Submissions

Electricity Authority

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Consultation on Transmission Pricing Methodology

Thank you for the opportunity to submit on this important topic.

No part of this submission is confidential and I am happy for all of it to be published.

This submission fully supports the reform of transmission pricing but notes:

- The cost benefit analysis has a small, non-material, flaw wrt the assumption that nodal pricing always provides an efficient transmission use signal;
- This flaw does not undermine the overall proposal;
- Showing possible nodal pricing 'inefficiencies' do not materially undermine the TPM proposal would make the TPM more durable should such 'inefficient' prices arise in future.

I note that some of these topics may be covered in your CBA Workshop in September. I apologise I am unable to attend that workshop and provide this submission in advance of the workshop.

Fully Support TPM Proposal

I fully support the TPM proposal and want to take the opportunity to congratulate the Electricity Authority (EA) on achieving a significant industry milestone on issuing this latest TPM Issues paper. It represents decades of industry work and the balanced and solid approach taken by the EA is reflected in this paper. It represents a solid base for the industry to (finally) move forward on this issue.

Although my submission identifies one minor weakness in the analysis, regarding the assumed efficiency of nodal price signals, I believe the overall conclusion is still robust. The durability of the proposal might be further enhanced by acknowledging situations in which nodal price signals might be slightly inefficient.

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Economic Analysis Assumes Nodal Pricing Always Efficient

The cost benefit analysis supporting the TPM proposal is generally robust and thorough. However, one area where it may not be quite complete is the assumption that nodal prices are always efficient regarding transmission usage. NZ market experience suggests situations can arise where locational signals are slightly efficient. In particular when transmission constraints are close to binding and the high prices spread to net generation areas. Thus sending a signal to inefficiently reduce demand, or increase generation investment, in counterproductive manner.

Nodal Price Signals Not Always Be Perfectly Efficient

Market experience to date suggests generators may have incentives to 'manage' constraint prices (the price difference across a constraint excluding the marginal losses component of the price) to maximise profit from a net generation area. This is possible even without any anti-competitive behaviour or market manipulation. They can do so by reducing the quantities offered to just avoid the constraint binding, and thus enjoy higher (than would otherwise be the case) prices in the net generation (or sending) area. This is explained further below.

Generators May Manage Price Signals Across Constraints

Generation offers are a repeat game. So even without collusion or any anti-competitive behaviour generators can learn to structure their offers to avoid transmission constraints binding and large price separation across constraints. This behaviour has been observed in the past and may materialise again. And in some situations, depending on overall hedge positions (energy and transmission hedges, including retail ownership hedges) and desired future positions, such behaviour could be profit maximising.

Slightly Inefficient Price Signals if Generators Manage Prices Across Constraints

For example if we were approaching a time when transmission investment might be needed high prices might be expected to arise in a net demand region. And such prices would be efficient. But generators in a net sending region might also want to receive these high prices and have incentives to avoid forcing the transmission constraint to bind and a high price separation to occur, with resulting much lower prices in the net generation region. In such a situation through repeat trial and error they may learn how to structure their offers to reduce the frequency of the constraint binding, or at least minimise the price difference when it did bind.

In this situation the demand within the net generation region might be subject to slightly inefficient price signals. I.e. Prices that signalled a need to reduce demand (in the net generation region) beyond what might be efficient.

Impact is Minor and Does Not Undermine TPM Proposal

I suggest the possibility of such 'inefficient' nodal price signals do not undermine the TPM proposal because:

- They occur relatively infrequently (only when constraints bind, which in itself may be limited by new investment (generation or transmission, or demand-side);
- They only affect a small proportion of demand; and
- The incentives to do so may be constrained by generators different commercial arrangements.

Regards

Neil Walbran

Managing Director

Response to specific consultation questions

Chapter 3

I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines?

Overall I support them, as they stand, and congratulate the Authority on getting to this point. I think they strike the right balance between efficiency and relatively low implementation and operating costs.

Chapter 4

I.3 Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?

Overall it does provide a reasonable estimate. However, it could be slightly improved by being clearer about the limitations of the assumption around nodal prices always providing an efficient signal for usage either side of a constraint. As outlined above there may be circumstances where generators could manage prices on the sending end to increase above local short run marginal cost. That is to minimise the constraint price. This would not imply any anticompetitive behaviour.

Also the existence of this possible ability to manage constraint prices does not materially undermine the CBA because:

- They occur relatively infrequently (only when constraints bind, which in itself may be limited by new investment (generation or transmission, or demand-side);
- They only affect a small proportion of demand; and
- The incentives to do so may be constrained by generators different commercial arrangements.

The durability of the proposal may be enhanced if the Authority were to acknowledge this limitation, and show the CBA conclusions are robust even in the face of this limitation.

I.4 Do you have any comments on the matters covered in chapter 4?

No further comments;

Chapter 6

I.5 How long should Transpower have to complete its development of the TPM and why?

The timeframe proposed by the Authority seems reasonable as it has taken into account Transpower's feedback and external advice.

I.6 What checkpoints (if any) should the Authority set in the TPM development process?

No comments.

I.7 How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

No comments.

I.8 In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

No comments.

Appendix A
I.9 What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

No comments.

Appendix B
General matters
I.10 Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?
No comments.

Connection charge
I.11 Should the current guidelines on connection charges be largely retained or are changes required?

No comments.

I.12 Should first-mover disadvantage be addressed in the TPM, and if so, how?
No comments.

Benefit-based charge
I.13 Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

Yes, as outlined in the proposal it will encourage better information disclosure during the consultation process on proposed grid investments.

I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how?

I support the proposal to recover some via a benefit based charge. I agree doing so increases the durability of the proposed arrangements, by reducing incentives to constantly relitigate the TPM.

Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

Yes, I support the proposal to recover the indentified past investments through a benefit based charge. It seems to strike the right balance between fairness and pragmatism, including minimising transaction costs.

I.15 Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

Ut would be good to get greater clarity on why NAaN was excluded. The explanation that 'it showed no net private benefit' does not seem to fully justify its exclusion as it could still be of less negative benefit to some parties than others.

I.16 How should the covered cost of the investment be defined?

The depreciated costs, as proposed by the Authority seems a reasonable approach.

I.17 How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments?

No comments.

How much discretion should Transpower have to determine the method?

No comments.

I.18 Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

No comments.

I.19 Should the guidelines distinguish between high-value and low-value investments?

No comments.

I.20 If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

No comments.

I.21 What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

No comments.

I.22 What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

No comments.

I.23 How should the costs of the investments that are not covered by the benefit-based charge be allocated?

No comments.

I.24 Should charges be revised if there has been a substantial and sustained change in grid use?

No comments.

If so, what threshold would be appropriate to define such an event?

No comments.

I.25 Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

No comments.

I.26 Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge?
No comments.

What are your views on the proposed reassignment provisions?
No comments.

Residual charge
I.27 Should the guidelines provide for a single residual charge or multiple residual charges?

No comments.

I.28 Should any remaining MAR be recovered through a fixed residual charge?

No comments.

Should the residual charge be allocated based on a customer's historical electricity demand?

No comments.

I.29 Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

No comments.

I.30 If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

No comments.

I.31 Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

No comments.

I.32 If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

No comments.

I.33 Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

No comments.

I.34 Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

No comments.

I.35 Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

No comments.

I.36 Should the residual charge apply to both generation and load customers, or only to load customers?

No comments.

Other

I.37 Are the proposed provisions relating to adjustments appropriate?

No comments.

I.38 Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?

No comments.

I.39 Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?

No comments.

I.40 Should the price cap be specified as a percentage of electricity bills or in some other way?

No comments.

I.41 Should the price cap apply only to load customers, or to generators as well?

No comments.

I.42 How should the price cap be funded?

No comments.

I.43 Are the proposed additional components appropriate?

No comments.

If not, what changes should be made?

No comments.

I.44 Should the guidelines include a peak charge?

No comments.

If so, should it be a core component of the proposal or an additional component?

No comments.

I.45 Should the peak charge be applied only where the grid would otherwise be congested?

No comments.

I.46 Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

No comments.

I.47 Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

No comments.

I.48 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?
No comments.

Appendix C
I.49 Do you have any comments on the matters covered in this appendix C?
No comments.

Appendix D
I.50 Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?

No comments.

I.51 Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

No comments.

I.52 Do you agree with the conclusions of appendix D?

No comments.

I.53 Do you have any comments on the matters covered in this appendix D?

No comments.

Appendix E
I.54 Do you agree with the conclusions we draw from Transpower’s report *The role of peak pricing for transmission*?

No comments.

I.55 Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

Yes, even with the limitations of nodal prices, as noted above, they are still the best signal. And it needs to be remembered that there is no perfect signal.

I.56 Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

Yes.

I.57 Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

I believe they should be. It will be up to the Authority to ensure they are. This is in spite of the know limitations of nodal prices, as outlined above. Alternative approaches run a high risk of doing more harm than good. The law of unintended consequences comes to mind.

I.58 Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

Yes.

I.59 Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

Yes, no other options need to be considered.

I.60 Do you have any comments on the matters covered in this appendix E?
No comments.

Appendix F
I.61 Should LCE be allocated to the specific investments to which it relates?

No comments.

If not, how should it be allocated?

No comments.

I.62 Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal?

No comments.

Would the resulting code provisions in relation to ACOT be efficient?

No comments.

I.63 Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty?

No comments.

If not, do you think it can be modified so as to ensure uncertainty is reduced?

No comments.

If so, how?

No comments.

I.64 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

No comments.

Appendix G
I.65 Do you have any comments on the matters covered in this appendix G?

No comments.

Appendix H
I.66 When commenting on details of the modelling using vSPD to propose the benefit allocation to recent major investments and the impacts modelling, please consider responding to these questions:
(a) Over what period should we undertake the vSPD modelling?

No comments.

(b) Should the vSPD modelling adopt a fixed VPO or a variable VPO?

No comments.

In either case, what is the appropriate level of the VPO?

No comments.

(c) Do you agree with the approach we have taken to net distributed generation?

No comments.

Do you agree with the application of our netting policy for particular generator(s)?

No comments.

If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.

No comments.

(d) Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted?
No comments.

If so, please provide reasoning/quantitative calculations.

I.67 In addition to the specific questions above, do you have any other comments on the matters covered in Chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).
No comments.