23 August 2024

Addressing more frequency variability in New Zealand’s power system
Electricity Authority
Via email: fsr@ea.govt.nz

Tēnā koe,

Addressing more frequency variability in New Zealand’s power system

Powerco is one of Aotearoa’s largest gas and electricity distributors and is committed to our role in Aotearoa achieving a net zero economy in 2050. We supply around 357,000 (electricity) and 114,000 (gas) urban and rural homes and businesses in the North Island.

We are playing our part in Aotearoa’s electrification, and we recognise the importance of this. We share the Electricity Authority's (Authority) objective that the Code’s common quality requirements must enable evolving technologies, especially inverter-based resources, as they are crucial enablers of consumer choice and the electrification of New Zealand’s economy. Addressing the identified common quality issues in a way that promotes the reliability of electricity supply for consumers is essential.

In the absence of specific Code requirements, we have developed utility-scale distributed generation (DG) connection standards to clearly communicate the responsibilities to DG customers seeking to connect. These standards are designed to prevent DG connections from causing issues for other customers. They include many of the improvements suggested in the consultation papers.

We are pleased that the Authority is consulting on the issues covered in these three papers, and we fully support the Authority in further investigating so that changes can be made to the Code to ensure it is suitable for the Electricity industry. Our summary views are:

Importance of industry collaboration	• A holistic approach to system operation is necessary. For example, improved visibility and integration between Transmission System Operator (TSO) and Distribution System Operators (DSO) SCADA systems (or ADMS) will be essential for managing frequency variability. • It is appropriate and fair that new generators contributing to voltage and system inertia issues have obligations for voltage stability and frequency control.

We need to ensure energy stability	• What happens in our networks will impact others. For example, network-wide voltage stability issues could potentially affect the transmission network. • Greater voltage regulation requirements may add costs to equipment, but the system stability benefits far outweigh them, especially when compared to the potentially significant network investments that might otherwise be needed.

This submission does not contain any confidential material and may be published in full. If you have any questions regarding this submission or would like to talk further on the points we have raised, please contact Gabriel Lim [redacted].

Nāku noa, nā,

Emma Wilson
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POWERCO

Attachment 1: Response to discussion document

Topic	Powerco response
Part 1: Addressing more frequency variability in New Zealand's power system	
Q1. Do you agree the Authority should be shortlisting for further investigation the first frequency- related option to help address Issue 1? If you disagree, please explain why?	Yes.
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	As increased levels of inverter-based generation gradually displace conventional generation, system inertia will decrease, leading to stability challenges. It is appropriate and fair that new generators contributing to this trend have obligations for frequency control. Inverter-based generation sources are easier and more cost-effective to scale down compared with conventional (grid-connected) generation. This likely means that the volume and proportion of smaller generation devices (potentially significantly smaller than 30MW) will increase substantially from current levels. Lowering the threshold would ensure that a high proportion of newly connected generation would comply with the Asset Owner Performance Obligations (AOPO). This approach would not only help support system stability but also result in a fairer system for all parties connected to the electrical grid, ensuring that new entrants contribute equitably to maintaining a stable grid. Where Powerco installs larger generating units or systems like Battery Energy Storage System (BESS), we include the requirement for frequency support if these are intended to be grid-tied under normal operations. For example, our Whangamata BESS includes this feature, despite it only having 2MW capacity. Powerco will likely offer our full available generation capacity if required during grid emergency issues, unless units are already operating or curtailed for other reasons, such as providing emergency standby supply. Additionally, Battery Energy Storage System could offer frequency support as an Ancillary Service. Lowering the threshold could result in some additional costs for ensuring generator compliance and conducting validation tests. For inverter-based generation, we do not expect these costs to be material, but it could be financially onerous for smaller conventional generation developers. However, it is likely that such developers will represent only a small proportion of future connected generation. Mechanisms could be established, as suggested, to exempt existing generation stations from the frequency support obligations.
Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?	As noted above, lowering the threshold could result in some additional costs for ensuring generator compliance and conducting validation tests. For inverter-based generation, we do not expect these costs to be material, but it could be financially onerous for smaller conventional generation developers.

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	Managing virtual generating stations will require additional cost for monitoring and coordination, with associated communications and control systems. However, these costs would likely already be incurred when installing the plant, in order to make it operational. The additional cost to ensure AOPO compliance is not likely to be significant. There may also be costs associated with managing compliance as a growing number of independently owned generators connect to the network, with significantly more generating stations providing frequency keeping services.
Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an under- frequency event for six seconds?	Powerco supports aligning AS/NZS 4777.2 with the code requirement for future generating stations to ride through under frequency events for six seconds to help maintain a secure grid. Pros: 1. The six-second requirement compels the Inverter-based resource (IBRs) to “hang on” to prop the grid frequency up during the under-frequency event, helping to stabilise the grid and prevent cascade failures. 2. Promotes consistency across the industry in New Zealand. Cons: 1. Some inverters from certain vendors may not meet this requirement, potentially increasing production costs. 2. It will take time for a significant portion of the network to have IBRs with this capability, delaying the full realisation of the ride-through benefit.
Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	Yes, the dead band should be based on the technology of the generating station, as different technologies have varying capabilities to respond to frequency changes. A single dead band across all technologies is not appropriate. Inverter-based generators are also unlikely to face additional costs for operating in a wider deadband, unlike conventional generation. Tailoring the dead band to the technology of the generating station would allow of the benefits of a wider deadband without compromising existing generation.
Q6. Do you consider the Authority should be shortlisting the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	Yes, widening of the normal band for frequency will allow a more flexible operating range as the limits are relaxed. For inverter-based equipment, the potential negative implications are likely to be minimal. While the widening the deadband will have potential implications on the operation of frequency sensitive equipment, we expect this sensitivity will reduce over time as more devices that are relatively insensitive to frequency changes are connected (such as switch-mode power supplies or inverter-driven motors). However, there will be potential cost implication to asset owners to change the frequency response characteristics of the assets which are currently used to provide frequency support as an ancillary service. Additional frequency response studies may be required.
Q7. Do you agree the Authority should be short listing the second frequency-related option to	Yes.

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help address Issue 1? If you disagree, please explain why.	
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	It would be a cost-effective option to improve frequency-keeping (assuming differentiation can be made between generation technology). We expect the cost-effectiveness to increase over time.
Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	Costs include upgrades for generating units to meet the requirement, as well as costs to cover compliance, validation tests, and certification to demonstrate capability.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	Benefits: Improves ability to provide frequency support especially during contingent events. Costs: With more static generating plants replacing traditional rotating ones, significant frequency fluctuations are likely to become more common. This shift would likely require more spinning reserves (or equivalent), which would have a cost-implication.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	Improved visibility and integration between Transmission System Operator (TSO) and Distribution System Operators (DSOs) SCADA systems (or Advanced Distribution Management Systems) will be essential. For Example, the TSO would need real-time visibility of the operating modes and outputs of embedded generators within a distribution network. A holistic approach to system operation is required.
Paper 2: An options paper that addresses voltage deviations and network performance issues	
Q1. Do you consider it likely that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems (when discharging) that connect to their networks? Please give reasons for your answer.	Yes, as distributors are required to maintain their network within the regulated voltage range. With increased penetration of generation connected to distribution networks, this can push voltages up beyond the limit which will negatively impact the other connected customers. Powerco already mandates generation plants above 1 MW connected to our local network to be designed with the capability to operate in voltage (V), power factor (pf), or reactive power (Q) modes. The actual control mode and operating point will be advised by our Network Operations Centre as operational parameters may need to be altered at times to accommodate changing network conditions.
Q2. Do you agree generating stations and energy storage systems connected to local distribution networks at the GXP voltage (which varies by local distribution network) should be required to support voltage, or do you consider the	We believe that generating stations and energy storage systems connected to the local distribution should be required to support voltage at the Grid Exit Point (GXP) voltage level. This is because the voltage rise due to the injection will be seen at any GXP voltage level. For example, a 5MW solar generator connected to a 11kV GXP could drive voltages higher at mid-day if it does not have voltage support obligations, placing the burden on

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obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (eg, 33kV)? Please give reasons for your answer.	the distribution network company to implement solutions to correct the voltage back towards 11kV. As more generators connect to the network, this situation becomes unsustainable.
Q3. Do you consider there should be a capacity threshold (eg, a nominal net export or nameplate capacity of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	Powerco believes that all generators above 1 MW should have obligations to support voltage. We mandate generators above 1 MW to provide ±33% voltage support (through reactive power) at the point of connection. This requirement helps Powerco maintain voltages within the regulatory limits for our connected customers and ensures that the responsibility for voltage stability is shared, at least in part, by the parties contributing to the issue.
Q4. What do you consider to be the pros and cons of requiring generating stations / energy storage systems connected to local distribution networks to have a reactive power range of ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?	Pros: 1. +33% reactive power range can be easily met by generating plants without the need to install additional reactive compensation equipment. 2. Lowers cost for the generator asset owner. Cons: 1. Potentially more generator asset owners will want to connect at the local distribution network due to the relaxed reactive power range, which may limit the size of units. 2. Poor power factor at the GXP can arise when there is enough embedded generation to net off the load.
Q5. Do you agree the Authority should be short listing the first voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.	Yes.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	We agree with the benefits outlined in the consultation paper (par 4.31). Expanding the requirement for reactive power capability to a broader range of parties should create a practical, cost-effective approach to voltage managements across all parts of the power system. Greater coordination and cooperation between operators would also be a beneficial outcome. Powerco's modelling suggests that the operating range of ±33% provides adequate support to maintain voltage on our network within regulated limits.

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	Greater monitoring requirements will bring additional cost. However, we believe this is far outweighed by the system stability benefits that could be achieved - particularly when compared with the potentially significant network investment costs that may otherwise be necessary to achieve the same outcome.
Q7. Under the first voltage-related option, what costs are likely to arise for the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network?	The costs that are likely to arise are: • Compliance and validation certification costs for capability benchmarking • Costs associated with the onerous response testing required when commissioning - these actions would be essential for completing the Asset Capability Statement submitted to the System Operator. However, as noted above, we believe these costs will be of a much smaller magnitude than might otherwise be incurred if network investment was required to maintain voltage stability.
Q8. Under the first voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?	Costs associated with compliance and validation testing for capability benchmarking. We don't believe that the additional cost would be material.
Q9. Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.	Yes
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	It allows integrated voltage management across transmission and distribution networks to maintain voltages within regulated limits. It will require additional costs to implement systems to coordinate, integrate and manage the voltage across transmission and distribution networks.
Q11. Under the second voltage- related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?	Compliance and validation testing to prove capability to meet Asset Capability Statement requirements.
Q12. Do you consider it likely that distributors will, in the absence of a Code requirement, place fault ride through obligations on some or all <30MW generating stations that connect to their networks? Please give reasons for your answer.	Yes. Powerco already mandates that generators submit a Fault Ride-Through (FRT) compliance study report for all generating stations above 1 MW. Powerco expects generators to remain connected during a voltage disturbance event and support system voltage. Pre-fault, the generation masks the load. If these generators drop off during the voltage disturbance, the network will suddenly see a step increase in load, and this will cause low voltages network-wide until on-load tap changers have time to react.

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Q13. Do you consider it appropriate to include in the Code fault ride- through curves for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account network protection considerations? Please give reasons for your answer.	Yes, because: • This provides Powerco with confidence that distributed generation will remain connected within the no-trip envelope and avoid sympathy trips. • In our Utility Scale DG Technical Requirements Standard, which can be found on our website, Powerco mandates generators to submit FRT compliance study reports for all generating stations above 1 MW
Q14. Do you consider there should be a threshold based on connection voltage and capacity (eg, a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations connected to distribution networks to ride through faults? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	Powerco mandates all generating stations above 1 MW to comply with the FRT requirement. We believe that any large-scale generation, which we define as above 1MW, must contribute to the ability to ride through faults. If they do not have this capability, we could see network-wide voltage stability issues following a voltage disturbance event. In some cases this can have an impact back through to the transmission network.
Q15. Do you agree the Authority should be short listing for further investigation the third voltage-related option to help address Issue 4? If you disagree, please explain why.	Yes
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	This provides Powerco with confidence that distributed generation will remain connected to the network for typical system faults and it also helps prevent sympathy trips. Expecting existing generation stations to comply with the changed requirement may be problematic, both technically and from a cost perspective. Earlier versions of the Institute of Electrical and Electronics IEEE standards associated with BESS standby power stations, for example, did not prescribe rigorous fault ride-through capability.
Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW	Where Powerco installs systems like BESS we already specify compliance with the fault ride through requirements.

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threshold if these generating stations must comply with the fault ride through AOPOs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?	
Q18. Do you have any comments on the Authority's assessment of options to help address Issues 2, 3 and 4 identified in our 2023 Issues paper?	Powerco supports the Authority's approach for these option assessments. This will require better visibility and integration of SCADA systems between Transmission System Operator (TSO) and Distribution System Operators (DSOs) to provide real-time view of the operating modes and outputs of the embedded generation.
Paper 3: A discussion paper that describes our thinking on the governance and management of harmonics	
Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If youdisagree, please explain why.	Yes. However, the word 'harmonic' is too narrow to cover the issues. Not all disturbances created are integral multiples of 50Hz. Recent changes in technology using high frequency switching devices means that we should also consider inter-harmonics and high frequency noise, possibly up to 150kHz. High frequency noise has also been called supra-harmonics, although strictly speaking, as the noise is related to the switching frequency and not the fundamental, they are not harmonics.
Q2. Do you agree the Authority has identified the main challenges with the existing arrangements for the governance of harmonics? If there are any additional challenges, pleaseset these out in your response	Yes.
Q3. Do you consider the existing regulatory framework for the governance of harmonics in New Zealand is compatible with the uptake of inverter-based resources? Please give reasons for your answer.	Powerco considers NZECP36 allocation inadequate and somewhat arbitrary. This is based on 30% of headroom approach and the fact it doesn't consider the size of the asset and the capacity at the point of connection. Additionally, there is no method provided for dividing the allocation when there are multiple potential connections. Furthermore, the background measurements are incomplete. A more detailed and applicable standard is required to cover the changing nature of the power system. Powerco believes moving forward, IEC61000 should be adopted for management and governance of harmonics in New Zealand.
Q4. Do you have any feedback on the Authority's suggested way forward to help address the challenges with the existing	It is a good approach to learn from overseas experiences and incorporate international best practice to our local networks, where appropriate.

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arrangements for the governance of harmonics?	
Q5. Do you have feedback on any ofthe elements of good industry practice relating to a framework for managing harmonics? This may include feedback relating to elementsyou consider are missing from the summary provided in section 5 of thispaper.	Currently Powerco considers both Transpower's NZECP36 allocation and the IEC:61000 allocation approaches and selects the most conservative allocation. Powerco supports the move towards IEC:61000 allocation.
Q6. Do you agree with a 'whole of system' approach to allocating harmonics, so that any differences inharmonic allocation methodologies between electricity networks do not cause excessive harmonics? If you disagree, please explain why.	Yes. Powerco supports a "whole of system" approach to allocating harmonics. The present framework allows some baseline harmonic planning level limits to be exceeded. The new approach would allow a more structured approach to allocating harmonics without exceeding established limits.
Q7. Do you have any feedback on the suitability for New Zealand's power system of the harmonics standard NZECP 36:1993, or the AS/NZS 61000 series of harmonics standards?	NZECP36 has not been updated for three decades. It has not kept up with changes in electronic switching technology, and we think it should be phased out. Powerco currently receives Transpower's NZECP36 allocations for the harmonic requirements at GXPs but finds that the '30% headroom' allocation method is poorly defined and arbitrary. Powerco supports moving to AS/NZS 61000 series to maintain the whole system approach.
Q8. Do you have any feedback on the alternative approaches to limitingharmonic emissions, including alternative approaches you considerto be appropriate for New Zealand's electricity industry?	Powerco supports investigating any alternative approaches that help maintain the whole of system approach.