

Proposal to amend the Electricity Industry Participation Code 2010

Send to info@ea.govt.nz or fax to 04 4608879

This form is to propose:

- ☐ An amendment to an existing clause in the Electricity Industry Participation Code 2010; or
☐ A new clause in the Electricity Industry Participation Code 2010.

Please complete as many sections of this form as possible and email or fax it to the above number/email address. The more information you include in your proposal, the faster your proposal will be able to be assessed/progressed.

Proposer's details

Name:	Ross Parry
Position in company:	Planning and Regulatory Manager
Company:	Transpower
Telephone:	04 590 6862
Email address:	ross.parry@transpower.co.nz
Signature:	
Date:	13 February 2015

The proposal / preferred option

Suggested proposal name (please keep it short)	TPM Operational Review: RCPD charges – setting the value of “N”
State the objective of your proposal.	The objective of the proposal is to improve efficiency in the electricity market by ensuring RCPD charges do not send excessively strong price signals against peak usage in the UNI and USI RCPD regions. ¹
Does the proposal relate to an existing Code clause?	Yes, clause 3 of Schedule 12.4 of the Code.

¹ RCPD: regional coincident peak demand, UNI: upper North Island, USI: upper South Island

If yes, please state the full clause reference.	
Describe the specific amendment(s) that you propose be made to the Code <i>OR</i> attach a draft of the proposed Code amendment (optional). Note the Code drafting manual provides guidance on drafting.	We propose the RCPD charges for UNI and USI be amended by resetting N from 12 to 100 (i.e. averaging users demand for pricing purposes over 100 instead of 12 half hour periods). If this proposal is rejected, we propose the RCPD charges for UNI only be amended by setting N from 12 to 100. Please refer to Attachment C for proposed Code drafting.
Identify how your proposal would support the Authority's objective, as set out in section 15 of the Electricity Industry Act 2010 (Act) ¹ , specifically addressing the competition, reliability and efficiency dimensions of the objective.	This proposal would be to the long-term benefit of consumers – by improving the efficient operation of the electricity industry (s 32(1)(c)) – on the basis 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 in the USI. - Grid investment since 2008 has increased the transmission costs which has resulted in even stronger RCPD price signals².
Which of the purposes listed in section 32(1) of the Act does your proposal most closely relate to?	- Setting N = 12, when a strong peak price signal is not warranted, creates a significant amount of inefficient peak avoidance. Setting N to 100 would eliminate a substantial proportion of the most inefficient peak avoidance. We estimate the change would result in allocative and productive efficiency benefits a range from: UNI range \$4.4M to \$13.2M (with a point estimate of \$8.5M) USI range \$2.1M to \$6.4M (with a point estimate of \$2.1M for USI)³. - We have not attempted to quantify dynamic efficiency gains. - While any change would slightly alter the allocation of interconnection costs.⁴ - Implementation is straightforward and we have not identified any costs that could potentially negate the benefits of the change: Although changing N to 100 will change the way firms respond to RCPD signals and in some cases increase the volume of response we believe that this will primarily involve low or zero cost responses and consequently is unlikely to cause any material cost. - The N = 100 setting is a familiar and well understood feature of the current TPM. A change from 12 to 100 is a predictable evolution given the current environment.
Identify whether you consider your proposed	This Code Amendment Proposal is not being made under urgency. The timing of the proposals was discussed and agreed with the Authority to

² The interconnection rate has increased by more than 60% (in 2014/15 terms) since 2008.

³ PV over 5 years, 8% discount rate. This analysis is different, but coherent with, analysis by the Authority in its PDWP and by Castalia analysis for Genesis Energy in response to the PDWP. Changing to N = 100 would eliminate a significant proportion of this inefficiency.

⁴ We estimate interconnection charges will change by -0.03%, -0.46, +1.39% and -0.46% respectively for UNI, LNI, USI and LSI under a scenario where the ratio between 12 and 100 RCPD peaks for UNI and USI broadly align with those of the LNI and LSI regions.

change to be urgent, providing supporting rationale.	enable the Authority to make a decision (indicative timing June 2015) in time for the changes to be implemented by 1 September 2015 and to take effect for Capacity Measurement Period (CMP 2015/16) 1 September 2015. Our expectation is that this change would need to be in place at the beginning of the CMP. On that basis, if a decision is not made and implemented before 1 September 2015 the change would be delayed for one year (foregoing estimated efficiency benefits of \$3.6m).								
Please set out the expected costs and benefits of your proposal. These should include your assessment of the direct cost to develop and implement the proposed Code amendment, and the consequential costs and benefits as a result of the amendments, to all affected parties.	Please read this conjunction with section 5.4 of Attachment B. Any transmission pricing methodology will cause some inefficiency. Our cost benefit analysis assesses the net cost of peak avoidance and transmission deferral benefit at N = 12 and N=100 for the UNI and USI regions. There are practical considerations that may influence the extent of the inefficiency associated with RCPD and affect the reliability of the analysis; they include: • The transmission pricing signal operates in conjunction with a range of other factors, such as wholesale electricity prices, distribution investment costs, etc (so it is difficult to isolate the effect of the transmission price on behaviour). • For many small users, the price signal is not passed on in their distribution or retail tariffs. In other words, the transmission price signal does not penetrate through to many end users. • Large direct connect users receive the price signal directly and there is evidence of strong responses. Some large, non-grid connected users have pass-through contracts that mean they receive unaltered RCPD price signals (we expect they would respond in a similar way to grid connected users). • EDBs are required to pay embedded generators on the basis of avoided transmission charges so, the price signal does penetrate through to embedded generators. In practice, parties will weigh up a range of factors when deciding whether to respond to transmission pricing signals. However, the strength of the signal when N=12 is high relative to wholesale electricity prices and standby generation costs, and approaches estimates of the cost at which some parties would be willing to temporarily cease consumption altogether i.e. the value of lost load, or VoLL. The figures below illustrate the expected response for different combinations of response (green: ongoing activity, orange: declining activity, red: no activity). N = 12 setting <table border="1"> <tr> <td>High fixed + High variable</td><td>High fixed + Low variable</td></tr> <tr> <td>Low fixed + High variable</td><td>Low fixed + Low variable</td></tr> </table> N = 100 setting <table border="1"> <tr> <td>High fixed + High variable</td><td>High fixed + Low variable</td></tr> <tr> <td>Low fixed + High variable</td><td>Low fixed + Low variable</td></tr> </table> <u>Costs</u> Our assessment of transaction costs associated with this proposal is: 1. We do not expect to incur any incremental costs to implement this proposal.	High fixed + High variable	High fixed + Low variable	Low fixed + High variable	Low fixed + Low variable	High fixed + High variable	High fixed + Low variable	Low fixed + High variable	Low fixed + Low variable
High fixed + High variable	High fixed + Low variable								
Low fixed + High variable	Low fixed + Low variable								
High fixed + High variable	High fixed + Low variable								
Low fixed + High variable	Low fixed + Low variable								

	2. We expect the Authority may incur modest incremental costs to process this Code change proposal (and will be incurred regardless of whether the proposal is accepted so should not affect the CBA). 3. We expect that our customers and other parties affected by RCPD price signals may incur modest incremental costs to change response behaviours. No indication of likely costs for 3 were provided through our consultation and we have not attempted to estimate these costs.⁵ Our expectation is these costs will be small (and unlikely to sway the cost benefit analysis). The proposal may impact the returns on some (sunk) peak avoidance investments. Setting N to 100 can be expected to decrease the influence of transmission prices on behaviour during the highest peak periods relative to an N of 12 (but to increase influence in the next tier of peak periods).⁶ For the reasons outlined in Attachment B (section 5.4.2) we do not believe this will result in a material, if any, increase in peak avoidance costs. We do not consider the proposal will displace any transmission deferral benefits that may accrue by keeping N at 12. This is because: • A large proportion of any transmission deferral benefit currently attributable to peak avoidance is likely to be preserved under an N of 100 (because the cost of this peak avoidance is very low). • We would expect to strengthen the price signal if an investment was pending and the incremental cost of increased peak avoidance was exceeded by the resulting transmission deferral benefits. <u>Benefits</u> Changing from allocating charges on the average of the 12 highest periods to the 100 highest periods will result in a change in focus for peak avoidance behaviour. We believe the response will differ between the UNI and USI regions. For the UNI, there does not appear to be coordinated load control. We understand that that moving to N=100 for UNI could <u>increase</u> the total volume of low cost peak avoidance activity. For the USI, load control is coordinated and load duration curves indicate aggressive peak avoidance that we understand already occur in hundreds of periods. Moving to N=100 for USI may <u>increase or decrease</u> the total volume of peak avoidance activity: there will less high cost peak avoidance activity but be more low cost peak avoidance activity. <u>Summary of costs and benefits</u>⁷ The analysis uses a discount rate of 8%, excludes wealth effects and shows net benefits of \$10.6M (5 year PV) from the proposal. Negative numbers denote costs relative to the status quo.
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⁵ We included specific questions about the costs of our proposals in the Second Consultation Paper.

⁶ Although this will differ between users and be affected by existing demand management practices and capabilities.

⁷ Please also refer to Attachments B and D for additional information and cost benefit modelling.

	Table 1: summary of CBA for changing N=12 to N=100 for UNI <table><tr><th>Benefits / (costs) \$M</th><th>Year 1</th><th>5 yr PV</th></tr><tr><td>Peak avoidance</td><td>\$1.63</td><td>\$10.6</td></tr><tr><td>Transmission deferral</td><td>\$0</td><td>\$0</td></tr><tr><td>Net benefit / (cost)</td><td>\$1.63</td><td>\$10.6</td></tr></table>	Benefits / (costs) \$M	Year 1	5 yr PV	Peak avoidance	\$1.63	\$10.6	Transmission deferral	\$0	\$0	Net benefit / (cost)	\$1.63	\$10.6
Benefits / (costs) \$M	Year 1	5 yr PV											
Peak avoidance	\$1.63	\$10.6											
Transmission deferral	\$0	\$0											
Net benefit / (cost)	\$1.63	\$10.6											
Who is likely to be substantially affected by this proposal?	Parties in the UNI and USI regions that are exposed to and respond to RCPD price signals. Other parties who pay RCPD charges.												
Identify whether you consider (providing supporting rationale): (i) your proposed change to be technical and non-controversial; or (ii) there is widespread support for your proposed change among the people likely to be affected; or (iii) there has been adequate prior consultation so that all relevant views have been considered.	(i) Technical and non-controversial The proposal itself did not elicit controversy and was supported by most (but not all) submitters who commented. A small minority of parties objected to consideration of RCPD charges within this operational review because they considered it beyond the scope of the operational review and best addressed through the Authority’s TPM review.⁸ (ii) Widespread support The option of setting N = 100 for UNI was supported by Contact Energy, Genesis Energy, Mighty River Power, NZAS ("don't disagree"), Northpower, Orion ("Yes, provided it is also set to 100 for USI."), PanPac, Powerco, Trustpower (with transition), Unison ("Only if there are minimal quantitative impact on the allocations of transmission charges to the regions") and Vector. The option of setting N = 100 for USI, as well, was supported by fewer parties: Contact Energy, Genesis Energy, Mighty River Power, Orion, Trustpower (with transition), Unison, and Vector. The only parties against were MEUG (on the basis that it should be left to the Electricity Authority), Norske Skog (at least for UNI) and WPI. (iii) Adequacy of prior consultation We consider there has been comprehensive (more than adequate) consultation on our Code Amendment Proposals, and all relevant views have been considered. This has consisted of: • Testing with the Authority and a subset of our customers and interested parties whether they considered that we should undertake a TPM Operational Review then notifying stakeholders of review, and maintaining details/updates on our website. • Issuing an Initial Consultation Paper that invited comments on our proposed TPM Operational Review process, our initial assessment of the potential problems with the TPM and on options we identified for addressing these problems. • Issuing an Update Paper summarising key themes from submissions and briefly sharing our views on these themes, responding to a small number of specific issues, and outlining the development of our thinking and how,												

⁸ Attachment B: TPM Operational Review: Background and Supporting Reasons and Supplementary Materials, 15 February 2015, section 3.3.

	in light of submissions, we intended to proceed. • Issuing a Second Consultation Paper that identified and analysed options for improving the TPM, set out our proposals, and detailed our responses to submissions on the Initial Consultation Paper and how we took these submissions into account. • Undertaking a series of Workshops (Auckland, Christchurch and Wellington) as part of the consultation on the Second Consultation Paper and a series of bilateral meetings with the Authority, customers and other interested parties. The substantial majority of submitters have supported our consultation process.
Why this is your proposed option?	We consider this proposed option: • Would eliminate the current over-signalling of the cost of demand during peak periods in the UNI and USI • Is consistent with the approach of the under the current TPM of applying a stronger price signal (through a smaller N) where transmission capacity is constrained/transmission investment will be required and a weaker signal (through a larger N) in regions that are not constrained.
Any other relevant information you would like the Authority to consider.	Refer to Attachment A: Background and Supporting Material, 13 February 2015 and all other accompanying material. Also to Attachment D: Quantitative Analysis

Assessment of alternative options

Please list and describe any alternative means of achieving the objective you have described for your proposal. For each alternative, please provide the information in the table below (i.e. repeat this table below for each alternative). The list of alternatives should include both regulatory (i.e. Code amendments) and non-regulatory options (e.g. education, information, voluntary compliance). If you have a preferred option please identify it and explain why it is your preferred option.

Option 1: RCPD N = 100 for UNI (retain N = 12 for USI)

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Set UNI N = 100, and retain USI N = 12 (our preferred option, if UNI and USI = 100 is rejected by the Authority).
The extent to which the objective of your proposal would be promoted or achieved by this option.	The full benefits of a switch from N = 12 to 100 that the Authority ⁹ and Castalia ¹⁰ identified would not be realised. (Neither separated the benefits into UNI and USI.)
Who is likely to be substantially affected by this option?	Parties in the UNI that are exposed to and respond to RCPD price signals.

⁹ Electricity Authority, TPM Review: problem definition modelling, 16th September 2014

¹⁰ Genesis Energy, TPM Review: problem definition working paper, submission, Appendix A.

The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	<u>Costs</u> As with proposed option (see above). <u>Benefits</u> As with proposed option (see above) although without the costs and benefits for changing N for USI.
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Option 2: RCPD N > 100

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	RCPD N > 100
The extent to which the objective of your proposal would be promoted or achieved by this option.	Although we consider an N of 12 provides too strong a price signal except where substantive capacity driven investment is imminent we consider that setting N > 100 may weaken the price signal too much. As outlined above, we expect that setting N = 100 will continue to elicit a substantial amount of the current peak avoidance activity. This is because very low (or zero cost) peak avoidance activity appears to remains viable at 100 peaks but may cease to be viable at a larger N. While the cost of this activity is small the option value it provides is potentially significant.
Who is likely to be substantially affected by this option?	Parties that are exposed to and respond to RCPD price signals.
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	We have not assessed the costs and benefits in any detail at this point. A key theme from the consultation processes was that it is desirable to retain some level of ongoing peak usage signalling. We also note the lack of support for N > 100. Contact Energy "...believe 100 peaks is sufficient. We believe that 100 peaks has a reduced signal when compared to 12 peaks, however network companies will still use the load management systems that they have invested in to manage to the 100 peaks which is in the commercial interest of their customers". Mighty River Power state that they "... would not recommend stepping above N = 100". Powerco argue "... no further review is necessary. Analysis undertaken by Transpower in 2006 showed that demand peaks level off at about N=100, so, if a customer is choosing to control at that level ... further increasing the N would be unlikely to have any effect on that behaviour. Also, as the "N" increases, the interconnection charge would increasingly resemble a per kWh charge, which could then have an inefficient effect on energy consumption and investment decisions by those customers that see the transmission charge separately."

Option 3: Other tariff designs

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Other tariff designs. For example, we could set charges based on: • setting N at an intermediate value between 12 and 100 • energy consumption (MWh) rather than peak demand • anytime maximum demand, rather than coincident demand • peak demand or energy during winter months only • 'weighted' peak demand (for example, a weighting factor could be applied to South Island demand to 'tilt' the price signal towards the North Island).
The extent to which the objective of your proposal would be promoted or achieved by this option.	We have not analysed any of these options in detail. In our view, they all suffer from the problem that they are too novel or unexpected to be introduced from 1 September 2015. The submissions we received on the Second Consultation Paper did not elicit any support for these options, or reasons to consider them further at this time.
Who is likely to be substantially affected by this option?	
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	

ⁱ Section 15: Objective of Authority

The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

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Proposer's details

Name:	Ross Parry
Position in company:	Planning and Regulatory Manager
Company:	Transpower
Telephone:	(04) 590 6862
Email address:	ross.parry@transpower.co.nz
Signature:	
Date:	24 March 2015

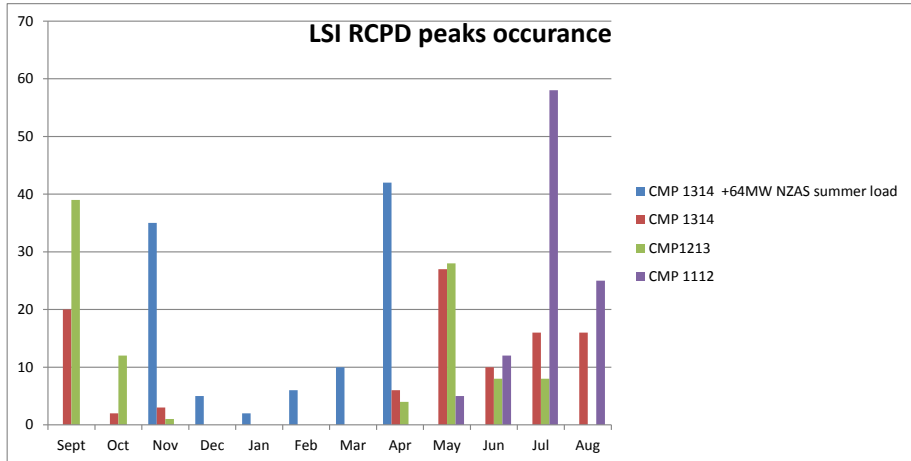
The proposal / preferred option

Suggested proposal name (please keep it short)	TPM Operational Review: Amend RCPD Capacity Measurement Period(CMP).
State the objective of your proposal.	To: 1. Remove the inefficient transmission pricing deterrent to increased summer production by NZAS at Tiwai Point and to remove the risk that increased production by NZAS causes large shifts in prices for other LSI consumers

	2. Remove any potentially inefficient RCPD related transmission pricing deterrent to increased electricity consumption in the generally non-peak period from November – April inclusive.
Does the proposal relate to an existing Code clause? If yes, please state the full clause reference.	Yes, the defined term CMP and potentially clause 34 of Schedule 12.4 of the Code.
Describe the specific amendment(s) that you propose be made to the Code OR attach a draft of the proposed Code amendment (optional). Note the Code drafting manual provides guidance on drafting.	For each RCPD region, amend the current CMP that runs from 1 September to 31 August to exclude the six months between 1 November and 30 April, starting if possible with the capacity measurement period from September 2015. (This exclusion could be reviewed periodically and adjusted if necessary in response to changing load growth patterns).
Identify how your proposal would support the Authority's objective, as set out in section 15 of the Electricity Industry Act 2010 (Act) ¹ , specifically addressing the competition, reliability and efficiency dimensions of the objective.	The proposal would support the efficient operation of the electricity industry for the long-term benefits of consumers. (See response on costs and benefits of the proposal.) By altering the RCPD CMP to exclude the months November – April (inclusive) the Authority would remove any transmission price deterrent faced by consumers over this period. We consider the likely consequence of this would be to increase energy consumption (and associated economic activity) during the generally non-peak summer months. One specific consequence of adopting this option would be to remove the current transmission pricing deterrent to increased summer production by NZAS at Tiwai Point and to allow that production to occur without large destabilising price swings for other LSI consumers. <u>Background on the situation at Tiwai Point</u> NZAS consumes a large proportion of total electricity supplied in LSI (average 67% in the year) which means a relatively small change in its demand behavior affects when the 100 regional peaks used to set transmission charges occur. This affects the incidence of charges for all users in the region and reduces the predictability of transmission charges. The ability to change the incidence of the LSI RCPD peaks and subsequent charges can affect NZAS' consumption decisions. For example, NZAS considered increasing production from late spring 2014 to early autumn 2015. While this would not affect transmission investment requirements it would shift most or all of the LSI regional peaks into the summer period making the production increase less economic. NZIER¹ and the Authority² have considered this problem. We have adopted the Authority's assessment of the efficiency impact of the current RCPD charges on the NZAS smelter; that assessment is: The interconnection charge may inefficiently deter the Tiwai smelter from seasonally varying its production. This may result in productive inefficiency in the range of \$4M–

¹ NZIER report to NZAS, Accommodating load growth: amending transmission prices to avoid inefficient demand loss, March 2014.

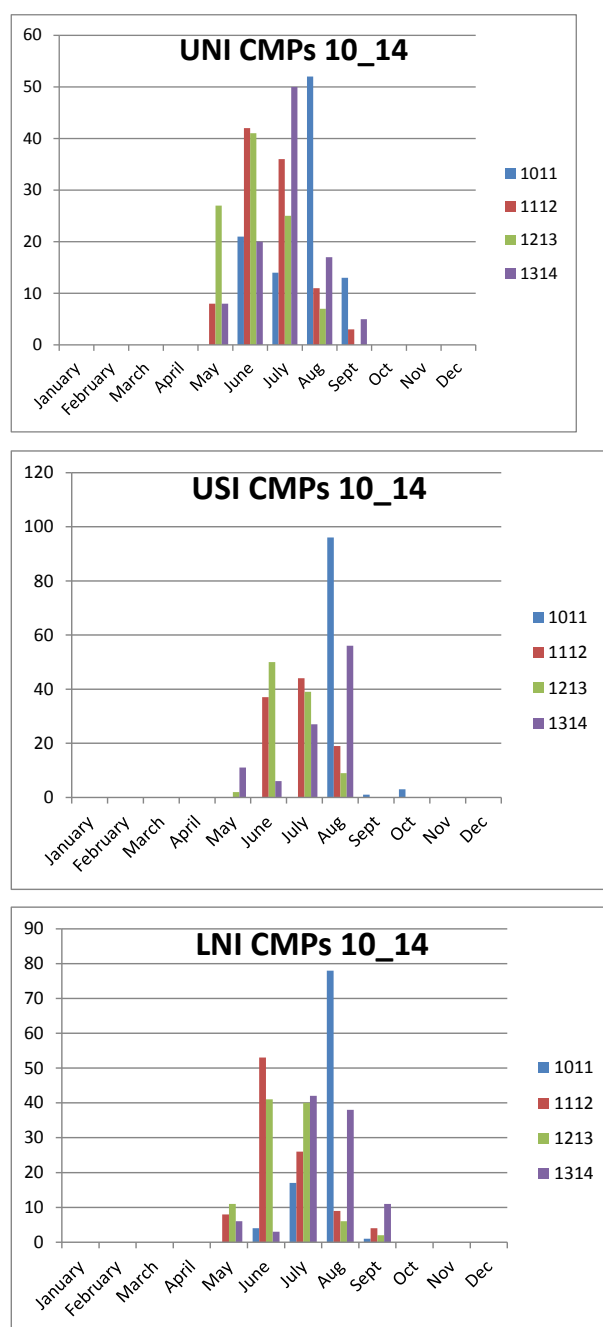
² September 2014, TPM review: problem definition working paper

	\$32M PV. We also agree with NZIER's analysis that the effect of the 64MW increase is to shift the majority of LSI RCPD periods into the summer months, with consequent impacts to others in the LSI through the greater allocation of charges under RCPD. This effect is shown in the graph below where the blue represent where LSI peaks would fall under a Tiwai plus 64MW scenario. 70 60 50 40 30 20 10 0 Sept Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug LSI RCPD peaks occurrence CMP 1314 +64MW NZAS summer load CMP 1314 CMP1213 CMP 1112 <table><thead><tr><th>Month</th><th>CMP 1314 +64MW NZAS summer load</th><th>CMP 1314</th><th>CMP1213</th><th>CMP 1112</th></tr></thead><tbody><tr><td>Sept</td><td>0</td><td>20</td><td>38</td><td>0</td></tr><tr><td>Oct</td><td>0</td><td>2</td><td>12</td><td>0</td></tr><tr><td>Nov</td><td>35</td><td>3</td><td>2</td><td>0</td></tr><tr><td>Dec</td><td>5</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Jan</td><td>2</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Feb</td><td>6</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Mar</td><td>10</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Apr</td><td>42</td><td>6</td><td>4</td><td>0</td></tr><tr><td>May</td><td>0</td><td>27</td><td>28</td><td>5</td></tr><tr><td>Jun</td><td>0</td><td>10</td><td>8</td><td>12</td></tr><tr><td>Jul</td><td>0</td><td>16</td><td>8</td><td>58</td></tr><tr><td>Aug</td><td>0</td><td>16</td><td>0</td><td>25</td></tr></tbody></table>	Month	CMP 1314 +64MW NZAS summer load	CMP 1314	CMP1213	CMP 1112	Sept	0	20	38	0	Oct	0	2	12	0	Nov	35	3	2	0	Dec	5	0	0	0	Jan	2	0	0	0	Feb	6	0	0	0	Mar	10	0	0	0	Apr	42	6	4	0	May	0	27	28	5	Jun	0	10	8	12	Jul	0	16	8	58	Aug	0	16	0	25
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Dec	5	0	0	0																																																														
Jan	2	0	0	0																																																														
Feb	6	0	0	0																																																														
Mar	10	0	0	0																																																														
Apr	42	6	4	0																																																														
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Which of the purposes listed in section 32(1) of the Act does your proposal most closely relate to?	32(1)(c) and (e)																																																																	
Identify whether you consider your proposed change to be urgent, providing supporting rationale.	This Code Amendment Proposal is not being made under urgency. The timing of the proposals was discussed and agreed with the Authority to enable the Authority to make a decision (indicative timing June 2015) in time for the changes take effect for Capacity Measurement Period (CMP 2015/16) 1 September 2015. In the case of the Tiwai Point smelter, our understanding is that NZAS would need to know by 31st July 2015 whether the change would be made in order to undertake preparatory works required to increase production for the 2015/16 summer. We estimate the cost of delaying for one year at \$1.46m³.																																																																	
Please set out the expected costs and benefits of your proposal. These should include your assessment of the direct cost to develop and implement the proposed Code amendment, and the consequential costs and benefits as a	<u>Benefits</u> By altering the RCPD CMP to exclude the months November – April the Authority would remove any transmission price deterrent faced by consumers over this period. We consider the likely consequence of this would be to increase energy consumption (and associated economic activity) during the generally non-peak summer months. This option would also remove the current transmission pricing deterrent to increased summer production by NZAS at Tiwai Point (the objective of our proposal). In our 13 February proposal we assessed the benefit of removing the deterrent to increased production at Tiwai Point to be in the range from \$4M-\$32M PV. We have																																																																	

³ Adopting the Authority's PDWP modelling with an assumed value of energy to NZAS of \$70/MWh and a 50% probability that increased summer production does not occur due to the delay.

result of the amendments, to all affected parties.	not modelled the scale of benefits flowing from the more general change to the CMP. We observe, however, that estimated benefits of increased production by NZAS (which accounts for approximately 13% of New Zealand electricity consumption) could provide a lower bound for removing a similar deterrent for the balance of New Zealand electricity consumption. That approach would imply conservative benefits of \$8M-64M PV from this option. We also expect the shortened CMP to result in fewer EOC applications which will yield a small reduction in administrative costs for Transpower and RCPD customers. <u>Costs</u> In our assessment excluding the 1 November to 30 April period from the RCPD CMP is unlikely to have any material effect of transmission investment requirements in the UNI, LNI and USI regions in the near or medium term. We also consider the change is unlikely to have any material effect of transmission investment requirements in the LSI region, although the situation here is less clear cut. In our proposal (13th February) we stated that increased production by NZAS over the summer period would not affect transmission investment (in the short to medium term at least). While that remains the case and the LSI region is a winter peaking region, parts of the region (notably South Canterbury) that are summer peaking are constrained and in need of capacity expanding transmission investment. Constraints in the 110kV South Canterbury network have been relieved for several years through short term measures (such as bus splits, special protection schemes and distributor load control) but investment to expand capacity is unavoidable and imminent. Any investments in this area (to meet the GRS), including in the short term the measures described above, must also demonstrate net economic benefits as the lines in question are not part of the core grid. We consider it unlikely that this investment could be economically deferred further through transmission pricing at this point (more generally, the lack of coincidence between peaks in the South Canterbury region and the wider LSI region mean that retaining the current CMP and RCPD settings (N=100) are unlikely to have any material impact on summer peak demand growth in the near term). We conclude that the transmission investment related costs of changing the CMP are likely to be negligible (arising from the LSI region) or non-existent (in relation to the UNI USI and LNI regions). However, if this proposal were adopted we would monitor changes in demand patterns to understand the effect of the change and, if necessary, to refine. We do not anticipate there would be any incremental costs to Transpower to implement this proposal. We expect the Authority may incur modest incremental costs to process this Code change proposal (and will be incurred regardless of whether the proposal is accepted so should not affect the CBA).
Who is likely to be substantially affected by this proposal?	NZAS will be substantially affected (positively). See assessment of excepted costs and benefits above. <u>Price effect analysis:</u> - UNI, USI and LNI customers We consider the impact on current charges for UNI USI and LNI to be the following. - There is likely to be a slight increase (well below 0.1%) in the allocation of RCPD charges to UNI, LNI and USI regions due to the very small reduction in the RCPD for the LSI region (approximately 0.1%, see table 1). - There is unlikely to be any change in the allocation of RCPD charges between customers with the UNI, LNI and USI regions. That is because none of the top 100 RCPD peaks have fallen between 1 November and 30 April for the UNI, LNI and USI in the last four CMPs (the period we assessed), see Figure 1.

Figure 1: RCPD peaks for UNI USI and LNI regions for CMPs 10_14



2. LSI customers

We consider the impact on current charges for LSI to be the following.

- There is likely to be a slight decrease (approximately 0.1%) in the allocation of RCPD charges to the LSI region due to the very small reduction in the RCPD for the LSI region (see table 1).
- There is likely to be a relatively minor change in the allocation of charges between LSI customers from the few lower-order LSI peaks that fall between 1 November and 30 April. As these few peaks are removed from the record they are replaced by lower peaks of the remaining six months. See Figure 2.
- The impact on consumer charges will differ depending on whether the user is directly exposed to the RCPD charge and / or distributor tariffs.

Figure 2: LSI peaks for CMPs 1011_1314

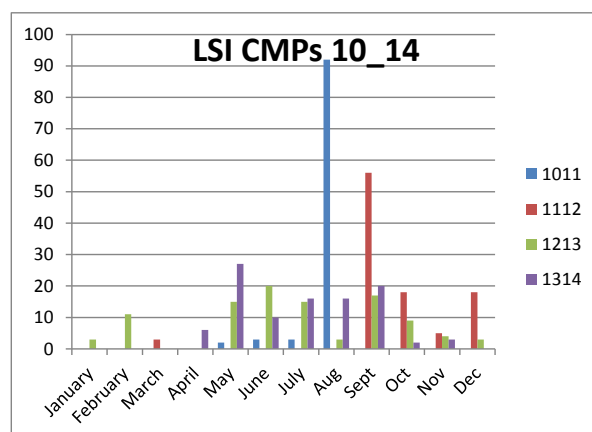


Table 1 Change to historic RCPD for LSI for four CMPs

LSI	CMP 1011	CMP 1112	CMP1213	CMP1314
RCPD	1,035,793	1,004,723	960,679	968,481
RCPD short CMP	1,035,793	1,002,022	959,514	968,196
	0.00%	-0.27%	-0.12%	-0.03%

General analysis:

With the exception of NZAS we do not have a clear view of exactly how consumers will respond to this change in RCPD price design.

If consumers increase summer consumption it may, in some circumstance, place additional demands on some distribution networks that may result in increased investment. However, this behaviour should be more strongly influenced by distribution tariff design than by transmission pricing arrangements.

Identify whether you consider (providing supporting rationale):

- (i) your proposed change to be technical and non-controversial; or
- (ii) there is widespread support for your proposed change among the people likely to be affected; or
- (iii) there has been adequate prior consultation so that all relevant views have been considered.

(i) Technical and non-controversial

We consider that the change may be technical and/or non-controversial however we have not had the opportunity to consult out customers at this point. As identified above, this proposal is likely to be net beneficial but may contribute to increased investment in distribution networks.

(ii) Widespread support

We have not had the opportunity to consult our customers on this proposal so cannot provide evidence of support or otherwise for this proposal.

(iii) Adequacy of prior consultation

We have not had the opportunity to consult our customers on this proposal so cannot provide evidence of support or otherwise for this proposal.

Why this is your

We consider that this proposal is likely to have net benefits. It is one of three

proposed option?	discrete proposals that, to some extent, overlap.
Any other relevant information you would like the Authority to consider.	Refer to Attachment B: TPM Operational Review Background and Supporting Material 13 February 2015, and all other accompanying material.

Assessment of alternative options

Please list and describe any alternative means of achieving the objective you have described for your proposal. For each alternative, please provide the information in the table below (i.e. repeat this table below for each alternative). The list of alternatives should include both regulatory (i.e. Code amendments) and non-regulatory options (e.g. education, information, voluntary compliance). If you have a preferred option please identify it and explain why it is your preferred option.

The alternatives described below are the same as those described by our proposal of February 13th 2015, Attachment A3 i.e. these are alternatives to the problem that NZAS is deterred from increasing production in the summer because of its effect on RCPD peak (and that increased production could cause unproductive volatility in RCPD charges for other LSI consumers).

We have not considered alternative options to the objective of this Code Change proposal for removing the transmission pricing deterrent for non-peak summer production between November – April inclusive.

Option1: Amalgamate RCPD regions

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Amalgamate UNI, LNI and LSI RCPD regions into a single RCPD region.
The extent to which the objective of your proposal would be promoted or achieved by this option.	The objective would be promoted (NZAS summer production would be insufficient to shift the peaks in an amalgamated region reducing the deterrent to increased production and the risk of large swings for LSI customers).
Who is likely to be substantially affected by this option?	All interconnection customers.
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	<u>Costs</u> Implementation costs for this option would be more material for Transpower and, we expect, those who respond to RCPD price signals than for the preferred option. We are mindful of the Authority's aim of making transmission charges more cost reflective and have sought to make proposals that are consistent with this aim. Similarly we recognise concerns expressed by stakeholders in relation to this option and agree with some of these. For example: • Proceeding with this proposal at this point, while outcomes of the Authority's review are unknown (but pending), could result in too much change too quickly that may create a perception of instability. • Amalgamating regions would disadvantage the remaining regions (in this

	case the USI) relative to the amalgamated region which would enjoy a larger diversity benefit. For example, a weather front may move up the island progressively rolling through a large region but may encompass a smaller region (causing a coincident peak as demand spikes due to cold weather). • This proposal is likely to make the allocation of interconnection costs between the North and South Islands less cost reflective⁴. <u>Benefits</u> The benefits are similar to those of the preferred option (NZAS could increase production over summer without incurring a disproportionate increase in transmission charges and without causing volatility in transmission charges for other LSI customers). This option would also provide a pathway to more targeted regions in future, though the size of this benefit is unclear (particularly in light of the Authority's ongoing review) and may be available through other means.
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Option 2: Separate NZAS region

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Create a fifth region with NZAS as the only demand; with its own RCPD and 'N'.
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⁴ Current allocations to between the North and South Islands, under the RCPD charge, are 66% and 34% respectively. We have compared the current allocation of interconnection charges to each Island to the book value of the grid in each Island. On this analysis we estimate the book value of the North Island grid represents 79% of interconnection assets and the South Island 21%. We have also compared the allocation of interconnection charges to each Island to the estimated replacement cost of the grid in each Island. On this analysis we estimate the estimated replacement cost of the North Island grid represents 73% of interconnection assets and the South Island 27%.

The extent to which the objective of your proposal would be promoted or achieved by this option.	This option would address the LSI stability problem by isolating NZAS from the rest of LSI. It would, however, only partially address LSI and NZAS issue of attracting RCPD charges to its summer production. We have undertaken internal analysis on having NZAS as its own region at different N's and confirm that this arrangement would still create an undesirable increase in its charges under summer production. Table 3 NZAS charges under different region and N scenarios <table><tr><td></td><td>Scenario</td><td>NZAS charge \$M</td></tr><tr><td>1</td><td>Status quo (100 peaks in LSI)</td><td>63.0</td></tr><tr><td>2</td><td>Status quo + 64MW Nov – April</td><td>69.5</td></tr><tr><td>3</td><td>LSI, LNI and UNI combined + 64MW Nov – April</td><td>63.0</td></tr><tr><td>4</td><td>Disregard Nov – April production between 572 and 636MW</td><td>63.0</td></tr><tr><td>5</td><td>Own region, N = 17520</td><td>62.8</td></tr><tr><td>6</td><td>Own region , N = 17520 + 64MW Nov – April</td><td>65.9</td></tr><tr><td>7</td><td>Own region, N = 100</td><td>63.9</td></tr><tr><td>8</td><td>Own region, N = 100, disregard Nov – April production between 572 and 636MW</td><td>63.5</td></tr></table>		Scenario	NZAS charge \$M	1	Status quo (100 peaks in LSI)	63.0	2	Status quo + 64MW Nov – April	69.5	3	LSI, LNI and UNI combined + 64MW Nov – April	63.0	4	Disregard Nov – April production between 572 and 636MW	63.0	5	Own region, N = 17520	62.8	6	Own region , N = 17520 + 64MW Nov – April	65.9	7	Own region, N = 100	63.9	8	Own region, N = 100, disregard Nov – April production between 572 and 636MW	63.5
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Who is likely to be substantially affected by this option?	All LSI interconnection customers.																											
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	This option could provide equivalent benefits under specific conditions (scenario 8 in table 1) and would entail additional minor administrative cost.																											

ⁱ **Section 15: Objective of Authority**

The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Proposal to amend the Electricity Industry Participation Code 2010

Send to info@ea.govt.nz or fax to 04 4608879

This form is to propose:

- ☐ An amendment to an existing clause in the Electricity Industry Participation Code 2010; or
- ☐ A new clause in the Electricity Industry Participation Code 2010.

Please complete as many sections of this form as possible and email or fax it to the above number/email address. The more information you include in your proposal, the faster your proposal will be able to be assessed/progressed.

Proposer's details

Name:	Ross Parry
Position in company:	Planning and Regulatory Manager
Company:	Transpower
Telephone:	(04) 590 6862
Email address:	ross.parry@transpower.co.nz
Signature:	
Date:	24 March 2015

The proposal / preferred option

Suggested proposal name (please keep it short)	TPM Operational Review: RCPD quantity adjustment provision
State the objective of your proposal.	To authorise Transpower, in certain specific circumstances, to isolate and remove an RCPD deterrent to extraordinary electricity consumption (and reduce the risk of unproductive price volatility potentially resulting from that consumption) where Transpower is satisfied the extraordinary consumption is unlikely to have any effect

	on transmission investment in the short or medium term. This provision would authorise Transpower to remove the transmission pricing deterrent to increased summer production by NZAS at Tiwai Point and to remove the risk that increased production by NZAS causes large shifts in prices for other LSI consumers.
Does the proposal relate to an existing Code clause? If yes, please state the full clause reference.	Clause 34 provides for adjustment to RCPD quantities (for exceptional operating circumstances). This would be a new adjustment authorisation provision.
Describe the specific amendment(s) that you propose be made to the Code OR attach a draft of the proposed Code amendment (optional). Note the Code drafting manual provides guidance on drafting.	Addition of a provision authorising Transpower to adjust RCPD quantities for a customer in circumstances where: 1. a customer's extraordinary electricity consumption could be expected to materially alter the timing of regional peaks 2. Transpower is satisfied that the extraordinary consumption is unlikely to effect transmission investment in the short to medium term 3. the customer has applied to Transpower before the start of the applicable capacity measurement period We consider that clause 34 is the logical place to house this provision.
Identify how your proposal would support the Authority's objective, as set out in section 15 of the Electricity Industry Act 2010 (Act) ¹ , specifically addressing the competition, reliability and efficiency dimensions of the objective.	The proposal would support the efficient operation of the electricity industry for the long-term benefits of consumers. (See response on costs and benefits of the proposal.) This general provision would reduce the risk that transmission pricing inefficiently deters electricity consumption. We consider a likely consequence of this would be to increase energy consumption (and associated economic activity) without any impacts on transmission investment. One specific consequence of creating this provision would be to permit Transpower to adjust RCPD quantities for NZAS at Tiwai Point for its summer production. <u>Background on the situation at Tiwai Point</u> NZAS¹ consumes a large proportion of total electricity supplied in LSI (average 67% in the year) which means a relatively small change in its demand behavior affects when the 100 regional peaks used to set transmission charges occur. This affects the incidence of charges for all users in the region and reduces the predictability of transmission charges. The ability to change the incidence of the LSI RCPD peaks and subsequent charges can affect NZAS' consumption decisions. For example, NZAS considered increasing production from late spring 2014 to early autumn 2015. While this would not affect transmission investment requirements it would shift most or all of the LSI regional peaks into the summer period making the production increase less economic. NZIER² and the Authority³ have considered this problem. We have adopted the Authority's assessment of the efficiency impact of the current RCPD charges on the NZAS smelter; that assessment is: The interconnection charge may inefficiently deter the Tiwai smelter from seasonally varying its production. This may result in productive inefficiency in the range of \$4M–

¹ New Zealand Aluminium Smelters who operate the Tiwai Point smelter

² NZIER report to NZAS, Accommodating load growth: amending transmission prices to avoid inefficient demand loss, March 2014.

³ September 2014, TPM review: problem definition working paper

	\$32M PV. We also agree with NZIER’s analysis that the effect of the 64MW increase is to shift the majority of LSI RCPD periods into the summer months, with consequent impacts to others in the LSI through the greater allocation of charges under RCPD. This effect is shown in the graph below where the blue represent where LSI peaks would fall under a Tiwai plus 64MW scenario. 70 60 50 40 30 20 10 0 Sept Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug LSI RCPD peaks occurrence CMP 1314 +64MW NZAS summer load CMP 1314 CMP1213 CMP 1112
Which of the purposes listed in section 32(1) of the Act does your proposal most closely relate to?	32(1)(c) and (e)
Identify whether you consider your proposed change to be urgent, providing supporting rationale.	This Code Amendment Proposal is not being made under urgency. The timing of the proposals was discussed and agreed with the Authority to enable the Authority to make a decision (indicative timing June 2015) in time for the changes take effect for Capacity Measurement Period (CMP 2015/16) 1 September 2015. In the case of the Tiwai Point smelter, our understanding is that NZAS would need to know by 31st July 2015 whether the change would be made in order to undertake preparatory works required to increase production for the 2015/16 summer. We estimate the cost of delaying for one year at \$1.46m⁴.
Please set out the expected costs and benefits of your proposal. These should include your assessment of the direct cost to develop and implement the proposed Code amendment, and the consequential costs and benefits as a result of the amendments, to all	<u>Benefits</u> The proposal would authorise Transpower, in certain specific circumstances, to isolate and remove an RCPD deterrent to extraordinary electricity consumption. We consider a likely consequence of this would be to increase energy consumption (and associated economic activity) without impacting transmission investment. One specific consequence of adopting this option would be to permit Transpower to adjust RCPD quantities to remove the current transmission pricing deterrent to increased summer production by NZAS at Tiwai Point and to avoid the risk of large unproductive price swings for other LSI consumers. In our 13 February proposal we assessed the benefit of removing the deterrent to increased production at Tiwai Point to be in the range from \$4M-\$32M PV. We have not modelled the scale of benefits flowing from the more general authorisation we

⁴ Adopting the Authority's PDWP modelling with an assumed value of energy to NZAS of \$70/MWh and a 50% probability that increased summer production does not occur due to the delay.

affected parties.	propose here. That approach would imply conservative benefits of \$4M-32M PV from this option. <u>Costs</u> We do not anticipate there would be any incremental costs to Transpower to implement this proposal (we expect the process to be similar to that applied by Transpower in relation to clause 12.34(2) of the TPM) . We expect the Authority may incur modest incremental costs to process this Code change proposal (and will be incurred regardless of whether the proposal is accepted so should not affect the CBA).
Who is likely to be substantially affected by this proposal?	We expect that NZAS will be substantially affected (positively). See assessment of excepted costs and benefits above. We consider it possible that other RCPD customers may benefit from this provision though have not canvassed our customers.
Identify whether you consider (providing supporting rationale): (i) your proposed change to be technical and non-controversial; or (ii) there is widespread support for your proposed change among the people likely to be affected; or (iii) there has been adequate prior consultation so that all relevant views have been considered.	(i) Technical and non-controversial We consider that the change may be technical and/or non-controversial however have not had the opportunity to consult out customers at this point. As identified above, this proposal is likely to be net beneficial but may contribute to increased investment in distribution networks. (ii) Widespread support We have not had the opportunity to consult our customers on this proposal so cannot provide evidence of support or otherwise for this proposal. (iii) Adequacy of prior consultation We have not had the opportunity to consult our customers on this proposal so cannot provide evidence of support or otherwise for this proposal.
Why this is your proposed option?	We consider that this proposal is likely to have net benefits. It is one of three discrete proposals that, to some extent, overlap.
Any other relevant information you would like the Authority to consider.	Refer to Attachment B: TPM Operational Review Background and Supporting Material 13 February 2015, and all other accompanying material.

Assessment of alternative options

Please list and describe any alternative means of achieving the objective you have described for your proposal. For each alternative, please provide the information in the table below (i.e. repeat this table below for each alternative). The list of alternatives should include both regulatory (i.e. Code amendments) and non-regulatory options (e.g. education, information, voluntary

compliance). If you have a preferred option please identify it and explain why it is your preferred option.

The alternatives described below are the same as those described by our proposal of February 13th 2015, Attachment A3 i.e. these are alternatives to the problem that NZAS is deterred from increasing production in the summer because of its effect on RCPD peak (and that increased production could cause unproductive volatility in RCPD charges for other LSI consumers).

Option 1: Amalgamate RCPD regions

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Amalgamate UNI, LNI and LSI RCPD regions into a single RCPD region.
The extent to which the objective of your proposal would be promoted or achieved by this option.	The objective would be promoted (NZAS summer production would be insufficient to shift the peaks in an amalgamated region reducing the deterrent to increased production and the risk of large swings for LSI customers).
Who is likely to be substantially affected by this option?	All interconnection customers.
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	<u>Costs</u> Implementation costs for this option would be more material for Transpower and, we expect, those who respond to RCPD price signals than for the preferred option. We are mindful of the Authority's aim of making transmission charges more cost reflective and have sought to make proposals that are consistent with this aim. Similarly we recognise concerns expressed by stakeholders in relation to this option and agree with some of these. For example: • Proceeding with this proposal at this point, while outcomes of the Authority's review are unknown (but pending), could result in too much change too quickly that may create a perception of instability. • Amalgamating regions would disadvantage the remaining regions (in this case the USI) relative to the amalgamated region which would enjoy a larger diversity benefit. For example, a weather front may move up the island progressively rolling through a large region but may encompass a smaller region (causing a coincident peak as demand spikes due to cold weather). • This proposal is likely to make the allocation of interconnection costs between the North and South Islands less cost reflective⁵. <u>Benefits</u> The benefits are similar to those of the preferred option (NZAS could increase production over summer without incurring a disproportionate increase in transmission charges and without causing volatility in transmission charges for other LSI customers).

⁵ Current allocations to between the North and South Islands, under the RCPD charge, are 66% and 34% respectively. We have compared the current allocation of interconnection charges to each Island to the book value of the grid in each Island. On this analysis we estimate the book value of the North Island grid represents 79% of interconnection assets and the South Island 21%. We have also compared the allocation of interconnection charges to each Island to the estimated replacement cost of the grid in each Island. On this analysis we estimate the estimated replacement cost of the North Island grid represents 73% of interconnection assets and the South Island 27%.

	This option would also provide a pathway to more targeted regions in future, though the size of this benefit is unclear (particularly in light of the Authority's ongoing review) and may be available through other means.
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Option 2: Separate NZAS region

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	Create a fifth region with NZAS as the only demand; with its own RCPD and ‘N’.																											
The extent to which the objective of your proposal would be promoted or achieved by this option.	This option would address the LSI stability problem by isolating NZAS from the rest of LSI. It would, however, only partially address LSI and NZAS issue of attracting RCPD charges to its summer production. We have undertaken internal analysis on having NZAS as its own region at different N's and confirm that this arrangement would still create an undesirable increase in its charges under summer production. Table 1 NZAS charges under different region and N scenarios <table><tr><td></td><td>Scenario</td><td>NZAS charge \$M</td></tr><tr><td>1</td><td>Status quo (100 peaks in LSI)</td><td>63.0</td></tr><tr><td>2</td><td>Status quo + 64MW Nov – April</td><td>69.5</td></tr><tr><td>3</td><td>LSI, LNI and UNI combined + 64MW Nov – April</td><td>63.0</td></tr><tr><td>4</td><td>Disregard Nov – April production between 572 and 636MW</td><td>63.0</td></tr><tr><td>5</td><td>Own region, N = 17520</td><td>62.8</td></tr><tr><td>6</td><td>Own region , N = 17520 + 64MW Nov – April</td><td>65.9</td></tr><tr><td>7</td><td>Own region, N = 100</td><td>63.9</td></tr><tr><td>8</td><td>Own region, N = 100, disregard Nov – April production between 572 and 636MW</td><td>63.5</td></tr></table>		Scenario	NZAS charge \$M	1	Status quo (100 peaks in LSI)	63.0	2	Status quo + 64MW Nov – April	69.5	3	LSI, LNI and UNI combined + 64MW Nov – April	63.0	4	Disregard Nov – April production between 572 and 636MW	63.0	5	Own region, N = 17520	62.8	6	Own region , N = 17520 + 64MW Nov – April	65.9	7	Own region, N = 100	63.9	8	Own region, N = 100, disregard Nov – April production between 572 and 636MW	63.5
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Who is likely to be substantially affected by this option?	All LSI interconnection customers.																											
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	This option could provide equivalent benefits under specific conditions (scenario 8 in table 1) and would entail additional minor administrative cost.																											

ⁱ **Section 15: Objective of Authority**

The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Proposal to amend the Electricity Industry Participation Code 2010

Send to info@ea.govt.nz or fax to 04 4608879

This form is to propose:

- ☐ An amendment to an existing clause in the Electricity Industry Participation Code 2010; or
☐ A new clause in the Electricity Industry Participation Code 2010.

Please complete as many sections of this form as possible and email or fax it to the above number/email address. The more information you include in your proposal, the faster your proposal will be able to be assessed/progressed.

Proposer's details

Name:	Ross Parry
Position in company:	Planning and Regulatory Manager
Company:	Transpower
Telephone:	04 590 6862
Email address:	ross.parry@transpower.co.nz
Signature:	
Date:	13 February 2015

The proposal / preferred option

Suggested proposal name (please keep it short)	TPM Operational Review: Reverse flows pricing impacts
State the objective of your proposal.	The objective of the proposal is to improve efficiency by providing a mechanism to address over-charging when a has correctly identified a reverse flow event caused by tying GXPs (aka paralleling).
Does the proposal relate to an existing Code clause? If yes, please state the full clause reference.	Yes, clause 3 and clause 34 of Schedule 12.4.

Describe the specific amendment(s) that you propose be made to the Code <i>OR</i> attach a draft of the proposed Code amendment (optional). Note the Code drafting manual provides guidance on drafting.0	We propose to introduce a specific provision which creates an obligation on Transpower – following Customer notification and the correct identification of a reverse flow situation under a GXP tie - to adjust AMD, AMI, RCPD and SIMI quantities (as relevant) to neutralise the impact of the reverse flow.
Identify how your proposal would support the Authority's objective, as set out in section 15 of the Electricity Industry Act 2010 (Act)ⁱ, specifically addressing the competition, reliability and efficiency dimensions of the objective.	The TPM requires AMD, AMI and RCPD to be calculated for each (single) connection location. There is no specific provision that caters for a situation where a customer's assets are simultaneously connected to the grid at more than one location. This means a standard calculation of AMD, AMI and RCPD would produce the following result in situations where electricity has flowed out of the grid, into an distributor's network, and then back into the grid at another connection location: - the "offtake" would include a quantity of electricity that flowed back into the grid from the distributor's assets and was not used by the distributor as genuine offtake - the "injection" would reflect electricity that had merely flowed through the distributor's assets and was not a genuine injection from the distributor's assets into the grid.
Which of the purposes listed in section 32(1) of the Act does your proposal most closely relate to?	The consequence of this is that the distributor would pay higher interconnection charges than that based on consumption on its network during peak periods, and would be over-charged relative to other customers. This would be allocatively inefficient signalling consumption should be lower in that network area relative to other networks. The proposal would support the statutory objective (section 32(1)(c)) by addressing the over-charging risk described above in circumstances where paralleling creates a reverse flow situation.
Identify whether you consider your proposed change to be urgent, providing supporting rationale.	The Code Amendment Proposal has not been made under urgency, The timing of the proposals was discussed and agreed with the Authority to enable the Commission to make a decision (indicative timing 1 June 2015). If this timing is missed there would be a delay by the time it takes the Authority took to consider the matter. We do not think a short delay is a material matter.
Please set out the expected costs and benefits of your proposal. These should include your assessment of the direct cost to develop and implement the proposed Code amendment, and the consequential costs and benefits as a result of the amendments, to all affected parties.	Parties that commented agreed the nature and the size of the issue is such that quantified CBA is unnecessary to establish the changes would be to the long-term benefit of consumers: Contact Energy, Genesis Energy, Meridian and Mighty River Power. Transpower does not anticipate there would be any material costs to developing and implementing the Code amendment. The benefits would be: - Providing confidence to customers that the risk of over-charging due to reverse flows from paralleling would be removed when identified by customers (and not at the discretion of Transpower). This reduces a potential impediment to s investing in assets prone to reverse flows. - Replaces the process of an EOC application and consideration, although the benefits are minor as the the customer would still need to notify and

	apply to Transpower for data adjustments from specifying the reverse flow situation.
Who is likely to be substantially affected by this proposal?	No party is substantially affected by the proposal although DISTRIBUTORS that can tie GXPs e.g. Vector and Orion are somewhat affected.
Identify whether you consider (providing supporting rationale): (i) your proposed change to be technical and non-controversial; or (ii) there is widespread support for your proposed change among the people likely to be affected; or (iii) there has been adequate prior consultation so that all relevant views have been considered.	(i) Technical and non-controversial The proposal is technical and non-controversial. Parties agreed this was an appropriate technical/operational matter to be addressed by Transpower e.g. Meridian recommended “any changes be limited to operational and technical matters such as maintenance costs and paralleling”.¹ (ii) Widespread support There is widespread support. The proposal was expressly supported by Contact Energy, ENA, Genesis Energy, Meridian (“so long as the circumstances are genuine”), Mighty River Power, Norske Skog, NorthPower, Powerco, Unison, Vector and WEL. WEL and Norske Skog's support was subject to materiality. (iii) Adequacy of prior consultation We consider there has been comprehensive (more than adequate) consultation on our Code Amendment Proposals, and all relevant views have been considered. This has consisted of: • Testing with the Authority and a subset of our customers and interested parties whether we should undertake a TPM Operational Review then notifying stakeholders of review, and maintaining details/updates on our website. • Issuing an Initial Consultation Paper which invited comments on our proposed TPM Operational Review process, our initial assessment of the potential problems with the TPM and on options we identified for addressing these problems. • Issuing an Update Paper summarising key themes from submissions and briefly sharing our views on these themes, responding to a small number of specific issues, and outlining the development of our thinking and how, in light of submissions, we intended to proceed. • Issuing a Second Consultation Paper which identified and analysed options for improving the TPM, set out our proposals, and detailed our responses to submissions on the Initial Consultation Paper and how we took these submissions into account. • Undertaking a series of Workshops (Auckland, Christchurch and Wellington) as part of the consultation on the Second Consultation Paper and a series of bilateral meetings with the Authority, customers and other interested parties. The substantial majority of submitters have supported our consultation process.
Why this is your proposed	We consider this proposed option:

¹ Meridian, Transpower TPM operational review: Second consultation paper, 19 December 2014, page 1.

option?	• Would address an omission in the current TPM. • Is more targeted with greater certainty (than the alternative EOC process which is presently being used) which will mean this issue is not a factor for distributors when deciding whether to invest for n-1 security by tying GXPs • This option would address the paralleling issue in full where instances of paralleling are correctly identified and substantiated by the customer and ourselves. • has widespread support.
Any other relevant information you would like the Authority to consider.	Refer TPM Operational Review: Background and Supporting Information, 13 February 2015 and all other accompanying material.

Assessment of alternative options

Please list and describe any alternative means of achieving the objective you have described for your proposal. For each alternative, please provide the information in the table below (i.e. repeat this table below for each alternative). The list of alternatives should include both regulatory (i.e. Code amendments) and non-regulatory options (e.g. education, information, voluntary compliance). If you have a preferred option please identify it and explain why it is your preferred option.

Option 1: Use existing EOC process

Brief description of an alternative means of achieving the objective. Note if this is your preferred option.	A data adjustment to correct the effect of this distortion of pricing input data could be made under the clause 34(2) provision for exceptional operating circumstance (EOC).
The extent to which the objective of your proposal would be promoted or achieved by this option.	This option is able to remedy distortions to pricing inputs due to the reverse flow issue.
Who is likely to be substantially affected by this option?	No party is substantially affected by the proposal although distributors that can tie GXPs e.g. Vector and Orion are somewhat affected.
The expected costs and benefits of this option, including direct costs to develop it, and consequential costs and benefits to all affected parties.	Parties that commented agreed that the nature and the size of the paralleling issue is such that quantified CBA is unnecessary to establish the changes would be to the long-term benefit of consumers: Contact Energy, Genesis Energy, Meridian and Mighty River Power. The costs of this option are minor: • Requirement for an EOC application • Potential uncertainty of outcome as Transpower's response to EOC applications is discretionary. The benefit is that no TPM change would be required (again minor).

ⁱ **Section 15: Objective of Authority**

The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.