For Submission to:

Electricity Authority

Submission on Transmission Pricing Methodology Consultation Paper

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Date: 28 February 2013

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1. ABOUT BULLER ELECTRICITY

Buller Electricity Limited (BEL) welcomes the opportunity to make a submission on the Electricity Authority's Consultation Paper "Transmission Pricing Methodology: issues and proposal". This report is BEL's response to the Consultation Paper.

BEL owns and operates the electricity distribution network within the Buller region and is owned by a consumer trust. BEL takes electricity from two grid exit points and supplies approximately 4300 homes, farms, and businesses. BEL is also the largest shareholder in Pulse Utilities New Zealand Limited (Pulse), the largest independent new entrant energy retailer. Accordingly, BEL has a unique perspective to offer in this consultation, as it is one of the few electricity distribution businesses (EDBs) to have active involvement in electricity retailing.

The Buller region is one of the more electrically remote regions in New Zealand. Consequently, consumers face some of the highest electricity prices in the country because of our distance from generation sources. Consumers are further impacted because of the locational price risk this distance creates and in the absence of suitable risk management tools, this risk reduces the level of retail competition that might otherwise be expected.

From BEL's perspective, it is important that the industry as a whole functions efficiently and effectively to ensure that the long term interests of consumers are protected. BEL contends that the way to achieve this is through competition (which gives choices to consumers) and through the replication of competitive outcomes (where competition is limited).

Therefore in making any change to the Transmission Pricing Methodology (TPM), care must be taken to avoid creating new risks for market participants without simultaneously proving market based measures to mitigate those risks.

2. A CONTEXT FOR REVIEWING TRANSMISSION PRICING

In reviewing the Authority's proposal for changing the basis of transmission pricing it is useful to consider the basis for the establishment of the market framework operating in New Zealand. This is important because it helps define the problem that needs to be addressed by any proposed change to transmission pricing.

The reform of the wholesale electricity market in the mid-90's was designed to promote a more open market in electricity, benefiting both consumers and generators. The underlying theme of the wholesale electricity market reform was the introduction of nodal pricing which occurred with the commencement of the market in October 1996. The desire for nodal pricing stemmed from the need to ensure economic efficiency (particularly allocative and dynamic efficiency) in the operation of the power system, and by doing so minimising the long run cost to end use consumers as a whole.

While opinion was originally divided on the merits or otherwise of nodal pricing, it is now almost universally agreed that in market based settings, nodal pricing provides superior outcomes to the alternatives. However, nodal pricing is a misnomer, in that what is referred to as nodal pricing is in reality ex-post, dispatch based pricing, with the observed prices at each node reflecting both the marginal cost of energy and transmission losses/constraints required to meet the load placed on the power system by consumers.

Accordingly, rather than the five components to transmission pricing usually referred to, there are in fact six key components to the transmission pricing regime in New Zealand (NZ):

1. Locational marginal energy prices which reflect the marginal cost of using the transmission system in real-time;
2. A (shallow) connection charge, to recover the cost of assets to connect specific customers to the grid;
3. A HVDC charge, to recover the cost of the DC link between South Island and North Island;
4. An interconnection charge, to recover the costs invested in other transmission infrastructure (i.e. the meshed network);
5. Charges to recover the cost of network reactive support assets; and
6. A prudent discount policy, to mitigate the extent to which other components of the transmission charges incentivise inefficient bypass of the grid.

Transmission pricing, to recover the efficient costs of a transmission service, must be considered holistically. Any change in some components of transmission pricing will necessarily impact other components, and will consequently change the signals for investment and consumption. For example, any introduction of a Scheduling-Pricing-Dispatch (SPD) algorithm for the allocation of interconnection costs may increase risks faced by those market participants already subject to SPD payments. Because loads are ultimately the beneficiary of the transmission system, any risk faced by a generator can be expected to be recovered by way of a risk premium, met by the load.

The other consideration for reviewing transmission prices is a choice between ex-ante and ex-post pricing. The relative merits of ex-post and ex-ante pricing in the electricity industry have been widely debated and is not addressed in this submission. In selecting ex-post nodal pricing the designers of the wholesale market recognised the inherent complexity of New Zealand's bulk transmission system and thus avoided the potential discrepancies between ex-ante pricing arrangements and ex-post realities.

At the same time the decision was taken to move forward with ex-post nodal pricing for pricing energy and the marginal use of the transmission system, a decision was also taken to use ex-ante pricing for the recovery of the fixed costs of the transmission network (where market participants know in advance what their transmission charges will be for the coming year). This position was based in large part on the knowledge that ex-ante prices in conjunction with a stable pricing methodology, provide economic signals that the recipients of the signals can respond to within a given timeframe.

3. OVERVIEW OF CONSULTATION PAPER

The current Consultation Paper identifies three key aspects of transmission charging that merit review:

1. Connection Charges - to recover the cost to Transpower of connecting parties to the transmission grid;

2. HVDC charge - to recover the cost of the high voltage direct current (HVDC) link between the North and South Islands; and

3. Interconnection charge - which recovers the cost of the interconnected grid in each Island.

The Authority comments that:

> *"…the connection charge is generally efficient but has identified some loopholes in the definition that, if addressed, would improve efficiency."*
>
> *"… the current HVDC and interconnection charges are not efficient as the charges do not necessarily relate to the costs and benefits of HVDC and interconnection services."* [1]

For the remainder of this submission, BEL is silent on the treatment of the Connection charge, instead focusing our comments on the HVDC and interconnection charges.

The EA is proposing to recover the costs of the transmission interconnection assets by way of a beneficiary pays approach. The benefits of transmission assets to a connected party will be calculated using the SPD model. Charges will be subject to a cap such that the total cost allocated to a market participant cannot exceed the benefit received. This charge will be calculated for each trading period and charged ex-post. This charge seeks to recover the cost of all new transmission assets with a value in excess of $2 million constructed after 28 May 2004 and Pole 2 of the HVDC.

[1] Transmission Pricing Methodology: issues and proposal - http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

As a revenue requirement shortfall may exist, the EA is proposing to recover any shortfall by way of a "postage stamp" interconnection charge applied equally to generation and load.

For the purposes determining the interconnection charge to be recovered, the EA is proposing to eliminate the current HVDC charge and include the costs associated with those assets in the interconnection component.

4. BENEFICIARY PAYS

BEL supports the EA's preference for a beneficiaries-pay approach to the allocation of interconnection costs. Based on the Consultation Paper it appears that the EA has convinced itself that the beneficiaries of interconnection assets are both loads and generators. This raises two issues:

1. Are generators beneficiaries of the interconnection assets; and

2. Is an allocation of interconnection costs to parties other than the ultimate beneficiaries of the transmission system – loads – economically efficient?

With respect to the first point, the EA suggests that:

> *"Another example of a beneficiary of the transmission grid and transmission services is a generator that is connected to the grid at a point that is distant from the load they supply. The generator benefits from transmission services through access to the wholesale market. The benefit the generator obtains from transmission services can change over time."*

As a distribution company BEL could happily argue for an allocation to both load and generators. However, an allocation to generators needs careful consideration, if the industry is to avoid further disputes of the type associated with the HVDC. Once connected, generators are subject to dispatch instructions from the System Operator who is tasked with meeting a range of principal performance obligations as set out in Part 7 of the code. It could be argued that generators are providing a service to the System Operator, with this being reflected in generators making "offers" for dispatch. If this is the case does that make the System Operator a beneficiary of the interconnection assets?

As can be imagined, this could quickly devolve into an esoteric debate about which comes first, the needs of generators, loads, or the system operator. The point that BEL make is that there does not appear to be a clear landing point on this issue either in New Zealand or internationally and it needs further consideration and justification of any decision.

With respect to the second issue, the EA suggests in the Consultation Paper that:

> *" A beneficiaries-pay approach is most likely to be required where the parties to a transaction will not self-identify or have the ability to free-ride or hold out, thereby making market or market-like approaches either not efficient or impractical (e.g. due to transaction costs)."*

BEL assumes that the reference to *"parties to a transaction"* refers to the case of a new investment in transmission assets, where a 'Causer Pays' approach may also be effective. If this is the case, then the salient point is surely that new investment is regulated by the Commerce Commission. In making their decision to approve or decline an application for new investment, the Commerce Commission must take into account all relevant information available to it under the variant of the Grid Investment Test that it now administers. It is unclear what consultation has taken place between the EA and the Commerce Commission, on linking the investment approval process and TPM, but alignment is essential if any change in TPM is going to succeed.

BEL supports a principle of setting prices to recover fixed interconnection costs in a manner that creates the lowest risk of distorting efficient nodal prices observed in the wholesale market. As mentioned previously, loads ultimately pay for the cost of the transmission network and consequently direct charging of interconnection costs to loads is unlikely to distort behaviour in the wholesale market. Conversely, the allocation of capped and residual interconnection costs to generators will in all probability impact offer prices, and will in the long run distort generation investment decisions, likely imposing higher energy prices on consumers, and as a result reduce the efficiency of the wholesale energy market.

5. RECOVERY OF HVDC CHARGES

BEL supports the EA's proposal to recover costs of the HVDC as part of the recovery of interconnection asset costs.

In 1996, a decision was made to recover the full cost of the HVDC from South Island generators alone. Prior to that time, the cost of the HVDC was shared between South Island generators and North Island customers. The 1996 decision set in motion a prolonged, distracting and wasteful debate that, even today, continues to cast an uncertain shadow over future generation investment on the South Island. If past history is any guide, the allocation of the HVDC costs is likely to be one of the more contentious aspects of the TPM proposal from the EA in which it seeks among other things to resolve this long-running dispute.

The 1996 decision to alter the previously-agreed-allocation was a fiasco, especially given the costs incurred by parties trying to resolve the dispute. Costs that no doubt give rise in part to the EA's assumed benefit of reducing lobbying and litigation costs associated with the TPM.

The then Electricity Commission's 2006 decision to charge the cost of the HVDC to the South Island generators must have seemed appealing for three reasons:

1. It maintained the status quo regarding payment for the HVDC link;

2. South Island generators earn a portion of their revenue by "exporting" some of their generation to the North Island; and

3. It created an illusion that end use customers were not being charged for the costs of the HVDC link.

To be fair, the Electricity Commission inherited a dispute that should never have arisen in the first instance, a dispute that should have been resolved long ago by others. But the Electricity Commission entered into a quagmire when it chose to rely on an ambiguous and ill-defined "user pays" principle that is separate from consideration of the benefits that stem from the assets being used.

Usage abstracted from the benefits of use means little—it is the value derived from usage that matters. I may "use" something that is freely provided, but would do something else entirely if I had to pay for it. If one were to judge my willingness to pay based on observing my "use" alone, then the resulting inferences can easily be wrong, and policy decisions founded on such observations are more likely to be inappropriate.

If observation were all that is required, then so much of economics would be so much easier. It is not the "use", but the benefits of use that should be taken into account when determining how to recover the costs of the HVDC. On that basis, clearly the beneficiaries, and thus the users - those who derive value from the existence of the HVDC - extend far beyond just the South Island generators.

It is important to bear in mind that although South Island generators actively export power to the North Island over the HVDC, North Island consumers just as actively import power over the HVDC in lieu of generating that power on the North Island from existing or additional power stations. This northwards flow is reversed in dry years when North Island generators export power and South Island consumers import. On that basis the proposal to treat the HVDC link as part of the interconnection assets makes eminent sense as the HVDC provides numerous benefits to the wholesale market.

Whether one's mantra is economic efficiency or fair and equitable treatment, the EA's proposed approach recreates the needed link between costs and benefits, avoids bad policy, eliminates potentially punitive cost allocations and will enhance long-term investment outcomes. This approach is consistent with ensuring that all potentially value-enhancing generation and transmission investments are given a fair opportunity, which is the path to longer-term benefits and lower costs of electricity supply for New Zealand.

6. INTERCONNECTION CHARGES

The EA is proposing to adopt an ex-post allocation method for interconnection charges based on the half hourly changes in benefits as identified by running the SPD model with and without transmission elements. This contrasts with the existing ex-ante allocation method, where market participants facing the charges know in advance what their charges will be for the coming year. Importantly BEL and other market participants also have certainty around the allocation methodology and therefore can take measures to minimise their expected future cost.

BEL has a number of significant concerns with the allocation approach proposed by the EA. The proposal introduces an unnecessary level of uncertainty around transmission costs into BEL's business. Not only will BEL face a volatile variable transmission charge from the SPD based charge, but BEL will also face uncertainty around any residual charge that may be levied to meet the shortfall after the calculation of the SPD charge. This will have cash management implications for BEL which will in all probability need to be managed through changes in banking arrangements, imposing higher costs on BEL which will be recovered from consumers.

As the EA is aware, one characteristic of the New Zealand energy market is the impact hydrological conditions have on generator offers, power flows, and market clearing prices. Using SPD to calculate interconnection charges introduces hydrological and generator outage risk into transmission pricing. At present with a relatively simple TPM, BEL can easily manage our exposure to future transmission prices by managing the load that is placed on the transmission system. Load management has been a feature of the electricity industry in New Zealand since the 1920's when the first ripple control system was introduced.

If the TPM is modified as proposed, BEL will need to invest in sophisticated modelling systems to forecast potential transmission costs – both the SPD derived charge and the residual - and determine whether there is merit in operating load management systems to minimise that cost where possible. This raises that distinct possibility that load management will need to be operated more frequently than currently and in many instances unnecessarily. If load management is unable to mitigate transmission price risk, then over time investment in load management systems will possibly decline leading to a requirement for increased investment in both transmission and distribution networks. An outcome that is contrary to that sought by the EA in promulgating possible changes to the TPM.

BEL currently sets its distribution prices following receipt from Transpower of the transmission charges to apply for the coming year. Moving to ex-post transmission prices will require BEL, in the absence of suitable risk management tools, to reconsider its pricing methodology in response to increasingly volatile cash flows. For instance, BEL may need to review its charges more frequently and change prices periodically throughout the year. Such a requirement will impose transaction costs not only on BEL but also retailers. Making matters worse, it may also increase price volatility faced by consumers or alternatively result in an increased risk premium charged by retailers to smooth retail prices faced by consumers. Such an outcome would decrease the level of efficiency currently observed in the market.

As noted, any move to SPD based pricing will increase the risk of default by a market participant. This would clearly need to be reflected in some form of prudential arrangement.

As a small distribution business, BEL does not currently hold a credit rating from any of the recognised rating agencies. Consequently, BEL (and others) could under amended market rules be required to post prudential guarantees in favour of Transpower. This would have serious implications on working capital requirements, for all those parties require some party to manage invoicing. While BEL is in a position to meet this requirement at a cost to consumers, given the prudential requirements currently faced by energy retailers, some firms may have to exit the industry, with implication for retail competition. BEL has been working to actively encourage retail competition in order to benefit consumers connected to our network. The cost to consumers associated with a reduction in competition will outweigh any benefit received from a change in TPM.

BEL submits that the EA needs to clarify the prudential requirements if any that will apply if the change in TPM is adopted.

Related to this is the proposal in the Consultation Paper to allow distributors the right to opt out of paying the residual charge, leaving responsibility to retailers. If this option was to be taken up by distributors and prudential requirements were also imposed on those retailers, then several may choose to exit the industry. If retailers were to leave the industry this would impact retail competition, increasing prices faced by end-use customers.

In the event that distribution companies do opt out, their incentive to control load may be reduced. If this should occur and as noted above, this may lead to a requirement for increased investment in transmission and distribution networks, reducing industry efficiency. This is an outcome that is contrary to that sought by the EA in promulgating possible changes to the TPM.

7. UNINTENDED CONSEQUENCES OF PROPOSED TPM

In this section BEL highlights some potential unintended consequences that based on our review of the Consultation Paper don't appear to have been adequately addressed by the EA in preparation of the document.

7.1. IMPACT ON EMBEDDED GENERATION

Government policy and EA reports recognise the benefits embedded generation can provide to efficient outcomes in the electricity market. This has led to the development of Part 6 of the Participant Code which is specifically designed to foster development of embedded generation. Embedded generation can bring many benefits to the market including:

- Avoiding the requirement for more costly investments in the transmission or distribution networks;
- Enhancing security of supply in regions remote from grid connected generation; and
- Reducing locational prices in regions where location factors are high due to line losses and constraints.

These benefits provide more efficient outcomes for the electricity market, support an increase in retail competition, and as a result, lower delivered electricity costs to consumers in the long run.

Recognising the benefit that embedded generation provides, the EA in Part 6 requires distribution companies to pay generators for avoided transmission costs. In developing the proposed TPM, the EA does not seem to have given adequate thought to the impact proposed mechanisms for the recovery of interconnection costs may have on future development of embedded generation.

Clearly there appears to be a disconnect between the EA's desire to encourage the development of embedded generation as reflected in Part 6, and this TPM. BEL suggests that there is a requirement to review in some detail the potential impacts of the TPM on embedded generation. This should include consideration of the impact on existing embedded generation and the incentives for future development if the TPM is implemented as currently structured.

7.2. Impact on Retail Competition

The risks associated with the wholesale market have required energy retailers to develop a suite of risk management tools to manage their exposure to wholesale market price volatility. The proposed change in TPM with ex-post half hourly prices and residual interconnection charges creates a new set of market risks that will need to be managed. Competition in the electricity market was delayed because of an absence of a liquid energy hedge market (which has not yet been satisfactorily addressed), and is still constrained by the absence of FTRs to manage locational price risk. If the EA wishes to adopt the TPM proposal as it stands, then the EA must simultaneously introduce tools to allow retailers to manage the risk exposure arising from the change in TPM or delay any change until such products are available.

Another oversight in presenting the proposed change in TPM is an absence of any discussion on the prudential requirements that would need to be met by a retailer facing the new charges. Current prudential arrangements for the Clearing Manager and distribution businesses in relation to line charges create a significant barrier to entry given the working capital that is tied up. Any increase in prudential requirement would exacerbate problems already being faced by new entrant retailers such as Pulse.

A further concern arises with respect to the calculation of net benefit to a market participant who has prudently hedged their exposure to the market. As BEL understands the proposal, the transmission cost faced by a retailer will be based on the benefit received by that retailer from investment in new transmission elements as expressed by the difference in observed energy prices with and without the transmission investment. However, any calculated benefit from transmission investment will be moderated by the extent of energy and locational hedging undertaken by the market participant. Unless this is accounted for, the differential in energy prices arising from the application of the TPM will result in a disproportionate share of transmission charges being allocated to the market participant.

Individually these factors may seem insignificant. However, in aggregate these factors will increase barriers to entry, reducing competition in the energy market, leading to increased costs to end use consumers.

7.3. Changes to Offer Strategies

SPD is currently used to schedule generation for dispatch by the System Operator in real-time. As discussed previously, the philosophy behind the establishment of the wholesale market was to keep arrangements simple and encourage generators to offer their generation capacity at marginal cost[2], secure in the knowledge that in the event that they were dispatched to meet load requirements they would receive the market clearing price at their injection point.

If generators are going to be subject to an interconnection charge that reflects their benefit from new transmission investments, then they have an incentive to change their offer prices to minimise the potential transmission cost. What form this may take is unclear, but some form of offer similar to a pay as bid structure would seem likely. Under this type of arrangement, generators will seek to offer their energy into the market at prices that most closely reflect their perception of likely market clearing prices.

BEL is unaware whether any research and modelling of this type of offer behaviour has been undertaken in New Zealand recently. BEL is aware that research into this matter was conducted several years ago by Nobel Laureate Vernon Smith for the former Officials Committee on Energy Policy. This research concluded that uniform price auctions were superior to pay as bid auctions and led to the market clearing arrangement currently implemented.

If generator offer strategies do change, then special attention will need to be paid to market monitoring. Clearly we can expect to see less efficient prices established if strategies change, imposing additional costs on consumers which do not appear to have been adequately considered in the cost benefit analysis.

[2] Putting to one side the reality that profit-maximising behaviour by generators implies an optimal bid price above marginal cost (which may be provided by another participant).