19 April 2024

Electricity Authority
PO Box 10041
Wellington 6143

Via email: fsr@ea.govt.nz

Tēnā koutou

Consultation Paper – The future operation of New Zealand's power system

The WEL Group (consisting of WEL Networks, NewPower Energy Services, NewPower Energy and Infratec) appreciates the opportunity to provide feedback on the Electricity Authority's (the Authority) Consultation Paper – The future operation of New Zealand's power system (the consultation).

WEL Networks (WEL) is New Zealand's sixth largest electricity distribution company and is 100% owned by our community through our sole shareholder WEL Energy Trust. Our guiding purpose is to enable our communities to thrive, and we work to ensure that our customers have access to reliable, affordable, and environmentally sustainable energy.

Infratec, NewPower Energy Services, and NewPower Energy are subsidiaries of WEL, which build, operate, and manage renewable generation solutions.

Together we form the WEL Group. We believe that efficient future power system operation in New Zealand will require extensive sector-wide alignment and coordination, involving policymakers, regulators, participants, and consumers. This will require concerted efforts by many players to raise public awareness, improve data access, adapt technology standards, introduce flexible regulations, and establish effective national policy statements for the power sector.

Appendix 1 to this submission includes responses to the Authority's specific questions, in the format requested.

Appendix 2 to this submission includes supplementary information/views which do not directly relate to any of the questions posed by the Authority, but we feel are important to share, nonetheless.

Should you require clarification on any part of this submission, please do not hesitate to contact me.

Ngā mihi nui

David Wiles

Revenue and Regulatory Manager

Appendix 1: WEL Network's response to the Authority's questions

Question		Comments
Q1.	Do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand? Please give reasons if you do not agree.	We agree that the Authority's description in section 3 captures the arrangements for real-time co-ordination of the system in a physical/engineering context, but not fully in a financial/markets and system ownership context. The later context is important as financial/markets and system ownership do and will influence solutions to issues with the physical/engineering context. For example, the current ancillary services contracts/markets and the future increased use of 'flexibility'. It would be useful to have a summary of the key power quality parameters that (must) apply across the entire system – relating to frequency, voltage and harmonics. Section 3 describes arrangements that exist to ensure these parameters are maintained or to return the system to the right parameters across the entire supply chain. It would be interesting to consider whether the Code could be simplified if there was no ownership demarcation across the intersection of high voltage (transmission) and lower voltage (distribution) lines. For example, are there details in distributors' 'Operations' Standards that could be uniform across New Zealand?
Q2.	Do you agree that we have captured the key drivers of change in New Zealand's power system operation? Please give reasons if you do not agree.	We largely agree that the Authority has captured the key drivers of change in New Zealand's power system operation. However, though perhaps not drivers of change, we detail four related 'influences of change' in Appendix 2.
Q3.	Do you have any feedback on our description of each key driver?	We do not have specific feedback on any of the key drivers as described. However, we suggest that the Authority consider these drivers in the context of how or whether the Authority: • has a mandate to influence these drivers • can regulate or facilitate to make a positive difference to the outcomes from these drivers • and therefore, decide where to focus resources.
Q4.	What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.	We have a number of suggested improvements to increase coordination in system operation: i. Access to sufficient market information:

		○ greater transparency about the need for and market value of services that assist power system co-ordination both in the transmission and distribution networks ○ real-time pricing includes the cost of existing transmission network constraints – we query if this sufficient to incentivise investment or behaviour change to alleviate future constraints. ii. Reducing asymmetry in available data and information: ○ the market has the ability to price energy and reserves in real-time but information about real-time consumption is tightly held. There are calls across the supply chain for timely access to consumption data. Technology is available off the shelf, or we could import the Australian or UK system of a central depository of meter data. Vector is spending over $1.5m to gain access to smart meter data and describes the numerous benefits of having this data in its report to the Commerce Commission.[1] iii. Using dynamic operating envelopes to enable optimisation of existing network infrastructure: ○ this is related to point ii above. Average capacity utilisation across all distributors was 56% in the year to 31 March 2022. Utilisation will be higher for some time periods or in some parts of these networks but also must be a lot lower than the average at other times/locations. Increasing utilisation of existing infrastructure across all distribution networks will deliver benefits for consumers. It would be a significant benefit if distributed generators could be informed early in the project feasibility stage about areas of the distribution network where network capacity: ○ is not a constraint on its operation ○ may be a constraint for a portion of the time. Distributors would also benefit as generation and load connection applications would be more targeted to locations that could provide benefits to the distributor and there would likely be less of a need to undertake a power system study for each new application.[2]

[1] See https://comcom.govt.nz/__data/assets/pdf_file/0034/337786/Vector-PRISMED-innovation-project-allowance-application-May-2023.pdf

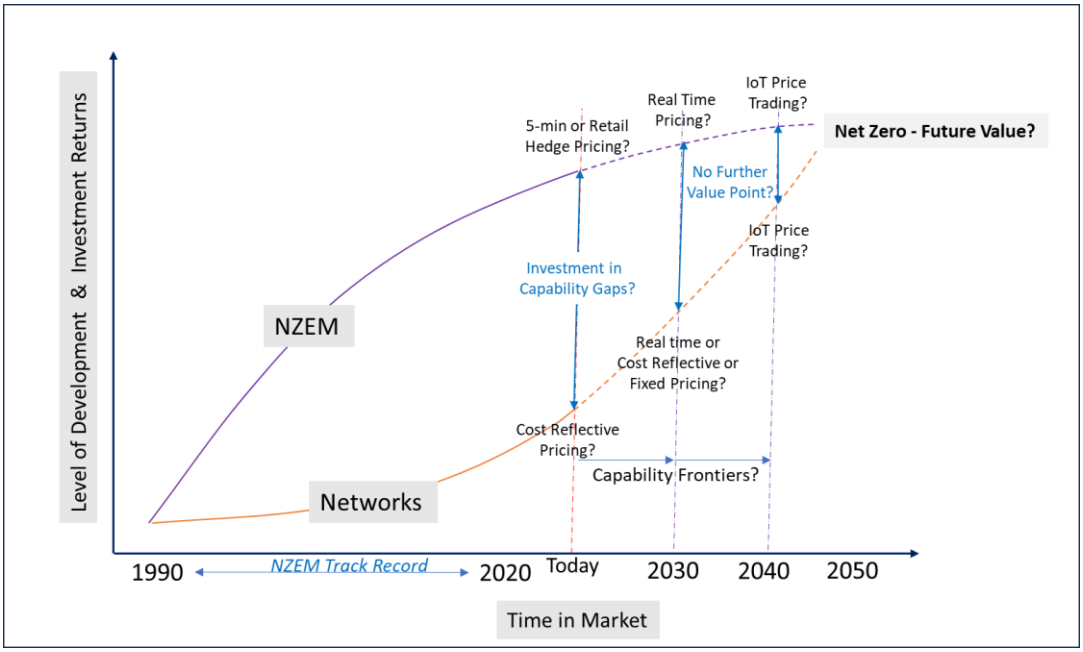
[2] This goes beyond and is more dynamic than the current requirement for distributors to publish congestion locations and a congestion management policy in Part 6 of the Code.

		FlexForum Insight in January 2023 on "*Making better use of available distribution network capacity will enable more affordable and reliable electrification*" explains this concept in excellent detail.[3]
Q5.	Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand? Please provide reasons for your answer.	We commend the Authority for undertaking and publishing this comprehensive review of relevant overseas jurisdictions. This information highlights that: • the same issues have arisen overseas that we expect to happen in NZ with a higher proportion of IVR technologies; • solutions are being identified and / or have been implemented; and • NZ is not unique, does not need to reinvent the wheel and should take advantage of the learnings from overseas. For example, incentivising provision of contestable voltage support services from IBR technologies; standard contracts and a trading platform or transparent auctions for DER flexibility services. Many of the solutions are market-based – see our answer to question 1. Where NZ is unique is with its ~250 locations where market prices are determined. We suggest this complexity, for a system of ~40TWh of demand, should be reviewed. We suggest the Authority consider whether this complexity is creating barriers to the development of contestable services that could solve power system coordination issues.
Q6.	Do you consider existing power system obligations are compatible with the uptake of DER and IBR-based generation? Please provide reasons for your answer.	There are two reasons why we believe the existing power system obligations are NOT compatible with the uptake of DER and IBR-based generation: i. The current power system operations obligations assume a historic demarcation between the System Operator (SO), with regards to DER and IBR generation segments, is at the GXP with the Network Operator controlling DER/IBR as a physical market aggregator. This may be the current reality but further clarity is required between the role and obligations of the SO and those of the Network Operators. ii. Existing power system obligations will have a number of historic and institutionalised use assumptions for DER and IBR, that need to be further tested by furnishing empirical evidence to support Code interpretations. For example:

[3] https://www.araake.co.nz/assets/Uploads/FF-insights-making-better-use-of-available-distribution-network-capacity-31-January-2023.pdf

		○ Synchronous generation power quality performance vs. synthesised IBR power quality performance – is there the same or superior power quality performance? ○ Ripple control ownership, procurement and uses relative to new DER ownership, procurement and uses - is there the same or different switching and market values? ○ Code hierarchies relating to power system operations – should these be the same or different given DER and IBR-based generation? Power system quality issues should be tested and solved once with the resulting approach applying universally across the entire system. That is, one testing regime for a particular technology should be agreed and used by Transpower and distributors.
Q7.	Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system? Please provide reasons for your answer.	We agree that there needs to be an increased level of coordination of network planning, investment and operations across the New Zealand power system. The reasons are: i. There are a number of co-ordination risks when considering the security and resilience vs. future costs of the power system including. For example: a. Consistency between short term security co-ordination and longer-term economic security i.e. recognition in a planning context that NZ's economy will be more than 80% dependent on electricity supply. b. Definitions of "system economic security" for example as regards N-security vs N-1 security of supply to consumers, all of whom are now expected to abandon fossil fueled alternatives. Consumers should be more informed about the cost versus security of supply trade-off and the impact of this on their economic livelihood. c. What would a normal economic pathway look like for a highly distributed energy system, without current Climate Change policy drivers? This counterfactual might highlight the underlying "hidden costs" of the current systems change inertia and thus market entry barriers. For example: ○ Lack of planning co-ordination between Transpower, as Grid Owner, and the 29 different distributors means that there is a lost opportunity cost between Grid and Network Alternatives, as the latter is merely an aggregation opportunity for the former.

		ii. For decades distributors have been using portfolio load design factors when designing 415V level networks. Currently, every separate DG and DER developer has to "discover" one of the 29 different distributors (plus Transpower regional planning) assumptions for every small to medium sized new DG/DER connection application. This is a very similar journey of frustration and cost as experienced with the RMA consenting process in different planning regions of NZ. In a DER inspired world there will be new portfolio factors in play that could be included consistently into all Distributor Planning and Grid Planning decision support models. These factors should be modelled centrally and required by Part 6 of the Code to streamline development of a dynamic connection envelope. iii. Should we entirely abandon energy system diversity for a reduction in future climate change risks? a. What is the future VoLL cost in an 80% electricity supplied system versus the current 25% contribution to primary energy made by electricity? This question should be answered and agreed before an energy market design change is implemented. b. Can we really expect the current market design to "price discover" both the most economic supply options on the hour and the adequate supply security for a 100% renewable system? Given the additional complexity of the drivers for change, there will be trade-offs to be made to help the price discovery process. c. In most other international jurisdictions, the initial trade-off was generally the subsidisation of new entrant technologies, through various feed-in-tariffs and other pricing or contracting tools to get early-stage renewables growth. What was the "investment cost" of these subsidies and what can we learn from the rapid growth of DER and DG? iv. Planning co-ordination is becoming more important as grid and network systems are merged with technologies. Risks of poor execution include: a. the current separation of energy market and network planning processes coupled with the technology convergence drivers outlined in this paper. b. imbalance of skilled resources addressing the potential for rapid market investment changes with distributors appearing or potentially under-resourced in planning

		and change management compared to energy businesses. c. unclear market frontiers between energy market and distribution businesses. Recognition is required of where the industry currently sits in the Pareto optimisation context:
		
Q8.	Do you think there are significant conflicts of interests for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.	A lack of consistency and transparency in grid or network modelling assumptions is a potential symptom of conflicts.[4] WEL has observed the Grid Owner using different system planning assumptions for different investment upgrade projects and these differ from System Operator assumptions. However, our view is that economies of scope within Transpower and individual distributors exists from being responsible for system operation and network planning. Rules already exist to manage any conflicts of interest – regulators could be more attuned to checking adherence with these rules, including the potential for more transparency regarding analysis of non-network solutions. We suggest the Authority prioritise reviewing / implementing suggestions to improve system coordination (provided in answer to

[4] Reference – NewPower's submission to Transpower on USI long-list options October 2023 https://static.transpower.co.nz/public/uncontrolled_docs/NewPower%20submission%20to%20Transpower%20on%20USI%20long%20list%20consultation%20October%202023.pdf?VersionId=8dQfOUpFQ0UKZZoBWCsnthx2HYWENcax

		question 4) – these solutions should improve transparency and reduce any potential for conflicts of interest.
Q9.	Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand, and whether there are other challenges or opportunities that we have not covered adequately in this paper? Please provide reasons for your answer.	We have the following views about other challenges and opportunities that have not been adequately covered in the consultation paper: i. There needs to be a more independent review of current "market performance" across both energy and network markets. The Authority seems conflicted, as both policy writer and market regulator, for the last 20 years energy market performance. ii. Likewise, ComCom appears out-of-touch and/or sitting-on-the fence with current market performance for competition outcomes and network regulations. Smaller and independent market participants have been operating at the margins of both energy and networks now for at least 15 years, without any acknowledgement from either the Authority or ComCom that the energy market is highly concentrated in market shares and distributors are disaggregated limiting the ability of some to achieve the level of efficiencies and co-ordination required to achieve economies of scope between market supply and market delivery. iii. The policy settings from MBIE are too weak and too high level to achieve the real changes required to enable decarbonisation. As such, many smaller participants are suffering from 'death-by-a-thousand-cuts' syndrome promulgated by endless consultations to achieve only incremental agency-based outcomes. iv. Reducing the current market power of incumbents - the MDAG analysis and reports on '*Pricing in a renewables-based electricity system*' provides thorough analysis and recommendations addressing current and potential market power issues as the power system evolves.[5]

[5] https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/

Appendix 2: Supplementary Information/Views

In addition to the six key drivers of change, WEL Group believes there are four other key influences of change that are not captured in the Authority's summary in the consultation paper:

i. Government policy changes which can, and have, had a substantial influence on power system security and resilience, including for example,
   a. government majority ownership and shareholder influences on future investment and business risk for three of the four incumbent gentailers and Transpower;
   b. various market interventions including network separation (Bradford-1998), asset swaps (Brownlee-2010), gas market exploration (Woods-2018), climate policy accelerated electricity and energy policy targets for 2030 and 2035 (Woods – 2020) and Project Onslow (Woods-2021).

ii. Development Market Access – including RMA requirements for access to land and energy resources, such as:
   a. changing RMA policies
   b. fast-tracking legislations for "selected" technologies, scale, resources
   c. food vs energy production in land use policy.

iii. Competition and Market Design, including for example:
   a. ownership concentration in the markets
   b. lack of market trading liquidity and price discovery
   c. credit management and prudential requirements.

iv. Network and Grid connections, including Code and regulatory management of:
   a. grid and network alternatives
   b. grid and network support contracts
   c. interface between transmission and network Code jurisdictions.

In our view, these four influences of change are the most important in terms of market entry barriers that are impacting New Zealand's rate of adoption, diversity and affordability of a highly renewable energy system compared with the other global market drivers included in the consultation paper.