28 July 2021

Alison Andrew
Chief Executive
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WELLINGTON

By email: Alison.Andrew@transpower.co.nz

Dear Alison

Transpower's proposed TPM

Thank you to you and your team for delivering Transpower's proposed TPM on 30 June 2021. I appreciate the substantial and sustained effort this has required from your team, which in my view is reflected in the quality of the proposed TPM and supporting material. We also appreciate the ongoing constructive engagement approach taken by Transpower staff during the development of the proposed TPM, including the checkpoints process, which ensured the proposed TPM was well understood by the Authority when it was received, and that key choices had already been subject to substantial discussion.

Having received Transpower's proposed TPM, the Authority's task is to decide whether to approve it for the purposes of consultation or refer it back to Transpower for amendment.[1]

The Authority has decided to consider this approve/refer-back decision in parts to allow us and Transpower to make best use of the next period.[2] This letter communicates our approve/refer-back decision in relation to all aspects of the proposed TPM except for Transpower's proposal in respect of the allocation of the benefit-based charge (BBC) – *Decision Part 1.*

The Authority has deferred its decision on whether to accept or refer back Transpower's proposal in respect of the allocation of the BBC – *Decision Part 2* – until later in August 2021. Authority staff are still reviewing Transpower's modelling that implements this aspect of the proposed TPM.

Decision Part 1: The Authority has decided to approve most parts of the proposed TPM for consultation

The Authority has decided to approve most aspects of the proposed TPM that are within the ambit of Decision Part 1 as ready for consultation, as we consider that they adequately conform with the 2020 TPM guidelines and with the Authority's statutory objective. These aspects are set out in the table below, in the left-hand column.

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[1] Electricity Industry Participation Code, clause 12.91: The Authority may refer back the proposed TPM back to Transpower where we consider it does not adequately conform to the requirement of consistency with both the guidelines and the Authority's statutory objective.

[2] As noted in the Terms of Engagement '*2021-07-15 Terms of Engagement TP/EA phase 6*' agreed between the Authority and Transpower dated 15 July 2021.

We have decided not to refer back some issues on which we have previously questioned Transpower's proposed approach.[3] The Authority has accepted, for consultation purposes, Transpower's approach on these matters. We intend to raise such specific issues for stakeholders' consideration as part of the Authority's consultation, to better inform the Authority's ultimate decision, but do not consider that the proposed TPM requires amendment in order to do this.[4] We have not commented further on these aspects of the TPM in this letter.

Decision Part 1: The Authority has decided to refer back specific aspects of the proposed TPM

The Authority has decided to refer back to Transpower six aspects of the proposed TPM within the ambit of Decision Part 1 for further consideration, as we consider that, while we understand Transpower's proposal, they do not adequately conform to the Code requirement of consistency with either the guidelines or the Authority's statutory objective. These aspects are set out in Table 1 below, in the right-hand column, are summarised in this letter and are discussed in more detail in Appendix A.

Table 1: Aspects that are accepted and referred back

The Authority accepts Transpower's TPM proposal in respect of:	**The Authority refers back Transpower's TPM proposal in respect of:**
• Grid Asset Classification (including Additional components A & B) • Connection charge (other than the first mover disadvantage issue (Type 2) and the injection overhead component) • BBC covered cost (other than the overheads issue) • Residual charge (other than the storage issue and adjustments issues discussed in this paper) • Adjustments (other than the two issues discussed in this paper) • Reassignment • Transitional price cap • Prudent Discount Policy (other than the standalone cost prudent discount) • Transpower's decision not to include additional components D to H (including the transitional congestion charge) at this time • Any other aspects of the proposed TPM within the ambit of Decision Part 1, and not explicitly referred back in this letter.	• Overheads (Connection charge: injection overhead component and Benefit-based charge: covered cost) • Connection charge - the first mover disadvantage issue (Type 2) • Application of the residual charge to storage • Adjustments: (i) setting the residual charge for a new entrant (ii) definition of reduction event - residual charge initial allocation • Prudent Discount Policy - the standalone cost prudent discount.

3 For example, we are not referring back the issue around weighting factors between generation and load in the simple method for BBC allocation or the whole-of-life issue in the adjustments provisions.

4 In our consultation paper we also intend to raise some other specific issues on which the Authority wishes to seek input from stakeholders, including for example, Transpower's proposed discretion to reclassify grid assets as connection assets (clause 25 of the proposed TPM) and some other matters relating to the adjustments provisions.

Next steps

The Authority invites Transpower to reconsider the six aspects of the proposed TPM that are being referred back in light of the feedback provided in this letter. As provided in clause 12.91 of the Code, the Authority requests that Transpower provides any revisions to its proposed TPM within 20 working days of the date of this letter, that is, by 25 August 2021.

As the Authority wishes to support Transpower to achieve this timeframe, we would encourage Transpower to focus its response to the Authority on any new reasoning and any new proposed TPM drafting that it decides to provide. We appreciate that, after consideration of the Authority's feedback, Transpower may determine not to revise its proposal for some aspects that have been referred back. For those aspects on which Transpower does not propose to change its position it will be sufficient to simply advise of this view and any new reasons supporting its position. We do not require Transpower to repeat what has previously been stated in the 30 June reasons paper about such matters. However, if Transpower does wish to submit further evidence or respond to the Authority's feedback, we will of course review that response and take it into consideration.

Summary of feedback on matters the Authority is referring back

In this section of the letter we explain the Authority's position on the six matters being referred back and our view on approaches we consider are likely to adequately conform with the guidelines and the Authority's statutory objective. In most cases the Authority's position reflects or builds on feedback we have provided during the checkpoints process. Appendix A sets out a further discussion of alternative approaches to these matters that the Authority considers are likely to be consistent with the TPM guidelines and statutory objectives.

Overheads (BBC: covered cost and Connection charge: injection overhead component)

Under the proposed TPM, a portion of all types of operating expenditure (opex) would be allocated to benefit-based investments (BBIs) and recovered through benefit-based charges (BBCs). This includes overheads; that is, costs relating to central corporate functions like finance and HR, which are not specifically related to particular grid investments.

Transpower has made a related proposal on the connection charge: it has proposed to recover some overheads via the connection charge as an "injection overhead component",[5] but only if the Authority did not accept its allocation of overhead opex to BBIs.

The Authority's view is that both proposals on the recovery of overheads are inconsistent with the guidelines, properly interpreted. The guidelines at clause 15 provide that the covered cost, (ie, the amount which is to be recovered in respect of a BBI) is to include "an amount of opex reasonably attributable to the benefit-based investment…". We consider that this provision should be interpreted having regard to the Authority's intentions, including as indicated elsewhere in the guidelines and in its 2020 decision paper and its 2019 issues paper. The Authority made several statements including in those papers indicating clear intent that overhead costs should be included in the residual charge rather than apportioned to benefit-based investments.[6]

Further, by placing additional costs on generators, the proposed approach could inefficiently discourage investment in generation and so make electricity prices higher than they need to be,

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5 The overhead injection component is a potential component of the connection charge, payable only by generators and intended to recover a portion of overhead opex.

6 For example, see the 2019 Issues paper, paragraph B.73.

imposing costs on consumers in the long term.[7] The proposed approach to the injection overhead component has similar problems as well as also being inconsistent with the wording of the guidelines.

We are referring both matters back as in our view, the proposed approach to these issues is inconsistent with the guidelines and would risk the proposed TPM not adequately conforming with the Authority's statutory objective.

The alternative approach we currently consider most likely to be consistent with the guidelines / our statutory objective is to recover overheads through the residual charge. Consistent with the Authority's 2020 decision on the TPM guidelines, we consider that the most efficient way to recover such costs is through a charge that affects the behaviour of transmission users as little as practicable.[8] The residual charge is designed with this objective in mind, and so in our view is the most efficient way of recovering remaining costs.

Connection charge – first mover disadvantage issue

The Authority continues to agree with Transpower that the first mover disadvantage (FMD) Type 2 issue for the connection charge merits a departure from clause 11 of the guidelines (which assumes that the first mover pays all connection charges), via clause 2 of the guidelines.

Failing to address the FMD issue could risk connection capacity being under-sized (given the expected increase in demand for connections associated with growth in renewable generation and as the economy electrifies) which would likely not adequately conform with the efficient operation limb of the Authority's statutory objective. A delay in investments in new generation or electrification is also a possible risk (although we consider under-sizing to be the more likely outcome).

However, as signalled during the checkpoints process, we do not agree with Transpower's view that socialising the costs of extra connection capacity across all customers is the appropriate response and so are referring back Transpower's proposed provisions relating to this issue. Socialising risks over-investment in connection capacity. While benefiting the connecting industrials and generators, it would also mean higher transmission charges and higher electricity prices for other customers, including (ultimately) residential consumers. We are referring this matter back as in our view, the proposed approach to this issue would see the proposed TPM not adequately conforming with particularly the efficient operation limb of the statutory objective.

Appendix A contains descriptions of alternative approaches we invite Transpower to consider, including the alternative we currently consider most likely to conform with the guidelines / our statutory objective: a targeted benefit-based allocation of additional capacity costs based on Transpower's proposed simple method for benefit-based allocation of the costs of low-value investments.[9] We consider this would most likely meet our statutory objective, where socialisation would not. Noting how this issue has developed since the guidelines were published, we will also be looking to undertake a full consultation on all options to address the FMD issue, likely in October 2021.

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[7] This was explained at paragraph B.224 of the 2019 Issues Paper: https://www.ea.govt.nz/assets/dms-assets/25/25467TPM-Issues-Paper-2019-Appendices-A-B-Guidelines-and-policy-proposal.pdf

[8] Other prices are designed to affect behaviour. Eg, the nodal price is designed to encourage efficient use of the grid and the benefit-based and connection charges are designed to encourage efficient grid investment.

[9] This can be achieved using Additional Component C as provided for in the guidelines.

Application of the residual charge to batteries and other energy storage systems

The proposed TPM's residual charge results in a potential competition problem affecting batteries and other energy storage systems ("storage"), which the Authority raised with Transpower in December 2020 and in March 2021.[10] During the checkpoint process Transpower has conveyed its view (which we accepted) that this is a policy matter most appropriately considered by the Authority. Transpower's proposed TPM therefore applies the residual charge to storage based on its full load, consistent with the guidelines.

The Authority considers that the proposed TPM creates a material competitive disadvantage for storage – as storage would pay the residual charge based on its full draw down of energy from the grid (not on its injection). This is an extra cost not faced by other generators. We are referring this matter back to Transpower as in our view, if not addressed, this issue would risk the proposed TPM not adequately conforming with the statutory objective.

The Authority considers that providing storage with an exemption from the residual charge equivalent to the exemption enjoyed by generation (including distributed generation) would better promote the statutory objective by addressing the competitive neutrality problem noted above. A description of the options the Authority is considering is set out at Appendix A.

In making our decision on the proposed TPM for consultation, we will take account of Transpower's analysis reported in the June 2021 reasons paper, earlier checkpoint material and its issues paper on this matter. While we would value and consider carefully any further input that Transpower is able to provide following its reconsideration of this issue, it is open to Transpower to make no further change to its proposal. Referring this back to Transpower is a precursor to the Authority fully engaging with stakeholders on this issue.

Adjustments - setting the residual charge for a new entrant

We are referring back Transpower's proposed method for setting residual charges for new entrants. The proposed TPM provides that the residual charge for a new entrant be set immediately equal to that of an equivalent existing customer.

We recognise this method is an available approach under the adjustments provisions of the guidelines. However, it could significantly disadvantage a new entrant (compared to existing customers that are expanding equivalently). This is because a new entrant investing in new electricity-consuming plant would begin paying residual charges immediately, whereas an existing customer undertaking an equivalent investment would not face similar-sized increase in its residual charge to the new entrant until seven years after the investment. We therefore see this as inconsistent with the competition limb of the Authority's statutory objective.

In our view a gradual ramp-up in the residual charge for new entrants - equivalent to the charge profile for an existing customer undertaking an equivalent investment - would better promote competitive neutrality and is more likely to be consistent with the Authority's statutory objective.

Adjustments - definition of reduction event - residual charge initial allocation

We are referring back the proposed approach to reduction events for residual charge allocation. Under the proposed TPM, Transpower has defined a 'reduction event'. This allows Transpower to adjust the initial residual charge of a pre-existing customer if there has been a change in the customer's expected maximum gross demand compared to its standard anytime maximum demand baseline due to an event or circumstance beyond its reasonable control. We agree this is consistent with the guidelines. However, subparagraphs (c) (ii) and (iii) in the proposed

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[10] Authority letter to Transpower, 7 December 2020, Transpower's TPM Checkpoint 2a submission; and Authority letter to Transpower, 18 March 2021, Proposed TPM residual charges and the treatment of batteries.

definition of “reduction event” then create restrictions on what may qualify as being beyond the customer’s control.

While we can see some such restrictions may be justified, the proposed restrictions appear unduly tight. This narrowed definition of a ‘reduction event’ appears to be inconsistent with the guidelines and with the policy intent previously expressed by the Authority, and potentially undermines the Authority’s intention that a downward adjustment to the initial residual charge of a distributor be allowed where a large industrial customer that was connected to the distribution network has closed down before commencement of the new TPM.

An alternative approach which we consider is more likely consistent with the guidelines and their intent is presented in Appendix A. This aims to better target the restrictions so that they do not exclude circumstances that the policy was intended to address.

Prudent Discount Policy - the standalone cost prudent discount

Under the proposed TPM, a standalone cost prudent discount (SACPD) would reduce a recipient’s benefit-based charges (BBCs) but would have no effect on its residual charge. This approach would cap the size of discount available and would mean the discount was funded only by those customers that are beneficiaries of the investments for which the recipient pays BBCs.

The Authority considers the proposed approach to this issue is inconsistent with the guidelines and would risk the proposed TPM not adequately aligning with the statutory objective. The guidelines provide that a prudent discount must be available to the extent that a customer’s transmission charges exceed the standalone cost of the transmission lines services it receives.

Transpower’s proposal potentially caps the size of the discount at a lower level than that, so may not achieve the objectives of the prudent discount policy (PDP) (particularly for any parties that would pay a high residual charge). Further, by placing additional costs on generators, the proposed approach to funding the PDP may raise some of the same efficiency issues that are discussed in the Overheads section of this letter and so is likely to be inconsistent with the Authority’s statutory objective. We are referring this matter back for these reasons.

We consider that the approach to the SACPD that Transpower proposed during the checkpoints process is likely consistent with the guidelines and the Authority’s statutory objective. Under this approach, a SACPD would be available to the extent that the recipient’s transmission charges exceed standalone cost. It would be funded through the residual charge and also by those customers that are beneficiaries of the investments for which the recipient pays BBCs (in proportion to the relative size of the recipient’s residual charge and BBCs).

Comments on the wording of the proposed TPM

A marked-up copy of the proposed TPM is attached at Appendix B. It contains comments on the draft wording of the proposed TPM which Transpower may wish to consider in terms of improving the clarity of the wording and ensuring that the proposed TPM is in the best possible shape for consultation. For the avoidance of doubt, the matters the Authority is referring back are those listed above; the drafting comments are instead matters for Transpower’s consideration with a view to ensuring that the proposed TPM is clearly communicating what Transpower intends it to.

If Transpower would like to make a resubmission on any of the matters referred back but considers this is not feasible within the required timeframe, I would encourage you to revert to the Authority without delay. We look forward to continuing the constructive engagement between Authority and Transpower staff, as we progress through the next stage of review and consultation on a proposed new TPM.

Yours sincerely

James Stevenson-Wallace
Chief Executive

Attachments

The following are attached to this letter:

- Appendix A: Matters the Authority refers back to Transpower
- Appendix B: Proposed TPM - marked-up with comments

Appendix A Matters the Authority refers back to Transpower

Overheads: BBC covered cost and Connection charge (injection overhead component)

A.1 The Authority considers that Transpower's proposed approach to recovering overhead opex (through the BBC and/or through the "injection overhead component" in the Connection charge) is inconsistent with the guidelines and places additional cost on generation, risking inefficiently delaying investment in generation (so would not adequately conform with the Authority's statutory objective). For these reasons, the Authority has decided to refer back the proposed TPM in respect of overhead allocation.

Transpower's proposal

A.2 Transpower proposes to use an accounting-based allocation approach to attribute capex, opex and other costs to a BBI to build up its covered cost. Under its proposed approach, the costs attributed to a BBI would be:

(a) directly attributable costs, meaning costs wholly and solely incurred in respect of the BBI (this captures capex costs and some types of opex)

(b) costs that are not directly attributable to the BBI but have a verifiable causal relationship with the BBI (by "verifiable" Transpower means able to be established and quantified in a robust and practicable way), and

(c) a portion of other costs where a direct or causal relationship with the BBI cannot be verified (overhead).[11]

A.3 Transpower's proposed TPM would allocate a portion of all types of operating expenditure to benefit-based investments (BBIs) and recover these costs through benefit-based charges (BBCs). This includes overhead opex, which relates to shared functions like finance and HR.

A.4 Transpower has made a related proposal on the connection charge: it proposed to recover some overhead opex via the connection charge paid by generators as an "injection overhead component".[12]

A.5 Transpower has stated that it would include an injection overhead component in the connection charge only if the Authority did not accept its allocation of overhead opex to BBIs. Effectively, Transpower's proposals on recovery of overheads via the BBC or via the connection charge are alternative proposals.

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11 We note, for context, that Transpower proposes to apply A.2(c) only to overhead *opex*. Another category of costs that would likely meet the definition of "a portion of other costs where a direct or causal relationship with the BBI cannot be verified" is non-network capex (such as IT systems, minor fixed assets such as laptops, and office buildings). The guidelines (implicitly) require non-network assets, as they do not meet the definition of either connection or interconnection assets, to be recovered via the residual charge. The proposed TPM is consistent with this.

12 The injection overhead component is a potential component of the connection charge, payable only by generators and intended to recover a portion of overhead opex.

Requirement in the guidelines

A.6 Clause 15(c) of the guidelines requires the covered cost of a BBI to include "an amount of opex reasonably attributable to the benefit-based investment based on an allocation of the opex allowance for the pricing year as set out in the IPP".

A.7 A key decision on covered costs, as Transpower explains at paragraph 17 of chapter 6, is which categories of its opex and other non-capex costs are reasonably attributable to investments in the interconnected grid.[13]

Assessment of Transpower's proposal

Transpower considers that all opex types are reasonably attributable to a BBI

A.8 In Transpower's view, opex is "reasonably attributable" to a BBI if:

(a) the opex is directly attributable to the BBI

(b) the opex has a verifiable causal relationship with the BBI, or

(c) the opex is overhead and an allocation of part of the opex to the BBI is objectively justifiable.

A.9 In our feedback on Transpower's 2b resubmission we explained, with reference to generally understood cost accounting concepts which portion of opex, in our view:[14]

(a) is most likely reasonably attributable to BBIs under clause 15(c) of the guidelines

(b) requires judgement as to whether it is captured by the reasonably attributable requirement in clause 15(c) or whether it should be recovered via the residual charge, on which point we had not settled on our view at that time.

A.10 We explained that:

(a) direct opex and shared direct opex are most likely reasonably attributable to a BBI under clause 15(c) of the guidelines

(b) shared opex (overhead opex) requires judgement in applying the guidelines; at that time we had not yet settled on our view as to whether overhead opex is:

(i) reasonably attributable to BBIs under clause 15(c) of the guidelines, or

(ii) whether it should be recovered through residual charges (being the least distorting approach).

A.11 In our feedback we also acknowledged that the use of these cost concepts is not required in the guidelines. We also agree with Transpower's statement that clause 15(c) of the guidelines does not use the words "directly attributable" or refer to only

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13 All BBIs are investments in the interconnected grid.

14 These cost concepts are directly opex, shared direct opex and shared opex. The characteristics of these cost types are as follows 1) Direct opex. Direct opex is incurred in relation to a specific BBI, ie, an incremental cost that would not be incurred without the BBI. Direct opex is wholly and solely incurred in relation to a BBI. 2) Shared direct opex. In practice, in the context of granular cost concepts like BBIs, some direct costs may be wholly and solely incurred in relation to a specific group of BBIs (rather than in relation to a specific BBI). 3) Shared opex. Shared opex (or overhead opex) is not incurred in relation to a specific BBI or an identifiable group of BBIs, ie, it is not incremental to a BBI or a specific group of BBIs. Shared opex is not wholly and solely incurred in relation to a specific BBI (direct opex) or in relation to a specific group of BBIs (shared direct opex).

avoidable or incremental costs being attributed to BBIs. Transpower considers it significant that these words are not used.[15]

A.12 We acknowledge Transpower's comment that its reasoning at paragraph 24 of chapter 6 (replicated in the table at paragraph A.20 below) applies equally to network and non-network overhead opex. Transpower does not consider that there is any basis for distinguishing between these types of overhead opex on the basis that network opex is "reasonably attributable" to BBIs but non-network opex is not. We note that:

(a) we consider it is useful to distinguish between these cost types because they help clarify the task required by the guidelines and to explain on which types of cost we potentially have a different view to Transpower

(b) in economic regulation, the rules regulators provide for cost allocation are typically aimed at creating efficient incentives. Not engaging with the nature of these costs might suggest the task at 15(c) is purely an accounting task and considerations of economics are irrelevant. That is not our view

(c) as we explain in the following section, the intent behind the TPM guidelines in relation to the allocation of costs (that are reasonably attributable) differs from other regulatory contexts for cost allocation, (eg, under Part 4 and Part 6 of the Commerce Act 1986).

Regulatory precedent under Part 4 and 6

A.13 Transpower distinguishes between three opex types as to how they might be allocated (as noted above), and concludes that all opex types are reasonably attributable to BBIs.

A.14 Transpower explains that the Commerce Commission has adopted a similar distinction between costs that are directly attributable (and therefore allocated entirely to the asset or service) and costs that are shared (and therefore allocated using causal allocators or proxies).

A.15 We acknowledge that the cost allocation input methodologies under Part 4 and Part 6 of the Commerce Act distinguish between costs that are directly attributable and costs that are not directly attributable. Costs that are not directly attributable (which includes overhead opex) must use causal allocators or, if not available, proxy allocators.

A.16 We consider the Part 4 / Part 6 precedent is useful for considering the basis (direct attribution, causal allocators or proxy allocators) on which costs should be attributed to BBIs.

A.17 However, we consider this precedent is not relevant for deciding which cost types should be allocated to BBIs under the proposed TPM.

A.18 The problem the cost allocation rules under Part 4 and Part 6 are intended to address arises as a result of regulated businesses such as fibre providers and electricity distributors providing more than one service. For example, for Transpower, the cost allocation input methodology sets the rules for the allocation of costs between transmission services and other services, (eg, the system operator). The cost allocation rules under Part 4 and Part 6 are intended to ensure monopoly power is not used to give a provider a cost advantage in an unregulated service (by allocating costs

[15] Para 20 of Chapter 6 of Transpower's reasons paper.

disproportionately to a regulated service). They are also intended to ensure that consumers of regulated services benefit over time from any efficiency gains achieved by providers supplying regulated and unregulated services together.

A.19 Cost allocation under the TPM is for a different purpose. The guidelines set out the Authority's intended allocation of overheads under the TPM. The proposed TPM should be consistent with that.

Other reasons

A.20 At paragraph 23 of chapter 6 Transpower provides other reasons for its proposal to allocate overhead opex to BBIs. In Table 1 below we set out each of Transpower's reasons and our view.

Table 1: Transpower's reasons and the Authority's responses

Transpower's reason	Our response
Transpower consider clause 15(c) of the guidelines requires the new TPM to attribute a portion of our overhead opex to BBIs.	We acknowledge Transpower's interpretation of the guideline. At paragraph A.22 we explain why our interpretation of the guidelines differs from Transpower's
All of our investments and services, including BBIs, contribute in some way to our overhead opex.	We agree, overhead opex by its nature supports all of Transpower's investments and services. The need for overhead opex is the result of all investments and services, and is not clearly attributable to any.
Our overhead opex is not solely attributable to our non-BBI interconnection investments, the costs of which will be recovered through residual charges paid by load customers, and is not solely incurred to provide services to load customers.	We agree that overhead opex is not solely incurred to provide services to load customers. However, the guidelines do not provide for the residual charge to reflect the cost to serve load customers. The purpose of the residual charge is to provide a mechanism to ensure that Transpower can recover up to its recoverable revenue in any pricing year in a way which is designed to minimise any effect on designated transmission customers' decision-making
In our view, if all overhead opex were recovered through residual charges, that would amount to a subsidy from load customers to the beneficiaries of BBIs, would make transmission charges less cost-reflective, and potentially be inefficient. For this reason, we do not consider an approach to covered cost that did not treat some part of our overhead opex as reasonably attributable to BBIs would be consistent with the efficiency limb of the Authority's statutory objective.	For overheads, a direct or causal relationship with the BBI cannot be verified. Rather, these costs are common, organisation-level costs. It follows that recovery of such costs through the residual charge does not create a cross-subsidy. Consistent with the Authority's 2020 decision on the TPM guidelines, the most efficient way to recover such costs is through a charge that affects the behaviour of transmission users as little as practicable. The residual charge is designed with this objective in mind, and so in our view is the most efficient way of recovering such costs.

Consistency with the guidelines

A.21 Transpower's position is that its approach is consistent with the guidelines, on the basis that overhead opex is "reasonably attributable" to BBIs.

A.22 The Authority's view is that Transpower's proposal on the recovery of overheads is inconsistent with the guidelines, properly interpreted. The guidelines at clause 15 provide that the covered cost, (ie, the amount which is to be recovered in respect of a BBI) is to include "an amount of opex reasonably attributable to the benefit-based investment…" It therefore envisages reasonable attribution of opex to individual benefit-based investments, rather than providing for allocation of a share of the opex which might be attributable to BBIs as a whole. We consider that this provision should be interpreted having regard to the Authority's intentions, including as indicated elsewhere in the guidelines and in its 2020 Decision paper and its 2019 Issues paper. Specifically, clause 6 of the guidelines, while concerning information Transpower is required to provide, signals the Authority's expectation that "unallocated opex" would be included in the residual charge. The Authority also made a number of statements in its 2019 Issues paper and 2020 Decision paper indicating clear intent that overhead costs should be included in the residual charge rather than apportioned to benefit-based investments.[16] Accordingly, the Authority's view is that overhead opex is not "reasonably attributable" to BBIs.

A.23 For similar reasons the Authority's view is that the "injection overhead component" in the Connection charge is inconsistent with the guidelines. The guidelines provide that connection charges recover the costs of connection investments – as outlined above, overhead costs cannot be considered "costs of connection investments", particularly in light of the Authority's previous comments that such costs should be recovered via the residual charge.

Concerns over the efficiency of Transpower's proposed approach to overheads

A.24 A key disadvantage of Transpower's proposed approach to overheads relates to efficiency. This arises because it places additional costs on generators that are not related to the benefits generators receive from the grid. These costs could act like a tax on generation and inefficiently discourage investment in generation. Dampening investment in generation could make electricity prices higher than they need to be. This would be inconsistent with the Authority's statutory objective, which requires it to promote efficient operation of the industry.

A.25 This was a key part of the Authority's reasoning for removing the HVDC charge and was also the reason the guidelines provide that generation does not pay the residual charge. This was explained at paragraph B.224 of the 2019 Issues Paper:[17]

A.26 The reason the Authority proposed restricting the residual charge to load customers is to avoid the abovementioned inefficiency. Any residual charge that is applied to generation (that is, injection into the grid) would likely largely be passed on to load in the form of higher energy prices, since new generators would then delay entering until the energy prices they expect to receive would cover their residual charge. That is, on average, prices would rise relative to the no-charge case before the next generator would find it profitable to invest. This means that effectively load customers would likely end up paying much of the charge whether or not the legal incidence of the charge is on load or generation. Since the charge would be passed through in nodal prices, it

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16 For example, see the 2020 Decision paper at paragraph 10.34 and the 2019 Issues paper, paragraph B.73 and B.194. We also note that the Authority's documentation around Additional Component F (which is also raised by Transpower) indicates that this additional component is concerned not with which costs should be recovered as part of BBIs' covered costs but rather how costs which are to be recovered are to be allocated between investments, and that, again, in considering Additional Component F, a view was expressed that common costs should not be allocated to BBIs using such methods: see 2019 Issues paper at paragraph 343.

17 https://www.ea.govt.nz/assets/dms-assets/25/25467TPM-Issues-Paper-2019-Appendices-A-B-Guidelines-and-policy-proposal.pdf

means that nodal prices would likely be higher, discouraging energy use (compared with the case where the entire charge is on load).

A.27 The Authority considers that an approach that recovers overheads through the BBC – and/or through the “injection overhead component” in the Connection charge – risks inefficiently discouraging investment in generation and so would be inconsistent with the efficiency limb of the Authority’s statutory objective.

A.28 Our view remains that a more efficient approach would be to recover overheads through the residual charge. Consistent with the Authority’s 2020 decision on the TPM guidelines, we consider that the most efficient way to recover such costs is through a charge that affects the behaviour of transmission users as little as practicable.[18] The residual charge is designed with this objective in mind, and so in our view is the most efficient way of recovering remaining costs.

Illustration of the impact of the Authority’s currently preferred approach

A.29 If overhead costs were recovered through the residual charge (instead of some being recovered through BBCs), benefit-based charges in total would be $17.7m lower, compared to indicative prices reflecting Transpower’s proposed TPM.[19] Residual charges would be higher by the same amount.

A.30 Over time, under both approaches to overheads, the proportion of costs recovered through the residual charge will gradually decline (for reasons such as the value of historical grid investments depreciating), and a greater proportion of costs will be recovered via benefit-based charges. If more overhead opex is recovered through the residual charge, that rate of decline will be slower (compared to the rate if some overheads were recovered through BBCs). For example, by 2035, this would mean an additional 5% of total transmission charges would be recovered via the residual charge (offset by a corresponding decrease in BBCs).[20]

Connection charge - the first mover disadvantage issue (Type 2)

A.31 As set out in the Authority’s responses to Transpower’s checkpoint 2b submission and resubmission on this issue, we agree that there will be circumstances where the first mover should not pay all the costs relating to anticipatory capacity included in a new connection investment, as in some cases that could risk connection capacity being under-sized (given the expected growth in demand for connections) which would likely not conform with the efficient operation limb of the Authority’s statutory objective. A delay in investments in new generation or electrification is also a possible risk (although we consider under-sizing to be the more likely outcome).

Considerations for approaches to address FMD Type 2 (consistent with the Authority’s statutory objectives and the 2020 TPM guidelines)

A.32 In describing approaches to resolve the FMD issue, we use the terms C for a first mover’s requested capacity (and any headroom designed for that first mover) and X for anticipatory connection capacity intended for later connections or substantial expansion.

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18 Other prices are designed to affect behaviour. Eg, the nodal price is designed to encourage efficient use of the grid and the benefit-based and connection charges are designed to encourage efficient grid investment.

19 Charges estimated for 2021/22. Source: Transpower estimate in response to Authority request for information.

20 Source: Transpower estimate in response to Authority request for information.

A.33 The Authority has considered different approaches to allocate the costs of anticipatory investments, to address the FMD. The following considerations were used to assist in assessing the merits of each option:

(a) addresses the FMD: reduces costs relating to anticipatory capacity from first mover (reduces the risk to the first mover so X-related costs) balance with the potential benefits to the first mover if X is built (as it can then share costs of C+X with the second connecting party). (The aim is no financial disincentive on balance, not necessarily to eliminate all risk)

(b) supports dynamic efficiency: achieves a right-sized grid over time: creates incentives for investment scrutiny, and minimises incentives for over- or under-investment

(c) supports allocative efficiency: does not design-in cross subsidies, as connecting parties pay in relation to their connection capacity

(d) good regulation: is feasible for Transpower to implement, and understandable for stakeholders

The Authority does not consider the proposal to address the FMD Type 2 by socialising the costs related to anticipatory connection investments to adequately conform with its statutory objective

A.34 Transpower's reasons paper, at Section 5.10 confirms that its proposal remains to fund X-related costs by allocating these across all connected customers, in proportion to each customers' replacement cost of their connection capacity ("socialisation").

A.35 In principle, we do not agree with Transpower's proposal that a socialisation approach is appropriate. Socialising risks creating cross-subsidies from other connecting customers (including ultimately residential customers) to industrials and generators and creates a risk that connection investments could be over-sized, including because this method does not create incentives for stakeholders to reveal known information about expected future connection capacity needs.

A.36 An example of this effect could be a planned connection investment upgrade to connect an electrifying dairy processing plant, where Transpower proposes anticipatory capacity (beyond normal headroom) for future electrification of new processing load. For the purposes of this example, we will assume there is a particular generator that is likely to benefit from investments to connect load in the area, as it would supply the additional demand enabled by the additional capacity. For example:

(a) We first assume that, at the point of the connection upgrade decision being made, the anticipated future electrification actually has a very low likelihood of proceeding – and this information is held by (or can be discovered by) a motivated party. If the additional costs were allocated based on benefit, the identified benefiting parties (such as the generator) would have an incentive to discover the key information and make the Commerce Commission aware of that information. The investment in additional capacity does have some possible value to the generator (and to the dairy plant), eg, in the event that the dairy plant or another company decides to expand its processing capacity. However, if the additional capacity costs are socialised, the investment is effectively costless to the generator (and to the dairy plant). So neither party would have an incentive to 'push back' on the proposed additional capacity by revealing or discovering the key information. We recognise that Transpower and the Commerce Commission have established and robust processes to seek information from stakeholders; we are not criticising these processes. Our concern is to ensure that transmission pricing provides stakeholders with appropriate incentives to seek out and reveal information to both Transpower and the Commission.

(b) Now if we assume the electrification is likely to proceed - the additional capacity costs would create expected benefits for businesses, (such as the generator). Socialisation of the costs means the generator's contribution is far less than its benefits, but residential consumers throughout the country (amongst others) would see marginally higher electricity bills due to paying for an investment from which they do not benefit, (ie, the socialisation problem that currently occurs for interconnection assets, and one of the issues that TPM reform is seeking to fix).

A.37 These problems risk potential over-investment in anticipatory capacity[21] and failing to promote efficient operation of the electricity industry. It was for these reasons that the Authority introduced its benefit-based approach to charging for interconnection investments; moving away from socialisation via the RCPD charge.[22] Moving to socialisation of extra capacity in connection investments would be inconsistent with the benefit-based approach of the TPM guidelines.

Alternative approaches to address FMD Type 2

A.38 This section contains descriptions of alternative approaches we invite Transpower to consider, including the approach we consider most likely to adequately conform with the guidelines and our statutory objective: a targeted benefit-based allocation of additional capacity costs based on Transpower's proposed simple method for benefit-based allocation of the costs of low-value investments. This can be achieved using Additional Component C as provided for in the guidelines.

Alternative: a targeted benefit-based allocation

A.39 The Authority considers that a targeted benefit-based allocation is most likely to be consistent with its statutory objective (as it is for interconnection assets). This is based on the BBC's simple allocation method, and works as summarised in Table 2 below:

21 Socialising the cost of anticipatory investments in greenfields capacity could also have the effect of quashing competition to build those connection assets.

22 In the 2020 Decision paper, the Authority noted: "The current RCPD charge also spreads the costs of each grid investment across all load customers regardless of whether they receive benefit from it. The costs of transmission investments that address a local or regional supply or grid reliability issue are in effect subsidised by all other consumers. To a large extent, this means that those who benefit from an investment only pay a small share of its costs, with most of the costs instead spread among many who do not benefit from the investment. As a result, no stakeholder has the right incentives to give Transpower and the Commerce Commission the best possible information on the actual value of grid investments or of alternative solutions."

Table 1: A benefit-based approach to allocating the costs of Xs

Anticipated purpose of X - second and subsequent movers are:	Suggested application of the simple method	Beneficiary parties would be parties who are:
Both load and generation customers	Simple method	Within region generation and load Upstream generation Downstream load
Load customers	One-sided simple method	Within region generation Upstream generation
Generation customers	One-sided simple method	Within region load Downstream load

A.40 This would apply only to Xs in the following way:

(a) For “ordinary” connections with a total capacity C, an ordinary connection charge would apply (on the basis that such an approach generally achieves the intent behind the simple method).

(b) For anticipatory connection investments with a total capacity C+X:

1. an ordinary connection charge would apply for the costs relating to the capacity that the connecting customer requests (C)

2. the proposed benefit-based approach would apply only to the costs of the additional anticipatory capacity (X).

A.41 We would propose the FMD solution should apply to brownfields Xs, and to consult on whether the solution should also apply to any greenfields Xs which are not covered by a commercial contract.[23]

A.42 The Authority recognises possible challenges in applying this method, and we welcome further discussion with Transpower on these, and with stakeholders through the consultation process:

(a) The simple method allocation tables are reviewed every five years and so could change over time (so the allocation tables used in this approach may also need to change over time to remain aligned).

(b) The resulting allocation may in some cases be widely spread so this option may not elicit as much scrutiny of investment proposals as the temporary socialisation option described below.

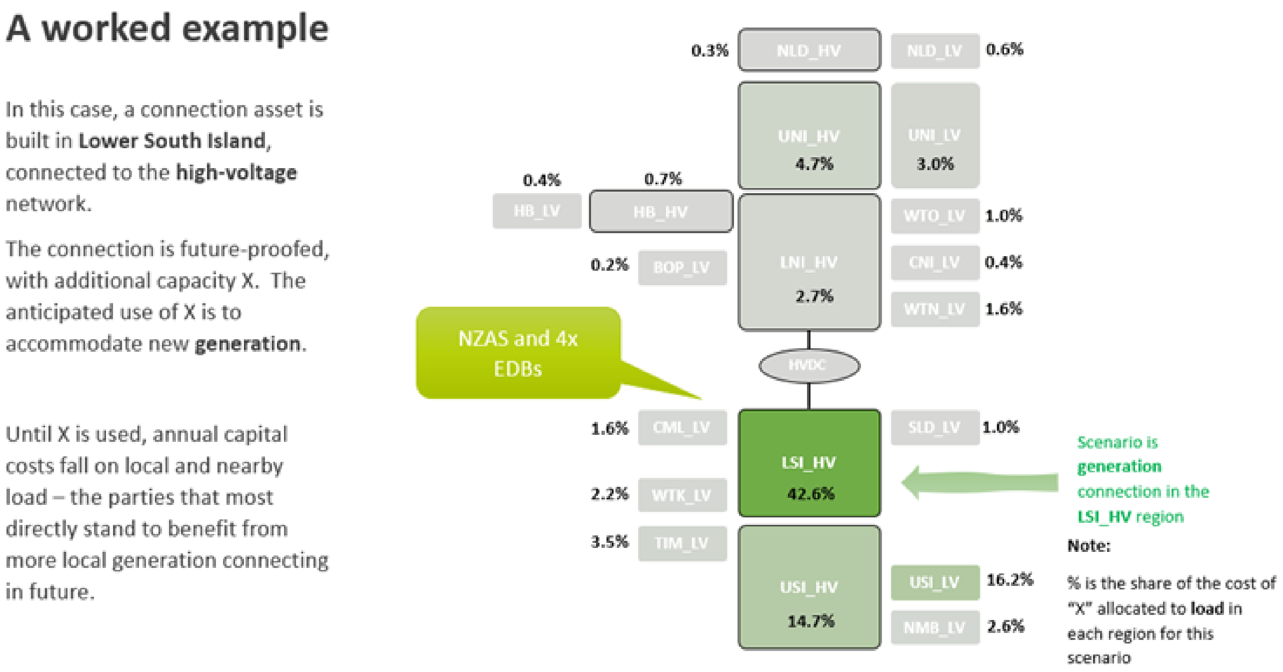
(c) On the other hand, in some cases the costs may be substantially concentrated on localised parties until a second connecting party arrives.

[23] Investments in new connection capacity (“greenfields”) are typically funded outside the TPM, through a commercial “new investment contract” (NIC) between the customer and either Transpower or another provider. Investments in greenfields capacity are subject to competition from non-Transpower providers who are able to build these connection assets. The Authority has previously recognised that commercial providers are able to make appropriate risk-return trade-offs in agreements with connecting customers, so there are incentives to invest efficiently. Applying a benefit-based approach to recover the costs of additional capacity C might adversely affect this competitive arena.

(d) Transpower has expressed concerns that a benefit-based approach might be too difficult to implement (or at a level of difficulty that is disproportionate to the problem). In our view, however, implementation of this option would not be too difficult, as allocation would be based on Transpower's proposed simple method for benefit-based allocation of the costs of low-value investments (so Transpower could largely use already existing allocation tables). We would be interested to hear from Transpower as to whether it continues to hold the view that the benefit-based option would be too difficult to implement (and if so, reasons why).

A.43 A worked example of this approach is shown in Figure 1.

Figure 1: A worked example of the targeted benefit-based allocation approach



Alternative: Temporary socialisation – up to ten years

A.44 Table 3 provides an overview of this "temporary socialisation" approach, which consists of two phases:

(a) Phase 1: for while only a first mover is connected.

(b) Phase 2: from when a second party connects to ten years later, or during years 11-20 - whichever is soonest.

Table 3: A temporary socialisation option

PHASE 1 (up to ten years)	The first mover pays C-related costs and X-related costs are socialised (in effect)	The mechanics are: • first mover pays connection charges relating to C and X • first mover receives a rebate each year for X-related charges • all rebates are recorded in a rebate account • the shortfall (due to rebates paid) is made up by adjusting all customers' connection charges • the rebate account is rolled forward each year with a financing charge also applied.
PHASE 2 (from when second mover arrives to ten years later, or from years 11-20)	The X-related costs are charged to whomever is connected	The mechanics are: • the rebate account begins to unwind, and the rebate unwind period is the same as the rebate windup period • unwind payments are allocated across the first, second and any subsequent movers • if a second mover has not arrived, the unwind begins anyway from year 11, meaning in effect the FM pays for depreciated X-related costs from year 10 on.

A.45 Phase 1 is similar to Transpower's socialisation proposal, via a rebate system. During Phase 2 the rebate is unwound, so in effect the first mover 'starts paying' for X-related costs. By this time (under this particular proposal) the first mover will have completed C-related payments and X-related charges will have depreciated substantially. After phase 2 the costs of C+X have been fully recovered.

A.46 Upsides of this approach include that:

(a) it does not permanently socialise the costs of X

(b) it uses the connection pool to reduce FMD and improves cashflows for the first mover

(c) it leaves the first mover with some residual risk and hence an incentive for investment scrutiny

(d) it does not dissuade the second mover from connecting; and

(e) it works well to present attractive cashflow profiles for both parties.

A.47 As above, the Authority recognises possible challenges in applying this method, and we welcome further discussion with Transpower on these, and with stakeholders through the consultation process. Challenges include that this option in effect delays and depreciates the cost (it does not eliminate the risk that the first mover would pay some additional cost in the event other parties do not connect). The approach also risks that a party receives rebates during Phase 1 and then exits, meaning that party would no longer be present to cover X-related costs in Phase 2. We recognise that this option might appear to some observers as overly complex; we would be interested in Transpower's views on this point.

A.48 In its resubmission on this aspect of the proposed TPM (that is, the FMD issue), we are not asking Transpower to repeat what has previously been stated in the 30 June reasons paper, but are particularly interested in any more detailed response you can provide about the workability of the alternative approaches we have put forward. This could include discussion of cases where the costs may be substantially concentrated on localised parties until a second connecting party arrives – and potential solutions to any problems that are identified.

A.49 Depending on Transpower's re-submission following this refer-back process, the Authority envisages that it may consult on the targeted benefit-based allocation option and the temporary socialisation option, alongside Transpower's proposal of socialisation (if this remains Transpower's proposal). The Authority will be able to consider any further evidence that emerges in submissions before making its final decision.

Application of the residual charge to batteries and other storage

A.50 Transpower's proposed TPM does not propose a change to how the residual charge should apply to batteries and other energy storage systems ("storage").[24,25] So, under the proposed TPM the residual charge would apply to storage based on its full load. This was expected: during the checkpoint process Transpower conveyed its view (which the Authority accepted) that the risk of the residual charge creating a competitive disadvantage for storage is a policy matter most appropriately considered by the Authority.

Electricity storage can provide valuable services

A.51 Storage can provide a range of valuable services. These include load smoothing, reserve energy, voltage support and frequency keeping.

A.52 Storage has some advantages over other resources: almost zero ramp rates, meaning that a MW of storage can operate more cost-effectively than a MW of generation; operating as both generation and load for reserve purposes; and storage can produce reactive power for voltage support, which not all generating plant can do.

A.53 By way of example of some of the benefits storage can provide, the Authority recently estimated that allowing batteries to offer instantaneous reserve could produce benefits of $44 million dollars (present value).[26] In South Australia the Hornsdale battery installation has been associated with an approximate 25% reduction in the costs of frequency control ancillary services.[27]

A.54 Transpower (2017) assessed the potential value of batteries in the New Zealand economy[28] and noted the range of services that can be provided by batteries. Figure 2

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24 However, Transpower's reasons paper Chapter 9 does describe its thinking to date on three potential options: no change, or (via Clause 2) a partial or full exemption from the residual charge for storage.

25 The term 'storage' is used in this letter to refer to any equipment functioning together as a single entity that is both able to store energy from a network and provide injection. This aims to cover all systems where electricity is the key input and output and hence can be said to store energy via electricity. The definition excludes storage of energy that does not involve electricity as an input and output such as conventional hydro storage, gas storage, coal stock-piles. The UK regulator Ofgem recently adopted a term electricity storage system. Staff are still working through the task of checking (and if necessary reconciling) the explanations and definitions for electricity storage used by Ofgem and by Australian regulators with the definition for Electricity storage system (ESS) that was introduced by the Authority in the recent Batteries as Instantaneous Reserve (BIR) decision and Code amendment.

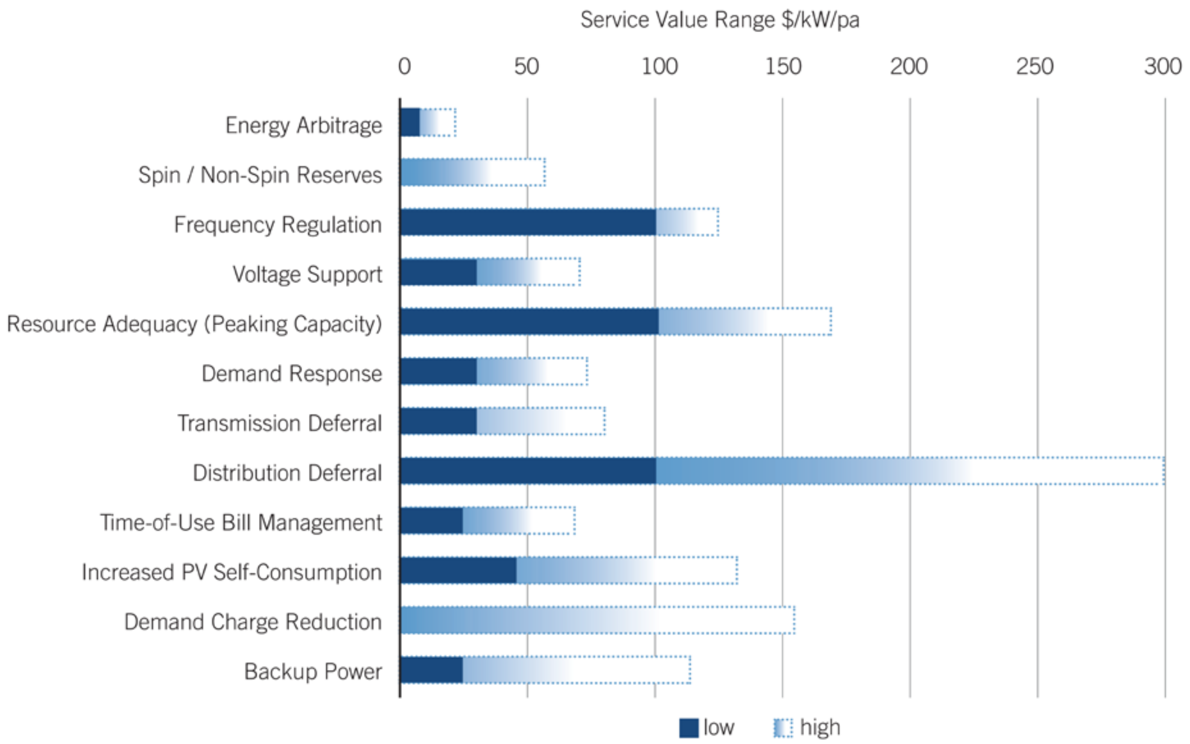
26 Electricity Authority, (2021), https://www.ea.govt.nz/development/work-programme/evolving-tech-business/batteries-as-instantaneous-reserve/consultations/

27 Aurecon Group, Hornsdale Power Reserve, 2020), https://www.aurecongroup.com/-/media/files/downloads-library/thought-leadership/aurecon-hornsdale-power-reserve-impact-study-2020.pdf

28 Transpower, 2017, Distributed Battery Energy Storage Systems in New Zealand. This report is a useful and thoughtful assessment of the potential uses of batteries in the New Zealand context. It's main findings around the relative value of batteries in different uses remains valuable even if they are somewhat dated in light of rapid declines in costs of batteries and rapid increases in knowledge about the deployment and operation.

summarises Transpower's high-level assessment of the relative value of services provided by batteries.

Figure 2: Transpower's 2017 assessment of the value of battery functions



Magnitude of the issue: potential competitive disadvantage to storage under proposed TPM

A.55 The Authority considers this a high priority issue, as in our view the proposed TPM creates a material competitive disadvantage for storage. This is because storage would pay the residual charge based on its full draw down of energy from the grid (not on its injection). This is an extra cost not faced by other generators.[29]

A.56 If not addressed, the competitive disadvantage could inefficiently discourage investment in energy storage and distort generation investment decisions (such as by substantially increasing the costs of intermittent renewables combined with energy storage). If not addressed, this issue would risk the proposed TPM not adequately conforming with the statutory objective.

A.57 Sense Partners estimate this causes a 3.75% higher investment cost for an energy storage system than for an equivalent generator.[30,31] Table 4 presents Sense's estimate of how the proposed residual charge affects this range of generation types.

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29 Another way to explain this is the proposed TPM would essentially result in the residual charge being paid twice for any final demand where storage had been used (once when the storage was charged, and once when the energy is used by the end customer). For services competing with storage, eg, peaking generation, this double charging does not occur.

30 Sense Partners' analysis relates to investment costs for a single simplified battery project for a battery with investment costs of $1m per MW.

31 This is more than de minimis. Sense Partners' analysis relates to investment costs for a single simplified battery project for a battery with investment costs of $1m per MW; compared with an equivalent grid-connected cogeneration plant or diesel generator, or network-level embedded hydro generator.

Table 4: Impact of residual charges on cost of investment for electricity producers and service providers

Investment type	Co-located with…	New transmission customer?	Connection level	Functions e.g.	Present value cost per MW ($m)	Proposed residual's % impact on investment cost
10 MW battery	None	No	Grid	Load shifting, reserve, voltage support, frequency keeping	0.03	**3.75%**
	Industrial load	No	Grid	Energy cost management, back-up supply	0.03	**3.75%**
	Renewable generation	No	Grid	Peaking capacity, frequency regulation	0.03	**3.75%**
1 MW battery	Embedded load	No	Local network	Load shifting, voltage support, network cost deferral	0.03	**3.75%**
	Embedded load and generation	No	Local network	Load shifting, voltage support, network cost deferral	0.03	**3.75%**
100 MW Hydro generator	None	Yes	Grid	Energy, reserve (tail-water depressed), frequency regulation	1.40	0.10%
	None	No	Grid	Energy, reserve (tail-water depressed), frequency regulation	0.50	0.07%
1 MW Hydro generator	Embedded load	No	Local network	Energy	Nil	Nil
10 MW cogeneration plant	Industrial load	No	Grid	Energy cost management, back-up supply	Nil	Nil
10 MW diesel generator	None	No	Grid	Peaking capacity	Nil	Nil
	Industrial load	No	Grid	Energy cost management, back-up supply	Nil	Nil
	Embedded load	No	Local network	Network cost deferral, back-up supply	Nil	Nil

A.58 The above effect is magnified for new customers; this is discussed in the adjustments section.

Alternative approaches for how the residual charge could apply to storage

A.59 The Authority sees providing an exemption from the residual charge for storage, using Clause 2 of the guidelines, as being needed to ensure that the proposed TPM is consistent with the Authority's statutory objective. The solution still requires further development, including on whether such an exemption should be a full exemption or a partial exemption. An exemption should remove the competitive disadvantage identified, and better promote the competition and efficiency limbs of the Authority's statutory objective.

A.60 Some parties have formed a view that treating storage differently to other load would create an unfair advantage to storage compared to other technologies, eg, embedded generation.[32] Our intention is not to provide energy storage with a competitive

32 The Independent Electricity Generators Association (IEGA) expressed this view when responding to Transpower's engagement on this matter.

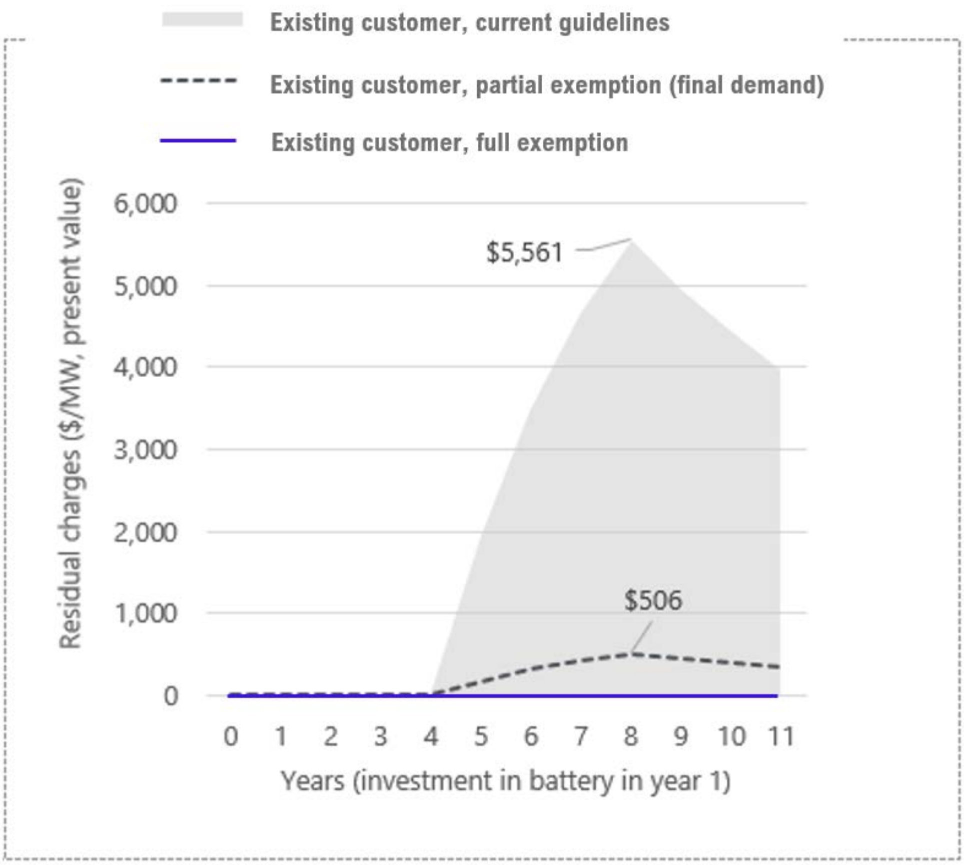
advantage; rather, we are aiming to remove an unintended structural disadvantage to storage that arises under the proposed TPM. Our intention is to propose a technology-neutral solution. We look forward though to better understanding and testing these concerns during consultation on the proposed TPM later this year.

A.61 The set of options considered by the Authority align with those considered by Transpower under Checkpoint 2c, which were:

> ***No change:*** *batteries and storage are treated as load customers for their entire offtake and embedded electricity consumption*
>
> ***Partial exemption:*** *storage exempted from the residual charge with respect to offtake and embedded electricity consumption while charging, except as to losses during transformation.*
>
> ***Full exemption:*** *storage fully exempted from the residual charge with respect to offtake and embedded electricity consumption while charging.*

A.62 A worked comparison of options has been undertaken, for a hypothetical 10MW energy storage investment by an existing designated transmission customer.[33] Figure 3 and Table 2 compare the options.

Figure 3: Application of residual charge under new TPM - worked example



33 A new transmission customer wouldn't have the ramp-up an existing customer does and so would face a higher allocation of the residual under no-change or a partial exemption. This situation is covered under the Adjustments discussion.

Table 2: Impact of alternative options on battery investment costs

	Existing customer	
Options	**PV cost per MW ($m)**	**% impact on investment cost**
No change	0.03	3.75%
Partial exemption: final demand	0.002	0.25%
Full exemption	Nil	Nil

A.63 In its resubmission on this aspect of the proposed TPM (that is, the application of the residual charge to storage issue), we are not asking Transpower to repeat what has previously been stated in the 30 June reasons paper, but are particularly interested in any more detailed response you can provide about the workability of the alternative approaches we have put forward.

Adjustments

A.64 Transpower has made significant changes to the adjustment provisions through the checkpoints process, and we now consider that the adjustments provisions are largely consistent with the guidelines and the Authority's statutory objective. We are referring back to Transpower two issues only, as discussed below.

Residual charge for new entrant and expanding customer

A.65 We are referring back Transpower's proposed method for setting residual charges for new entrants (part of the adjustments section).

A.66 Under the proposed TPM, the residual charge for a new entrant is set differently from an expanding existing customer.

A.67 Specifically, the proposed TPM makes no specific provision for adjusting the residual charge of an expanding incumbent. As a result, the general provisions of Part E of the proposed TPM apply, which provide for a lagged adjustment to its residual charge to reflect its increased energy use. This is consistent with the guidelines. In particular clause 33(a)(ii) of the guidelines omits any reference to the residual charge of an expanding incumbent, meaning that the general residual charge provisions (clauses 27 to 30) apply.

A.68 In contrast, clause 91 of the proposed TPM provides that Transpower must set the residual charge for a new entrant so that it incurs a residual charge equal to that of an equivalent incumbent from the day that it connects to the grid. This is also an approach available under clause 33 of the guidelines. Clause 33 makes clear that the new entrant must pay a residual charge, that 'ultimately' reflects the charge that an equivalent incumbent must pay, but is not prescriptive about when it should become liable for it.

A.69 The approach proposed at clause 91 of the proposed TPM has the advantage that it provides competitive neutrality as compared to an incumbent that is otherwise similar to the entrant and has relatively static load. However, because an expanding incumbent would only face an increase in its residual charge after the lagged adjustment applies, it would also have the effect of making it harder for a new entrant to enter than it would for an incumbent to expand by the same amount, for example by opening a new factory. In addition, it would provide an artificial and potentially inefficient incentive for a new entrant to structure itself as an incumbent to avoid the initial step in the residual charge.

A.70 This effect is illustrated in Figure 4. It shows that:

(a) a new customer investing in new electricity consuming plant would begin paying residual charges straight away (the shaded light blue area in the figure). In this worked example:

(i) the charges start at $99,500 per MW (roughly the size of current coincident peak demand charges)

(ii) charges decline gradually over time as the amount of revenue recovered from the residual charge declines[34] and because the values below are in present value terms to reflect implications for current investment decisions.

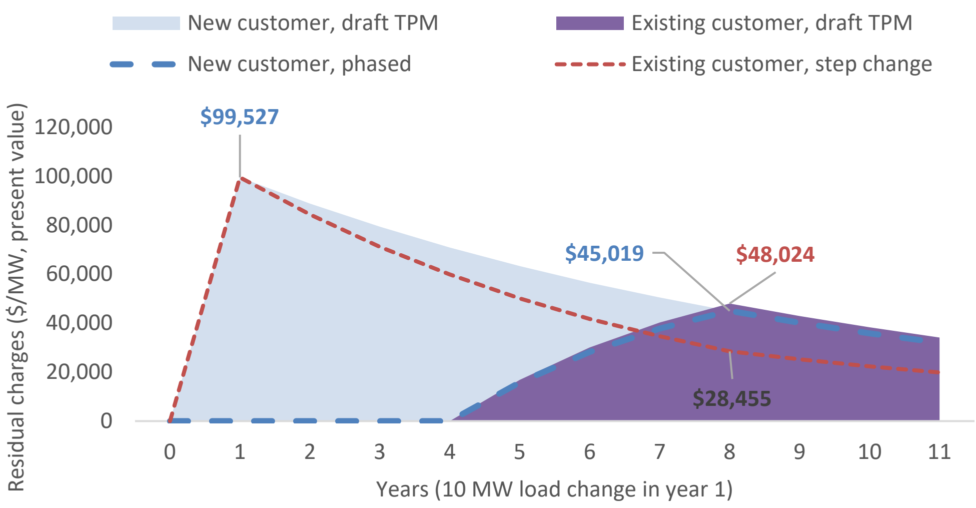
(b) an existing customer[35], undertaking an equivalent investment, would not face similar sized charges to the new entrant until seven years after the investment. In this example:

(i) there would be no increase in residual charges until the fourth year after the investment

(ii) by year eight, the existing customer's charges (the purple area in the figure) are fractionally higher than the new customer's charges.[36]

Figure 4: Residual change options, impacts on new versus existing customers

Present valued annual residual charges per MW for a 10MW investment in new load



A.71 We are referring this matter back as in our view, the proposed approach would risk the proposed TPM not adequately conforming with the statutory objective. On balance, we consider that matching the treatment of a new entrant with an expanding incumbent is

34 Assumed, in this example, to decline by a consistent compounding 3% per annum.

35 This example assumes the existing customer has 40 MW historical average AMD for the purpose of setting residual charges and that both national consumption and the customer's consumption grows at a constant 1% per annum.

36 The growth in the existing customer's demand interacts with growth in demand from pre-existing assets to cause a slightly higher charge than for a new customer, at least in this example where it is assumed that pre-existing demand grows but that the new investment is for a fixed level of demand that does not grow.

more important than matching the treatment to an existing (and unchanging) incumbent, because both the potential new entrant and the potential expanding incumbent face real immediate resource decisions.

A.72 Transpower may wish to consider the approach the Authority currently considers most likely to be consistent with both the guidelines and the Authority's statutory objective, which is to apply a residual charge to a new entrant so that it is similar to the increase in the residual charge that an expanding incumbent would pay. That is:

(a) the new customer would not face residual charges until four years after the investment

(b) charges would begin at one-quarter of full charges and increase by one-quarter each of the next three years until reaching the same level as that of an equivalent incumbent that had not changed its energy use.

A.73 As is noted above, clause 33 of the guidelines is not prescriptive about the timing of the implementation of the new entrant's residual charge. We therefore consider that this proposal is also consistent with clause 33 and is more likely consistent with the Authority's statutory objective.

A.74 The approach would apply to a new entrant that connects directly to the grid. Clause 33(e) then requires the same treatment in respect of a large plant that connects to the grid through a designated transmission customer. No specific provision would be required to achieve this, as it would occur automatically through the operation of the standard lagged adjustment in Part E of the proposed TPM to the designated transmission customer.

A.75 Another option for addressing the disparity between the residual charge for a new entrant and an incumbent would be introduce a step change in the residual charges of existing customers when there is a substantial change in use. We do not favour this option as it would defeat the purpose of the lagged change in the residual charge provided for in the guidelines, which is intended to reduce the risk of inefficient distortion to customers' grid use decisions.

A.76 Transpower's proposed approach and options the Authority has considered are shown in Figure 4 above.

Definition of a reduction event for the residual charge

A.77 We are referring back the proposed approach to reduction events for the residual charge.

A.78 Under clause 69 of the proposed TPM, a pre-existing customer's initial residual charge allocation can be reduced if there is a "reduction event"; ie, a reduction in the customer's expected maximum gross demand compared to the baseline otherwise used to allocate the residual charge to the customer. This is consistent with clause 29 of the guidelines, which allows such an adjustment where Transpower considers a customer has experienced a substantial change to demand due to factors that are largely beyond a customer's control or influence.

A.79 The guidelines were written as intended to allow, for example, a downward adjustment to the anytime maximum demand AMD (and so the residual charge) of a distributor where a large industrial customer that was previously connected to the distribution network has closed down.[37] A recent example could be the NZ Refinery's proposal to shift from refining to importing, which would reduce demand on Northpower's network.

A.80 The definition of a "reduction event" in the proposed TPM (clause 3) is intended to give effect to this.

A.81 However, we are referring this definition back to Transpower because this definition seems to be unduly narrow, in a way that appears to be inconsistent with the guidelines and does not reflect the Authority's intention that a downward adjustment to the initial residual charge of a distributor be allowed where a large industrial customer that was connected to the distribution network has closed down.

A.82 In particular, sub-paragraphs (c) (ii) and (iii) of the definition of reduction event appear to preclude the adjustment for some events that are beyond the customer's reasonable control. Specifically:

(a) It appears likely that sub-clause (ii) would prevent Transpower from treating the exit of an industrial plant as an adjustment event in setting a distribution network's residual charge. As is noted above, it is this sort of event that the provision was intended to target. We consider it may be legitimate to distinguish between a change in the market for electricity lines services (a distributor, for example) – which should be allowed for – and more general changes in market conditions – for example, for the market for the output of a large direct-connect industrial (the international market for some exported product, for example).

(b) It appears likely that subclause (iii) would exclude adjustment to a distributor's residual charge if one of its customers substantially reduced its demand because for example it was adjudicated bankrupt or put into liquidation. We consider that this is quite similar to the industrial exit discussed above. We think it legitimate to distinguish this from the situation where the designated transmission customer itself was (for example) put into liquidation, which should not of itself trigger an adjustment to the residual charge.

Prudent Discount Policy - the standalone cost prudent discount

The approach to a standalone cost prudent discount (SACPD)

A.83 Under the proposed TPM, a SACPD would reduce a recipient's BBCs to zero but would have no effect on a recipient's residual charge. Transpower's reasons paper describes this approach as "consistent with the alternative project substituting for all transmission services the recipient receives from the interconnected grid, ie, that deliver positive net private benefits to the recipient."[38] A SACPD would have no effect on a recipient's residual charge.

A.84 The Authority is not comfortable with this approach, because the guidelines provide that a prudent discount must be available to the extent that a customer's transmission charges exceed the standalone cost of the transmission lines services it receives. Transpower's proposal potentially caps the size of the discount at a lower level than that and so is inconsistent with the guidelines. It limits the discount available

37 This is discussed for example in the document *TPM second issues paper: supplementary consultation*, 13 December 2016 at page 32.

38 Transpower's June 2021 reasons paper at section 5.6.

(particularly for any parties that would pay a high residual charge) and so may not achieve the objectives of the PDP.[39]

A.85 Transpower's proposal is being referred back on that basis.

Funding the SAC prudent discount

A.86 Under the proposed TPM, SAC prudent discounts would be funded entirely by payers of benefit-based charges. This is related to the proposal that a SAC prudent discount would reduce a recipient's BBCs to zero but have no effect on a recipient's residual charge.

A.87 The guidelines do not directly specify how the PDP is to be funded. During the checkpoints process, Transpower proposed a mixed funding model (via both benefit-based charges and the residual charge), which the Authority indicated would likely be acceptable as consistent with the guidelines.

A.88 The Authority's view is that the proposed approach could distort customers' grid use and investment decisions. These potential efficiency effects are similar to those discussed in the overheads section of this letter. These effects are inconsistent with the efficient operation limb of the Authority's statutory objective (as well as its intent in respect of the guidelines). We are referring back the proposed funding approach on this basis.

39 It is relevant here that one of the main reasons for the Authority's introduction of the SAC PDP was to mitigate the risk that for some parties a high residual charge might push their charges above standalone cost. See the Authority's Supplementary Consultation Paper, February 2020, paragraph 6.17: "Initially at least, the majority of the costs of pre-2019 investments are proposed to be recovered through the residual charge, which is not based on the benefits customers receive from the grid. So customers that receive below-average benefits from the grid (perhaps because they are located close to generation) may nevertheless pay a large residual charge, and as a result be charged above standalone cost."

Appendix B Proposed TPM - marked-up with comments