Submission on The future operation of New Zealand's power system

19 April 2024

1 Submission and contact details

Consultation	Submission on The future operation of New Zealand's power system
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2 Confidential information

There is no confidential information provided in this submission. This submission can be publicly disclosed.

3 Introduction

Wellington Electricity Lines Limited (**WELL**) appreciates the opportunity to provide a submission on the Electricity Authority's (**EA**) consultation '*The future operation of New Zealand's power system'* (**the paper)**.

The paper as a whole has a strong focus on system operation, specifically on what impacts generation assets and transmission grid operation. This is evident in the five pages that describe the operations of Transpower as opposed to the one page about distributors, despite 5 out of the 6 key drivers in the paper, only or unevenly impacting distribution networks ability to manage network security. The two largest and most complex or unknown of these drivers are consumer and operational technology. An example of this is the uptake of EVs, which if the status quo stays the same, only distributors risk quality reduction from connection of new large devices.

The challenges that have influenced the previous decade's power system development are becoming less relevant. For example, the risk of overbuilding has significantly reduced due to the large amount of new demand and capacity needed to support electrification. The 'just in time' nature of the current development in electricity services means that the sector is not designed for disruptions and innovation is often not encouraged due to uncertainties of deliverability.

Many customers are not directly engaged in the electricity industry and how New Zealand is able to produce highly renewable, reliable, and affordable electricity. Customers are sheltered by the realities of wholesale market price fluctuations through fixed-term contracts and one-month billing cycles that hide the intricacies of managing a power system operation 24 hours a day, 7 days a week. But this is changing.

Retailers are doing good work applying distribution networks time of use (TOU) pricing tariffs to shift customers' load away from the peaks. Pricing in this manner means that customers are paying for the costs that they drive. As more customers get engaged in their energy use, and purchase distributed energy resources (DER) or customer energy resources (CER), the focus and volatility of the electricity market shift closer to the distributor and end customer (the ICP) and away from the traditionally centralised GXP (System Operator) management. For example, flexibility services using customer devices located on distribution networks will be used to support the transmission grid and purchased by the SO, but they will also be used for; non-grid activities like managing distribution network security, alternatives to building traditional network capacity, arbitraging spot prices, sharing electricity between customers, and providing customers with their own electricity requirements and backup supply.

The future power system will have a larger number of industry participants and operations will shift from a single controller to directly between participants. This may see a greater amount of automation to ensure a secure supply is maintained. WELL advocated for the EA to lead the coordinated approach required between participants as part of the *EV Connect*[1] programme. This was to influence the scope of regulatory changes needed to develop flexibility services.

[1] Wellington Electricity, 2021. *EV Connect Roadmap* Available athttps://www.welectricity.co.nz/major-projects/ev-connect/document/322

4 Consultation Questions

4.1 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.

WELL generally agrees with the described summary of existing arrangements of power system operation and would like to further expand the description in a few areas.

Before real-time system coordination

Describing 'power system operation' as "*real-time coordination of NZ's power system"* is too narrow because many power system operations occur well ahead of real-time. Power system operations also include the coordination of outages and asset availability and the week-ahead wholesale market which are coordinated in advance of their execution. Distribution network's involvement in power system operation mostly occurs in the time leading up to real-time operations through planned outages. The current definition of power system operation would ignore these activities. In the future, the coordination of flexibility services will occur in advance of real-time operations to manage the impacts of DER/CER on network capacity. DER/CER devices will provide greater flexibility to defer distribution investment by shifting peak electricity consumption and that will flow through to transmission and generation management in real-time.

Reduction in electricity demand through hot water control

The description of constraining and disconnecting demand is only a response to the "cascade failure of the power system". Constraining demand should also include using ripple control to manage constraints by shifting away from congested periods. A secondary benefit is provided for system security to prevent cascade failure.

Distribution and transmission operation consequences

Under point 3.46, it is important to include that distribution network operations and asset ownership decisions do not impact the wholesale price of electricity across the country, whereas the system operator (SO) decisions and grid owner (GO) outages on transmission assets do. This is an important differentiation when considering whether to separate distribution operations and ownership discussed later in the paper.

4.2 Q2 Do you agree that we have captured the key drivers of change in New Zealand's power system operation in section 4? Please give reasons if you do not agree.

WELL agrees with the drivers as described in this chapter and believes there are three small adjustments to be made.

Decarbonisation

The first change is to identify New Zealand's decarbonisation goals as the key driver of 'Electrification'. Decarbonisation and the government's emission reduction plan (ERP) is a large contributor to the country's need to electrify at pace. This will likely be through the conversion of other energy sources to electricity. For example, a customer could remove their gas operated appliances in favour of an electric alternative to reduce their greenhouse gas emissions and this would drive the need to increase network capacity for the increase in load. This is also connected to a change in customer preference as elaborated below.

Consumer Preference

The definition of Driver 2: consumer technology should be expanded to recognise that consumer preferences is driving the uptake of new technology. In future, there will also be additional consumer choices about whether they want to participate in flexibility services or whether they want to pay more for the convenience of being able to use electricity whenever they want. Consumer preference will drive engagement with their electricity usage and get involvement from more industry participants to provide these services.

Affordability

Another component driving change in the NZ power system is the rising cost of living and the impact affordability has on the ability of families and businesses to pay to electrify their energy use. If families and businesses cannot afford the upfront costs of electrification (e.g. purchases of EV's or non-gas appliances) then New Zealand's decarbonisation could stall. Government assistance may be needed to support families and businesses to decarbonise. For example, electric vehicles will provide households with a 25-50% savings in their overall energy bill from being able to avoid more expensive oil-based fuel. However, families will only have access to these savings if they can afford the upfront cost of an electric vehicle.

4.3 Q3 Do you have any feedback on our description of each key driver in section 4?

As above

4.4 Q4 What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.

The most helpful changes that will increase coordination in the systems operation are:

- The streamlined provision of data to provide visibility of distribution networks
- Rules to allow networks to manage the rapid uptake of EVs and
- Co-ordinating flexibility services on distribution networks

Our submissions on '*Updating Regulatory settings*[23]', industry publication *EV Connect*[4] and Our Asset Management Plan (AMP) Chapter 4[5] detail the regulatory changes needed to support the rapid update of EVs and the development of non-wire flexibility services.

4.4.1 Streamlined provision of data to provide network visibility

Our AMP highlighted that networks were not designed to provide the predicted load growth from connecting EVs[6]. Networks often also don't have visibility of the low-voltage network that these devices are connecting. This includes visibility of existing and forecast constraints and available network capacity. Streamlined access to smart meter data and the location of where large devices are connecting will provide network visibility of the low voltage network (including constraints and available capacity) and the location of where large new loads are connecting. Networks will be able to forecast where DER could be causing quality issues. Our February 2023 submission to the EA's *Updating Regulatory Settings for Distribution Networks: Issues Paper* [7]provides further details on the changes needed.

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[2] Wellington Electricity, 2021. *Submission on Updating Regulatory Setting for Distribution Networks* Available at https://www.ea.govt.nz/documents/1735/Wellington-Electricity-Updating-the-Regulatory-Settings-for-Distribution-networks.pdf

[3] Wellington Electricity, 2023. *Submission on Updating Regulatory Settings for Distribution Networks: Issues Paper* Available at https://www.ea.govt.nz/documents/3414/7._Wellington_Electricity_submission_9Su9FOG.pdf

[4] Wellington Electricity, 2021. EV Connect Roadmap

[5] Wellington Electricity, 2024. *Asset Management Plan 2024: Chapter 4* Available at https://www.welectricity.co.nz/disclosures/asset-management-plan/document/336

[6] Wellington Electricity, 2024. AMP

[7] Wellington Electricity, 2023 February. *Submission on Updating Regulatory setting for distribution networks pages 4-5*.

4.4.2 Managing the rapid connection of DER

Before flexibility services have been developed as a meaningful demand management response, EDBs must develop processes and tools to accommodate large DER onto their networks. WELL has started to model and test the impact of the large-scale connection of DER to its distribution network. WELL's studies have indicated that 50% penetration of EV chargers larger than 2.5 kW would exceed what the Wellington network has been designed to accommodate[8].

The simultaneous operation of large DER risk causing LV networks to exceed their safe operating limits. The operating limits include both thermal and voltage limits, with both needing to be managed to provide a secure supply. Currently, EDBs have no visibility of where many of these devices are connecting and have no way of ensuring that they will operate within the network's operating constraints.

EDBs will need an early form of a flexibility service to manage the rapid connection of large DER. Important early steps are needed so that networks can manage, aggregate, and coordinate the connection of large DER so their combined operation remains within the network's operating limits. These are also early steps in the development of a full flexibility service – they provide a simplified flexibility service providing network security while the industry develops flexibility services that deliver the full value stack. The early steps, preceding the development of the full flexibility services are:

1. Customer education and strong peak period price signals to encourage customers to use electricity during off-peak periods, especially large new appliances like EV chargers.

2. An application process for the connection of large DER (over 2.5 kVA) to provide EDBs with visibility of where DER want to connect so that they can test whether the network can securely connect that device. There is currently an application process for solar devices, but not for other DER like EV chargers. The process will need to be automated to streamline the connection process.

3. Strong incentives or standards to ensure DER devices are capable of being remotely managed and can participate in flexibility services.

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[8] Wellington Electricity, 2024 April. AMP pages 67-68

4. All large DER are to be registered and participating in flexibility services so that their use can be managed away from peak demand periods on the network.

These four steps will help EDBs to accommodate DER, providing a stable platform to facilitate the development of more complex flexibility services and a market for trading flexibility. The implementation of these changes will either need very fast policy updates or it may be that networks will need to apply them through their own network connections standards. It could be that initial implementation is via network connection standards with the permanent solution reflected in a later Electricity Code change.

The development of flexibility services is complex and will need time and funding to develop. EDBs will not have the allowances to develop flexibility services or to purchase those services until the next regulatory period in 2025. Furthermore, EDBs will need to develop an Advanced Distribution Management System and Distribution System Operator capabilities to incorporate flexibility services into their demand response. Experience from WELL's sister companies in Australia shows this to be a multiple-year process. An early form of a flexibility service and a change in customer behaviour is needed before then to manage the connection of large DER and to shift electricity use to off-peak periods.

4.4.3 Co-ordinating flexibility services on distribution networks

EDBs need the ability to manage flexibility services connected to their networks. Unlike hot water ripple control, EDBs will not have direct oversight or control of the operation of these services.

Careful planning is needed to design a regulatory framework to ensure flexibility services are available whenever they are needed by networks (both EDBs and the System Operator) to maintain network security. Flexibility services first need to be available in emergency situations – when direct intervention is needed to 'keep the lights on' – and then once the distribution network and grid is operating stably, to be available wherever they provide the most value to customers.

Practically this will mean the development of a flexibility market which assigns flexibility services to where they provide the most value (i.e. who will pay the most to buy the services) and will have a set of prioritising rules that provides emergency access to all services. The regulatory framework setting the terms and conditions for services between EDBs and retailers provides an example of how this could work in practice. The Default Distribution Agreement (DDA) outlines that parties other than EDBs can provide load control services on the distribution network but must provide EDBs and the System Operator access to those services in emergency situations. Similar rules could be expanded to include flexibility service providers.

Flexibility services using customer devices connected to distribution networks could also be directly managed by parties outside of the distribution network i.e. the system operator directly controlling devices to manage grid-level security. EDB will also need the ability to ensure that the operation of these devices remains within the network's operating limits. EDBs are responsible for distribution network quality and face fines of up to $5m per quality breach for non-performance. Therefore, an EDB must have direct oversight of how these devices are being used so that they can meet their regulatory obligations.

There is currently no agreement between end customers and Transpower and the EA needs to be cognisant that rapid load changes can destabilise network supply quality and affect a customer's equipment. Damage claims must be addressed to the responsible party who has caused the disruption. This would require a Code change to extend liability to the SO when the distribution network quality of supply is compromised by their direct action or inaction causing damage to retailer-connected customers to a distribution network.

4.5 Q5 Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand? Please provide reasons for your answer.

WELL has been able to draw parallels between the uptake of solar PV in Australia and the forecast growth of EVs in NZ. To manage the very high penetration of PV, South Australian regulators have applied regulatory rules to manage the connection of solar inverters. If a customer agrees to participate in flexibility services that can turn down the amount of energy being exported from an inverter, then there is a high limit on how much they can export. If a customer chooses not to participate, then they have a very low export limit applied. This regulatory framework has increased the amount of electricity consumers have exported from before the framework was applied (household PV is now the largest electricity generator in South Australia) and they have been able to maintain network security. Before the framework was applied the network was browning out due to the mid-day export peak exceeding the lower voltage network limit. This approach provides a proven solution to managing the rapid uptake of EV's. Customers could be free to connect large EV chargers if they are participating in a flexibility service so their devices can be turned down if network capacity is running out.

The United Kingdom (UK) has invested heavily in the development of flexibility services and now has a viable non-wire alliterative to building traditional infrastructure. New Zealand hasn't made the same investment and now must rapidly develop a large demand-side flexibility capability. Boston Consulting Group's 'The Future is Electric'[9] calculated that New Zealand needs 4.8GW of demand-side flexibility to manage intermittent renewable generation and to help keep electricity prices affordable (by reducing the amount of new infrastructure that needs building).

4.6 Q6 Do you consider existing power system operation obligations are compatible with the uptake of DER and IBR generation? Please provide reasons for your answer.

WELL believes that the existing power system operation obligations are compatible with the uptake of DER and IBR generation as long as there are sufficient regulatory changes to address the lack of visibility and control of DER. WELL is encouraged by the EA's comments about the steps they are considering to allow consumer information to be shared. This has proved to be a barrier to establishing an LV management function and incorporating flexibility into an EDB's demand management.

4.7 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.

WELL agrees there needs to be an increased level of coordination in the investment needed into the power system to facilitate the electrification of the economy. The BCG report *The Future is Electric*[10], provides a roadmap of the large amount of investment needed to develop the infrastructure to deliver new decarbonisation-related demand. A major risk that is outlined in the BCG report is that if transmission and distribution capacity is not able to keep up with generation and demand growth, then the new generation capacity will be stranded, unable to deliver the newly generated electricity to customers. While EDBs and Transpower need to make significant investments ($71b and $29b respectively)[11], regulatory allowances to start the build, have not yet been approved. Coordination between sector participants and regulators will be essential.

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[9] Boston Consulting Group, 2022 October. *The Future is Electric* Available at https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf Page 14

[10] BCG, 2022. Page 14

[11] BCG, 2022. Page 14

WELL believes there needs to be an increase in horizontal and vertical coordination for the following reasons:

- We will all be competing for the same resources and do not want to cannibalise each other by not coordinating our efforts.
- There are opportunities for training and recruitment that can be shared and efficiencies gained across all areas of the electricity supply system.
- There is a deliverability risk due to the scale of investment and growth expected over the coming decades.
- As a small country, we need to be able to compete with the global supply chain of resources and we should aggregate our procurement to have greater buying power with international companies.

4.8 Q8 Do you think there are significant conflicts of interest for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.

4.8.1 Favouring flexibility over traditional capex solutions

The paper implies that distribution networks will favour increasing their regulated asset base (RAB) over using non-wire solutions. Part 4 of the Commerce Act (the IRIS mechanism) incentivises networks to choose the least cost method of providing new capacity. EDBs will be indifferent to traditional or non-traditional network solutions. Furthermore, most networks are forecasting a significant increase in capex spend and new debt and equity funding is likely to be scarce. Networks are more likely to favour non-traditional solutions (where they are viable) to relieve the pressure on any funding constraints.

There are also growing regulatory obligations for disclosing how networks are incorporating non-traditional services. This will provide additional confidence to customers that networks are considering the best solution to deliver the demand increase.

4.8.2 Separation of flexibility providers and EDBs

In general we agree that EDBs should not participate in providing flexibility services (the key reasons being that EDBs would block the rest of the flexibility service value stack). This comes with the assumption that all flexibility services operate under a common hierarchy of needs that allow EDBs and the grid operator to call on services in emergency situations – emergency situations being when direct intervention is needed to 'keep the lights on'. These would be rare events that would have a limited impact on competing flexibility services.

This also assumes that EDBs can maintain the existing hot water control capability. Distribution networks and the national grid have been designed to include the existing hot water ripple control demand management capability. This capability must be maintained for networks to continue to provide existing levels of supply security. The flexibility service that the Authority could consider allowing EDBs to provide directly is for a network battery that could be moved around a network as an emergency response or to temporarily top up or support a third-party flexibility response – similar to a network using diesel generation.

4.8.3 Different profit motives

The paper also comments on the different profit motives of private vs. state-owned companies. The regulatory regime mitigates this suggested issue because network ownership and planning is regulated by the Commerce Commission who ensure that these companies are not making excessive profits.

Its also important to note that state-owned companies also have a mandate to provide a profit and dividends to their shareholders (the state).

4.8.4 Separation of the DSO and network ownership

WELL does not agree that there is any value or need to separate network operations from ownership as described in the EY appendix of this paper. WELL agrees that there are opportunities for a DSO to provide economies of scale. However, the regulatory incentives provided under Part 4 regulation will incentivise and reward networks to combine or outsource delivery functions if it is efficient to do so.

The owner of an EDBs is responsible for maintaining quality on their networks and they will need to maintain the ability to manage that quality. If operations were separate from asset ownership, it would be impossible to regulate quality because there is no clear party who would be responsible for a network's quality performance (SAIDI and SAIFI).

The reasons for separating the grid owner and operator do not apply to the same extent to distribution networks. Decisions made by the System Operator impact the wholesale price of electricity and ancillary service payments that are passed through the ancillary service providers. Network scale decisions made by the distribution owner don't have the same impact on the price of generation.

4.9 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.

WELL believes that the Authority needs to speed up the implementation of the outcomes of previous consultations and give industry participants greater direction for the future system operation. As highlighted in the BCG 'Future is Electic'[12], if the whole industry doesn't keep pace with increasing demand then customers will experience increasing outages as their reliance on electricity grows. Everybody must deliver their part in increasing the capacity of the electricity supply chain. An example of this is how slow the change to get access to consumption data has taken. WELL has been advocating for these changes since the 2021 consultation *Updating Regulatory Settings.* This has taken three years to get a result that doesn't fit the purpose we advocated it for. We cannot delay further growth of flexibility services while traditional costs escalate, and the uncertainty risk continues to overhang investor decisions. The government Emissions Reduction Plan was published over 2 years ago and while other industries are ramping up delivery, the energy sector is hampered by regulatory barriers. Immediate changes are needed now, as new devices are being installed that networks are not designed to manage and have little ability to influence and mitigate any security risks they impose on the network.

5 Closing

WELL thinks what has been outlined in this paper and other referenced consultations will provide the EA with a large number of areas to focus on for future system operation regulation and how this contributes to the wider Future Security and Resilience programme. If you have further questions regarding any aspect of our submission, please contact Chloe Sparks at chloe.sparks@welectricity.co.nz.

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[12] BCG, 2022. Page 48