Transmission Pricing Methodology: Consultation Paper

2 December 2021

Overview

Northpower and Top Energy welcome the opportunity to provide feedback on the Electricity Authority's Transmission Pricing Methodology consultation paper.

This paper is focused on the proposed text of the TPM as developed by Transpower and reviewed by the Authority, on the basis that the Authority has already issued its TPM guidelines to Transpower. Our previous submissions covered off our views around the selection of the Benefit Based approach selected by the Authority in its TPM guidelines.

Theme	Key feedback and recommended Options
First mover Advantage Type 1	We **agree** with the introduction of Funded Asset Component (FAC) mechanism to address Type 1 First Mover disadvantage and don't believe that this will result in any material competition concerns in the market for generation development.
First mover Advantage Type 2	We **disagree** with the proposed Benefits Based Cost Allocation for anticipatory connection investments as this will lead to load customers paying high costs without any benefit which is not consistent with the Guidelines. We **agree** with Transpower's recommendation that any anticipatory capacity is recovered by spread across *all* transmission customers.
Transitional Congestion Charge	We **disagree** with the decision not to implement a transitional congestion charge. We think the 300MW increase in peak demand forecast by Transpower is too low, and without a peak charge there is increased risk to grid security.
Prudential Discount commencement date	We **disagree** with the current proposal which requires existing prudent discount holders to re-apply under the new TPM, and effectively prevents any participant from applying for a prudent discount until the new TPM is implemented.
Prudential discount timeframe	We **disagree** with the default maximum period of 15 years. Agreements should match the usable life of alternative new assets, otherwise consumers might be incentivised to inefficiently build the new assets to gain long term certainty as to cost.
Disconnection of embedded plant	We **request clarification** of the proposed wording, and propose an approach whereby large embedded plant is treated as if it were directly connected to the grid, and both benefit based and residual costs cease upon disconnection and are recovered across other beneficiaries (for BBI) and all load consumers (for residual costs) from the following pricing year. We would not support an approach that simply reallocates residual costs within the same region.
Caps on pass through of increases in Transmission charges	We **support** that a price cap is implemented to manage price shock however we **disagree** that this is applied on notional electricity bill. We propose it is based on notional dollar value.

First mover disadvantage Type 1

We agree with the introduction of Funded Asset Component (FAC) mechanism to address Type 1 First Mover disadvantage and don't believe that this will result in any material competition concerns in the market for generation development.

First mover disadvantage Type 2

The TPM proposes that where Transpower build a connection asset with excess capacity in anticipation of uncertain future customers, the cost of that anticipatory capacity would be allocated to *regional beneficiaries* until such future customers connect.

Our concern is that in our area, we are the only *regional beneficiary*. The analysis in Appendix E section E.15 shows that 99.7% of the cost would fall onto load customers in the Northland low voltage region. In other words, Transpower can construct capacity that is not required or requested by us, and this will still be charged to us.

This runs counter to the basic principle of the TPM that the beneficiary of the cost pays. In this scenario, we would bear all of the cost and risk, and the benefit of lower connection costs (from efficiently building larger scale connection assets) would go to the future hypothetical connecting party. This in effect socialises the costs of the early investment to residential and small commercial consumers, and privatises the benefits to the later connecting party which is likely to be a large load or generator.

Another purported benefit of the TPM was the additional scrutiny that investments would receive from stakeholders, because they would be deemed to benefit and therefore have to pay for them. In this scenario, we would still have to pay even if we opposed the investment and did not directly benefit.

We submit that if Transpower wants to build a connection asset with excess capacity in anticipation of uncertain future customers, the cost should either be:

1) Absorbed by Transpower through a lower return on its RAB; or

2) Spread across *all* transmission customers as proposed by Transpower.

Our preferred approach is that the costs of building early are met by Transpower and accumulated, and then charged to parties when they connect. That means the parties receiving the benefit of the efficiencies of building early receive the additional timing costs of doing so as well, avoiding socialising the costs and privatising the benefits as would be achieved under the second option.

Transitional Congestion Charge

Transpower has completed analysis that shows removing the RCPD price signal could result in up to 300MW[1] of additional peak load. We are concerned as to the accuracy of this analysis, and particularly the potential for increased grid instability, resulting in more instances of the black-outs experienced on 9 August 2021.

To put Transpower's forecast in context, Northpower and Top Energy's demand response / controllable load on an average winter's night is shown below. The table shows that Northland load would increase by ~10% if we stopped responding to the RCPD price signal.

Demand response	
Northpower	**Top Energy**
• ~31MW of controllable load, with ~20MW of load controlled at any one time. Peak load (net of DG and load control) of 185MW.	• 18MW of controllable load with ~ 7MW controlled at any one time. On 9 August 2021 Anytime Maximum Demand of 16MW peak during the emergency event. • In addition, 14MW of Diesel generation available for network purpose to manage load

The ~27MW increase represents nearly 10% of the total increase that Transpower has allowed for, yet we only represent 3.7% of the grid's peak load. While we might have a high level of mass market ripple control compared to some networks, we also have a high level of large industrials embedded in our networks, which we do not control the load of. Extrapolating this result, peak load could increase by 10% or ~700MW on the grid.

While we understand the theory that 'nodal pricing sends a price signal' to control load on cold winter nights because of high spot prices, in reality it doesn't work because neither networks nor consumers receive this price signal. Retailers receive this signal, and while we have engaged with them as to whether they want us to load control to manage their generation costs, we received little interest. This is complicated by the fact that ripple control is not configured, or easily configurable, to control or not control based on who the retailer for the ICP is.

Consumers for the most part do not receive spot price signals to manage their load, nor do they have the automated ability to do so. As such, increases in load will drive spot prices higher, and retailers will respond by increasing their (for the most part non-cost reflective) price signals across the board rather than using a targeted price signal to incentivise consumers to avoid peak times.

[1] https://www.ea.govt.nz/assets/dms-assets/28/Monthly-SO-and-System-Performance-Report-to-the-Electricity-Authority-for-July-2021.pdf

We do agree that distributors will continue to use ripple control to manage their own network peaks, but this is limited to the *actual* timeframes that distributors have congestion. Currently we expect to employ load control very rarely outside of managing planned or unplanned outages, and we caution Transpower not to over-estimate the amount that networks will need to use load control to manage their own congestion.

For example, during the grid emergency event on 9 August 2021, Northpower did not have any congestion on its network which required control, and we foresee little requirement to control demand in the near future for the purposes of managing our network. While Top Energy did experience some isolated congestion e.g. Taipa substation, future upgrades mean we also see little requirement to control demand in the future for the purposes of managing our network.

As such, we are concerned as to whether generators and Transpower have the capacity to respond to a 700MW increase in peak load, and whether they can do so without frequently resorting to emergency measures and requiring curtailment.

Prudential Discount commencement date

We understand from Transpower that any prudent discounts approved under the current TPM will need to be re-applied for under the proposed TPM.

Northpower is currently reviewing its connection assets at BRB, due to the upcoming de-rating of the refinery plant which is embedded in our network at this GXP. This de-rating will reduce our load at BRB by ~61%, and means that we no longer need the 220kV connection assets at this GXP which cost ~$1.7m p.a.

There are two options open to us:

- To connect at MDN, resulting in a considerable cost saving, and stranding of the spur from MDN to BRB which is treated as a connection asset under the TPM.

- To apply for a prudent discount on the basis of the above.

If we apply for a prudent discount, the primary benefit falls to Transpower and to other future connecting parties. While our cost would be reduced to the actual cost of implementing an alternate connection at MDN, we would only gain cost certainty for 15 years under the proposed TPM and would then have to re-apply.

By contrast, Transpower would avoid the stranding of assets between BRB and MDN. Transpower would then need to weigh up whether to decommission the assets, or leave them in situ in-case a new customer connected in the future.

A future customer would benefit from sharing the costs with us, rather than paying the entire $1.7m annual cost of the GXP, and also from not having to pay for new assets to be constructed (in the event that they had been decommissioned).

However, the TPM as drafted introduces considerable issues, which pushes us towards a conclusion to disconnect from BRB, despite that long term likely being an inefficient outcome for the Grid:

- If we apply for a prudent discount now, our application is unlikely to take effect before the new TPM takes effect. Once the new TPM takes effect, we have to re-apply, incurring further cost. It is unclear whether, under this scenario, we would have to wait a further notional period of time for the hypothetical new assets to be 'constructed' under the new TPM, or if the time elapsed for hypothetical construction under the existing TPM would count.

- If we wait until the new TPM is introduced, we would have to continue paying the higher asset cost until the new TPM becomes effective and we can apply under it. The hypothetical 'construction' time would not commence until the new TPM took effect and our application was approved. There is also no certainty that our application would be approved, we could wait until the new TPM is implemented and the application could still be declined.

As such, in order to gain certainty as to cost reductions and avoid having to pay higher connection costs for longer than we need to, based on the current proposed draft the most logical outcome is to disconnect at BRB and connecting at MDN. However, this is likely an inefficient outcome, because it results in decommissioning working assets, and removes capacity at BRB that other parties may want to utilise in the future for new generation or load developments.

Prudential discount timeframe

We submit that a prudential discount agreement should be for the useful life of the assets which would have been built, and that a 15 year timeframe is not realistic. If the timeframe is arbitrarily short, consumers may look to build new assets rather than take a prudential discount in order to lock in lower costs for a longer period.

Disconnected of embedded plant

Clause 86(6) states that if the "large plant owner or a related entity of the large plant owner is a customer after the disconnection of the large plant" effectively the BBI reduction adjustment does not apply and the notional exiting customer's BBC for the continuing BBI must be attributed to the relevant person (the large plant owner) in its capacity as a customer.

If there is more than 1 relevant person, it applies to the large plant owner, and if the large plant owner is not a customer after the disconnection of the large plant, a related entity is determined by Transpower.

We are not clear whether this applies to the large plant owner being a ***customer*** *of* ***Transpower***, or a ***customer*** *of a* ***transmission customer*** (i.e. an EDB). The definition of “customer” is a “**designated transmission customer**”, but neither “designated”, “transmission”, or “designated transmission customer” are defined in the definitions section.

We’re also not clear whether this definition would prevent a customer who de-rates, and will therefore continue to be a *customer* of the EDB, from having their continuing BBI charges (which are charged to the EDB and passed through to the customer) reduced and re-allocated under this clause.

We request the proposed wording is clarified as to whether when a large plant is embedded in a EDB and de-rates its plant, will the BBI charges which are charged to the EDB (and passed through to the customer) be reduced and reallocated, or is the “large plant owner” a customer and therefore will be captured by 86(6) resulting in any BBI commissioned in the last 10 years continuing to be charged to the customer (via the EDB).

We support an approach whereby large embedded plant is treated as if it were directly connected to the grid, and both benefit based and residual costs cease upon disconnection (and are adjusted on de-rating) and are recovered across all other beneficiaries (for BBI) and all load consumers (for residual costs) from the following pricing year. It is important that costs are recovered from all remaining transmission customers, and not simply spread across the remaining customers in the region.

This approach is critical to enable large embedded customers to pivot as industries evolve and change, to avoid scenarios where they might otherwise have to close. It also ensures that consumers do not run the risk of paying a large industrial’s transmission costs after they close or change their business model, simply because they happen to be embedded for historical reasons.

Caps on pass through of increases in Transmission charges

We note that the TPM proposes a cap on the total *electricity bill* not the total *transmission component* of the electricity bill. A 3.5% increase in total electricity bills, plus inflation currently running at 4.8%, could see consumers receiving electricity bill increases of up to 8.5%.

In addition, the cap does not apply to new investments. Our significant concern is not the immediate 3.5% increase, but where prices land in 30 years' time as more and more investments are allocated under the BBI model.

We agree that a cap should be applied to manage price shock on any individual load connection. However, the limit on the total increase in interconnection charges relative to the charges a customer incurred should be based on 2021/2022 rather than 2019/2020 and the price cap should be expressed in nominal dollars terms rather than % change in the notional bill.

Applying the calculation to the proceeding period will ensure that the transitional cap achieves its purpose of limiting the actual price shock to connection customers. Given the nature of current RCPD charges these can vary greatly from year to year potentially resulting in a significant differential between 2019/20 to 2021/22.

Applying a price cap in nominal dollars will mean that, all else equal, similar customers will have the same cap avoiding the issue of these customers have different increases all because of the cost of their current supply. This is particular important for rural networks with lower socio-economic demographics.

For example, the charges for Top Energy have been estimated at $5.9m in Table 6 an increase of $0.9m based on current methodology. However, Top Energy’s Transmission charges for 2022/23 year, as notified by Transpower are $2.2m. As a result, Top Energy’s Transmission charges will be increasing by $3.7m, a 270% increase. This increase is significantly higher than any other distribution customers with the next largest at 197%.

Despite Transmission charges increasing by $3.7m (270%) the price cap proposed in 12.39 will still not be reached meaning that customers would still face this increase. This is because it is based on the change notional electricity bill rather than actual dollars.