OJI
Beyond the Boundaries

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Jean-Pierre De Raad
Manager, Network Pricing
Electricity Authority
By email to submissions@ea.govt.nz

Dear Jean-Pierre

Re: 2019 Issues Paper: Transmission Pricing Review consultation paper

Introduction

1. This is a submission by Oji Fibre Solutions (NZ) Ltd (OjiFS) on the "2019 Issues Paper: Transmission Pricing Review Consultation paper" published 23 July 2019.[1] We refer to the consultation paper as 'Issues Paper' or 'the Paper' throughout this submission.

Background to Oji Fibre Solutions

2. Oji Fibre Solutions is an Australasian pulp, paper and packaging products processing business with substantial direct investment in the New Zealand economy. OjiFS exports to global markets, predominantly in Asia, with major competitors spread around the globe. OjiFS is also a substantial employer with over 1400 direct employees based in NZ.

3. OjiFS operates some of New Zealand's largest industrial sites and is one of the largest producers of biofuel renewable energy, with over 80% of our process energy needs derived from renewable sources. OjiFS generates approximately 300 GWh per annum of electricity via cogeneration plants utilising some of this process heat, but nevertheless is one of New Zealand's largest electricity consumers, with gross load in the order of 950 GWh per annum.

4. OjiFS has sites throughout NZ, but has two large electricity points of supply at Kinleith and Kawerau. At present, OjiFS is not a direct connect, but is supplied via various EDBs.

5. OjiFS is a member of the Major Electricity Users Group (MEUG) and the TPM Group. To the extent that this submission does not conflict with anything in the MEUG submission or the TPM Group submission, OjiFS supports and endorses both the MEUG submission and the TPM Group submission.

6. This submission is not confidential.

[1] Refer web page https://www.ea.govt.nz/dmsdocument/25466-consultation-paper-transmission-pricing-methodology2019-issues-paper-full-document at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/

Submission Response

General Comments

7. The Issues Paper makes the claim that this proposal will deliver significant benefits to consumers. Our view is that the CBA justifying this claim has numerous errors and makes incorrect assumptions (see paragraphs 22-26 for details). Our view is that the proposal is most definitely not in the best interests of consumers and indeed has a far greater potential to add significant costs to consumers.

8. The Paper also makes the claim that the proposal supports the transition to a low-emissions economy at least cost to consumers. Our view is that the instead the proposal creates additional costs that will not only defer investment in new renewable energy, but will increase the emissions from non-renewable sources, particularly thermal electricity generation.

9. In particular, we note that the proposal creates a significant disincentive for OjiFS to invest in energy infrastructure in the central North Island. OjiFS's potential investments would increase the supply of base-load renewable electricity. However, the increased costs arising under the proposal will reduce the commercial viability of such investments.

Problem Definition

10. We disagree with the Authority's view on flaws with the current TPM. In particular, our view is that the RCPD mechanism is an effective means for reducing peak demand and deferring grid investment. We agree that it is perhaps stronger than it needs to be, but that it has the desired effect and provides correct incentives for reducing congestion on transmission and distribution networks.

11. We disagree with the comment that the RCPD charge "inefficiently discourages use at times consumers most value it, even when there are no grid congestion issues". For Oji FS, and indeed most consumers, peak periods are not necessarily the times when consumers most value it. OjiFS requires electricity 24 hours a day, 365 days a year, and electricity at any one point in time is equally as valuable as at any other point in time. We believe that this is likely to apply to most, if not all, consumers to some extent. Electricity demand is highly inelastic, with significant amounts of load unable to respond to RCPD signals, with the majority of load insulated from locational marginal pricing signals. Consequently, to move load from peak periods, a strong targeted pricing signal is required to incentivise customers who are able to respond.

12. We also disagree with the following statement that the RCPD charge "encourages customers to unnecessarily invest in technologies such as batteries and distributed generation to avoid paying transmission charge, shifting charges to others without reducing Transpower's costs." While such investment may not reduce Transpower's costs in the short term, in the medium to long term, any deferral of transmission investment does indeed reduce Transpower's costs, and therefore reduces charges to a wider number of customers. We also note that any investment in batteries and distributed generation also reduce the requirement for further investment in both distribution networks and grid-connected generation. Indeed, without such investment in renewable distributed generation, the marginal fuel source will continue to be thermal generation, thereby increasing carbon emissions.

Statutory Objective

13. OjiFS agrees that the aim of setting a TPM that is "service-based and cost-reflective" is consistent with the Authority's statutory objective. However we note that this lacks sufficient clarity at the present point in time and does not appear to take into account issues such as reliability, security or circumstances where investments provide few (if any) benefits. We also note that this is a reasonable objective on the basis that the benefits of investment are greater than the cost, and that (given potential technology changes) consideration must continue to be on minimising potentially unnecessary investments.

Benefit Based Charges

14. We agree that customers which benefit from specific assets should pay the costs associated with those assets. We note with some concern the proposal indicating that benefits and allocation of costs should be set before the investment is made. Our view is that this is highly problematic – the electricity system is dynamic and beneficiaries (and the level of benefits) change on a half-hourly basis. The assumptions made in predicting benefits are going to be at best inaccurate.

15. For instance, the beneficiaries will change – existing customers may exit the location, while new customers may connect. Any mechanism needs to make sure that new customers pay a fair proportion of the costs (as they clearly benefit), while customers which no longer benefit should not be required to pay for an asset that they clearly no longer benefit from.

16. In our view, the assessment of benefits should be calculated ex-post, that is, after the period over which the benefit is assessed. Just as RCPD charges use an assessment period which is applied during the following pricing year, benefit based charges should be calculated during one assessment period for application during the following pricing year. We also have the view that the payment of costs should not exceed the benefits accruing to a specific customer over the assessment period.

Nodal Pricing Incentives

17. Nodal pricing is limited in terms of its application to transmission investment. We agree that nodal pricing is an effective way for optimising supply and demand in real time. However, we believe that the inherent short term nature of nodal pricing (i.e. half hourly trading periods) has limited impact on longer term decision making (e.g. the 50 year plus investment life of transmission assets, generation assets and industrial investments). Although we agree that nodal prices do provide a weak signal for longer term investments, we do not believe nodal pricing signals provide sufficient signalling of the incremental costs and/or benefits of such investments. Oji therefore has concerns that significant change will reduce the incentive for parties to reduce congestion, and therefore lead to potentially unnecessary and costly transmission upgrades in the future.

HVDC Charges

18. We note the Issue Paper's statement that HVDC cost allocation distorts new generation investment. We agree that new investment in SI generation should have an even playing field when compared to potential new investment in NI generation. However, we do note that the original investment in the HVDC was made in conjunction with investment in SI hydro generation. In our view, the underlying charge for HVDC forms part of the cost to SI generators. In the absence of the HVDC, investment in generation and transmission assets

would have been made in the North Island, so therefore the cost of the initial HVDC investment is intrinsic to SI generation.

19. We do however note that Pole 3 investments are distinct from the initial investment associated with SI generation investment. We note that Pole 3 investments provide substantial benefits to other participants, particularly NI generation during periods of low SI lake levels. We therefore consider that the Pole 3 and subsequent projects should be funded by both SI and NI generation investment. This therefore removes any distortionary effect HVDC charges have on new generation investment.

RCPD Charges

20. Our view is that the RCPD charge is a crucial component of transmission pricing and should remain for all regions. With the benefit based charges applying to more recent investments, the RCPD charge should reduce. We agree that the RCPD charge is stronger than it needs to be to create an efficient price signal, but that without this signal there is a very real risk that inefficient transmission investment will occur. Rather than throwing the baby out with the bathwater, our view is that this charge should be amended in line with the long-run marginal cost of transmission, and potentially calculated across a larger number of trading periods to ameliorate any inefficiencies in the price signal.

Residual Charges

21. We note that the impact of benefit based charges and a retained RCPD charge will reduce the residual charge. However, we also note that the residual charge should be service based and cost reflective. In our view, service based should be related to the total energy supplied by the transmission network. As peaking charges will be made using the now retained RCPD charge, the residual should be calculated using net load (MWh/GWh). This would have the advantage of spreading the cost across all load and therefore not unduly incentivise inefficient investment in distributed generation or batteries.

Cost Benefit Analysis

22. The fundamental issue with the CBA is that it assumes a fall in wholesale electricity pricing as a result of investment in new generation in response to increases in load. New generation will only be built if it increases the profitability of the owner of such new generation. Fundamentally this relies on sustained higher electricity prices to justify the investment. The logical conclusion is therefore that consumers cannot therefore benefit from lower electricity prices which will not eventuate.

23. The proposal, as stated, assumes increased electricity demand to occur in response to signals to maximise use of transmission assets. In the medium term, marginal increases in electrical energy will be met by thermal generation. The cost of thermal generation is a function of the short run marginal cost (SRMC) of the fuel, including carbon, operational costs and the cost of capital associated with the thermal plant. This will continue to put upward pressure on both spot pricing and contract pricing (eg. CfDs and FPVV contracts). Higher prices will only increase costs to consumers.

24. The Authority assumes (not unreasonably) that new generation will be built to meet this additional load. However, in the medium term, the marginal electrical energy will continue to be produced by thermal generation at a higher cost (note that the assumption of reaching 100% renewable generation seems unlikely, and at best is decades away). So effectively, the

additional generation comes at a significant cost, as does any additional investment in both transmission and distribution assets.

25. We also note that the CBA assumes exposure to nodal pricing (including TOU pricing) increases over time. Very few consumers have significant exposure to nodal pricing. The vast majority of smaller consumers are on FPVV (retail) contracts, whereas commercial and small industrial customers are on fixed TOU tariffs. While large industrial consumers are exposed to nodal pricing, the majority of exposed load is managed through hedge contracts (eg. Contracts for differences). While there is an argument that these parties can reduce load in response to high prices, the reality is that there is limited ability for large users to respond in real time, with any load reductions needing to be planned well ahead of time.

26. We therefore believe that not only is the benefit of more electricity use at peak demand is overstated, the benefit of lower prices in the future is vastly overstated. This therefore calls into question the validity of the CBA.

Recommendations

27. In response to the Authority's invitation for an alternative approach, we suggest the following:

Benefit based charge

a. A benefit based charged should be implemented for specific assets when benefits are demonstrably obtained by a small number of participants. Any benefit based charge should be determined on the basis of **actual** benefits, determined retrospectively, with pricing applied for the following pricing year (in a similar manner to the current RCPD assessment period). The amount of the charge for any participant should be limited to the amount of the benefit gained over that assessment period. In addition, we suggest the BBC should initially be applied only to the following historic assets:
   - North Island Grid Upgrade
   - Wairakei Ring
   - Lower South Island Reliability
   - Lower South Island Renewables

HVDC charge

b. A revised HVDC charge should apply only to existing generation capacity. The original HVDC investments formed part of the original South Island generation investment and as such the cost of this investment should be borne by existing generation. We agree that the present charging regime creates a disincentive for **new** generation in the South Island and therefore new generation should not be required to pay for the pre-HVDC Pole 3 assets.

c. HVDC Pole 3 assets provide benefits to both North Island and South Island generation depending on lake levels and generation flows. We therefore have the view that the costs of HVDC Pole 3 should apply equally to both North and South Island generation, including any new generation.

RCPD Charge

d. An RCPD charge is essential in managing peak demand. We acknowledge that the existing RCPD charge is stronger than required. We therefore suggest that the RCPD charge should remain for all regions, albeit with design modifications to reflect the LRMC of transmission. While we don't have a definitive view on the level of the charge, based on previous analysis completed by Transpower, a charge of $70 per kW, potentially over an increased number of peaks may be sufficient to provide the desired efficiencies.

Residual Charge

e. Any residual charge (we expect this to be minimal given the RCPD charge and BBC) should be allocated on a net MWh basis rather than a gross MW AMD. The residual charge should be a proxy to reflect actual grid use. By using a net MWh approach, this spreads the cost equally across all consumers.

OjiFS is more than happy to meet with the Authority to discuss our concerns and our suggestions as above.

Feel free to contact me if you have any questions on our submission.

Regards

Darren Gilchrist
Energy Manager