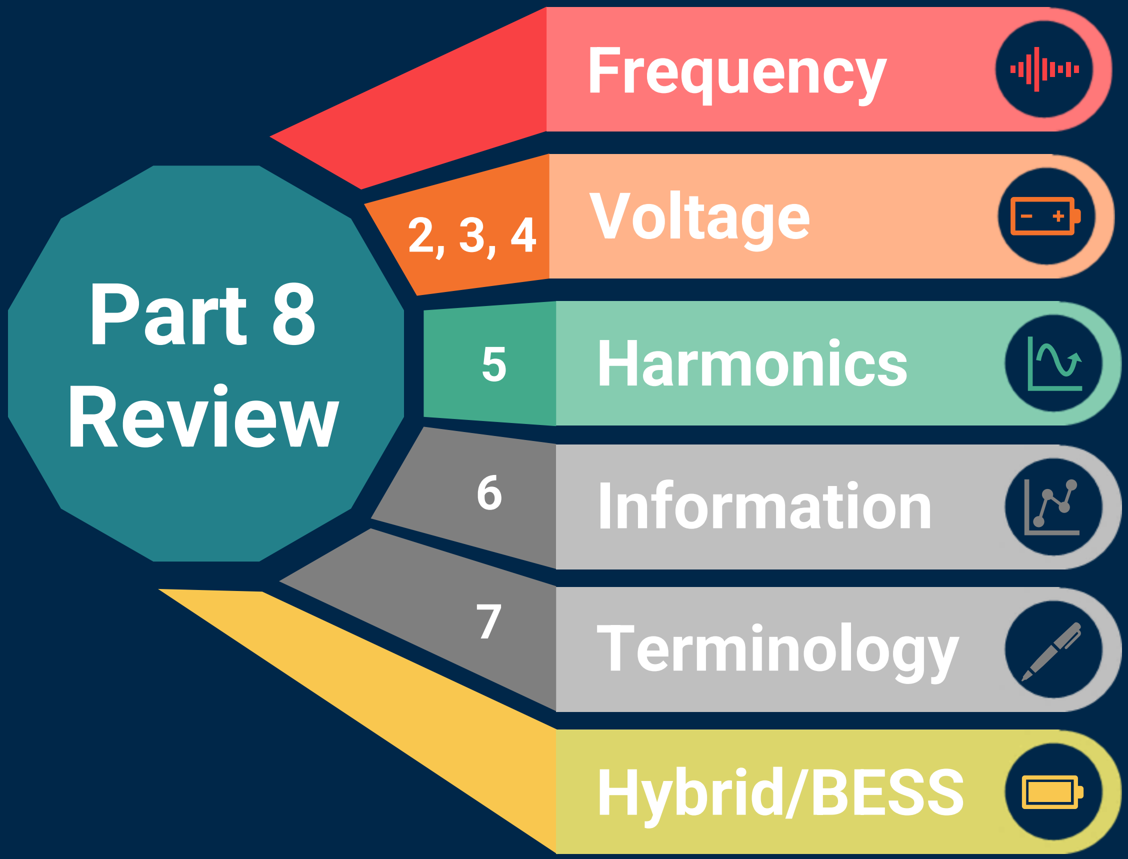
Future Security and Resilience: Common Quality Technical Group (FSR CQTG)



Meeting 17: 19 August 2026

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Purpose

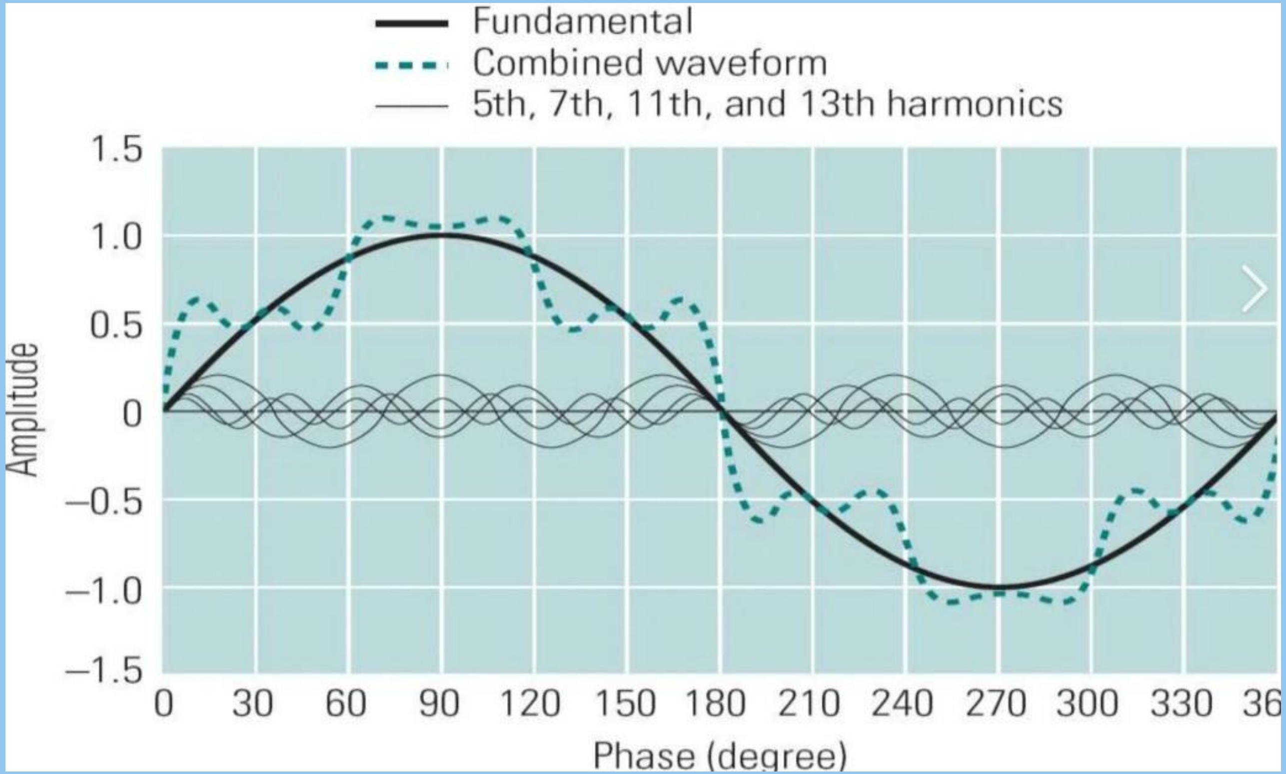
Discuss and provide feedback on topics in the agenda

Agenda

Time	Item
9:00 am	Welcome & introductions to new members
9:05 am	Minutes and actions from previous meetings
9:15 am	Harmonics – feedback from submissions & next steps
10:00 am	Morning tea
10:15 am	BESS/Hybrids: AOPOs and wholesale market enhancements
11:45 am	Update on large loads
12:30 pm	Lunch
1:00 pm	System inertia – needs date analysis
1:30 pm	Power factor hybrid curve extension
2:00 pm	Clause 8.23
2.30 pm	Afternoon tea
2:45 pm	Reactive power flows/voltage coordination
3.30 pm	Feedback on FSR roadmap
3.45 pm	Update on items in holding pen
3.55 pm	AOB
4.00 pm	End of meeting

Minutes and actions

Harmonics


Fundamental
Combined waveform
5th, 7th, 11th, and 13th harmonics
1.5
1.0
0.5
0
−0.5
−1.0
−1.5
Amplitude
0
30
60
90
120
150
180
210
240
270
300
330
36
Phase (degree)

Purpose of today's discussion

- Summarise consultation outcomes.
- Present preliminary conclusions.
- Highlight implementation issues.
- Seek CQTG technical advice before detailed policy and Code development.

Today's discussion is about the preliminary conclusions and next steps, not revisiting the consultation.

Process:

Issues Paper → Discussion Paper → Consultation ✓ → Preliminary Conclusions (Today) → Policy Design → Code Amendments

Background

- Current framework (NZECP 36:1993) is over 30 years old
- Electricity system has changed significantly
- Rapid growth in inverter-based resources and DER
- More power electronic equipment and complex interactions
- Need nationally consistent planning and connection processes

Objectives of the consultation

- Modernise New Zealand's harmonics framework
- Improve reliability and power quality
- Reduce connection uncertainty
- Align with international standards
- Clarify regulatory responsibilities
- Support increasing DER penetration

Outcome sought: a future-proof, nationally consistent framework.

Consultation overview

- 16 submissions received
- EDBs, Transpower, generators, consultants, suppliers, industry organisations and technical experts
- Builds on 2023 Issues Paper, 2024 Discussion Paper and previous CQTG discussions

Overall message: strong consistency across submitters.

Consultation options considered

Three options were presented during consultation:

Option 1 – Modern regulatory framework	Option 2 – Guidance-led approach	Option 3 – Update NZECP 36
Replace NZECP 36 with a modern framework based on AS/NZS 61000 and the EEA Power Quality Guidelines.	Retain the existing regulatory framework but significantly expand industry guidance through the EEA Power Quality Guidelines.	Revise and modernise NZECP 36 as a New Zealand-specific harmonics standard.
National planning levels in the Code	Guidance only	New NZ Code of Practice
International alignment	Maximum flexibility	NZ-specific solution
Future-proof approach	Limited regulatory certainty	Significant ongoing maintenance

The consultation sought feedback on the advantages, disadvantages and implementation implications of each option before determining the preferred regulatory direction.

Key consultation messages

What did we hear?

Five clear messages:

1. NZECP 36 is no longer fit for purpose
2. Strong support for international standards
3. Mandatory planning levels supported
4. Engineering flexibility remains essential
5. Implementation is now the major challenge

Consultation outcome

Option 1 – Strong support

Option 2 – Useful supporting guidance

Option 3 – Limited support

Why was Option 1 preferred?

- Regulatory certainty
- National consistency
- International alignment
- Technology neutral
- Flexible implementation

Preliminary preferred approach

Electricity Industry Participation Code

- National harmonics planning levels
- Roles and responsibilities
- Connection and compliance obligations
- Monitoring and governance

↓

Technical Standards

- AS/NZS 61000 Series
  - Transmission planning levels
  - International technical standards

↓

Practical Implementation Guidance

- EEA Power Quality Guidelines
  - Distribution harmonics
  - Allocation methodologies
  - Assessment pathways
  - Worked examples
  - Practical implementation guidance

Key Design Principles

Principle	Outcome
Modern	Aligns with current international standards and engineering practice
Nationally consistent	Common planning levels and regulatory expectations across New Zealand
Technology neutral	Applies equally to conventional plant and inverter-based resources
Flexible	Engineering judgement retained through supporting guidance rather than prescriptive Code requirements
Future-proof	Technical guidance can evolve without frequent Code amendments

Key implementation decisions

THE CONSULTATION HAS CLARIFIED THE DIRECTION – THE NEXT CHALLENGE IS IMPLEMENTATION

- Planning levels – nationally consistent harmonics limits.
- Allocation methodologies – consistent but flexible.
- Proportionate assessment – simple for low-risk, detailed for high-risk.
- Transition arrangements – existing vs new assets.
- Compliance framework – clear responsibilities.
- Supporting guidance – practical methods and worked examples.

Key message: We now need to decide HOW implementation should occur.

Regulatory framework

Three complementary roles:

MBIE / WorkSafe

- Product and equipment standards

Electricity Authority

- Planning levels
- Code obligations
- Compliance

EEA

- Technical guidance
- Assessment methods
- Worked examples

Principle:
Regulation defines the outcome.

Guidance explains how to achieve it.

Technical implementation

Applying international standards to NZ conditions.

Network characteristics:

- Radial networks
- Weak systems
- Rural feeders
- Diversity assumptions

Emerging technologies:

- Inverter-based resources
- Interharmonics
- Supraharmonics
- Measurement consistency

Outputs: Updated EEA Guidelines, worked examples, templates and Technical Working Group.

Compliance framework

Code
↓
Planning Levels
↓
Connection Agreements
↓
Monitoring
↓
Investigation
↓
Resolution

Consultation themes:

- Code establishes framework.
- Site-specific requirements remain contractual.
- Engineering issues resolved through technical processes.

Remaining issues/Further work: distributor obligations, cost recovery, evidence thresholds and disputes.

Harmonics Measurement Database

Potential benefits:

Better planning

Reduced duplication

Lower study costs

Better evidence

Challenges:

Cost

Governance

Data quality

Cyber security

Preliminary view: Evaluate through a staged pilot before national implementation.

Proposed work programme

2026

- Confirm preferred framework
- Detailed policy development
- Technical Working Group

2027

- Draft code drafting
- Consultation
- Implementation planning

Delivered collaboratively by the Authority, MBIE, WorkSafe, EEA and industry.

Advice sought from CQTG

We are seeking CQTG advice to test the proposed direction and shape the detailed implementation work.

1 Direction

- Do you support progressing Option 1 as the preferred approach?
- Do you agree planning levels should be mandatory, with detailed allocation methods retained in guidance?

2 Technical design

- What New Zealand-specific adaptations or guidance are needed before implementation?
- What should a proportionate screening and assessment framework look like?

3 Implementation

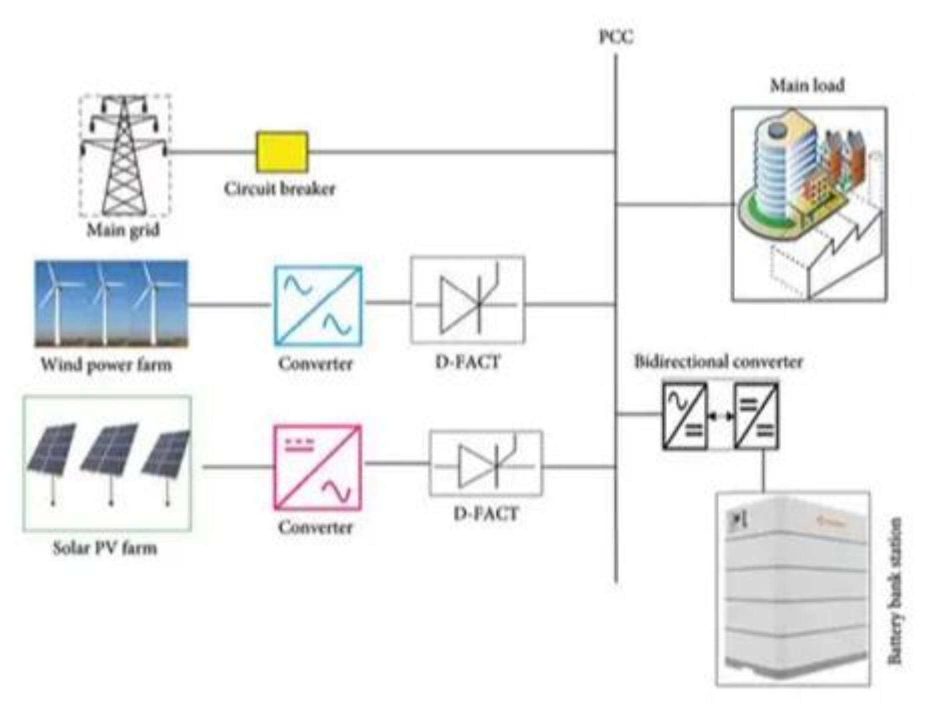
- Does the proposed hybrid compliance model provide the right balance between Code obligations and connection agreements?
- Should we establish a technical working group, and keep a staged measurement-database pilot in scope?

Key question: Are there any technical issues that would materially change this direction before we move into policy and Code design?

MORNING TEA

BESS and Hybrids:

- AOPOs
- Wholesale market arrangements



Hybrid / BESS: Issues

Five topics:

1. Updating generating asset definitions
2. Non-idle state AOPOs for BESS-hybrid stations
3. Idle state AOPOs for BESSs and BESS-hybrid stations
4. Wholesale market enhancements for BESS-hybrid stations
5. BESS-hybrid large loads and BESS-hybrid large load-generation

Updating generating asset definitions

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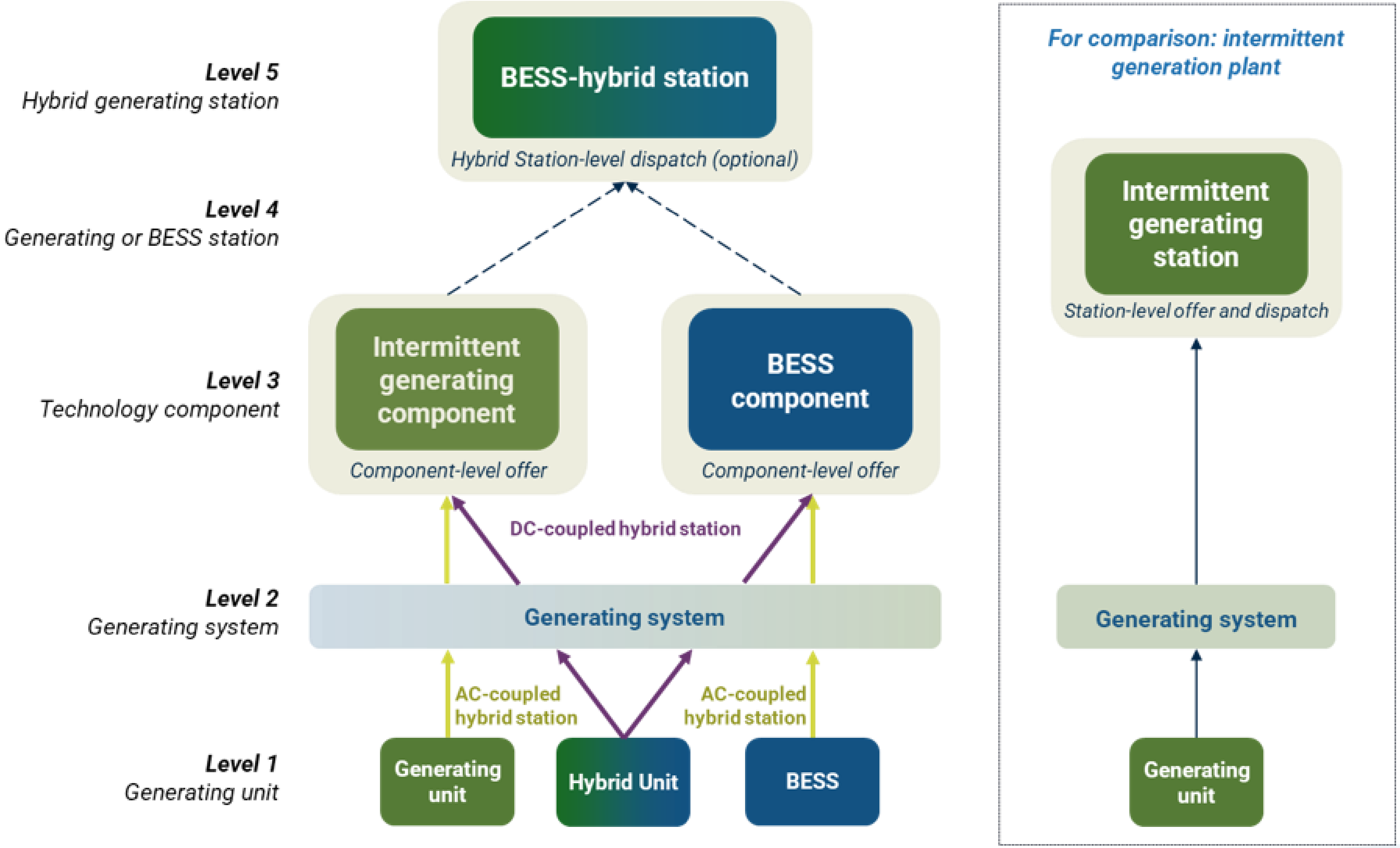
Topic 1: Updating generating asset definitions



Topic 1: Updating generating asset definitions

Key points from submitters:

- Broad support for the 5-level framework.
- Must work for both AC- and DC-coupled hybrid stations.
- Obligations should apply clearly to a single level.
- Hybrid definitions should reflect operational control, not just co-location.
- Framework should accommodate future configurations (eg, load + BESS).

Proposed approach:

- Retain the 5-level framework.
- Refine definitions before drafting.
- Test against real-world configurations and single-line diagrams.
- Future-proof where practical.

Topic 1: Updating generating asset definitions

Questions for the CQTG:

- Does the 5-level framework work equally well for synchronous and inverter-based plant?
- Are there any hybrid configurations the 5-level framework cannot accommodate?
- Should hybrid status depend on operational control as well as physical configuration?

Non-idle state AOPOs for BESS-hybrid stations

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Topic 2: Non-idle state AOPOs for BESS-hybrid stations

Key points from submitters:

- Most submitters supported hybrid station-level AOPOs because the power system experiences the hybrid station's net response.
- Hybrid station-level AOPOs were seen as:
  - simpler to implement
  - more flexible for operators
  - better suited to DC-coupled hybrid stations
  - less likely to cause unnecessary BESS cycling.
- A minority preferred technology component-level AOPOs, arguing obligations should follow the capability of each technology.
- Several submitters supported different asset levels for different purposes, rather than one level for the entire Code.
- Submitters generally agreed that a BESS should not be required to compensate for a co-located generating station operating at its maximum output.

Topic 2: Non-idle state AOPOs for BESS-hybrid stations

Frequency point of compliance – proposed approach:

- Assess frequency AOPOs at BESS-hybrid station level.
- Clarify treatment of:
    - separately owned technology components (eg, BESS / solar PV generation)
    - separately controlled technology components
    - DC-coupled configurations that limit the SO's visibility of technology component outages.

Questions for the CQTG:

- Is station-level assessment the right approach for frequency AOPOs?
- Are there any configurations where component-level frequency AOPOs would be preferable?

Topic 2: Non-idle state AOPOs for BESS-hybrid stations

Voltage point of compliance – proposed approach:

- Assess voltage AOPOs at BESS-hybrid station level.
- Clarify treatment of:
  - separately owned technology components (eg, BESS / solar PV generation)
  - separately controlled technology components
  - DC-coupled configurations that limit the SO's visibility of technology component outages.

Questions for the CQTG:

- Is station-level assessment the right approach for voltage AOPOs?
- Are there any configurations where component-level voltage AOPOs would be preferable?

Topic 2: Non-idle state AOPOs for BESS-hybrid stations

Implementation:

- Retain component-level treatment where needed for:
  - ownership
  - offers
  - dispatch
  - metering
  - settlement
- Clarify "maximum possible injection" in the Code.
- **SO's working interpretation:**
  If a generator's assets are operating at their maximum continuous MW output power, maintaining pre-event output during a UFE is sufficient for the generator to comply with the clause 8.17 requirement

Questions for the CQTG:

- What visibility does the System Operator need over individual components if AOPOs are assessed at station-level?
- How should separately owned or controlled co-located assets be treated?
- Should the 10 MW threshold apply at station-level or component-level?

Idle state AOPOs for BESSs and BESS-hybrid stations

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Topic 3: Idle state AOPOs for BESSs and BESS-hybrid stations

Key points from submitters:

- Most submitters opposed idle-state **frequency** AOPOs.
- Views on idle-state **voltage** AOPOs were more mixed.
- Several submitters argued costly services should be procured rather than compulsorily acquired for free via AOPOs.
- Several submitters considered compulsory voltage support easier to justify than compulsory frequency support because the former is lower cost.
- NewPower estimated material costs for it from idle-state frequency AOPOs.
- Transpower and Tesla supported idle-state AOPOs for connected assets.

Topic 3: Idle state AOPOs for BESSs and BESS-hybrid stations

Proposed definition of ‘idle’:

- When a BESS or BESS-hybrid station is electrically connected to the network, but:
    - it is not injecting or consuming active power or reactive power, and
    - it is not cleared for dispatch in the energy and/or ancillary services markets

Topic 3: Idle state AOPOs for BESSs and BESS-hybrid stations

Questions for the CQTG:

- How should "idle" be defined – physical state, market/dispatch status?
  - Where should active and reactive power be measured?
- Is there sufficient power system benefit to justify idle frequency AOPOs?
- Without an idle voltage support obligation, where would the costs likely transfer to?
- Should voltage support be treated as a minimum obligation associated with remaining connected, or as a service that should be procured where needed? Why?
- Would having idle-state voltage AOPOs but not idle-state frequency AOPOs create unintended operational or compliance issues?

Wholesale market enhancements for BESS-hybrid stations

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Hybrid / BESS: Issues

Wholesale market enhancements – issues

Authority consulted on several issues with how BESS-hybrid stations might operate in the wholesale market:

- Offering by station or technology component
  - including configurations that may warrant single-station offers.
- If offering by component:
  - whether ‘station dispatch’ should apply
  - how inverter constraints should be modelled
  - how constrained costs should be calculated.

Hybrid / BESS: Feedback

Feedback – component offering

- All 11 submitters who commented **broadly supported** allowing BESS-hybrid stations to offer by component, with qualifications, noting it provides **trading flexibility**.
- Several submitters highlighted that component-level offering should **not be the only option**.
- Several submitters noted that component-level offering could increase **implementation complexity**.
- Transpower was concerned applying intermittent generation (IG) treatment to BESS-hybrid stations could "**create ambiguity** in gate closure arrangements, dispatch expectations, compliance assessment, forecasting, and the management of forward obligations across dispatch intervals and trading periods".

Hybrid / BESS: Feedback

Feedback – component offering

- **Potential asymmetry** between common-quality obligations assessed at station level and trading obligations assessed at component level.
- **Competitive neutrality across technologies**: requirements associated with component-level offering, metering or compliance should not favour AC-coupled, DC-coupled, standalone or hybrid configurations.

FOR DISCUSSION

Hybrid / BESS: Proposals

Component offering – proposals

- Hybrid stations should offer by component:
    - Component offering appears feasible for both AC- and DC-coupled hybrids
- We could provide for single-station offering, eg, if the BESS never charges from the network:
    - Particularly if a component is smaller than the Code thresholds for offering, the station may be offered as an IG or BESS station
- The SO should have rights to require offering by component in order to comply or plan to comply with its principal performance obligations (PPOs) (*consistent with excluded generating stations*)
- There isn't a strict need for symmetry between trading obligations and AOPOs

Hybrid / BESS: Feedback

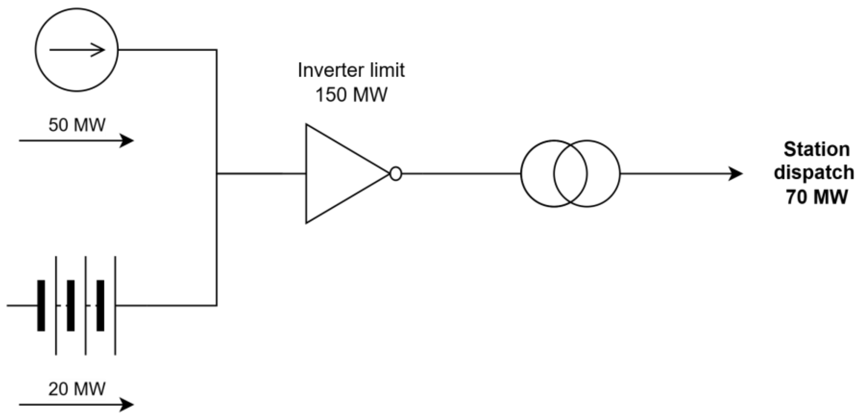
Feedback – station dispatch

- All 11 submitters who commented supported extending station dispatch arrangements to BESS-hybrid stations offered by technology component.
- Many submissions emphasised the need for detailed design to address forecasting, compliance and operational complexities.
- Several submitters identified state-of-charge (SoC) forecasting accuracy as a key issue requiring further consideration.

FOR DISCUSSION

Hybrid / BESS: Proposals

Station dispatch – proposals



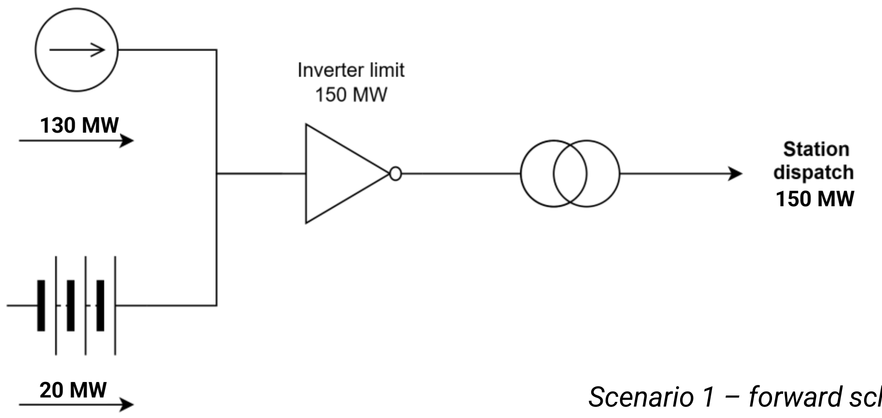
Illustrative example

- IG continues to have flexibility to vary with resource (unless constrained)
- More IG output could mean more injection to network, or reducing BESS output (conserving charge or charging)
- Less IG output could mean increasing BESS output to firm the BESS-hybrid station output
- **What are the limits?**

FOR DISCUSSION

Hybrid / BESS: Proposals

Station dispatch – Scenario 1



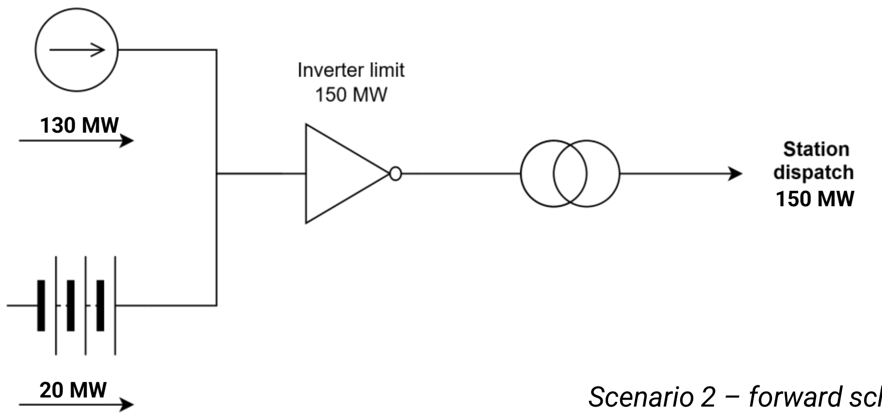
Scenario 1 – forward schedule outcome

- Scenario 1: inverter-constrained, more IG resource in Real Time
- IG floats above 130 MW, BESS backs off
- If IG capacity > inverter limit, BESS could start charging

FOR DISCUSSION

Hybrid / BESS: Proposals

Station dispatch – Scenario 2



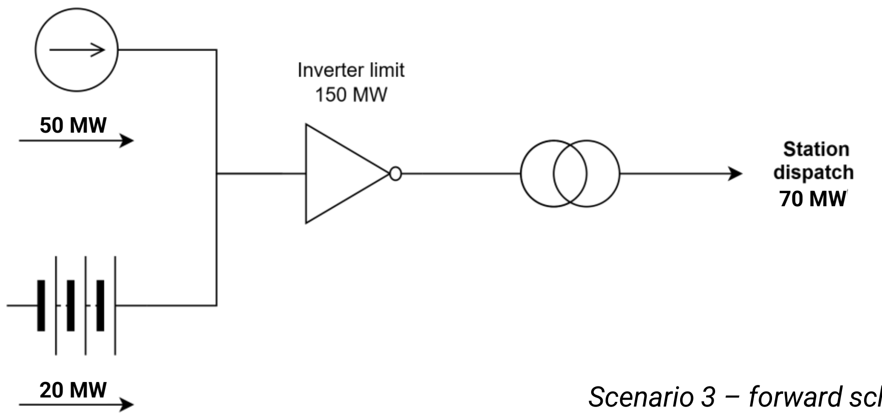
Scenario 2 – forward schedule outcome

- Scenario 2: inverter-constrained, less IG resource in Real Time
- IG output below 130 MW
- BESS may firm up to inverter limit, or not

FOR DISCUSSION

Hybrid / BESS: Proposals

Station dispatch – Scenario 3



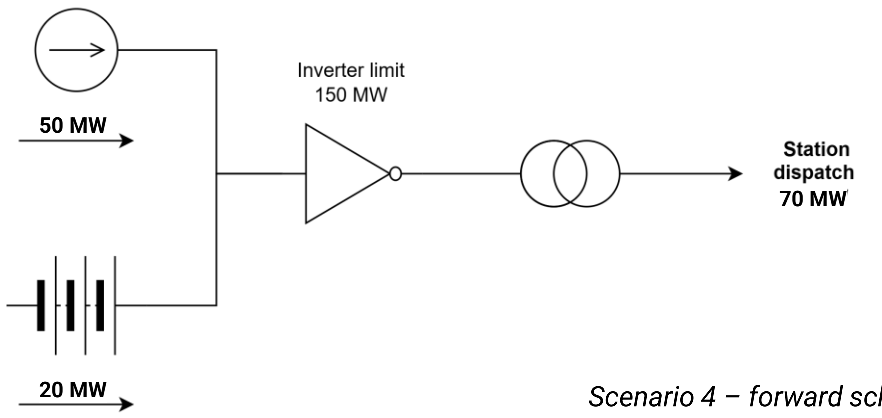
Scenario 3 – forward schedule outcome

- Scenario 3: not constrained, more IG resource in Real Time
- IG may float above 50 MW – what happens to the extra?
- Propose hybrid owner can elect to inject, or reduce BESS output (including charging) **provided at least scheduled station output is injected (>= 70 MW)**

FOR DISCUSSION

Hybrid / BESS: Proposals

Station dispatch – Scenario 4



Scenario 4 – forward schedule outcome

- Scenario 4: not constrained, <u>less</u> IG resource in Real Time
- BESS may inject to compensate for lack of IG output, **but not more than what was scheduled (<= 70 MW)**

Hybrid / BESS: Feedback

Feedback – inverter constraints and constrained costs

- Responsibility for notifying inverter limit should sit with the BESS-hybrid station owner.
- Most submitters that expressed a clear preference supported applying a static market node constraint.
- Several submitters supported enabling component-level constrained cost calculations for DC-coupled BESS-hybrid stations
    - However, there was concern about how DC-side metering would be implemented in practice.

FOR DISCUSSION

Hybrid / BESS: Proposals

Inverter constraints

- Market-node constraints are preferred and lower risk than transmission constraints
- Participants recommended static inverter limits but providing dynamic limits (through BESS component offer) would be more practical and should not be difficult to implement

Component-level constrained costs

- Benefits are unclear, particularly if BESS-hybrids are required to be station dispatch groups for the purposes of constrained cost calculations
- Suggest defer updating constrained cost changes until a wider review is undertaken

BESS-hybrid large loads and BESS-hybrid large load-generation

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BESS-hybrid large loads: New Issue

New Issue – BESS coupled with large loads

- A BESS may be coupled with a large inverter-based load (IBL)
- In this configuration a BESS may never inject into the transmission grid or distribution network
- Datagrid's Southland data centre is an example
    - The BESS's primary purpose is load management, not generation – the BESS is to be used to smooth rapid changes in data centre demand
- Datagrid seeking:
    - relief from generator-style offering requirements, or
    - treatment as net load where exports remain below 10MW threshold

BESS-hybrid large loads: New Issue

Just when you thought it was complicated enough…

- We have Contact Energy’s announcement of a large data centre coupled with a BESS coupled with a solar PV generating station…

Asset Owner Performance Obligations

AOPOs for BESS-hybrid large loads are just starting to be considered

- Other jurisdictions are at most 1 year ahead in grid code drafting
- Operating modes are largely speculative
- If not injecting into the network, generator-type frequency and voltage AOPOs for a BESS-hybrid large load may not be justified
- Other obligations that minimise a BESS-hybrid large load's impact on the power system are likely justified (eg, fault ride through (FRT) and active power ramping limits)

Market arrangements

Market arrangements should consider how the BESS is going to be operated

- As already noted, operating modes are largely speculative
- If the BESS never injects, should it need to submit generation offers?
  - Compare with small embedded generation at large loads
- If the load is not dispatchable and the BESS is smoothing, then the BESS is not dispatchable either

System Operator update on technical requirements for large loads

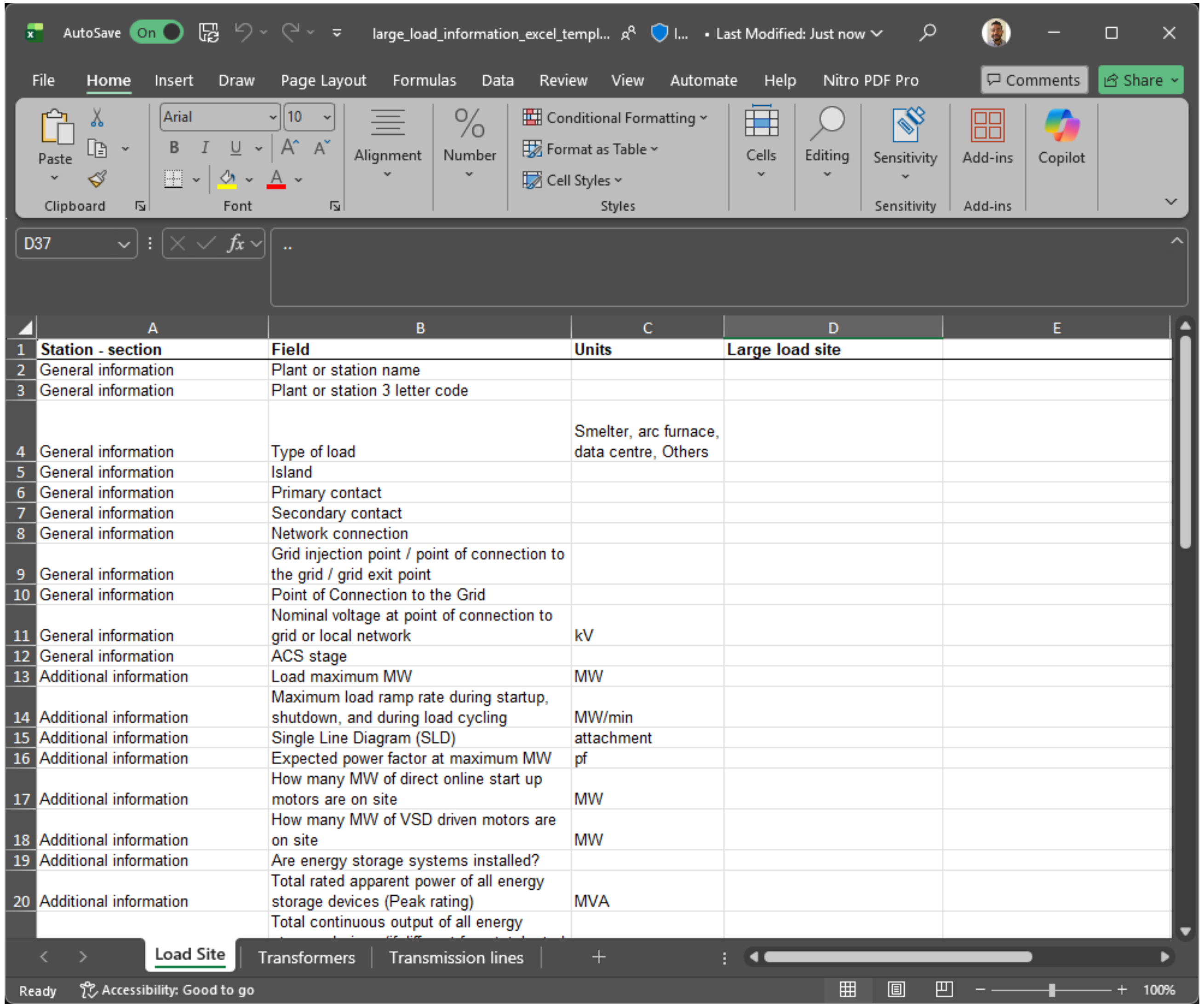
Contents

The contents of this information pack represent high level draft requirements which are a work in progress at the time of this session. Requirements may change as these become finalised.

ACS Information Sharing

ACS template uploaded to [System Operator website]() for large loads to submit, broadly covering:

- Active power of the load (maximum, seasonal variation, load cycling behaviour)
- Power factor during various modes of operation
- Load composition e.g. motor loads, electronic loads
- High voltage assets e.g. transformers, shunt capacitors
- High level protection information and expected ride through behaviour during network disturbances
- Station transformers
- Transmission lines or cables connecting the load facility to the GXP
- Shunt capacitors or reactors on site



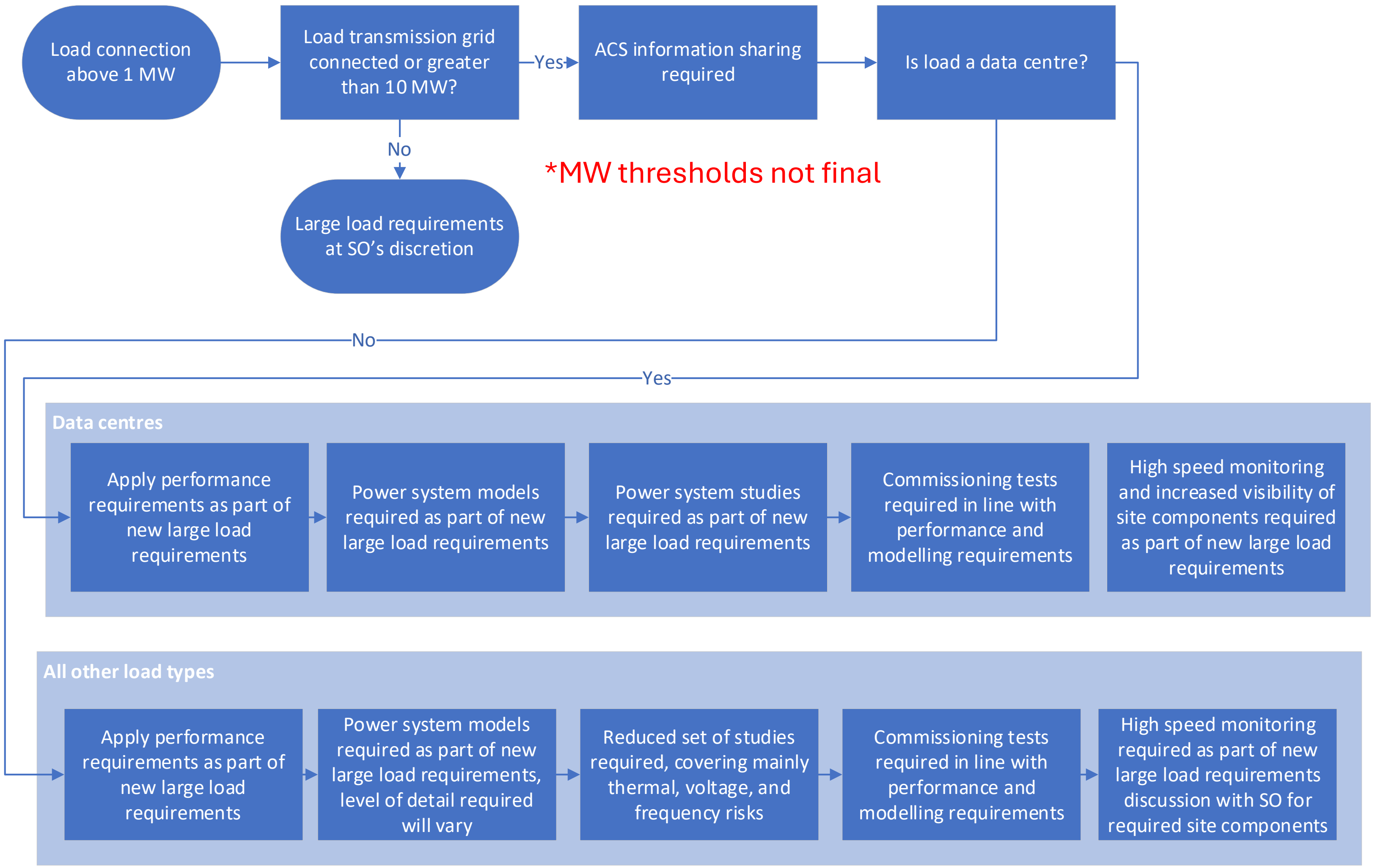
	Station - section	Field	Units	Large load site
1	**Station - section**	**Field**	**Units**	**Large load site**
2	General information	Plant or station name		
3	General information	Plant or station 3 letter code		
4	General information	Type of load	Smelter, arc furnace, data centre, Others	
5	General information	Island		
6	General information	Primary contact		
7	General information	Secondary contact		
8	General information	Network connection		
9	General information	Grid injection point / point of connection to the grid / grid exit point		
10	General information	Point of Connection to the Grid		
11	General information	Nominal voltage at point of connection to grid or local network	kV	
12	General information	ACS stage		
13	Additional information	Load maximum MW	MW	
14	Additional information	Maximum load ramp rate during startup, shutdown, and during load cycling	MW/min	
15	Additional information	Single Line Diagram (SLD)	attachment	
16	Additional information	Expected power factor at maximum MW	pf	
17	Additional information	How many MW of direct online start up motors are on site	MW	
18	Additional information	How many MW of VSD driven motors are on site	MW	
19	Additional information	Are energy storage systems installed?		
20	Additional information	Total rated apparent power of all energy storage devices (Peak rating)	MVA	
		Total continuous output of all energy		

Power system stability challenges

#	Challenges
1	Fault ride through capability creating over-frequency risks
2	Fast active power ramps can make normal band frequency difficult to manage
3	Frequency and voltage issues due to load rejection / site tripping
3	Uncoordinated reconnection following a disconnection due to network disturbance, or site disconnection
4	Oscillations driven by large loads due to active power cycles or control system interactions
5	Other stability requirements

Scope and applicability of requirements

- Requirements address the following main areas:
    - Performance requirements
    - Connection studies
    - Modelling requirements
    - Testing
    - Data recording and SCADA monitoring
- Application of requirements will vary depending on size and type of load



Performance Requirements

#	Requirement
1	Active power ramp rate
2	Steady state voltage range
3	Frequency ride-through capability
4	Voltage ride-through capability
5	Active power recovery following voltage ride-through event
6	Voltage phase jump withstand capability
7	Reconnection following a disconnection from the grid
8	Power quality requirements (no changes expected)
9	Automatic under frequency load shedding (no changes expected)

Power system studies

- Studies for connecting loads parallel generator connection studies, applicability of these studies will depend on the load type and characteristics

#	Power system study
1	Power-flow study
2	*Reactive power capability*
3	*Frequency regulation tuning study*
4	*Voltage regulation and tuning study*
5	*Short circuit study*
6	FRT study
7	*Transient stability study (impact on surrounding generation)*
8	Oscillations due to active power cycling (depending on load behaviour)
9	Over-frequency study

Load Modelling Requirements

Large loads will be required to submit power system models. Requirements will vary for load types and may include:

- Standard models (e.g. CMLD or PERC1 model formats)
- User defined models if loads cannot be adequately represented in standard models
- RMS models required, EMT may be required for some load types
- The model must accurately represent:
    - Dynamic behaviour under voltage and frequency fluctuations
    - Include any ride-through disconnection and reconnection characteristics
    - Represent any control action affecting and responding to grid voltage and frequency

Testing

Testing requirements to be developed, will follow from performance requirements and assessment of model validity.

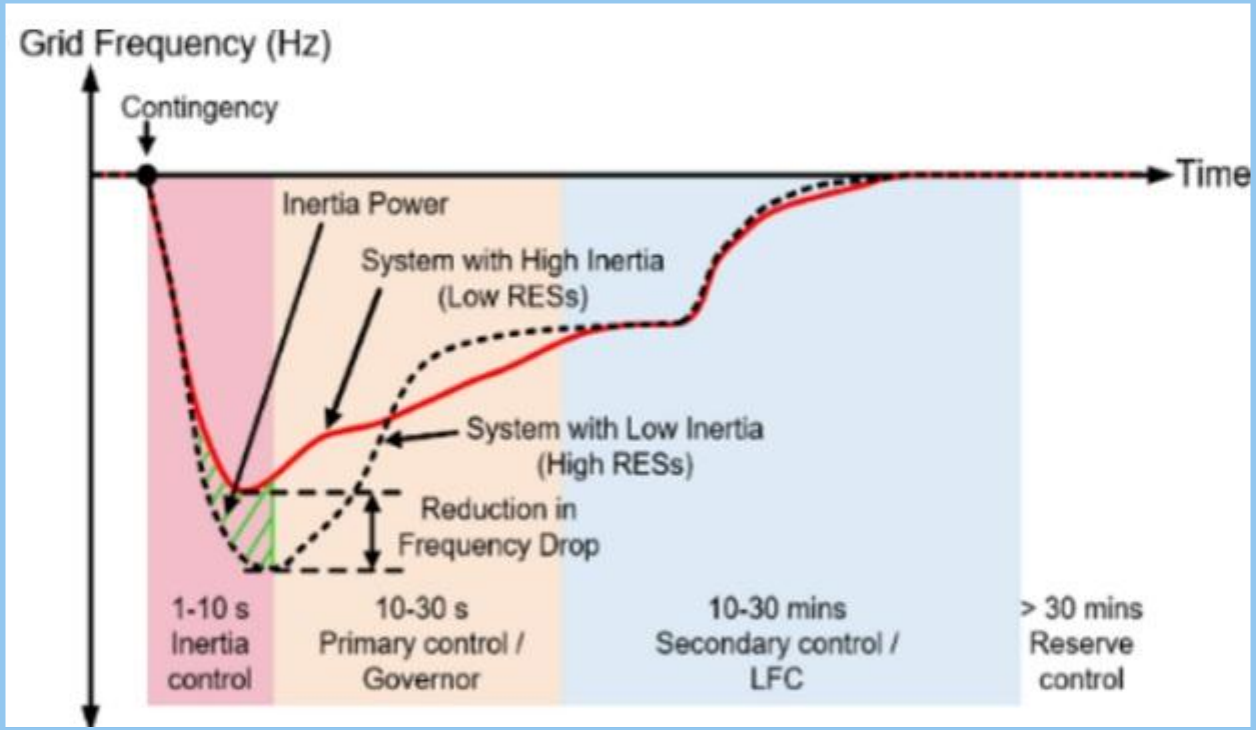
Data recording and SCADA monitoring

Sites will be required to:

- Provide SCADA indications for overall load as well as individual components within the site. Requirements will depend on load type and composition.
- High resolution recording for ongoing monitoring of performance during normal operation and disturbances

LUNCH

System Operator update on system inertia - needs date analysis



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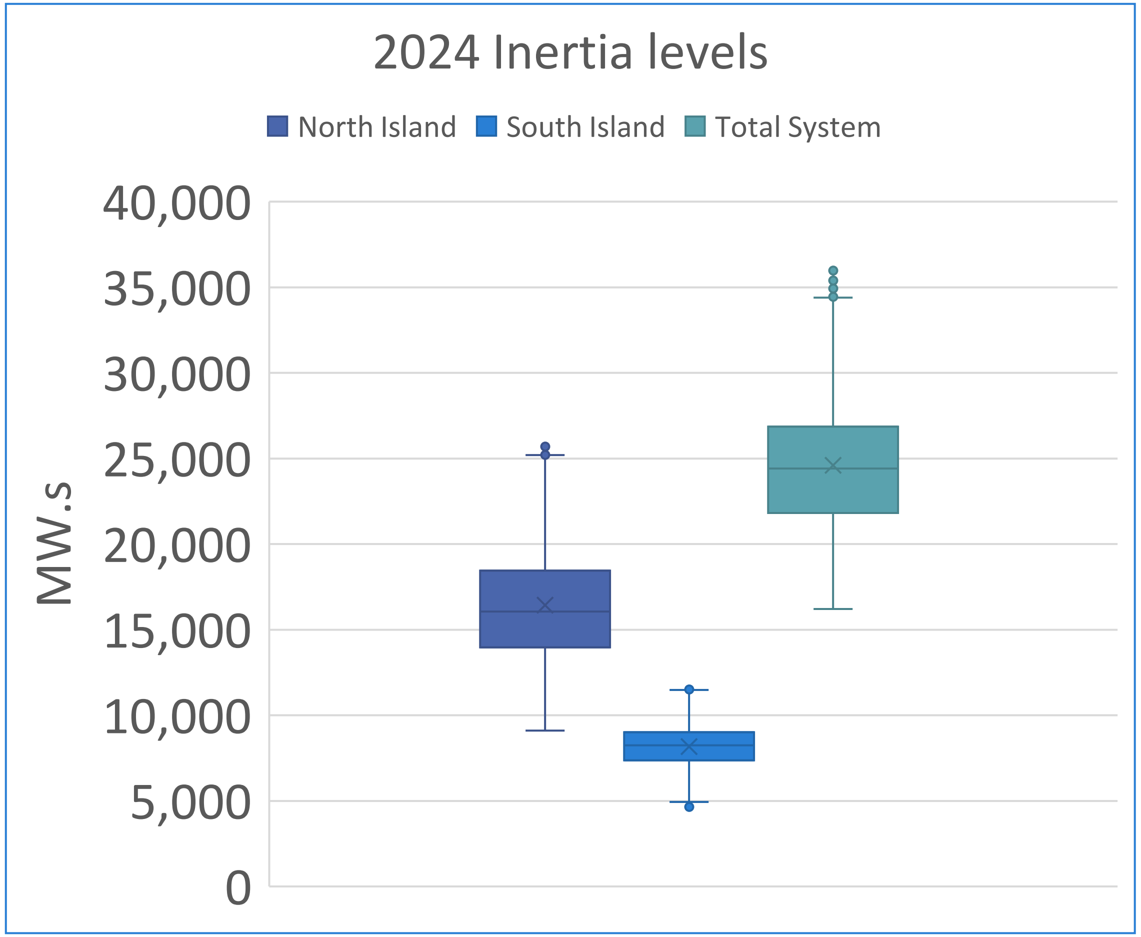
Inertia in New Zealand – Island characteristics

- Low inertia in the South Island does not necessarily coincide with low inertia in the North Island; **one island can experience higher inertia while the other is low**, depending on the generation mix present in each island at a given time.
- Most hydro generation is located in the **South Island**, contributing to more **stable inertia levels**, while the **North Island** has a higher proportion of IBRs, leading to **greater inertia variability**.

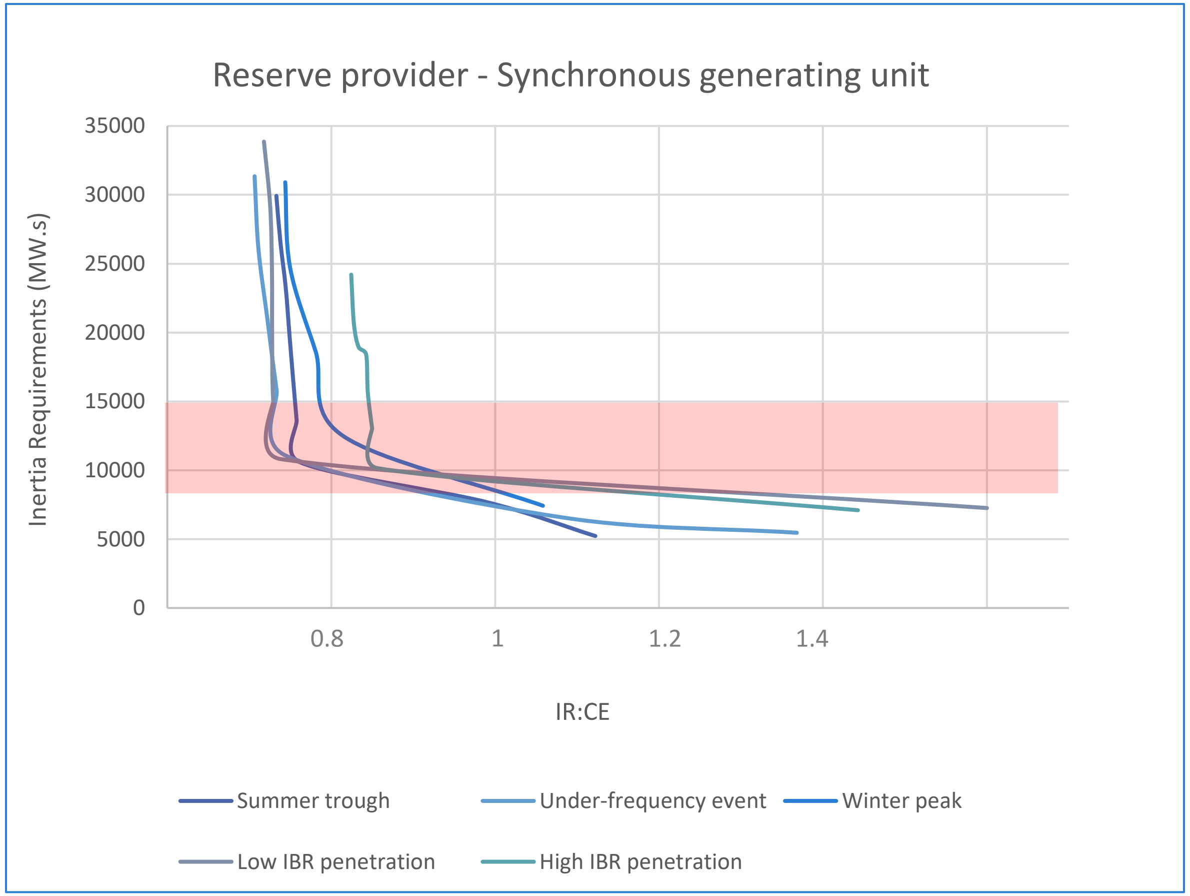


Refresher on 'Minimum inertia study' outcome

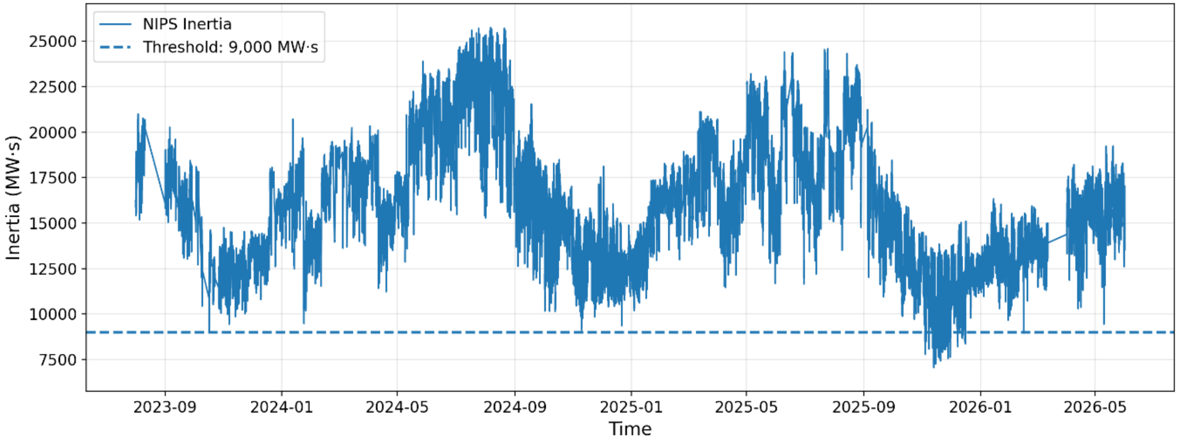
Conclusion

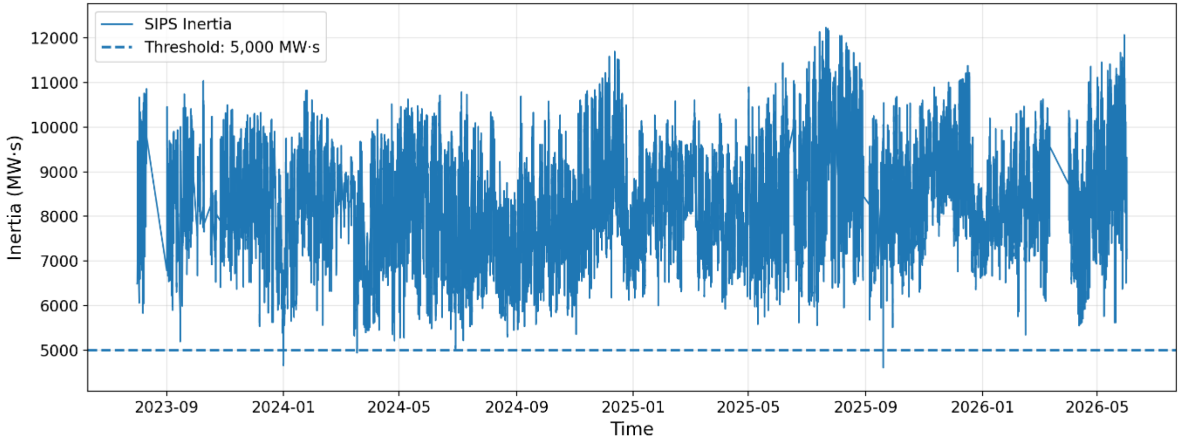
The minimum inertia level for:

- Combined NZPS – Between 10,000 MW·s and 15,000 MW·s
- NIPS - 9,000 MW·s
- SIPS - 5,000 MW·s



Inertia needs-date Analysis - Study Objective





To determine when future system conditions may reach a point where low-inertia levels can no longer be accommodated without additional operational measures or increased market interventions.

Study Assumptions

Probabilistic study like this one is driven by a lot of assumptions like:

- The forecast only covers **a four-year horizon (2026 -2029).**
- **existing market design/products assumed unchanged** for the study period.
- **does not incorporate inertia contributions** from load and IBRs (HVDC included).
- the **forecasting is to be done on a trading-period basis**, as synchronous units are typically dispatched and remain close to their scheduled capacity for the duration of a trading period.
- this study instead uses the conservative expected (mean) **trough island forecast (one datapoint per trading period) .**
- The generation assumed to be commissioned in the study period is extracted from the Transpower website and the internal System Operator's commissioning database.
- In the 2026 – 2029 period, TPR 2025 assumes the only generation to be retired is Taranaki Combined Cycle (383 MW) by the end of 2025. **TCC is assumed to remain online only until July 2026.**

Study Assumptions

- The forecast **SIPS solar capacity factors** are based on the historical performance of a single site and **do not capture the impacts of geographical diversification**. As additional farms are commissioned, the SIPS solar capacity factor may change.
- The system demand data used for historical analysis is net of DER. For future DER considerations, an **increase of 100 MW/year is added to account for overall DER growth**. DER is forecast to reach a total of 950MW by 2029.
- **BESS charging during future daytime trough hours is not considered** and current charging and discharging trends have not been established as yet due to BESS only recently being connected.
- **Large load sensitivity is considered** but no projects are in delivery stage yet. The sensitivity assumes a **cumulative additional load connected from mid-2027 reaching 1,110 MW by 2029 with an approximate 30/70 split**, with more of the load in the NIPS.

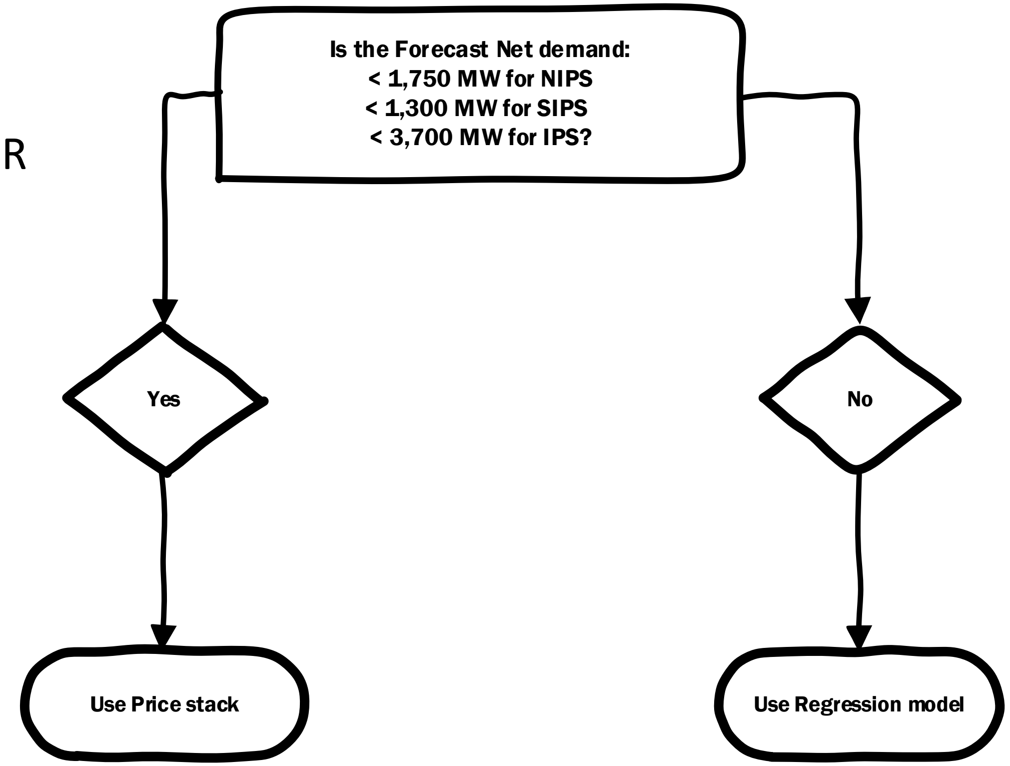
High level methodology

Stage 1: Historical data analysis

1. **Net Demand** = system demand - intermittent generation
2. **Wind and solar capacity factors per trading period** calculated to quantify the amount of energy generated by IBR relative to its installed capacity.
3. Two **capacity-factor profiles** were developed to test the sensitivity of the forecast results to different IBR output assumptions:
   a) The 'Average CF' profile represents the mean of the available 2024 and 2025 trading-period capacity factors.
   b) The 'High CF' profile represents the maximum observed capacity factor for each trading period.
4. **Relationship between inertia and other system parameters** (net demand, HVDC flow, NFR, Risk size) was explored.

Stage 2: Inertia forecasting

The forecast net demand was calculated for each trading period under each capacity-factor scenario; High and Average, including DER during daylight hours only.



The model's input feature vector is:

$$x_t = [ND_{NIPS,t}, ND_{SIPS,t}, ND_{IPS,t}, H_{NIPS,t}, H_{SIPS,t}, H_{IPS,t}, NFR_{NIPS,t}, NFR_{SIPS,t}, S_t]$$

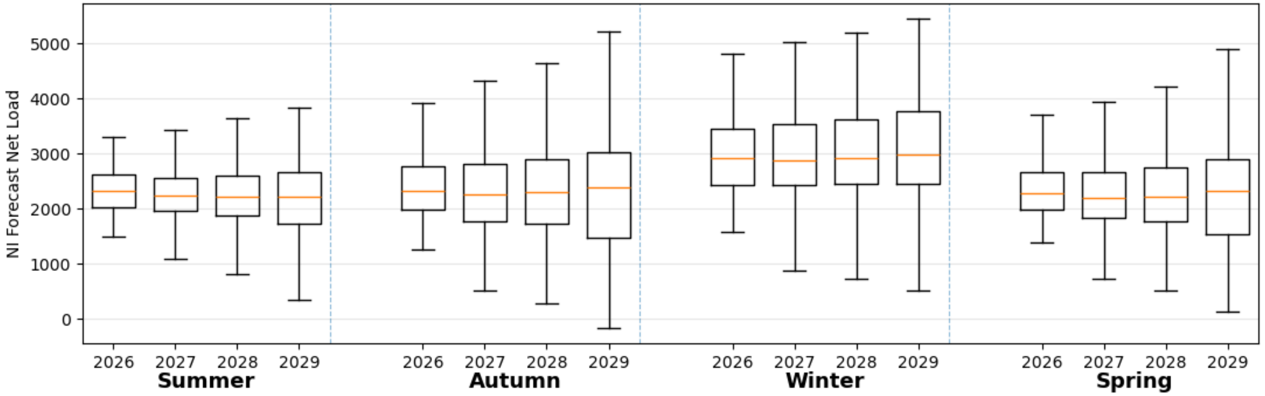
which includes net demand, inertia, NFR and seasonal/time variables.

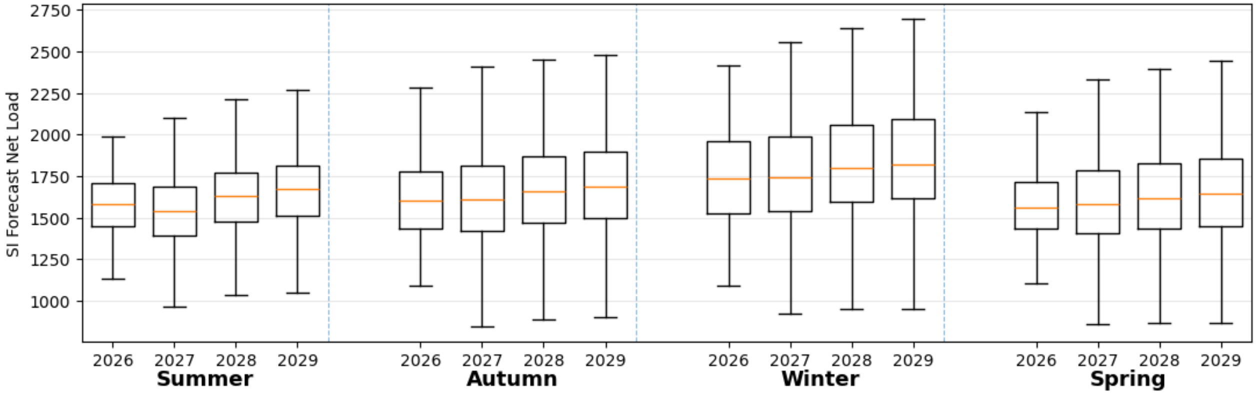
The model then predicts the expected inertia i.e.

$y_{TP} = [H^{forecast}_{NIPS,TP}, H^{forecast}_{SIPS,TP}]$ for each trading period.

Results – Seasonal net demand

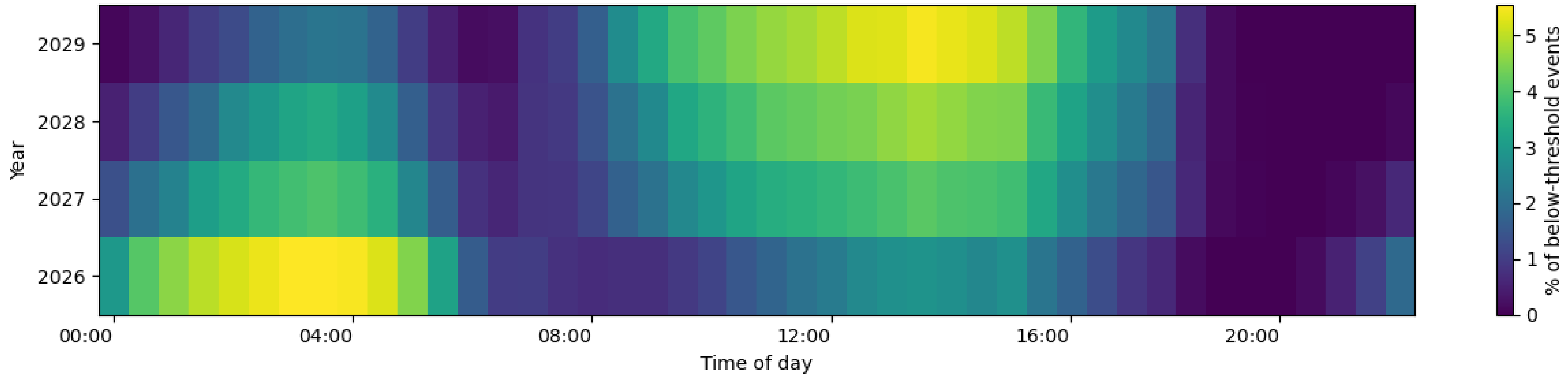
In the NIPS, **net demand decreases over time**, with autumn having the lowest values. However, in the SIPS, demand growth from 2027 onwards, offset the impact of increasing IBR and limit large reductions in net demand.





Results – Daily minimum net demand shift

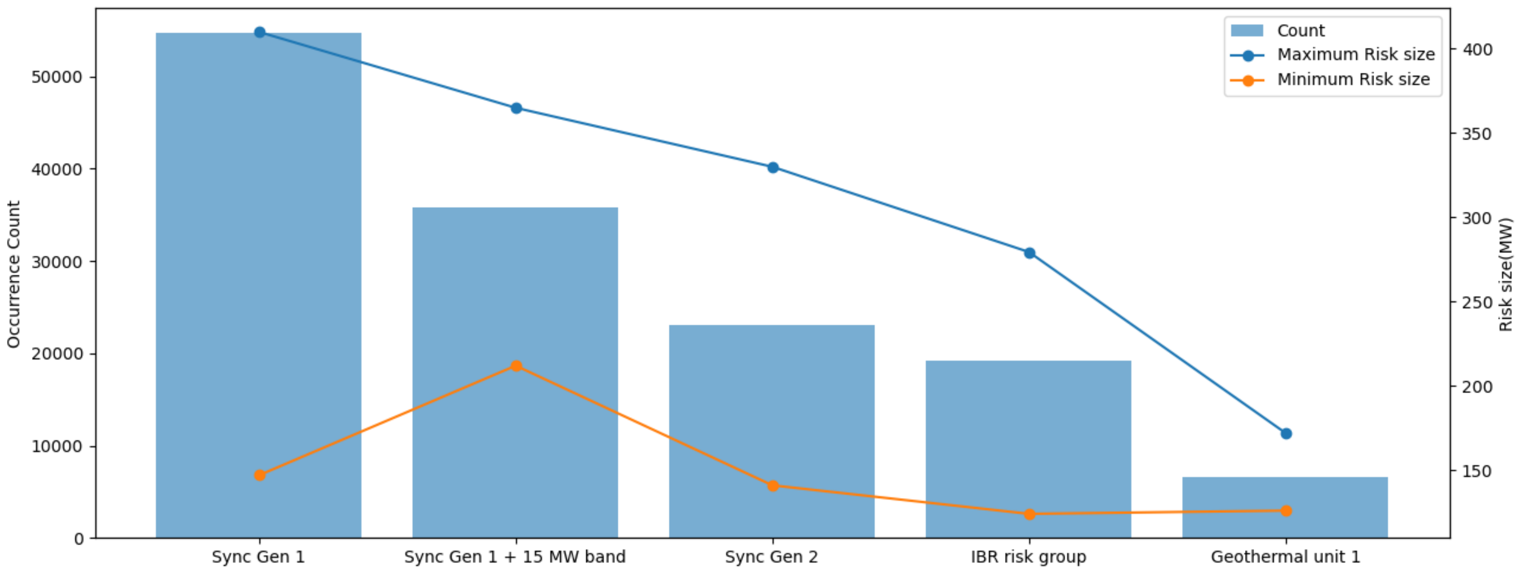
- With solar generation penetration still being relatively low, in the studied periods, the **minimum net demand typically occurs overnight**, between 03:00 and 04:00, and as early as 01:00 during summer.
- As solar penetration increases, **the daily minimum net demand will start occurring during the day**, i.e. between 14:00 and 15:00, and potentially as late as 16:00 during summer. This is also driven by higher wind output occurring in the afternoon hours.



Low-inertia occurrences by time of day.

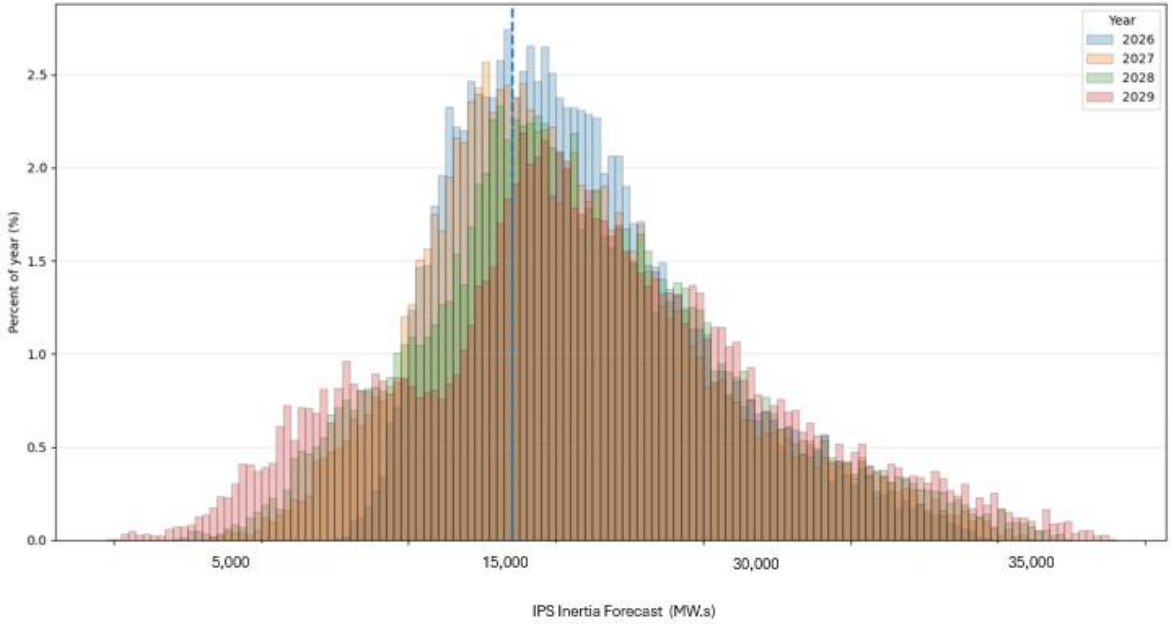
Results – Risk size considerations

- Currently, the large synchronous generators usually set the risk, followed by IG risk groups. The next risk plant considered is geothermal generation, which SPD dispatches down during low-demand periods as a lower-cost solution.
- During the **instances where the inertia threshold has been breached**, the **binding risk has always been the IBR risk group with a maximum size of 280MW**.
- According to the connection pipeline at the time of this study, a future IBR risk group may be up to 400MW.

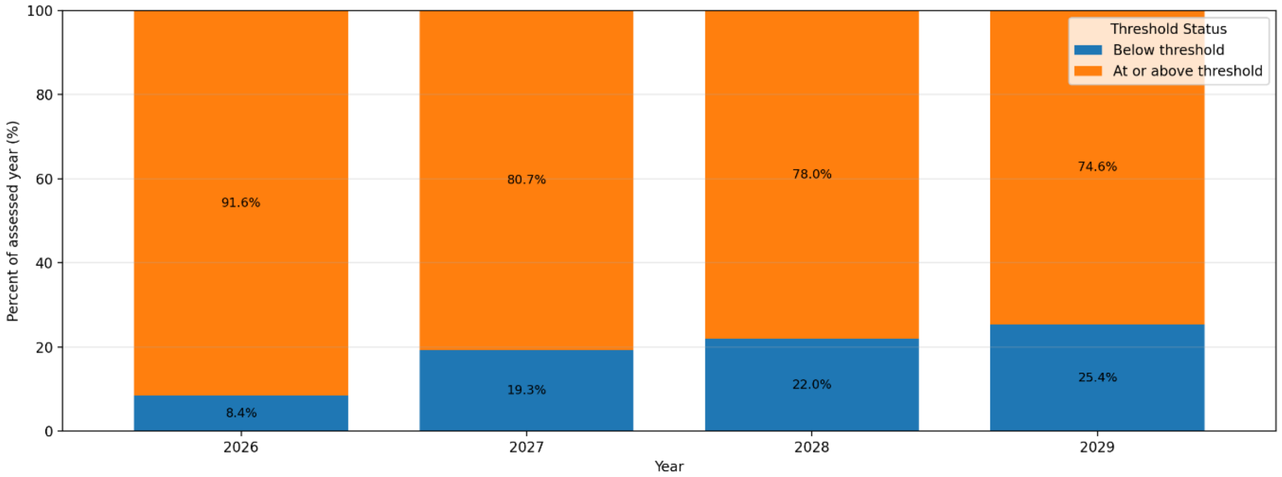


Count and size (maximum and minimum) of the top 5 ACCE risks covered in 2024 and 2025

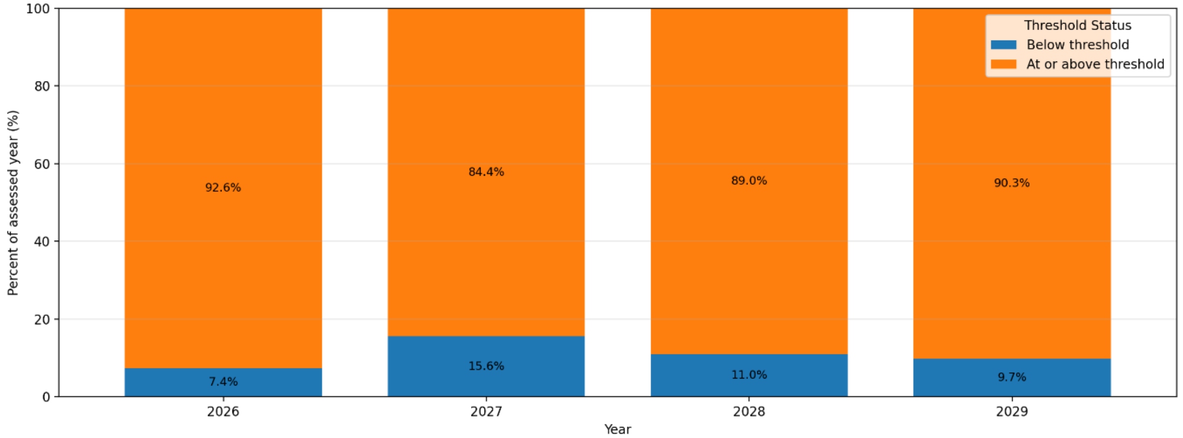
Results – Inertia forecasting



The number of trading periods below the minimum inertia thresholds increase over the years especially for IPS and NIPS.

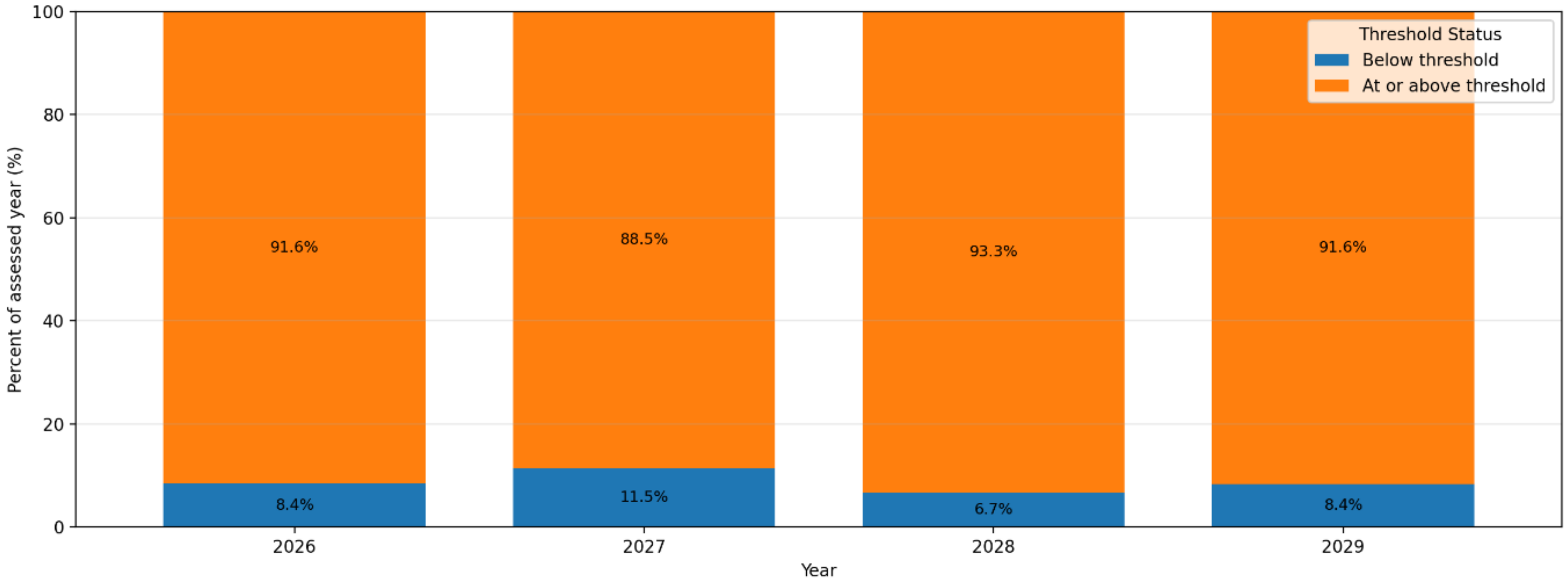


NIPS inertia forecast assessment showing the percentage of trading periods below the minimum island inertia threshold per year.



SIPS inertia forecast assessment showing the percentage of trading periods below the minimum island inertia threshold per year.

Results –Large load sensitivity



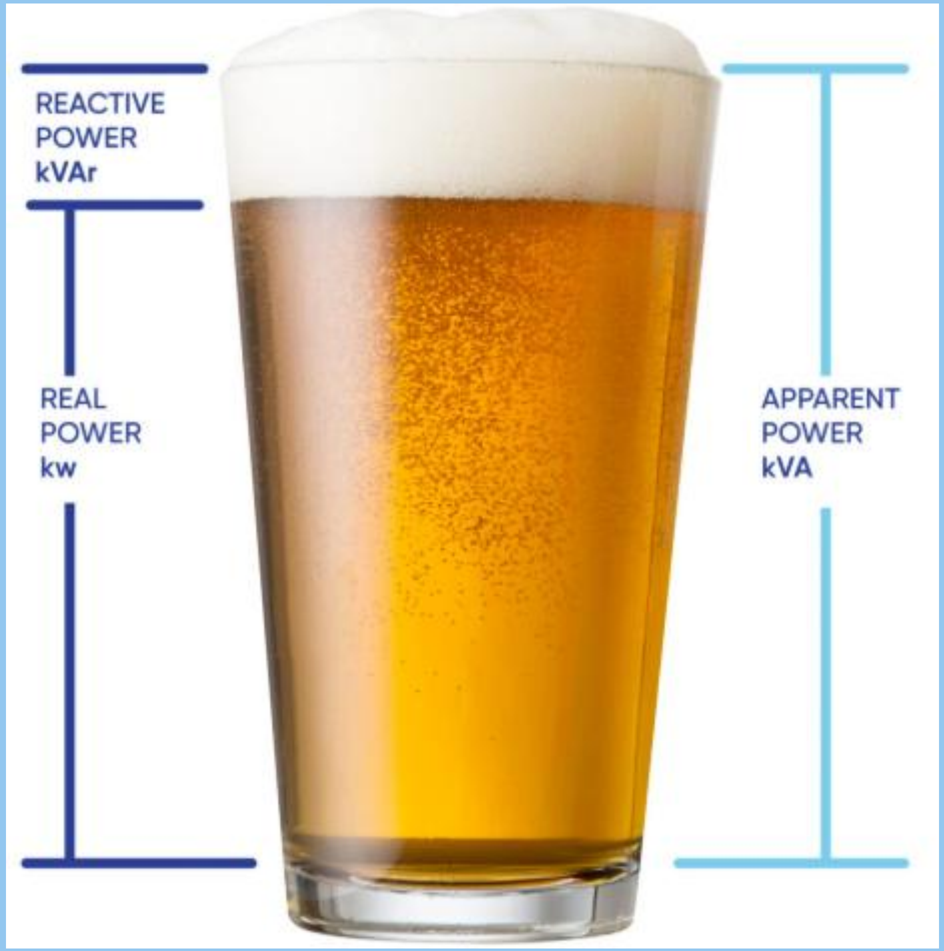
NIPS Inertia forecast assessment (when including 'possible' large loads) showing how many trading periods of each year, inertia is forecast to be below the minimum inertia island threshold.

Large loads also introduce their own operational considerations, including voltage quality requirements, active power ramping behaviour, and the potential to create large credible risks. The sudden loss or reduction of a large load may itself present a frequency stability challenge if system inertia is insufficient. Accordingly, **prospective large-load developments should be treated as a sensitivity that may defer the inertia need-date rather than as a substitute for an inertia solution**. Should significant large-load projects proceed, the need-date assessment can be revised.

Conclusions and Recommendations

- **Under the specified study assumptions, the analysis shows that low-inertia conditions are expected to become more frequent over 2027.**
    - Progress the recommendations identified in the Minimum Inertia Study and undertake further work to determine which options should be implemented long-term.
    - Future inertia work needs to be extended to defining RoCoF criteria for both generation and large load and determining whether over frequency will be a concern considering large loads tripping in low inertia scenarios.
    - Establish a real-time inertia monitoring capability ahead of the deployment of any inertia solution.
    - Build capability for short-term inertia forecasting using information available from market schedules (NRSS/NRSL/WDS).

System Operator update on work on GXP reactive power criteria



Scope

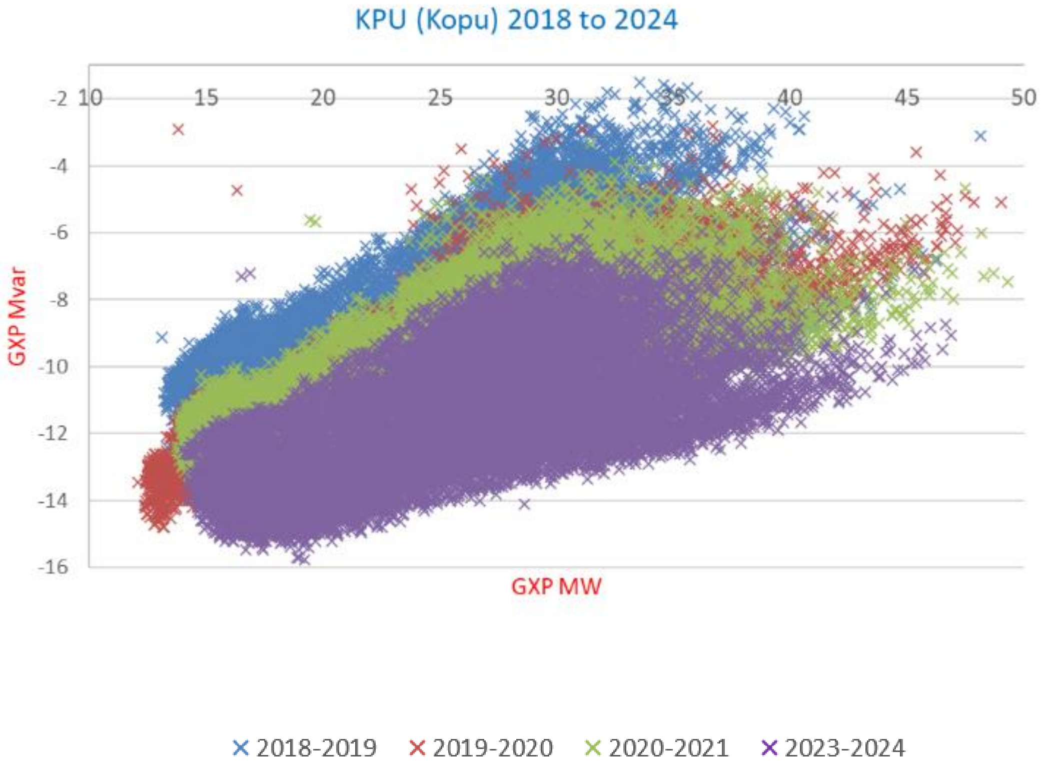
Extending work previously done by investigating alternative reactive power criteria.

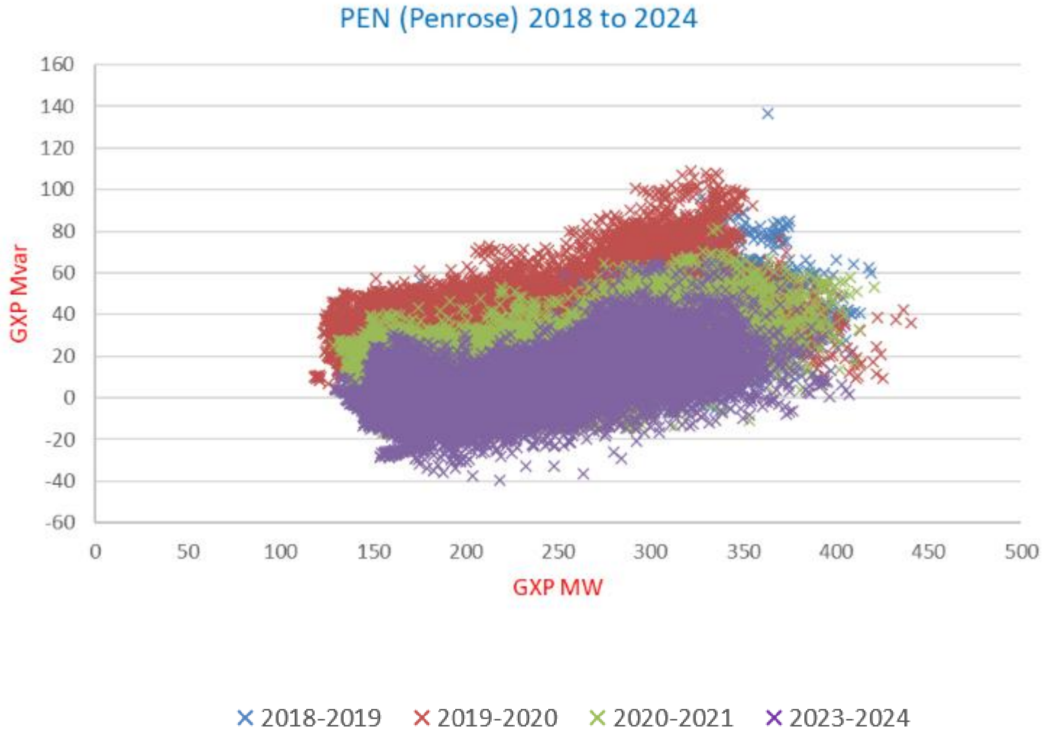
Builds on the original paper with further analysis and different combinations of power factor and constant limits.

Study period and data is the same as the original paper

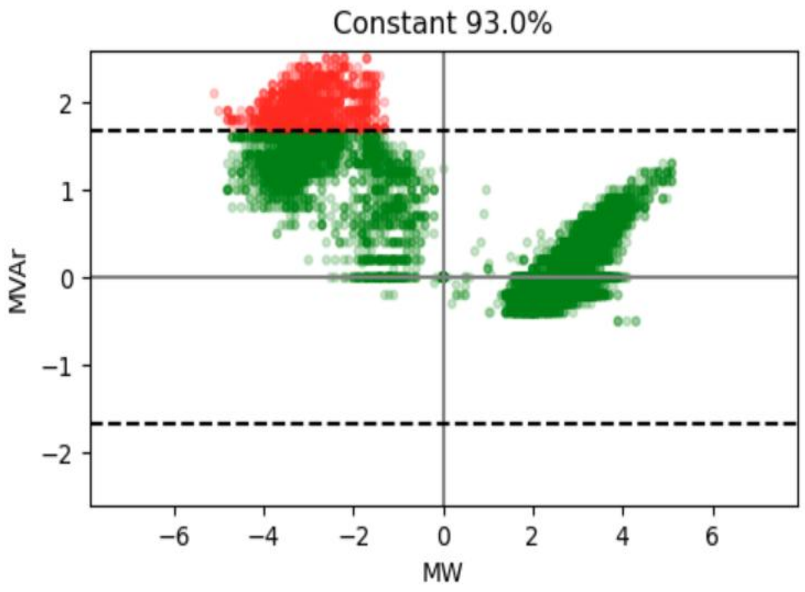
(09/2023 to 09/2024)

GXPs trending towards MVAr export

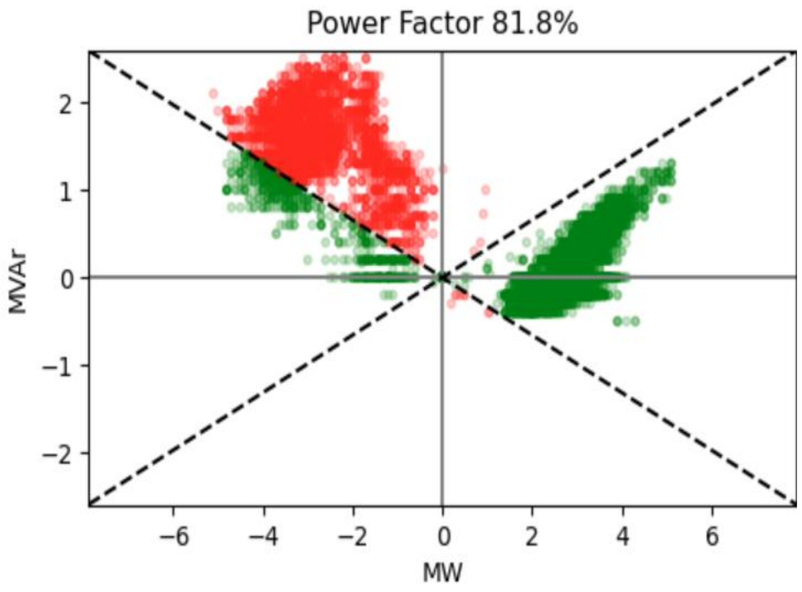




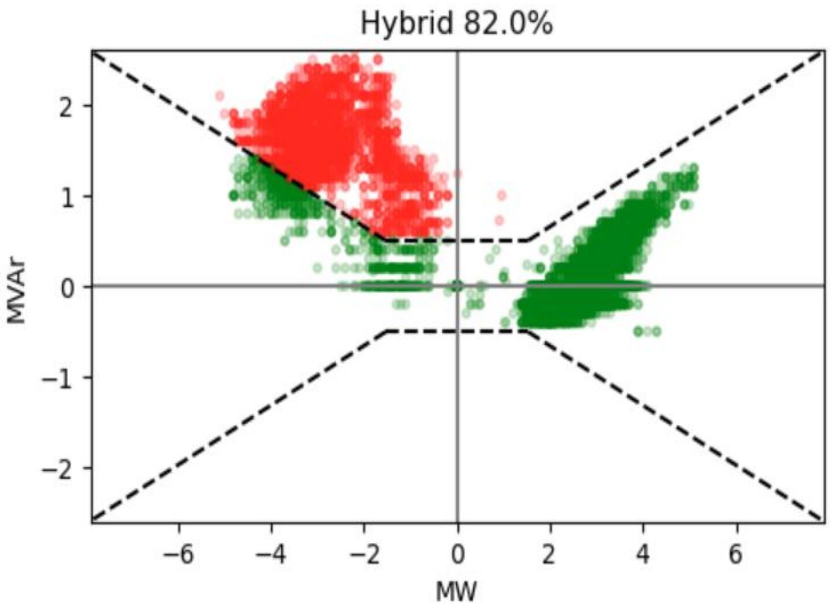
Constant



Power Factor

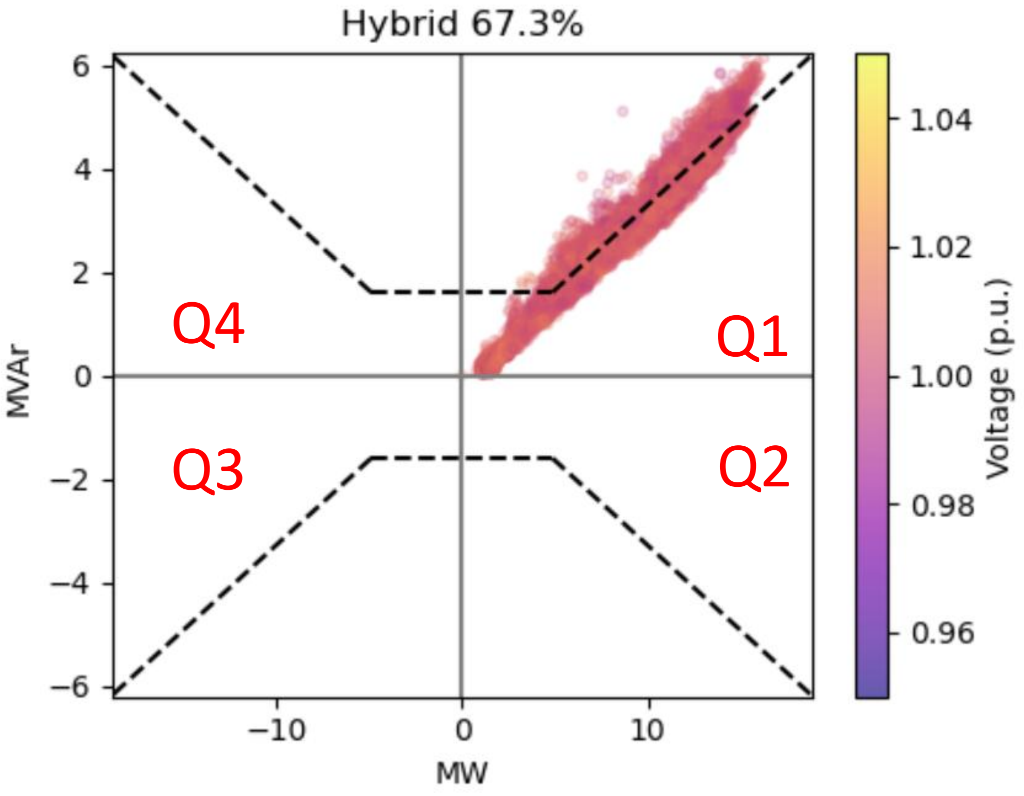


Hybrid

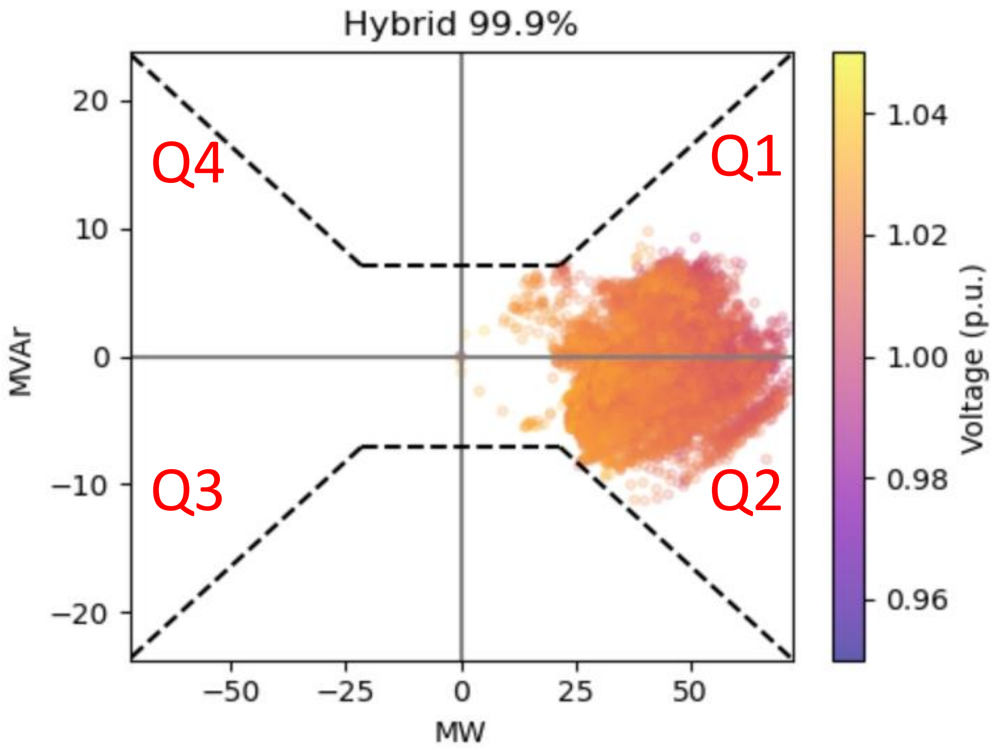


Present Behaviour

LFD GXP Operating in Quadrant 1 with positive MW/MVAr relationship.

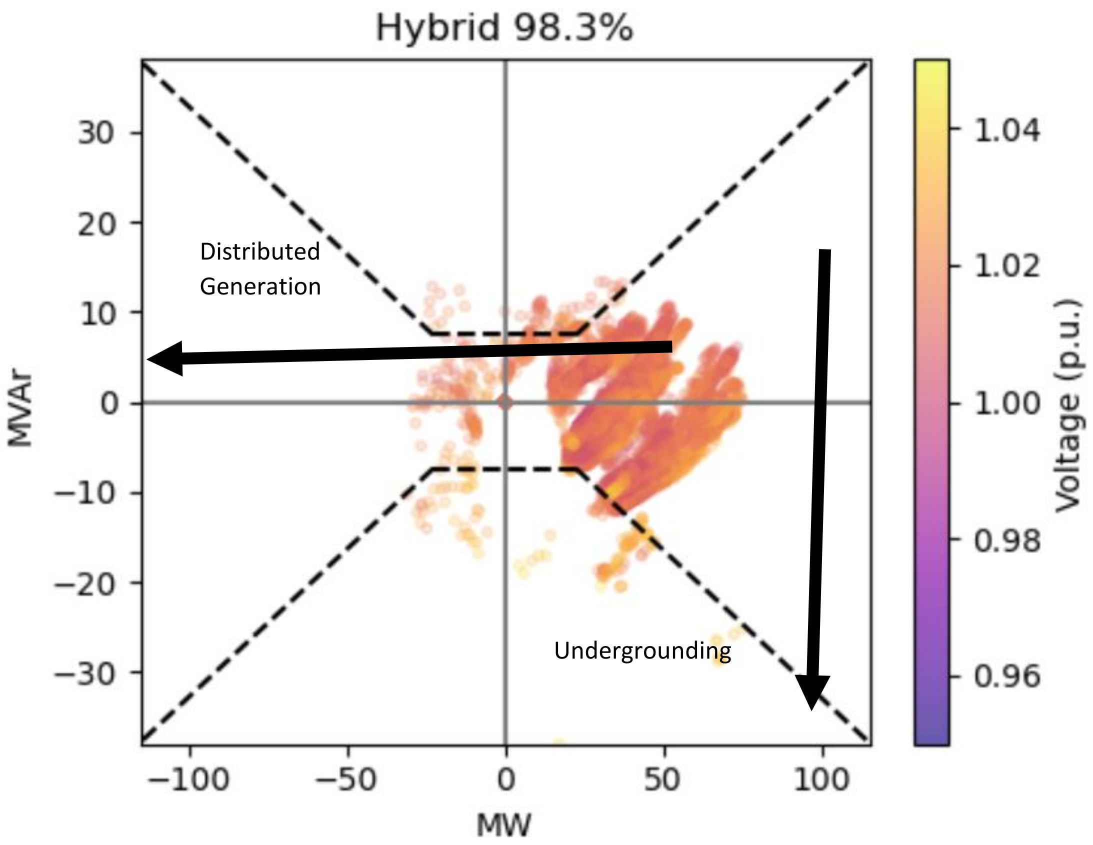


KOE GXP operating in Quadrants 1 and 2 with no clear MW/MVAr trend.



Expected Future Behaviour

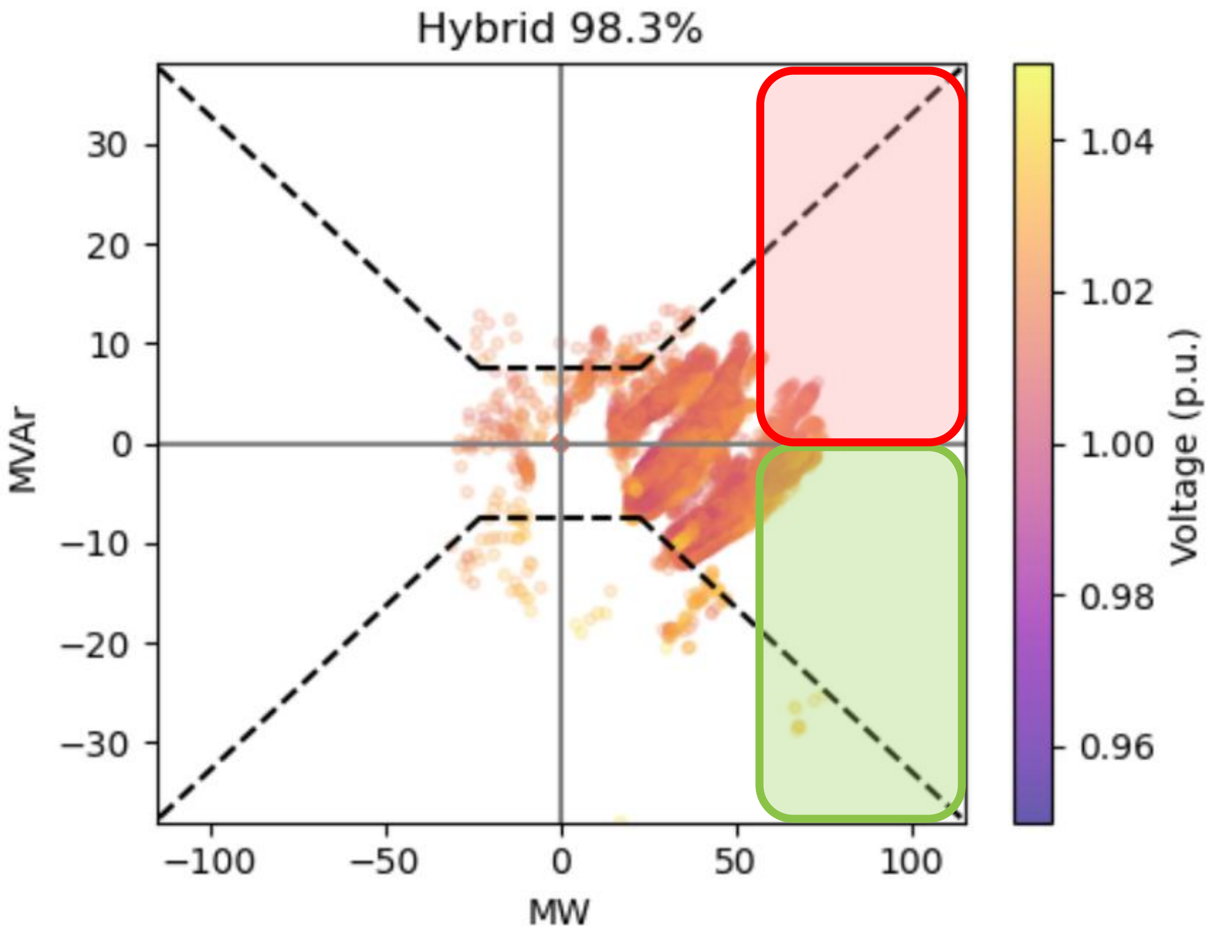
- Undergrounding makes networks more capacitive.
- Power electronics loads consume less reactive power
- Distributed generation lowers net load at GXP



High Load

- Undervoltage/lack of capacitive headroom
- Default Transmission Agreement limits apply during regional peak demand

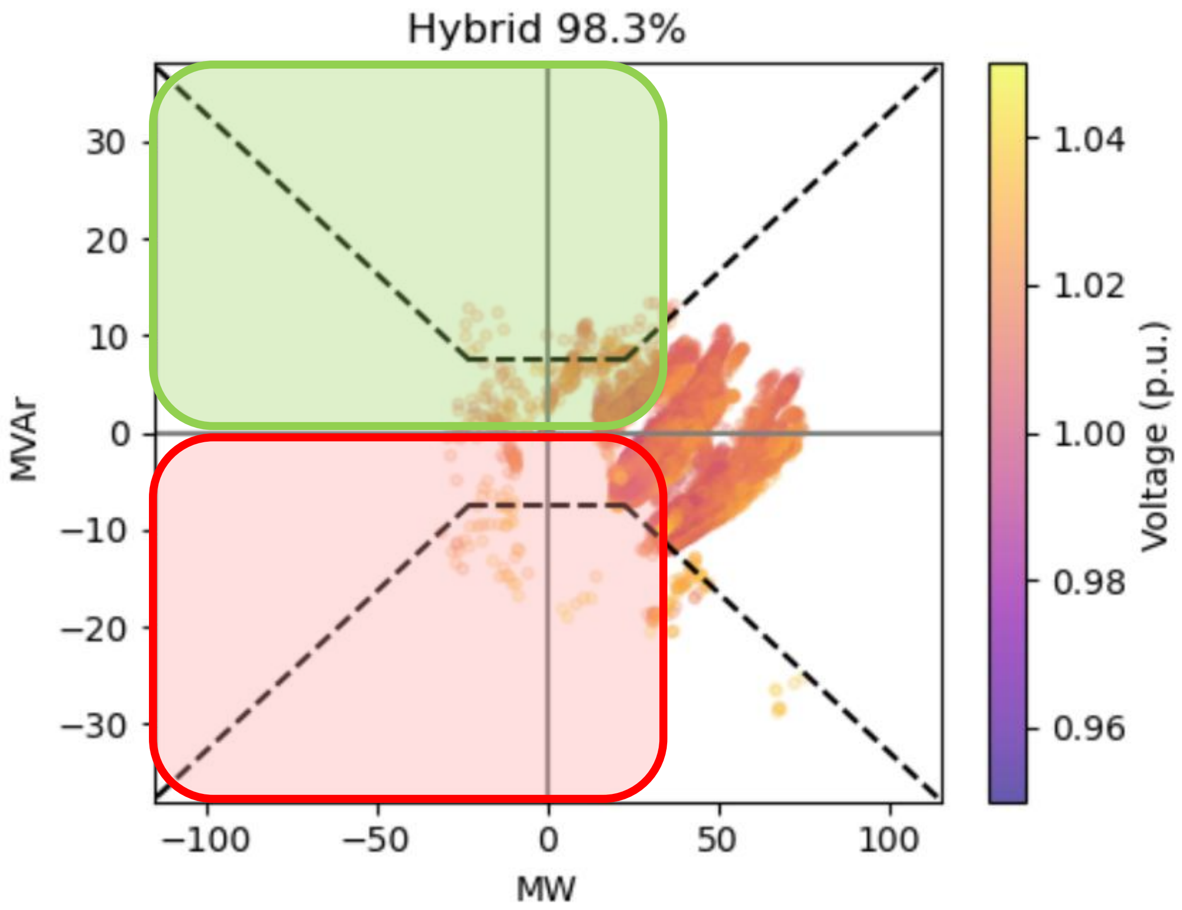
Generally beneficial and generally harmful operation (for "conforming" GXP)



Light Load

- Overvoltage/lack of inductive headroom
- Less generation online
- Default Transmission Agreement limits do not address light load
- Real power export not seen yet, could occur in future

Generally beneficial and generally harmful operation (for “conforming” GXP)

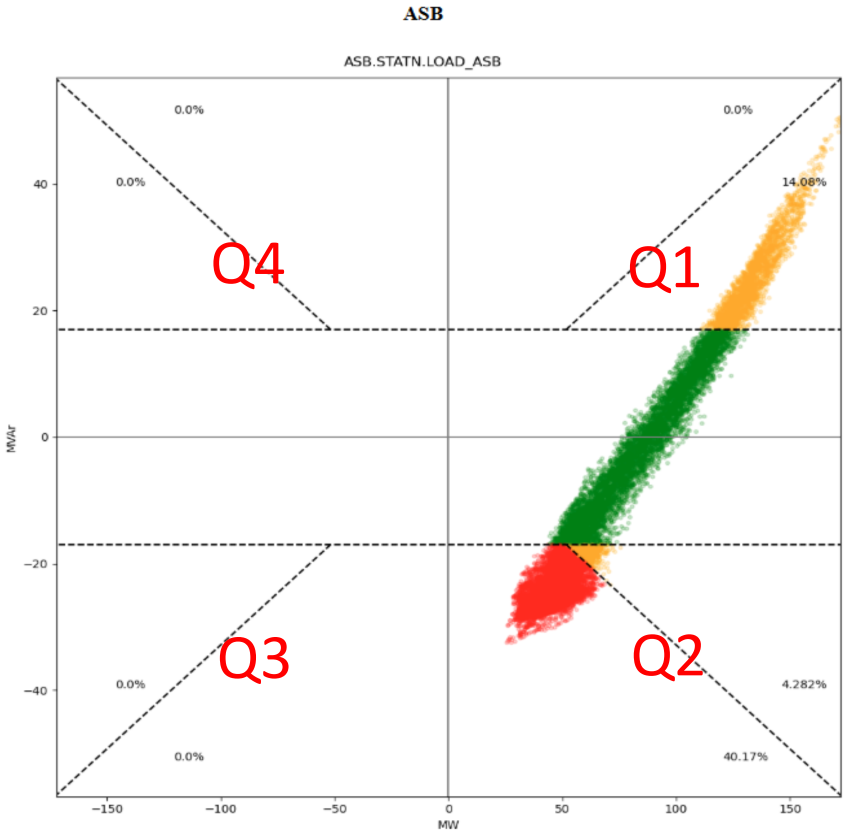


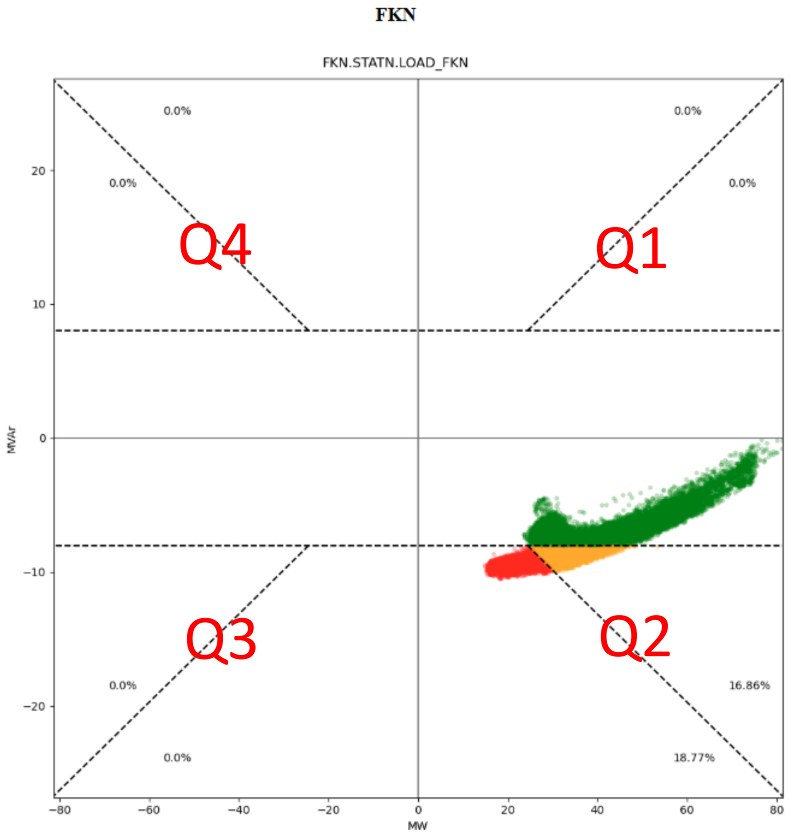
Analysis by Quadrant

Q1: Constant limit too onerous (10% of all trading periods in orange region)

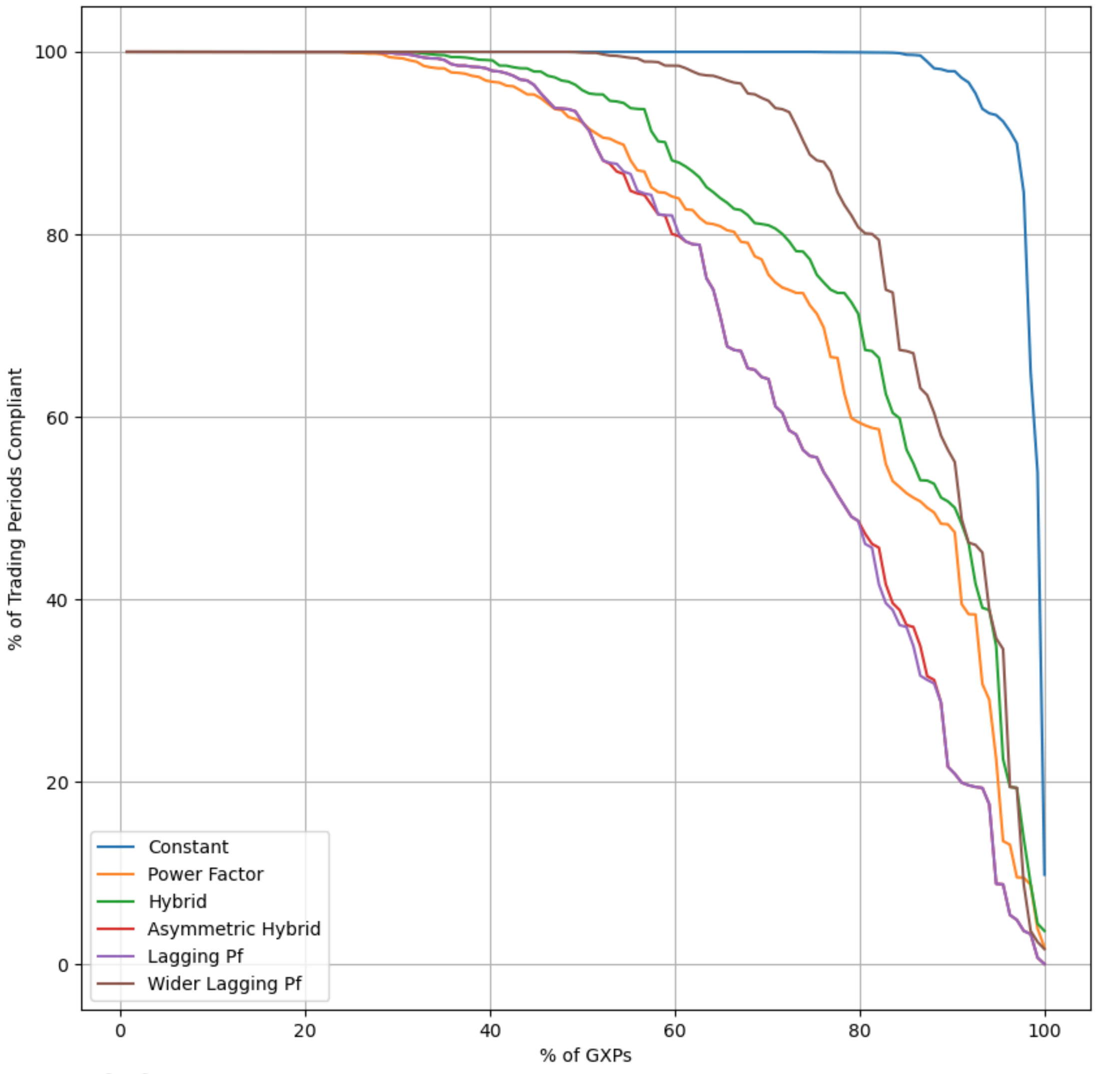
Q2: Power factor limit does not match GXP behaviour, instead allows MVAr export during lighter load (not beneficial).

Q3 and Q4: No data

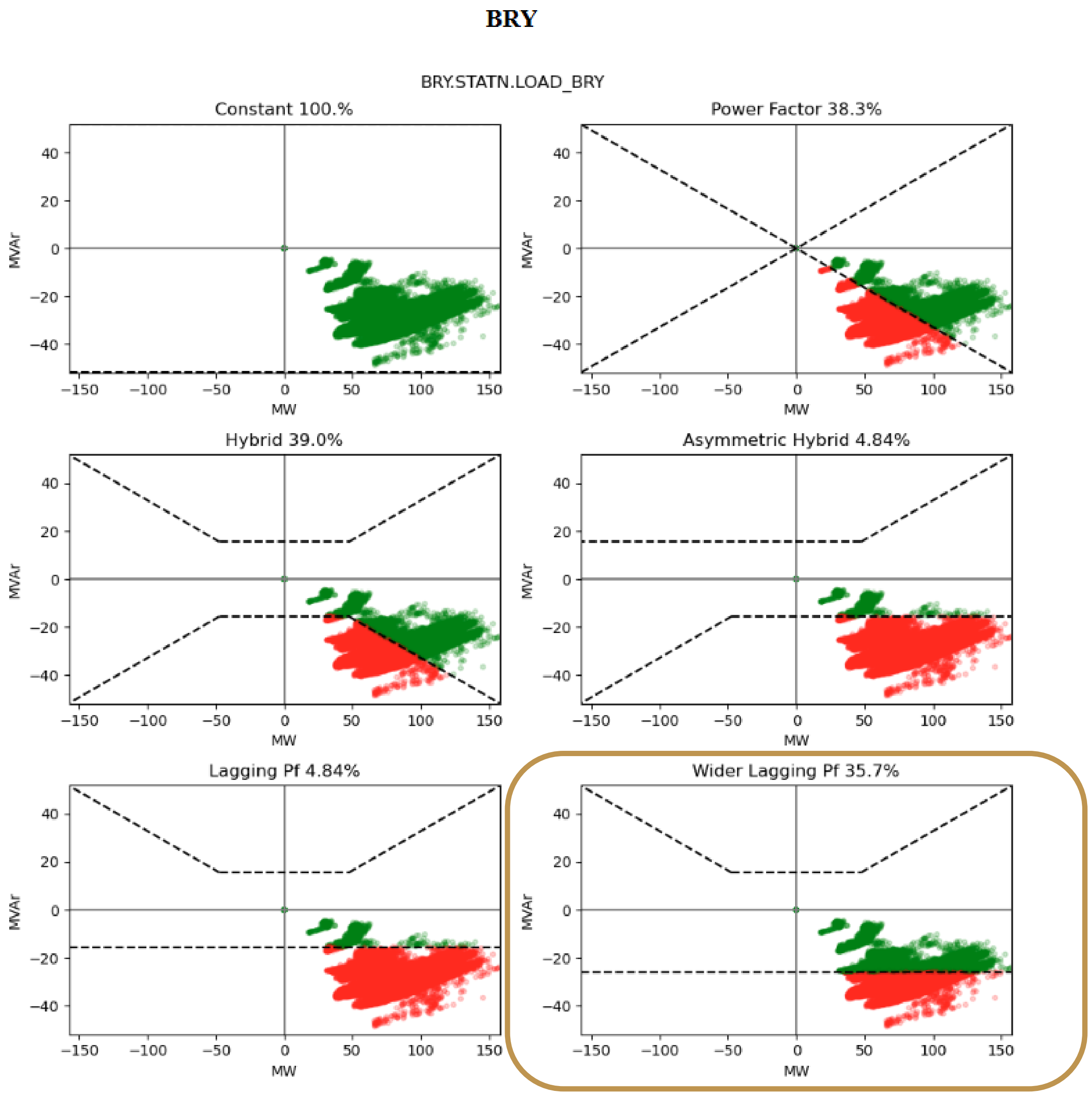




Compliance



% of Trading Periods Compliant
% of GXPs
Constant
Power Factor
Hybrid
Asymmetric Hybrid
Lagging Pf
Wider Lagging Pf



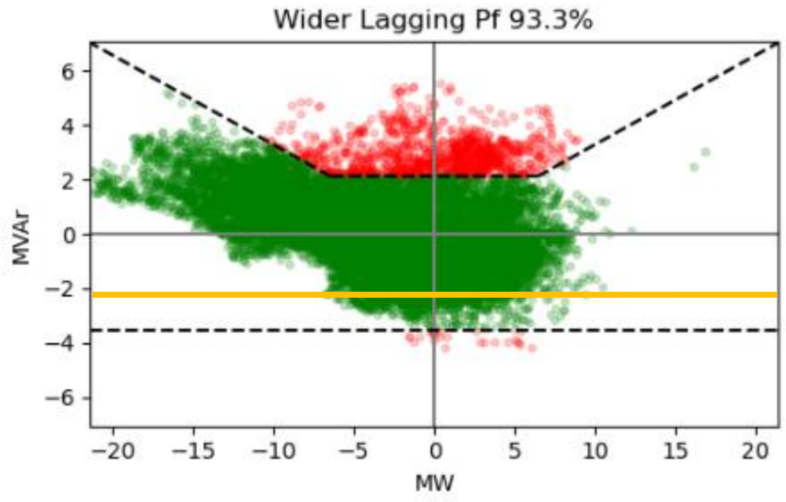
BRY
BRY.STATN.LOAD_BRY
Constant 100.%
Power Factor 38.3%
Hybrid 39.0%
Asymmetric Hybrid 4.84%
Lagging Pf 4.84%
Wider Lagging Pf 35.7%
MVAr
MW

Maximum Effect on UNI/USI Reactive Margin

- Calculated the *maximum* difference between two constant criteria

- Upper North Island: ~82 MVAr for each 10% change in limit.

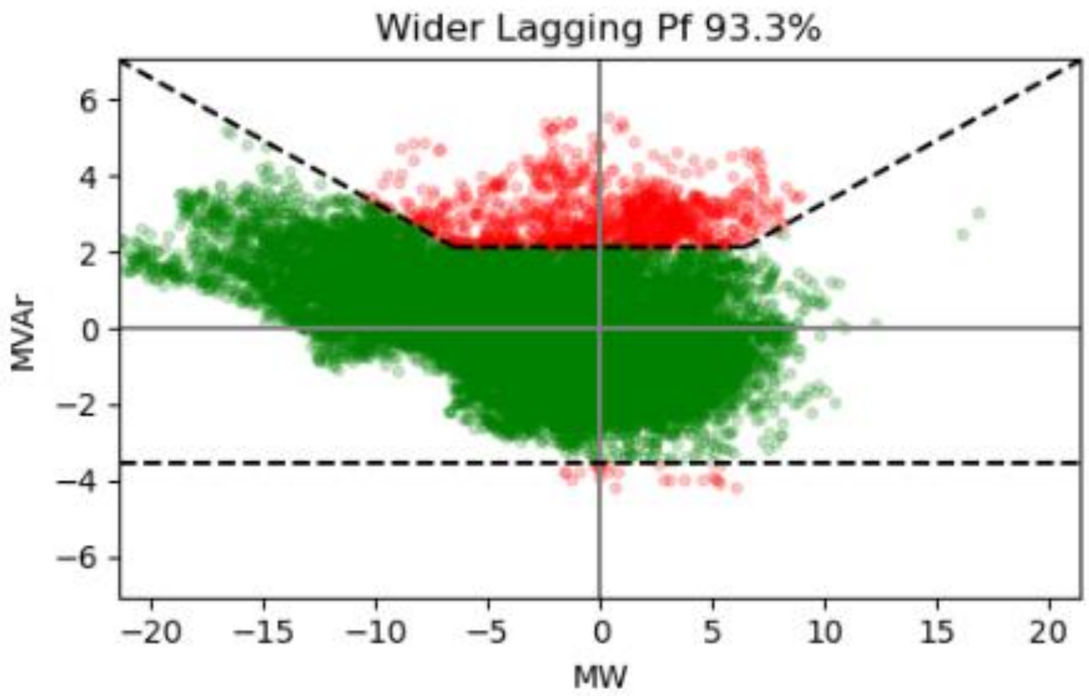
- Upper South Island: ~48 MVAr for each 10% change in limit.



Recommendation

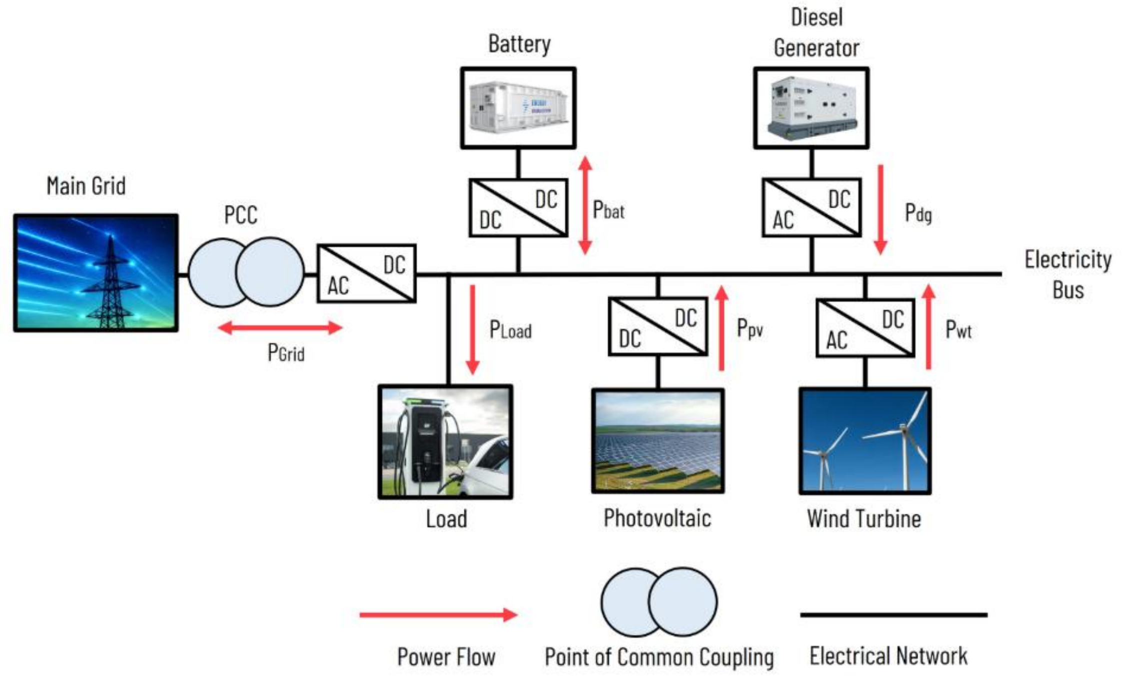
- MVAr import hybrid limit 0.95 Power Factor at 30% of peak load

- MVAr export constant limit 0.95 Power Factor at 50% of peak load



- Monitoring framework and coordination by request

Clause 8.23:
Voltage support AOPOs



Mixed views from submitters on moving point of measurement to (HV) side of connection transformer

FOR

- Aligns with network impacts
- Better reflects modern inverter-based generating stations with dispersed generating units, where reactive power materially altered between unit & network point of connection (eg, losses)
  - Fewer points of compliance for a generating station
  - Provides flexibility around the reactive power provided by different generating units at a station
- Aligns with overseas jurisdictions
- Current obligation is difficult for System Operator to test, model, and monitor

Mixed views from submitters on moving point of measurement to (HV) side of connection transformer

FOR

- Support if—
  - gives System Operator better visibility of service being delivered to transmission grid, and
  - power system benefit > asset owner cost & risk
- But requires further assessment of interaction between reactive power obligations and—
  - generation plant design / generator voltage ratings
  - transformer impedances and tap ranges/settings
  - voltage control philosophies
  - measurement arrangements (eg, some generators have no revenue metering on HV side of connection transformer)
- Need clarity of 'connection transformer' meaning

Mixed views from submitters on moving point of measurement to (HV) side of connection transformer

AGAINST

- No benefit to generators
- Generating unit voltage control is at the unit, not the generating station point of connection
- Avoids need to factor in system losses between generating unit and point of connection
- Connection transformer impedance typically set by fault level requirements on LV busbar, not by generating unit reactive power import/export requirements
- Should instead be reviewing:
  - 50% reactive power export requirement at high (1.10pu) grid voltages
  - 33% reactive power import requirement at low (0.95pu) grid voltages

Percentage contribution

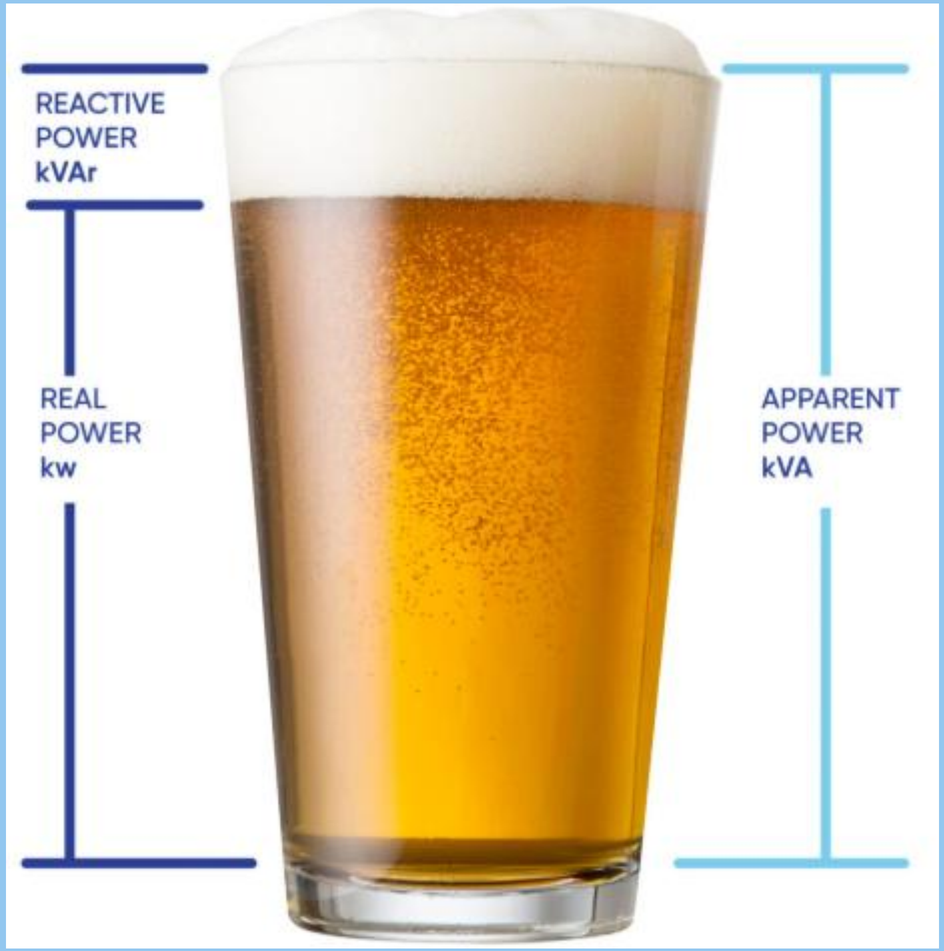
- Insufficient information currently to identify a preferable reactive power import/export requirement
- % contribution should be set at level technically justified to support voltage stability on transmission grid
  - No higher than this
- ±33% below 110kV and ±39.5% at & above 110kV may align capability with benefit
  - But this needs to be supported by System Operator technical analysis
- An alternative = set requirement on a case-by-case basis for generating stations

Transitional arrangements

- Support for some form of exclusion / grandfathering for existing generating assets
  - Reviewing dispensations a material undertaking
- Grandfathering arrangements can be used to maintain existing reactive power import capability
- Have proportionate compliance demonstration requirements for older generating plant
- Need for extensive legacy arrangements may indicate proposed obligations not appropriate for all existing generating plant
- Apply proposed obligations to new generating stations electrically connecting after an agreed date
- Do not entrench a durable advantage for incumbents over new entrants

AFTERNOON TEA

Discussion on proposed issues & options to address reactive power flows and voltage coordination



Why are we discussing this now?

New Zealand's power system is changing rapidly through increasing DER, inverter-based resources, battery storage, EVs and power electronics.

These technologies are changing power factor behaviour, reactive power flows and voltage profiles. While the system continues to operate securely, evidence suggests voltage management is becoming more operationally intensive.

The objective is to understand whether existing technical and regulatory frameworks remain fit for purpose.

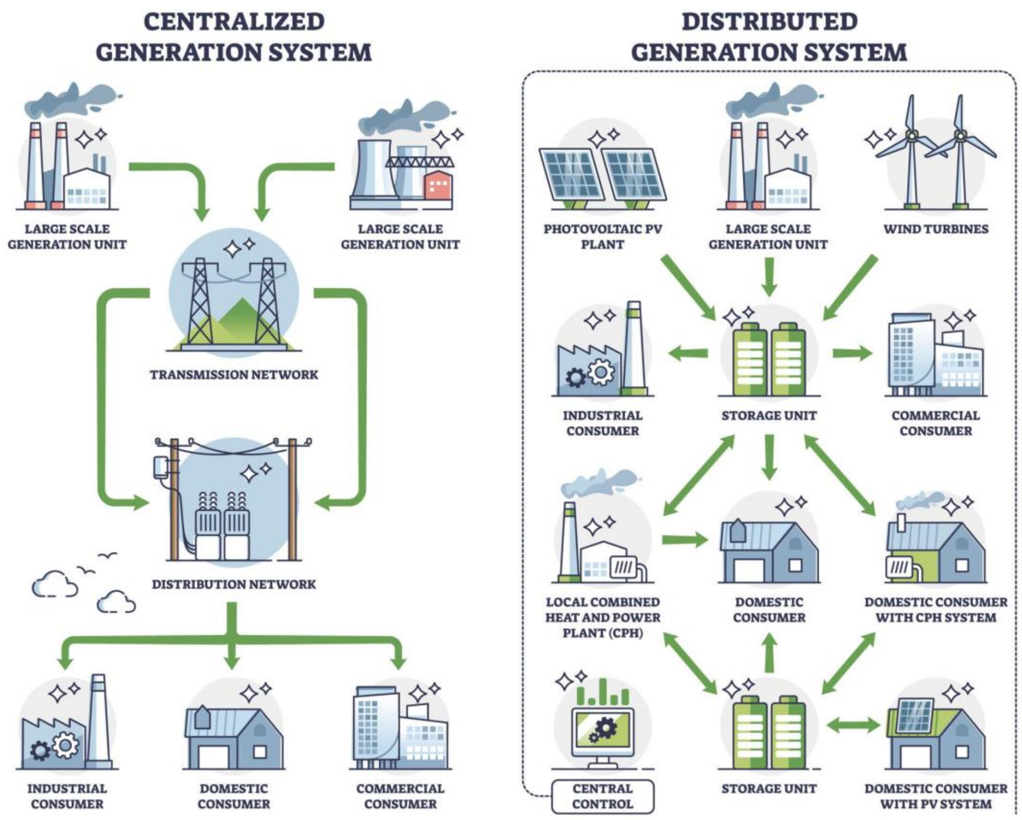
How the power system is changing?

Traditional system:

- Large synchronous generators
- Passive customer loads
- Predictable reactive power flows

Emerging system:

- Distributed generation and batteries
- Smart inverters and flexible demand
- Millions of devices capable of influencing voltage



The emerging technical issue

Historically:

- Reactive power generally flowed from transmission to customer loads.
- Voltage management focused on peak demand.

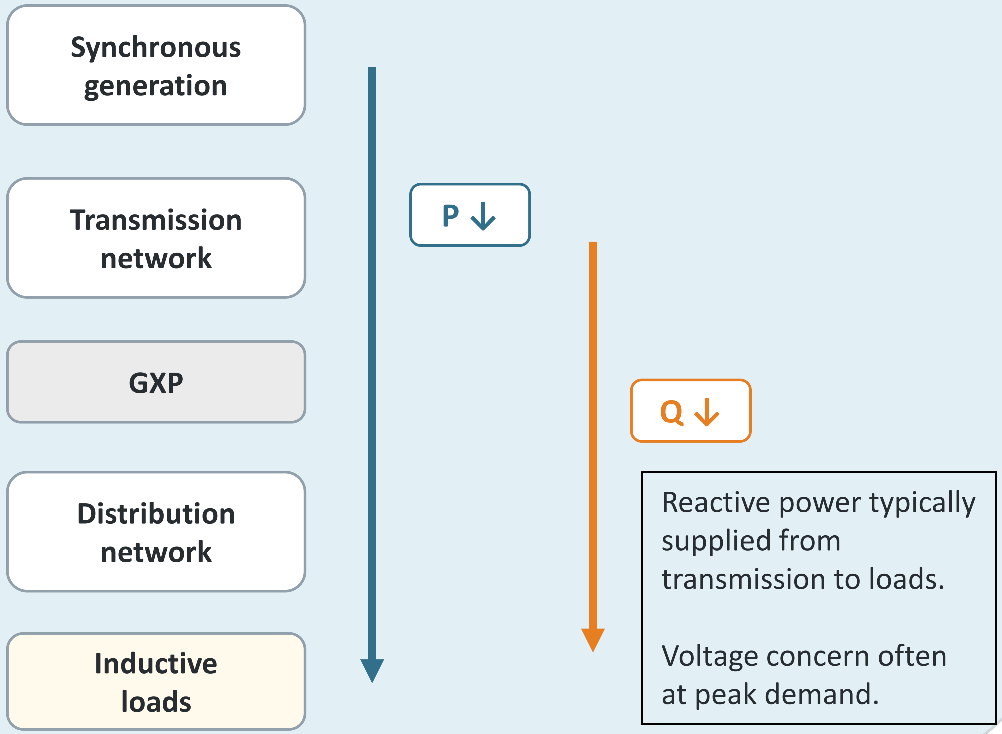
Emerging observations:

- Overnight leading power factors.
- Reactive power exported from some distribution networks.
- Greater operational intervention to manage voltage.

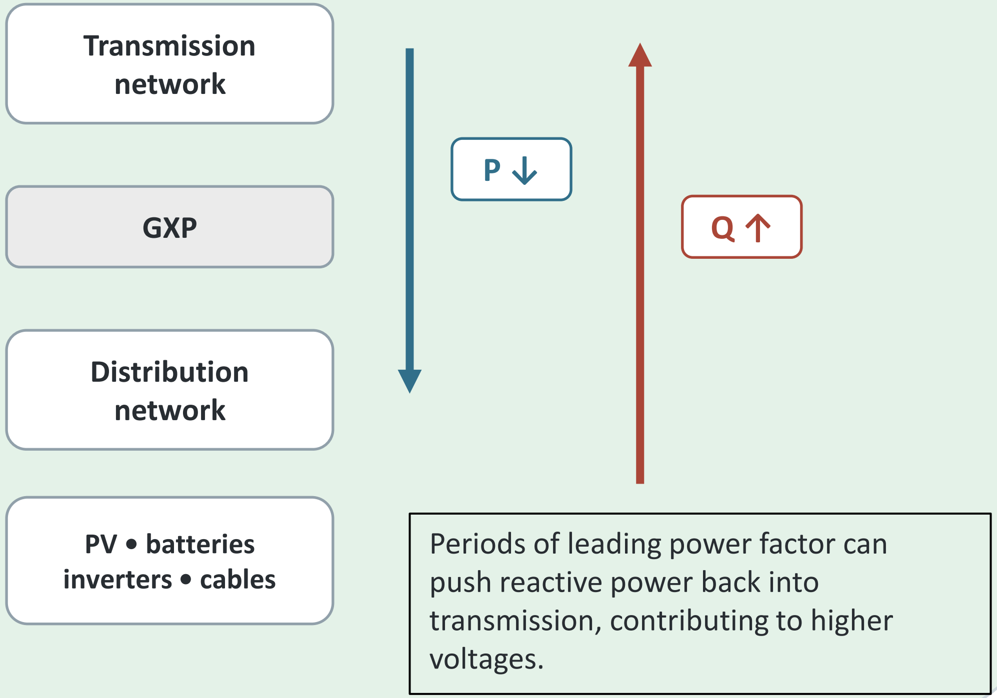
The emerging technical issue

Reactive power flows are becoming less predictable — and in some conditions may reverse at the GXP.

Historically: lagging demand



Emerging trend: leading / capacitive conditions



CQTG input sought: Does this framing reflect the emerging issue, and what evidence or examples should be added?

Why does this matter?

Potential implications include:

- Increased operational complexity.
- Greater transmission/distribution coordination.
- Future voltage stability considerations.
- Possible investment and market impacts.
- Need to review technical obligations.

This work is intended to be proactive rather than a response to a current reliability issue.

What is International Experience Telling Us?

Voltage management and reactive power are becoming strategic issues in power systems around the world

The transition to inverter-based resources, distributed energy resources (DER) and changing demand patterns is challenging traditional approaches to voltage management. While the specific circumstances differ between jurisdictions, there are several consistent themes emerging.

International experience	What have we learnt?	Questions for New Zealand
Spain (2025 system event)	Post-event investigations identified voltage management and reactive power as significant contributors to system performance during a major disturbance.	Are our current voltage support arrangements sufficient as the generation mix changes?
North Macedonia (ENTSO-E investigation)	The investigation highlighted the importance of reactive power capability, voltage control and coordination between network operators.	Do we have adequate coordination between transmission and distribution networks?
Australia (AEMO)	High rooftop PV penetration is changing midday and low-load voltage conditions. Networks are increasingly relying on inverter Volt-VAr and Volt-Watt functions to manage voltage.	How will increasing DER participation influence reactive power flows and voltage behaviour in New Zealand?
United Kingdom (National Grid ESO)	As synchronous generation retires, new market arrangements are being developed to procure dynamic reactive power and voltage support services.	Will future reactive power requirements require new procurement or market mechanisms?
Europe (ENTSO-E Future System Operation)	Future system studies emphasise the need for stronger voltage control frameworks, enhanced reactive power capability and improved system visibility.	Are existing technical standards and Code requirements still fit for purpose?

Common international themes

Across these studies, several common themes are emerging:

- Increasing operational effort is required to manage voltage.
- Reactive power is becoming more dynamic and less predictable.
- Distribution-connected resources are having a greater influence on transmission system operation.
- Traditional sources of reactive power are reducing as synchronous generation is displaced.
- Greater coordination, visibility and new technical requirements are being considered internationally.

Developing evidence

Emerging evidence includes:

- Changing GXP power factor trends.
- PV inverter voltage control studies.
- Operational observations from the System Operator.
- Distribution network experience.

Further technical evidence is still being gathered before developing policy options.

What is the problem statement?

The current regulatory framework was largely developed assuming:

- Lagging power factors.
- Predictable reactive power flows.
- Strong synchronous generation.

We need to determine whether those assumptions remain valid and whether changes are required.

Proposed work programme

Developing an evidence-based pathway for future voltage management and reactive power policy

Objective

The objective of this work programme is to determine whether New Zealand's existing technical and regulatory frameworks remain fit for purpose as the power system evolves, and if not, identify practical and proportionate options for future consultation.

The programme is intended to be evidence-based, collaborative and technology-neutral. It does not assume that regulatory change is required. Instead, it seeks to understand the emerging issues, evaluate potential responses and determine whether changes are justified.

Proposed approach

Emerging Issues

↓

Problem Definition

↓

Technical Evidence

↓

Develop & Assess Options

↓

Issues & Options Paper

↓

EA Board

(February 2027)

Proposed Work Programme cont.

Stage	Purpose	Key Outputs
1. Define the Problem	Confirm the scope of the work, understand the emerging issues and agree the key technical questions requiring further investigation.	Agreed problem statement and scope.
2. Gather Evidence	Analyse operational experience, technical studies, international developments and future system trends to establish a robust evidence base.	Technical evidence and identification of knowledge gaps.
3. Develop and Assess Options	Investigate potential near-term improvements and longer-term policy options. Assess each option against technical, economic and regulatory criteria.	Shortlisted options with preliminary assessment.
4. Prepare Issues & Options Paper	Develop a balanced consultation paper that clearly explains the issues, supporting evidence and potential options.	Draft consultation paper for review.
5. Board Consideration	Seek approval to undertake public consultation on the proposed Issues & Options Paper.	Board-approved consultation (subject to approval).

Indicative timing

Timing	Activity
Aug – Sep 2026	Define problem and confirm scope
Sep – Oct 2026	Technical analysis and evidence gathering
Oct – Nov 2026	Develop and assess options
Nov – Dec 2026	Draft Issues & Options Paper
Jan – Feb 2027	Internal review and EA Board consideration

Key dependencies

- Ongoing engagement with the Common Quality Technical Group (CQTG)
- Input from Transpower, distributors, generators and technical experts
- Consideration of international experience and emerging research
- Coordination with other Future Security and Resilience workstreams

Potential Near-Term Improvements

Technical and regulatory refinements that could improve the existing framework without requiring major policy redesign

Several issues have been identified where relatively small amendments may improve clarity, remove unintended barriers, or better align the Code with current operational practice. These changes could potentially be progressed independently of the broader review if supported by further analysis and consultation

Potential Improvement	Why is it being considered?	Discussion with CQTG
Update the definition of "Voltage Support"	The current definition primarily reflects reactive power injection and may not adequately recognise reactive power absorption, which is becoming increasingly important during low-demand periods.	Does the existing definition remain fit for purpose?
Review cost recovery provisions (Clause 8.67)	Existing charging arrangements were developed around historical operating conditions and may not fully reflect periods when voltage support is required overnight.	Should the charging framework better align with future operational requirements?
Review TPM treatment of voltage support assets	Current arrangements may not provide efficient cost signals where network investment is driven by local voltage management requirements.	Are there opportunities to improve cost allocation while maintaining fairness?
Improve terminology and internal consistency	Some Code terminology no longer reflects current operational practice following recent amendments.	Are there additional drafting improvements that should be considered?

Potential Longer-Term Workstreams

Understanding whether New Zealand's voltage management framework remains fit for purpose as the power system evolves

These workstreams are intended to inform the Issues and Options Paper and explore whether changes to technical requirements, operational arrangements or regulatory settings may be needed over the longer term.

Workstream	Why is it important?	Key Questions
Reactive Power Capability	Traditional synchronous generation is reducing while inverter-based resources are increasing. Future reactive power capability requirements may need to evolve.	Should minimum reactive capability be required from more connected parties?
Voltage Support Framework	Voltage support obligations have historically focused on maintaining voltage during periods of high demand. Future operating conditions may require greater emphasis on low-load and leading power factor conditions.	Do existing obligations remain appropriate?
Transmission–Distribution Coordination	Distribution-connected DER is increasingly influencing transmission network voltage and reactive power flows.	Are clearer responsibilities and coordination arrangements required between Transpower and distributors?
Visibility, Monitoring and Information	Effective voltage management increasingly relies on visibility of DER capability, inverter settings and network conditions.	What additional monitoring or data sharing may be required?
Future Technical Standards	Existing connection requirements were developed for a different power system.	Should technical standards evolve to reflect increasing inverter-based resources?
Economic and Market Mechanisms	Future reactive power services may be delivered by a broader range of technologies, including distributed resources.	Are existing procurement and pricing arrangements likely to remain efficient?

How will we assess potential options?

Evaluation Criteria

Criterion	Question
Technical effectiveness	Will it improve voltage management and system operability?
Future proof	Will it remain suitable as DER and inverter-based resources increase?
Proportionate	Does the benefit justify the cost and implementation effort?
Technology neutral	Does it avoid favouring particular technologies or solutions?
Efficient	Does it support efficient investment and operation?
Deliverable	Can it be implemented within existing industry frameworks?

Discussion questions

1. Have we correctly defined the problem?
2. Have we identified the right workstreams?
3. What evidence is still required?
4. Should quick wins be separated?
5. Are there additional issues the Authority should investigate?

Next steps

- **August–October:** Technical engagement and evidence.
- **November–December:** Draft Issues & Options paper.
- **January 2027:** Internal review.
- **February 2027:** EA Board.

Seek CQTG agreement on the proposed direction and priorities.

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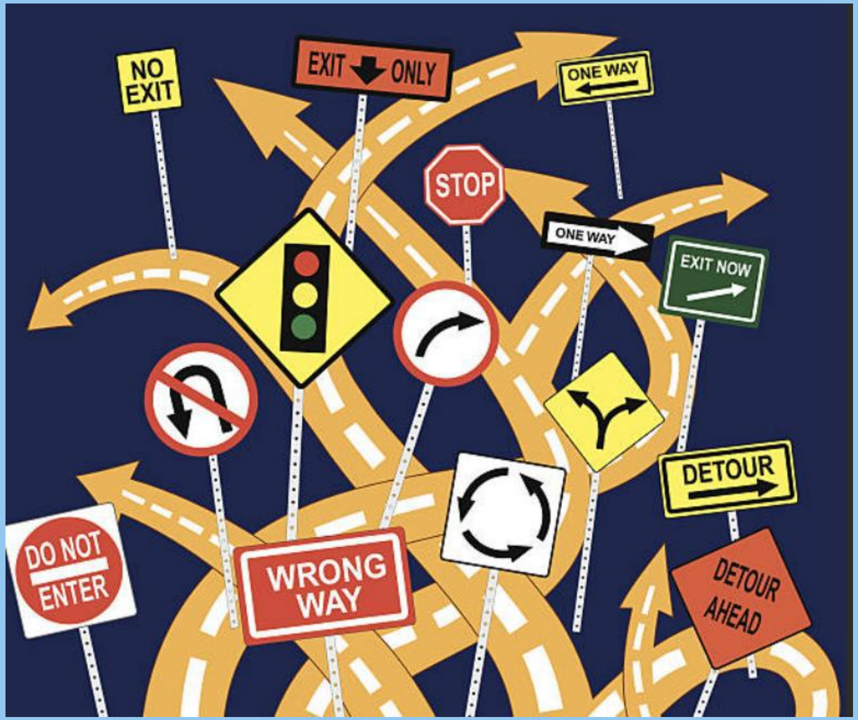
STUART JOHNSTON
stuart.johnston@ea.govt.nz

Update on draft of revised FSR roadmap

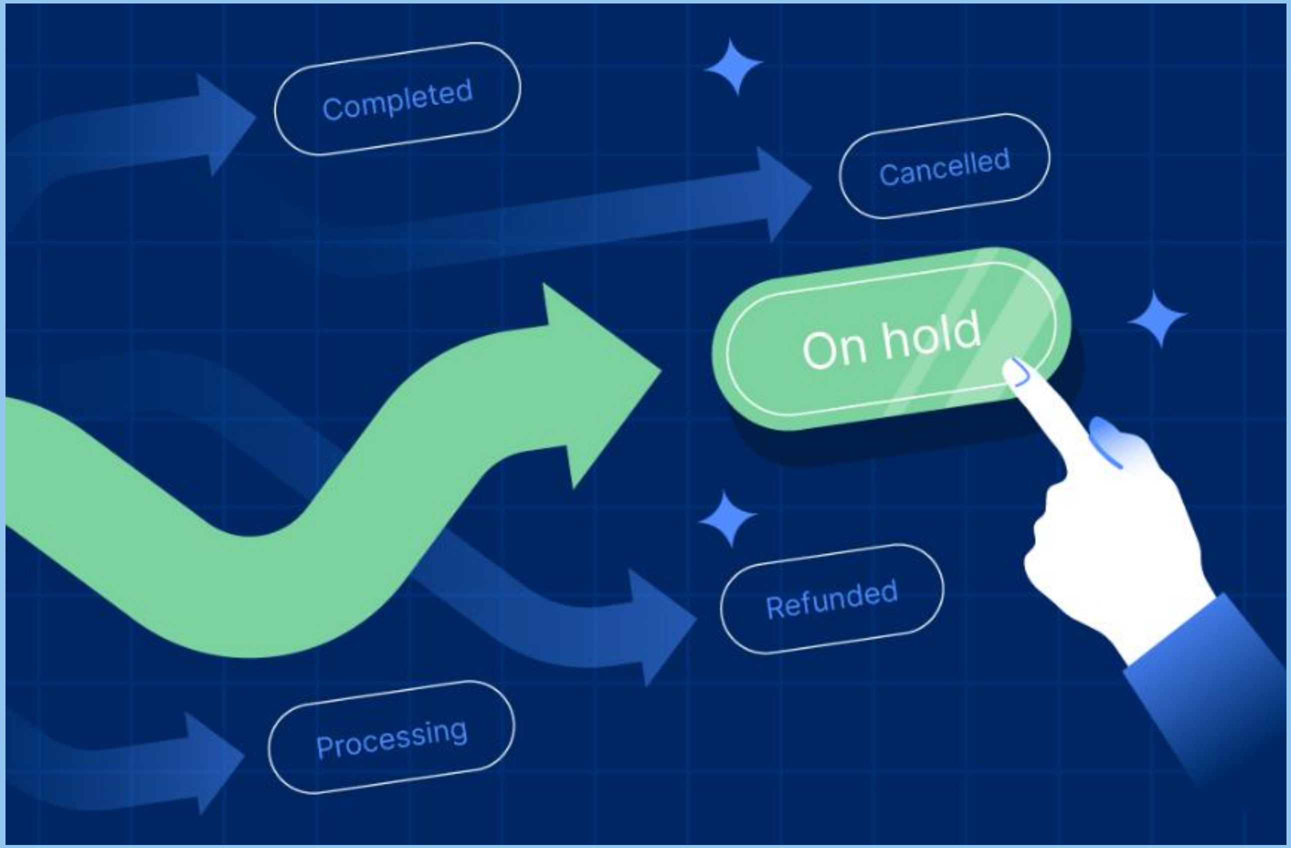


Opportunity or challenge		Activity	Organisation	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Accommodating future changes within technical requirements	7.1	Review and update Part 8 of the Code	Electricity Authority, System Operator										
	7.2	Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8											
	7.3	Identify standards to support technical requirements in the Code											
	7.4	Update the Policy Statement to manage emerging risks											
	7.5	Update the System Operator's policies, procedures, guidelines and tools											
Coordination of increased connections	3.1	Update Grid Owner and System Operator commissioning processes and Default Transmission Agreement	Electricity Authority, System Operator										
	3.2	Review the approach to planning connection studies											
	3.3	Review operational study tools											
Operating with low system strength	6.1	Investigate system strength challenges and opportunities	Electricity Authority										
	6.2	Amend the Code to support performance criteria											
	6.3	Develop suitable market products and tools											
Enabling DER services for efficient power system operations	1.1	Enhance the Code and market system dispatch capability to accommodate DER bids and offers	Electricity Authority, System Operator										
	1.2	Improve real-time security modelling within operational tools											
	1.3	Investigate new DER services to support efficient operation of the power system											

Opportunity or challenge	Activity		Organisation	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
Visibility and observability of DER	2.1	Establish the impact of DER	Electricity Authority, System Operator										
	2.2	Determine the credible event risk of DER											
	2.3	Update the Code to clarify DER obligations and operational requirements											
	2.4	Update procedures and tools to include DER asset information											
Balancing renewable generation	4.1	Improve market system and generation/demand forecast	Electricity Authority										
	4.2	Consider new or revised ancillary services to maintain balancing											
Managing reducing system inertia	5.1	Create a frequency reserve strategy to manage low inertia	Electricity Authority, System Operator										
	5.2	Ensure the Code defines and market system can accommodate new reserve types											
	5.3	Incorporate new reserve types in the Procurement Plan and testing methodology											
	5.4	Update operational procedures and tools											

Opportunity or challenge	Activity		Organisation	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
Leveraging new technology to enhance ancillary services	8.1	Investigate changes to ancillary services	Electricity Authority, System Operator										
	8.2	Ensure tools monitor the performance of the power system											
	8.3	Update the Code, market system and Procurement Plan to enable new technology to provide ancillary services											
Maintaining cyber security	9.0	Continually review and update cyber security measures	New Zealand energy sector										
Growing skills and capabilities of the workforce	10.0	Encourage and train the workforce's next generation	New Zealand energy sector, educational institutions, professional associations										
Future System Operations	11.1	Design and delivery of one or more DSOs	Electricity Authority, Transmission System Operator (TSO), Energy Networks Aotearoa (ENA), EECA, distributors, flexibility services providers (FSPs), Commerce Commission										
	11.2	Driving efficiencies	Electricity Authority, TSO, ENA, EECA, MBIE, distributors, FSPs, Commerce Commission, DPMC, EEA										
	11.3	Accelerating flexibility	Electricity Authority, TSO, ENA, EECA, distributors, retailers, FSPs, Commerce Commission, Flex Forum, MBIE										
	11.4	Distribution network connection and pricing	Electricity Authority, ENA, EECA, Electricity Engineers Association, distributors, retailers, Commerce Commission										
	11.5	Prioritising consumers	Electricity Authority, TSO, ENA, EECA, distributors, FSPs,										

FSR holding pen



Holding pen: Status – “Active” related to frequency (Issue 1*)

Option	Comment
Lower the minimum frequency keeping threshold below 4MW and have a national market for frequency keeping.	• In 26/27 work plan. • Project: ***Frequency strategy.*** • Issues/Options paper to Dec 26 Board.
Allocate frequency keeping costs to the causers of frequency deviations.	
Put in place ramping limits on generation plant and load for post-disturbance or change-of-MW output (eg, due to wind gusts or cloud covering).	
Resources (e.g. generating stations, battery energy storage systems) must make available X% of maximum rated capacity to support frequency in under-frequency events.	
Establish a new ancillary service market product for 1 second reserve.	
Establish a new ancillary service contract for inertia (accommodating both synchronous and synthetic inertia).	
Widen the normal band, since electrical appliances can operate within a frequency range that is wider than 50Hz ± 0.2Hz.	
Increase, from 45Hz to 47Hz, the minimum frequency at which South Island generation assets must remain synchronised for 30 seconds following an under-frequency event.	
Review the dispensation and equivalence arrangements framework (for frequency obligations).	• In 26/27 work plan. • Project: ***Review of dispensation & equivalence arrangements.*** • Issues/Options paper to May 27 Board.

* See Addressing more frequency variability in New Zealand’s power system- Appendix A

Holding pen: Status – “Complete” related to frequency (Issue 1)

Option	Comment
Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code.	Complete. May 2025 – Frequency Code amendments
Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.	
Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.	
Remove the obligation on the system operator to eliminate from the power system any deviations from New Zealand standard time caused by variability in system frequency.	Complete. May 2025 - Part 8 omnibus

Status – “Removed” of items related to frequency (Issue 1)

Option	Comment
Require / incentivise improved forecasting by generators. (Refer to MDAG’s options paper for price discovery in a renewables-based electricity system, and the Authority’s issues and options paper on a review of forecasting provisions for intermittent generators in the spot market.)	Out of scope. Part of the Authority’s review of forecasting provisions for intermittent generators in the wholesale electricity spot market.

Holding pen: Status – "Active" related to voltage (Issues 2, 3 & 4*)

Option	Comment
Manage the import and export of reactive power at a GXP (eg, by revising the GXP power factors distributors must maintain, as specified in the Connection Code).	• In 26/27 work plan. • Project: ***Reactive power flows.*** • Issues/Options paper to Feb 27 Board.
Establish a new ancillary service contract for reactive power management.	
Consider a standard for generation assets to ride through multiple faults in quick succession (within several minutes). For example, in Australia the recommended capability is 1.8 per unit seconds (ie, a generator can dissipate full power output for 1.8 seconds). If a system fault is typically cleared in 200 milliseconds, then a generator would tolerate approximately 9 successive bolted faults, before the power dissipation capability would be exceeded.	• In 26/27 work plan. • Project: ***System strength.*** • Issues/Options paper to June 27 Board.
Establish a new ancillary service contract for system strength.	

Impose greater obligations on distributors and the system operator to maintain certain voltage ranges / system strength at GXPs/GIPs.	• In 26/27 work plan.
	• Projects:
	  • ***1. Reactive power flows.***
	  • ***2. System strength.***
	• Issues/Options paper to:
	  • 1. Feb 27 Board.
	  • 2. June 27 Board.

Review the dispensation and equivalence arrangements framework (for voltage obligations).	• In 26/27 work plan. • Project: ***Review of dispensation & equivalence arrangements.*** • Issues/Options paper to May 27 Board.

* See Addressing larger voltage deviations and network performance issues in New Zealand's power system – Appendix A

Holding pen: Status – "Complete" related to voltage (Issues 2, 3 & 4)

Option	Comment
Assign voltage support obligations to some additional parties (eg, some distributed generation and energy storage systems).	May 2025 – Voltage Code amendments.
Lower the 30MW threshold for generating stations to be excluded by default from complying with the fault ride through AOPOs in clauses 8.25A and 8.25B of the Code.	May 2025 – Voltage Code amendments.

Holding pen: Status – "Pending" related to voltage (Issues 2, 3 & 4)

Option	Comment
Require alignment of voltage-related connection standards across distribution networks.	TBC – Network connections project (model connection and operation standards).
Revise or remove the fault ride through envelope specified in Part 8 of the Code.	Consider including a review of the fault ride through envelopes in the FSR team's 27/28 work plan.

Holding pen: Status – "Removed" related to voltage (Issues 2, 3 & 4)

Option	Comment
Widen the voltage ranges for which distribution-connected assets must be capable of being operated.	Implemented via 13 June 2025 Government announcement.

Holding pen: Status – "Pending" related to Code terminology (Issue 7)

Option	Comment
NEW, ie, not in the published list of options on hold: Definitions: • Generating unit • Generating system • Generating station • Grid • Connected to the grid • Point of connection • Point of compliance • Synchronised	Not currently scheduled in a specific work plan. However, some of the definitions will be considered by current projects, ex, hybrids

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