



15 July 2025

Electricity Authority

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Submission on proposed amendments to voltage-related code

Manawa Energy welcomes the opportunity to provide a submission to the Electricity Authority on its proposed changes to the voltage-related code. Manawa Energy's views and questions follow in the body of this submission. Appendix A contains answers to the Authority's specific questions, and Appendix B contains Manawa Energy's 2024 submission.

Legacy status needs to apply to all existing small hydro

The Authority proposes lowering the threshold for net maximum export from 30MW to 10MW. This change would mean some generating stations would have to comply with the voltage-keeping AOPs and technical codes in Part 8.

Manawa Energy supports the proposal for new generation stations. However, Manawa Energy strongly opposes the proposal for existing hydropower generating stations. Instead, Manawa Energy would like:

- the legacy clause to apply to all small hydro generating stations less than 30MW, without having to complete costly fault ride through studies
- the application for legacy status to be straightforward and not involve significant cost (the suggested notification via the asset capability statement seems to be a pragmatic approach)
- the legacy status to be permanent — not to be revoked after a finite period or if the generating station's export capacity is increased

Manawa Energy disagrees that smaller generating stations must complete fault ride through studies.

Manawa Energy would like the requirement for fault ride through studies completely removed for existing hydro generation stations, or at least significantly reduced. Such studies could cost \$40,000 to \$100,000 per generating unit and between \$2-5M for all of Manawa Energy. The purpose of the EA proposal is to address the impact of an increasing proportion of inverter-based generation. These costly studies on small hydro generators will not address the cause of the issue, provide a negligible benefit, and the cost will flow through to consumers.

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Questions remain

- **What is the definition of 'generator' and 'generation station'?** Currently it appears most of Manawa Energy's fleet may be subject to the new requirements. For example, the Kumara-Dillmans-Duffers hydropower scheme is a cascading scheme, with three power stations, a 6.5MW synchronous generator, a 3.8MW synchronous generator and a 0.6MW asynchronous generator. Total output is 10.9 MW across the scheme, embedded behind the KUM0661 GXP. Manawa Energy considers these to be three separate generation stations, but the current proposal appears to treat these stations as a single generation station. Manawa Energy has several power schemes with similar set-ups.

An added complexity is that there are differences within each station, which would drive additional cost for fault ride through studies. For example, at Coleridge G1 (13.5MW), G2 and G3 (12.5 MW) each are governed synchronous machines, whereas G8 and G9 are two 3.5MW actuated synchronous machines, that cannot comply with the proposed requirements. Completing fault ride through studies on the small units costs the same as on large units, and there is negligible benefit in carrying out these costly studies.

- **Why would, or should, a capacity increase remove legacy status?** What constitutes an upgrade to a station that is subject to the legacy clause? What would happen for example, if there is a small efficiency upgrade (like new intake screens, turbine replacement) that increases total capacity from 10MW to 10.1MW? Who and what determines if non-compliant stations that are upgraded would need to comply with the new obligations?
- **The proposal on embedded stations and default control mode also needs clarifying**
In principle, Manawa Energy supports the proposed default mode set to voltage control mode but seeks clarification on how this will work. Who will be policing and providing the direction on requests and managing this process? The system operator or the EDB?

Manawa Energy is a wholly owned subsidiary of Contact Energy

Manawa Energy owns and operates a diverse portfolio of 41 power stations across 25 hydro-electric power schemes, supplying around 5% of New Zealand's electricity needs. Manawa also jointly owns and operates King Country Energy's six hydro-electric power stations. Approximately 60% of this combined electricity is connected to ten different distribution networks across New Zealand, which makes this New Zealand's largest distributed generation portfolio, with multiple stations operating successfully for more than 100 years.

Manawa Energy has made previous submissions on this topic to the Authority. Those submissions have been backed up with examples of various generating plant types (for example, asynchronous and synchronous plant), machine voltage control types (from none to automatic voltage controllers).

On 11 July 2025, Manawa Energy became a wholly owned subsidiary of Contact Energy. Given the timing of the acquisition, this submission was prepared independently and can be assumed to reflect Manawa Energy's view as an operator of small-scale hydro generation rather than that of the combined entity that encompasses both Contact Energy's and Manawa Energy's generation portfolios.

Kind regards,

Mike Moeahu
Principal Generation Engineer

Appendix A: Answers to consultation questions

Submitter: Manawa Energy	
Promoting reliable electricity supply: A voltage-related Code amendment proposal	
Q1. Do you agree the issues identified by the Authority are worthy of attention?	<p>Yes, Manawa Energy agrees with the issues identified. But Manawa Energy does not agree with some of the suggested options and reasons for solutions. The following are the key points.</p> <ul style="list-style-type: none"> • Compliance will be costly and challenging for existing assets. • Most of Manawa's generation is embedded and currently support the distribution networks. Some generation stations can be a significant distance away from a transmission GXP and provide voltage and frequency support on the distribution networks. • New BESS, wind and photovoltaic cell technology have driven the requirement for more voltage stability. But existing plant may not always be able to comply, and proving their ability to comply will be costly. • Further clarification is needed on how much the code amendments apply to Manawa Energy's generators, stations and schemes or whether they will be exempted by the proposed legacy clause. Similarly, clarification is needed on the details of the legacy clause, such as upgrade limits. • Fault ride through obligations and capability on existing synchronous and asynchronous assets is very prescriptive and will be difficult to comply with, and proving compliance and modifying equipment will be costly. • The proposal will affect existing embedded generation and new intermittent generation. Along with the distribution network loads, will cause challenges for the GXP and transmission load flows and voltage management.
Q2. Do you agree with the objective of the proposed amendment? If not, why not?	<p>We agree with the objective in principle.</p> <p>However, we would like the following clarified.</p> <ol style="list-style-type: none"> 1) "We propose some embedded generating stations operate in a default voltage control mode." <ol style="list-style-type: none"> a) Where our generator configuration and EDB networks allow, we should be able to meet the voltage control mode, or where required power factor or VAR mode. When requested by System Operator or EDB we provide reactive power support in VAR mode. b) 3.2 (a), (b), (c), and (d). c) 3.3 Default requirement on an embedded generating station would be for it to actively export or import reactive power that is a minimum of 33% of the maximum continuous MW output power of the generating station. d) The connection voltage between existing embedded generating station, local distribution network, transmission network. The impact of

	<p>the distance, load bases of the EDB, their own line reactance issues and such, will potentially have greater effects on the voltage.</p> <p>2) "We propose smaller generating stations have fault ride through obligations."</p> <p>a) 3.4 and 3.5, clauses are for generation stations and not generators where Manawa have challenges in complying due to the types of generators, example synchronous and asynchronous that cannot comply.</p> <p>b) This obligation should not be required for existing generation stations assets below 30 MW</p> <p>3) "We propose 'legacy clause' arrangements be adopted."</p> <p>a) 3.15 and 3.16 clauses we support conditionally on clarification on Category A and Category B interpretations.</p> <p>4) The legacy clause would no longer apply if a generating station were upgraded.</p> <p>a) Manawa Energy opposes having the legacy clause revoked based on a capacity upgrade and does not understand why this is relevant to hydro. Manawa Energy is not aware of any upgrades from asynchronous generators (cannot comply) to governed synchronous generators (can comply) in the last 50+ years. If there have been such upgrades, they would be a tiny proportion of NZ generation, and not material to the issue the EA is attempting to address.</p> <p>b) For example, how will the code apply if a turbine's efficiency is improved from 10MW to 10.3MW? By having this clause, it creates significant uncertainty for small replacements and upgrades – for example, new screens before penstocks increasing output by 3%, new distributor assembly increasing efficiency by 5%. Would the machine then require fault ride through studies and dispensation due to a minor upgrade? The investment uncertainty this clause creates and the associated costs to then complete fault ride through studies and get dispensation has negligible benefit, and that cost will flow onto consumers.</p>
Q3. Do you agree we have correctly identified the benefits and costs of the proposed amendment?	<p>Manawa Energy does not agree that the relative costs have been considered and wishes to make the following points.</p> <ul style="list-style-type: none"> • There will be an additional \$2-5M of costs for Manawa Energy for modelling and studies for the System operator even with embedded generators. Most EDM currently do not require these studies. • The mechanism around the implementation of the legacy clause and providing the system operator the information seems reasonable. However, more clarification of the process is required. • The cost to comply with the proposed code and plant modifications will be significant if imposed without allowances for existing generators.

	<ul style="list-style-type: none"> This requirement will drive inefficient replacements of components on existing hydro generators, to avoid accidentally increasing capacity and “losing the legacy clause”.
Q4. Do you agree the benefits of the proposed amendment outweigh its costs?	<p>No. The cost will be substantial to Manawa Energy, which will ultimately be passed onto consumers. There is negligible benefit for consumers in having existing small hydropower meeting these requirements.</p> <p>The benefit cost ratio would be higher if the proposal was limited to <i>new</i> generating stations only.</p>
Q5. Do you agree the proposed amendment is preferable to other options? If you disagree, please explain your preferred option in terms consistent with the Authority’s statutory objective in section 15 of the Electricity Industry Act 2010.	<p>Manawa Energy disagrees that the proposed amendment is preferable to other options.</p> <p>Manawa Energy’s preferred option is for the legacy clause to apply to all existing small hydro power stations.</p> <p>If the legacy clause does not apply to all existing small hydropower station, then there will be a substantial relative cost added to existing small hydro generation, with negligible benefit, that will flow through to consumers.</p>
Q6. Do you agree the proposed amendment complies with sections 17(1) and 32(1) of the Act?	Not with all of it – as discussed above.
Q7. Do you have any comments on the drafting of the proposed amendment?	No, not in addition to those raised above.

Appendix B: Manawa Energy’s EA Submission 22 August 2024

22 August 2024

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Manawa Energy submission– Review of the common quality requirements in the Code

Introduction

Manawa Energy (**Manawa**) welcomes the opportunity to provide a submission to the Electricity Authority (the **Authority**) on its three-part review of the common quality requirements in the Code (the **Consultation Papers**), as part of the Authority's wider Future Security and Resilience Project.

The Consultation Papers are a collection of three documents that look to address more frequency variability (**Paper A**), larger voltage deviations (**Paper B**), and the governance and management of harmonics (**Paper C**), in New Zealand's power system.

Manawa is an independent power producer that owns and operates a diverse portfolio of 41 power stations across 25 hydro-electric power schemes, supplying around 5% of New Zealand's electricity needs. Manawa also jointly owns and operates King Country Energy's (**KCE**) 6 hydro – electric power stations. Approximately 60% of this combined electricity is connected to ten different distribution networks across New Zealand, which makes this portfolio the largest of distributed generation (DG) in New Zealand, with a strong interest in the impacts of any changes to common quality requirements.

Manawa's views on option 1 of Paper A follows in the body of this submission, and answers to the Authority's specific questions for Paper A, Paper B and Paper C are included as Appendix A. These views are supported by further information about Manawa's generation portfolio included in Appendix B and an expert report, Grandfathering of Technical Standards, from Calderwood Advisory Limited (**Calderwood Report**) included as Appendix C.

Manawa's views

Paper A – option 1

Manawa agrees with the issue that Paper A is trying to address, that *"an increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the 'normal band' of 49.8–50.2 Hertz (Hz), which is likely to be exacerbated over time by decreasing system inertia."* However, Manawa **does not agree** with option 1 to *"lower the 30 megawatt threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations (AOPOs) and technical codes in Part 8 of the Code"* as a way of addressing this issue.

Manawa has a number of existing assets that would be affected if the threshold was to be lowered to either 5MW or 10MW. As detailed in Table 1 below, Manawa and KCE have 60 units (111 MW of capacity) under the 5 MW threshold. There are a further 27 units (at 328 MW of capacity) within the 5 – 30MW

band that may be impacted if the threshold was lowered to 5MW and 15 units (at 238 MW of capacity) within the 10 – 30MW band that may be impacted if the threshold was lowered to 10MW (the two thresholds considered by Paper A). Not only does Manawa & KCE have a large number of generation assets that would be impacted, but a variety of generator types within that (see Table 2 below) and fuel sources (hydro storage that ranges from months to hours, run of river, and diesel). Table 3 describes the number of generation types that may not be compliant and some examples of the complexity that would be involved in complying.

Table 1: The number and size of Manawa and KCE assets

	Units	Total unit capacity (MW)	Stations	Total station capacity (MW)
0-5MW	60	111	27	60
5-10MW	12	90	9	70
10-30MW	15	238	5	96
30 MW+	2	80	6	293
Overall Total	89	519	47	519

Table 2: Manawa and King Country Energy generator types

Generator Types	Units	MW	GOV	Actuated	Induction	AVR
Synchronous (Hydro)	65	473	39	24		65
Induction (Hydro)	15	28			15	
Pump / Induction Generators (Hydro)	6	9			6	
Diesel generators	5	9	5			5
Total	89	519	42	24	19	68

Table 3: Description of Manawa and King Country Energy units that may not be compliant at a 5MW threshold

Potential non-compliant unit types	Number and description of potential non – compliant units at 5MW threshold	Station examples
Induction generators (Hydro)	19 induction generators may not comply. These generators are part of schemes that have either smaller or larger machines that are synchronous. They also have flat output due to managing in or out of conveyance systems.	<p>As an example, on the West Coast, Dillmans has a 3.5MW induction generator. It is the first station on a canal supplying water from a storage lake. The end of the canal is Kumara Power station that has a 6.5MW synchronous generator (Governor & AVR) that connects to the Transpower 66kV line at Kumara Substation. The Dillman machine starts after the Kumara as it supports the network as the induction machine.</p> <p>With the proposed requirement for frequency and voltage control system, the Dillman machine would not comply. The option would be to apply for dispensation. The alternative would be to either remove from service or replace with a synchronous generator.</p> <p>With Dillmans 3.5MW induction generator and Kumara's 6.5 MW synchronous generator, they provide 10MW of inertia with any voltage and frequency management by the Kumara generator.</p> <p>This would be relevant to all of our 21 induction machines. The cost to achieve compliance would not be viable or easy to quantify. To replace 21 induction machines would be in the millions. There will be ongoing compliance costs such as environmental and plant requirements if the assets were not able to operate.</p>
Actuated synchronous (Hydro)	26 generators are actuated synchronous due to being small machines lower than 3 MW but part of a larger station or scheme. The conveyance systems supplying them, or being supplied by them, could not sustain managing frequency excursions. The balancing of conveyance systems, because of the low	<p>As an example, Wairau, a 7.2MW synchronous generator (Actuated & AVR), is at the end of a canal on the Branch scheme. The water is from the river to a storage lake and passes through Argyle Power Station that has a 3.8MW synchronous generator (Governor & Static AVR) to supply the canal to Wairau. Both stations connect to the Transpower 110kV line at the Argyle Transpower Substation. The Wairau machine starts after the Argyle machine as it waits for water to supply the generator.</p> <p>The machine does not have a governor. It was originally specified with one but it was removed because it was unstable and could not comply with the capability of frequency response. This was due to the lack of water into the canal. The machine controller (PLC) manages output of the machine relative to the available water (canal level at penstock intake). The requirement for managing frequency in this situation would, and has, caused tripping and lack of</p>

	volume, does not warrant or sustain governors.	capability to manage frequency response due to available water. Argyle generator will have some capability to manage frequency as it is connected at the same point on the grid and scheme transmission. The frequency will be monitored by the protection. Both Argyle and Wairau have AVR's, and voltage issues will be managed by the AVR's.
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This variety within Manawa's generation portfolio makes the quantifying of the costs and benefits of option 1 a challenging task. However, we have included some of the considerations that will need to be taken into account below.

In terms of benefits, Manawa's view is that they would be limited for existing generation. Because Manawa is already embedded in networks, costly upgrades will provide no further value to frequency (and voltage). Furthermore, it's likely that the cost to upgrade much of the existing generation would be too high and so dispensations would be sought. This would provide no additional benefit to the system either.

In contrast, the costs to existing generation would be significant:

- Much of Manawa's portfolio is made up of old assets, with a fair number being over 100 years old. Retrofitting these plants in the manner that would be required is not commonly done and so may not be achievable or bespoke solutions would be needed. The cost estimate could be in the range of \$5M – \$10M per unit. However, this is incredibly difficult to estimate and so could be significantly more. It also doesn't factor in any loss of generation that may occur as a result of the proposal e.g. from outages to upgrade or loss of capacity (these costs would be in the millions).
- The technical studies required to confirm compliance cost the same irrespective of generator size, making them disproportionately more expensive for smaller generation. It's noted in Paper A that placing less onerous testing requirements could lower this cost, but it's currently estimated at \$70k - \$200k per unit.
- Some schemes have ramp rate and spilling restrictions that would hinder their ability to comply, meaning resource consent variations would need to be sought. Again, this is difficult to estimate depending on what is required to vary the consent but could range from \$10k - \$100k. It should be noted that similar to technical studies, costs are not proportionate to size, making consenting proportionately more costly for smaller stations.
- Paper A raises the option of applying to the system operator (SO) for a dispensation from full compliance. However, this is also not without cost. This cost again is difficult to estimate but given a technical report may be required to prove a dispensation is required the cost could be in the range of \$70k - \$100k. There are also ongoing costs to continue to prove compliance which would be in the order of \$30k every 6 to 8 years.

There is real concern for Manawa that the costs of meeting compliance, via modification to plant and consents or through dispensation, could make some schemes unviable. Shutting down plant that could not comply (either physically or because the economics no longer stack up) would be the worst outcome for a power system that is needing to significantly increase generation. It's important to note that many of the costs cited above not only have upfront costs but ongoing costs that need to be considered.

Given this concern, Manawa does not support option 1 and sees that the 30MW threshold should be retained. Alternatively, Manawa may support option 1 if it only applied to new generation and existing generation was grandfathered.

The Calderwood Report looks at the National Electricity Market (**NEM**) in Australia which provides an example of grandfathering technical standards.

"The key difference between the NEM and the New Zealand market is the way technical standards are treated over time. The NEM has always operated on the basis that performance standards are agreed at the time a plant is first connected or for some requirements changes are made to a generating system. Any changes to the technical standards over time are only applied to new connections. The rationale for this is that new generation should be designed to not degrade the existing system and for new generation to pay the incremental costs associated with the new plant is the correct economic driver. The principle of grandfathering existing connections from changes to their technical standards has remained under two reviews of the NEM technical standards in 2007 and 2018."

Manawa encourages the Authority to consider grandfathering in this instance as the cost/benefit trade-off for the threshold change is notably weighed towards cost for existing plant. Given the issue that option 1 is trying to address is largely a result of expected new generation then it would be more appropriate for the cost of compliance with any rule changes to be met by the participants wanting to add new variable generation on the grid, rather than existing generation.

If you have any questions regarding the content of this submission, please contact Mike Moeahu, Principal Engineer Generation

Appendix A submission questions and comments for Papers A, B & C

Paper A: Addressing more frequency variability in NZ's power system	
Questions	Comments
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?	<p>No.</p> <p>The costs significantly outweigh the benefits.</p> <p>Please see body of submission for further information for the challenges Manawa would experience with our machine types and frequency management systems.</p>
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	<p>There are limited benefits, but costs include costly retrofitting, ongoing compliance costs, consent variation costs, or costs of dispensation.</p> <p>Please see body of submission for further information.</p>
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?	<p>5MW would affect 14 stations and 10MW would affect 5. The costs would vary between each station given different generator and fuel types.</p> <p>For some stations there is concern that the costs would make them unviable, even the costs associated with dispensation.</p> <p>Manawa has roughly estimated \$5M – \$10M for upgrades, \$70k - \$100k for technical reports associated with proving compliance or requesting dispensations, \$10k - \$100k for consent variations, not including any ongoing costs.</p> <p>Please see body of submission for further information.</p>
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?	<p>Manawa believes there is more discussion and analysis to be undertaken and clarity of AS/NZS 4777.2 to include in the Code.</p>
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.	<p>Yes. Manawa would consider a maximum band appropriate if it was achievable by the existing plant. If it were not achievable due to the plant type and technology, it would be appropriate if these were a part of a dispensation or a grandfathering system.</p> <p>New generation would be appropriate if achievable.</p>
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	<p>No in general.</p>

identified frequency-related issue? Please give reasons with your answer.	<p>We consider that for some of our non-frequency systems, induction and actuated machines, this will have no benefit.</p> <p>The remaining machines would depend on their governor systems machines. The conveyance systems will have challenges depending on the bands that could be instigated.</p> <p>Manawa does not see that the cost is worth it.</p>
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. Addressing more frequency variability in New Zealand's power system	<p>No.</p> <p>Existing generation should be grandfathered for reasons outlined in prior questions on the type of generators and frequency controls to meet the Code.</p> <p>New machines and frequency control systems will be able to be easily programmed, unlike most older systems.</p>
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	<p>No benefit to existing plant unless it was capable of being easily programmed.</p> <p>Manawa's actuated machines do a dampened approach to this to manage conveyance challenges. If the target was to dampen the frequency controller there may be further discussion to be had on this.</p> <p>The costs will be significant for upgrading generators to meet the Code. This will require significant cost to study and identify options.</p>
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?	<p>Like Q3, the costs would vary between each station and therefore providing an accurate estimate is difficult.</p> <p>To accurately quantify would require studies on what would be required and at what cost, which will be significant. Manawa has estimated \$5M – 10M for upgrades, \$70k - \$100k for technical reports associated with proving compliance or requesting dispensations, \$10k - \$100k for consent variations, not including any ongoing costs.</p> <p>If it were a new machine this could be part of the design.</p>
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	<p>The option to procure more frequency keeping and instantaneous reserve under status quo arrangements is Manawa's favoured approach.</p> <p>Manawa agrees with the assessment of benefits and costs made in paper A, that the option is</p>

	<p>Manawa sees this as an opportunity to add capability to provide further frequency response services by the generators. There is an opportunity for new generation to consider this capability in their designs. It will require more tuning of the guide to reflect this potentially.</p>
<p>Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?</p>	<p>Manawa disagrees with the proposed options 1 and 2 but agrees with option 3.</p> <p>The unintended consequences associated with high costs from 1 and 2 could make some stations unviable which would be the least desirable outcome for a power system that is needing to significantly increase generation.</p> <p>We believe the options being consider have been taken on the premiss that all existing and future plant are the same. This is not the case as existing plant are of diverse types and controls that modifying to meet the new Code requirements are challenging, and if achievable will be expensive.</p> <p>Manawa believes that the lowering of the 30MW limit to 5MW for existing generation will not change the balance needed for managing the system with new generation technology (wind / solar). As we have submitted, we like others have diverse types of generators and fuel sources and how they are conveyed and managed. This diversity does mean that they all cannot meet compliance and will not be able to without significant investment.</p>
<p>Paper B: Addressing larger voltage deviations and network performance issues in NZ's power system</p>	
Questions	Comments
<p>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.</p>	<p>Yes, this will be actioned within their current rules and requirements in the connection agreements with the distributed generators. Some may reflect EIPC requirements as well as the needs of the distributor and the agreements and requirements with connection to the grid exit point to Transpower.</p> <p>Voltage support has been challenging given the variety and size and load variance. Distributors have been working with other EDB's, including Transpower, to assist with management within their own networks.</p>

	<p>Common Code requirements as discussed, being spread to distribution companies has merits and challenges associated with the diversity of the networks and the existing generation in that network versus new generation, such as solar and wind. The Code should not make rules if they are not achievable by all parties.</p>
<p>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.</p>	<p>No because in general if the generation is not directly connected to the Grid exit point, there are already requirements for that voltage support of the distribution network.</p> <p>The existing generation can support the network and will already be doing this. The agreement between the generator and distributor will outline these requirements.</p> <p>Note the variabilities in the distribution network on load factors, types of lines versus cables and transmission equipment have an influence on the voltage. So where possible it should support and not make the network unstable.</p> <p>There is the ability to work with the distributor to have some commonality with their guidelines and the Code, but allowances will be needed for the variability.</p> <p>The existing generation should have dispensation, as to change the generator type or add additional systems will be expensive and cost prohibitive.</p>
<p>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.</p>	<p>Yes, for new generation.</p> <p>Grandfathering for existing generation where it is not capable of providing will be required because of the type and capacity preventing compliance e.g. induction generators. It is expected that the existing generation will already be providing support to the network where it can.</p>
<p>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 $\pm 33\%$ rather than the $+50\%/-33\%$ range specified in clause 8.23 of the Code?</p>	<p>Previously discussed above but in our experience, distribution networks have challenges with large reactive power capability.</p> <p>As with other generators in these networks managing voltage rise and not operating in the over excited in (+ MVAR) operating region.</p> <p>We tend to manage the voltage by using the plants we can in the under excited (-MVAR)</p>

	<p>operating. Not all our embedded generation would have the capacity to meet compliance with the Code and relief would be required in the form of dispensation and grandfathering of the existing plant.</p> <p>Cost to comply if the Code was as per the Transpower Grid would be significant and is commented on in other parts of the submission.</p>
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.	<p>No, existing generation should be grandfathered.</p> <p>Yes for new generation as this would be appropriate and could be designed to contribute to grid voltage effectively.</p>
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	<p>The benefits include the potential to improve or maintain voltage management as new generation is brought onto the network. However, the challenge is still existing embedded generation may not be able to comply due to type and associated equipment as offload transformers. Grandfathering of existing schemes will protect these assets.</p> <p>Compliance costs will be significant as mentioned in other parts of this submission. Changing hardware as transformers will come at a cost and make variability a challenge.</p>
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?	<p>For new designers there will be costs of hardware such as transformers and this is dependent on size. There will be compliance costs for testing and studies to meet the code.</p> <p>The same would be for existing generation to confirm that the existing equipment will comply, or dispensations provided. Fault ride through studies and capability will cost. If modifying, hardware will have challenges and viability of the plant could be at risk. The costs could be in the millions of dollars depending on the size of the generation plant. With the rotating generation the fault ride has limited improvement of the existing installations and compliance costs to complete the study and model is in the \$40K - \$80k per unit range.</p>
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?	N/A
Q9. Do you agree the Authority should be short listing the second voltage-related option to help	N/A

address Issues 2 and 3? If you disagree, please explain why.	
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	N/A
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?	N/A
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.	<p>No.</p> <p>At this stage it is unlikely, but with further consideration the distributors may adopt due to poor performance as generation increases with wind and solar.</p> <p>Generation that does affect the grid directly are being asked to undertake fault ride through studies where applicable.</p>
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.	<p>We believe that fault ride through issues requires more industry discussion between the grid owner / operator, distributor, and the generator. At this stage, the SO and the grid owner are asking generators that may affect the grid to export and to model fault ride through. This is on a case-by-case basis.</p> <p>The existing generation should be grandfathered.</p>
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.	<p>Yes, for new generation.</p> <p>Grandfathering for existing generation where it is not capable of providing is required because of the type and capacity preventing this. e.g. induction generators.</p> <p>It is expected the existing generation will already be providing support to the network where it can.</p>
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.	<p>Yes for new generation and no for existing generation as there are associated costs for the studies and the likelihood that no change can be undertaken without significant costs, or not being able to comply.</p> <p>The existing generation should be grandfathered.</p>
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	New installations that are designed and built to aid with managing the third voltage related option have benefits as they are more likely to influence the network and the grid. Compliance

	<p>costs however, could also become a burden on new installations.</p> <p>As previously said, existing generation would have challenges to comply.</p> <p>The existing generation are most unlikely to be able to be manage ride through in any meaningful way. The cost to change the plant to comply could be significant along with compliance costs.</p>
Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if these generating stations must comply with the fault ride through AOPs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?	<p>The costs to model and comply fault ride though could be between \$50K- \$100K per unit. Any modifications to hardware to derate will effectively put the viability of the plant at risk.</p> <p>The plant modifications could be from \$50K - \$1M or multiple of millions of dollars. More dispensations will need to be applied for with a cost to prove between \$50K- \$100K.</p>
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?	<p>The existing generation should be grandfathered, and a clause included in the Code to cover application of options 1, 2 & 3.</p> <p>For new installations we agree with the proposed Code to ensure these installations are compliant and designed appropriately to meet these requirements.</p> <p>Any code changes need to consider other compliance constraints imposed for example, make sure that resource consents are not in conflict with the Code and the type of installation and generator.</p> <p>For existing plant, they may not be able to comply with all or some of options 1,2 & 3. Given they provide limited benefit yet require significant cost, Manawa is of the view that existing plant needs to be grandfathered.</p>
Paper C: The governance and management of harmonics in NZ's power system	
Questions	Comments
Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If you disagree, please explain why.	Yes, it is a topic evolving and more information and discussions to follow.
Q2. Do you agree the Authority has identified the main challenges with the existing arrangements	Yes, it is a topic evolving and more information and discussions to follow.

for the governance of harmonics? If there are any additional challenges, please set these out in your response	
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.	<p>No, it does not meet new standards and evolving inverter applications.</p> <p>The number of reference codes and new views on to managing harmonics can be applied.</p>
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?	No, not at this stage.
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.	No, not at this stage.
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 not cause excessive harmonics? If you disagree, please explain why.	Seems a reasonable approach. However, more information and discussions to tease out the how, why, when and how much is in its infancy. This paper is a good starting point.
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?	No, other than it is time to discuss what is the pathway forward and fit for the new environment.
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?	No, other than it is time to discuss what is the pathway forward and fit for the new environment.

Appendix B – further information about Manawa’s generation portfolio

Introduction

This document is prepared to support Manawa Energy’s submission on consultation papers A, B and C.

This further information reflects Manawa’s operational responsibility of KCE’s assets and so includes data for both Manawa’s and KCE’s assets.

Manawa’s fleet includes 41 stations and 76 generating units, KCE’s fleet has 6 stations and 13 generating units.

The data is distributed across the individual units and stations by type.

Tables 1 & 2 provide a view of the comparison in megawatts and across number of units and stations.

Table 3 is a view of the generation types across the fleet.

Table 4 provides a high-level view of some of the key points.

Tables 5, 6 & 7 provide a view of the generator units and distribution of type, megawatts, and megawatt bands.

Tables 8, 9 & 10 provide a view of the generating stations and units and distribution of type, megawatts, and megawatt bands.

Table 1: Existing 30 MW

	MW	Units	MW	Stations
5MW	111	60	60	27
10MW	90	12	70	9
30MW	238	15	96	5
Total Currently	439	87	226	41
30 MW+	80	2	293	6
Overall Total	519	89	519	47

Table 2: Proposed 5 MW

	MW	Units	MW	Stations
5MW	111	60	60	27
30MW	328	27	166	14
Total	439	87	226	41
30 MW+	80	2	293	6
Total	519	89	519	47

Table 3: Generator Types

Generator Types	Units	MW	GOV	Actuated	Induction	AVR
Synchronous (Hydro)	63	473	39	24		63
Induction (Hydro)	15	28			15	
Pump / Induction Generators (Hydro)	6	9			6	
Diesel generators	5	9	5			5
Totals	89	519	44	24	21	68

- **Variation of Fuel Sources**
- Large Storage – months of storage
- Medium Storage – days
- Small Storage - hours
- Run of river / irrigation / canals – continuous
- Run of river / irrigation / canals – Days
- Run of river / irrigation / canals – hours
- Diesel – hours / days
-

Table 4: What it means

Key points	Units
MW limit 5 MW	We have 60 units 111 MW of capacity under the 5 MW threshold proposed. Further 27 units at 328 MW of capacity between 5 – 30 MW band. This will mean we will have many machines that will potentially not be compliant. Due to the diversity of types and how they control frequency and voltage.
Induction Generators	21 Induction generators will not be compliant for frequency / voltage management.

	These generators are part of schemes that are either small and larger machines are synchronous. Also, they are flat output due to managing in or out of conveyance system.
Pump / Generators	Converting 6 - 1.5 MW pumps converted to induction generators when not pumping, will not be compliant for frequency and voltage management.
Actuated Synchronous Generators	24 generators are actuated due to either being small machines lower than 5 MW or by exception above 5MW are part of a larger station / scheme. The majority are related to conveyance restrictions supplying them or being supplied by them could not sustain managing frequency excursions. The balancing of conveyance systems because the low volume does not warrant or sustain governors.
At risk Capacity	If we were to meet compliance that is not already covered with dispensations or existing designs and capacity of 328 MW could be all or part at risk. This will potentially make schemes not viable to modify if it was achievable at all.
Compliance costs	Additional and ongoing compliance costs on our smaller generators be significant. This will be in total to the amount of units we have be in the \$70 – 200,000 per unit along with ongoing compliance costs in the

Generation by Units

Table 5: Current Bands

MW Bands	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 30	87	439	42	24	21	66
30 +	2	80	2			2
Total	89	519	44	24	21	68

Table 6: Proposed 5 MW Band

MW Bands	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 5	60	111	17	23	20	40
5.0 – 30+	29	408	27	1	1	28
Total	89	519	44	24	21	68

Table 7: Option Bands added 5 – 10 MW

MW Bands	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 5	60	111	17	23	20	40
5.0 – 10	12	90	10	1	1	11
10 - 30	15	238	15			15
30 +	2	80	2			2
Total	89	519	44	24	21	68

Generation by Stations

Table 8: Current Bands

Bands MW	Number Stations	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 30	41	67	226	24	22	14	47
30 +	6	22	293	20	2	7	21
Total	47	89	519	44	24	21	68

Table 9: Proposed 5 MW Band

Bands MW	Number Stations	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 5	27	38	60	6	19	13	25
5 – 30	14	29	166	18	3	8	21
30 +	6	22	293	20	2		21
Total	47	89	519	44	24	21	68

Table 10: Bands 5 and 10MW

Bands MW	Number Stations	Number Units	Output MW	Synch Gov	Actuated	Induction	AVR
0 - 5	27	38	60	6	19	13	47
5 – 10	9	21	70	12	3	8	
10 – 30	5	8	96	7	1		
30 +	6	22	293	19	2		21
Total	47	89	519	44	24	21	68

Appendix C – Grandfathering of technical standards



GRANDFATHERING OF TECHNICAL STANDARDS

REPORT PREPARED FOR MANAWA ENERGY

Version 1.0 – 20 August 2024

Revision history

Revision	Date	Details
0.1	15 August 2024	Draft for Client
1.0	20 August 2024	Final

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1 Background

The Electricity Authority (**Authority**) is presently consulting on proposed changes to Electricity Industry Participation Code 2010 (**Code**) in relation to common quality requirements in Part 8.

The Authority's preferred option is to reduce the 30 MW threshold to 5 MW for generating stations to be required to comply with the frequency related and fault ride through obligations in Part 8 of the Code by amending clause 8.21, with the potential to either require cost prohibitive upgrades of existing small generators or subject them to the process of negotiating dispensations with the System Operator.

This paper compares the New Zealand common quality obligations with the generator performance standards in the National Electricity Market (**NEM**) in Australia.

2 Eastern Australia Electricity Market

2.1 NEM

The NEM operates in the interconnected eastern states of Australia, being Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania. The NEM is regulated by the National Electricity Rules (**NER**) in a similar way that the Code operates in New Zealand.

2.2 NEM Regulatory Functions

Unlike New Zealand where the Authority has multiple responsibilities in regulating the electricity market, in Australia there are multiple bodies that are involved in the electricity regulatory process.

Table 1 compares the regulatory functions in New Zealand and the NEM. For the purposes of the day-to-day approval of departures from system

standards the respective bodies are the System Operator in New Zealand and the local network service provider and AEMO in Australia.

Table 1 - Comparison of Regulatory Functions

Function	New Zealand	NEM
Approving rule changes	Authority	Coalition of Australian Governments (COAG)
Analysing, consulting and determining proposed rule changes	Authority	Australian Energy Market Commission (AEMC)
Monitoring and enforcing compliance	Authority	Australian Energy Regulatory (AER)
Real time operation of the electricity system	System Operator function of Transpower	Australian Energy Market Operator (AEMO)
Approval of departures from default system standards	System Operator function of Transpower	Network Service Providers with advice from AEMO on certain system security issues

2.3 Generator Technical Performance Standards

In the NEM generator technical performance standards, like the Code's common quality requirements apply to generators greater than 5MW.

However, the technical performance standards are determined at the time of connection based on the impact on the electricity system at that point. Subsequent generation plant must meet the test of not reducing

system security. The original agreed performance standards are not altered after commissioning unless there is changes to the generating system.

Prior to connection new generation plant must propose a negotiated access standard for each performance standard where the plant cannot meet the automatic standard. In practice the proposed standards are agreed with the respective network service providers and AEMO (for standards where AEMO is involved) before the connection application is lodged.

3 Comparison of NER and the Code

Table 2 compares the administration of technical requirements for generators in the Code and the NER.

The Australian interconnected eastern grid and the New Zealand grid are very similar technically with both grids experiencing a rapid increase in intermittent renewable generation much of which is asynchronous and dependent on variable fuel sources (wind and solar). As a result, the technical standards, although different at the detailed end as very similar in concept.

The key difference between the NEM and the New Zealand market is the way technical standards are treated over time.

Table 2 - Technical Requirements in Code and NER

Provision	Code	NER
Technical Standards for new Generation	New generation is required to comply with the requirements of Schedule 8.3 of the Code (including the Technical Codes), as amended from time to time.	New generation is required comply with performance standards as agreed as part of the connection process
Generation size de minimis	Presently 30 MW but proposed to be lowered to 5 MW.	5 MW (was 30 MW until 2018)
Dispensations and Departures from standards	<p>Departures from the requirements Schedule 8.3 are managed using dispensations.</p> <p>Dispensations are only for a fixed time period are reviewed at the end of each period. Dispensations are only required for generators less than 30 MW.</p> <p>If the de minimis is lowered to 5 MW then all generators less than 30 MW that do not meet the requirements will need to either upgrade equipment or apply for dispensations.</p>	The default requirement for a standard is the 'automatic standard' Each standard also has a 'minimum standard'. A generator is allowed to connect if it can meet the automatic standard. If the automatic standard cannot be met then the proponent must negotiate with both the Network Service Provider and AEMO (for standards that impact security of supply) to agree a level between the minimum and automatic standard that does not reduce overall system security.

Provision	Code	NER
		Once a standard has been agreed it is incorporated into the connection agreement and does not change with subsequent changes to standards or the system.
Changes to technical standards over time	Existing generators must comply with modified technical standards or apply for a dispensation	Existing generators are not required to modify their access standards. This is widely supported within the NEM.
Changes to Generation Systems	New systems must comply with the default standards or apply for a new dispensation.	Like for like replacements are exempt from re-negotiating access standards and only modifications that may affect system security require new negotiated standards.

The key difference between the NEM and the New Zealand market is the way technical standards are treated over time. The NEM has always operated on the basis that performance standards are agreed at the time a plant is first connected or for some requirements changes are made to a generating system. Any changes to the technical standards over time are only applied to new connections. The rationale for this is that new generation should be designed to not degrade the existing system and for new generation to pay the incremental costs associated with the new plant is the correct economic driver. The principle of grandfathering existing connections from changes to their technical standards has remained under two reviews of the NEM technical standards in 2007 and 2018.

By comparison in New Zealand the Code does not consider grandfathering of technical requirements for existing generators if the technical standards are changed.

4 AEMC Review of Technical Standards in the NEM

The last review of the technical standards in the NEM was carried out in 2017 and 2018 I was triggered as a rule change request by AEMO to the AEMC.

Box 1 is an excerpt from the decision paper.

12.2.1

Background and first round stakeholder views

The rule change request focused on changes to the access standards for connecting generating systems (Schedule 5.2).⁸¹⁵ It did not propose changes to the access standards for connecting customers (Schedule 5.3) and market network service providers (Schedule 5.3a). However, the rule change request proposed changes to the process to negotiate access standards, which apply to the negotiation of access standards for connection applicants,⁸¹⁶ including connecting generating systems, customers and market network service providers. The last time the generator access standards were reviewed in detail was in 2006 and 2007, when a number of changes were made to accommodate the connection of asynchronous generating systems.

The current arrangements in the NER do not prescribe a process for the regular review of the access standards. However, one of the functions of the Reliability Panel is to monitor, review and publish a report on the implementation of automatic access standards and minimum access standards as performance standards in terms of whether:⁸¹⁷

- their application is causing, or is likely to cause, a material adverse effect on power system security, and
- the automatic access standards and minimum access standards should be amended or removed.

Box 1 - Excerpt from AEMC decision paper on changes to the technical standards - 2018

Part of this review lowered the threshold for negotiating access standards from 30 MW to 5MW.

Because the NER only sets performance standards as part of a connection agreement this reduction does not affect any existing generator, including those with between 5 MW and 30 MW.

5 Summary

The change from a 30 MW to 5 MW threshold in the NEM has a significantly lower impact on existing small generators than the proposed change to the Code.

The proposed change to the Code could result in uneconomic decommissioning of existing small generation assets.