Promoting reliable electricity supply – a voltage-related Code amendment

Decision paper

10 March 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

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

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

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

We sought feedback on a Code amendment proposal

In June 2025, we sought feedback on a Code amendment proposal that would:

- place voltage support obligations on embedded generating stations that can export 10 megawatts (MW) or more of electricity and which are connected at the grid exit point voltage
- lower, to 10MW, the threshold for generating stations to comply with the Code's fault ride through asset owner performance obligations.[1]

The purpose of the Code amendment proposal was to help address three aspects of a voltage-related problem identified in the review of common quality requirements:[2]

- Under current regulatory settings, an increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause larger voltage deviations. These deviations will be exacerbated by changing patterns of reactive power flows.
- Under current regulatory settings, increasing amounts of inverter-based variable and intermittent resources will reduce the transmission grid's system strength. This will increase the likelihood of network performance issues if inverter-based resources disconnect from the power system.
- Over time, a decreasing proportion of generation capacity is expected to be subject to the Code's fault ride through obligations. This will come about as more generating stations export less than 30MW to a network, thereby falling below the current threshold for needing to comply with these obligations.

[1] See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal*.

[2] See the Authority's consultation paper *Future Security and Resilience - Review of common quality requirements in Part 8 of the Code – Issues paper*.

We are proceeding with the Code amendment proposal, with some changes

After considering submissions, the Authority has decided to proceed with the Code amendment proposal, with some changes in response to submitter feedback and input from the Common Quality Technical Group.

We consider the Code amendment will promote reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The amendment will do this by assisting the System Operator and distributors to manage voltages across New Zealand's power system at lower cost than under the status quo arrangements. Among other things, this in turn will reduce the risk of consumers facing economic costs associated with:

- their electrical equipment operating sub-optimally or being damaged by greater voltage deviations or greater voltage instability
- more power supply interruptions due to voltage events.

As evidenced by a large blackout on the Iberian Peninsula in April 2025, the costs associated with voltage-related events on the power system can be extremely large.

Next steps

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

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1. Purpose

We are amending the Code

1.1. This paper sets out the Authority's decision to amend the Electricity Industry Participation Code 2010 (Code) to:

(a) place voltage support obligations on embedded generating stations that have a maximum continuous megawatt (MW) output power of 10MW or more and which are connected at the grid exit point (GXP) voltage

(b) lower, to 10MW, the threshold for generating stations to comply with the Code's fault ride through asset owner performance obligations.

1.2. This Code amendment helps address a voltage-related problem identified in the Authority's review of the common quality requirements in Part 8 of the Code.

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

The Code amendment benefits consumers

1.4. We consider the Code amendment will promote reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The amendment will do this by assisting the System Operator and distributors to manage voltages across New Zealand's power system at lower cost than under the status quo arrangements. Amongst other things, this in turn will reduce the risk of consumers facing economic costs associated with:

(a) their electrical equipment operating sub-optimally or being damaged by greater voltage deviations or greater voltage instability

(b) more power supply interruptions due to voltage events.

1.5. As evidenced by a large blackout on the Iberian Peninsula in April 2025, the costs associated with voltage-related events on the power system can be extremely large. This blackout of the Spanish and Portuguese power systems was the most severe blackout on the European power system in over 20 years.[3] It caused major economic loss, disrupting millions of consumers, with several deaths possibly linked to it.[4]

Next steps

1.6. The Code amendment will come into effect on 1 July 2026.

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3 See 28 April 2025 Blackout.

4 See Authorities investigating link between deaths and blackout.

2. Background to the Code amendment

The Future Security and Resilience (FSR) work programme

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

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

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

(a) Ancillary services (multiple frequency keeping) review

(b) Improving network visibility

(c) Developing solutions for peak capacity issues

(d) More efficient connection prices and processes

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

(f) The Power Innovation Pathway programme.

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

The Authority sought feedback on a Code amendment proposal

2.5. In June 2025, we sought feedback on a Code amendment proposal that would:

(a) place voltage support obligations on embedded generating stations that can export 10MW or more of electricity and which are connected at the GXP voltage

(b) lower, to 10MW, the threshold for generating stations to comply with the Code's fault ride through asset owner performance obligations.[6]

2.6. The purpose of the Code amendment proposal was to help address three aspects of a voltage-related problem identified in the review of common quality requirements:

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

6 See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal*.

(a) Under current regulatory settings, an increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause larger voltage deviations. These deviations will be exacerbated by changing patterns of reactive power flows.

(b) Under current regulatory settings, increasing amounts of inverter-based variable and intermittent resources will reduce the transmission grid's system strength. This will increase the likelihood of network performance issues if inverter-based resources disconnect from the power system.

(c) Over time, a decreasing proportion of generation capacity is expected to be subject to the Code's fault ride through obligations. This will come about as more generating stations export less than 30MW to a network, thereby falling below the current threshold for needing to comply with these obligations.[7]

We received 10 submissions

2.7. We received 10 submissions on the consultation paper from the 11 parties listed in Table 1.[8]

Table 1: List of submitters

Submitter	Role
Contact Energy	Generator–retailer
Electricity Engineers' Association of New Zealand (EEA)	Representative body for electrical engineers
Independent Electricity Generators Association (IEGA)	Representative body for generators
Manawa Energy	Generator
Mercury	Generator–retailer
Meridian Energy	Generator–retailer
NewPower Energy Services (NewPower)	Holding company for a generator and an engineering, procurement and construction company
Powerco	Distributor
Transpower	Transmission grid owner
Transpower	System Operator
WEL Networks	Distributor

7 See the Authority's consultation paper *Future Security and Resilience - Review of common quality requirements in Part 8 of the Code – Issues paper*.

8 Transpower's submission was on behalf of the System Operator and the transmission grid owner.

3. The Authority's decision on the Code amendment proposal

The Authority's Code amendment proposal

3.1. The Authority's Code amendment proposal comprised two elements:

(a) a voltage support element

(b) a fault ride through element.

> **What is 'voltage support'?**
>
> Voltage support refers to the ability of an electrical device connected to a network to help maintain voltage on the network within a defined range by producing or absorbing reactive power. Voltage support typically is provided by generating units, synchronous condensers, and reactive power compensation devices such as capacitors, reactors, static synchronous compensators (STATCOMs) and static Volt-Amps reactive (VAr) compensators (SVCs).

> **What is 'fault ride through'?**
>
> Fault ride through refers to the ability of a generating unit to remain electrically connected to a network and operate in a stable manner during a transient voltage disturbance on the network (eg, a large drop in voltage accompanying a fault on the transmission grid).

The voltage support element of the Code amendment proposal

3.2. The Authority proposed to amend Part 8 of the Code to require an embedded generating station to continuously export or import reactive power to regulate voltage at the embedded generating station's point of connection to a local distribution network, if all of the following conditions hold:

(a) the embedded generating station is connected to the local distribution network at the same nominal voltage as the supply busbar voltage of the GXP that is electrically closest to the embedded generating station[9]

(b) the embedded generating station's maximum export of electricity to the local distribution network is 10MW or more

(c) the distributor that operates the local distribution network has not directed the embedded generating station to operate in an alternative voltage control mode to accommodate conditions on the local distribution network[10]

(d) for an embedded generating station with a maximum export power of 10MW or more and which was first electrically connected to the local distribution network before 1 July 2026, the embedded generating station is able to comply with the requirement without being modified.

9 In other words, there is no transformer stepping down voltage between the GXP and any transformer at the embedded generating station's point of connection to the local distribution network.

10 For example, requiring the embedded generating station to export or import reactive power with a reactive power droop characteristic, responding to the voltage measured at the generating station's point of connection to the local distribution network.

3.3. The Authority proposed the default requirement on an embedded generating station would be for it to continuously export or import reactive power that is a minimum of 33% of the maximum continuous MW output power of the generating station. The reactive power and the maximum continuous MW output power would be measured at the embedded generating station's point of connection to the local distribution network. However, the distributor and embedded generator would be permitted to agree an alternative reactive power capability range for the generating station.

The fault ride through element of the Code amendment proposal

3.4. The Authority proposed to amend Part 8 of the Code to lower the threshold for generating stations to comply with the fault ride through obligations in clauses 8.25A and 8.25B of the Code. The threshold would be lowered from 30MW to 10MW maximum exported power.

3.5. For generating stations with maximum exported power of 10MW or more but less than 30MW, and that were first electrically connected to the network before 1 July 2026, the requirement to comply with the fault ride through obligations would apply only if the generating station was able to comply without being modified.

Submitter feedback and the Authority's responses

3.6. This section summarises submitter feedback on the Code amendment proposal and the Authority's responses. This feedback is grouped by:

(a) feedback applicable to the overall proposal

(b) feedback specific to the voltage support element of the proposal

(c) feedback specific to the fault ride through element of the proposal.

3.7. The submission summaries in this Part are not exhaustive, so we encourage you to review individual submissions for a comprehensive account of submitters' views. Full submissions are available on our website.[11]

Feedback on the overall Code amendment proposal and the Authority's responses

Differing views on the level of analysis supporting the proposal

3.8. The IEGA suggested there had been a lack of expert and robust analysis to support the level of change for new embedded generation and the cost to participants. In contrast, the EEA endorsed the technical basis for the problem definition. The EEA believed the Code amendment proposal struck an appropriate balance between technical effectiveness, implementation feasibility, and regulatory proportionality.

3.9. The Authority disagrees with the IEGA's view that there has been a lack of expert and robust analysis to support the level of change for new embedded generation and the cost to industry participants. In addition to the Authority's own analysis, the Code amendment has received expert input from the System Operator, including through several power system studies, and from the Common Quality Technical Group. We are grateful to these parties for the time and effort they have contributed over a period that now spans several years.

11 See Electricity Authority | Future security and resilience | June 2025 voltage-related common quality Code amendment proposal | Submissions.

Mixed feedback on the Authority's assessment of benefits and costs

3.10. Submitters were split over the Authority's assessment of the Code amendment proposal's benefits and costs. Manawa Energy considered the proposal's benefits did not outweigh its costs. WEL Networks considered the Authority's conclusion that the proposal had a net benefit was quite subjective. Contact Energy thought the benefits of the Code amendment proposal had been overestimated. NewPower considered a net benefit calculation to support the proposal was missing.

3.11. In contrast, the EEA agreed the Authority had identified the key benefits and costs associated with the proposal and had provided a well-reasoned qualitative and quantitative assessment. The EEA agreed the benefits of the Code amendment proposal outweighed the costs, as did Mercury and Transpower.

3.12. In response to submitter feedback, the Authority has elaborated upon and clarified several of the Code amendment's benefits and costs. In particular, we have aggregated quantified benefits and costs rather than leaving them disaggregated. See Part 4 of this paper, which contains our refined assessment of the Code amendment's expected benefits and costs, in response to submitters' feedback. We remain of the view that the Code amendment will have an overall net benefit.

3.13. A case study highlights the potential savings available under the Code amendment from reduced investment in transmission-scale dynamic voltage support equipment. In 2024, as part of the Authority's options analysis prior to the Code amendment proposal, the voltage studies undertaken by the System Operator included a study case demonstrating the increased effectiveness of voltage support closer to where voltage is to be regulated. The study involved applying a contingency at a Kopu GXP transformer and then restoring the GXP voltage to its pre-contingency value by adjusting the reactive power output of the Hamilton STATCOM that the Kopu GXP relies on. Restoring the Kopu GXP's voltage to its pre-contingency value required the Hamilton STATCOM's output to increase by 170MVAr. In comparison, an increase of only 14MVAr in the output of a hypothetical STATCOM at the Kopu GXP would have been required.[12]

Widespread feedback on the draft Code

3.14. Most submitters provided some suggested changes to the draft Code amendment included in the proposal or sought clarification of Code terminology. For example, Manawa Energy believed the draft Code meant the proposed 'legacy clause' arrangements would not apply to existing small hydro generating stations.

3.15. Several submitters provided feedback on the proposed definition of 'maximum export power'. The EEA submitted that the Code should clarify whether the 10MW threshold applied to nameplate capacity, average export, or export under specific operating conditions. NewPower and WEL Networks submitted there should be clarity around how the maximum export power for generating stations with multiple generating plant should be calculated. They also highlighted that the nameplate rating of intermittent generation is subjective. NewPower and WEL Networks also suggested aligning or linking the use of 'generating plant' in the definition of 'maximum export power' with the use of 'generating station' in the asset owner performance obligations.

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12 See Appendix C (p.27) of the Authority's consultation paper *Addressing larger voltage deviations and network performance issues in New Zealand's power system*.

3.16. The Authority has incorporated in the Code amendment a number of the changes suggested by submitters, and made several clarifications to the Code drafting to address issues raised by submitters. For example, we have clarified the voltage ranges for which reactive power is to be exported/imported, aligning these with the equivalent ranges for transmission-connected generating stations. We have also clarified that the default voltage support obligation applies when the embedded generating station is synchronised. Again, this aligns with the voltage support obligation on transmission-connected generating stations under clause 8.23 of the Code. Regarding a point raised by WEL Networks, we note that applying the voltage support obligation to embedded generating stations at all times also aligns with the equivalent obligation on transmission-connected generating stations under clause 8.23.[13]

3.17. The Authority notes we are reviewing the wording of clause 8.23, as part of our work on asset owner performance obligations for hybrid plant. When doing this we will consider the implications of any potential wording changes for both transmission-connected and distribution-connected generating stations. We will invite feedback from stakeholders in due course.

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

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

3.20. In some instances, we have not amended the Code in response to submitter feedback. For example, in relation to Manawa Energy's feedback on the Code drafting, we consider the definitions of 'generator' and 'generating station' do not need to be amended in order for the 'legacy clause' arrangements in the Code amendment to apply to existing generation that is unable to comply with the new Code obligations.

General support for the use of 'legacy clause' arrangements

3.21. There was general support from submitters for the Authority's proposed use of 'legacy clause' arrangements as part of the Code amendment proposal. Submitters agreed this would avoid costly upgrades to existing generation.

3.22. Manawa Energy considered a generating station with 'legacy' status should retain this status if the generating station was upgraded. Mercury considered 1 July 2026 was

13 WEL Networks submitted that the obligation on embedded generators should apply only during normal operation.

too soon to be the cut-off date for a generating station to be subject to the 'legacy clause' provisions.

3.23. The Authority notes submitters' general support for 'legacy clause' arrangements. As set out in paragraph 3.65, in response to submitter feedback we have:

(a) extended by one year (ie, to 1 July 2027) the cut-off date for a generating station to be subject to the 'legacy clause' provisions, and

(b) provided that a generating station with 'legacy clause' status will not lose this status if its MW capacity increases by less than 5MW.

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

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

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

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

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

Some support for mandating grid-forming inverters

3.26. Contact Energy considered that mandating grid-forming inverters would address the identified voltage issues without needing to focus on existing excluded generating stations. Contact Energy believed the Authority should consider making grid-forming capability mandatory for new generation connections and any existing connections that could be upgraded. This was on the basis that inverter manufacturers can enable grid-forming capability via firmware/control upgrades at a competitive cost.

3.27. The IEGA queried why the Authority had not investigated or commented on requiring grid-forming inverters on new inverter-based generation to address the identified voltage issues.

3.28. NewPower encouraged the Authority to investigate grid-forming inverters and the role of this technology in maintaining system strength / inertia. Since generators would incur additional costs to install grid-forming inverters, NewPower believed there should be financial incentives for generators to cover these additional costs.

3.29. The Authority notes the support from some submitters for mandating the use of grid-forming inverters. We will review grid-forming inverter technology as part of a future investigation into the system strength-related operational challenges that New

Zealand's power system is likely to face due to a high level of penetration of inverter-based resources.

Implementation considerations

3.30. The EEA believed robust implementation support would be critical to realising the benefits of the Code amendment proposal, particularly for smaller distributors and generators with limited in-house technical resources. The EEA encouraged the Authority to work with the Commerce Commission over the Code amendment proposal's implications for distributors' price-quality paths.

3.31. We note the EEA's encouragement of the Authority and the Commerce Commission working together over any implications of the Code amendment for distributors' price-quality paths. The Authority considers the Code amendment does not require distributors to incur any material incremental costs relative to status quo arrangements. In its submission, Mercury noted the need for coordination between distributors and Transpower, in its roles of System Operator and transmission grid owner, under the voltage support element of the Code amendment proposal (see paragraph 3.44(c)). We consider this does not represent an incremental cost of the Code amendment because we understand distributors and Transpower already liaise, as appropriate, on voltage support/reactive power support/power factor requirements for new embedded generation connections. We consider the Code amendment supports, rather than mandates, a continuation of this coordination.

Feedback on the voltage support element of the proposal and the Authority's responses

Most submitters supported the voltage support element of the proposal

3.32. Most submitters agreed with the voltage support element of the Code amendment proposal. Of those who did not, NewPower said distributors should control distribution network voltage and reactive power flows rather than the System Operator utilising embedded generation to control transmission grid voltage and reactive power flows. Meanwhile, WEL Networks considered the status quo would likely be superior to the Code amendment proposal because distributors will likely place higher reactive power capability requirements on embedded generation above 10MW than the Authority was proposing.

3.33. NewPower and the IEGA preferred the use of an ancillary service contract for reactive power management. NewPower also suggested the Authority develop an ancillary service product for dynamic voltage support. Similarly, Meridian Energy said that, over the longer term, the Authority should seek to establish a market-based framework to incentivise the provision of voltage support. However, Meridian Energy accepted that some regulated obligations may need to be imposed in the interim.

3.34. The Authority notes the points raised by submitters who did not agree with the voltage support element of the Code amendment proposal. To NewPower's first point above (in paragraph 3.32), the Code amendment has been designed specifically to ensure that embedded generating stations' support of transmission grid voltage and reactive power flows is not at the expense of distributors controlling distribution network voltage and reactive power flows.

3.35. Under the Code amendment, the distributor and embedded generator are able to agree on an alternative capability to the ±33% requirement. We note WEL Networks' view that distributors will likely place higher reactive power capability requirements on embedded generation above 10MW than the ±33% requirement. No other submitters shared this view. Accordingly, the Authority is not convinced this is sufficient reason to rely on the status quo arrangements instead of proceeding with the Code amendment.

3.36. The Authority notes the IEGA's and NewPower's preference for voltage support to be provided via ancillary service contracts, and Meridian Energy's view that, over the longer term, we should seek to establish a market-based framework to incentivise the provision of voltage support. We also note Contact Energy's observation in its submission that the System Operator has not formally signalled a need to procure voltage support via ancillary service contracts.

3.37. We remain of the view that the Code amendment better promotes the efficient operation of the electricity industry than relying on status quo arrangements, which include voltage support procured by the System Operator. We estimate the cost of voltage support provided under the Code amendment to be less than voltage support provided as an ancillary service – see our assessment in Part 4 of this paper.

3.38. In summary, the difference in cost is equal to the contract administration and compliance costs associated with tendering, entering into, and delivering voltage support as an ancillary service. We note that our assessment assumes embedded generators provide voltage support as an ancillary service at cost. This is consistent with adopting a conservative approach to estimating the Code amendment's benefits (ie, this assumption minimises the cost of the alternative to the Code amendment).

3.39. In response to Contact Energy's submission, we point to the recent power system studies undertaken by the System Operator demonstrating that voltage support will be needed in the absence of the Code amendment.[14] Whether this is provided via ancillary service contracts and/or network investment and/or non-network solutions purchased by network owners will depend on the relative costs of these alternative solutions.

3.40. In response to Meridian Energy's submission, we reiterate the point made in our consultation on the Code amendment proposal, which is that this Code amendment does not preclude moving to a market-based framework in the future.[15]

A need to explain the basis for the 33% default reactive power requirement

3.41. The IEGA, NewPower and WEL Networks submitted the Authority had not demonstrated that a mandatory default reactive power requirement of 33% of a generating station's maximum continuous MW output power is optimal—

(a) for voltage management on distribution networks

(b) in terms of the reactive capability of the generating station's equipment.

3.42. The IEGA queried the technical rationale for using 33%.

14 See Appendix C of the Authority's 25 June 2024 consultation paper *Addressing larger voltage deviations and network performance issues in New Zealand's power system*.

15 See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal* – pp.31–32.

3.43. The basis for using ±33% may be summarised as follows:

(a) First, most modern electricity generation equipment supplied internationally comes with this capability. Therefore, any equipment-related incremental costs associated with using ±33% are likely to be minimal.

(b) Second, an embedded generating station exporting/importing reactive power that is 33% of the station's maximum continuous MW output power will be operating at a 0.95 power factor (as measured at the station's point of connection to the local distribution network). The Authority considers this results in a reasonable sharing of responsibility for voltage stability between distributors and embedded generating stations. Powerco made this same point in its submission on our June 2024 consultation paper *Addressing larger voltage deviations and network performance issues in New Zealand's power system*, which set out short-listed options to address the voltage problem. Powerco also noted its modelling suggested the operating range of ±33% provides adequate support to maintain voltage on Powerco's network within regulatory limits.[16]

(c) Third, a number of overseas jurisdictions require generating stations, particularly wind and solar photovoltaic generating stations, to be capable of providing voltage support by exporting/importing reactive power at ±33% of active power / operating at 0.95 lagging/leading power factor (eg, Great Britain,[17] Ireland,[18] Norway,[19] and the United States of America[20]). The Authority notes generating stations subject to this requirement overseas include stations similar in size to embedded generating stations subject to the Code amendment. The Australian National Electricity Market's automatic access standard[21] is higher – at ±39.5%.[22] However, a generator participating in the Australian National Electricity Market can negotiate a lower technical requirement as part of connecting their generating station to the power system.

Some submitters identified practical considerations

3.44. Contact Energy and Mercury noted there would be practical considerations associated with embedded generation meeting the proposed reactive power requirements, such as:

(a) Embedded generation may be unable to provide voltage support above what is agreed with the distributor, since this support is governed by the operating voltage range at the generating station's point of connection with the distribution network, and by the distribution network's power quality requirements.

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16 See Powerco's submission at Electricity Authority I June 2024 FSR consultation I Powerco submission.

17 See *Section ECC 6.3.2 of the Great Britain Grid Code*.

18 See *Section DCC 11.5.2 of ESB Networks' Distribution Code*.

19 See *Statnett's functional requirements in the power system (FIKS)*, which sets out the minimum technical requirements Statnett requires for approving connection to the transmission and higher voltage distribution networks.

20 See the Federal Energy Regulatory Commission's *Order No. 827*.

21 Generating stations that meet the ±39.5% standard would not be denied access to the power system because of this technical requirement.

22 Ie, a generating station is capable of exporting and importing continuously at its connection point an amount of reactive power of at least the amount equal to the product of the rated active power of the generating system and 0.395. See *Australian National Electricity Rules, Chapter 5, Chapter Schedule 5.2, Clause S5.2.5.1*.

(b) Requiring embedded generating stations to be in voltage control mode and provide reactive power support is incompatible with the existing requirements for maintaining power factor at the GXP under the Default Transmission Agreement template (Schedule 12.6 of the Code). The IEGA also submitted on this point – saying a reactive power range needed to be linked to the power factor limits in Schedule 12.6 of the Code.

(c) If embedded generating stations must provide voltage control, their control systems and settings will need to be coordinated between stations, the distributor and Transpower, to avoid the control systems "fighting" each other. This coordination is likely to require additional studies and discussion, which will have resourcing implications for the affected parties.

3.45. Manawa Energy sought clarity on whether the System Operator or the distributor would be managing and policing the default voltage support obligation. The EEA submitted that, while the Code amendment proposal allowed distributors to direct an embedded generating station to operate in an alternative voltage control mode to the default mode, further guidance may be helpful to ensure expectations are consistent across parties.

3.46. The Authority agrees with submitter feedback about practical considerations associated with the Code amendment. The Code amendment is designed to accommodate considerations such as:

(a) distribution network operating conditions and distributors needing to operate their networks in accordance with good electricity industry practice

(b) distributors' power factor obligations under the Default Transmission Agreement template (Schedule 12.6 of the Code)

(c) the need for coordination between embedded generating stations, the distributor, and Transpower in its roles of System Operator and a transmission grid owner. (We note this coordination is already occurring with the material increase in embedded generation being connected, or planned to be connected, to various distribution networks at the GXP voltage.)

3.47. The primary way in which the Code amendment accommodates these considerations is by providing for distributors to require embedded generators to operate their stations in an alternative voltage control mode to the default mode specified in the Code amendment. Distributors may do this in response to any of the above considerations.

3.48. Further to the IEGA's and Mercury's point about distributors' power factor obligations under Schedule 12.6 of the Code, the Authority notes we are considering amending these power factor obligations as part of our work on managing reactive power flows at GXPs. Specifically, we are considering whether distributors' voltage support assets should be capable of managing reactive power within a power factor range of 0.95 lagging to 0.95 leading at their points of connection (GXPs) to the transmission network.[23]

[23] See the Authority's consultation papers *Promoting reliable electricity supply - a voltage-related Code amendment proposal* – p.21 (paragraphs 3.12–3.14), and *Addressing larger voltage deviations and network performance issues in New Zealand's power system* – pp.25–28.

3.49. In response to Manawa Energy's query whether the System Operator or the distributor manages and polices the default voltage support obligation, the Authority notes:

(a) the distributor will in effect be managing the obligation, to the extent that the distributor can instruct an embedded generator to operate their station in an alternative voltage control mode

(b) the System Operator will be monitoring embedded generators' compliance with the obligation since the System Operator is responsible for monitoring compliance with Part 8 of the Code.[24]

3.50. We agree with the EEA about the desirability of consistency and reasonableness across distributors regarding the provision of voltage support by embedded generating stations, including reactive power export/import and power factor requirements. We have reflected this feedback in the Code amendment by explicitly referring to the applicability of good electricity industry practice to a distributor's direction for an embedded generating station to operate in an alternative voltage control mode.

Extent to which voltage support transmission investment would be avoided

3.51. Contact Energy and NewPower thought the Authority should not use the avoided cost of all potential future transmission-scale dynamic voltage support equipment as a benefit. They believed it is not obvious that embedded generation providing voltage support would materially defer this cost.

3.52. Transpower, in its role as a transmission grid owner, noted the Code amendment proposal could help Transpower avoid having to consider some voltage support investments in the transmission grid. Transpower also considered the system security and resilience benefits to New Zealand consumers would substantially outweigh the initial and ongoing compliance costs for some asset owners and the increased costs for the System Operator associated with commissioning, testing and validating models, compliance monitoring, and greater co-ordination of system operation.

3.53. Transpower expected improved resilience for regions would result from extending fault ride through obligations to smaller generating units. Transpower, as a transmission grid owner, submitted that, in the absence of fault ride through obligations on generators (transmission-connected or embedded), it might need to invest in transmission assets to ensure adequate voltage recovery after faults. Transpower noted parties *not* causing the issue would end up paying some of the cost of such investment.

3.54. One of the clarifications to our assessment of the Code amendment proposal's benefits and costs relates to avoided transmission investment. Some submitters thought we believed the proposal would avoid or defer the need for *all* potential future transmission-scale dynamic voltage support equipment. This was not our view. Rather, we considered the Code amendment proposal would defer, and in some cases possibly avoid, the need for some of this investment – a point Transpower agreed with in its submission.

24 See clause 8.27 of the Code.

Feedback on the fault ride through element of the proposal and the Authority's response

Support for a lower cost approach to proving fault ride through compliance

3.55. Contact Energy supported the use of a high-level assessment of fault ride through compliance rather than in-depth studies, believing this would result in the same outcome but at significantly reduced cost. Manawa Energy noted the cost of in-depth studies could be $40,000–$100,000 per generating unit for Manawa Energy's existing hydro generating stations with a maximum export of 10–29.99MW, equating to $2 million – $5 million for Manawa Energy.

3.56. Mercury also said there was considerable time and cost associated with the existing fault ride through studies required by the System Operator, and that completing these would be onerous for smaller generators. Mercury supported simplified arrangements for generating stations with an output of less than 30MW – for example, using a supplier statement that technology complies with 'no trip zone' settings.

3.57. The EEA particularly supported proportionate obligations on embedded generators. Transpower supported the ongoing work between the System Operator and the Authority towards a proportionate cost approach to fault ride through assessments.

3.58. The Authority said in our consultation on the Code amendment proposal that we want compliance obligations on generating stations subject to the Code amendment to be proportionate to the generating station's size and impact on the power system. We said we were working with the System Operator on options to make proportionate the cost for assessing compliance with the Code's fault ride through obligations and that consultation on these was planned for later in 2025.[25]

3.59. In addition to working with the System Operator, the Authority has also engaged with the Common Quality Technical Group on this matter. Following feedback from this group, the Authority has requested the System Operator to implement an amendment to the fault ride through studies undertaken by generators to prove compliance with the Code's fault ride through requirements. Specifically, a generator with a generating station that has a maximum continuous MW output power of 10MW or more but less than 30MW may prove compliance by undertaking a single machine infinite bus test, using the fault ride through curve in the Code.

3.60. The System Operator is reflecting this in its connection study guidelines. Since these guidelines are not an Authority document, we have not consulted on this change. However, interested parties are welcome to provide feedback on the updated guidelines once these are published by the System Operator.

Possible alternative – rely on additional instantaneous reserve

3.61. NewPower submitted that a possible additional alternative to the fault ride through element of the Code amendment proposal would be to procure additional instantaneous reserve to cover a generating station's inability to ride through transmission faults. The cost of the additional instantaneous reserve could be paid by the non-compliant generator.

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25 See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal* – p.23.

3.62. The Authority did not include this as an alternative in our consultation because we consider this is provided for under the existing Code provisions. The owner of a generating station with a maximum continuous output of 10MW or more but less than 30MW, which cannot comply with the fault ride through element of the Code amendment proposal, can apply for a dispensation. Dispensations are conditional on asset owners paying any identifiable costs incurred by the System Operator as a result of their non-compliance. This means the System Operator can recover from the non-compliant generator the cost of additional instantaneous reserve procured due to the generating station's non-compliance.

3.63. The Authority notes however that a generating station's non-compliance would result in the asset owner being allocated additional instantaneous reserve costs under a dispensation only if:

(a) the generating station was considered a contingent event primary risk because of its inability to ride through transmission faults and the generating station was the binding risk in a given trading period, or

(b) the generating station was part of a group of generating stations considered to be a contingent event primary risk because of their inability to ride through transmission faults, and that group of generating stations was the binding risk in a given trading period.

3.64. We also note that recovering these instantaneous reserve costs would require a change to the System Operator's systems and processes, which we expect would have a material cost.

The Authority's decision

3.65. After considering submissions, the Authority has decided to proceed with both elements of the Code amendment proposal, but with the following changes:

(a) the default voltage support obligation on embedded generators will apply when voltage at the embedded generating station's point of connection to the local distribution network is within the relevant 11–110 kiloVolt (kV) voltage range set out in new clause 8.23A of the Code

(b) the default voltage support obligation on embedded generators will apply when the embedded generating station is synchronised with the local distribution network – this aligns with existing clause 8.23 of the Code

(c) the term 'maximum continuous MW output power' has been defined instead of amending the existing defined term 'maximum export power'

(d) the cut-off date for a generating station to be subject to the 'legacy clause' provisions in the Code amendment is moved from 1 July 2026 to 1 July 2027

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

3.66. The Authority has also requested the System Operator implement an amendment to the fault ride through studies the System Operator requires generators to undertake to prove compliance with the Code's fault ride through requirements. Specifically, a generator with a generating station that has a maximum continuous MW output power of 10MW or more but less than 30MW may prove compliance by undertaking a single machine infinite bus test, using the fault ride through curve in the Code.

3.67. The Authority thanks submitters for their feedback on the Code amendment proposal. We have made the above changes to the proposal in response to this feedback.

4. The Code amendment is consistent with our main statutory objective

4.1. The Authority's main statutory objective, under section 15(1) of the Electricity Industry Act 2010 (Act), is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

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

4.3. After considering all submissions on the Code amendment proposal, the Authority considers the final Code amendment is consistent with our main statutory objective, and with section 32(1) of the Act.[26]

4.4. The amendment promotes reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers by assisting the System Operator and distributors to manage voltages across New Zealand's power system at lower cost than under the status quo arrangements. Amongst other things, this in turn will reduce the risk of consumers facing economic costs associated with:

(a) greater voltage deviations or greater voltage instability causing electrical equipment to operate sub-optimally (eg, malfunctioning or using more energy than necessary) or to be damaged, or their quality of supply deteriorating (eg, flickering lights)

(b) voltage events resulting in 'sympathetic' tripping[27] of generating units/stations that in turn result in more power supply interruptions for consumers.

4.5. In making this Code amendment the Authority has applied our Code amendment principles, which are set out in our consultation charter.[28] In summary, we consider there is a clear case for regulation, having evaluated the Code amendment against the status quo arrangements and alternative options, and having assessed the Code amendment's benefits and costs.

The Code amendment's benefits are expected to exceed its costs

4.6. Having assessed the Code amendment's expected benefits and costs, the Authority considers the benefits will outweigh the costs. We also consider the Code amendment achieves its objective at lower economic cost than the main alternatives. In making our assessment, we have considered submitter feedback on the Code amendment proposal. Some submitters agreed with our assessment that the proposal's benefits would outweigh the costs. Others considered the benefits would not outweigh the costs or were unclear whether the benefits would outweigh the costs.

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26 Section 32(1) of the Act specifies what the Code may contain.

27 'Sympathetic' tripping of a generating unit occurs when the generating unit's protection equipment disconnects the unit from the network because of a disturbance on the network.

28 See Electricity Authority I Consultation Charter 2024.

4.7. In assessing the Code amendment's expected benefits and costs, we have built on our assessment for the Code amendment proposal. We have sought to clarify some misunderstandings surrounding our assessment of the proposal's benefits and costs, which led some submitters to raise concerns about our assessment. In particular, we have aggregated quantified benefits and costs rather than leaving them disaggregated. This has required us to make assumptions about the increase in the number of electricity generating stations with a capacity of 10MW or more but less than 30MW over the period of our assessment, which is 15 years.

Table 2: Summary of Code amendment's expected benefits and costs over 15 years

Benefit / Cost	Magnitude
Benefit of procuring less voltage support as an ancillary service*	$73m – $79.5m
Benefit of avoiding the need to invest in network-related assets to export/import reactive power^	$74.5m – $104m
Benefit of reduced operating costs associated with network-related assets exporting/importing reactive power^	$39.5m – $43m
Benefit of procuring less instantaneous reserve to manage the risk of 'sympathetic' tripping of generating units/stations	$1.5m – $4.5m
Benefit of supporting quality of electricity supply to consumers and reduced risk of electrical equipment malfunctioning or being damaged	Potentially material
Benefit of reduced risk of consumers' power supply being interrupted due to voltage-related power system disturbances	Potentially material
Benefit of the power system having relatively more capacity to transfer active/real power	Potentially material
Benefit of power system losses being lower	Potentially material
Benefit of generating stations being 'constrained on' less to export reactive power	Modest
Cost of embedded generating stations increasing their apparent power export capability	$7.5m – $12.5m
Cost of additional operating costs associated with embedded generation exporting/importing reactive power	$65m – $66m
Cost of obtaining 'legacy' status, obtaining a dispensation, proving fault ride through compliance	$0.5m – $1m
Expected net benefit *(ancillary services provide voltage support)*	**−$5m – $11m**
Expected net benefit *(network investment provides voltage support)*	**$36m – $78.5m**

Notes:

* This benefit is an alternative to investing in network-related voltage support assets.

^ This benefit is an alternative to procuring less voltage support ancillary services.

4.8. Table 2 summarises the expected benefits and costs of the Code amendment. Reflecting status quo arrangements, we have calculated two net benefit ranges:

(a) the first applies when ancillary services are used to provide the voltage support provided under the Code amendment

(b) the second applies when network investment is used to provide the voltage support provided under the Code amendment.

4.9. Compared to using ancillary services to provide the voltage support provided under the Code amendment, the estimated quantified net benefit of the Code amendment over 15 years ranges from approximately −$5 million, under a high cost / low benefit scenario, to approximately $11 million, under a low cost / high benefit scenario.

4.10. The Authority considers that, under this status quo arrangement, on the balance of probabilities the Code amendment's quantified net benefit will be positive. This is on the basis that it is reasonable to expect the Code amendment's quantified benefits and costs will fall somewhere in between the estimated upper and lower bounds. Absent any other information and treating all values within the range as equally likely, the most likely outcome is a positive net benefit. Factoring into our assessment the Code amendment's non-quantified benefits leads us to conclude that the Code amendment has a positive expected net benefit when compared to the use of ancillary services to provide the voltage support.

4.11. Compared to using network investment to provide the voltage support provided under the Code amendment, the estimated quantified net benefit of the Code amendment over 15 years ranges from approximately $36 million, under a high cost / low benefit scenario, to approximately $78.5 million, under a low cost / high benefit scenario. This is a clear positive expected net benefit, even before the Code amendment's non-quantified benefits are factored in.

Assessing the Code amendment's benefits and costs

4.12. The aim of the Code amendment is to facilitate the secure and resilient supply of electricity to consumers at the level of quality they desire, and at a lower cost than under the status quo arrangements.

4.13. Consistent with the first part of its aim, the Code amendment benefits consumers by reducing the risk of them facing economic costs associated with:

(a) greater voltage deviations or greater voltage instability causing electrical equipment to operate sub-optimally (eg, malfunctioning or using more energy than necessary) or to be damaged, or their quality of supply deteriorating (eg, flickering lights)

(b) voltage events resulting in 'sympathetic' tripping of generating units/stations that in turn result in more power supply interruptions for consumers.

4.14. Consistent with the second part of its aim, the Code amendment benefits consumers by—

(a) in relation to the voltage support element of the Code amendment:

(i) avoiding costs associated with the System Operator procuring voltage support as an ancillary service, and/or

(ii) deferring, and in some cases avoiding, some of the need to invest in transmission and distribution network-related assets to support voltage, thereby avoiding:

a. the capital cost associated with this investment

  b. the ongoing operating costs (eg, energy losses), associated with this investment, and/or

 (iii) deferring, and in some cases avoiding, some of the need to pay for non-network solutions to support voltage

(b) in relation to the fault ride through element of the Code amendment, the System Operator procuring less instantaneous reserve to manage the risk of 'sympathetic' tripping of generating units/stations.

4.15. It is difficult to quantify the benefit described in paragraph 4.13. Doing so requires an assessment of the extent to which the Code amendment lowers the risk of these adverse outcomes. For the voltage support element of the Code amendment, this in turn requires knowledge of the stock of consumer electrical equipment in New Zealand and its operating capabilities and usage.

4.16. It is easier to quantify the benefit described in paragraph 4.14, and the key expected costs of the Code amendment, which are:

(a) the apparent power export capability of embedded generating stations being increased to avoid revenue foregone from reduced active/real power export when the station is exporting or importing reactive power

(b) additional operating and maintenance costs, associated primarily with energy losses, from embedded generating stations exporting or importing reactive power

(c) compliance costs.

4.17. We start first with our assessment and quantification of these key costs.

Estimate of key costs of the Code amendment

4.18. After considering submitter feedback, we have not identified any key expected costs associated with the Code amendment that are additional to those described in our 2025 Code amendment consultation. However, as noted in paragraph 4.7, we have revised our 2025 assessment to produce aggregated estimates of these costs.

Cost of increased apparent power export capability

4.19. The Code amendment places an obligation on some embedded generating stations to regulate voltage at their point of connection to a local distribution network if certain conditions hold. These embedded generating stations are to do this by continuously exporting or importing reactive power that is a minimum of 33% of the maximum continuous MW output power of the generating station. This equates to the embedded generating station operating at a power factor of 0.95.

4.20. There is an opportunity cost associated with these generating stations providing this voltage support. While operating at a 0.95 power factor so as to export/import reactive power, the station cannot export approximately 5.26% of its active/real power potential. Consequently, the embedded generator cannot sell this active power in the wholesale electricity market, meaning potential revenue is foregone. Other things being equal, consumers will pay for this via higher electricity prices.

4.21. Therefore, in assessing the Code amendment's expected costs, the Authority has assumed the owners of embedded generating stations that must comply with the Code amendment will increase the stations' apparent power export capacities relative to the counterfactual of no voltage support obligation applying to them. This is so the embedded generating stations' active power export potential can be realised.

4.22. We consider this to be a reasonable, albeit conservative, assumption. It is conservative because an embedded generator may not increase an embedded generating station's capacity solely because of the Code amendment. One of the conditions that must hold before an embedded generating station provides the default voltage support is for the local distribution network operator to not direct that the station operates in an alternative voltage control mode. For the developer of a proposed embedded generating station, such a direction might be expected to have a more significant influence on the sizing of the generating station's apparent power export capacity than the default voltage support requirement.

4.23. To gain an understanding of the materiality of this cost at an aggregated level over the (15-year) period of our analysis, we have looked at Transpower's generation connection pipeline.[29] This says 9.3% of new generation capacity is embedded generation that requires new or upgraded Transpower assets. Drawing on information provided by the System Operator, we have increased this figure to 11% to account for embedded generation that does not require new or upgraded Transpower assets,[30] and we have assumed all such generation will need to comply with the Code amendment. Further, we assume this 11% represents a reasonable estimate of the percentage of new generation investment that will be subject to the Code amendment over the next 15 years. This timeframe aligns with Transpower's 2025 Transmission Planning Report, which contains a forecast out to 2040 of new generation capacity to be built.

4.24. The 2025 Transmission Planning Report forecasts approximately 10 gigawatts of new generation capacity being built over the next 15 years – see Table 3-1.[31] Given the assumptions in paragraphs 4.21 and 4.23, we estimate embedded generators will install approximately 76MVA[32] of additional (apparent power) capacity by 2040, to offset the effect on active power exports from operating at a 0.95 power factor instead of a unity power factor.

4.25. Almost all forecast new embedded generation out to 2040 uses inverters. Based on figures provided to the Authority via our engagement with the Common Quality Technical Group, the capital cost to install a one MVA inverter and associated equipment in an embedded generating station is estimated to be in the range of $150,000–$250,000 in 2025 dollars. Using this as a conservative estimate of the incremental cost of each additional MVA of inverter capacity gives an estimated cost of approximately $7.5 million – $12.5 million for the installation of additional (apparent power) capacity over the period 2026–2040.[33]

29 See Transpower connection pipeline - as at October 2025.

30 The System Operator provided the Authority with a list of embedded generating stations the System Operator has been advised are scheduled to be commissioned over the period mid-2026 to mid-2028.

31 See Table 3-1 of the *Transmission Planning Report*.

32 Approximately 1.4 gigawatts multiplied by 5.26%.

33 The Authority considers this cost estimate to be conservative on the basis that an additional MVA of inverter capacity will be less than the cost of installing a one MVA inverter and associated equipment in an embedded generating station.

Additional operating and maintenance costs associated with providing voltage support

Cost of energy losses

4.26. Inverters incur energy losses to export or import reactive power. This will represent an ongoing incremental cost of the Code amendment. In their submission on the Authority's June 2024 voltage options consultation paper, NewPower and Infratec NZ provided an estimate of $26,000 as the annual cost of producing one MVAr of reactive power every hour of the year, using a particular type of inverter.[34] We used this as an upper bound estimate in our assessment of the Code amendment proposal's expected costs.[35]

4.27. We have used this same methodology to give an upper bound estimate of the losses associated with embedded generating stations providing voltage support under the Code amendment over the 15-year period 2026–2040. We have assumed the MVAr exported or imported at a 0.95 power factor is 32.87% of active power (MW) and that $150/MWh is the average wholesale price of electricity in real terms (ie, 2025 dollars). We note $150/MWh is below the average of current ASX forward market prices, which is approximately $165/MWh. However, we are comfortable using $150/MWh because our period of analysis is 15 years rather than three years[36] and forecasts of wholesale electricity prices out to 2040 are closer to $150/MWh than $165/MWh.[37]

4.28. Over the 15-year period, the amount of losses incurred by inverter-based embedded generation continuously exporting or importing reactive power is estimated to be almost 845.5GWh of electricity,[38] which costs approximately $63.5 million in today's dollars. The losses increase from a little under 19.3GWh in 2026 to 83GWh by 2040.

4.29. We consider this methodology to be very conservative. The electrical connection of an embedded generating station for every hour in a year is theoretically achievable but practically unlikely. Forced or unforced outages mean an embedded generating station may be electrically connected for 98–99% of the time[39] rather than 100%. This methodology also assumes the Code amendment is the sole reason for an embedded generating station continuously exporting or importing reactive power while operating at a 0.95 power factor. In reality some embedded generating stations will export or import reactive power due to distributor requirements.

Other additional operating and maintenance costs

4.30. In addition to energy losses, there are various other operating and maintenance costs associated with inverters, such as monitoring and inspections, finance and insurance, and predictive and corrective maintenance. We have assumed the annual cost of

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34 NewPower and Infratec NZ noted the inverter model consumed approximately 20 kilowatts of active power for every one MVAr of reactive power produced. NewPower and Infratec NZ assumed an average annual energy spot price of $150/MWh across all 8,760 hours of a year.

35 See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal* – p.28.

36 The maximum period that ASX forward prices extend out to.

37 See, for example, the Climate Change Commission's long-run wholesale electricity price forecasts in *Draft advice on Aotearoa New Zealand's fourth emissions budget*, April 2024, p.122.

38 We assume inverter losses are approximately the same regardless of whether the inverter is exporting reactive power into, or importing reactive power from, the local distribution network.

39 Ie, approximately 3.5–7 days per annum.

these other operating and maintenance costs is 2% of inverter capital costs.[40] This translates to a cost of approximately $1.75 million – $2.75 million over our 15-year analysis period.

Compliance costs

4.31. The last identified material cost of the Code amendment is the cost associated with embedded generation owners complying with the new Code obligations. There will be some administrative compliance costs, such as owners of existing 10–29.99MW generating stations advising the System Operator of stations that are unable to comply with the Code requirements. We estimate the administrative cost associated with the generation owners advising the System Operator will be no more than $2,500 per station. This relates primarily to the cost of the generation owner updating its asset capability statement information and the System Operator reviewing this information. For the purposes of assessing the Code amendment's costs we have assumed 20 10–29.99MW generating stations are unable to comply with the Code requirements,[41] which gives a one-off cost of $50,000.

4.32. Over the next 15 years there may be some requests for dispensations from the owners of new generating stations that are unable to comply with the new Code requirements. We expect these will be rare because of modern technology being able to meet the new requirements. Nevertheless, to be conservative, the Authority assumes that each year for the next 15 years one generating station with a maximum continuous MW output power of 10MW or more but less than 30MW will be unable to comply with the new Code requirements. Informing this assumption is the current number of generating stations with a capacity in this range, and the number of such stations in Transpower's generation connection pipeline.

4.33. Based on historical data, the Authority estimates the cost of a typical dispensation from the proposed voltage support obligations or the proposed fault ride through obligations would be approximately $15,000–$25,000 (2025 dollars). This gives a cost estimate of approximately $150,000–$250,000 for dispensations under the Code amendment.

4.34. The Authority considers the most significant compliance-related cost will be the cost of generators undertaking fault ride through studies to prove their generating units can ride through transmission faults. As noted in paragraph 3.59, the Authority has requested the System Operator implement an amendment to the fault ride through studies undertaken by generators to prove compliance with the Code's fault ride through requirements. A generator with a 10–29.99MW generating station will be able

40 We have used 2%, rather than 1%, so as to reflect higher operating and maintenance costs associated with inverters exporting/importing reactive power continuously, rather than only when real/active power is being injected into the local distribution network.

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

to prove compliance by undertaking a single machine infinite bus test, using the fault ride through curve in the Code.

4.35. The Authority expects this approach will significantly reduce this compliance cost – perhaps to $15,000–$20,000 per generating station, on average (2025 dollars). Using this range, we estimate the incremental cost of fault ride through studies under the Code amendment will be approximately $300,000–$700,000 (2025 dollars), over the period 2026–2040. This assumes 2 to 4 generating stations with a maximum continuous MW output power of 10MW or more but less than 30MW connect to a network each year. This assumption has been informed by the projects in Transpower's generation connection pipeline.

Estimate of material benefits of the Code amendment

4.36. As noted in paragraph 4.14, the Code amendment:

(a) avoids costs associated with the System Operator procuring voltage support as an ancillary service, and/or

(b) defers, and in some cases avoids, some of the need to invest in transmission and distribution network-related assets to support voltage, thereby avoiding:

(i) the capital cost associated with this investment

(ii) the ongoing operating costs (eg, energy losses), associated with this investment, and/or

(c) defers, and in some cases avoids, some of the need to pay for non-network solutions to support voltage.

4.37. As with the Code amendment's key costs, we have revised our 2025 assessment of the Code amendment's material benefits to produce aggregated estimates. This includes estimates for the two status quo arrangements we assume would be used to provide the voltage support provided under the Code amendment – namely the procurement of ancillary services and investment in network assets.

4.38. For the purposes of our analysis, the Authority has made some key simplifying assumptions.

4.39. First, we assume the key benefits of the voltage support element of the Code amendment proposal are:

(a) avoiding costs associated with the System Operator procuring voltage support as an ancillary service, and/or

(b) deferring, and in some cases avoiding, some of the need to invest in transmission and distribution network-related assets to support voltage.

4.40. In other words, we assume the deferral, and in some cases avoidance, of non-network solutions purchased by network owners to support voltage is not a key benefit. This is on the basis that in recent years Transpower, as a transmission grid owner, has found non-network solutions to support voltage to not be as cost effective as network solutions.[42] This assumption has the effect of making our estimate of the Code amendment's benefits more conservative. That is, the estimated benefits are

42 See, for example, Transpower - Work on voltage management project to commence and Transpower - Second stage of $144m grid project brought forward in response to electricity demand increases.

smaller than if we were to include the avoided cost of non-network solutions to support voltage.

4.41. Second, we assume the two key benefits of the voltage support element of the Code amendment are mutually exclusive. That is, the key benefit of the voltage support element of the Code amendment is either avoiding the procurement of voltage support ancillary services or avoiding investment in voltage support network assets. This removes the need to assume an appropriate ratio of the two benefits. We consider understanding the respective benefits to be the important consideration in our assessment of the Code amendment's benefits.

4.42. Next, we assume voltage support provided by embedded generating stations under the Code amendment will avoid the need for an equivalent amount of voltage support provided by network-related assets such as STATCOMs and SVCs. Put another way, we are assuming the Code amendment will result in the total MVAr capacity of network-related voltage support assets being lower than they otherwise would be by approximately the MVAr capacity of compliant embedded generating stations.

4.43. In reality the Code amendment may also result in the future deferral of some network-related voltage support assets that are over-sized for reasons of scale efficiencies or cost-effectiveness. However, we consider this benefit relatively uncertain and so, in the interest of being conservative, we have not included it in our assessment.

4.44. Finally, we assume the amount of voltage support ancillary services and investment in voltage support network assets increases in line with the forecast increase in voltage support provided by embedded generation out to 2040. This is on the basis that, absent the Code amendment, this level of voltage support would still be needed to supplement other voltage support required to operate the power system.

Procuring less voltage support as an ancillary service

4.45. For the purposes of our assessment of the Code amendment's benefits, the Authority assumes only generators provide voltage support as an ancillary service. This is on the basis that generators should be able to provide voltage support at lower cost than network owners. This is consistent with our estimates of the Code amendment's costs and benefits – ie:

(a) the additional capital and ongoing costs associated with generating stations increasing their apparent power export capability and continuously exporting or importing reactive power

(b) the reduced capital and ongoing costs associated with less investment in network assets providing voltage support.

4.46. We also assume inverter-based generation would typically provide voltage support ancillary services. This is on the following basis:

(a) In relation to existing generation, the owners of inverter-based generation competing to supply voltage support ancillary services would *on average* face a lower cost in providing the services than the owners of non-inverter-based generation. The owners of existing inverter-based generation could over-size their generating stations' inverters to avoid the opportunity cost of foregone earnings from (electrical) energy sales in the wholesale electricity market. In comparison, the owners of existing non-inverter-based generation are assumed to face higher upgrade costs to upsize their generating stations' generators relative to the stations' turbines. All else being equal, this would therefore be expected to make these stations uncompetitive relative to inverter-based generation in the provision of voltage support ancillary services.

(b) In relation to new generation, the overwhelming majority of this is forecast to be inverter-based generation,[43] and so it is reasonable to assume that typically this type of generation would be providing voltage support as an ancillary service.

4.47. In estimating the Code amendment's benefit of avoiding the procurement of voltage support ancillary services, we have used our estimates of the cost to increase embedded generating stations' apparent power export capability and for them to continuously export or import reactive power. That is, we estimate inverter-based generation owners would:

(a) spend approximately $9 million – $15 million installing, and operating and maintaining, additional (apparent power) capacity over the period 2026–2040

(b) spend approximately $63.5 million on wholesale electricity over the period 2026–2040 to cover inverter-related electrical losses.

4.48. To these costs we add an estimate of the contract administration and compliance costs associated with tendering, entering into, and delivering voltage support as an ancillary service. We estimate this cost would be, on average, approximately $50,000–$100,000 per annum in 2025 dollars, or $500,000 – $1 million over 15 years. This assumes the System Operator contracts annually with several voltage support ancillary service providers.

4.49. The Authority notes our estimate of the benefit of avoided voltage support ancillary service costs excludes any return on investment or profit margin. This is to ensure our benefit estimate is conservative.

Reduced investment in reactive power network assets

4.50. Using the same information and input assumptions we used in estimating the key costs of the Code amendment, we estimate approximately 475MVAr of reactive power capacity will be subject to the default voltage support obligation by 2040. This includes 110MVAr of existing capacity provided by 335MW of embedded generation that will be able to comply with the Code amendment's voltage support obligation.

4.51. Figures available to the Authority indicate:

(a) the per-MVAr capital cost to install a STATCOM and associated equipment on a distribution network are in the range of $250,000–$300,000

(b) the per-MVAr capital cost to install a STATCOM and associated equipment on New Zealand's transmission grid are in the range of $250,000–$400,000.[44]

4.52. To be conservative in our estimate of benefits, we have used a per-MVAr capital cost range of $250,000–$350,000. This gives a benefit from the avoided capital cost of investing in network-related voltage support assets in the range of $74.5 million – $104 million.

43 See Transpower connection pipeline - as at October 2025.

44 See the Authority's consultation paper *Promoting reliable electricity supply - a voltage-related Code amendment proposal* – p.27.

4.53. We have used STATCOMs in our analysis on the basis that they are the network-related voltage support asset for which costs are most likely to be avoided under the Code amendment. STATCOMs provide voltage support in a manner most similar to inverter-based generation. A STATCOM offers superior reactive power compensation compared to SVCs. We note Transpower initially proposed using SVCs in its Waikato and upper North Island voltage management project investments but then ended up installing STATCOMs.

Reduced operating and maintenance costs associated with reactive power network assets providing voltage support

Reduced cost of energy losses

4.54. STATCOMs incur energy losses when operating. The Authority has used an estimate of 10kW per MVAr as an upper bound estimate of these losses.[45]

4.55. Consistent with our estimate of the energy losses associated with embedded generating stations providing voltage support under the Code amendment, we assume STATCOMs operate across all 8,760 hours of a year. Over the 15-year period of our analysis, the energy losses incurred by STATCOMs used instead of embedded generation to provide voltage support is estimated to be approximately 422.75GWh of electricity. This equates to approximately $32 million, in today's dollars.

Reduction in other operating and maintenance costs

4.56. The Authority estimates annual operating and maintenance costs of STATCOMs, excluding energy losses, to be on average 1% of the capital cost.[46]

4.57. This gives a benefit of approximately $7.5 million – $11 million in reduced operating and maintenance costs, excluding energy losses, associated with reduced investment in network assets providing voltage support.

Less instantaneous reserve procured to manage the risk of 'sympathetic' tripping

4.58. The Authority expects that, absent the Code amendment, the System Operator would have procured relatively more instantaneous reserve in managing the increased risk of generating units tripping during transmission faults. The System Operator would have procured this additional reserve whenever a 10–29.99MW generating station with non-compliant generating units[47] was part of the binding contingent event risk. Proceeding with the Code amendment avoids the incremental cost of this reserve.

4.59. The quantum of this avoided cost over the next 15 years is hard to estimate due to the types of assumptions required. Difficult assumptions include:

(a) the MW capacity of 10–29.99MW generating stations with non-compliant generating units

45 See, for example, Kurthakoti, D., 2025, Reactive Power Utilization: Generation Plants - A need, nice to have or easy to enforce?

46 See, for example, Transpower's estimate of annual operating costs for its Waikato and upper North Island voltage management project investments.

47 Ie, generating units that do not comply with the Code's fault ride through requirements.

(b) the frequency with which the System Operator would have procured instantaneous reserve to cover this non-compliant generation, which would depend on when this generation was part of the binding contingent event risk

(c) the amount of instantaneous reserve the System Operator would have procured to cover non-compliant generation, which would depend on the type of generation – ie, variable and intermittent versus controlled storage generation.

4.60. To provide an indication of the materiality of the benefit of avoided instantaneous reserve costs, the Authority has estimated the avoided cost of fast instantaneous reserve and sustained instantaneous reserve.

4.61. Consistent with one of our assumptions used in estimating the incremental cost of fault ride through testing under the Code amendment, we assume 2 to 4 generating stations with a capacity of 10MW or more but less than 30MW connect to a network each year. We assume that, had the Code amendment not been made, the average capacity of these stations would have been 27.5MW. Both of these assumptions have been informed by the projects in Transpower's generation connection pipeline. The capacity assumption also makes sense from an economic perspective – a developer looking to build a generating station with a capacity less than 30MW will want to maximise potential revenue while minimising compliance costs and the possibility of the station's output reaching the 30MW threshold.

4.62. We assume the cost of fast instantaneous reserve (in 2025 dollars) is $4.45/MW per trading period, and the cost of sustained instantaneous reserve (in 2025 dollars) is $3.85/MW per trading period.

4.63. These estimates are based on the approximate average price of fast instantaneous reserve and sustained instantaneous reserve in the North Island over the five years to 31 December 2024.

4.64. Following discussion with the System Operator, we assume the System Operator applies a fast instantaneous reserve factor of 0.5 and a sustained instantaneous reserve factor of 1.0. This results in the System Operator buying:

(a) fast instantaneous reserve for affected trading periods that is 50% of the MW generating capacity included in the contingent event risk

(b) sustained instantaneous reserve for affected trading periods that is 100% of the MW generating capacity included in the contingent event risk.

4.65. Lastly, we assume the System Operator would have included the MW capacity of non-compliant 10–29.99MW generating stations included in the contingent event risk for 0.5–1% of trading periods (ie, 87.5–175 trading periods per annum or approximately 1.7–3.4 trading periods per week). This assumption is based on discussions with the System Operator, as well as Contact Energy's feedback on the Code amendment proposal. Contact Energy considered that cumulative additional reserve costs to cover the risk of 'sympathetic' tripping of non-compliant 10–29.99MW generating stations could be minimal. This was because of the highly locational nature of a voltage deviation event making this risk marginal.

4.66. We consider this last assumption to be conservative. In 2025 the System Operator purchased instantaneous reserve for approximately 12–13% of trading periods to cover a contingent event risk involving generation that is non-compliant with the Code's fault ride through requirements.

4.67. Based on the above information and input assumptions, the Authority estimates that, over the 15-year assessment period:

(a) avoided fast instantaneous reserve costs under the Code amendment could be in the range of $600,000 – $2.4 million

(b) avoided sustained instantaneous reserve costs under the Code amendment could be in the range of $500,000 – $2.1 million.

The Code amendment's non-quantified benefits

4.68. In addition to the quantified benefits discussed above, the Code amendment has several other expected benefits, which the Authority has not sought to quantify. These include:

(a) reducing the risk of consumers facing economic costs associated with greater voltage deviations or greater voltage instability causing electrical equipment to operate sub-optimally (eg, malfunctioning or using more energy than necessary) or to be damaged, or their quality of supply deteriorating (eg, flickering lights)

(b) reducing the risk of consumers facing economic costs associated with voltage events resulting in more power supply interruptions to consumers

(c) the power system having relatively more capacity to transfer active power

(d) losses across the power system being lower

(e) reducing the need for generating stations to be 'constrained on' to export reactive power.[48]

4.69. We consider the first four benefits listed above have the potential to be material. For example, the Ministry of Business, Innovation and Employment (MBIE) reports that transmission and distribution losses have been approximately 3,000GWh per annum over the period 2015 to 2024.[49] At our assumed wholesale electricity price of $150/MWh, just a 0.1% reduction in these losses as a result of embedded generation providing voltage support would deliver a benefit of $450,000 annually ($3.85 million over 15 years).

4.70. Another example of a potentially material benefit is reducing the risk of interruptions to consumers' power supply due to voltage-related power system disturbances. The Code places a value of $20,000 on one MWh of unserved energy (lost load).[50] So, small reductions in power outages can provide material benefits to consumers.

4.71. The Authority has erred on the side of conservatism and not sought to quantify such benefits due to a high degree of uncertainty and/or insufficient information to inform our assessment. For example, and as noted in paragraph 4.15, quantifying the first two benefits listed above requires assessing the extent to which the Code amendment lowers the risk of these adverse outcomes. For the voltage support element of the Code amendment, this in turn requires knowledge of New Zealand's stock of consumer electrical equipment and its operating capabilities and usage.

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48 A 'constrained on' situation occurs when the System Operator gives a dispatch instruction to a generator and the generator's offer price for that dispatched quantity of electricity is higher than the final price for the trading period. See clause 13.202 of the Code.

49 See the latest New Zealand Energy Quarterly (September 2025) and associated electricity statistics, available at New Zealand Energy Quarterly and Data tables for electricity.

50 See clause 4 of Schedule 12.2 of the Code.

4.72. Not estimating some of the Code amendment's benefits means we have a quantified net benefit that is accordingly lower. Further reducing the quantified net benefit is the conservatism in our analysis, as noted throughout our assessment of the Code amendment's benefits and costs.

4.73. Despite these factors, we consider the Code amendment has a quantified net benefit. Taking into consideration non-quantified benefits further increases the Code amendment's net benefit.

5. Attachments

5.1. The following appendix is attached to this paper:

Appendix A Approved Code amendment

Appendix A Approved Code amendment

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

A.2. Code amendments are shown as follows:

a. text or formatting is red underlined where the consultation paper proposed it be added to the Code

b. deleted text is red strikethrough where the consultation paper proposed it be deleted from the Code.

c. text or formatting is shown in blue underlined where drafting changes were made following consultation and it is to be added to the Code

d. deleted text is in blue strikethrough where drafting changes were made following consultation and it is to be deleted from the Code.

A.3. As noted in paragraph 3.18, the new definition 'maximum continuous MW output power' requires a consequential amendment to the definition of 'point of connection'. This is to make clear that the definition of 'maximum continuous MW output power' applies to embedded generation under Technical Code A of Schedule 8.3 of the Code.

A.4. Further minor consequential amendments are required to clauses 4(5) and 6 of Technical Code A to make clear that the reference to 'point of connection' is a reference to a point of connection on the transmission grid.

Part 1
Preliminary provisions

…

1.1 Interpretation

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

…

good electricity industry practice means:

(a) in relation to a **grid owner** transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced **asset owner** engaged in the management of a transmission **network** under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection., with the The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission **network** and the applicable law; and

(b) in relation to a **distributor**, the exercise of that degree of skill, diligence, prudence, foresight and economic management that would reasonably be expected from a skilled and experienced **electricity network** owner engaged in New Zealand in the **distribution** of **electricity** under conditions comparable to those applicable to the **distributor's network** consistent with applicable law, safety and environmental protection, with the determination of comparable conditions to take into account factors such as the relative size, duty, age and technological status of the relevant **distribution network** and the applicable law

…

maximum continuous MW output power means:

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

(b) for each **generating station**, **embedded generating station** or **generating unit** for which a **generator** or an **embedded generator** is not required to submit an **offer** under this Code, the maximum **active power** output (in **MW** alternating current (a.c.)) of the **generating station**, **embedded generating station** or **generating unit** at its **point of connection** that can be maintained continuously over a 5-minute period of time under ideal operating conditions—

    (i) as specified in the **asset capability statement** for the **generating station**, **embedded generating station** or **generating unit**; and

    (ii) with the **generating station**, **embedded generating station** or **generating unit** maintaining compliance with this Code in the absence of any exemption, **dispensation**, **equivalence arrangement** or similar

…

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

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

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

…

point of connection means—

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

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

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

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

…

Part 8
Common quality

…

8.21 Excluded generating stations

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

(b) clause 8.25D, an excluded generating station means a generating station that has a maximum export power of less than 10 MW, unless the Authority has issued a direction under clause 8.38 that the generating station must comply with clauses 8.25A and 8.25B.

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

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

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

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

(4) Subject to subclause (5), a **generating station** or **embedded generating station** that first **electrically connects** to the **grid** or directly or indirectly to a **local network** on or after 1 July 2026 and before 1 July 2027 and

which would have been an **excluded generating station** if the definition of that term in the Code immediately before the commencement of the [*name of the amending instrument*] applied to it, is an **excluded generating station** if—

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

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

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

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

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

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

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

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

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

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

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

…

8.23 Voltage support AOPOs for grid-connected generating stations

…

8.23A Voltage support AOPOs for embedded generating stations

(1) Unless agreed otherwise with the **distributor** who operates the **local network**, each **embedded generator** must ensure that each **embedded generating station** it owns or operates to which clause 5(2A) of Technical Code A applies is, when **synchronised** with the **local network**, at all times capable of—

(a) when the voltage at the **embedded generating station's point of connection** to the **local network** is within the applicable range of nominal voltage in the table below, exporting a minimum **reactive power** of 33% of the **maximum continuous MW output power** of the **embedded generating station**, as measured at the **embedded generating station's point of connection** to the **local network**:

Nominal **local network** voltage (kV)	Voltage range for which **reactive power** is required			
	Minimum (kV)		Maximum (kV)	
110	99	-10.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

(b) when the voltage at the **embedded generating station's point of connection** to the **local network** is within the applicable range of nominal voltage in the table below, importing a minimum **reactive power** of 33% of the **maximum continuous MW output power** of the **embedded generating station**, as measured at the **embedded generating station's point of connection** to the **local network**:

Nominal **local network** voltage (kV)	Voltage range for which **reactive power** is required			
	Minimum (kV)		Maximum (kV)	
110	104.5	-5.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%

11	10.725	-2.5%	11.275	2.5%

Schedule 8.3
Technical codes

Technical Code A – Assets

…

4 Requirements for grid and grid interface

…

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

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

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

…

5 Specific requirements for generators

…

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

(a) a voltage **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

(b) in order to meet the **asset owner performance obligations**, either—

(i) a connection transformer with an appropriate range of taps on each transformer together with an on-load tap-changer; or

(ii) **assets** to give a dynamic performance equivalent to those required by subparagraph (i).

(2A) Each **embedded generator** must at all times ensure that each of its **embedded generating stations** connected to a **local network** is equipped with, and operates when the conditions specified in subclause (2B) apply, a voltage **control system** that enables the **embedded generating station** to export or import **reactive power** through the **embedded generating station's point of connection** to the **local network** so as to regulate voltage at the **embedded generating station's point of connection** to the **local network**.

(2B) ~~Subclause (2A) only applies in respect of an~~ The conditions that apply under subclause (2A) are that the **embedded generating station**—

(a) ~~that is connected~~ **electrically connects** to the **local network** at the nominal voltage of the electrical busbar—

(i) at which a **grid owner** has agreed to provide services to the **local network** owner; and

(ii) that is electrically closest to the **embedded generating station**; and

(b) ~~that~~ has a ~~**maximum export power**~~ **maximum continuous MW output power** of 10 **MW** or more~~; and~~.

(2C) Subclause (2A) only applies in respect of an **embedded generating station**—

~~(c)~~(a) if the **distributor** who operates the **local network** has not directed the **embedded generator** to operate the **embedded generating station** in an alternative voltage control mode (such as constant **reactive power** or constant power factor) for the purpose of enabling the **distributor** to operate the **local network** in accordance with **good electricity industry practice**; and

~~(d)~~(b) that, if first **electrically connected** to a **local network** before 1 July ~~2026~~ 2027, is able to comply, without modification, with all the requirements in ~~subclauses~~ subclause (2A) and ~~(2C)~~ in clause 8.23A.

~~(2C) Unless agreed otherwise with the **local network** owner, each **embedded generator** who owns or operates an **embedded generating station** to which subclause (2A) applies must ensure that the **embedded generating station** when **electrically connected** to the **local network** is at all times capable of—~~

~~(a) exporting a minimum **reactive power** of 33% of the maximum continuous **MW** output power of the **embedded generating station**, both as measured at the **embedded generating station's point of connection** to the **local network**; and~~

~~(b) importing a minimum **reactive power** of 33% of the maximum continuous **MW** output power of the **embedded generating station**, both as measured at the **embedded generating station's point of connection** to the **local network**.~~

(2D) Subclause ~~(2B)(d)~~ (2C)(b) ceases to apply in respect of an **embedded generating station** from the date—

(a) a modification is made to the **embedded generating station** that means it is able to comply with all the requirements in ~~subclauses~~ subclause (2A) and ~~(2C)~~ clause 8.23A; or

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

(2E) Each **embedded generator** must update the **asset capability statement** for an **embedded generating station** to—

(a) explain the extent to which the **embedded generating station** complies with the requirements of subclause (2A), where that subclause applies; and

(b) record any direction given in respect of the **embedded generating station** under subclause ~~(2B)(c)~~ (2C)(a).

(2F) When preparing the information required under subclause (2E), an **embedded generator** is not required to undertake and provide power system studies that are additional to the power system studies the **embedded generator** must undertake for, and provide to, the **distributor** who operates the **local network** to which the **embedded generating station** is connected.

…

6 Specific requirements for connected asset owners

Each **connected asset owner** must agree with the **system operator** any temporary or permanent connection of the **connected asset owner's assets** if those **assets** become simultaneously connected to the **grid** at more than 1 **point of connection** on the **grid**.

…