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Electricity Authority
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TRUSTPOWER SUBMISSION: TRANSMISSION PRICING METHODOLOGY: 2019 ISSUES PAPER SUPPLEMENTARY CONSULTATION

1.1. Purpose of consultation

1.1.1 This submission relates to the supplementary consultation the Electricity Authority (**Authority**) is undertaking on elements of the proposed Transmission Pricing Methodology (**TPM**) Guidelines in its 2019 Issues Paper as described in its consultation paper dated 11 February 2020 (**Consultation paper**).

1.1.2 The Consultation paper proposes four refinements to the Authority's earlier TPM proposal.

1.1.3 These are:

a) a change to the method used to set annual benefit-based (**BB**) charges for new (post-2019) transmission investments;

b) a cap to an assessed beneficiary's obligation to pay BB charges in respect of plant that closes down;

c) the inclusion of an adjustment mechanism for the residual charge based on energy use; and

d) a new right for a transmission customer to apply for a prudent discount if it considers its transmission charges would exceed the standalone cost of the transmission services it receives.

1.2. Summary of Trustpower views

1.2.1 For the reasons set out below, Trustpower:

a) does not support the proposed change to the method used to calculate the annual BB charges;

b) agrees that the liability of to pay BB charges in the event of plant closure needs to be addressed but proposes a different solution as we do not think that plant that closes down should have any liability to continue to pay assessed BB charges;

c) supports an adjustment to the residual charge but proposes a different lagging period; and

d) does not agree with the proposed new prudent discount arrangements which have been poorly justified in the Consultation paper.

1.3. Sequencing of response to submissions on the 2019 Issues Paper

1.3.1 We are also concerned about the sequencing of this consultation before stakeholders have received any feedback on their submissions on the more substantive elements of the proposed reform to the TPM Guidelines.

1.3.2 We think it is appropriate for the Authority to respond to stakeholders on matters of substance before seeking further feedback on design details.

1.3.3 It is clear from submissions that this includes feedback on whether the benefits of this reform will exceed its costs and on the risks associated with the removal of a permanent peak demand charge.We, and other stakeholders, have made similar comments about the Authority's processes in previous consultation rounds.

1.3.4 We suspect all stakeholders will find it increasingly difficult to justify the resources spent in engaging in these processes if the Authority's response to its stakeholders on matters of substance is incomplete or excessively delayed.

2.1. Proposed refinement

2.1.1 The total amount of BB charges required for each investment is a fixed amount.

2.1.2 In the Consultation paper the Authority has proposed a change to the time profile which applies to the recovery of BB charges.

2.1.3 Specifically, it proposes to change the basis for recovery of these charges from indexed historic cost (which effectively back loads cost recovery) to depreciated historic cost (which front loads cost recovery).

2.2. Our view

2.2.1 This change will align the annual allocation of costs with the determination of Transpower's annual allowable costs as the Commerce Commission uses depreciated historic when calculating Transpower's revenue requirements.

2.2.2 We can understand why the Commerce Commission would apply a straight line depreciation to a regulated asset base comprising many assets of different ages to determine an aggregate revenue allowance. However this does not make it appropriate for the Authority to use this method for the allocation of BB charges for individual transmission assets.

2.2.3 Our view is that the proposed change moves the Authority *away from* the purpose of service or benefits based pricing. This is because transmission assets are typically built ahead of demand. It follows that there will be more beneficiaries and benefits later in the assets' life once demand has grown.

2.2.4 As we have previously submitted, the valuations used for BB charging should ,as a matter of principle, be based on replacement costs. This reflects the fact that the service provided by transmission assets does not change significantly over time and so it is inappropriate to depreciate the value of assets in assessing the benefits that customers receive from them.

2.2.5 We understood that the implementation of indexed historic cost previously proposed by the Authority was intended to approximate replacement cost – and that the intent of the indexation is to match movements in replacement cost.

2.2.6 We accepted that the use of indexed historic cost was a pragmatic alternative to replacement costs and suggested that this be made clear in the rules around indexation.

2.2.7 We do not support the replacement of an indexed historic cost recovery profile in the context of BB charges as it is not based on the benefits received from the relevant asset.

3.1. Proposed refinement

3.1.1 The TPM Guidelines in the 2019 Issues Paper provide that once a transmission customer has been allocated a share of a BB charge, that share *will not change* except where the guidelines provide otherwise (such as where new large consumers or generators emerge, or plant ownership transfers).[1]

3.1.2 We are not sure how it is proposed to enforce this obligation but we presume that this will be a matter for the TPM development stage.

3.1.3 The current issue relates to plant closures. The Authority recognises that the proposed TPM Guidelines could be inequitable when BB charges are allocated to plant that closes down.

3.1.4 As a consequence it now proposes to cap the BB charges paid by a generator or load that closes down to payment for the first ten years of a new transmission investment only. If a transmission asset is more than ten years old then the BB payment obligation will cease immediately on plant closure.

3.1.5 After the payment obligation ceases, BB charges are reallocated amongst remaining beneficiaries of that asset.

3.2. Rationale for the proposed refinement and our view

3.2.1 We support the Authority's plan to change the current open-ended obligation to pay assessed BB charges but think the cessation of the obligation to pay should apply at plant closure rather than continue for a period of up to ten years.

3.2.2 The Authority's rationale for BB charges is to ensure parties have strong incentives to reveal their future intentions in the transmission planning process, including in relation to plant closures.

3.2.3 We note that some market participants (listed companies) already have continuous disclosure obligations. But perhaps more importantly, plant closures can be the result of any number of market events, technological developments or regulatory changes. There is no reason to assume that these events will be known at the time transmission planning decisions are made.

3.2.4 In our view it is unfair to penalise the owner of a closing plant by requiring it to continue to pay *assessed* BB charges for up to ten years after a new transmission investment was commissioned when it is clearly no longer receiving *any* transmission services in relation to that plant.

3.2.5 The Consultation paper suggests BB payment obligations are similar to take or pay obligations. Our view is that this is not the case of a willing buyer and willing seller of long life assets. The actual investment decision for a new BB asset is made by the Commerce Commission assessing the submissions made to it, not as a result of a commercial negotiation between a willing buyer and a willing seller.

3.2.6 Once the investment has been approved the TPM is activated and payment obligations follow. This means that a party can be allocated costs even if it has submitted that it is not in its own private benefit for an investment to made. Continuing those obligations post-plant closure seems excessively unfair and impracticable.

3.2.7 We also note that BB charges could deter new investment in low emissions technologies if payment obligations continue for up to ten years after plant closure.

[1] See Guidelines 25 and 42-45

4.1. Proposed refinement

4.1.1 The 2019 Issues Paper proposed that gross anytime maximum demand (**AMD**) should be the initial allocator for the residual charge using four year average annual values of gross AMD for the 2014-18 period, with provision for Transpower to update the allocator through an operational review of the TPM. Updates would use gross AMD lagged by ten years (to weaken incentives for parties to game allocations).

4.1.2 The Authority now proposes that the initial AMD-based allocation is automatically adjusted annually based on changes in a four-year rolling average of customers' gross annual energy usage (measured in MWh), lagged by seven years.

4.2. Our view

4.2.1 In our submission on the 2019 Issues Paper we submitted that a *net* rather than *gross* load approach should used as the net approach best reflects the burden that a customer places on network. We remain of this view.

4.2.2 We also noted that:

> *"For the residual charge to be durable it must be capable of evolving with changing circumstances, rather than only in extreme circumstances…Solutions such as a rolling average over multiple years may assist with providing a cost allocation mechanism that evolves with changing circumstances while lessening the likelihood of distortionary responses"*

4.2.3 The proposed refinement achieves this objective. However we suggest that a five year rolling average of customers' net energy with no lag should be used so load sees adjustments more quickly as circumstances change, similar to the present HVDC allocator.

5.1. Current Prudent Discount Policy

5.1.1 The current TPM Guidelines provide:[2]

> *"*A prudent discount policy should be adopted to ensure that inefficient by-pass of the existing grid ***does not occur.*** (emphasis added)

5.1.2 To qualify for a discount under the current TPM an applicant must be able to demonstrate that it is "*technically and operationally feasible, and commercially beneficial*" for it to by-pass the grid.

5.1.3 The rationale for granting a prudent discount in the situation of **technical by-pass** is that it prevents inefficient investment and avoids other transmission users paying higher transmission charges. The assessment in the Authority's 2019 Issues paper that a prudent discount granted in these circumstances is a "win-win" is correct.

5.1.4 We would also add that in our experience the current rules set a tough standard. However we think that this is appropriate as the consequence of granting a prudent discount is that transmission costs are reallocated to other users.

5.2. Authority's prior proposals

5.2.1 In July 2016 the Authority decided to widen the criteria under which prudent discounts could be granted, including to situations where:

a) there is a material risk that the consumer's transmission charges would cause the consumer to close down its plant; or

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[2] Section 18

b) the customer was able to establish that its transmission charges exceed the standalone costs for delivering electricity to it.

5.2.2 These scenarios move beyond the relatively straightforward notion of technical by-pass to encompass concepts of **economic by-pass**.

5.2.3 In these situations, a good deal more judgement is required about whether a discount should be granted and if so, at what level.

5.2.4 Following extensive feedback, the Authority:

a) in its December 2016 consultation paper, scaled back its proposals in relation to the material risk of closure noting the serious information asymmetry issues involved; and

b) in its 2019 Issues paper, removed the right to permit a transmission customer to apply for a prudent discount if its transmission charges exceeded the standalone cost of delivering it electricity

5.2.5 In effect this was a return to the status quo. We agreed with this approach.

5.3. Proposed refinement

5.3.1 However, the Authority now proposes to reinsert the earlier provision, which provided for a pricing relief for a customer who could establish that its transmission charge were higher than the standalone costs of supply, with a few further refinements which take it outside the realm of a technical by-pass.

5.3.2 The Consultation paper indicates that the standalone cost is the cost of supplying a single customer with transmission services. These services include all revelant dimensions including grid reliability, energy security and price considerations.

5.3.3 If the true standalone costs are used then this proposal is a technical by-pass and thus would be already covered by the prudent discount in the 2019 Issues paper.

5.3.4 However, the Authority wants to relax the requirement to prove that bypass is actually possible.The Consultation paper states that[3]:

> *"The current policy and that proposed in the 2019 Issues Paper do not explicitly cover the situation where bypass of the existing network would be a financially viable option in theory, but "other considerations" stand in the way."*

5.3.5 The example given of "other considerations" is the prospect that it would not be possible for Rio Tinto to obtain consent for the construction of a duplicate transmission link through a world heritage site.

5.3.6 In this situation, grid exit cannot occur as the costs of by-pass are infinity, but the Authority appears to agree with Rio Tinto's assertion that a transmission owner in this situation in a workably competitive market would be prepared to offer a price discount based on calculations of the hypothetical costs of standalone supply.

5.3.7 The Authority describes in the Consultation paper two possible methods Transpower could adopt to determine whether a customer's transmission charges are less than its standalone costs.

> *"One approach would be to require a hypothetical business case for grid bypass in favour of alternative supply in which this assumption is made. An alternative approach might be to calculate the replacement cost of the transmission network of a hypothetical efficient grid owner that provides transmission services to the customer making the application and to no other customers. "*

[3] P17

5.3.8 It suggests that the costs of greenfield resource consents should be included in the prudent discount application but the applicant should not also have to prove that those consents would in fact be granted.

5.3.9 At this point the Authority has moved away from its stated objective to discourage inefficient disconnection from the grid and moved back to its previous objective of granting discounts to applicants whom it considers face inequitable charges and/or might be at risks of market exit.

5.4. Rationale for change of view

5.4.1 The trigger for this change of view appears to be the written and oral submissions made by Rio Tinto which have indicated that it:

a) is currently ineligible for a prudent discount as it would never be able to by-pass the grid as "*resource consent would never be given to build a duplicate transmission corridor through pristine wilderness*"[4]

b) has experience"…*in other jurisdictions where a more pragmatic approach is taken to concept of a prudent discount*[5]"; and

c) *"There is a prudent discount regime in the rules in Australia which we have been able to use."*[6]

5.5. Overseas precedent

5.5.1 In terms of overseas precedent, we are not aware of the terms under which Rio Tinto was granted relief from transmission charges in Australia. These agreements are not publicly disclosed.

5.5.2 Under the National Electricity Market (**NEM**) rules there is a discretion for transmission network service providers to provide prudent discounts to prevent a transmission customer "*altering its behaviour to the point of adopting the most attractive alternative*" provided that these changes do not place other transmission customers "*in a worse position than if the discount was not offered*".

5.5.3 If the discount does not meet these tests then there are consequences for the transmission network service provider's own revenue recovery.This ensures that the discount is not larger than than the transmission customer's most attractive alternative.

5.5.4 We acknowledge that the NEM rules contemplate both technical and economic by-pass. In other words, a customer's most attractive alternative might be to shut down.

5.5.5 However, in relation to technical by-pass we do not interpret the NEM rules as allowing the transmission network service providers to grant discounts where there is fact no credible alternative supply option. Our Australian-based consultants have confirmed that this an actual not hypothetical assessment.

5.6. Analysis of proposal and our view

5.6.1 We think the Authority's proposal suffers the same risks as its predecessor namely that applicants would be encouraged to obfuscate their current situation and seek a discount under any number of hypothetical scenarios, resulting in the inefficient deployment of resources both

[4] Rio Tinto submission on the Electricity Authority's 2019 Issues Paper at paragraph 63.
[5] Rio Tinto oral submission on 2 December.
[6] Rio Tinto oral submission on 2 December.

trying to get and determine a discount (including appeals and litigation). This could be a perilous exercise.

5.6.2 If the discount is too high then the decision-maker will needlessly raise prices for all the other electricity consumers (including consumers with their own hardship concerns), and if it is too low (or slow) it will have no effect as the business will exit the market.

5.6.3 Taking all these factors into account we do not believe this proposal has been sufficiently justified to be included as a mandatory component of the TPM Guidelines. However, if this change is to be included we suggest that it be an Additional Component to be included in the TPM entirely at Transpower's discretion.

5.6.4 For the record, we should also share that we are not confident Tiwai Point would qualify for a prudent discount under this policy as we suspect that if you consider the costs of transmission links to Manpouri and presumably Roxburgh-Clyde power stations, as well as the reliability, energy security and market benefits the smelter receives from being part of the interconnected grid system it seems unlikely that its stand alone costs would be less than its current charges.

5.6.5 Members of our team can recall smelter owners resisting both splits of ECNZ and the development of the wholesale market on the basis that the smelter required supply from a single (preferrably government-owned entity) to provide it with a safe and secure energy supply. Against this context it is somewhat surprising it is now claiming it only benefits from access to a small fraction of the core grid.

6.1.1 Each of these four refinements in the Consultation paper have been proposed to address particular inequities of the current proposal:

a) the proposed shift to depreciated historic cost is in part motivated by a concern that in the later years of a transmission asset's life the actual beneficiaries are likely to diverge significantly from the assessed beneficiaries;

b) the proposed cap on liability for BB charges for an owner of plant that closes down recognizes the inequity of being charged for access which a customer cannot use, albeit still enabling 10 years of charges;

c) the new adjustment mechanism for the residual charges recognizes the inequities associated with a fixed AMD calculation; and

d) the expanded prudent discount policy is designed to provide payment relief to some businesses whose charges under the proposed TPM are seen as unfair.

6.1.2 However, the grant of relief in each of these circumstances is likely to trigger additional charges to other customers which are unforeseeable and outside of their control. There are also many other scenarios under the proposed TPM Guidelines which could result in unfairness but where the rules will not permit relief to be granted.

6.1.3 This does not augur well for durability.

For any questions relating to the material in this submission, please contact me or alternatively Fiona Wiseman, Senior Advisor – Strategy and Regulation on 027 549 9330.

Best regards,

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