Future Security and Resilience: Common Quality Technical Group (FSR CQTG)

Meeting 5: 10 June 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

AGENDA

Time	Item
8.45 am	**Sign in at reception (to meet Rob Mitchell)**
9:00 am	**Meeting starts - Minutes and Actions from previous meeting (15 mins)**
9:15 am	**Part 8 Code amendment proposal paper – Part 1** • Feedback and discussion on items related to issue 6 (FSR-001 to FSR-003)
10:15 am	**Morning tea (15 minutes)**
10:30 am	**Part 8 Code amendment proposal paper – Part 1 (continued)** • Feedback and discussion on items related to issue 7 (FSR-004 to FSR-009)
11:45 am	**Definition of 'generating unit'**
12:00 pm	**Fault ride-through curves – presented by Vong**
12:30 pm	**Lunch (30 minutes)**
1:00 pm	**BESS obligations – presented by Vong**
2:00 pm	**Update on relevant workstreams from Operations Policy team**
2:30 pm	**Afternoon tea (15 mins)**
2:45 pm	**Update on relevant workstreams from Retail & Networks team**
3:15 pm	**Update on status of other options in the long list of options** • Options being progressed in other Authority workstreams • Options proposed to be progressed in other Authority workstreams Options the Authority considers should not be progressed
3:55pm	**Next meeting (5 mins)**
4:00 pm	**End of meeting**

OBJECTIVES

The primary objectives of CQTG meeting #5 are:

(a) For the CQTG to provide feedback on the first batch of Code amendment proposals, related to issue 6 (network information) and issue 7 (Code terminology)

(b) For the Authority to provide the CQTG with an update on the status of options that did not get short listed

MINUTES & ACTIONS

- Confirm the minutes from meetings #3 and #4
- Update on the action items recorded in the minutes

FSR-001: Periodic testing of inverter-based resources

Common Quality Technical Group meeting

10 June 2024

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Wind generating units excluded from periodic testing requirements

- Reasons for this (in 2008) no longer valid in 2024
- Absence of wind generating units from routine testing regime can reduce confidence of system operator and asset owners in assets meeting the Code’s performance requirements
- Exclusion of wind generating units from periodic testing regime inconsistent with:
  - promoting competitive neutrality amongst technologies and fuels
  - signalling full costs and benefits of alternative technologies and fuels providing service / output

Periodic testing requirements designed for synchronous machine-based generating units

- Clauses 3, 4 and 5 of Schedule 8.3, Technical Code A, Appendix B use terminology specific to synchronous machine-based generating units
- Synchronous machine-based generating units no longer the predominant generation technology being installed

Proposal

Remove wind generating units' testing exception

- Remove wind-powered generating units' exception from routine testing requirements

Add periodic tests for inverter-based resources

- Amend clause 3 of Technical Code A, Appendix B to refer to 'frequency control system'
- Amend clause 4 of Technical Code A, Appendix B to apply to transformers connected to the transmission network
- Amend clause 5 of Technical Code A, Appendix B to refer to 'voltage control system'

FSR-002:Provision of asset capability information to network operators and owners

Common Quality Technical Group meeting

10 June 2024

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Modelling data affects Transpower's ability to effectively plan and manage the power system

- For an accurate and effective power system study to be carried out by Transpower both as a system operator as well as a grid owner, it is becoming increasingly important that the model data used as inputs is sufficiently detailed to accurately reflect the performance of generating units and other power system equipment.
- Despite the provisions in the Code as stated in the existing arrangement section, there is still ambiguity among asset owners to provide the level of detail and accuracy of the power system model to the Transpower (both as the system operator as well as a grid owner). This increases the transactional cost and connection application timeframes

Proposal

- The Authority proposes to amend the Code to include an obligation for asset owners to provide specific asset capability information that the Transpower (both as a system operator and as a grid owner) require to meet their regulatory obligations.
- This code amendment will specify the level of detail, accuracy and the format of the power system modelling information of the generating plants. This code amendment will also include provisions for the Transpower as a grid owner to obtain the same information from the asset owners as the Transpower as the system operator.

FSR-003: Asset owner obligation for provision of detailed dynamic(RMS/EMT) model for control interactions investigation

Common Quality Technical Group meeting

10 June 2024

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Provision of detailed dynamic models for control interaction investigation

- In the past Small Signal Oscillations have been of low magnitude and were adequately damped with inherent network controls.16 However, with increased penetration of inverter-based resources (IBRs), SSOs have been observed by several system operators in overseas jurisdictions
- With the current modelling approach and tools (like conventional phasor-based modelling software), system operators such as AEMO have been unable to capture the impact of large-scale IBR on the small-signal stability.The current phasor-based modelling tools provide overly optimistic and inaccurate response of IBR for a sub-synchronous event.
- Currently, it is not of concern in New Zealand as the number of large-scale grid-connected IBR is comparatively low. However, the Authority believes it worthwhile to have arrangements in place for the system operator to access dynamic modelling data of IBRs and get support from asset owners, should it undertake system-wide stability studies.

Proposal

- The Authority proposes to amend the Code to include obligations for asset owners to provide detailed dynamic models (RMS/EMT) over generating life of generating assets they own and/or which are connected to their asset(s) (in the case of network owners).
- The Authority also proposes to amend clause 2(5)(b) of Technical Code A, to require asset owners to provide modelling information that is compatible with the system operator's software, by providing a list of permitted software platforms that asset owners can choose from;

FSR-004: Embedded generation to provide an asset capability statement

10 June 2024

Common Quality Technical Group meeting

Asset owners must provide an asset capability statement for assets connected to the grid

- Code wording could be interpreted as only requiring an asset capability statement (ACS) for generation that is directly connected to the grid.
- System operator requires an ACS to enable the system operator to plan to comply, and comply with its principal performance obligations (PPOs).
- Embedded generation can affect the system operator's ability to comply with its PPOs.
- This interpretation would not promote the interests of the efficient, reliable operation of the power system.

Proposal

Clarify that an ACS is also required for embedded generation

- Amend clause 2(5) of Technical Code A to clarify that assets connected to the grid indirectly through another network, must also provide an ACS to the system operator.

2 General requirements

…

(5) Each **asset owner** must provide the **system operator** with an **asset capability statement** in the form from time to time **published** by the **system operator** for each **asset** that is proposed to be connected, or is connected to, or forms part of the **grid** directly or indirectly through 1 or more other **networks**. The **asset capability statement** must—

(a) …

FSR-005: Include distributors and energy storage systems as potential causers of under-frequency events

10 June 2024

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The Authority is required to determine the causer of an under-frequency event

- The process for determining the causer of an under-frequency event (UFE) is set out in the Code.
- The Code specifies that a causer may be either a generator or grid owner.
- The power system has changed significantly since the rules were introduced. There is an increasing amount of generation embedded within distribution networks.
- In reality, UFEs may also be caused by distributors and owners of energy storage systems (ESS) but the Code does not reflect this.
- This does not promote the reliability and efficiency of the power system as financial disincentives may not be applied to the correct participant.

Proposal

Add distributors and owners of ESS as potential causers of a UFE

- Amend the definition of "causer" in clause 1.1, and consequential changes to clauses 8.60 and 8.61 to include distributors and owners of ESS as potential causers.
- This will enable the Authority to determine a causer of a UFE to be either:
  - a generator
  - a grid owner
  - a distributor
  - An owner of ESS.

Proposal continued

Add distributors and owners of ESS as potential causers of a UFE

Part 1 **Preliminary provisions**

1. Interpretation

…

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

(a) if the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's**,~~ or~~ **grid owner's**, **distributor's** **asset** or **assets**, or an **energy storage system**, the **generator**,~~ or~~ **grid owner**, **distributor** or owner of the **energy storage system**; unless—

FSR-006: Specify that adjustable droop must be within the specified range

10 June 2024

Common Quality Technical Group meeting

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Generating units must have a speed governor that has an adjustable droop over the range of 1% to 7%

- There is a difference between having a speed governor with an adjustable droop over the range of 1% to 7%, and actually applying settings within this range.
- For example, a speed governor may have an adjustable droop over the range of 1% to 10%. Since it is capable of being within the 1% to 7% range, the requirement may be met even if the actual settings applied are outside of this range.
- This interpretation does not promote efficiency or reliability of the electricity industry as it negatively impacts on generators' ability to respond to frequency deviations.

Proposal

Specify that the speed governor settings agreed upon by the generator and the system operator must be within the droop range in subclause Schedule 8.3, Technical Code A, subclause 5(1)(c)(ii).

5 Specific requirements for generators

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

...

(c) each of its **generating units** has a speed governor that—

(i) provides stable performance with adequate damping; and

(ii) has an adjustable droop over the range of 1% to 7%; and

(iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics; and

(d) appropriate speed governor settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The settings must be within the range specified in Schedule 8.3, Technical Code A – Assets, clause 5, subclause 1(c)(ii). (…)

FSR-007: Amend the requirement for generating units to have a speed governor

10 June 2024

Common Quality Technical Group meeting

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Generating units must ensure that each of their generating units has a "speed governor"

- Generating units that use inverters when functioning may not have speed governors.
- Currently, these inverter-based resources rely on dispensations or equivalence arrangements.
- This imposes avoidable administration costs on the generator and the system operator.

Proposal

Replace the requirement for a "speed governor" with the requirement to have a "frequency control system" in Schedule 8.3, Technical Code A, subclause 5(1)(c).

5 Specific requirements for generators

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

…

(c) each of its **generating units** has a ~~speed governor~~ **frequency control system** that—

(…)

The term "speed governor" appears elsewhere in the Code. We propose each of these references also be amended to "frequency control system".

- Clause 1.1 – the definition of control system
- Schedule 8.3, Technical Code A, subclause 5(1)(d) – regarding appropriate speed governor settings
- Schedule 8.3, Technical Code A, Appendix B, clause 3(a) and clause 3(b) – regarding the testing of speed governors

FSR-008: Amend the requirement for generating units to have an excitation system

10 June 2024

Common Quality Technical Group meeting

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Each generator must ensure that each of its generating units is equipped with an excitation and voltage control system

- The Code was written when the vast majority of the generation came from synchronous machines.
- Inverter-based generation do not have an “excitation system”, but do have other systems in place to control voltage.
- As a result, inverter-based generation needs to rely on dispensations or equivalence arrangements

Proposal

Remove the requirement for an "excitation system" in subclause Schedule 8.3, Technical Code A, clause 5(2)(a). A requirement for a "voltage control system" is more technology neutral.

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~~n excitation and~~ 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

(…)

FSR-009: Replace references to ‘static var compensators’ with ‘reactive compensation devices’

10 June 2024

Common Quality Technical Group meeting

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Static var compensators are not the only devices that provide dynamic reactive power compensation

- Grid owners are required to periodically test their static var compensators, which are devices that provide dynamic reactive power compensation by either injecting or absorbing reactive power.
- Static var compensators are the only type of dynamic reactive power compensation device that must have routine testing done, with the current wording of the Code.
- The omission of other types of dynamic reactive power compensation devices from the periodic testing requirements does not signal the full benefits and costs of those technology types, and infers some competitive advantage to them.

Proposal

Replace references to “static var compensation devices” with “reactive compensation device” in Schedule 8.3, Technical Code A, Appendix B, clause 9.

9 Grid owner ~~static var compensator~~ reactive compensation device transient response and control

Each **grid owner** must—

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

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

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

(…)

Consequential changes would also need to be made to other parts of the Code, including:

- **Clause 1.1 – definition of “reactive capability”**
- **Schedule 12.5 – Asset category**

Definition of ‘generating unit’

Common Quality Technical Group meeting

10 June 2024

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Current definition: As drafted vs intent

As drafted

- all equipment functioning together as a single entity to produce electricity

Intent

- the smallest entity, including all related equipment essential to its functioning as a single entity, that can produce electricity in isolation from other entities that are part of the same system

Intended application

A generating unit

- Hydro, gas, coal, geothermal, and wind turbine generators
- A string or array of solar photovoltaic (PV) panels with one inverter
- A string or array of batteries with one inverter
- A solar farm or battery farm with one inverter

Not a generating unit

- Individual solar PV panels in a solar PV string or array
- Individual batteries in a battery string or array
- A string of wind turbines

‘Single entity’ intended to mean ‘smallest entity’

‘Single entity’ intended to cover size and ability to operate independently

- Concern with referring to a specific device / piece of equipment
  - Generators, solar PV panels and battery cells need add-ons to produce power
- Concern with using ‘smallest’ in the definition:
  - Could be interpreted to mean only the smallest units will meet the definition but larger units will not
- However not referring to ‘smallest’ risks broader-than-intended interpretation
  - Eg, wind farm / solar PV farm / battery farm

Revised definition

As drafted

- all equipment functioning together as a single entity to produce electricity

‘Strawman’ revised definition

- the smallest entity comprised of all equipment functioning together as a single entity to produce electricity
- the smallest technically and operationally independent collection of equipment functioning together as a single entity that can produce electricity in isolation from other such entities that are part of the same electricity generation system

Implications for Code obligations

Part 1

- Single credible contingency event
- Station security constraint

Part 8

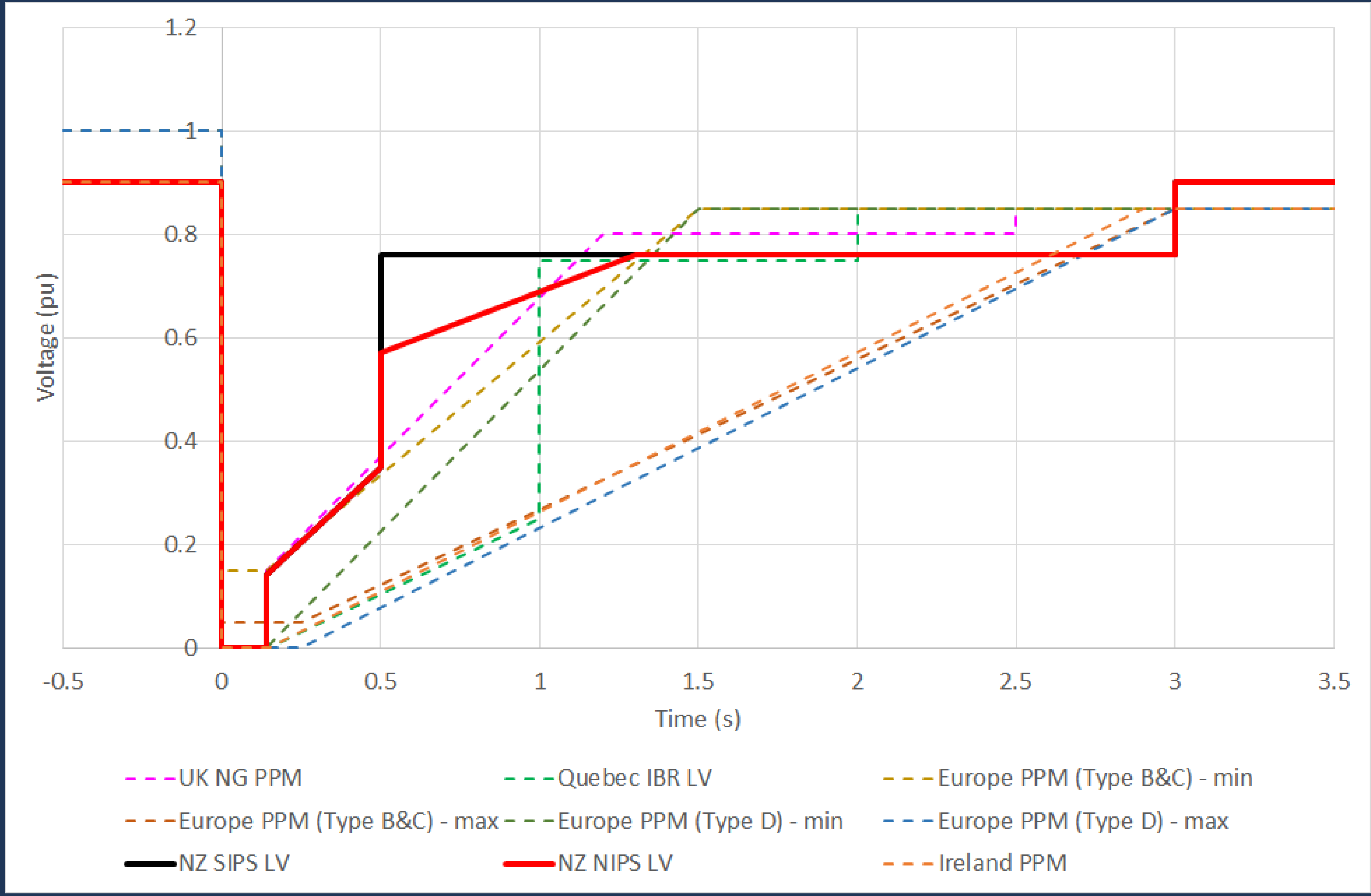
- Clause 8.23
- Schedule 8.3, Technical Code A, clause 5
    - Specific requirements for generators
- Schedule 8.3, Technical Code A, Appendix B, clause 4
    - Generating unit transformer voltage control
- Schedule 8.3, Technical Code C, Appendix A, Table A1

Fault Ride-through (FRT) Curve Review

- To support the Electricity Authority's review of Part 8 (Common Quality)
- CQTG June 2024 Update

To assess the need to have different FRT curve for synchronous and inverter-based generation

New Zealand FRT curve against curves applied for inverter-based generators

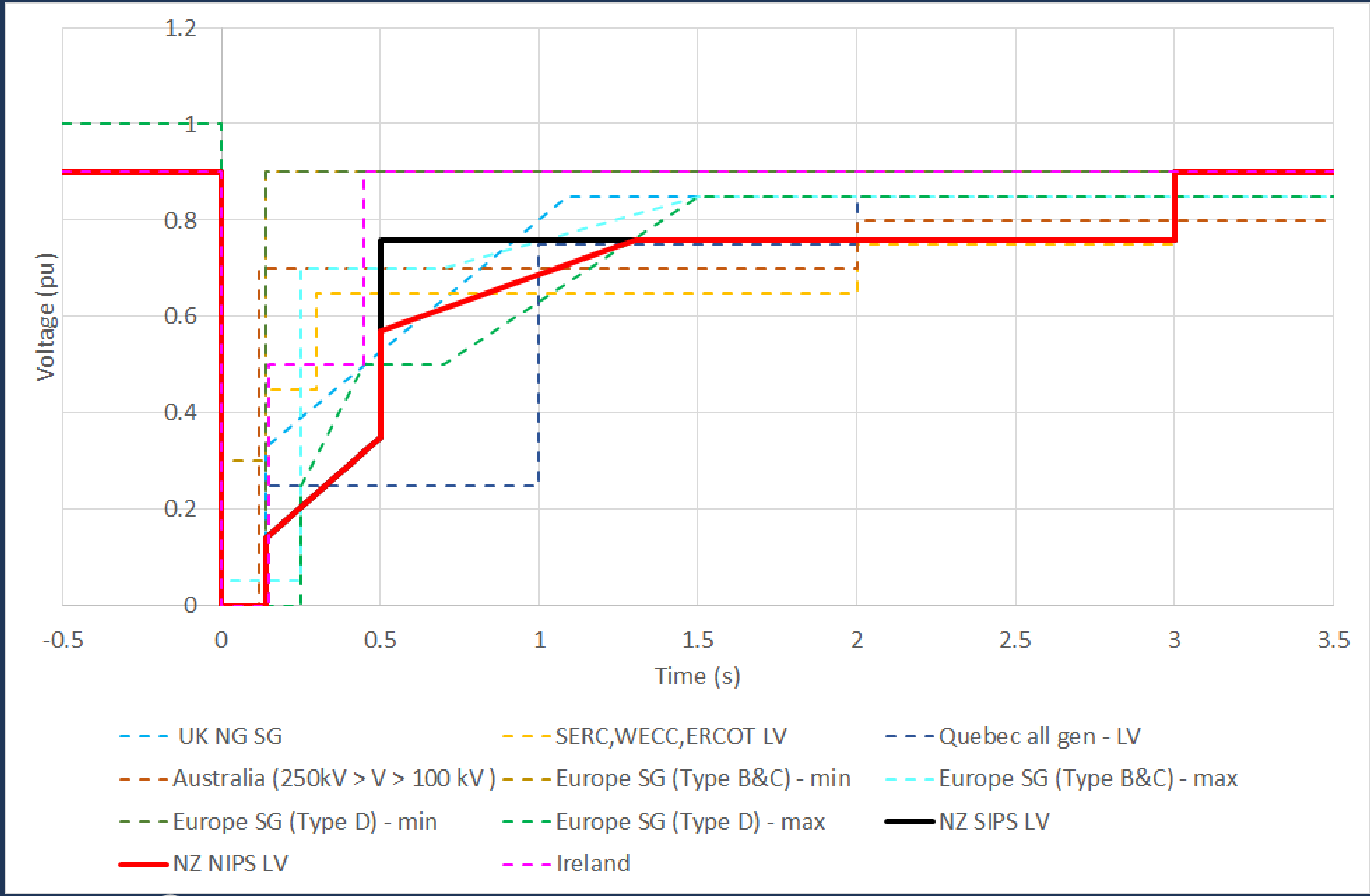


Curves for inverter-based generators

Findings

Majority of the IBR FRT curves are more stringent compared to New Zealand IBR FRT curves.

New Zealand FRT curve against curves applied for synchronous generators

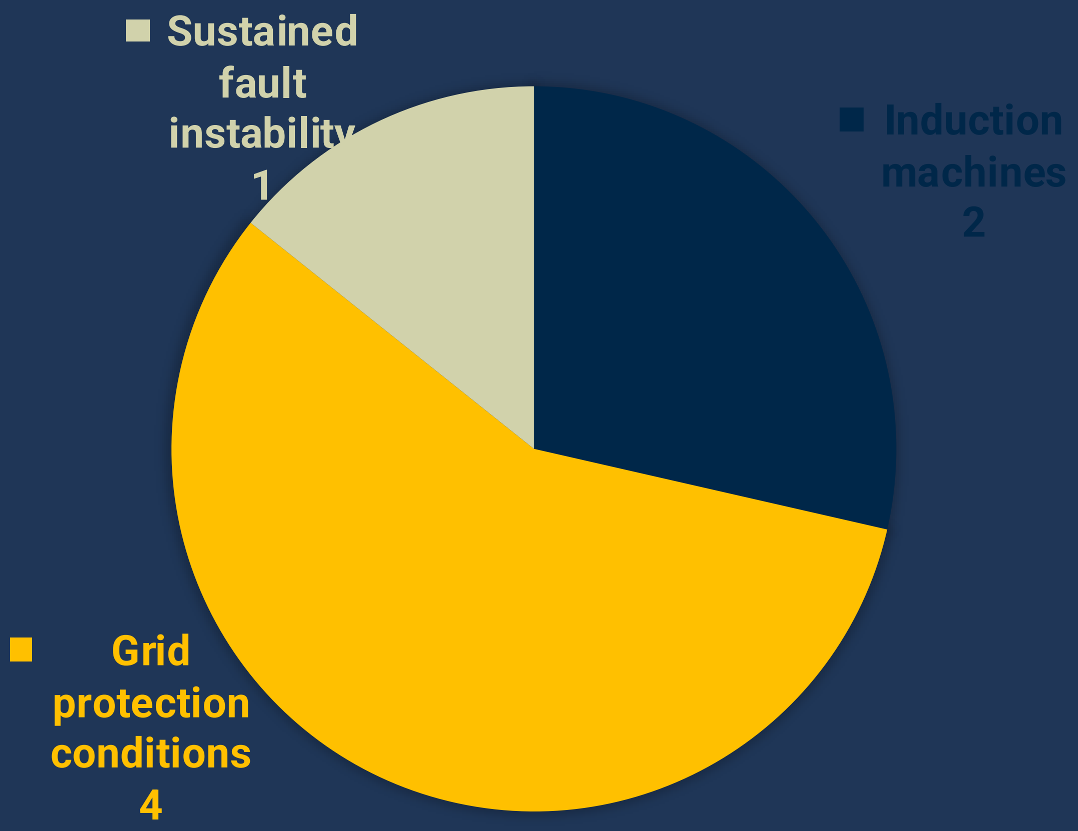


Curves for synchronous generators

Findings

Majority of the FRT curves for synchronous machines are less stringent compared to New Zealand IBR FRT curve.

Dispensations for fault ride through (8.25A of the Code)



7 Dispensations

Findings

- 4 dispensations are related to CB fail protection
- 1 dispensation is related to local operating conditions and machine characteristics
- 2 dispensations are related to old DFIG technology

Findings and recommendations

- ❖ Multiple factors lead to assets not meeting the FRT requirements
- ❖ Most new generators are inverter-based, so the present FRT curve is still relevant
- ❖ Synchronous machines may have difficulty meeting the current FRT requirements
- ❖ Not the most urgent common quality issue to solve now
- ❖ But will require review of the present FRT curve for synchronous generating units to avoid unnecessary compliance management

We recommend including this item in the to-do list to review the FRT curves when resources are available

Questions

Thank you

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Technical requirements for Battery Energy Storage System (BESS)

- To support the Electricity Authority’s review of Part 8 (Common Quality)
- CQTG 10 June 2024 Update

Background on BESS and Code requirements

- Current technical requirements based on Code requirements developed for synchronous generating unit and demand.
- BESS is very versatile, can be seen as energy source when discharging and network offtake when charging.
- BESS can provide various ancillary services.
- Code amendment in March 2022 allows BESS to offer as instantaneous reserves:
  - Generalise the meaning of the defined term **instantaneous reserve,**
  - Generalise the meaning of **interruptible load,**
  - Define new terms **energy storage system** (ESS) and **generation reserve**, and
  - Update various parts of the Code to allow BESS to offer instantaneous reserve – the procurement plan was amended to accommodate this.
- The amendment in 2022 was a simple interim measure to allow BESS to provide generation reserve while discharging but did not address any issues associated with common quality - offers would simply use the tail water

System operator applied common quality on BESS

	Bess when charging	BESS when discharging
Voltage support (reactive power curve) + voltage control	?	Point of connection to the **grid** Point of connection to the **grid**
Voltage range	?	
Frequency support + frequency control	?	Greater than 30 MW
Frequency range	?	Greater than 30 MW
Fault ride through	?	Greater than 30 MW
AUFLS provision	yes	NIL
Periodic testing	yes	yes
SCADA indications and measurements	Plant ~~and string level~~	Plant and string level
Testing at commissioning	?	Basic + need to demonstrate compliance
Modelling	?	Basic + demonstrate performance where an obligation exists

Current issues faced by asset owner and system operator

- ❖ Ambiguity in technical requirements.
- ❖ Difficult for system operator to monitor and check compliance.
- ❖ Difficult for asset owner to meet compliance.
- ❖ Ambiguity in compliance requirements making it difficult to:
  - ❖ Derive testing methodologies,
  - ❖ Determine modelling requirements, and
  - ❖ Determine connection study requirements and technical assessments.
- ❖ May not utilise BESS capability fully with two different obligations.
- ❖ Needs to consider other operational needs like:
  - ❖ Information needed for real-time operation, and
  - ❖ Security studies.
- ❖ Needs to consider future technology like hybrid plant to avoid re-work.

Current issues faced by asset owner and system operator

- Provision of AUFLS by BESS is problematic
  - Load would not be disconnected on an AUFLS activation as required by the Code.
  - A BESS can quickly change from charging to injecting immediately which is more helpful to the power system than disconnecting.
  - If required to disconnect then the BESS is precluded from offering other ancillary services such as black start.
  - The Code does not allow the same demand to be used for AUFLS and IL simultaneously, so a BESS can only really provide ‘compliant’ IL or AUFLS individually at the expense of the other.
- A BESS is primarily connected to the power system to support injection when required rather than as an offtake customer.

Questions

Thank you

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Update on relevant workstreams from Operations Policy team

Chris Otton

Manager Policy - Operations

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Update on relevant workstreams from Retail & Networks team

Allen Davison

Principal Analyst – Retail & Networks

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Update on status of other options in the long list of options

Options that may be assessed further along the Part 8 review

Issue no.	Option description	Update on status
2, 3, 4	Revise or remove the fault ride through envelope specified in Part 8 of the Code	Voltage study 3 will help inform this option. Unlikely to be considered further because of other options being higher priority.
2, 3, 4	Impose greater obligations on distributors and the system operator to maintain: - certain voltage ranges at GXP/GIPs - system strength at GXP/GIPs	Voltage ranges - this is being addressed as part of the options paper. System strength - propose removing this as it is difficult to impose such obligations on NZ's power system.
2, 3, 4	Consider a standard for generation assets to ride through multiple faults in quick succession (within several minutes). For example, in Australia they recommend a capability of 1.8 p.u.s (i.e. the generator can dissipate full power output for 1.8 s). If a system fault is typically cleared in 200 ms, then the generator would tolerate approximately 9 successive bolted faults, before the power dissipation capability would be exceeded.	Propose this continues to remain on hold. In the NZ context, given the amount of synchronous generation, this is considered a HILP at this stage. Currently the SO manages connection requests in a bespoke manner, ie, if the connection request is closer to the HVDC link, the requester is provided with the HVDC commutation failure curve for their connection studies. (As at 8 December 2023, the Authority decided to defer analysing this option for the time being. This was for two reasons: 1. because of the system operator's practice of including credible contingencies in the connection studies for proposed new connections, with the modelling of faults that have the potential to cause a multiple fault event 2. resourcing constraints within the Authority.)
2, 3, 4	Develop suitable technical requirements for fault ride through for embedded / distributed generation, which are consistent with and elaborate upon the fault ride through requirements in the Code.	Voltage study 3 will help inform this option. May be considered for 2024-25. CQTG has recommended the Authority commence a project on this in the next financial year, with involvement of Authority, system operator, ENA and EEA.

Options that may be assessed as part of a different project: (Operations Policy team – 1 of 2)

Issue no.	Option description	Update on status
1	Resources (eg, generators, batteries) must make available X% of maximum rated capacity to support frequency in underfrequency events	May be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	New market product – 1 second reserve / synthetic inertia	May be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	Widen the normal band	May be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	Have a new ancillary service for inertia (NB: differs slightly from the option above that relates only to synthetic inertia)	May be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.

Options that may be assessed as part of a different project: (Operations Policy team – 2 of 2)

Issue no.	Option description	Update on status
1	Lower the minimum frequency keeping threshold below 4 MW and have a national market for frequency keeping	To be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	Allocate frequency keeping costs to the causers of frequency deviations	To be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	Put in place ramping limits on generation plant and load for post-disturbance or change-of-MW output (eg, due to wind gust or cloud covering)	May be investigated as part of the Ancillary Services (frequency keeping) Review. Initial investigations/scoping around frequency regulation has commenced. Next stage of this work is subject to prioritisation for 2024/25.
1	Remove the obligation on the system operator to eliminate from the power system any deviations from New Zealand standard time caused by variations in system frequency	Work is underway. Consultation paper due Q3 2024.
1	Review the dispensations and equivalence arrangements framework (for **frequency** obligations)	To be prioritised for 2025/26
2, 3, 4	Review the dispensations and equivalence arrangements framework (for **voltage** obligations)	To be prioritised for 2025/26

Options that may be assessed as part of a different project: (Retail & Networks team)

Issue no.	Option description	Update on status
2, 3, 4	Require alignment of voltage-related connection standards across distribution networks	Connection and operation standards (COPS) will be considered during Stage Two of the Network Connections project, commencing in early 2025. The work has not been scoped but is likely to include, for example: • whether COPS should be better cemented in the Code (eg, COPS are not current defined, does the Code give distributors the necessary powers to enforce)? • whether minimum quality thresholds should apply (eg, coverage)? • mechanisms to provide greater COPS consistency across networks (eg, whether certain requirements should be mandatory) • how industry could assist to improve compliance with COPS (eg, guidelines). The Network Connections Technical Group (NCTG) is assisting the Authority with this and wider Part 6 work. Input from the CQTG on COPS would be valued.
6	Establish a protocol for setting the frequency in islanded networks, including who the grid forming generator is	Not previously considered but this could be added to work on COPS above.
6	Establish a registry of distributed energy resources	Work underway by Retail & Networks policy team in the Authority. First stage involves capturing more granular DG data on the ICP registry, with consultation to be released mid-2024. Second stage will look to include DER (eg, EV chargers), with consultation likely around late 2024.

Options proposed to be removed from Part 8 review (1 of 2):

Issue no.	Option description	Update on status
1	Increase, from 45 Hz to 47 Hz, the minimum frequency at which South Island generation assets must remain synchronised for 30 seconds following an underfrequency event	This is highly unlikely to be justifiable for the long-term benefit of consumers and is therefore being removed from option list. Note: This option, if considered, would have effects in other areas such as AUFLS, implementation on reserves etc.
2, 3, 4	Establish a new ancillary service for reactive power management	Current ancillary services address this option.
2, 3, 4	Establish a new system strength ancillary service	This option would be difficult to implement on NZ's power system.
5	Make the system operator responsible for managing harmonics on the transmission network (eg, a new PPO) and distribution network operators responsible for managing harmonics on distribution networks, with costs recovered from the causers of the harmonics	The CQTG has agreed the obligation should stay with the asset owner rather than with operators.

Options proposed to be removed from Part 8 review (2 of 2):

Issue no.	Option description	Update on status
6	Where a flexibility provider is providing a service to an asset owner, leave it to the flexibility provider rather than the asset owner to provide the network operator with the information required by the network operator to use the flexibility service	CQTG agreed this should be a contractual matter.
6	Require asset owners' vendors to provide asset capability information that network operators require to meet their regulatory obligations	This option would require vendors to be made industry participants, which would require legislative change. Would be high risk of unintended consequences - with vendors asking why they have to be a participant in order for them to provide information that the asset owner could provide. Also, the vendor's involvement with a network-connected asset typically is not for the life of the asset.
6	Require asset owners' vendors to provide asset capability information, encrypted if required by the vendor, that network owners require to optimise their network investments	This option would require vendors to be made industry participants, which would require legislative change. Would be high risk of unintended consequences - with vendors asking why they have to be a participant in order for them to provide information that the asset owner could provide. Also, the vendor's involvement with a network-connected asset typically is not for the life of the asset.

Next meeting

Purpose: Review feedback from submitters and the proposed Code amendments to address issues 1 to 7

Proposed next meeting date: September/October 2024

Location: Wellington

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