Transmission Pricing Review – 2019 Issues Paper

Submission to the Electricity Authority

1/10/2019

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Buller Electricity Limited (BEL) appreciates the opportunity to make a submission to the Authority in respect of the Transmission Pricing Review – 2019 Issues Paper.

Our submission consists of 2 sections which firstly, provide our general overview and comments of the proposal and secondly, our response to the specific questions raised in the consultation paper.

1. General Overview & Comments

The Authority has clearly further developed, refined and matured its Transmission Pricing Methodology (TPM) proposal over the past 3 years. As it is difficult to see how further work would result in major changes, and in the interests of moving this process forward, it is now time for Transpower to be given the task of developing a TPM which meets the proposed guidelines.

A key development in this proposal is that the Authority is now of the view that Locational Marginal Pricing (LMP) is a fully efficient signal for grid use and investment in the long-term, and the need for a peak transmission charge as a component of the TPM will diminish over time. While it is generally well accepted that LMP is efficient in the short-term, many in the industry will remain of the view that LMP is no replacement for a peak transmission charge as a forward-looking signal to manage grid congestion and defer grid investment. The idea that the LMP will work alongside the TPM and be the only price signal used to manage transmission peaks and congestion, has the potential to facilitate significant change in the way the industry operates, and demand is managed. How well this works in practice and the outcomes it delivers remain to be seen. In the interests of furthering the industries understanding in relation to the future role and scope of demand management, it is suggested that the Authority should publish an information and discussion document which details the how it is envisaged nodal, transmission and distribution pricing will interact in a cohesive manner.

A consequence of the overly strong pricing signal provided by the existing RCPD peak charge is that the true value of existing load control by Distributors has been lost. If transmission peak charges are to be removed/unwound from the TPM it is important that sufficient time is allowed for the emergence and uptake of the new business models and load management practices the Authority alludes to, and evidence is provided to demonstrate they are delivering their intended outcomes.

As the guidelines are now less prescriptive there is significant scope for Transpower to have more design influence in developing a TPM which meets the proposed TPM guidelines. As a result of this many of the key questions and issues the Authority has raised in the 2019 Issues Paper regarding implementation decisions will be further reviewed and debated prior to the TPM being finalised.

A significant shortcoming of the Authority's Transmission Pricing Review – 2019 Issues Paper is that the impact modelling focuses solely on year one, and the information provided to assess the merit of alternative implementations is not exhaustive. No information is provided for transmission customers to assess the impacts on the TPM proposal beyond the initial 2021-22 year. For BEL, as a customer at the end of the transmission grid which makes use of a higher than average proportion of grid assets, we have no idea how a shift to benefit-based charging will impact us and potentially increase our charges in the long-term.

BEL is of the view that the Anytime Maximum Demand (AMD) data used in the impact modelling results in our residual charge allocation being significantly greater than what it should be. This is due to a double counting issue and substantial change in grid use, which should result in our AMD data being adjusted as detailed in our response to Question 69.

2. Response to Questions

Chapter 2 Current TPM situation and problem

Q1. Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

The Authority has correctly identified the key issues which exist with the existing TPM – in particular the RCPD peak charge used to allocate the cost of the Interconnected Grid.

Chapter 3 Overview of the proposed TPM

Q2. What are your overall views on the Authority's proposal for changes to the TPM guidelines?

The Authority has clearly and thoroughly developed its views for changes to the TPM guidelines and explained the reasons for the decisions which have been made.

Chapter 6 TPM development and approval process

Q5. How long should Transpower have to complete its development of the TPM and why?

Given the length of time the Authority has taken to progress TPM reform to its current status, the proposed timeline for Transpower to develop and implement the TPM is ambitious. This is especially the case as the guidelines now provide Transpower with more flexibility and consequently more development and decision-making responsibility on key issues. This will add to Transpower's burden in terms of the development, consultation and implementation workload which will be required, and take more time.

Q7. How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

Consultation.

Appendix B Reasons for policy positions in the proposed guidelines

Q10. Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

Yes, the provisions give Transpower sufficient flexibility to develop the TPM.

Benefit-based charge

Q13. Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

Yes, the introduction of a benefit-based charge should promote efficiency.

Q14. Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

The main reason for recovering the cost of the 7 proposed existing major pre-2019 investments through a benefit-based charge is to back date the TPM changes to the date of these investments – in a going forward manner e.g. not in a fully retrospective manner – making in the Authority's view the proposal more durable and efficient.

One of the supporting arguments the Authority has put forward for doing this is that the beneficiaries of future investments will not have to pay for the 7 pre-2019 investments as well as their own future investments. Using a similar argument, it can however also be stated that the beneficiaries of the 7 pre-2019 investments are paying for their own pre-2019 are well as other customers pre-2019 investments. The only way to fully absolve this issue is to allocate a benefit-based charge for all pre-2019 investments.

While BEL has no objections to the inclusion of pre-2019 investments in the benefit-based charge the following are key factors which need to be considered when selecting which investments to include:

- How accurately, fairly and consistently benefit-based allocation of investments can be determined. For larger investments, or those which have facilitated later investments and/or change of grid use, the development of a realistic counterfactual case to assess the benefit-based allocation is not necessarily straight forward, in some cases requiring a number of simplifications, assumptions and judgements in order to obtain realistic vSPD modelling results e.g. the HVDC and NIGU investments. Other submitters will be in a better position to comment on the modelling variations which exist, but in some cases this has been observed to be significant – and this unfortunately brings into question the robustness of a benefit-based approach for such investments.
- The impact of including historic investments in the benefit-based charge diminishes over time as the value of the investment depreciates
- The administrative burden required to determine the benefit-based allocation

It is understood that some additional pre-2019 investments were not considered for the benefit-based charge as they were found to currently have no benefits. As the decisions to proceed with these investments were made for valid reasons and they may result in benefits in the future, the exclusion of these investments on the basis given is not necessarily seen as being valid.

While it is difficult to assess the impact of including a greater number of pre-2019 investments without having a full chronological list of historic investments, the inclusion of the 7 pre-2019 investments chosen possibly provides the best outcome in terms of the tradeoff which exists between the durability objectives the Authority is seeking achieve and the administrative burden require to determine the benefit-based allocation.

Q18. Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

A net load approach should be used to determine customer benefits.

Q19. Should the guidelines distinguish between high-value and low-value investments?

Yes, the guidelines should distinguish between high-value and low-value investments.

Q20. If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

At this stage BEL considers that low-value investments should be allocated via the benefit-based charge using a simple method, as that would ensure that the TPM is more consistent in terms of the use of a benefit-based methodology and limits the importance of the low-value investment qualifying threshold.

Q21. What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

In order to be able to make an informed decision on this matter further information on the historic and/or future expected number of low-value investments needs to be provided. This would provide some sense as to the scale, impact and materiality of this decision.

Q24. Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

Yes, charges should be able to be revised if there has been substantial and sustained change in grid use. The reliance on the Authority's proposal on somewhat 'discretionary' change of grid use threshold criteria in a number of areas is a key weakness.

Q25. Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

No, the implementation of charges for low-value post-2019 investments should not be deferred. Using a simple benefit-based allocation methodology should mean there is a limited development and administration burden associated with the implementation of these charges.

Residual charge

Q27. Should the guidelines provide for a single residual charge or multiple residual charges?

Further information needs to be provided on the relative scale, impact and materiality of these options so that an informed decision can be made.

Q28. Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?

The remaining MAR should be recovered by through a residual charge allocated based on a customer's historic use of the transmission grid.

Q29. Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

We are of the view that the residual charge should be allocated based on historic use of the transmission grid. Whether it be net, gross and/or customer connection point aggregated, AMD as an allocator is a very rudimentary measure of grid use as it does not differentiate between locations. The Authority has shown limited interest in presenting results using more sophisticated and/or enduring measures of grid use such as that offered by flow tracing. Alternative methods could potentially provide very useful results for comparison with AMD and benefit-based allocations, and/or a better year one starting point allocation for the residual charge.

While the allocation of the residual charge should be made based on historic grid use a significant TPM design issue is how often this allocation should be updated and/or under what level of 'discretionary' substantial change of grid use criteria. As a region grows it would seem reasonable that it is allocated a greater proportion of the residual charge as its ability to pay (larger customer base) and use of the grid will also increase. While using a measure of grid use over a specific historic period which rolls forward year by year would naturally self-adjust for such changes, it would make the residual charge avoidable which is contrary to the outcome the Authority has indicated it is seeking to achieve. The merits of the available options need to be carefully considered so the relative scale, impact and materiality of this important design decision can be properly evaluated.

Q30. If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

If the residual charge is to be allocated based on AMD it should be the aggregated coincident AMD across the multiple points of connection for a customer. Such an approach would not disadvantage customers with more points of connection, and it would automatically eliminate charging anomalies such as double counting and those created when load is switched between GXPs.

Q31. Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

Comparative results should be provided so that the materiality between a gross and net load approach can be evaluated. In general, a gross load AMD allocation would appear to be more appropriate.

Q32. If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

The Authority/Transpower needs to provide information on the relative scale, impact and materiality of these options so that an informed decision can be made.

Q34. Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

No, the Authority should not determine the initial allocation of the residual charge in advance.

Q35. Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

Yes, the residual charge should be adjusted to account for a substantial change to demand due to factors over which it has no control.

Q36. Should the residual charge apply to both generation and load customers, or only to load customers?

The residual charge should be allocated to both load and generation customers. This would better align the residual charge with the benefit-based charge which is allocated to both load and generation.

Other

Q39. Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?

Yes, the TPM should include a price cap. The price cap of 3.5% of total electricity bills provides a reasonable balance.

Q43. Are the proposed additional components appropriate? If not, what changes should be made?

The proposed additional components are appropriate.

Q44. Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

The guidelines should include a peak charge as an additional component.

Q45. Should the peak charge be applied only where the grid would otherwise be congested?

The peak charge should be applied uniformly across the transmission grid as a transitional charge as the industry moves away from the existing RCPD charge.

BEL is not in favour of a locational peak charge for the following reasons:

- Customers in constrained/congested areas will needlessly pay more if the peak charge is locational
- Transmission customers should be educated in the sense that the consequences of demand growth leading to the need for grid investment should be well known in advance given the long investment approval and consultation process
- If a transmission customer deems that demand peaks need to be managed then they will be able to repackage transmission charges in a manner which achieves what they

consider to be the best outcomes e.g. residual and benefit-based transmission charges can be repackaged partially or fully as a peak charge to end-use consumers

- Determining a locational peak charge simply adds administrative burden to Transpower when the focus should be in other areas

Q46. Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

The peak charge should be phased out by simple reducing the rate at which it is applied on a year by year basis. As this is being done the wholesale market needs to provide evidence that it is behaving in a manner which is consistent with that envisaged by the Authority – there being no unintended consequences. It will take some time for the industry to establish the true value of existing load control by Distributors and for new demand response systems and business models to be implemented. While the time period over which peak charges should be phased out is unknown and cannot be predicted in advance a 5-10 period seems reasonable.

Q47. Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

No, the guidelines should not make applying a benefit-based charge to additional pre-2019 investment a core component. A fully informed decision on this issue can only be made if the Authority/Transpower provided information as to the scale, impact and materiality of the issue. See our response to Q14. for a list of factors which BEL considers need to be taken in to account when assessing the number of historic investments which should be included in the benefit-based charge.

Appendix E

Q60. Do you have any comments on the matters covered in this appendix E?

The Authority has developed its views on the role and need for LRMC type peak charge as a core component of a TPM over the past 10 years. The Authority's current view that Locational Marginal Pricing (LMP) can be used to signal the need for large-scale long-term transmission investment – as well as the more readily accepted function of signaling short-term constraints – provides an elegant solution which ties in well with demand response and future business models. While this clearly has the potential to change the way the industry operates, it will take a significant period for this level of change to become evident and accepted. How well this works and the outcomes it delivers remains to be seen.

In the interests of furthering the industries understanding in relation to the future role and scope of demand management, it is suggested that the Authority should publish an information and discussion document which details how it is envisaged nodal, transmission and distribution pricing will interact in a cohesive manner.

Appendix H

Q69. Do you consider the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.

BEL is of the view that the AMD data used for determining our residual charge should be adjusted due to a double counting anomaly and a material change of grid use. The double counting anomaly was also present in the impact modelling related to the May 2016 TPM consultation as highlighted in our July 2016 submission. This issue was acknowledged by the Authority in the December 2016 Supplementary Consultation.

The double counting anomaly occurs because of the network configuration which exists at the BEL owned Robertson St Substation where the ORO1101 & ORO1102 are operated in parallel. At any point in time the load can be supplied from either GXP as a result of a planned or unplanned outage of Transpower or BEL assets.

A material change in grid use occurred at the end of June 2016 when the Holcim cement plant at Cape Foulwind was closed. Over 90% of the load at the former WPT0111 GXP was attributed to the cement plant and following the close all supply from the WPT0111 GXP ceased.

BEL's residual charge allocation of $1.3M in the impact modelling was determined using the Gross AMD values in Table 1.

AMD Period	**ORO1101**	**ORO1102**	**WPT0111**	**Total**
1 July 2014 – 30 June 2015	8.91	8.97	8.99	26.87
1 July 2015 – 30 June 2016	8.47	8.10	9.34	25.90
1 July 2016 – 30 June 2017	10.23	9.25		19.48
1 July 2017 – 30 June 2018	10.41	9.34		19.75
Average AMD (MW)	**9.51**	**8.91**	**4.58**	**23.00**

Table 1 Gross AMD used to determine BEL's Residual Charge in the impact modelling

BEL has determined that the Gross AMD which should be used in the impact modelling, and these values are provided in Table 2. The calculation requires a knowledge of the Holcim load and distributed generation, and the supporting data is available on request.

AMD Period	**Gross AMD**
1 July 2014 – 30 June 2015	10.82
1 July 2015 – 30 June 2016	10.63
1 July 2016 – 30 June 2017	10.15
1 July 2017 – 30 June 2018	10.99
Average AMD (MW)	**10.65**

Table 2 BEL determined Gross AMD which should be used in the impact modelling