Chairman: Ben Gibson, [redacted]
Secretary: David Inch, [redacted]

INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

15 July 2025

Future Security and Reliability team
Electricity Authority
P O Box 10041
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Dear team,

Re: Consultation Paper—Promoting reliable electricity supply – a voltage-related Code amendment proposal

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

The Authority's proposals, to be effective from 1 July 2026, are to:

1. place obligations on embedded generating stations that can export 10MW or more of electricity and which are connected at the grid exit point voltage (the voltage on the distribution network side of the GXP ie, the voltage of the GXP supply busbar); and
2. lower, to 10MW, the threshold for generating stations to comply with the Code's fault ride through asset owner performance obligations.

Our understanding of the proposed Code amendments is that:

- embedded generating stations with a maximum export power of 10MW or more are subject to these new requirements
- if an embedded generating station commissioned before 1 July 2026 can not comply (without modification) from either obligation they are grandfathered from BOTH new obligations
- any modification made to the embedded generating station to increase its maximum export power must include modifications to ensure compliance with both the voltage support and fault ride through obligations
- the onus is on the asset owner to update the station's Asset Capability Statement if it can't comply and if modifications are made that mean it must comply.

[1] The Committee has signed off this submission on behalf of members.

The IEGA supports the Authority's proposals that the new obligations would not apply to generating stations commissioned before 1 July 2026 that are not able to comply without modification. We note the exception will only apply if the relevant generator notifies the system operator that the generating station is not able to comply with these provisions, via the asset capability statement for that generating station.

Default voltage control mode

If an embedded generating station is covered by all Code requirements to offer voltage support it is not clear from the consultation paper why the Authority is setting a default requirement:

" to actively 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 both be measured at the embedded generating station's point of connection to the local distribution network. However, the distributor and embedded generator may agree an alternative reactive power capability range for the generating station." (paragraph 3.3)

We have the following questions:

- how was 33% determined – what is the technical rationale for this setting?
- how does 33% compare with the requirements on generators that are not embedded?
- what is the cost to the generator and to the overall market supply of this requirement?

Our feedback in August 2024 was[2]:

> *"It is not apparent that the existing +50%/-33% reactive power range requirement is optimal or even appropriate for the future. It is not obvious what reactive power range is appropriate for distribution networks.*
>
> *A reactive power range needs to be linked to the power factor limits requirement. It is not appropriate for these to be defined independently of each other as presented in the consultation paper.*
>
> *No analysis of the costs and benefits for any combination of reactive range has been presented so an opinion on pros and cons of any arrangement does not have much value."*

It is a significant step to determine a specific provision of reactive power. Both Vector[3] and Orion[4] suggested in their August 2024 submissions that more detailed analysis should be undertaken first before this type of Code amendment:

Vector: "We agree that the existing arrangements for coordinating voltage across GXPs can be improved and we suggest that the Authority prioritise a review that clarifies the shared responsibility between the SO, grid owner, and distributors. Ideally a comprehensive review would make it clear what actions each party can take and to what extent they are responsible for voltage, power factor, and reactive power. This would include guidance about when and where different types of equipment should be deployed to make the coordination of voltage and power factor at GXPs as efficient as possible."

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[2] Response to Q4 https://www.ea.govt.nz/documents/5534/IEGA_L1xcLvt.pdf
[3] Page 1 https://www.ea.govt.nz/documents/5526/Vector_IOICZoM.pdf
[4] Page 3 https://www.ea.govt.nz/documents/5521/Orion_nVLyZMv.pdf

> Orion's view is that if uniform voltage support is required across the network, there should be a clear mechanism for compensation, as the primary value accrues to Transpower. If Transpower wishes to opt out of this responsibility, it's important to understand why and determine who should bear the associated costs.
>
> This issue highlights the need for a more comprehensive discussion about the allocation of responsibilities and costs in maintaining voltage stability across the network. Any solution should consider the varied nature of local distribution networks and ensure that voltage support obligations are placed where they can be most effective and efficient.

This interconnectedness is demonstrated by the Authority referring to Transpower Grid Owner investing $101m in two 150MVAr STATCOMs (one at Hamilton and another at Otahuhu). Are the Code changes proposed by the Authority (and System Operator) really going to improve voltage so much that this is the last investment in voltage support by the Grid Owner?[5]

Concluding remarks

The grandfathering of embedded generation commissioned before 1 July 2026 that can not be compliant with the proposed Code changes without modification is important given:

- the cost benefit analysis is highly qualitative (and the Authority states "the cost of the proposed Code amendments are relatively significant")
- the Authority has focused on the proposed amendments because they are "quick wins" from their perspective with the economic case for these changes at this time uncertain (noting that supporting voltage will reduce energy exports and raise the levelised cost of energy for any new embedded generation).

We query why the Authority has not investigated or commented on the option of requiring grid-forming inverters on new IBR generation plant to address the future issues the SO is forecasting.

Our preferred solution continues to be market based – a market for a new ancillary service contract for reactive power management. This is consistent with Principle 5 – preference for market solutions – in the Authority's Consultation Charter.[6] A market also ensures greater competition in the provision of voltage support (Principle 4) and is flexible to allow for innovation (Principle 6) – for example BESS providing dynamic voltage support on the transmission and distribution networks at a lower cost than traditional STATCOM solutions. A market for reactive power management is also less prescriptive compared with the proposed Code change (Principle 7). Our August 2024 submission focuses on the benefits of a market based solution.

Overall, we suggest there has been a lack of expert and robust analysis to support the level of change for new embedded generation and the cost to participants.

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

Yours sincerely

Ben Gibson
Chair

[5] Paragraph 3.50 of consultation paper
[6] https://www.ea.govt.nz/documents/482/Consultation_Charter_2024.pdf