Transpower's proposed variation to the Transmission Pricing Methodology (four components)

Decisions and reasons

4 August 2015

Contents

1. Introduction

1.1.1 This paper sets out:

(a) the decisions of the Electricity Authority (Authority) on four components of a proposal by Transpower New Zealand Limited (Transpower) to amend the transmission pricing methodology (TPM).

(b) the Authority's reasons for its decisions, including the Authority's comments on key issues raised in the feedback it received.

1.1.2 The Authority is an independent Crown entity whose statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

1.1.3 Transpower is the owner and operator of the national transmission grid.

1.1.4 Transpower has carried out an operational review of the TPM. Schedule 12.4 of the Electricity Industry Participation Code 2010 (Code) sets out the TPM.

1.1.5 In February 2015, Transpower submitted to the Authority a proposed variation to the TPM, made up of five components. Transpower submitted two further components in March 2015.

1.1.6 The Authority considered Transpower's proposal and, in April 2015, published a consultation paper regarding four of the components titled 'Transpower's proposed variation to the Transmission Pricing Methodology'.[1] The consultation paper:

(a) explained three problems Transpower had identified

(b) set out four proposed amendments to the Code to address the problems identified, corresponding to four components of Transpower's proposal

(c) sought feedback on the four components covered by the consultation paper

1.1.7 The problems identified in the consultation paper were that:

(a) the regional coincident peak demand (RCPD) allocation of the interconnection charge[2] can incentivise a higher level of demand response and embedded generation than is efficient – given that most regions of the

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[1] The Authority subsequently published a second consultation paper titled 'HVDC component of Transpower's proposed variation to the Transmission Pricing Methodology' (https://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/consultations/#c15388). The HVDC component of the proposed variation set out that the TPM should be amended to allocate HVDC charges on a per-MWh basis, with an initial transition period. The Authority anticipates publishing another Decisions and Reasons paper in August 2015, in relation to its consultation on the HVDC component.

[2] The interconnection charge is one of the three main charges under the TPM, along with the connection and HVDC charges, and is paid by load.

country are not expected to face transmission capacity constraints in the next few years

(b) in particular, the RCPD allocation can cause inefficient demand response in the summer months, including at the New Zealand Aluminium Smelters (NZAS) smelter

(c) the process for dealing with reverse flows is not clear enough.[3]

1.1.8 The consultation paper proposed that the Code should be amended to:

(a) use N=100 for all four RCPD regions in the calculation of the interconnection charge *(the 'N=100 component' of the proposal)* [4]

(b) exclude summer trading periods (ie, from November to April inclusive) from the capacity measurement period (CMP) used to calculate RCPD *(the 'amended RCPD CMP component')*

(c) for the purpose of identifying regional peak demand periods in a region, require Transpower to disregard a change in a customer's offtake if Transpower is satisfied that:

(i) the change would alter the incidence of a majority of the peaks in a relevant region

(ii) the change in offtake would not occur, absent the adjustment referred to above

(iii) the change is unlikely to lead to increased transmission investment

(the 'RCPD quantity adjustment provision component')

(d) require Transpower to adjust transmission charges when a reverse flow situation occurs *(the 'reverse flows component')*.

1.1.9 The objective of the amendments in (a) to (c) above is to promote efficiency for the long-term benefit of consumers, by reducing the incentives for inefficient investment in, and operation of, demand response and embedded generation.

1.1.10 The objective of the reverse flows component ((d) above) is to promote efficiency for the long-term benefit of consumers, by supporting efficient investment in, and operation of, Transpower's customers' distribution networks.

1.1.11 The Authority received feedback from 23 submitters. Table 1 sets out the list of submitters.

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3 Reverse flow occurs when electricity flows from the grid into a connection location, through the network of a customer (usually a distributor), and back into the grid at another connection location.

4 Here, N refers to the number of regional coincident peaks that are averaged in calculating the allocation of the charge. At present, the Upper North Island (UNI) and Upper South Island (USI) regions use N=12, while the Lower North Island (LNI) and Lower South Island (LSI) regions use N=100.

1.1.12 The submissions on the consultation paper, and a summary of submissions, are available on the Authority's website.[5]

Table 1: List of submissions

Generators, retailers and their representatives	**Consumers and consumer representatives**	**Distributors and distributor representatives**	**Other**
Contact Energy Genesis Energy – including a report by Castalia Independent Electricity Generators Association – including a report by Andrew Shelley Economic Consulting Meridian Energy Mighty River Power Nova Energy Pioneer Generation Ringa Matau Trustpower	Carter Holt Harvey Pulp & Paper Fonterra Cooperative Group Major Electricity Users Group – including a report by the New Zealand Institute of Economic Research Norske Skog Tasman New Zealand Steel Pacific Aluminium Winstone Pulp International	Aurora Energy Northpower Orion Powerco Unison Vector	Transpower

5 http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/consultations/#c15231

2. The Authority has decided to proceed with the N=100 component of the proposal

2.1 The interconnection charge will use N=100 in all four regions

2.1.1 The Authority has decided to amend the Code to implement the N=100 component of the proposal.

2.1.2 The form of the Code amendment is included in the marked-up version of the TPM in Appendix A.

2.1.3 The Authority has consulted with Transpower about when the proposed change will take effect. The change will take effect from 1 April 2017, so that it applies to the calculation of prices for the 2017/18 and subsequent pricing years, but not the 2016/17 pricing year. The capacity measurement period (CMP) for the 2017/18 pricing year begins on 1 September 2015.[6] This means that, in practice, participants will need to take into account the impact of the change from 1 September 2015.

2.1.4 At present, the RCPD allocation of the interconnection charge uses N=12 for the Upper North Island (UNI) and Upper South Island (USI) regions, and N=100 for the Lower North Island (LNI) and Lower South Island (LSI) regions.

2.1.5 From the 2017/18 pricing year onwards, the RCPD allocation of the interconnection charge will use N=100 for all four regions. That is, the allocation in each pricing year will be based on demand during the top 100 coincident demand peaks in each region in the CMP for that pricing year.

2.1.6 As part of this amendment, the Authority is making a minor change to Appendix B of the TPM. The amendment removes the tables of connection locations that existed at the time the current TPM came into force. The tables functioned mainly as an illustration of the connection locations covered by the description of each region, but had become out of date.

2.1.7 The Authority has decided to adopt a revised approach to describing the regions in Appendix B of the TPM. The change is intended to improve the clarity of the Appendix, and to confirm with accuracy the current boundaries between regions.

2.1.8 Otherwise, the drafting of the N=100 component has not changed from the version that was consulted on.

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6 A CMP is the 12-month period from 1 September to 31 August inclusive. A pricing year is a 12-month period from 1 April to 31 March inclusive. .

2.2 The decision supports the Authority's statutory objective

2.2.1 The Authority expects the amendment to promote the statutory objective by reducing the incentives for inefficient investment in, and operation of, demand response and embedded generation in the UNI and USI.

2.2.2 Based on the information available, the economic cost of demand response and embedded generation would be likely to exceed any transmission investment deferral benefits it produced.

2.2.3 The Authority expects the amendment to have no material effect on competition or reliability.

2.3 The proposal is preferable to the status quo

2.3.1 The Authority considers that the proposal is preferable to the status quo and that its expected net economic benefit is positive. The proposal is also preferable to the alternatives, as set out in Section 2.4.

2.3.2 The CBA in the consultation paper identified a base case and four sensitivity cases – differing mainly in terms of:

(a) the likelihood of substantial new transmission investment being required in the absence of an interconnection price signal

(b) the elasticity of industrial load to transmission price signals

(c) the extent to which charges on *net* load will result in inefficient investment in embedded baseload and/or intermittent generation.

2.3.3 The consultation paper emphasised that *'at this stage the Authority takes no view as to the relative probabilities of the base case and the four sensitivity cases. The Authority is not necessarily asserting either that the base case holds, or that any one of the five cases considered holds. The cases are merely chosen in order to illustrate how the conclusion depends on the input assumptions.'*

2.3.4 The key benefit modelled was a possible reduction in the use of inefficient demand response and/or back-up generation – ie activity that occurs to avoid transmission charges, but which has a public cost that is greater than the public benefit.

2.3.5 The key costs modelled were:

(a) a possible increase in economically inefficient demand response and/or embedded peaking generation, which could occur if some parties extended their peak avoidance activity to target a greater number of trading periods

(b) a possible reduction in transmission deferral incentives – and hence higher transmission costs over time.

2.3.6 The estimated net economic benefit of the proposal ranged from $5 million present value in the base case to $17 million in a sensitivity case.

2.3.7 The CBA in the consultation paper extended over a horizon of 15 years, and used (when comparing the proposal with the status quo):

(a) a factual in which the proposed amendment (N=100) remains in force for 15 years

(b) a counterfactual in which the status quo (N=12 in the UNI and USI) remains in force for 15 years.

2.3.8 Following the release of the Authority's TPM options working paper, the Authority has reviewed these scenarios. The Authority is now of the view that, for the purposes of considering the proposed amendment, it should assume that the TPM will be changed as a result of the Authority’s review. From an analytical point of view, this assumption is conservative: if the TPM is not changed as a result of the Authority's review, then the benefits of the proposed N=100 component will be greater than set out below.

2.3.9 Specifically, the Authority has revised the CBA of the N=100 component, assessed relative to the status quo, using:

(a) a factual in which N=100 remains in force for five years, before being replaced by some other interconnection charging arrangement

(b) a counterfactual in which the status quo (N=12 in the UNI and USI) remains in force for five years, before being replaced by some other interconnection charging arrangement.

2.3.10 The Authority chose to assume that the TPM would change in five years on the basis of its best judgement about the likely amount of time that would be required for:

(a) the Authority to publish new Guidelines (if it decides to do so)

(b) Transpower to propose, and the Authority to approve, a new TPM consistent with the new Guidelines (once the Authority has published the new Guidelines)

(c) the new charges to come into force under the new TPM.

2.3.11 The revised CBA is described in Appendix B of this paper.

2.3.12 Under the revised CBA, the expected net benefit of the proposed amendment (relative to the status quo) is still positive, at

(a) $0.9 million present value, in the base case

(b) from $1.3 million to $2.8 million present value, in the four sensitivity cases.

2.3.13 Submitters had mixed views as to whether the proposal was preferable to the status quo. Fourteen submitters supported the proposed amendment, while four submitters opposed it.

2.3.14 Table 2 lists the disadvantages of the proposal (compared with the status quo) that submitters raised, and the Authority's comments on each.

Table 2: Submitter comments on the disadvantages of the N=100 component, relative to the status quo

Submitter comment	Authority response
The CBA should take account of the potential outcomes from the Authority's review of the TPM, rather than using the status quo as the counterfactual.	The Authority agrees that it is worthwhile to consider whether the proposal would still be expected to produce positive net benefits, if it was only in place for a relatively short time because a new TPM arose from the Authority's TPM review. Appendix B of this paper describes the revised CBA, in which the benefits and costs of the proposal are evaluated over five years only, which assumes that the TPM is changed as a result of the Authority's review. Under this revised CBA, the expected net benefit of the proposal (relative to the status quo) is still positive.
The CBA does not recognise the desirability of maintaining a price signal to encourage the deferral of transmission investment where this is economic.	The CBA did recognise the potential impact of different TPM options on the timing of new investment in transmission capacity. The base case included an assumption that the long run marginal cost of transmission expansion in the UNI and USI regions was approximately $80/kW per year, and approximately $40/kW per year in the LNI and LSI regions. These assumptions were varied in some alternative sensitivity cases. Indeed, the N=100 option would preserve a relatively strong signal to defer transmission investment. Accordingly, the Authority considers that it took transmission deferral benefits into account in the analysis.

Submitter comment	Authority response
The CBA overstates the cost and/or understates the available quantity of demand response resources – including demand response available to CHH, Norske Skog and NZ Steel.	The Authority acknowledges these uncertainties. However, it also notes that these matters primarily affect charging options that involve a per-MWh charge. That is, these matters primarily affect the alternatives in a way that emphasises the inferiority of those alternatives compared with the proposal.
The CBA understates the elasticity of demand of industrial consumers.	
The CBA does not account for potential second-round effects. For example, if users facing an increased share of transmission charges responded by reducing their demand, this would reduce the remaining demand base, resulting in higher per unit charges, which could lead to further demand reductions.	
A more granular CBA would be required to assess TPM options that are less closely related to the existing TPM, because it is more difficult to predict possible outcomes based on past experience.	

Submitter comment	Authority response
Some submitters expressed general concerns about the CBA rather than questioning specific assumptions. For example, some considered that the CBA was too high level. Some submitters considered that the CBA did not adequately address uncertainty via the use of sensitivity analysis. Another criticism was that the CBA lacked sufficient precision to be used for decision making purposes.	The Authority acknowledges the uncertainties in the CBA assumptions, and notes that it specifically sought information from submitters to refine the assumptions. It appreciates the information submitters provided in response. The Authority also recognises that any CBA will inevitably be a simplification of the real world. Notwithstanding this, the Authority considers the CBA has helped to identify the key value drivers and areas of judgement for each TPM option. The CBA framework has highlighted that the key downside risk from adopting N=100 for all regions is a possible increase in inefficient demand response or operation of embedded generation within the UNI and USI regions as a result of N being a larger number of periods. In the base case assumptions for the CBA, such effects are not considered likely. Submitters did not submit any specific information to suggest the Authority should revisit this assumption. For this reason, the CBA indicates that moving to N=100 for all regions is likely to yield a positive net benefit.
The identified benefit is small, relative to the amount of wealth transfers involved.	The Authority agrees. However, as stated in the Authority's *Interpretation of the Authority's statutory objective,*[7] its calculation of benefits to consumers excludes wealth transfers, unless there are efficiency effects from such transfers. The Authority does not consider that the efficiency effects of the wealth transfers resulting from the amendment, if any, would be sufficient to result in the expected net benefit being negative.

7 http://www.ea.govt.nz/dmsdocument/9494

Submitter comment	**Authority response**
The proposal will adversely affect some participants.	The Authority agrees that the amendment may create private benefits to some parties and cause private disbenefits to others. Any substantive change to the TPM is likely to advantage some parties and disadvantage others. However, this is not a consideration in the Authority's decision making. Rather, the Authority is concerned with the net economic benefit of the amendment. This includes considering whether the amendment would result in wealth transfers that affect efficiency – but in this case, the Authority does not expect that any wealth transfers would lead to efficiency losses.
The proposal might not result in a change in participant behaviour.	The Authority expects that the amendment will affect participant behaviour, because it will considerably reduce the marginal price signal in the top 12 coincident peak periods (the current RCPD periods) in the UNI and USI regions. Several submitters (including Norske Skog and Northpower) commented that the amendment is likely to deter some participants from controlling load at coincident peak times.
The proposal might result in an increase in peak demand, and hence: • inefficiently bring forward transmission investment • cause overloading of assets • prevent the efficient decommissioning of existing assets.	The Authority agrees that the amendment will result in an increase in regional coincident peak demand in the UNI, and possibly to a lesser extent in the USI. However the Authority does not expect that this will inefficiently bring forward transmission investment, cause overloading of assets, or prevent the efficient decommissioning of existing assets. The case for the amendment is predicated on Transpower's advice that *'when the TPM was introduced in 2008, N was set at 12 for UNI and USI to reflect anticipated grid upgrade requirements. That grid investment has occurred in the UNI, alleviating the need for (and benefits of) the strong price signal provided by N=12. For the USI a combination of grid investment and flatter load growth has reduced the need for (and benefit of) a strong peak price signal.'*

Submitter comment	Authority response
	The Authority further notes that: • there will still be some load control at peak times under N=100, which may help to defer any transmission investment into the UNI and USI • Transpower can contract for demand response to efficiently defer transmission investment • if need be, the TPM can be amended again to reintroduce stronger signals for peak load control in some regions.
Because the proposal would not be durable, it would not have the desired effect on investment.	The Authority considers that, even if the amendment is only in place for five years, it is still likely to have a beneficial effect on distributed generation investment incentives.
Moving to N=100 may raise the interconnection rate, which would increase the incentive for demand response.	The Authority agrees that the interconnection rate is likely to increase as a result of the amendment,[8] relative to what it would otherwise have been. However, the Authority considers that any increase in the interconnection rate is likely to be small, and that the effect on behaviour is not likely to be significant compared to the direct effect of increasing N from 12 to 100 on load parties in the UNI and USI.
The proposal would not result in cost-reflective charges.	The Authority agrees that the amendment will not result in fully cost-reflective charges. The TPM Guidelines require that the interconnection charge is on a postage stamp basis, which limits the extent to which it can be cost-reflective. The Authority is investigating more cost-reflective options in its own review of the TPM.

2.4 The proposal is preferable to the alternatives

2.4.1 The Authority considers that the amendment is preferable to alternatives that are consistent with the current TPM Guidelines.[9]

8 The interconnection rate is likely to be higher, because total RCPD is likely to be lower as a result of moving to N=100 in the UNI and USI. Total RCPD is in the denominator of the calculation of the interconnection rate; if it falls, then the interconnection rate rises. See clause 29 of the TPM (Schedule 12.4 of the Code).

2.4.2 The consultation paper assessed the N=100 component against four alternative options:

(a) an RCPD option with N=500 in all four regions *(the N=500 option)*

(b) a per-MWh charge on gross load *(the per-MWh option)*

(c) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load *(the 50:50 option)*

(d) an option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross load *(the LRMC option)*.

2.4.3 The consultation paper concluded that under base case assumptions, the proposal was preferable to the alternative options. However, under each of the sensitivity cases described in Section 2.3, at least one alternative option was preferable to the proposal. The Authority considered updating the CBA of the alternative options over a five year horizon, as it did for the proposal. However, based on the information the Authority has, the Authority could not robustly determine that one or more alternatives would be preferable to the proposal, across the range of sensitivities. Further investigation is feasible, but the Authority envisages that the result would only be a delay in achieving the benefits of the proposal, rather than the identification of a superior alternative. The Authority anticipates that even if it undertook further investigation, it would again be in a position of needing to apply tie breaker principles 4 – 8. As noted below, the proposal is identified as preferable under those principles.

2.4.4 The Authority sought submitter feedback on the potential impacts of the proposal and alternatives on participant behaviour, and the merits of the proposal relative to the alternatives.

2.4.5 Three submitters commented that the N=500 option is likely to deliver more benefits than the proposal.

2.4.6 Eight submitters opposed the N=500 option, for reasons including that:

(a) it would have higher implementation cost for participants

(b) it would not result in significantly different outcomes from N=100

(c) it could cause a greater amount of inefficient load management

(d) peak demand would increase in all regions.

[9] The TPM Guidelines are currently those published by the Electricity Commission on 24 March 2006 (http://www.ea.govt.nz/dmsdocument/2990). Under clause 12.89(1) of the Code, Transpower's proposed variation to the TPM must be consistent with the TPM Guidelines. Therefore, in the context of Transpower's review, the Authority only considered alternatives that were consistent with the TPM Guidelines. Some alternatives that are not consistent with the TPM Guidelines are being considered as part of the Authority's own review of the TPM.

2.4.7 Meridian's submission expressed in-principle support for charging based on gross load. Otherwise, no submitters supported the 50:50, per-MWh or LRMC options.

2.4.8 Fifteen submitters opposed the 50:50 and/or per-MWh options, and seven submitters opposed the LRMC option, for reasons set out in the summary of submissions published by the Authority. Key reasons included that:

(a) per-MWh charges would inefficiently discourage electricity consumption by industrial consumers, possibly endangering the viability of some industrial consumers

(b) per-MWh charges would not provide a signal for coincident peak load control

(c) per-MWh charges would not be cost-reflective

(d) LRMC charges would be complex

(e) there was insufficient evidence to support a move to either per-MWh or LRMC charges

(f) per-MWh or LRMC charges would be less consistent with Code amendment principle 4 ('small-scale, trial and error') than the proposal.

2.4.9 The Authority considers that:

(a) under the base case, the N=100 option is preferable to the N=500, 50:50, per-MWh and LRMC options

(b) despite submitters' comments, there may be some sets of assumptions under which each of these alternatives is preferable to the proposal

(c) it cannot robustly determine that one or more of the alternatives are preferable to the proposal in the short to medium term.

2.4.10 As set out in Section 2.5, the Authority's application of the Code amendment principles leads it to choose the N=100 option over the N=500, 50:50, per-MWh and LRMC options. This is because the N=100 option best satisfies Code amendment principle 4 ('Preference for small-scale 'trial and error' options').

2.4.11 The Authority considered and rejected other alternatives to the amendment. The consultation paper set out that:

(a) the Authority would not consider some alternatives any further, because they would not support the statutory objective to the same extent as the proposal. These alternatives included:

(i) a per-MWh charge on winter load only

(ii) an anytime maximum demand (AMD) charge

(iii) an alternative that was the same as the proposal (ie setting N=100 in all four regions) but with an initial transition period

(b) the Authority would not consider a 'tilted postage stamp' charge any further, because the LRMC-based option above is a better way of achieving the same end

(c) the Authority would not consider a capacity-based residual charge any further *in this context,* because in the absence of a market, market-like or beneficiaries-pay charge (which are not possible under the current TPM Guidelines), it would not provide sufficient signals for efficient deferral of transmission investment[10]

(d) the Authority would not consider a RCPD charge in which the value of N could vary over time any further, because the same outcome could be achieved under the proposal – simply by waiting until significant transmission investment was likely, and then initiating a new Code amendment proposal to reduce the value of N.

2.4.12 No submitters provided evidence to suggest that the Authority should further consider any of these alternatives in this context.

2.4.13 Two submitters proposed other alternatives:

(a) Aurora recommended that interconnection charges should be allocated according to anytime maximum demand at individual GXPs

(b) Unison recommended that the transmission pricing methodology should include some fixed charges on load parties.

2.4.14 The Authority considers there is insufficient evidence at this point to show that either of these options is superior to the proposal. However, the Authority may consider such options as part of its own review of the TPM.

2.5 The amendment complies with section 32(1) of the Act, and with the Code amendment principles

2.5.1 The consultation paper set out:

(a) that the N=100 component complies with section 32(1) of the Act

(b) that the N=100 component complies with Code amendment principles 1 and 3 – ie it is lawful and its net benefits have been quantified

(c) a *tentative* view that the N=100 component complies with Code amendment principle 2 – ie that it provides clearly identified efficiency gains relative to the status quo and alternatives

[10] However, the Authority is considering a capacity-based residual charge, in conjunction with a market-like and/or beneficiaries-pay charge, as part of its own review of the TPM.

(d) that the ‘tie-breaker’ Code amendment principles 4 to 8 did not help to discriminate between the N=100 proposal and the alternatives. *(The Authority has since changed its view on this point – see below.)*

2.5.2 Fourteen submitters supported the proposed amendment. Three of them agreed that it complies with the Electricity Industry Act 2010 (Act) and the Code amendment principles.

2.5.3 Four submitters opposed the proposed amendment, for the reasons set out in Section 2.3. Of these, three submitters (Meridian, NZIER for MEUG, and NZAS) stated that the proposed amendment did not comply with the Act and/or the Code amendment principles.

2.5.4 Having considered submissions, the Authority considers that the amendment:

(a) complies with section 32(1) of the Act, and is lawful

(b) promotes the statutory objective – for the reasons set out in Section 2.1.8

(c) provides clearly identified efficiency gains relative to the status quo, and has a positive net expected benefit relative to the status quo – for the reasons set out in Section 2.3.

2.5.5 As set out in Section 2.4, there are some sets of assumptions under which the N=100 option provides a positive net expected benefit relative to the other alternatives considered. There may be other sets of assumptions under which one or more of the alternatives (including the N=500, 50:50, per-MWh and LRMC options) provide greater net expected benefits than N=100.

2.5.6 The Authority’s consultation charter sets out that the ‘tie-breaker’ Code amendment principles 4 to 8 apply when the CBA of the Code amendment options demonstrates a positive net benefit relative to the counterfactual, but is inconclusive about which is the best option.

2.5.7 Originally, the Authority considered that the ‘tie-breaker’ Code amendment principles did not help to discriminate between the proposal and the alternatives. However, having considered submissions,[11] the Authority has decided that the N=100 component is more consistent with Code amendment principle 4 (‘Preference for small-scale ‘trial and error’ options’) than the other alternatives considered.

2.5.8 The amendment is a ‘smaller-scale’ option compared with the alternatives, in the sense that:

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[11] In particular, Trustpower commented that *‘we struggle to understand how the Authority has determined that “neither the proposal, nor any of the alternative options, is a small-scale ‘trial and error’ option”, relative to the status quo. We think the MWh option advanced by the Authority as a possible TPM change is an order of magnitude greater change to the TPM than a minor increase to the value of N, particularly if charges were moved to a gross load basis.’*

(a) it directly affects only two regions of the country (UNI and USI), while the alternatives affect all four regions

(b) it represents a smaller change from current arrangements than the alternatives

(c) it can be enacted and, if desirable, refined or reversed with less disruption than the alternatives.

2.5.9 For completeness, Code amendment principles 5 to 8 do not help to discriminate between the proposal and the alternatives considered.

2.5.10 On balance, therefore, the Authority considers that proceeding with the amendment is consistent with the Code amendment principles.

2.5.11 If the RCPD charge is still in place in several years' time, it may be appropriate to consider whether another interconnection charging option would better promote the statutory objective. For instance, if N=100 were to result in inefficient demand response, there might be grounds for moving to one of the other options, eg N=500 in one or more regions.

3. The Authority has decided to proceed with the amended RCPD CMP component, but not the RCPD quantity adjustment provision

3.1 The Code will provide for summer trading periods to be excluded from the calculation of RCPD, in the LSI, LNI and UNI regions

3.1.1 The Authority has decided to implement the amended RCPD CMP component of the proposal, with one refinement to the proposal consulted on. The refinement is that summer trading periods will be excluded in the LSI, LNI, and UNI regions only. Summer trading periods will continue to be included in the calculation of RCPD for the USI.

3.1.2 The form of the Code amendment is included in the marked-up version of the TPM in Appendix A. The Authority has consulted with Transpower about when the change will take effect. The change will take effect from 1 April 2017, so that it applies to the calculation of prices for the 2017/18 and subsequent pricing years, but not the 2016/17 pricing year.

3.1.3 Accordingly, from the 2017/18 pricing year onwards, the RCPD allocation of the interconnection charge will be based on coincident demand peaks occurring between 1 May and 30 October (inclusive) only, for the LSI, LNI and UNI regions.

3.1.4 For example, the allocation of charges in the 2017/18 pricing year (beginning 1 April 2017) will be based on demand during coincident peaks occurring between 1 September 2015 and 30 October 2015 inclusive, and between 1 May 2016 and 31 August 2016 inclusive.

3.1.5 Section 3.4 sets out the reasons for the Authority's decision that the change will only apply to three out of four RCPD regions.

3.1.6 Otherwise, the drafting of the amended RCPD CMP component has not changed from the version that Transpower consulted on.

3.2 The decision supports the Authority's statutory objective

3.2.1 The Authority expects the amendment to promote the statutory objective by removing an inefficient incentive for load parties to decrease summer electricity consumption.

3.2.2 The Authority expects the main benefit of the amendment to stem from removing the disincentive on NZAS to increase production at the Tiwai smelter during the summer months, from the summer of 2015-16 onwards. The summer of 2015-

2016 would, without this amendment, be included in the CMP used to calculate RCPD for the 2017/18 pricing year. Transpower has indicated that an increase of up to 60 MW in smelter demand in the summer months would not lead to significant additional transmission investment being required.

3.2.3 The Authority expects the amendment to have no material effect on competition or reliability.

3.3 The amendment is preferable to the status quo

3.3.1 The Authority considers that the amendment (a refined version of the proposal consulted on) is preferable to the status quo and its expected net economic benefit is positive. The amendment is also preferable to the alternatives, as set out in Section 3.4.

3.3.2 The consultation paper set out that the proposal is expected to produce a net economic benefit of between $4 million and $32 million in present value terms, relative to the status quo.

3.3.3 As set out in Section 2.3, the Authority now considers that the benefits and costs should be considered over five years only. However, the lower estimate of net economic benefit ($4 million present value) set out in the consultation paper was based on a horizon of just three years. Therefore, a cost-benefit analysis horizon of 5 years does not alter the Authority's conclusion that the expected net benefit of the proposal (as consulted on) is positive. The refinement to the proposal consulted on does not affect that analysis.

3.3.4 Submitters raised mixed views about whether the amendment is preferable to the status quo. Eleven submitters supported the proposed amendment, while seven submitters opposed it.

3.3.5 Table 3 lists the disadvantages of the proposal (relative to the status quo) submitters raised, and the Authority's comments on each.

Table 3: Submitter comments on the disadvantages of the amended RCPD CMP component, relative to the status quo

Submitter comment	**Authority response**
The proposal could lead to increases in summer peak demand, which could inefficiently bring forward transmission investment.	As set out in Section 3.4, the Authority considers that this is only a potential problem for the USI. This problem has been resolved by changing the proposal to amend the CMP in the LSI, LNI and UNI regions only.

<table>
<tr><th>Submitter comment</th><th>Authority response</th></tr>
<tr><td>The proposal amounts to preferential treatment of NZAS.</td><td rowspan="2">The Authority agrees that the amendment may provide private benefits to NZAS and some other parties (eg summer-peaking loads in the LSI), and may cause private disbenefits to other parties (eg winter-peaking loads in the LSI, and possibly loads in other regions). Any substantive change to the TPM is likely to advantage some parties and disadvantage others.

However, this is not a consideration in the Authority's decision making. Rather, the Authority is concerned with whether the amendment will result in a net economic benefit. This includes considering whether the amendment would result in wealth transfers that affect efficiency – but in this case, the Authority does not expect that any wealth transfers would lead to efficiency losses.</td></tr>
<tr><td>The proposal will adversely affect some participants.</td></tr>
<tr><td rowspan="3">The proposal is ad hoc, unprincipled, and/or a bespoke solution that may result in other participants lobbying for similar adjustments.</td><td>The Authority agrees that the amendment is intended to address a specific problem.[12] However this does not detract from the fact that the problem is a material one and that addressing it is expected to yield an economic benefit.</td></tr>
<tr><td>The Authority does not agree that the amendment is 'unprincipled'. Rather, it is intended to promote the statutory objective.</td></tr>
<tr><td>The Authority does not agree that the amendment is a bespoke solution. It addresses disincentives for any party outside the USI to increase summer load at potential regional coincident peak times. It applies to all participants in the LSI, LNI and UNI, rather than NZAS alone (as per Transpower's original proposal).</td></tr>
<tr><td>The proposal deals with a problem that may not exist after the Authority's review of the TPM.</td><td>The Authority agrees that the amendment deals with a problem that may not exist after the Authority's review of the TPM. However, as set out in Section 3.3, the Authority expects the amendment to produce a net economic benefit even if it is only in effect for a relatively short time because a new TPM arises from the Authority's TPM review.</td></tr>
</table>

[12] The Authority's review aims to provide more general solutions to the problems with the current TPM.

3.4 The amendment is preferable to the alternatives

3.4.1 The Authority considers that the amendment (a refinement of the proposal consulted on) is preferable to alternatives that are consistent with the current TPM Guidelines.

3.4.2 In relation to the refinement, several submitters commented that it could lead to summer peak demand being higher than it would otherwise have been in some regions, which in turn could inefficiently bring forward transmission investment. The Authority sought comment from Transpower on the possible effects on transmission investment.

3.4.3 Transpower confirmed that it does not expect the summer peak demand growth to drive a need for new transmission to serve the LSI, LNI or UNI in the next decade. It would therefore be inefficient for the interconnection charge to create a signal to reduce peak summer demand in these regions. (There may be investment to serve summer peak demand in sub-regions, such as the lower Waitaki Valley, but not at the half-island level. Under the RCPD methodology, providing a price signal in relation to this investment, while allowing customers in other parts of the LSI to increase summer demand, would likely require creating a separate region for the Waitaki Valley. This is an issue better addressed through the Authority's review.)

3.4.4 However, Transpower advised that summer peak demand growth could drive a need for new transmission investment to serve the USI in the early 2020s.[13]

3.4.5 Transpower has expressed the view that amending the CMP in the USI would not bring forward transmission investment, on the basis that:

(a) if necessary, the TPM could be amended again to provide an incentive for summer load control

(b) in the event that summer peak demand overtook winter peak demand as the driver of transmission investment, Transpower would be able to procure summer load control at a low cost through its demand response programme.

3.4.6 However, the Authority:

(a) would prefer not to amend the CMP in the USI now, if the expectation is that it will need to reverse the amendment in a few years, and that there would be no benefit in the meantime

(b) considers that the value of summer load control in the USI can be appropriately signalled through spot prices and transmission pricing signals (which provide the same incentive to all load customers) rather than through Transpower's demand response programme (which provides an incentive only to selected providers).

[13] See e.g. http://www.comcom.govt.nz/dmsdocument/12557.

3.4.7 Neither Transpower nor the Authority has identified a material benefit from amending the CMP in the USI.

3.4.8 Therefore, the Authority has decided to amend the CMP for the LSI, LNI and UNI regions only.

3.4.9 Another alternative is the ‘RCPD quantity adjustment provision component’ proposed by Transpower – which was intended to address essentially the same problem as the ‘amended RCPD CMP component’. The consultation paper sought feedback on this component of the proposal, and said that the two components could be alternatives to each other or could complement each other.

3.4.10 Under the ‘RCPD quantity adjustment provision component’, Transpower would be required to disregard a customer's offtake changes in a region for the purpose of determining regional peak demand periods, in cases where a change in the customer’s offtake:

(a) would alter the incidence of a majority of peaks in the region

(b) would not impact on transmission investment requirements

(c) would not occur in the absence of the adjustment for the change.

3.4.11 Some submitters considered that the ‘RCPD quantity adjustment provision’ was preferable to the ‘amended RCMP CMP’.

3.4.12 The Authority considered enacting the ‘RCPD quantity adjustment provision’ instead of the ‘amended RCPD CMP’, but decided against it because the ‘RCPD quantity adjustment provision’ would be less transparent and would not provide NZAS with sufficient flexibility.

3.4.13 NZAS submitted that *‘at this point we would prefer the RCPD quantity adjustment provision not be progressed on its own, as any final decision NZAS makes to restart idled capacity may not be made until after the capacity period commences. The quantity adjustment proposal on its own removes the flexibility NZAS requires when making decisions to restart idled capacity.’*

3.4.14 The Authority considered enacting the ‘RCPD quantity adjustment provision’ *as well as* the ‘amended RCPD CMP’, but decided against it, because the ‘RCPD quantity adjustment provision’ would provide little incremental benefit.

3.4.15 The only submitter that commented that the Authority should proceed with *both* proposals was Nova. It appears, however, that Nova may have overestimated the flexibility provided by the ‘RCPD quantity adjustment provision’. Nova submitted that *‘the ‘quantity adjustment provision’ will have a valuable role to play in circumstances where manufacturing plants with embedded co-generation capability are forced to decide between shutting processing during short term* *generation outages, or incurring much higher transmission charges for 12 months as a result of continuing operations through those periods.*'

3.4.16 The Authority expects that few manufacturing plants would be able to meet the first criterion of the 'RCPD quantity adjustment provision' – ie that a change in their offtake would alter the incidence of a majority of peaks in their region. Therefore, the incremental benefit of enacting the 'RCPD quantity adjustment provision' would probably be less than Nova had anticipated.

3.4.17 The Authority considered and rejected other alternatives to the amendment. The consultation paper set out that:

(a) the Authority would not further consider some alternatives, because they would not support the statutory objective to the same extent as the proposal. These alternatives included:

(i) the 'bespoke NZAS component' – ie allowing NZAS to increase electricity consumption from 572 MW to 636 MW in the summer months without this being reflected in the calculation of RCPD

(ii) creating a new RCPD region including only the NZAS smelter

(iii) amalgamating the LSI, LNI and UNI regions into a single RCPD region – so that regional peaks in the 'super-region' would not occur in the summer months

(iv) excluding summer trading periods from the calculation of RCPD, as per the proposal, but in the LSI region only

(b) moving to a per-MWh or capacity-based allocation of the interconnection charge could potentially solve the problem, but the Authority would not consider it further *in this context* (see Section 2.4).

3.4.18 No submitters provided evidence to suggest that the Authority should consider these alternatives further.

3.4.19 One submitter proposed another alternative. Aurora suggested that *'it is more appropriate to resolve the problem through a prudent discount-like approach'*. However, the Authority has not adopted this alternative, because it considers that amending the Code provides participants with more certainty about how interconnection charges will be calculated.

3.5 The amendment complies with section 32(1) of the Act, and with the Code amendment principles

3.5.1 The consultation paper set out the Authority's view that the amended RCPD CMP component complies with section 32(1) of the Act, and with the Code amendment principles.

3.5.2 Eleven submitters supported the proposed amendment. Five of them agreed that it complies with the Act and the Code amendment principles.

3.5.3 Seven submitters opposed the proposed amendment, for the reasons set out in Section 3.3. One submitter (Norske Skog) stated that the proposed amendment did not comply.

3.5.4 The Authority agrees that the amendment, as originally proposed, may not have been consistent with the Authority's objective, in that it could inefficiently bring forward transmission investment. This may not have provided a clearly identified net efficiency gain, as required by the Code amendment principles. However, the Authority considers that this problem has been resolved by changing the amendment to apply to the LSI, LNI and UNI only, and that the amendment now complies with the Act and the Code amendment principles.

4. The Authority has decided to proceed with the reverse flows component

4.1 The Code will provide for Transpower to adjust transmission charges when a reverse flow situation occurs

4.1.1 The Authority has decided to amend the Code to implement the reverse flows component of the proposal.

4.1.2 The form of the Code amendment is included in the marked-up version of the TPM included in Appendix A. The Authority has consulted with Transpower regarding when the change will take effect. The change will take effect from 1 April 2017, so that it applies to the calculation of prices for the 2017/18 and subsequent pricing years, but not the 2016/17 pricing year.

4.1.3 The amendment will apply when one of Transpower's customers notifies Transpower that a GXP tie[14] has caused reverse flow[15] in the customer's network, and Transpower agrees. Under these circumstances, Transpower must adjust the customer's anytime maximum demand or injection (AMD or AMI),[16] historical anytime maximum injection (HAMI)[17] and/or RCPD to minimise the impact of the distortion created by this reverse flow.

4.1.4 The amendment is intended to provide distributors with more certainty about how Transpower will handle the effect of reverse flows on transmission charges.

4.1.5 The Authority has made several changes to the drafting, relative to the version consulted on (Table 4).

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[14] A GXP tie is defined as a situation in which GXPs are simultaneously connected to the grid at more than one point of connection.

[15] Reverse flow is defined as electricity exiting the grid at a GXP and entering the grid at another GXP as a result of a GXP tie.

[16] AMD and AMI are used in allocating connection charges between connected parties.

[17] The Authority is currently consulting on another amendment to the TPM, under which the HAMI allocation of the HVDC charge would be progressively replaced with a per-MWh allocation. If this amendment was enacted, then Transpower would also be required to adjust the 'SIMI' allocator of the per-MWh charge under the circumstances described.

Table 4: Changes to the drafting of the reverse flows component

Change	Reasons for change
Definition of 'GXP tie' has been changed to 'a situation in which GXPs are simultaneously connected to the grid at more than one point of connection'.	Transpower requested this change, for consistency with the drafting used in Schedule 8.3, Technical Code A, clause 6.
In order to take advantage of the amendment, a customer must have an agreement with the system operator under Schedule 8.3, Technical Code A, clause 6.	If the customer does not have such an agreement with the system operator, Transpower may not have access to the metering information necessary to determine the effect of reverse flows.
In order to take advantage of the amendment, a customer must notify Transpower that reverse flow has occurred within 20 business days of the reverse flow occurring.	Northpower requested clarification on when a party should notify Transpower of reverse flows, and expressed concern that parties might notify Transpower after prices had been calculated, resulting in recalculation of prices. The 20 business day time frame prevents customers from notifying Transpower of reverse flows after Transpower has calculated prices for the relevant pricing year. The Authority considers that it should be practicable for parties to notify Transpower of reverse flows within 20 business days.
If Transpower adjusts charges under the amendment, it must, within 20 business days of making the adjustment, make available on its website the reasons for the adjustment, and how the adjustment was calculated.	Powerco suggested, and the Authority agrees, that it is desirable to provide transparency on the application of the amendment.

4.2 The decision supports the Authority's statutory objective

4.2.1 The Authority expects the amendment to promote the statutory objective, to the extent that it supports efficient investment in, and operation of, Transpower's customers' networks. If the amendment did not occur, some Transpower customers might build or configure their networks to avoid reverse flows.

4.2.2 The Authority expects the amendment to have no material effect on competition or reliability.

4.3 The proposal is preferable to the status quo

4.3.1 The Authority considers that the proposal is preferable to the status quo and that its expected net economic benefit is positive. The proposal is also preferable to the alternatives, as set out in Section 4.4.

4.3.2 The consultation paper did not quantify the expected net benefit of the proposal, but set out that:

(a) while the expected benefit is probably not very large – given that reverse flows can already be resolved under the 'exceptional operating circumstances' provisions of the TPM – it is probably greater than zero

(b) the proposed amendment is not expected to cause significant disbenefits

(c) the Authority expects the proposed amendment will not have significant transactional costs or benefits.

4.3.3 As set out in Section 2.3, the Authority now considers that the benefits and costs of the proposed amendment should be considered over five years only. However, this does not alter the Authority's conclusion that the expected net benefit of the proposal is greater than zero.

4.3.4 Some submitters agreed that the proposed amendment is preferable to the status quo. No submitters disagreed with the statement that the proposed amendment is preferable to the status quo, or provided evidence to suggest that the proposed amendment will not produce a net economic benefit.

4.4 The proposal is preferable to the alternatives

4.4.1 The Authority considers that the amendment is preferable to alternatives that are consistent with the current TPM Guidelines.

4.4.2 The consultation paper did not identify any alternatives that could promote the statutory objective to the same extent as the proposal.

4.4.3 Some submitters agreed that the proposed amendment is preferable to other options. No submitters disagreed with the statement that the proposed amendment is preferable to the status quo, or proposed an alternative to the proposal, or provided evidence to suggest that an alternative is superior to the proposal.

4.5 The amendment complies with section 32(1) of the Act, and with the Code amendment principles

4.5.1 The consultation paper set out the Authority's view that the reverse flows component complies with section 32(1) of the Act, and with the Code amendment principles.

4.5.2 A majority of submitters supported the proposed amendment. No submitters opposed the amendment, or provided evidence to suggest that it does not comply with the Act or the Code amendment principles.

5. Responses to process issues raised in submissions

5.1 The Authority must meet the requirements set out in the Act when amending the Code

5.1.1 Andrew Shelley Economic Consulting (ASEC) submitted that *‘it is not obvious that the Authority needed to conduct the level of analysis included in the consultation paper, nor that it needed to develop alternative options to those advanced by Transpower. The Code appears to set out different roles for Transpower and the Authority, the Authority’s role essentially being one of ensuring that Transpower has followed due process, rather than one of duplicating Transpower’s consultation and decision-making processes.’*

5.1.2 Trustpower’s submission expressed concern that *‘the Authority’s oversight role does not require it to substitute its judgment for that of Transpower’s but merely to check that Transpower has turned its mind to the objectives set out in section 15 and exercised its judgment reasonably… The Authority’s supplementary analysis of options and other matters in the Consultation Paper has stepped beyond assessing Transpower’s compliance with the process and content requirements in Part 12, and led it to the development or partial development of a methodology – which is the role entrusted to Transpower.’*

5.1.3 The Authority does not agree with Trustpower or ASEC's characterisation of the Authority's role. The TPM is part of the Code and any amendment to the TPM will involve the Authority exercising its functions under sections 16(1)(b) and 38 of the Act. It must do so in a manner that it considers is most consistent with its objective under section 15 of the Act. The Authority is required to exercise its own judgment as to whether any proposed amendment to the Code is consistent with the objective of the Authority and meets the requirements of section 32 of the Act.

5.1.4 The Authority is not permitted to simply rely on the view of another party, such as Transpower, and nothing in the Code could, as a matter of law, modify the requirements of the Act in that regard. In fact, the relevant provisions of the Code are consistent with this interpretation of the Authority's role. The Authority is given the function under clause 12.91 of approving a TPM (or amendment to the current TPM), referring it back to Transpower, or of ultimately amending a TPM itself, based, as a central consideration, on the Authority's view as to the extent to which the proposed TPM is consistent with the Authority's objective in section 15. That judgment is not permitted to be based, as Trustpower asserts, only on whether the Authority considers that Transpower ‘*turned its mind’* to whether the TPM is consistent with the objective.

5.1.5 Trustpower also commented that *'it is clear from an examination of Subpart 4 of Part 12 of the Code that the Authority is responsible for developing a framework for a pricing methodology, and also has a role to confirm (on behalf of transmission customers) that Transpower has followed the process and content guidelines in the Code. On the other hand, Transpower is responsible for the development and ongoing review of a methodology for allocating its revenue requirements amongst its transmission customers (which conforms to that framework and the other process and content guidelines in the Code).'*

5.1.6 The Authority does not accept that its role in approving a TPM is to be exercised *on behalf of transmission customers*. The Authority is specifically directed in section 15 of the Act to promote competition in, reliable supply by, and the efficient operation of, the electricity industry *for the long-term benefit of consumers*. The Authority would be acting contrary to the Act if it took the view that it was required to exercise its function of approving a TPM on behalf of transmission customers.

5.2 Transpower's review of the TPM is not limited to 'technical' or 'operational' matters, or to proposals that have no adverse effects on parties

5.2.1 Meridian's submission comments that *'although Transpower used the language of an "operational review" and "fine tuning", it was in fact undertaking a substantive review that overlapped with the Authority's full review of the TPM… Substantive issues are best dealt with as part of the Authority's review… Of the proposals being consulted on by the Authority, only reverse flows is of a technical nature that makes it appropriate to be considered separately from the Authority's TPM review.'*

5.2.2 Winstone Pulp International (WPI) submitted that some of the alternatives considered by the Authority *'cannot be treated as operational changes, but rather are major departures from the current TPM methodology, with potential for serious unintended consequences. WPI believes the EA should set these options aside. Instead they could be considered… as part of the EA's review.'*

5.2.3 Major Electricity Users' Group (MEUG) submitted that *'only clear-cut problems with the TPM that have no downside for other parties not directly affected can be considered as variations within the existing TPM guidelines.'*

5.2.4 NZ Steel submitted that *'of its nature, [Transpower's application to amend the TPM] is restricted to changes that are likely to be non-contentious'.*

5.2.5 The Authority does not agree that Transpower's review must be confined to:

(a) non-substantive issues

(b) operational changes

(c) options that are not major departures from the current TPM methodology

(d) non-contentious options

(e) options that do not leave any party worse off.

5.2.6 Rather, Transpower may propose any changes to the TPM that are consistent with the current TPM Guidelines and any determination under Part 4 of the Commerce Act, promote the Authority's statutory objective, and meet the other requirements set out in the Code.

5.3 Consultation requirements have been met

5.3.1 Trustpower submitted that *'we believe that Transpower must consult with stakeholders on its proposals. … The [N=100 component] and [reverse flows component] have been consulted on by Transpower [but] the [amended RCPD CMP component] and [RCPD quantity adjustment provision component] appear to have been included in the Authority's Consultation Paper in substitution for consultation by Transpower… Thus we think it is open to the Authority to approve the first, fourth and fifth code changes as having clearly met administrative law consultation requirements. We have reservations about whether this is true of the second and third TPM changes as these are new to stakeholders.'*

5.3.2 Transpower's original proposal involved adjusting NZAS transmission charges on a bespoke basis. Transpower had consulted on that component of its proposal. In response to the Authority's concerns, Transpower submitted further components relating to the amended RCPD CMP component and RCPD quantity adjustment component designed to address the Authority's concerns about the 'bespoke' component.

5.3.3 The Authority considers that Transpower was entitled to submit the further components, having taken into submissions made to it on the issue that the original 'bespoke' component was intended to address. Participants have had a further opportunity to make submissions in the consultation the Authority undertook as required under clause 12.92 and section 39 of the Act.

5.3.4 Therefore the Authority does not agree that there has been any failure to comply with consultation requirements for the components relating to amended RCPD CMP and RCPD quantity adjustment provisions.

Glossary of abbreviations and terms

'50:50 option'	An alternative to the N=100 component, under which the interconnection charge would be a 50-50 mix of the status quo and a per-MWh charge on gross load
Act	Electricity Industry Act 2010
'Amended RCPD CMP component'	Transpower's proposal to exclude periods between November and April (inclusive) from the calculation of the RCPD allocation of the interconnection charge
Authority	Electricity Authority
'Bespoke NZAS component'	Transpower's proposal to treat, for the purpose of the interconnection charge, NZAS loads between 572-636 MW as if they were just 572 MW, during the period from November to April inclusive
CMP	Capacity measurement period – a 12-month period from 1 September to 31 August inclusive – used to calculate transmission charges for subsequent pricing years
Code	Electricity Industry Participation Code 2010
Connection charge	The component of the TPM that recovers the costs of providing connection services
GXP tie	A situation in which GXPs are simultaneously connected to the grid at more than one point of connection
HVDC charge	The component of the TPM that recovers the costs of the high voltage direct current inter-island link
'HVDC component'	Transpower's proposal to allocate HVDC charges on a per-MWh basis, with an initial transition period
Interconnection charge	The part of the TPM that recovers all TPM costs not recovered through the HVDC charge or connection charge
'Line maintenance component'	Transpower's proposal to adjust the formula for the line maintenance component of the connection charge
LNI, LSI	Lower North Island and Lower South Island – two of the four regions used in the calculation of the RCPD allocator of the interconnection charge

'LRMC option'	An alternative to the N=100 component, under which the interconnection charge would be a combination of a regional LRMC-based charge and a per-MWh charge on gross load
N	The number of regional coincident peaks used in the calculation of the RCPD allocator of the interconnection charge
'N=100 component'	Transpower's proposal to use N=100 for all four RCPD regions, in the calculation of the interconnection charge
'N=500 option'	An alternative to the N=100 component, under which RCPD would be set to 500 in all four regions
NZAS	New Zealand Aluminium Smelters Ltd
'per-MWh option'	An alternative to the N=100 component, under which the interconnection charge would be a per-MWh charge on gross load
Pricing year	A twelve-month period from 1 April to 31 March inclusive, for which transmission charges are calculated
RCPD	Regional coincident peak demand – the allocator used in the interconnection charge
'RCPD quantity adjustment provision component'	Transpower's proposal to require Transpower to disregard customer's offtake changes in a region for the purpose of determining regional peak demand periods, in cases where a change in the customer's offtake would alter the incidence of a majority of peaks in the region, would not impact on transmission investment requirements, and would not occur in the absence of the adjustment for the change
Reverse flow	Defined as electricity exiting the grid at a GXP and entering the grid at another GXP as a result of a GXP tie
'Reverse flows component'	Transpower's proposal to provide for Transpower to adjust transmission charges when a reverse flow situation occurs
TPM	Transmission pricing methodology
UNI, USI	Upper North Island and Upper South Island

Appendix A Drafting showing proposed changes to the Electricity Industry Participation Code 2010

Appendix B Effect of shortening the horizon of the CBA for the N=100 component

B.1 As set out in the main text, the CBA in the consultation paper extended over a horizon of 15 years, and used:

(a) a factual in which the proposed amendment (N=100) remains in force for 15 years

(b) a counterfactual in which the status quo (N=12 in the UNI and USI) remains in force for 15 years.

B.2 Following the release of the Authority's TPM options paper, the Authority has revised the CBA of the N=100 component, using:

(a) a factual in which N=100 remains in force for five years, before being replaced by some other interconnection charging arrangement

(b) a counterfactual in which the status quo (N=12 in the UNI and USI) remains in force for five years, before being replaced by some other interconnection charging arrangement.

B.3 This Appendix provides the results of the revised CBA.

B.4 The CBA set out in the consultation paper was implemented in a spreadsheet model.[18] In comparing the N=100 component with the status quo, the main elements taken into account were:

(a) a possible reduction in the use of inefficient demand response/back-up generation – ie, activity that occurs to avoid transmission charges, but which has a public cost that is greater than the public benefit

(b) a possible increase in economically inefficient demand response and/or embedded peaking generation, which could occur if some parties extended their peak avoidance activity to target a greater number of trading periods

(c) a possible reduction in transmission deferral incentives – and hence higher transmission costs over time.

B.5 The CBA in the consultation paper estimated the expected net benefit of the N=100 component, relative to the status quo, as:

(a) $5 million present value, under the base case

(a) from $6 million to $17 million present value, in four alternative sensitivity cases.

[18] http://www.ea.govt.nz/dmsdocument/19324

B.6 A range of alternative sensitivity cases were considered in the consultation paper. They were labelled Case A through Case D, and incorporated:

(a) decreasing likelihood of transmission investment being required in the absence of a clear peak avoidance signal

(b) decreasing amount and elasticity of price-elastic industrial load

(c) some assumptions about inefficient investment in embedded baseload and intermittent generation, which are not relevant to this Appendix (because they were put in place to model the benefits of per-MWh charging options, which are not considered here).

B.7 The expected net benefits were calculated using an 8% real discount rate.

B.8 When the same analysis is carried out over a horizon of five years (ie only benefits and costs generated in the first five years are included), the expected net benefit of the N=100 component, relative to the status quo, is estimated to fall to:

(a) $0.9 million present value, under the five-year base case

(b) $1.3 million to $2.8 million present value, in the four five-year sensitivity cases.

B.9 The reduction in expected net benefits, relative to the CBA shown in the consultation paper, arises largely because the main gain from adopting N=100 is deemed to lie in reducing inefficient investment in new embedded peaking generation capability.

B.10 For simplicity, the Authority's original CBA assumed such deferred investment to be nil for the first five years, and then to be equivalent to 1% of peak demand in the UNI and USI in each year after the fifth.[19]

B.11 However, the assumption of nil deferred investment in the first five years was unrealistically conservative, and would not have been made if the first five years were the primary focus of the analysis.

B.12 Therefore, the revised CBA assumes such deferred investment to be equivalent to just 0.33% of peak demand in the UNI and USI (ie less than 15 MW), in each of the five years modelled.

B.13 The Authority considers that it is reasonable to assume that new embedded peaking generation capability could be constructed in the UNI and USI in the near term, under status quo arrangements (RCPD with N=12). Such generation would likely be eligible to receive 'avoided cost of transmission' (ACOT) payments in

[19] The NZIER report (at footnote 6) attached to the MEUG submission appears to question whether the CBA calculations correctly reflected the assumption that new back-up generation is not committed before year five. The Authority confirms that the CBA calculations do reflect this assumption, and note that this was achieved by setting 'New Back up' generation levels for the first five years to zero in row 47 of the 'CBA Inputs' tab in the Base Case.

excess of $100/kW, in exchange for operating in a small number of potential coincident peak periods. These payments would be sufficient to cover the majority of the capital costs of the plants. The owners would also be able to obtain additional revenue from the energy market.

B.14 The Authority considers that it is reasonable to assume that adopting the proposed amendment will largely prevent such investment from occurring. From the 2015/16 capacity measurement period, commencing in September 2015, N=100 will apply in the USI and UNI. New embedded peaking generation in these regions will need to operate roughly eight times as often in order to receive the same level of 'avoided cost of transmission' payments as under N=12. Given the relatively high short-run marginal cost of peaking generation, this will make constructing new embedded peaking generation, where this would be economically inefficient, much less attractive.

B.15 The Authority notes that it is undertaking a review of the pricing principles for distributed generation, which are set out in Schedule 6.4 to the Code. This review may affect ACOT payments. However, since the review is at an early stage there is insufficient information to justify changing the relevant assumptions in the CBA.