14 August 2024

Future Security and Resilience Project
Electricity Authority
By e-mail: fsr@ea.govt.nz

Dear Future Security and Resilience Project,

The governance and management of harmonics

Lodestone Energy welcomes the opportunity to provide feedback on the Electricity Authority's consultation about the governance and management of harmonics within the NZ power system. This letter forms the entirety of our submission and includes some brief background on Lodestone.

Lodestone Energy was founded in 2019 with the mission to "harness the sun's energy to power Aotearoa's zero carbon future". We were the first company in NZ to deliver large scale solar to the grid and currently have two operating solar farms in Kaitaia and Edgecumbe. We have a third under construction in Waiotahe, with a planned pipeline to deliver another 11 sites over the next few years. Our position as an early mover has given us some unique insight into the challenges of integrating solar with the existing grid, in particular technical requirements when embedded within a distribution network.

Our specific feedback to your questions is as follows:

Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If you disagree, please explain why.	Largely yes, with a couple of caveats. The paper makes an implicit assumption that IBR will make harmonics problems worse. This is not necessarily the case. Some recent literature (refer University of Wollongong's Impact and Management of Harmonics study, Dec 23) have shown that harmonics problems can actually be reduced following the introduction of IBR. Additionally, the costs to consumers and some of the research cited references power quality issues, rather than harmonics specifically. It is important to draw the distinction between power quality and harmonics, which are just one aspect of power quality. Hence as currently presented, costs to consumers for harmonics issues might be overstated. If this results in additional costs of compliance for network customers, then such costs might outweigh any real or perceived cost savings from harmonics issues.
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, please set these out in your response	Yes. Our view is that the most significant issue is the lack of consistency between the Electricity Safety Regulations, The Code, and various other guidelines that promote good industry practice, for example, the EEA Power Quality Guidelines. The lack of consistency is creating uncertainty and

	often raising perceived risks that in our view are seldom substantiated.
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.	No, see prior answer.
Q4. Do you have any feedback on the Authority's suggested way forward to help address the challenges with the existing arrangements for the governance of harmonics?	As an overarching industry body, the Authority can take a leadership position to ensure consistency in NZ's standards and regulations regarding harmonics. Furthermore, it is important to ensure that perverse outcomes are not mandated, such as an over reliance on pre-emptive installation of harmonic filters, which has become common practice in Australia.
Q5. Do you have feedback on any of the elements of good industry practice relating to a framework for managing harmonics? This may include feedback relating to elements you consider are missing from the summary provided in section 5 of this paper.	Section 5.24, we think network users "should" conduct studies is not the most appropriate way to frame the process. Our view is this language could be softened to state that a robust harmonics management process should first consider the likelihood of there being harmonics issues before jumping straight to system studies, which are often time consuming and expensive. For example, if the connecting party's load or generation is very small relative to the system strength, then it's unlikely that harmonics would be an issue, and no studies should be required. Additional thought should be given to mandating harmonics monitoring for all network users. This should again be a staged process based on the size of the connection relative to the network. Furthermore, a framework is needed to define how the information should be monitored, collected, processed and stored, along with clear roles and responsibilities to ensure consistency throughout the country. 5.28 Mitigating harmonics is a complex process that "often"… We feel this should say "sometimes requires installation of harmonic filters" rather than "often". 5.34. Harmonic impedance polygons are not a way of allocating harmonic current, rather a way of assessing harmonic compliance once an allocation has been provided. Hence, we don't agree that generation of harmonic impedance polygons is likely a "better" way to allocate harmonic current. It is a complex approach and requires considerable expertise in power system modelling along with access to advanced tools. Many distribution companies in NZ do not have such resources at their disposal.
Q6. Do you agree with a 'whole of system' approach to allocating harmonics, so that any differences in harmonic allocation methodologies between electricity networks do	The challenge with whole-of-system approaches is their complexity, particularly when it comes to large harmonic models. We are in favour of clear, simple processes for assessing harmonics and connection risk. The voltage droop allocation methodology proposed by the University of Wollongong and discussed in the EEA guide is one such

not cause excessive harmonics? If you disagree, please explain why.	method that strikes a reasonable balance between compliance, complexity, and risk.
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?	NZECP is no longer fit for purpose being over 30 years old with roots going back much further. We support harmonics management approaches based on up to date modern standards that better reflect the makeup of contemporary networks. The AS/NZS 61000 series is an improvement in this regard. We do not consider Transpower's current method of allocating a fixed percentage of headroom to each user as fair and equitable. At a minimum, any robust method should consider the relative size of each connection compared with the capacity of the upstream connection point. At present, perverse outcomes occur where the first connecting party gets a larger percentage allocation, regardless of their project size. We have also seen the fixed percentage method result in essentially no allocation of harmonic emissions at certain frequencies, which is not reflective of the risk of equipment problems, nor practical to achieve from a mitigation standpoint. This becomes a particular problem in distribution networks where an already small allocation is further sub-divided by the EDB.
Q8. Do you have any feedback on the alternative approaches to limiting harmonic emissions, including alternative approaches you consider to be appropriate for New Zealand's electricity industry?	We are strongly opposed to the pre-emptive installation of harmonic filters. As indicated earlier in our submission, this approach has been followed in Australia with poor results, the costs of which are disproportionate to the risks being mitigated. Often the connecting harmonic filters cause more problems than they solve (e.g. they may interfere with existing ripple control systems), simply because they are designed when looking only at a single project rather than taking a more robust system view to harmonics mitigation. We favour simple methods such as the voltage droop method that can be easily understood and implemented by most network utilities in NZ. Furthermore, we believe that network utilities should take a pragmatic and constructive approach to working with connecting parties to resolve any identified harmonics issues without applying punitive measures. This will lead to lower cost outcomes for NZ consumers.

Kind regards,

Peter Apperley
General Manager, Engineering
[redacted]

LODESTONE ENERGY

20 August 2024

Future Security and Resilience Project
Electricity Authority
By e-mail: fsr@ea.govt.nz

Dear Future Security and Resilience Project,

Addressing more frequency variability in New Zealand's power system

Lodestone Energy welcomes the opportunity to provide feedback on the Electricity Authority's consultation on Addressing more frequency variability in New Zealand's power system. This letter forms the entirety of our submission and includes some brief background on Lodestone.

Lodestone Energy was founded in 2019 with the mission to "harness the sun's energy to power Aotearoa's zero carbon future". We were the first company in NZ to deliver utility scale solar bid into the market and currently have two operating solar farms near Kaitaia and Edgecumbe. We have two more farms under construction in Waiotahe and near Whitianga, with a planned pipeline to deliver another 9 sites over the next few years. Our position as an early mover has given us some unique insight into the challenges of integrating solar with the existing grid, in particular technical requirements when embedded within a distribution network.

Our specific feedback to your questions is as follows:

Q1. Do you agree the Authority should be short listing for further investigation the first frequency-related option to help address Issue 1? If you disagree, please explain why.	Yes, with a few caveats and comments. As pointed out in the paper, most of the generation affected by this change will be small scale wind and solar. It is worth emphasizing that these plants will not be able to provide under-frequency support in the form of increased output during an event, due to the nature of their resource. Changing the MW threshold will not alter this. Furthermore, Lodestone is strongly opposed to any suggestion of pre-event curtailment to create "headroom" for under frequency events. We are aware that this is not being proposed by the current change, however, do note that it was investigated by Transpower. We don't view this as a credible economic development and it would significantly disadvantage solar, wind and geothermal generation. The difference in the scenarios observed in the Transpower paper is a result of a decision by the SO to trip 20% of excluded generation stations. This 20% reduction is based on observations from one event in the USA (the Odessa disturbance), so we question whether the selection of assumptions is valid. Consequently, it is not clear that the proposed benefit shown by Transpower would eventuate in practice as most modern grid connected solar and wind would remain connected despite the 30 MW threshold; it is economically incentivised to do so already.

	Finally, we also view this change as an opportunity to standardise frequency compliance between the North and South Island. At present the South Island has a requirement to ride through frequency disturbances between 45 and 47 Hz for 30 s; clause 8.19 (3) (b). Such a requirement is onerous in comparison to international standards and places additional costs on generation developers by limiting the potential equipment that can be procured. We suggest that clause 8.19 (3) is removed from the Code.
Q2. What do you consider to be the main benefits and costs associated with the first frequency-related option?	Clarity and standardisation of requirements for all grid connected plant. The main concern we have is increased compliance costs. Because the cost of completing consultant studies to demonstrate frequency event compliance is relatively similar regardless of plant size, this places a potential disadvantage on small scale projects where such costs become a larger percentage of the total project cost.
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?	The evidence and benefit of choosing 5 MW as opposed to 10 MW is not strong in the Transpower paper. As discussed in our prior answer, our main concern is around increased compliance cost for small projects. Choosing a 10 MW threshold as opposed to 5 MW would be beneficial in this regard.
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 underfrequency event for six seconds?	We generally support alignment of the Code with accepted national and international standards where it makes sense to do so and doesn't introduce unnecessary compliance costs.
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.	No. Lodestone is in favour of technology agnostic rules that facilitate competition across technologies. Choosing a different maximum dead-band for different technologies would appear to be counter to this principle and would also add more complexity to the Code. As discussed in the EA paper this would also be out of line with other international jurisdictions.

Q6. Do you consider the Authority should be short listing 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.	No comment.
Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why.	Yes.
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	No comment.
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?	No comment.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	We would advocate against this option being investigated in lieu of developing a functioning capacity market for frequency control services. Lodestone believes that the EA should rather spend the necessary effort to develop a functioning frequency control capacity market to provide additional incentives for battery storage projects. Such a market would have the added benefit of improving system frequency performance as more battery projects come online. We think this should be a high priority.

	Frequency control capacity markets are commonplace in overseas jurisdictions and have been shown to deliver excellent outcomes, both in terms of financial incentives and also system frequency control. Some relevant links below: https://www.energy-storage.news/uks-latest-frequency-regulation-grid-service-launched/ https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/guide-to-ancillary-services-in-the-national-electricity-market.pdf

Kind regards

Peter Apperley
General Manager, Engineering
[redacted]

20 August 2024

Future Security and Resilience Project
Electricity Authority
By e-mail: fsr@ea.govt.nz

Dear Future Security and Resilience Project,

Addressing larger voltage deviations and network performance issues in New Zealand's power system

Lodestone Energy welcomes the opportunity to provide feedback on the Electricity Authority's consultation about addressing larger voltage deviations and network performance issues in New Zealand's power system. This letter forms the entirety of our submission and includes some brief background on Lodestone.

Lodestone Energy was founded in 2019 with the mission to "harness the sun's energy to power Aotearoa's zero carbon future". We were the first company in NZ to deliver utility scale solar bid into the market and currently have two operating solar farms near Kaitaia and Edgecumbe. We have two more farms under construction in Waiotahe and near Whitianga, with a planned pipeline to deliver another 9 sites over the next few years. Our position as an early mover has given us some unique insight into the challenges of integrating solar with the existing grid, in particular technical requirements when embedded within a distribution network.

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, and we have observed this already happening for our solar projects connected to distribution networks. EDB's would benefit from additional guidance and potential standardisation across NZ. This does not necessarily have to happen within the Code but could be in the form of industry guidelines from reputable organisations such as the EEA.
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 obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (eg, 33kV)? Please give reasons for your answer.	Yes, with some caveats. Our view is that blanket approaches for voltage regulation for sub-transmission voltages can be difficult. For example, it is impractical for some 33 kV connected plant to produce the range of reactive power currently stipulated in the Code -33%/+50%. To do so, would cause 33 kV voltages to go outside the normal band because of the system impedance. Any Code amendment needs to effectively consider nuances that occur at sub-transmission levels. Although it would add complexity to the Code, it could be a better solution to have flexible requirements for sub-transmission connections. For example, smaller reactive power requirements and the option to agree an alternative voltage control strategy with the EDB,

	such as power factor or reactive power control, where it makes sense to do so.
Q3. Do you consider there should be a capacity threshold (eg, a nameplate capacity or nominal net export 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.	We do not support a capacity-based threshold to support voltage for generating stations in distribution networks. We think there are better ways to ensure cost effective outcomes for the grid. Principally, each distributor knows their network best, and therefore they should be responsible for agreeing practical voltage support arrangements with generating stations connected to their network. One possible option is an overarching guideline/recommendation within the Code that could include suggested limits, but with the caveats that these are subject to negotiation between parties based on the needs and limitations of the connected networks.
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?	Having a more nuanced approach to voltage control at distribution level is important. It is not practical to have a fixed reactive power range due to the effect on distribution network voltages. Generators must be able to negotiate and agree technical requirements with the EDBs and receive a dispensation from the System Operator based on that agreement. A further concern with this proposal is the lack of economic assessment of the costs and benefits of such a change on end use customers. Although using ±33% as the reactive power threshold would be a lesser requirement than the transmission requirement of +50/-33%, it is not practical because of situations where the network impedance makes achieving even these limits impossible whilst also maintaining voltage within the normal band. We recommend that any voltage control requirements applied to sub-transmission networks are more nuanced and include the ability for the embedded generation proponent to negotiate appropriate technical requirements that are fit for purpose with individual EDBs.
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.	No, we do not support option one without modifications as described in the previous answers.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	See previous answers.
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	We believe that the first voltage-related option, as it currently is written will result in several unintended consequences and costs including: • Significant additional power system study costs • Increased project costs due to delay and uncertainty in meeting impractical thresholds

a point of connection to the local distribution network?	• Increased equipment costs for meeting impractical thresholds • Increased generation losses to meet reactive power requirements • Increased compliance costs
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?	There will be costs associated with additional connection delays and meeting impractical voltage support requirements if the revised Code is not fit for purpose.
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, we strongly support a coordinated approach to voltage management at the GXP and removal of the power factor requirements, which are no longer fit for purpose with significant embedded generation.
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	The paper has summarised these well.
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?	No comment.
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, and we have observed this occurring already for our embedded generation stations.
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, however, we are mindful of the potential increased compliance cost burden that may result from this change.
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	We believe that maintaining an appropriate capacity threshold such as 10 MW is important to avoid creating a disproportionate cost burden on smaller generating stations. Our view is that it would be pragmatic to align this threshold with the threshold proposed for frequency disturbance ride through compliance as discussed in the EA's other Part 8 discussion paper.

implications of having / not having a capacity threshold.	
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, with the caveats mentioned in our previous answers.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	Standardisation of fault ride through requirements across grid connected generation is beneficial for grid security and reliability and most modern IBR can meet the proposed requirements. The main disadvantage of lowering the threshold for compliance is an increased compliance demonstration burden. One possible solution to this is to permit smaller generating stations to demonstrate compliance by supplying FRT settings and asset capability documents only and not require them to undertake exhaustive power system dynamic simulations. Furthermore, the EA should provide some leeway for existing plant to achieve compliance. It would be beneficial to have a "grandfathering" clause in the Code that would either exempt already connected plant, or allow a reasonable period of time for compliance to be achieved.
Q17. What costs are likely to arise for owners of (single site and virtual) generating stations under the 30MW 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?	See our previous answers.

Kind regards.

Peter Apperley
General Manager, Engineering
[redacted]