Orion

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Electricity Authority
Wellington
by email: submissions@ea.govt.nz

SUBMISSION ON TRANSMISSION PRICING REVIEW 2019 ISSUES PAPER SUPPLEMENTARY CONSULTATION

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Transmission pricing methodology: 2019 issues paper – Supplementary consultation" (the **paper**) released by the Authority on 11 February 2020.

2 We note that we raised substantive issues in response to the 2019 consultation paper, and we hoped that the Authority would take the opportunity to make further progress in these areas. We are concerned that the supplementary consultation might draw attention away from issues that, for us, are more important.

3 The issues of concern which we raised in our previous submission, and, which we ask the Authority to address, are:

3.1 fundamental issues with the cost benefit analysis (CBA),

3.2 contradictions with the revised distribution pricing principles,

3.3 inappropriate reliance on nodal pricing to influence investment,

3.4 inappropriate use of anytime maximum demand to establish the initial residual cost allocation, and

3.5 the proposed application of an *additional* peak charge in areas where transmission customers already respond in a way that reduces Transpower's costs.

4 We note the Authority's indication that further stakeholder engagement may still occur and urge the Authority to address these issues.

5 In terms of the issues raised in this supplementary consultation, we comment as follows.

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Using depreciated historic cost for benefit based charges

6 We would prefer an indexed historic cost approach so that charges remain level (in real terms), because this would:

6.1 better reflect the provision of a service which does not diminish over time (so the charges should not diminish), and

6.2 avoids the saw-tooth volatility in charges when the asset is replaced at the end of its life.

7 However, we accept that a depreciated historic cost provides better alignment with the existing charging (and proposed residual charges), better alignment with the Transpower's price regulation (thereby avoiding distortions to the residual charge) and also helps address stranding risk (with a front loaded recovery).

8 While not taking a position on which should be used, we do support the flexibility for Transpower to propose an alternative method in specific cases where that might better meet the Authority's statutory objective.

10 year cap on benefit based charges following closure

9 The Authority has proposed that a transmission customer be released from charges under a benefits based allocation 10 years after the commissioning date of the grid investment, in the event that the customer elects to close its plant.

10 In reality, this provision is only likely to be an option for direct connect customers, and not for EDBs. We understand that the charges avoided would instead fall to the remaining pool of transmission customers, meaning that EDB's carry some investment risk for these private companies. In some situations, the benefits based allocation may mean that the charges instead fall to a relatively small remaining group of customers that share the benefit of the grid investment, and may even fall to a single other customer.

11 We accept that there is no easy solution to this situation, and the Authority has attempted to balance the interests of the parties with the proposed 10 year minimum term. However, once that minimum term has been reached, the transmission customer has a standing and immediate exit strategy available to them, and one which might have a significant impact on the charges to another transmission customer that shares in the allocation (with effectively no notice).

12 We instead support the inclusion of a residual charge at the point of closure that reflects a calculation of the present value of future benefit based charges had the closure not occurred.

13 A second best alternative to this, which would still provide more certainty and a window for mitigating actions for other customers, would be to augment the minimum 10 year term with a 3 year minimum charge period. That is, once 7 years has been reached, and thereafter, charges would remain payable for 3 years after any plant closure.

Updating the residual charge allocation

14 The Authority proposed that the initial allocation of residual charges be based on a single measure of historical maximum demand. To reflect changes that occur over time, the Authority is now proposing that this initial allocation be updated based on changes in energy volumes (with averaging and a lag).

15 We agree that a mechanism to adjust the relative magnitude of the residual change is desirable. However, we consider that the use of changes in energy volume as a driver for this update will create the very distortionary incentives that the Authority is trying to avoid. Albeit with a delay, each transmission customer will be aware that reducing volumes (for example, by installing photovoltaics, as many direct connect customers are considering) will garner an additional benefit of reduced residual charges, over and above the actual economic benefits of that investment. This will lead to inefficient investment at the expense of other transmission customers.

16 We also note that the Authority's main aversion to the use of maximum demand as a mechanism to update the allocation is that "a customer could adjust this at low cost relative to other measures". This statement appears to fundamentally undermine the very basis for the TPM proposals – the Authority's cost benefit analysis (which we do not agree with) suggests there is a very significant cost in adjusting and reducing maximum demand.

17 Regardless, we suggest that if a demand measure is appropriate for the initial allocation, then it is also appropriate for the ongoing update. Building on our suggestion in our previous submission, we suggest:

17.1 basing and updating the allocation on a measure of peak demand averaged over the top (say) 500 hours, as this extended duration significantly limits the ability for inefficient response, and

17.2 measuring this peak demand over balancing areas, rather than at individual grid exits, in order to avoid load being represented twice when it is switched between supply points

Prudent discount for charges above standalone cost

18 The Authority has proposed that the prudent discount be extended to include hypothetical assessment of standalone costs where duplication is not technically feasible. This is proposed as a mechanism to address inefficient closure, and the Authority concludes that it would derive net benefits because a successful application would avoid an inefficient disconnection.

19 In our view, the link between a customer's desire to pay less and a decision to close is not absolute. Making the assumption that, in the absence of a successful application, a closure would occur, is an aspect of the information asymmetry that led the Authority to withdraw the previous prudent discount policy that directly addressed the threat of closure.

20 We are also concerned that the provision of a discount for direct connect customers will shift the cost burden to distribution businesses, and on to their customers, who do not have access to the same relief.

21 We consider that the inclusion of a hypothetical bypass assessment provides too much latitude to manipulate the assessment, ignoring the real world restrictions of the environment in which Transpower operates. We submit that the prudent discount provision should be limited to situations where bypass is technically feasible and genuinely workable.

Concluding remarks

22 Thank you for the opportunity to make this submission. Orion does not consider that any part of this submission is confidential. If you have any questions please contact Alex Nisbet (Pricing Manager) on 03 363 9737 or alex.nisbet@oriongroup.co.nz.

Yours sincerely

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