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Electricity Authority

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20 August 2024

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Review of Common Quality Requirements in the Code

Transpower welcomes the opportunity to submit to the Authority's consultation on its Review of the Common Quality requirements in the Code, published 25 June 2024.

This review has, appropriately, been the priority focus of the Electricity Authority's Future Security and Resilience (FSR) programme. The analysis by the FSR team, supported by Transpower in its system operator role, and with the robust review and discussions by the Common Quality Technical Group, has established a thorough process for developing the options.

Transpower has two roles in the New Zealand Power System, as the system operator and grid owner. This submission covers both system operator and grid owner views in the frequency, voltage and harmonics matters canvassed by the consultation.

As system operator, the obligations in Part 8 concerning frequency and voltage have a significant impact on future security of the power system and on our approaches to meeting our principal performance obligations.

System operations experts within Transpower have been supporting the Authority in its review of Part 8 and provided technical studies which are published alongside the consultation papers. These studies demonstrate the challenges of managing frequency and voltage as the system transitions from one dominated by predictable, synchronous generators to one with growing variable, inverter-based generation.

As grid owner, Transpower must ensure that its assets are capable of being operated within specific voltage ranges. Grid capacity for real power flow is dependent on managing reactive power at the grid edge (i.e. grid exit points and grid injection points). For voltage constrained regions the grid owner must assess how connections to the grid affect regional load limits under steady state conditions. Furthermore, without generator (grid connected or embedded) ride through obligations, the grid owner may need to invest in grid assets to ensure adequate voltage recovery after faults, with costs recovered from those not causing the issue. Obligations that extend to smaller generation units are expected to improve resilience for regions.

Concerning harmonics, the regulations need to achieve a balance so that (to the extent practicable) harmonics are mitigated at source. We appreciate the Authority's ongoing attention to this important system performance issue.

In our view, as both system operator and grid owner, extending the reach of the existing frequency and voltage obligations is in the long-term interests of consumers. There will be both initial and ongoing compliance costs for some asset owners and Transpower, in its role as system operator, will incur increased costs of commissioning testing and validating models, compliance monitoring, and greater co-ordination of system operation. These additional costs, however, will be substantially outweighed by the benefits to New Zealand.

Priorities for regulatory change are to:

- **Lower the excluded generation threshold** for frequency (frequency option 1) and for fault-ride through (voltage option 3) from 30 MW to 5MW as we are already seeing an increase in the number of new connections at these levels. With expectations for the majority of future investment being from variable and intermittent resources, being clear on quality performance settings is critical to manage system stability and reliability for consumers.
- **Extend voltage obligations and enable power factor management at the GXP** (voltage options 1 and 2) to ensure the most efficient provision of voltage management costs, and efficient use of the power system.

We respond to the questions on each of the three consultations in the appendices, and have also raised additional points where relevant.

Support review of the dispensation process

Finally, the Authority has signalled that the dispensation process will be reviewed for the financial year 25/26. We strongly support a timely review to ensure that future performance obligations are not at risk of being undermined by recourse to the current dispensation process. While a dispensation process can help manage legacy asset operation during transition, future investment should be made knowing expectations for common quality performance, and reviewing the dispensation process is a key part of this.

Yours sincerely

Joel Cook

Head of Regulation

Appendix – Responses to questions about frequency options

<table>
<tr><th>Question</th><th>Response</th></tr>
<tr><td>Q1. Do you agree the Authority should be short listing for further investigation the first frequency related option to help address Issue 1? If you disagree, please explain why?

[First option is lower the 30MW threshold e.g. to 5MW].</td><td>The system operator strongly supports the Authority short-listing the option to lower the threshold for excluded generating stations. This change is important for ensuring system stability performance from the anticipated but potentially unstructured increase in DER, which could impede greater renewables penetration if that cannot be assured. The analysis in Appendix C (Frequency Consultation paper) shows that lowering the threshold will enable the system operator to better manage risk and system frequency under higher Inverter Based Resource penetration. Importantly, it will avoid increased risk of cascade failure as a result of sympathetic tripping, increased AUFLS events, and the need to purchase increased reserves. The analysis made realistic (not overly conservative) assumptions that a maximum of 20% of generation below the threshold would trip in response to frequency drop.

Importantly, without lowering the threshold, the system operator (and consumers), will face greater uncertainty around the security of the system and an increased need for reserves and a higher reliance on AUFLS.

It is worth commenting that other jurisdictions with larger power systems have already lowered their thresholds.</td></tr>
<tr><td>Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?

[First option is lower the 30MW threshold e.g. to 5MW].</td><td>The risks and costs of not lowering the threshold are significant. These cover the costs of potential increase and size of AUFLS events and the increase in reserve costs to cover potential secondary risk.

Benefits
Reduced costs for reserves. These costs are recovered from generators and HVDC owner (grid owner).
Reduced risk of sympathetic tripping of smaller DERs during an under-frequency event. This secondary tripping may result in AUFLS events, or in extreme cases cascade failure with more significant loss of supply for consumers.
Where there is uncertainty in the levels of potential secondary risk, this will likely increase the two costs above.
Costs
5MW<30MW generators will have increased administrative cost to comply with the new</td></tr>
</table>

Question	Response
	obligations (Please refer to question 3 for more details on these costs). • Current generators below the 30 MW threshold may have costs in control systems needed to meet the obligations or compensate for not meeting them. • The system operator will need to extend the commissioning and testing compliance process for the wider range of generators, and potentially work with participants and the Authority on this process. • Costs associated with monitoring compliance.
Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?	• Administrative costs include providing asset capability statement information, undertaking connection studies, following system operator commissioning and testing process. • Upgrading existing equipment to comply.
Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an underfrequency event for six seconds?	AS/NZS 4777.2 specifies the expected performance and behaviour of inverters at low voltages (such as households or small-scale commercial) and the necessary tests for compliance. The Code would need to follow the Standard for under-frequency event ride through. All manufacturers will design and build their devices based on Standards; the Code needs to align to the Standard so that asset owners can procure equipment/devices that can comply with the Code. Most significant benefits of this alignment are consistency with international standards which will make it easier for asset owners to procure equipment which can comply with the Code.
Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	As a general principle, we support the same dead-band for all technologies. This is because • if the inherent deadband of a particular technology is wider than the permitted deadband, the system operator can consider dispensations as a way to manage this, and • it will be easier to manage with one single deadband than with different ones for different technologies. It is not only different technologies that have different inherent deadbands, but often different stations or different manufacturers.
Q6. Do you consider the Authority should be short listing the widening of	No. New Zealand already has a wide normal band (50Hz +/- 0.2Hz) compared with other jurisdictions.

Question	Response
the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	Widening the normal band would need to be complemented with a defined dead-band policy. If the dead-band policy solves the issue then widening the normal band would be moot. We consider the Authority should pursue the option to introduce a maximum dead band which is narrower than our current normal frequency band (see Q7).
Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why. [Second option is to introduce a maximum dead-band].	Yes. We agree the Authority should be short listing the option to introduce a maximum dead band. This will provide a clear obligation on deadbands. Without this clarity, there is a risk some generators may apply a wide band which is not in the best interests of the system. The analysis in Appendix D (Frequency Consultation paper) recommended implementing a dead band of ±0.1 Hz for new generating units connecting to the power system.
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option? [Second option is to introduce a maximum dead-band].	**Benefits** • Frequency keeping costs should be reduced if generating units support frequency regulation withing the normal frequency band as well as outside. **Costs** • Costs to some asset owners in changing deadband settings and updating their models, depending on their inherent deadbands. (Some will have no cost here). • For some generating units, changing deadbands away from inherent deadbands may lead to increased wear and tear or maintenance costs. • Costs associated with managing the testing and model validation process.
Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	For those generators which have an inherent deadband that is narrower than a mandated Code requirement, the size of the inherent deadband is usually related to hardware. Hence, costs associated with upgrading would be significant.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option [Procure more frequency keeping and instantaneous reserve under status quo arrangements]	This option is effectively the status quo, but with increased intermittency from wind and solar (Appendix D), it is likely the system operator will need to extend the frequency keeping band to avoid more frequency excursions. The **benefits** are:

Question	Response
	• Maintaining frequency quality with increased intermittency • If, there is no deadband set, avoided costs associated with the deadband option above.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	We recognise that there is a useful long list of options, but that the Authority's identification of the short list and the assessment of this short list is a pragmatic assessment approach. At this time, it is important to prioritise options for addressing electricity transition issues in a timely fashion. Some of the options we, both as system operations and grid owner, would have liked to see picked up earlier are now being addressed (for example the information provision.)

Appendix – Responses to questions about voltage options

Question	Response
Q1. Do you consider it likely that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems (when discharging) that connect to their networks? Please give reasons for your answer	It is more likely that individual distributors will place voltage support obligations on generating units or energy storage systems *consistently* if there is a Code obligation on them to require voltage support - including reactive power capability. Such an obligation should support distributors being able to require such control from its connected generation with positive impacts from whole of system perspective. It would also enable consistency in requirements which is of benefit to generator and ESS developers and both system operations and distribution system operations.
Q2. Do you agree generating stations and energy storage systems connected to local distribution networks at the GXP voltage (which varies by local distribution network) should be required to support voltage, or do you consider the obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (e.g., 33kV)? Please give reasons for your answer.	We agree the voltage support requirements should be applied to units connected at the GXP voltage. The voltage study findings (Appendix C of Voltage Consultation Paper) demonstrated that proximity to the grid improves voltage support. This implies any obligation should apply *at the GXP supply bus* voltage. Assets connected further away from GXP have less impact or effectiveness in controlling GXP voltage.
Q3. Do you consider there should be a capacity threshold (e.g., a nominal net export or nameplate capacity of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	We agree there should be a capacity threshold of 5MW to exempt smaller generating units, or ESS, from voltage obligations. The smaller units are not as effective in controlling the GXP voltage, meaning there is little value in putting additional compliance costs for these units. We agree with the Authority's view that "*if an export threshold were to be adopted, we suggest the threshold be consistent with the export threshold for meeting the frequency AOPOs, as is the case now*." [para.6.26] There are other factors that are relevant from a voltage control perspective such as the impedance of the connection. (See comment on Q18.)
Q4. What do you consider to be the pros and cons of requiring generating stations / energy storage systems connected to local distribution networks to have a reactive power range of ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?	To manage reactive power, our preference is to retain the existing +50%/-33% for synchronous generating units. However, we recognise that a symmetrical range makes sense for inverter-based units – the capability curve is essentially symmetrical for a single unit. A symmetric reactive power range may be a better match to IBR technologies. This would need further investigation to define the range. However, for *distribution* connections,

Question	Response
	+/- 33% may be adequate, with further investigation for transmission connections.
Q5. Do you agree the Authority should be short listing the first voltage-related option to help address Issues 2 and 3? If you disagree, please explain why [First option is to assign voltage support obligations to additional parties].	We agree. We note issue 2 system strength was not explicitly covered in the voltage paper, however this issue requires a watching brief on inverter selection, as 'grid forming' inverters are more robust to network disturbances than 'grid following' inverters.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option? [First option is to assign voltage support obligations to additional parties].	Our key concern is ensuring voltage support at GXPs and consider obligations should also cover reactive power capability (see response to Q9). **Benefits.** • Consistency and fair allocation of voltage support. All assets connected to networks should share in providing voltage support to reduce the risk of voltage excursions. • Better management of reactive power flow reduces system losses and potentially can defer investment in reactive power compensation devices. • Better utilisation of network capacity by meeting reactive power demand locally. **Costs** • Costs will fall to generating units but this will mean they will fall where they are most effectively met. This is consistent with the voltage study that shows that multiple DER operating in voltage control mode can better maintain the local voltage than where DER operates in reactive power control mode. • Implementation for system operator and participants including new compliance processes • Participants providing asset capability statement and telemetry information. • Participants undertaking connection studies • Participants following system operator commissioning and testing process. • Provision of telemetry and SCADA monitoring for dispatch. For participants this may be one of the largest costs. In particular, the voltage options proposed *require* co-ordination between the system operator and EDBs. The system operator will face (non-trivial) implementation and ongoing costs for tools, co-ordination framework, communications. These all need to be captured and evaluated. Conceptually, starting on the co-ordination

Question	Response
	path appears to break policy ground for system operations across transmission and distribution networks.
Q7. Under the first voltage-related option, what costs are likely to arise for the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network? [First option is to assign voltage support obligations to additional parties].	**Costs** • See costs in Q6
Q8. Under the first voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network? [First option is to assign voltage support obligations to additional parties].	Costs for transmission-connected ESS will be as for others – see Q6. Energy Storage Systems are key for creating benefits to system operation and consumer supply continuity. However, ESS obligations are currently not clear in the Code and is an area for regulatory attention.
Q9. Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3? If you disagree, please explain why. [Second option is to manage import and export of reactive power at the grid exit point. Issue 2 is larger voltage deviations, Issue 3 is about network system strength, under increasing amounts of variable and intermittent resources].	Yes. This option allows the system operator to determine when it needs to request that distributors redispatch their assets to regulate voltage at GXPs. For the grid owner, we note the proposal by the Authority to "*require that distributors' voltage support assets (if any) are capable of operating within a power factor range of 0.95 lagging to 0.95 leading at their points of connection (GXPs) to the transmission network*" [refer 5.1]. We support the Authority reviewing the Connection Code for reactive power for a range of conditions. In particular, light loads overnight that cause leading power factor that has consequences for grid operation and investment. For voltage constrained regions such as the upper North and upper South Island, the grid owner should be able to require that connections to the grid (or the distribution network) should not reduce regional transfer limits due to poor power factor.
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	**Benefits (as avoided costs)**. • Major benefit is optimised reactive power flow. This minimises system losses, and enables increased utilisation of network capacities to transmit useful power flow.

Question	Response
[Second option is to manage import and export of reactive power at the grid exit point].	• Avoided or deferred network or reactive power compensation devices investment. **Costs** • Development, implementation and ongoing costs for coordination between the SO and EDB. Again, there are other factors that are relevant her, as covered in our response to Q4.
Q11. Under the second voltage related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network? [Second option is to manage import and export of reactive power at the grid exit point].	Costs for transmission-connected ESS will be as for others – see Q6.
Q12. Do you consider it likely that distributors will, in the absence of a Code requirement, place fault ride through obligations on some or all < 30MW generating stations that connect to their networks? Please give reasons for your answer.	A Code obligation would support EDBs to request that their connections should be able to ride through (network) faults and enable consistency across distributors. Consistency has benefits for developers, generators, and system and distribution operations.
Q13. Do you consider it appropriate to include in the Code fault ride through curves for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account power system protection considerations? Please give reasons for your answer.	Either in the Code (which implies obligation and risk of breach) or operational guidelines that support distributors with best practice response. The impact of the potential clause will be more of an issue for distributors and embedded generators. Its effect may mean that more embedded generation stays connected for transmission/distribution network faults, which is a benefit to grid stability and continuity of supply to consumers.
Q14. Do you consider there should be a threshold based on connection voltage and capacity (e.g., a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations connected to distribution networks to ride through faults? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	We agree with the Authority's view that if an export threshold were to be adopted, the threshold should be consistent with the export threshold for meeting the frequency AOPOs, as is the case now. [para.6.26]. Not having a capacity threshold would mean every size of distributed generation faces performance obligations, and in the view of the system operator, the effects of smaller (than threshold) generators not being able to ride-through frequency and faults or support voltage are likely to be immaterial to grid stability.
Q15. Do you agree the Authority should be short listing for further	We strongly agree.

Question	Response
investigation the third voltage-related option to help address Issue 4? If you disagree, please explain why. [Third option is lower the 30MW threshold for excluded generation stations. Issue 4 is about fault ride-through].	Low voltage fault ride through is vital to avoid sympathetic tripping of other plant and reduce risk of Under-Frequency events. The analysis is in Appendix D of the Voltage consultation paper.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option? [Third option is lower the 30MW threshold for excluded generation stations].	**Benefits** • Reduced number of under-frequency event results from network faults, and consequential costs associated with redispatch following and event. • Reduced number of voltage excursion events resulting from network faults, with consequential risk of cascade failure. **Costs** • Smaller generators must go through the same compliance process as grid connected generators. The cost involves carrying our connection studies and commissioning and testing process. • The system operator will have a larger number of asset owners undergoing compliance requirements.
Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if these generating stations must comply with the fault ride through AOPOs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?	For virtual stations, the effect of a fault is dispersed so we consider low voltage fault ride through would be less of a concern. It is difficult to assess fault ride through for virtual stations, and not practical to do so for each individual generating unit.
Q18. Do you have any comments on the Authority's assessment of options to help address Issues 2, 3 and 4 identified in our 2023 Issues paper?	We recognise that there are other options, but that the Authority's identification of these options and the assessment of these is a pragmatic assessment approach. At this time, it is important to prioritise options for addressing electricity transition issues in a timely fashion. Some of the options we, both as system operations and grid owner, would have liked to see picked up earlier are now being addressed (for example the information provision.) The options should be tested for different potential connection points and configurations to ensure the

Question	Response
	choice of connection and configuration does not enable asset owners to circumvent obligations. For example: • The asset selection or configuration of connection can add impedance significantly. For example, a long circuit can introduce additional impedance and reduce the actual reactive power range at the point of connection to the distribution or transmission network. The requirement for reactive support could be reviewed to apply at the point of connection (PoC) -as occurs in Australia - and not (as now) at the generating unit terminals. Compliance is also more complex for IBR farms with collector networks if compliance is assessed at unit terminals rather than PoC. • If a distributor with a 9MW load connects an embedded 10MW generator it can be both a GXP and GIP at different times. Does the Distributor have the same obligations at the PoC as would a 10MW Generator with a 9MW local service load?

Appendix – Responses to questions about governing harmonics

Question	Response
Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If you disagree, please explain why.	Yes, and the webinar about the Harmonics issues was extremely helpful.
Q2. Do you agree the Authority has identified the main challenges with the existing arrangements for the governance of harmonics? If there are any additional challenges, please set these out in your response.	Yes, and agree these are challenges.
Q3. Do you consider the existing regulatory framework for the governance of harmonics in New Zealand is compatible with the uptake of inverter-based resources? Please give reasons for your answer.	No. NZECP36 assumes harmonics are only caused by loads, which no longer applies with inverter-based generation. Most existing grid scale inverter-based plant produce sufficiently low harmonics that - barring harmonic resonance or poor controller tuning – mean the generator is unlikely to cause immediate issues. It is the net effect of many inverters all connecting that eventually causes harmonic issues. Any allocation-based methodology where farms can connect "for free" (without installing or paying costs for filtering), will eventually result in a first mover advantage or with the network bearing the cost of filtering, since the amount of harmonics on the network would increase with each additional farm that is connected, until the limits are reached, at which point future farms will have minimal harmonic allocation. It is generally better to cancel harmonic currents, e.g. by transformer vector group choices, or controls, than to filter them as there is less chance for resonances.
Q4. Do you have any feedback on the Authority's suggested way forward to help address the challenges with the existing arrangements for the governance of harmonics?	The Authority states "*In the context of harmonics, an open access approach would make the network company responsible for co-ordinating harmonic management on their network.*" In the view of the grid owner, the "open access" approach implies no allocations, which could then require real time monitoring and curtailments to respect harmonic limits. We therefore do not think that "open access" is a workable approach. The question of harmonic allocation an active area of discussion internationally, and we consider the EA should not

Question	Response
	impose a harmonic allocation methodology on the grid owner.
Q5. Do you have feedback on any of the elements of good industry practice relating to a framework for managing harmonics? This may include feedback relating to elements you consider are missing from the summary provided in section 5 of this paper.	No further comment.
Q6. Do you agree with a 'whole of system' approach to allocating harmonics, so that any differences in harmonic allocation methodologies between electricity networks do not cause excessive harmonics? If you disagree, please explain why.	Yes. The physics of harmonics does not respect commercial boundaries. The question of harmonic allocation is still an active area of discussion internationally. Given there is no clear position on this currently, we do not think the EA should impose any harmonic allocation methodology on the grid owner. This would allow the most flexibility in implementing improved harmonic allocation methodologies as they appear.
Q7. Do you have any feedback on the suitability for New Zealand's power system of the harmonics standard NZECP 36:1993, or the AS/NZS 61000 series of harmonics standards?	Most methodologies impose harmonic current magnitude limits on harmonic sources (load/generation), while the network has the responsibility of managing the harmonic voltage. We consider this approach makes sense. However, the harmonic current limits do not explicitly mention the phase of the harmonic current. Therefore, a generator (for example) which installs a harmonic filter may still end up in breach of harmonic regulations. The grid owner supports a move to align NZ with international standards such as AS/NZS 61000 (and move away from NZECP36).
Q8. Do you have any feedback on the alternative approaches to limiting harmonic emissions, including alternative approaches you consider to be appropriate for New Zealand's electricity industry.	To compare the alternative approaches, we propose that each pro or con to be evaluated for all approaches consistently. A *hybrid approach* could be considered. Loads are given some harmonic current allowance; generators are given 'net-zero' allocation (to treat synchronous and non-synchronous generation on the same basis): 1. **Identify egregious potential harmonic issues.** Using Harmonic Polygons and Amplification factors, assess against some fixed limit, e.g. 50% or some function of farm MW, of the entire limit. Engineering judgement is used to resolve any issues (i.e. this happens in practice now). 2. **Calculate net emissions** (e.g. in real-power Watts) of the farm. Farms should be encouraged to use harmonic

Question	Response
	phase cancellation etc where available to reduce the amount of net harmonic current being created in the first place. 3. **Install C-type harmonic filtering at the highest background frequency** (or whatever as requested by the network operator). 4. Loads are given current limits, but clarified for the cases where the load acts as a harmonic sink.