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To: Electricity Authority Future Security and Resilience Workstream Stakeholders

Date: 30 May 2023

Re: Response to review of common quality requirements in part 8 of the Code – issues paper

ElectroNet welcomes the opportunity provided by the Electricity Authority (hereafter referred to as the EA) to provide feedback on the issues paper discussing a review of part 8 of the Code. We agree this is a critical and important piece of work for the EA and that they are right to prioritise it.

As part of our response, we have drawn on our expertise as power systems consultants, designers, and constructors. Moreover, we have sought input from a range of our clients for whom part 8 directly affects their obligations to the power system, ability to connect, and costs of compliance.

We have structured our response as follows:

- Our background and experience (Section 1).
- Our response to the questions outlined by the EA (Section 2).
- Our views on other priority issues within part 8, including important issues that the Code is currently silent on (Section 3).

1 Our background and experience

ElectroNet provides consulting, project management and construction services to the electricity industry in Australia and New Zealand. Our experienced team has been involved in delivering the electrical balance of plant for all grid scale wind farms constructed in New Zealand since 2013. We have played a key role in the establishment of grid injection points in the transmission system including Waipipi wind farm, Turitea wind farm, McKee power station, and Junction Road power station. We are heavily involved in electrical design and refurbishment activities for many of the major electricity asset owners in New Zealand. In addition, we have designed, built and operate our own hydro power station at Amethyst.

Our experience and expertise includes:

- Power system analysis and modelling. Use of industry leading tools such as PSS/E, DIgSILENT PowerFactory, and PSCAD/EMTDC to undertake modelling and simulations that prove compliance with part 8.
- We have undertaken grid compliance modelling within New Zealand and importantly within Australia for the last ten years. Our Australian experience gives us an important contrast to New Zealand and we have first-hand experience of lessons learned in the National Electricity Market (NEM) during their rapid uptake of inverter based resources (IBR) in the last decade.

- Design of high voltage electricity supply networks. This includes, primary, secondary, and protection systems' design.
- Construction of electricity supply networks. This includes procurement of components, installation, project management, and commissioning.

Our experience with end-to-end supply and design, and in particular with IBRs enables us to provide an informed and practical viewpoint to the review of part 8.

2 Response to questions with the part 8 issues paper

2.1 Issue #1: inverter based resources cause more frequency fluctuations

Do you agree with the description of the first common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.

ElectroNet agrees that there is the potential for low inertia generation systems to cause more frequency fluctuations. However, our view is that IBR is unfairly targeted as the causer of this issue. We think that the issue is not so much IBR vs synchronous, but rather frequency sensitive generation vs non-frequency sensitive generation.

To elaborate further, it has been demonstrated widely overseas that IBR resources can reduce frequency fluctuations by providing a rapid change in power output. Their response speed is normally much faster than the response of synchronous machines. An example of this from Australia would be the response of the Hornsdale power reserve (colloquially known as the big battery) to frequency responses within the National Electricity Market on the east coast of Australia (NEM). Figure 1 shows an example, taken from an Australian Energy Market Operator (AEMO) report [1] of the battery's ability to follow changes in system frequency more precisely than a steam turbine generator.

The system operator also has direct experience for how IBR can aid in the reduction of frequency fluctuations, when it switched on multiple frequency keeping (MFK) and frequency keeping control (FKC) using the HVDC link (a type of IBR).

Figure 1 Accuracy and speed of regulation FCAS response – large conventional steam turbine

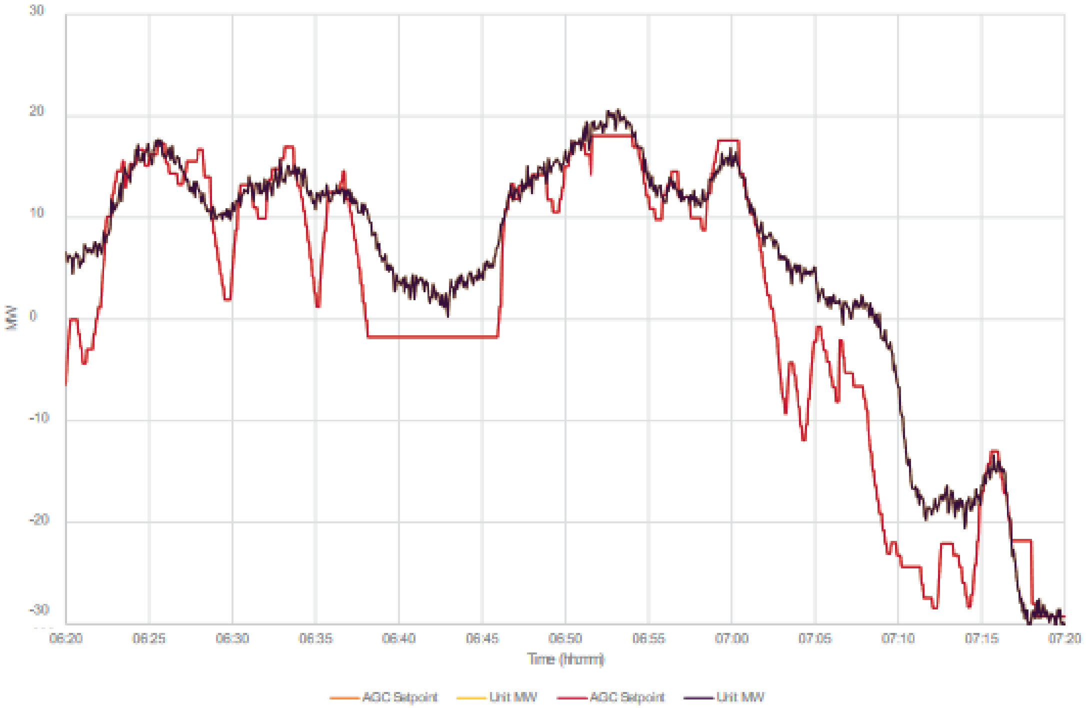

Figure 2 Accuracy and speed of regulation FCAS response – Hornsdale Power Reserve

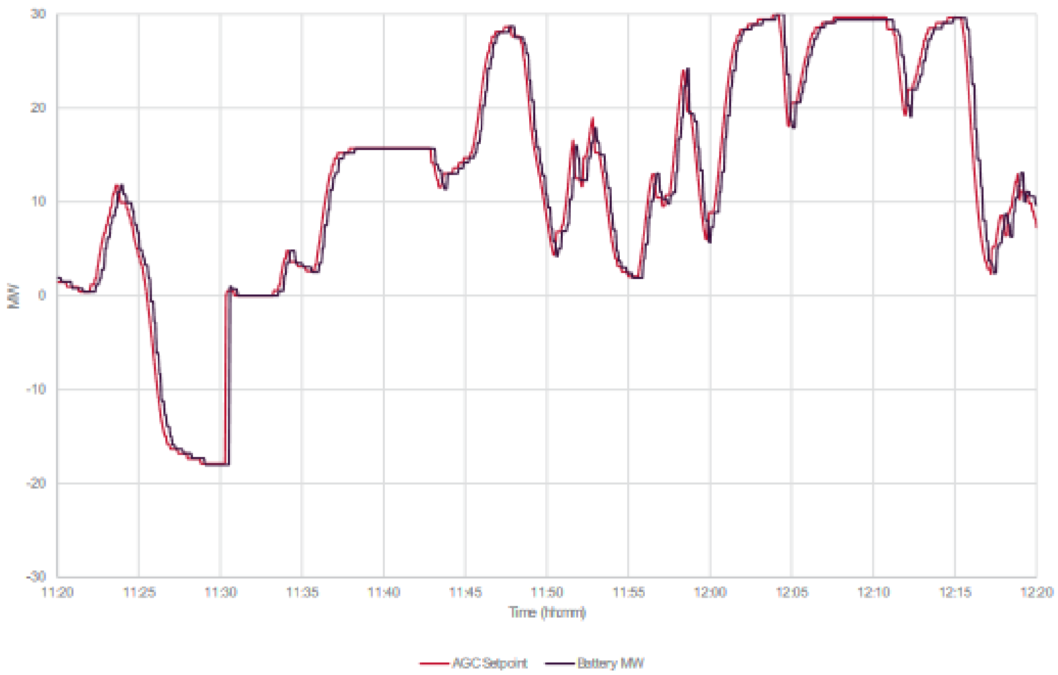

Figure 1: Accuracy and speed of regulation of FCAS response for Hornsdale Power Reserve [1]

2.1.1 Incentive to build generation less than 30 MW

The EA mentions that there is an apparent incentive to build generating stations less than 30 MW to avoid frequency support obligations. In practice ElectroNet does not think this is a strong incentive. It is not a significant cost (relative to the project cost) for IBR generators to provide frequency support functions – this is essentially a software setting. We note there are some limitations with this feature, which we discuss in more detail in Section 2.1.4.

Our view is that the main driver for connection to a distribution network or transmission system is project economics and geography. It is a considerable expense and barrier to small scale projects to fund the development of a new transmission grid injection point (GIP). Furthermore, IBR projects are generally distributed in nature and often far from the nearest transmission networks. Distribution networks with their wider reach, in many cases provide a more natural connection.

Despite not necessarily being a significant project cost to comply with frequency support obligations, it does feel appropriate for there to be some threshold for which relief from some part 8 obligations is appropriate. Currently, there seems to be a lack of evidence for the 30 MW threshold as being "right sized" for New Zealand. For comparison, in the National Electricity Market (NEM) in Australia, a much bigger system, we note that their requirement for exemption from NER obligations is for stations less than 5 MW.

2.1.2 Code silence on the use of frequency response dead-bands

ElectroNet agrees that the Code should avoid ambiguity in this area and specifically allow the implementation of frequency dead-bands. This is a reasonable thing to do for the reasons mentioned in the consultation paper.

However, we don't agree that setting a dead-band guarantees reduced responsiveness of the generating plant. Gains outside of the dead-band can be set higher to compensate for reduced response when operating inside the dead-band.

We think part 8 should aim to be technology agnostic and recognise the strengths and weaknesses of various technologies. Frequency control is not an inherent weakness of IBR, rather it is a strength due to its ability to respond to frequency fluctuations within milli-seconds.

2.1.3 Some generation usually operates at its maximum MW capacity rating

We acknowledge that under-frequency support from generators designed to operate at close to maximum resource capability is limited. However, this is not strictly an IBR issue. For instance, as mentioned, geothermal generators also typically run at maximum output, and therefore are unable to provide significant under-frequency response.

We think this issue should be framed in terms of the energy resource, and the inherent characteristics of these, rather than IBR vs synchronous.

2.1.4 Granting of frequency response dispensations for IBR

It is ElectroNet's view that the system operator is performing reasonably in granting dispensations to IBR from frequency control obligations, where that obligation would create an unreasonable commercial demand on the generation. There is no technical impediment to IBR providing both under-frequency and over-frequency support. However, to provide under-frequency support would require that wind and solar plants were operating at less than maximum available resource output – to allow some headroom to respond to an under-frequency fluctuation. This would impose significant cost on the project in terms of wasted energy and the result, depending on how significant the curtailment was, would render some projects uneconomic. This would not be in the best interests of NZ consumers.

Our view is that part 8 should remove any mention of the term speed governor, which is a term that is not technology agnostic, and instead use a more technology agnostic term such as frequency controller, or frequency response mechanism.

2.1.5 Reduction in system strength due to IBR

Overseas experience, particularly in Australia, shows that increasing IBR penetration can lead to a reduction in system strength, if the IBR displaces synchronous generation. The NEM has recently implemented a rule change that provides a method of cost recovery for system strength remediation [2]. The principal idea behind this rule change is to allow efficient coordination of system strength on the power system. This means that generators such as grid following IBR, that "degrade" system strength are now forced to install appropriate mitigation such as condensers, or to pay a proportionate fee to allow the network service provider (NSP) in their region to install mitigation.

In NZ, our need for system strength mitigation is currently less acute than Australia, because it is not expected that our synchronous hydro or geothermal generation, would be retired in favour of IBR generation; at least not in the short to medium term. However, we think it would be beneficial to start considering how provisions could be introduced to the Code to allow for system strength remediation and the equitable sharing of these costs. To avoid NZ getting into a "rules regrets" scenario, we advocate for a more frequent code review process. This issue is discussed in more depth in Section 2.6.4.

2.2 Issue #2, #3, #4: inverter based resources cause more voltage issues

2.2.1 Incentive to build generation less than 30 MW and connect to distribution networks

The issues paper makes the claim that there is currently an incentive to build generating stations less than 30 MW within distribution networks because such stations are exempt from voltage performance requirements such as fault ride through and voltage regulation.

In our experience, we do not observe this is a strong incentive. We observe that right size projects will connect to appropriate voltage levels and networks. Typically, this means that projects larger than 50 MW will connect directly to the transmission system, and projects less than 50 MW to the distribution system, but there are exceptions. We note this is not a hard rule and some distribution networks can host projects larger than 100 MW.

For IBR, built at grid scale, which is essentially anything larger than a few MW, these stations mostly have inherent voltage control capability, and it is not a significant project cost to have this setup to provide appropriate support to the network. Such capability can be enabled within software and tuned appropriately.

We note that there is an inconsistent approach to voltage control by EDBs across NZ. Our experience has shown that this creates considerable uncertainty for developers and can create delays as project proponents discuss the appropriate voltage control strategy with the EDBs. Greater clarity in part 8 could assist this process, by providing more appropriate guidance to EDBs on this issue, and potentially setting some basic requirements.

2.2.2 Some generation usually operates at its maximum MW capacity rating

Whilst this is true, we think this issue is incorrectly framed. In utility scale solar and wind projects, the converters are usually sized in such a way that there is sufficient headroom when operating at maximum power output, to provide the necessary reactive power demanded by the grid code clause 8.23. If sufficient headroom is not available, then additional reactive plant is usually procured to make up the shortfall. This has been the case in recent projects such as the Turitea wind farm.

Like the grid code in Germany [3], we think the EA should consider implementing voltage support requirements that are more carefully considering the nuances of the connection point voltage and capability of regional networks. For instance, we don't think it makes sense to require generation stations to provide large amounts of reactive power when the grid voltage is high, or when the plant is embedded into a distribution system behind significant impedance. Likewise, it makes little sense to require significant reactive power import when the voltage is low; we note that part 8 only requires import down to 0.95 pu, despite the operational voltage being allowed to operate down to 0.9 pu. A similar more flexible approach would be beneficial for reactive power export. It is not in the interests of consumers to require the installation of additional reactive plant, purely for compliance purposes, and not for any demonstrable system need or benefit.

The German grid code allows network operators to select between three different capability curves, depending on the needs of the network. This allows for a nuanced selection of appropriate plant capability based on system needs. We believe a similar approach in NZ could have merit.

2.2.3 Inverter based resources cause greater voltage deviations

ElectroNet disagrees with the framing of this issue and believes IBR is unfairly targeted. We also think that separate issues have been conflated.

We agree that increasing penetration of IBR can result in a reduction of system strength, assuming that it is displacing synchronous generation. Although this is related to the quality of the voltage waveform, it is not related to the ability of the IBR to regulate voltage. As mentioned previously, all grid scale IBR can regulate system voltage precisely and more accurately than synchronous machines. What is lacking is clarity around reactive power and voltage control requirements so that this capability is made available from all reasonably sized plants. Secondly consistency of compliance measurement points is important. We discuss this separately in Section 2.6.3.

We discuss the system strength issue separately in Section 2.1.5. As mentioned there, we think some consideration for how NZ will handle mitigation of system strength problems going forward is worthwhile, although not as high priority as some of the other issues identified. Lessons from Australia could be instructive. This issue is less urgent in NZ due to our large installed base of low marginal cost synchronous hydro generation, which is unlikely to be displaced by IBRs in the short to medium term.

For Fault Ride Through (FRT), in our experience, most IBR does not have difficulty meeting the existing requirements in part 8. On the contrary, it is synchronous machines that we have observed having the most difficulty riding through the FRT curve. This is because the NZ grid code FRT requirements do not appropriately consider technology differences and capabilities.

To address this, consideration of different fault ride through curves for different technologies is recommended. This has been seen in the British grid code, where synchronous machines have more permissive FRT requirements than IBR [4].

2.2.4 Inverter based resources can cause network performance issues

We think this issue is too non-specific. For instance, the discussion that low quality voltage waveforms can cause more IBR to disconnect is unsubstantiated. Is there evidence that such events are happening, or will be likely to start happening in the future? Case study four talks at length about the differences between low and high system strength GXPs, but does not provide evidence that the lower strength GXP would cause more IBR to disconnect.

We believe that if the fault ride through requirements are set appropriately – this should include consideration of the appropriate size of the generation station for which they need to apply, then this concern is somewhat overstated.

For small scale commercial and residential IBR, adherence to AS4777 should ensure that this generation remains connected during most typical system disturbances such as faults on the transmission and distribution system.

2.2.5 Increasingly less generation subject to fault ride through obligations

We agree that increasing embedded IBR penetration will likely result in less generators being subject to the Code's fault ride through obligations as they currently stand. However, as stated in the prior section, if small scale IBR is required to adhere to AS4777, then it is required to remain connected for some disturbances, albeit not to the same extent as larger grid connected generation.

We think consideration of the appropriate generation size for adherence to the fault ride through standard in the Code has merit. At present, the 30 MW threshold feels lacking in evidence as an appropriate threshold and is out of step with other international jurisdictions. For example:

- In Australia, adherence to the NER (which includes fault ride through) is required for all stations greater than 5 MW.
- In the UK, a type B generator [5], which requires some form of FRT, is >1 MW
- In Ireland and Northern Island, a type B generator is >0.1 MW
- In the Baltic countries a type B generator is >0.5 MW

We accept that there is concern about placing undue costs on participants by lowering the threshold for which FRT applies. However, in practice it is not difficult for modern IBR to meet reasonable FRT standards and to demonstrate compliance through modelling and simulation. Furthermore, although modelling and simulation incurs a cost for these projects, such costs are usually small in terms of overall project costs. It is expected for instance to be less than 1% of total project cost for a 5 MW project. Furthermore, much of the modelling and simulation work that is currently done is necessary for tuning and ensuring optimal performance of the IBR and would be done irrespective of FRT requirements.

2.3 Issue #5: There is some ambiguity around harmonics standards

We agree that there is considerable ambiguity around harmonic compliance for grid connected generation. We also agree that at present there is a lack of clarity for how various harmonics standards should be applied to new projects. This uncertainty is adding risk to projects and resulting in additional cost spend for developing "ad-hoc" compliance approaches.

We also agree that the main harmonic requirement referenced by the Code for HV connections is NZECP36, which was published in 1993 and is now 30 years old. It has no reference to IBR and considers harmonics to be a problem of loads only.

2.3.1 Ambiguity managing the flow of harmonics through a GXP

We agree that there is ambiguity about how to manage the flow of harmonics through a GXP and that the industry would benefit from clearer, more pragmatic standards and compliance assessment processes.

2.4 Issue #6: Insufficient information on assets wanting to connect

We agree that there is ambiguity about the type of information that should be provided about equipment by Asset Owners. Our view is that standardisation of information and modelling requirements would ease the compliance burden. However, the following considerations are important:

- Information requirements should be appropriate to the stage of project. It would be inappropriate to require detailed transient models for a project that is in the concept stage and is yet to receive resource consent – i.e it is plausible that the project won't proceed to construction.
- Information requirements should be appropriate to the size of the project. Additionally, it would be helpful if the information requirements developed by the EA/SO are based on project size and have similar thresholds to the requirements for FRT, frequency and voltage support. It is logical and pragmatic to align these thresholds.
- Information requirements should recognise natural differences in capabilities of different technologies. At a minimum, there should be different templates for synchronous machines and IBRs.
- Modelling and information requirements should be software platform agnostic, if possible. The industry faces high barriers to entry through vendor lock in, and where possible the EA should aim to avoid nominating a preferred software platform. However, we do understand that pragmatically, it may be preferrable to nominate a software platform that the SO is familiar with, although it should not be mandatory. To avoid placing undue demands on the SO, if an industry participant wants to submit a model and/or information in a non-preferred platform or format, then the SO should have a mechanism to recover costs for model/information conversion.
- Model provision requirements are presently vague and subject to interpretation by the system operator. There should be greater clarity on what software models are required and for what aspects of the Code they should be used for to demonstrate compliance. For instance, it is preferable to be explicit to state something like for connections where the

short circuit ratio (SCR)[1] is less than three, RMS simulations must be benchmarked against an EMT model to verify accurate performance of the model.

2.5 Issue #7: Some Code terms missing or not fit for purpose

We agree that the Code is missing some terms and others need revision in line with modern technology.

2.6 Other high priority issues

In this section we have listed some other issues that the Code is currently silent on, but we believe are important to provide guidance on.

2.6.1 Active and Reactive Power priority – additional clarity of requirements

In the FRT 8.25B clause, the Code is not explicit about the trade-off between reactive and active power during a fault. For instance, 8.25B requires that each generator must oppose the change in its terminal voltage by providing reactive current. However, it does not explicitly state how active power should be treated during such a fault period.

During a fault, most IBR will prioritise reactive current instead of active current to stabilise the system voltage; although typically it is a configurable parameter. The Code should be more explicit to state that this behaviour is permitted, and it would also be helpful to the network to specify reactive current (Iq) injection behaviour. It is common overseas to require an Iq injection ratio of 2 to 1, (Australia, Germany). This means that for a 1% reduction in connection point voltage, the generator must produce at least a 2% increase in reactive current. However, careful design of such a requirement is important. It is difficult, sometimes impossible, for IBR to achieve Iq injection factors of two if the measurement location is at the PoC and the IBR network contains significant impedance; commonly the case for large wind farms with multiple collector network voltage levels. The NER in Australia was recently amended to revise the minimum access standard to 0%/% reduction for these and other reasons.

2.6.2 Code Silent on EMT Modelling Requirements

It has been a noticeable trend overseas to require electro-magnetic transient (EMT) analysis to prove the compliance of IBR to technical codes. In the Australian NEM, it is additionally required to benchmark RMS models against EMT models.

The reason for using EMT models is to ensure the control system and power electronic behaviour, including DC transients is properly accounted for in the modelling. This becomes especially important when the PoC is “weak”. There are various methods for defining what is meant by a weak grid, however, a commonly used metric is the Short Circuit Ratio (SCR). Transpower has already provided guidance in their Connection Study Guide (CSG) stating that EMT studies are required when the SCR is less than three [6]. Currently, the CSG states that EMT studies are only required for FRT analysis. However, there is still a lack of clarify on the extent of studies required. For instance, should all FRT simulations be repeated in the EMT domain? For some projects, this would potentially mean over 1000 EMT studies could be required. Furthermore, there are no standarised publicly available EMT

[1] This is just an example criteria, not necessarily the recommended method of determining if/when EMT studies should be required.

system models for New Zealand. This starts to become a considerable burden on projects and is impractical to do at scale.

It is our view that the Code should anticipate an increasing need for EMT analysis. However, there is merit in discussing the necessary extent of EMT studies. Should these be limited to Multi Machine Infinite Bus models (MMIB) for weak grids only, to avoid prolonged delays accessing and developing extensive EMT models of the larger power system? Once it has been reasonably established that the RMS model is a reasonable representation of the EMT model, potentially with known caveats, then it could be acceptable to complete wider system analysis using RMS models only.

2.6.3 Definition of Point of Connection

Currently there is ambiguity in the Code regarding the point of connection for generation projects. The industry would benefit from clearer guidance on how the connection point is determined. Clarity on the connection point would also enable additional clarity on other compliance issues such as reactive power capability and power quality.

An example of how the ill-defined connection point creates a lack of clarity currently is illustrated below for how reactive power capability is defined and measured. Figure 2 shows a typical wind farm connection to the 110 kV transmission system. Currently, the compliance point for measuring reactive power is stated as the LV side of the generator step up transformer. It could reasonably be interpreted as point A and has been for some projects. The policy statement which is incorporated into the Code by reference, has subsequently clarified that for renewable energy parks, the compliance measurement point should be point B. However, this still leaves some room for ambiguity and potential inconsistency in compliance requirements.

For example, in the network in Figure 2, a 10 km overhead line incurs some reactive losses between points D and C, and therefore the wind farm is required to provide less reactive power to the grid than another generator where the step-up transformer is directly connected. Essentially such a wind-farm is “freeloading” off other system participants.

To illustrate the difference further we have undertaken an example load-flow calculation, for a representative 100 MW wind farm. We have illustrated two examples with the connection point voltage set to 1.05 pu and 0.95 pu and shown the measured reactive power contribution from the wind farm at various points. Note, we are assuming the following impedances based on 100 MVA and we have “aggregated” the collector network to a single lumped generator as is common practice:

- main transformer: j0.15 pu
- overhead line: j0.03 pu
- WTG transformer: j0.08 pu
- Collector cable impedance: ~0 pu

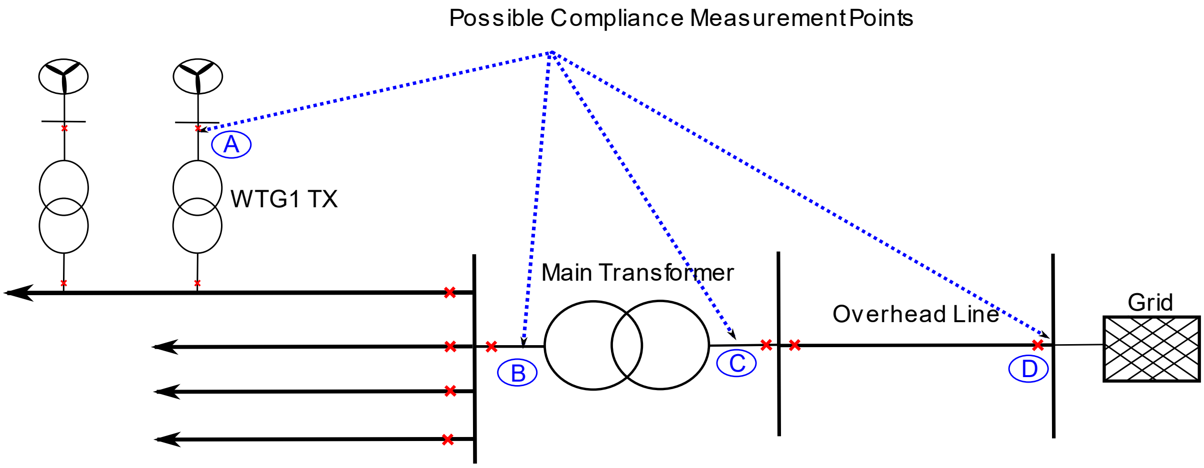

Figure 2: Example of a Typical Wind Farm Reticulation Network Showing Possible Compliance Measurement Points

Table 1 shows the measured reactive power at the compliance points A through D with the wind-farm producing 90 MW and attempting to control compliance point C voltage to 1 pu. Note that in this example, the wind farm is at the limit of its Q capability for this power output in both system states modelled. As shown in the table, there is a 40-50 Mvar difference in measured reactive power quantity between the generator terminals and the grid point of connection at D. This has several implications:

- Measuring compliance at the PoC (D) would require IBR to have additional reactive power export capability relative to the existing measurement point of the main transformer LV terminals.
- If the compliance point is shifted to the PoC (D), then the requirement of 50% reactive export capability would be very onerous on projects.

Table 1: Measured Reactive Power at Various Compliance Points

Compliance Point	Grid Voltage 1.05 pu	Grid Voltage 0.95 pu
A	-40.1 Mvar	40.2 Mvar
B	-67.6 Mvar	12.8 Mvar.
C	-86.6 Mvar	0.4 Mvar
D	-90.2 Mvar	-1.6 Mvar

This example shows that where compliance is assessed matters for the technical capability of the plant. Our view is that there should be less ambiguity about the Point of Connection for grid connected assets. This would ensure clarity about where compliance requirements such as reactive power are assessed and ensure more consistent technical capability across grid connected assets.

Specifically on reactive power requirements, if the PoC is adjusted and clarified, then we think the limits should also be revisited. It is reasonable to expect that the positive code compliance requirement of +50% should be reduced, likewise the import requirement of -33% should be reviewed to ensure it is set appropriately. Furthermore, as discussed in Section 2.2.2, there is some merit in the approach of having more nuanced reactive power capability requirements which consider the specifics of the local network and generator technology, like in the German grid code.

Further work and consultation with industry is recommended to ensure that the Code gets these settings correct.

2.6.4 Revision of Technical Aspects of the Code

To anticipate potential changes in technology, and to avoid regrets, it should be easier and follow a more transparent process to alter technical requirements and aspects of the Code. It is our view that technical requirements are best established by industry experts in collaboration with the system operator and network owners. The Code could require that the system operator establish model guidelines and model information requirements documents, leaving the technical details to them rather than specifying them directly in the Code. This would allow the SO to adjust technical requirements more dynamically in line with changing technical capability and system needs; appropriate safeguards in terms of industry consultation should also be guaranteed to avoid unilateral action by the SO.

2.6.5 Under-frequency ride through threshold in the South Island

At present the Code requires South Island generators to ride through a 45 Hz frequency for up to 30 s. Practical experience has shown that this is outside the range of typical equipment norms and has potentially discouraged some South Island generation development, due to limiting the available equipment and the ability to maintain competitive tension from suppliers.

Revisiting whether it is appropriate to maintain this under-frequency ride through requirement in the South Island and whether it should be revised to a more pragmatic level is recommended.

2.6.6 Clarity for BESS technical requirements

The Code should be more explicit on the technical requirements for BESS, especially when they are charging and operating as a load. Do they have voltage and frequency support obligations in this scenario, and if so, how do these differ from when they are exporting and operating as a generator?

Once again, we thank the EA for the opportunity to comment on this important piece of work. We are also open to and encourage further discussion. Overall, the objective should be to refine part 8 to enable fair and balanced outcomes for NZ consumers and electricity industry participants.

Yours sincerely

Brad Henderson

for ElectroNet Ltd

3 References

[1] Australian Energy Market Operator, "Initial Operation of the Hornsdale Power Reserve," April 2018. [Online]. Available: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/Initial-operation-of-the-Hornsdale-Power-Reserve.pdf. [Accessed 09 May 2023].

[2] Australian Energy Market Commission, 21 October 2021. [Online]. Available: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system. [Accessed 11 May 2023].

[3] VDE, "Transmission Code 2007: Network and System Rules of the German Transmission System Operators," 2007.

[4] National Grid ESO, "The Grid Code: Connection Conditions (Appendix 4, Fault Ride Through Requirements)," 2023.

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