major new customer or generator in the network. Changing flows will affect LRMC estimates of transmission augmentation costs in different parts of the network. The effect is that the signal that a locational transmission price is intended to transmit may then no longer be accurate and will require rebalancing. The instability of such charges is amplified if transmission prices must be rebalanced to recover a fixed portion of TNSPs' annual revenue requirements. In effect, existing grid users will then face a highly variable transmission charge whose value as a longer term signal is questionable.

There are also other difficulties. Locational charging approaches based on LRMC estimates essentially require the TNSP to act as a central planning body whose role is to forecast future investments on the part of private sector entities and associated network expansion costs. In practice, this implies a considerable degree of judgment, and potentially exposes TNSPs to complaints that the charging regime is arbitrary and non-transparent.

Finally, there is a question of the materiality of locational transmission prices. For the overwhelming majority of small consumers, the demand for electricity is relatively inelastic to small price changes, particularly in the short term. For such consumers, transmission costs make up a small percentage (around five percent) of electricity bills, and it is not clear whether a locational adjustment would be material. Larger consumers, for whom transmission prices may represent a material cost component already pay a CRNP charge. While this may be some way removed from an 'accurate' LRMC charge, it does provide an approximate locational signal without the drawbacks of instability and complexity that characterises LRMC charges. TransGrid comments further on the materiality of transmission prices under Question 20.

4 That is, LRMC price calculations typically rely on a hypothetical load or generation increment at selected network nodes.

18. If transmission pricing arrangements should consider both the short and long run, what approach should the Commission take to determine the appropriate balance between these aims?

Current transmission pricing arrangements in the NEM represent a workable balance between short and long term pricing objectives. Short term (static) pricing objectives would suggest some form of Ramsay pricing arrangement whereby charges are levied on those users least able to avoid them. TNSPs typically have limited information about customer characteristics in this regard, but the inelastic nature of the demand for transmission services by the majority of customers, and the scope for discounting where customers have a realistic alternative would broadly meet this criterion. These pricing arrangements are complemented by a locational (longer term) charging component in the form of the CRNP part of customer charges.

6 Relevant NEM Context

19. To what extent are existing signals from other aspects of the NEM arrangements (or requirements from regulatory settings outside the NEM) sufficient to promote efficient behaviour by actual and potential consumers and producers of electricity in the short and long run?

Generators and customers in the NEM currently face a number of locational signals. Significant locational signals are provided from loss factors, through the need to justify network augmentations under the Regulatory Test and from the fact that generators are not guaranteed firm access to the market (and must therefore make an assessment of future network constraints). Furthermore, the regional design of the NEM was intended to signal broad energy price trends – and hence the demand-supply balance – at a regional level.

More generally, it should be recognised that generation investment decisions are driven by other considerations that are frequently more important than locational transmission signals. The base load generators that have been developed since the NEM commenced [Millmerran and Kogan Creek] are believed to be at the bottom of the cost curve because of low fuel costs and generation technology adopted. They achieve much of this advantage by locating close to suitable coal fields. Similarly, investment in peaking generators is partly driven by wholesale price risk management strategies and expectations of periods of relatively high wholesale prices in a given region. In this context, a generator's location within a given region may be determined by other factors such as fuel, water, and environmental issues. As long as there is scope to offer incentives related to transmission investment deferral (network support) that may result from such generators, generators can be encouraged to locate efficiently from a transmission constraint perspective.

In summary, TransGrid agrees with the view expressed in the Issues Paper that these sources of locational signals will tend to encourage consumers and producers of electricity to make efficient consumption and investment decisions. On balance, the existing arrangements appear acceptable from the perspective of providing appropriate signals to consumers, and providing reasonable certainty, clarity and consistency in transmission pricing across the NEM.

20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

The discussion in section 6.2 of the Issues Paper highlights the fact that transmission price signals to DNSPs have to be interpreted by the DNSP into their own Network Use of System Charge component in prices to end use customers. In most cases, any sophisticated transmission price signal cannot readily be carried through to individual customers unless these are large loads with full half hourly metering.

To the extent that this is practical, DNSPs have already adopted network pricing structures that are broadly linked to the existing transmission price structures in their particular region of the NEM. It is therefore reasonable to ask whether much effort should be directed at changing the structure of transmission prices, if such changes do not translate into prices charged to consumers. A pragmatic approach may be to set aside consideration of any changes to transmission pricing structure until there is wider roll out of half hourly metering.

In this context it also worth reiterating the materiality of the issue for most end use consumers. Transmission charges typically make up around 5 percent of the delivered energy price to end use consumers. At present, pricing structures are prescribed for most of each TNSP's revenue – about two thirds in TransGrid's case, with these making up fixed charges. So only about one third of the transmission charge is variable - or less than 2 percent of the delivered energy charge. It is doubtful whether the price signal from this small component would influence behaviour for the overwhelming majority of consumers.

21. If so, should prescription be limited to prices for particular network users?

TransGrid has noted the benefits of prescriptiveness in transmission pricing in its responses to Question 1ff. as a means of clarifying outcomes for network users and reducing potential disputes. While there may therefore be benefits from prescribing Rules for transmission prices to generators or large loads, this may nonetheless lead to a potentially anomalous situation where transmission prices for some users are prescribed, and those for others are not. In theory at least, transmission prices for different types of customers may then evolve along different lines. As noted above, it may be more appropriate to revisit this question at a later point in time.

7. Allocation of Regulated Revenue Across Transmission Users

22. Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?

The NEM nominally has a shallow connection policy so that customers are only charged for the transmission assets directly attributable to them. Where additions to the shared network that are required for a new connection are justified under the Regulatory Test, then these works are funded by all customers.

For a load connection any additions to the shared network that are required to support the connection will normally pass the reliability limb of the Regulatory Test. These additions then become part of the standard charges paid by all customers. However, given the way that costs are allocated under the CRNP methodology, the connecting customer will normally be allocated a significant proportion of the cost, as the customer who makes most use of the new assets. In this sense, CRNP charging may represent an approximation of a 'deep' connection approach.

For generator connections, however, the connection policy is a hybrid shallow/deep approach.[5] Where a generator connection requires additions to the shared network in order to complete the connection, those shared network additions have to be funded. Under the current arrangements, if such augmentations do not pass the Regulatory Test, the only

5 The Issues Paper highlights some confusion over the shallow/deep terminology and the distinction between 'shallow' and 'deep' connection charges, on the one hand, and the question of who pays for augmentations to the shared network, on the other. One view is that deep connection charges merely attribute a wider collection of radial assets to an individual user, but not components of the shared network. That is, such a charging approach shifts the balance between connection and shared transmission charges, but does not imply that connecting users must pay for upgrades of the shared network. The Issues Paper takes the approach that deep connection charges may include the costs of augmentations to the shared network.

alternative is for the generator to fund them as a funded augmentation. However, as noted in TransGrid's response to Question 8, the Rules are ambiguous about the precise nature of the rights and obligations that negotiated connection charges would entail.

TransGrid's response to Question 8 and submission on the Revenue Requirements Issues Paper (Question 30) also emphasised that when augmentations of the shared network to support a generator connection does not pass the Regulatory Test, this hybrid system leads to a range of uncertainties:

- The classification of the funded assets, and whether and how they should be included in the prescribed asset base;
- The treatment of the asset, if load growth means that the augmentation would pass the Regulatory Test some years after it has been funded;
- Payment and refunds if subsequent generators or customers connect at the same location;
- The treatment of surplus capacity arising from the lumpiness of investment and economies of scale; and
- The determination of transmission prices .

The question of how the costs of augmentations to the shared network that are required to support a new connection should be funded is an intractable one. In part, it relates to the difficulties of identifying 'causers' or 'beneficiaries' in a shared transmission network, but it also arises because of scale and scope economies in transmission investment.

If such an augmentation does not pass the Regulatory Test, then customers could justifiably argue that they should not be required to pay for such an investment. However, given the economics of transmission, the alternative of levying the entire cost of augmenting the shared network on the connecting party will realistically prevent such investment from ever taking place. Transmission investment cannot be tailored to meet the requirements of the connecting party, but takes place in very substantial increments. Such investment also typically confers a range of wider network benefits on all users.

Furthermore, once commissioned, other network users cannot be excluded from benefiting from an investment, and this creates a 'free rider' problem. Even if a connecting party were prepared to wear this cost, questions then arise about the contributions that subsequent connecting parties should make. Finally, investment in the shared network offers no guarantee of long term access – network flows are such that congestion may nonetheless limit access at some future point in time. The beneficiaries pay approach that was explored by NECA attempted to deal with these issues, but foundered on the difficulty of allocating costs to beneficiaries in a way which was sensible and would not result in endless disputes (as noted in the Issues Paper in section 7.1.3.2).

Various pragmatic approaches have been adopted in other markets, in recognition of the difficulties that funded augmentations pose. Alberta in Canada, for example, applies arbitrary additional charges to generators which connect in generation rich areas. In the US, markets such as PJM and NEPOOL have developed 'participant funding' approaches whereby connecting generators are required to pay a portion of the cost of augmenting the shared network that is defined in relation to a grid expansion plan benchmark (for instance, in terms of advancing a given investment proposal). It should be noted that in these latter examples generators receive financial transmission rights in response to such funding that remove some of the financial risk arising from future restrictions on physical access to the resulting transmission capability. The Issues Paper describes the approach in New Zealand where generators contribute to radial augmentations but not to "core assets" (section 7.1.1.1). TransGrid understands that a similar approach has been adopted in Western Australia.

In summary, the question of funding arrangements for shared network augmentations appears to be a valid concern to NEM generators requiring further consideration. All of the options described above appear to have shortcomings in one way or another. However, they demonstrate that most jurisdictions have adopted a pragmatic, simplified approach to generator contributions towards shared network costs. Given the substantial capacity increments that are typically required for transmission investments, the risk is that reliance on the Regulatory Test alone may deter some worthwhile generation investment from taking place in the NEM. TransGrid would be pleased to assist the Commission in developing workable proposals this respect.

23. If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?

As noted under Question 22, where upgrades are needed to allow a connection which complies with Chapter 5 standards then the shared network augmentation must be funded. If those works do not pass the Regulatory Test, then the connecting party would need to fund them.

24. If a deep connection approach is to be adopted in the NEM, how should it be formulated?

TransGrid has addressed this issue in its response to Questions 22 and 25. There is already a de facto deep connection approach for customer connections, but a deep connection approach for generators raises a broad range of issues (free rider, connections of subsequent parties, conversion to prescribed status, etc) which have not been fully resolved and that need to be addressed. TransGrid would favour a pragmatic approach to dealing with these issues.

25. Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

Deep connection is compatible with open access transmission, provided payment of the deep connection charges does not imply corresponding property rights to the connecting party. However, a requirement to fund deep network connection without corresponding access rights would further reduce the likelihood that a connecting party would be willing to fund major deep augmentations. This provides quite a strong price signal which may influence generator location and timing. The Commission may wish to consider options to mitigate the strength of this signal if it is considered to be too strong. Measures such as partial generator funding (as in New Zealand), or generator funding for a specified period before automatic conversion to prescribed status are options that could be assessed.

As far as TransGrid is aware the management of free rider characteristics associated with transmission investment are not readily solved. The processes adopted in the north eastern United States appear to go some way in this regard but these regimes may not be truly open access, and it has been argued that these arrangements have contributed to material under investment in transmission, particularly investment in capacity that facilitates an efficient and competitive market. In any case they involve property rights over transmission which the Issues Paper notes is outside the scope of this review.

26. Do signals from the regional pricing structure of the NEM, non-firm generator access and transmission investment arrangements provide efficient locational and operational signals to generators, loads and competing sources of energy supply?

As noted in TransGrid's response to Question 19, it is considered that NEM participants currently receive a range of existing signals. It is considered that, in combination with broad information provision requirements placed on TNSPs and NEMMCO, such signals generally support efficient investment decisions on the part of market participants.

27. Are there reasons why generators should make some contribution to shared network costs? If so, what approach should be used to determine the share of shared network costs should be paid by generators?

As noted in Section 7.1.1 of the Issues Paper, the ultimate incidence of charges levied on generators will be on customers. The main reason for considering generator usage charges would be to provide stronger price signals for generator location, if this were considered to be necessary. However, the problems outlined in TransGrid's response to Question 22 of determining the correct price signal for each location over time remains and seems to be a matter for arbitrary judgement.

It should also be recognised that generator transmission prices for the shared network pose a difficulty that relates to defining the charging basis. The fixed costs of transmission are typically driven by peak injections or demand, but charges levied on that basis would be viewed as disadvantaging peaking generators. Conversely, energy based charges will impose a relatively greater burden on base load plant (and may impact on energy prices in the NEM).

At present the Rules imply that the transmission network is designed to meet the needs of customers. Generators pay only connection charges and do not contribute to the wider network costs. If generators were to pay Usage Charges then this would signal a change to this approach and generators could then argue that their reliability (access) needs should be considered and accommodated. This may trigger additional transmission investment to improve generator access, increasing overall transmission costs. As such, a changed approach to generator charging for transmission would need to be carefully reviewed.

28. Is the current shared network charging regime the best approach for achieving the NEM objective? If not, what improvements could be made?

TransGrid considers that the current shared network charging regime represents a balanced approach to ensuring that customers' long term interests are reasonably well served:

- Given the inherent limitations in transmission pricing, TNSPs are able to recover the efficient costs of providing transmission services in a manner that limits the distortionary effect of such charges; and
- Within this charging framework, the locational pricing component provides a stable longer term signal to support investment in relatively low cost parts of the network.

As noted above, there may be benefits to developing a pragmatic compromise to address situations where generator connections may require augmentations of the shared grid that, viewed in isolation, may be considered uneconomic.

It is worth putting these comments in a wider context. In deciding on a transmission pricing approach there are inevitable trade-offs between methodologies which may each be optimal from particular perspectives, and the practicality of establishing prices which provide a reasonable degree of certainty for customers. CRNP pricing provides approximate locational cost signals, appears to be reasonably well understood by the TNSPs and participants, and delivers a reasonable certainty in pricing outcomes for customers from year to year. Transmission pricing invariably involves such tradeoffs, and the question is not whether the current transmission pricing regime is flawed, but whether there is a demonstrable net gain from moving to an alternative approach.

As noted in TransGrid's overview of current arrangements, the efficiency of the current arrangements does not appear to depend on the use of CRNP per se.

29. Are there arrangements operating in other jurisdictions for the recovery of shared network costs that would be more appropriate for the NEM? If so, which jurisdictions and which aspects of their arrangements would be appropriate for the NEM?

As noted in the responses to Questions 10 and 28, TransGrid does not believe that there is a strong case for change to alternative methods used in other jurisdictions. Transmission pricing is an element of the overall regulatory package and cannot be sensibly considered in isolation from other aspects of the market. As noted above under Question 19, economic signals are also provided to potential generators or customers from other elements of the NEM. Signals arising from the energy market and under the Regulatory Test are likely to represent a more accurate and transparent indication of future cost trends than what could hope to be achieved via complex and (arguably) arbitrary locational prices.

The extensive reviews undertaken under the auspices of the National Grid Management Council, ACCC, and NECA, showed that all pricing arrangements have anomalies, and this also applies to the various international locational pricing approaches referred to in the Issues Paper. It is also worth pointing out that these locational pricing approaches are interesting, because they represent the exception, rather than the Rule: transmission pricing in the overwhelming number of electricity systems in the US and Europe is highly averaged, rather than locational. The CRNP approach was found to be the best option at that time, given the Australian context of a moderately integrated network covering substantial distances and long, radial lines.

30. How much discretion should TNSPs have to discount charges?

The discount regime allowed under the Rules and under the Discount Guidelines provide an effective mechanism for dealing with pricing anomalies. Given that revenue shortfalls arising from discounting must be recovered from other transmission customers, discounts should only be approved in circumstances where the alternative is that a customer no longer contributes to the cost of the shared network and other customers are worse off as a result.

This is an efficient outcome. In effect, the discount regime allows TNSPs (with specific AER approval) to modify transmission prices in relation to those large customers who are particularly price sensitive. The fact that there are very few discount applications indicates that for customers, the standard prices give a reasonable price signal or that the transmission price signal is not significant in decision making. As noted in TransGrid's response to Questions 12, 13 and 32, it is appropriate that AER should approve discounts and the recovery of discount costs from other customers, subject to compliance with the Rules and guidelines.

31. Should TNSPs be entitled to recover the cost of discounts from other loads?

As noted in response to earlier questions, this results in economically efficient outcomes as suggested by the principles of Ramsay pricing.

32. Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine? If so, what should be the general content of these Rules or AER discretions?

The Rules should incorporate the economic principles underlying the Guidelines issued by the ACCC. The Rules should also give the AER the power and the responsibility to approve discounts at the time they are put forward by TNSPs and for the life of the proposed discount arrangement. The AER should then have the responsibility and discretion to issue and maintain Guidelines amplifying the discount processes, consistent with the principles in the Rules.

While the change in approach to revenue setting has reduced the optimisation risk in the assessment of discounts, the fundamental position is unchanged. Discounts should only be offered where the alternative is uneconomic duplication of resources. In essence, the Discount Guidelines released by the ACCC are still appropriate and no further conditions would appear to be necessary.

For clarification it worth noting that while the discussion in the Issues Paper refers to TNSPs negotiating with large users over discounts, discount prices will in fact not be negotiated prices but simply reflect the cost of the customer's alternative option, while negotiations tend to be limited to discussion of technical parameters and costs.

33. Should avoided TUOS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?

As highlighted in TransGrid's response to Question 14, avoided TUOS rebates are matters between DNSPs and generators embedded in their networks.

34. Is the appropriateness of TUOS rebates contingent on whether generators pay shared use of system charges?

As noted under Question 14, TUOS rebates represent a very approximate signal in relation to the benefits that an embedded generator may confer on the network at some future point in time. The appropriateness of TUOS rebates then depends on the view as to whether providing an arbitrary ongoing payment to an embedded generator represents the most cost-effective locational signal for new generators. This mechanism should be reviewed in the broader context of network support arrangements.

35. If TUOS rebates are retained, what charges should they comprise?

TransGrid's response to Question 15 suggested that there may be merit in limiting TUOS rebates to the locational component of transmission prices.

8. Structure of Prices

36. To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?

TransGrid has commented on this matter in its response to Questions 2 and 20. At present, pricing structures are prescribed for most of each TNSP's revenue – about two thirds in TransGrid's case. Current arrangements provide a balance, in terms of establishing a set framework for certain charges while the current discretion in setting Usage Charge structures provides each TNSP with an opportunity to match transmission pricing arrangements with conditions in its own network.

37. Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?

There is considerable benefit in the current level of prescription in pricing structure. Reduced prescription will lead to increased negotiation with those customers with resources to seek price advantages. This would add to overall costs without any benefits to most customers.

There is already guidance on pricing structures in the Rules and in the determinations made by the ACCC. For example, the ACCC has indicated that the Common Service and General

Charges (which are closely prescribed) are intended to recover costs without providing price signals which would influence customers to change their behaviour. The Usage Charge structure on the other hand is intended “to reflect the conditions in the transmission network which influence network investment” (Clause 6.5.4(b)(1)).

38. Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?

TransGrid has addressed this question in its response to Questions 20 and 37.

39. How much discretion over charging structures should be left to the TNSP and the AER?

TransGrid has addressed this question in its response to Questions 20 and 37.

9. Pricing of Non-prescribed Services

40. Are the negotiation provisions in the Rules regarding prices for non-prescribed services appropriate? What difficulties (if any) have been experienced? 6.5.9

TransGrid’s response to Question 6 highlighted the present confusion in relation to the range of definitions of service categories. If it is intended to retain a category of services which are not contestable but also not prescribed, then it would be useful to provide more guidance in the Rules in relation to the definition of such services. The Negotiating Framework required under Clause 6.5.9 should then apply.

41. Should Rules provide criteria in relation to pricing outcomes for non-prescribed services?

As a general matter, the Rules should not seek to prescribe pricing outcomes for contestable services. However, if these are services which are not contestable, then some degree of regulation appears to be appropriate. One solution that would reduce the scope for disputes is to make these services prescribed. If they are not prescribed then prices will be subject to negotiation, with dispute resolution available if required to resolve conflicts. Adding criteria in the Rules for pricing contestable services appears unnecessary.

42. Should a price monitoring regime be considered for non-prescribed services?

If these services are not prescribed or contestable, then prices will be negotiated with reference to normal commercial practice. In most cases the connecting parties to a transmission network will be large entities with sufficient resources to negotiate satisfactory outcomes. The Negotiating Framework established by each TNSP under the Rules already provides for dispute resolution processes to resolve such conflicts. In this context, price monitoring appears an unnecessary additional burden on TNSPs. There also appear to be practical difficulties with price monitoring in this context in that a ‘reasonable price’ may be difficult to assess without actually going through steps that are analogous to establishing a regulated price. If this were to be contemplated then it would be simpler for all parties to make these services prescribed.

43. If so, what criteria would be appropriate? Would these be the same for all non prescribed services?

TransGrid has addressed this question in its response to Questions 41 and 42. Price monitoring does not appear to be appropriate response for services that are essentially contestable.

44. Are the current dispute resolution provisions in Chapter 8 of the Rules appropriate for disputes over pricing of non-prescribed services? What (if any) alternative dispute resolution processes may be appropriate?

Pricing of non-prescribed services comes under the Negotiating Framework, which each TNSP is required to publish. The framework is required to include dispute resolution processes. As the framework must be developed through a consultation process, there is opportunity for customer input on dispute resolution. In TransGrid's experience these arrangements are working satisfactorily and do not require amendment.

10. Inter-regional Issues

45. Could the current provisions in the Rules regarding inter-regional TUOS payments be improved? If so, how?

The provisions regarding inter-regional TUOS payments are based on agreement between jurisdictions. As such, this is a matter for the Ministerial Council on Energy (MCE) to establish a policy position. Ideally, this would include clear guidance on the methodology to be used in any determination ahead of a possible Rule change.

46. What are the impediments, if any, to reaching interregional agreements?

As noted in TransGrid's response to Question 45, an MCE policy decision in support of universal inter-regional TUOS payments would be required before this could be introduced. The previous NEM Code had required NECA to undertake a review of all aspects of this particular arrangement for possible inter-regional TUOS payments. This task is unfinished.

47. Should the Rules provide criteria for determining the 'extent of use of a network'? If so, what criteria would be appropriate?

As noted in TransGrid's response to Question 45, it is not appropriate to consider changes to the detailed Rules unless the MCE has established a policy position which requires such changes.

48. Is there a need for greater clarity in the Rules on the treatment of the negotiated charge paid by the importing region to the exporting region for the purposes of determining annual aggregate revenue requirement of a TNSP?

TransGrid considers that this is a policy matter for the MCE.

49. Would it be appropriate to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review?

See Question 45. This is not an issue for TransGrid as the NSW jurisdiction has not agreed with other jurisdictions on payments under this clause. A decision to extend the operation of the clause until the end of the review appears sensible.

50. Do the current, or alternative arrangements provide TNSPs with adequate incentives to invest in assets that facilitate electricity flows between adjacent jurisdictions? If not what improvements could be made?

As noted in the Issues Paper, while TNSPs operate under a revenue cap where the full amount of settlement residue auction proceeds must be returned to customers through reduced charges, this revenue stream does not act as a disincentive for TNSPs to invest in inter-regional augmentations.

This question does raise two main issues, however:

- Whether the Regulatory Test provides appropriate outcomes; and
- Whether the returns available to TNSPs for regulated investment are adequate where that investment is not mandated to meet reliability criteria.

The responses to the AEMC's TNSP Revenue Regulation consultation indicated that there is a perception among some commentators that investment in infrastructure that is designed to enhance competition is not sufficient, and this issue may need further attention. While the ACCC has undertaken a number of reviews of the content and processes surrounding the Regulatory Test, TransGrid's experience as a proponent of inter-regional network augmentations highlighted the risks that such investment entail for TNSPs. Such proposals have been controversial and require a considerable advance effort – in terms of internal and external resources – on the part of TNSPs. Nonetheless, and irrespective of the outcome of the Regulatory Test, these processes have also demonstrated there is no guarantee to TNSPs that the resulting investment would eventually be permitted to take place.

We note that in the US the Federal Energy Regulatory Commission (FERC) has recently proposed arrangements that ensure that development costs of interstate links are recoverable by transmission investors. A similar mechanism in the NEM would encourage 'for profit' TNSPs to seek out interregional development opportunities. FERC also identified the levels of return on and return of capital as important incentives in this regard. Regardless of the investment incentives involved, both the form and the processes associated with the Regulatory Test will ultimately establish the relevant approval 'hurdle' and this is a matter that is outside the scope of this review.

It is also important that interstate TUOS arrangements are revenue neutral. That is each TNSP investing in an interconnection should fully recover the regulated revenue associated with their portion of the new interconnection investment.

51. Should the negotiations of inter-regional payments be between TNSPs rather than jurisdictional governments?

As noted in the response to Question 45, any TNSP negotiations on the mechanics of payments should be conducted under clear policy principles established by the MCE.

52. Should incentives/penalties be in place in the Rules to ensure that an inter-regional agreement is in place?

TransGrid has addressed this issue in its response to Question 45. If the MCE were to adopt a policy that inter-regional payments should be made, this would need to include guiding principles (possibly adopted in the Rules) together with revenue neutrality requirements to allow any necessary TNSP-TNSP agreements to be established.

53. Should the provisions of clause 3.6.5 be replaced by a modified approach to TUOS pricing more generally?

See Question 45. It would not be appropriate to change these rules through this review without a policy decision by the MCE.