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

Meeting 9: 18 February 2025

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AGENDA

Time	Item
8:45 am	**Sign in at reception (to meet Rob Mitchell)**
9:00 am	**Meeting starts - Minutes and Actions from meetings #7 & #8**
9:15 am	**Frequency Code amendment proposals – consultation paper (Issue 1)** • Feedback and recommendations on the draft consultation paper • Presentation on narrow dead band implementation in the NEM • Presentation on the impact of BESS in the NEM
10:15 am	**Morning tea (15 minutes)**
10:30 am	**Frequency Code amendment proposals – consultation paper (continued)**
11:00 am	**GXP power factor study (Issue 3)**
12:00 pm	**Lunch (30 minutes)**
12:30 pm	**Co-ordinating reactive power flows through GXPs (Issue 2)**
1:30 pm	**Threshold for voltage obligations (Issue 2 and 4)**
2:15 pm	**BESS literature review**
3:00 pm	**Afternoon tea (15 mins)**
3:15 pm	**Information requirements - document incorporated by reference (Issue 6)**
4:15 pm	**AOB / Next meeting**
4:30 pm	**End of meeting**

OBJECTIVES

The primary objectives of CQTG meeting #9 are for the CQTG to:

(a) finalise the CQTG #7 & #8 meeting minutes

(b) provide feedback on the Code amendment proposals for frequency

(c) provide feedback on the SO system studies on reactive power flow at the GXP

(d) provide feedback on the threshold for voltage obligations

(e) provide feedback on the SO literature review on BESS

(f) provide feedback on the draft Document Incorporated By Reference (DIBR) related to issue 6 (information requirements)

MINUTES & ACTIONS

- Confirm the minutes from meetings #7 and #8
- Update the action items recorded in the minutes

Frequency Code amendment proposals – consultation paper (Issue 1)

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Options proposed by the Authority

- **Option 1:** Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes.
- **Option 2:** Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.
- **Option 3:** 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.

Option 1

Lowering the 30MW threshold

Benefits

- Reduced likelihood of triggering an AUFLS block
    - greater visibility to the system operator of generation at risk of secondary tripping
- Improved system performance during UFEs
    - requires more generators to remain synchronised and maintain their pre-event output
- Additional net free reserves provided by new generators under 30MW
    - more (smaller) generators would be required to provide governor/frequency response
    - less reserve needed.

Option 1

Lowering the 30MW threshold

BESS

- Lowering the 30MW threshold is likely to impact on the costs of reserves in future.
- In addition, the introduction of large BESS in NZ could also have an impact on the cost of reserves, which could materially impact our CBA.
- We looked at the impact that BESS had on the prices of IR in Australia.

Hornsdale Power Reserve

Impact on prices of reserves

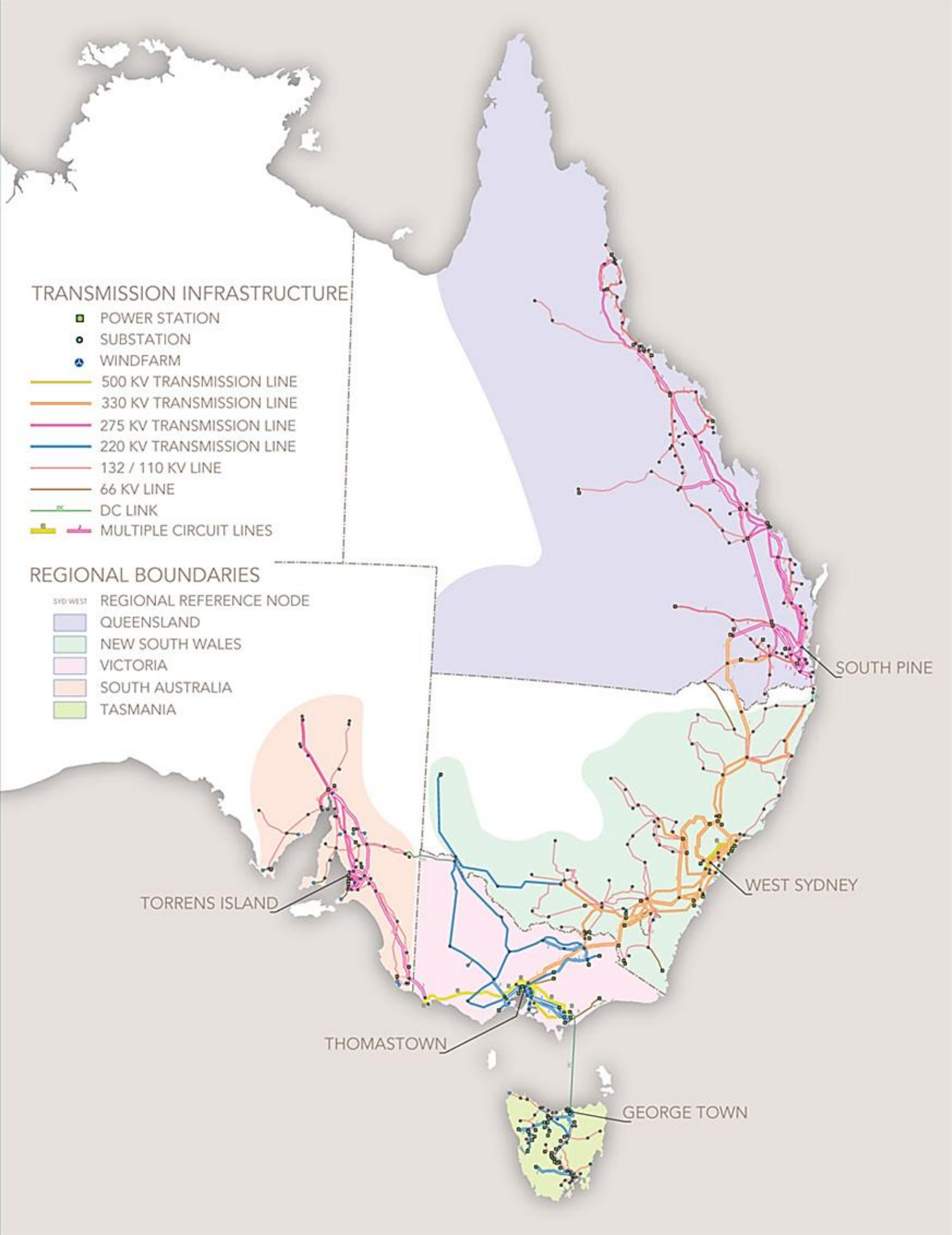
Capacity (2017)

- Energy storage capacity = **129MWh**
  - **10MWh** for SA government
  - **119MWh** for Neoen
- Discharge capacity = **100MW**
  - **70MW** for SA government
  - **30MW** for Neoen

Services offered

- ***Regulation FCAS** = frequency keeping*
- ***Contingency FCAS** = reserves*

FCAS market	Registered capacity (MW)	Comments
Raise Regulation FCAS	100MW	• HPR's full discharge capacity registered • Normally only 30MW is bid into the market. The 70MW discharge capacity reserved by the SA Government is not normally bid into this market
Lower Regulation FCAS	80MW	• HPR's full charge capacity registered • Normally only 40MW is bid into the market. The 40MW charge capacity reserved by the SA Government is not normally bid into this market.
Raise 6 second Contingency FCAS (R6)	63MW	• Registration limit is set by AEMO in consideration of permissible droop response settings • HPR's full 100MW discharge capacity is however enabled to respond to contingency events as required across each of the 6 second, 60 second and 5 minute timescales
Raise 60 second Contingency FCAS (R60)	19MW	
Raise 5 minute Contingency FCAS (R5)	41MW	
Lower 6 second Contingency FCAS (L6)	63MW	• Registration limit is set by AEMO in consideration of permissible droop response settings • HPR's full 80MW charge capacity is however enabled to respond to contingency events as required across each of the 6 second, 60 second and 5 minute times-cales
Lower 60 second Contingency FCAS (L60)	19MW	
Lower 5 minute Contingency FCAS (L5)	41MW	



HPR's effect on prices

2019 calendar year

In the mainland NEM, supplied:

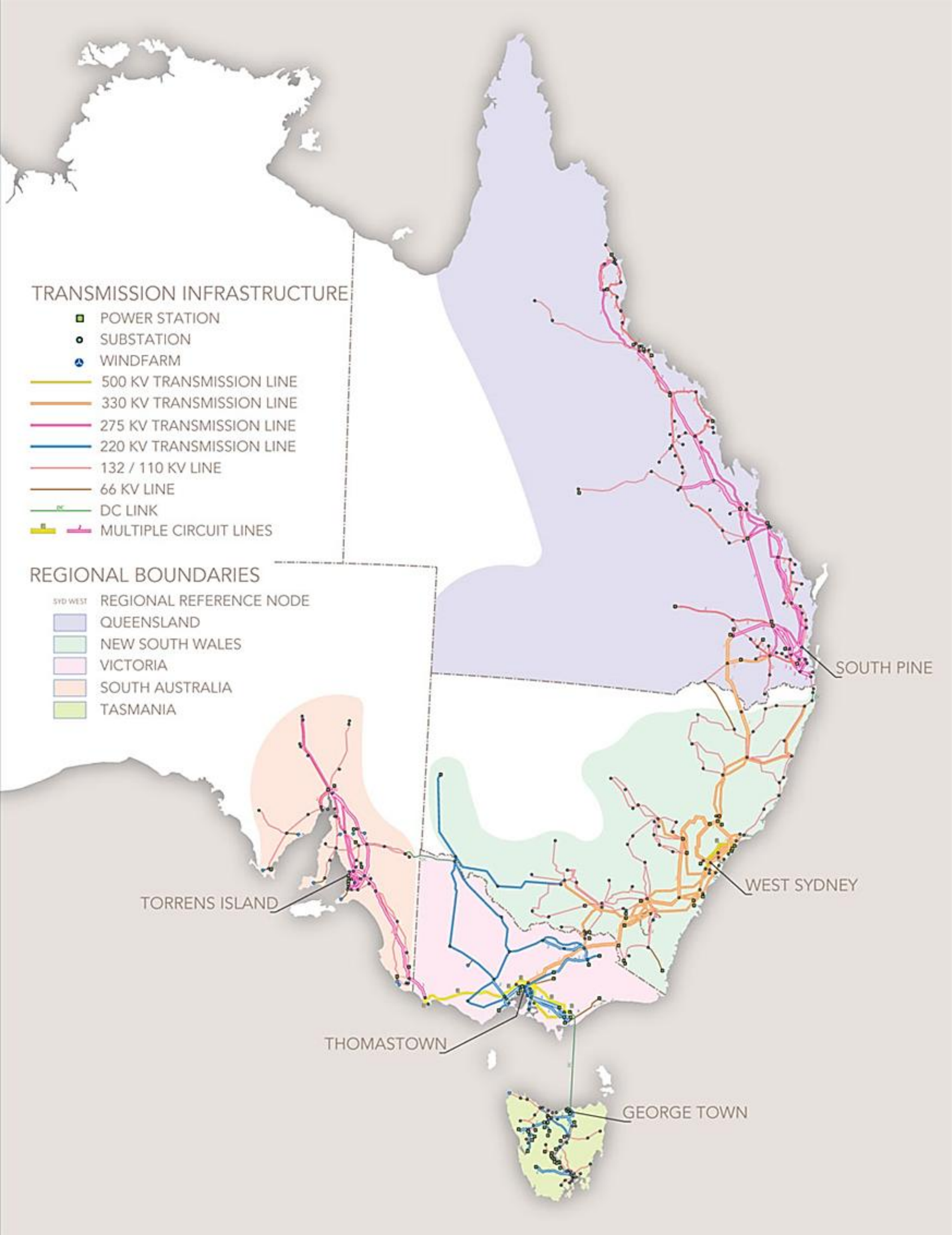
- 15% of contingency FCAS
- 12% regulation FCAS

(Total estimated saving of **$116m**)

In South Australia:

- Average annual regulation FCAS costs from SA generators fell from **$470/MWh** to less than **$40/MWh**

(**91%** reduction)

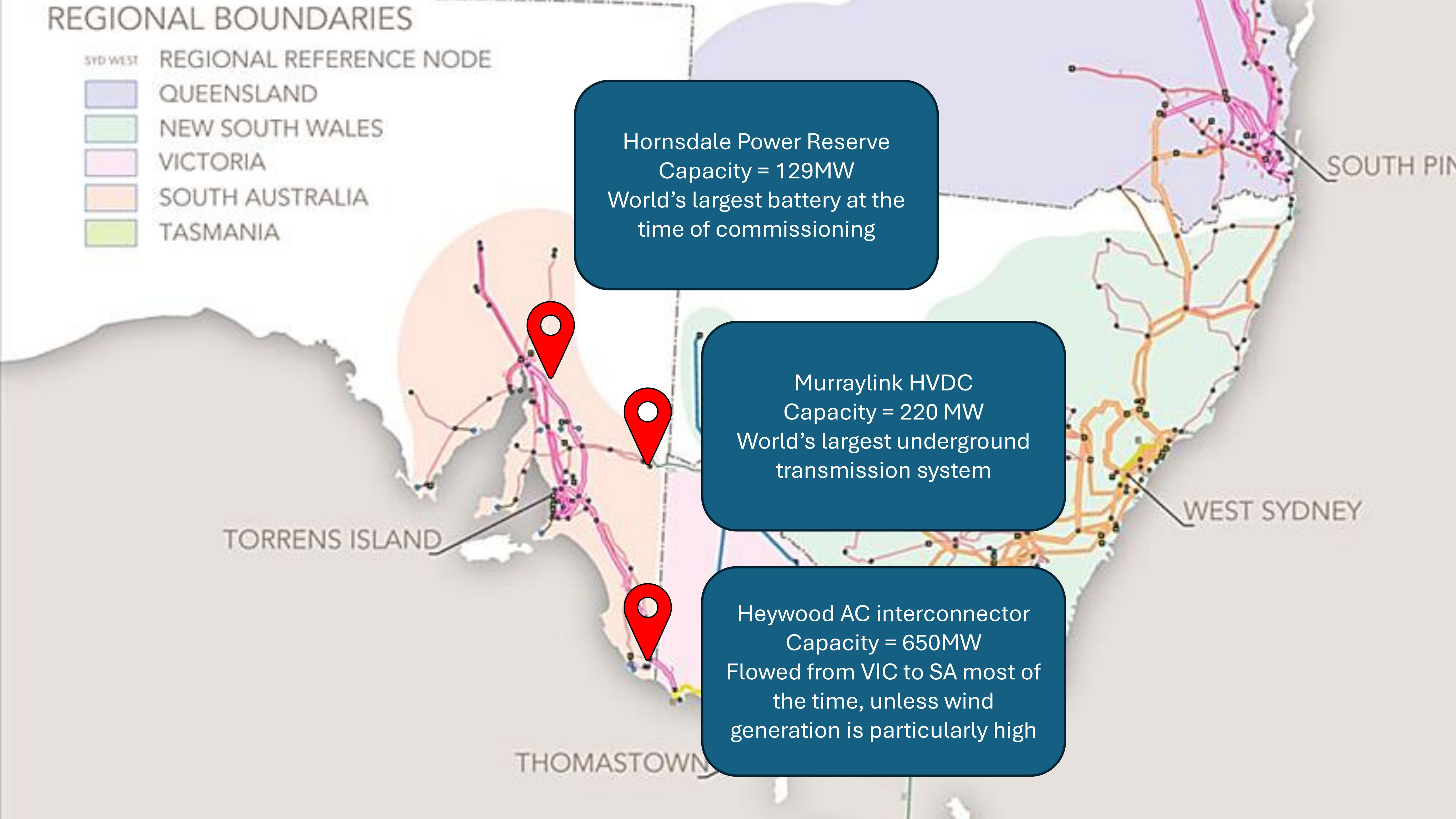


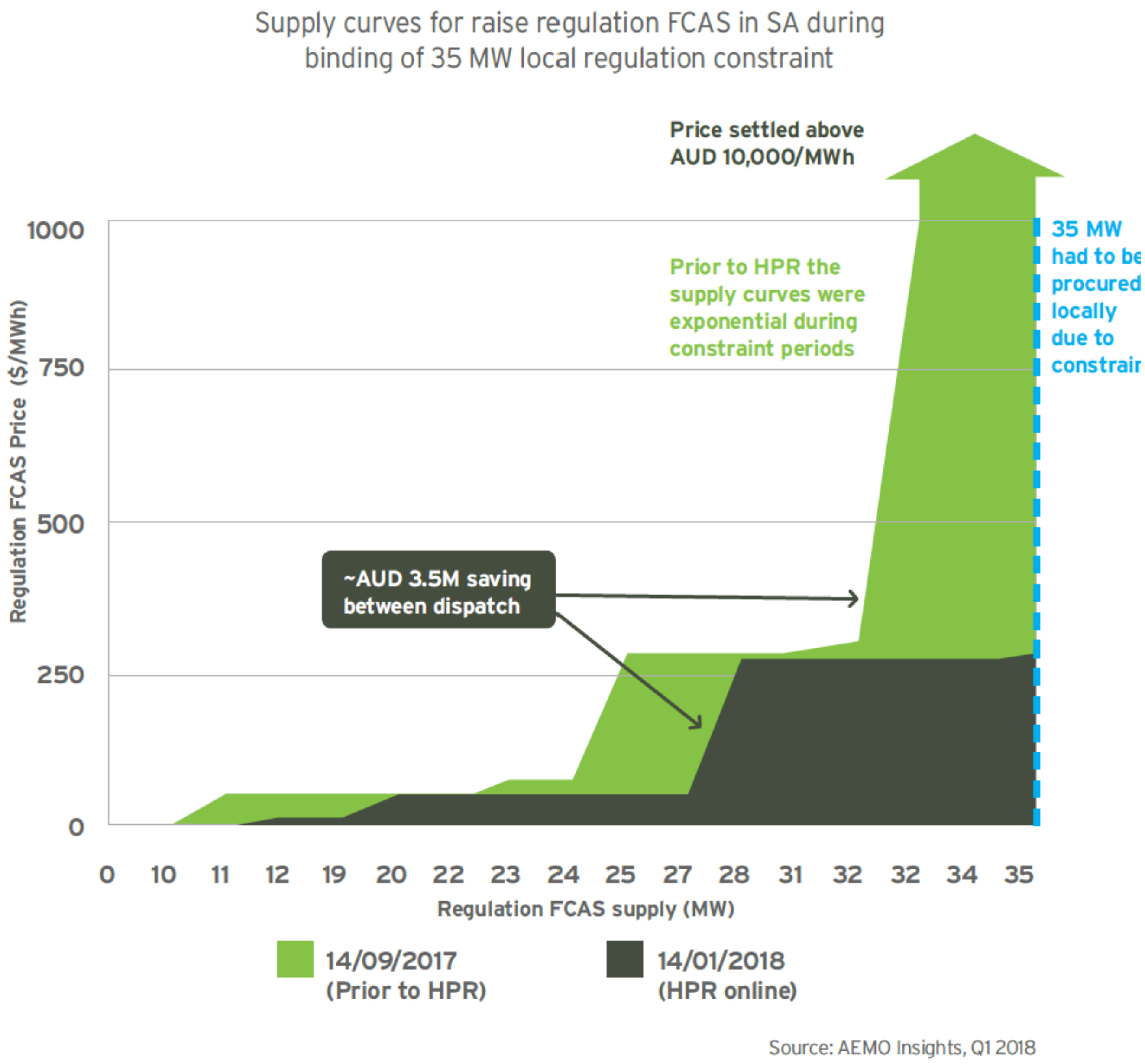
HPR's effect on prices

Background

- AEMO required 35 MW of local FCAS to be procured during periods of contingency risk

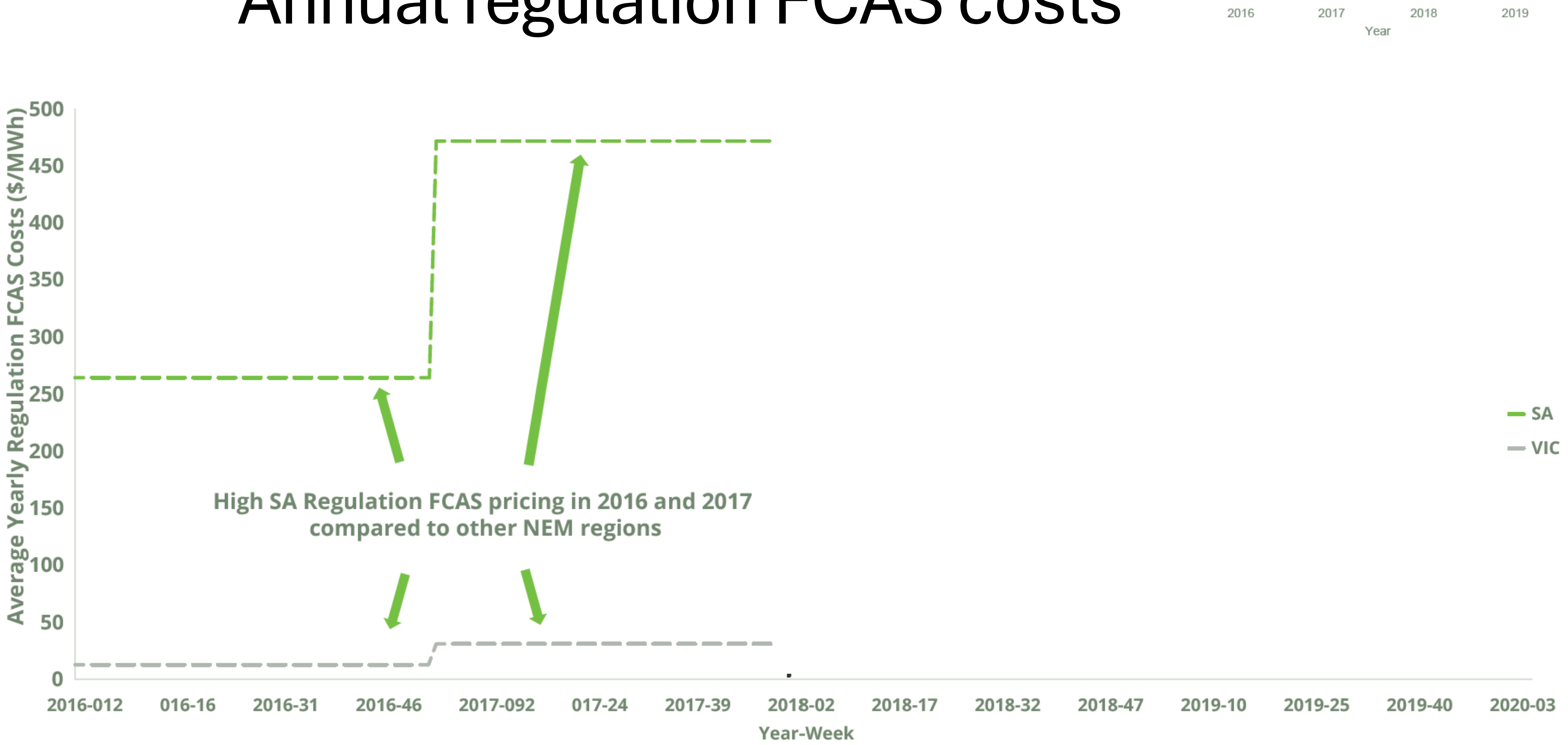
N-CONFIDENCE: ORGANISATION


REGIONAL BOUNDARIES
SYD WEST REGIONAL REFERENCE NODE
QUEENSLAND
NEW SOUTH WALES
VICTORIA
SOUTH AUSTRALIA
TASMANIA
Hornsdale Power Reserve
Capacity = 129MW
World's largest battery at the time of commissioning
Murraylink HVDC
Capacity = 220 MW
World's largest underground transmission system
Heywood AC interconnector
Capacity = 650MW
Flowed from VIC to SA most of the time, unless wind generation is particularly high
TORRENS ISLAND
WEST SYDNEY
THOMASTOWN

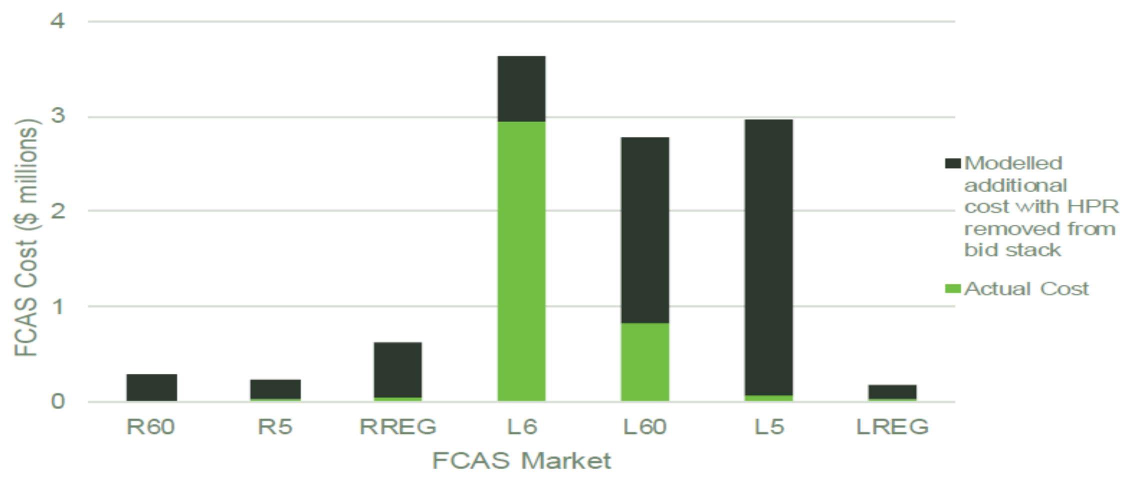


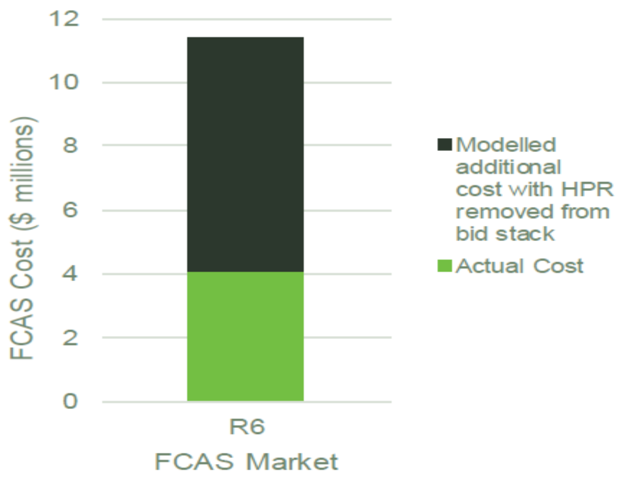
Supply curves for raise regulation FCAS in SA during binding of 35 MW local regulation constraint
Price settled above AUD 10,000/MWh
35 MW had to be procured locally due to constrair
Prior to HPR the supply curves were exponential during constraint periods
~AUD 3.5M saving between dispatch
Regulation FCAS Price ($/MWh)
1000
750
500
250
0
0 10 11 12 19 20 22 23 24 25 27 28 31 32 32 34 35
Regulation FCAS supply (MW)
14/09/2017 (Prior to HPR)
14/01/2018 (HPR online)
Source: AEMO Insights, Q1 2018

Annual regulation FCAS costs



16 November 2019 – islanding event





	R6	R60	R5	RREG	L6	L60	L5	LREG	TOTAL
Actual Cost (HPR Present)	$4,103,240	$2,524	$25,693	$43,852	$2,950,069	$837,194	$61,373	$29,545	$8,053,489
Modelled Cost HPR removed from bid stack)	$11,418,127	$297,632	$238,674	$624,422	$3,625,910	$2,776,240	$2,969,081	$172,705	$22,122,791
Cost Differential	$7,314,887	$295,108	$212,980	$580,569	$675,840	$1,939,046	$2,907,708	$143,159	$14,069,301
Savings (%)	64%	99%	89%	93%	19%	70%	98%	83%	75%

AER v Hornsdale Power Reserve Pty Ltd [2022] FCA 738

- firmware upgrade accidentally changed HPR's droop settings from **1.7%** to **3.7%**.
- This went unnoticed for 4 months.
- Kogan Creek coal generator (750MW) in Queensland tripped on October 9 2019:
  - HPR provided **13.4MW** rather than the **29MW** it was required to supply.
  - Issue was not identified immediately, only during a regular AEMO audit of FCAS payments a month after the incident.
  - Audit found that HPR did not supply the amount that they had been paid for.

Summary

(Slide 1 of 2)

HPR had a major impact on the costs of FCAS, however:

- Significant part of that was due to eliminating a constraint
- Does not have the same incentives as a privately owned BESS due to contractual with SA government

Early BESS focused on providing FCAS, reducing the costs as more expensive providers/generating types were displaced.

However, these cost reductions weren't as large as the ones when HPR entered the market.

Summary

(Slide 2 of 2)

New BESS is focusing on, and expected to continue focusing on energy arbitrage as the priority revenue stream.

- "By 2030 over **80%** of battery project revenues will come from energy arbitrage, as FCAS markets saturate"
  - *Max Whiteman, research associate of Asia Pacific Power & Renewables at Wood Mackenzie*

Authority's BESS projects

- Upcoming workstreams for BESS

References

- Reports from Aurecon Group:
  - Technical and market impact report - 2018
  - Technical and market impact study – 2020
  - HPR expansion project – 2023

Option 1

Lowering the 30MW threshold

Costs:

Minor:

- Modern technology used for new generating stations should inherently be able to comply:
  - Uses same equipment as overseas markets with stricter requirements
- For generating stations that are capable of complying, the cost is minor – essentially changing a software setting.

Option 1

Lowering the 30MW threshold

What size should the threshold be?

10MW:

- *Almost* aligns with clause 13.25, which states that generators are not required to submit offers for generating stations that are 10MW or smaller.
  - A station at exactly 10MW would have to comply with frequency AOPOs, but would not be required to submit offers.
- Reducing the threshold below 10MW would require generating stations to install a data transmission system with Transpower (SCADA – ICCP/Web Services)

Option 1

Lowering the 30MW threshold

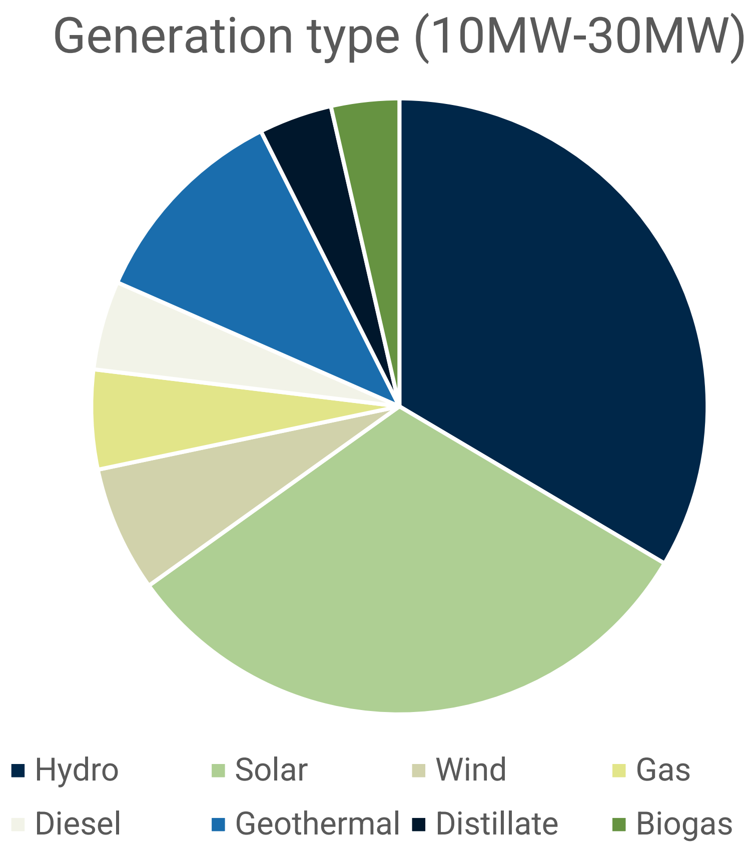
Existing generation under 30MW

Possible grandfathering approaches

Summary of ACS information

10 - 30MW category

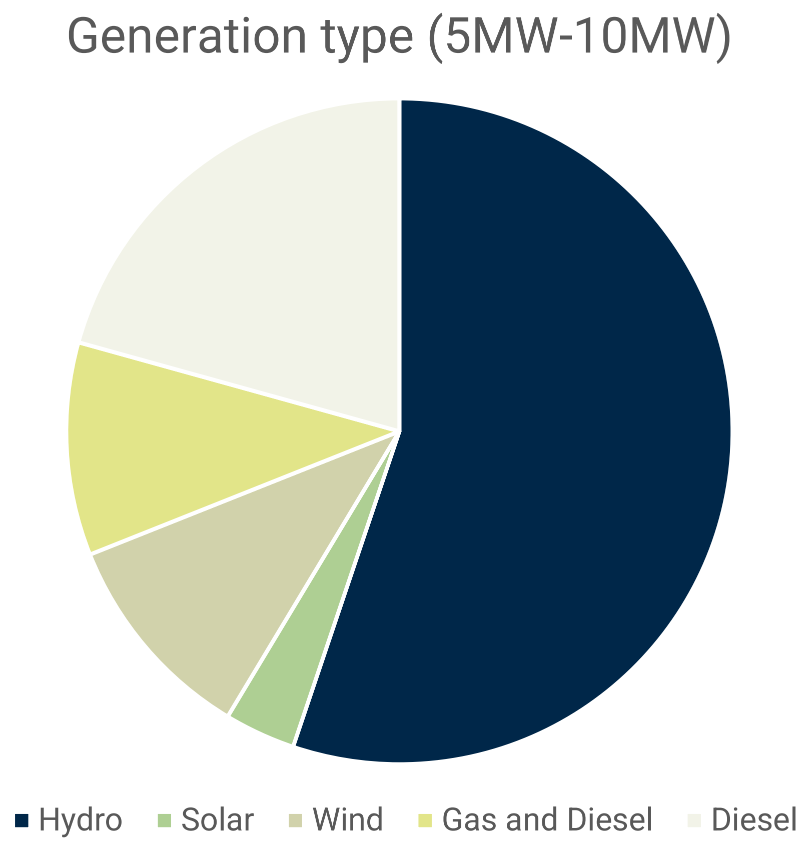
- **17** generating stations
- Approximately **364MW** combined capacity
  - Hydro - 122MW
  - Solar - 115MW
  - Wind - 24MW
  - Gas - 19MW
  - Diesel - 17MW
  - Geothermal – 40MW
  - Distillate – 14MW
  - Biogas – 13MW



Summary of ACS information

5-10MW category

- **23** generating stations
- Approximately **145MW** combined capacity
  - Hydro - 80MW
  - Solar - 5MW
  - Wind - 15MW
  - Gas and diesel - 15MW
  - Diesel - 30MW



Option 1

Lowering the 30MW threshold

When should the lower threshold take effect?

Lower threshold to affect generating stations:

- commissioned after a certain date?
- financially committed after a certain date?
- any other proposed alternatives?

Option 1

Lowering the 30MW threshold

Other CBA-related questions

- Estimate of costs imposed on generators:
  - when applying for a dispensation?
  - control system changes?
  - ongoing asset testing / compliance-related costs?
  - complying with an under-frequency event investigation?

Option 2

Setting a permitted maximum dead band

Benefits

- Reduces the amount of frequency keeping
  - the existing MFK band of ±15MW is likely to be sufficient until at least 2035
- Reduces the disproportionate wear and tear on some generators
  - greater changes in output - further from the optimal set point – the greater the physical and operational stress. This leads to increased maintenance, reduced efficiency and higher operating costs.
- Less reliance on a relatively small pool of generators
  - Additional safety net if Transpower had an internal service failure of its SCADA system and temporarily loses visibility.
  - Increases the proportion of generators automatically providing frequency support.

Option 2

Setting a permitted maximum dead band

AEMO's implementation of a narrower dead band

- **Action item 7.14:** Authority to further investigate option 2, with a particular focus on learnings from Australia's implementation of a uniform small deadband.

Implementation of narrower deadband in the NEM

Summary

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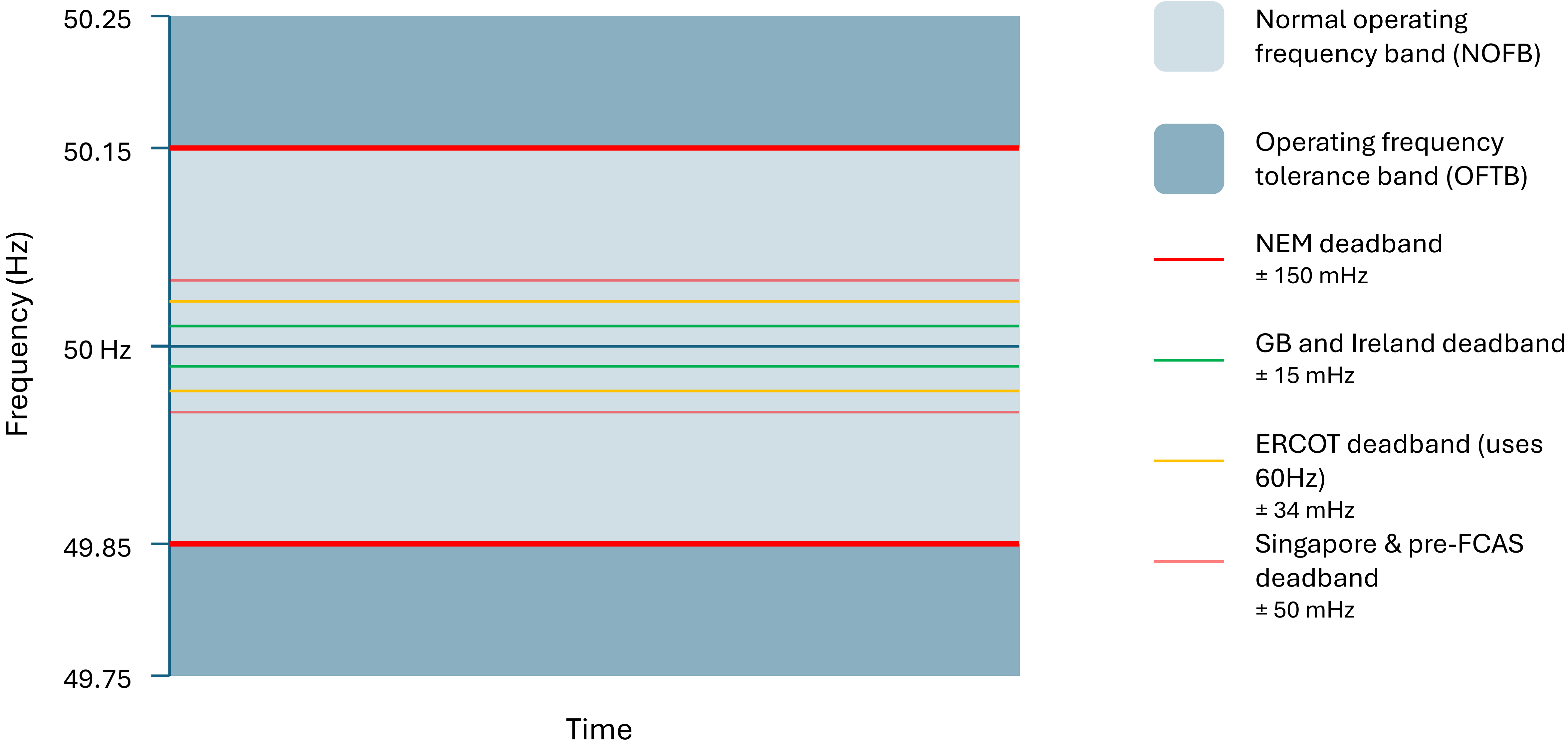
Maximum permitted deadbands



Maximum permitted deadbands

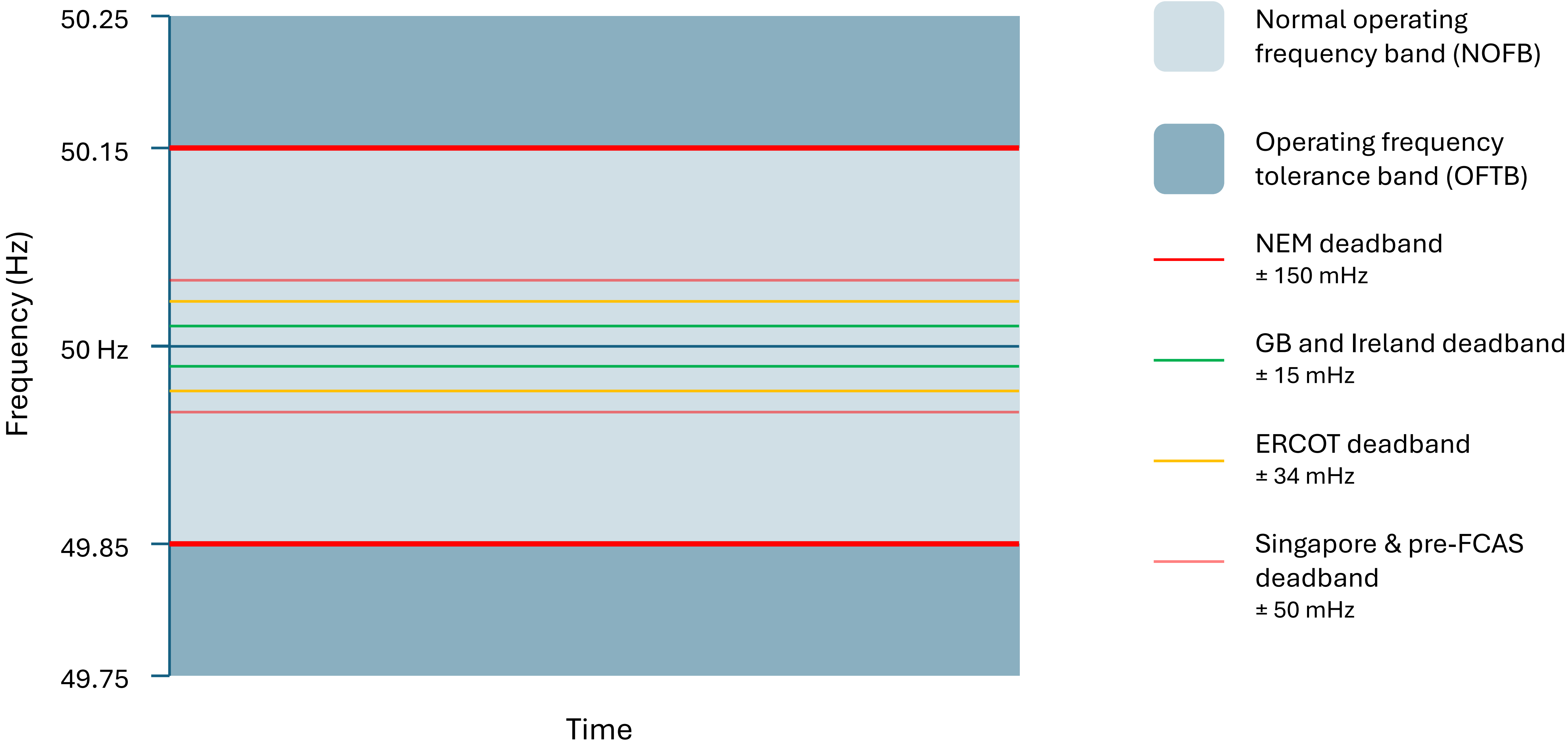


Figure 2 Monthly mainland frequency distribution since 2007

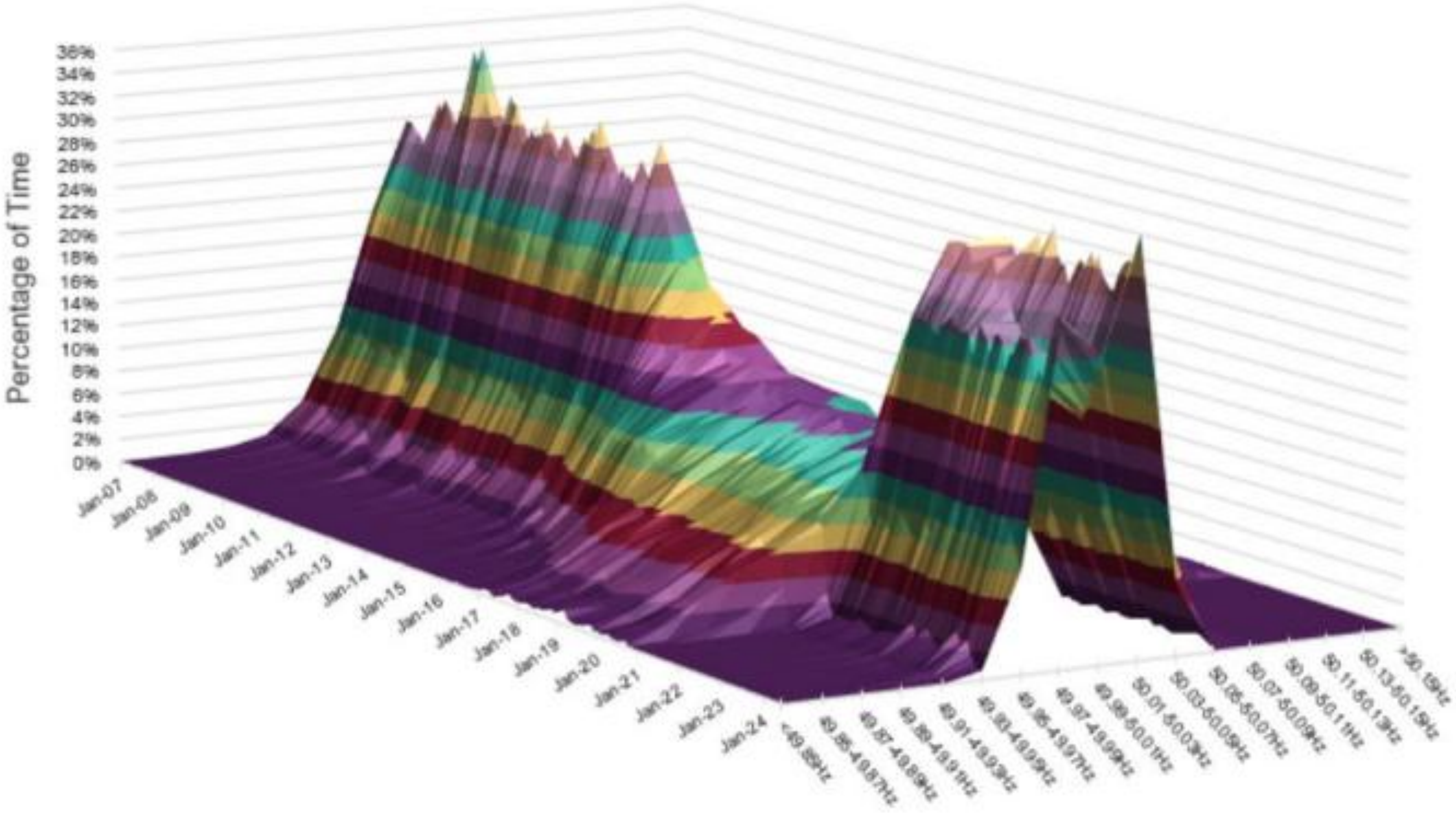
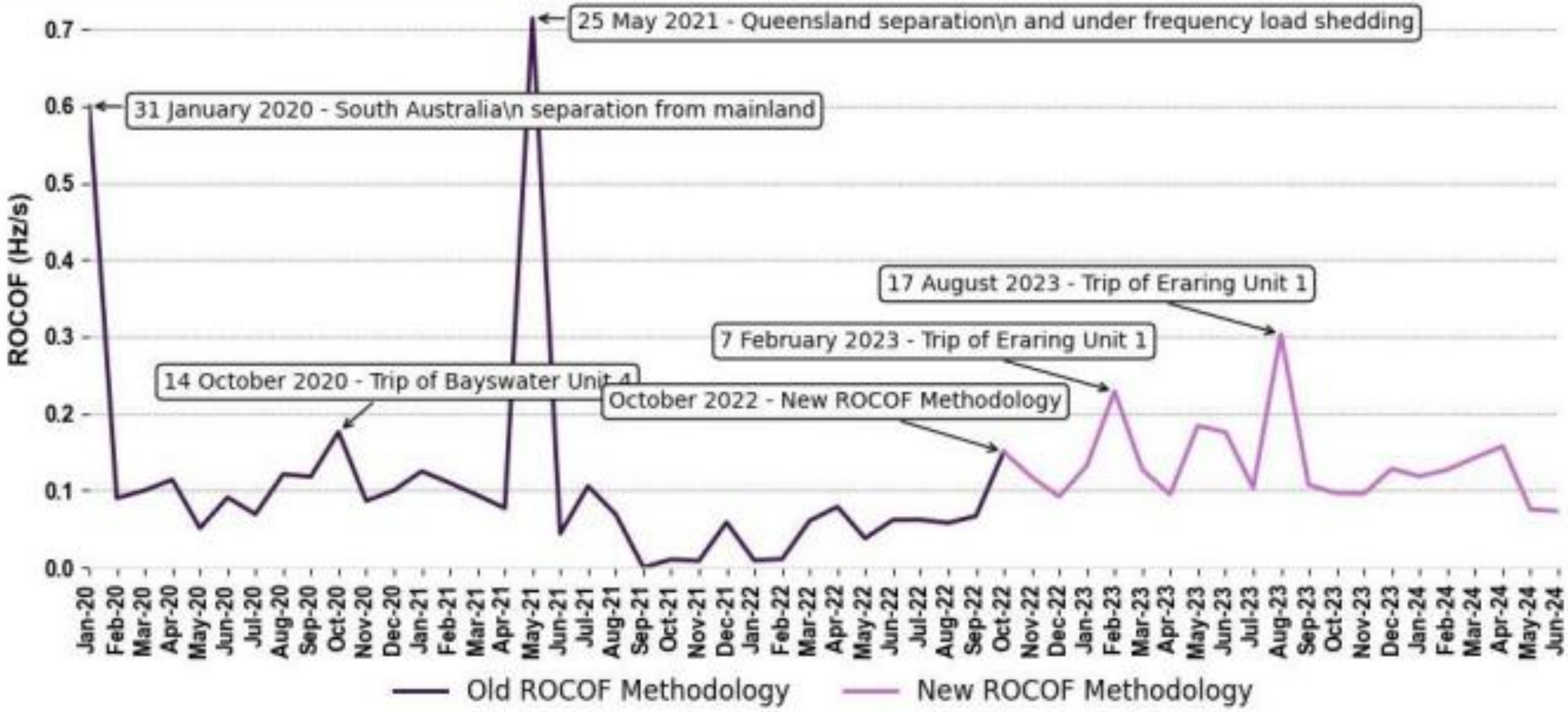


Figure 10 Monthly maximum RoCoF recorded in any mainland region since 2020



Note: 31 January 2020 RoCoF as measured in South Australia and 25 May 2021 RoCoF as measured in Queensland. New ROCOF calculation methodology used as of October 2022.

Implementation

- Uniform deadband applies to all types of generation.
- Slow progress – lack of consultancy resource which has led to AEMO prioritising generators with a higher MW capacity.
- Difficulties with IBR complying with different requirements
- Requirement on AEMO to publish regular reports on implementation progress:
    - Guidance on transitioning to new requirements
    - Register of generating units that do not fully meet the requirements, with details on any exemptions or variations.
    - Date expected to be compliant (or multiple dates if a staged approach is agreed with AEMO)
    - Reporting on system frequency trends to show the impact of the narrower deadband on system frequency
        - Duration of under-frequency events
        - Distribution of frequency over longer time periods

- AEMO publishing regular progress updates on the status of other improvements being investigated to better manage frequency, for example the implementation of a very fast FCAS and studies on system inertia.

Reducing costs imposed on participants

- No requirement to maintain headroom, footroom or stored energy for the purpose of providing PFR.
- When idle, no requirement to provide PFR although they may be financially incentivised to do so.
- Generators can implement a varied deadband with approval from AEMO.

- AEMO has discretion in the modelling and testing requirements:
  - Can provide data from an actual frequency response instead of test data
  - Only one unit is required to be tested if part of a "generating system" made up of identical units
  - Recent tests can be used, or test results from earlier periods reused if no material changes have been made
  - Allowance for some tests to be deferred and included in next scheduled periodic test

- No additional monitoring is undertaken by AEMO

Exemptions and variations

- Generators can apply on certain grounds:
  - Lack of capability to comply due to inherent design characteristics
  - The generator would operate unstably if required to comply
  - Dispatch inflexibilities
  - Regulatory/resource licensing or consents
  - Unreasonably disproportionate costs imposed on the generator affecting its viability

Information that may be required to support applications for exemptions or variations is stated up front

- Provision of OEM specifications
- Test results from the OEM
- A recent assessment from a consulting engineer
- Provision of regulatory consents or other conditions of operation
- Connection agreements with distributors that evidence any operating restrictions
- Documentation evidencing the expected capex and opex costs of modifying and operating the unit

PFR requirements in the NEM

(Approximate, as of mid 2023)

320
generating stations

45
variations approved

15
exemptions granted

Variations and exemptions

- **23** out of the 45 variations are to apply a dead band that is wider than the regulated dead band of ±15mHz (other options were to vary the droop and/or response time requirements).
- **22** of those have been approved by AEMO to apply dead bands that are ±100mHz or narrower – only one of them is outside that range (Meadowbank hydro run-of-river with an approved dead band of ±150mHz

Generation type	% exempt and varied
Coal	55%
Natural gas	43%
Hydro	9%
Wind	16%
Solar	8%

Questions for the CQTG:

1. Does the amount of variations and exemptions indicate that technology specific dead bands may be beneficial?
2. Views on a preferred dead band range? ±15mHz, ±100mHz, ±150mHz?

Option 2

Setting a permitted maximum dead band

Estimating costs for the CBA

- Avoided cost of procuring additional frequency keeping
  - Estimating the costs of widening the band by ±1MW in each island – is it practical to estimate the cost increase to be linear?

- Estimated costs to generators for:
  - applying for dispensations?
  - control system upgrades?
  - Ongoing asset testing / compliance related costs?

- Any other suggestions on quantifiable benefits or costs?

Voltage (Issues 2 – 4)

GXP power factor study (Issue 3)

- Overview of system studies
- Key preliminary findings

GXP reactive power flows co-ordination (Issue 3)

- What might co-ordination look like?

Voltage support obligations (Issue 2)

Fault ride through (Issue 4)

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GXP power factor study (Issue 3)

TRANSPOWER

Reactive Power Flow at the GXP

Study and Findings

18.02.2025

Studies will be undertaken to analyse the reactive power flowing through GXPs and to determine appropriate requirements to manage the reactive power flow.

Stage 1

Analyse reactive power flowing through all the Transpower GXPs

Stage 2

a) Investigate appropriate technical criteria to manage reactive power flowing through the GXPs
b) Investigate the level of reactive power that the system operator or distribution network operators will have to manage when applying a technical criterion

Stage 3

Investigate the effects on managing transmission voltages and voltage stability if the GXP power factor is managed to appropriate limits

GXP reactive power flow requirements

Background

The system operator must maintain pre- and post-contingent event voltage within the Asset Owner Performance Obligation (AOPO) voltage range, that is:

+/- 10% for 220 and 110 kV nominal grid voltage
+/- 5% for 66 and 50 kV nominal grid voltage

To manage transmission system voltages, the system operator currently employs measures such as:

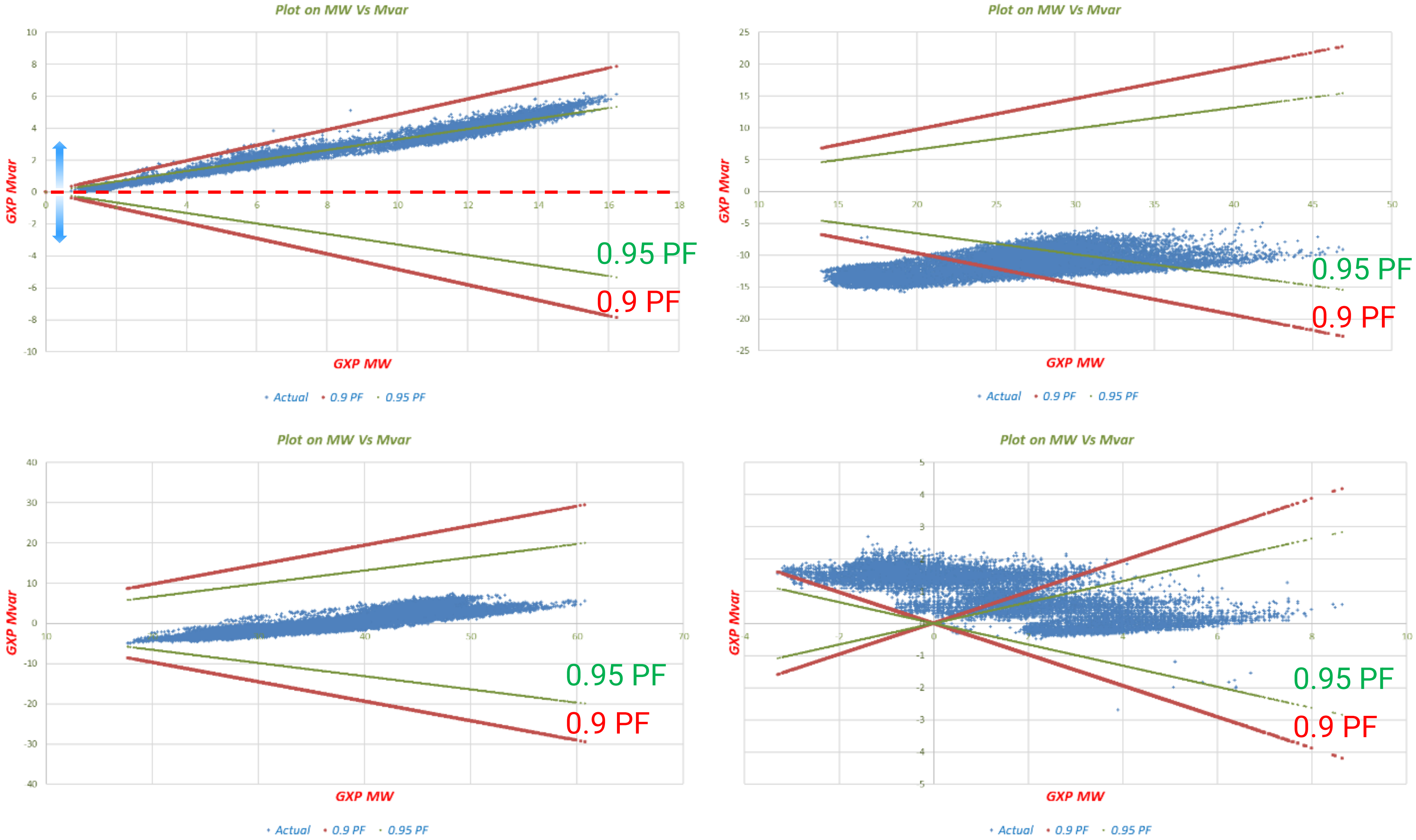
- Dispatching a generator to absorb or produce reactive power
- Using SVCs / STATCOMs to regulate voltages
- Tapping transformers
- Switching on/off capacitor banks and reactors
- Switching out lightly loaded transmission circuits

Stage 1

Analyse reactive power flowing through all the Transpower GXPs

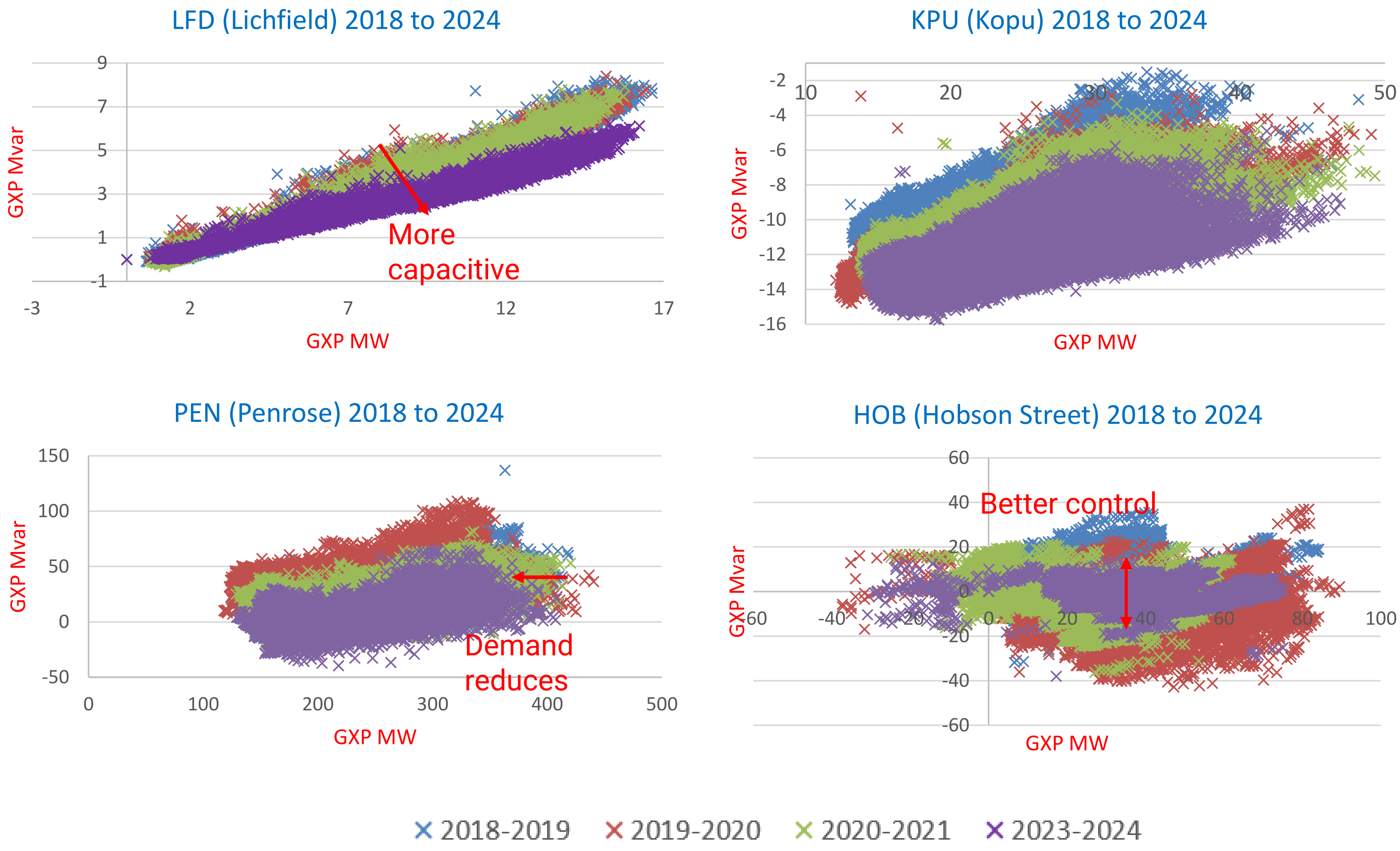
Characterisation of GXPs

- **Type 1:** Active and reactive power flowing into the substation
- **Type 2:** Active power flowing into and reactive power flowing out of the substation
- **Type 3:** Active flowing into and reactive power flowing into or out of the substation
- **Type 4:** Active power and reactive power flowing into or out of the substation



Why investigate now?

- Change in operational needs to improve efficiency
- Change in network characteristics
- Change in demand behaviour
- Uptake of distributed generation



Key observations

- GXPs seem to be more capacitive
- GXP demand reducing
- Better reactive power control

Stage 2

a) Investigate appropriate technical criteria to manage reactive power flowing through the GXPs
b) Investigate the level of reactive power that the system operator or distribution network operators will have to manage when applying a technical criterion

Literature research

AEMO

- > 400kV : 0.98 lagging to unity
- 250kV – 400kV : 0.96 lagging to unity
- 50kV – 250 kV : 0.95 lagging to unity
- 1kV – 50 kV : 0.90 lagging to 0.90 leading

North American Electric Reliability Corporation (NERC)

- Transmission network planner and distribution network planner performed joint studies to determine a set of mutually agreed minimum and maximum power factors
- Different ISOs impose different power factor requirements ranging from 0.95 to as high as 0.998
  - For example: PJM sets a minimum power factor of 0.97 lagging in their planning studies and the California ISO imposes a requirement of 0.97 lagging and 0.99 leading to maintain reactive power at the grid interface

European Network of Transmission System Operators for Electricity

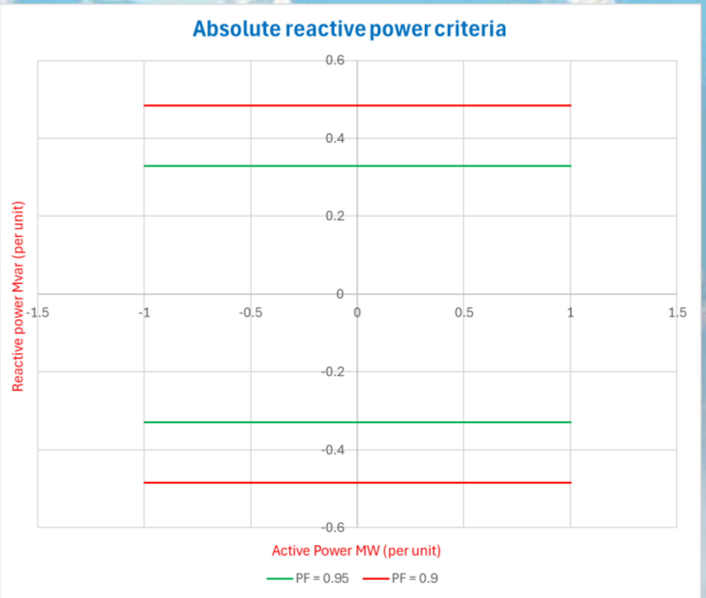
- European system operators require transmission-connected distribution networks to maintain a power factor greater than 0.9 of the larger of their maximum import/export capability except in situations where either technical or financial benefits are demonstrated.
- Not exporting reactive power at active power flow of less than 25% of the maximum import capability.

Assessment criteria

Power factor

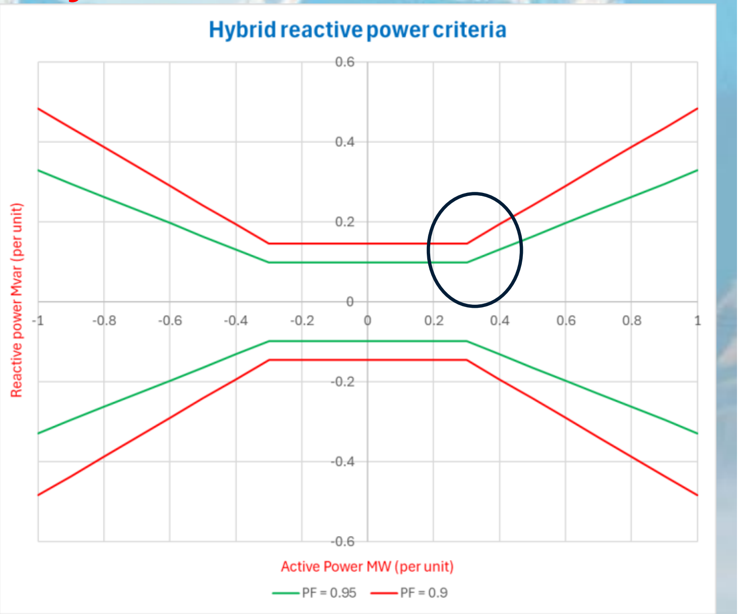
- Reactive power limit depends on the active power flow
- Too stringent at low active power demand

Absolute reactive power



- Reactive power limit depends on maximum active power demand
- Too lenient at low active power demand

Hybrid



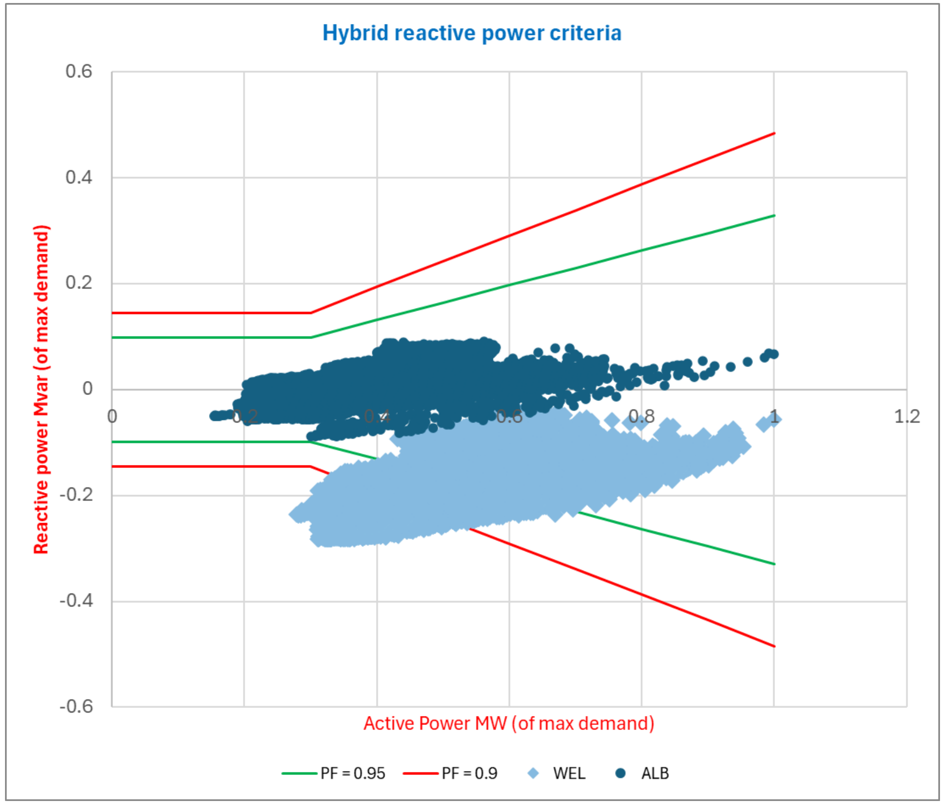
- Combination of power factor and absolute reactive power criteria
- Resolves low active power demand problem

Grid Zone Analysis

GXP	Type	Export Q (% of Trading Periods (TPs))	Import Q (% of TPs)	PF Limit 0.95 (% of TPs)	PF Limit 0.90 (% of TPs)	Q Limit 0.95 (% of TPs)	Q Limit 0.90 (% of TPs)
HEP	3	81	18	1.09	0.00	0.00	0.00
ALB	3	46	54	0.00	0.00	0.00	0.00
HEN	3	100	0	7.15	0.00	0.00	0.00
BRB	3	94	3	9.90	0.17	0.00	0.00
KOE	3	66	34	0.19	0.02	0.00	0.00
MPE	3	61	39	0.66	0.03	0.00	0.00
MTO	3	98	0	18.88	5.42	0.00	0.00
SVL	2	100	0	26.44	3.70	0.00	0.00
SWN	4	18	54	25.83	19.35	0.00	0.00
WEL	2	100	0	49.27	28.25	0.00	0.00
WRD	3	96	0	45.17	22.42	0.00	0.00

Grid Zone Analysis

GXP	0.9 Hybrid 30% of Q limit (% of TPs)	0.9 Hybrid 40% of Q limit (% of TPs)	0.9 Hybrid 50% of Q limit (% of TPs)	0.95 Hybrid 30% of Q limit (% of TPs)	0.95 Hybrid 40% of Q limit (% of TPs)	0.95 Hybrid 50% of Q limit (% of TPs)
HEP	0.00	0.00	0.00	0.01	0.00	0.00
ALB	0.00	0.00	0.00	0.00	0.00	0.00
HEN	0.00	0.00	0.00	0.36	0.00	0.00
BRB	0.17	0.01	0.00	9.90	9.73	2.80
KOE	0.00	0.00	0.00	0.01	0.00	0.00
MPE	0.00	0.00	0.00	0.62	0.09	0.00
MTO	5.39	1.89	0.00	18.88	18.22	10.88
SVL	0.32	0.00	0.00	26.44	15.40	0.00
SWN	0.00	0.00	0.00	0.00	0.00	0.00
WEL	28.25	26.47	16.90	49.27	49.27	48.54
WRD	21.11	12.51	7.61	45.12	38.75	25.91



Analysis summary – Power factor and absolute reactive power criteria

	PF Limit of 0.95	PF Limit of 0.90	Q Limit 0.95	Q Limit 0.90
substations with > 1% affected TPs	85	51	16	3
% of substations with > 1% affected TPs	66	40	13	2
% TPs affected (average of all substations)	17.76	8.13	2.26	0.26

- We analysed 128 substations
- Number of trading periods (TPs) ≈ 17,520
- ‘*substations with > 1% affected TPs*’ – the number of substations where the criteria were violated in more than 1% of trading periods
- ‘*% of substations with > 1% affected TPs*’ – the percentage of substations where the criteria were violated in more than 1% of trading periods (ie, substations with >1% affected TPs / 128 substations)
- ‘*% TPs affected (average of all substations)*’ – the percentage of trading periods in which the criteria were violated

Analysis summary – Hybrid criteria

0.90 PF hybrid reactive power criteria

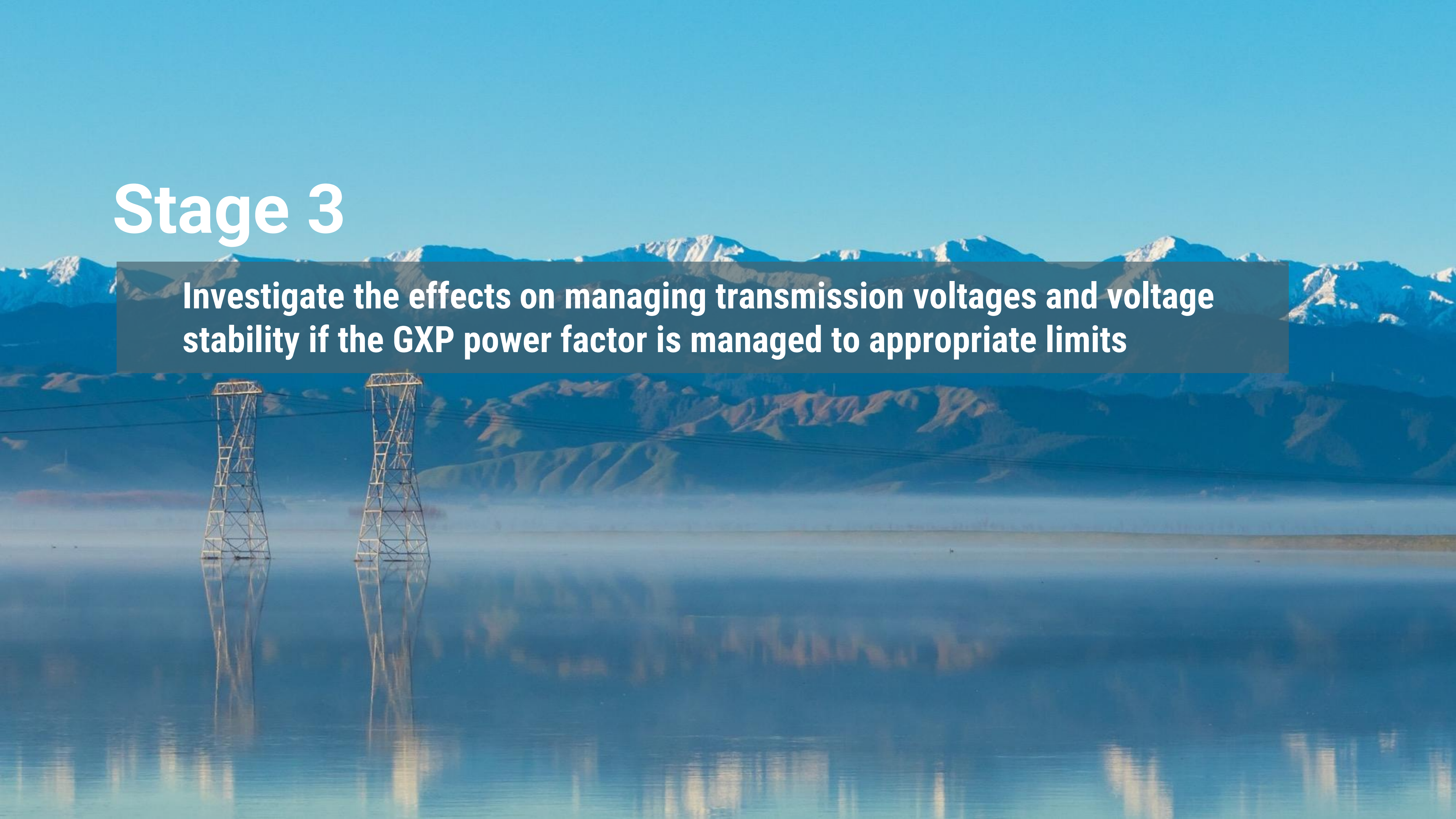
Reactive power (Q) limit	10%	20%	30%	40%	50%	60%	70%	80%	90%
substations with > 1% affected TPs	50	48	40	29	21	14	9	6	3
% of substations with > 1% affected TPs	39	38	31	23	16	11	7	5	2
% TPs affected (average of all substations)	7.57	7.17	5.97	4.19	3.00	2.08	1.43	0.92	0.45

0.95 PF hybrid reactive power criteria

Reactive power (Q) limit	10%	20%	30%	40%	50%	60%	70%	80%	90%
substations with > 1% affected TPs	85	82	72	64	48	39	30	23	19
% of substations with > 1% affected TPs	66	64	56	50	38	30	23	18	15
% TPs affected (average of all substations)	17.2	16.7	15.7	12.9	9.8	7.3	5.5	4.2	3.1

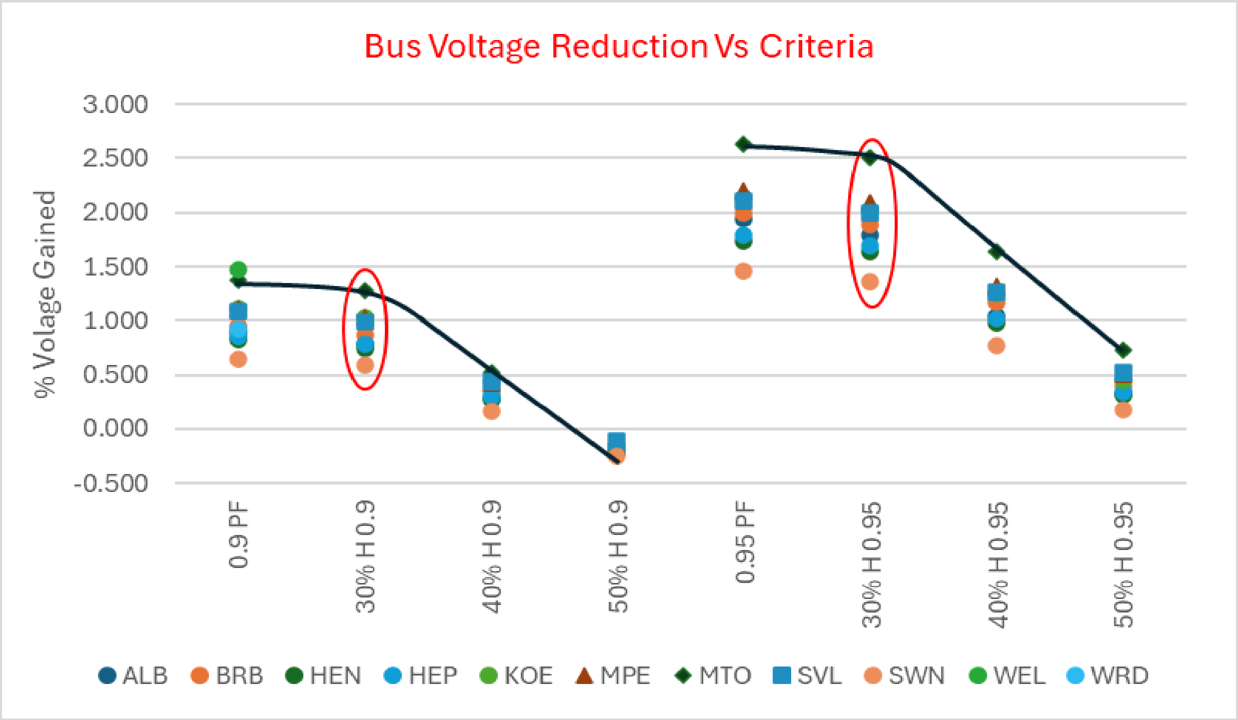
Stage 3

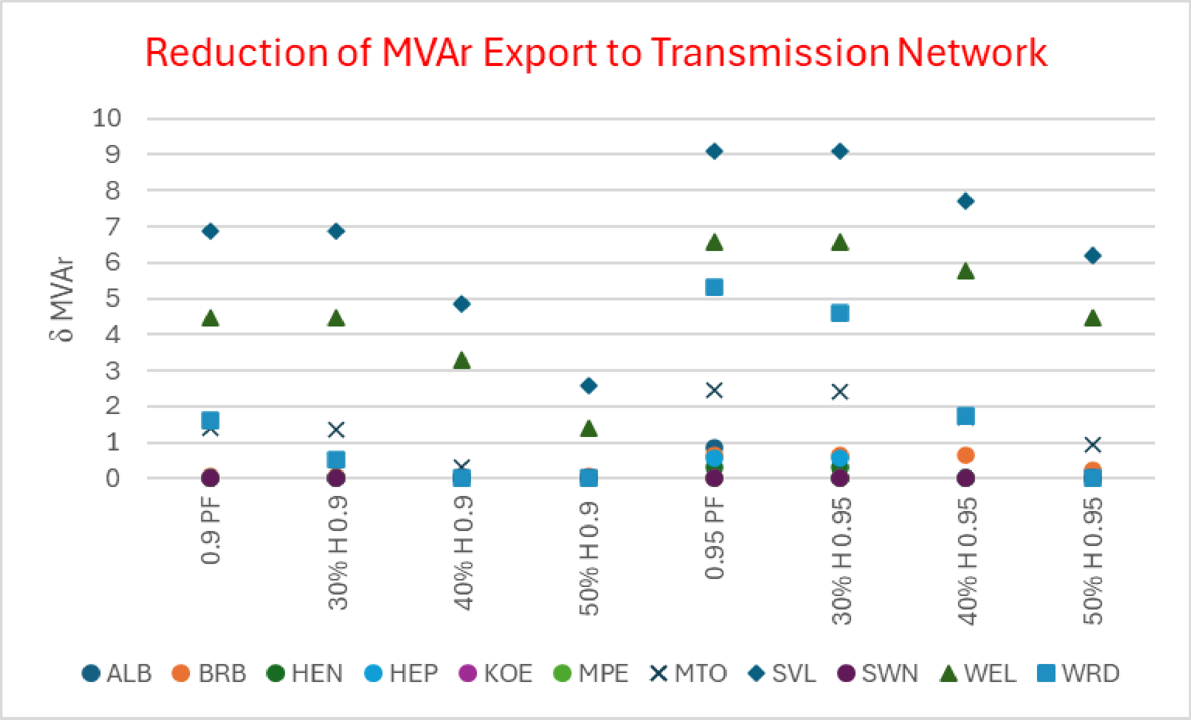
Investigate the effects on managing transmission voltages and voltage stability if the GXP power factor is managed to appropriate limits



Benefit of applying hybrid criteria and reactive power control margin

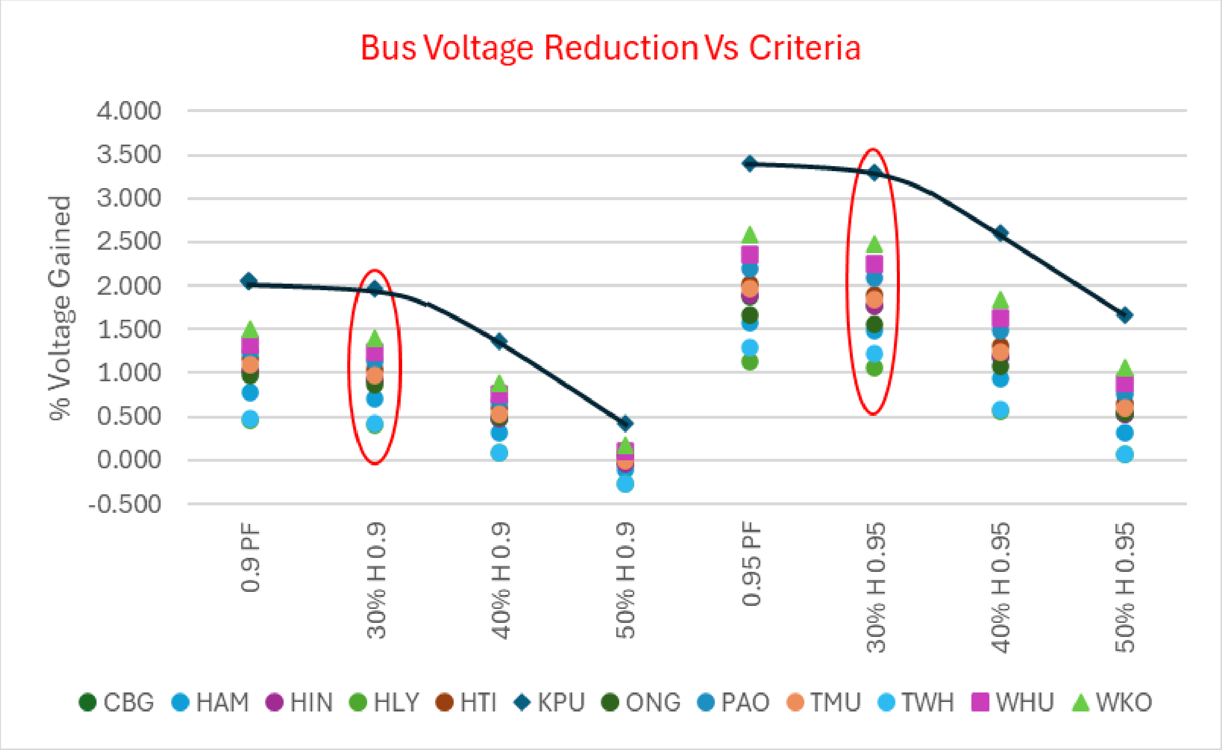
Grid zone 1 (Northland)

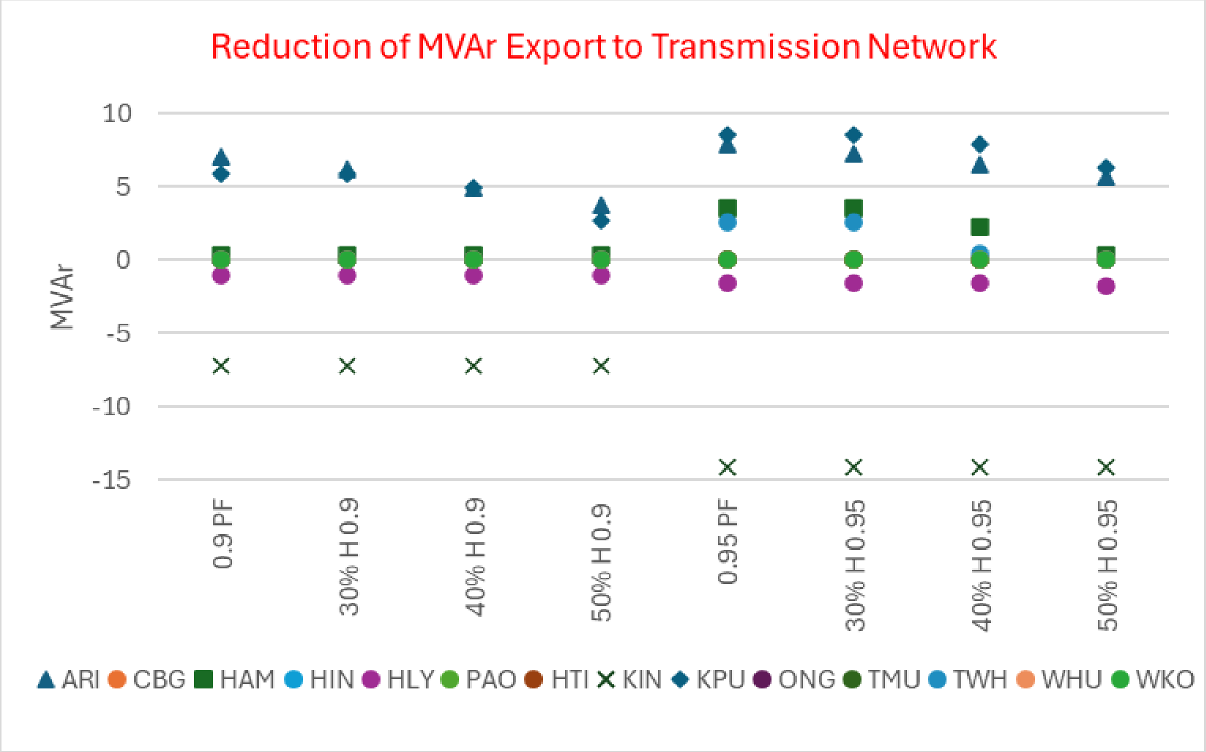




Benefit of applying hybrid criteria and reactive power control margin

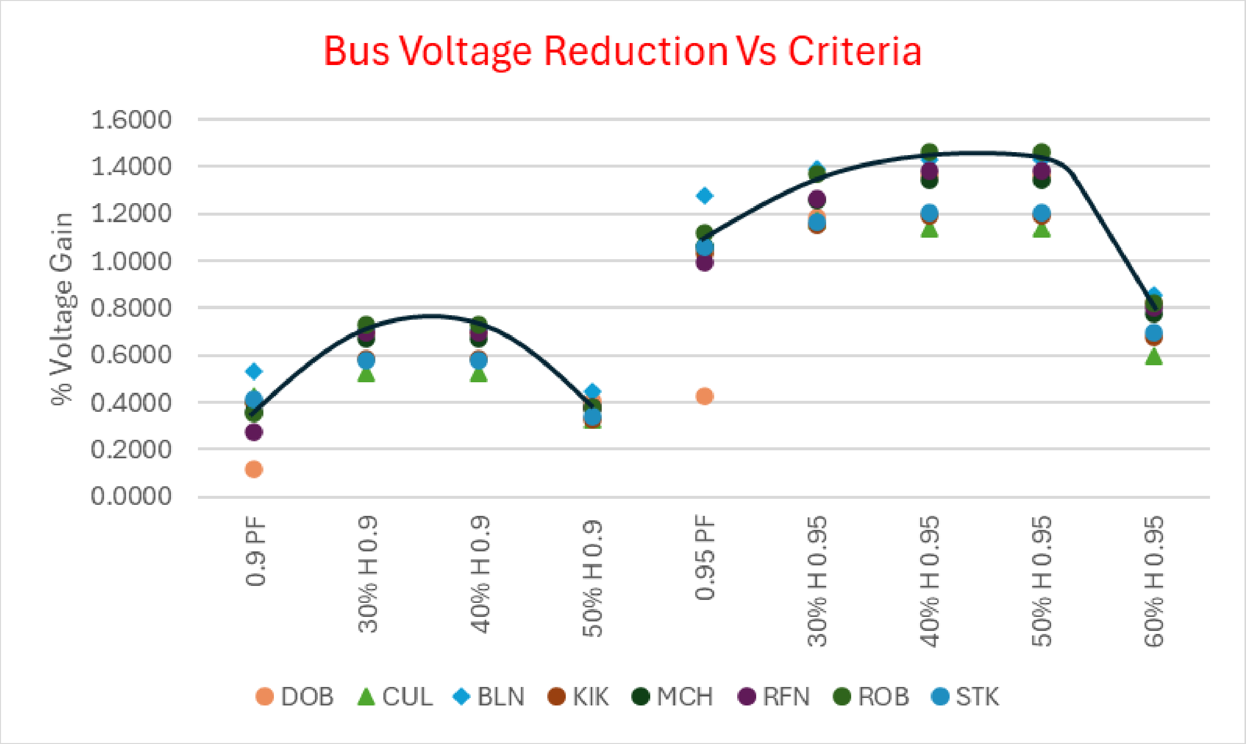
Grid zone 3 (Hamilton)

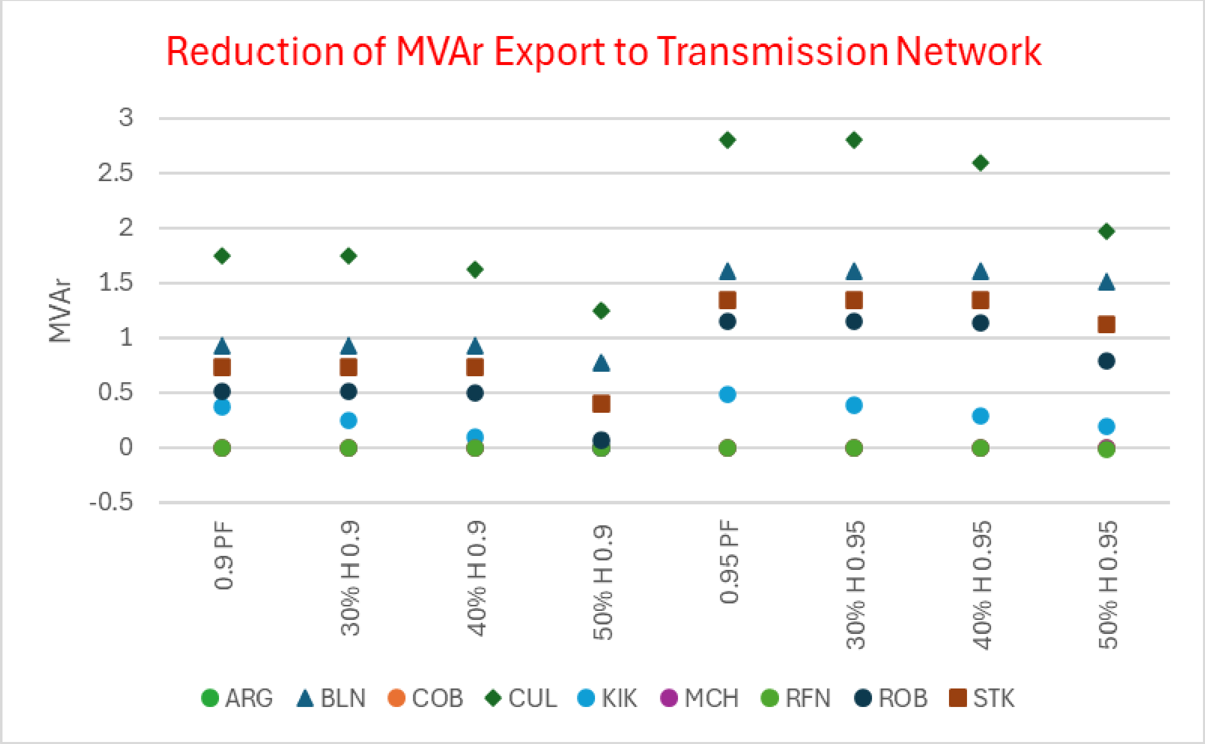




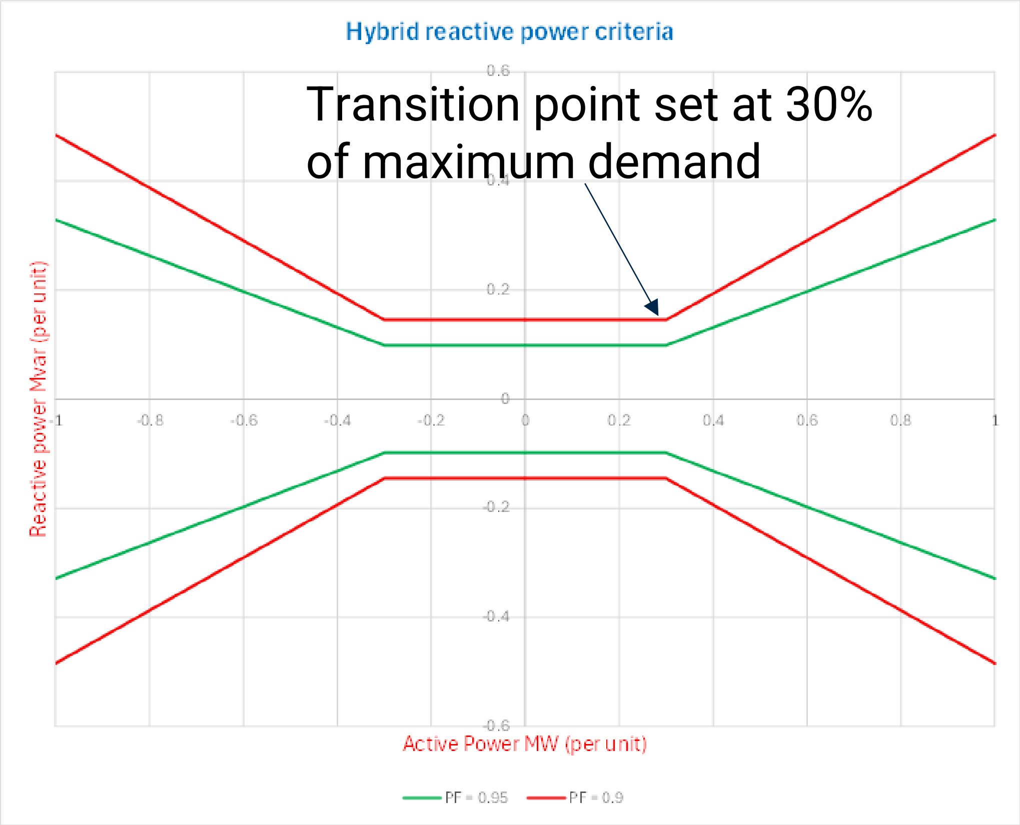
Benefit of applying hybrid criteria and reactive power control margin

Grid zone 9 (Nelson)





Our recommendations



Thank you

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Managing GXP reactive power flows: Options for system operator – distributor co-ordination

Background and context

- Relates to common quality key issue 2

  An increasing amount of variable and intermittent resources, primarily in the form of wind solar PV generation, is likely to cause larger voltage deviations, which are exacerbated by changing patterns of reactive power flows

- Aim of system operator – distributor co-ordination:

  Regulate GXP voltage more effectively by minimising reactive power flowing through the GXP

- Avoid distribution and transmission assets working against each other

Managing GXP reactive power flows: Options for system operator – distributor co-ordination

Background and context (continued)

- System operator's voltage studies 1 and 2 report recommended:
  - *System operator and distributors share responsibility for regulating GXP voltage*
  - *Distributed energy resources at GXP voltage provide distributor and system operator with visibility of DERs' operating status and active/reactive power output*
  - *DER have capability to accept reactive power dispatch instructions from distributor*

- Authority and system operator have brainstormed what this could look like

Status quo

- Distributors ensure their networks operate at nominal transmission grid voltages (220/110kV +/-10% and 66/50kV +/-5%)
- System operator uses telephone calls to applicable distributor if distributor needs to influence GXP voltage / GXP reactive power import or export
- Distributor then co-ordinates its assets and, where able, DER assets to influence GXP voltage / GXP reactive power import/export
- System operator does not have real-time indications of reactive power at low voltage side of GXP
- System operator has no view of distributor's network
- Distribution and transmission assets can work against each other in terms of reactive power flows
- System operator receives from DER generation:
    - Energy offers if generating station capacity >10MW
    - Real-time indications if generating unit maximum continuous rating >5MW
- System operator and distributors have few or no DER generation models

Co-ordination option (per system operator recommendation in report for voltage studies 1 & 2)

- System operator can send electronic dispatch notifications to distributor when needed to influence GXP voltage / GXP reactive power import or export
- Distributor co-ordinates its assets and DER assets to influence GXP voltage / GXP reactive power import/export

Characteristics of the option

Voltage management	• Distributor must control reactive power flow at the GXP, based on dispatch instructions from the system operator • Eg: if system operator observes DER generation output is 'fighting' the transmission grid in terms of voltage/ reactive power flows at the GXP • System operator gives dispatch notifications to distributor per current dispatch arrangements (4 mins to acknowledge)
Communications	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C

Modelling and analysis	• System operator has partial view of distributor's network
	• Distributor's network modelled as another reactive asset in the system operator's reactive power controller
	• System operator requires network connectivity model showing connection path of DER to the GXP
	• System operator's TSAT model requires DER dynamic models (generator and voltage control system)
	• Asset owner to provide:
	    • Validated dynamic models
	    • Special protection scheme models

Event response	• Expect DER to respond to voltage disturbances • System operator does not perform contingency analysis
Compliance	• DER voltage control testing obligation • System operator checks compliance with AOPOs

Advantages of the option relative to the status quo

Operations	• Improved operational efficiency from distribution and transmission assets not working against each other in terms of reactive power flows • Better visibility of distribution networks better enables system operator to manage the transmission grid more efficiently
Modelling and analysis	• System operator and distributors better able to model their networks as a result of receiving DER network connectivity model (as applicable)
Other	• Potentially defer investment in grid voltage management assets

Disadvantages of the option relative to the status quo

Operations	• Distributor may have to invest in network comms / control path with the DER to issue voltage instructions
	• Cost of operational co-ordination between Transpower's supply transformer tap changers and the DER generation
	    • System operator may push tap changers to limits
	    • May need comms/alarms for awareness
	• Challenges may arise from increased need for SCADA indications and data sharing (eg, how best to share data)
	• Roles and responsibilities around managing GXP voltage not as clear
	    • Under status quo distributor clearly responsible for its network operating when grid voltages within ranges specified in clause 8.22 of the Code

Modelling and analysis	• More modelling required
Other	

A couple of alternatives / counterfactuals

Alternative 1 – System operator has visibility of DER [and distributor?] active / reactive power status only

- System operator receives real-time indications from DER [and distributors?]
- DER and distributor not required to have capability to receive voltage dispatch instructions

Alternative 2 – System operator dispatches DER for voltage / reactive power

- System operator can send voltage control and reactive power electronic dispatch instructions at all times directly to the DER
- System operator receives real-time indications from DER [and distributors?]

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER directly
Voltage management	• Distributor co-ordinates with DER to manage GXP voltage (low voltage side of GXP)	• System operator dispatches DER electronically per current dispatch arrangements
Communications	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C

Modelling and analysis – SCADA data	• No network modelling required / no DER model required, although network connectivity model required where DER can connect to multiple GXPs (e.g. Aniwhenua)	• For real-time contingency analysis system operator needs:
		  • Distribution network model covering connection path from GXP to DER
		  • DER model data

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER

Modelling and analysis – Power system tools (VSAT / TSAT)	• Distributor's network modelled as another reactive asset in the system operator's reactive power controller	• TSAT needs DER dynamic models (generator and voltage control system)
		• Asset owner to provide:
		  • Validated dynamic models
		  • Special protection scheme models

Modelling and analysis – Market model	• DER generation netted off from GXP load if DER generation is not offered into the wholesale electricity market	• For real-time energy dispatch, the system operator:
		  • Needs energy offers from DER
		  • Fully models DER with reactive power capability
		  • DOES NOT need to model all the distribution network

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER
Event response	• Expect DER to respond to voltage event • System operator does not perform contingency analysis	• Expect DER to respond to voltage event • System operator performs full contingency analysis
Compliance	• DER voltage control testing obligation • System operator checks compliance with AOPOs	• DER voltage control testing obligation • System operator checks compliance with AOPOs

Advantages of the alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER

Operations	• Having more distribution voltage information enables system operator to better manage voltage on the transmission grid	• More efficient power system operation
		  • System operator has more visibility / a single view of distribution and transmission assets
		  • System operator can use full capability of DER
		  • System operator has more confidence in performance of DER
		  • Enables operational co-ordination between tap changers on Transpower’s supply transformers and DER generation

Advantages of the alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER
Modelling and analysis	• Provision of more SCADA and voltage information improves system operator's modelling	• System operator's (VSAT) modelling tools can make use of the DER's reactive power curve in the models, enabling full use of the generating unit, and thereby reducing the need to be conservative in contingency analysis
Other		• Potentially defer investment in grid voltage management assets • May reduce some of the need for DSO(s) and/or effort/cost to establish DSO(s)

Disadvantages of alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER
Operations	• Cost of SCADA indications • Data sharing hurdles • Potential for inconsistency in dispatched DER voltage set point across distributors	• Cost of SCADA indications • Data sharing hurdles • Potential for system operator directions to cause distributors issues managing their networks • Learning curve for system operator on behaviour of distribution networks • Potential more outage management workload for system operator • Cost of some distribution network outages possibly needing to feed into the planned outage co-ordination process (POCP)

Disadvantages of alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER

Modelling and analysis		• Network modelling costs for DER, distributors and system operator
		  • Currently, system operator and distributor network models incompatible
		  • Significant amount of modelling required in system operator's tools
		  • Distributors must tell system operator of abnormally configured assets

Other	• Potentially more investment in grid voltage management assets • From build-up of incremental inefficiencies over time	

Voltage support obligations

Option 1: Overview

Assign voltage support obligations to some additional parties

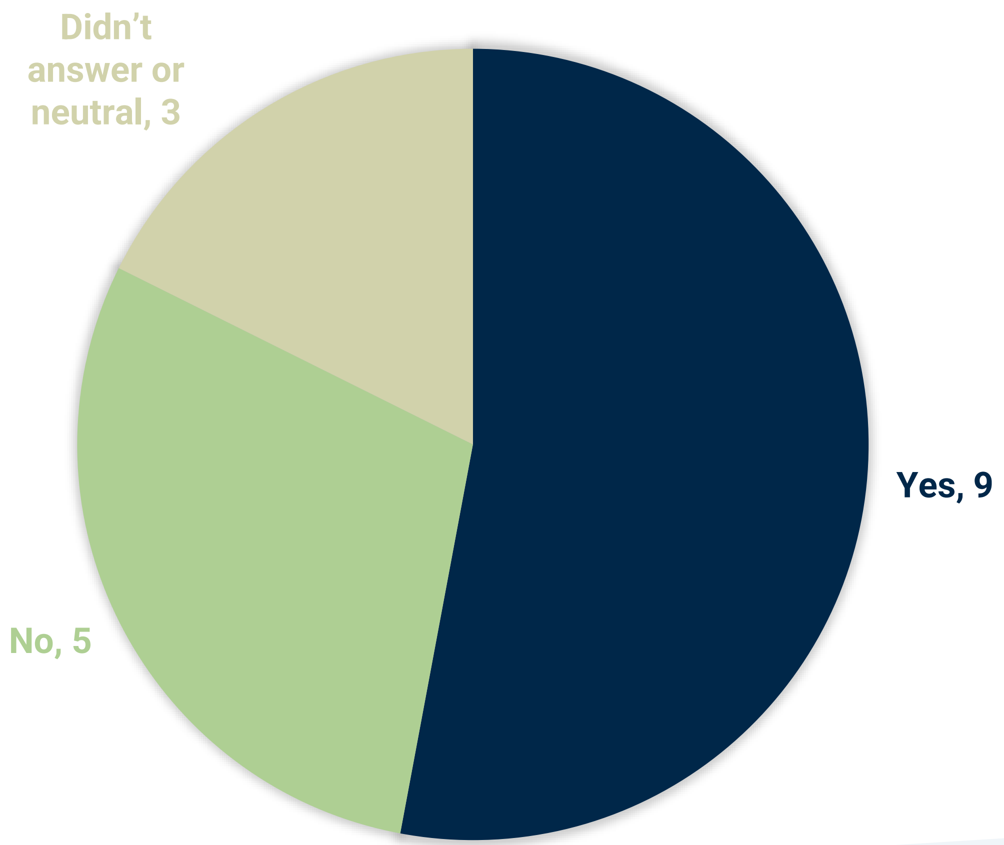
- Extend voltage obligations to distributed generation, embedded generating stations, and distribution-connected energy storage systems (when connected to a local distribution network at a nominal voltage equal to GXP voltage).

Option 1: Submitter feedback

Question 5: Should option 1 be short-listed?

Submitter feedback on short-listing option 1

- 17 submissions on voltage:



Option 1: Reasons for not supporting option 1

- 5 submitters didn't support progressing option 1 (**IEGA, Manawa, NewPower, Pioneer, WEL Networks**).
- Key reasons can be summarised as:
  - distributors should make these decisions for their own networks (ie, voltage should be managed via the distributor's Connection and Operation Standards)
  - mandating AOPOs cost embedded generators money and foreclose additional revenue streams like voltage support ancillary services.

Option 1: Support with caveats

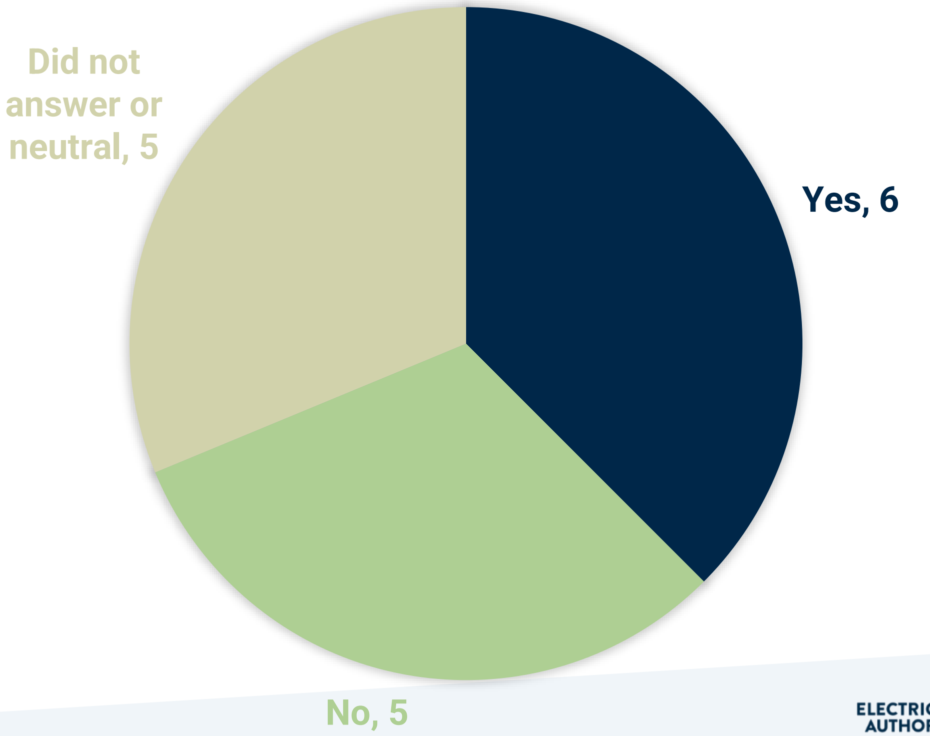
Support with caveats:

- Code amendments should consider nuances that occur at sub-transmission levels. Better solution would be to have flexible requirements for sub-transmission connections (**Lodestone**).
- Obligations should not extend to direct reactive power instructions from third parties (**Vector**).
- Any solution should consider the varied nature of local distribution networks and ensure that voltage support obligations are placed where they can be most effective and efficient (**Orion**).

Option 1: Capacity threshold

Under option 1, we also sought feedback on:

- Whether there should be a capacity threshold (eg, nameplate capacity or nominal net export value) for generating stations and energy storage systems connected to local distribution networks to support voltage (**Question 3**).



Option 1: Submitter feedback on capacity threshold

Support capacity threshold:

- **EEA and Orion**: should be voltage-related (ie, relative to each distribution network) rather than a fixed value
- **Powerco**: Mandates generators >1 MW provide ±33% voltage support at point of connection
- **Transpower**: 5 MW
- **Manawa, Meridian**: didn't suggest a threshold.

Neutral:

- **Mercury**: neutral on a threshold, but if Authority decided to implement one it should be 10 MW.

Option 1: Submitter feedback on capacity threshold

Do not support capacity threshold:

- **IEGA, NewPower, Pioneer, WEL Networks, Lodestone**

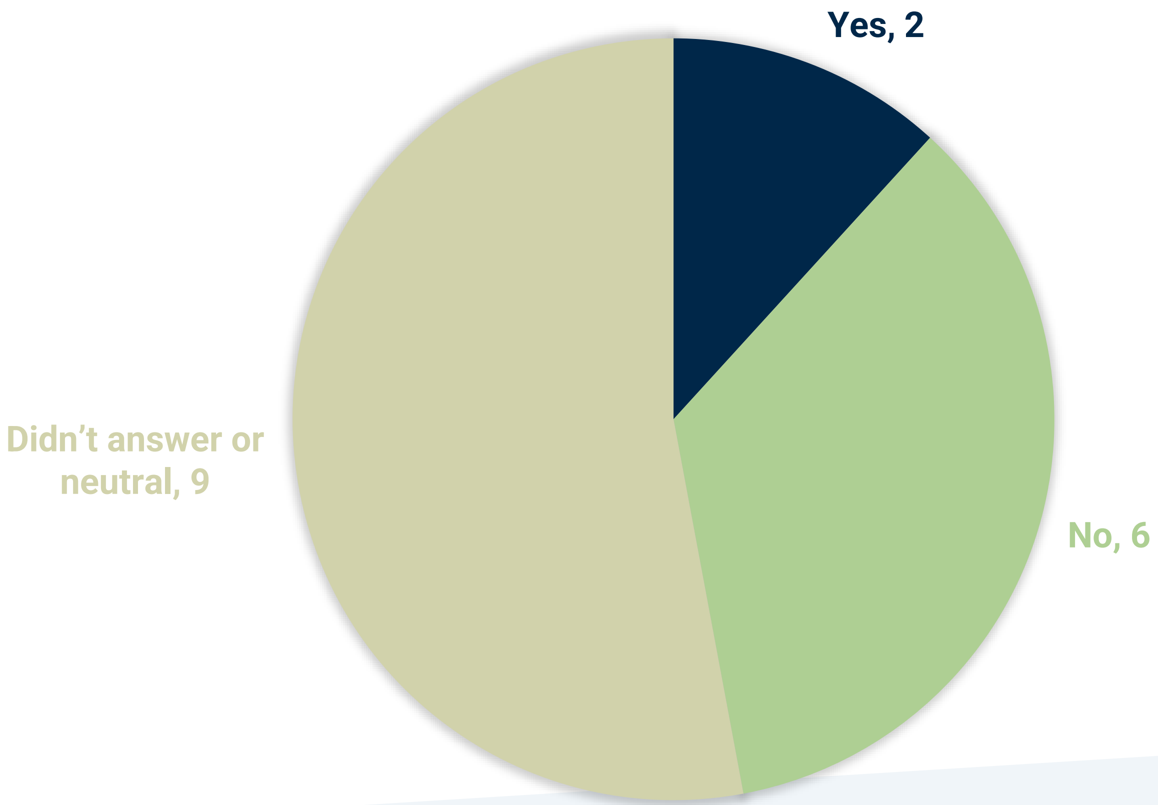
Reasons:

- Capacity threshold should be set by distributors based on their networks
- One size fits all approach is inappropriate
- Any threshold should be based on ability of distributed generation to affect voltage across distribution network
- Already addressed through distribution network connection process
- SO's modelling did not provide a case for applying a generation capacity threshold relating to voltage support.

Option 1: Reactive power range

Under option 1, we also sought feedback on:

- The pros and cons of having a reactive power range of ±33% rather than +50%/-33% when connected to the local distribution network (**Question 4**).



Option 1: Submitter feedback on changing the reactive power range

Did not support (IEGA, Lodestone, Manawa, NewPower, Pioneer, Mercury):

- The reactive power range should be linked to the power factor limits requirements. These need to be considered together.
- Needs a further assessment of the costs and benefits.
- Several submitters were unsure that the proposed reactive power range is the appropriate one – more research is needed.

Option 1: Authority's preliminary thinking

- Embedded generation connected at GXP voltage and which exports 10MW or more must operate in voltage control mode when electrically connected and dispatched
  - Distributor may direct embedded generation to operate in alternative mode if necessary to accommodate distribution network conditions
- Embedded generators provide info to system operator showing they are compliant, but do not have to do any modelling additional to that required by the distributor
- Grandfather existing embedded generating stations exporting less than 30MW where the station is not capable of providing voltage support
  - Opt-in approach
- Consider embedded generation reactive power support capability in FY2025-26

Option 3: Overview

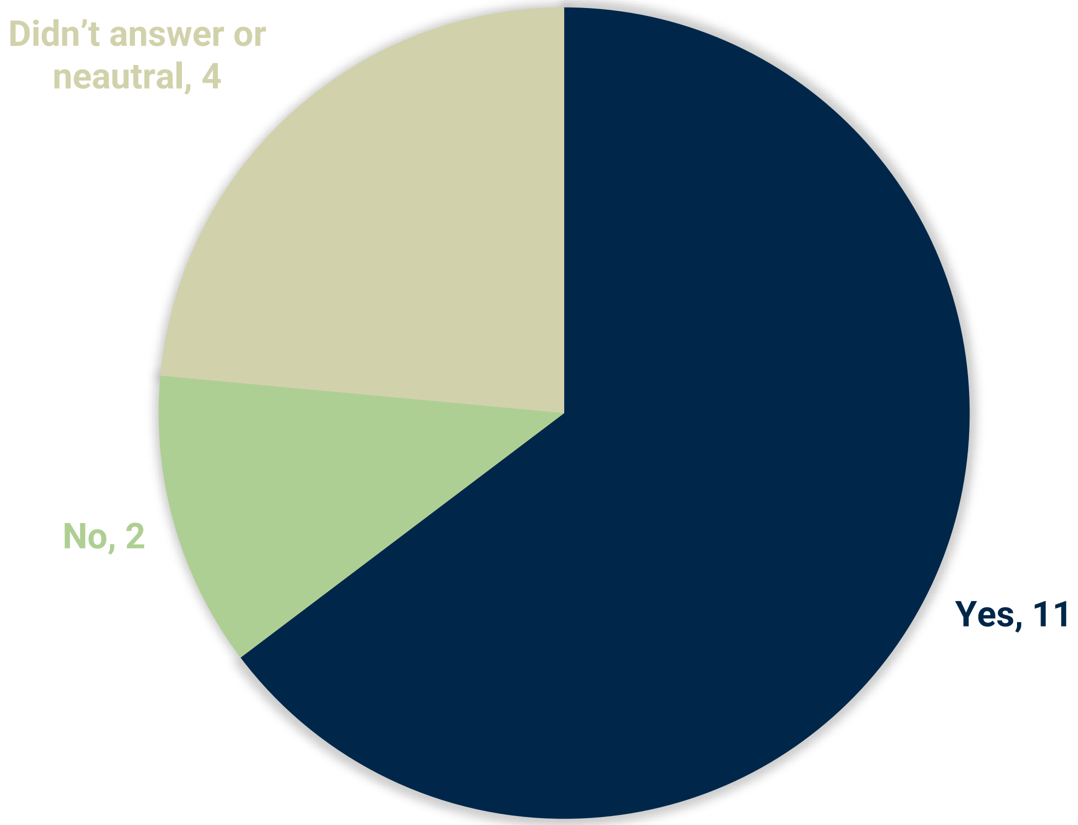
Require more generating stations to comply with the fault ride through (FRT) obligations

- Lower the 30 MW threshold for excluding generating stations to comply with FRT obligations in the Code
- Maybe include FRT curves in the Code for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account network protection considerations?
- Maybe have a threshold based on connection voltage and capacity?

Option 3: Submitter feedback

Question 15: Should option 3 be short-listed?

Should the fault-ride through option be short-listed?



Option 3: Submitter feedback

Most said yes to option 3, but with caveats

- Existing generation should be grandfathered (**Manawa**)
- Demonstrating compliance using the current methodology is too onerous to be applied to small generators (**Mercury, Meridian**)
- Authority to investigate if it’s more efficient to include FRT obligations in distributor connection agreements instead of the Code **(NewPower)**
- Distribution network protection considerations should take precedence over Code FRT requirements **(WEL Networks)**.

Option 3: Submitter feedback

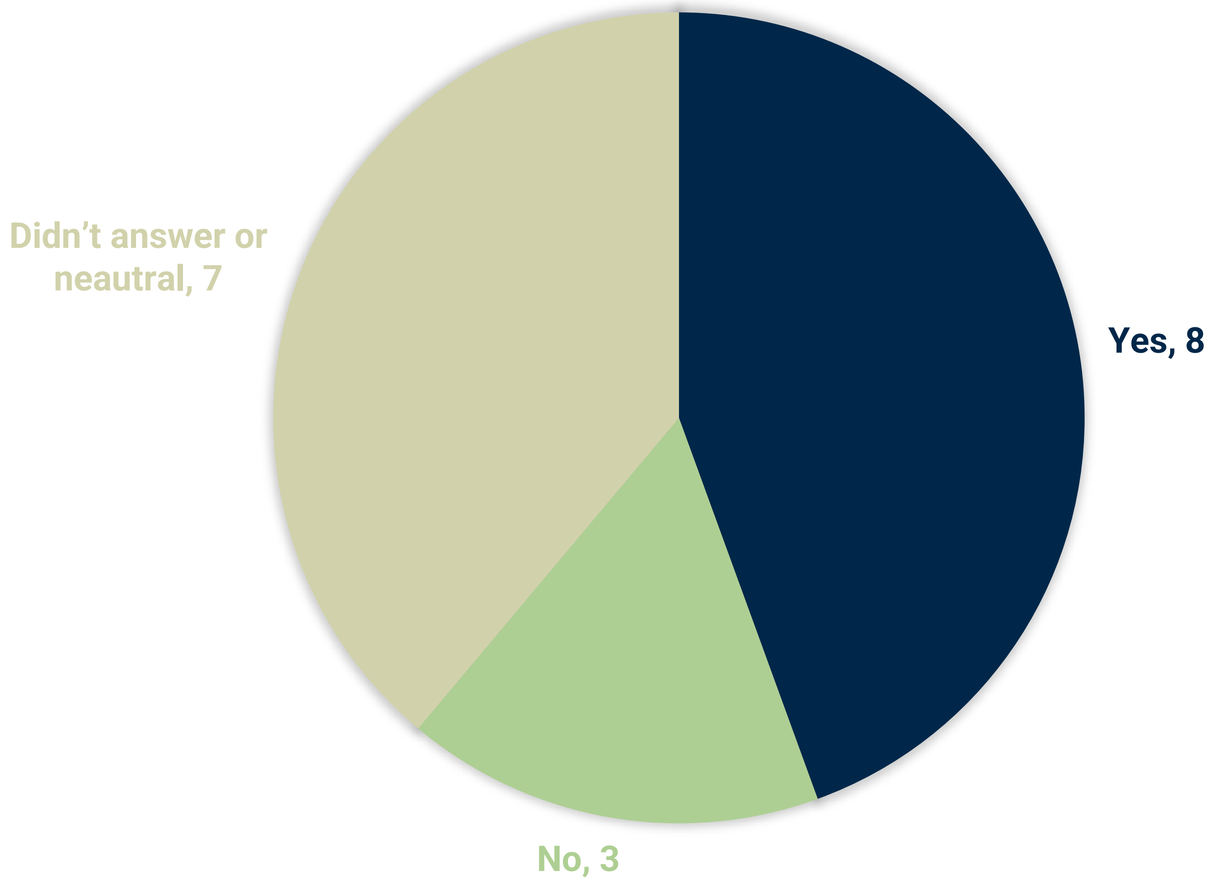
Who said no to short-listing option 3 and why

- **IEGA** – a robust CBA is required, including the costs for the SO of implementing and monitoring compliance.
- **Pioneer** – Emphasis in distribution networks is typically clearing the fault and anti-islanding protection.

Option 3: Submitter feedback

Question 13: Should the Code include FRT curves for distribution networks?

Should distribution fault-ride through curves be included in the Code?



Option 3: Submitter feedback

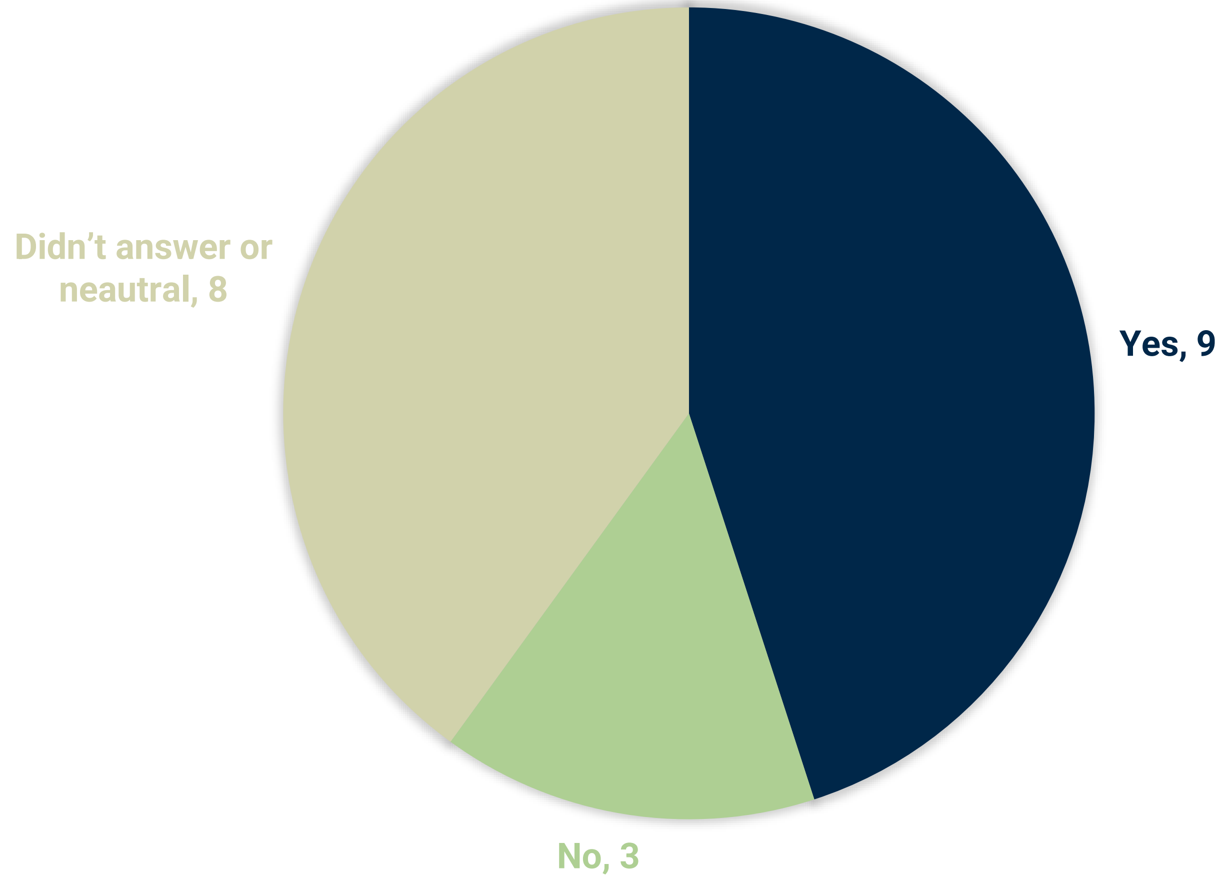
Why fault-ride through curves should NOT be included in the Code

- Distribution network protection considerations should take precedence over Code fault ride through requirements (these requirements better placed in distributor standards than the Code) (**IEGA**).
- Existing transmission FRT envelopes in the Code are modelled based on the location of the relevant generating station on the power system (**Meridian**).
- Protection schemes are set up to ensure faults are cleared. This is a different priority to transmission where redundancy under a range of scenarios are required (**Pioneer**).

Option 3: Submitter feedback

Question 14: Should there be a threshold based on connection voltage and capacity?

Should there be a threshold based on connection voltage and capacity?



Option 3: Submitter feedback

Who didn't agree there should be a threshold based on connection voltage and capacity, and why

- Changing the threshold for excluded generating stations for voltage will also change the threshold for frequency obligations (**IEGA**)
- Retain the 30MW threshold **(Pioneer)**
- The benefits of DG connected riding through transmission faults accrues mainly to the distribution network – should be up to the distributor to specify the threshold (**WEL Networks**)

Option 3: Submitter feedback

Feedback on what the threshold should be

- Threshold to consider compliance costs (**Manawa, Mercury, Meridian, Transpower**)
- **10MW** to reduce compliance costs on smaller generation (**Lodestone**)
- **Powerco** mandates compliance with FRT for generating stations >1MW
- Base threshold on voltage instead of capacity (**EEA, Orion**)
- All generation comply with FRT but <**10MW** don't need to demonstrate compliance (**Genesis**)

Option 3: Authority's preliminary thinking

- In FY2025-26:
  - For transmission faults, consider FRT curves applicable to machine-based synchronous and inverter-based generation
  - Consider FRT curves for distribution faults
- Grandfather existing embedded generating stations exporting less than 30MW where the station is not capable of FRT
  - Opt-in approach

Clause 8.23: Point of compliance

- System operator reviewing Policy Statement
  - Clause 114 (*Generator Asset Capability Assessment, Voltage*)
- System operator considering proposed clarifications
  - Measure reactive power support at grid injection point (HV side of transformer) rather than at generating unit terminals
- Original (2001) thinking behind clause 8.23 was to require a generator's reactive power capability at the grid injection point
- However, point of reference moved to generating unit terminals, to be consistent with:
  - Then-current international practice, and
  - Standard design of generating plant

Clause 8.23: Point of compliance

- Clause 8.23 may no longer:
  - Align with current practices, and/or
  - Accommodate emerging technology
- Various overseas jurisdictions specify reactive power requirement at connection point (eg, AEMO, EirGrid, FERC) rather than at generating unit terminals (NESO)
- Wind and solar PV generating unit terminals not so near to the grid
  - Clause 8.23 doesn’t consider notional aggregation point for this type of generation
- Any proposed change to point of compliance may require:
  - Investigation on changing the reactive power support capability percentages (ie, +50% / -33%), and
  - The voltage range at which this support is required

Managing GXP reactive power flows: Options for system operator – distributor co-ordination

Background and context

- Relates to common quality key issue 2

  An increasing amount of variable and intermittent resources, primarily in the form of wind solar PV generation, is likely to cause larger voltage deviations, which are exacerbated by changing patterns of reactive power flows

- Aim of system operator – distributor co-ordination:

  Regulate GXP voltage more effectively by minimising reactive power flowing through the GXP

- Avoid distribution and transmission assets working against each other

Managing GXP reactive power flows: Options for system operator – distributor co-ordination

Background and context (continued)

- System operator's voltage studies 1 and 2 report recommended:
  - *System operator and distributors share responsibility for regulating GXP voltage*
  - *Distributed energy resources at GXP voltage provide distributor and system operator with visibility of DER's operating status and active/reactive power output*
  - *DER have capability to accept reactive power dispatch instructions from distributor*

- Authority and system operator have brainstormed what this could look like

Status quo

- Distributors ensure their networks operate at nominal grid voltages (220/110kV +/-10% and 66/50kV +/-5%)
- System operator uses telephone calls to applicable distributor if distributor needs to influence GXP voltage / GXP reactive power import or export
- Distributor then co-ordinates its assets and, where able, DER assets to influence GXP voltage / GXP reactive power import/export
- System operator does not have real-time indications of reactive power at low voltage side of GXP
- System operator has no view of distributor’s network
- Distribution and transmission assets can work against each other in terms of reactive power flows
- System operator receives from DER generation:
  - Energy offers if generating station capacity >10MW
  - Real-time indications if generating unit maximum continuous rating >5MW
- System operator and distributors have no DER generation models

Co-ordination option (electronic dispatch notifications to distributor)

- System operator can send electronic dispatch notifications to distributor when needed to influence GXP voltage / GXP reactive power import or export
- Distributor co-ordinates its assets and DER assets to influence GXP voltage / GXP reactive power import/export

Characteristics of the option

Voltage management	• Distributor must control reactive power flow at the GXP, based on dispatch instructions from the system operator • Eg: if system operator observes DER generation output is ‘fighting’ the transmission grid in terms of voltage/ reactive power flows at the GXP • System operator gives dispatch notifications to distributor per current dispatch arrangements (4 mins to acknowledge)
Communications	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C
Modelling and analysis	• System operator has partial view of distributor’s network • Distributor’s network modelled as another reactive asset in the system operator’s reactive power controller • No network modelling required / no DER model required, although network connectivity model required where DER can connect to multiple GXPs (eg, Aniwhenua)
Event response	• Expect DER to respond to voltage event • Do not expect DER to respond to contingent event
Compliance	• DER voltage control testing obligation • System operator checks compliance with AOPOs

Advantages of the option relative to the status quo

Operations	• Improved operational efficiency from distribution and transmission assets not working against each other in terms of reactive power flows • Better visibility of distribution networks better enables system operator to manage the transmission grid more efficiently
Modelling and analysis	• System operator and distributors better able to model their networks as a result of receiving DER network connectivity model (as applicable)
Other	• Potentially defer investment in grid voltage management assets

Disadvantages of the option relative to the status quo

Operations	• Distributor may have to invest in network comms / control path with the DER to issue voltage instructions
	• Cost of operational co-ordination between Transpower's supply transformer tap changers and the DER generation
	    • System operator may push tap changers to limits
	    • May need comms/alarms for awareness
	• Challenges may arise from increased need for SCADA indications and data sharing (eg, how best to share data)
	• Roles and responsibilities around managing GXP voltage not as clear
	    • Under status quo distributor clearly responsible for its network operating when grid voltages within ranges specified in clause 8.22 of the Code

Modelling and analysis	• More modelling required
Other	

A couple of counterfactuals

Counterfactual 1 – System operator has visibility of DER and distributor active / reactive power status only

- System operator receives real-time indications from DER and distributors
- DER and distributor not required to have capability to receive voltage dispatch instructions

Counterfactual 2 – System operator dispatches DER for voltage / reactive power

- System operator can send voltage control and reactive power electronic dispatch instructions at all times directly to the DER
- System operator receives real-time indications from DER and distributors

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER
Voltage management	• Distributor co-ordinates with DER to manage GXP voltage (low voltage side)	• System operator dispatches DER electronically per current dispatch arrangements
Communications	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C	• System operator has real-time indications of reactive power at GXP • DER must provide real-time telemetry data indications to system operator (can be provided by third party using ICCP) • Compliance with Technical Code C

Modelling and analysis – SCADA data	• No network modelling required / no DER model required, although network connectivity model required where DER can connect to multiple GXPs (eg, Aniwhenua)	• For real-time contingency analysis system operator needs:
		  • Distribution network model covering connection path from GXP to DER
		  • DER model data

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER

Modelling and analysis – Power system tools (VSAT / TSAT)	• Distributor's network modelled as another reactive asset in the system operator's reactive power controller	• TSAT needs DER dynamic models (generator and voltage control system)
		• Asset owner to provide:
		  • Validated dynamic models
		  • Special protection scheme models

Modelling and analysis – Market model	• DER generation netted off from GXP load if DER generation is not offered into the wholesale electricity market	• For real-time energy dispatch, the system operator:
		  • Needs energy offers from DER
		  • Fully models DER with reactive power capability
		  • DOES NOT need to model all the distribution network

Characteristics of the alternatives

	System operator has visibility only	System operator dispatches DER
Event response	• Expect DER to respond to voltage event • Do not expect DER to respond to contingent event	• Expect DER to respond to voltage event • Expect DER to respond to contingent event
Compliance	• DER voltage control testing obligation • System operator checks compliance with AOPOs	• DER voltage control testing obligation • System operator checks compliance with AOPOs

Advantages of the alternatives relative to the status quo

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</table>

Advantages of the alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER
Modelling and analysis	• Provision of more SCADA and voltage information improves system operator's modelling	• System operator's (VSAT) modelling tools can make use of the DER's reactive power curve in the models, enabling full use of the generating unit, and thereby reducing the need to be conservative in contingency analysis
Other		• Potentially defer investment in grid voltage management assets • May reduce some of the need for DSO(s) and/or effort/cost to establish DSO(s)

Disadvantages of alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER
Operations	• Cost of SCADA indications • Data sharing hurdles • Potential for inconsistency in dispatched DER voltage set point across distributors	• Cost of SCADA indications • Data sharing hurdles • Potential for system operator directions to cause distributors issues managing their networks • Learning curve for system operator on behaviour of distribution networks • Potential more outage management workload for system operator • Cost of some distribution network outages possibly needing to feed into the planned outage co-ordination process (POCP)

Disadvantages of alternatives relative to the status quo

	System operator has visibility only	System operator dispatches DER

Modelling and analysis		• Network modelling costs for DER, distributors and system operator
		  ◦ Currently, system operator and distributor network models incompatible
		  ◦ Significant amount of modelling required in system operator's tools
		  ◦ Distributors must tell system operator of abnormally configured assets

Other	• Potentially more investment in grid voltage management assets ◦ From build-up of incremental inefficiencies over time	

BESS literature review

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BESS and Hybrid Plants

Literature Review

18.02.2025

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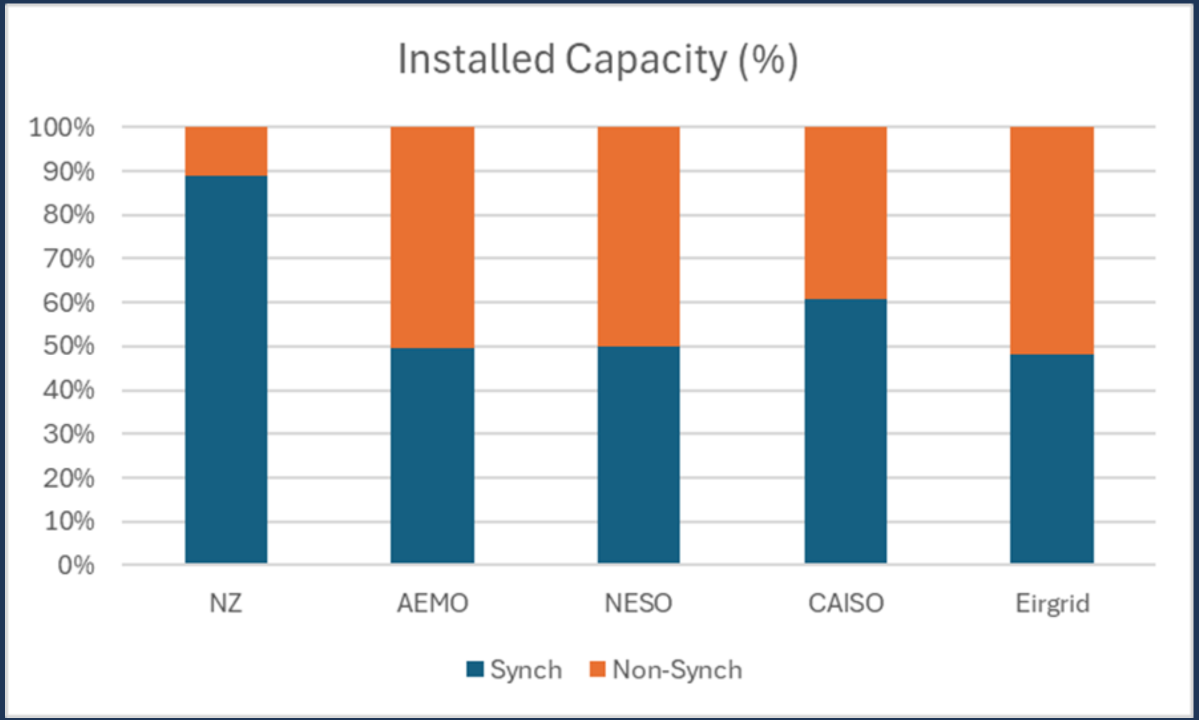
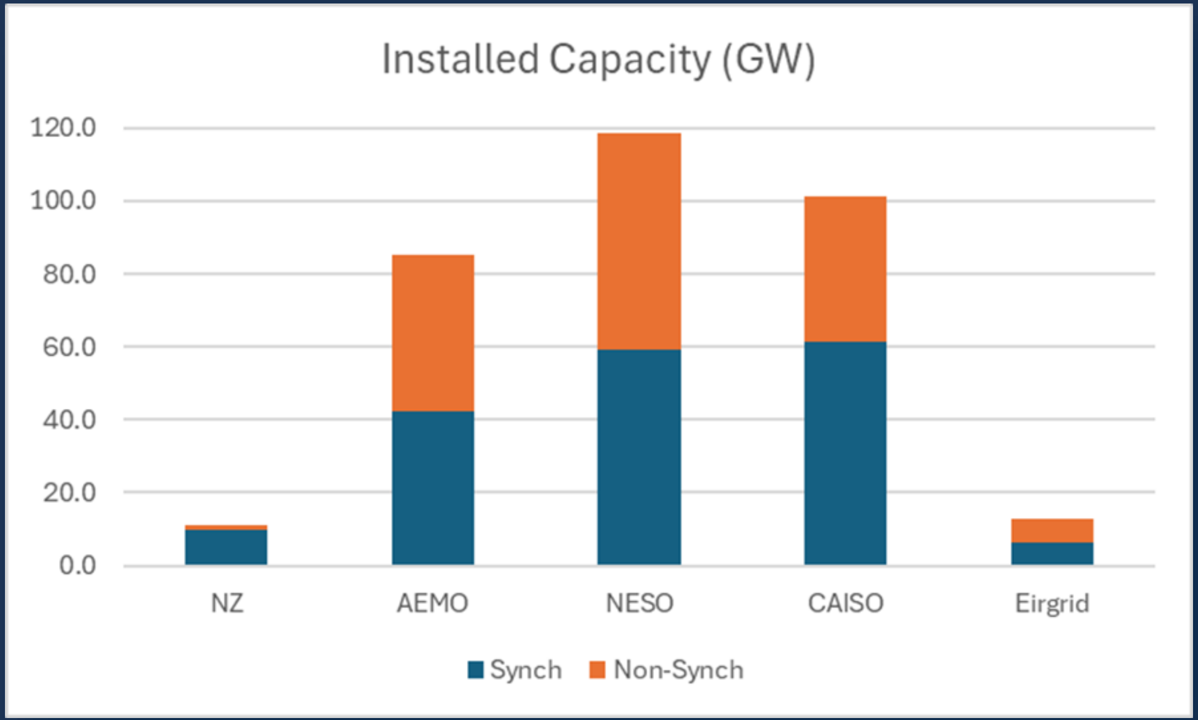
Structure of BESS Section

Report presents literature review of BESS obligations in other jurisdictions, as requested by CQTG at previous meeting

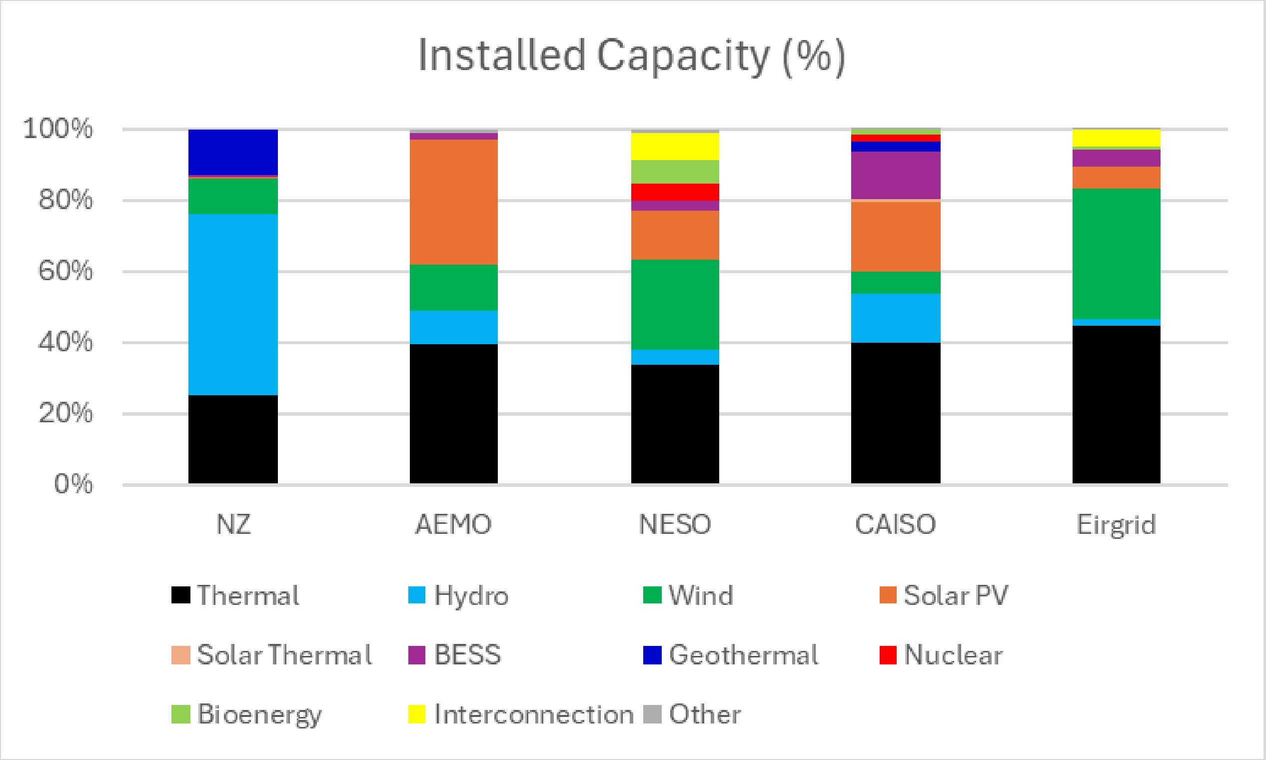
Need to consider international obligations in the context of the size and generation mix of those systems

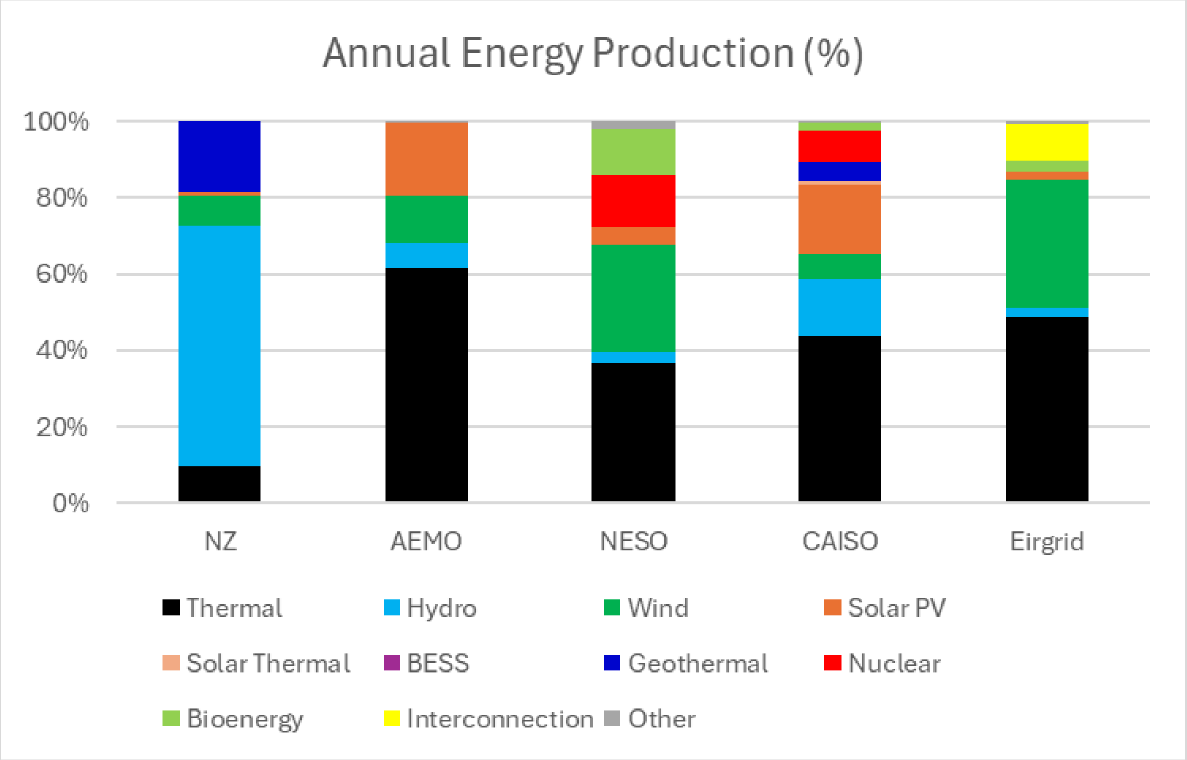
International Comparisons – System Capacity





International Comparisons





Frequency Support Obligations (Cl. 8.17 and Cl. 5 of Tech Code A)

- **All jurisdictions require frequency response when injecting or charging**
- **When the BESS is idle only Eirgrid always requires frequency response**
  - Other jurisdictions only require if the BESS is cleared for ancillary services

System	Deadband (Hz)	Droop (%)
AEMO	+/-0.015	<= 5
NESO	-0.5/+0.4	2-10
CAISO	+/-0.036	<= 5
Eirgrid	+/-0.5	2-10

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Voltage Support Obligations

- **Eirgrid requires support when injecting, charging, idle**
- **AEMO requires support when injecting or charging**
- **NESO requires support when active power is above 20% maximum continuous output**
  - When below 20% MCO, BESS must switch to power factor control, with unity power factor set point
- **CAISO requires voltage support if connection studies identify need**
  - Specified as power factor
- **Requirement is symmetrical for import and export**

System	Reactive Power Range (%MCO)	Power Factor at MCO
AEMO	+/-39.5	0.93
NESO	+/-33	0.95
CAISO	+/-33	0.95
Eirgrid	+/-33	0.95

Operational Issues – Technical Code C and Modelling

- **Details of modelling will depend on decision on obligations**
- **Technical Code C (Operational Communications) not fit for purpose for IBR – this project provides good opportunity for review**
- **System operator needs string level indications and state of charge:**
  - To enable accurate modelling in real-time tools
  - To inform forecasting and study assumptions
  - For event investigation purposes

Indication or measurement	Values required	Accuracy[3]
Station net MW	Import and export	±2%
Generating unit gross MW[1]	Import and export, for each **generating unit**	±2%
Station net Mvar	Import and export	±2%
Generating unit gross Mvar[1]	Import and export, for each **generating unit**	±2%
Generating unit circuit breaker status[1]	Open /closed /in transition/ indication error[2]	N/A
Grid interface circuit breaker status	Open /closed /in transition/ indication error[2]	N/A
Grid interface disconnector status	Open /closed /in transition/ indication error	N/A
Special protection scheme status	Enabled/disabled/summer/winter	N/A
Maximum output capacity of **generating station** (for **intermittent generators** only)	Number of connected **generating units** × **MW** capability of each **generating unit**	N/A

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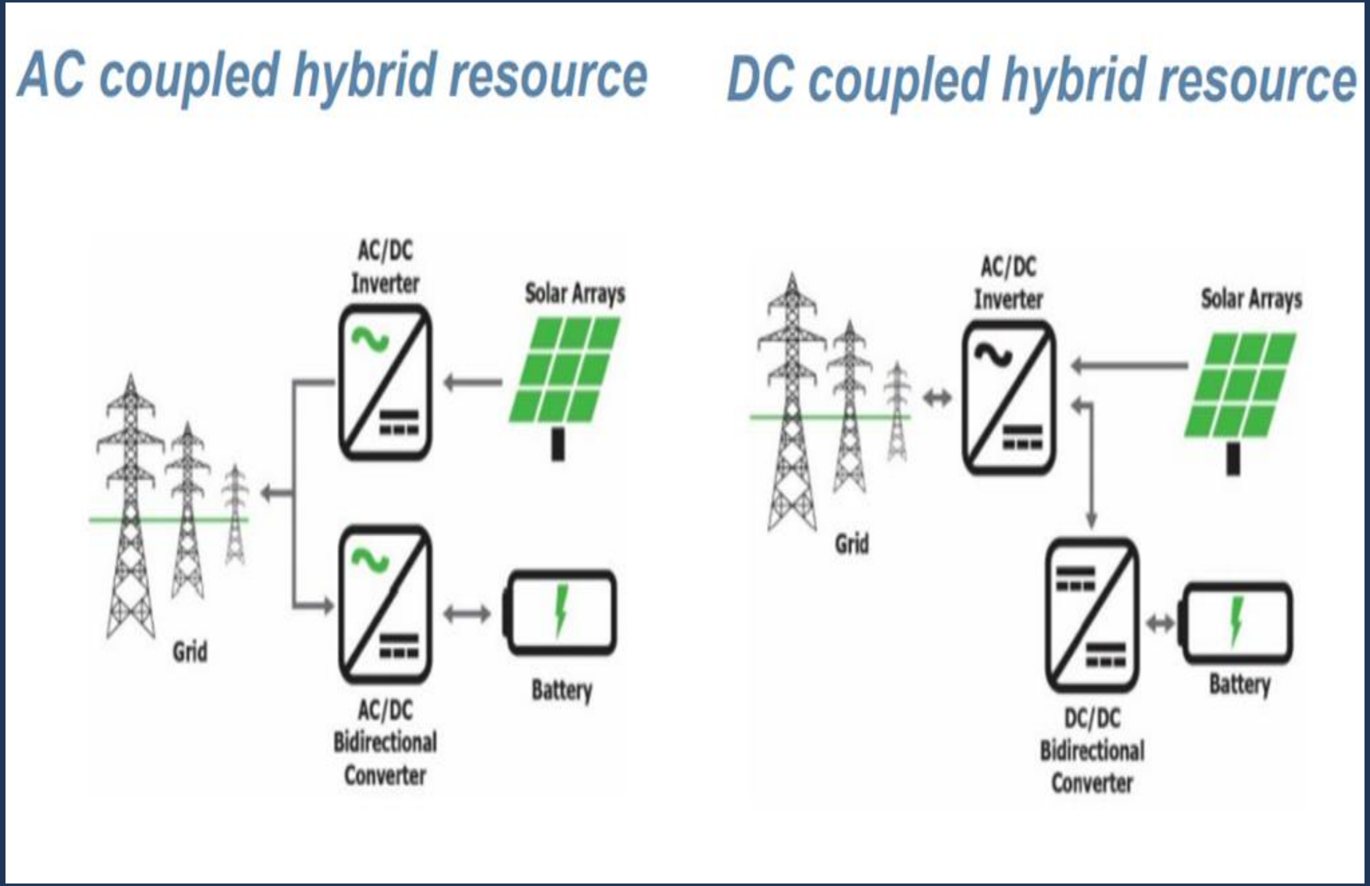
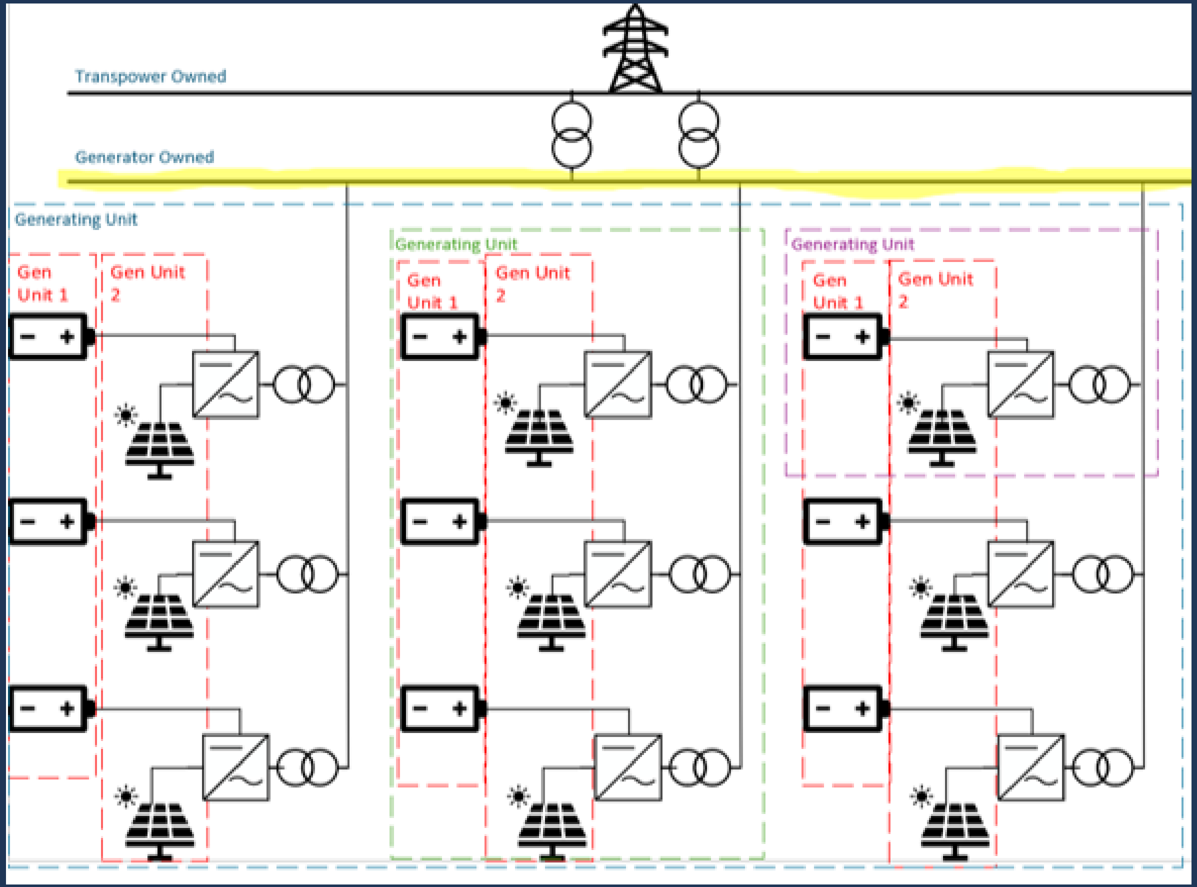
Hybrid Plants - Overview

- **A hybrid plant is a plant where some form of generation is combined with a BESS**
- **Can be any type of generation but PV-BESS hybrid is most common**
- **At times will effectively operate as standalone BESS or PV**
  - i.e. at night PV output will be 0 but BESS may operate



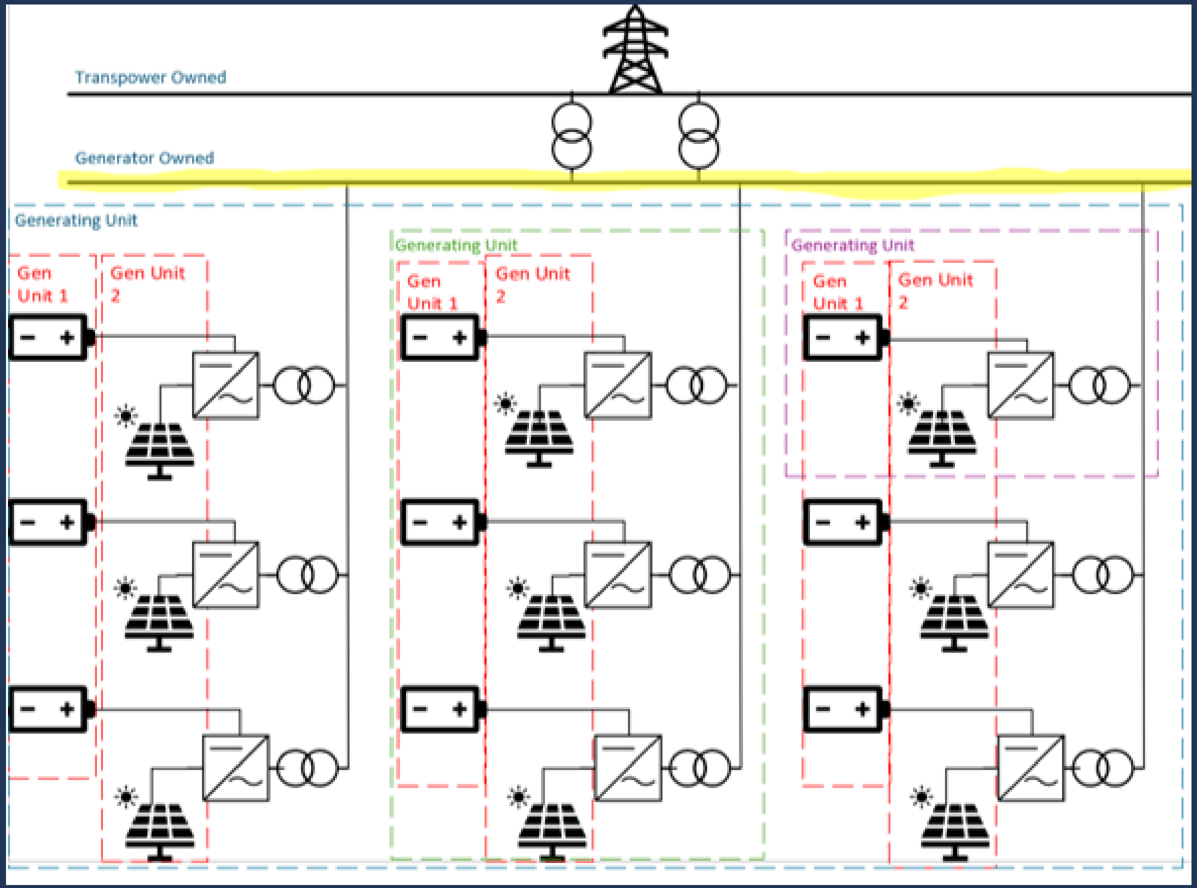
Hybrid Plants – Generating Unit

- Main issue is different generating unit configurations
- Points to the need to define some common quality obligations (eg, real-time comms) at inverter string level
- CQTG has discussed possible need for a definition that sits between 'generating station' and 'generating unit' (eg, 'generating system')
- Consider implications for, in particular, Part 8 of the Code (Common Quality) and Part 13 (Trading Arrangements)



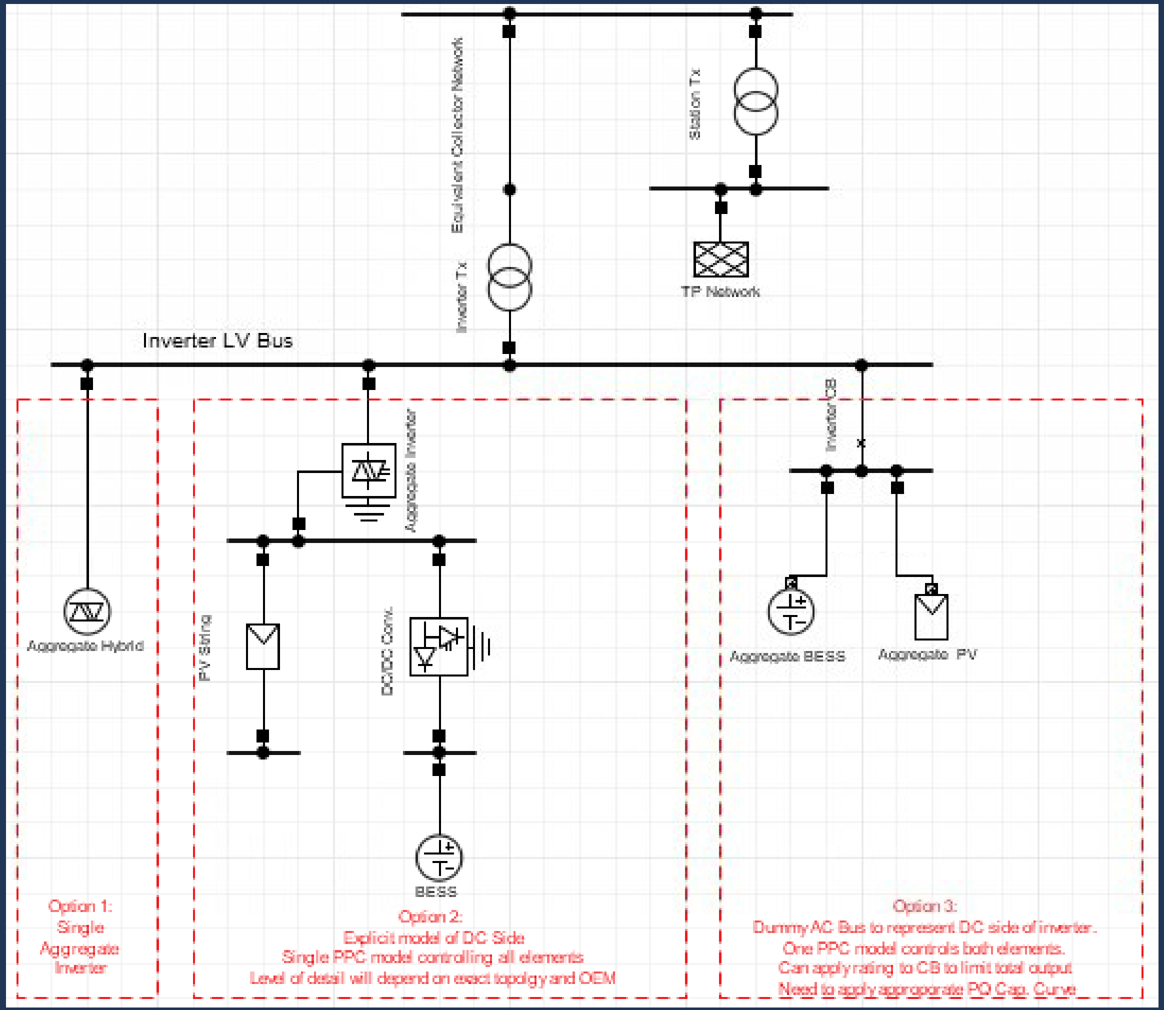
Hybrid Plants – Common Quality

- **We expect that once final obligations for standalone BESS are decided, and definitions are clarified, most of the obligations for hybrid plants will fall into place**
- **A few unique issues will remain:**
  - Interpretation of 8.17 – does 'maximum possible contribution' refer to PV+BESS or BESS only
  - Application of commissioning and testing requirements when a hybrid plant is created by adding BESS to an existing PV station (or vice-versa)



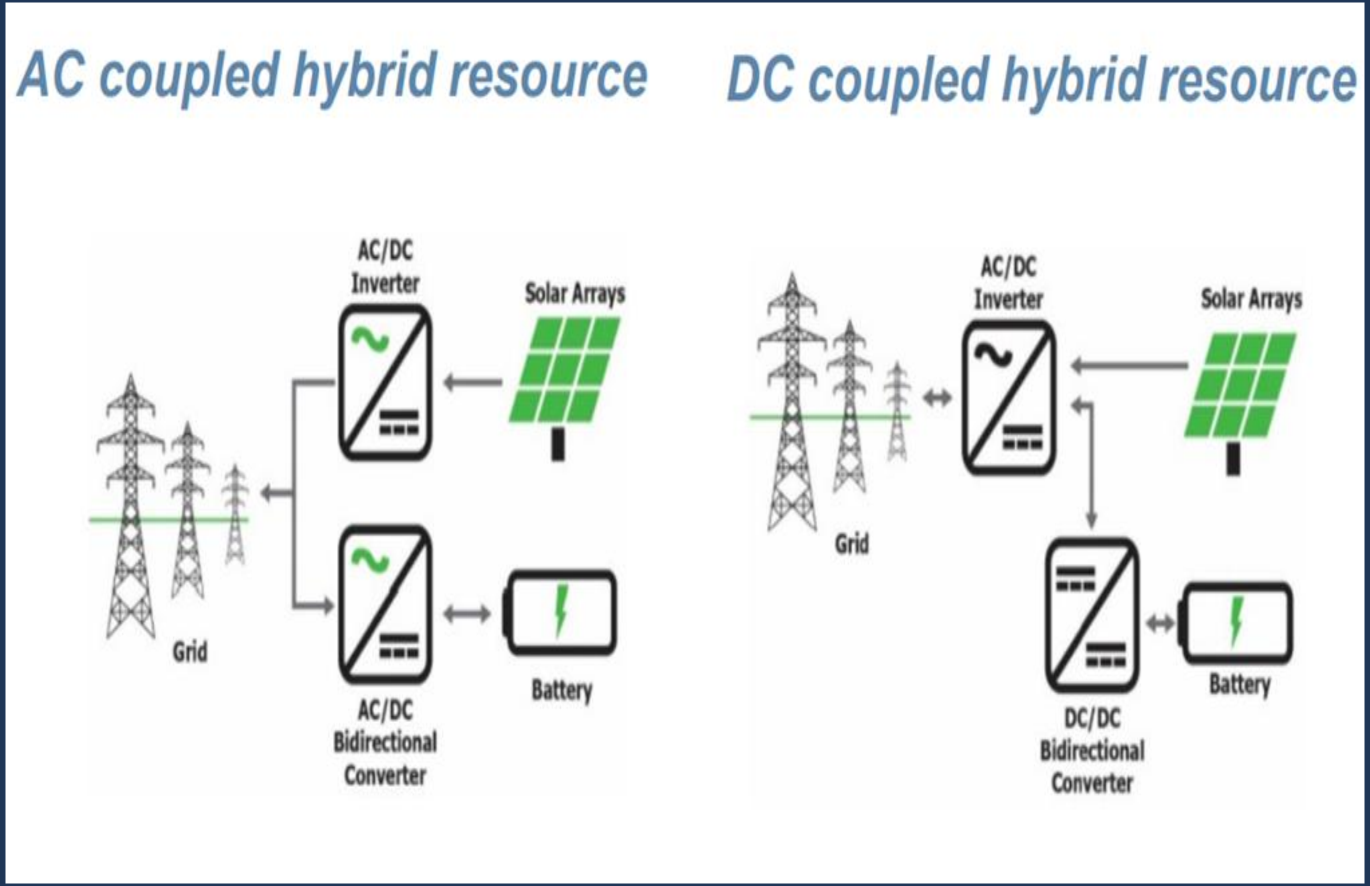
Hybrid Plants – Operational Issues

- **Similarly to BESS, need to update Technical Code C to be fit-for-purpose**
- **More complex to model than standalone BESS, especially for DC-coupled plants**
    - Required detail will depend on obligations and specifics of equipment
- **We recommend that Asset Owners considering installing hybrid plants discus appropriate modelling with the SO and their OEM before conducting connection studies**



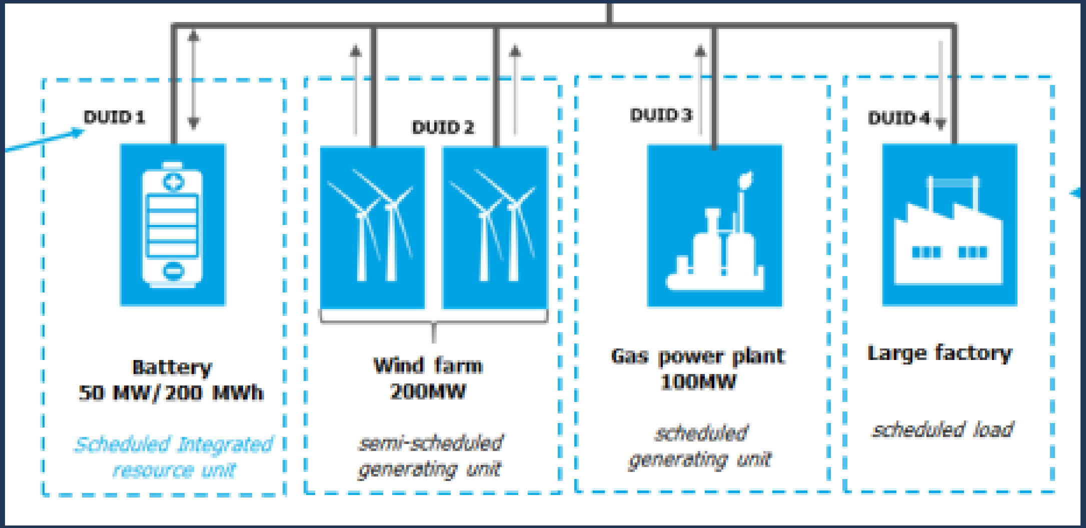
Hybrid Plants – Market Issues

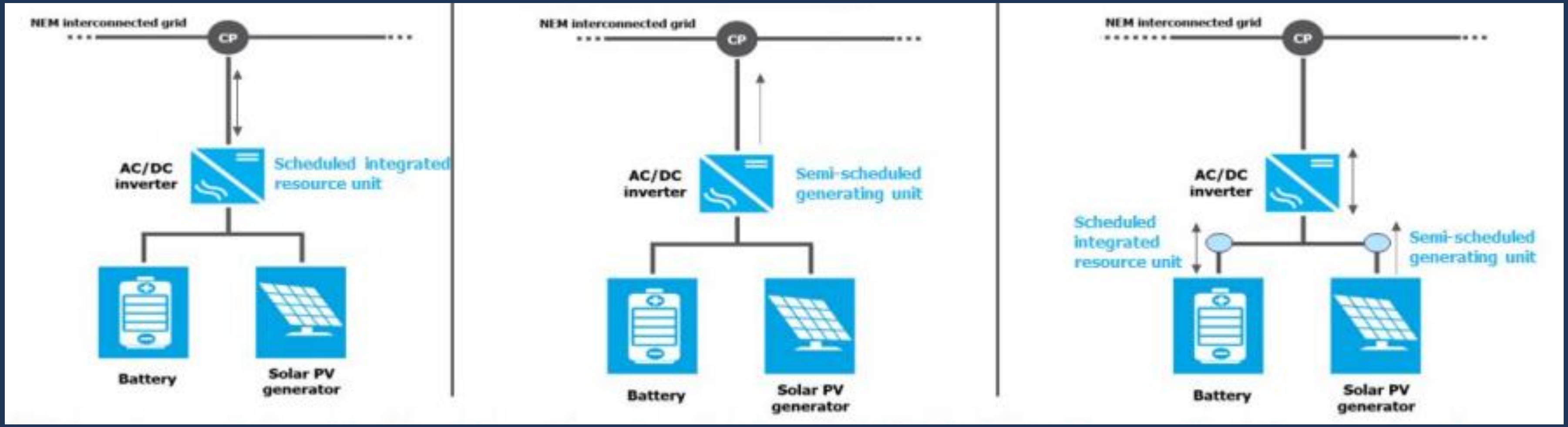
- **Several issues relating to market participation:**
  - Are PV and BESS offered separately or together?
  - Is a hybrid plant considered intermittent?
  - Co-optimisation of risk when offered by station – issue for all IBR
  - Participation in Ancillary Services markets
- **Being addressed by other projects**
- **Need to consider when looking at definitions – eg, ‘generating system’**



International Comparisons - AEMO

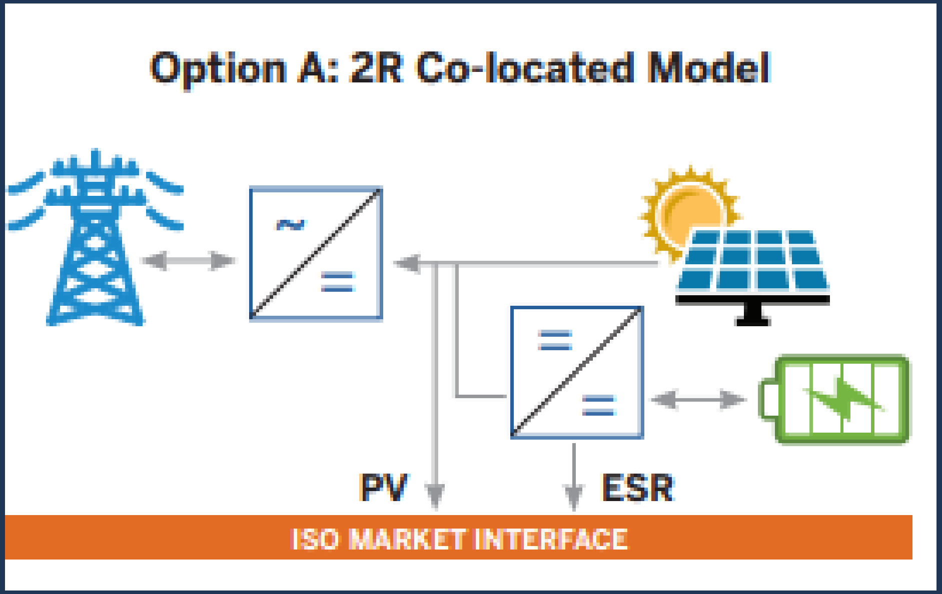
- **AEMO imposes the same common quality obligations on hybrid plants as for BESS, with droop based on inverter capacity**
- **Diagrams show how Australia's national electricity market treats AC-coupled plants (top) and DC-coupled plants (bottom)**
- **Terminology:**
  - 'DUID' ~= 'Pnode' in NZ context
  - 'semi-scheduled' ~= 'intermittent' in NZ context

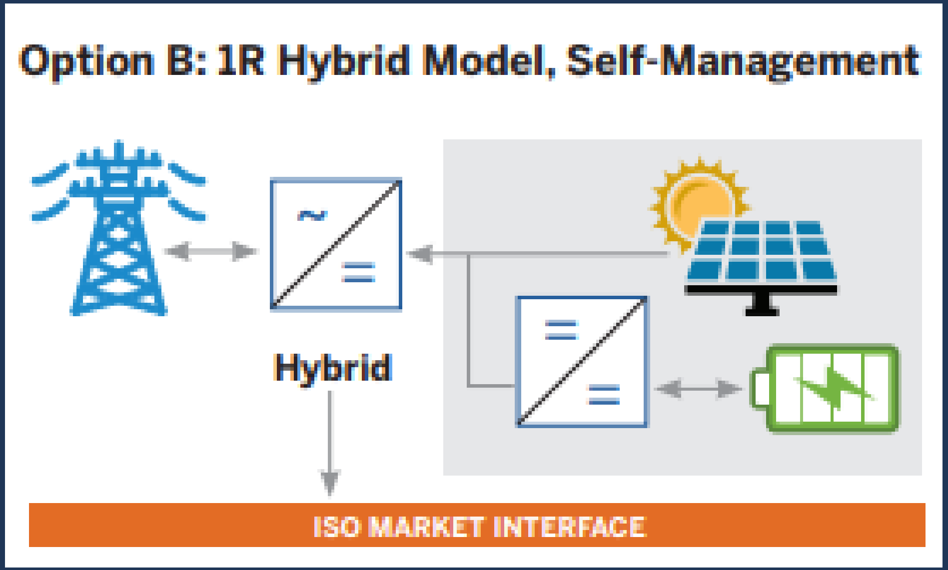




International Comparisons - CAISO

- **CAISO imposes the same common quality obligations on hybrid plants as for BESS**
- **Offer two models:**
  - ‘co-located’ (separate bids, PV intermittent)
  - ‘hybrid’ (single bid, non-intermittent)
- **No differentiation between AC- and DC-coupled**
- **Co-located model allows for ‘Aggregate Capability Constraint’ in the market system to limit total injection**
- **NB: CAISO operates a resource adequacy program as well as an energy market – beyond the scope of this paper but provides some interesting insights into forecasting**





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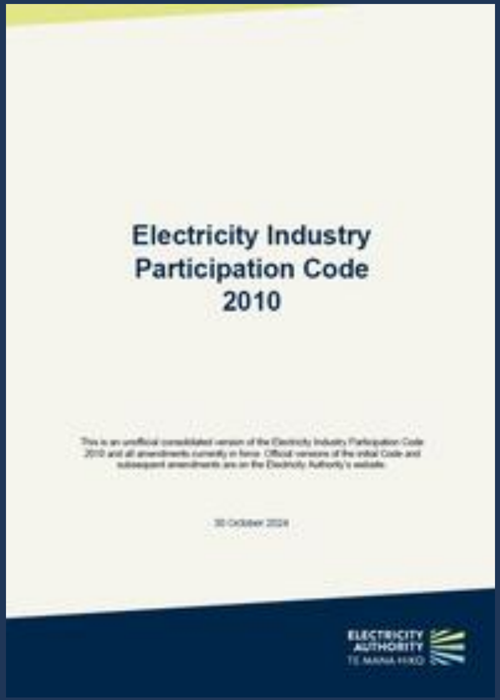
Key Items of Note


Electricity Industry
Participation Code
2010

- All jurisdictions we considered imposed frequency obligations on BESS when charging and injecting
- Approach to voltage support varies widely
  - Most similar system to New Zealand (Eirgrid) imposes +/-33% when charging, injecting, and idle
  - All jurisdictions have symmetrical import / export requirements
- Technical Code C needs updating for IBR
- The term 'generating system' or similar needs to be defined for hybrid plants

Next Steps Discussion

- Authority / CQTG to decide if any power system studies are required
- Other projects to address market issues
- System operator will progress work on Technical Code C and modelling / tools issues
- Technical Code C changes will be minor

Thank you

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Information requirements (Issue 6) – Document Incorporated By Reference (DIBR)

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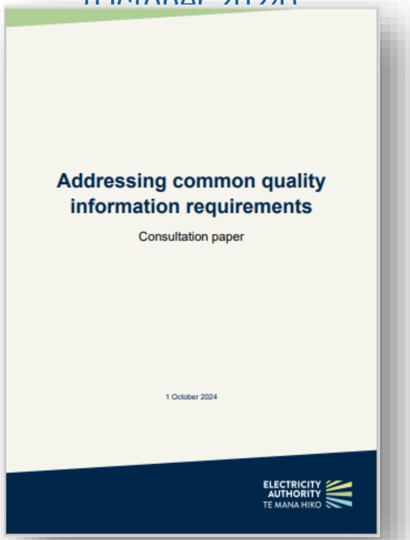
A Document Incorporated By Reference for Common Quality Information Requirements

18.02.2025

Quick Recap

- CQTG Meetings
- Draft papers (EA)
- Draft Document Incorporated By Reference in the Code (SO)
- Effective comms (SO/EA)

EA published an Options Consultation Paper
(October 2024)


Addressing common quality information requirements

Consultation paper

1 October 2024

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EA to publish Code Amendment Proposal Consultation Paper
(Scheduled: June 2025)

- **Option 1: Update/clarify common quality (CQ) related information requirements in the Code**
- **Option 2: Enable SO and distribution network operators to share CQ-related information**
- **Option 3: Enable SO to share CQ-related information with Transpower as a transmission network owner**

Link to Electricity Authority Options Paper: Part 8 common quality information requirements | Our consultations | Our projects | Electricity Authority (ea.govt.nz)

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Update and Clarify CQ Related Information

Under option 1, the Code would be amended to update CQ-related information requirements relating to:

(a) Testing and commissioning of new assets and upgrades to existing assets, including the timing of the provision of information

(b) Undertaking transmission and distribution system studies and investigating transmission and distribution system CQ issues

Document Incorporated By Reference in the Code

Consultation Summary

Consultation document suggested it may be desirable to move CQ information requirements from Part 8 to a Document Incorporated By Reference (DIBR) in the Code

Pros

A DIBR in the Code, specifying the CQ-related asset information requirements necessary for the SO to meet its CQ Code obligations would:

(i) enable some of the CQ-related information requirements to be developed by the SO, who has specialist knowledge and expertise in this area

(ii) facilitate more timely updates to the CQ-related information requirements, through the SO being able to update drafts of the document itself rather than via the Authority

(iii) enable the main body of Part 8 of the Code to be shorter, simpler, and clearer

Cons

(i) There is a risk that material incorporated by reference is not appropriate for legislation because the material was developed for another purpose (e.g. for a guideline)

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Draft CQ Information Requirements DIBR

Based on options consultation submissions, the Authority has asked the SO to develop a draft CQ Information Requirements DIBR

Preliminary Draft Table of Contents

Contents

Draft CQ Information Requirements DIBR intended to be consulted on as part of the Information Requirements (Issue 6) Code Amendment Consultation scheduled for June 2025

SO also to consult separately

CQ Information Requirements DIBR – Chapter Overview (Draft)

Introduction – Covers the purpose and scope of the DIBR and how the DIBR supports/enables the SO to plan to comply, and to comply, with its Principal Performance Obligations (PPOs).

Chapter 1: ACS Requirements – Covers asset capability statement (ACS) information to be provided to the SO.

Chapter 2: Commissioning Timeline – Covers the asset commissioning timeline and what information is required and by when for commissioning new assets or changing existing assets.

Chapter 3: Modelling Requirements – Covers what models / modelling information the SO requires and by when, with reference to confidentiality requirements set out in the main body of the Code.

Chapter 4: Connection Study Requirements – Covers what an asset owner (AO) must do to complete its connection study/studies, when the connection study/studies must be repeated, and requirements for sharing study results with the SO.

Draft Table of

SO Common Quality Information Requirements Document

Contents

1

SO Common Quality Information Requirements Document

Chapter 5: Commissioning Testing Requirements – Covers AO testing requirements during pre-commissioning, commissioning, and post-commissioning.

Chapter 6: Periodic Testing Requirements – Covers AO periodic testing requirements, including for machine-based synchronous, asynchronous and inverter-based resource (IBR) generation (incl. BESS, solar and wind).

Chapter 7: Model Update Requirements – Covers the requirements and timeframes for model revalidation after periodic testing.

Chapter 8: Operational Communication Requirements – Covers the requirements for communications between AOs and the SO, excluding the content of communications.

Glossary of Terms – Any additional terms not defined in Part 1 of the Code.

Key Items of Note

Code provisions that would be migrated to the CQ information requirements DIBR:

- ***Technical Code A – Assets***
    - ***Some of clause 2 (relating to ACS information, commissioning of assets, and testing of assets)***
    - ***Appendix B: Routine testing of assets and automatic under-frequency load shedding systems***
- ***Technical Code C – Operational communications***

Thank you

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CQTG meetings #7 & #8 – Outstanding actions

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Outstanding actions

No.	Action	Who	Status
5.4	Periodic testing of wind generation: Authority to consider reviewing the periodic testing requirements, so that Part 8 of the Code contains high-level output-focussed obligations and specific testing requirements are placed in a separate document incorporated by reference into the Code.	Authority	
5.15	Authority to consider the appropriateness of including in the Code a new definition 'generating system'.	Authority	
7.1	CQTG chair to sign the minutes of the fifth (subject to amendment of paragraph 2.3(a)) and sixth CQTG meetings, and publish the minutes on the Authority's website.	Authority	
7.2	Voltage issue: Authority to consider clarifying the terms "synchronised", and "available for dispatch" in clause 8.23 of the Code.	Authority	
7.3	Voltage issue: Authority to consider a threshold of 5MW or 10MW, working with the system operator, and considering compliance costs, and considering grandfathering for some or all existing generating stations that are under the 30MW threshold (including what clauses/subclauses would be subject to grandfathering).	Authority	
7.4	Voltage issue: Authority to consult distributors (likely via Electricity Networks Aotearoa (ENA)) on a ±33% net reactive power range for generators connected to distribution networks, explaining the reasons for this range when doing so.	Authority	
7.5	Voltage issue: System operator to carry out further voltage-related studies to determine whether the GXP power factor requirements in the Code should be revised.	System Operator	
7.6	Voltage issues: System operator to share the high-level scope of the voltage-related studies with the CQTG's voltage sub-group for feedback.	System Operator	
7.7	Voltage issue: Authority to consider submitters' concerns about the potential costs of Option 2 as part of evaluating the option's benefits and costs.	Authority	
7.8	Voltage issue: Authority to obtain from Professor Neville Watson relevant GFM papers (eg, a 2023 PhD thesis, CIGRE papers).	Authority	

Outstanding actions

No.	Action	Who	Status
7.9	Voltage issue: Authority to add GFM as a topic to the system strength work in the FSR roadmap (item 6) in the next financial year.	Authority	
7.10	Harmonic issue: Authority to raise the device standard issue with MBIE and propose removing NZECP 36:1993.	Authority	
7.11	Harmonic issue: Authority to invite Professor Neville Watson to the Authority/MBIE/WorkSafe monthly meetings on the harmonics issue.	Authority	
7.12	Harmonic issue: Authority to develop harmonics options 1 and 2, discuss with the harmonics subgroup, and present a draft options consultation paper to the CQTG in Q1 2025.	Authority	
7.13	Frequency issue: Authority to consider a threshold of 5MW or 10MW, working with the system operator, and considering compliance costs and grandfathering (including what clauses/subclauses would be subject to grandfathering).	Authority	
7.14	Frequency issue: Authority to clarify whether the proposal is to align the Code with AS/NZS 4777.2 by amending the Code or the standard.	Authority	
7.15	Frequency issue: Authority to further investigate option 2, with a particular focus on learnings from Australia's implementation of a uniform small deadband.	Authority	
7.16	System operator to conduct a literature review on BESS performance obligations and share a proposed high-level scope for system studies with the CQTG.	System Operator	
8.1	Authority / system operator to define "point of control" and specify the applicable transformer for routine testing of IBR in the DIBR	Authority/ System Operator	
8.3	Graeme to email Vong information on ESS capability as input to the system operator clarifying the ACS information requirements	Graeme Ancell	

Outstanding actions

No.	Action	Who	Status
8.6	Authority to clarify in the DIBR which: (i) control setting changes are considered/deemed to affect frequency control, and (ii) firmware changes are considered/deemed to affect frequency response performance.	Authority	
8.7	Authority to clarify in the DIBR which: (i) control setting changes are considered/deemed to affect voltage control, and (ii) firmware changes are considered/deemed to affect voltage response performance.	Authority	
8.9	Sheila to discuss internally the possibility of the NCTG looking at testing obligations on distribution-connected dynamic reactive power compensation devices.	Sheila	
8.11	Authority to elaborate on this interpretation in the proposed DIBR.	Authority	
8.12	Sheila to follow on Stuart M's question regarding how aggregators with ESS should be treated under the Code's AUFLS obligations.	Sheila	
8.13	Authority to clarify the difference between the consideration of Issue 6 (information requirements) in the decision paper, as opposed to its consideration in the separate information requirements workstream.	Authority	
8.14	Authority to share files via Microsoft Teams, requesting members to go into the folder to find the documents rather than providing direct links.	Authority	
8.15	Authority to send the meeting slides to CQTG members	Authority	