ENERGY TRUSTS OF NEW ZEALAND INC.
P O Box 61
Orewa
Auckland 0946
Our address for service is

ETNZ
PO Box 61
Orewa
Auckland 0946

29 November 2021

Submission on Proposed Transmission Pricing Methodology Consultation paper

Our position summarised

As the organisation representing consumer and community owners of EDBs, ETNZ has both an asset owner and a consumer perspective in making this submission. In particular, we have focused on the impacts of the proposed TPM on our beneficiaries, who are predominantly household and network-connected businesses but who also include a range of community enterprises.

As a general comment we consider that there is an excessive weighting of transmission costs towards households and other consumers under the proposed TPM, especially in areas where a judgement call has been made on Benefit-based charge allocations.

Allocation of BBCs

Section 5.2 of the Consultation paper states *Benefit-based charges are intended to promote more efficient investment by* <u>*transmission customers*</u> *and increase scrutiny of proposed transmission investments.* <u>*Consumers*</u> *who would benefit and end up paying for a grid investment would have a greater interest in having a say on that investment, to make sure it is fit for purpose and better than alternative solutions.*

In our view "transmission customers" are primarily the parties who use the Grid: i.e. the generators who inject their product into it at their connection points, and then on-sell it to retailers at Grid Exit Points.

We recognise that successive TPMs have loaded transport charges through the Grid onto consumers (generally via EDBs) as a convenience. This may not have been unreasonably distortionary while only very limited demand-side and local generation technologies were available to compete with Grid-dependant generators, but that is no longer the case.

Accordingly, especially with the Government's policy focus on green energy and climate change reduction, we would expect the TPM allocation processes to at least apportion a major share of transmission asset and investment costs to those Grid-dependant generators.

Put simply, if the large Grid-dependant generators continue not to be required to take Grid transport and associated costs into account, they will be more inclined to make investments that lead to additional transmission loadings, meaning more expenditure on supporting Transpower infrastructure.

While the Consultation paper discusses the generation/load allocation in some depth, it comes to a vague position on a 50/50 split that's phased in gradually and then reviewed in 5 years:

> 5.41 However, this [the 50/50 split] is a finely balanced decision and the Authority is conscious of the potential long-term effect. Given the uncertainty, we would welcome submissions and further clear and robust evidence to substantiate any particular weighting factor, and the materiality of this factor for decisions on investment in generation.

In effect, the proposed TPM seems – on the limited evidence available, and taking the price capping arrangements into account – to result in around 5% of the Grid transport cost being reallocated to generators over the 5 years before the allocation formula is reviewed.

Given the EA's comment (s. 5.34) that *The Authority has investigated whether the proposed weighting factor is appropriate as a starting point, including by providing Transpower with analysis, which suggested that an allocation in the range of 20–30% to generation might better reflect the benefits generation would receive from investments (relative to load)* we have no confidence that any eventual review will lead to an increased proportion of the costs of moving electricity through the Grid being met by the generators who rely on the assets involved, and we may well see offtake load carrying even more of the price burden.

It is significant that the Consultation paper uses the Waikato/UNI programme as a model to help understand the approach to be used to allocated Benefit-based charges:

> 5.20 The resiliency method (clauses 57-59 of the proposed TPM) will apply for a sub-set of BBIs that are primarily needed to mitigate high-impact, low

probability risks such as a cascading outage that could result in an island-wide black-out. To illustrate the application of the resiliency method, Transpower provided the WUNIVM (Waikato and Upper North Island Voltage Management project) case study.

5.21 For BBIs that are primarily intended to mitigate cascade failure, the method allocates costs to offtake customers across the entire island in which the system event is being mitigated, (eg, the North Island) in proportion to their historical load.

Our concerns about the future allocation of the BBC are reinforced by the use of this example. As shown in Appendix E of the *Reasons paper*, no part of the costs of this $140+ million dollar programme will be allocated to generation, even in 2030, 8 years after its commencement:

TRANSPOWER NEW ZEALAND LIMITED

Table 1: Indicative intra-regional allocators, customer allocations, and benefit-based charges for the Waikato dynamic reactive device

	Intra-regional allocator/net-private benefit (average kWh p.a. 1 Sep 2015 – 31 Aug 2020)	Customer allocation under the proposed TPM	Indicative charge under proposed TPM in 2030 ($k)	Estimated interconnection charge attributed to BBI in 2030 under current TPM ($k)
Alpine Energy	0	0.00%	0	71
Aurora Energy	0	0.00%	0	129
Beach Energy Resources	60,999,380	0.27%	17	6
BHP NZ Steel	483,368,071	2.14%	133	6
Buller Electricity	0	0.00%	0	4
Centralines	117,522,930	0.52%	32	14
Contact Energy	4,885,856	0.02%	1	0
Counties Power	567,704,777	2.51%	156	74
Daiken Southland Ltd	0	0.00%	0	5
Eastland Energy	292,013,728	1.29%	80	39
Electra	330,859,777	1.46%	91	43
Electricity Ashburton	0	0.00%	0	31
Horizon Energy	435,128,468	1.93%	119	8
KiwiRail Holdings Ltd	47,729,800	0.21%	13	6
Mainpower	0	0.00%	0	70
Marlborough Lines	0	0.00%	0	45
Methanex NZ	49,357,517	0.22%	14	4
Nelson Electricity	0	0.00%	0	7
Network Tasman	0	0.00%	0	76
Network Waitaki	0	0.00%	0	23
Norske Skog Tasman	9,339,555	0.04%	3	0
Northpower	1,072,251,294	4.75%	294	102
NZ Aluminium Smelters Ltd	0	0.00%	0	421
OMV NZ Production Ltd	79,219,974	0.35%	22	7
Orion	0	0.00%	0	424
Pan Pac Forest Products	469,509,631	2.08%	129	13

TPM Proposal Reasons Paper Appendix E: Resiliency method case study -WUNIVM 30 June 2021 Page E.6

TRANSPOWER NEW ZEALAND LIMITED

	Intra-regional allocator/net-private benefit (average kWh p.a. 1 Sep 2015 – 31 Aug 2020)	Customer allocation under the proposed TPM	Indicative charge under proposed TPM in 2030 ($k)	Estimated interconnection charge attributed to BBI in 2030 under current TPM ($k)
Powerco	4,344,039,116	19.23%	1192	562
Powernet	0	0.00%	0	150
Scanpower	82,330,272	0.36%	23	9
The Lines Company	255,270,369	1.13%	70	25
Top Energy	158,578,513	0.70%	44	29
Unison Networks	1,299,921,533	5.76%	357	178
Vector	8,557,464,186	37.89%	2349	1172
Waipa Networks	405,594,488	1.80%	111	48
WEL Energy	963,909,264	4.27%	265	134
Wellington Electricity	2,254,116,609	9.98%	619	340
Westpower	0	0.00%	0	10
Winstone Pulp International	234,830,513	1.04%	64	16
Total		100%	$6,200	$4,300

This transfer of responsibility (in terms of who bears the costs) would be a further move in a series of system support changes that have resulted in transferring to consumers costs involved in enabling generators to provide a stable, merchantable product to the wholesale electricity market.[1] In its draft decision in approving the programme, the Commerce Commission made it clear that the primary reasons making the support investments necessary are decisions made by generators that benefit them commercially:

> "X6 Transpower considers, and we agree, Stage 1 is needed because Transpower's studies show that during periods of high demand there are risks of widespread interruptions to supply due to large fluctuations in voltages in the transmission network. Such fluctuation in voltages can occur after an unplanned disconnection of a major component from the transmission network when the two 250MW-Rankine generation units at Huntly Power Station (Rankines) are not in service during periods of high demand.
>
> "X7 The other aspect of the investment need for Stage 1 is the effects on voltage stability in the WUNI region that could occur if Genesis Energy Limited (Genesis) removes the Rankines from normal service. While Genesis has not announced its position on the Rankines' future, Transpower has prepared and submitted the MCP on the basis of Genesis retiring the Rankines, without replacement, by the end of 2022.5

We recommend that the Authority ensures that early proactive steps are taken to ensure that BBC weightings ensure that parties injecting electricity into the Grid meet the greater part of the costs of transporting that electricity to GXPs. We also recommend that the very significant uncertainties associated with the proposed review in 5 years' time of the generation/load allocation be avoided, and instead that early steps are taken to ensure that Grid-dependant generators

[1] Other examples are the decommissioning of the synchronous condenser service provided by the Marsden A station in 2007, and allocating the under frequency load shedding burden to (mainly) domestic consumers without compensation.

meet the full costs of the transmission equipment required to move their product to the point of sale.

Application of Residual charge to battery storage

The Consultation paper covers this issue in considerable depth, using the following definition of the technologies it will apply to:

> 7.36 We propose the term 'battery storage' instead of the term 'battery' that was proposed by Transpower. However, the wording in the definition otherwise aligns exactly with that proposed by Transpower. It is a deliberately broad definition and includes a range of methods and equipment for storing electricity, including:
> (a) Electro-chemical storage, eg, lithium-ion and redox flow batteries.
> (b) Electrical storage, eg, capacitors.
> (c) Mechanical storage, eg, compressed air energy storage, flywheels and pumped hydro storage systems.
> (d) Chemical storage, eg, hydrogen.

We follow, and have no particular issues with, applying the approach as explained to the 'battery storage' technologies covered in '(a)' and '(b)' and parts of '(c)' and '(d)". However, we question its applicability to pumped hydro systems such as the 'Project Onslow' option. (We are uncertain about how a major hydrogen project might be treated but suspect that our concerns about pumped storage would also apply to it.)

We note that "The residual charge is to be paid by all transmission customers to the extent they are load customers." and that "This means battery storage (including grid-connected batteries) would attract a residual charge only to the extent that it finally consumes electricity (that is, the difference between energy in and out)."

In the case of a pumped storage project requiring the Grid to export electricity to GXPs, this would mean that it would result in a relatively small charge based on the net energy it produces, and this might be reduced further if a circuit that by-passed the Grid were used to power its pumping function from run-of-river generation.

- First, we are unclear from the explanation in the Consultation paper that the residual charge will be paid by customers 'to the extent that they are load customers', whether this small charge would in fact be met by the pumped storage owner or would be allocated to a pool of 'load customers' along with the other residual charges. The latter would be unreasonable, and it should be made clear that this is not how the TPM will be applied.

- Second, it seems from the discussion in the Consultation paper that the other transmission costs resulting from transporting electricity from pumped storage through the Grid will be met by (mainly) end consumers through the BBC, with no apparent mechanism for this to be reallocated to the generator benefitting from the pumped storage over time, as that generator seems to have been exempted from anything other than the residual charge. This would be inconsistent with the proposed forward allocation of BBC costs. Again, this should be clarified.

Prudent discounts

We are most uncomfortable with the concept of deals being struck with favoured customers (and revised from time-to-time, like the aluminium smelter deal) when this is at the expense of other consumers. There is a long history, in New Zealand and elsewhere, of politically supported arrangements of this type that involve cross-subsidising particular industries or plants. We would expect the EA to agree that cross-subsidies of that type are economically inefficient.

At the very least we would like to see total transparency applying to all prudent discount arrangements, independent and publicly accessible audits of them, and yes, we support the provision of a "Prudent discount manual" that is binding on Transpower. We would also like to see the Electricity Authority similarly bound to prevent arrangements that have the effect of cross-subsidising favoured Participants being included in the Code.

Karen Sherry
Chair, ETNZ