# Part 8 Code terminology and network information

Decision paper

1 April 2025

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 in a highly electrified future, ensuring it is set up to deliver the best possible outcomes for consumers. To help achieve this, we are proactively refining industry rules to support greater electrification while maintaining a stable and reliable power system for decades to come. This paper outlines the Authority's decision to amend Part 8 of the Code.

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 technologies, addressing security and resilience risks, and building a power system that is reliable, flexible, and consumer-focused.

One of the most critical parts of the FSR programme is a review of the common quality requirements[1] 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.

**We sought feedback on nine proposed Code amendments**

In October 2024, we proposed nine amendments to Part 8 of the Code to help address the following key common quality issues:

- outdated or missing terms in the Code
- insufficient information for network owners and operators.

We received 14 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 seven of the nine proposed Code amendments**

The Authority considered all submissions and has decided to proceed with the following seven Code amendments:

- Remove the exclusion for wind-powered generating units from periodic testing requirements.
- Clarify that embedded generators must provide an asset capability statement in the format specified by the system operator.
- Expand the under-frequency event (UFE) provisions to include any industry participant whose actions could cause a UFE.
- Update the requirement for a speed governor to allow for a speed governor and/or a frequency control system.
- Remove the requirement for an excitation system while maintaining the requirement for a voltage control system.
- Amend some of the periodic testing requirements to apply to all types and owners of grid-connected dynamic reactive power compensation devices.

[1] 'Common quality' means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons.

- Treat energy storage systems as only generation under Part 8.

These changes will make the Code more consistent, enhance system reliability and resilience, and better accommodate evolving technologies, particularly inverter-based resources such as wind generation, solar photovoltaic generation and battery energy storage systems. This will give consumers greater choice and flexibility in how they use and supply electricity, ultimately delivering long-term benefits.

At this time, we have decided not to change:

- the definition of ‘generating unit’ (FSR-008)
- clause 8.25A to clarify the fault ride through (FRT) requirements for machine-based synchronous generating units (FSR-009).

We will consider these further as we progress Code amendment proposals on frequency, voltage and common quality information requirements and as part of a broader review of the FRT requirements in the Code.

**Next steps**

The Code amendments will come into effect on 1 May 2025.

# Contents

# 1. Introduction

1.1. 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.

1.2. The Authority's Future Security and Resilience (FSR) workstream is one of several initiatives supporting the electrification of New Zealand's economy. Key complementary workstreams the Authority is working on include:

(a) Improving network visibility

(b) Developing solutions for peak capacity issues

(c) More efficient connection prices and processes

(d) Multiple Trading Relationships (MTR) and switch process review

(e) The *Power Innovation Pathway (PIP)* programme.

1.3. While we cannot 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 evolving technologies, while addressing the security and resilience risks posed by increased distributed generation and bi-directional electricity flows. This will help build a secure, adaptable, and consumer-focused power system.

## The Authority is reviewing Part 8 common quality requirements

1.4. This paper is part of the Authority's multi-year Future Security and Resilience (FSR) work programme. 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 Electricity Industry Participation Code 2010 (Code).

1.5. The Authority's website provides more information on the FSR programme and the context for this decision paper.[2]

## The Authority received 14 submissions

1.6. The nine Code amendment proposals in the October 2024 consultation aimed to help address two key issues identified as part of our review of the Part 8 common quality requirements.[3]

2 See Electricity Authority I Future security and resilience.

3 See Electricity Authority I Future security and resilience I October 2024 common quality Code amendment proposals.

**Issues addressed**

**Issue 6:** **Network owners and 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.**

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

1.7. We received 14 submissions on the consultation paper from the 15 parties listed in Table 1.[4] Submissions are available on the Authority's website.[5] Section 3 of this paper includes a summary of submitters' feedback on each of the Code amendment proposals.

4 Transpower's submission is primarily on behalf of the system operator, with the grid owner providing feedback on Code amendment proposal FSR-006 (dynamic reactive power compensation devices).

5 See Electricity Authority I Future security and resilience I October 2024 common quality Code amendment proposals I Submissions.

**Table 1: List of submitters**

| Submitter | Role | Proposals considered |
|---|---|---|
| Electricity Engineers' Association of New Zealand (EEA) | Representative body for electrical engineers | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Electricity Networks Aotearoa (ENA) | Representative body for distributors | FSR-002, FSR-003, FSR-007, FSR-008 |
| Lodestone Energy | Generator | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Major Electricity Users' Group (MEUG) | Representative body for large electricity users | FSR-003, FSR-006 |
| Manawa Energy | Generator | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Mercury | Generator–retailer | FSR-001, FSR-002, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Meridian Energy | Generator-retailer | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| NewPower | Owner/operator of solar photovoltaic generation and battery energy storage systems | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Orion | Distributor | FSR-002, FSR-003, FSR-007, FSR-008 |
| Powerco | Distributor | FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007 |
| SolarZero | Flexibility provider | General comments |
| Transpower (grid owner) | Transmission grid owner | FSR-006 |
| Transpower (system operator) | System operator | FSR-001, FSR-002, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-008, FSR-009 |
| Vector | Distributor | FSR-002, FSR-003 |
| WEL Networks | Distributor | FSR-001, FSR-003, FSR-004, FSR-005, FSR-006, FSR-007, FSR-009 |

## 2. The Authority finalised the Code amendments after considering submissions

2.1. After considering all submissions, the Authority has decided to make the following seven amendments to the Code.

**Table 2: List of Code amendments proceeding**

| Proposal | Topic | Page |
|---|---|---|
| **FSR-001** | Amend Schedule 8.3 to remove the exclusion for wind-powered generating units from the periodic testing requirements. | 9 |
| **FSR-002** | Amend Schedule 8.3 to clarify that embedded generators must provide an asset capability statement in the format specified by the system operator. | 10 |
| **FSR-003** | Amend clause 1.1 and clauses 8.60 - 8.66 and insert a new clause 8.64A so that the Code applies to all potential causers of under-frequency events. | 12 |
| **FSR-004** | Amend clause 1.1 and Schedule 8.3 to refer to a speed governor and/or a frequency control system, which broadens the obligation to apply to both machine-based and inverter-based generating units. | 15 |
| **FSR-005** | Amend clause 1.1 and Schedule 8.3 to remove the requirement for an excitation system but retain the requirement for a voltage control system, which can be applied to all generation technologies. | 17 |
| **FSR-006** | Amend clause 1.1, Schedule 8.3, and Schedule 12.5 to replace the references to static var compensators with references to dynamic reactive power compensation devices. | 19 |
| **FSR-007** | Amend clause 8.19 and Schedule 8.3 and insert a new clause 8.1B to treat energy storage systems that are 30MW and above as only generation for the purposes of Part 8. | 21 |

2.2. These Code amendments will come into effect on 1 May 2025.

2.3. The Authority has decided to not proceed with the following proposals:

(a) Amending the definition of generating unit (FSR-008). We want to consider this proposal further during 2025 as we progress Code amendment proposals on frequency, voltage and common quality information requirements.

(b) Clarifying the applicability of the fault ride through requirements to machine-based synchronous generating units (FSR-009). We consider the proposal would not promote the Authority's statutory objectives better than the existing dispensations regime.

2.4. Most submitters expressed support for modernising the Code's common quality requirements, to better accommodate technological advancements.

2.5. However, practical concerns were raised about implementing some of the proposals – for example, requiring old generating plant to comply with certain technical requirements. There was also some concern about a regulatory gap in the treatment of generation/load aggregators and hybrid arrangements, such as a generating station combined with a battery energy storage system (BESS).

2.6. This section summarises the submissions on each of the proposals in the October 2024 consultation paper. However, the summaries are not exhaustive, and we encourage you to review individual submissions for a comprehensive account of submitters' views.

## FSR-001: The Authority has decided to remove the exclusion for wind-powered generation from periodic testing requirements

### The Authority's proposal

2.7. Currently, all generating units for which wind is the primary power source (wind generating units) are excluded from the periodic testing requirement in Appendix B of Technical Code A, Schedule 8.3 of the Code. Other forms of generation, such as hydro, thermal, solar photovoltaic, and BESS, do not have an exclusion.

2.8. To align testing obligations across all generation types, the Authority proposed to remove the exception for wind-powered generating units from the periodic testing requirements. The objective of this change was to promote competitive neutrality, enhance grid reliability, and ensure compliance with the Code's asset owner performance obligations (AOPOs).

2.9. The Authority also proposed a transitional provision allowing wind-powered generating units commissioned before 1 January 2016 to complete the applicable periodic tests before 31 December 2028.

### Stakeholder feedback

2.10. Most submissions on this Code amendment proposal supported the principle of placing periodic testing obligations on wind generation to ensure consistency with other technologies. Some submitters emphasised the need for further clarity, flexibility, and tailored testing approaches to ensure the change would be practical, cost-effective, and aligned with the technological characteristics of wind generation.

2.11. The EEA, Lodestone Energy, NewPower, Transpower as the system operator, and WEL Networks supported the proposal. The system operator highlighted the importance of periodic testing to the system operator's maintenance of accurate generator models and to promoting secure operation of the (transmission) grid. NewPower suggested allowing flexibility in the transition timeframe, particularly for wind farms undergoing repowering.

2.12. Meridian Energy supported the intent of the proposal but noted it is not feasible to test the frequency response of wind generating units as described in clause 2 of Appendix B, Technical Code A. In its submission Mercury noted that generating unit governor response and voltage response (clauses 3 and 5 of Appendix B, Technical Code A) cannot be tested at the generating unit level but rather only at the generating station level.

2.13. Manawa Energy did not comment on the proposal and requested additional information on the testing process, including whether it would apply to individual turbines or entire wind farms.

### The Authority's decision

2.14. The Authority has decided to proceed with the proposal, but we have clarified that for inverter generation:

(a) the periodic testing requirements in clause 2 of Appendix B, Technical Code A apply to protection settings rather than to protection relays, and

(b) the periodic testing requirements in clauses 3 and 5 of Appendix B, Technical Code A apply at the frequency controller / voltage controller. Typically, this is at the generating station level rather than at the generating unit level.

2.15. We note these clarifications are consistent with the system operator's inverter generation tests.[6]

## FSR-002: The Authority has decided to clarify that embedded generators must provide an asset capability statement in a format specified by the system operator

### The Authority's proposal

2.16. Under Part 8 of the Code, embedded generators larger than 1MW are required to provide the system operator with an asset capability statement (ACS) to enable the system operator to assess compliance with the requirements of the Code's AOPOs and technical codes.[7]

2.17. However, Technical Code A of Part 8 of the Code could be improved by:

(a) clearly specifying which embedded generators must submit an ACS in the system operator's specified format, and

(b) including a cross-reference to the 1MW embedded generator size threshold that this requirement applies to.

2.18. The Authority proposed an amendment to Technical Code A of Part 8 of the Code to clarify that embedded generators with a generating unit rated at a net maximum capacity of 1MW or greater must provide ACS information in the format specified by the system operator.

### Stakeholder feedback

2.19. Most submitters supported the proposal, but some queried the threshold for providing ACS information, how the existing obligations apply to aggregators and back-up generators, and the level of detail required from embedded generators

2.20. The EEA, Lodestone Energy, Manawa Energy, Mercury, Meridian Energy, Powerco, and Transpower as the system operator supported the proposal. The EEA, Meridian Energy, and Powerco agreed the amendment would improve clarity and streamline data collection processes, supporting system reliability and efficiency.

2.21. Mercury suggested a threshold higher than 1MW may be appropriate, to avoid capturing commercial scale solar and BESS installations. In contrast, the EEA

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6 See [Transpower I GL-EA-010 Generator Testing Requirements].

7 The Code defines 'asset' to mean equipment or plant that is connected to or forms part of the grid (transmission network) and, in the case of Part 8, expressly includes 'equipment or plant of an embedded generator.'

considered that a 1 MW threshold strikes a balance between comprehensive data collection and a reasonable compliance burden on smaller generators. Further to this point, the EEA suggested monitoring for potential data gaps caused by smaller generators configuring their systems to remain below the 1MW threshold to avoid compliance obligations.

2.22. Powerco suggested granting distributors access to the ACS platform for all embedded generation on their networks.[8]

2.23. Manawa Energy expressed conditional support, urging the Authority to accommodate legacy generating units with technical limitations through grandfathering provisions or dispensations in the Code.

2.24. Several submitters raised concerns about generator aggregators and their exclusion from the Code. The EEA, ENA, NewPower, Orion, and Vector recommended that the Authority include aggregators as participants and establish obligations for them to provide ACS information, given their growing role in managing distributed energy resources.

2.25. The ENA, Orion, and Vector also sought guidance on the obligations of parties that use back-up generators, noting potential confusion caused by the differences in the Code's definitions of 'distributed generation' and 'embedded generating station.' The ENA queried whether compliance obligations should differ between back-up generators and generators with an 'every day' energy role. Orion suggested the Authority should exclude back-up generators from the requirement to provide ACS information to the system operator.

2.26. NewPower did not support the proposal. It considered the proposal imposed disproportionate compliance costs on smaller generators. NewPower suggested this could create barriers to entry for generation near the 1MW threshold. It argued that the system operator and grid owner should bear the costs of translating smaller generator data into usable formats.

2.27. NewPower recommended the information requirements for smaller generators should be explicitly less onerous than those for larger generators. This approach would recognise that smaller generation has less impact on the power system and that meeting the same requirements imposes a proportionally greater financial burden on them compared to larger generators. NewPower suggested the system operator develop a simplified ACS format for smaller embedded generators, ensuring it aligns with the relevant AOPOs in the Code and the level of detail needed for Transpower's modelling.

### The Authority's decision

2.28. The Authority has decided to amend the Code as proposed but with a minor clarification to say the 1MW threshold is 1MW alternating current (AC) capacity (as opposed to 1MW direct current (DC) capacity).

2.29. The capacity of inverter-based resources is often stated in terms of DC capacity. However, when it was implemented, the 1MW threshold was intended to be stated in terms of AC capacity. We want to ensure this intent is clear. We note other

8 The Operations Customer Portal enables the system operator and industry participants to submit and share information online, including ACS.

references to MW thresholds in the Code may also require a similar clarification, however to do so would be beyond the scope of this Code amendment proposal.

2.30. The Authority acknowledges the concerns raised by Mercury and NewPower about the 1MW threshold. We also note the points made by the ENA, Orion and Vector about the obligations on back-up generators. However, the Code amendment does not introduce new obligations regarding the size or type of embedded generator required to provide ACS information or the nature of that information.

2.31. The Code amendment clarifies the format of information to be provided to the system operator. Under Technical Code A, Schedule 8.3 of the Code, all embedded generators with a generating unit with rated net maximum capacity of 1MW or greater must already provide ACS information to the system operator. This requirement applies regardless of how frequently the generation operates, meaning ACS information must be provided for back-up generation with one or more generating units with a rated net maximum capacity of 1MW or more.

2.32. The Authority will consider feedback on developing a simplified ACS format for smaller generators as part of our work on options to address the common quality-related information requirements issue.[9] Similarly, we will consider as part of this work Powerco's suggestion to grant distributors access to ACS information for embedded generators connected to distributors' respective networks. Mechanisms to safeguard confidential information will be a key consideration in this work.

2.33. The Authority acknowledges the EEA's concern that the 1MW threshold could incentivise generators to adjust their configurations to remain below the threshold. We believe this incentive is likely to exist regardless of the threshold.

2.34. Where control of an embedded generation asset is shared between two parties, the obligation to provide ACS information rests with the asset owner. This ensures clarity and consistency in compliance obligations. The system operator may seek clarification or additional details on shared control arrangements if necessary to ensure Code obligations are met.

2.35. The system operator does not require older assets with limited information capabilities to provide the same ACS information as newer assets. Therefore, the Authority does not consider it necessary to introduce grandfathering or dispensations for legacy assets.

2.36. The Authority recognises that the Code currently does not regulate aggregators. Addressing the inclusion of aggregators in the Code is beyond the scope of this proposal but will be considered in the Authority's broader work on encouraging investment and innovation in flexibility services.

## FSR-003: The Authority has decided to include all participants as potential causers of under-frequency events

### The Authority's proposal

2.37. The Code requires the Authority to determine the causer of an under-frequency event (UFE). A UFE occurs when the frequency on the transmission grid falls below

9 Electricity Authority, Addressing common quality information requirements: Consultation paper, October 2024.

49.25Hz due to an interruption to or reduction of electricity injected into the grid, including from the high voltage direct current (HVDC) link between the North Island and South Island.

2.38. Currently, the Code limits potential causers of a UFE to generators or (transmission) grid owners. The Authority proposed broadening the UFE provisions to include any industry participant whose actions could cause a UFE.

2.39. With the increased uptake of inverter-based resources (IBRs), UFEs could potentially be caused by participants not currently recognised under the Code. Expanding the definition of ’causer’ to encompass all participants whose actions may cause a UFE would ensure all participants have appropriate incentives to avoid actions that could lead to UFEs.

### Stakeholder feedback

2.40. The proposal received mixed feedback. While most submitters supported the intent to modernise the UFE framework, concerns were raised about potential liability risk for distributors, the limited mechanisms distributors have for preventing/managing UFE risks on their networks, and the potential impact of aggregators, who are not recognised as industry participants under the Code.

2.41. The ENA, Manawa Energy, Meridian Energy, Orion, Powerco, Transpower, and Vector supported the intent of holding UFE causers accountable.

2.42. However, the EEA, the ENA, Orion, Powerco, and Vector were concerned that distributors could be held liable for UFEs caused by actions beyond their control, such as those by (non-retailer) aggregators, traders, or distributed generators. For example, Orion and Vector were concerned about the risk of distributors being defaulted to as the party responsible for a UFE in lieu of a proper investigation being conducted to identify the root cause of the UFE. These submitters proposed the Authority develop clearer mechanisms for attributing responsibility for UFEs and consider including aggregators as industry participants under the Code.

2.43. WEL Networks also submitted the Authority should consider including aggregators as potential causers of UFEs, as well as owners of large amounts of DER.

2.44. The EEA and Orion queried whether the proposal was necessary, given the Authority’s view that future UFEs are likely to continue being caused by generators or the HVDC owner. MEUG also raised this point in its submission, noting it was unaware whether an electrical load had ever caused a UFE, or could cause a UFE.

2.45. The ENA and Vector suggested the Authority explore placing clearer expectations or requirements in the Code to ensure distribution-connected parties operate their assets to avoid causing UFEs. These submitters, along with Powerco, also queried whether distributors should have additional powers and capabilities to prevent / manage local network emergencies.

2.46. Powerco believed the proposed Code drafting needed further consideration, to clarify that a participant’s *unplanned* demand increase was the cause of a UFE. Powerco submitted this was distinct from a demand change due to a response to market prices or a network management response.

2.47. The risk of unintended network management consequences was one of Powerco’s key concerns. It noted a distributor’s actions, or the operation of a distribution network, could result in an unexpected loss of electricity export from the distribution network to the transmission network. However, Powerco submitted this would be the result of the distributor following good electricity industry practice rather than suddenly increasing electricity demand (as envisaged under the proposal). Powerco believed the proposal may interfere with this good practice and cause distributors to mitigate the risks of being unreasonably found to be a UFE causer (eg, by limiting the connection of distributed energy resources or placing more onerous requirements on distributed energy resources).

2.48. Powerco proposed the Authority treat any BESS with a capacity of >60MW as a non-conforming load at a grid exit point (GXP). Requiring BESS of this size to make demand bids into the wholesale electricity market would minimise the risks associated with a sudden increase in demand.

2.49. Lodestone Energy, NewPower, and WEL Networks opposed the proposal. Lodestone Energy noted Transpower's preference, in the case of generating assets connected to an existing transmission circuit at 'N' security, to pass on to the generator any UFE event charges incurred by Transpower due to its assets causing the electrical disconnection of the generator's assets. Lodestone Energy expected distributors would take a similar approach and was concerned the proposal would impose additional complexity and legal costs for little power system benefit, particularly since most distribution-connected generation would remain below the 60MW threshold for liability to pay event charges. Lodestone Energy felt a more fulsome review of the approach to frequency management, including whether or not penalties for UFE should be retained, would be a better approach.

2.50. NewPower and WEL Networks submitted the proposal needed further assessment and recommended a comprehensive review of the UFE management framework in the near term. NewPower thought the Authority had not considered the cost implications of including distributors as potential UFE causers. NewPower believed the proposal may have an unintended consequence of causing distributors to either upgrade certain connections or to try to pass through UFE costs to distributed generation.

### The Authority's decision

2.51. The Authority has decided to proceed with the proposal, but we have:

(a) amended the definition of 'under-frequency event' to include an increase in electricity demand as a reason for frequency on the transmission grid to fall below 49.25Hz, and

(b) made some minor clarifications to clauses 8.64 and 8.64A, to improve their accuracy and readability.

2.52. We note distributors' concern about the risk of them being held liable for UFEs caused by the actions of others. However, the Code includes robust processes to determine UFE causers. Under clause 8.60, the system operator investigates the circumstances of a UFE and provides a detailed report to assist the Authority in determining the causer. Clause 8.61 requires the Authority to consult with affected parties on the findings before making a final determination.[10]

2.53. If an embedded generator or other participant causes a UFE, that party—not the distributor—will be liable to pay UFE event charges (subject to the 60MW threshold). Importantly, if the system operator and the Authority cannot identify a specific causer, there is no default causer, ensuring distributors will not be unfairly assigned responsibility for events beyond their control. Additionally, if a UFE is caused by a party that is not an electricity participant, there is no causer because the proposed definition of causer in the Code specifies that it must be a participant.

2.54. While the Authority agrees that generators and the HVDC owner are likely to remain the primary causers of UFEs, it is prudent regulatory practice to future-proof the Code so that all potential causers of UFEs are covered by the UFE provisions. This is particularly important as the power system evolves, with more embedded generation and bi-directional energy flows between the transmission and distribution networks.

2.55. The Authority notes the concern of Lodestone Energy and NewPower that distributors may try to pass on UFE event charges. We note the regulated terms for distributed generation in Schedule 6.2 of the Code apply when a distributed generator and a distributor cannot agree a connection contract.[11] These terms make no provision for a distributor to pass on event charges to a distributed generator.

2.56. The Authority acknowledges that the Code currently does not regulate aggregators. However, this matter is beyond the scope of this proposal. The Authority is considering the role of aggregators as part of our work programme on encouraging investment and innovation in flexibility services. If this leads to aggregators being classified as participants, they would then be considered potential causers under this proposal (FSR-003).

2.57. Finally, we note that several submissions referred to UFEs being caused by sudden load reductions by, for example, distributors, traders or aggregators. We note such load reductions would cause frequency to increase rather than decrease. The possibility of over-frequency events falls outside the scope of the Code amendment.

## FSR-004: The Authority has decided to amend the requirement to have a speed governor

### The Authority's proposal

2.58. Currently, generators must ensure that each of their generating units has a speed governor to regulate frequency. The Authority proposed to replace the requirement for a speed governor with a requirement to have a speed governor and/or a frequency control system.

2.59. This change would accommodate inverter-based generation, where generating units do not use traditional speed governors, and reduce administrative burdens associated with equivalence arrangements.

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10 The Authority is currently considering a Code amendment proposal that would require us to consult on the findings only when the causer is unknown or disputed.

11 See clause 9 of Schedule 6.1 of the Code.

### Stakeholder feedback

2.60. All submissions on the proposal supported it, agreeing with the need to ensure the requirement accommodates new and evolving technologies. While they supported the proposal, some submitters underscored the importance of ensuring clear definitions, practical testing protocols, and transitional arrangements to minimise unintended consequences.

2.61. The EEA recognised the amendment as a timely response to the increasing adoption of IBRs. However, the EEA expressed concern about potential compliance costs for owners of small-scale inverter-based generation, and the potential for inconsistencies in enforcement standards across different sizes of generating station.

2.62. Transpower, as the system operator, noted the Code amendment would reduce the number of requests for equivalence arrangements, which in turn should reduce administrative costs for itself and generators with IBRs.

2.63. Mercury was supportive of the proposal except for the proposed changes to clause 3 of Appendix B, Technical Code A, Schedule 8.3 of the Code. Mercury said it is not practical to test wind turbines and IBRs at a generating unit level and that tests should be done at the plant controller level.

2.64. NewPower submitted that testing should only be required after a change to control settings that would affect frequency control. NewPower also highlighted the need for periodic testing to accommodate minor adjustments to control settings as part of daily operation (ie, settings changes with negligible effects should not necessitate retesting). NewPower also suggested some revisions to the drafting of the proposed Code.

2.65. Manawa Energy supported the proposal at a conceptual level but considered grandfathering arrangements would be needed for existing assets unable to meet the requirement to have a speed governor and/or frequency control system.

### The Authority's decision

2.66. The Authority has decided to proceed with the proposal but with the following two clarifications in relation to inverter generation:

(a) The periodic testing requirements in clause 3 of Appendix B, Technical Code A apply at the frequency controller. Typically, this is at the generating station level rather than at the generating unit level. We note this clarification is consistent with the system operator's inverter generation tests.[12]

(b) Periodic testing is also triggered by a change to control settings that affect frequency control and by changes to the firmware that have the potential to materially affect the performance of the frequency response of the generating units or generating station.

2.67. The Authority agrees with the concerns raised regarding testing practicality and the breadth of testing triggers under the drafting of the proposed Code amendment. These clarifications more clearly reflect our policy intent.

[12] See Transpower I GL-EA-010 Generator Testing Requirements.

2.68. In relation to the EEA's concern about introducing additional compliance costs for owners of small-scale inverter-based generation, we note the Code amendment does not apply to excluded generating stations.[13] Hence, it does not impose additional compliance obligations or costs on small-scale inverter-based generation owners, such as residential or small commercial consumers.

2.69. We note Manawa Energy's point that grandfathering arrangements will be required for existing assets that cannot meet the requirement to have a speed governor and/or voltage control system. We consider these assets should have in place a dispensation or equivalence arrangement for the existing obligation to have a speed governor. The system operator has advised us there would be a very modest cost to amend a dispensation from the current requirement to apply to the new requirement. Therefore, the Authority considers it unnecessary to grandfather existing non-compliant assets.

2.70. As part of a separate FSR workstream, the Authority is considering whether 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.[14] We acknowledge Manawa Energy's concern about some existing assets being unable to comply with the requirement to have a speed governor or frequency control system under a lower excluded generating station threshold. The Authority is considering the need for grandfathering arrangements under a lower threshold as part of this separate workstream.

## FSR-005: The Authority has decided to amend the requirement to have an excitation system

### The Authority's proposal

2.71. Currently, generators must ensure that each of their generating units connected to the (transmission) grid is equipped with an excitation and voltage control system. The Authority proposed to remove the requirement for an excitation system, which is specific to synchronous machine-based generation.

2.72. The proposal aimed to reduce administrative burdens associated with equivalence arrangements for IBR owners while ensuring clarity and flexibility in compliance obligations.

### Stakeholder feedback

2.73. The proposal was widely supported by stakeholders who submitted on it. Submitters highlighted the importance of clear definitions, practical testing protocols, and transitional arrangements to ensure effective implementation.

2.74. Lodestone Energy, Meridian Energy, Powerco, and WEL Networks, expressed full support for the proposal, acknowledging that it reflected the transition to modern generation technologies and reduced unnecessary compliance costs.

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13 Clause 3 of Appendix B of Technical Code A, Schedule 8.3.

14 See Electricity Authority I Future security and resilience I June 2024 Review of common quality requirements in the Code.

2.75. The EEA supported the proposal but suggested guidelines and transitional provisions to help the system operator and distributors adapt to new voltage control standards without compromising grid stability.

2.76. Transpower, as the system operator, noted the Code amendment would reduce the number of requests for equivalence arrangements, which in turn should reduce administrative costs for itself and generators with IBR.

2.77. Mercury was supportive except for the proposed changes to clause 5 of Appendix B, Technical Code A, Schedule 8.3 of the Code. Mercury said it is not practical to test wind turbines and IBRs at a unit level and that tests should be done at the plant controller level.

2.78. NewPower submitted that testing should only be required after a change to control settings that would affect voltage control. Also, retesting for firmware updates should only be required if the change had the potential to materially impact the performance of the frequency or voltage control. NewPower also queried whether power converters (inverters) should be included as for voltage controls.

2.79. Manawa Energy supported the proposal at a conceptual level but considered grandfathering arrangements would be needed for existing assets that are unable to meet the requirement to have a voltage control system.

### The Authority's decision

2.80. The Authority has decided to proceed with the proposal but with the following two clarifications in relation to inverter generation:

(a) The periodic testing requirements in clause 5 of Appendix B, Technical Code A apply at the voltage controller. Typically, this is at the generating station level rather than at the generating unit level. We note this clarification is consistent with the system operator's inverter generation tests.[15]

(b) Periodic testing is also triggered by a change to control settings that affect voltage control and by changes to the firmware that have the potential to materially affect the performance of the voltage response of the generating units or generating station.

2.81. The Authority agrees with the concerns raised regarding testing practicality and the breadth of testing triggers under the drafting of the proposed Code amendment. These clarifications more clearly reflect our policy intent. In response to NewPower's query, the Authority's view is that power converters / inverters should have voltage control.

2.82. We note Manawa Energy's point that grandfathering arrangements will be required for existing assets that cannot meet the requirement to have a voltage control system. We consider these assets should already have in place a dispensation or equivalence arrangement for the existing obligation to have an excitation system. The system operator has advised us there would be a very modest cost to amend a dispensation from the current requirement to apply to the new requirement. Therefore, the Authority considers it unnecessary to grandfather existing non-compliant assets.

[15] See Transpower l GL-EA-010 Generator Testing Requirements.

2.83. As part of a separate FSR workstream, the Authority is considering whether to lower the 30MW threshold for generating stations to be excluded by default from complying with the fault ride through AOPOs in Part 8 of the Code.[16] We acknowledge Manawa Energy's concern about some existing assets being unable to comply with the Code's fault ride through requirements under a lower excluded generating station threshold. The Authority is considering the need for grandfathering arrangements under a lower threshold as part of this separate workstream.

## FSR-006: The Authority has decided to amend the Code to refer to dynamic reactive power compensation devices

### The Authority's proposal

2.84. Currently, the periodic testing requirements in Part 8 of the Code refer to specific types of dynamic reactive power compensation devices[17] – namely static var compensators, capacitors, and synchronous compensators owned by grid (transmission network) owners.[18]

2.85. The Authority proposed to amend some of the periodic testing requirements to apply to all types and owners of grid-connected dynamic reactive power compensation devices.

### Stakeholder feedback

2.86. The proposal received broad support from stakeholders who submitted on it. Some submitters raised concerns about potential unintended consequences under the proposal and compliance burdens on smaller operators.

2.87. Lodestone Energy, Powerco, Meridian Energy, and WEL Networks supported the proposal. Transpower, both as system operator and a grid owner, also supported the proposal, provided the changes to the periodic testing requirements were limited to clause 9 of Appendix B, Technical Code A, Schedule 8.3 of the Code. This was to avoid unintended effects on other devices covered by the periodic testing requirements (eg, synchronous compensators).

2.88. The EEA agreed that requiring periodic testing of dynamic reactive power compensation devices is critical for maintaining grid stability and operation efficiency. However, the EEA considered that requiring all such devices to undergo periodic testing could create complexities for how distributors manage power factor at GXPs and impose a disproportionate compliance burden on smaller operators of these devices.

2.89. Mercury noted some of the required information (models / block diagrams) may be difficult to obtain for older devices. Mercury suggested the Code should allow testing at the overall system level rather than just the reactive device (eg, for a wind farm, test the overall wind farm voltage control system). Mercury also suggested implementing a lower size limit and clarifying what is meant by the term 'connected

16 See Electricity Authority l Future security and resilience l June 2024 Review of common quality requirements in the Code.

17 Dynamic reactive power compensation devices help to regulate the voltage at their points of connection to a network, by injecting or absorbing reactive power.

18 See clauses 9, 10 and 11 of Appendix B, Technical Code A of Schedule 8.3.

to the grid'. MEUG's submission also said this term was ambiguous, which meant it was not clear exactly which dynamic reactive power compensation devices would be captured by the proposal.

2.90. NewPower submitted that the term 'dynamic reactive power compensation device' needed to be more clearly defined, as technically any inverter can dynamically control its reactive power and therefore be covered by this term.

2.91. Manawa Energy's support for the proposal was subject to a reasonable de minimis being applied in relation to testing, as the cost on small IBRs to undertake testing would not be justifiable.

### The Authority's decision

2.92. The Authority has decided to proceed with the proposal but with two changes:

*(a)* defining the term 'dynamic reactive power compensation device' – to mean *a device, other than a **generating unit** or synchronous condenser, that normally is provided specifically to inject or absorb **reactive power** and which includes static synchronous compensators, static synchronous series compensators, thyristor controlled series devices and thyristor controlled shunt devices*

(b) amending the phrase 'connected to the grid' to be '*directly* connected to the grid'.

2.93. The first change is to remove the potential misunderstanding identified by NewPower, while the second change is to eliminate the potential misunderstanding identified by Mercury and MEUG.

2.94. The Authority notes the EEA's point about unintended consequences. We consider the obligation to periodically test dynamic reactive power compensation devices should not impose significant operational challenges on distributors. The periodic testing requirement is relatively infrequent.

2.95. We also consider the Code amendment should not impose a disproportionate compliance burden on smaller operators of dynamic reactive power compensation devices. This is because the periodic testing obligation applies only to dynamic reactive power compensation devices directly connected to the transmission network. By their nature, these are expensive assets, the periodic testing of which amounts to a small fraction of the asset's cost.

2.96. With increasing amounts of distributed energy resources on New Zealand's power system, there may be a need to require periodic testing of distribution-connected dynamic reactive power compensation devices. The Authority is maintaining a watching brief on this potential need.

2.97. The Authority also notes Mercury's feedback about possible difficulties obtaining models or block diagrams for older devices. The Authority considers that, if a block diagram cannot be obtained from the original equipment manufacturer, an asset owner should be able to produce a block diagram by relying on the simulation software used in the periodic testing of the device.

## FSR-007: The Authority has decided to amend the Code to treat energy storage systems as only generation for the purposes of Part 8

### The Authority's proposal

2.98. The Authority proposed to treat any energy storage system (ESS) that is not an 'excluded generating station'[19] as generation for the purposes of Part 8 of the Code.

2.99. The proposal's objective was for the Code to enable the capabilities of ESSs to be better realised in relation to supporting common quality on the power system. It would do this while reducing transaction costs associated with ESS owners seeking equivalence arrangements or exemptions from their AUFLS obligations under the Code.

### Stakeholder feedback

2.100. Most submissions on the proposal supported it but there was significant emphasis in submissions on the need for a comprehensive, long-term regulatory solution to address the rapidly evolving role of ESSs in the power system.

2.101. Lodestone Energy, Manawa Energy, Mercury, Meridian Energy, Powerco and Transpower, as the system operator, supported the proposal. The system operator submitted that the proposal should include ESS obligations at 0MW and 0Mvar (standby mode). Powerco queried whether the proposal conflicted with FSR-003, which appeared to treat an ESS as load for the purpose of UFE responsibility.

2.102. The EEA generally supported the aim of better integrating ESSs within the power system but recommended a full and urgent evaluation of the role of ESSs under Part 8 rather than an interim solution. This was to ensure ESSs can be optimally leveraged for the electricity sector's efficient operation. The ENA and Orion also supported a full (and in Orion's case urgent) evaluation of the role of ESSs in Part 8, to ensure the efficient operation of the power system. Orion had concerns about the proposal being positioned as an interim measure.

2.103. The EEA, the ENA, Orion and Powerco also queried whether the 30MW threshold for being an excluded generating station applied to single site installations or smaller batteries aggregated across multiple sites and operating as a virtual power plant. Orion considered this question needed to be addressed before the proposal was implemented, to avoid regulatory uncertainty. Orion noted the real, persistent challenge of aggregated residential batteries on its ability to meet its AUFLS obligations. Powerco noted it expected the 30MW excluded generating station threshold would be changing in the near term.

2.104. Several submitters noted the proposal could have unintended consequences. The EEA and Orion were concerned the proposal may limit ESSs' versatility and create regulatory uncertainty surrounding the treatment of batteries functioning as virtual power plants. Orion noted this regulatory uncertainty could inadvertently discourage innovative business models that rely on aggregating smaller storage systems. The EEA also thought the proposal may complicate network planning and cost allocation

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19 See clause 8.21 of the Code, which says an excluded generating station is a generating station that exports less than 30MW to a local network or to the transmission grid (unless the Authority directs otherwise).

processes, particularly within distribution networks. In contrast, the system operator submitted the proposal should not create more uncertainties or 'bake in' obligations.

2.105. NewPower and WEL Networks did not support the proposal. These submitters considered the proposal did not promote competition in the electricity industry. This was because the proposal would create an additional barrier to embedded BESS below the 30MW threshold entering the (reserves) market, in the form of AUFLS-related costs. The submitters believed distributors would, via their connection agreements, seek to mitigate the distributor's AUFLS requirements arising from the charging of embedded BESSs below the 30MW threshold. NewPower also noted that these smaller BESSs would have to apply for exemptions from their AUFLS obligations, which would have a cost.

2.106. To address this issue, WEL Networks suggested the reference to the threshold in clause 8.21(1) of the Code (30MW) be changed to clause 8.21(2) (1MW). NewPower instead suggested the Authority implement the second alternative option put forward in the proposal's regulatory statement. This alternative option was to amend the AUFLS Technical Requirements (ATR) report to specify that in the case of an AUFLS event, an ESS is required to reduce demand rather than to have a system that automatically electrically disconnects demand.

2.107. NewPower submitted the Code definitions for 'ESS', 'generation, and 'intermittent generation' needed to be better defined. Gathering different technologies under the ESS term would slow deployment, create unfair market conditions and lead to perverse outcomes. Also, the Code needed to incorporate hybrid systems (solar photovoltaic generation / wind generation coupled with a BESS).

2.108. NewPower was also concerned that the proposal would require embedded BESSs that were 30MW and above to provide voltage support for the grid. It expressed concern that this would mean the system operator would have the ability to control voltage on a distribution network, creating a conflict between the distributor and the system operator.

2.109. NewPower and WEL Networks also queried whether the requirements of clause 8.24 of the Code (load shedding obligations to support voltage) should be reviewed as well in respect of transmission-connected BESS.

### The Authority's decision

2.110. The Authority has decided to proceed with the proposal but with clause 8.24 of the Code amended to clarify that ESSs exporting 30MW or more are not subject to the AUFLS obligation set out in clause 8.24(2).

2.111. The Authority considers this amendment to be an important step in regulating ESSs under Part 8 of the Code. The amendment offers improved power system management and reliability, with ESSs able to offer more reserves. The amendment will also reduce transaction costs associated with larger ESSs putting in place equivalence arrangements or seeking exemptions from their AUFLS obligations.

2.112. The Authority acknowledges this Code amendment does not remove the AUFLS obligation on embedded ESSs below the 30MW threshold. However, as noted in the consultation paper, these ESSs are not required to contribute to supporting frequency management and frequency during under-frequency events.

2.113. The Authority considers that clauses 8.17 and 8.19 of the Code in effect require an ESS to contribute to supporting frequency management and frequency during under-frequency events as per the guidance in the box below.

**Guidance on ESS obligations for frequency support**

**Supporting frequency management**

Regardless of whether an ESS is charging or discharging, an ESS must at all times move around its charge/discharge set point to support frequency as frequency varies at the ESS's point of connection with the network.

**Supporting frequency during an under-frequency event**

If an ESS is charging prior to a UFE, the ESS must meet its obligation to sustain pre-event output and thereby contribute to supporting frequency, by ceasing to charge immediately and, in accordance with clause 8.17, make the maximum possible injection contribution to restore frequency to the normal band.

If an ESS is discharging prior to a UFE, the ESS must sustain pre-event output in accordance with sub-clauses 8.19(1)(a)–(f) for as long as the ESS has sufficient capacity (charge) to do so.

2.114. We also note the Code amendment does not change the obligation on North Island connected asset owners and South Island grid owners to have an AUFLS system that automatically electrically disconnects ESS demand, rather than reducing ESS demand to zero. Further work is needed in considering the implications for AUFLS provision of ESSs in charge mode being treated differently to other load in an AUFLS event.

2.115. We would like to clarify that the amendment does not introduce new requirements or change the voltage obligations on embedded generators, including ESSs. Under the amendment embedded generators connected to distribution networks are not required to provide voltage support for the grid. We note this matter is being considered in a separate workstream within the Authority's FSR work programme.[20]

2.116. The Authority recognises this Code amendment is an interim measure, and we acknowledge the need for a more comprehensive approach to the regulation of ESSs. We have multiple workstreams underway to address operational and market-related matters relating to ESSs. This includes work to improve BESS modelling and participation in the wholesale and ancillary service markets and upcoming changes (effective 1 April 2026) to the Transmission Pricing Methodology (TPM) for emerging technologies such as BESS.[21]

2.117. The Authority recognises that the Code currently does not regulate aggregators. However, addressing the inclusion of aggregators in the Code is beyond the scope of this proposal. The Authority is considering this matter as part of our work programme on encouraging investment and innovation in flexibility services.

2.118. Regarding Powerco's query, the Authority considers this Code amendment does not conflict with our Code amendment under FSR-003. If an ESS that is not an

[20] See Electricity Authority I Future security and resilience I June 2024 Addressing larger voltage deviations and network performance issues in New Zealand's power system.

[21] See Electricity Authority I Transmission pricing methodology I November 2024 Transmission pricing methodology amendments: a level playing field for emerging technologies.

excluded generating station were to cause a UFE through the act of charging, the owner or operator of the ESS would simply have the UFE-related Code obligations of a generator rather than a load.

## FSR-008: The Authority has decided to defer clarifying the definition of generating unit

### The Authority's proposal

2.119. The Authority proposed to amend the definition of 'generating unit' to clarify that a generating unit is the smallest set of equipment capable of producing electricity independently, with its own frequency and/or voltage control systems.

2.120. This change seeks to address uncertainties and inconsistencies in the application of Code obligations, particularly for newer technologies such as wind farms, solar photovoltaic systems, and battery farms.

### Stakeholder feedback

2.121. There were mixed views expressed in submissions on this proposal. The EEA, Lodestone Energy, Manawa Energy, and Meridian Energy supported it. NewPower and Transpower, as the system operator, did not support it. Although they made a submission on this proposal, the ENA, Mercury and Orion did not indicate support for or against it.

2.122. The EEA and Orion considered the term "smallest set" needed to be clarified, along with whether basic inverter control functions/settings would satisfy this definition. They also queried whether the proposed definition aligned with the definition of 'generating unit' recently introduced into Schedule 11.1 of the Code.[22] The EEA suggested the proposed amendment could be improved by including specific guidance on how it applied across different technology types and different sizes of generating unit.

2.123. Manawa Energy also thought the definition could be clearer – for example, whether the definition was intended to apply to a single generating turbine or an entire windfarm. Manawa Energy also noted the definition would not be applicable to asynchronous generators with no speed control or voltage control. Mercury made the same point, suggesting that in addition to old wind turbines some actuated hydro machines would not have frequency or voltage control systems.

2.124. The ENA was unsure whether the proposed definition was any clearer than the existing definition. The ENA also believed the Authority should consider how aggregators should be considered in the definition of 'generating unit'.

2.125. In not supporting the proposal NewPower submitted that further investigation is required. For instance, 'generating unit' could be defined in terms of switches (eg, circuit breakers) at a generating station's point of connection with the network. In the case of a solar farm, NewPower argued that a string of solar panels[23] with an inverter should not be considered a 'generating unit', but rather a collection of string inverters.

22 Electricity Authority, Code amendment omnibus three: Decision paper, August 2024.

23 Solar panels connected in a series.

2.126. Given the use of the term ‘generating unit’ in several other parts of the Code, NewPower considered it likely that a change to the definition would cause interpretation problems. NewPower also considered it preferable to define common quality performance and obligations at an asset owner’s point of connection with a network rather than within the asset owner’s site.

2.127. The system operator agreed a new definition of ‘generating unit’ is needed but considered the proposed definition would not solve all the problems the system operator may face in applying the definition. For example, under the proposed definition, an entire wind farm, solar farm, battery farm, or hybrid plant could be treated as a single generating unit. As a result, the system operator would need to specifically request indications and measurements for single inverter strings outside of the usual commissioning information provision, requiring more effort. Additionally, the system operator was concerned the proposal would limit the system operator’s ability to request more asset information for its operational needs.

2.128. The system operator suggested some alternative options to the proposal. One option would allow both the system operator (for common quality purposes) and Transpower, as a grid owner, to apply the term ‘generating unit’ with discretion, taking into account the characteristics of the generating technology. Another option proposed defining ‘generating unit’ in a separate document incorporated by reference in the Code. This document could provide more detail around string-level generating units and hybrid plants while accommodating future technologies as they emerged.

### The Authority’s decision

2.129. The Authority has decided to not proceed with the proposal at this time but to consider it further during 2025 as we progress Code amendment proposals on frequency, voltage and common quality information requirements.

2.130. The Authority notes NewPower’s concern about the frequent use of “generating unit” in Parts 12–15 of the Code. During proposal development, we reviewed the use of the term throughout the Code and found no instances where the proposed definition would lead to unintended consequences in Parts 12–15. However, we want to avoid any possible unintended consequences as we progress Code amendment proposals relating to Part 8 of the Code.

2.131. Whether it is appropriate to place common quality obligations at the generating unit level or generating station level (or some other level) was beyond the scope of this amendment. This matter is being considered as part of the Authority’s separate FSR workstreams looking at frequency, voltage, harmonics and information requirements. These workstreams also consider the system operator’s ability to request information from generators in instances where a generating unit and a generating station are one and the same. However, as with managing the risk of unintended consequences, the Authority has decided it is prudent to progress further the above FSR workstreams before making any change to the definition of generating unit.

2.132. We agree with submitters that the proposal would have meant some types of actuated, asynchronous, or induction electricity generating units with no frequency or voltage control systems would have been no longer defined as a generating unit. We consider an amended definition must address this issue.

2.133. The Authority considers many of the points raised in submissions highlight the need for an amended definition to strike an appropriate balance between specificity and flexibility, supporting consistent regulatory application across all relevant parts of the Code.

## FSR-009: The Authority has decided to not amend the Code's fault ride through requirements for machine-based synchronous generating units

### The Authority's proposal

2.134. Clause 8.25A of the Code sets out generator fault ride through (FRT) requirements. These define how long and under what conditions generators subject to the FRT requirements must remain connected to the transmission network during faults.

2.135. The FRT requirements in clause 8.25A of the Code have posed significant challenges for some machine-based synchronous generating units.

2.136. The Authority proposed to allow a machine-based synchronous generating unit to be treated as compliant with the FRT requirements in clause 8.25A if:

(a) the generator could demonstrate that full compliance was not possible due to the generating unit's inherent stability characteristics, and

(b) the generating unit complied with the requirements in subclauses (1) and (2) of clause 8.25A to the extent reasonably possible taking into account the generating unit's inherent stability characteristics; and

(c) the generator had taken all reasonable measures to support grid stability taking into account the generating unit's inherent stability characteristics.

### Stakeholder feedback

2.137. The proposal received mixed feedback from stakeholders who submitted on it. The EEA, Lodestone Energy, Manawa Energy, Mercury, and Meridian Energy supported the proposal. NewPower, WEL Networks and Transpower, as the system operator, did not support the proposal.

2.138. While Manawa Energy supported the proposal at a conceptual level, it submitted that existing generators would need to be grandfathered.

2.139. Lodestone Energy and the EEA submitted that, in the long term, a better solution would be tailored FRT curves for different types of generation. WEL Networks and Transpower also supported this approach but preferred retaining the status quo over the proposed change in the interim.

2.140. The EEA recommended establishing clear criteria for assessing "reasonable measures." This would ensure generators make consistent and diligent efforts to maximise their contribution to FRT compliance by fully exploring all technical options to enhance their FRT capabilities.

2.141. Transpower submitted that while the proposal removed the requirements and transaction costs associated with dispensations, FRT compliance assessments would still incur transaction costs. Transpower would still need to complete these assessments, as both the system operator and as a grid owner. Additionally, the system operator highlighted ambiguity in how asset owners could adequately demonstrate their inability to fully comply with the FRT requirements and show they had taken all reasonable steps to support grid stability.

2.142. The system operator also noted that retaining the use of dispensations for generation that did not comply with the Code's FRT requirements would provide a potential mechanism to pass on the resulting costs of non-compliance to the non-compliant generator.

2.143. NewPower and WEL Networks submitted that the proposal amounted to special treatment for synchronous generation, which no other technology received under the Code. They queried why this problem had only now been identified, years after the Code's FRT requirements were developed, and whether the performance shortfall of non-compliant generating units would increase the amount of instantaneous reserve the system operator needed to procure.

2.144. NewPower and WEL Networks were uncertain how many synchronous generating units were non-compliant or whether this non-compliance could be more easily managed through dispensations rather than the proposed Code amendment. NewPower asked the Authority to publish the total aggregate power capacity (in MW) of existing non-compliant synchronous generating units. NewPower was concerned about the number of such units, including whether this was a risk to the transmission network that was being, or needed to be, managed.

### The Authority's decision

2.145. The Authority has decided to not proceed with the proposal.

2.146. Having carefully considered submissions, we are not convinced the proposal would promote the Authority's statutory objectives any better than the dispensations regime that is already in place.

2.147. The Authority acknowledges Transpower's point that there will be transaction costs associated with generators demonstrating:

(a) it is not possible for them to comply fully with the Code's FRT requirements due to a generating unit's inherent stability characteristics, and

(b) they have taken all reasonable measures to support the stability of the grid, taking into account the generating unit's inherent stability characteristics.

2.148. In relation to the first transaction cost, as noted in the consultation paper, we expect the incremental cost to be minimal. Generators already study and advise the system operator of any issues they face complying with the Code's FRT requirements because of the inherent stability characteristics of their generating units.

2.149. However, we acknowledge that the second transaction cost is a reasonably material incremental cost of the Code amendment over the dispensations regime that is in place. This is because the system operator does not currently require non-compliant generators to demonstrate they have taken all reasonable steps to support grid stability as a condition of granting a dispensation.

2.150. The Authority agrees with submitters who suggested the Authority should investigate FRT requirements based on generation type (eg, machine-based synchronous generation and IBR-based generation). We intend to review the current FRT requirements in the Code to assess the extent to which these should differ between different generation technologies. We may consider adopting a similar approach to overseas jurisdictions (ie, different FRT curves for machine-based synchronous generation and IBR-based generation), or another suitable solution.

2.151. Regarding NewPower's request for the total aggregate power capacity of existing non-compliant synchronous generating units, the system operator has granted dispensations from the FRT requirements in clause 8.25A of the Code to three machine-based synchronous generating stations. The Authority notes the system operator has also granted dispensations from the FRT requirements in clause 8.25A to wind farms that do not use synchronous machines. Table 3 lists the dispensations the system operator has granted for clauses 8.25A and 8.25B of the Code and the nameplate capacity of each generating station.

**Table 3: List of dispensations granted based on non-compliance with clauses 8.25A and 8.25B of the Code**

| Unit | Code obligation | Non- compliance | Nameplate capacity |
|---|---|---|---|
| **Junction Road G1 and G2** | 8.25A(1) and 8.25B(1)–(2) | Trip even for a low impedance 3-phase-to-ground fault in the SFD-MKE-MNI 110kV circuit | 100 MW |
| **McKee G1 and G2** | 8.25A(1) and 8.25B(1)–(2) | Trip even for a low impedance 3-phase-to-ground fault in the SFD-MKE-MNI 110kV circuit | 100 MW |
| **Ngawha B** | 8.25A | Unit trips for 110kV, 500 ms faults with a retained voltage between 0.35 p.u. and 0.59 p.u. | 31.57 MW |
| **Tararua Wind Farm 1 (connected to Bunnythorpe GXP)** | 8.25A and 8.25B | Trip even for a single phase-to-ground fault | 33.7 MW |
| **Tararua Wind Farm 2 (connected to Linton GXP)** | 8.25A and 8.25B | Trip even for a single phase-to-ground fault | 34.3 MW |
| **Waipipi Wind Farm** | 8.25B(2) | Does not recover active power in direct proportion to voltage after the fault when WGO (Weak Grid Option) mode enabled | 133 MW |

2.152. The generating stations represent a mix of baseload, peaking, and variable and intermittent generation.

# 3. The amendments are consistent with our main statutory objective

3.1. The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

3.2. After carefully considering all submissions on the Code amendment proposals, the Authority considers the final Code amendments are consistent with our main statutory objective, and with section 32(1) of the Act.

3.3. The suite of amendments promotes the three limbs of the Authority's main statutory objective as follows:

(a) **Competition** is supported by enhancing competitive neutrality amongst emerging and established technologies, fostering innovation and reducing barriers to entry for emerging technologies.

(b) **Reliable supply** is supported by ensuring that all relevant parties, including owners of evolving technologies such as IBRs, comply with clear and consistent common quality-related performance requirements. This will help to maintain the stability of the power system as increasing amounts of variable and intermittent generation connect to it.

(c) **Efficient operation** is enhanced through reduced administrative burdens, such as dispensations and equivalence arrangements for technologies like inverter-based generators. Streamlining compliance requirements minimises unnecessary costs for asset owners and the system operator, while providing the system operator with accurate, standardised data for planning and operational decisions.

3.4. In making these Code amendments the Authority has applied our Code amendment principles, which are set out in our consultation charter.[24] In summary, we consider there is a clear case for regulation, having evaluated the benefits and costs of the Code amendments and compared them against alternative options. The next sub-section summarises this evaluation.

## The benefits of the amendments are greater than the costs

3.5. We consider the benefits of the suite of Code amendments will outweigh the costs, for the reasons set out in the consultation paper and further below.

3.6. While some submitters agreed with this assessment, others considered that the benefits would not outweigh the costs, or were unclear whether the benefits would outweigh the costs.

3.7. We have sought to address these concerns by making various changes to the proposed amendments. In particular, we have clarified that:

(a) For inverter generation, the periodic testing requirements in clauses 2, 3 and 5 of Appendix B, Technical Code A, Schedule 8.3 of the Code apply at the point of control for a generating unit. Typically, this is at the generating station level

24 See Electricity Authority I Consultation Charter 2024.

rather than at the generating unit level. We note this clarification is consistent with the system operator's inverter generation tests.[25]

(b) In order to trigger the periodic testing requirement, a change to the firmware of inverter generation must have the potential to materially affect the performance of the frequency/voltage response of the generating units or generating station.

(c) Dynamic reactive power compensation devices do not include generating units, unless that generating unit is normally specifically provided to be capable of providing or absorbing reactive power.

(d) A generating unit includes all actuated, asynchronous or induction machines that produce electricity.

3.8. The Authority considers that these changes address any issues that may have caused the costs of the proposals to outweigh the benefits.

3.9. In this decision paper, the Authority has also clarified some misunderstandings about the following proposals, which led some submitters to raise concerns about our assessment of the benefits and costs of these proposals:

(a) The provision of ACS information in the format required by the system operator.

(b) Applying the Code's UFE provisions to all potential causers of UFEs.

3.10. In the case of the proposal to clarify the applicability of the FRT requirements to machine-based synchronous generating units, the Authority has concluded that, on balance, the proposal's benefits may not outweigh its costs. For this reason, we have decided not to proceed with this Code amendment proposal.

[25] See Transpower I GL-EA-010 Generator Testing Requirements.

# 4. Attachments

4.1. The following appendices are attached to this paper:

**Appendix A Approved Code amendments**

**Appendix B Feedback being considered elsewhere**

# Appendix A Approved Code amendments

A.1. This appendix sets out the Code amendments the Authority has decided to make in accordance with the decisions set out in the main body of this document.

A.2. Code amendments are displayed as:

(a) Text or formatting is <u>black underlined</u> if it is to be added to the Code and neither subparagraph (c) or (d) applies.

(b) Text is shown in ~~black strikethrough~~ if it is to be deleted from the Code and neither subparagraph (c) or (d) applies.

(c) For Code clauses shown in our consultation paper on the Code amendment proposal:

(i) text or formatting is <u>red underlined</u> if it is to be added to the Code and it was not shown as such in the consultation paper

(ii) deleted text is ~~red strikethrough~~ if it is to be deleted from the Code and it was not shown as such in the consultation paper.

(d) For Code clauses not shown in our consultation paper on the Code amendment proposal:

(i) the clause is in blue

(ii) text or formatting is <u>blue underlined</u> if it is to be added to the Code

(iii) text is ~~blue strikethrough~~ if it is to be deleted from the Code.

# Part 1

# Preliminary provisions

## 1.1 Interpretation

…

**causer**, in relation to an **under-frequency event**, means—

(a) if the **under-frequency event** is caused by an interruption <u>to</u> or reduction of **electricity**<u> supply, or an increase in **electricity** **demand**,</u> from a single ~~**generator's** or **grid owner's**~~ <u>**participant's**</u> **asset** or **assets**, the ~~**generator**, or **grid owner**~~ <u>**participant**</u>~~;~~<u>,</u> unless<u> another **participant's** act or omission or property causes the interruption to or reduction of **electricity** supply or the increase in **electricity** **demand**, in which case the other **participant** is the causer</u>~~—~~

~~(i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's asset** or **assets** but another **generator's** or a **grid owner's** act or omission or~~

~~property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or~~

~~(ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **grid owner's asset** or **assets** but a **generator's** or another **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**~~; or

(b) if the **under-frequency event** is caused by more than 1 interruption to or reduction of **electricity** supply or increase in **electricity demand**, the ~~**generator** or **grid owner**~~ **participant** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption to or reduction of **electricity** supply or increase in **electricity demand**; but

(c) if an interruption to or reduction of **electricity** supply, or an increase in **electricity demand**, occurs in order to comply with this Code, the interruption to or reduction of **electricity** supply or the increase in **electricity demand** must be disregarded for the purposes of determining the **causer** of the **under-frequency event**

…

**control system** means equipment that adjusts the output voltage, frequency, **active power** ~~**MW**~~ or **reactive power** (as the case may be) of an **asset** in response to certain aspects of **common quality** such as voltage, frequency, **active power** ~~**MW**~~ or **reactive power**~~, including speed governors and exciters~~

…

**dynamic reactive power compensation device** means a device, other than a **generating unit** or synchronous condenser, that normally is provided specifically to inject or absorb **reactive power** and which includes static synchronous compensators, static synchronous series compensators, thyristor controlled series devices and thyristor controlled shunt devices

…

**reactive capability** means the **reactive power** injection or absorption capability of **generating units** and other **reactive power** resources such as ~~Static Var Compensators,~~ capacitors, reactors, ~~and~~ synchronous condensers and **dynamic reactive power compensation devices**, and includes **reactive power** capability of a **generating unit** during the normal course of the **generating unit** operations

…

**under-frequency event** means—

(a) an interruption to or reduction of **electricity** injected into the **grid**; or

(b) an interruption to or reduction of **electricity** injected from the **HVDC link** into the South Island **HVDC injection point** or the North Island **HVDC injection point**; or

(c) an increase in the **demand** for **electricity** supplied by the **grid** at a **point of connection** with the **grid**; or

(d) an increase in the **demand** for **electricity** at the point at which **electricity** is supplied to the South Island **HVDC injection point** or to the North Island **HVDC injection point**—

if there is, within any 60 second period, an aggregate change to the ~~loss of~~ **injection** of or **demand** for **electricity** in excess of 60 **MW** (being the aggregate of the net changes to ~~reductions in~~ the **injection** of or **demand** for **electricity** (expressed in **MW**) experienced at ~~**grid injection**~~ **points of connection** with the **grid** and **HVDC injection points** by reason of paragraphs (a) to ~~or~~ (~~b~~ d)), and such change ~~loss~~ causes the frequency on the **grid** (or any part of the **grid**) to fall below 49.25 Hz (as determined by **system operator** frequency logging)

…

# Part 8
# Common quality

…

## 8.1B Application of this Part to energy storage systems

(1) For the purposes of this Part, the owner or operator of an **energy storage system** with a capacity equal to or greater than the threshold in clause 8.21(1), in relation to that **energy storage system**, is required to comply only with the obligations under this Part that apply to a **generator** or **embedded generator**, regardless of whether the **energy storage system** is discharging or charging.

(2) For the avoidance of doubt, the thresholds in clauses 8.21(1) and 8.21(2) apply to an **energy storage system** as if the **energy storage system** is a **generator**.

…

## 8.19 Contributions to frequency support in under-frequency events

…

(5) Each North Island **connected asset owner** and each South Island **grid owner** must ensure that it has established and maintained **automatic under-frequency load shedding** in block sizes and with relay settings in accordance with the **technical codes**.

(6) For the purposes of subclause (5), the owner or operator of ~~a~~ an ~~battery~~ **energy storage system** with a capacity equal to or greater than the threshold in clause

8.21(1) is not considered a **connected asset owner** in relation to that ~~battery~~ **energy storage system**.

…

### 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** that exports less than 30 **MW** to a **local network** or the **grid**, unless the **Authority** has issued a direction under clause 8.38 that the **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 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 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).

…

### 8.24 Load shedding obligations to support voltage

…

(2) In order to prevent the collapse of the **network** voltage, each **connected asset owner** must ensure that, if possible, it has established load shedding in block sizes and at voltage levels (and, if automatic systems are established, with relay settings) in accordance with the **technical codes** or otherwise as the **system operator** reasonably requires.

(3) For the purposes of subclause (2), the owner or operator of an **energy storage system** with a capacity equal to or greater than the threshold in clause 8.21(1) is not considered a **connected asset owner** in relation to that **energy storage system**.

…

### 8.60 System operator must investigate causer of under-frequency event

(1) The **system operator** must promptly advise the **Authority**~~,~~ and every ~~**generator**, **grid owner** and any other~~ **participant** substantially affected by an **under-frequency event**, that an **under-frequency event** has occurred.

(2) The **system operator** may, by notice in writing to a **participant**, require a **participant** to provide information required by the **system operator** for the purposes of this clause.

(3) A notice given under subclause (2) must specify the information required by the **system operator** and the date by which the information must be provided (which must not be earlier than 20 **business days** after the notice is given).

(4) A **participant** who has received a notice under subclause (2) must provide the information required by the **system operator** by the date specified by the **system operator** in the notice.

(5) Within 40 **business days** of receiving the information, or such longer period as may be agreed by the **Authority**, the **system operator** must provide a report to the **Authority** that includes the following:

(a) whether, in the **system operator's** view, the **under-frequency event** was caused by a ~~**generator** or **grid owner**~~ **participant**, and if so, the identity of the **causer**:

(b) the reasons for the **system operator's** view:

(c) all of the information the **system operator** considered in reaching its view.

**8.61 Authority to determine causer of under-frequency event**

(1) The **Authority** must determine whether an **under-frequency event** has been caused by a ~~**generator** or **grid owner**~~ **participant** and, if so, the identity of the **causer**.

(2) The **Authority** must **publish** a draft determination that states whether the **under-frequency event** was caused by a ~~**generator** or **grid owner**~~ **participant** and, if so, the identity of the **causer**.

(3) The **Authority** must give reasons for its findings in the draft determination.

(4) The **Authority** must consult every ~~**generator**, **grid owner** and other~~ **participant** substantially affected by an **under-frequency event** in relation to the draft determination.

(5) When the **Authority publishes** the draft determination under subclause (2), the **Authority** must give notice to ~~**generators**, **grid owners**, and other~~ **participants** substantially affected by the **under-frequency event** of the closing date for submissions on the draft determination.

(6) The date referred to in subclause (5) must be no earlier than 10 **business days** after the date of **publication** of the draft determination.

(7) The **Authority** must **publish** submissions received under subclause (4) unless there is good reason for withholding information in a submission.

(8) For the purposes of subclause (7), good reason for withholding information exists if there is good reason for withholding the information under the Official Information Act 1982.

(9) Following the consultation under subclause (4), the **Authority** must **publish** a final determination.

…

**8.64 Allocating event ~~Event~~ costs ~~allocated~~ to event causers where electricity supply interrupted ~~to~~ or reduced ~~of electricity supply~~**

The **event charge** payable by the **causer** of an **under-frequency event** where the cause of the **under-frequency event** is an interruption to or reduction of **electricity** (referred to as "Event e" below) must be calculated in accordance with the following formula:

$$EC = ECR * (\Sigma_y (INT_{ye} \text{ for all } y) - INJ_D)$$

where

| | |
|---|---|
| EC | is the **event charge** payable by the **causer** |
| ECR | is $1,250 per **MW** |
| $INJ_D$ | is 60 **MW** |
| $INT_{ye}$ | is the loss of electric power (expressed in **MW**) ~~lost~~ at point y by reason of Event e (being the net reduction in the **injection** of **electricity** (expressed in **MW**) experienced at point y by reason of Event e) excluding any loss of electric power (expressed in **MW**) at point y by reason of secondary Event e |
| y | is a **point of connection** or the **HVDC injection point** at which the **injection** of **electricity** was interrupted or reduced by reason of Event e. |

**8.64A Allocating event ~~Event~~ costs ~~allocated~~ to event causers where ~~increase in~~ electricity demand increase**

The **event charge** payable by the **causer** of an **under-frequency event** where the cause of the **under-frequency event** is an increase in **electricity demand** (referred to as "Event e" below) must be calculated in accordance with the following formula:

$$EC = ECR * (\Sigma_y (INC_{ye} \text{ for all } y) - CON_D)$$

where

| | |
|---|---|
| EC | is the **event charge** payable by the **causer** |
| ECR | is $1,250 per **MW** |
| $CON_D$ | is 60 **MW** |
| $INC_{ye}$ | is the increase in **electricity demand** ~~of electric power~~ (expressed in **MW**) at point y by reason of Event e (being the net increase in the **demand** for **electricity** (expressed in **MW**) experienced at point y by reason of Event e) excluding any |

increase in **electricity demand** ~~or loss of electric power~~ (expressed in **MW**) at point y by reason of secondary Event e

y is a **point of connection** or the point at which **electricity** is supplied to the **HVDC link** at which an increase in **electricity demand** occurs by reason of Event e.

**8.65 Rebates paid for under-frequency events**

An **event charge** that has been paid for an **under-frequency event** (referred to as "Event e") under clause 8.64 or under clause 8.64A must be rebated in accordance with the following formula to persons who are allocated **availability costs** in accordance with clause 8.59:

…

**8.66 Payments and rebates**

All costs calculated in accordance with clauses 8.59, ~~and~~ 8.64 and 8.64A are payable by the relevant **participants** to the **system operator**, and all **event charge** rebates calculated in accordance with clause 8.65 are payable by the **system operator** to the relevant **participants**, in accordance with clause 8.69.

…

# Schedule 8.3
# Technical codes

*Technical Code A – Assets*

…

**2 General requirements**

…

(2) Each **asset owner** must provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, to allow the **system operator** to assess compliance of its **asset** or any configuration of **assets** with the requirements of the **asset owner performance obligations** and **technical codes** at each of the following times:

…

(2A) For **asset owners** that are **generators**, the obligation to provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, applies only to **generators** with a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2).

…

(5) Each **asset owner** must provide the **system operator** with an **asset capability statement** in the form from time to time **published** by the **system operator** for each **asset** that—

(a) is—

(i) proposed to be connected, or is connected to, or forms part of the **grid**~~.~~; or

(ii) proposed to be connected, or is connected directly or indirectly to a **local network**; and

(b) forms part or all of a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2) at the **point of connection** to the **network**.

(5A) The **asset capability statement** must—

(a) include all information reasonably requested by the **system operator** so as to allow the **system operator** to determine the limitations in the operation of the **asset** that the **system operator** needs to know for the safe and efficient operation of the **grid**; and

(b) include any modelling data for the planning studies, as reasonably requested by the **system operator**; and

(c) be updated and reissued to the **system operator** as information and design development progresses through the study, design, manufacture, testing and **commissioning** phases; and

(d) be complete and up to date before the **commissioning** of the **asset**; and

(e) be complete and up to date at all times while the **asset** is—

(i) connected to, or forms part of, the **grid**~~.~~; or

(ii) connected directly or indirectly to a **local network**.

…

## 5 Specific requirements for generators

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

…

(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

(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.

…

(2) Each **generator** must ensure that each of its **generating units** connected to the **grid** is equipped with—

(a) a ~~an excitation and~~ voltage ~~control system~~ **control system** with a voltage set point that is adjustable over the range of voltage set out in clause 8.23 and operates continuously in the voltage control mode when **synchronised**; and …"

…

*Appendix B: Routine testing of assets and automatic under-frequency load shedding systems*

**1 Periodic tests to be carried out**

(1) This Appendix sets out periodic tests required for the purposes of clause 8(2) of **Technical Code** A.

(2) Each **asset owner** may be legally required, other than under this Code, to carry out additional tests to ensure that their **assets**, including **automatic under-frequency load shedding** systems, are safe and reliable.

~~(3) For the purposes of this Appendix, **generating unit** does not include a **generating unit** for which wind is the primary power source.~~

(4) Each **asset owner** with one or more **generating units** commissioned before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.

**2 Generating unit frequency response**

Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38, must—

(a) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** analogue over-frequency relays and analogue under-frequency relays at least once every 4 years; and

(b) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** non-self monitoring digital over-frequency relays and non-self-monitoring digital under-frequency relays at least once every 4 years; and

(ba) for **generating units** with an inverter, test the trip frequencies and trip time delays of non-self monitoring digital over-frequency protection settings and non-self monitoring digital under-frequency protection settings for the **generating units** at least once every 4 years; and

(c) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and

(ca) for **generating units** with an inverter, test the trip frequencies and trip time delays of self monitoring digital over-frequency protection settings and self monitoring digital under-frequency protection settings for the **generating units** at least once every 10 years; and

(d) based on the tests carried out in accordance with paragraphs (a) ~~to (c)~~, (b), (ba), (c) or (ca), provide a verified set of under-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(e) based on the tests carried out in accordance with paragraphs (a) ~~to (c)~~, (b), (ba), (c) or (ca), provide a verified set of over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

### 3 Generating unit ~~governor and speed~~ frequency control system ~~systems~~

Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 must—

(a) for each of its **generating units** with no inverter, test the ~~governor system~~ response of the ~~each of its~~ **generating** ~~**units'**~~ **unit's** mechanical or analogue speed ~~governors~~ governor and/or mechanical or analogue frequency **control system** ~~**systems**~~ at least once every 5 years; and

(b) for each of its **generating units** with no inverter, test the ~~governor system~~ response of the ~~each of its~~ **generating units'** digital or electro-hydraulic ~~speed governors~~ frequency **control system** ~~**systems**~~ at least once every 10 years; and

(ba) for its **generating units** with an inverter, test the response of each frequency **control system** used for those **generating units** at least once every 10 years; and

(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter ~~inverters~~ test the response of ~~control settings for~~

each ~~**generating unit's**~~ frequency **control system** used for those **generating units** within 3 months of a change to the control settings and/or firmware of the frequency **control system** (where the change to the firmware has the potential to materially affect the performance of the frequency response of the **generating units** or **generating station** that the **generating units** are part of); and

(c) based on the tests carried out in accordance with paragraphs (a), ~~or~~ (b), (ba) or ~~(ba)~~ (bb), provide a verified set of modelling parameters and governor or frequency **control system** ~~system~~ response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the ~~governor~~ frequency **control system**; and

(ii) for **generating units** with a turbine, a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and

(iia) for **generating units** with a power converter, a block diagram showing the mathematical representation of the power converter and its electrical control; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iv) for **generating units** with an inverter ~~inverters~~, a verified set of control settings and relevant firmware version identifiers for ~~each **generating unit's**~~ the frequency **control system** used for each **generating unit**.

…

## 5 Generating unit voltage response and control

Each **generator** with a **point of connection** to the **grid** must—

(a) for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the ~~each of its~~ **generating** ~~**units'**~~ **unit's** analogue ~~excitation~~ voltage **control system** ~~**systems**~~ at least once every 5 years; and

(b) for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the ~~each of its~~ **generating** ~~**units'**~~ **unit's** digital ~~excitation~~ voltage **control system** ~~**systems**~~ at least once every 10 years; and

(ba) for its **generating units** with an inverter, test the response of each voltage **control system** used for those **generating units** at least once every 10 years; and

(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter ~~inverters~~ test the response of ~~control settings for~~ each ~~**generating unit's**~~ voltage **control system** used for those

**generating units** within 3 months of a change to the control settings and/or firmware of the voltage **control system** (where the change to the firmware has the potential to materially affect the performance of the voltage response of the **generating units** or **generating station** that the **generating units** are part of); and

(c) based on the tests carried out in accordance with paragraphs (a), ~~or~~ (b), (ba) or ~~(ba)~~ (bb), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the ~~automatic~~ voltage **control system** ~~regulator~~; and

~~(ii) a block diagram showing the mathematical representation of the exciter; and~~

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iv) for **generating units** with an inverter ~~inverters~~, a verified set of control settings and relevant firmware version identifiers for ~~each **generating unit's**~~ the voltage **control system** used for each **generating unit**.

…

**9 ~~Grid~~ Asset owner ~~static var compensator~~ dynamic reactive power compensation device transient response and control**

Each ~~**grid**~~ **asset owner** with a **dynamic reactive power compensation device** directly connected to the **grid** must—

(a) test the transient response, steady state response and a.c. disturbance response of each of its ~~static var compensators~~ **dynamic reactive power compensation devices** at least once every 10 years; and

(b) test the operation of each of its ~~static var compensators~~ **dynamic reactive power compensation devices'** analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its ~~static var compensators~~ **dynamic reactive power compensation devices'** digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph (a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and a.c. disturbance response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including –

(i) a block diagram showing the mathematical representation of the ~~static var compensator~~ **dynamic reactive power compensation device**; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and

(iii) a detailed functional description of all the components of the ~~static var compensator~~ **dynamic reactive power compensation device** and how they interact in each mode of control; and

(iv) step response test results; and

(v) a.c. fault recovery disturbance test results; and

(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a set of **control system** test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

…

**11 Grid owner synchronous compensators**

Each **grid owner** must –

(a) test each of its synchronous compensators' analogue and electromechanical ~~excitation systems~~ voltage **control systems** at least once every 5 years; and

(b) test each of its synchronous compensators' digital ~~excitation systems~~ voltage **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including –

(i) a block diagram showing the mathematical representation of the ~~automatic~~ voltage **control system** ~~regulator~~; and

~~(ii) a block diagram showing the mathematical representation of the exciter; and~~

(iii) a detailed functional description of the ~~excitation system~~ voltage **control system** in all modes of control; and

(iv) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.

…

*Technical Code B – Emergencies*

…

**7 Load shedding systems**

…

(2) Every South Island **grid owner** must ensure, at all times, that an **automatic under-frequency load shedding ~~system~~** system is installed in accordance with subclause (6A) for each **grid exit point** in the South Island.

…

(6) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (1) must enable, at all times, automatic **electrical disconnection** of **demand** either**—**

(a) as 2 blocks of **demand** (each block being a minimum of 16% of the **connected asset owner's** total pre-event **demand** excluding the pre-event **demand** of **energy storage systems** with a capacity equal to or greater than the threshold in clause 8.21(1))…; or

(b) in accordance with the **system operator's AUFLS technical requirements report**, as agreed with the **system operator** and subject to subclause (6AA).

(6AA) Each North Island **connected asset owner** must transition as soon as reasonably practicable, and must be proactively engaging with the **system operator** to transition as soon as reasonably practicable, to an **automatic under-frequency load shedding** system that complies with the **system operator's AUFLS technical requirements report**. The transition must be completed before 30 June 2025.

(6AB) Despite subclause (6AA), each North Island **connected asset owner** must exclude the pre-event **demand** of **energy storage systems** with a capacity equal to or greater than the threshold in clause 8.21(1) in accordance with subclause (6)(a) until such time as the requirement to include this measure in its **automatic under-frequency load shedding** system is included in the **system operator's AUFLS technical requirements report**.

(6AC) For the avoidance of doubt, in relation to subclause (6AB), each North Island **connected asset owner's automatic under-frequency load shedding** system must comply with the **system operator's AUFLS technical requirements report** in all other respects from 30 June 2025.

(6A) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (2) must enable, at all times, automatic **electrical disconnection** of 2 blocks of **demand** (each block being a minimum of 16% of the **grid owner's** total pre-event **demand** excluding the pre-event **demand** of **energy storage systems** with a capacity equal to or greater than the threshold in clause 8.21(1)) subject to subclause (8)…

…

# Part 12
# Transpower

…

# Schedule 12.5
# Availability and reliability index measures

…

In row 11 of column 2 of the table in Schedule 12.5 of the Code, replace the words 'Static var compensators' with '**Dynamic reactive power compensation devices**'.

# Appendix B Feedback being considered elsewhere

B.1. **Error! Reference source not found.** provides a summary of submitter feedback that i s being considered as part of the wider FSR work programme.

**Table 4: Summary of submitter feedback addressed in the wider FSR programme**

| FSR programme | Submitter feedback to be considered |
|---|---|
| **Issue 1:** Frequency variability[26] | Grandfathering arrangements for existing assets that are unable to comply with the requirement to have a speed governor or frequency control system under a lower 'excluded generating station' threshold. |
| **Issues 2, 3, 4: Voltage deviations and network performance issues[27]** | Grandfathering arrangements for existing assets that are unable to comply with the Code's fault ride through requirements under a lower 'excluded generating station' threshold. |
| | Assign voltage support obligations to some additional parties. |
| | Placing common quality obligations at the generating unit level or generating station level. |
| **Issue 7: Common quality-related information requirements[28]** | Developing a simplified ACS format for smaller generators. |
| | Granting distributors access to ACS information relating to embedded generators connected to their respective networks. |
| **Future projects** | Review the current FRT requirements in the Code to assess the extent to which these should differ between different generation technologies. |
| | Long-term regulatory solution to address the rapidly evolving role of ESSs in the power system. |

B.2. We acknowledge that some flexibility traders that are managing aggregated distributed generation may not be able to be regulated under the Code, because they are not within the meaning of industry participant. The Authority is considering the role of aggregators as part of our work programme on encouraging investment and innovation in flexibility services.

26 Electricity Authority, Addressing more frequency variability in New Zealand's power system: Consultation paper, June 2024.

27 Electricity Authority, Addressing larger voltage deviations and network performance issues in New Zealand's power system: Consultation paper, June 2024.

28 Electricity Authority, Addressing common quality information requirements: Consultation paper, October 2024.