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Submissions
Electricity Authority
By email to: submissions@ea.govt.nz

CONSULTATION PAPER- TRANSMISSION PRICE REVIEW
WINSTONE PULP INTERNATIONAL LIMITED'S SUBMISSION

This is Winstone Pulp International Limited's (WPI) submission on the Electricity Authority's paper "Transmission Price Review, Consultation Paper, dated 23rd July 2019.

Our submission focuses on the issues of highest importance to WPI, that are:

- Improving transmission pricing so that future investments are more efficient, and their costs are appropriately allocated to the beneficiaries.
- Achieving a pricing regime that provides a reasonable balance between preventing avoidance behaviour and allowing annual charges to be adjusted to account for underlying load growth and genuine changes in the requirements of consumers.
- Achieving an allocation of costs between different consumer groups and regions, generators and Transpower that is sustainable in the long-term.

Our responses to questions in the consultation paper that relate to our focus issues are provided in the attached table. WPI's silence on other EA's questions only indicate that we have not focused on those issues.

We also support the Major Electricity Users Group's (MEUG) separate submission on this consultation paper.

Thank you for the opportunity to make this submission.
Yours sincerely

P Saunders.

Paul Saunders
General Manager Operations

Authority's suggested question and page reference in consultation paper	**WPI submission**
Chapter 3	
I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines (page 19)	We generally accept the Authority's problem definition and the proposed principles for the revised transmission pricing methodology (TPM). However, we do have concerns regarding the detailed application of these principles for achieving a practical and fair methodology. Our key concerns are summarised below. We do not agree that the cost recovery methodology for the existing HVDC assets from all South Island Generators needs to be changed. We view the status quo as workable and not detracting from the overall outcomes that may be achieved by the proposed methodology. It is not clear to us why the Authority considers it important to recover the historic HVDC investments through the benefit-based charge and a positive CBA for this, as a standalone change, has not been demonstrated. However, we do agree that other historic HVAC interconnection investments and all future HVDC/AC investments should be recovered through a benefit-based charge. We do not agree with the proposal to pre-fix and semi-permanently lock-in Residual Charges paid by existing grid customers based on their historic AMD, i.e. with no provision for these to be adjusted each year to account for gradual changes to generation and demand patterns. We do not agree with the Authority's rationale that pre-determined fixed residual charges are needed to prevent avoidance behaviour. We are not aware of evidence suggesting that a rolling average AMD approach (say by using a two-year rolling average) would open the door for material avoidance behaviour. We think that a rolling average AMD would provide a fairer and more pragmatic balance between preventing avoidance and allowing for annual adjustments to account for underlying load growth and genuine changes in the requirements of large electricity users. We note that the use of a rolling average AMD should strengthen pricing signals for managing peak grid demand, and this could therefore also mitigate the need for a Transitional Peak Charge. We also think that the use of AMD based on a single trading period at the GXP is unfair to Direct Connects (and potentially large embedded users) because our peak demand would not be reduced by the load diversity that is available to end users within distribution networks. See further comments in I.29

Authority’s suggested question and page reference in consultation paper	**WPI submission**
Appendix B	
Benefit-based charge	
I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge and, if so how? Which pre 2019 investments should be recovered in this manner? In particular’ do you consider the cost of some past investments be recovered through a benefit-based charge?	We do not agree that the cost recovery methodology for the existing HVDC assets from South Island Generators should be changed (as noted in I.2). Otherwise we agree that the cost of major pre-2019 interconnection investments should be recovered through a benefit-based charge. See also I.23.
I.17 How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method? (page 128)	Subject to finalising the list of historic assets to be covered by the benefit-based charge, we see no reason why the percentage allocations should not be finalised by the Authority and included in the TPM guidelines. This would allow Transpower to focus on the methodology to be applied for future grid investments rather than repeating work on allocating the cost of historic investments already done by the Authority.
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)? (page 139)	We agree with the Authority’s preferred approach for cost allocation where the estimated energy cost savings using vSPD modelling are positive and can be quantified using this methodology. The alternative is inferior because it relies largely on judgements and is more likely to create unfair boundary issues.
I.23 How should the costs of the investments that are not covered by the benefit-based charge be allocated? (page 140)	We suggest that the costs of the three additional existing major investments, as identified by the Authority (Ref #B148), initially be allocated using the bespoke methodology proposed by the Authority. With 5-yearly reviews and forecast grid demand increases, these costs could eventually be allocated using the standard vSPD methodology for pre-2019 major assets.
I.24 Should charges be revised if there has been a substantial and sustained change in grid	For fairness, we think all benefit-based charges covering historic investments should be re-estimated and reset every 5 years to account for substantial changes in grid use and for gradual load pattern changes.

Authority's suggested question and page reference in consultation paper	**WPI submission**
use? If so, what threshold would be appropriate to define such an event? (page 145)	
I.25 Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long? (page 146)	No. With the Authority's proposal for a simplified methodology, we do not think a delay is needed.
Residual charge	
I.29 Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach? (page 153)	We agree that a form of AMD is a more suitable allocator than kWh, subject to addressing the concerns we have raised in I.2. To address our concern about the inconsistent treatment of Directly Connects compared to consumers within distribution networks, it would be fairer to either: • Allocate residual charges based on AMD at the ICP level; or • Base the effective AMD for Direct Connects on an average of more than one trading period, with the number of trading periods used (N) set to provide a similar outcome for Direct Connects compared to users imbedded in distribution networks. We think that one of the above modified AMD approaches, would address some of the potential drawbacks with AMD that the Authority discusses in the consultation paper.
I.31 Should demand be measured using a net load or gross load approach for the allocation of the residual charge? (page 154)	We agree with the Authority's rationale for using gross load as the preferred allocator.
I.34 Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines? (page 155)	We don't think Residual Charges can or should be allocated until the Authority has approved the scope and nature of any Additional Components that will be included in the detailed methodology.
I.35 Should a customer's residual charge allocation be adjusted to account for a substantial	Yes - see previous comments in I.2

Authority's suggested question and page reference in consultation paper	**WPI submission**
change to demand due to factors over which it has no control? (page 156)	
Other	
I.42 How should the price cap be funded? (page 169)	We think the cap should be funded only by those who would receive material private wealth benefits from the new methodology, i.e. only those who benefit by more than a pre-determined threshold.
I.44 Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component? (page 175)	We are concerned that the pricing signals provide by the proposed TPM may not be enough to manage peak grid congestion and that the proposed guidelines do not provide enough direction to Transpower on this matter. However we think that this risk could be mitigated by using a rolling average AMD to allocate the Residual Charge, by strengthening direct pricing signals to residential consumers (through both time of use energy and distribution pricing) and by enabling the commercial availability of ripple control for grid load shifting at times of congestion.
Appendix E	
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? (page 222)	See I.44
Appendix H	
I 67 Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO? (page 271)	We support the Authority's proposal to use a variable VPO that is based on a maximum 1.2 multiplier. This is a reasonable level and reflects realistic costs for transmission alternatives and potential demand responses. Diesel peakers are not a realistic long-term transmission alternative.