Promoting reliable electricity supply: Frequency-related Code amendments

Decision paper

10 March 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the security and resilience of New Zealand's power system for a highly electrified future, ensuring it is set up to deliver the best possible outcomes for consumers. To help achieve this, we are refining industry rules to support greater electrification while maintaining a stable and reliable power system for decades to come. As the sector evolves, it is critical that we, as a regulator, anticipate challenges and enable a smooth transition to a more electrified economy.

Through our multi-year Future Security and Resilience (FSR) programme, we are taking a forward-looking approach by enabling new and evolving technologies, addressing security and resilience risks and building a power system that is reliable, flexible and future-focused.

A critical part of this programme is a review of the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). These requirements are foundational to the safe and reliable supply of electricity to consumers.

Historically, New Zealand's power system relied on a relatively small number of large synchronous generators with predictable physical characteristics. Today, the increasing uptake of variable and intermittent inverter-based resources means the system increasingly behaves like a 'system of systems', where frequency outcomes can be shaped by the interactions and coordinated behaviour of thousands of distributed, software-driven devices. This introduces new modes of failure that are faster, harder to predict and more complex to manage. Minor settings differences or local behaviours can quickly propagate through the system, increasing the risk of large-scale disturbances.

We sought feedback on two proposed Code amendments

In May 2025, we published the Promoting reliable electricity supply: Frequency-related Code amendment proposals consultation paper, which proposed two amendments to Part 8 of the Code to:

- Lower the 30 megawatt (MW) 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.
- Set a permitted maximum dead band beyond which a generating station must contribute to frequency management and frequency support.

These amendments were proposed to help address the first of seven key issues identified in the review of common quality requirements:[1]

> **Issue 1:** 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.

[1] Review of common quality requirements in Part 8 of the Code – Issues paper.

We received 11 submissions on the proposed Code amendments. The submissions and consultation paper are available on the Authority's website. We thank submitters for taking the time to share their views on the proposals.

We are proceeding with both of the proposed Code amendments with some changes

The Authority has considered all submissions and has decided to proceed with both proposed Code amendments.

We have made some changes to the proposed Code amendments in response to submitter feedback and input from the Authority's Common Quality Technical Group (CQTG).

Changes to the first Code amendment proposal include:

- The term "maximum continuous MW output power" has been defined and used instead of amending the existing defined term "maximum export power".
- A generating station subject to the 'legacy clause' provisions in the Code amendment will not lose its 'legacy' status should its maximum continuous MW output power increase by less than 5MW above its 30 June 2027 level.

Changes to the second Code amendment proposal include:

- Generators must comply with a maximum dead band[2] of the greater of ±0.1Hz or the generating unit's inherent dead band, as agreed with the System Operator acting reasonably, at the time of the generating unit's next routine test.
- Geothermal generating units are excluded from the dead band requirement due to their inherent inability to comply.
- The term "inherent dead band" has been defined in clause 1.1 of the Code.

These changes will promote the reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

They will enhance electricity reliability by improving frequency stability and reducing the risk of tripping an automatic under-frequency load shedding (AUFLS) block[3] and widespread outages. Two recent blackouts overseas, in Chile and the Iberian Peninsula in 2025, demonstrate that these risks are real. These events disrupted millions of consumers, resulted in multiple deaths and caused major economic loss, highlighting how frequency and voltage disturbances can escalate rapidly when system settings and technical performance are not sufficiently robust. Strengthening the common quality requirements in Part 8 of the

[2] A '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] AUFLS is a protection mechanism designed to help maintain power system stability during emergency conditions. When power system frequency drops below critical thresholds, AUFLS automatically disconnects predefined blocks of electrical load to quickly restore the supply-demand balance and prevent a widespread blackout.

Code helps reduce the risk of cascading failures and supports a more resilient transition to a power system with higher penetration of inverter-based resources.

They will also promote the efficient operation of the electricity industry by reducing the need for additional instantaneous reserve and frequency keeping, helping to keep power bills lower for consumers.

Some submitters also expressed support for other options, such as creating a capability market for frequency support which would allow participants to offer services for which they are paid. The Authority has noted this feedback.

Next steps

The Code amendments will come into effect on 1 July 2026.

Contents

1. Purpose

We are amending the Code

1.1. This paper sets out the Authority's decision to amend the Code to:

(a) lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code.

(b) set a permitted maximum dead band beyond which a generating station must contribute to frequency management and frequency support.

1.2. The reasons for our decision are set out in this paper.

1.3. Alongside this paper, the Authority is publishing a decision paper on a Code amendment to help address voltage-related issues also identified in our review of the Part 8 common quality requirements. Readers will note these frequency- and voltage-related Code amendments make identical changes to the Code provisions defining an 'excluded generating station'.

The Code amendments benefit consumers

1.4. These amendments will promote:

(a) the reliable supply of electricity by the electricity industry for the long-term benefit of consumers, by having more generating stations support frequency stability and by improving the responsiveness of the power system to frequency fluctuations. This better enables the System Operator to manage the power system frequency and reduces the likelihood of AUFLS events and the risk of cascade failures.

(b) the efficient operation of the electricity industry for the long-term benefit of consumers, by:

i) reducing the System Operator's need to procure additional instantaneous reserve, particularly to cover the risk of secondary tripping[4] by generating stations that export 10MW or more but less than 30MW

ii) sharing frequency management across more generating stations, which will lessen disproportionate wear and tear on the subset of generating units that currently bear much of the burden helping the System Operator to manage frequency within the normal band.

Next steps

1.5. The Code amendments will come into effect on 1 July 2026.

[4] Secondary tripping is also commonly referred to as 'sympathetic tripping' and occurs when the protection equipment of a generating unit or generating station disconnects the unit/station from the network because of a disturbance on the network.

2. Background to the Code amendments

The Future Security and Resilience (FSR) work programme

2.1. New Zealand's power system is undergoing a significant transformation. As the economy becomes more electrified, managing peak demand fluctuations, increasing variability and intermittency of energy sources, and maintaining system resilience will become more difficult. A critical challenge for a change of this scale will be delivering a level of security, reliability and quality of electricity supply that reflects consumers' preferences and minimises total costs.

2.2. The Authority's FSR work programme[5] is one of several initiatives supporting the electrification of New Zealand's economy. The FSR programme seeks to ensure New Zealand's power system (at both the transmission and distribution levels) remains secure and resilient as the country transitions towards a lower emissions economy. The highest priority activity in the FSR work programme is a review of common quality requirements in Part 8 of the Code.

2.3. The Authority wants the Code's common quality requirements to enable evolving technologies, particularly inverter-based resources. Examples of inverter-based resources include solar photovoltaic generation, wind generation, and battery energy storage systems (BESSs).

2.4. We see these technologies as a key enabler of:

(a) consumers having more choice and flexibility around their electricity use and supply

(b) the electrification of parts of New Zealand's economy, such as transportation and heating

2.5. Key complementary workstreams the Authority is working on include:

(a) Ancillary services (multiple frequency keeping) review

(b) Improving network visibility

(c) Developing solutions for peak capacity issues

(d) More efficient connection prices and processes

(e) Multiple trading relationships and a review of the consumer switching process

(f) The Power Innovation Pathway programme.

2.6. While we cannot accurately predict how power system operation will evolve in the coming years, we can proactively prepare the system for better outcomes. We can ensure common quality requirements support new and evolving technologies, while addressing security and resilience risks posed by these technologies and increased electrification. This will help build a secure, adaptable, and consumer-focused power system.

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[5] More information about the FSR programme is available on the Authority's website – see Electricity Authority | Future security and resilience.

The Authority sought feedback on Code amendment proposals

2.7. On 6 May 2025, the Authority consulted on two proposals to help address a frequency-related common quality issue, which is the first of seven key issues identified in our review of common quality requirements in Part 8 of the Code. The identified issues are:

(a) **Issue 1:** 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 49.8–50.2Hz, which is likely to be exacerbated over time by decreasing system inertia.

(b) **Issue 2:** An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause larger voltage deviations, which are exacerbated by changing patterns of reactive power flows.

(c) **Issue 3:** Increasing amounts of inverter-based variable and intermittent resources will reduce the transmission network's system strength thereby increasing the likelihood of network performance issues if inverter-based resources disconnect from the power system.

(d) **Issue 4:** Over time increasingly less generation capacity is expected to be subject to fault ride through obligations in the Code, as more generating stations export less than 30MW to a network.

(e) **Issue 5:** There is some ambiguity around the applicability of harmonics standards and who manages harmonics (including the allocation of harmonics).

(f) **Issue 6:** Network operators have insufficient information on assets wanting to connect, or which are connected to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner.

(g) **Issue 7:** The Code is missing some terms that would help enable technologies and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies.

2.8. Maintaining frequency within the normal band is important for secure and reliable power system operation. Under clause 7.2A(2) of the Code, the System Operator is required to keep frequency within this band. Increasing penetration of variable and intermittent generation, combined with declining inertia on the power system, is expected to make frequency more variable and harder to maintain at a constant level, increasing the risk of under-frequency events and the adverse outcomes associated with them.

2.9. The proposed Code amendments aim to ensure more generating stations contribute to frequency management and support. Specifically, the first amendment will require generators with smaller generating stations to comply with frequency-related obligations in Part 8 of the Code by lowering the threshold for excluded generating stations from 30MW to 10MW.

2.10. The second amendment aims to improve the responsiveness of generating stations to fluctuations in frequency by specifying a maximum permitted dead band of the greater of ±0.1Hz or the inherent dead band[6] of the generating unit, as agreed with the System Operator, acting reasonably.

2.11. These amendments will help the System Operator maintain frequency stability and reduce reliance on more costly ancillary services. By increasing the number of generating stations supporting and managing the system frequency, New Zealand's power system can operate more reliably and efficiently.

The Authority received 11 submissions on the frequency-related Code amendment proposals

2.12. The Authority received 11 submissions on our May 2025 consultation on the two Code amendment proposals, from the parties listed in Table 1. Submissions are available to read on the Authority's website. Section 3 includes a summary of submitters' feedback on each of the Code amendment proposals.

Table 1: List of submitters

Submitter	Category
Contact Energy	Generator-retailer
Genesis Energy	Generator-retailer
Independent Electricity Generators Association (IEGA)	Representative body for independent electricity generators
Brian Johnston	Independent
Bryan Leyland	Independent
Manawa Energy	Generator
Mercury Energy	Generator-retailer
Meridian Energy	Generator-retailer
NewPower Energy	Owner/operator of solar PV generation and BESSs
Powerco	Distributor
Transpower	Submitted in its role as System Operator

6 Inherent dead band means the continuous range of system frequency values around 50 Hertz within which a generating unit does not provide an immediate active power response, due to the physical characteristics of the generating unit.

3. The Authority finalised the Code amendments after considering submissions

3.1. After considering all submissions, the Authority has decided to amend the Code in a manner that is largely as proposed.

3.2. This section outlines:

(a) the Code amendments proposed in the May 2025 consultation paper

(b) the key feedback received from submitters on those proposals

(c) the Authority's final decisions, including changes made to the original proposals in response to submitter feedback.

3.3. The submission summaries in this Part 3 are not exhaustive, and we encourage you to review individual submissions for a comprehensive account of submitters' views.

Code amendment 1 – Smaller generating stations to comply with frequency-related obligations

The Authority's proposal

3.4. The Authority proposed to lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code. Under the proposal, generating stations exporting 10MW or more would be required to comply with the frequency-related AOPOs and technical codes in Part 8.

3.5. We also proposed the following legacy clause[7] provisions:

(a) owners of generating stations commissioned before the effective date of the Code amendment and which export 10MW or more but less than 30MW do not need to comply, in respect of those generating stations, with:

(i) the frequency-related AOPOs in clauses 8.17 and 8.19 of the Code, and

(ii) the provisions in Technical Code A of Schedule 8.3 of the Code, relating to the obligations of asset owners in respect of frequency

(b) the above only applies:

(i) in respect of generating stations that are not able to meet these requirements without modification, and

(ii) if the relevant owner of the generating station updates the asset capability statement for that generating station to record that it cannot meet these requirements

(c) the System Operator must publish on its website a list of generating stations that do not need to comply

(d) the above 'legacy clause' arrangement would no longer apply to a generating station if the generating station:

[7] A legacy clause is also known as a 'grandfather/ing clause'.

(i) is altered such that it has the capability to meet the above frequency-related Code obligations, or

(ii) increases its generation export capacity (measured against an amended, generalised, definition of maximum export power).

Submitters' views and Authority's response

3.6. Contact, Meridian, Manawa, Powerco and Transpower generally supported the proposal, noting that it would improve frequency stability and system resilience.

3.7. However, Contact and Manawa's support was conditional on the effectiveness of the legacy clause. Manawa also argued that the legacy status should remain in place even if a station's export capacity increased.

3.8. NewPower, IEGA and Manawa raised concerns about disproportionate costs for smaller generators, particularly for engineering studies. Manawa estimated costs of $5-10 million per generating station if they were required to upgrade their stations in order to comply. Manawa estimated that, if they were to seek dispensations for their non-compliant stations, the total cost to Manawa would be in the range of $4 to $5 million.

3.9. Most submitters supported the intent of the legacy clause but opposed the possibility of it applying for a finite period (eg, 10 years), arguing that would only delay costs rather than prevent them. Some submitters also requested clarity on what constituted a material upgrade that would revoke the legacy status of a generating station.

3.10. In response, we note that we have implemented the legacy clause in a way that addresses this feedback. Specifically, the Code amendment now provides that a generating station will not lose its legacy status if its maximum continuous MW output power increases by less than 5MW above its 30 June 2027 level.

3.11. Proportional compliance approaches were suggested for existing stations that can comply and would need to demonstrate compliance to the System Operator. This included reducing costs for generators by having the System Operator assess compliance based on documentation provided by original equipment manufacturers (OEMs) or based on event-based compliance, rather than requiring system studies.

3.12. In response, we recognise concerns about disproportionate costs for smaller generators and have made the following changes to reduce these:

(a) **Existing generating stations that can comply**: Compliance obligations will be proportionate to the size of the generating station and its potential to impact the power system.

For the frequency management requirements in clause 8.17 of the Code, the System Operator is updating its connection and study guidelines to allow compliance assessments to occur during the generating station's next routine test, rather than immediately, thereby minimising cost to the asset owner.

For the frequency support requirements in clause 8.19 of the Code, compliance assessments will rely on information contained in asset capability statements.

These changes will reduce testing and modelling costs. As these guidelines are not Authority documents, we have not consulted on these changes.

Interested parties should provide feedback on the updated guidelines once these are published by the System Operator.

(b) **New generating stations**: Compliance costs are expected to be minor. Modern technology already supports frequency management, and testing can be integrated into commissioning.

3.13. NewPower believed that costs might be passed through to other electricity market products, obscuring the true cost of frequency management.

3.14. In response, we do not consider, in this context, that ancillary services are necessarily the most cost-reflective solution as the allocation of their costs can create a free-rider problem. This is discussed further in paragraphs 3.27 to 3.293.273.29.

3.15. Submitters highlighted potential unintended consequences, such as:

(a) developers sizing generating stations just below the 10MW threshold to avoid triggering Part 8 obligations (NewPower submission)

(b) discouraging upgrades to generating stations' export capacity (Manawa submission)

(c) reputational risks if renewable energy is spilled (Meridian submission)

(d) disincentives for investment in BESS (NewPower submission).

3.16. We acknowledge Manawa's concern that lowering the threshold could lead to developers under-sizing generating stations and the discouragement of station capacity upgrades. However, we do not consider the avoidance of frequency support obligations to be a strong driver of investment or design decisions. This assessment is based on our understanding that the cost and operational complexity[8] associated with complying with the frequency-related AOPOs is relatively modest compared to the capital investment required to construct new generation and the ongoing revenue available from additional output.

3.17. In contrast, decisions about plant sizing and upgrades are primarily driven by resource availability, connection capacity, capital costs and expected wholesale market revenues. As a result, we do not consider that developers would rationally forego additional capacity or upgrades solely to avoid frequency obligations.

3.18. NewPower requested clarity on how AOPOs apply to BESS and hybrid plants, particularly regarding the interpretation of "maximum possible injection" for intermittent generation.

3.19. For variable and intermittent generation, the "maximum possible injection" obligation in clause 8.17 of the Code applies to the generating station's power injection at any point in time, not necessarily the export capacity or maximum continuous MW power output. We are reviewing AOPOs for hybrid plant and BESS and plan to consult on these in mid-2026.

8 Compliance typically involves control settings, validation testing and basic operational capability that are commonly incorporated into modern generating plant designs.

3.20. NewPower suggested changes to the proposed amendment to the clause 1.1 definition of “maximum export power”.

3.21. In response to submitter feedback on the proposed definition of ‘maximum export power’, the Authority has decided to insert a new definition – ‘maximum continuous MW output power’. We consider this approach addresses the issues raised by submitters without the risk of unintended consequences associated with further amending the definition of ‘maximum export power’, which relates specifically to obligations on distributed generation under Part 6 of the Code. Also, and importantly, the meaning of ‘maximum continuous MW output power’ is consistent with the meaning of ‘Station Maximum Continuous Output (MCO)’ used by the System Operator in specifying certain asset capability statement information that asset owners must provide to the System Operator.

3.22. Meridian, NewPower and Manawa emphasised their preference for the creation of a dedicated capability market for frequency response to improve cost transparency and better enable efficient investment. We note the feedback from submitters that expressed support for the following projects:

(a) Investigate new markets and products that support frequency stability. This would likely address the remainder of the longer-term concerns raised by submitters, such as NewPower’s concerns that investment in BESS will be discouraged, or costs might be recovered via other market products instead.

However, even if a new product or market were implemented in the future, the frequency-related AOPOs in Part 8 of the Code would continue to be necessary until any new product or market clearly demonstrates that it could replace the existing requirements.

In addition, establishing physical capability in smaller generating stations now prepares these assets for potential future developments like a capability market.

(b) Review and consider common quality requirements for the demand-side of the electricity industry. This includes considering the impact on the power system of large load connections such as data centres, which are expected to connect to New Zealand’s power system in the near future.

Our decision

3.23. The Authority has decided to proceed with the proposed Code amendment, with the following changes:

(a) The term “maximum continuous MW output power” has been defined instead of amending the existing defined term “maximum export power”

(b) The cut-off date for a generating station to be subject to the ‘legacy clause’ provisions has been extended by one year to 1 July 2027

(c) A generating station subject to the ‘legacy clause’ provisions in the Code amendment will not lose its ‘legacy’ status should its maximum continuous MW output power increase by less than 5MW above its 30 June 2027 level.

3.24. These changes provide clarity on what constitutes an upgrade to a generating station by linking it to output power. The 5MW allowance enables production efficiency improvements to be made at a generating station without the station losing its legacy status.

3.25. A revised cut-off date of 1 July 2027 is intended to result in a generating station being subject to the 'legacy clause' provisions if the generation station owner/ developer has made significant commitments at the time this Code amendment comes into force. To give effect to this intent, we have included in the Code amendment a requirement that the generating station's owner has, before 1 August 2026:

(a) secured financing that enables the owner to develop and commission the generating station; and

(b) obtained all consents necessary to enable the owner to develop and commission the generating station; and

(c) obtained the right to use the land on which the generating station is to be located.

3.26. The Authority considers 5MW to be a conservative allowance for improvements in the efficiency of a generating station with a maximum continuous MW output power of 10MW or more but less than 30MW. This threshold represents anywhere between almost 17% (for a 29.99MW station) and almost 50% (for a 10MW station) of the pre-existing maximum continuous MW output power.

3.27. Some submitters again expressed their preference for 'Option 3',[9] which the Authority decided not to investigate further. Option 3 was included in the short list of options to help address the frequency-related issue despite this option requiring no changes to the Code. This is because a Code-mandated maximum dead band beyond which a generating station must contribute to supporting frequency has implications for the System Operator's procurement of multiple frequency keeping (MFK) and instantaneous reserve. The System Operator expects the MFK frequency keeping band may need to widen over the coming years because of variable and intermittent generation causing more frequency variability within the normal band. The widening of the MFK frequency keeping band may not be as large if there is a permitted maximum dead band on all generation in the vicinity of ±0.1Hz.

3.28. Increasing the amount of MFK and instantaneous reserve does not directly resolve the issue of greater frequency fluctuations within the normal band. Instantaneous reserve acts primarily to restore frequency to within the normal band after a disturbance on the power system, while the MFK service typically responds too slowly to maintain frequency within the normal band in real time. MFK does not eliminate the need for fast primary response, so additional instantaneous reserve will likely still be required to reduce the risk of an AUFLS event.

3.29. We also disagree with claims from submitters that frequency keeping is necessarily the most cost-reflective approach. MFK is procured as a system-wide service, and

[9] Option 3: Procure more frequency keeping to manage frequency within the normal band (49.8-50.2Hz) and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

its costs are currently socialised as they are spread across purchasers rather than charged to those causing frequency deviations. For example, generators with wide dead bands still benefit from system stability without paying proportionally for the extra MFK procured to offset their lack of response, creating a free-rider problem.

Code amendment 2 – A maximum dead band beyond which a generating station must contribute to frequency management and support

The Authority's proposal

3.30. The Authority proposed to amend clause 5 of Technical Code A of Schedule 8.3 of the Code to set a permitted maximum dead band of ±0.1Hz, beyond which a generating unit would have to contribute to frequency management and frequency support. This obligation would apply to existing and new generating units.

3.31. We also proposed inserting a new subclause to only apply the new requirement as at the time of the next periodic test of the generating unit.

Submitters' views and Authority response

3.32. Submitters noted that certain technologies may not be able to comply or may face excessive costs, including geothermal (Contact and Mercury submissions), run-of-river hydro and older machines with mechanical governors (Manawa), wind turbines (Meridian), Kaplan turbines (IEGA), Huntly thermal units (Genesis) and BESS (NewPower).

3.33. Meridian, IEGA and Manawa suggested instead a more flexible approach to the dead band requirement to allow for generating stations that are physically unable to comply with the proposed uniform dead band, such as specifying technology-specific dead bands or requiring compliance with the inherent dead band of the generating unit.

3.34. We acknowledge that a uniform dead band may not be the most efficient approach. We considered technology-specific dead bands as an alternative. However, this approach would require both ongoing, costly system studies to determine appropriate dead band settings, and updating them over time as generating fleet composition, control system and operating practices evolve. These studies would be necessary to ensure that technology-specific settings continue to deliver the intended frequency performance without adverse interactions across the power system. In addition, applying a single dead band to an entire technology class risks mischaracterising real world differences between individual units (eg, differences between sub-categories within generating technologies such as Francis versus Kaplan hydro turbines).

3.35. To address this, we have included an option for generators to comply with the inherent dead band of the generating unit, subject to System Operator agreement, even if it falls outside ±0.1Hz. This case-by-case mechanism provides flexibility while avoiding the need to maintain a complex and evolving set of technology-specific limits while ensuring performance obligations reflect actual plant capability. It also addresses cost concerns raised by Meridian and Manawa for technologies that would face disproportionately high costs under a strict ±0.1Hz dead band requirement.

3.36. Some submitters believed the costs would be higher than what the Authority anticipates. For example:

(a) Manawa estimated that narrower dead bands could shorten maintenance intervals, adding $2-8 million annually in costs. IEGA noted hydro units used for frequency regulation experience 7-10 times more wear on regulating mechanisms. Meridian considered that wear and tear costs are likely to be material, but agreed that they are difficult to quantify. Our response to these costs is provided throughout section 4 of this paper. To summarise, the inclusion of an option to comply with the inherent dead band, as agreed with the System Operator, will allow existing settings to be retained where supported by the inherent dead band. Regarding IEGA's point, we see the example as being illustrative of one of the underlying problem this Code amendment seeks to address, namely the disproportionate wear and tear currently imposed on a relatively small subset of generating stations

(b) Meridian estimated that moving from ±0.15Hz to ±0.1Hz for their wind generation could result in 6.1GWh of annual 'energy spill', costing approximately $912,000 per year at an assumed wholesale price of $150/MWh. Our response is discussed in paragraphs 4.30 to 4.32. We acknowledge that narrower dead bands may lead to some energy spill, however we consider that several mitigations are likely to reduce the magnitude of spill compared with Meridian's estimate.

(c) NewPower estimated a 5,000% increase in costs for its Rotohiko BESS, while Meridian estimated $640,000 annually if applied to BESS while idle. Submitters warned that BESS operators may disconnect when idle to avoid costs, reducing reserve availability and security of supply. Our response to NewPower's estimate is provided in paragraph 4.29 and to Meridian's estimate is in paragraphs 4.17 to 4.18. We acknowledge that specifying a maximum permitted dead band for BESS is not costless, however we consider that NewPower's estimate is materially overstated. Regarding Meridian's feedback, the Code amendment does not introduce a requirement for BESS to comply with the frequency-related AOPOs while idle.

3.37. Manawa estimated that seeking dispensations for its generating stations that cannot comply with the new dead band requirement would be around $4 to $5 million across its fleet.

3.38. In response to Manawa's estimate of dispensation costs, the legacy clause removes the need for dispensations for existing generating stations that cannot comply without modification.

3.39. Submitters highlighted that a uniform dead band could impose higher costs than a technology-specific approach and may shift costs from generators equipped for frequency keeping to all generators. We do not consider frequency keeping to be truly cost reflective, as discussed in paragraph 3.29. Some submitters also raised concerns about unintended consequences, such as increased administrative burden for dispensations. We expect this cost to be minor, as discussed in paragraph 4.16.

3.40. Meridian, NewPower and Manawa reiterated their preference for a dedicated capability market for frequency response.

3.41. As we noted under the first Code amendment above, we have noted the support from submitters for the following two projects:

(a) Investigate new markets and products that support frequency stability. This would likely address the remainder of the longer-term concerns raised by submitters, such as NewPower's concerns that investment in BESS will be discouraged, or costs might be recovered via other market products instead.

However, even if a new product or market were implemented in the future, the frequency-related AOPOs in Part 8 of the Code would continue to be necessary until any new product or market clearly demonstrates that it could replace the existing requirements.

In addition, establishing physical capability in smaller generating stations now prepares these assets for potential future developments like a capability market.

(b) Review and consider common quality requirements for the demand-side of the electricity industry. This includes considering the impact on the power system of large load connections such as data centres, which are expected to connect to New Zealand's power system in the near future.

Our decision

3.42. The Authority has decided to proceed with the proposed Code amendment, with the following changes:

(a) Generators must comply with a maximum dead band of the greater of ±0.1Hz or their generating unit's inherent dead band, agreed with the System Operator, acting reasonably.

(b) Geothermal generating units are excluded from the dead band requirement due to their inherent inability to comply.

3.43. We have also defined the term 'inherent dead band' in clause 1.1 of the Code, which is the continuous range of system frequency values around 50 Hertz within which a generating unit does not provide an immediate active power response, due to the physical characteristics of the generating unit. Allowing generators to use the inherent dead band, conditional on the System Operator's agreement, provides:

(a) a compliance path for generating units unable to comply with a ±0.1Hz dead band.

(b) flexibility for generating units that can comply with a ±0.1Hz dead band but would face disproportionately high costs (eg, wear and tear) due to technology type or configuration

(c) an alternative to relatively costly dispensations.

3.44. Specifying a maximum dead band ensures that frequency control is shared more evenly across generating units, which is likely to reduce overall wear and tear. When dead bands are too wide, fewer generating units respond, forcing those units to operate further from their optimal set point which increases mechanical and thermal stress on governors and turbines.

3.45. To further reduce costs, generators must demonstrate compliance during their generating unit's next routine test rather than immediately. This integrates verification into existing processes, adding only a relatively minor incremental cost.

4. The amendments are consistent with our main statutory objective

4.1. The Authority's main statutory objective, under section 15(1) of the Act, is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

4.2. The Authority's additional objective, under section 15(2) of the Act, is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective applies only to the Authority's activities in relation to the direct dealings between industry participants and these consumers. This additional objective does not apply to the current Code amendment.

4.3. After considering all submissions on the Code amendment proposal, the Authority considers the final Code amendment is consistent with our main statutory objective, and with section 32(1) of the Act.

4.4. The amendments promote the three limbs of the Authority's main statutory objective as follows:

(a) **Competition** is supported by promoting competitive neutrality amongst emerging and established technologies.

(b) **Reliable supply** is promoted by having more generating stations support frequency stability and by improving the responsiveness of the power system to frequency fluctuations. This better enables the System Operator to manage the power system frequency and reduces the likelihood of AUFLS events and the risk of cascade failures.

(c) **Efficient operation** is promoted by:

i) reducing the System Operator's need to procure additional instantaneous reserve to cover the risk of secondary tripping from generating stations that export 10MW or more but less than 30MW

ii) sharing frequency management across more generating stations, which will lessen disproportionate wear and tear on the subset of generating units that currently bear much of the burden helping the System Operator to manage frequency within the normal band.

4.5. In making these Code amendments the Authority has applied the principles set out in our consultation charter.[10] In summary, we consider there is a clear case for regulation, having evaluated the benefits and costs of the Code amendments against the status quo arrangements and alternative options. The next sub-section summarises this evaluation.

The benefits of the amendments are greater than the costs

4.6. Having assessed the Code amendments' expected benefits and costs, the Authority considers the benefits will outweigh the costs. We also consider the Code

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[10] See Electricity Authority | Consultation Charter 2024.

amendment achieves its objective at lower economic cost than the main alternatives. In response to submitter feedback, we have made some changes to the proposals we consulted on to significantly reduce the implementation costs.

4.7. Summaries of the expected benefits and costs for each of the two Code amendments are provided below.

Assessing the first Code amendment's benefits and costs

Table 2: Summary of the first Code amendment's expected benefits and costs

Benefit / Cost	Magnitude
Improved power system stability	Potentially material
Reduced likelihood of AUFLS events and their costs, by improving the System Operator's visibility of generating stations at risk of secondary tripping	Potentially material
Avoided cost of procuring additional instantaneous reserve	Potentially material
Additional wear and tear costs for some generators	Potentially material
Compliance-related costs for generators	Minor incremental cost
Administrative costs for generators and the System Operator	Minor incremental cost

4.8. Key changes to the Code amendment proposal that have affected the proposal's estimated benefits and costs are:

(a) Introducing proportional compliance requirements for 10–29.99MW generating stations, including reliance on asset capability statement information and compliance checks during routine testing, as applicable. This significantly reduces incremental compliance costs for smaller generating stations by allowing compliance to be assessed through existing processes, and in some cases, through documentation rather than full testing (as discussed in paragraph 3.12).

(b) A generating station subject to the 'legacy clause' provisions in the Code amendment will not lose its 'legacy' status should its maximum continuous MW output power increase by less than 5MW above its 30 June 2027 level. This change prevents unnecessary dispensation costs that would otherwise arise from minor updates (as discussed in paragraphs 3.24 to 3.26).

4.9. The benefits of the Code amendment are, primarily, improved power system stability and avoided costs, such as reduced risk of an AUFLS event, and avoided instantaneous reserve procurement costs. Quantified examples of these avoided costs include:

(a) avoided instantaneous reserve costs – equating to approximately $234,000[11] per year in the case of a 24MW generating station at risk of sympathetic tripping

(b) lower risk of an AUFLS event – hundreds of thousands of dollars over the 15-year period of our assessment, assuming a minor reduction in a risk that otherwise has a probability close to one,[12] and based on our estimate of $6m per hour for one of these events in the North Island.

4.10. These figures are indicative, rather than precise, estimates, as actual costs will depend on market conditions and the System Operator's future procurement approach. However, they demonstrate the material scale of the avoided costs.

4.11. Some submitters disagreed with the costs estimated by the Authority for the first Code amendment proposal and provided further information through their submissions. This is summarised below, along with our response, which is that this information does not change our view of the proposal's costs.

4.12. We remain confident that the benefits of the proposal outweigh the associated costs, including any potential additional wear and tear for some generators. Broadening participation in frequency management will reduce the disproportionate mechanical stress currently carried by a relatively small number of units and is expected to lower overall wear and tear costs across the fleet by distributing the responsibility more evenly.

4.13. Therefore, after considering and responding to submitter feedback, we still consider the first Code amendment has a net benefit.

Dispensation costs

4.14. Manawa estimated that the cost of seeking dispensations for its 10–29.99MW generating stations that cannot comply with the frequency-related AOPOs and technical codes in Part 8 of the Code would be around $4 to $5 million across its fleet.

4.15. In response, the Authority notes the legacy clause arrangements in the Code amendment remove the need for asset owners to seek dispensations for existing generating stations that cannot comply without modification.

4.16. There will be some administrative compliance costs, such as owners of existing 10–29.99MW generating stations advising the System Operator of stations that are unable to comply with the Code requirements. We estimate the administrative cost associated with the generation owners advising the System Operator will be no more than $2,500 per station. This relates primarily to the cost of the generation owner updating its asset capability statement information and the System Operator reviewing this information. For the purposes of assessing the Code amendment's

[11] The estimated benefit has reduced from the consultation paper figure because the fast instantaneous reserve cost assumption was refined from $5/MWh to $4.45/MWh per trading period, following the use of more granular data. This estimate is based on the approximate average price of fast instantaneous reserve in the North Island over the five years to 31 December 2024.

[12] Based on the historical average time period between AUFLS events.

costs we have assumed 20 10–29.99MW generating stations are unable to comply with the Code requirements,[13] which gives a one-off cost of $50,000.

Costs incurred by BESS to provide frequency support when idle

4.17. Meridian estimated that a BESS providing frequency support while idle could incur costs of about $640,000 per year and considered there should be a way to recover these costs via revenue earned through market mechanisms.

4.18. In response, the Authority notes the Code amendment does not introduce a requirement for BESS to meet the frequency-related AOPOs, including frequency support, while idle.

Assessing the second Code amendment’s benefits and costs

Table 3: Summary of the second Code amendment's benefits and costs

Benefit / Cost	Magnitude
Deferring the need for additional MFK ancillary service	Potentially material
Improved frequency quality	Potentially material
Improved power system resilience	Potentially material
Reduction in disproportionate wear and tear costs for some generators	Potentially material
Increase in wear and tear for some generators	Potentially material
Energy ‘spill’ from intermittent generation	Potentially material
Control system changes	Minor incremental cost
Periodic testing	Minor incremental cost

4.19. Key changes to the Code amendment proposal that have affected the proposal’s estimated benefits and costs are:

[13] We understand that at least the following 16 generating stations may fall into this category: the Paerau and Patearoa hydro power scheme (10.2MW), the Redvale landfill biogas plant (12.7MW), Whirinaki wood pulp mill co-generation (13.5MW), Lloyd Mandeno power station (16MW), Glenbrook steel mill co-generation TA1 (18.8MW), Glenbrook steel mill co-generation TA2 (18.8MW), Ruahihi power station (20MW), Te Ahi O Maui geothermal power station (24MW), Te Rere Hau wind farm 1 (24MW), TOPP1 (Binary) geothermal power station (24MW), Wheao power station (24MW), Te Rere Hau wind farm 2 (24.5MW), Aniwhenua power station (25MW), Ngawha geothermal power stations 1 and 2 combined (25MW), the Highbank and Montalto power scheme (28MW), and Te Huka (Binary) geothermal power station (28MW).

(a) Enabling the use of the inherent dead band of the generating unit (with System Operator agreement) instead of a strict ±0.1Hz requirement, thereby reducing costs for generators, associated with either their generating units being non-compliant or the generator facing disproportionately high compliance costs (discussed in paragraph 3.35).

(b) Excluding geothermal generating units from the dead band requirements, to avoid unnecessary transaction costs associated with the owners of these units seeking dispensations, since they are unlikely to ever be able to comply (discussed in paragraph 3.42).

4.20. These changes strike a practical balance between costs and benefits, reducing significant costs to minor incremental ones.

4.21. The benefits of the Code amendment are, primarily, improved power system stability and avoided costs. The most significant avoided cost is expected to be the deferred need to procure additional MFK, at approximately $800,000 per year for every 1MW increase in the frequency keeping band across both islands.

4.22. These figures are indicative, rather than precise, estimates, as actual costs will depend on market conditions and the System Operator's future procurement approach. However, they demonstrate the material scale of the avoided costs. Our assessment of these benefits has not changed from our assessment of them for the Code amendment proposal.

4.23. Some submitters disagreed with the Authority's cost estimates for the second Code amendment proposal and provided additional information through their submissions. This is summarised below, along with our response, which is that this information does not change our view of the proposal's costs once the changes we are making to the proposed amendments in response to the submissions have been taken into account.

4.24. Therefore, after considering and responding to submitter feedback, we still consider the second Code amendment has a net benefit.

Dispensation costs

4.25. Manawa estimated that seeking dispensations for its generating stations that cannot comply with the new dead band requirement would be around $4 to $5 million across its fleet. We have removed the need for dispensations by including a legacy clause so that existing generating stations that cannot comply without modification will not be required to comply. For the dead band requirements, we have also allowed generators to retain their current settings when these are supported by the inherent dead band of the generating unit, and with agreement from the System Operator, further removing the need for dispensations.

Increased wear and tear costs for some generators

4.26. Manawa submitted that the second Code amendment proposal would increase mechanical wear and tear on Manawa's assets, and as a result they may need to shorten their maintenance and refurbishment intervals which could cost Manawa an additional $2 to $8 million per annum. We acknowledge that tighter frequency dead bands may increase control activity for some generating technologies, particularly where mechanical response is required. In response, we have drafted the Code amendment to allow generators to retain their existing settings where these reflect the inherent dead band of the generating unit, subject to agreement with the System Operator, acting reasonably. In such cases, the dead band requirement would not impose material incremental wear-related costs on the generator.

4.27. The IEGA submitted that hydro units operating with no dead band can experience up to seven times more wear and tear costs than a similar unit set at a ±0.2Hz dead band. They view this as evidence of the burden imposed by narrower dead band settings. While outcomes will vary by plant and control configuration, we consider that this example actually illustrates inefficiencies in the current framework, which allows some generators to set excessively wide dead bands. This amplifies wear on generators with more responsive generating units. By spreading frequency-management responsibilities across a wider set of generating stations, it is reasonable to expect a reduction in the severity of frequency excursions and the need for large corrective movements by individual units, thereby moderating wear-related impacts across the system as a whole.

4.28. The IEGA also recommended that the requirement should simply be for generators to notify the System Operator of the dead band that each generating unit is operating to, rather than applying a uniform limit. We consider the final Code amendment achieves a similar outcome by allowing generators to operate with a dead band wider than ±0.1Hz where this is necessary due to the inherent dead band of the generating unit, while preventing dead bands from being set wider than what a generating unit is inherently capable of sustaining.

4.29. NewPower's estimate that a ±0.1Hz dead band would increase Rotohiko BESS frequency management costs by around 5,000% appears to us to be overstated. The estimate assumed a continuous 24/7 frequency response with a zero dead band, which does not reflect how frequency services are provided. In practice, frequency response is event-driven and intermittent. We expect appropriate droop settings to be applied to BESS to deliver a response proportionate to other types of generating technologies. Moving to a ±0.1Hz dead band will tighten control around 50Hz, reducing the size of frequency deviations before response is triggered. Smaller, more frequent corrections are generally less damaging than infrequent large actions, which impose higher stress on batteries and accelerate degradation.

Value of 'spilled' energy from reduced wind output

4.30. Meridian estimated that tightening dead bands for wind generating stations in New Zealand from ±0.15Hz to ±0.1Hz would lead to 6.08GWh of 'spilled' energy per annum at the current level of installed wind generation capacity. This would result in a minimum of $912,000 of lost energy each year, assuming a wholesale price of $150/MWh, with the aggregate value of lost energy increasing over time as more wind generation was installed.

4.31. We recognise that spilled energy from wind generation represents a cost of the Code amendment. However, Meridian's estimate may overstate the actual cost, for reasons that include:

(a) reduced frequency volatility and shorter duration of over-frequency events that generators are required to respond to, as frequency is stabilised earlier due to the improved primary response.

(b) the growing international trend of integrating BESS with intermittent generating stations. While not currently widespread, such configurations can enable a portion of generation that would otherwise be 'spilled' during over-frequency conditions to be stored and later injected.

(c) The potential of modern wind technology to enable some of the wind energy to be stored as kinetic energy in the rotor, reducing the amount of energy spilled.

4.32. The Authority also notes that wind generation, due to its intermittent and variable nature, contributes to the frequency-related issue that this Code amendment is addressing, particularly during periods of high output and low system inertia. In this context, requiring wind generating stations to provide more responsive frequency support promotes efficiency by assigning a portion of the frequency management burden towards a technology that contribute to the conditions giving rise to that need in the first place.

Costs of control system changes for existing generating stations that can comply

4.33. Manawa estimated that redesigning and implementing control system changes for its generating stations could cost between $2 to $7 million for stations that are technically able to meet the new dead band requirement.

4.34. We consider that these stations are likely to fall under the legacy clause arrangements if they cannot meet the narrower dead band without modification. This means they will not be required to comply until a compliant control system is installed.

Costs associated with demonstrating compliance to the System Operator

4.35. Manawa considered the verification and testing requirements set by the System Operator to be costly, with testing costs alone ranging from $2 to $5 million across its fleet. However, under the Code amendment these requirements will only need to be demonstrated at the time of the next periodic test. This approach creates only a minor incremental cost because the new requirements align with the existing periodic testing timelines rather than creating a separate testing process.

5. Attachments

5.1. The following appendix is attached to this paper:

Appendix A Approved Code amendments

Appendix A Approved Code amendments

A.1. This appendix sets out the Code amendment the Authority has decided to make following our consideration of submitter feedback and in accordance with the decisions set out in the main body of this document.

A.2. For Code clauses shown in our consultation paper on the Code amendment proposal:

a. text or formatting is red underlined if it is to be added to the Code

b. deleted text is ~~red strikethrough~~ if it is to be deleted from the Code.

A.3. Changes to the text or formatting of Code drafting shown in our consultation paper on the proposed Code amendment are shown in blue. Text is shown in blue underlined if it is to be added to the Code, and in blue ~~strikethrough~~ if it is to be deleted from the Code.

A.4. The new definition 'maximum continuous MW output power' requires a consequential amendment to the definition of 'point of connection'. This is to make clear that the definition of 'maximum continuous MW output power' applies to embedded generation under Technical Code A of Schedule 8.3 of the Code.

A.5. A further minor consequential change, to clause 4(5) of Technical Code A is required to make clear that the reference to 'point of connection' is a reference to a point of connection to the transmission grid. All other references to 'point of connection' in Technical Code A clearly refer to a point of connection to the transmission grid.

Part 1
Preliminary provisions

…

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

…

inherent dead band means the range of system frequency values around 50 hertz within which a **generating unit** does not provide an immediate frequency control response, due to the physical characteristics of the **generating unit**

maximum continuous MW output power means:

(a) for each **generating station**, **embedded generating station** or **generating unit** for which a **generator** or an **embedded generator** must submit an **offer** under this Code, the maximum dispatch quantity (in **MW** alternating current (a.c.)) of the **generating station**, **embedded generating station** or **generating unit** as specified in the **asset capability statement** for the **generating station**, **embedded generating station** or **generating unit**; or

(b) for each **generating station**, **embedded generating station** or **generating unit** for which a **generator** or an **embedded generator** is not required to submit an **offer** under this Code, the maximum **active power** output (in **MW** alternating current (a.c.)) of the **generating station**, **embedded generating station** or **generating unit** at its **point of connection** that can be maintained continuously over a 5-minute period of time under ideal operating conditions and with the **generating station**, **embedded generating station** or **generating unit** maintaining compliance with this Code in the absence of any exemption, **dispensation**, **equivalence arrangement** or similar as specified in the **asset capability statement** for the **generating station**, **embedded generating station** or **generating unit**

…

~~**maximum export power** means, in respect of a **generating plant**, the lesser of—~~

~~(a) the **nameplate capacity** of the **generating plant** minus the minimum load at its **point of connection**; or~~

~~(b) the power export limit imposed by an **active power** export control device~~

…

point of connection means—

(a) a point at which **electricity** may flow, via one or more phases or conductors—

(i) into or out of a **network**; or

(ii) both into and out of a **network** at the same time, where each directional flow is on different phases or conductors; and

~~(b) for the purposes of **Technical Code A** of Schedule 8.3, means a **grid injection point** or a **grid exit point**~~

…

Part 8
Common quality

…

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in **Technical Code** A of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** or **embedded generating station** that has a ~~**maximum export power**~~ **maximum continuous MW output power** of ~~exports~~ less than ~~30~~ 10 **MW** ~~to a **local network** or the **grid**~~, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** or **embedded generating station** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in **Technical Code** A of Schedule 8.3.

(2) Whether likely to be **an excluded** ~~**generation**~~ **generating station** or not, a **generator** who is planning to connect to the **grid** or a **local network** a **generating unit** with rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.) capacity) must provide the **system operator** with written advice of its intention to connect together with other information relating to that **generating unit** in accordance with clause 8.25(4).

(3) A **generating station** or **embedded generating station** that was an **excluded generating station** immediately before 1 July 2026 that would no longer be an **excluded generating station** due to the commencement of the [*name of the amending instrument]* continues to be an **excluded generating station** if—

(a) it is not able to comply, without modification, with one or more of the requirements it would be subject to if it was no longer an **excluded generating station**; and

(b) the **asset owner** of the **generating station** or **embedded generating station** updates the **asset capability statement** for the **generating station** or **embedded generating station** to record that this subclause applies to the **generating station** or **embedded generating station**.

(4) Subject to subclause (5), a **generating station** or **embedded generating station** that first **electrically connects** to the **grid** or directly or indirectly to a **local network** on or after 1 July 2026 and before 1 July 2027 and which would have been an **excluded generating station** if the definition of that term in the Code immediately before the commencement of the [*name of the amending instrument*] applied to it, is an **excluded generating station** if—

(a) it is not able to comply, without modification, with one or more of the requirements it would be subject to if it was no longer an **excluded generating station**; and

(b) the **asset owner** of the **generating station** or **embedded generating station** updates the **asset capability statement** for the **generating station** or **embedded generating station** to record that this subclause applies to the **generating station** or **embedded generating station**.

(5) In order for subclause (4) to apply to a **generating station** or **embedded generating station** the **asset owner** of the **generating station** or **embedded generating station** must confirm in writing to the **system operator** before 1 August 2026 that the following have occurred in respect of the **generating station** or **embedded generating station**:

(a) the **asset owner** has secured financing that enables the **asset owner** to develop and **commission** the **generating station** or **embedded generating station**:

(b) the **asset owner** has obtained all consents necessary to enable the **asset owner** to develop and **commission** the **generating station** or **embedded generating station**:

(c) the **asset owner** has obtained rights to use the land on which the **generating station** or **embedded generating station** is to be located.

~~(4)~~(6) ~~Subclause~~ Subclauses (3) and (4) ~~ceases~~ cease to apply in respect of a **generating station** or **embedded generating station** from the date—

(a) a modification is made to the **generating station** or **embedded generating station** that means it is able to comply with all the requirements it would be subject to if it was not an **excluded generating station**; or

(b) the **generating station's** or **embedded generating station's** ~~**maximum export power**~~ **maximum continuous MW output power** increases by 5 **MW** or more above its ~~**maximum export power**~~ **maximum continuous MW output power** immediately before 1 July ~~2026~~ 2027.

~~(5)~~(7) An **asset owner** must, as soon as practicable, update the **asset capability statement** for a **generating station** or **embedded generating station** to record when subclause (3) or (4) ceases to apply to the **generating station** or **embedded generating station**.

~~(6)~~(8) The **system operator** must **publish** and maintain a list of **generating stations** and **embedded generating stations** to which subclause (3) or (4) applies.

…

Schedule 8.3
Technical Codes

Technical Code A – Assets

…

4 Requirements for grid and grid interface

…

(5) At a point of connection to the **grid**—

(a) an **asset owner**, other than a **grid owner**, must provide a means of checking **synchronisation** before the switching of **assets** if it is possible that such switching may result in **electrical connection** of parts of the New Zealand electric power system that are not **synchronised**; and

(b) a **grid owner** must provide a means of checking **synchronisation** before the switching of **assets** in locations agreed with the **system operator** so that it is not possible for such switching to result in **electrical connection** of parts of the New Zealand electric power system that are not **synchronised**.

…

5 Specific requirements for generators

(1) Each **generator** must ensure that—

(a) each of its **generating units**, and its associated **control systems**,—

(i) supports the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; and

(ii) is able to **synchronise** at a stable frequency within the frequency range stated in the **asset capability statement** for that **asset**; and

(b) the rate of change in the output of any of its **generating units** does not adversely affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations**. The rate of change must be adjustable to allow for changes in **grid** conditions; and

(c) each of its **generating units** has a speed governor and/or frequency **control system** that—

(i) provides stable performance with adequate damping; and

(ii) has an adjustable droop over the range of 1% to 7%; and

(iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics; and

(iv) operates with a dead band not exceeding the greater of:

(A) ±0.1 Hertz; or

(B) the **inherent dead band** of the **generating unit**, as agreed with the **system operator** acting reasonably; and

(d) appropriate speed governor and/or frequency **control system** settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The performance of the **generating unit** is then assessed by measurements from **system tests** and final settings are then applied to the **generating unit** before making it ready for service after those final settings are agreed between the **system operator** and the **generator**. An **asset owner** must not change speed governor and/or frequency **control system** settings without **system operator** approval.

(1A) For a **generator** with a **generating unit** that has **electrically connected** to a **network** prior to the commencement of the [name of the amending instrument], the ~~The~~ requirement in subclause (1)(c)(iv) only applies from the time of the next periodic test of the **generating unit** carried out in accordance with Appendix B of **Technical Code A** following the commencement of the *[name of the amending instrument]* ~~that subclause~~.

(1AB) The requirement in subclause 1(c)(iv) does not apply to **generating units** for which geothermal heat is the primary power source.