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Transmission pricing methodology

The Electricity Commission's consultation paper

Report to MEUG

1 February 2007

Preface

The New Zealand Institute of Economic Research (NZIER) is a specialist consulting firm that uses applied economic research and analysis to provide a wide range of strategic advice to clients in the public and private sectors, throughout New Zealand and Australia and further afield.

NZIER is also known for its long-established *Quarterly Survey of Business Opinion* and *Quarterly Predictions*.

NZIER was established in 1958.

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1. Purpose

On 1 November 2006, the Electricity Commission (the Commission) released a consultation paper[1] on the pricing methodology proposed by Transpower[2] for recovering the costs of electricity transmission from its customers. The consultation paper presents the proposed transmission pricing methodology (TPM), together with its assessment by the Commission.

The Electricity Governance Rules 2003 (the Rules) require consultation on the proposed TPM. The Commission has invited submissions on its consultation paper by 5pm, 2 February 2007. The Major Electricity Users Group (MEUG) has commissioned NZIER to provide advice on the proposed TPM and the Commission's assessment. This report presents our analysis.

2. Proposed TPM

2.1 Purpose

The proposed TPM seeks to ensure that Transpower recovers the full economic costs of electricity transmission, according to set pricing principles designed to achieve economically efficient prices to transmission customers[3].

2.2 Components

The proposed TPM has the following components:

- connection charges
- HVDC charges
- interconnection charges
- charges for new connections
- prudent discounts
- nodal pricing
- treatment of transmission alternatives

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[1] Electricity Commission (2006) *Transmission Pricing Methodology Consultation Paper*, November, www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/tpmnov06/TPM-consultation-paper.pdf

[2] Transpower New Zealand (2006) *Transmission Pricing Methodology*, June, www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/tpmnov06/TPAG-Proposed-tpm.pdf

Transpower New Zealand (2006) *Transmission Pricing Methodology: Supplementary Material*, June, www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/tpmnov06/TPAG-Supplementary-Material.pdf

[3] See Section 3.1, below, on the Commission's regulatory framework.

- treatment of costs not approved as part of the grid upgrade plan
- transitional arrangements and
- implementation.

The proposals for each of these components are summarised in Section 4, below. The key changes proposed by Transpower from the current methodology are summarised in Appendix A.

2.3 Process

The Rules require that Transpower prepare a proposed TPM. The Commission assesses whether the proposed TPM conforms adequately to the requirements of rule 7.2.1 of Section III of Part F of the Rules. If so, the Rules require the Commission to publish the proposed TPM for industry consultation. Following consultation and any consequent amendments, the Commission makes a recommendation to the Minister of Energy to include the TPM as a schedule to the Rules.

3. Commission's assessment

3.1 Regulatory framework

There are three components to the regulatory framework adopted by the Commission in assessing the components of the proposed TPM:

- rule 7.2.1 requirements for the proposed TPM to be consistent with:
  - any determination made under the threshold regime for electricity lines businesses in Part 4A and under sections 70 to 74 of the Commerce Act 1986
  - the pricing principles of rule 2 and how they should be interpreted and applied as set out in rule 3 of the Rules
  - the guidelines developed by the Commission to assist Transpower in developing the proposed TPM
- practical considerations, transaction costs and the desirability of consistency and certainty (rule 3.1) and
- the Commission's principal objectives and specific outcomes as set out in section 172N of the Electricity Act 1992.

3.2 Assessment criteria

With no determination under Part 4A or sections 70 to 74 of the Commerce Act, the Commission has therefore adopted the following assessment criteria:

- pricing principles:

- the costs of connection and use of system should as far as possible be allocated on a user pays basis (rule 2.1)
- the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options (rule 2.2)
- pricing for new generation and load should provide clear locational signals (rule 2.3)
- sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users (rule 2.4)
- the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints (rule 2.5)
- transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights) (rule 2.6)
- in applying the pricing principles, Transpower and the Board should take into account practical considerations, transaction costs and the desirability of consistency and certainty (rule 3.1)
- where conflicts arise in applying the pricing principles set out in rule 2, they should be resolved with the objective of best satisfying the Board's principal objective (rule 3.2)

- guidelines:
  - a definition of deep connection should be developed and applied consistently and transparently; the definition of deep connection must avoid subsidisation of interconnection assets to the extent practicable (guideline 9)
  - the costs of connection assets are to be recovered from those connected to them (guideline 10)
  - where parties share the use of connection assets, the costs should be allocated among them on a peak demand or injection basis, in a manner than maximises efficiency (guideline 11)
  - charges for existing and new interconnection assets should be on a postage stamp basis; this is similar to the current interconnection charges (guideline 12)
  - Transpower should review the existing basis on which it calculates the interconnection charges at a grid exit point; specifically, Transpower should review whether using the 12 highest half hour offtake peaks in the 12 months up to and including the current month is the most consistent with the

pricing principles in rule 2 of section IV of Part F; this review includes consideration of anytime versus regional or national coincident peaks (guideline 13)

  - Transpower should also review whether permitting greater aggregation across grid exit point loads for the purpose of calculating interconnection charges to encourage peak load management within regions would produce prices more consistent with the pricing principles in rule 2 of section IV of Part F (guideline 14)
  - the costs of the HVDC link and any replacement of or upgrade to it should be charged to all South Island generating stations that inject into the grid (guideline 15)
  - in allocating those costs, Transpower should consider the linkages with other elements of market pricing, and in particular, with the allocation of loss and constraint rentals or any revenue from financial transmission rights for transmission assets covered by the charge (guideline 16)

- practical considerations:
  - make it difficult for participants to game the pricing signal
  - provide accurate signals
  - provide predictable/stable signals
  - provide effective signals
  - provide signals to small and large participants
  - transparent and understandable calculation mechanism
  - transaction costs

- consistency:
  - between elements (internal component consistency)
  - between components (internal TPM consistency)
  - with the wider transmission contracting/regulatory framework
  - with the treatment of assets under the proposed interconnection rules
  - between charging for existing and new assets
  - with nodal pricing and the grid investment test (GIT)
  - with the current charging methodology (while recognising that current methodology was set on a transitional basis)
  - with the treatment of similar participants in the market (for example, a dissimilar treatment would be to apply a charge to one participant and not to another equivalent one)

- regulatory certainty:
  - the desirability of regulation being stable and not changing frequently, suddenly, or in unpredictable ways
  - the desirability of predictable and rational decision-making in relation to regulation
  - the impact of regulatory changes on prices
- principal objectives:
  - to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable and environmentally sustainable manner
  - to promote and facilitate efficient use of electricity
- specific outcomes:
  - energy and other resources are used efficiently
  - risks (including price risks) relating to security of supply are properly and efficiently managed
  - barriers to competition in the electricity industry are minimised for the long-term benefit of end-users
  - incentives for investment in generation, transmission, lines, energy efficiency and demand-side management are maintained or enhanced
  - the full costs of producing and transporting each additional unit of electricity are signalled
  - delivered electricity costs and prices are subject to sustained downward pressure and
  - the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.

In its assessment, the Commission has also considered reasonably practical alternative options, and the costs and benefits of the proposed option relative to any alternatives.

3.3 Commission's findings

The Commission assessed, firstly, whether there was sufficient information provided in Transpower's submission to enable assessment and, secondly, whether the proposed TPM adequately conforms to the pricing principles and guidelines in accordance with rule 7.2.1. The Commission is satisfied in these two

respects and has approved and published the proposed TPM for industry consultation.

4. NZIER's analysis

The Commission has invited feedback on the proposed TPM and its assessment. In its consultation paper, it poses 42 questions. We present our analysis below, following a brief description of each component of the proposed TPM, identified reasonably practicable alternative options and the Commission's assessment. Our analysis is also summarised in Appendix B.

4.1 Process and assessment

a) Process following consultation (Section 2.7 of the consultation paper)

Q1. Do you agree that the process set out in Figure 2-2 is consistent with the rule requirements?

Figure 2-2 sets out the draft programme of consultation and implementation of the TPM. It does conform to the Rules, but we consider it would be desirable, if the Commission does propose any material amendments to the TPM, to consult on these with not only Transpower, as planned, but also other parties.

b) Determination under the Commerce Act (Section 3.2)

Q2. Do you agree that rule 7.2.1.1 is not relevant in this case?

Rule 7.2.1.1 relates to any determination under Part 4A or section 70 to 74 of the Commerce Act 1986. Although a settlement agreement between Transpower and the Commerce Commission relating to these provisions has been mooted, this does not appear to constitute a determination. On this basis we agree that rule 7.2.1.1 is not relevant. If, however, the settlement agreement, which will be subject to consultation, does not proceed and a determination is made, this would no longer hold.

c) Assessment of the proposed TPM against the regulatory framework (Section 4.2)

Q3. Do you agree that it is not necessary for the Commission to separately assess consistency against the Government Policy Statement (GPS)? If not, please provide details of what aspects of the GPS you consider are not covered by the regulatory framework herein?

Agreed, given that the specific outcomes of the GPS are included in the Commission's assessment criteria.

Q4. Do you agree that it is not necessary for the Commission to separately assess consistency against the National Energy Efficiency and Conservation Strategy

(NEECS)? If not, please provide details of what aspects of the NEECS you consider are not covered by the regulatory framework herein?

Agreed, given that the NEECS goals are implicit in the pricing principles and specific outcomes included in the Commission's assessment criteria.

4.2 Connection charges

4.2.1 Proposal

The objective of connection charges is to allocate the costs of connection as far as possible on a user pays basis, avoiding subsidisation of interconnection assets to the extent practicable. Transpower's proposals pertain to the definition of connection assets and nine pricing elements for assigning assets to customers and calculating the connection charge:

- geographical grid definition
- definition of connection nodes and links
- allocation of shared assets between customers
- allocation of shared land assets between interconnection and connection
- allocation of shared other assets between interconnection and connection
- allocation valuation methodology
- maintenance charges
- operating charges and
- connection charge calculations.

In the proposed TPM, Transpower identifies connection assets by representing the grid in terms of links and nodes and defining all nodes connected to network spurs to be connection assets (the augmented loop flow definition).

In the proposed TPM, the grouping of physical assets to form links and nodes is based on a geographical definition of the transmission grid, which uses the physical grid and groups assets according to geographical location. This may require Transpower to exercise some discretion in grouping assets into links and nodes.

Under the proposed augmented loop flow method of defining connection assets, a connection node is defined as any node that is not an interconnection node. An interconnection node is defined as any node connected to two or more nodes in a "loop", other than a "small regional loop". A loop is a continuous path of nodes and links with the same start and end node. A small regional loop occurs where a loop path exists between any group of nodes (excluding Benmore and Haywards) that have only a single link from the loop to the next node outside the loop.

In the proposed TPM, the costs of shared connection assets are allocated to each transmission customer according to anytime maximum demand for loads, based on the average of the top 12 peaks, or anytime maximum injection for injections, based on the highest single peak.

Transpower proposes that land and buildings be shared according to the relative value of all other assets at that node allocated to connection and interconnection.

For all other shared assets, Transpower proposes that charges be allocated according to the ratio of anytime maximum demand or anytime maximum injection to the total nameplate capacity rating of the asset.

The proposed valuation methodology for connection cost allocation is to use standard replacement cost to calculate the required return on capital from the connection assets to a customer, with adjustment for any initial optimisation of asset values.

The proposed TPM allocates to connection customers the maintenance costs for connection assets only – the replacement cost of substations and a rate per kilometre for 220kv+ lines, tower lines and pole lines, averaged over the preceding four years.

The proposed TPM allocates operating costs to users according to number of switches.

The calculation of connection charges follows from the above proposed pricing elements.

4.2.2 Alternative options

The Commission's consultation paper describes five reasonably practicable alternative options for defining connection assets – on the basis of uncertainty-based power flow, average power flow and unidirectional flow, the core grid definition and Transpower's current definition. Under the current method, interconnection nodes are defined as nodes connected to at least three other nodes or between two interconnection nodes; connection nodes are defined as nodes connected to only one other node or no more than one interconnection node.

The current transmission grid definition uses the optimised grid and groups assets by electrical configuration.

Transpower identifies two alternative options to the augmented loop flow method in defining connection nodes and links – the loop path method and the current method.

Transpower presents a coincident peak load model as an alternative option for allocating the costs of shared connection assets.

The Commission identifies an alternative option for allocating shared land assets as calculating land costs for providing standalone services for both connection and interconnection and allocating the total cost of the actual land used accordingly. It considers there to be no reasonably practicable alternative options to the proposal for allocating other shared assets.

Transpower outlines four practical alternatives to use of replacement cost in valuing connection cost allocation – historic cost, indexed historic cost, optimised deprival value and optimised replacement cost. The Commission has also considered a direct charging method, using the same valuation as for revenue setting purposes.

Transpower indicates an alternative option of allocating total HVAC maintenance costs across all HVAC assets, by asset type, rather than levying maintenance charges for connection assets only. The Commission has also considered direct charging of maintenance costs to specific connection points.

Transpower and the Commission consider that there are no reasonably practicable alternative options to the proposed method for allocating operating costs.

4.2.3 Commission's assessment

The Commission acknowledges that there is no unique and definitive method for determining which assets constitute deep connection assets and, in a connected network system, no clear physical boundary between connection and interconnection assets. The deeper the definition, the stronger the user pays and locational signals, but also the greater the difficulty in accurately identifying each customer's use of specific assets and the less transparency and stability. Although not as deep as the power flow options, the definition of connection assets adopted by Transpower in the proposed TPM is relatively simple, transparent and stable over time. The Commission assesses the proposed definition to achieve the required balance between depth, signals and practicality.

The Commission considers the proposed geographical grid definition to be better aligned with a user pays approach, by geographically identifying the assets required to connect a transmission customer to the grid, as well as more difficult to game the electrical configuration of the grid, more stable over time, to provide more accurate and effective signals, slightly less transparent, and likely to have similar or lower transaction costs, than the current method.

With regard to the definition of connection nodes and links, the Commission assesses the proposed augmented loop flow method to incur similar transaction costs to the alternative options, but to provide greater benefits through a deeper connection definition allowing transmission customers greater influence over service levels for more assets affecting their quality of supply, and through locational signals to new load and generation.

The Commission regards the proposed method for allocating the costs of shared connection assets as preferable to the alternative options in aligning more closely with user pays and a "fair" allocation between customers, as well as being simpler to administer. The Commission notes that there may be value in allowing parties who share connection assets to negotiate and determine a mutually agreed allocation of shared connection assets and be charged accordingly, with anytime maximum demand or anytime maximum injection as the default if agreement cannot be reached.

In the Commission's opinion, the proposed method for allocating shared land assets is simpler to administer and costs significantly less than the alternative option and provides a reasonable basis for a "fair" allocation between connection and interconnection.

The Commission judges the proposed method for allocating all other shared assets to provide a reasonable basis for "fair" allocation between connection and interconnection, which is simple and transparent.

For allocation valuation, the Commission finds the alternative option of a direct charging mechanism superior, in terms of the pricing principles, to the proposed use of replacement cost. In terms of practicality, however, the Commission expresses concern that a direct charging mechanism may incur high transaction costs (from the effects on cash flow of larger changes in connection charges when new or replacement assets are commissioned, particularly for customers who are reliant on a small number of connection assets) and be less stable than Transpower's proposal. The Commission considers that the advantages of the proposal are similar charges for similar assets across the grid, such that customers with similar capacity requirements face similar levels of charges regardless of location, and smoothing of charges between customers, enabling more efficient cash flow management for any single customer. It has the disadvantage of cross-subsidising connection costs between transmission customers using old and new assets. The Commission assesses the balance of costs and benefits to lie in favour of Transpower's proposal.

The Commission assesses that the proposed approach to maintenance charges makes the maintenance costs of connection assets more transparent and thereby incurs lower transaction costs to transmission customers than either of the alternative options. It highlights that, as above, a direct charging mechanism may incur significant transaction costs.

The Commission deems the proposed method for allocating operating costs to be appropriate and practical.

The Commission is of the view that the proposed calculation of connection charges is a transparent and practical application of the pricing elements.

4.2.4 Our analysis

a) Deep connection definition (Section 5.3)

Q5. Do you agree that the appropriate balance between the depth of connection definition and the efficiency of the pricing signals has been struck in the proposed TPM?

We consider that for the existing grid the proposed approach is not unreasonable, given the guidelines that Transpower has been provided with by the Commission. For investments in grid capacity, however, we believe defining connection assets using a "but for" test would be superior in terms of the requirement to "avoid subsidisation of interconnection assets to the extent practicable", the pricing principles in the Rules and the assessment criteria proposed by the Commission in general.

The "but for" approach has been developed and successfully implemented by PJM Interconnection, the Independent System Operator (ISO) for a large part of the eastern and mid-west United States as an integral part of its Regional Transmission Expansion Planning Protocol (RTEPP). The approach is utilised to identify the particular cost causer associated with an investment in the interconnected grid.

> *The process identifies whether the particular upgrade would have been needed* but for *the actions of a particular entity or set of entities. For example, if a generator [connection] to the grid causes a reliability problem (identified as a violation of NERC criteria), the generator is identified under the "but for" analysis and knows up front the cost of the upgrade needed to effectuate its interconnection. On the other hand, if the reliability violation results from load growth or other system conditions, the particular transmission zone is identified for such costs to be assigned.*[4]

When a generator or particular load or loads can be identified as the "causer" or "user" of the investment, the charges relating to the assets would be assigned to that party or parties. When no party or parties can be identified using this approach, the assets would be classified as interconnection assets.

Compared with Transpower's proposal, the "but for" approach would reduce the extent to which parties not responsible for investment in assets, and who would make no effective use of them, end up having to pay for them and so subsidise them. It would also provide beneficiaries of investment with stronger incentives to identify least-cost investment options (rule 2.2) as they would bear all the costs and not just a small proportion relative to their share in interconnection contracts. Moreover, it would provide clearer locational signals to new generation and load (rule 2.3).

[4] http://www.pjm.com/documents/downloads/presentations/20050422-zibelman-testimony-ferc-transmission-technical-conf.pdf

This proposal could be applied consistently across the grid and over time. It clearly conforms to the guidelines the Commission gave Transpower, including that the TPM should use a deep connection definition of connection assets. Over time, the adoption of the approach would reduce the interconnection assets to those assets for which the generators or loads responsible for the investment cannot be identified, and this is all that should be paid for by the averaging process of postage stamp interconnection charges if grid investment is to be as efficient as possible.

PJM claims that its approach "provides certainty both in the process and in the business rules. Investors can point to settled rules with settled milestones and a track record of consistent outcomes." Between 1999 and early 2005 PJM used its procedures which involve "but for" to deal with 533 generator connection requests.[5]

An assessment against the regulatory framework criteria relevant to connection assets identified by the Commission of the "but for" approach to defining connection assets compared with Transpower's proposal is contained in Appendix C. This clearly demonstrates the superiority of the "but for" approach to defining connection assets in the New Zealand context.

Q6. If so, why do you agree with this? If not, where should the appropriate balance be struck and why?

No. See answer to Q5.

Q7. Are there any more suitable alternatives for defining deep connection that conform with the guidelines and pricing principles and are practical to apply consistently across the grid and over time?

Yes. See answer to Q5.

b) Geographical grid definition (Section 5.5)

Q8. Do you consider that the alternative presented is the only reasonably practical alternative? If not, please provide a description of the alternative including the implications of adopting such an alternative and an assessment of it against the regulatory framework.

No. See answer to Q5. We strongly believe the option proposed by Transpower is inferior in terms of the assessment criteria to the alternative "but for" approach we have put forward.

Q9. Do you consider it appropriate that Transpower may have to exercise discretion in grouping assets into links and nodes?

[5] loc.cit.

Someone is going to have to exercise discretion if the current proposal is accepted. It would seem desirable for whoever is going to do so be provided with guidance on the factors it should consider when doing so. A right of appeal to the Commission or the Rulings Panel against how it has exercised its discretion may also be worthwhile. Transpower appears to be an appropriate party to hold the discretion subject to these checks and balances.

c) Definition of connection nodes and links (Section 5.6)

Q10. Do you agree that the proposed links-node definition is the best alternative for defining the connection assets? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

No. See answer to Q5. We strongly believe the option proposed by Transpower is inferior in terms of the assessment criteria to the alternative "but for" approach we have put forward.

d) Allocation of shared assets between transmission customers (Section 5.7)

Q11. Do you agree that the proposed allocation of shared connection assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed.

Q12. Do you consider having the proposed method as a default mechanism but allowing customers to voluntary to agree on a sharing of costs is desirable?

Yes.

e) Allocation of shared land assets between connection and interconnection (Section 5.8)

Q13. Do you agree that the proposed allocation of shared land assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed.

f) Allocation of shared other assets between interconnection and connection (Section 5.9)

Q14. Do you agree that the proposed allocation of other shared assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed.

g) Allocation valuation methodology (Section 5.10)

Q15. Do you agree that the proposed valuation allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Like the Commission, we consider that the alternative option of a direct charging mechanism better conforms to the pricing principles than does Transpower's proposal of using replacement cost. A direct charging mechanism would be more consistent with a user pays approach and better reflect locational differences. We acknowledge that under this approach, the step changes in charges when new or replacement assets are installed would be large relative to the business size of some customers. Transpower's proposal would smooth charges across users of old and new assets; in effect, a customer would be "subsidised" when the assets it uses are new and would "subsidise" others when the assets it uses become older than the average age of all connection assets. We do not accept, however, the Commission's assessment that Transpower's proposal is the more suitable option in practice. We consider the direct charging mechanism should be adopted.

Q16. Do you consider that the costs associated with a direct charging mechanism are likely to outweigh any benefits from a more closely aligned user pays approach?

No.

Q17. Do you consider that the upgrade or replacement of a single connection asset (or group of associated assets) is likely to create cash flow management issues for grid-connected parties?

No. If they are too small to be able to manage this demand on cash flow, they should merge with parties that are big enough to do so.

h) Allocation of maintenance costs (Section 5.11)

Q18. Do you agree that the proposed maintenance cost allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed.

i) Allocation of operating costs (Section 5.12)

Q19. Do you agree that the proposed operating cost allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed.

j) Connection charge calculation (Section 5.13)

Q20. Do you agree with the Commission's assessment of the calculation mechanism?

Agreed.

4.3 HVDC charges

4.3.1 Proposal

Transpower proposes to allocate the HVDC charge to all South Island generating stations that inject into the grid, according to their single (N=1) historical anytime maximum injection (HAMI) over the preceding five years. Under guideline 15, this method applies to charging for the costs of the existing HVDC link as well as any future replacement or upgrade.

4.3.2 Alternative options

The proposal is a change from the current method of allocation according to the single anytime maximum injection (AMI) over the preceding 12 months.

Other alternative options identified by Transpower are allocation according to the generation plant's name plate capacity rating or HAMI calculated using 100 peak injections instead of the single peak injection.

4.3.3 Commission's assessment

The Commission considers Transpower's proposal preferable to the alternatives in minimising transaction costs and being practical and transparent, whilst reflecting the level of use of the HVDC link. It notes that the proposed allocation method may create some incentive for South Island generators to withhold generation at the very highest peak injection periods, but only where the value of this peak capacity is low relative to the HVDC charge, and this incentive is minimised by calculation of HAMI over a five year period. The Commission considers that use of such a long time period in calculations also discourages inefficient embedding of generation.

4.3.4 Our analysis

a) The HVDC allocation method (Section 6.3)

Q21. Do you consider that, in light of the above reasoning, it is reasonable to charge HVDC payments to South Island generators but give rights to other parties affected by the HVDC link under the interconnection rules?

We have indicated previously[6] that, subject to the adoption of an appropriate regulatory regime to deal with market power issues, our first preference is adoption of a merchant transmission investment approach to paying for use of the existing HVDC link and any new HVDC assets. Under this approach Transpower would buy and sell electricity at each end of the link at Benmore and Haywards and retain the difference between what it pays for the electricity it buys and what it receives in selling it. Of the options presented by the Commission previously[7], we favoured charging existing South Island generators for the existing HVDC link and existing and future South Island generators for any new HVDC assets.

In the absence of the option of merchant transmission investment arrangements, we therefore agree with Transpower's proposal that HVDC costs be charged to South Island generators. Application of the same method for the existing link and any future replacement or upgrade ensures that repairs/replacements and upgrades are treated consistently and avoids definitional difficulties in differentiating between the two.

The second part of the question relates to a concern about the consistency of the charging regime for the HVDC link and its inclusion under the proposed interconnection rules. We agree with the Commission that the approach it has adopted is not unreasonable, but consider it preferable to treat HVDC assets as a distinct class of assets and that the decision rights in relation to them should rest largely with Transpower and the parties paying for them, in the same way that the rights in relation to other connection assets are handled.

Q22. Do you agree that the HAMI method is preferable to the name plate rating allocation mechanism?

Agreed, given that peak injection better reflects actual use than does nameplate capacity and this method does not discourage small net injections by embedded generators.

Q23. Do you agree with Transpower that N=1 is a better option than N=12 or N=100 for the allocation of the HVDC charges to South Island generation plant?

No view.

b) HVDC charge calculation method (Section 6.4)

Q24. Do you agree with the Commission's assessment of the HVDC charge calculation mechanism?

Agreed, given the proposed allocation method.

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[6] NZIER (2005) *HVDC Transmission Pricing Methodology – the Electricity Commission's Issues Paper*, report to MEUG, December.

[7] Electricity Commission (2005) *HVDC Transmission Pricing Methodology*, Issues Paper, November.

4.4 Interconnection charges

4.4.1 Proposal

The objective of interconnection charges is to recover the balance of Transpower's HVAC revenue requirement not recovered by the connection charge. There are four pricing elements to the proposed charges for existing and new interconnection assets:

- the regional definition
- the number of peak demand periods used (value of N)
- the coincident peak allocation and
- the capacity measurement period.

The proposed TPM defines four regions for the interconnection charge (upper North Island, lower North Island, upper South Island and lower South Island), the boundaries of which are to remain static but to include additions to each region of any new grid exit points built therein. Increases in regional peaks are reasonably good indicators of the need for grid investment in the associated regions. Transpower's analysis[8] shows no consistent relationship between the timing of national system peaks and regional peaks, such that basing interconnection charges on national coincident peak demand could encourage consumption reductions at times irrelevant to the investment drivers in some regions.

In its interconnection charge calculations, Transpower proposes to use a constant number of peak demand periods (value of N) – 12 in each of the upper North Island and upper South Island and 100 in each of the lower North Island and lower South Island. N=12 provides an incentive to reduce peak demands, whilst N=100 significantly reduces the incentive to modify consumption behaviour. The adoption of N=12 reflects major new investment planned for the upper North Island and upper South Island, whilst N=100 is adopted to ameliorate inefficient signals to reduce consumption in the lower North Island and lower South Island where there is no transmission-related need to do so.

Transpower proposes to allocate interconnection charges according to regional coincident peak demand, determined by the average of the top 12 coincident peak half-hourly demands for each of the upper North Island and upper South Island and the average of the top 100 regional coincident peak half-hourly demands for each of the lower North Island and lower South Island.

The proposed TPM aligns the periods over which these demands are measured with the preceding April to March pricing year.

[8] Transpower (2006) *Transmission Pricing Methodology – Briefings 28, 29 and 30 November 2006.*

4.4.2 Alternative options

The proposal is a change from the current method of allocation nationally, according to the 12 highest anytime maximum demands, calculated as a monthly rolling average over the preceding 12 months.

Alternative options are to have a greater number of regional definitions or a single national region. A possible addition is a mechanism for setting and reviewing regional boundaries. Different values of N could be adopted in interconnection charge calculations. Interconnection charges could be allocated according to anytime maximum demand or a system of coincident peak demand.

4.4.3 Commission's assessment

The Commission favours the proposal for four regions over a single national region, to enable price signals that incentivise regional demand-side management. Static regional boundaries incur lower transaction costs. The Commission notes that more than four regions could be defined and regional boundaries could be located differently, which may better reflect the grid's transmission investment requirements, but considers the proposal to seem consistent with Transpower's future investment programme. Defining more regions may enhance locational signals, but would be subject to greater disagreement on which regions are less or more constrained and the efficiency of the pricing signal.

The Commission agrees with Transpower that there is no unique value of N that would achieve the desired demand efficiency and investment outcomes. It considers that the values proposed provide an appropriate balance between encouraging peak load management and avoiding inefficient incentives to reduce energy consumption or to embed generation. The use of a different value of N in each region allows for weighting charges towards regions requiring ongoing transmission investment and provides a signal promoting dynamic efficiency in demand-side management.

The Commission favours the proposal of coincident peak allocation over the alternative options on the grounds that, although this method may result in less stable charges and higher transaction costs, it is more likely to enable savings in transmission investment over the longer run through incentives to transmission customers for regionally co-ordinated management of peak demand.

The Commission considers that use of the preceding April to March pricing year as the period over which demands are measured would incur lower transaction costs than the capacity measurement period in the current methodology through providing transmission customers with certainty as to their charges within each pricing year.

Overall, the Commission considers that the proposal provides efficient and effective pricing signals to encourage peak load management.

4.4.4 Our analysis

a) The regional definition (Section 7.3)

Q25. Do you agree that the proposed regional definition is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?

Agreed. We favour the definition of multiple regions over a single national region to provide locational signals to demand and investment. The regional definitions proposed seem somewhat arbitrary, but a reasonable, practical compromise.

Q26. Do you consider that it is appropriate for the regional definitions to remain static over time or should there be some other review and setting mechanism than rule 11.2 to transition these? In considering this, you should comment on the likelihood of instability and holdout behaviour if there was such a mechanism.

Static regional definitions have the advantages of certainty and lower transaction costs. There may be a case for reviewing, perhaps every five years (a sufficiently long time period to avoid holdout behaviour), whether the distinctions between regions remain valid, but we consider that Part F, section IV, rule 11.2 provides sufficient mechanism ("The Board may review an approved transmission pricing methodology if it considers that there has been a **material change in circumstances**" [emphasis added]).

b) The number of peak demand instances (Value of N) (Section 7.4)

Q27. Do you agree that the proposed regional definition is the best alternative? If not, why not, and what would be a more suitable alternative?

Agreed, as a reflection of current investment plans.

Q28. Is it appropriate for the value of N to remain fixed or should there be some mechanism for regions to transition between N=12 and N=100? If so, what should that mechanism be and how would it line up with the guidelines and pricing principles?

The Rules provide an opportunity for the Commission to review an approved TPM if it considers that there has been a material change in circumstances. We consider that this provides sufficient mechanism for altering the value of N in a given region for changes in investment plans and requirements.

c) Coincident peak allocation

Q29. Do you agree that the proposed coincident peak allocation is the best alternative? If not, why not, and what would be a more suitable alternative?

Transpower should be required to provide more analysis of its proposal and its consequences than it has done to date.

d) Capacity measurement period

Q30. Do you consider that the proposed capacity measurement period is preferable to the alternative?

We consider the proposal – the preceding April to March pricing year – and the current method – the rolling average over the 12 months up to and including the current month – equally preferable. The proposed method provides greater stability within a pricing year, but uses older data (in effect, adding a further time lag), the disadvantage of which depends on how much demand varies between one year and the next.

We highlight, however, that, under the proposal's greater time lag, decisions being made by customers prior to determination of future TPM arrangements would influence charges following implementation of the proposed TPM. We suggest that a shorter period, involving a time lag of up to only one year, be adopted at least initially, to ensure that customers are provided with "fair notice" of the basis of their future charges and opportunity to adjust their demand according to this price signal. Following due transition, the capacity measurement period could, if necessary, be gradually extended to that of the proposal, although this would extend the time lag between levels of demand and resulting charges and therefore impede the timeliness of response to price signals.

Q31. Do you consider there are reasonably practicable alternatives?

The more detailed analysis we have argued Transpower should be required to undertake should identify any reasonably practicable options.

4.5 Charges for new connections (Section 8)

4.5.1 Proposal

Transpower proposes to base charges to new customers, whether connection, HVDC or interconnection charges, on their forecast demand, adjusted every three months until a full set of 12 months data has been recorded.

4.5.2 Alternative options

Transpower identifies the alternative option of charging new customers an estimate, adjusted at the end of 12 months for any difference between estimated and actual demand.

4.5.3 Commission's assessment

The Commission considers Transpower's proposal to use actual data as soon as practicable preferable to the identified alternative option, in achieving the same outcome but at lower transaction costs.

4.5.4 Our analysis

Q32. Do you agree with the Commission's assessment of the proposal?

Agreed.

4.6 Prudent discounts (Section 9)

4.6.1 Proposal

The objective of the prudent discount regime is to help ensure that the TPM does not provide incentives for economically inefficient bypass of existing grid assets. It aims to deter investment in alternative projects that would allow a customer to reduce its own transmission charges at the expense of increasing total economic costs nationally. To obtain a prudent discount under the proposed regime, the customer's alternative project must be technically, operationally and commercially viable, have reasonable prospect of successful implementation, and be uneconomic to implement under Transpower's economic costs of providing existing grid assets and the customer's economic costs if it proceeded with the alternative project.

4.6.2 Alternative options

Transpower and the Commission consider that there are no reasonably practicable alternative options.

4.6.3 Commission's assessment

The Commission is satisfied that the benefits of the proposal, in reducing charges to avoid inefficient bypass, outweigh the costs to Transpower of administering the prudent discount regime and the costs to transmission customers of investigating alternative connection configurations. It is satisfied that the systems and processes of the proposed prudent discount regime are sufficiently transparent and balanced with regard to the needs and obligations of all parties involved. The Commission notes that the impact of the prudent discount regime may be affected by the outcome of the Commerce Commission's control enquiry and the form of administrative settlement.

4.6.4 Our analysis

Q33. Do you agree that the proposal will prevent inefficient by-pass?

Agreed. We support the use of prudent discounts.

Q34. Do you agree that there are no practical alternatives to the proposal?

Agreed.

Q35. Do you agree that the proposed process is workable and balanced in terms of the rights and obligations on each of the parties?

Agreed. We recommended previously[9] that, for transparency, the details of any prudent discount agreements into which Transpower enters should be published, which we note is included in the proposed prudent discount regime.

4.7 Nodal pricing (Section 10)

4.7.1 Proposal

The proposed TPM is designed to provide locational consumption signals to new investment through deep connection charges, HVDC charges to South Island generators and regional coincident peak demand allocation of interconnection charges (each of which are outlined above).

4.7.2 Commission's assessment

The Commission is satisfied that, in the proposed TPM, Transpower has sought to take into account nodal pricing to the extent possible within the limits of the regulatory framework.

4.7.3 Our analysis

Q36. Do you agree with the Commission's assessment that the proposed TPM is consistent with locational signals provided by nodal pricing?

Agreed.

4.8 Treatment of transmission alternatives (Section 11)

4.8.1 Proposal

To recover the costs of any alternatives to transmission that it funds, Transpower proposes identifying transmission alternatives as substituting for the services provided by either connection assets, interconnection assets or both (e.g. generation, demand-side management). Transpower proposes recovering actual costs incrementally as they are incurred, allocated pro rata according to whether substituting for connection or interconnection assets and each customer's share of total connection or interconnection charges.

4.8.2 Alternative options

Transpower also identifies the alternative option of adding a forecast of transmission alternative costs to either connection or interconnection charges, adjusted at the end of each pricing year for any difference between forecast and actual costs.

[9] NZIER (2004) *Proposed Guidelines for Transpower's Transmission Pricing Methodology: Comments on the Electricity Commission's Proposals*, November.

4.8.3 Commission's assessment

The Commission considers Transpower's proposal preferable to the identified alternative option, in achieving the same outcome but at lower transaction costs.

4.8.4 Our analysis

Q37. Do you agree this is an appropriate mechanism for recovering the cost of transmission alternatives?

We agree that the proposal is an appropriate mechanism for recovering the costs of transmission alternatives funded by Transpower. We have highlighted previously[10], however, that this does not imply that Transpower should be the sole provider/funder of transmission alternatives, which, in our view, would entrench Transpower's monopoly position and may stifle the consideration and adoption of efficient alternatives to transmission.

4.9 Treatment of costs not approved as part of the GUP (Section 12)

4.9.1 Proposal

The proposed TPM is designed to recover the full economic costs of transmission, such that an additional methodology for recovering costs not approved as part of a GUP is unnecessary.

4.9.2 Commission's assessment

The Commission is satisfied that the proposed TPM is sufficient not to require extension.

4.9.3 Our analysis

Q38. Do you agree that the proposal meets guideline 6 and process requirement 6? If not, what alternatives are there within the boundaries of the current regulatory framework, including the Commerce Act?

Transpower should not be able to recover costs for grid investments that have not been approved under Part F procedures and that are not used and useful. If the proposed TPM allows Transpower to recover costs for grid investments that do not meet these two requirements, it should be amended to make it clear that the recovery of costs applies only to grid investments that do meet these requirements.

[10] NZIER (2005) *Guidelines for Transpower's Transmission Pricing Methodology – EC's Decisions and Strategic Risks*, report to MEUG, January.

4.10 Transitional arrangements (Section 13)

4.10.1 Proposal

Transpower proposes no transition period, on the grounds that adoption of the proposed TPM would involve relatively small changes in transmission service charges.

4.10.2 Alternative options

The Commission has considered the alternative option of a transition period.

4.10.3 Commission's assessment

The Commission considers Transpower's proposal preferable to a transition period, given the small (absolute, if not percentage) changes in transmission service charges to specific customers relative to the transaction costs of managing transitional arrangements.

4.10.4 Our analysis

Q39. Do you consider that there should be transitional measures put in place and, if so, how would this be implemented?

No, we agree that the costs of establishing and operating transitional arrangements would be large relative to the proposed changes.

4.11 Implementation (Section 14)

4.11.1 Proposal

For consistency with other proposals on the Benchmark Agreement and Interconnection Rules, and to minimise transaction costs, an implementation date of 1 April 2008 is proposed.

4.11.2 Commission's assessment

The Commission has consulted industry previously on the proposed process and timeframe for implementation of the proposed TPM. The majority of submissions supported implementation on 1 April 2008.

4.11.3 Our analysis

We consider this implementation date reasonable.

4.12 General consideration of the TPM as a whole (Section 15)

4.12.1 Our analysis

Q40. Do you agree with the Commission's assessment of the general issues in respect to the proposed TPM?

Agreed.

Q41. Do you consider that there are other general issues that are important in respect to the proposed TPM? If so, please explain why they are important in the context of the regulatory framework and how, if necessary these issues might be resolved.

We consider that the proposed TPM still contains some inefficient discrimination against distributed generation. This is an issue we have raised in previous consultations[11]. Our concern is that parties that install generation equipment behind embedded load would pay interconnection charges that reflect a level of security that they would not willingly purchase. The inclusion in the proposal of a deeper connection definition than used in the current methodology goes someway to ameliorating this concern by reducing the level of interconnection charges. The adoption of our suggested "but for" test would result in a TPM that deals more effectively with this concern and inefficiency.

Q42. Do you consider that the proposed documentation surrounding the proposed TPM is clear and understandable in accordance with Guidelines 4 and 5?

Yes, if the Commission's consultation paper is read in conjunction with Transpower's submission and supplementary material. No one document alone provides sufficient overview or explanation of the components of the proposed TPM, however.

5. Conclusions

We agree with Transpower's proposals and the Commission's assessment of the proposed TPM in most respects. Where our views differ significantly is with regard to:

- the desirability of consulting with other interested parties, in addition to Transpower, in the event that the Commission proposes any material amendments to the TPM
- for investments in grid capacity, defining connection assets using a "but for" test would be superior to the proposal in meeting the assessment criteria. See Appendix C.

[11] NZIER (2005) *Guidelines for Transpower's Transmission Pricing Methodology – EC's Decisions and Strategic Risks*, report to MEUG, January.

- the desirability of Transpower being given guidance on the factors it should consider in exercising discretion in grouping assets into links and nodes, and a right of appeal to the Commission or the Rulings Panel against how it has exercised its discretion
- the direct charging mechanism for valuation allocation should be adopted in preference to Transpower's proposal and supported on practicality grounds by the Commission
- the need for more analysis of the regional coincident peaks approach to allocating interconnection charges
- at least initially, the proposed coincident peak capacity measurement period should be shorter with up to a twelve months lag.

Appendix A Summary of key changes

The most significant differences between the proposed TPM and the current methodology are in the three components of connection charges, HVDC charges and interconnection charges. The key changes proposed in these areas are summarised below.

Component	Proposal	Current method
Connection charges		
Definition	Uses the physical grid and groups assets according to geographical location, with connection assets defined as all nodes connected to network spurs (the augmented loop flow method).	Uses the optimised grid and groups assets by electrical configuration, with connection nodes defined as nodes connected to only one other node or no more than one interconnection node.
Valuation	Replacement cost, with adjustment for any initial optimisation of asset values.	Optimised replacement cost.
Allocation	Asset return rate based on total connection asset value; maintenance costs for substation and lines connection assets, averaged over preceding four years	Asset return rate based on total AC asset value; maintenance costs for all AC substation and lines assets, averaged over preceding four years
HVDC charges		
Allocation	Single historical anytime maximum injection over preceding five years.	Single anytime maximum injection over preceding 12 months.
Interconnection charges		
Allocation	Regional coincident peak demand, according to the 12 peak demand periods in each of the upper North Island and upper South Island and 100 peak demand periods in each of the lower North Island and lower South Island.	Nationally, according to the 12 highest anytime maximum demands.
Calculation	Annually, using measured demands over the preceding April to March pricing year.	Monthly rolling average over the preceding 12 months.
Aggregation of grid exit point loads	Aggregation, through basing regional coincident peak demand charges on average demands over aggregations of grid exit points.	No aggregation.

Source: NZIER, based on Transpower (2006) *Transmission Pricing Methodology – Briefings 28, 29 and 30 November 2006*

Appendix B Summary of NZIER's analysis

Question	Comment	Response
Q1. Do you agree that the process set out in Figure 2-2 is consistent with the rule requirements?	We consider that it would be desirable, if the Commission does propose any material amendments to the TPM, to consult on these with not only Transpower, as planned, but also other interested parties.	The diagram setting out the draft programme of consultation and implementation of the TPM does conform with the Rules.
Q2. Do you agree that rule 7.2.1.1 is not relevant in this case?	Rule 7.2.1.1 relates to any determination under Part 4A or section 70 to 74 of the Commerce Act 1986. If the settlement agreement, which is subject to consultation, does not proceed and a determination is made, agreement with Q2 does not hold.	Although a settlement agreement between Transpower and the Commerce Commission on these provisions has been mooted, this does not appear to constitute a determination. On this basis we agree that rule 7.2.1.1 is not relevant.
Q3. Do you agree that it is not necessary for the Commission to separately assess consistency against the Government Policy Statement (GPS)? If not, please provide details of what aspects of the GPS you consider are not covered by the regulatory framework herein?		Agreed.
Q4. Do you agree that it is not necessary for the Commission to separately assess consistency against the National Energy Efficiency and Conservation Strategy (NEECS)? If not, please provide details of what aspects of the NEECS you consider are not covered by the regulatory framework herein?		Agreed.
Q5. Do you agree that the appropriate balance between the depth of connection definition and the efficiency of the pricing signals has been struck in the proposed TPM?		We consider that, for the existing grid, the proposed approach is not unreasonable, given the guidelines that Transpower has been provided with by the Commission. For investments in grid capacity, however, we believe that defining connection assets using a "but for" test would be superior in terms of the

		requirement to "avoid subsidisation of interconnection assets to the extent practicable" and the pricing principles in the Rules.
Q6. If so, why do you agree with this? If not, where should the appropriate balance be struck and why?		No. See answer to Q5.
Q7. Are there any more suitable alternatives for defining deep connection that conform with the guidelines and pricing principles and are practical to apply consistently across the grid and over time?		Yes. See answer to Q5.
Q8. Do you consider that the alternative presented is the only reasonably practical alternative? If not, please provide a description of the alternative including the implications of adopting such an alternative and an assessment of it against the regulatory framework.		No. See answer to Q5. We strongly believe the option proposed is inferior in terms of the guidelines and the Rules to the alternative "but for" approach we have put forward.
Q9. Do you consider it appropriate that Transpower may have to exercise discretion in grouping assets into links and nodes?	Someone is going to have to exercise discretion if the current proposal is accepted. Transpower appears to be an appropriate party to hold the discretion subject to checks and balances.	It would seem desirable for whoever is going to do so be provided with guidance on the factors it should consider when doing so. A right of appeal to the Commission or the Rulings Panel against how it has exercised its discretion would also be worthwhile.
Q10. Do you agree that the proposed links-node definition is the best alternative for defining the connection assets? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?		No. See answer to Q5. We strongly believe the option proposed is inferior in terms of the guidelines and the Rules to the alternative "but for" approach we have put forward.
Q11. Do you agree that the proposed allocation of shared connection assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be		Agreed.

applied practically and consistently across the grid?		
Q12. Do you consider having the proposed method as a default mechanism but allowing customers to voluntary to agree on a sharing of costs is desirable?		Yes.
Q13. Do you agree that the proposed allocation of shared land assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?		Agreed.
Q14. Do you agree that the proposed allocation of other shared assets is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?		Agreed.
Q15. Do you agree that the proposed valuation allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?	Like the Commission, we consider that a direct charging mechanism better conforms to the pricing principles, in being more consistent with a user pays approach and better reflecting locational differences. We acknowledge that under this approach, the step changes in charges when new or replacement assets are installed would be large relative to the business size of some customers. We do not accept, however, the Commission's assessment that Transpower's proposal is the more suitable option in practice.	We consider that the direct charging mechanism should be adopted.
Q16. Do you consider that the costs associated with a direct charging mechanism are likely to outweigh any benefits from a more closely aligned user pays approach?		No.
Q17. Do you consider that the upgrade or replacement of a single connection asset (or group of associated assets) is likely to create cash flow management issues for grid-		No. If they are too small to be able to mange this effect on cash flow, then they should merge with parties that are big enough to

connected parties?		do so.
Q18. Do you agree that the proposed maintenance cost allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?		Agreed.
Q19. Do you agree that the proposed operating cost allocation is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?		Agreed.
Q20. Do you agree with the Commission's assessment of the calculation mechanism?		Agreed.
Q21. Do you consider that, in light of the above reasoning, it is reasonable to charge HVDC payments to South Island generators but give rights to other parties affected by the HVDC link under the interconnection rules?		In the absence of the option of merchant transmission investment arrangements, we agree with Transpower's proposal that HVDC costs be charged to South Island generators. We agree with the Commission that the approach it has adopted is not unreasonable, but consider that it would be preferable to treat the HVDC assets as a distinct class of assets and that the decision rights in relation to them should rest largely with Transpower and the parties paying for them in the same way as the rights in relation to other connection assets are handled.
Q22. Do you agree that the HAMI method is preferable to the name plate rating allocation mechanism?		Agreed.
Q23. Do you agree with Transpower that N=1 is a better option than N=12 or N=100 for the allocation of the HVDC charges to South Island generation plant?		No view.

Q24. Do you agree with the Commission's assessment of the HVDC charge calculation mechanism?		Agreed.
Q25. Do you agree that the proposed regional definition is the best alternative? If not, why not, and what would be a more suitable alternative that could be applied practically and consistently across the grid?	We favour the definition of multiple regions over a single national region to provide locational signals to demand and investment. The regional definitions proposed seem somewhat arbitrary, but a reasonable, practical compromise.	Agreed.
Q26. Do you consider that it is appropriate for the regional definitions to remain static over time or should there be some other review and setting mechanism than rule 11.2 to transition these? In considering this, you should comment on the likelihood of instability and holdout behaviour if there was such a mechanism.		We consider that Part F, section IV, rule 11.2 provides sufficient mechanism to review the TPM.
Q27. Do you agree that the proposed regional definition is the best alternative? If not, why not, and what would be a more suitable alternative?		Agreed.
Q28. Is it appropriate for the value of N to remain fixed or should there be some mechanism for regions to transition between N=12 and N=100? If so, what should that mechanism be and how would it line up with the guidelines and pricing principles?		We consider that Part F, section IV, rule 11.2 provides sufficient mechanism to review the TPM.
Q29. Do you agree that the proposed coincident peak allocation is the best alternative? If not, why not, and what would be a more suitable alternative?		Transpower should be required to provide more analysis of its proposal and its consequences than it has done to date.
Q30. Do you consider that the proposed capacity measurement period is preferable to the alternative?	Under the proposal's greater time lag, decisions being made by customers prior to determination of future TPM arrangements would influence charges following implementation of the proposed	We suggest that a shorter period, involving a time lag of up to only one year, be adopted at least initially, to provide customers with "fair notice" of the basis of their future charges and

	TPM.	opportunity to adjust their demand according to this price signal. Following due transition, the capacity measurement period could, if necessary, be gradually extended to that of the proposal, although this would impede the timeliness of response to price signals.
Q31. Do you consider there are reasonably practicable alternatives?		The more detailed analysis we have argued Transpower should be required to undertake should identify any reasonably practicable options**.**
Q32. Do you agree with the Commission's assessment of the proposal?		Agreed.
Q33. Do you agree that the proposal will prevent inefficient by-pass?		Agreed.
Q34. Do you agree that there are no practical alternatives to the proposal?		Agreed
Q35. Do you agree that the proposed process is workable and balanced in terms of the rights and obligations on each of the parties?		Agreed.
Q36. Do you agree with the Commission's assessment that the proposed TPM is consistent with locational signals provided by nodal pricing?		Agreed.
Q37. Do you agree this is an appropriate mechanism for recovering the cost of transmission alternatives?		Agreed.
Q38. Do you agree that the proposal meets guideline 6 and process requirement 6? If not, what alternatives are there within the boundaries of the current regulatory framework,	Transpower should not be able to recover costs relating to grid investments that have not been approved under Part F procedures	If the proposed TPM allows Transpower to recover costs for grid investments that do not meet these two requirements, it should be amended to make it clear that the recovery of costs applies

including the Commerce Act?	and which are not used and useful	only to grid investments that do meet these requirements.
Q39. Do you consider that there should be transitional measures put in place and, if so, how would this be implemented?		No, we agree that the costs of establishing and operating transitional arrangements would be large relative to the proposed changes.
Q40. Do you agree with the Commission's assessment of the general issues in respect to the proposed TPM?		Agreed.
Q41. Do you consider that there are other general issues that are important in respect to the proposed TPM? If so, please explain why they are important in the context of the regulatory framework and how, if necessary these issues might be resolved.	We consider that the proposed TPM still contains some inefficient discrimination against distributed generation.	The adoption of our "but for" approach would result in a TPM that deals more effectively with this concern and inefficiency.
Q42. Do you consider that the proposed documentation surrounding the proposed TPM is clear and understandable in accordance with Guidelines 4 and 5?		Yes, if the Commission's consultation paper is read in conjunction with Transpower's submission and supplementary material.

Appendix C Relevant regulatory framework criteria

Guidelines		
9	A definition of deep connection should be developed and applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent practicable.	"But for" significantly superior to Transpower's proposal regarding the definition of connection and interconnection in terms of avoiding subsidisation of interconnection assets. PJM's experience shows that "but for" can be applied consistently and transparently in practice. Transpower's proposal is not consistent between constrained and unconstrained regions.
10	The costs of connection assets are to be recovered from those connected to them.	"But for" complies with this requirement. Transpower's proposal conforms by definition.
11	Where parties share the use of connection assets then the costs should be allocated among them on a peak demand or injection basis, in a manner than maximises efficiency.	Guideline capable of being satisfied under both "but for" and Transpower's proposal.
12	Charges for existing and new interconnection assets should be on a postage stamp basis. This is similar to the current interconnection charges	"But for" and Transpower's proposal both comply by definition. Both determine interconnection as assets that are not connection assets or HVDC assets.
13	Transpower should review the existing basis on which it calculates the interconnection charges at a grid exit point. Specifically, Transpower should review whether using the 12 highest half hour offtake peaks in the 12 months up to and including the current month is the most consistent with the pricing principles in rule 2 of section IV of part F. This review includes consideration of anytime versus regional or national coincident peaks.	Not relevant to choice between "but for" and Transpower's proposal.
14	Transpower should also review whether permitting greater aggregation across GXP loads for the purpose of calculating interconnection charges to encourage peak load management within regions would produce prices more consistent with the pricing principles in rule 2 of section IV of part F.	Not relevant to choice between "but for" and Transpower's proposal.
15	"The costs of the HVDC link and any replacement of or upgrade to it should be	Not relevant to choice between "but for" and Transpower's proposal.

	charged to all South Island generating stations that inject into the grid."	
16	"In allocating those costs, Transpower should consider the linkages with other elements of market pricing, and in particular with the allocation of loss and constraint rentals or any revenue from financial transmission rights for transmission assets covered by the charge."	"But for" leads naturally to a method of allocation financial transmission rights resulting from grid investment. Transpower's proposal does not.
Pricing principles		
2.1	The costs of connection and use of system should as far as possible be allocated on a user pays basis.	"But for" will result in more of the assets being allocated on a user pays basis than Transpower's proposal.
2.2	The pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options.	"But for" provides stronger incentives than Transpower's proposal to identify least cost options, including energy efficiency and demand management options.
2.3	Pricing for new generation and load should provide clear locational signals.	"But for" provides clearer locational signals to new generation and load than Transpower's proposal.
2.4	Sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users.	Not relevant to choice between "but for" and Transpower's proposal.
2.5	The overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints.	"But for" will result in transmission charges that vary more depending on the marginal cost of supply of transmission services than Transpower's proposal.
2.6	Transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights)".	Not relevant to choice between "but for" and Transpower's proposal.
3.1	In applying the Pricing Principles, Transpower and the Board should take into account practical considerations, transaction costs and the desirability of consistency and certainty.	PJM experience as cited in the text indicates that "but for" does achieve consistency and certainty. PJM have demonstrated that "but for" is practical. Transpower's proposal is practical, but the treatment of nodes that may be relatively close could be very inconsistent. Moreover, the regions

		that are constrained will vary over time and so Transpower's proposal will lead to inconsistency and unpredictability from this.
3.2	Where conflicts arise in applying the Pricing Principles set out in rule 2, they should be resolved with the objective of best satisfying the Board's principal objective.	"But for" is not in conflict with the pricing principles.
Practical considerations		
a	Make it difficult for parties to game the pricing signal.	PJM's experience does not suggest "gaming" is an issue with "but for". Gaming to ensure what would otherwise be a connection asset is defined to be an interconnection asset is a small risk under Transpower's proposal.
b	Provide accurate signals.	"But for" provides more accurate signals of the consequences of generation and load location than Transpower's proposal. PJM has suggested that parties are reasonably clear even before they commit to investments. See quotes in text.
c	Provide predictable/stable signals.	"But for" signals should be predictable and stable. Redefinition of regions depending on where there are constraints will lead to Transpower's proposal resulting in instability and unpredictability.
d	Provide effective signals.	"But for" signals the marginal cost of an investment decision and is effective in this sense. Transpower's proposal does not signal marginal cost consequences of decisions and so is not effective in stimulating efficient decisions.
e	Provide signals to small and large participants.	Not relevant to choice between "but for" and Transpower's proposal.
f	Transparent and understandable calculation mechanism.	PJM's experience suggests that "but for" is transparent and understandable to participants. Transpower's proposal is also reasonably understandable.
g	Transaction costs	"But for" will involve higher transaction costs than Transpower's proposal as it will require assessment of the consequences of various investments instead of the application of an engineering definition to identify connection assets.

Principal objectives		
a	To ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner.	"But for" has superior efficiency properties to Transpower's proposal because it has those making decisions about investing in load and generation face the marginal costs of their decisions whereas Transpower's proposal does not. Moreover, it is more equitable that those that cause an expansion of the grid should bear the costs of their actions and not pass them on to others.
b	To promote and facilitate the efficient use of electricity.	Since under "but for" decision makers about generation and load face the marginal costs of their decisions this should promote efficient use of electricity by reducing decisions that result in transmission losses inefficiently because transport costs are averaged and cross subsidised. Transpower's proposal will lead to higher transmission losses because those making locational decisions will not face the full transmission costs of those decisions.
Specific outcomes		
a	Energy and other resources are used efficiently.	See previous two responses.
b	Risks (including price risks) relating to security of supply are properly and efficiently managed.	Not relevant to choice between "but for" and Transpower's proposal.
c	Barriers to competition in the electricity industry are minimised for the long-term benefit of end-users.	Increasing competition by cross-subsidising transportation of electricity is not in the long-term benefit of end-users, so Transpower's proposal is not superior on the grounds it will expand the grid and increase competition.
d	Incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced.	Inefficient investment will be discouraged by "but for" but efficient investment will be encouraged. Transpower's proposal will encourage inefficient investment in transmission, generation and load.
e	The full costs of producing and transporting each additional unit of electricity are signalled.	"But for" will satisfy this requirement, but Transpower's proposal will not because it has higher levels of cross-subsidisation.
f	Delivered electricity costs and prices are subject to sustained downward pressure.	Not relevant to choice between "but for" and Transpower's proposal.

g	The electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.	Not relevant to choice between "but for" and Transpower's proposal.
Consistency		
a	Between elements (internal component consistency).	Not relevant to choice between "but for" and Transpower's proposal.
b	Between components (internal TPM consistency).	"But for" is more consistent with the charging for the HVDC link than Transpower's proposal.
c	With the wider transmission contracting/regulatory framework.	Not relevant to choice between "but for" and Transpower's proposal.
d	With the treatment of assets under the proposed interconnection rules.	Not relevant to choice between "but for" and Transpower's proposal.
e	Between charging for existing and new assets.	"But for" does involve different treatment between existing and new assets and the Transpower proposal does not.
f	With nodal pricing and the grid investment test (GIT).	Not relevant to choice between "but for" and Transpower's proposal.
g	With the current charging methodology (while recognising that current methodology was set on a transitional basis).	"But for" is not as consistent with the current charging methodology as Transpower's proposed methodology.
h	With the treatment of similar participants in the market (for example, a dissimilar treatment would be to apply a charge to one participant and not to another equivalent one).	"But for" results in a consistent treatment of participants but the Transpower proposal does not. Under the Transpower proposal the treatment depends on whether the participant is in a constrained or unconstrained region.
Regulatory uncertainty		
a	The desirability of regulation being stable and not changing frequently, suddenly, or in unpredictable ways.	PJM has demonstrated that "but for" can lead to regulatory stability. Transpower's proposal will lead to unpredictability and instability because treatment will depend on whether a region is classified by Transpower as constrained or not and this will change over time, but not necessarily in way that is

		completely predictable.
b	The desirability of predictable and rational decision-making in relation to regulation.	"But for" is a rational approach. Transpower's proposal has logic but it leaves more costs to be spread among all participants in a region on an averaging basis that has no relation to what is driving costs or any other factor.
c	The impact of regulatory changes on prices.	Not relevant to choice between "but for" and Transpower's proposal.