Submission on Mass Participation in the Electricity Market

Submitter	Energy Link Ltd
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Question	Comment
Q1. What is your view of the potential competition, reliability and efficiency benefits of more participation?	Our view is that advances in technology and its price-performance ratio will inevitably place pressure on traditional approaches to providing a secure supply of electricity at low cost. The industry needs to work out which and when, and if the Code or other aspect of market structure need to change to facilitate positive change.
Q2. What is your view of the opportunities to promote competition and more participation in the electricity industry?	Prioritise technologies and other developments that have the greatest positive risk-adjusted net benefit.
Q3. What other issues might inhibit efficient mass participation? Please provide your reasons.	In our opinion, there are three key barriers to mass participation in the electricity market: • reconciliation; • the restriction of one retailer per ICP; • prudential requirements for spot purchasers. We have heard from a number of consumers that they are interested in being their own market participant. They might, for example be a consumer with many sites (ICPs), some with the ability to generate their own power. When one ICP has power in excess of its own requirements, it might wish to sell or gift the excess to one or more other ICPs. The three key barriers to becoming a market participant have discouraged participation in the past and will continue to do so into the future if they are not removed or lowered. P2P exchanges might be one way of achieving the aims of these consumers but, as far as we're aware, P2P exchanges can currently only work when one retailer supplies all of the exchange participants, as this is the only way that they can manage the relevant cash flows. In principle, it would be possible for the retailer operating the P2P exchange to make arrangements with other retailers to participate, however this could be frustrated by the non-participation of many retailers. **Reconciliation**

	The current Code requirements around reconciliation and prudential requirements were put in place under the implicit assumption that all participants would be either large businesses, or 100% dedicated to being an electricity market participant (e.g. a small retailer). But for the purposes of allowing mass participation these requirements are overly onerous and expensive. Opening up the market for more general participation could be achieved by certifying service providers to undertake metering and reconciliation on behalf of non-retailer participants. For example, the role of MEP could be extended to include reconciliation, on a number of conditions: 1. all ICPs have TOU meters with remote reading capability; 2. all ICPs are owned or controlled by entities that have registered under the Code as a 'special' class of participant, such class being exempt from the requirement to be a reconciliation participant and all that goes with it; 3. there is workable competition amongst MEPs. **Multiple Retailers per ICP** This is already on the EA's work program. It would facilitate the entry of many small participants that wish to retail electricity but who find the requirement to provide 100% of supply to each of their ICPs overly onerous. For example, a small wind farm owner may wish to sell electricity to its nearby local community. To do so would require that it be the retailer at each of the relevant ICPs and this would make it liable for the purchase of all electricity supplied to each of these ICPs in each trading period, at prevailing spot prices. Or a consumer may have surplus power from solar panels which it wishes to sell or gift to a consumer at a distant ICP. In the former case, the market would need to allow more than one retailer at each ICP, and facilitate the clearing and settlement using the windfarm as the base retailer and other retailers as default retailers to top up supply. In the simplest case of just one ICP, in a trading period when the windfarm cannot supply the ICP, the owner of the ICP would nominate its default retailer which would make up the deficit. **Prudential Requirements** The PRs impose additional risk and cost on spot purchasers, primarily due to the length of time that the net exposure is assessed over, i.e. up to around 50 days. To facilitate much wider participation, the special class of

	participant could include a requirement for daily settlement. In the case where the participant is a retailer, then the exit period prudential margin (EPPM) would need to be retained. But in the case of a consumer, who could be disconnected in the event of default, the EPPM could be set to zero, thus reducing the PRs to zero. Settlement would have to be done by direct debit. **Selling Power Across the Grid** Some of the arrangements suggested above would require calculation of the amount of power sold at a GIP which then is transferred to a distant GXP, e.g. in the case of a consumer that generates excess solar power at an ICP at one GXP and then supplies it to another of its ICPs at a distant GXP. This could be also be achieved by the exchange of money, which then leads to the condition that the value of energy must be preserved across the grid. Hence, if reconciled energy E_a is injected at GXP A, then the power deemed to be sold at distant GXP B[1] would be given by $E_bS_b = E_aS_a$ or $E_b = Ea \times (Sa/S_b)$ Some or all of the additional settlement calculations could be undertaken by the Clearing Manager and/or by third parties that are qualified to undertake them, e.g. third party trading platforms. **Costs and Benefits** The above suggestions are provided in the spirit of the consultation. We offer no thoughts or insights on whether the net benefit of any of the suggestions would be positive.
Q4. What is your view of the opportunities for network businesses to obtain external help to provide aspects of the network service using competition or market mechanisms?	No response.
Q5. What do you think are the main challenges to be dealt with to increase the use of competition in supplying network services? What are your reasons?	
Q6. What is your view on whether open access is required and what would be the elements for an effective open access framework?	Open access to the grid was a prerequisite for establishing the competitive electricity market, and apart from the different scales, this suggests the same could apply to distribution networks.
Q7. How effective are the	No response.

[1] We haven't checked, but this may be the same principle used in the old MARIA in the days when the spot market operated as a net pool.

existing arrangements for open access? What are the problems?	
Q8. What type of distributor behaviours and outcomes should the Authority focus on to understand whether changes are required to support open access?	No response.
Q9. What changes to existing arrangements might be required to enable peer-to-peer electricity exchange?	See our response to Q3.
Q10. What are the costs and the benefits of enabling peer-to-peer electricity exchange?	No response.
Q11. What is your view of the possibility for, and impact of, any current or future blurring of participant type? What are your reasons?	Any blurring is a function of market arrangements that are not keeping pace with technology, which suggests that the regulator needs to ensure that the arrangements actually do keep pace.
Q12. What types of participation are or might be prevented because the party is not recognised as a participant? What are the potential impacts?	No response.
Q13. What challenges might new forms of generation, such as virtual power plants, or small and dispersed generators, face in entering the market?	See our response to Q3.
Q14. What changes might be required to the rule book to facilitate the emergence of virtual power plants or demand response?	See our response to Q3.
Q15. Would the functioning of the market for hedges and PPAs and the availability of finance be improved if there were greater transparency of long-term prices and greater standardisation of terms and conditions for long-term contracts?	We define any contract over five years in length to be long term. Contracts running longer than five years tend to include price adjustment mechanisms which mitigate the risk of one party or the other becoming disadvantaged by the contract to such a great extent that they attempt to exit the contract. Adjustment mechanisms are added which suit the parties to the long term contract, obvious examples being indexation of the contact electricity price to aluminium prices (i.e. contract between Meridian Energy and NZ Aluminium Smelters), and the indexation of Mehanex’s gas prices to methanol prices (an example borrowed from the market for natural gas).

	There are examples of the use of changes in futures prices as an adjustment mechanism. For example[2], it may be agreed that the prices for the first five years of the contract are fixed then in the sixth and subsequent years the price is adjusted using the prices at the front end of the futures forward curve current at the time. Simply adding more quarters to the futures market would not achieve anything because the quarters further out the curve are already much less liquid than nearer-term quarters, and long term contracts would adjust prices that far out in any case. We conclude, therefore, that attempts to increase transparency or standardisation on contracts of more than five years would be futile. The reality is that any party making significant investments in electricity assets with lives of greater than five years need to fully inform themselves of the risks this entails and act accordingly.

[2] Refer to the Trustpower Demerger booklet.