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

Meeting 7: 17 October 2024

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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 #5 & #6**
9:15 am	**Voltage options paper** • Key points from the submissions • Recommendations on which options to progress, including any additional options raised in the submissions • Recommendations on any refinements to the options, or further investigation into aspects of the options. • GXP power factor study - scoping
10:15 am	**Morning tea (15 minutes)**
10:30 am	**Voltage options paper (continued)**
11:30 am	**Harmonics discussion paper** • Key points from the submissions • Recommendations on which options to progress, including any additional options raised in the submissions • Recommendations on any refinements to the options, or further investigation into aspects of the options.
12:30 pm	**Lunch (30 minutes)**
1:00 pm	**Harmonics discussion paper (continued)**
1:30 pm	**Frequency options paper** • Key points from the submissions • Recommendations on which options to progress, including any additional options raised in the submissions • Recommendations on any refinements to the options, or further investigation into aspects of the options.
2:45 pm	**Afternoon tea (15 mins)**
3:00 pm	**Frequency options paper (continued)**
3:45pm	**AOB / Next meeting**
4:30 pm	**End of meeting**

OBJECTIVES

The primary objectives of CQTG meeting #7 are for the CQTG to:

(a) provide feedback on the submissions from the June 2024 consultations related to issue 1 (frequency), issues 2 to 4 (voltage) and issue 5 (harmonics)

(b) provide feedback on the Authority's proposed options.

MINUTES & ACTIONS

- Confirm the minutes from meetings #5 and #6
- Update the action items recorded in the minutes

Feedback on minutes – CQTG #5 (10 June 2024)

Matt Copeland feedback:

- 2.3 (a) – I think is worded slightly wrong. OEMs don’t tend to be reluctant about providing black box models, more around unencrypted models from my experience.

  Would replacing 'black box' with 'unencrypted' make this clearer?

- 2.3 (c) – don’t recollect this alternative proposal, or don’t understand it as worded.

  This proposal came from Rob Orange.

Feedback on minutes – CQTG #5 (10 June 2024)

Barbara Elliston:

- Action 5.13[1] address the discussion recorded as 3.1(c)[2] - recommendation from the CQTG to treat BESS as generation for the purposes of Part 8.
- Is there any action item flowing from discussion recorded as 3.1(d)[3], or some page holder for the future – "*CQTG recommended focusing on the optimal product or service that can be obtained with a new technology, and then design the Code to enable it to be delivered*"

Notes:

1. Action 5.13: Authority to add a Code amendment proposal to treat BESS as generation for the purposes of Part 8.
2. 3.1(c): A recommendation from the CQTG to treat BESS as generation for the purposes of Part 8. This is intended to be a short-term solution to provide clarity and improve efficiency by simplifying the Part 8 requirements on BESS. The CQTG noted that this suggestion alone would not maximise the benefits that BESS can provide to the power system, and more work is needed to come up with a more comprehensive solution for BESS in the Code.
3. 3.1(d): BESS provides new capabilities to the electricity market. The Authority should ensure that the Code is updated promptly to avoid constraining emerging technologies by requiring them to comply with outdated rules. The CQTG recommended focusing on the optimal product or service that can be obtained with a new technology, and then design the Code to enable it to be delivered.

Feedback on minutes – CQTG #6 (15 August 2024 - online)

None

Actions

No.	Action	Who	When
1.7	• Authority to engage with MBIE, urging MBIE to prioritise proposing an amendment to the Electricity (Safety) Regulations 2010, to permit the supply of electricity to installations operating at 230 volts AC to be within 10% of 230 volts AC.	Authority	Open
5.1	• CQTG chair to sign the minutes of the third and fourth CQTG meetings, and publish the minutes on the Authority's website.	Authority	
5.2	• FSR-001 (Periodic testing of wind generation): Proceed with the current Code amendment proposal.	Authority	
5.3	• FSR-001 (Periodic testing of wind generation): Look at broadening the term 'control system' in the Code in a way that can apply to all technologies – for example, a control system is a system that dynamically adjusts control output signals in a programmed response to continuously changing input signals.	Authority	
5.4	• FSR-001 (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	
5.5	• Authority to exclude FSR-002 and FSR-003 from the Code amendment proposal paper and consider a revised approach to moving these options forward.	Authority	
5.6	• FSR-004 (Embedded generation to provide an ACS): Authority to progress this item and specify an appropriate (eg, 1MW) threshold at the point of connection that applies to both generation and load.	Authority	
5.7	• FSR-005 (Expand definition of "causer" for an UF event): Authority to amend the wording and progress this item.	Authority	
5.8	• Authority to exclude the FSR-006 Code amendment proposal from the paper and consider whether droop settings are appropriately included in Part 8 of the Code or elsewhere (eg, a document incorporated by reference in the Code or in a system operator technical document).	Authority	
5.9	• FSR-007 (Amend requirement for generating units to have a speed governor): Authority to proceed with the proposal.	Authority	

Actions contd.

No.	Action	Who	When
5.10	• FSR-008 (Amend requirement for generating units to have an excitation system): Authority to proceed with the proposal	Authority	
5.11	• FSR-008 (Amend requirement for generating units to have an excitation system): Authority to consider revising the reference to ‘voltage control mode’ in clause 5(2)(a) of Technical Code A of Schedule 8.3 of the Code, as part of addressing the three key voltage-related issues.	Authority	
5.12	• FSR-009 (Replace references to static var compensators’ with ‘reactive compensation devices’): Authority to proceed with the proposal, subject to changing the term to “dynamic reactive power compensation devices”.	Authority	
5.13	• Authority to add a Code amendment proposal to treat BESS as generation for the purposes of Part 8.	Authority	
5.14	• Authority to add a Code amendment proposal to amend the definition of ‘generating unit’, and share it with the CQTG for review.	Authority	
5.15	• Authority to consider the appropriateness of including in the Code a new definition ‘generating system’.	Authority	
5.16	• Authority to add a Code amendment proposal in relation to the FRT requirements.	Authority	
5.17	• Authority to to send these updates in written form, along with the meeting slides, to the CQTG ie, • update on relevant work steams from the Retail & Networks team • Update on status of other options in the long list of options	Authority	

Options to address the voltage common quality-related issue

Option 1

Amend Parts 6 and 8 of the Code to require

- existing and new distributed generation,
- embedded generating stations, and
- distributed-connected energy storage systems

connected to a local distribution network at a nominal voltage equal to the GXP voltage to have reactive power capability to meet voltage support AOPOs specified in the Code

Option 1

Key points raised in submissions:

Where to specify requirements?

- Most agreed that all generating units connected to the GXP should provide voltage support
- Different views on where the obligation should sit:
    - EEA industry guidelines [difficult to enforce]
    - Distribution connection and operating standards [costly for distributors to negotiate with individual generators]
- Questions from submitters on how existing generation will be treated (and if they will have capability to comply)
    - Needs further consideration (eg, grandfathering clauses, dispensations)

What is the CQTG's view?

Option 1

Key points raised in submissions:

Capacity threshold

What is an appropriate capacity threshold?

Submitters suggested:

- Include an overarching guideline in the Code for a suggested limit – but subject to negotiation between parties based on needs and limitations
- Adopt the capacity threshold adopted for frequency keeping obligations
- 1MW threshold (Powerco – already have this requirement in place)
- 5MW threshold (Transpower)

What is the CQTG's view?

Option 1

Key points raised in submissions:

Changing the reactive power range

Reactive power range: ±33% rather than +50%/-33%

- No strong support or objection to this proposal.
- Noted benefits in making this change but several cons:
  - High compliance costs for smaller renewable distribution energy projects (which could discourage investments in these projects)
  - Proposed range too demanding for many renewable energy sources.
  - Solar could struggle to meet this requirement without compromising their efficiency (they may need to operate at reduced active power output, reducing their overall energy yield and economic viability)

What is the CQTG's view?

Option 1

Next steps

Authority proposes to investigate option 1 further with obligations specified in the Code (rather than guidelines etc), including:

- Doing further work on what the threshold should be
- Investigating how to treat existing generation and how the new requirements will be implemented (eg, grandfathering, dispensation arrangements)
- Deciding whether to proceed with the proposal to change the reactive power range

Option 2

Amend Part 8 of the Code to require the system operator and distributors to co-ordinate with each other in managing reactive power flows through a GXP, in either direction, in order to support voltage on both sides of the GXP

Option 2

Key points raised in submissions

- Most submitters agreed to investigate option 2 further (except IEGA and NewPower)
- There are benefits but several significant costs for distributors were noted:
  - Need DERMS systems for real-time visibility and forecasting
  - Investment in new processes, tools, and methods to manage voltage across the networks
  - Ongoing operational costs to manage a more complex voltage support
  - BESS incur losses when in idle state to provide voltage control (rather than powered-down state)

CQTG – how significant are these costs and what are the options to reduce these costs?

Option 2

Next steps

Authority proposes to proceed with investigating option 2 further – specifically:

- Look further into the costs raised by submitters to make an assessment on whether the benefits of this change would be expected to outweigh the costs
- Establish an appropriate range for reactive power flows at the GXP, informed by system studies

To determine appropriate power factor to manage reactive power flowing through GXPs

Voltage Studies

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

Overview of voltage studies and *study cases*

Stage 1

Analyse reactive power flowing through all Transpower's GXPs

Extract historical data for all GXPs

Data resolution: 30-minute for past one year

Calculate power factor and determine direction of flow

Stage 2

Determine appropriate power factor to manage reactive power flow through GXPs

Analyse reactive power flowing through GXP

Determine the appropriate power factor to manage reactive power flow

Discuss possible actions to manage reactive power flow

Stage 3

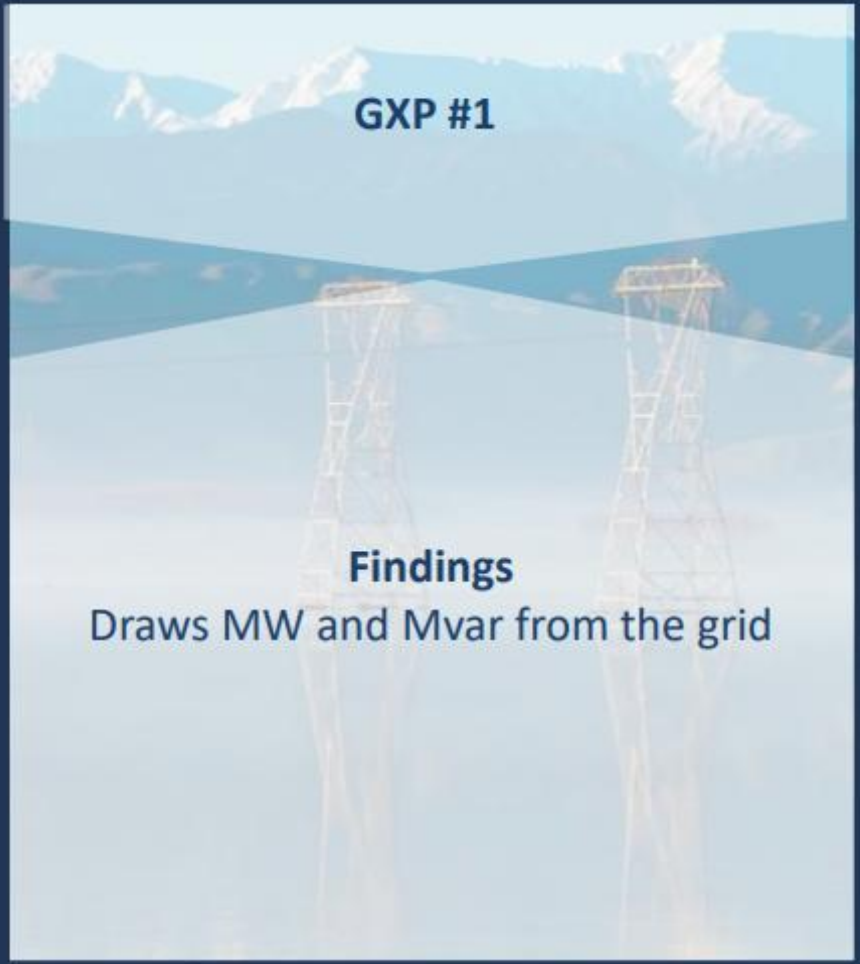
Analyse the effects on manage voltage and voltage stability limits at the grid side

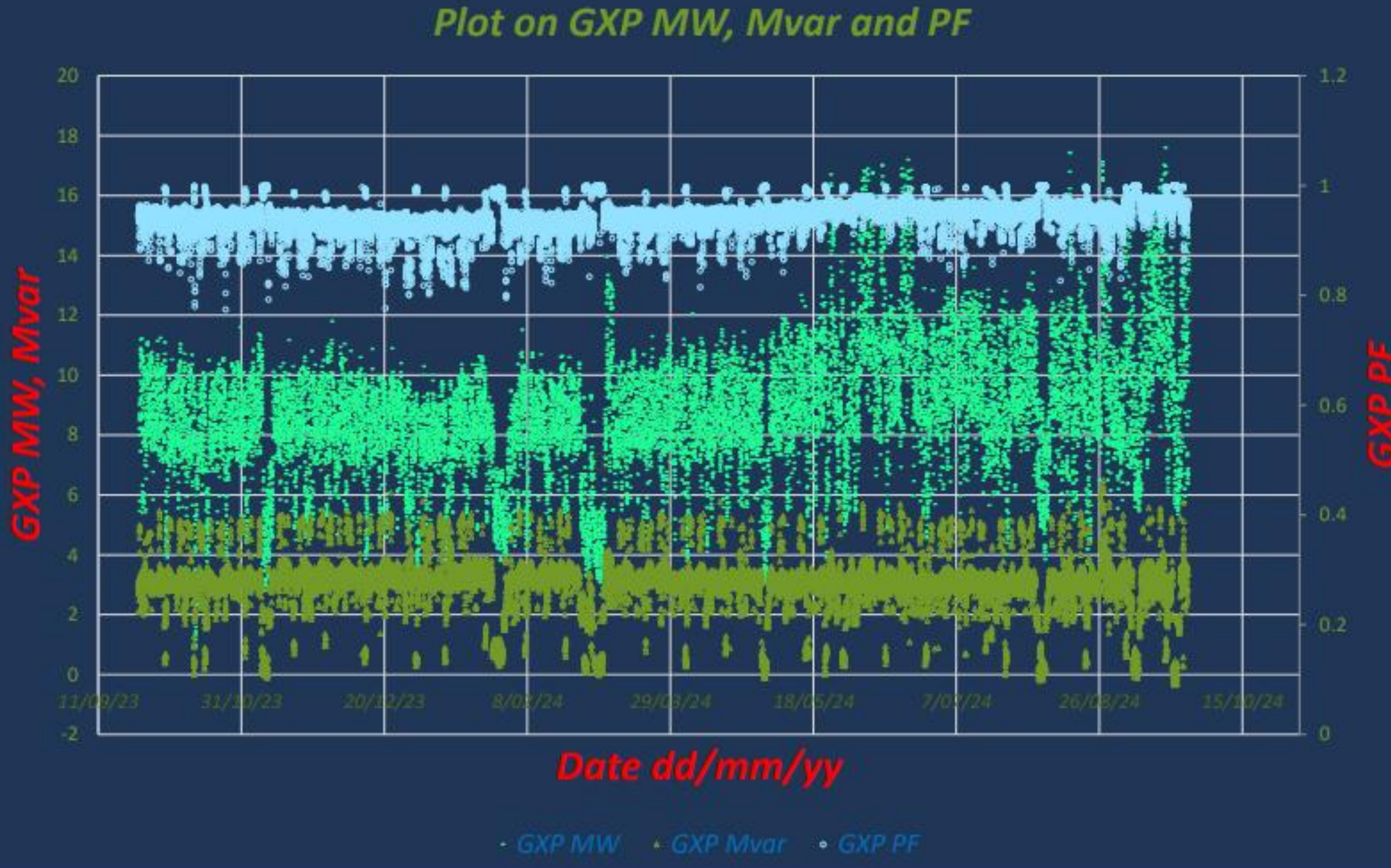
Investigate the effects of managing reactive power flow on managing grid side voltages

Investigate the effects on voltage stability limits

GXP PF study stage 1 & 2

GXP PF study stage 1





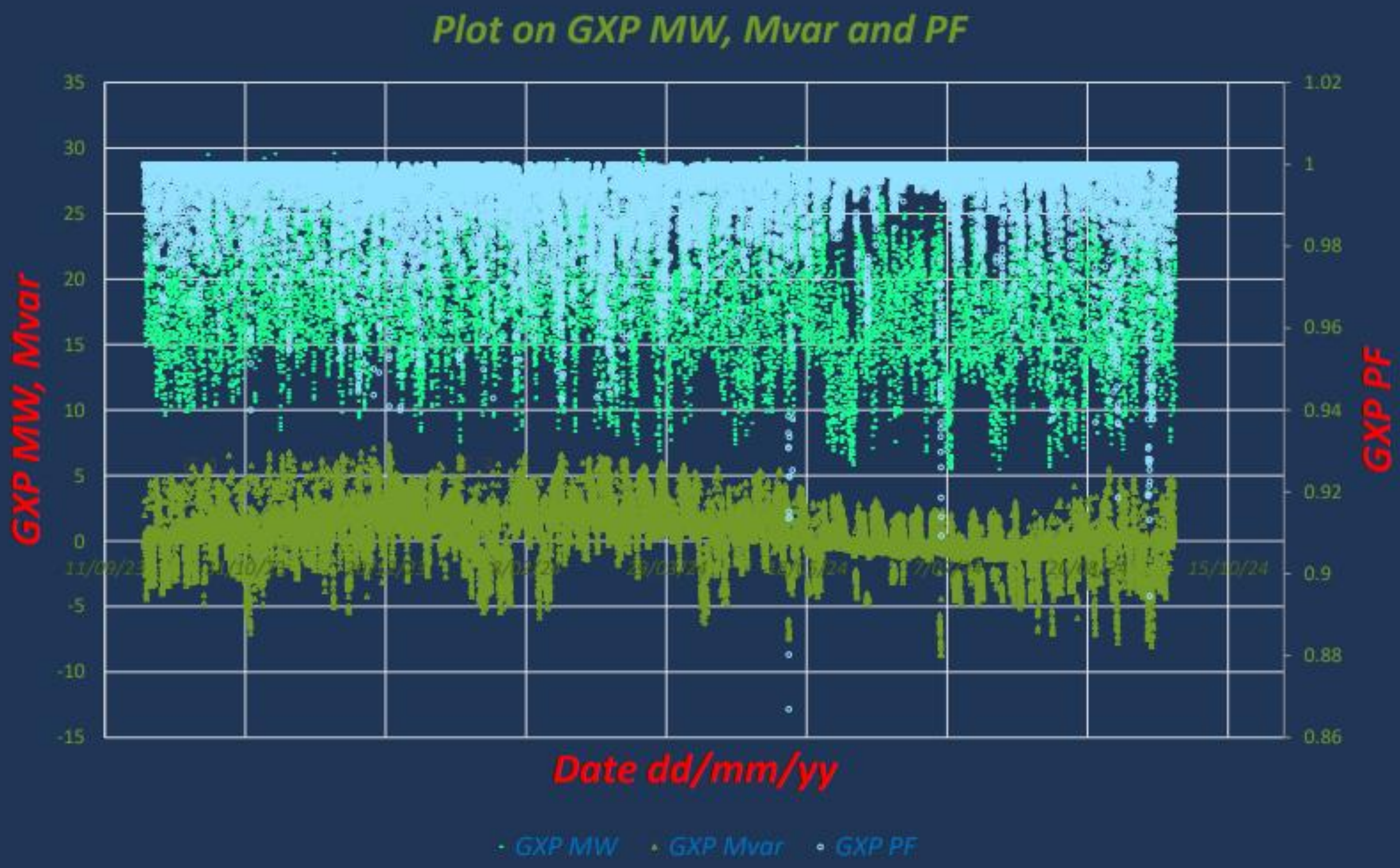
GXP PF study stage 1

GXP #2

Findings

Draws MW from the grid and

Draws and injects Mvar from/to the grid



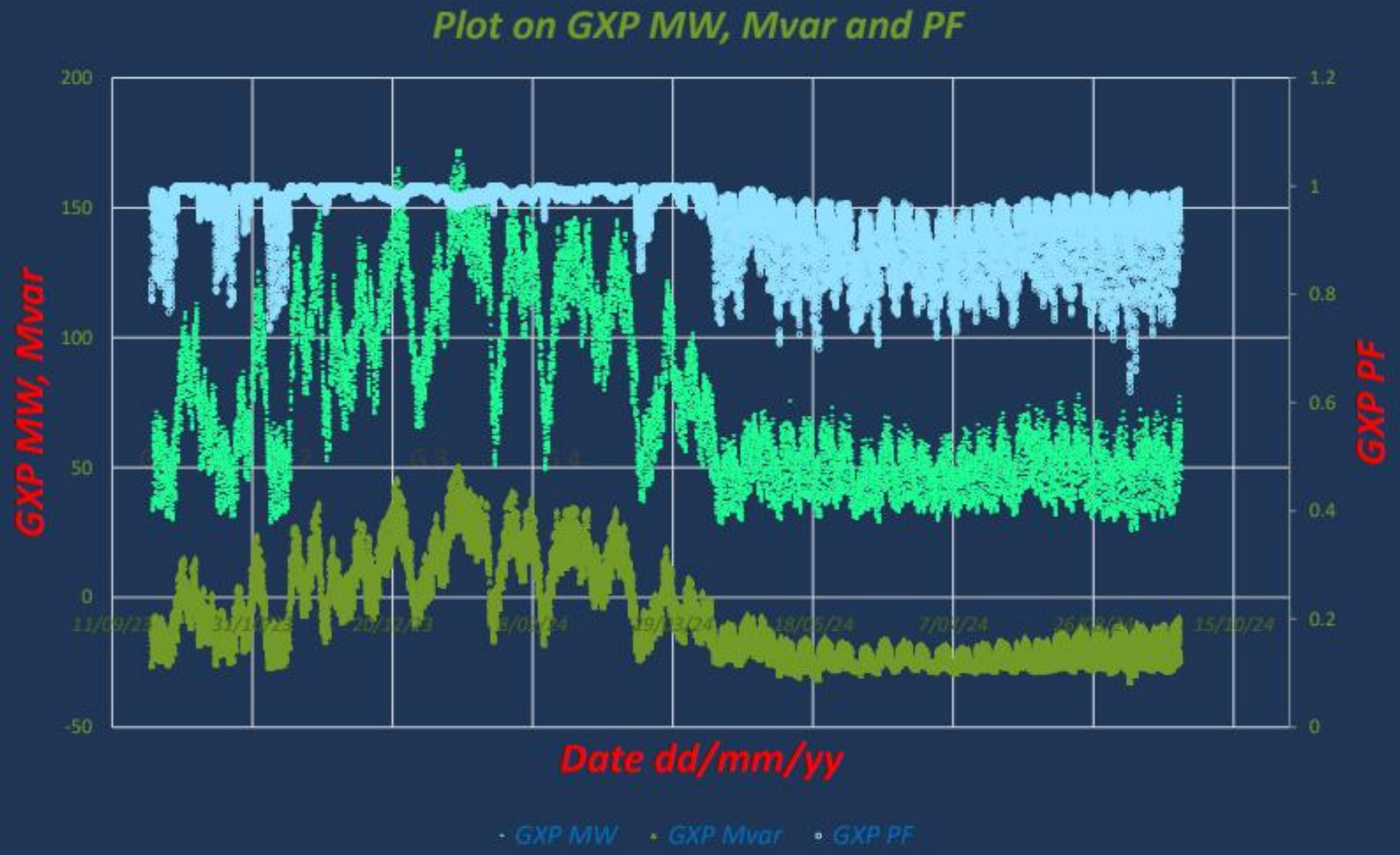
GXP PF study stage 1

GXP #3

Findings

Draws MW from the grid and

Draws and injects Mvar from/to the grid

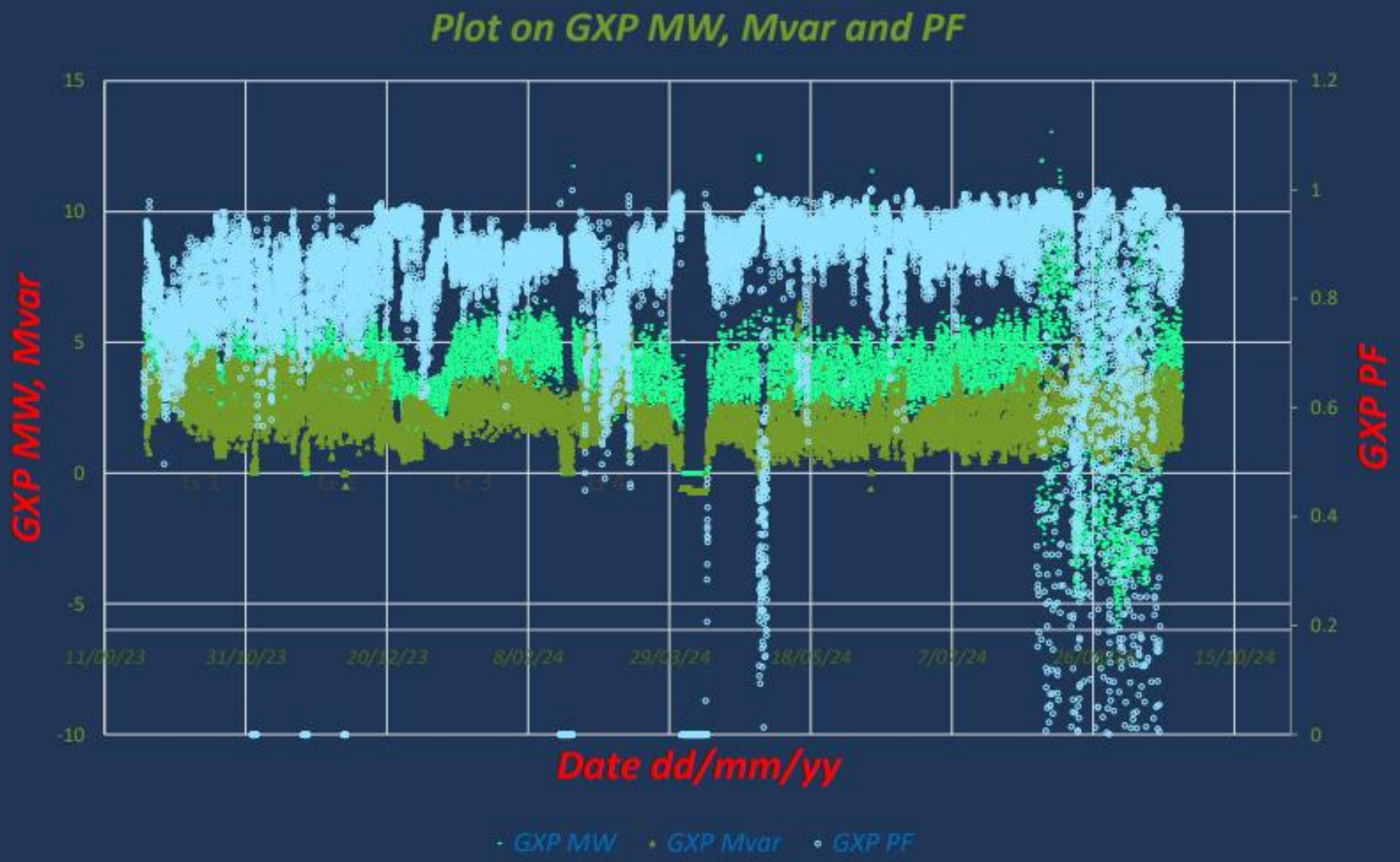


GXP PF study stage 1

GXP #4

Findings

Draws and injects MW and Mvar from/to the grid



GXP PF study stage 2

GXP #1

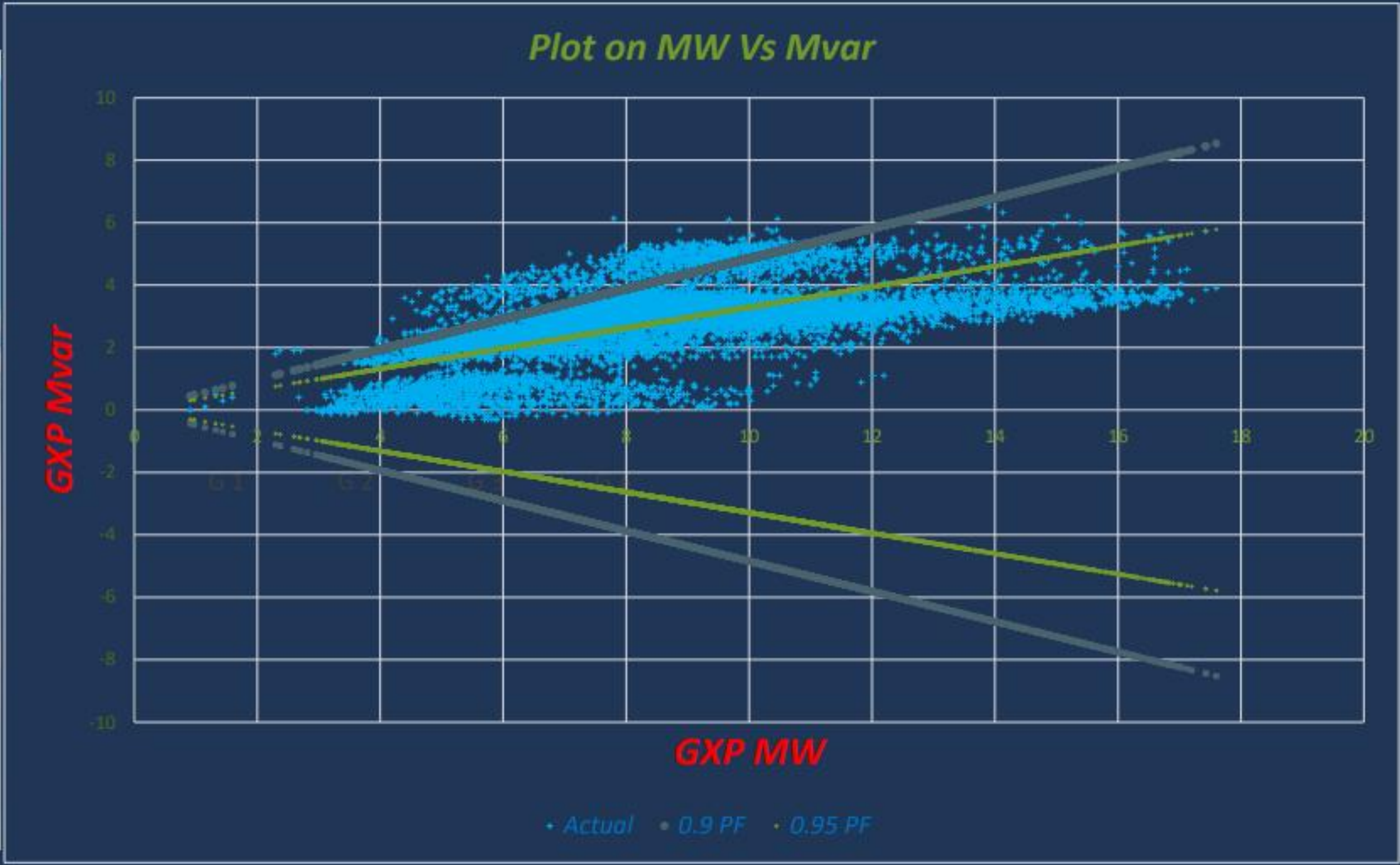
Findings

10873/17630 TP outside 0.95 PF

max 2.2 Mvar above 0.95 PF

963/17630 TP outside 0.9 PF

Max 3.5 Mvar above 0.9 PF



GXP PF study stage 2

GXP #2

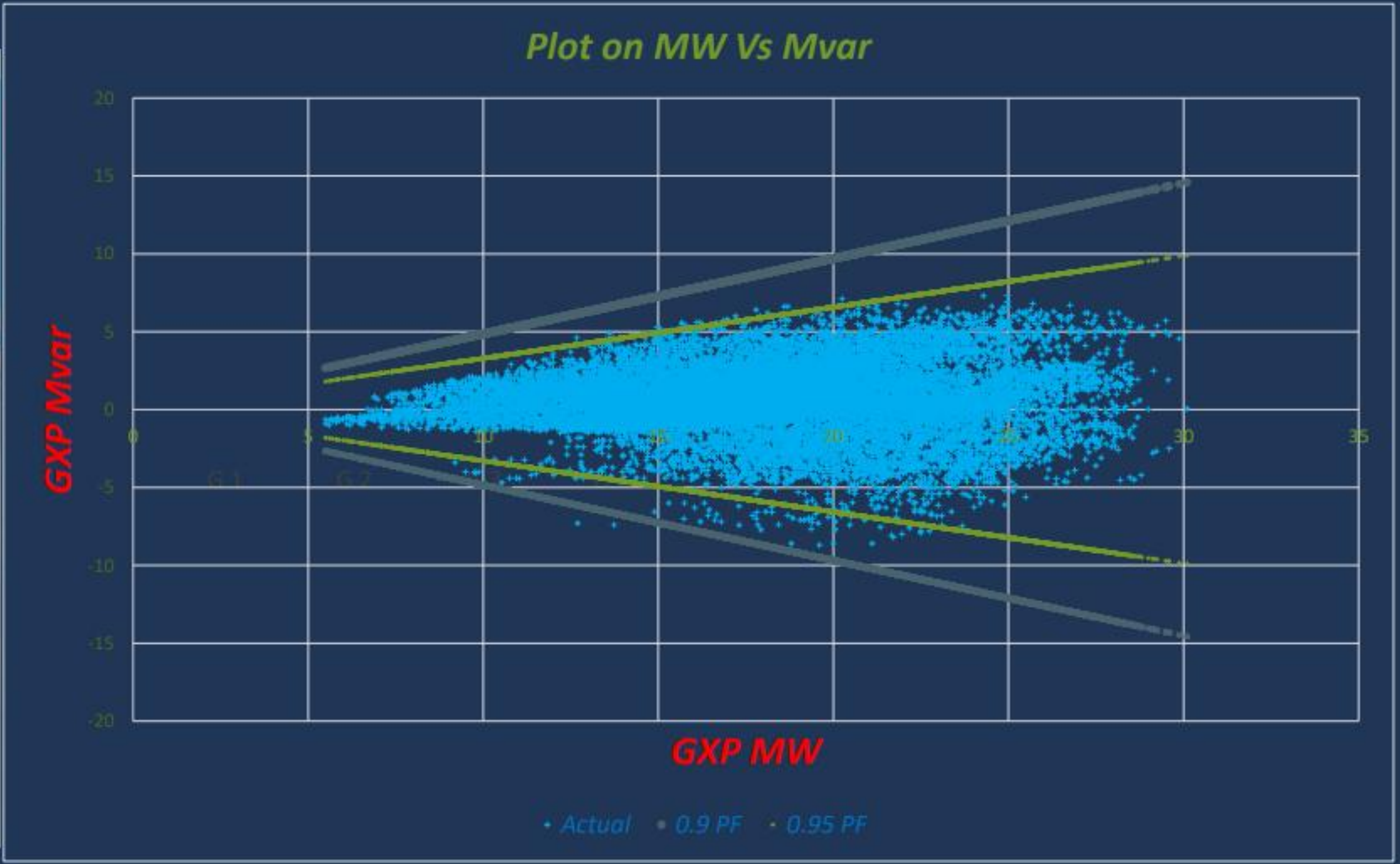
Findings

101/17630 TP outside 0.95 PF

max 3 Mvar above 0.95 PF

3/17630 TP outside 0.9 PF

Max 1 Mvar above 0.9 PF



GXP PF study stage 2

GXP #3

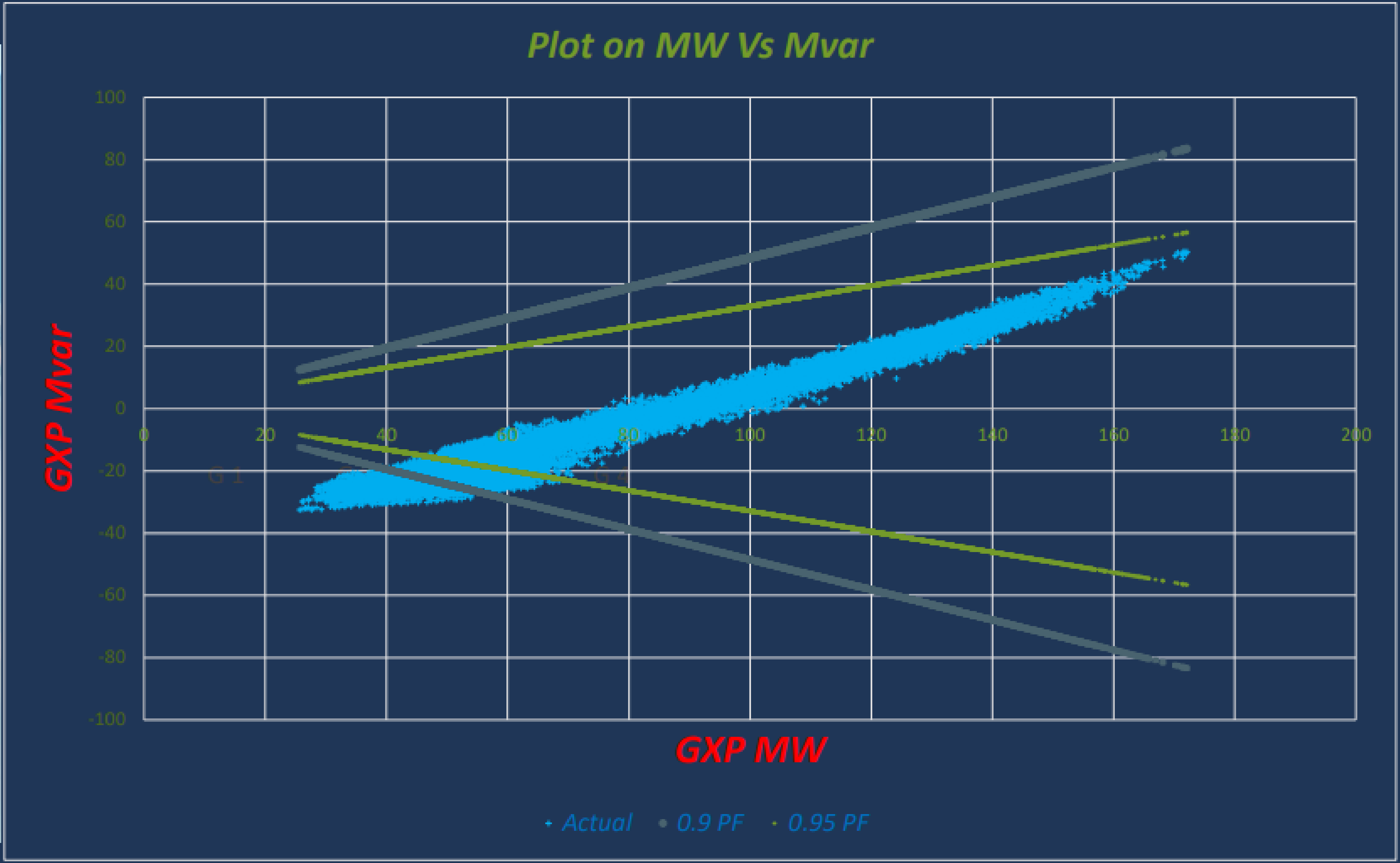
Findings

7155/17630 TP outside 0.95 PF

max 23 Mvar above 0.95 PF

4067/17630 TP outside 0.9 PF

Max 20 Mvar above 0.9 PF



GXP PF study stage 2

GXP #4

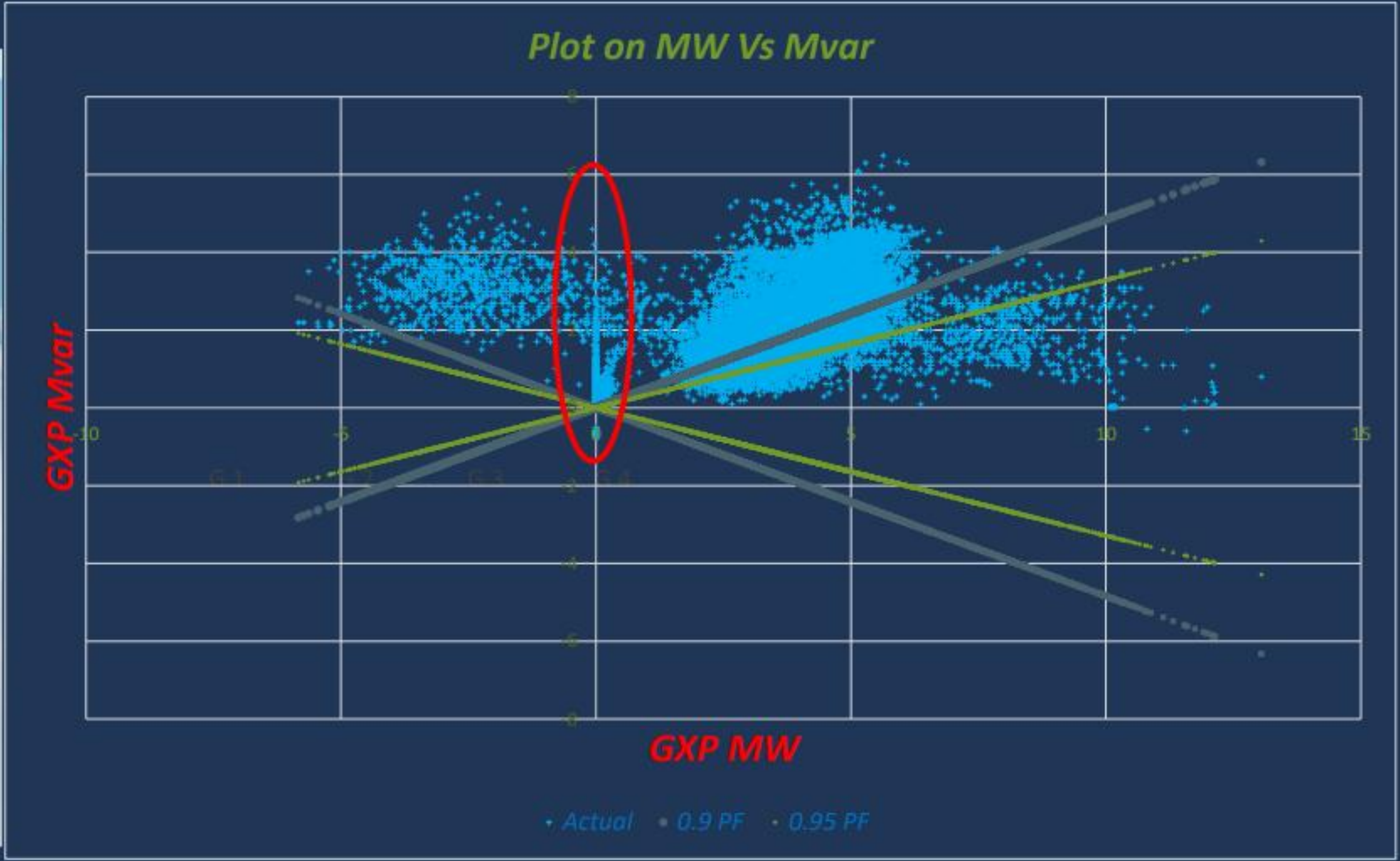
Findings

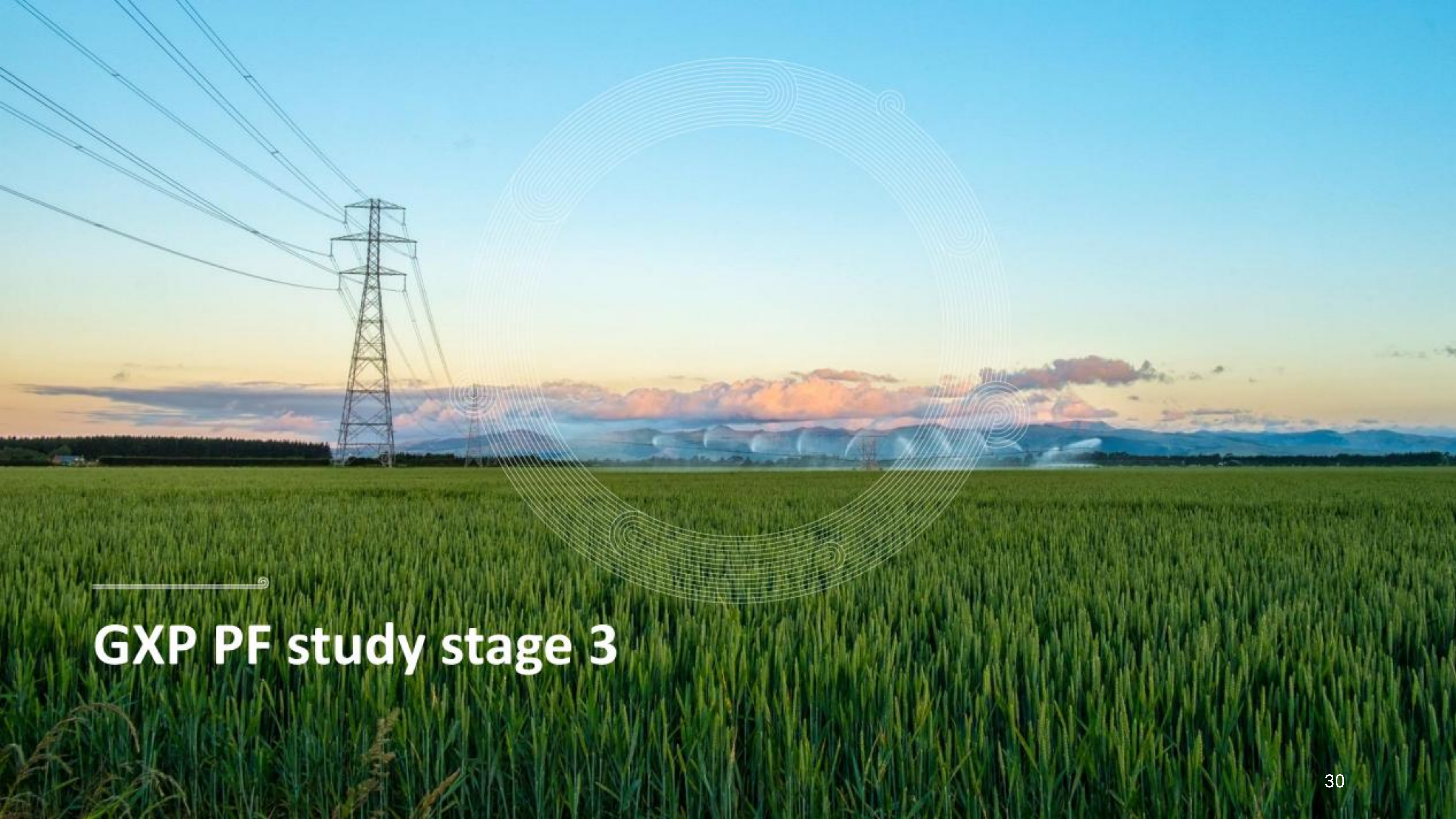
15959/17630 TP outside 0.95 PF

max 4.6 Mvar above 0.95 PF

11188/17630 TP outside 0.9 PF

Max 3.5 Mvar above 0.9 PF





GXP PF study stage 3

GXP PF study stage 3

Analyse the effects on manage voltage and voltage stability limits at the grid side

Benefits

Learn the effects of managing reactive power flow on grid system voltages

- ❖ Understand the effects of managing reactive power flow through GXP can affect grid system voltages regulation
  - ❖ Bigger GXP may have more impacts
  - ❖ Regional effects and impacts on voltage stability limits
- ❖ May not paint the whole picture
  - ❖ Coordinated reactive power dispatch can benefit the power system:
    - ➢ More effective grid system voltage regulation
    - ➢ Better voltage profile across the system improves asset utilisation
  - ❖ Studies is sensitive to:
    - ➢ Regional changes
    - ➢ Voltage management within distribution network
    - ➢ GXP loadings

Thank you

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Option 3

Propose to amend clause 8.21 of the Code to change the threshold for generating stations to be excluded by default from complying with the fault ride through AOPOs in the Code

The changed threshold would apply to existing and new generating stations

Option 3

Key points raised in submissions

- Submitters were supportive of lowering the threshold but different views on what the threshold should be
- Many were concerned about the significant cost for smaller generators to demonstrate compliance – particularly for generation less than 10MW
- Manawa provided costs:
    - to model and comply with FRT, $50k – $100k per unit
    - Plant modifications $50k – $1M or multiple of millions
    - Applying for dispensations between $50k – $100k

Option 3

Key points raised in submissions:

Reduce compliance costs for small generators

Options to make compliance less costly:

- All generation complies with FRT requirements – less onerous requirements for <10MW (eg, supply FRT settings and asset capability documents, not undertake exhaustive power system dynamic simulations)
- Threshold only applies to DG connected at GXP voltage
- For 10–30MW generation, use single machine infinite bus rather than full network modelling

CQTG: What are your views on these proposed options?

- Authority needs to consider existing generation, which may not have the required capability
- Grandfathering is an option

Option 3

Next steps

Authority proposes to proceed with investigating option 3 further – specifically:

- Determine what the threshold should be
- Consider the likely costs for smaller generators to demonstrate compliance (especially those under 10MW)
- Consider options to reduce the costs of compliance for smaller generators
- Investigate how existing plant should be treated

Alternative options proposed by submitters

- Reactive power export requirements reduce linearly to zero, as the voltage at the point of connection increases from 1.05 to 1.1 [**Genesis**]
- Grid forming technologies – can solve multiple issues, but has drawbacks around fault ride through and other areas [**NewPower, IEGA**]
- Market-based solutions in the longer term to incentivise providing voltage support [**Meridian, WEL, IEGA**]
- Transmission-based assets to manage voltage may be more efficient investment than the options considered [**IEGA**]
- Appropriate standards (eg, AS 4777) are needed for increasing amounts of solar, battery and EV chargers [**Mercury**]

Options to address the harmonics common quality-related issue

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Key points raised in submissions

Governance of harmonics

- New Zealand harmonics governance no longer fit for purpose
- Need consistency across regulatory instruments
- NZECP 36:1993 should be replaced:
  - Tailored version of AS/NZS 61000 or IEC 61000 standards, OR
  - EEA's January 2024 PQ guidelines, with inclusion of 220kV and above voltages

Key points raised in submissions

Management of harmonics

- Not a given that IBR always make harmonics worse
- 'For' and 'against' views on whether centralised harmonics database would have a net benefit
- Support for 'whole-of-system' approach for allocating harmonics:
  - Consistency across distribution, BUT
  - Transpower, as grid owner, doesn't want a methodology imposed on it because of evolving thinking in harmonics allocation

Key points raised in submissions

Management of harmonics (continued)

- Two views on 'open access' approach:
  - Warrants further investigation
  - Shifts costs from planning stage to real-time network operation
- 'Net absorber' approach doesn't look at combined effect of multiple harmonics causers
- 'Apply charges to emitters' approach faces challenges identifying emitters
- 'Pre-emptive installation of filters' likely to impose unnecessary investment costs
- Two hybrid approaches put forward:
  - Combine elements of 'open access' and 'apply charges'
  - Transpower's bespoke approach

Suggested short-listed options

Option 1

- Revoke NZECP 36:1993, mandate aspects of AS/NZS 61000 standards, recommend *but not mandate*, an option for limiting and allocating harmonics

Option 2

- Revoke NZECP 36:1993, mandate aspects of EEA PQ guidelines, recommend *but not mandate*, an option for limiting and allocating harmonics

Option 3

- Revoke NZECP 36:1993, recommend *but not mandate*, aspects of EEA PQ guidelines and an option for limiting and allocating harmonics

Sub-option of each option

- Establish a publicly available database of harmonic emissions

Options to address the frequency common quality-related issue

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Option 1

Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code.

The changed threshold would apply to existing and new generating stations and energy storage systems.

Option 1

Key points raised in submissions

- Technology-specific challenges with lowering 30MW threshold:
  - Operational (eg, no governor)
  - Financial – implementation (eg, retrofitting) and ongoing (eg, compliance costs)
- Consider market-based approach for maintaining frequency
- 5MW threshold would impose significantly higher costs than 10MW threshold, for limited additional benefit
- Two views on aligning AS/NZS 4777.2 with Code re generating stations riding through UFEs for 6 seconds:
  - Support for alignment
  - More analysis and discussion needed

Option 1

Next steps

Authority proposes to proceed with investigating option 1 further – specifically:

- Determine what the threshold should be
  - 5MW or 10MW, or variation (eg, 10MW historical but 5MW from some future date)?
- Consider the likely costs for smaller generators
  - Implementation costs
  - Compliance costs
- Consider options to reduce the costs of compliance for smaller generators

No further system studies needed

Option 2

Set a permitted dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

The changed threshold would apply to existing and new generating units.

Option 2

Key points raised in submissions

- Some support for:
  - Differing deadbands – reflect technology differences
  - Uniform deadband – simpler system management
- Limited support for widening the normal band
- Technology-specific challenges with deadband(s):
  - Operational (eg, higher wear and tear)
  - Financial – implementation (eg, equipment upgrades) and ongoing (eg, reduced revenue and compliance costs)
- Consider market-based approach for maintaining frequency
- Considering minimum ramp rate requirement
- Consider restructuring IR market to better incentivise IBR to contribute to frequency control

Option 2

Next steps

Authority proposes to proceed with investigating option 2 further – specifically:

- Common deadband?
- OEM-based deadband?

No further system studies needed

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 3

Key points raised in submissions

- Current band won't be fit for purpose in the future
- Modern technology can provide frequency management without being dispatched
- More frequency keeping doesn't directly address more frequency variability
- Support for 1 second reserve category
- Have low barriers to entry
- Using existing market services likely more efficient than implementing a capability market for ocntrol response
- Should the FK band vary across time periods (eg, morning and evening load ramps, solar ramps)?

Option 3

Next steps

Authority doesn't need to investigate this option further since it reflects the status quo – the Code provides for the system operator to procure more FK and IR

No further system studies needed

Any Other Business

- BESS – AOPO system operator studies

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BESS AOPO Studies Scope

Presentation to CQTG

17/10/202

Introduction

- To determine if BESS should have voltage support, frequency support, and FRT obligations
- Consider discharging, charging and idle when assessing obligations
- Hybrid plant obligations – discussion only
- All studies will include literature review

Study 1 - Voltage Obligations

- To determine if voltage support obligation should apply when operating in discharging, charging and idle mode.
- To determine impact of voltage support obligations, we will reproduce voltage stability curves for areas with known voltage stability issues (Upper South Island / Upper North Island), with expected BESS connections with and without the BESS providing voltage support.
- Will also study impact on overnight high voltages and associated removal of circuits.
- Complete literature review to determine BESS voltage obligations in other jurisdictions, and the impacts.

Study 2 - Frequency Obligations

- To determine if 8.17, 8.19, and other technical Codes are applicable to BESS
- Will determine:
  - If BESS has the capability to meet the obligations
  - Consider SoC when assessing BESS capability
  - Consider if obligations should be modified such that a BESS is not required to cross 0MW in response to frequency
- Study approach – set up simplified model of BESS frequency control,

which includes SoC, and inject frequency data to assess SoC variations

Study 3 - Fault Ride Through Obligations

- To determine if 8.25A – 8.25C should apply to BESS
- Study to determine:
  - Is a typical BESS capable of riding through a fault?
  - What would be the impact of BESS not complying on voltage recovery, given expected amount of BESS uptake?

Study 4 – Hybrid Plants

- Several issues to consider relating to hybrid plants:
  - Where is compliance assessed?
  - Do obligations change based on operating mode (i.e. frequency capability is different when injecting, BESS vs PV)?
  - Should BESS-PV hybrids and BESS-Wind hybrids be treated differently?
- Consider AC coupled hybrids system only
- Complete literature review and provide general discussion in the report

Excluded from Scope

- Distributed BESS or aggregators / VPPs
- Cost Benefit Analysis
- Required changes to market and operational tools – note this could be a significant piece of work for SO, but beyond scope of this analysis.

Thank you

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Next meeting

Purpose: Discuss the draft consultations on options and draft Code amendment proposals

Proposed next meeting date (TBC): February 2025

Location: Wellington

Reading material

Links to relevant information provided during the meeting:

- Transpower report: Preparing for an increase in IBR (June 2023)
- NERC: Quick reference guide – IBR activities (June 2023)
- AEMO: Primary frequency response incentive arrangements (September 2022)
- AEMO: Primary frequency response requirements (February 2023)

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