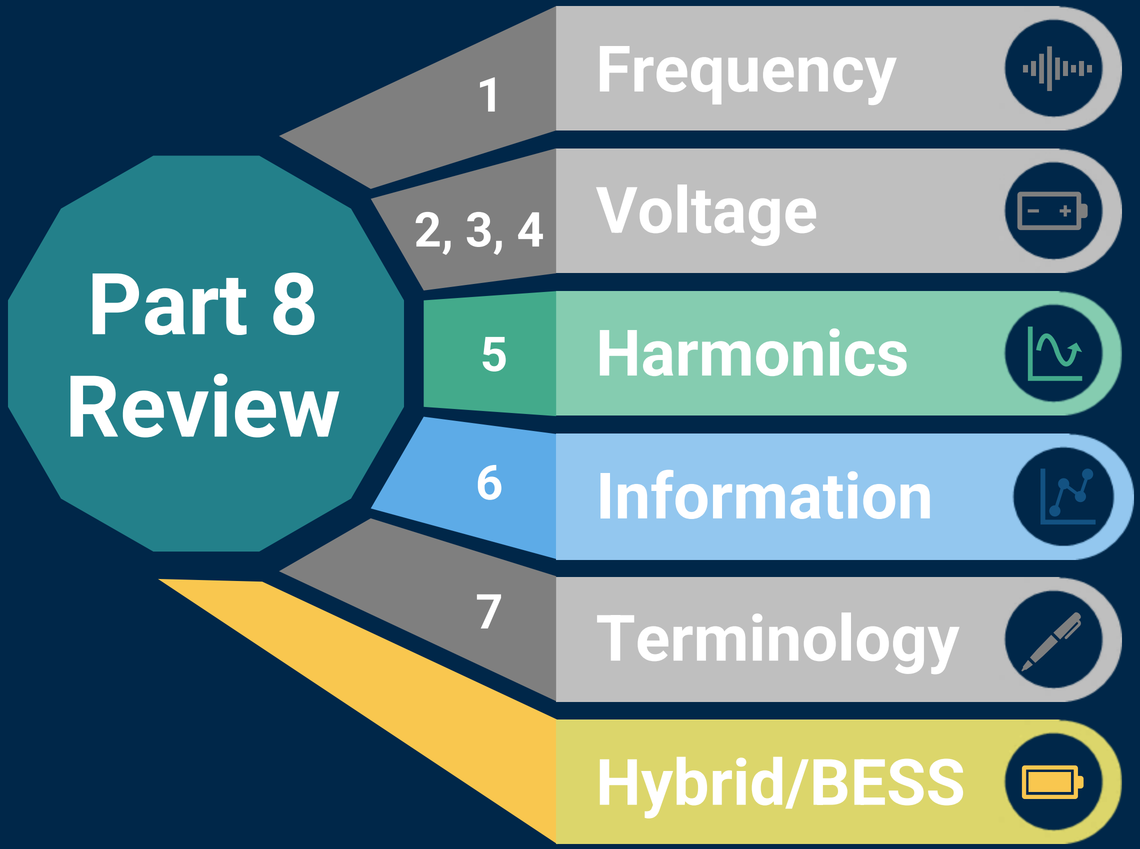
Future Security and Resilience: Common Quality Technical Group (FSR CQTG)



Meeting 16: 25 February 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Purpose

Provide feedback on:

- Hybrid plant/ BESS AOPOs
- Information stage 2 preliminary thinking
- Harmonics: draft Options paper

Agenda

Time	Item
9:00 am	Welcome
9:05 am	Minutes from previous meetings
9:15 am	Hybrid plants - AOPOs
10:30 am	Morning tea
10:45 am	Clause 8.23 voltage support obligations
11:30 am	Information – Part 2 (Options 2 & 3)
12:30 pm	Lunch
1:00 pm	Information – Part 2 (*continued*)
1:30 pm	Harmonics
2:30 pm	Afternoon tea
2:45 pm	Work plan for 2026/27
3:15pm	AOB
3:30pm	End of meeting

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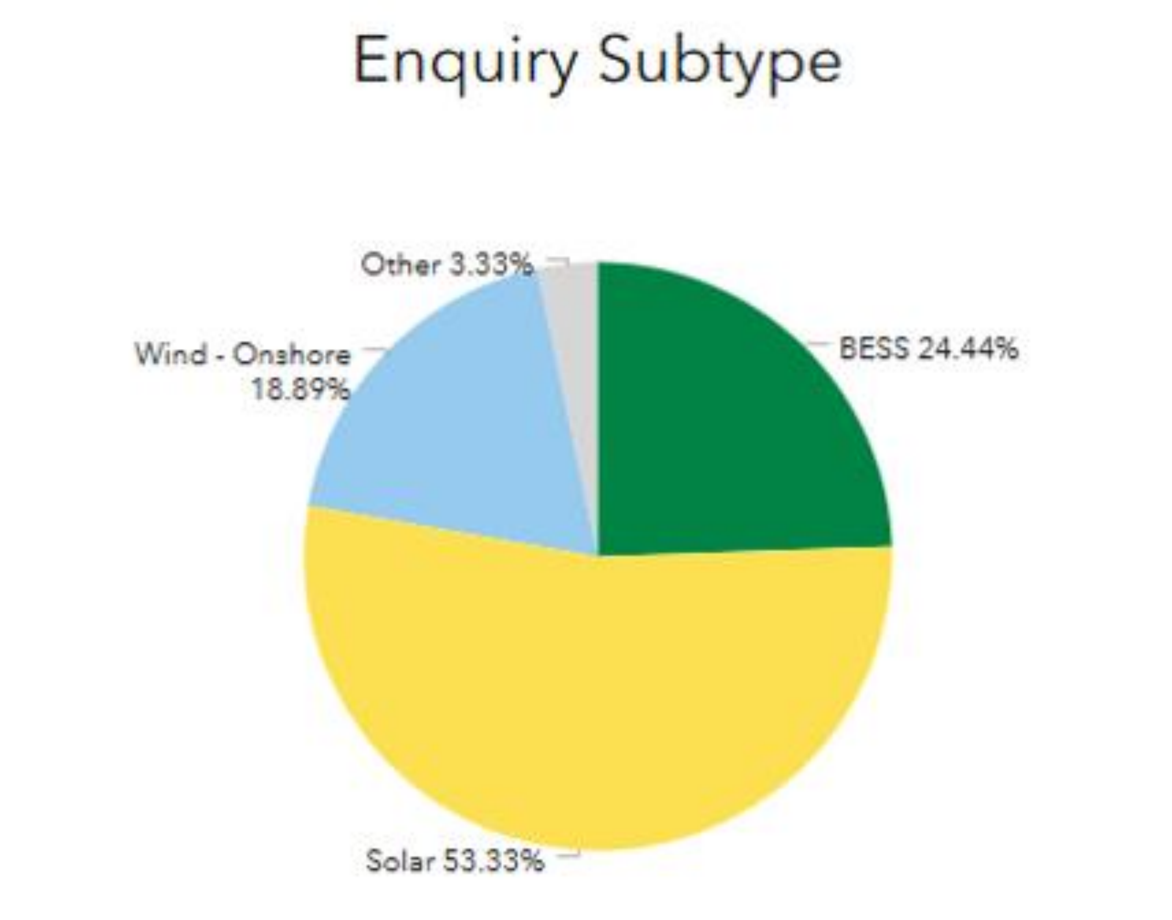
Hybrid Plant Integration

System Operator Recommendations

25.02.2025

Setting the Scene

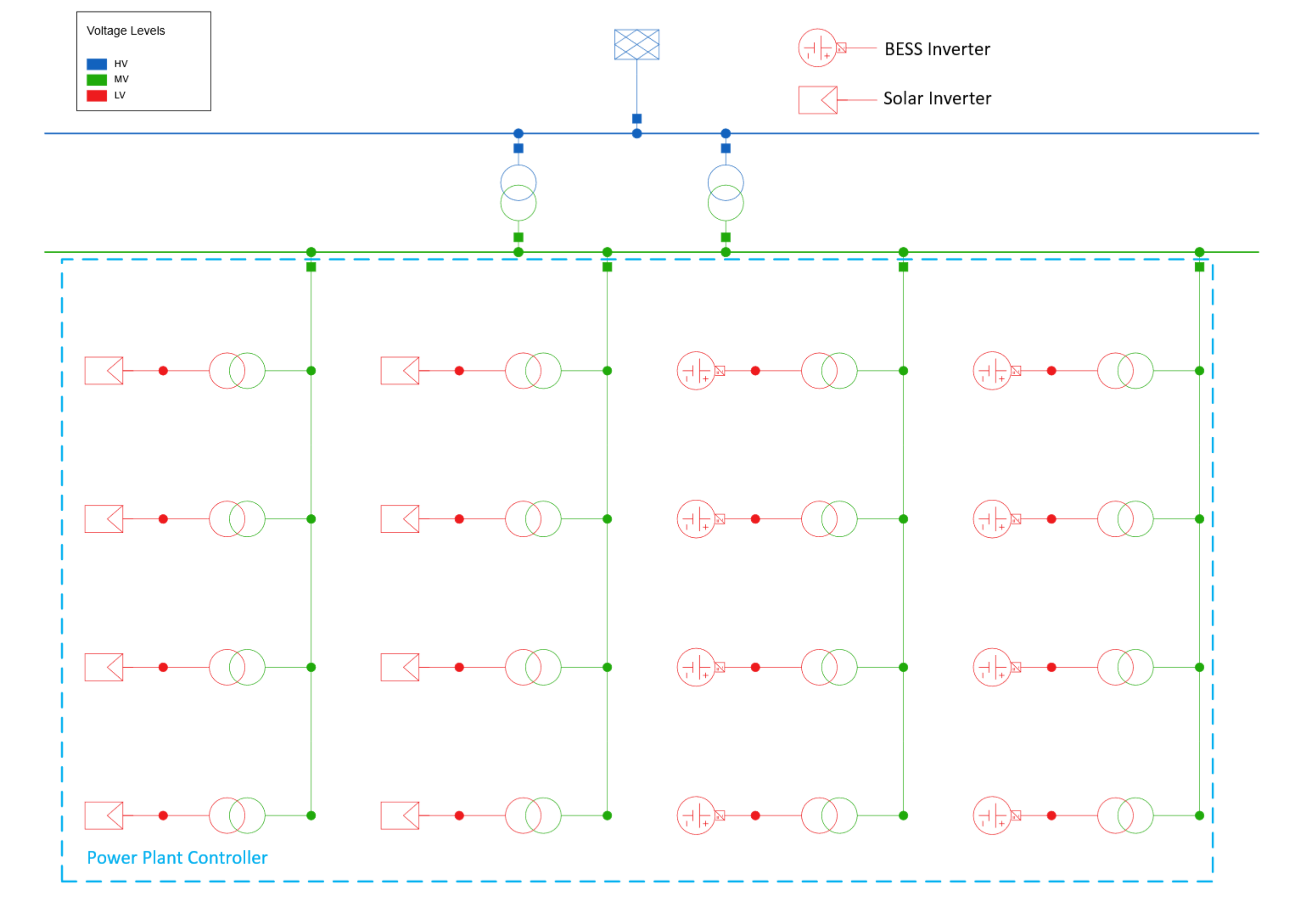
- One hybrid plant (RUK) in commissioning
- Graph is most recent TP connection pipeline. Only ~5 of those BESS projects are standalone; the rest are combined with solar
- SO has had discussions with several developers who intend to build most or all future solar developments as hybrids
- Price of batteries continues to fall, and likelihood of curtailment increasing as more solar connected



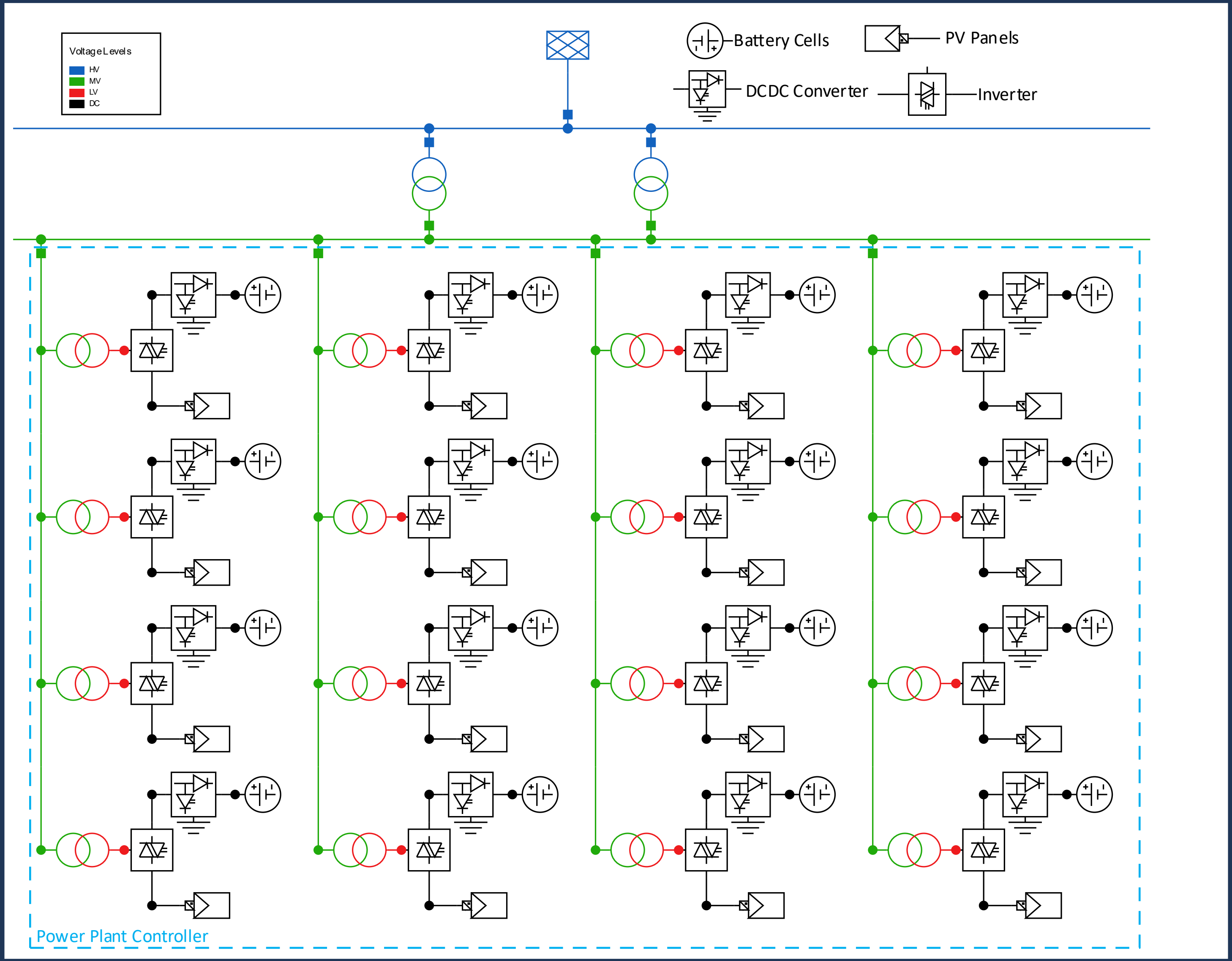
Scope of Hybrid Plants Report

Hybrid Plants Defined

- A hybrid plant is a plant where some form of generation is combined with a BESS. Can be any type of generation but PV-BESS hybrid is most common
- Internationally, it is common for combined generation and BESS capacity to exceed plant export capacity by a significant amount



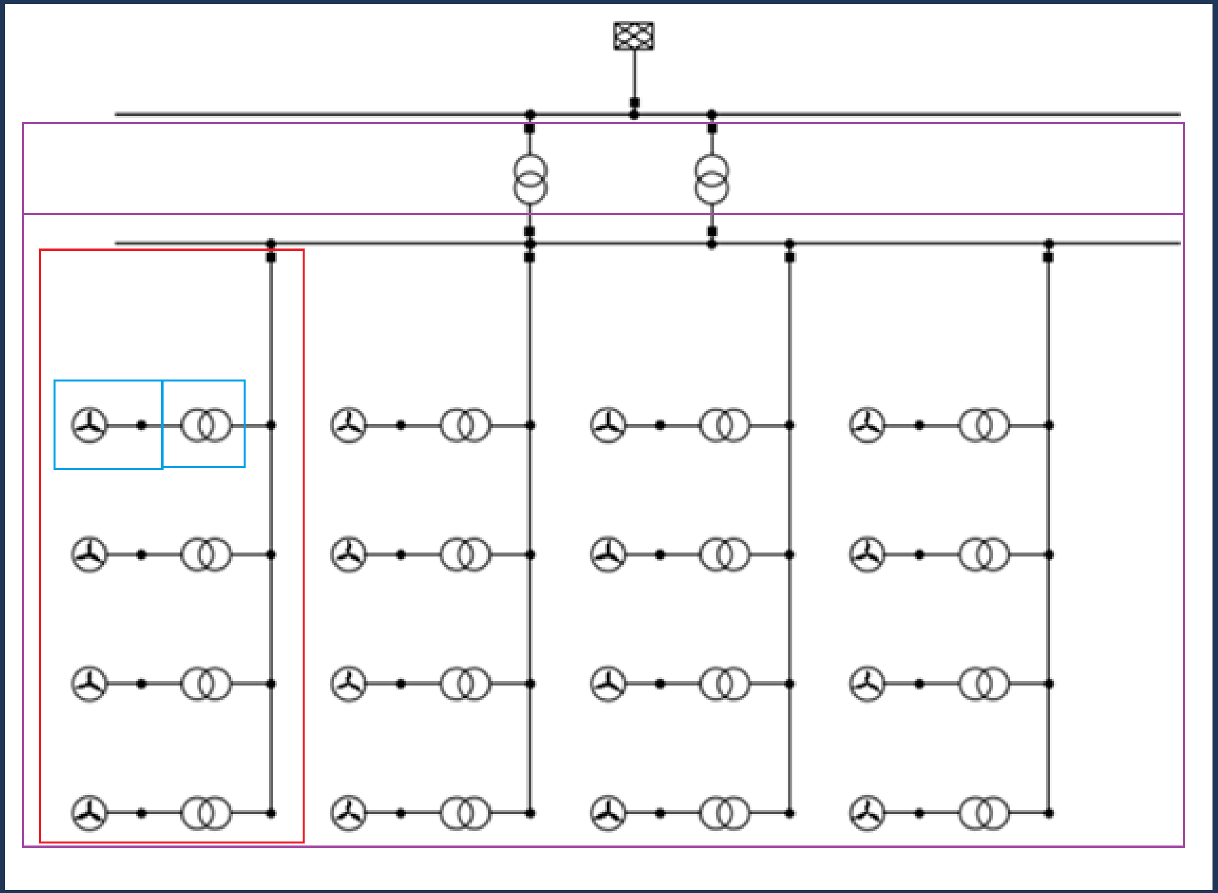
DC-Coupled Hybrid



Co-located Plant

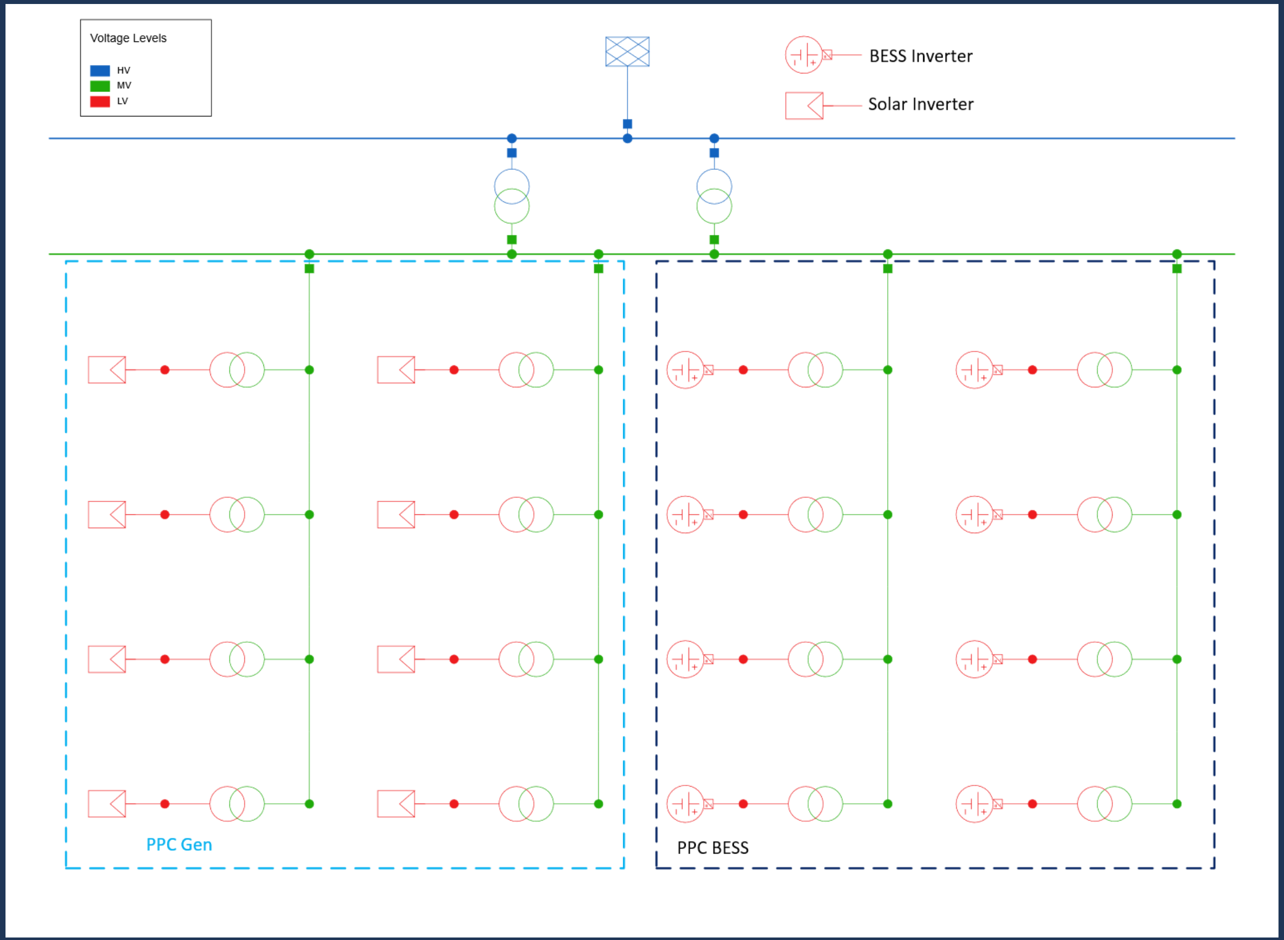
Generating Unit Definition

- ‘generating unit means all equipment functioning together as a single entity to produce electricity’
- An issue for all IBR, not just hybrids
- Particularly problematic for DC-coupled plants
- Need to consider implications for Common Quality (Part 8) and Trading Arrangements (Part 13) - is not possible to have a definition that works in both contexts



Generating Station Definition

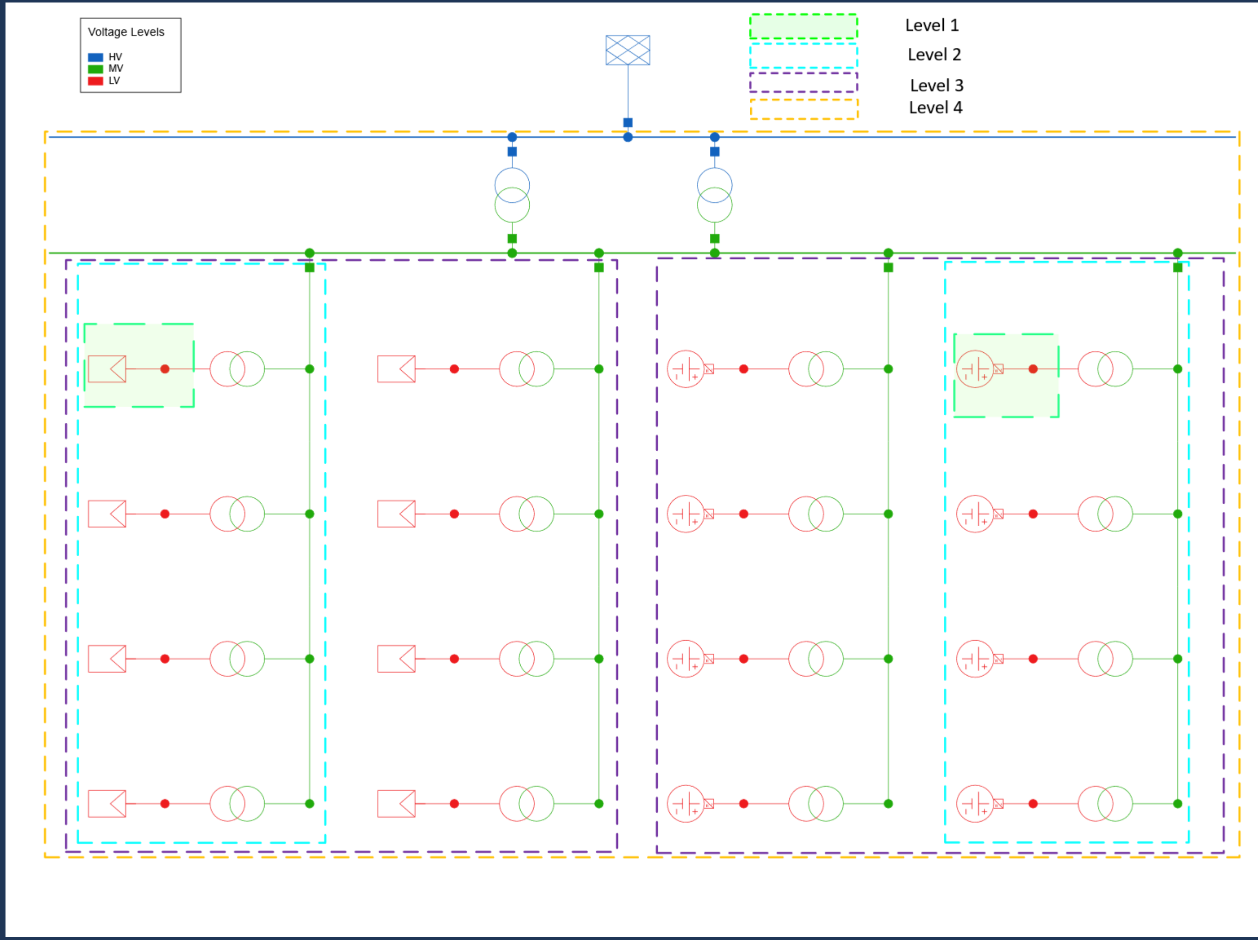
- 'generating station means 1 or more generating units that are directly connected to the grid or to a local network and that inject into the grid or a local network (as the case may be) at a single point of injection'
- Regardless of how 'generating unit' is interpreted, this definition means that a co-located plant is a single generating station



Intermittent Generation and Clause 13.11

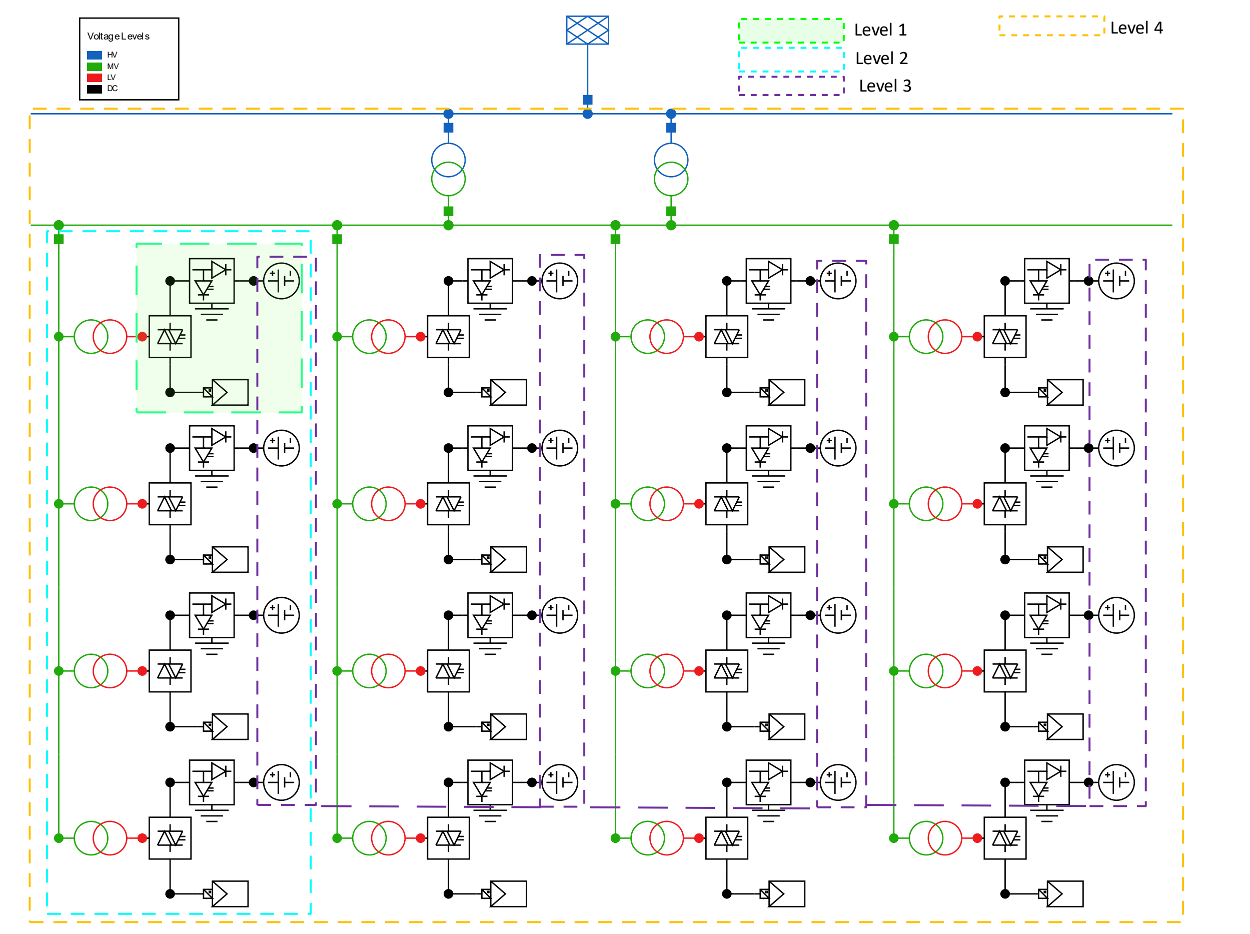
- ‘intermittent generating station means a generating station that relies on a variable resource that is not stored and in respect of which a generator has not been approved by the system operator under clause 13.3F as a dispatch notification generator’
- ‘…Despite clause 13.10, a generator, other than an intermittent generator, may offer electricity in respect of any generating plant on a unit basis
- Either the whole hybrid plant is intermittent or none of it is, and if it is intermittent the BESS and generation cannot be offered separately

System Operator Proposed Solution



Level No.	Description	Requirements	SO Proposed Term
1	The individual inverter or wind turbine	Control system must be stable and operate correctly and be modelled.	Generating Unit
2	Often called a feeder or string. A group of inverters connected via a common circuit	Indications of MW, Mvar and circuit breaker (CB) status. The level where credible event risk typically applies[6]	Generating System
3	The group comprising all of a particular resource at a generating station, i.e. the BESS or generation. Note that in a DC-coupled plant, this grouping would be on the DC side, although the grouping would only apply if the BESS and generation are offered separately	Indications of MW, market offers, dispatch, and intermittent status. In a co-located plant, this is the level at which the PPCs operate, therefore relevant performance and modelling requirements apply at this level	*No recommendation, for the Authority to discuss with the CQTG*
4	The entire station including the BESS and generation. This is where the 'excluded generating station' threshold is applied	Indications, performance and modelling of PPC, reactive power requirements, etc.	Generating Station

System Operator Proposed Solution – DC-Coupled



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4	The entire station including the BESS and generation. This is where the 'excluded generating station' threshold is applied	Indications, performance and modelling of PPC, reactive power requirements, etc.	Generating Station

Maximum Continuous Output

- Addressed as part of the voltage options paper. We recommend adopting that proposed definition.

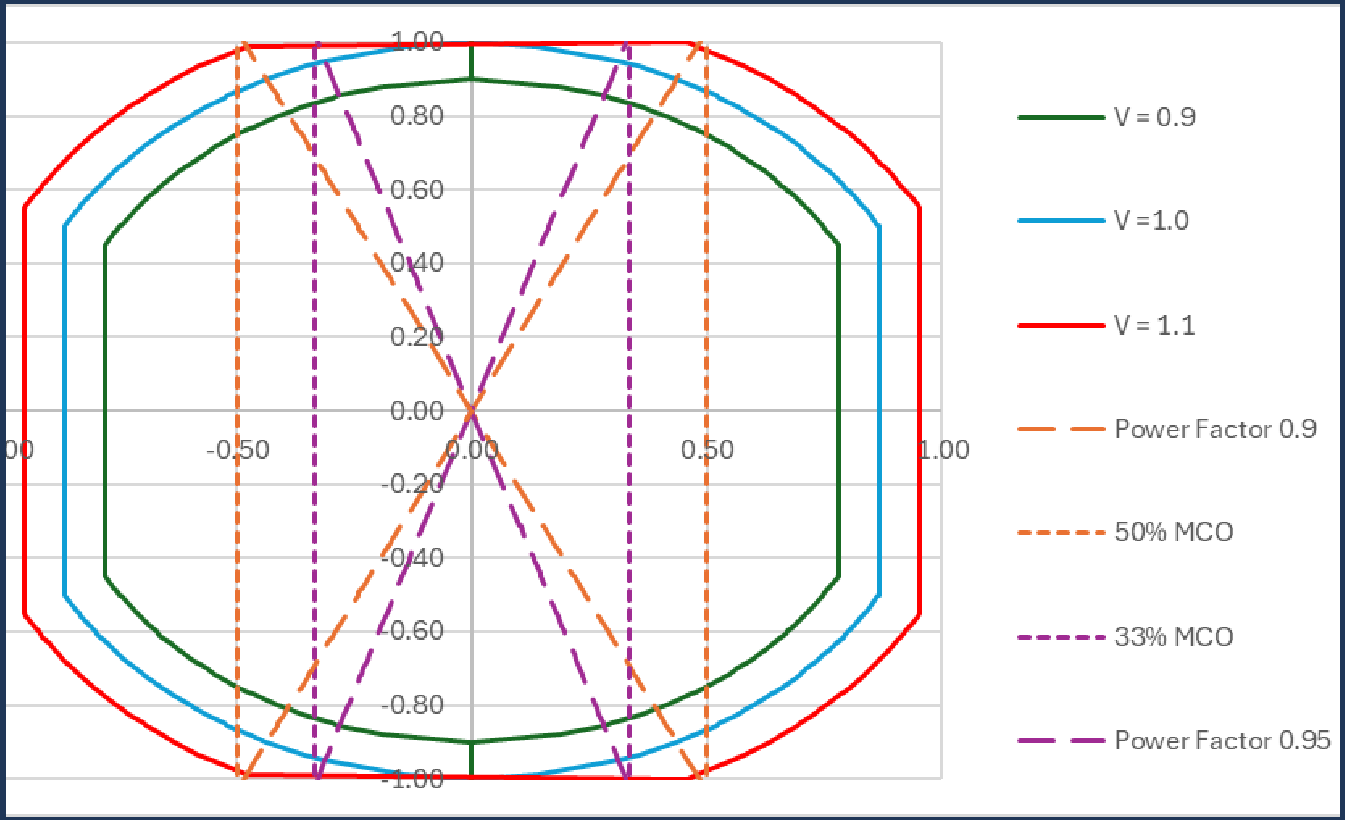
maximum continuous MW output power means—

(a) for a **generating station** or **generating unit** for which an **offer** must be submitted, the maximum dispatch quantity (in **MW** alternating current (a.c.)) of the **generating station** or **generating unit** as specified in the **asset capability statement** for the **generating station** or **generating unit**; or

(b) for a **generating station** or **generating unit** for which an **offer** is not required to be submitted, as specified in the **asset capability statement** for the **generating station** or **generating unit** the maximum **active power** output (in **MW** alternating current (a.c.)) of the **generating station** or **generating unit** at its **point of connection** that can be maintained continuously over a 5-minute period of time under ideal operating conditions and with the **generating station** or **generating unit** maintaining compliance with this Code in the absence of any exemption, **dispensation, equivalence arrangement** or similar

Hybrid Plants – Voltage Support Obligation (Clause 8.23)

- There is no difference in technical ability to provide voltage support between hybrids and other IBR
- For an AC coupled plant, it may be advantageous for the BESS to provide more reactive power than the generation. We support this approach and recommend ensuring Code drafting allows it
- Broader work to review point of compliance for 8.23 particularly relevant to hybrids



Hybrid Plants – Frequency Management 8.17

- **The IG will normally not respond to underfrequency because it is at its max given resource. The controller could be designed to compensate; however, we do not think it is required to.**
- **When responding to over-frequency, it may be advantageous to hold the BESS constant and ramp generation down further to compensate. We support this arrangement conceptually**
- **We have recommended a broader review of 8.17**

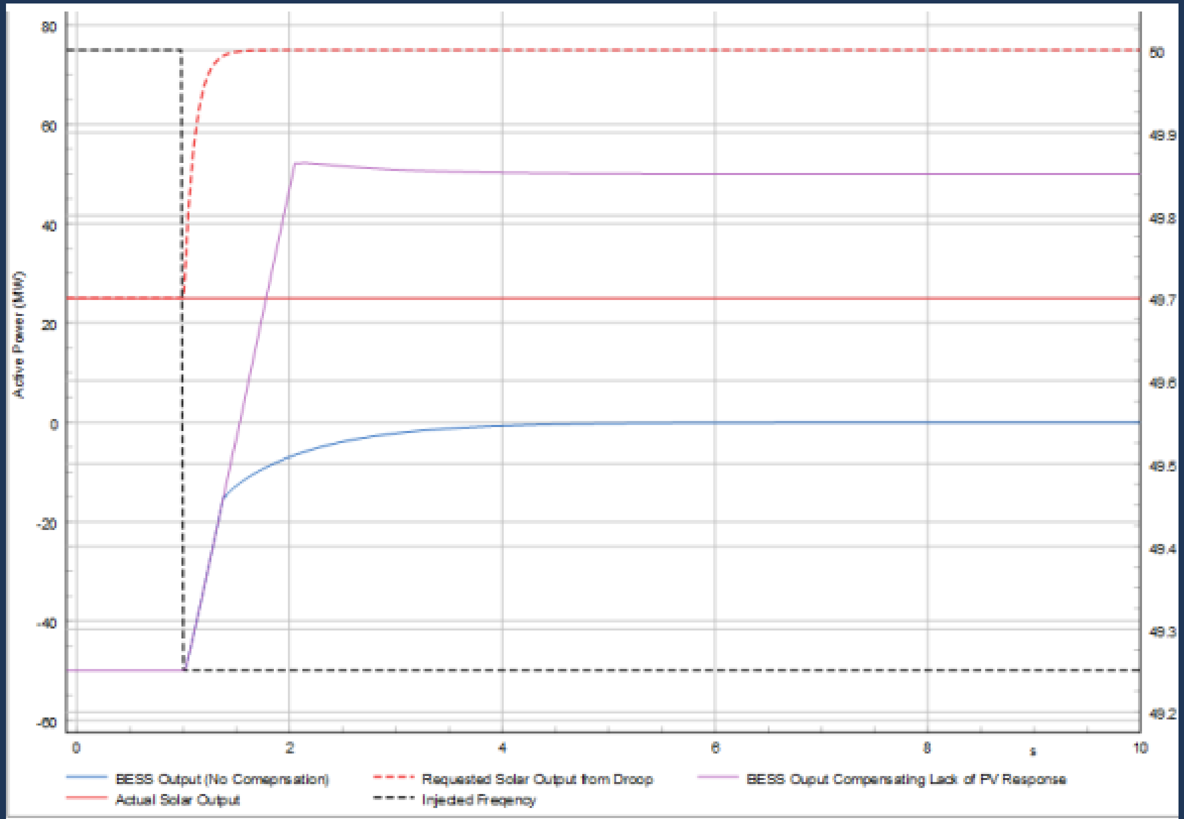


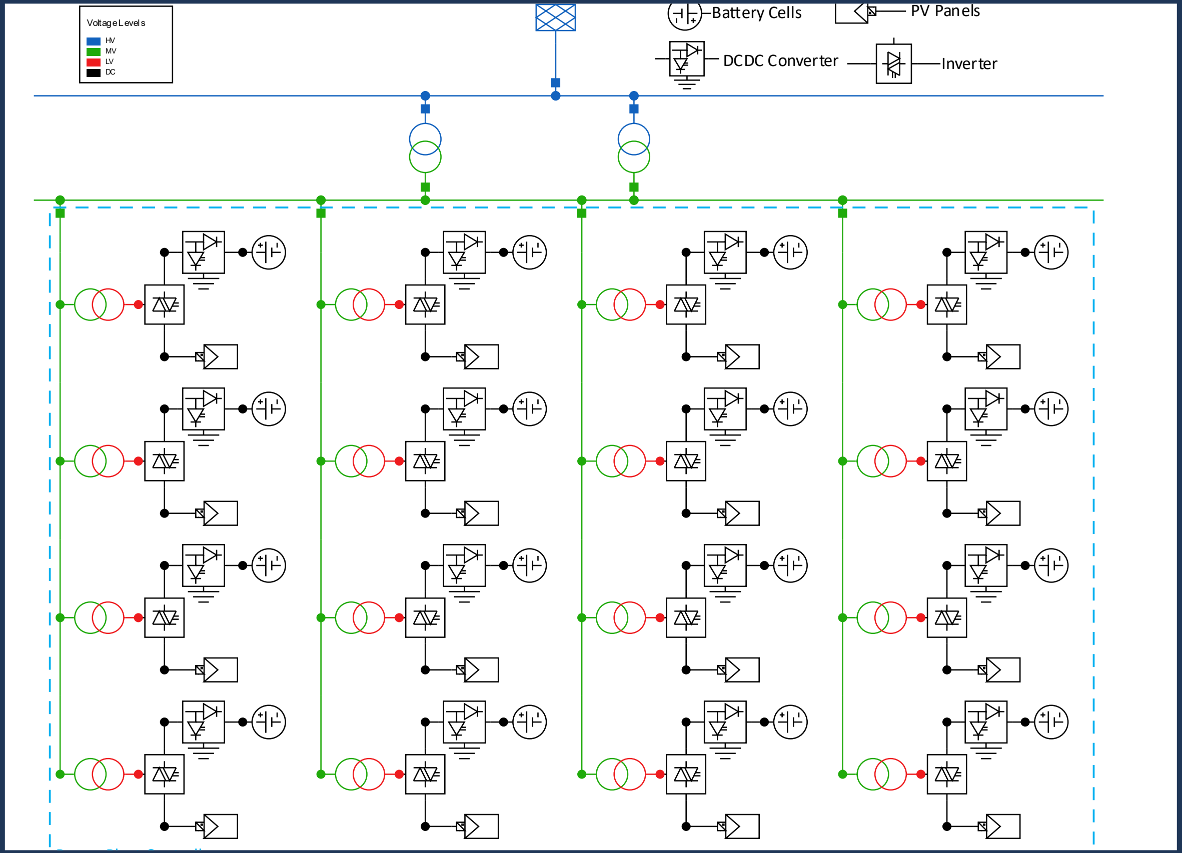
Figure 4-1: Response to a frequency step

Obligations While Idle

- **Part of this work was to address obligations for BESS and Hybrids while idle**
- **We recommend that voltage obligations apply whenever the plant is connected, but that frequency obligations do not apply when a BESS is idle**
- **We recommend that a BESS is considered idle when it is:**
  - Connected to a network, and
  - Is neither absorbing nor injecting active power, and
  - Is not cleared for any ancillary services
- **We recommend the BESS component of a hybrid plant is considered idle when:**
  - The BESS component is being charged from the generation and there is no net flow to or from the grid
  - The generation is injecting but the BESS is at 0MW and not cleared for ancillary services
- **This proposal ensure obligations are only imposed if costs can be recovered via AS offers**

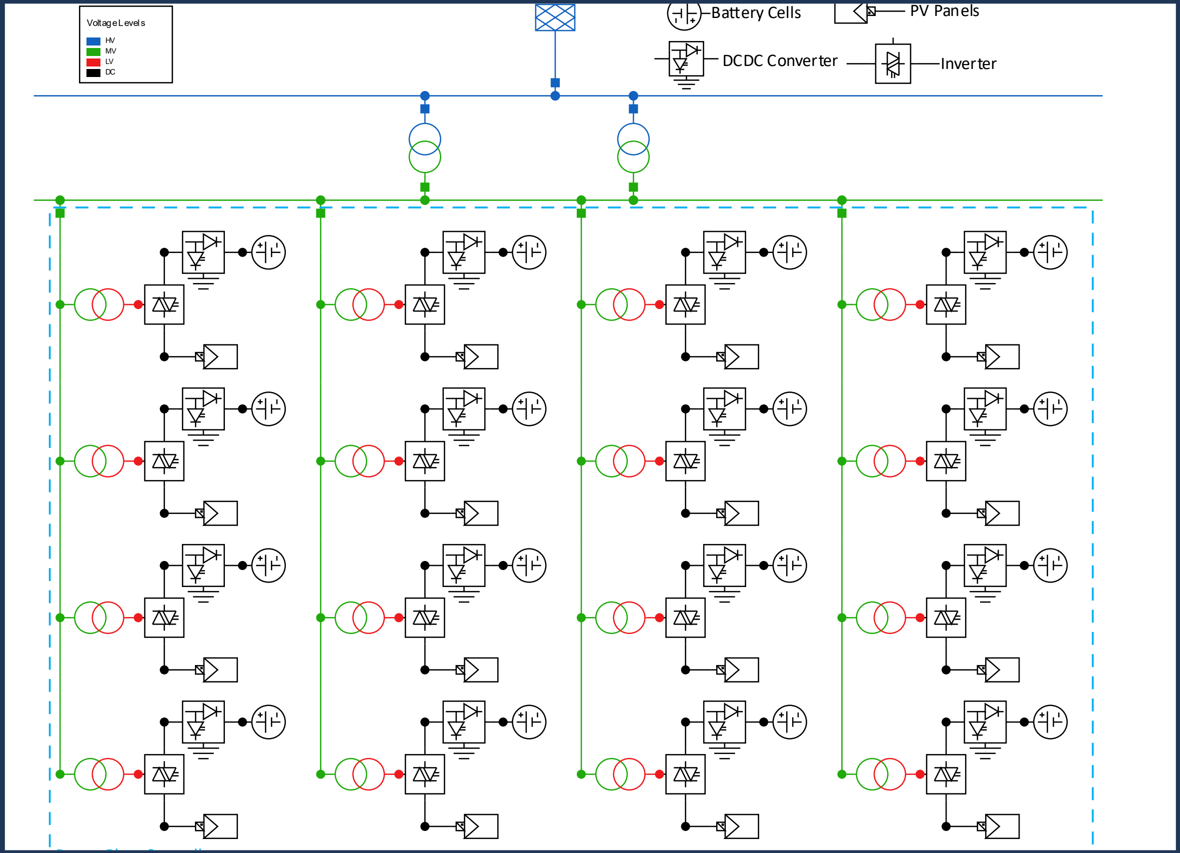
Hybrid Plants – Reserves

- **The BESS component can provide reserves the same as a standalone BESS**
- **There is no technical reason that IBR can't provide reserves, although there are potential issues with tools and the Central Forecaster provisions of the Code**
- **If a hybrid plant were offered as a single entity, the reserves could theoretically be provided by either component**



Hybrid Plants – Frequency Keeping

- The BESS component could provide MFK subject to current limitations (i.e. must be injecting energy)
- Similarly to reserves, no technical reason IBR can't provide but Code and tool issues
- Best design for plant would probably be to provide up-regulation with BESS and down with IG. System Operator supports in principle, but currently only possible if offered as a single entity
- Note MFK review in progress

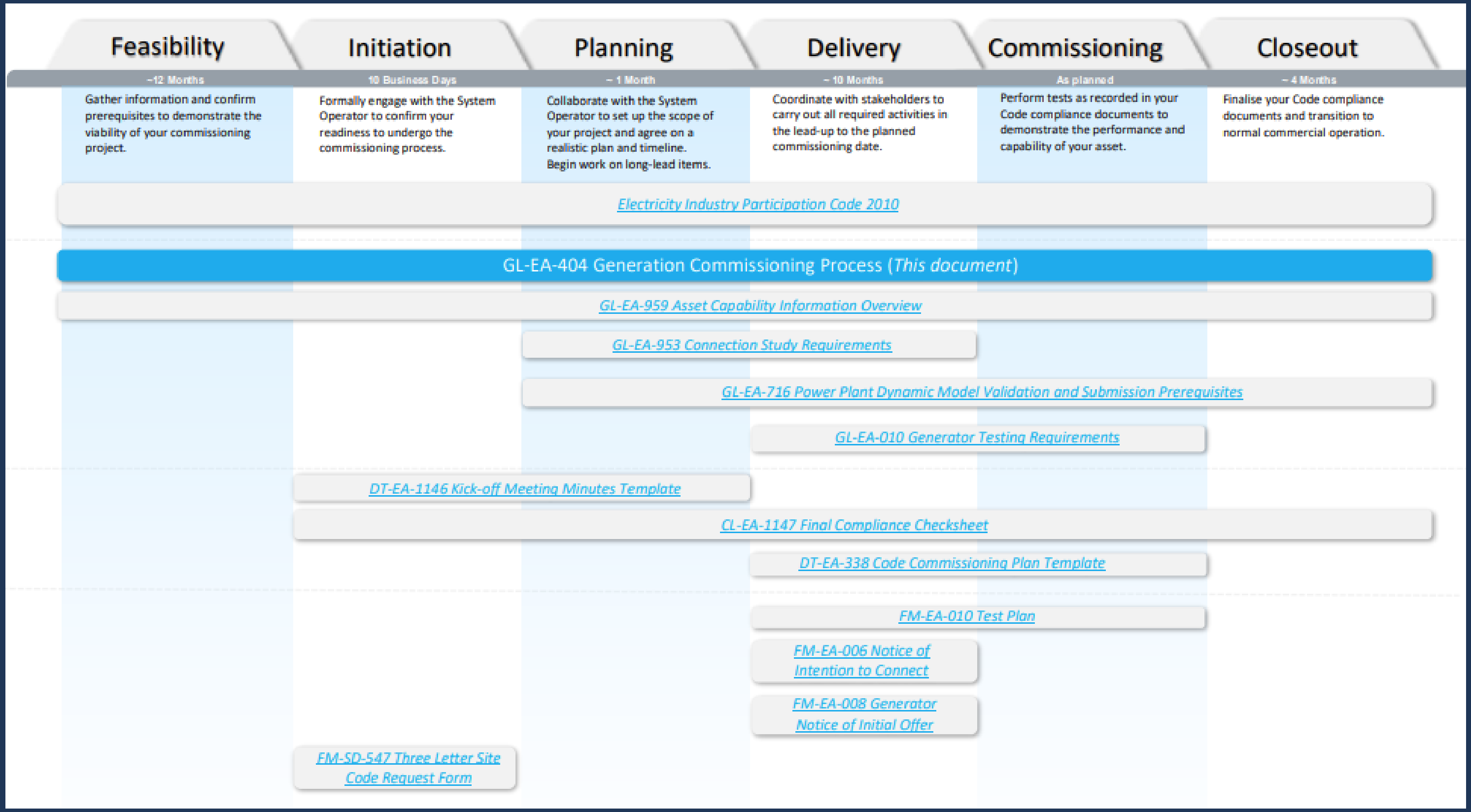


Managing Capacity Limits

- **As discussed, internationally it is common for BESS + generation to exceed plant capacity, and several proposed hybrid plants in the pipeline use this configuration. Almost all DC Coupled plants are limited by inverter capacity**
- **There may be some issues with SO tools, depending on market arrangements:**
  - If the hybrid plant is offered and dispatched as a single entity, we expect the offer would not exceed plant capacity and there would be no issues
  - If the capacity is limited by TP owned equipment, it would be managed by the tools like any other transmission constraint. This may or may not result in optimal dispatch for the AO
  - If the capacity limit is internal to the hybrid plant, it would be difficult for the SO to manage
- **Note that hybrid plants would face the same non-physical dispatch issue as standalone BESS currently do, but we expect this to be resolved via another SO/EA project**

Hybrid Plants – Commissioning

- Hybrid plants can be commissioned in stages
- AC Coupled is effectively a new asset and requires full commissioning
- DC coupled will vary case by case. An agreed commissioning plan is required, which will specify the applicable parts of the process.
- Connection studies should consider the hybrid plant from the start. They may or may not need repeating depending on elapsed time and any design changes.

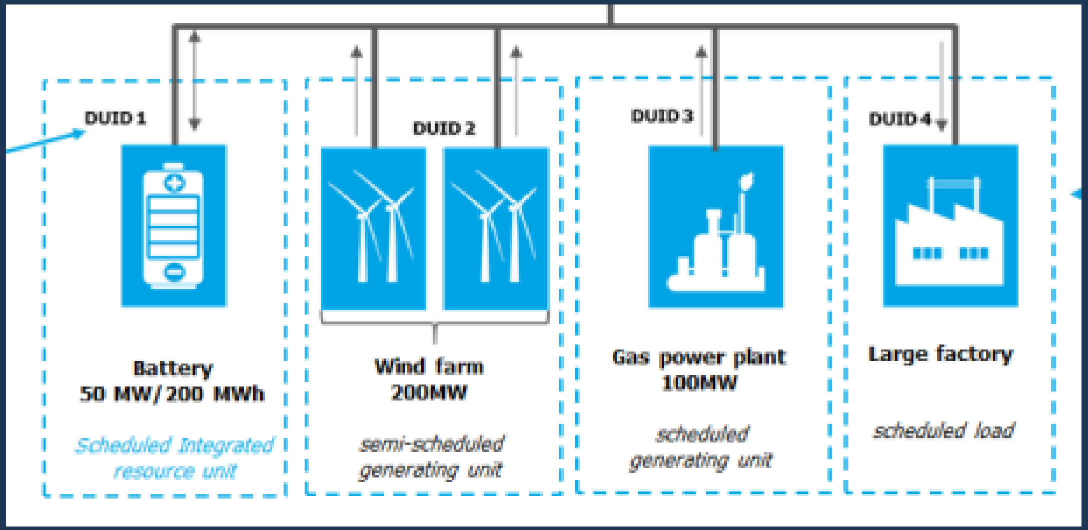


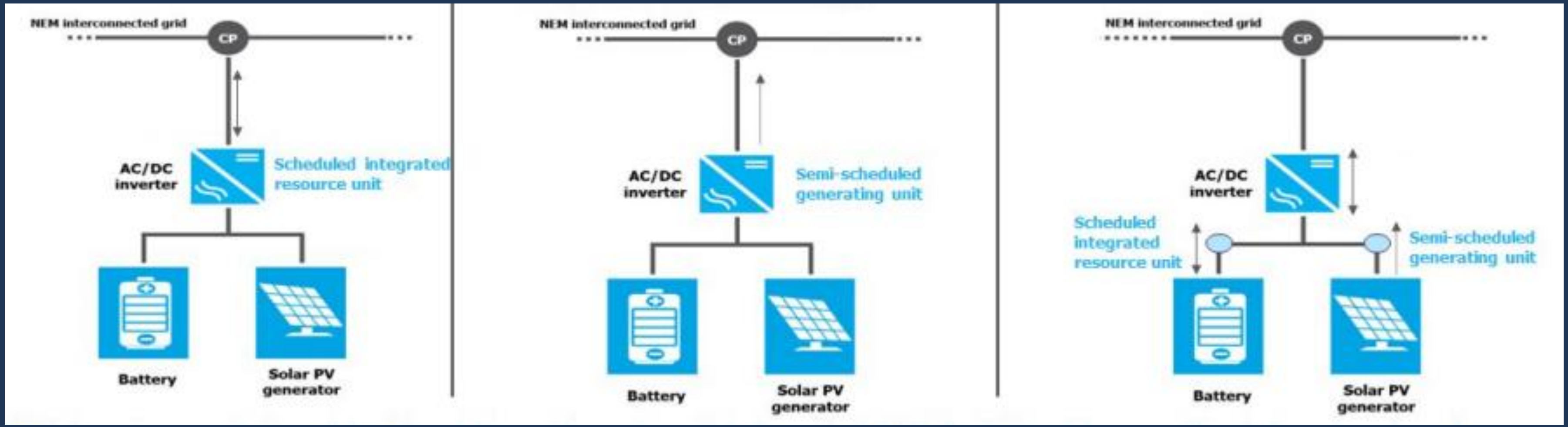
Proposed Interim Market Arrangements

- Although market design is out of scope, an interim solution is likely required so that hybrid plants which commission in the short term have clear obligations
- The System Operator recommends that the generation and BESS components are offered separately, and the generation is considered intermittent. We also recommend that DC-coupled plants be allowed to elect, with SO agreement, to operate as a single dispatchable generator
- This proposal will allow hybrid plants to commission and minimize potential tool issues until detailed market design and tool changes can be completed
- Note that regardless of market design, we will dispatch hybrid and co-located plants a single station voltage setpoint

International Comparisons - AEMO

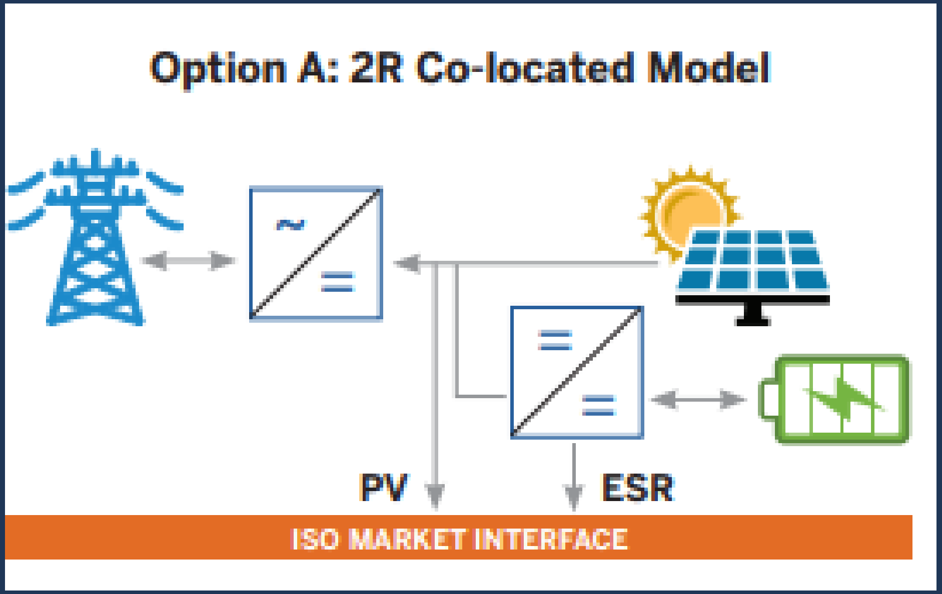
- AEMO impose the same common quality requirements as BESS on hybrid plants, with droop based on inverter capacity
- Diagrams show how market treats AC coupled (top) and DC coupled (bottom) plants
- Note AEMO have implemented additional logic in their scheduling software to ensure feasible dispatch

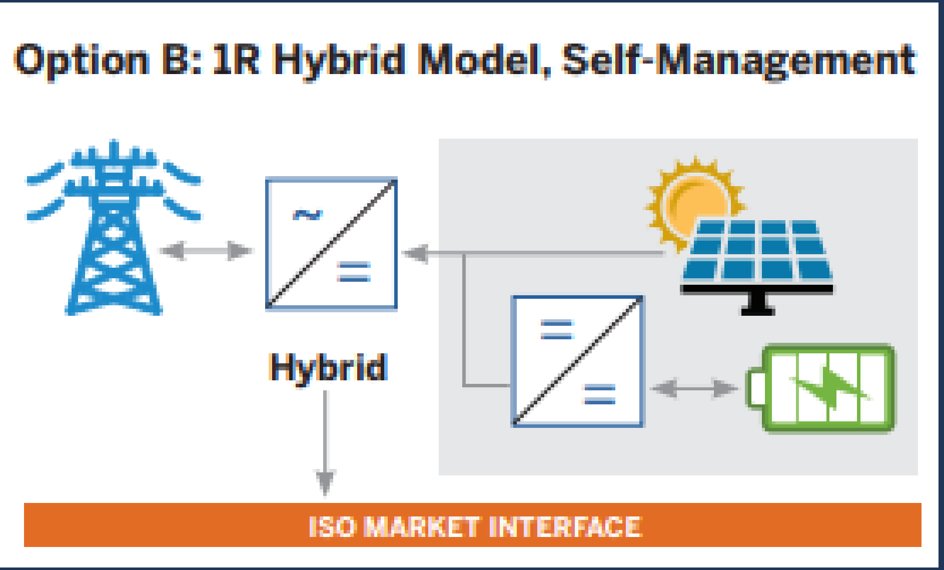




International Comparisons - CAISO

- CAISO impose the same common quality requirements as BESS on hybrid plants
- Offer two models - ‘co-located’ (separate bids, PV intermittent) and ‘hybrid’ (single bid, non-intermittent). Don’t differentiate between AC and DC coupled
- Co-located model allows for ‘Aggregate Capability Constraint’ in the market system to limit total injection
- Note that CAISO operate a capacity market as well as an energy market – beyond the scope of this paper but provides some interesting insights into forecasting





Questions

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Potential Market Arrangements Overview

- **Broadly speaking, four possible options for hybrid plants operating in the market:**
  - Generation and BESS offered and dispatched separately, only generation considered intermittent
  - Generation and BESS offered and dispatched as a single, non-intermittent entity. BESS would need to compensate for variability of generation for duration of gate closure
  - Generation and BESS offered separately but dispatched as a station dispatch group, with generation considered intermittent. BESS would need to compensate generation variability but only within dispatch interval (5min)
  - Generation and BESS offered and dispatched as a single intermittent generator
- **Advantages and disadvantages for all options**

Separate Offers and Dispatch

- **Advantages:**
  - Allows unique, fit for purpose rules for different assets
  - Allows intertemporal optimization of BESS, should that be a feature of the market in future
  - Arguably provides best representation of short run marginal cost of each component
  - Allows for existing forecasting, offer revision, and dispatch accommodations for intermittent generation to be utilized.
- **Disadvantages:**
  - Potential for tool problems / non-physical dispatch
  - Increased offer complexity for Asset Owners, depending on their offering strategy
  - Not clear if / how the IG flag would be applied

Single offer and dispatch, non-intermittent

- **Advantages:**
  - Better frequency regulation as generation variability automatically managed
  - Least likely to result in non-physical dispatch and generally easiest to implement in market tools
  - Allows flexibility for traders
  - Makes the System Operator's post gate closure security checking process easier
- **Disadvantages:**
  - Risk not allowing generation component to be intermittent discourages investment in hybrid plants
  - Unclear if and how central forecaster would forecast output
  - The site would not be subject to the offer obligations associated with intermittent generation.
- **Requires sufficiently sized BESS to manage intermittent generation, considering gate closure**

Separate Offers, Station Dispatch Group

- **Advantages:**
  - Smaller BESS required than for single dispatchable offer
- **Disadvantages:**
  - Worse frequency regulation and increased offer complexity compared to single offer.

Combined Intermittent Offer

- **Advantages:**
  - Allows maximum flexibility for Asset Owners
- **Disadvantages:**
  - Worse frequency regulation
  - Central Forecaster could not forecast accurately
- **SO do not support this option, but have included it for completeness**

Technical analysis supporting a proposed change to clause 8.23

Date: 25 February 2026

Aim:

1. Move the point of compliance to the point of connection
2. Reduce the minimum requirements [%]
    1. Option 1: 39.5 %
    2. Option 2: 33 %

Study:

1. Assess existing reactive power export at the point of connection to the grid → inform if a reduced requirement will adversely impact the grid.

Report:

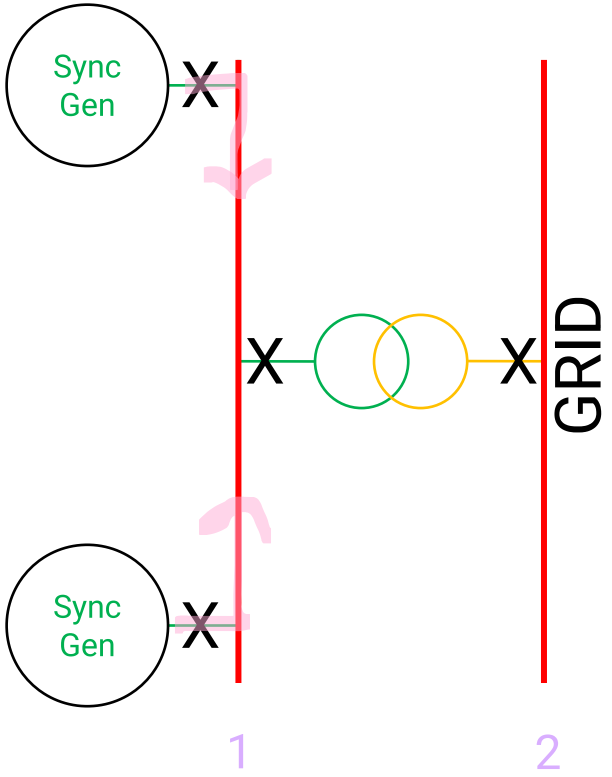
1. Outlines the study & recommendations

Outcome (EA responsibility): EA paper

1. Wording of clause 8.23.
2. Final recommendation of the minimum requirements.

The Problem

The problem



8.23 Voltage support AOPOs

Each **generator** with a **point of connection** to the **grid** must at all times ensure that its **assets**—

(a) when the voltage at its **grid injection point** is within the applicable range of nominal voltage, are capable of exporting (over excited) when **synchronised** and made available for **dispatch** by the **system operator**, a minimum net **reactive power** which is 50% of the maximum continuous **MW** output power as measured at the following **generating unit** terminals:

Nominal grid voltage (kV)	Voltage range for which **reactive power** is required			
	Minimum (kV)		Maximum (kV)	
220	198	-10.0%	242	10.0%
110	99	-10.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

Generator Asset Capability Assessment

Voltage

114. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant reactive capability** with respect to the **AOPOs** set out in clause 8.23 of the **Code** by;

114.1 assuming:

- the **generating plant** and the **grid** bus are represented as a two-bus system.
- the **generating plant's** outputs are net **active power** and **reactive power** after accounting for local supply or auxiliary load and are measured at the **generating plant** terminal entering the **generating plant** transformer
- the **generating plant** has a terminal voltage control range of +/- 5% unless otherwise stated in the relevant **asset capability statement**.

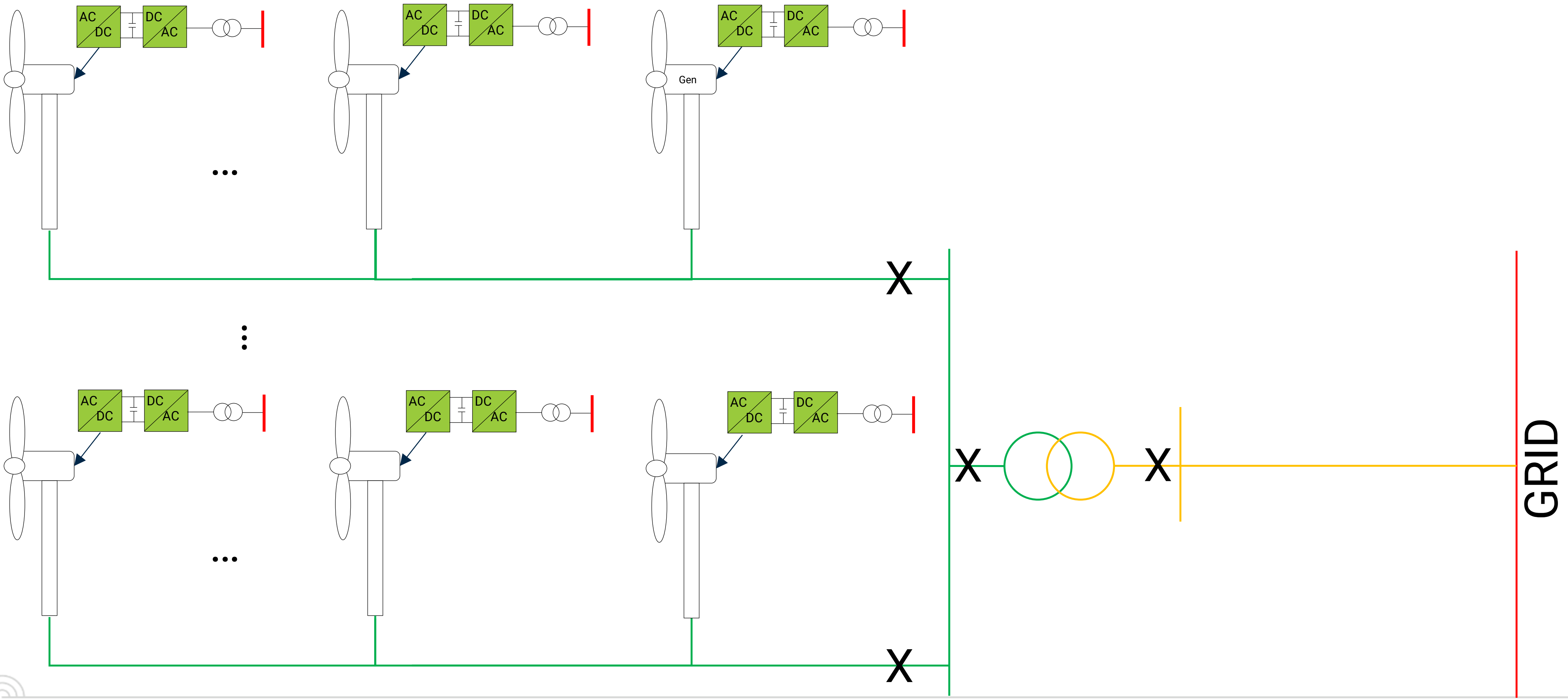
generating plant means equipment collectively used for generating **electricity**

electricity means electrical energy measured in kilowatt-hours (kWh)

1. Inconsistencies in the wording (not covered in the report)
2. Intention was to measure reactive power at the generating unit terminals. (captured in the Policy Statement)

Fits quite well with synchronous plants

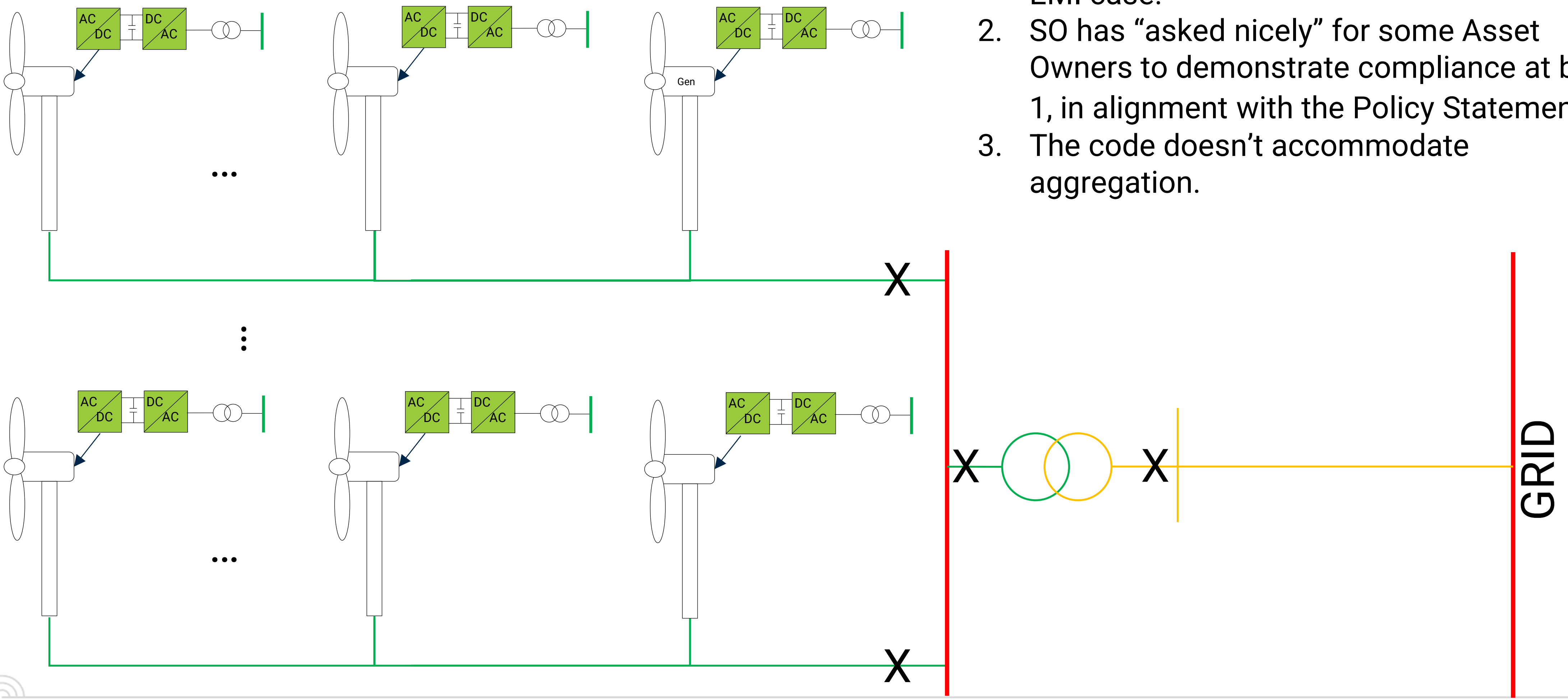
The problem



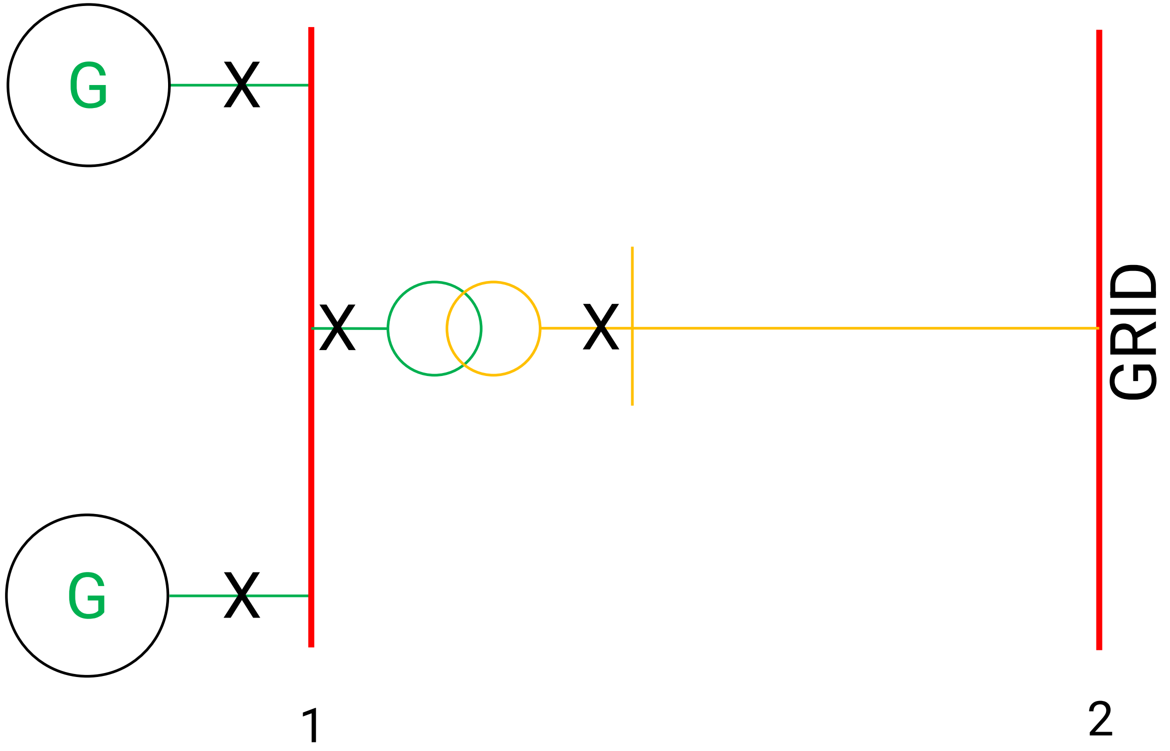
The problem

Remember that the Code takes precedence, but there are two considerations made in the study.

1. Collector network is not modelled in the EMI case.
2. SO has “asked nicely” for some Asset Owners to demonstrate compliance at bus 1, in alignment with the Policy Statement.
3. The code doesn’t accommodate aggregation.



The Study



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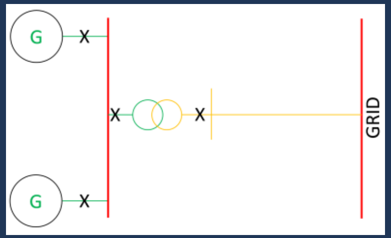
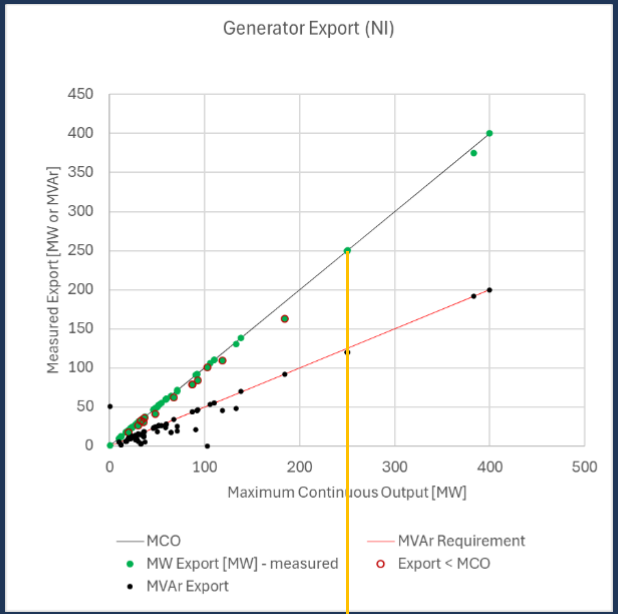
3. The code doesn't accommodate aggregation.

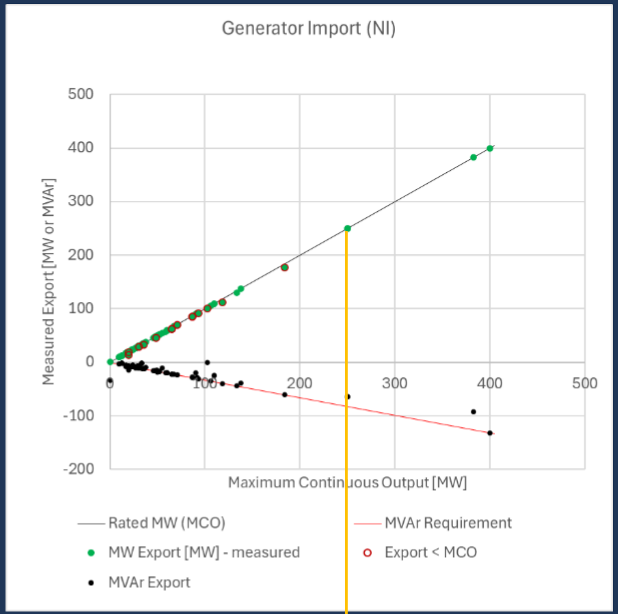
Study:

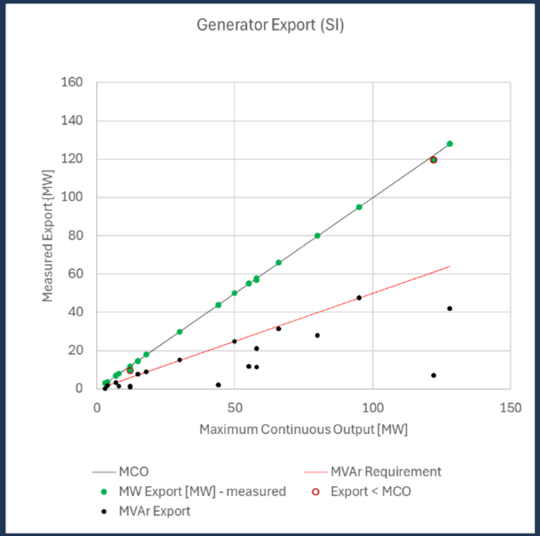
1. Term "connection transformer" (term used, once, in Sch 8.3, TC A for specifying tap changer obligations. In the context of the study, connection transformer is the interfacing transformer connecting the generating plant to the grid (collector station transformer or generating unit transformer).
2. Assessment was completed on existing infrastructure to assess the reactive power at bus 1 (point of compliance) and compared to what was exported to the grid i.e. bus 2.

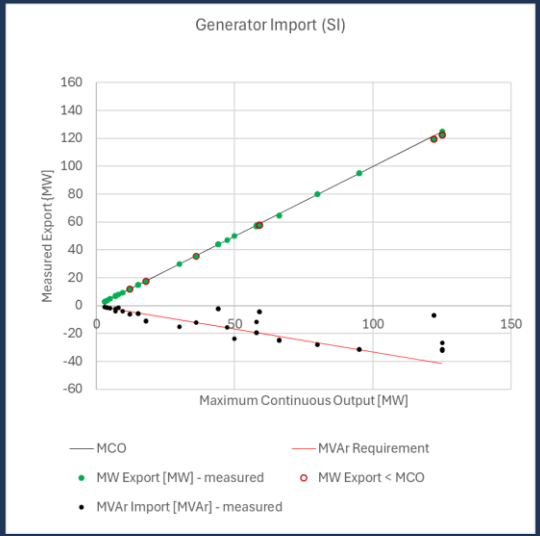
Results – dispatch at each station





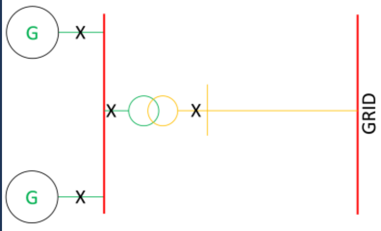




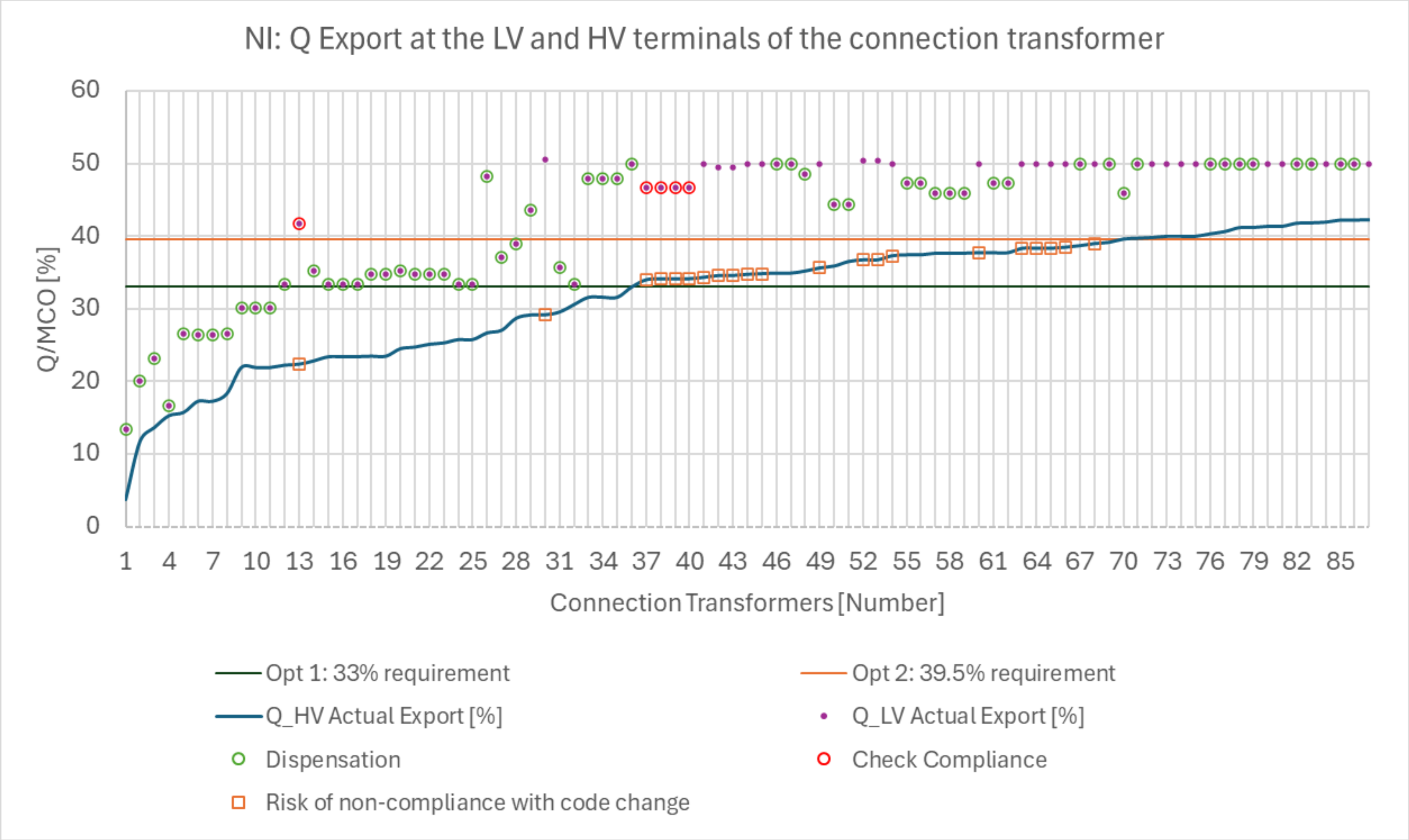


For each generating station, the generating units were loaded to their MCO with a minimum export (50%) and import (33%). Reactive power capability curves were modelled as it is in real-time and EMI case.

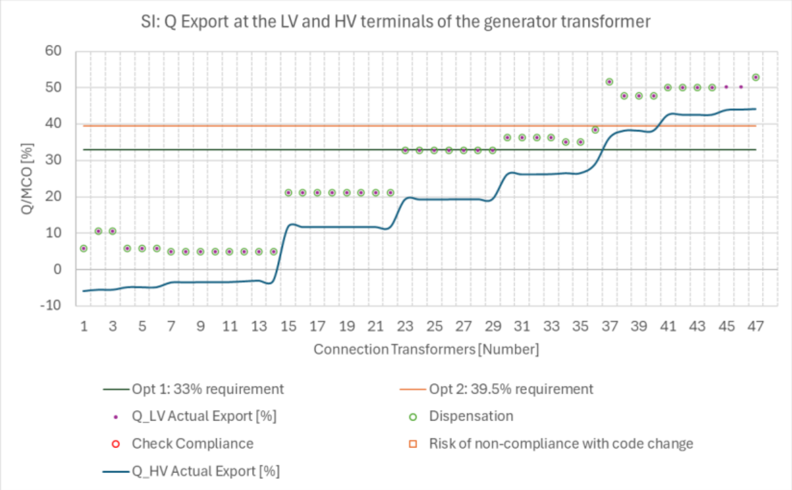
Results – Q export at HV compared to LV



North Island:

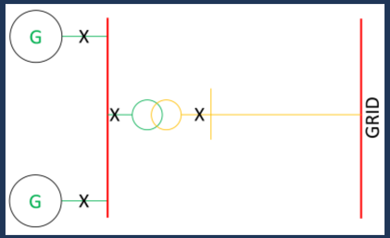


South Island:



Results – Q export at HV compared to LV

…with transformer reactance



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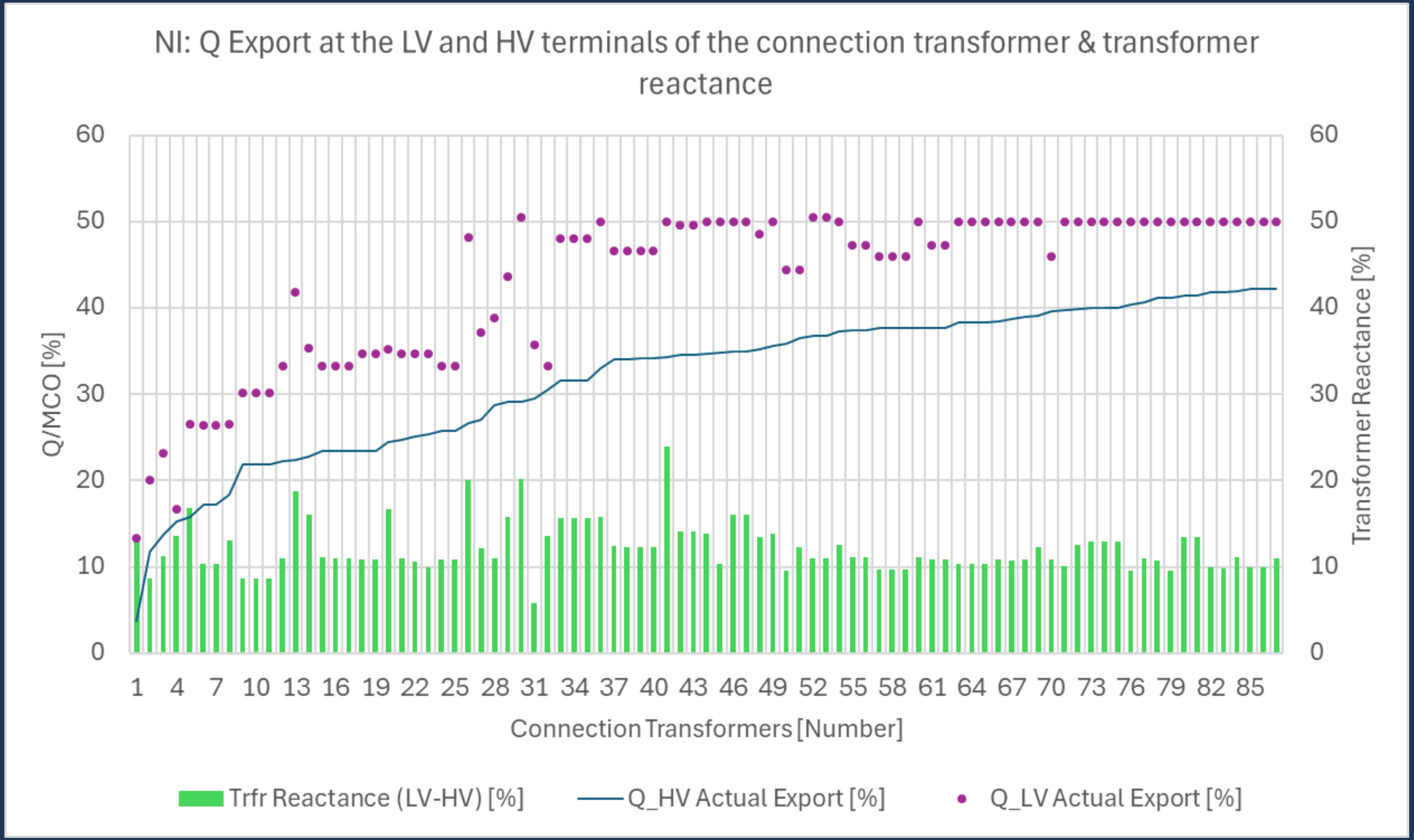
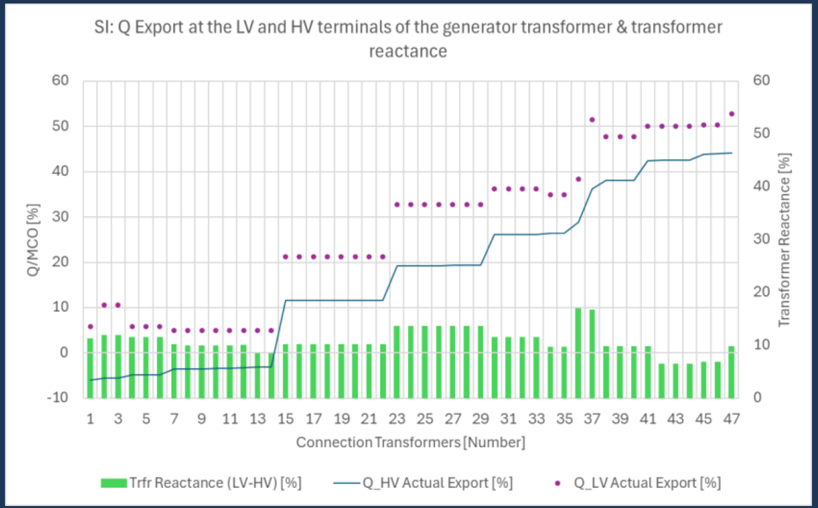
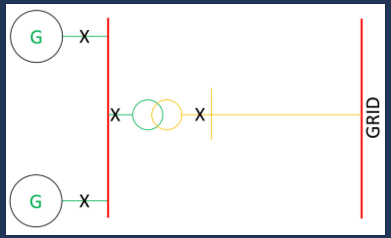
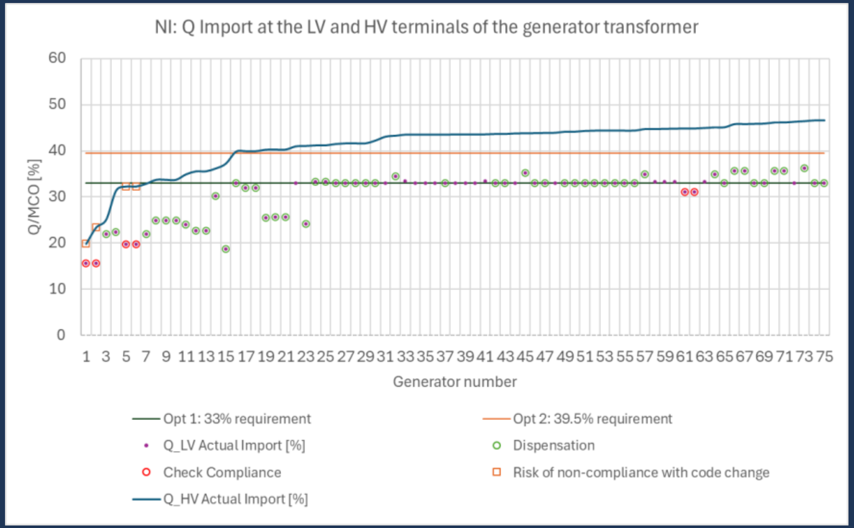


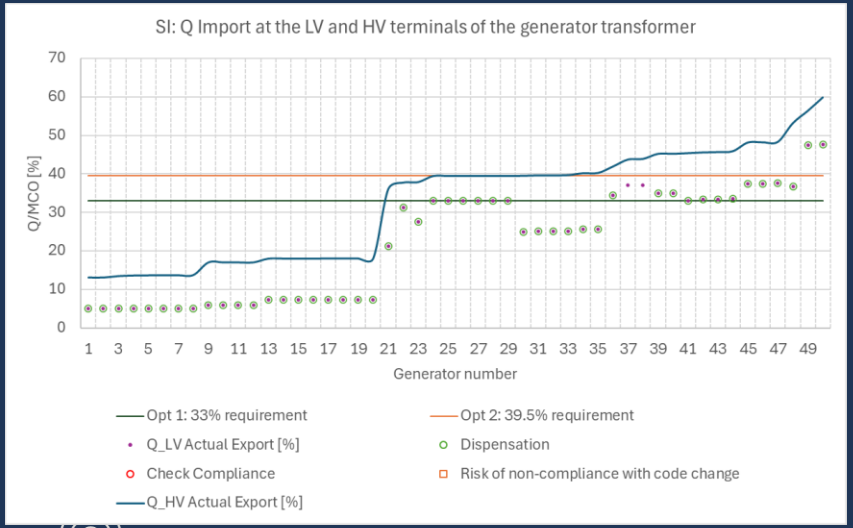
South Island:



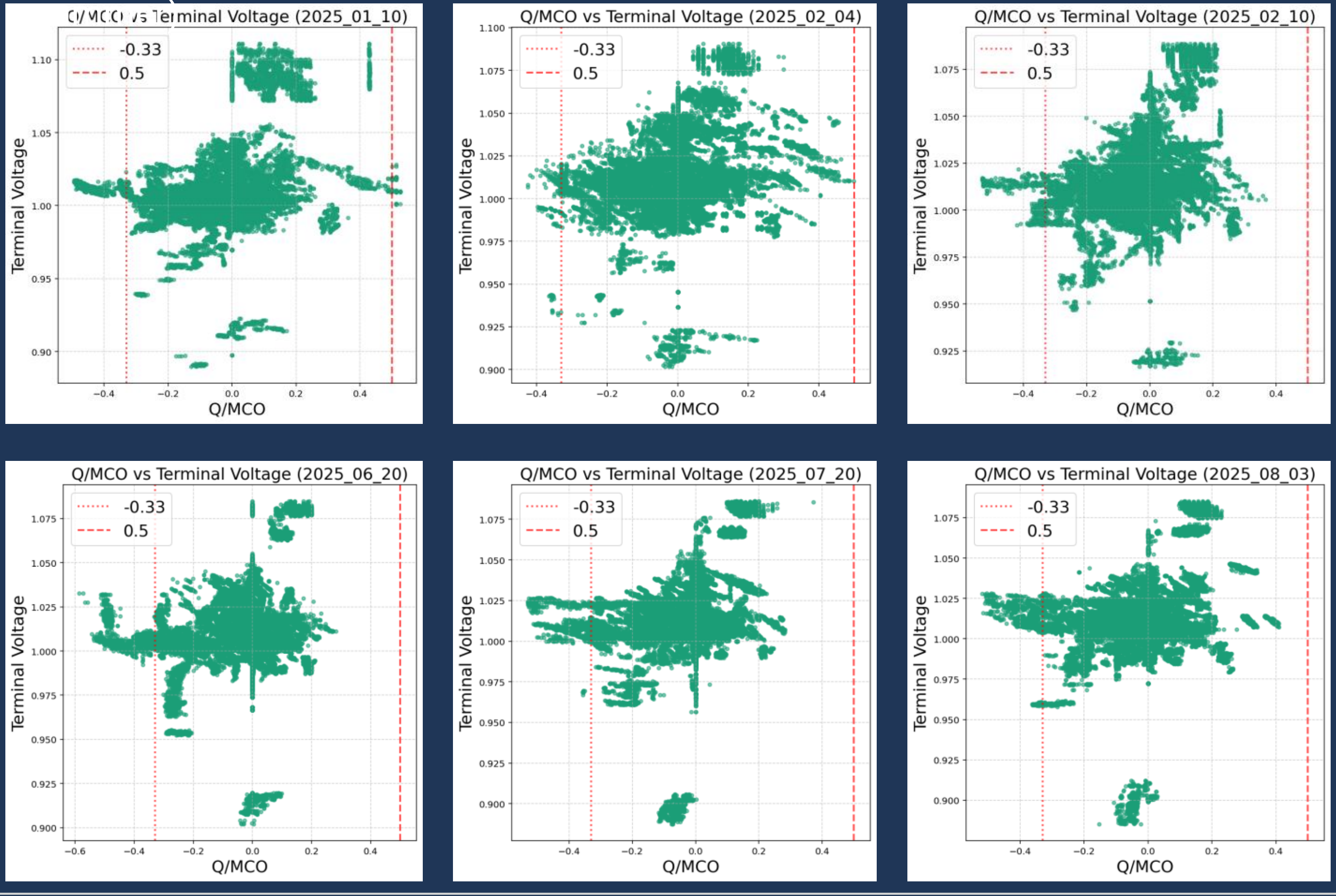
Results – Q import at HV compared to LV







Sense check on whether we use the import capability. Plotted data from real-time casefiles (operating data over 24 hours for 6 separate days in winter and



Conclusion:

1. On average, we get 33.43 % Q export at the POC to the grid in the North Island, and 17.21 % in the South Island.
2. Reducing the threshold should not adversely impact the grid with future connections considering the export levels we currently receive.
3. Reactive power capability information will remain at the generator terminals or the LV side of the connection transformer, as the connection transformer is modelled in real-time tools.

Recommendations:

1. Move the point of compliance in clause 8.23 of the Code to be at the point of connection to the grid.
2. There is no explicit recommendation on the percentage value of the new limits, ±39.5% or ±33%. However, it is recommended that any change to the Code should not diminish the existing available reactive power support.
3. Clause 8.23 specifies that a “minimum” reactive power support is required, and the intention should be to utilise inherent reactive power capability of plant when required to support grid voltage.
4. Changes should be implemented with a grandfathering clause with an option to impose new obligations after routine testing or major plant changes.
5. No recommendation on changing the voltage range requirements i.e. to remain the same.

Wrapping it up

Points for discussion:

1. Change to 8.23 was supported in Feb ‘25 CQTG meeting.
2. Do you prefer 33% or 39.5%?
3. What do you think about the temporary grandfathering?
4. Do you have a concern about the SO using the inherent capability of the plant? (Note this is an existing requirement)
5. Do you have concerns about providing reactive power capability information to the SO.
6. Other concerns with the recommended changes?

Let’s discuss

Thank you

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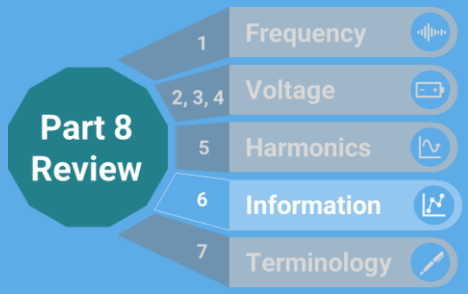
Issue 6: Information



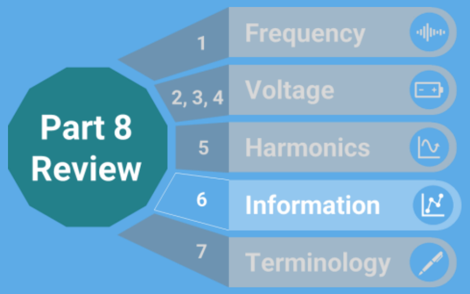
Issue 1 – Access to ACS information

- To access ACS information, Transpower, as a transmission grid owner, must source ACS information directly from each transmission-connected entity or seek their explicit authorisation.
- Distributors cannot access ACS information.

Preliminary thinking

- System Operator publishes ACS information online.
- This would provide all industry participants with a single source of asset capability information.
- Negligible implementation costs
  - Compared to some costs for providing certain participants with access to ACS database.

Issue 6: Information



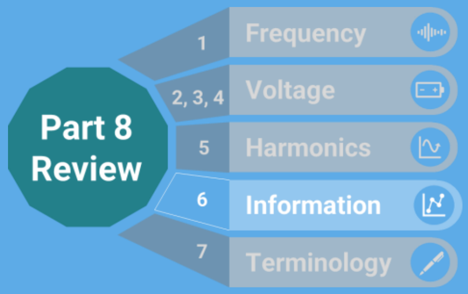
Issue 2 – Grid owner access to models

- Connection Code requires transmission-connected entities to provide modelling information to Transpower, as a transmission grid owner.
- However, this duplicates the provision of modelling information to the System Operator.

Preliminary thinking

- Upon request, the System Operator shares modelling information with Transpower, as a transmission grid owner.
- Costs will vary depending on implementation – e.g. direct sharing vs access to System Operator platform.
- Benefits have not been quantified.

Issue 6: Information



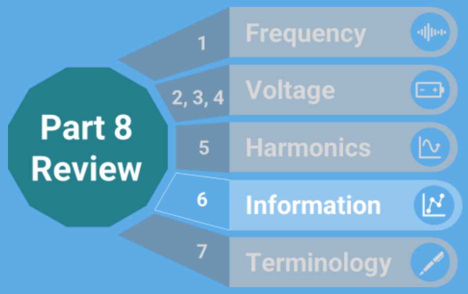
Issue 3 – Grid owner access to information about applications for dispensations & equivalence arrangements

- Code does not provide a clear mechanism for System Operator share with Transpower, as a grid owner, certain information about applications for dispensations and equivalence arrangements when a review is needed to assess potential impacts on the transmission grid.

Preliminary thinking

- Enable System Operator to share information in an asset owner’s application for a dispensation or equivalence arrangement with Transpower, as a transmission grid owner, when a grid owner review is needed to assess potential impacts on the transmission grid.

Issue 6: Information



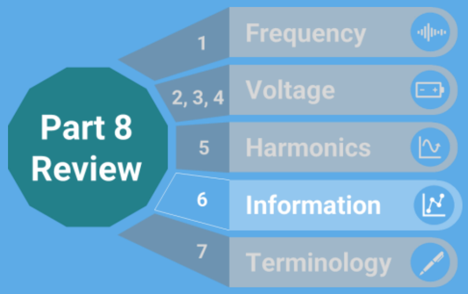
Issue 4 – Benchmarking TSAT models and conducting FRT studies

- Asset owners may be unable to benchmark TSAT models or conduct FRT studies if OEMs do not disclose the necessary models to the asset owner because of the OEMs’ concerns around protecting their IP in models.

Preliminary thinking

- Enable asset owners to contract the System Operator to benchmark TSAT models and conduct FRT studies.
- Seeking legal advice on:
  - whether a market operation service provider can charge for specific activities, and
  - if a Code amendment is necessary.

Issue 6: Information



Issue 5 – Visibility of large loads

- Large power electronics-based loads, such as data centres, produce new challenges for load forecasting, modelling, assessing power system impacts, planning, and operations.
- System Operator has no visibility of large loads on the transmission network or on distribution networks.

Preliminary thinking

- Require large loads connecting to the transmission network or to distribution networks to submit ACS information to the System Operator.
- System Operator developing estimates of costs and benefits.

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Large load modelling and performance requirements

Draft requirements for CQTG discussion

25/02/2026

Scope of these requirements

- Applied to “large loads”, – aggregated GXP loads are not a focus of this workstream
- Requirements are categorised and staged as follows:
  - Operational ACS and protection information (preliminary view - all large loads)
  - Modelling and performance requirements (preliminary view - considering threshold/grandfathering)
- Requirements should be useful to System Operator and not over-burden industry participants
- Requirements are still in development and provided in draft for discussion

“Large load” definition

- Define large loads as:
  - Loads which are direct consumers on the (transmission) grid (any MW)
  - Loads embedded in the distribution network which are:
    - >xMW (e.g. 10MW), or
    - >x% of the total GXP load (% value to be confirmed e.g. 50%, peak / light load?)
- Large loads may be a single site or ‘cluster’ of loads

Load Modelling Requirements

Load type	Description	Required when
Power-flow studies model	P and Q characteristics for load-flow steady state thermal and voltage studies. Major site components such as station transformers, shunt capacitors and reactors, filter banks. Load profile, load cycling behaviour.	All loads meeting the large load threshold discussed in previous slide.
Dynamic studies ZIP model	Simplified model for dynamic studies specifying a component of constant power, constant current and constant impedance for active and reactive power. ZIP load models may also be applicable to power-flow studies.	All loads meeting the large load threshold discussed in previous slide.
Dynamic studies standard models	Standard models established in industry such as CLOD or CMLD models.	Large loads which have greater than x% of their load as motor loads (% value to be determined)
Dynamic studies user defined models	Bespoke user defined models to capture specialised characteristics of loads e.g. power electronic based loads, UPSs characteristics, or any active control systems which affect power system dynamics.	Transmission grid-connected large loads
Protection and ride through capability	Voltage and frequency ride through capability, trip % and reconnection characteristics. May be categorised across the site to apply different ride through characteristics for different load components.	All loads meeting the large load threshold discussed in previous slide.

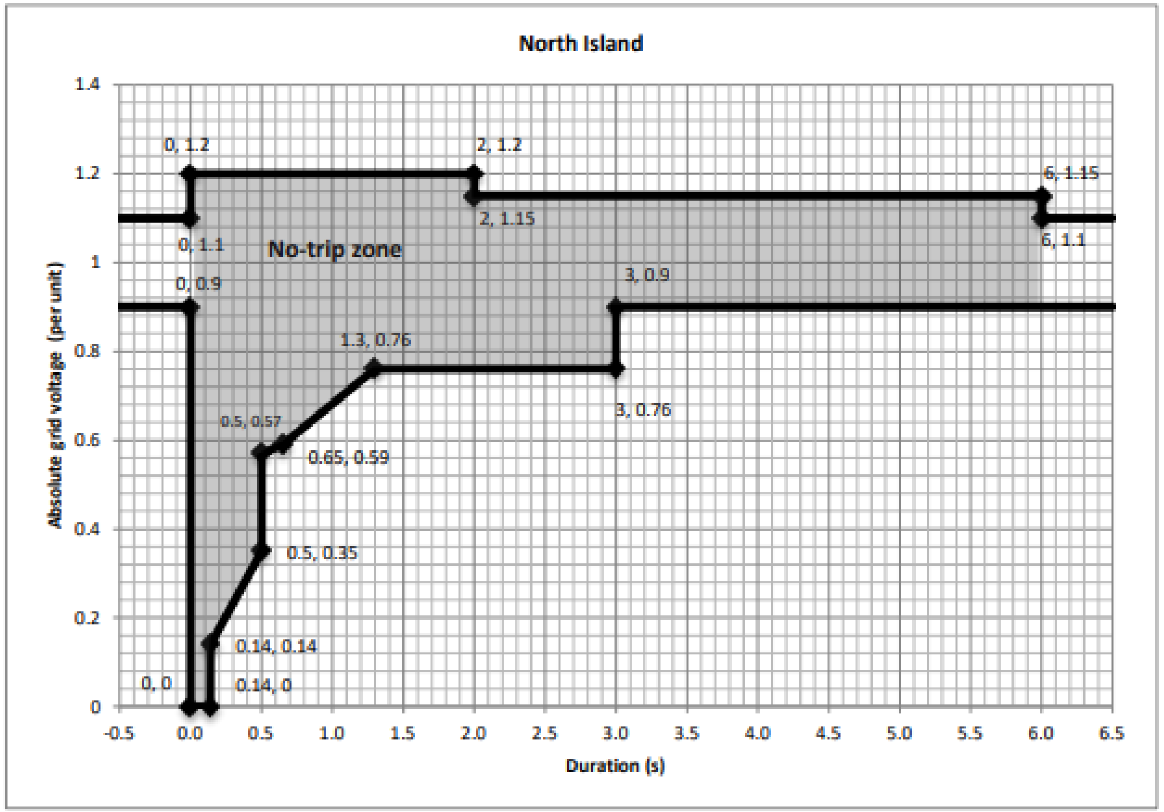
Performance Requirements

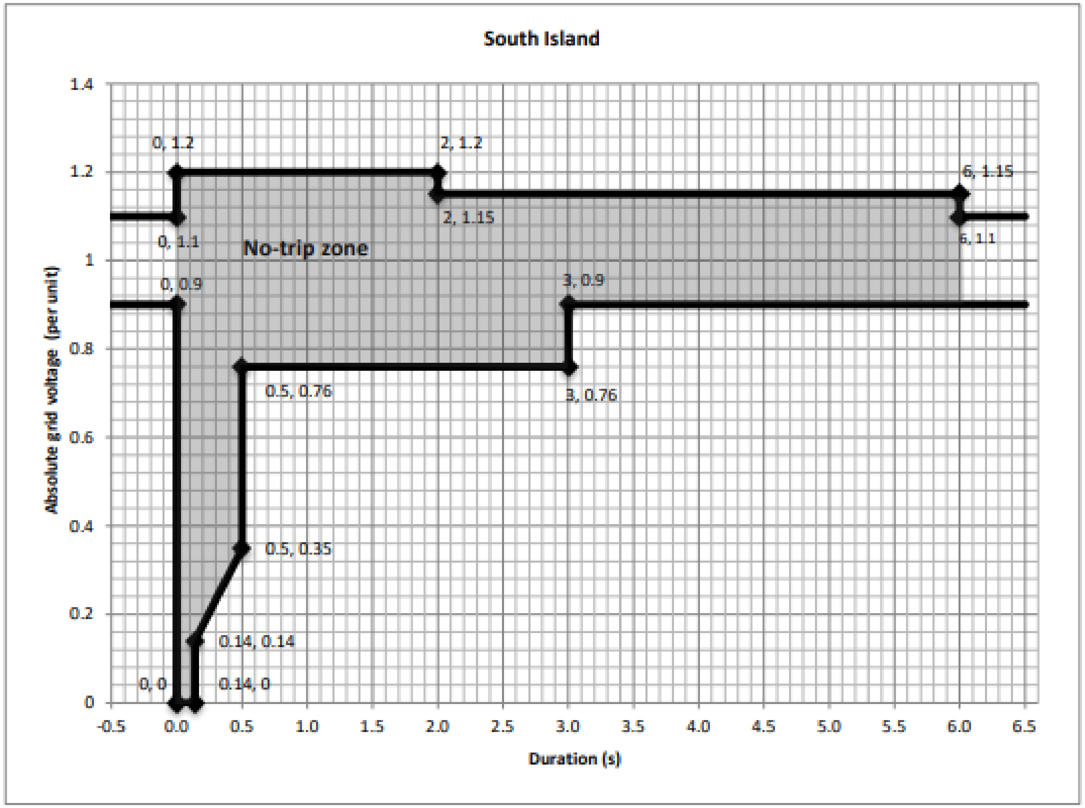
Requirement name	Description	Requirement
Active power ramp rate	Ramp rate limit when changing steady state operating level, or shifting between operating modes	Specified in Policy Statement – clause 39: • 40 MW/min • 75 MW over 5-minute period • Or as otherwise specified by the System Operator
Steady state voltage range	Remain connected within normal steady state operating voltage range	Align with Code clause 8.22(1)(b) for generators: • +/-10% for 220kV and 110kV • +/-5% for 66kV and 50kV
Frequency ride-through capability	Remain connected and maintain pre-disturbance active power during ride through event (unless adjusting active power for frequency control e.g. IL or AUFLS)	Align with Code clause 8.19 (1) and (3) for NI and SI frequency envelopes. Required to ride through over frequency events <52 Hz in the NI and <55 Hz in the SI
Voltage ride-through capability	Remain connected during ride through event. Circuit breakers connecting the facility to the grid must remain closed during voltage ride-through event.	Align with Code clause 8.25A fault ride through requirements for generators.

Performance Requirements Continued

Requirement name	Description	Requirement
Active power recovery following voltage ride-through event	Voltage sensitive loads which may switch to a UPS during severe voltage dips must restore their active power consumption from the grid very soon after voltage recovery	Active power must be recovered to: • 76% of its pre-disturbance value within 500ms of voltage recovering above 0.76 pu • 90% of its pre-disturbance value within 500ms of voltage recovering above 0.90 pu • In the case of an over-voltage event, 90% of its pre-disturbance value within 500ms of voltage recovering to 1.15 pu
Reconnection following a disconnection from the grid	Restriction on reconnection of the facility following a disconnection from the grid due to a grid disturbance.	Facility must obtain permission from System Operator before reconnecting.
Power quality requirements	Power quality requirements are as per default transmission agreement or as agreed with Grid Owner (or distributor requirements for loads embedded in the distribution network).	Requirements are as per default transmission agreement covering: • Power factor • Harmonics • Voltage imbalance • Voltage flicker
Automatic under frequency load shedding	All load customers are subject to AUFLS requirements, managed directly by transmission customers in the North Island or managed by Transpower, as a grid owner, in the South Island.	The AUFLS technical requirements are provided in Schedule 8.6 of the Code. Large loads may need to seek equivalence arrangements if the AUFLS blocks cannot be achieved directly.

FRT Curves


North Island
No-trip zone
0, 1.2
2, 1.2
6, 1.15
2, 1.15
0, 1.1
6, 1.1
3, 0.9
0, 0.9
1.3, 0.76
3, 0.76
0.5, 0.57
0.65, 0.59
0.5, 0.35
0.14, 0.14
0, 0
0.14, 0
Absolute grid voltage (per unit)
Duration (s)


South Island
No-trip zone
0, 1.2
2, 1.2
6, 1.15
2, 1.15
0, 1.1
6, 1.1
3, 0.9
0, 0.9
0.5, 0.76
3, 0.76
0.5, 0.35
0.14, 0.14
0, 0
0.14, 0
Absolute grid voltage (per unit)
Duration (s)

Complex (CLOD) and Composite (CMLD) standard models

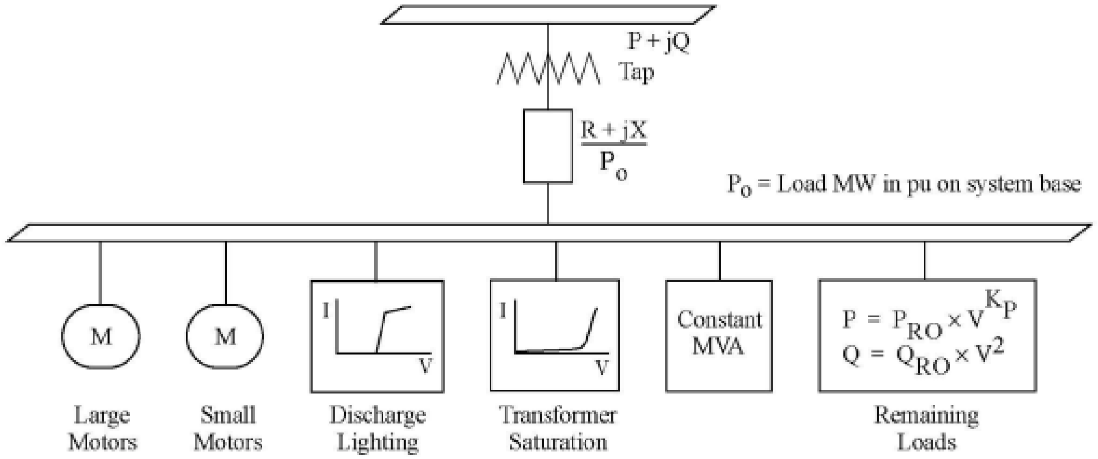


Figure 2-1
The CLOD model [1]

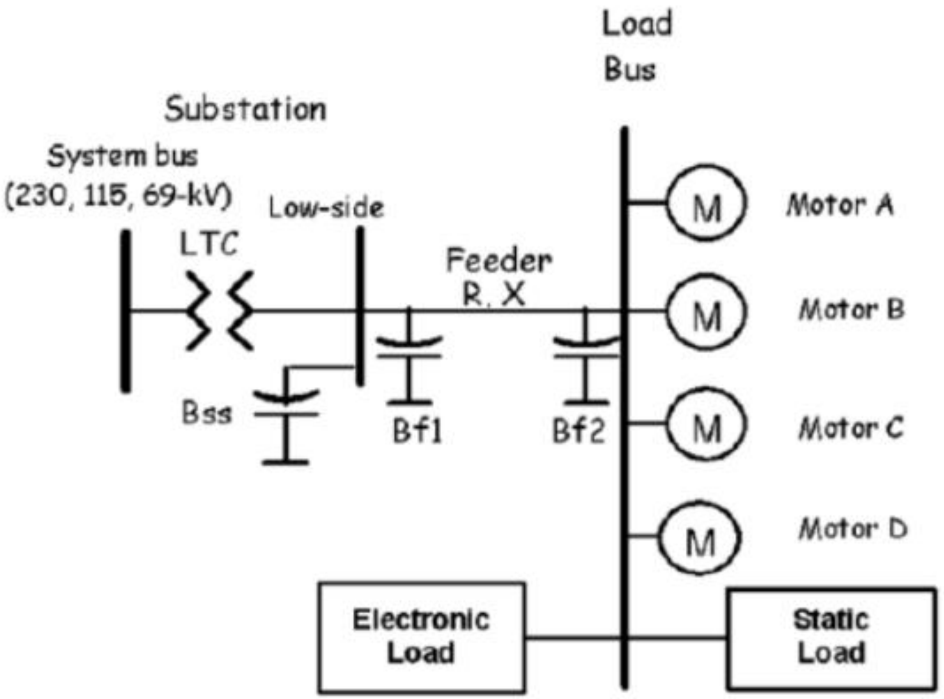
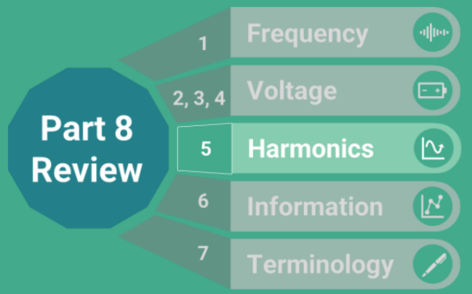


Figure 3-1
WECC Composite Load Model [2]

[Technical Reference on the Composite Load Model]

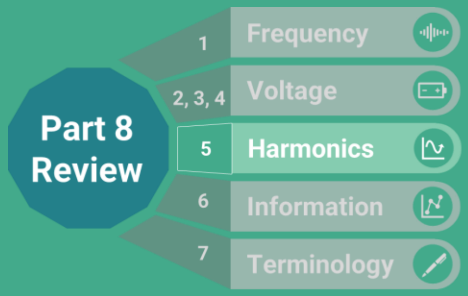
Issue 5: Harmonics



Option 1:

- Revoke NZECP 36:1993
- Mandate aspects of:
    - AS/NZS 61000 series of standards for transmission-level harmonics
    - EEA Power Quality Guidelines for distribution-level harmonics.

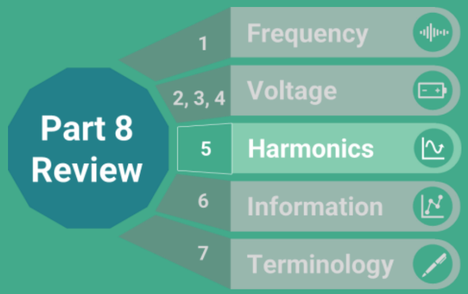
Issue 5: Harmonics



Option 2:

- Revoke NZECP 36:1993
- Recommend aspects of an expanded version of the EEA Power Quality Guidelines that also covers:
    - harmonics on New Zealand’s transmission network
    - a preferred option for limiting and allocating THD.

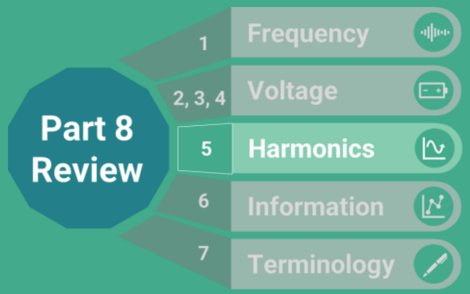
Issue 5: Harmonics



Option 3:

Amend NZECP 36:1993 to address its shortcomings.

Issue 5: Harmonics



Sub-option:

Establish a publicly available database of harmonics measurements.

Work plan *under consideration* for 2026/27

Future security and resilience (FSR) roadmap

Challenges & Opportunities	Activity	Why is it required?	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Accommodating future changes within technical requirements	Review and update Part 8 of the Code	To ensure the technical requirements in Part 8 are aligned to new generation technologies.										
	Review and update Parts Parts 6, 7, 13, 14 of the Code to ensure they align to Part 8	To ensure the technical performance of DER is aligned to Part 8 of the Code and enable DER to offer ancillary services, thereby ensuring the effective operation of the power system and market system.										
	Identify standard to support technical requirements in the Code	To ensure appropriate standards are in place that ultimately maintain and ideally improve the security of the system										
	Update the Policy Statement to manage emerging risks	To ensure the System Operator can manage new risks and thereby maintain the security and reliability of the system.										
	Update the System Operator's policies, procedures, guidelines and tools	To ensure the secure and efficient operation of the power system and the electricity market.										
Managing reducing system inertia	Create a frequency reserve strategy to manage low inertia	To ensure the effective operation of the system.										
	Ensure that the Code and market system can accommodate new reserve types	To ensure system frequency is maintained within the normal band.										
	Incorporate new reserve types into the Procurement Plan & testing methodology	To ensure system frequency is maintained within the normal band.										
	Update operational procedures and tools	To ensure system frequency is maintained within the normal band.										
Operating with low system strength	Investigate system strength challenges and opportunities	To ensure performance levels for IBR are appropriate and ultimately maintain the secure and stable operation of the system										
	Amend the Code to support performance criteria	To ensure performance levels for IBR are appropriate and ultimately maintain the secure and stable operation of the system.										
	Develop suitable market products and tools	To ensure system strength does not drop below the level that can cause IBR to operate below the defined performance level										
Balancing renewable generation	Improve market system and generation/demand forecast	To reduce the proportion of inaccurate offers, inaccurate demand forecasts and any combined inaccuracies, and thereby ultimately ensure the security and reliability of the system.										
	Consider new or revised ancillary services to maintain balancing	To ensure system frequency is maintained within the normal band.										
Coordination of increased connections	Update Grid Owner and System Operator commissioning processes and benchmark agreement	To ensure the timely and efficient integration of DER into the system.										
	Review the approach to planning connection studies	To reduce the effort required to carry out planning and connection studies and thereby ensure adequate assessment of the impacts of new connections.										
	Review operational study tools	To enable power system operations to benefit from the capability of DER.										

Challenges & Opportunities	Activity	Why is it required?	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Coordination of increased connections	Update Grid Owner and System Operator commissioning processes and benchmark agreement	To ensure the timely and efficient integration of DER into the system.										
	Review the approach to planning connection studies	To reduce the effort required to carry out planning and connection studies and thereby ensure adequate assessment of the impacts of new connections.										
	Review operational study tools	To enable power system operations to benefit from the capability of DER.										
Enabling DER services for efficient power system operations	Enhance the Code and market system dispatch capability to accommodate DER offers	To ensure that market dispatch capability can accommodate all participants who wish to be dispatched and those participants who are required to be dispatched.										
	Improve real-time security modelling within operaitonal tools	To ensure DER ability to actively and optimally support the security and reliability of supply is accounted for within operational tools and procedures.										
	Investigate new DER services to support efficient operation of the power system	To ensure the system fully utilises DER capability, to ultimately improve its operation.										
Visibility and observability of DER	Establish the impact of DER	To establish operational measures to maintain the system's security.										
	Determine the credible event risk of DER	To mitigate the risk that may result from widespread disconnection or the unstable operation of DER.										
	Update the Code to clarify DER obligations and operational requirements	To ensure that uptake of DER occurs according to an appropriate regulatory framework.										
	Update procedures and tools to include DER asset information	To increase the visibility and observability of DER, to enable improved demand forecasting, outage assessments, security of supply modelling, system security forecasts and annual security assessment, among other procedures and tools, and thereby ultimately enhance the secure operation of the system.										
Leveraging new technology to enhance ancillary services	Investigate changes to ancillary services	To ensure the System Operator procures the right type of services to manage the power system at the lowest cost to consumers.										
	Ensure tools monitor the performance of the power system	To ensure the power system continues to operate in a safe and secure manner										
	Update the Code, market system and Procurement Plan to enable new technology to provide ancillary services	To enhance and increase competition in the ancillary services market and maintain the security of the power system										
Maintaining cyber security	Continually review and update cyber security measures	To improve the effectiveness of cyber security measures and ensure they are up to date										
Growing skills and capabilities of the workforce	Encourage and train the workforce's next generation	To mitigate workforce shortages and ensure that the expected transition within the energy sector takes place in a safe and timely manner.										

Tasks under consideration for 2026/27:

- **System strength- Stage 2:** Investigating system strength including considering GFM inverters. This work will involve power system studies to inform an options paper.
- **System inertia:** Next steps following the report done last year.
- **Information:** Options 2 & 3 – next step following the Code amendment proposals we intend doing this financial year.
- **Harmonics:** Next steps following the options paper we intend doing this financial year.
- **Part 8: Voltage issue #2:** Next steps for managing reactive power flows across GXP's.
- **BESS & Hybrid AOPOs:** Code amendment proposals following an issues and options paper we intend doing this financial year.
- **Frequency:** Consider creating a frequency strategy to manage low inertia.
- **Large data centre connections:** Consider investigating AOPOs
- **Clause 8.23 (voltage support obligations):** Clarifying of *Point of Connection*, what is meant by *synchronised* and *available for dispatch* and the definition of *Generating Unit*.
- **FSR roadmap:** Review/revise the roadmap.

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