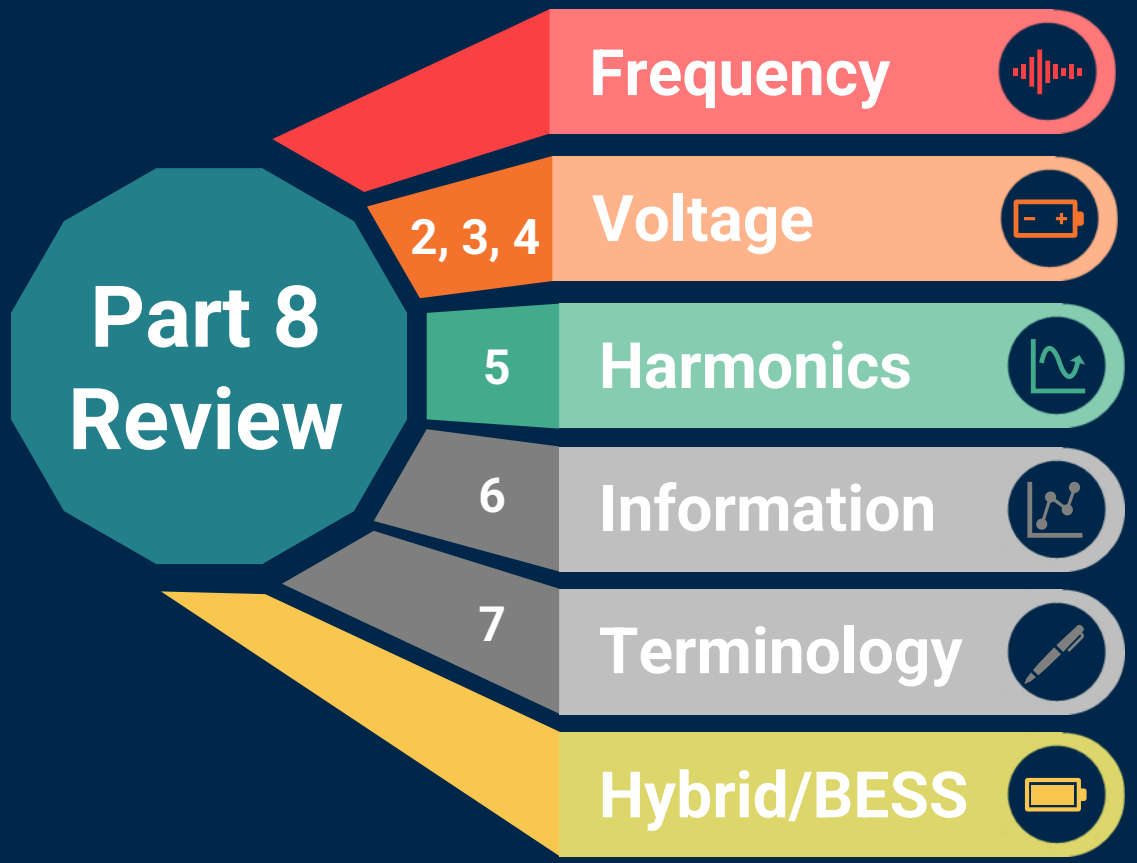
Future Security and Resilience: Common Quality Technical Group (FSR CQTG)



Meeting 18: 15 October 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Purpose

Discuss and provide feedback on topics in the agenda

Agenda

Time	Item
9:00 am	Welcome
9:05 am	Minutes from meeting #17
9:15 am	Reactive power flows/voltage coordination
10:15 am	Morning tea
10:30 am	Frequency management strategy update
11:45 am	SO update on fast frequency response studies
12:30 pm	Lunch
1:00 pm	BESS/Hybrids: AOPOs
1:45 pm	SO update on system strength studies
2.30 pm	Afternoon tea
2:45 pm	Information requirements Stage 2 consultation
3.45 pm	AOB
4.00 pm	End of meeting

Minutes and actions



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.

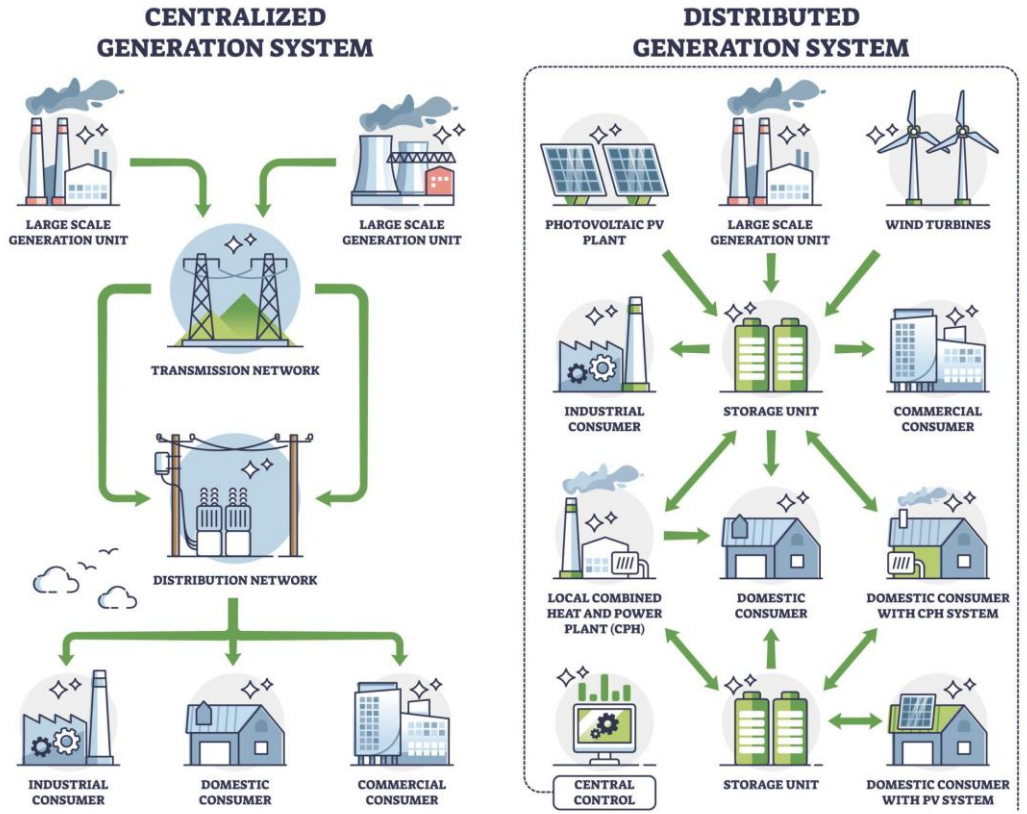
How the power system is changing?

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.

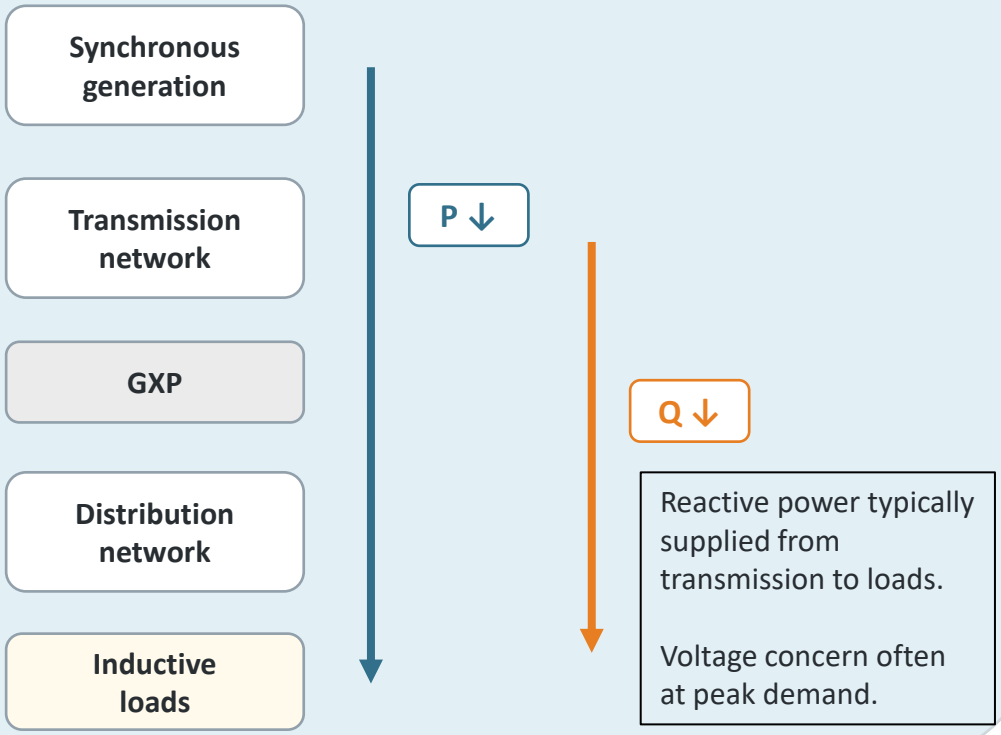
Emerging observations:

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

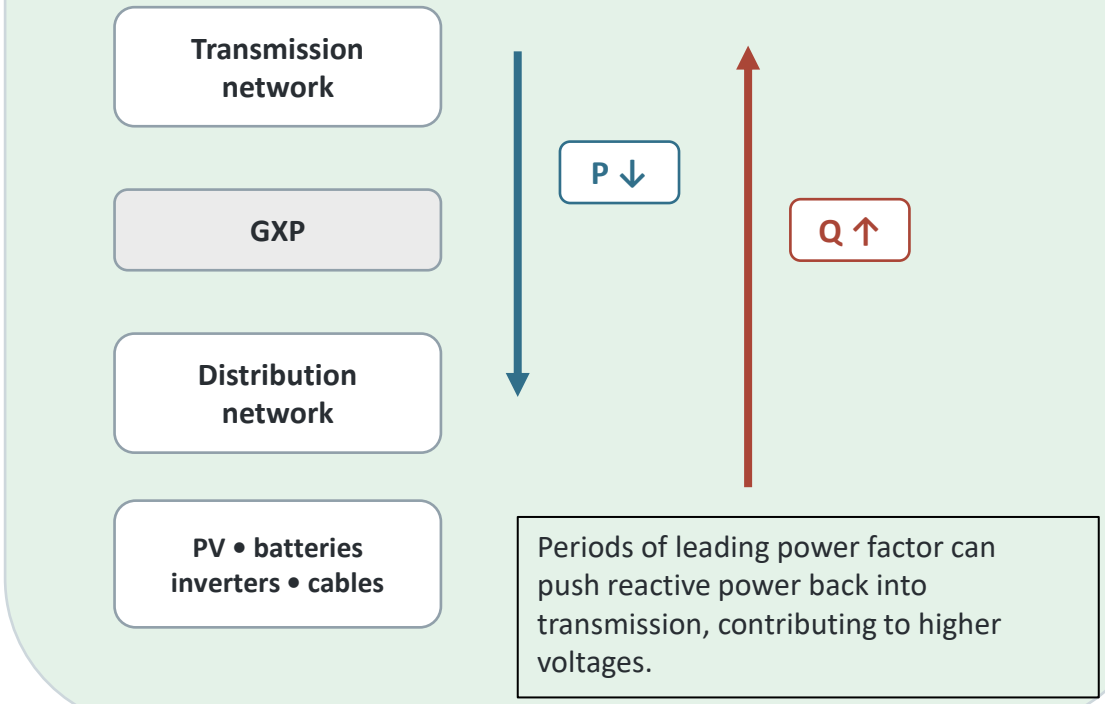
The emerging technical issue

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.

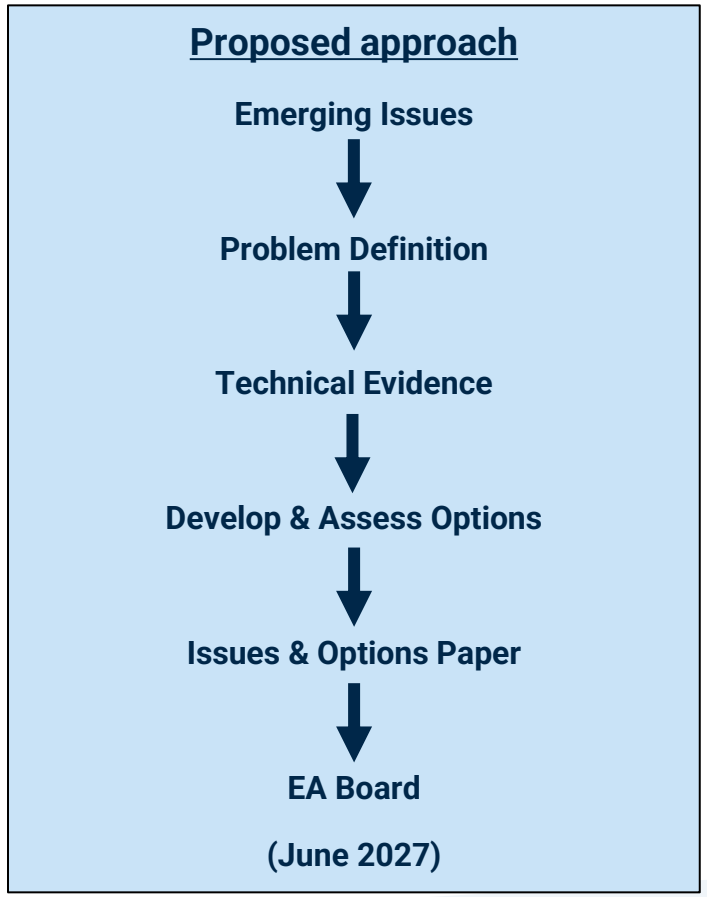
Proposed work programme

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 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 26 – Mar 2027	Draft Issues & Options Paper
Apr – June 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?**

Quick(er) wins – potential early improvements

Possible targeted changes that could progress separately from the broader review, subject to evidence and consultation

Voltage support definition	Test whether reactive power absorption is adequately recognised.
Clause 8.67 – cost recovery	Clarify whether existing provisions remain appropriate for low-demand and overnight voltage support.
TPM / voltage-support assets	Identify specific allocation or treatment issues and whether these can be resolved independently.
Code terminology and consistency	Correct outdated terminology, cross-references or inconsistencies where justified.

CQTG input sought: Which are genuinely low-complexity, high-value changes? What evidence, dependencies or risks should we consider?

Next steps

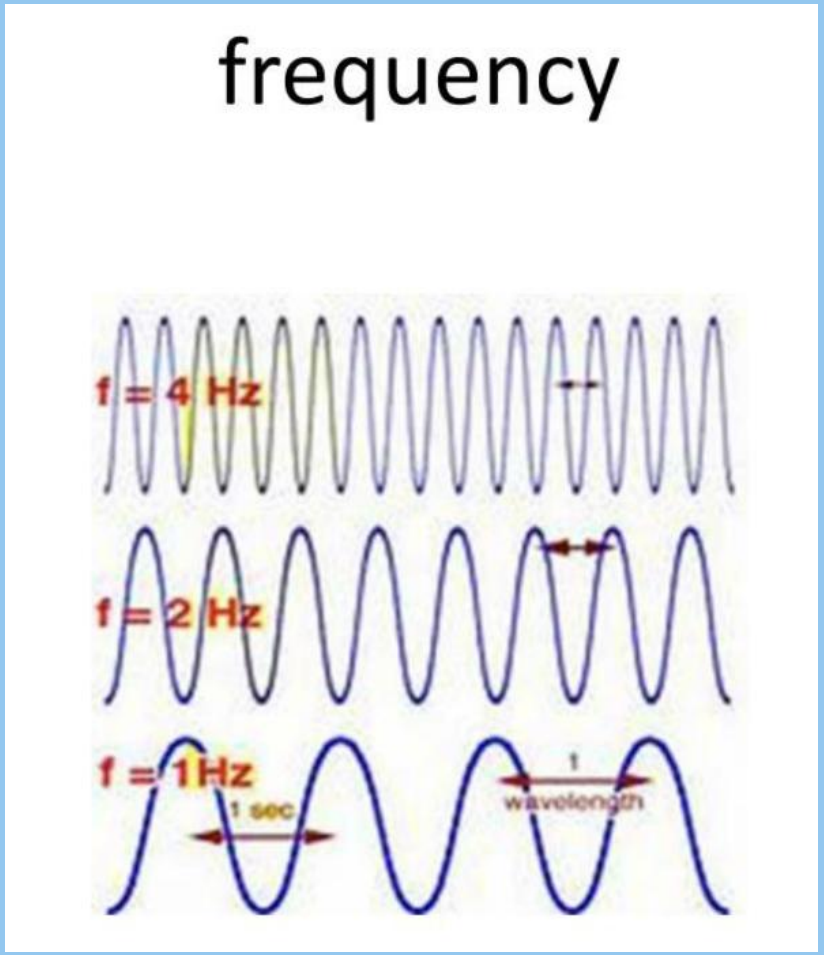
- **August–October:** Technical engagement and evidence.
- **June 2027:** Authority Board.

Seek CQTG agreement on the proposed direction and priorities.

MORNING TEA



Frequency management strategy: Update on issues and options workstream



Context

2022 FSR roadmap

- *Create a frequency reserve strategy to manage low inertia*

Draft updated FSR roadmap

- *Create a frequency management strategy*
  - *Considers both frequency regulation & frequency reserve (ie, contingency management)*

Work undertaken/underway

- *2024–2025:*
  - System Operator studies to determine minimum system inertia threshold for stability of New Zealand power system frequency
- *2025–2026*
  - Current performance of multiple provider frequency keeping (MFK)
  - System Operator studies to determine potential need date for one or more options to manage low inertia conditions on the power system
- *2026–2027*
  - System Operator studies on effectiveness of fast frequency response
  - Authority consultation on frequency management strategy
  - HVDC link owner considering future capability of upgraded HVDC link control system

Purpose of frequency management strategy

Set a clear direction for the evolution of frequency management to 2035 as New Zealand's economy electrifies and new and evolving technologies connect to New Zealand's power system

Frequency management – Overarching objective

To deliver stable frequency of an acceptable quality to consumers at the lowest cost

(Long-term objective of the Authority's 2014–2018 investigation into normal frequency management)

(Noting that the elaboration of the principal performance s (PPOs) and dispatch objective in the Code is currently insufficient to describe this objective – because an acceptable frequency quality is not specified)

ISSUES IDENTIFICATION

Six key frequency management issues identified

Six key frequency management issues identified, relating to:

1. **Appropriate incentives for transmission network investments** that materially affect power system operation
2. **Falling power system inertia** – impacts frequency regulation in the normal band & contingency management
3. **More frequent & bigger frequency variations** – inside & outside the normal band
4. **Effective/efficient procurement of frequency management services** – from primary frequency response (PFR) to dispatch
5. **Appropriate incentives to minimise power system needs / costs** – particularly the allocation of frequency ancillary service costs, and trading conduct provisions
6. **South Island frequency range of 45–55 Hz is wider than many other jurisdictions** – this may be limiting investment in some technologies

1. Appropriate incentives for transmission network investments

1A. The HVDC link control system is planned to be replaced

This control system has a significant effect on managing power system frequency

- Frequency keeping modulation control (FKC) enables sharing between North Island & South Island of:
  - MFK
  - Single frequency keeping (SFK)
  - Instantaneous reserve (forward & reverse)
  - Diversity of load & intermittent generation (reduces frequency keeping)

1B. Frequency management may not be considered when AC transmission network investments are made

- Eg, selection of STATCOMs over synchronous condensers means less available system inertia

2. Falling power system inertia

Power system inertia is falling due to less machine-based synchronous generation being dispatched relative to total dispatched generation

This increases the rate of change of frequency (RoCoF) on the power system

Following a large enough contingency on the power system, frequency could fall to the specified minimum faster than the time it takes for AUFLS relays to operate (leading to system collapse)

3. More frequent & bigger frequency variations

An increasing amount of variable & intermittent resources, primarily in the form of wind & solar photovoltaic (PV) generation but also certain large loads, is likely to cause more real-time / near real-time variability in frequency* which is likely to be exacerbated over time by decreasing system inertia

** In other words, the 'quality' of frequency is likely to deteriorate – inside & outside the normal band*

The mitigations for variability from the supply-side are likely to be different to those from the demand-side. Large proportions of online variable and intermittent IBR provide good automatic down regulation, but up regulation is more costly

4. Effective/efficient procurement of frequency management services

MFK does not manage frequency in real time

- Because speed of response of generator governors / frequency control systems & FKC is faster than speed of MFK controls

A potentially fast responding MFK provider has no incentive to actually implement a fast(er) response

MFK responds continuously within the timeframe between fast governor / frequency control system response & real-time energy dispatch – allowing governors to return to dispatch setpoints

Questions to consider

1. Would a real-time frequency regulation ancillary service be more economically efficient than relying on generator governors / frequency control systems?
2. Can frequency management services to manage the gap between PFR & dispatch be delivered more efficiently?

5. Appropriate incentives to minimise power system needs / costs

Arrangements should incentivise participants to minimise their impact – reducing need for system services to compensate

Examples:

- All frequency keeping costs are currently paid by purchasers even though variable & intermittent generation is contributing to more variability of frequency within the normal band
- All over-frequency reserve costs are currently paid by the HVDC link owner but some large loads have the potential to cause over-frequency deviations
- Generators may not be adequately incentivised to meet & adhere to dispatch setpoints
- Intermittent generation may have too much flexibility to deviate from dispatch

6. South Island frequency range of 45–55 Hz is wider than many other jurisdictions

Code obligations may be limiting generation investment in the South Island

Clause 1.1(1) of the Code:

- maximum South Island frequency is 55 Hz *

Clause 8.19(3) of the Code:

- South Island generation, other than excluded generating stations, must remain synchronised & sustain pre-event output for 30 secs if frequency falls below 47 Hz but not below 45 Hz**

South Island distribution network assets may not enable South Island embedded generation to deliver the lower frequency limit's intended outcome

- Eg, a popular distribution network auto-recloser only supports a setting down to 46 Hz

** This definition proposed to be moved to the PPOs in clause 7.2A of the Code from 1 Dec 2026*

*** To help facilitate investment decisions, the System Operator is providing guidance on the duration envelope for riding through 45–47 Hz under-frequency events*

ISSUES PRIORITISATION

Six key frequency management issues prioritised

Prioritisation of six key frequency management issues:

1. **Appropriate incentives for transmission network investments** that materially affect power system operation – specifically, the HVDC link control system replacement
2. **Falling power system inertia** – impacts frequency regulation in the normal band & contingency management
3. **More frequent & bigger frequency variations** – inside & outside the normal band
4. **Effective/efficient procurement of frequency management services** – from primary frequency response (PFR) to dispatch
5. **Appropriate incentives to minimise power system needs / costs** – particularly the allocation of frequency ancillary service costs, and trading conduct provisions
6. **South Island frequency range of 45–55 Hz is wider than many other jurisdictions** – this may be limiting investment in some technologies

Basis for prioritisation of six key frequency management issues

The basis for prioritisation of the six key frequency management issues may be summarised as follows:

- HVDC link control system replacement is No. 1 because of Transpower's intention to submit a major capex proposal to the Commerce Commission in mid-2027
- Falling power system inertia is No. 2 because of the material increase in the number of low inertia periods over the past year (Sept 2025 – Sept 2026), & predicted continuation of this out to 2029 (see System Operator's *TAS120 Inertia needs date study*)

Basis for prioritisation of six key frequency management issues

The basis for prioritisation of the six key frequency management issues may be summarised as follows:

- More frequent & bigger frequency variations is No. 3 because it is already under consideration as part of the Authority's FSR work programme
- Effective/efficient procurement of frequency management services is No. 4 because it is already under consideration by the Authority

Basis for prioritisation of six key frequency management issues

The basis for prioritisation of the six key frequency management issues may be summarised as follows:

- Appropriate incentives to minimise power system needs / costs is No. 6 because its consideration depends on the outcome of work undertaken as part of considering effective/efficient procurement of frequency management services
- South Island 45–55 Hz frequency range limit is No. 7 because investment in IBR technologies is occurring in the South Island despite the 45–55 Hz range

OPTIONS IDENTIFICATION

1. Appropriate incentives for transmission network investments

1A. The HVDC link control system is planned to be replaced

Engage with HVDC link owner over proposed functionality/capability of a replacement HVDC link control system

- Assess benefits & costs of FKC & any other functionality/capability that affects frequency management (eg, reserve sharing limit)

1B. Frequency management may not be considered when AC transmission network investments are made

Require transmission grid owners to consider inertial effects when making network investments

2. Falling power system inertia

Change parameters of 6 sec fast instantaneous reserve (FIR) service

- Eg, reduce interruptible load response time from 1 sec to 0.5 sec (but overall IL provision may be depleting)
- Eg, reduce tail-water depressed (TWD) response time from 6 sec to 4 sec

Create <6 sec instantaneous reserve service(s), or change existing 6 sec reserve service to be <6 sec reserve service

- Eg, 0.5 sec or 1 sec instantaneous reserve, which could be provided by interruptible load & BESSs

Establish a new ancillary service contract for inertia (accommodating both machine-based synchronous inertia & synthetic inertia)

Require transmission grid owners to consider inertial effects when making network investments

(Per options to address the issue *Appropriate incentives for transmission network investments*)

2. Falling power system inertia

Change scheduling, pricing & dispatch (SPD) tool's logic to:

- constrain output of binding risk low-inertia generation in low inertia conditions
- constrain on inertia providers based on their inertia constant during low inertia periods

Subject to technology capability, expand frequency range permitted during & after a contingent event

- Eg, 47.5–52.5 Hz during a North Island contingent event (currently 48–52* Hz)
- Eg, 47.5–55.5 Hz during a South Island contingent event (currently 48–55* Hz)
- Eg, 49–51 Hz within 60 secs after the contingent event (currently 49.25–50.75 Hz)

* Proposed to be from 1 Dec 2026

Are interim measures justified, if full mitigations are likely to take a long time to implement?

3. More frequent & bigger frequency variations

Have a capability market for generator governor response / frequency control system response

- Per Authority's 2018 *Normal Frequency Management Decision Paper*

Have a national frequency keeping market based on station-based frequency control

Co-optimise MFK with energy & reserves

Lower minimum MFK threshold below current threshold of 4 MW

Define in the Code metrics for acceptable frequency quality (via the PPOs in Part 7)

3. More frequent & bigger frequency variations

Resources (e.g. generating stations, battery energy storage systems (BESSs)) must make available X% of maximum rated capacity to support frequency in under-frequency events

Have ramping limits on generation for post-disturbance or change-of-MW output (eg, due to wind gusts or cloud covering)

Strengthen dispatch compliance Code requirements

Review dispensation & equivalence arrangements framework (for frequency obligations)

4. Effective/efficient procurement of frequency management services

Have a capability market for generator governor response / frequency control system response

- Per Authority's 2018 *Normal Frequency Management Decision Paper*

Have a national frequency keeping market based on station-based frequency control

5. Appropriate incentives to minimise power system needs / costs

Allocate frequency keeping & over-frequency reserve costs to all exacerbators of system frequency variations

- Per Authority's 2012 *Decision-making and economic framework for transmission pricing review* & 2013 *Decision-making and economic framework for distribution pricing*

6. South Island frequency range of 45–55 Hz is wider than many other jurisdictions

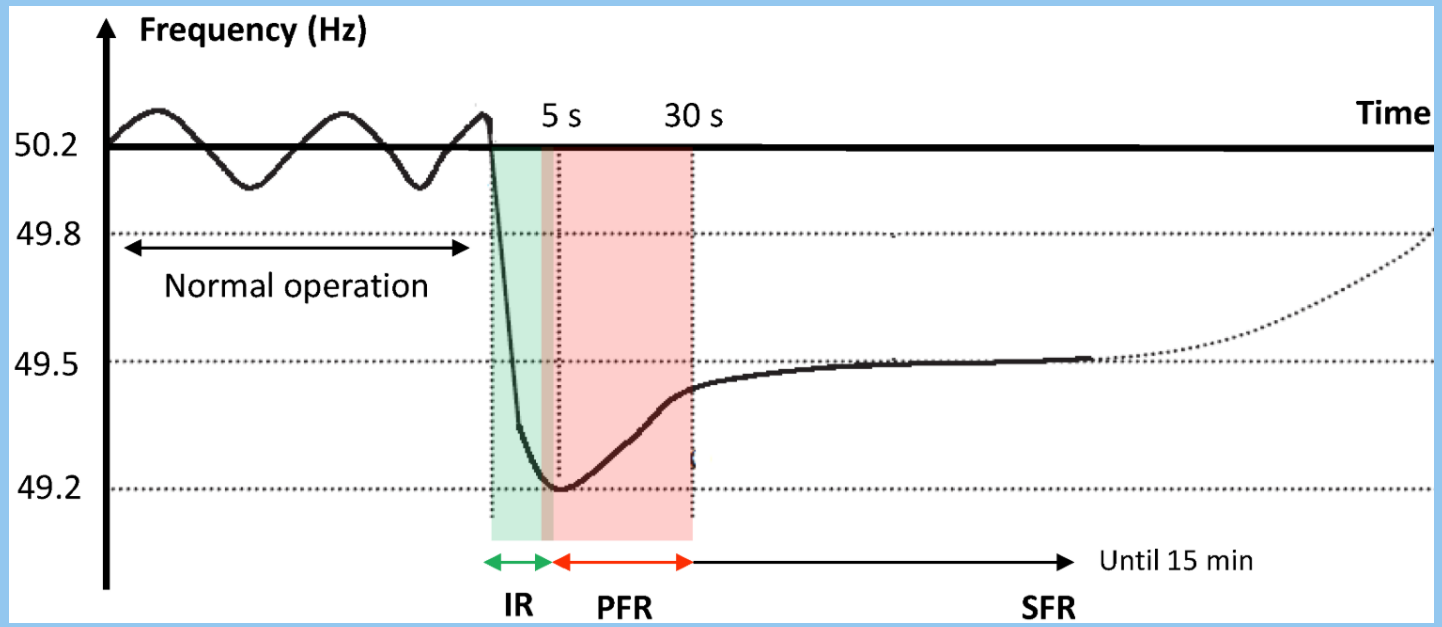
Raise minimum under-frequency limit for South Island to align with common international standards for generation & network equipment

Formalise System Operator's guidance on the duration envelope for riding through 45–47 Hz under-frequency events

LUNCH



System Operator update on fast frequency response effectiveness studies



TRANSPOWER

TAS123 Frequency management strategy update

CQTG update

15 October 2026

Frequency Management Journey

Minimum Inertia Report

- Identified the need for managing inertia on the system
- Identified min inertia levels for existing power system operation
- Recommended potential mitigation options

TAS120 Inertia need date report

- Reinforced the need to address lowering inertia issues on the power system
- Identified the growing inertia challenge over 2027 to 2029
- Recommended the need for the System Operator to establish inertia monitoring and forecasting capabilities

TAS123 Frequency management strategy

- Review international practice for frequency management
- Review current state of frequency management
- Investigate options for future frequency management

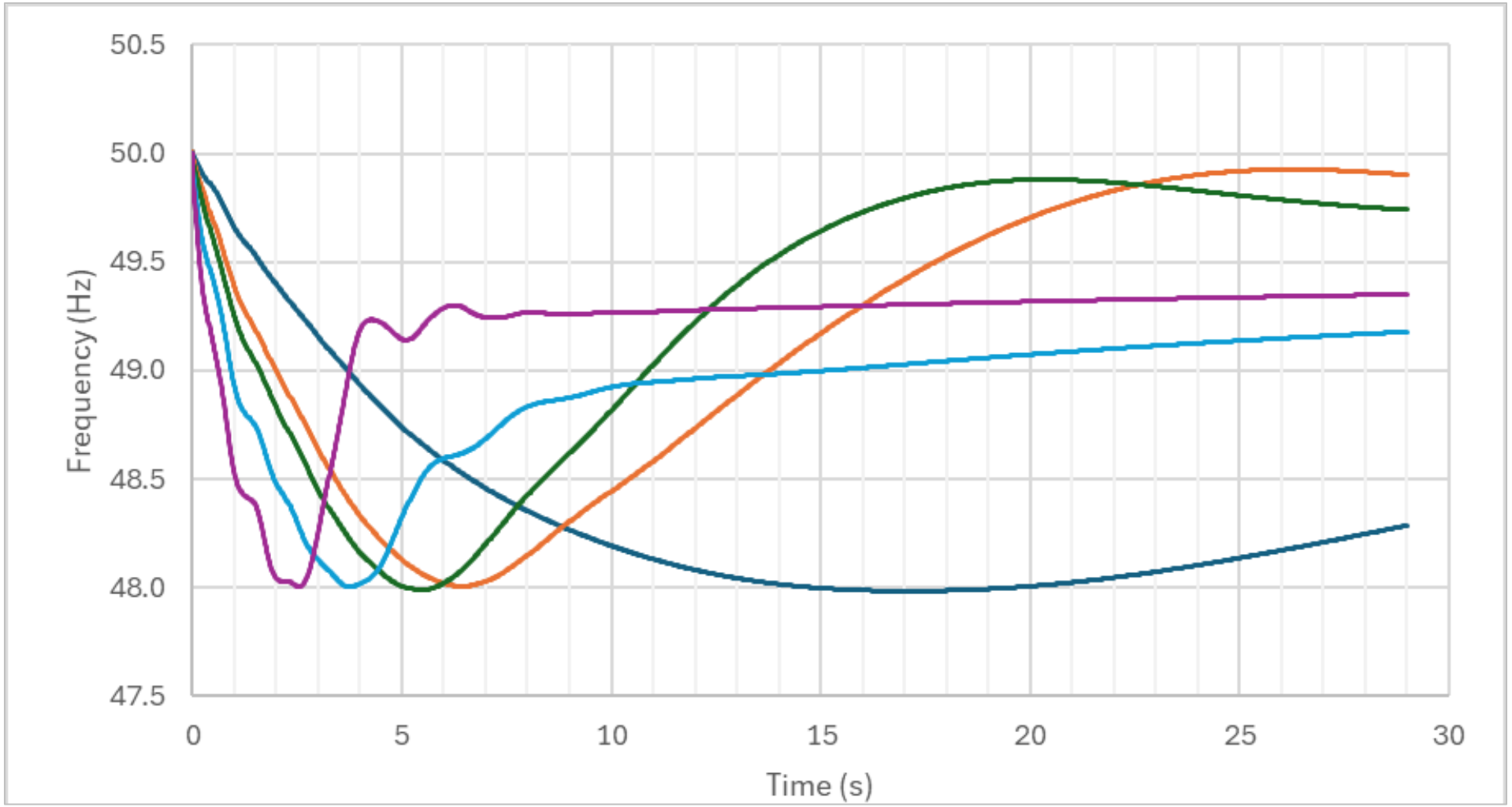
Problem Statement and Methodology

The Minimum Inertia report established that with higher RoCoF, 6s reserve is less effective, meaning higher quantities of reserve are required to secure the power system. How effective is faster reserve at securing frequency in future low inertia scenarios?

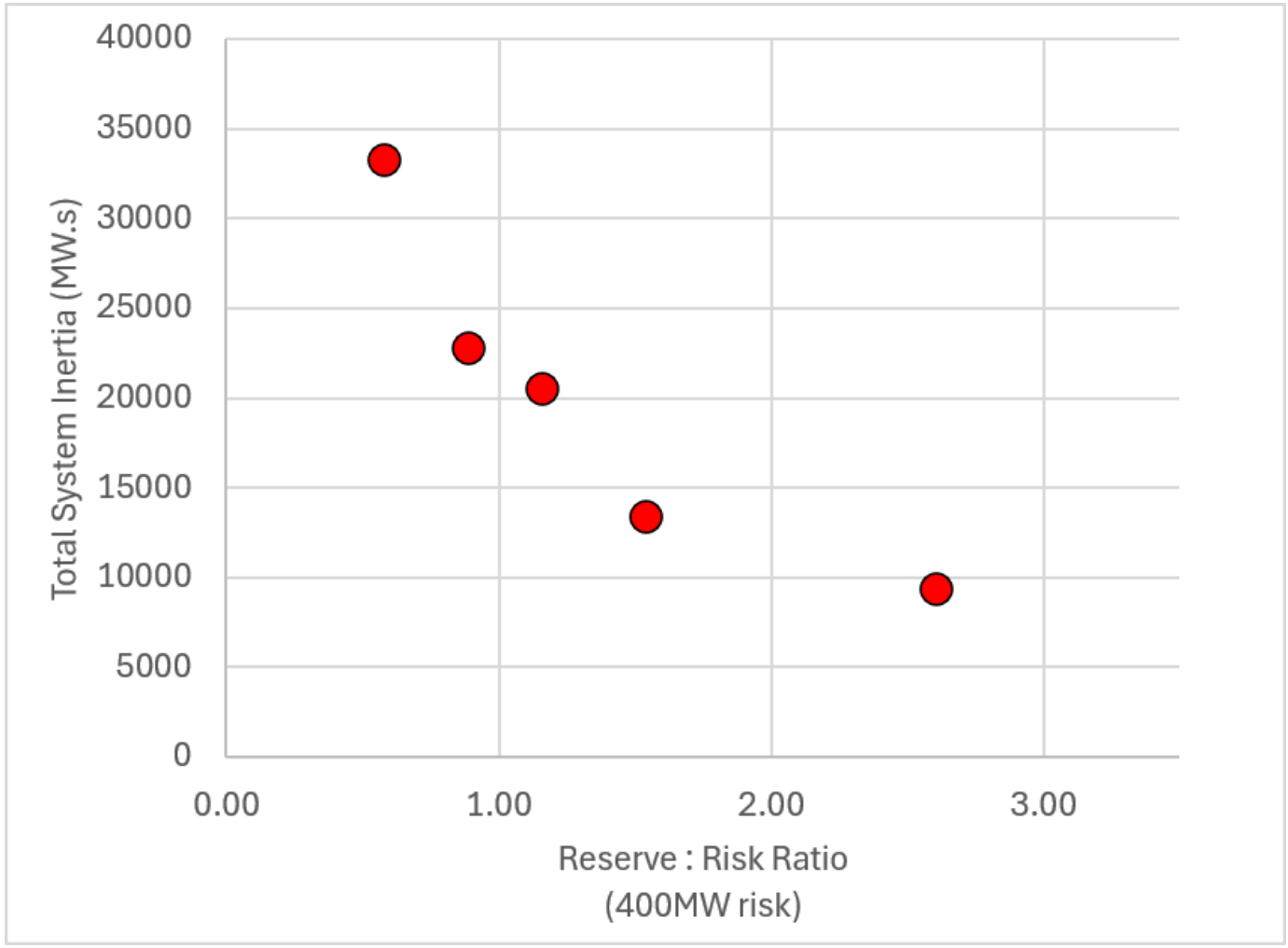
Methodology:

1. Set up future high RoCoF (low inertia, high risk) scenarios for NI and SI, AC and DC, CE and ECE risks.
2. Model fast FIR(F-FIR) response with 3s, 2s and 1s response times.
3. For each scenario, find the reserve required to secure frequency against limits (e.g. 48Hz for CE)
4. Assess the impact F-FIR has on the quantity of reserve required in each scenario.

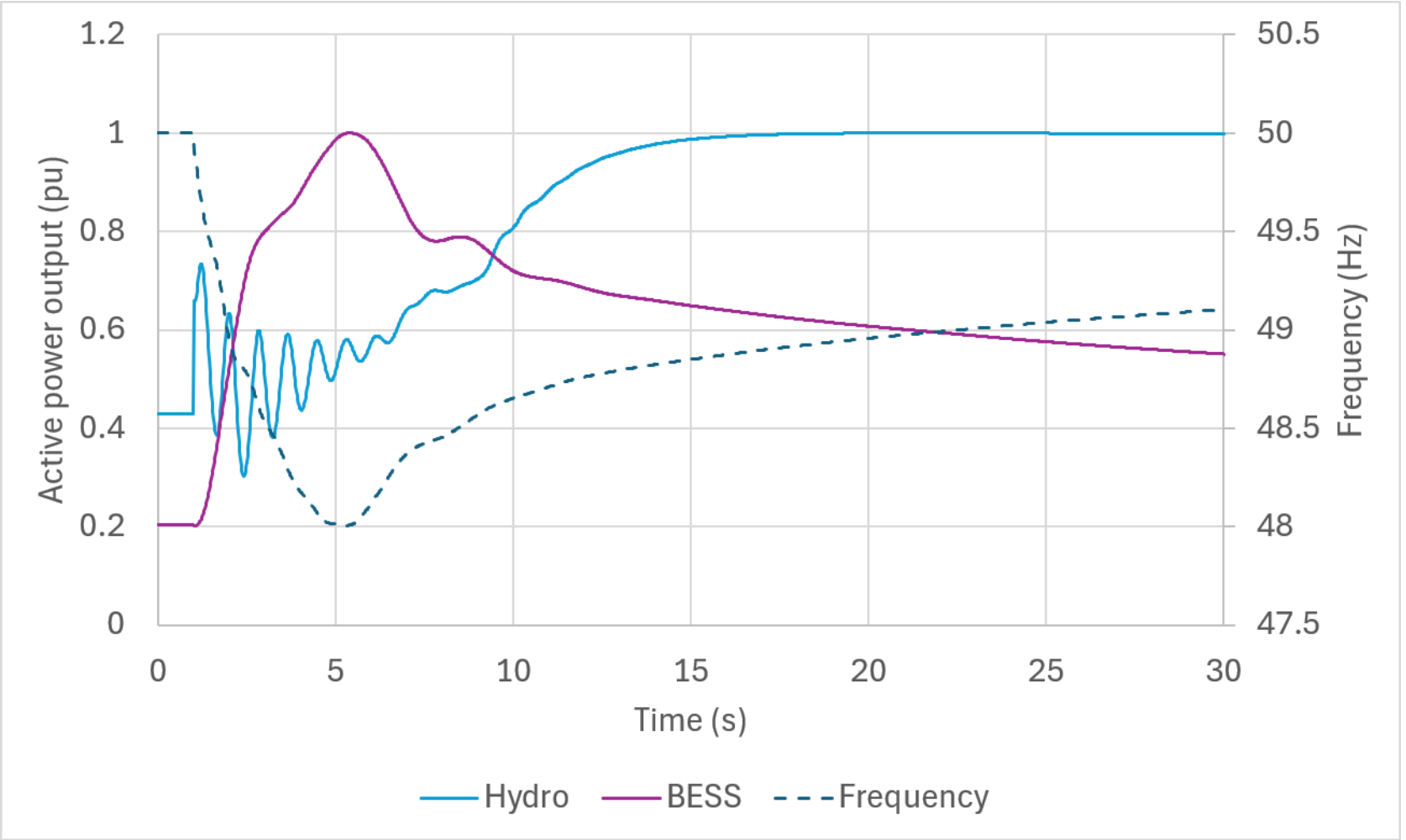
Lowering inertia means faster RoCoF and earlier frequency nadir



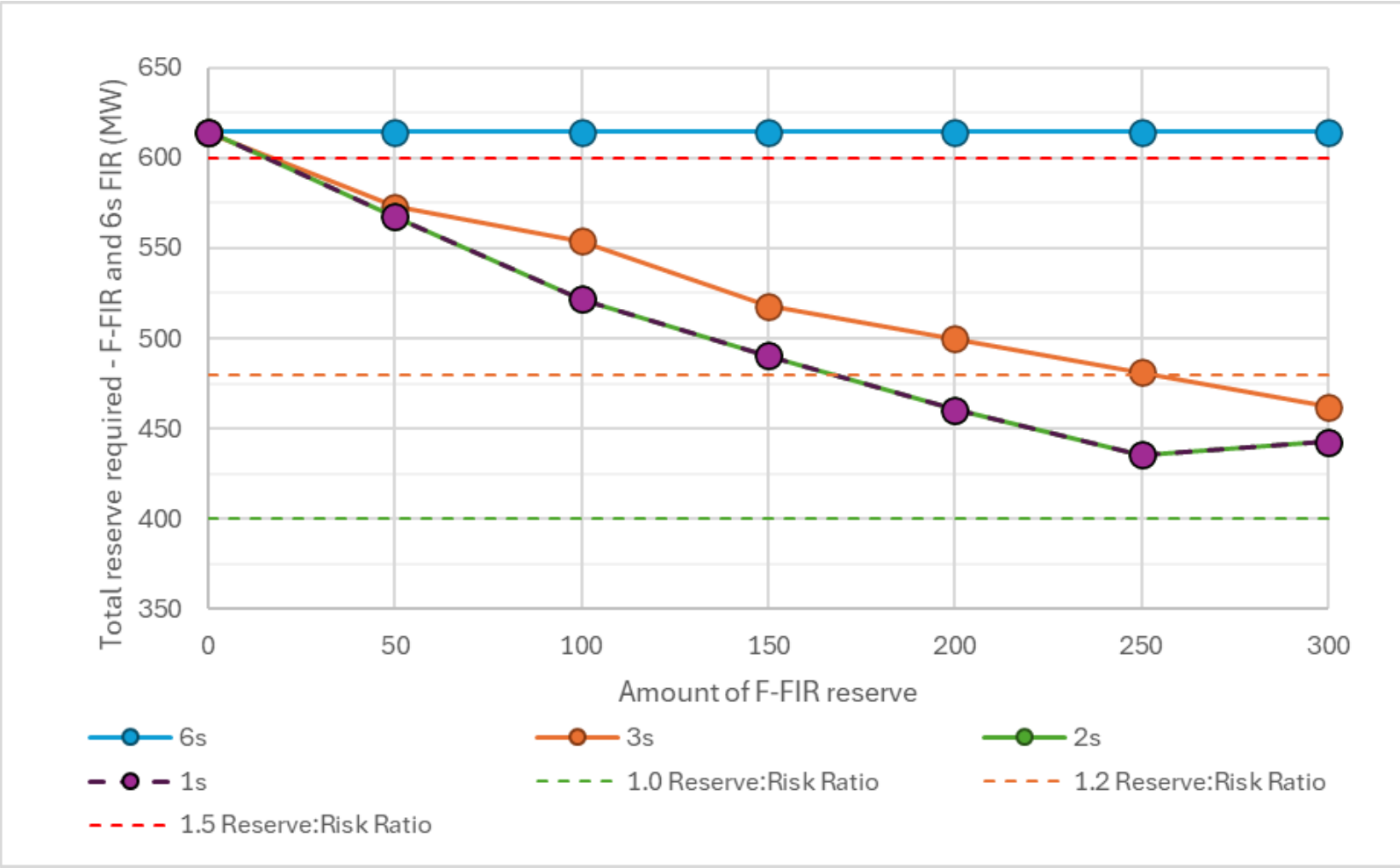
More reserve is required in low inertia scenarios to secure the power system



Slower responding generation is less effective at arresting faster falling frequency



Faster frequency response can reduce the amount of reserve required on the system



*minimum value at 250MW is a product of how reserve response is defined and the support received from the HVDC

Potential management strategies for a future low inertia system

1. **Operate with a minimum inertia or maximum RoCoF limit** – implement constraints on dispatch to ensure that minimum levels of inertia are maintained on the system
2. **Reserve categorisation and prioritisation of more effective reserve in RMT -** Implement logic in RMT to distinguish between reserve types and prioritise reserve which is more responsive immediately following the disturbance
3. **F-FIR incorporated into reserve management strategy –** Implement a faster reserve product into the market, may be a fixed quantity or fully co-optimized with existing FIR

Future operating configuration may include some combination of the above

Other challenges being addressed in TAS123

Initial specifications for a faster FIR product (high level testing methodology and definitions)

Reserve response behaviour from BESS

Treatment of synthetic inertia vs inertia from synchronous machines

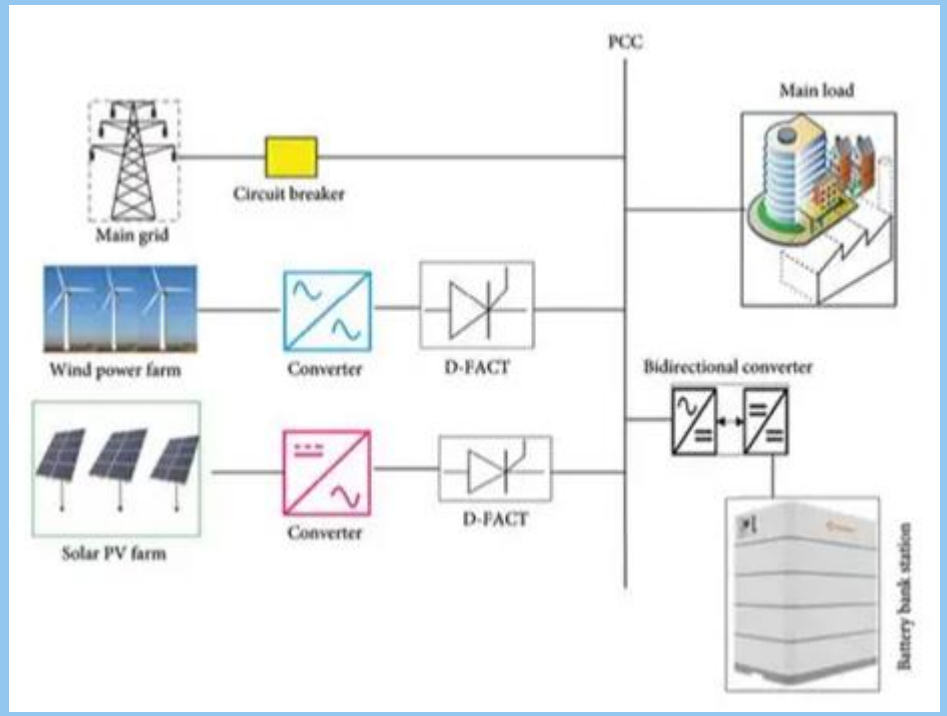
IL operation time

Co-ordination of AUFLS under high RoCoF system

Management of over-frequency

BESS and Hybrids:

- AOPOs
- Wholesale market arrangements



AOPOs FOR BESSs AND BESS-HYBRID STATIONS

No AOPOs for an asset that is idle

Current thinking of staff is no AOPOs on an asset that is idle

Key reasons:

- AOPOs would be applied inconsistently across assets not actively participating in power system's operation
- potentially material operational & wear-related costs for BESSs & BESS-hybrid stations in the idle operating state – contrary to general intent behind AOPOs
- dampening of investment signals for BESSs & BESS-hybrid stations – contrary to competitive neutrality across technologies
- behavioural or operational incentives for asset owners to alter controller or operating states solely to manage exposure to AOPOs – potentially increasing complexity for operational monitoring & compliance assessments

Definition of ‘idle’

idle means—

a) in respect of a **generating station** or an **embedded generating station** with one or more inverters, [but not a **battery energy storage system station** or a BESS-hybrid generating station,] the station—

   i. is not scheduled for dispatch of—

      a. **active power** that is more than the station’s **MW** (alternating current (a.c.) capacity) auxiliary load; or

      b. **frequency keeping**; or

      c. **instantaneous reserve**; and

   ii. unless agreed otherwise with the **system operator** or the owner of the **network** to which the station is connected, is not exporting **reactive power** into or importing **reactive power** from the **network** to which the station is connected; and

b) in respect of a **battery energy storage system station** or a BESS-hybrid generating station, the station—

   i. is not for a period of at least the current **trading period**, scheduled for dispatch of—

      a. **active power** that is more than the station’s **MW** (alternating current (a.c.) capacity) auxiliary load; or

      b. **frequency keeping**; or

      c. **instantaneous reserve**; and

   ii. unless agreed otherwise with the **system operator** or the owner of the **network** to which the station is connected, is not exporting **reactive power** into or importing **reactive power** from the **network** to which the station is connected

Where to assess that an asset is idle

Is ‘point of connection’ sufficiently clear?

point of connection means—

a) a point at which **electricity** may flow, via one or more phases or conductors—

   i. into or out of a **network**; or

   ii. both into and out of a **network** at the same time, where each directional flow is on different phases or conductors; and

b) [Revoked]

Maybe assess whether an asset is idle at the point at which electricity conveyed through the point of connection is measured by the metering installation(s) per clause 10.13(3) of the Code?

What about when metering is not at point of connection?

AOPOs for BESS-hybrid generating stations not idle

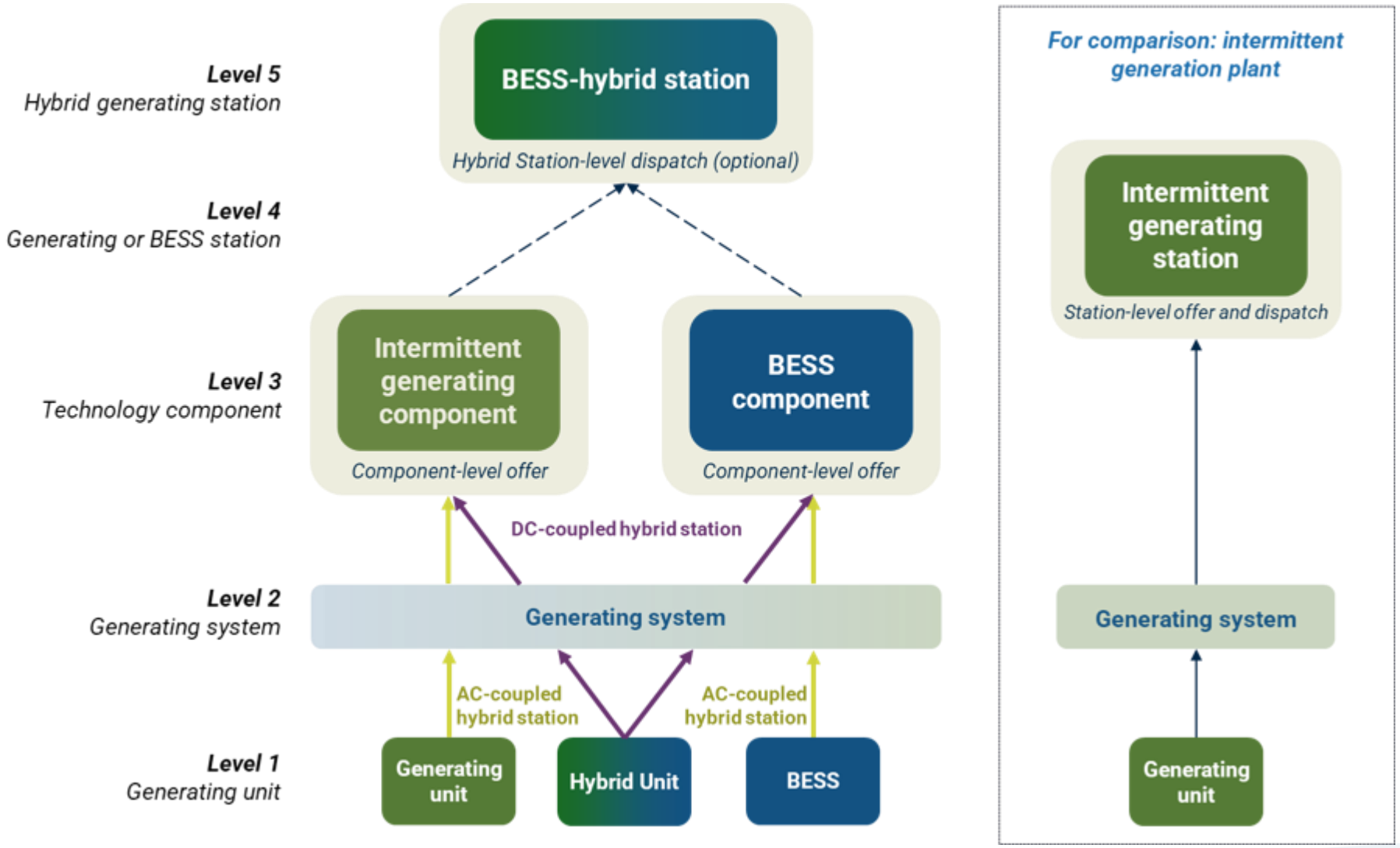
- AOPOs assessed at station level rather than technology component level
  - Use BESS-hybrid generating station's maximum continuous MW output power
- Although AOPOs assessed at station level, for a BESS-hybrid station the BESS not required to compensate for intermittent generation's lack of response to changes (falls) in frequency
- System Operator needs visibility (indications) of individual technology components
  - Eg, through state of charge monitoring for the BESS component

Co-located vs AC-coupled vs DC-coupled

- Differentiating between co-located, AC-coupled & DC-coupled where each has a single point of injection
- **Co-located vs AC-coupled**
  - Co-located has separate power plant controllers / separate operational control
  - AC-coupled has single power plant controller / common operational control
- **AC-coupled vs DC-coupled**
  - AC-coupled has technology components not sharing inverters
  - DC-coupled has technology components sharing inverters

UPDATING GENERATING ASSET DEFINITIONS

High-level framework for generating asset definitions



High-level framework for 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)

Current thinking of staff

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

Definition of ‘generating unit’

generating unit means the minimum [collection of] ~~all~~ equipment functioning together as a single entity [that is necessary] / [necessary] to produce **electricity**

Concise Oxford English Dictionary, 11th edition, revised:

Entity means a thing with distinct & independent existence

Equipment means

1. The items needed for a particular purpose
2. The process of supplying those items

Definition of ‘generating system’

generating system means two or more **generating units** connected to a common electrical conductor that can be isolated via a **circuit breaker** [and includes auxiliary or **reactive power** plant located on the **generating station's** side of the **point of connection** with the **network** to which the **generating station** is connected and which is necessary for the generating system to meet its obligations under the Code]

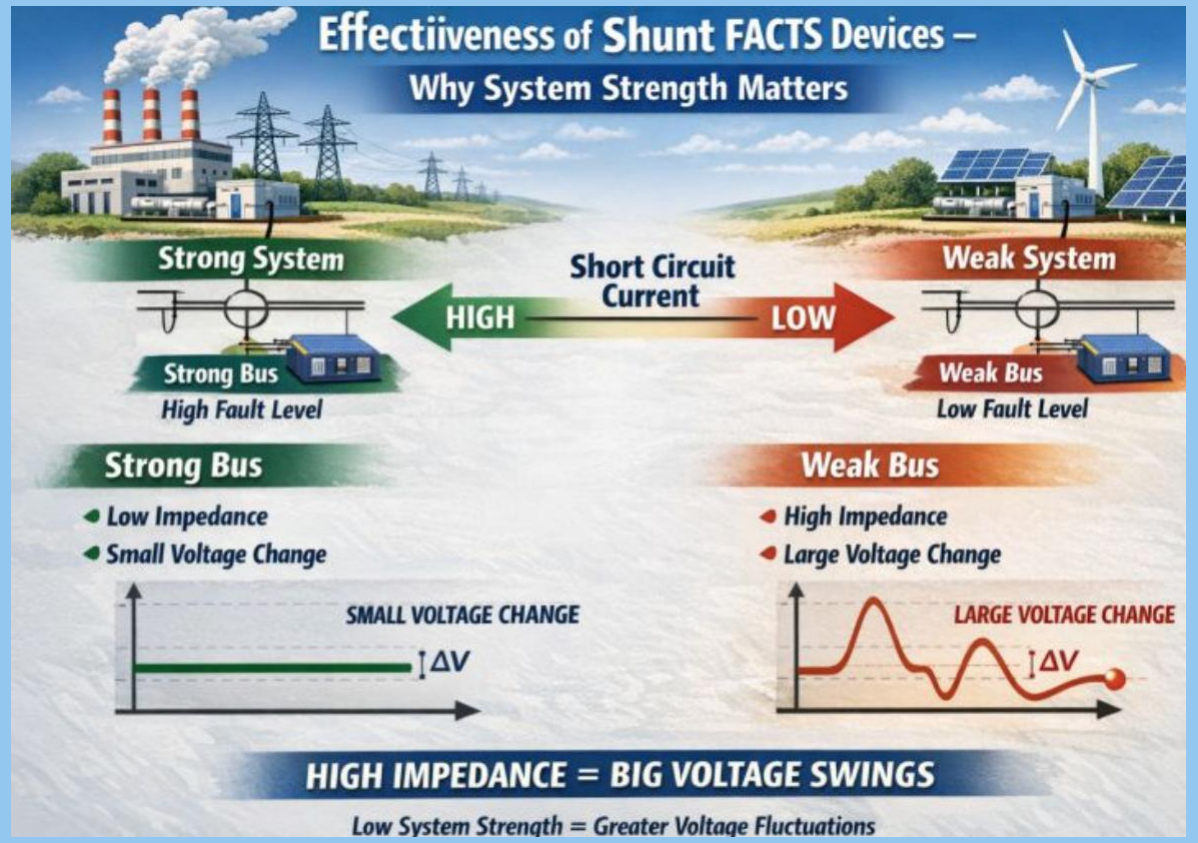
Blue text in square brackets draws on the definition of ‘generating system’ in the Australian National Electricity Rules

Definition of ‘generating station’ & ‘embedded generating station’

generating station means 1 or more **generating units** or **generating systems** 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**

embedded generating station means 1 or more **generating units** or **generating systems** that are directly connected to a **local network** or an **embedded network** and that injects into a **local network** or an **embedded network** at a single point of **injection**

System Operator update on system strength studies



TRANSPOWER

System Strength Assessment – Phase 2

Study scope, methodology and process flow

CQTG Presentation

15th October 2026

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Key findings from previous work (Phase 1)

- System Strength
  - Ability to maintain a stable voltage waveform during normal and disturbed conditions
  - Influenced by fault level, voltage control systems and converter interactions

- Limitations of conventional assessment techniques
  - No single metric or analysis method captures all system-strength and converter-interaction phenomena
  - International practices, metrics and acceptance thresholds are not yet fully harmonised
  - Conventional SCR has limitations in multi-IBR and meshed networks
  - Detailed EMT simulation is computationally intensive

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Objectives of this work (Phase 2)

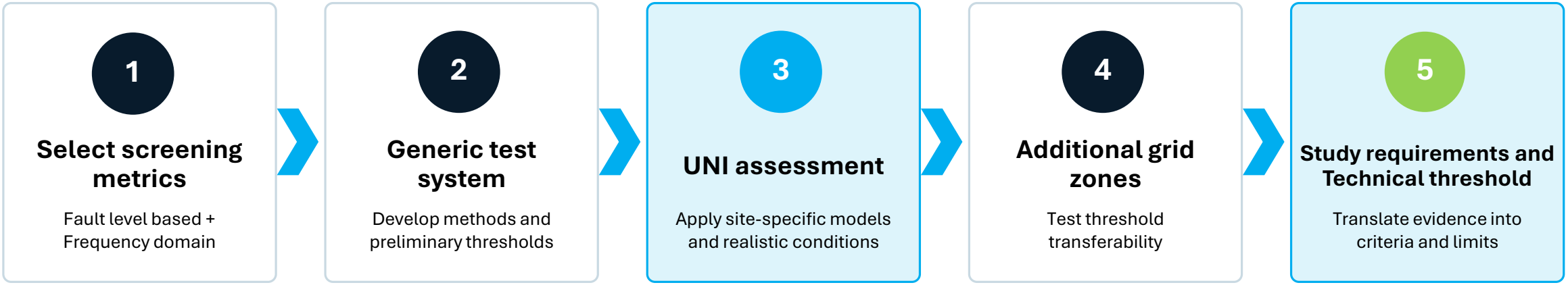
Develop an integrated system-strength assessment **framework**

- **Part 1**
  - Select screening metrics and validate **stability thresholds**
  - Develop Study methodology and **procedure**
  - Establish **operational boundaries** for weak system conditions
- **Part 2**
  - Translate validated outcomes into planning, operational and connection **requirements**

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Study framework

A staged approach to focus detailed EMT effort on the critical cases.



Core strategy **Develop a fast, repeatable, and scalable screening process to identify critical operating conditions, followed by targeted EMT simulations to validate stability boundaries.**

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1 Screening metric selection

Complementary indicators are required because no single metric captures network strength, converter interactions and dynamic margin.

Fault level-based screening metrics

SCRIF

Electrical coupling between IBRs
Converter interaction risk

IPSCR

Aggregate IBR penetration relative to strength
Regional weak-area screening

AFL

Available fault level at a location
Practical planning and operational indicator

Frequency domain screening metrics

Eigenvalue analysis

Damping ratio analysis

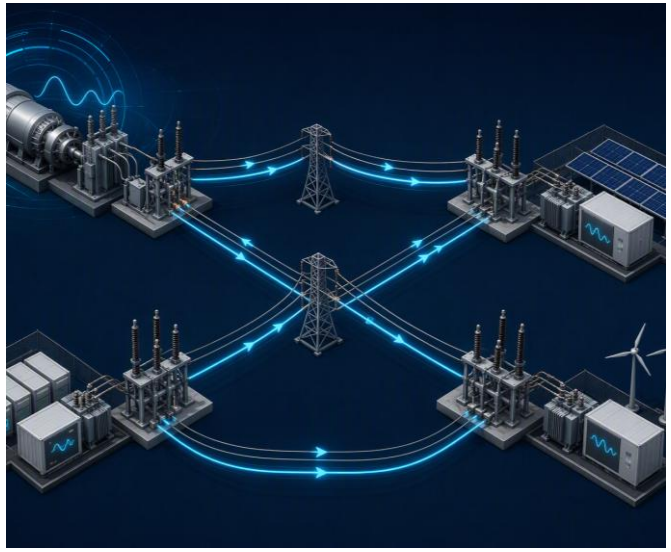
Impedance / admittance margins

Selection principle: quantifiable, scalable and suitable for correlation against EMT stability outcomes.

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2 Generic test system studies

A generic four-bus system is used to develop methods, assess stability boundaries and establish preliminary thresholds.



WS1A	PSAT + Python	SCRIF, IPSCR, AFL
WS1B	SSAT #	Eigenvalues, damping ratio, Impedance / admittance margin
WS1C	PSCAD	Switching and fault studies

Output:

preliminary screening thresholds, phase-angle deviation limits and EMT validation process.

 # Model obtained by conducting impedance scan of site specific PSCAD model

Assessment steps

Stress the system

Reduce source strength.
Increase network impedance.
Increase IBR penetration.

Apply disturbances

Line and load switching.
Network reconfiguration.
3-phase and 2-phase faults.

Assess stability

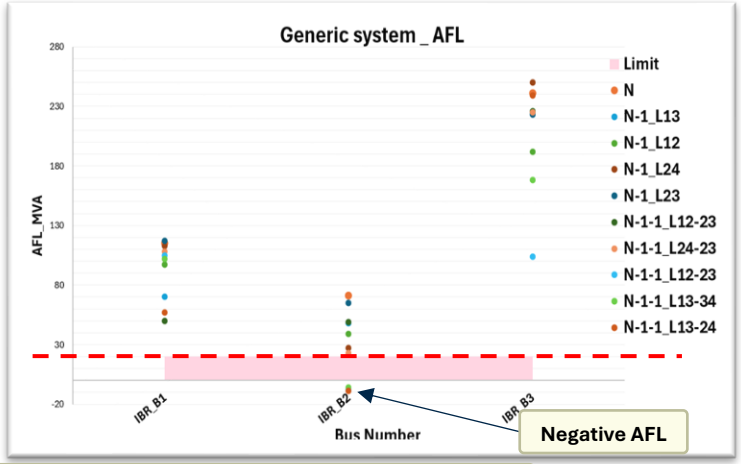
Sustained or growing oscillations.
Failure to recover V, P or Q.
Protection-driven plant disconnection.

Correlate evidence

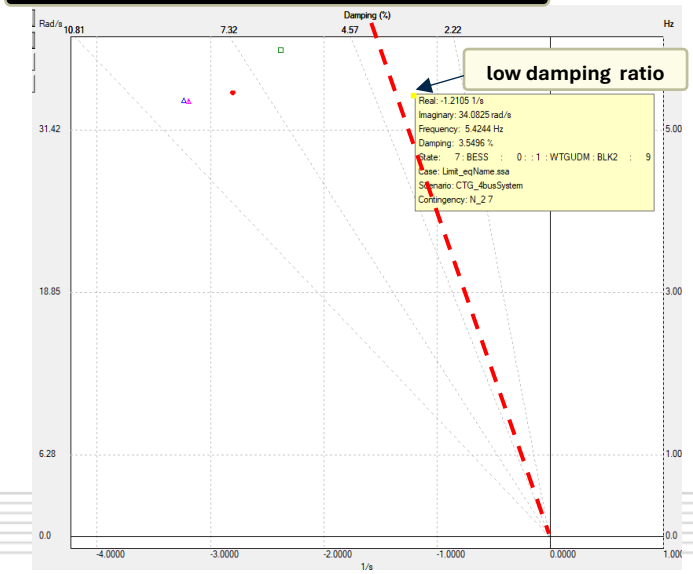
Compare screening metrics and phase-angle deviation with EMT performance.

2 Generic test system results

WS1A: Fault level screening



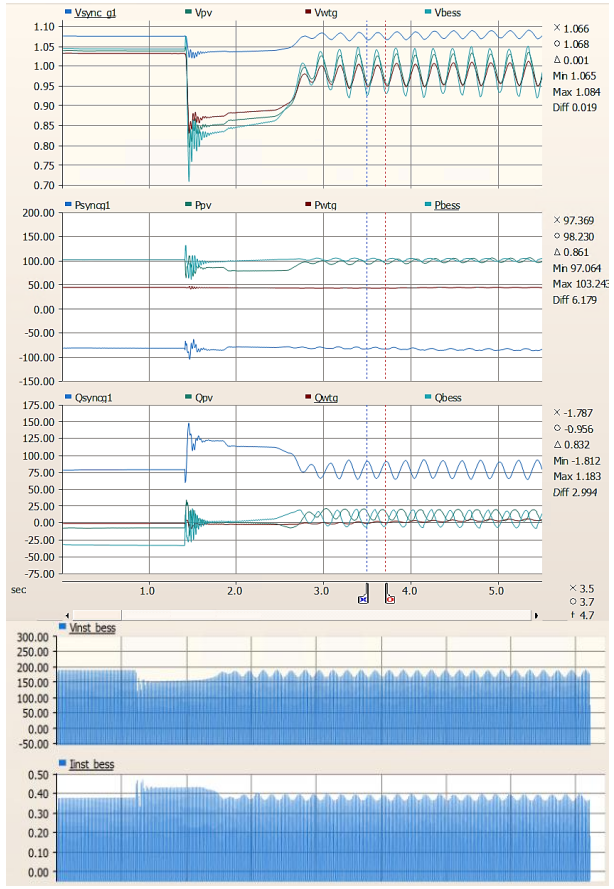
WS1B: Small signal screening- SSAT



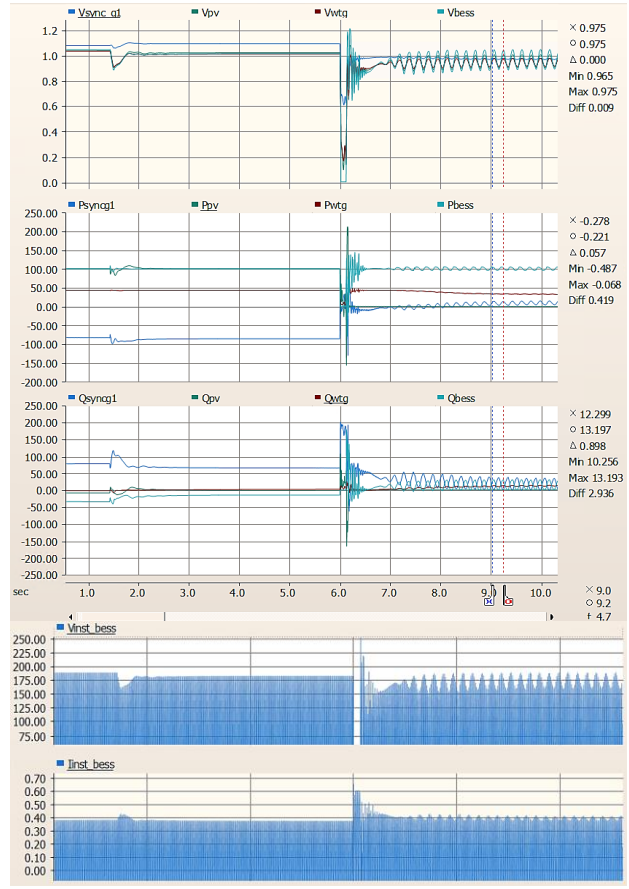
Critical contingencies

Critical operating condition

WS1C: EMT- Switching studies



WS1C: EMT-Fault studies



Good correlation between fault level screening, small-signal screening and EMT results

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3 UNI assessment

The generic test-system methodology is applied using site-specific models and realistic operating conditions.



Assessment envelope

- Five peak-load & five light-load power flow scenarios.
- N, N-1 and N-1-1 network conditions.
- Fault level, small-signal & frequency-domain screening.
- Critical cases selected by screening studies and validated using EMT studies.
- Additional EMT sensitivity analysis.

Key outcome **EMT-validated contingencies and operating conditions susceptible to CDI.**

WS2A	PSAT + Python	SCRIF, IPSCR, AFL
WS2B	SSAT #	Eigenvalues, damping ratio, frequency-domain margins
WS2C	PSCAD	Switching and fault studies

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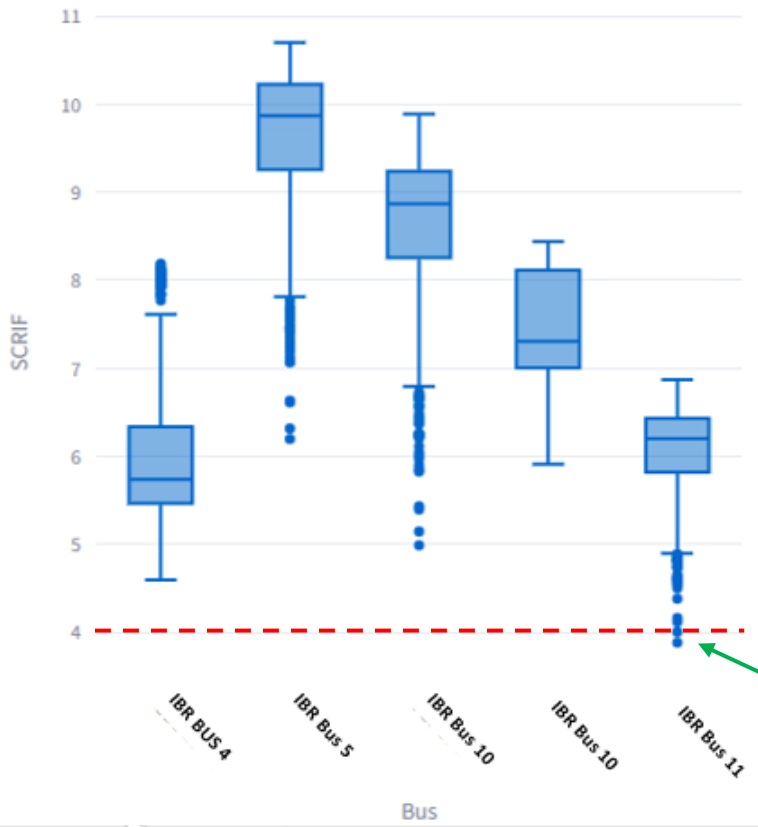
 # Model obtained by conducting impedance scan of site specific PSCAD model

3 UNI assessment – Screening results so far

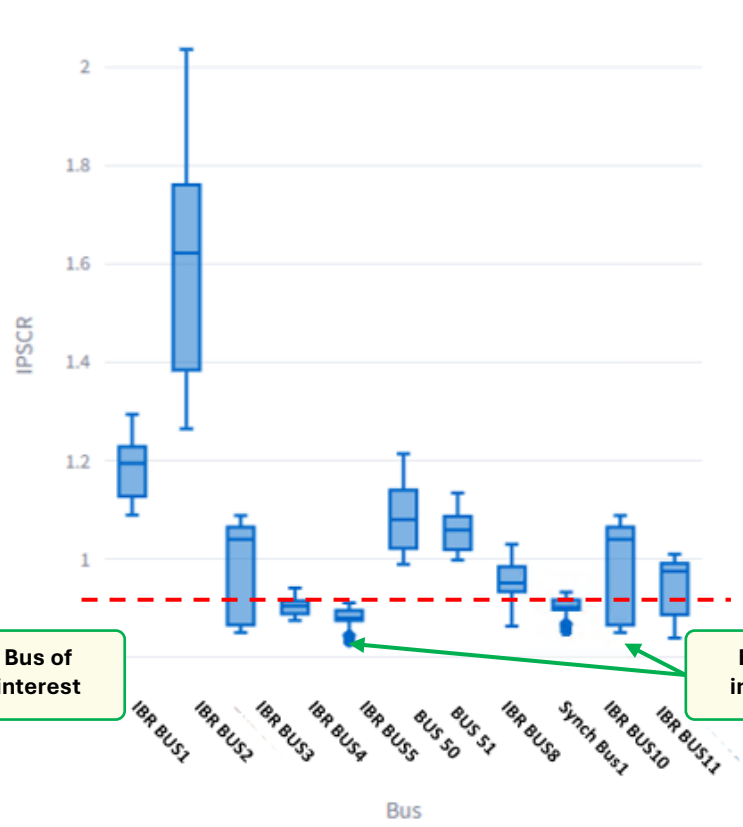
WS2A: Fault level screening

Draft results only

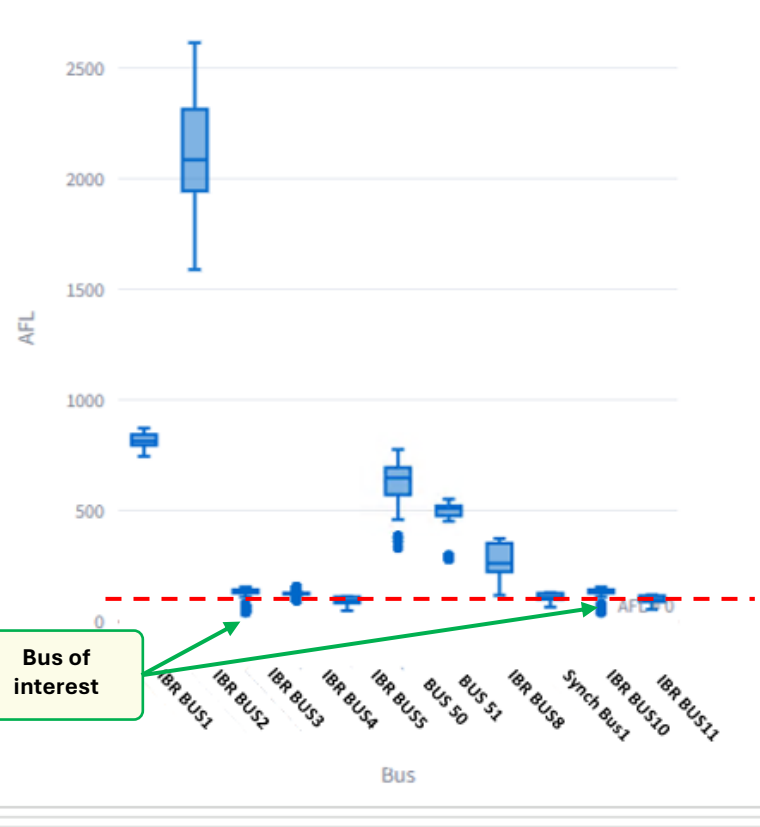
SCRIF Distribution



IPSCR Distribution



AFL Distribution



Bus of interest

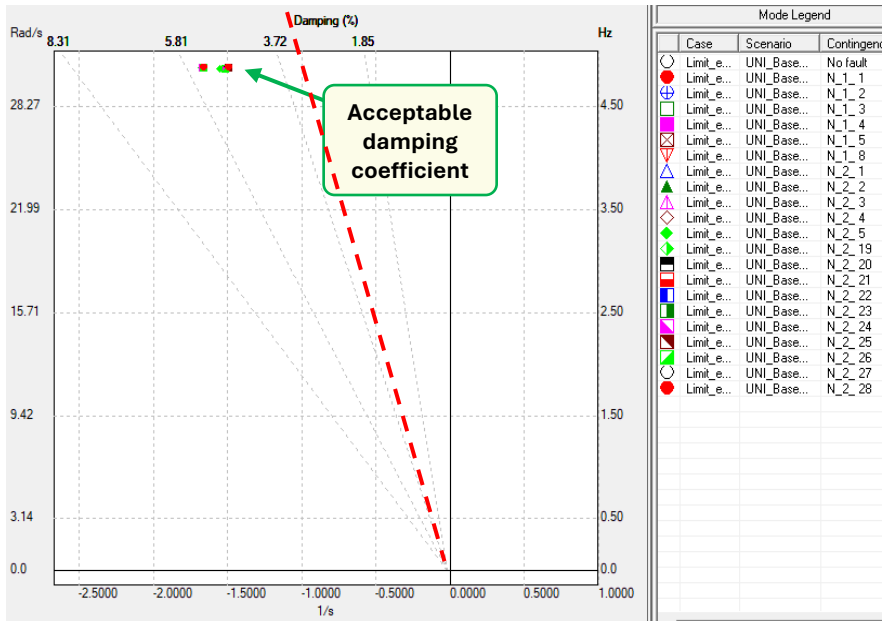
Bus of interest

Bus of interest

3 UNI assessment – EMT and Small signal results so far

Draft results only

WS2B: Small signal screening- SSAT



WS2C: EMT studies





Limitations :

- **Limited PSCAD models availability**
- **Difference in component representation**
- **Iterative process**

3 UNI assessment output

The UNI assessment links metric thresholds to operational limits and mitigation options.

Faul level-based screening	Minimum SCRIF, IPSCR and AFL values
Frequency domain screening	Minimum damping ratio and acceptable frequency-domain margins
Large disturbance	Maximum post-disturbance phase-angle deviation
Operating envelope	Active and reactive power limits required for stable operation
Control mode sensitivity	Conditions where GFM provides benefit relative to GFL

Validated against PSCAD outcomes and used as a baseline for additional Grid zone assessment.

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4 Additional grid zones

Repeat the methodology in three regions with different topology, generation mix and system strength characteristics.
Zone are selected based on difference in generation mix and topology

UNI baseline → Grid zone 2-3 → Grid zone 4-5 → Grid zone 9-10

Validation questions

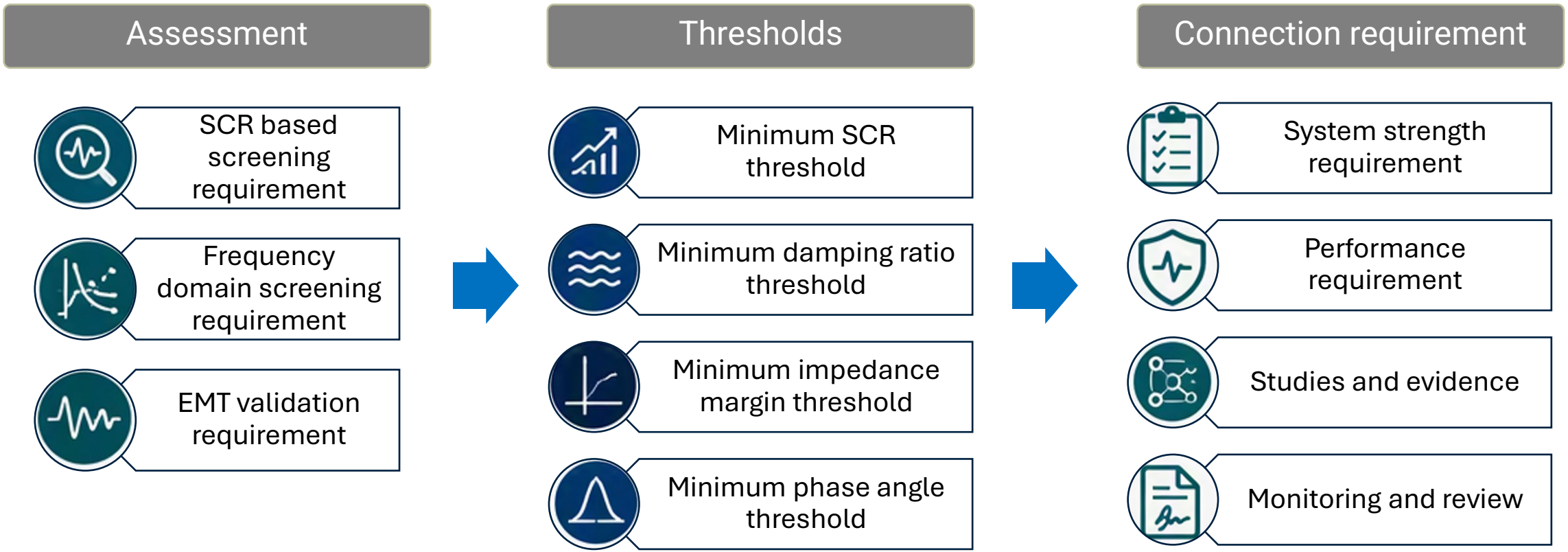
- Are SCRIF, IPSCR and AFL thresholds transferable?
- Are damping-ratio and frequency-domain thresholds transferable?
- Does the phase-angle / EMT stability boundary remain correlated with EMT stability?
- Are system-wide thresholds defensible, or are region-specific values required?

Output:
Validation of repeatability of the assessment framework.
Validation of SCR based and frequency domain thresholds, phase-angle deviation and identified stability boundaries across power system.

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5 Study requirements and Technical threshold

Validated thresholds are translated into planning criteria, operational limits and connection assessment requirements.



Thank you

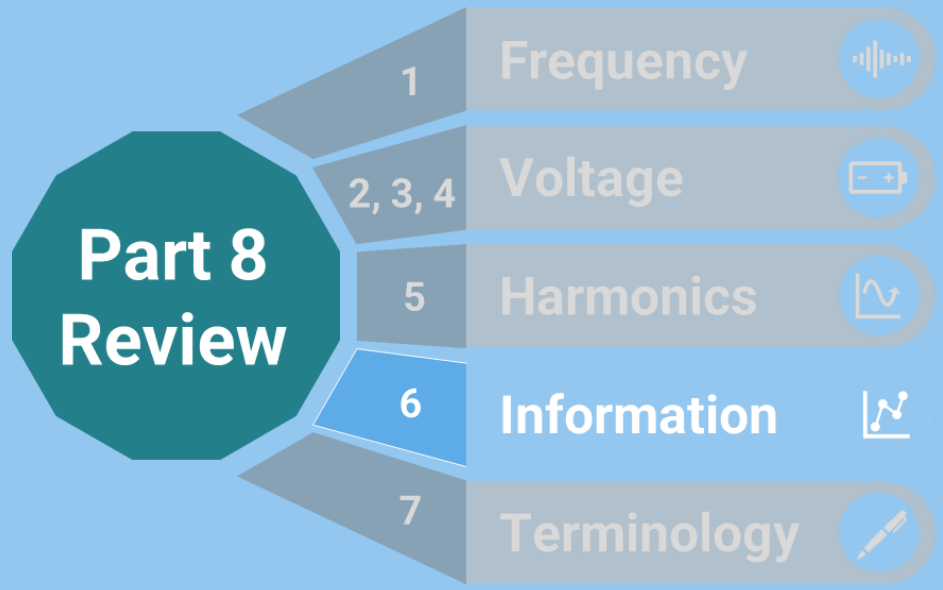
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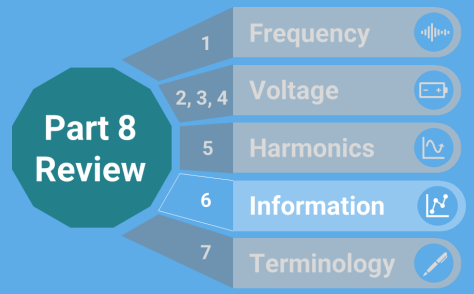
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Information requirements Stage 2 Code amendment proposal consultation



Issue 6: Information

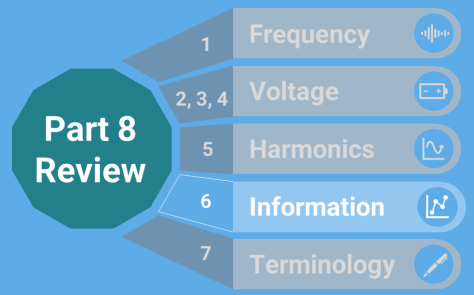


Consulted on proposal for Transpower to share common quality information between System Operator and grid owner

Most submitters supported the proposal and agreed that it would improve efficiency, reduce duplication, and support more effective transmission planning and operational decision-making.

However, some submitters raised concerns about the security arrangements for confidential modelling information.

Scope of audits



Compliance with the Code requirements governing the security, confidentiality, storage, and access arrangements for modelling information.

3 Requirements for asset information

(1) *[Revoked]*

(2) Information about an **asset**, **supply** or **demand** of other **asset owners** must only be disclosed by the **system operator**—

- (a) as expressly provided for in this Code; or
- (b) as reasonably required in a **grid emergency** or to ensure the security of the **grid**; or
- (c) as required by law; or
- (d) otherwise as may be agreed with the relevant **asset owners**.

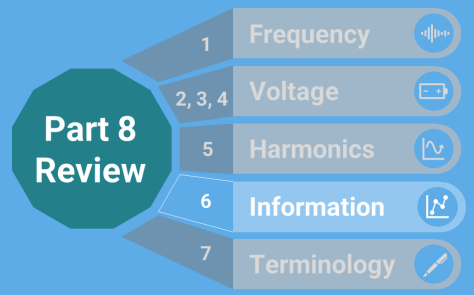
(2A) The **system operator** must—

- (a) store the information provided under clause 2(10)(c) in a secure server that is accessible only to **system operator** employees, contractors or advisers that require access to the information to perform their roles; and
- (b) treat the information provided under clause 2(10)(c) as confidential to the party that provided the information except as required by law; and
- (c) ensure that it has systems, policies, procedures and confidentially obligations in place for the purpose of ensuring, as far as reasonably possible, that any person given or who has access to information in accordance with paragraph (a) does not disclose the information to any other person, except persons given access to that information in accordance with paragraph (a) or as required by law.

(3) *[Revoked]*

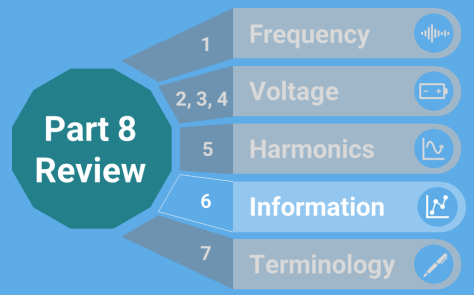
(4) Each **asset owner** must ensure that all supporting information for the operational control of **assets** is kept up to date.

Conduct of audits



- Authority or approved external auditor may conduct audits
- Auditor appointed from Authority-approved panel
- Auditor rotation required after 2 consecutive audits
- Information must be provided free of charge
- Information must be provided within 15 business days
- Audits completed in accordance with Part 16A of the Code
- Audit required for material change to systems or processes
- Publish final reports within 20 business days

Types of audits



1

Regular audits

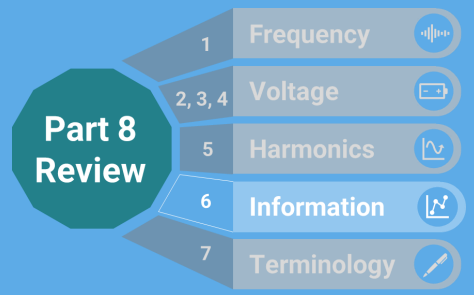
Transpower's System Operator and transmission network owner functions to undertake an audit every three years.

2

Other audits

Authority can initiate audit and industry participants can recommend the Authority conduct audit at any time.

Audit costs

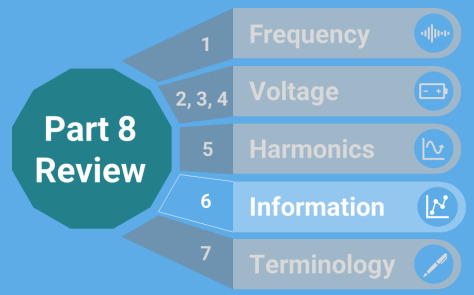


1

Regular audits

Cost met by the subject of the audit – ie, Transpower's System Operator or transmission network owner function.

Audit costs



2

Authority-initiated audit

- If a breach is found, cost is met by subject of audit and Authority, in proportions determined by Authority
- If no breach or minor breach found, cost is met the Authority

Participant-initiated audits

- Cost is met by subject of audit and the participant that requested the audit, in proportions determined by Authority

AOB



ELECTRICITY AUTHORITY
TE MANA HIKO

NGĀ MIHI