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17 June 2025

Submissions
Future Security and Reliability team
Electricity Authority
P O Box 10041
Wellington 6143

By email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—Promoting reliable electricity supply: Frequency-related Code amendment proposals

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) proposed frequency-related Code amendments.[1]

The IEGA comprises about 30 members who are either directly or indirectly associated with predominantly small-scale power schemes connected to local distribution networks throughout New Zealand for the purpose of commercial electricity production. IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, who have made significant economic investments in renewable generation plant and equipment. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand.[2] We are price takers in the electricity market – the majority of our members do not have the financial or human capacity to operate 24/7 dispatching into the wholesale market.

Members' own and operate the full range of renewable generation technologies: hydro, wind, geothermal, solar and biomass and energy storage.

Comments on Proposals

1. **Lowering the threshold from net maximum export of 30MW to 10MW for generating stations to be excluded by default from complying with frequency-keeping AOPOs and technical codes in Part 8**

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[1] The Committee has signed off this submission on behalf of members.
[2] Or fifth after the Contact Manawa transaction is completed

The IEGA supports the Authority's proposal that the lower threshold would not apply to generating stations commissioned before 1 July 2026 that are not able to comply without modification unless they are upgraded or increase their export of electricity. We note the exception will only apply if the relevant generator notifies the system operator that the generating station is not able to comply with these provisions, via the asset capability statement for that generating station.

If these noncompliant generating stations are subsequently upgraded, compliance with the frequency-related asset owner performance obligations would be required. It is important to have the clarity about what constitutes an upgrade to a generating station that is subject to the 'legacy clause' under the proposed Code amendment.

We suggest the requirement to be compliant if export capacity increases above 10MW may discourage generators from making any changes to trigger this increased output – given the investment to increase capacity also now must include investment to meet the frequency keeping obligations.

Impact on battery energy storage systems (BESS)

The proposals are unclear of the costs to be applied to BESS when they are idle. The Electricity Authority proposes "asset owner performance obligations should apply to energy storage systems when they are idle (ie, neither charging nor discharging)". The IEGA believes this should not be a compulsory requirement. Allowing a market based solution will ensure that BESS will provide the service at the most economical price.

2. **Halve the permitted maximum dead band beyond which a generating station must contribute to frequency management and frequency support for all existing and new generating units**

The IEGA **strongly disagrees** with the proposal to halve the permitted maximum dead band from +/-0.2Hz to +/-0.1Hz.

Footnote 11 of the consultation paper explains what a frequency dead band is and how it impacts the System Operator's management of the power system:

> "A frequency 'dead band' in a generating unit's frequency control system halts the generating unit's frequency response within that band. This reduces the generating unit's response to frequency deviations. A dead band can be inherent in moving parts – a generating unit with an inherent dead band will not respond, at least immediately, to small changes in system frequency. A dead band can also be a settable parameter – a frequency control system with a dead band setting of ±0.1Hz will not respond until system frequency is lower than 49.9Hz or higher than 50.1Hz" [3]

[3] Paragraph 7.4

The IEGA query that if all generators respond at 49.9Hz, there may be the potential to destabilise the system. Therefore, it may be easier to manage the power system if there are some generators responding at 49.9Hz and some responding at 49.8Hz.

Further, the consultation paper states:

> "More and more generators are applying frequency dead bands to their generating units to reduce wear and tear on their equipment caused by responding to frequency fluctuations. The system operator advises this is degrading the system operator's ability to manage frequency within the normal band and also adversely affecting the system operator's management of momentary fluctuations."

Why does the System Operator want everyone to have the same dead band if individual generators implementing them is impacting their ability to manage the system? **Is a better solution requiring generators to inform the System Operator of the dead band they are operating to?**

Requiring all generators to contribute to frequency keeping is expected to reduce the current reliance on a relatively small number of generators doing frequency keeping.[4] These generators are currently offering this service at a value procured by the System Operator. Do these generators want to sell less of this service? The proposal shifts the cost of this service from generators that have the right equipment and want to offer the service to all generators regardless of the cost of operating within a tight dead band. The Authority "expects" the costs faced by generators will be lower than the cost of increased frequency keeping[5] – but there is no quantitative analysis of this assertion.

The Authority is proposing that existing and new generating units can apply to the System Operator for a dispensation if it is unable to meet the =/-0.1Hz dead band requirement due to technical constraints.

The Authority and System Operator explain that generators can still seek dispensations from this requirement – but this is not a costless exercise for the generator or the System Operator. The Consultation paper is explicit about the Authority's understanding of dispensation application costs (estimated at $70,000 to $100,000). The IEGA notes that this may be an excessive impost on many of its members who operate small, intermittent generation.

Impact on existing hydro assets

A dead band determines when a governor decides to respond to frequency change and makes a physical movement of the regulating gear in the case of a :

a. Francis turbine – the guide vanes
b. Kaplan turbine – the guide vanes and runner hub
c. Pelton turbine – a spear valve

The equipment is most often connected to hydraulic servomotors by a series of linkages and bearings.

Movement of the turbine regulating gear causes wear to the bearings in the mechanism and is one of the determinants of when the machine must be overhauled. As the majority of the turbines are of an

[4] Paragraph 7.11
[5] Paragraph 7.14

old design, given their installation date, they have been embedded in concrete in a way that full disassembly of the machine is required to change these bearings and other parts of the regulating mechanism.

The cost of a major overhaul varies significantly depending on the size and type of turbine technology, from $2-5m for a Francis machine, and even more for a Kaplan. Major overhauls are generally planned once in the ~40-50-year life of the machine and are expected in an interval of 15-25 years.

There are some hydro asset owners in NZ who are operating units with zero dead band and have seen bearings in brand new hydraulic servomotors worn to end of life in a period of about 5 years.

Studies have shown that hydro units used for frequency regulation encounter high wear of the regulating mechanism, in the range of 7-10 times more, which will bring the maintenance frequency substantially forward.

A comparison was made between a hydro unit with zero dead band and a unit with a +/- 0.2Hz deadband at the same station, and in a day the unit's servomotor with zero dead band did approximately 2km of movement, versus the unit with a 0.2Hz deadband did about 300m. This illustrates the massive effect on the turbine governing regulating mechanism on wear from dead band settings. This example indicates the difference between these settings is almost 7 times more wear.

As Kaplan turbines are an expensive technology to maintain, given the adjustable pitch propeller is expensive to repair, they are regarded as only suitable for a baseload role. **We recommend that a 0.2Hz deadband is set for Kaplan turbines or a permanent exclusion is applied to this technology**. The alternative is to detune the Kaplan hub so it does not respond to frequency (only the guide vanes) but that has the effect of the turbine running off cam, losing efficiency and therefore income for its owner, as well as potentially causing cavitation which will damage the turbine.

The Consultation paper comments that "more generators" are applying frequency dead bands to their generating units. It could be more likely that this is becoming more obvious to the System Operator than before. Modern hydro governors allow this parameter to be set and configured, whereas older technology still had dead band, but it was hidden in mechanical linkages. It is unlikely that there has been a significant degradation in dead band settings. Note that the same thing can occur in modern governors, which is why the dead band testing considers the real frequency change that produces a change at the turbine regulating gear.

Terminology not clear

Clause 8.17 states. *"Each generator (while synchronised) and the HVDC owner must at all times ensure that its assets, other than any generating units within an excluded generating station, make the **maximum possible injection** contribution to maintain frequency within the normal band (and to restore frequency to the normal band)."*

This term maximum possible injection is unclear in terms of definition and enforcement. What testing will be required to determine whether equipment 'passes' this test. For each scheme there are a number of factors at any one time that can affect maximum generation. These include physical constraints, fuel availability resource consent requirements (eg ramp rates), legacy design, and many more. Each one may become the constraint at any time.

Clause 5.14 from the paper states *"Intermittent generators are considered to meet the clause 8.19 requirement to maintain pre-event output by continuing to generate at their available capacity, provided their output is in line with their forecast output."*

It appears clause 8.19 is inconsistent with 8.17 and again is unclear on how this would be enforced. In particular for intermittent generation the output could have been declining anyway at the time of the event due to weather conditions, so how would it suddenly be able to sustain output.

Cost benefit analysis

The IEGA disagrees that a benefit of these Code changes is "promoting efficiency by reducing the need for the system operator to procure additional ancillary services, lowering the possibility of future cost increases". Procurement of ancillary services is a competitive market that must be efficient. If ancillary service prices increase this should incentivise innovation and increasing supply of frequency keeping service.[6]

The cost benefit analysis in the Consultation paper does not demonstrate a case that procuring more frequency keeping and widening the normal frequency keeping band is more costly than requiring a permitted maximum dead bank on all generation of +/-0.1Hz.[7] Further Table 5 does not include the costs of increased maintenance that generators will face.

A market-based solution of procuring frequency management is fairer as it means that the generators incurring cots in providing frequency keeping are being compensated and the price offered by a generator will reflect the cost incurred by the generator to provide the service. With a frequency keeping budget of $12 million a saving of 50% means a saving of $6 million. The IEGA recommends the Authority collect more information about the expected cost of all generators complying with a dead band of +/-0.1Hz as a saving of $6m is unlikely to be more than the cost of increased maintenance.

The proposed Code changes impose costs on generators (and therefore all consumers). This cost is being imposed in advance of the Authority and System Operator understanding available technologies that could result in power system issues not eventuating to the extent the System Operator expects. The IEGA submits the Authority should investigate grid-forming inverters before any Code amendments are implemented.[8]

Concluding remarks

The IEGA believes the paper presented provides a number of technical issues that have been thought through from an ideal 'green field' starting point. The economic analysis of the proposals to correct

[6] Note paragraph 4.44 lists the opportunity cost of not developing a capacity market for frequency services was listed as a cost of Option 3 when it should be listed as a benefit. This paragraph notes submitter support for creating a very fast reserve capacity – another form of market based ancillary service that will help with reduced inertia in the system

[7] Paragraph 4.7 discusses the option of procuring more frequency keeping

[8] The Consultation paper discuses grid-forming inverters in footnote 16: "An inverter-based resource that uses a 'grid-forming' inverter can provide 'synthetic' inertia. This inverter forms a voltage angle independently of the network to which it is connected and controls its output voltage so as to synchronise with, and remain synchronised with, the network. To date, most inverters installed in New Zealand have been 'grid-following' inverters. This type of inverter tracks the voltage angle of the network to which it is connected, to control the output of the inverter-based resource and thereby remain synchronised with the network. The Authority will review grid-forming inverter technology as part of an investigation into the system strength-related operational challenges that New Zealand's power system is likely to face due to a high level of penetration of inverter-based resources."

these issues for existing generation is not robust and makes a number of erroneous assumptions around that capability of that band of existing generators.

The IEGA supports option 3.

The IEGA **strongly recommends** the Authority:

- urgently investigate a requirement to use Grid Forming Inverters[9] on new IBR generation plant in advance of imposing cost on existing generators from requiring a tight dead band; and
- collect information to enable a more thorough cost benefit analysis of the option of imposing a tight dead band of +/-0.1Hz on all existing and new generators compared with the cost of procuring frequency keeping from generators that nominate to be compensated for providing the frequency keeping service.
- Use grandfathering instead of dispensation process.

Our August 2024 submission listed the benefits of a market-based solution. The current consultation paper has not disproved these benefits.

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

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Ben Gibson
Chair

[9] Note the System Operator recommended in its June 2023 report that "*asset owners looking to connect IBRs greater than 1 MW are recommended to use GFM inverter technology to ensure their asset remain stable following system events".* Source: https://static.transpower.co.nz/public/bulk-upload/documents/Preparing%20for%20an%20increase%20in%20inverter-based%20resources%20v1.0.pdf?VersionId=bLFY0dB4Za1FfNAEh1V_75DOZ3_vmPb5