GHD Advisory

GHD advice for the 2022 Frequency Operating Standard review

Power system and economic impacts due to variation of the Primary Frequency Control Band in the NEM

Australian Energy Market Commission

21 November 2022

→ **The Power of Commitment**

Project name	AEMC - Advice for the frequency operating standard review 2022
Document title	GHD advice for the 2022 Frequency Operating Standard review | Power system and economic impacts due to variation of the Primary Frequency Control Band in the NEM
Project number	12587342
File name	12587342 - GHD Final Report - AEMC advice for the 2022 Frequency Operating Standard Review.docx

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S0	A	Luke Hyett			D Bones		4/10/2022
S1	A	Luke Hyett	Matt Nichol				11/11/2022
S4	A	Luke Hyett	Matt Nichol		D Bones	DBones	21/11/2022

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→ The Power of Commitment

Executive summary

GHD has prepared independent advice to inform the Reliability Panel's review of the National Electricity Market (NEM) Frequency Operating Standard (FOS). Specifically, we have undertaken power system simulation studies to investigate the potential implications of adopting different settings for the Primary Frequency Control Band (PFCB). This advice will inform the Panel's consideration of the appropriate settings for the PFCB. The settings are defined under Chapter 10 of the National Electricity Rules (NER) as 49.985 Hz to 50.015 Hz or another range specified by the Reliability Panel.

The PFCB is part of the framework implemented in the NER through the mandatory Primary Frequency Response (PFR) rule[1] that allows the Australian Energy Market Operator (AEMO) to specify the Primary Frequency Response Requirements (PFRR) that generators are required to meet. The mandatory PFR rule also allows the Reliability Panel to specify a PFCB as part of the FOS. Under clause 4.4.2A of the NER, the PFCB sets a limit on the deadband that AEMO may specify in the PFRR. AEMO must not require a deadband that is narrower than the PFCB.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1.3 and the assumptions and qualifications contained throughout the Report.

GHD has performed power system studies to identify and quantify the consequences of modifying or maintaining the current PFCB. This work has considered system operations under both "system normal" conditions and following significant events such as non-credible contingencies including events that trip multiple large generating units, disconnect significant loads or trip interconnectors. The outcomes of this analysis indicate the potential impact of changing the PFCB settings on frequency control, the resilience of the power system and system-wide costs. High-level findings from this analysis include:

- Power system frequency control under normal operation is degraded by a wider PFCB and improved by a narrower PFCB. Remaining within the Normal Operating Frequency Band (NOFB) as the currently specified in the FOS is only possible with a PFCB set inside the NOFB.
- Power system resilience is degraded by a wider PFCB, with significantly more load shedding and worse frequency nadirs observed when non-credible contingencies occur. In addition, conditions for the resynchronisation of islanded parts of the NEM are worsened with a wider PFCB.
- Costs attributable to market participants providing PFR decrease with a wider PFCB. With a wider PFCB, less aggregate movement across dispatch intervals is required from generators to meet the PFCB requirements.
- Costs attributable to market participants providing Regulation Frequency Control Ancillary Service (R-FCAS) increase with a wider PFCB. More aggregate movement is required from R-FCAS providers due to the larger deviations in system frequency experienced with a wider PFCB.
- Wider PFCBs reduce system resilience and increase costs to market participants and customers. These costs are primarily due to the increase amount of load shedding following non-credible contingency events with wider PFCBs.

Modelling approach

Our study utilised two different power system models for the two separate study tasks, 1a and 1b.

- Task 1a focused on normal frequency operation. A model was used representing the NEM as a single node, with several discrete generators connected to a single main busbar. This allowed the frequency response of different generator technologies to be represented.
- Task 1b focused on frequency control following contingencies. A model was used representing different regions in the NEM as interconnected nodes, allowing for the simplified modelling of interconnectors between each region.

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[1] The final rule determination available at **Mandatory primary frequency response | AEMC**

Both models were developed using DIgSILENT PowerFactory, based on a previous single node model developed by DIgSILENT Pacific to study Automatic Generation Control (AGC) in the NEM. Assumptions common to both tasks have been listed below:

- Two “study years” were analysed by GHD. The first includes a representation of 2022 dispatch conditions. The second study year was 2033, which was chosen to evaluate the impact of the retirement of the majority of the existing coal plant on the NEM.
- Generation in the model was split by aggregate fuel type, including sub and supercritical coal, wind, solar, battery energy storage systems, combined cycle gas turbines, open cycle gas turbines, and hydro units.

Task 1a – Normal frequency operation

The purpose of these studies was to simulate the NEM under normal frequency operating conditions. This was done using a “single bus” model. The single bus model provides an adequate representation of the mainland NEM for the purposes of simulating frequency control, as although the NEM is geographically dispersed, it is managed as a single frequency region under normal conditions.

- Three six-hour periods were simulated using historical 4-second aggregate forecast error data. Three six-hour periods were selected out of two weeks’ worth of NEM SCADA data from September 2021. These periods represent the lowest, highest, and average levels of forecast error across the two weeks.
- Two dispatch scenarios were selected for the 2022 study case. They represent low and high Variable Renewable Energy (VRE) generation conditions.
- A specific subset of generation was used to simulate the units enabled to provide C-FCAS.
- Different PFCB deadbands were tested using the model, including 5, 15, 50 and 150 mHz deadbands across each study case.
- Where appropriate, additional sensitivity study cases were undertaken to test different elements or changes to the model assumptions.

These power system analysis studies aimed to understand the impact of the PFCB on:

- The ability to control the system frequency and meet the current FOS (ie maintain frequency within the NOFB).
- Work done by PFR providers.
- Work done by R-FCAS providers
- The relative system wide costs for each considered PFCB option.

Task 1b – Contingent frequency operation

The purpose of these studies was to simulate the NEM under significant contingent conditions, modelling the impact of varying the PFCB on NEM frequency before, during and after a major non-credible contingency such as an interconnector trip or a major generation or load trip event. A multi-node model representing mainland regions linked by interconnectors was used to simulate the NEM under these conditions. The multi-node model allowed us to assess the impact of contingency events that led to the separation of regions from the rest of the NEM.

- Several major contingency events were studied, including the trip of the Queensland – New South Wales Interconnector (QNI) under a high load condition, the trip of the Heywood interconnector, trip of multiple large generating units, and the disconnection of mutiple large loads.
- 15 mHz and 150 mHz deadbands were tested for each of the study cases and contingency events.

The purpose of these power system analysis studies was to understand the impact of the PFCB on:

- Frequency nadirs under major contingencies.
- Load shedding under the studied contingencies.
- Frequency recovery and stability following the studied contingencies.
- The relative costs of any reduction in reliability observed for each PFCB option.

Task 1b also included additional analysis to understand the impact of the PFCB settings on the ability to resynchronise islanded regions. This analysis used a similar approach to task 1a, with frequency deviation modelled over a 6-hour period simulating Queensland islanded from the rest of the NEM.

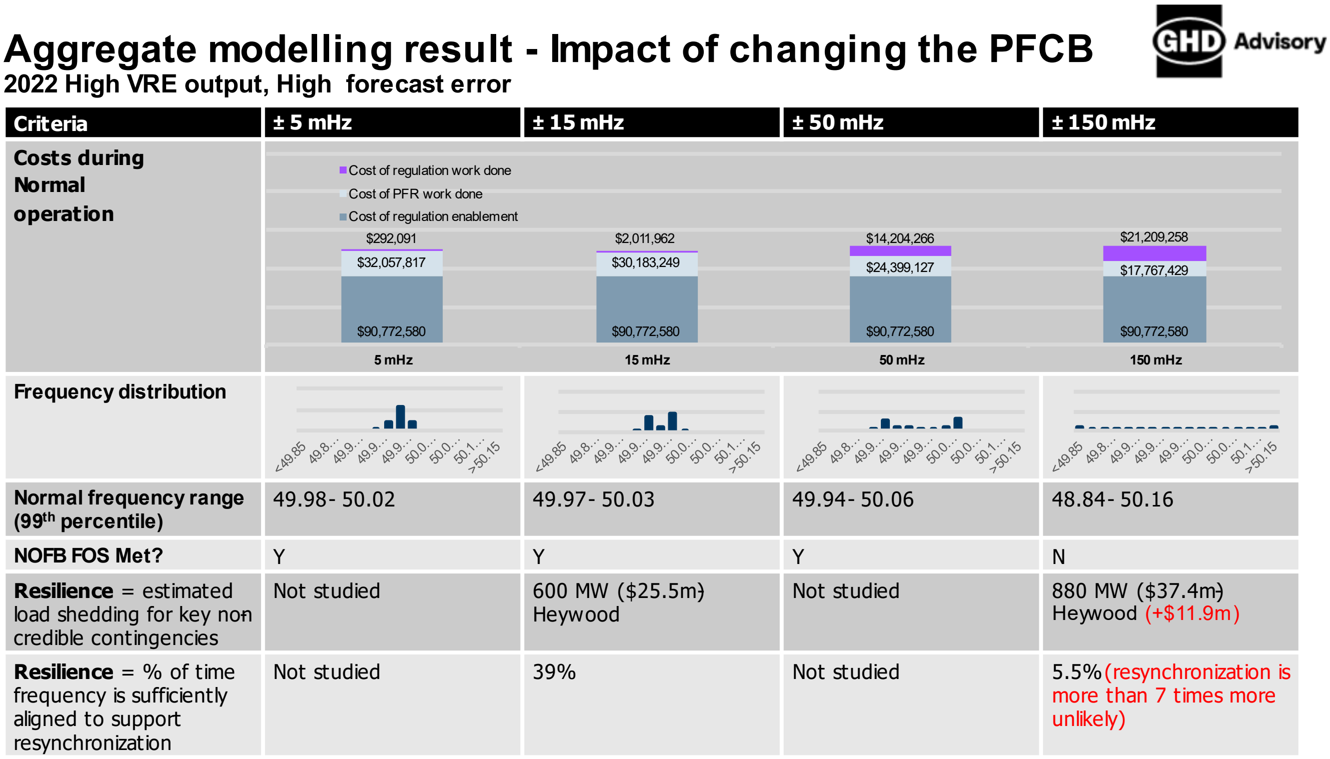
Key results

The major findings of this work indicate that there is no compelling reason to move away from the current PFCB of +/- 15 mHz. Across the scenarios considered, GHD observed consistent patterns arising from widening the PFCB, including:

- Increased work done by R-FCAS service providers
- Decreased quality of frequency control during normal operation
- Decreased system resilience
- Increased aggregate system wide costs
- Reduced work done by generators providing PFR

A summary of the trends observed in GHD's studies can be seen in Figure 1. These trends have been extrapolated to provide annualised values but are based on a specific 6-hour forecast error period. Consequently, they may be exaggerated based on the scenario chosen. Our report presents similar results developed using simulations of the different 6-hour periods, which collectively show a plausible range of outcomes. The patterns observed across the entire set of simulations were consistent and showed:

- A wider deadband decreases generator movements attributable to PFR but increases movements attributable to R-FCAS. This results in an overall increase in costs on a system wide basis.
- A wider deadband can significantly reduce power system resilience, resulting in an increased likelihood of load shedding during non-credible events and a lower probability of resynchronisation after islanding events.
- Widening the PFCB to ±150 mHz results in frequency deviations exceeding the NOFB specified in the FOS.



Aggregate modelling result - Impact of changing the PFCB

2022 High VRE output, High forecast error

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Criteria	**± 5 mHz**	**± 15 mHz**	**± 50 mHz**	**± 150 mHz**
Costs during Normal operation	Cost of regulation work done: $292,091 Cost of PFR work done: $32,057,817 Cost of regulation enablement: $90,772,580 5 mHz	$2,011,962 $30,183,249 $90,772,580 15 mHz	$14,204,266 $24,399,127 $90,772,580 50 mHz	$21,209,258 $17,767,429 $90,772,580 150 mHz
Frequency distribution	<49.85 49.8… 49.9… 49.9… 49.9… 50.0… 50.0… 50.1… >50.15	<49.85 49.8… 49.9… 49.9… 49.9… 50.0… 50.0… 50.1… >50.15	<49.85 49.8… 49.9… 49.9… 49.9… 50.0… 50.0… 50.1… >50.15	<49.85 49.8… 49.9… 49.9… 49.9… 50.0… 50.0… 50.1… >50.15
Normal frequency range (99th percentile)	49.98 - 50.02	49.97 - 50.03	49.94 - 50.06	48.84 - 50.16
NOFB FOS Met?	Y	Y	Y	N
Resilience = estimated load shedding for key non credible contingencies	Not studied	600 MW ($25.5m) Heywood	Not studied	880 MW ($37.4m) Heywood (+$11.9m)
Resilience = % of time frequency is sufficiently aligned to support resynchronization	Not studied	39%	Not studied	5.5% (resynchronization is more than 7 times more unlikely)

Figure 1 – Slide summary of modelling results for 2022 High VRE, high forecast error scenario

For 2033, results were generally similar to 2022, although our analysis used to R-FCAS prices derived from September 2021 NEM results to calculate the costs of PFR or regulation for both 2022 and 2033. The following trends were observed in the 2033 scenarios:

- 2033 results were similar to 2022 for frequency control under normal operating conditions, with greater reliance on inverter conneted generating systems and Battery Energy Storage Systems (BESS) to provide PFR.
- Higher RoCoF was observed in 2033 during non-credible contingency events due to lower power system inertia.
- For some 2033 contingency events studied, less load shedding was observed compared to a 2022 incident due to the faster acting C-FCAS response from new technologies such as BESS.

Annual costs for the NEM have been extrapolated based on 6-hour periods which may not represent the variability likely across a year. Considering the range of annual costs estimated from analyais of different 6 hour periods may provide a more informed view of the potential variation in annual costs with different PFCB settings. A comparison between the annual costs under normal operation for the different combinations of VRE dispatch and forecast error variability considered in the 2022 simulations can be seen in Figure 2. The difference in costs between the scenarios takes into account the differences in the simulated work done by PFR and R-FCAS providers and the difference in the R-FCAS enablement for the period in different historiacal 6 hour periods. Total annual costs under normal operation for a 15 mHz deadband vary between $65m and $123m across these scenarios.

As a reference, historical regulation costs in the NEM range from $4.6m in 2013 to $126.8m in 2019, with an average over the years 2019-21 of $93m[2]. The analysis included in the AEMC's PFR incentive arrangements final determination expected the scale of gross frequency performance payouts to be in the order of $90m per year[3], falling within the range of scenarios considered by GHD in this analysis.

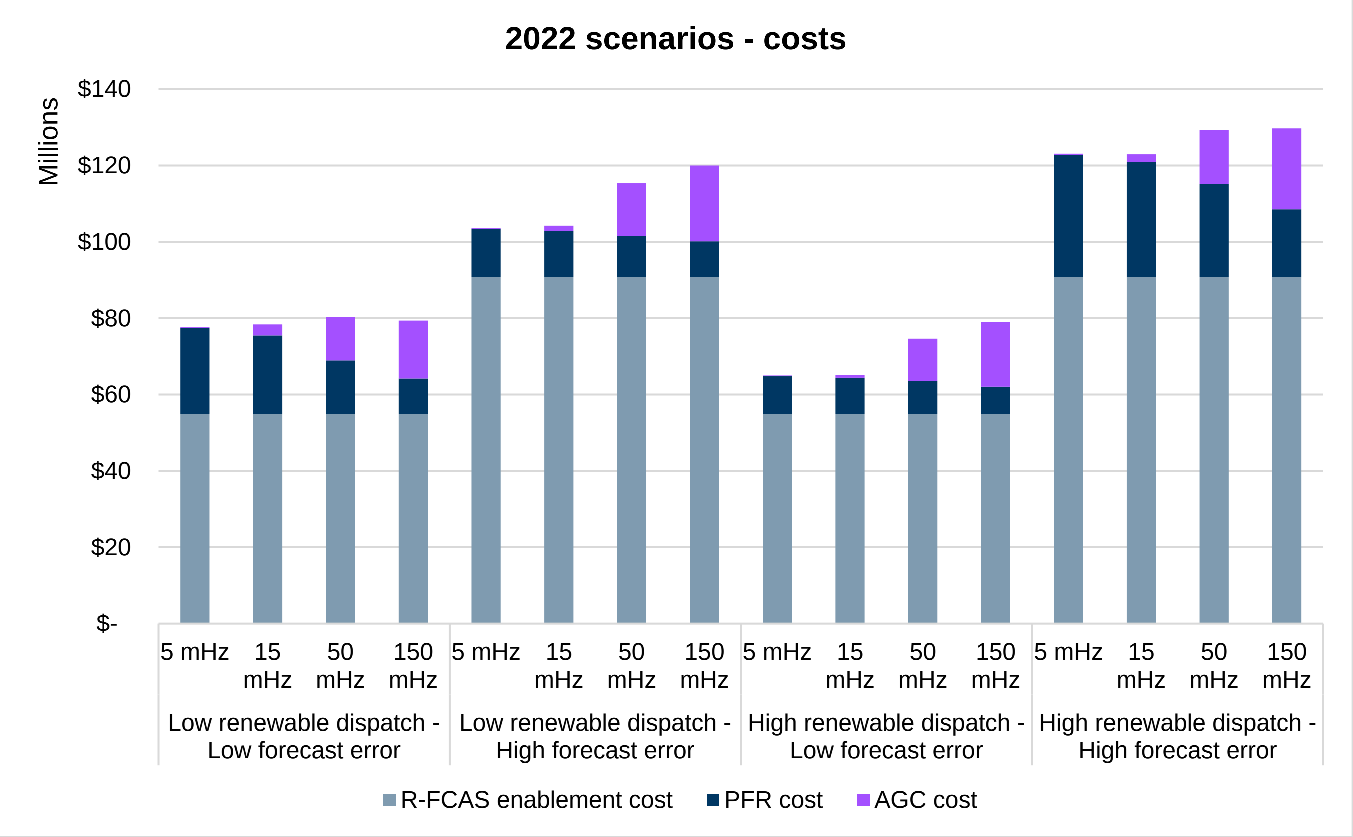

Figure 2 – Summary of annualised costs comparing the lowest and highest variability scenarios for 2022

Costs during normal operation

A combination of PFR and R-FCAS controls power system frequency under normal conditions. PFR keeps frequency close to 50 Hz by utilising the frequency controllers of generators that provide PFR. The controllers

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[2] Appendix E of the PFR Incentive Arrangements Final Determination. Available at **Primary frequency response incentive arrangements | AEMC**

[3] Page 74 of the PFR Incentive Arrangements Final Determination. Available at **Primary frequency response incentive arrangements | AEMC**

respond to correct frequency deviations outside of their deadband. R-FCAS enabled generators, under normal operation, move to address both forecast errors and load changes on the power system and provide reserve capacity to assist in responding to contingency events. Changes to the PFCB impact both the work required from generators providing PFR and how R-FCAS is utilised.

Under the mandatory PFR requirements currently implemented on the NEM, there is a requirement for generators to provide a frequency response via a governor or frequency controller. This action can cause generators to move marginally from their setpoints. This movement affects generation technologies differently, but can have the following impacts:

- Loss of energy generated by wind and solar generators which are typically dispatched at their rated capacity wherever possible, and therefore can only provide a downward frequency response.
- Wear and tear on synchronous generators due to speed changes and actuator movement from governor action.
- Loss of warranted cycling capacity on BESS due to the energy requirements of providing a PFR response.

The estimated costs of frequency control deviations – both PFR and R-FCAS duty – were determined using the methodology set out in the AEMC's primary frequency response incentive arrangements final determination[4]. The new pricing arrangements for frequency performance payments come into effect on 8 June 2025. These arrangements provide a pricing methodology that is designed to compensate PFR providers for the benefit they provide to the system over each 5-minute trading interval.

The three major costs for frequency control during normal operation were, therefore:

- Regulation enablement – which provided for a quantity of R-FCAS which was assumed to be fixed and not changed, irrespective of the PFCB setting.
- Regulation "work done" – which was calculated and priced on the same basis as PFR, with a fixed price paid per MW/hr of capacity used, based on historical R-FCAS NEM prices from the September 2021 period.
- PFR "work done" – calculated with a fixed price paid per MW/hr of capacity used, based on historical NEM R-FCAS prices from the September 2021 period.

The analysis found that a reduction in PFR work caused by the widening of the PFCB, resulting in a decrease in PFR costs, was entirely offset by an increase in the requirement for R-FCAS providers to do work. Therefore, there was no compelling case to widen the deadband on this basis, as the system wide costs marginally increased as the deadband was widened across a range of scenarios.

Additional analysis was undertaken to estimate whether PFR Incentive Arrangement based payments provided sufficient cost recovery for a BESS providing PFR. The analysis considered the BESS levelized cost of energy, as published in the 2022 AEMO Integrated System Plan, as a benchmark for sufficient cost recovery. This analysis modelled the impact of a mandatory PFR requirement by measuring energy throughput for a BESS providing PFR and comparing the anticipated PFR payment against the revenue required to compensate for use of warranted BESS charge/discharge cycles to provide PFR. The analysis found that, based on historical prices paid for frequency regulation in September 2021, payments were likely to be sufficient for BESS to recover their costs.

With a wider deadband, it was found that increased AGC movement was not effective in controlling frequency. Therefore, a further sensitivity study was undertaken with de-tuned AGC settings to explore whether reducing the AGC proportional gain would reduce the required AGC response. This study found that while lowering the AGC proportional gain significantly reduced the AGC movement with narrow band PFCB settings, there was very little difference observed in AGC response at wider deadband levels.

Frequency distribution and achieving the FOS

AEMO is required to use reasonable endeavours to meet the frequency operating standard set by the Reliability Panel[5]. AEMO attempts to keep the system frequency as close to 50 Hz as possible, with the aim of producing a resilient and reliable power system that has predictable behaviour during contingency events.

The analysis undertaken found that:

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[4] Refer to the **Primary frequency response incentive arrangements | AEMC** final determination

[5] NER Clause 4.4.1

- Frequency regulation worsened as the PFCB was widened, as illustrated by the frequency distributions shown in Figure 8 of this report.
- The frequency was not able to be maintained within the NFOB specified in the FOS when the PFCB was set to ±150 mHz.

Resilience impacts

Control of power system frequency within a narrow PFCB is valuable to consumers primarily due to the resilience benefits provided. The simulations undertaken in task 1a demonstrate that frequency is often at or near the edge of the PFCB. For a wider PFCB, this means that it is likely that the frequency will be further from 50 Hz when a contingency occurs. This results in a greater chance that the response to the contingency event triggers emergency controls such as under frequency load shedding or over frequency generator tripping. Wider PFCBs also tend to result in worse frequency nadirs and greater amounts of under frequency load shedding to arrest the frequency change. The increased utilisation these emergency controls means that the resilience of the power system is reduced and the impact on consumers – through load shedding – is increased.

One measure of the reduction in power system resilience can be obtained by valuing the increased potential for load shedding by applying a Value of Customer Reliability (VCR) metric, which places a value on the cost to consumers of supply interruption. Although the precise probabilities of events occurring and causing load shedding are difficult to calculate, our review of system incident reports published by AEMO suggests that non-credible contingency events with the potential to result in large frequency deviations, significant load shedding, or separation of regions have a frequency of one event every year. Resilience is, therefore, an important consideration when evaluating a preferred PFCB.

The analysis undertaken found that:

- System resilience significantly decreased with a wider PFCB, with lower frequency nadirs and worse frequency recovery observed.
- The amount of load shedding significantly increased with a wider PFCB, along with associated costs due to load shedding. Increasing the PFCB to ±150 mHz could increase the cost associated with increased load shedding by $11.9m per event.
- The probability of successful resynchronisation of islands decreased with a wider PFCB. Table 11 indicates that increasing the PFCB to ±150 mHz could make it 7 times less likely for islanded regions to resynchronise quickly. The load shedding costs shown in Table 13 (Appendix B) assume all load is restored within one hour of the contingency, which is unlikely to be achieved if synchronisation is delayed. Therefore, a wider PFCB may result in synchronisation delays, increasing costs due to load shedding.

Conclusion

The total energy requirement to provide PFR is relatively small, but the selection of the PFCB can impact generators, and consumers by altering the power system's resilience. The selection of the PFCB also impacts the ability to maintain frequency within the NOFB specified in the FOS. The optimal setting of a PFCB should consider the materiality of the costs attributable to generators relative to the costs of increased or decreased resilience of the power system. Based on the analysis results, there is no compelling reason to move away from the current PFCB, as no substantial reductions in costs to consumers have been identified, and a significant reduction in power system resilience is observed as the PFCB is widened.

However, this analysis relies on historical pricing data to determine the likely payments under the PFR incentives arrangements scheme. Due to the uncertainty in the future around the pricing of these payments, the impacts of the aggregate costs to administer a PFR requirement may change. On this basis, this could result in a need to review the PFCB setting after the PFR incentives scheme is implemented on the NEM and more pricing data is available.

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1. Introduction

1.1 Purpose of this report

The purpose of this report is to assist the AEMC with a review of the current Frequency Operating Standard (FOS) in the NEM. The mandatory PFR rule established a framework that allows AEMO to specify Primary Frequency Response Requirements (PFRR) that generators are required to meet. This rule also allows the Reliability Panel to specify a Primary Frequency Control Band (PFCB) in the FOS. Under the NER (clause 4.4.2A) the PFCB sets a limit on the deadband AEMO may specify in the PFRR. AEMO must not require a deadband which is narrower than the PFCB. Through this review the Reliability Panel is seeking to establish appropriate settings for the PFCB. The Rules define the PFCB as 49.985 Hz to 50.015 Hz, or such other range as specified by the Reliability Panel.

To inform the Reliability Panel's review the AEMC has sought independent technical advice from GHD on the expected costs and benefits of different settings for the PFCB in relation to the distribution of frequency during normal operation and the provision of primary frequency response to support power system resilience to larger disturbances.

This report presents the work undertaken by GHD to provide analysis and advice relating to the costs and benefits of the different PFCB settings. We anticipate that the AEMC may publish this report to allow feedback from interested parties to inform the Reliability Panel's review of the NEM FOS.

1.2 Terminology used in this report

Table 1 – Acronyms and abbreviations

Abbreviation	Description
ACE	Area Control Error
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CSV	Comma Separated Values
C-FCAS	Contingency-Frequency Control Ancillary Service
FCAS	Frequency Control Ancillary Service
FOS	Frequency Operating Standard
GHD	GHD Pty Ltd
Hz	Hertz
MGU	Motor-Generator Unit
MPFR	Mandatory Primary Frequency Response
nadir	The frequency nadir is the lowest frequency reached following a contingency event
NEM	National Electricity Market
NER	National Electricity Regulation
NOFB	Normal Operating Frequency Band
NSW	New South Wales
OCGT	Open Cycle Gas Turbine
PFCB	Primary Frequency Control Band
PFR	Primary Frequency Response

Abbreviation	Description
PFRR	Primary Frequency Response Requirement
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales Interconnector
R-FCAS	Regulation Frequency Control Ancillary Service
RoCoF	Rate of Change of Frequency
SA	South Australia
SCADA	Supervisory Control and Data Acquisition
VIC	Victoria
VRE	Variable Renewable Energy
WECC	Western Electricity Coordinating Council

1.3 Scope and limitations

This report: has been prepared by GHD for Australian Energy Market Commission and may only be used and relied on by the Australian Energy Market Commission for the purpose agreed between GHD and the Australian Energy Market Commission as set out in section 1.1 of this report.

GHD otherwise disclaims responsibility to any person other than the Australian Energy Market Commission arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report. GHD disclaims liability arising from any of the assumptions being incorrect.

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1.4 Assumptions

GHD has relied on data provided by the AEMC and AEMO to undertake the studies presented in this report. GHD has assumed that the data provided is materially accurate and correct.

GHD has developed single mass and multi region models in PowerFactory to inform our investigation into the costs and benefits of different PFCB settings. The models were developed by extending a single mass PowerFactory model for the NEM developed by DIgSILENT Pacific for AEMO.

Where necessary, GHD has revised the PowerFactory model provided by AEMO, however we have not independently validated that model. GHD has assumed for the purposes of the studies documented in this report that AEMO was previously satisfied that the DIgSILENT Pacific model provided a valid representation of the NEM suitable for studying frequency regulation.

2. Context

The Reliability Panel is undertaking a review of the current FOS for the NEM. GHD have been engaged by the Australian Energy Markets Commission (AEMC) to provide technical and regulatory advice, to assist with the Reliability Panel's determination of the appropriate setting for the PFCB in the FOS.

This report describes the modelling undertaken to inform the Reliability Panel's consideration of the specification of the PFCB.

2.1 The Frequency Operating Standard

The FOS defines the required frequency performance for the NEM. AEMO is required by Clause 4.4.1 of the National Electricity Rules to use reasonable endeavours to control the power system frequency, and to ensure that the FOS is achieved. In the NEM, the nominal power system frequency is set at 50 Hz, and the power system operates within a range set around this frequency. For the mainland NEM, this range is defined by Table A1.1 of the FOS, which sets standards around accumulated time error, the normal operating range, and allowed excursion levels due to contingencies. An extraction of the frequency limits defined in Table A1.1 of the FOS is provided in Table 2.

Table 2 – Extraction of Table A1.1 as defined in NEM FOS

Condition	Containment	Stabilisation	Recovery
Accumulated time error	15 seconds	n/a	n/a
No contingency event or load event	49.75 to 50.25 Hz, 49.85 to 50.15 Hz - 99% of the time	49.85 to 50.15 Hz within 5 minutes	
Generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 5 minutes
Protected event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz (Reasonable endeavours)	49.5 to 50.5 Hz within 2 minutes (Reasonable endeavours)	49.85 to 50.15 Hz within 10 minutes (Reasonable endeavours)

Under normal conditions, the allowed frequency range is set by the "no contingency event or load event" limits, referred to as the Normal Operating Frequency Band (NOFB). This range is set relatively close to 50 Hz, allowing for small deviations in frequency due to forecast errors and load changes, but keeping frequency tightly regulated to allow for the secure operation of the power system.

Frequency is allowed to diverge further due to specific events which may occur on the power system, including generation and load events, which may involve sudden increases or decreases in the level of active power required from or supplied to the power system. Other events that may impact power system frequency include separation events which create islands with an imbalance between supply and demand, protected events and multiple contingency events. The NER provide a specific framework for defining a protected event, which is defined as a high impact non-credible contingency event for which AEMO must maintain power system security standards.

Frequency control is important to all Participants in the NEM. Appropriate control of frequency under normal conditions to be close to 50 Hz is important to maintain secure power supplies to Consumers, which may have electrical loads impacted by fluctuations in power system frequency. This control of frequency also impacts synchronous generators, which by definition are synchronised to the power system, and therefore are impacted by changes in frequency in the form of electrical torque causing speed changes. Generators equipped with governors or other frequency controllers are also impacted by frequency changes as frequency controllers will change their active power output in order to resist the change in frequency.

Under contingent conditions, good frequency control is important to minimise load or generator shedding. Load and generation shedding schemes are used as emergency controls providing additional response to maintain system stability, reduce the risk of widespread blackouts and prevent damage to connected electrical equipment following more extreme disturbances.

2.2 The Primary Frequency Control Band

The Primary Frequency Control Band (PFCB) is a frequency deadband introduced as part of the 2020 Mandatory Primary Frequency Response (MPFR) rule. This rule requires all generators to contribute primary frequency control to re-establish effective regulation of frequency closer to 50 HZ and within the NOFB. The setting for the PFCB appearing in the NER, was developed in consultation the Australian Energy Market Operator to provide appropriate regulation of frequency. The NER defines the PFCB as 50 +/- 0.015 Hz or the range specified in the FOS.

The MPFR rule introduces provisions allowing AEMO to specify Primary Frequency Response Requirements (PFRR) that generators must meet unless they gain an exemption from AEMO. The PFRR specify a deadband that is applied equally to all generators on the NEM regardless of technology type or fuel source. If the frequency moves beyond the deadband generators are required to provide PFR to correct the deviation in frequency from 50 Hz. The NER require that the deadband specified in the PFRR be no narrower than the PFCB. The NER allows generators to apply for exemptions or variations to the deadband for plants not able to meet the specification for economic or technical reasons.

A deadband refers to a range through which an input can be varied without initiating a response from a controller. Within this frequency range, generators with governors or other frequency control systems do not need to respond. The current PFCB is set well inside the NOFB. As governor action or other frequency control actions that rely on changing generator active power do not operate instantaneously, setting the PFCB well inside the NOFB supports maintaining frequency within the NOFB.

2.3 Observations from the NEM

Historically, the NEM frequency has been maintained around 50 Hz under normal operating conditions by a combination of:

- Synchronous generator and load inertia, which resists frequency changes due to inherent stored energy in the rotational mass of generators and motor loads.
- Generators responding to correct locally sensed frequency deviations through their governor controls, prior to the MPFR rule change generators were not required to provide this form of response.
- Generators and Battery Energy Storage Systems (BESS) responding to Automatic Generation Control (AGC) signals. By following raise and lower commands issues centrally through the AEMO AGC system, Regulation Frequency Control Ancillary Service (R-FCAS) providers act to correct frequency deviations.

A power system with a high level of inertia will not change frequency quickly due to imbalances between active power generated and supplied to loads. Power system frequency changes are inherently resisted by stored energy in inertial masses synchronised to the power system, which naturally slow rate of change of frequency (RoCoF). Similarly, generators with active local frequency controllers will, subject to those controller settings and energy source availability, increase their active power in response to a frequency decline, or vice versa for a frequency increase. AGC is slower acting than these mechanisms but is required to maintain power system frequency across longer time periods between dispatch intervals, where significant load changes can still occur.

As a power system historically dominated by synchronous generators, the NEM has had tight frequency regulation, around 50 Hz, due to both governor control and the inherent slowness in frequency changes caused by high levels of inertia. This was in line with most large, synchronised power systems worldwide, which have historically also exhibited these characteristics. As seen in Figure 3, frequency regulation in the NEM remained close to 50 Hz prior to 2014, with the frequency following a normal frequency distribution around 50 Hz. During this period, frequency remained close to 50 Hz for the majority of the time, and inside the NOFB the vast majority of the time. However, from 2014, an increasing proportion of generators connected to the NEM disabled their frequency control systems inhibiting those generators from providing PFR. Frequency was therefore no longer controlled by the response of the majority of synchronous plant acting under governor control, but instead only regulated by resistance to changes from inertia, and response from R-FCAS providers and sometimes C-FCAS generators which remained under governor control.

The impact of this change is immediately apparent in Figure 3. Frequency was no longer regulated tightly around 50 Hz, but instead fluctuated significantly within the NOFB. Although frequency excursions outside the NOFB remained rare, the distribution of power system frequency significantly worsened. Following this degradation of frequency performance, AEMO submitted a rule change request to the AEMC, and interim primary frequency response requirements were implemented on the NEM. These requirements have since been made permanent in the form of the MPFR rule. An associated improvement in the frequency performance of the NEM has been observed as these requirements have been rolled out on connected generators.

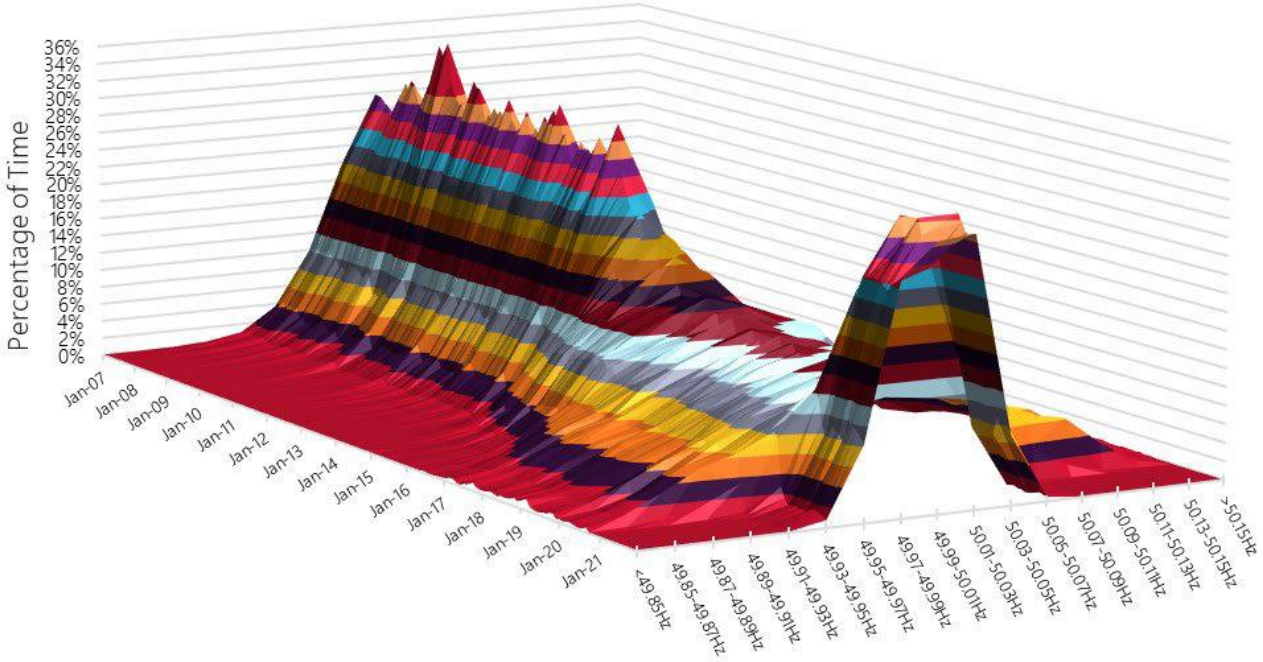

Figure 3 – Monthly frequency histogram for the NEM

3. Method

The advice provided in this report has been informed by:

- Information and models provided by the AEMC and AEMO
- Engagement with stakeholders including the Reliability Panel through workshops
- Modelling undertaken using PowerFactory software

The following sections explain the methodology relating to the power system modelling undertaken to evaluate the costs and benefits to the power system in terms of:

- Frequency regulation under normal conditions
- “Duty” imposed on generators
- Impact on utilisation of facilities providing R-FCAS controlled via the AEMO AGC system
- Frequency stability under contingent conditions
- Resilience under contingent conditions

The simulation studies have been grouped into task1a simulations, which consider the ability to control frequency under normal system conditions, and task 1b, which explores frequency control following significant contingency events.

3.1 Task 1a - Model development and PFR cost analysis

The purpose of task 1a was to simulate the power system under normal operating conditions to determine the impact of different settings for the PFCB. This task required the development and use of an appropriate NEM wide study model.

GHD received a single bus PowerFactory model of the NEM from AEMO to undertake this work. This model was developed by DIgSILENT Pacific for use during a contract undertaken for AEMO. That work involved modelling the regulation of frequency via the AGC system controlling generators providing R-FCAS.

3.1.1 Model details

The “single bus” model developed by DIgSILENT Pacific included generators, busbars and transformer elements, all connected to a single busbar. A single bus model is considered to be an adequate representation of the mainland NEM for the purposes of simulating frequency control under normal conditions, as although the NEM is geographically dispersed, it is usually managed as a single frequency region, and frequency dynamics are relatively slow[6]. The model split generation into several generic types, primarily separated by fuel source and generation technology. These types were as follows:

- Sub-critical coal
- Super critical coal
- Combined cycle gas turbines (CCGT’s)
- Open cycle gas turbines (OCGT’s)
- Hydro
- Inverter connected generation (PV & Wind)

Each generator had a specific dynamic model applied. Synchronous generators included a generic governor and automatic voltage regulator elements, while the inverter connected generation was modelled based on the REPC_A controller model developed by the Western Electricity Coordinating Council. Details of these controllers as well as their settings are given in Appendix C.

In addition to their separation by type, generators in the model were assigned specific roles. A number of generators were modelled with governors disabled, which can be seen in Figure 4 under the right-hand section labelled “Generating plants with no frequency droop”. AGC generation was also modelled separately to other generation, which had the separately developed AGC dynamic model interfaced with the governors of these generators. Finally, a “Redispatch” function was modelled through the MGU generators, which were redispatched to follow load changes every 5 minutes into a simulation.

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[6] The mainland regions are managed as a single frequency region unless contingency events or planned network outages result in the electrical separation of portions of the NEM.

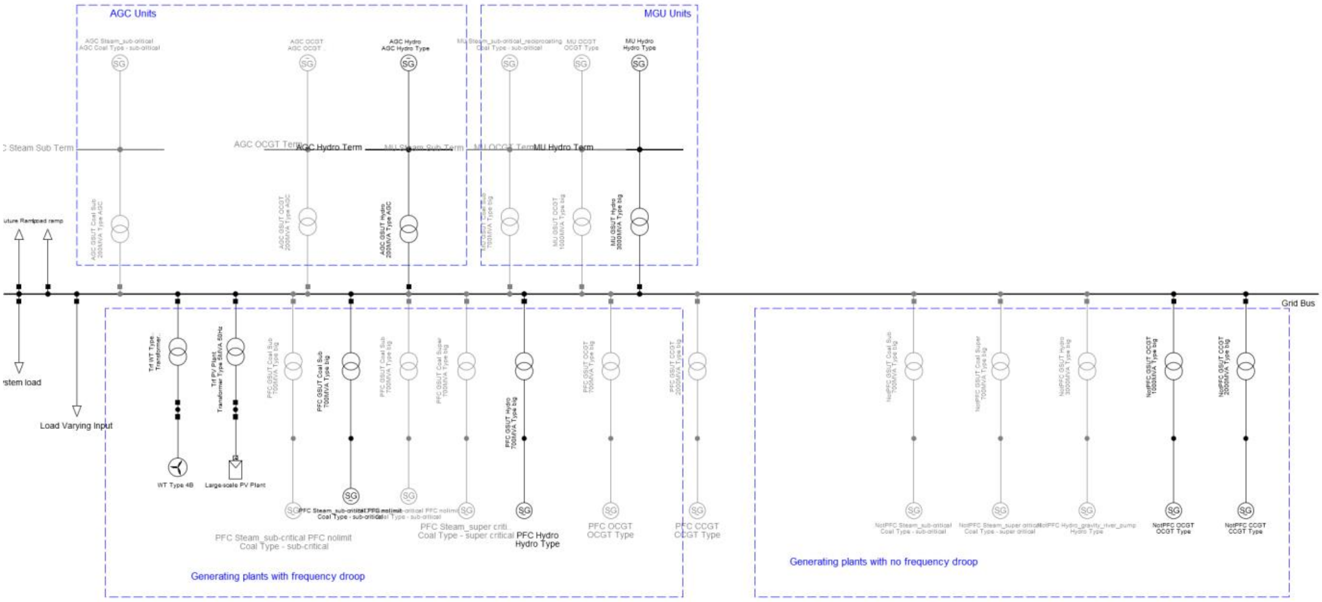

Figure 4 – Screenshot of a single line of the DIgSILENT Pacific developed model provided to GHD by AEMO

The loads in the model were split into two, with the following characteristics:

- A dynamic load representing the initial NEM system-wide load. This load had a frequency dependence of 1%, meaning that it would change its active power consumption by 1% for every 1% reduction in frequency. This load dependence on frequency is an assumption commonly used during planning studies and has been studied in detail on the NEM and other power systems.
- A static load representing the load changes throughout the simulation. This load was modified throughout the course of the simulation using data fed into the load via a CSV file which contained time dependant load variation data.

The model developed by DIgSILENT Pacific was considered a valid representation of the NEM for the purposes of this task, which did not consider any locational elements to the analysis. DIgSILENT's analysis had focused on the performance of the developed AGC model to represent the NEM's frequency over 30-minute test periods. These periods were simulated through open loop and closed loop testing. The closed loop testing involved feeding in NEM load data through a measurement file played into a load to cause a variance across the 30 minutes.

GHD conducted an investigation into the performance of the model for the purposes of investigating the impact of different settings for the PFCB. Several changes were made to the model in order to better represent the NEM for the purposes of this study, which are detailed in the following section.

3.1.2 Model changes and revisions

After conducting a review of the DIgSILENT model and report, GHD made some initial changes to the AGC model implemented by DIgSILENT. GHD noted that during closed loop testing DIGSILENT had occasionally observed a skew in frequency of the model marginally away from 50 Hz due to AGC action. This had been rectified on a case-by-case basis by applying a bias to the frequency setpoint in the AGC. This bias was typically minor in nature e.g., 0.034 Hz, but was considered an issue in the study due to the nature of the investigations to be undertaken by GHD, which involved the study of deadbands close to that level, e.g. 5 mHz.

After investigation of the DIgSILENT model, GHD determined that the bias seen in the AGC signal was due to the implementation of a frequency rate limited deadband within the AGC model seen in Figure 5.

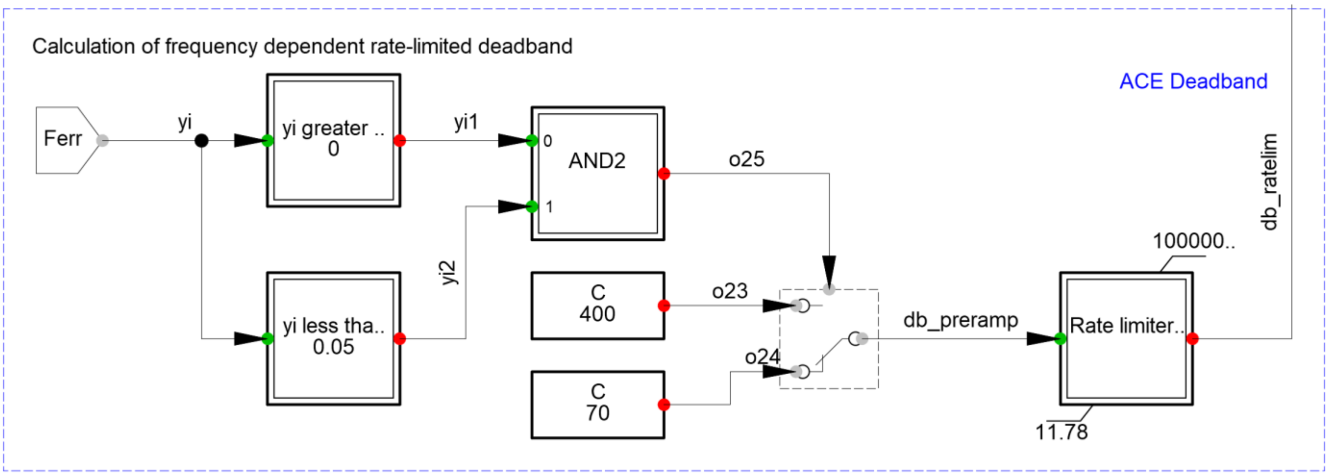

Figure 5 – Frequency rate limited deadband

The frequency rate limited deadband was meant to be applied to the Area Control Error signal, which determined when the AGC signal was activated due to time error to bias the frequency. While the deadband should have been applied evenly based on frequency error magnitude, in practice the calculation was not magnitude based, and therefore the ACE deadband was applied unevenly to over frequencies compared to under frequencies, creating a systemic bias in the AGC.

GHD were not able to make changes to the block diagram of the AGC models due to model compatibility issues preventing modification. However, parameters within the AGC model could be modified, and this issue was resolved after consultation with the AEMC by setting both constants in the rate limited deadband to 70 so it was applied evenly.

Other changes were made to the DIgSILENT model in order to better represent the NEM for the purposes of the task 1a studies. These changes were as follows:

- MGU generators were disabled – these generators were included in the original model to represent redispatching generators, which was not a necessary action due to the methodology applied for the task 1a studies.
- Separate C-FCAS machines were implemented for the task 1a studies that implemented a PFCB of ± 500 mHz. For the C-FCAS cases, it was assumed that machines carrying C-FCAS would not be allowed to have deadbands set outside of the NOFB, and so deadbands for these machines were set at ± 150 mHz.
- Separate BESS models were implemented to model the provision of primary frequency response from these devices. The BESS models were based on the WECC BESS template in PowerFactory.
- The AGC model was modified to allow a BESS model to be incorporated as part of the AGC response. Testing of the BESS response compared to other AGC generators showed that there was very little observable difference in performance, as can be seen in the below Figure 6.

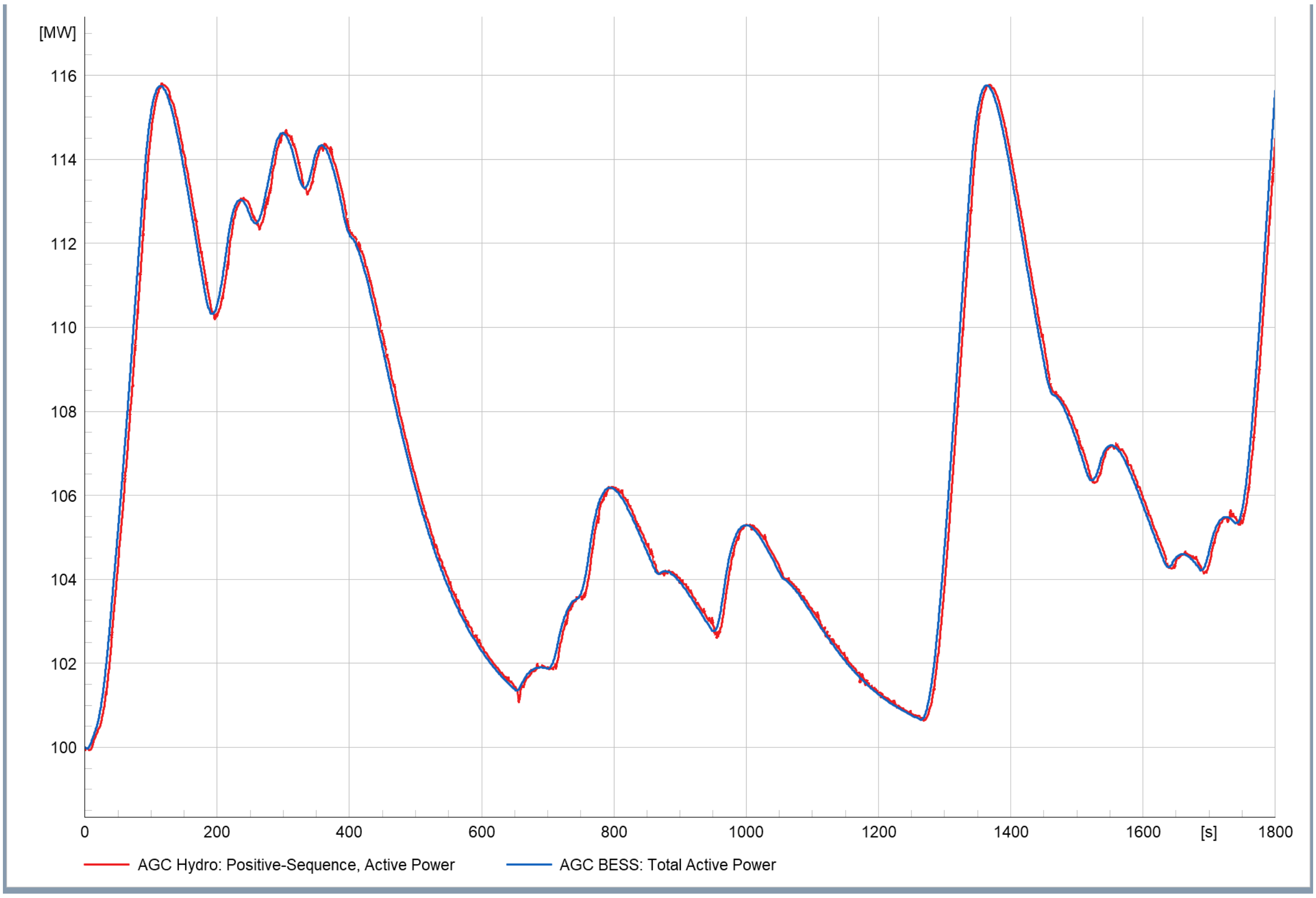

Figure 6 – Testing of AGC BESS response compared to AGC Hydro unit

3.1.3 Studies methodology

The studies undertaken by GHD for task 1a were established based on the following principles:

- Within the limitations of the simplified model, implement an accurate representation of NEM demand and supply conditions at initialisation. This required that generation dispatch at the start of the simulation was aligned with historical dispatch observed in the NEM. Synchronous generator capacity for each unit type was rounded to the nearest 650 MVA, as these were the size of the generators represented in the model.
- No load variations over time were represented during the study period. This allowed for the 5-minute redispatch model to be disabled, the “Load Varying Input” load was varied based on the negative of aggregate generation forecast error.
- Three six-hour periods were studied using 4-second aggregate forecast error data. The three six-hour periods were selected from two weeks’ worth of NEM SCADA data provided by the AEMC and included the lowest, highest and average levels of forecast errors throughout the two weeks, as measured by the standard deviations of each six-hour period.
- Two “study years” were studied by GHD, including a representation of 2022 dispatch conditions which included both a low VRE (variable renewable energy) and high VRE scenario. The other study year chosen was 2033, chosen to evaluate the impact of the retirement of the majority of the existing coal plant on the NEM by that year.

The 2022 study year was based on existing NEM generation and dispatch data. The 2033 study year was developed using the following assumptions consistent with the step change scenario from the 2022 Integrated System Plan published by AEMO.

- Renewable generation capacity = 22.2 GW (30% of capacity providing raise and lower PFR)

– Supercritical Coal = 740 MW[7] (providing raise PFR only as it is assumed to be on min gen)

– Subcritical Coal = 542 MW[8] (providing raise PFR only as it is assumed to be on min gen)

– BESS = 750 MW (providing raise and lower PFR)

– Hydro = 1.2 GW (providing raise and lower PFR assuming it is operating to store excess renewable generation

A number of study cases were simulated for each study year as shown in Table 3. The tested the impact of changing the PFCB settings and proportion of the installed plant providing PFR. The proportion of plant modelled as not providing an PFR is identified in the table as non-responsive.

Table 3 – Modelled PFCB settings and proportion of plant providing PFR for each study year

Case	Proportion of Generation	PFCB	Study purpose
1	100%	+/- 15 mHz	Comparison of results for cases identifies how the relaxation of mandatory provision influences the resulting frequency distribution and cumulative change in output required from responsive plant.
2	50% 50%	+/- 15 mHz Non-responsive	
3	100%	+/- 50 mHz	Comparison of cases 1, and 3-7 indicates the impact of narrower and wider PFCB
4	100%	+/- 100 mHz	
5	100%	+/- 150 mHz	
6	100%	+/- 5 mHz	
7	100%	+/- 500 mHz	
8	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	Sensitivity case applied to compare against case 7 to test impact of C-FCAS enabled plant providing a response from the edge of the NOFB.
9	30% 70%	+/- 15mHz +/- 150mHz	Case 9 tests impact of some capacity responding more quickly than the majority and offer a comparison against the impact of alternative settings.

Additional combinations of 30%/70% deadbands were initially considered. However, these were discarded after reviewing the results from Case 9.

3.1.4 Sensitivity studies

Analysis of the initial study cases identified the need to undertake additional analysis to further understand some aspects of the modelling. Further studies were undertaken, primarily to analyse the impact of changes to:

– BESS droop settings – BESS were modelled in all scenarios with a frequency control droop setting of 2.5%, in line with an estimate of aggregate performance of currently installed BESS across the NEM. For the sensitivity study, BESS frequency controllers were modelled to respond with a droop setting of 5%, in line with other generation installed in the model.

– AGC settings – Changing the PFCB had a significant impact on utilisation of facilities providing R-FCAS within the model. Additional sensitivities were conducted to understand whether “de-tuning” the AGC by reducing the proportional gain, would reduce the utilisation of facilities providing R-FCAS and frequency distribution.

The primary purpose of these studies was to assess the impact of the changes on the ability to control frequency at close to 50 Hz, the utilisation of plant providing a PFR response or R-FCAS and the costs attributable to specific PFCB settings under normal conditions.

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[7] This equates to an installed capacity of 1692 MW

[8] This expiates to an installed capacity of 1390 MW

De-tuning of the AGC model for the sensitivity study, was undertaken after consultation with AEMO to determine which parameters could be de-tuned to feasibly reduce utilisation of R-FCAS. The AGC as modelled in PowerFactory aggregates proportional and integral control signals to create an output signal, which is then sent to generation. Of these, only the proportional gain applied to the AGC signal was modified, as it would have the most significant impact in reducing the response required by the AGC under wider deadband settings. The structure of both signals can be seen in the below Figure 7, with the modified element circled in red.

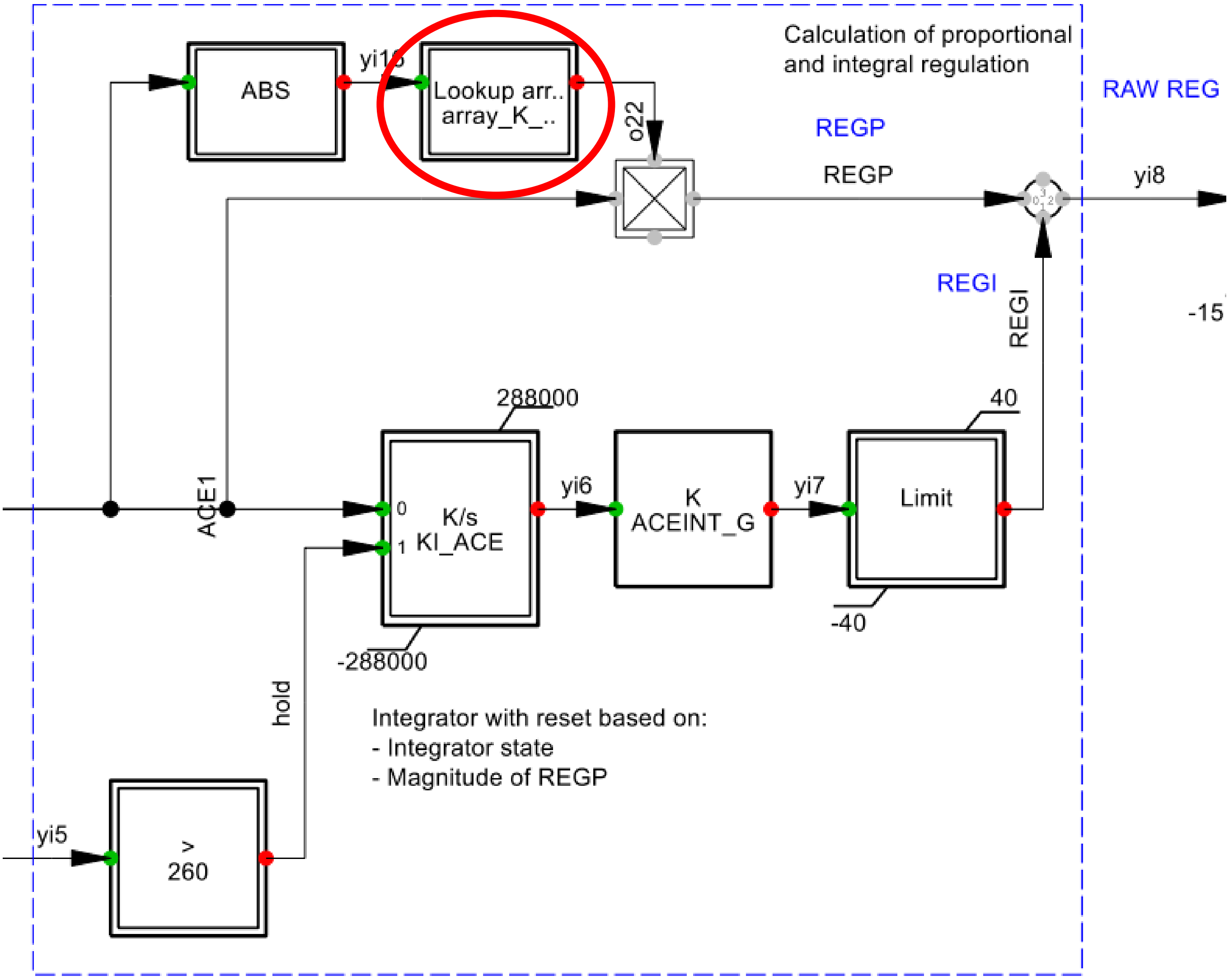

Figure 7 – AGC model parameter changes

The proportional signal was based on a lookup array that applied a gain to the signal depending on the magnitude of frequency deviations. This approximates the approach applied in AEMO's to AGC, which has "normal", "assist" and "emergency" gains specified separately. Table 4 shows the proportional AGC gains applied in the model.

Table 4 – AGC gain settings

Setting	Gain (before modification)	Gain (after modification)
Normal	0.55	0.275
Assist	0.65	0.65
Emergency	0.8	0.8

The "normal" gain signal was halved for the "AGC setting" sensitivity study. It was not considered desirable or feasible to reduce the gain for either the assist or emergency settings. The assist and emergency settings can be required during normal operation, but also play important roles in driving frequency back to 50 Hz after contingency events as part of secondary frequency response, and therefore contribute to power system security.

3.1.5 Costing methodology

The task 1a studies quantified the impact of changing PFCB settings on the utilisation of plant providing PFR and R-FCAS. By appropriately valuing the change in utilisation we are able to provide an indicative assessment of the costs of providing PFR and R-FCAS and how those costs change with different PFCB settings.

Costs attributable to the provision of PFR differ depending on the technology type. Implicit or explicit costs imposed on generators providing PFR may include:

- Loss of energy generated by wind & solar generators which are typically dispatched at rated capacity where possible, and therefore can only provide a downward frequency response.
- Wear and tear on synchronous generators due to speed changes and actuator movement due to governor action.
- Loss of warranted cycling capacity on BESS due to the energy requirements of providing a PFR response.

Similar factors are also likely to influence the costs incurred by generators providing R-FCAS.

Costs associated with different PFCB settings for the power system under normal operation have been estimated using the pricing arrangement reflected in the PFR Incentives Arrangements planned to be established in the NEM by 2025. These arrangements provide a pricing methodology which is designed to compensate PFR providers for the benefit they provide to the system over each 5-minute trading interval.

The following three major costs are incurred by market participants providing frequency control during normal operation:

- Regulation enablement – which is the cost paid to R-FCAS provided to compensate them for the opportunity costs associated with reserving capacity to provide regulation “work done”. The regulation requirement was assumed to be fixed and not changed irrespective of the PFCB setting.
- Regulation “work done” – values the work done or utilisation of plant providing R-FCAS. It was calculated and priced on the same basis as PFR, with a fixed price paid per MW/hr of capacity used across any 5-minute trading interval. The costs are calculated by valuing the work done at the historical R-FCAS NEM prices from the September 2021 period.
- PFR “work done” – values the work down by plant providing PFR. It is calculated with a fixed price paid per MW/hr of capacity used, based on historical NEM R-FCAS prices from the 2021 period.

The following equation was used to calculate the payout of PFR and Regulation work for each 5-minute interval, referred to in the equation as the frequency performance payment (FPP):

FPP = $\boldsymbol{CF\ x\ \frac{Price_{regulation}}{12}\ x\ RCR}$

Where:

- CF is the **Contribution Factor** – for aggregate system response this value was equal to 1.
- RCR is the **Requirement for Corrective Response**, measured in this case as the maximum and minimum movement from their setpoints achieved by PFR or R-FCAS generators across each 5-minute interval.
- Price of regulation (price in $/MWh) is divided by 12 to give a pricing value for each 5-minute interval.

This work has not attempted to forecast future prices for frequency regulation. All prices used in modelling have been based on historical data from the 01-15 September 2021 which is the two-week period used to develop the six-hour forecast error profiles used in the PowerFactory studies. Changes to the price of regulation going forward will have a significant impact on the cost of administering any PFCB requirement, although any such change is unlikely to impact the general trends observed in this report regarding the change in work down with different PFCB settings.

3.2 Task 1b – Modelling and analysis of PFR resilience benefits

The purpose of task 1b was to simulate the power system under contingent conditions to determine the impact of different settings for the PFCB on system resilience, by evaluating impacts on system frequency nadirs, the need for load shedding and generator tripping. This task required the development of an appropriate NEM system wide study model, with multiple regions represented. This task focused on testing system resilience to non-credible, multiple contingency or protected events. The studies focussed on these more extreme events as we assumed that sufficient C-FCAS would be enabled by AEMO to secure the system against credible contingency events.

To carry out this task, GHD modified the single bus model used in task 1a to represent different regions of the mainland NEM. The model was separated into three regions, representing Queensland, a combined New South Wales and Victoria, and South Australia. Tasmania was not represented separately in this model but was instead included as a static load.

3.2.1 Model details

Task 1b required representation of interconnector flows, and so separate regional islands were defined to represent the states of the mainland NEM. Each island had a separate group of generation, loads, as well as dynamic models including a separate AGC system.

Each island was tested to determine that the AGC signal worked correctly independently, and that the model was able to operate correctly when operating both as separated islands, and when connected to each other. Testing of these conditions revealed issues which were explored further by GHD:

- Interconnector impedances between SA-VIC (Heywood) and QLD-NSW (QNI) were extracted from PSS/E raw file data provided by AEMO and converted for use in the PowerFactory model.
- Testing of the model after interconnector impedances were input revealed the presence of inter-area oscillatory instability when flows on interconnectors were increased. These issues meant studying phenomena such as frequency stability were not possible using the model.
- To resolve the oscillatory stability issues, interconnector impedances were halved, to preserve the relative relationship between the islands, but to prevent the oscillatory instability. It was considered impractical to consider other solutions such as implementing power system stabilisers given the time required to tune those models.

Once the model assumptions were finalised and the model was verified to be stable for a variety of different normal and post-contingent conditions, development of the model regions to approximate the NEM dispatch took place. The models for the contingency studies were developed based on the high VRE 2022 study case used in task 1a studies. Further modifications were made to that dispatch case to develop 3 separate dispatch conditions, in order to test specific system contingency events including:

- Interconnector tripping – A scenario was developed with flows of 1200 MW on the QNI and 600 MW on Heywood Interconnector to evaluate the response of the power system to interconnector trips.
- Generation / load tripping – A scenario was developed to test the response of the system to a 600 MW load trip, and a 1130 MW trip of a generation – considered to be the non-credible trip of the Loy Yang A units.
- Interconnector open – A scenario was developed with the QNI open, to test the system operation under islanded conditions and assess whether frequency was likely to be sufficiently well controlled to successfully synchronise Queensland with the rest of the NEM.

3.2.2 Studies methodology

The studies undertaken by GHD for task 1b were established based on the following principles:

- Implement an accurate representation of NEM demand and supply conditions at initialisation as could be achieved by a simplified model. Generators were separated by type, and by region. Synchronous generator capacity for each unit type was rounded to the nearest 650 MVA, as these were the size of the generators represented in the model. Dispatch was then tweaked from this starting point as required to represent the conditions pre-contingency event.

- The AGC model was disabled for the purpose of the short-term studies assessing interconnector / generation / load tripping. This was undertaken in order to allow frequency to change due to load variations before the trips were undertaken, in order to simulate an event at a “worst case”, edge of deadband scenario. AGC generation still provided a PFR response in these simulations. This assumption is reasonable as AGC is not expected to play a significant role in determining the frequency nadir following a large contingency event.

For each of the contingency events considered, the impact of different deadbands and combinations of responsive plant were assessed. The details of the combinations considered are shown in Table 5.

Table 5 – Events and deadbands considered for task 1b studies

Case	Responsive plant	PFCB	Frequency at time of event	Event (revised)	Study purpose
1	100%	+/- 15 mHz	50.015 Hz	QNI separation with the loss of 1200 MW transfer from QLD to NSW	Comparison of results for cases 1-2 identifies how wider PFCB impacts frequency response for mainland regions.
2	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	50.15 Hz		
3	100%	+/- 15 mHz	49.985 Hz	South Australia separation following the transfer of 650 MW from Vic to SA across the Heywood link	Comparison of results for cases 3-4 identifies how wider PFCB impacts frequency response for Tasmania.
4	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	49.85 Hz		
5	100%	+/- 15 mHz	49.985 Hz	Simultaneous trip of large level of generation. We propose 2x Loy Yang A units at full load, 1130 MW*	Comparison of results for cases 5-6 identifies how wider PFCB impacts frequency response for mainland regions.
6	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	49.85 Hz		
7	100%	+/- 15 mHz	50.015 Hz	Trip of large NEM load. 600 MW of net load as per Western Downs – Columboola event	Comparison of results for cases 7-8 identifies how wider PFCB impacts ability to align frequencies in adjacent regions while may inform ability to synchronise.
8	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	50.15 Hz		
9	100%	+/- 15 mHz	50 Hz	Loss of SCADA, uses the 1a study model)	Comparison of results for cases 8-9 assess the frequency deviation should a loss of SCADA occur.
10	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	50 Hz		
11	100%	+/- 15 mHz	50 Hz	Resynchronisation studies, using the task 1a model	Comparison of results for cases 9-10 explore the extent to which the frequency in QLD (islanded) and the NEM align.
12	100%	+/- 500 mHz +/- 150 mHz (C-FCAS)	50 Hz		

*equivalent sized trip of hydro generation was undertaken in 2033 following the planned retirement of Loy Yang A

Cases 9-10 were undertaken using the task 1a study model. Cases 11-12 required an open QNI, meaning Queensland was disconnected from the remainder of the NEM, and were undertaken to determine whether the wider deadband resulted in a lower probability of resynchronisation being possible, due to islanded frequencies drifting further apart than they otherwise may have been.

The cases listed in Table 5 were simulated for a 2022 study year and a 2033 study year. In the 2033 studies 30% of solar and wind generators were assumed to be capable of providing raise PFR. This assumption reflects a situation that may arise under periods of high renewable generation where those generators are otherwise constrained from achieving full output consistent with energy source availability.

3.2.3 Sensitivity studies

After reviewing the original results from the 2033 cases studied, additional sensitivities were conducted to determine the impact of varying the levels of PFR raise capability available from inverter connected solar and wind generators. In 2033, it was originally assumed that 30% of installed renewable generation would be capable of providing both raise and lower PFR, with the remainin 70% of this plant capable of only providing lower PFR. This assumption inherently assumes a significant level of curtailment of renewable generators in order for them to have capacity to provide raise PFR, which is typically not expected from currently installed plant. It was therefore necessary to determine how sensitive the 2033 resilience results were to this assumption.

Additional studies were undertaken for the 2033 study cases to determine:

- The impact of 50% of renewable plant providing raise PFR.
- The impact of 20% of renewable plant providing raise PFR.
- The impact of 10% of renewable plant providing raise PFR.

Due to the nature of the 2033 scenario studied, renewable plant made up the majority of plant on the power system. With significant overbuild of renewable generation anticipated by the AEMO ISP, some curtailment of resource at times of high production is expected. It is therefore considered a reasonable assumption that some headroom would be available to provide raise PFR during these times, particularly with the introduction of PFR incentives payments in the NEM, which may be valuable when a significant level of zero-marginal cost generation is dispatched on the NEM.

3.2.4 Resilience costing methodology

The value of power system resilience can be quantified by valuing the additional load shedding attributable to a reduction in resiliency. While consumers do not directly experience the consequence of minor frequency deviations under normal operation, there are well developed methodologies for valuing load loss within power systems.

Costing for resilience has therefore been based on the Value of Customer Reliability (VCR) framework developed by the AER[9]. In our studies, this is applied whenever load shedding results from a non-credible contingency event. The 2019 NEM VCR figures developed by the AER were adjusted by the CPI to develop a load-weighted VCR value for 2021. This cost is shown in Table 6 and applies across all scenarios.

NSW, VIC, QLD and SA load-shed quantities were recorded as part of this analysis. Data for the ACT UFLS relays was not available to us, and the ACT was, therefore, excluded from this analysis. This is considered reasonable as the ACT is relatively heavily interconnected, and we would expect identical results to those recorded for NSW. Finally, this analysis did not consider the impacts of mainland NEM frequency on TAS.

Table 6 – VCR value

Year	$/kWh
2019 AER NEM VCR	40.99
2021 CPI adjusted NEM VCR	42.52

All load shedding events were assumed to last for 1 hour. Hence, our analysis assumes all load is resupplied after 1 hour following the contingency. In practice, this is likely to be an optimistic assumption, particularly for a wider PFCB scenario, where interconnector contingency events may result in delays in the resynchronising of separated regions and, consequently, delays in restoring all load.

While the precise probability of a non-credible contingency event resulting in load shedding is not easily quantified, an indication of the potential likelihood can be gained from a review of historical incidents. Appendix D presents a review of system incident reports published by AEMO. This review suggests that non-credible contingency events with the potential to result in large frequency deviations, significant load shedding, or separation of regions have a frequency of about one event every year. It is, therefore, important to consider whether the amount of load shedding during such events is influenced by the PFCB setting.

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[9] Refer to table 5.22 in the December 2019 AER publication **Final report on VCR values** and **AER - 2021 VCR Annual Adjustment**

4. Findings of 2022 studies

4.1 Impact of PFCB on frequency distribution

4.1.1 Impact of alternative PFCB settings – 100% of plant responsive

The studies listed in Table 3 allowed assessment of the impact of changing the PFCB setting on the resulting frequency distribution. The studies considered two dispatch cases and three forecasting error variations. A summary of the frequency distributions modelled for each study case can be seen in Figure 8. The results presented in Figure 8 were developed from task 1a studies performed for the 2022 study year. Similar frequency distribution results were obtained from studies performed for 2033. The simulation results show that:

- A steady degradation in the quality of the frequency distribution is observed as the PFCB is widened.
- With the PFCB widened to +/- 500 mHz and C-FCAS modelled, the C-FCAS generators actively respond to arrest frequency variations at the edge of the NOFB. This results in the frequency distribution being similar to that achieved with the PFCB set to +/- 150 mHz.
- Across the 6-hour period more time was spent at the extremes of the PFCB in the simulations with high variations in the forecast errors compared to the simulations with lower variations in the forecast. This highlights the impact forecast accuracy has on the likelihood of frequency being maintained at close to 50Hz. The resilience study results presented in section 4.3 demonstrate that the further the frequency deviates from 50 Hz, during normal operation the greater the risk of load shedding or generator tripping in response to more extreme contingencies.

Low VRE – Low Forecast Error

Figure 9 to Figure 14 show individual results for the cases studies using low VRE dispatch and low levels of forecast error with the various PFCB settings. Each figure presents two charts. The one on the left show the frequency distribution achieved while the one on the right shows the frequency trace for the 6-hour period.

A complete set of frequency distributions results for have been shown for this scenario. In this scenario there is a lower level of VRE generation modelled together with a 6-hour period of low forecast error variability. This condition represents a less challenging frequency regulation scenario as there are lower forecast errors and a higher proportion of synchronous generation which provides inertia and PFR capacity able to respond to both under and over frequency events. The following observations are apparent:

- A comparison of Figure 9 and Figure 10 showing the 5 mHz and 15 mHz deadband study results indicates that minimal benefit, in terms of tighter frequency regulation, is achieved by decreasing the deadband to 5 mHz. This is primarily due to delays in generator governor actions – generators are unable to respond quick enough to every minor change in frequency to control frequency to align with the edges of the 5 mHz deadband. The maximum and minimum frequency deviations are similar with both deadband settings although with the 15 mHz deadband the frequency is more often at those maximum and minimum levels.
- Figure 11 displays the frequency distribution given a +/-50 mHz PFCB. This deadband setting maintained the frequency within the limits of the current NOFB. However, the quality of the frequency distribution is impacted as indicated by the shape of the frequency distribution. The frequency distribution is flat rather than a Gaussian distribution centred around 50 Hz. With the +/-50 mHz deadband the frequency is more likely to be at the edges of the dead band than at 50 Hz indicating that this combination of settings provides inferior control of frequency than narrower deadbands.
- Figure 12 and Figure 13 show the frequency distribution when operating PFR providers with a deadband of +/- 150 mHz and +/- 500 mHz, respectively. These figures show that the frequency distribution under these settings is wider than the current NOFB.
- Figure 14 shows two frequency distributions with a +/-500 mHz PFCB. The blue bars on the histogram show the distribution achieved without modelling the contribution from service providers enabled to provide C-FCAS. The orange bars show the distribution achieved if C-FCAS providers act to regulate frequency once the frequency moves beyond the limits of the current NOFB. In this study the C-FCAS provided are modelled

with a deadband of +/- 150 mHz. It can be seen that if a proportion (~40% in this instance) of the generators operate with the narrower deadband the frequency distribution of the network is improved.

It can be seen from a review of the figures in this section that only the 5 mHz deadband appears to result in a frequency distribution which spends the majority of the time in the smallest bin centred on 50 Hz. Adopting other deadband settings result in a distribution where the frequency is often closer to the edges of the frequency range defined by the deadband. This trend is even more pronounced for the high forecast error cases shown in Appendix A.

Considering the impact of the alternative PFCB setting studied, a number of conclusions can be reached with regards to the quality of the frequency distribution achieved by with different PFCB settings.

- A 5 mHz deadband results in the tightest frequency regulation but it does not appear practicable to achieve frequency regulation within those settings given delays in the response of plant.
- Frequency control is more sensitive to the PFCB than any other change to current conditions on the NEM, including levels of forecast error and levels of synchronous inertia dispatched.
- A PFCB set at or exceeding the current NOFB of +/- 150 mHz would not be sufficient to allow AEMO to meet its current target of maintaining power system frequency within the NOFB.

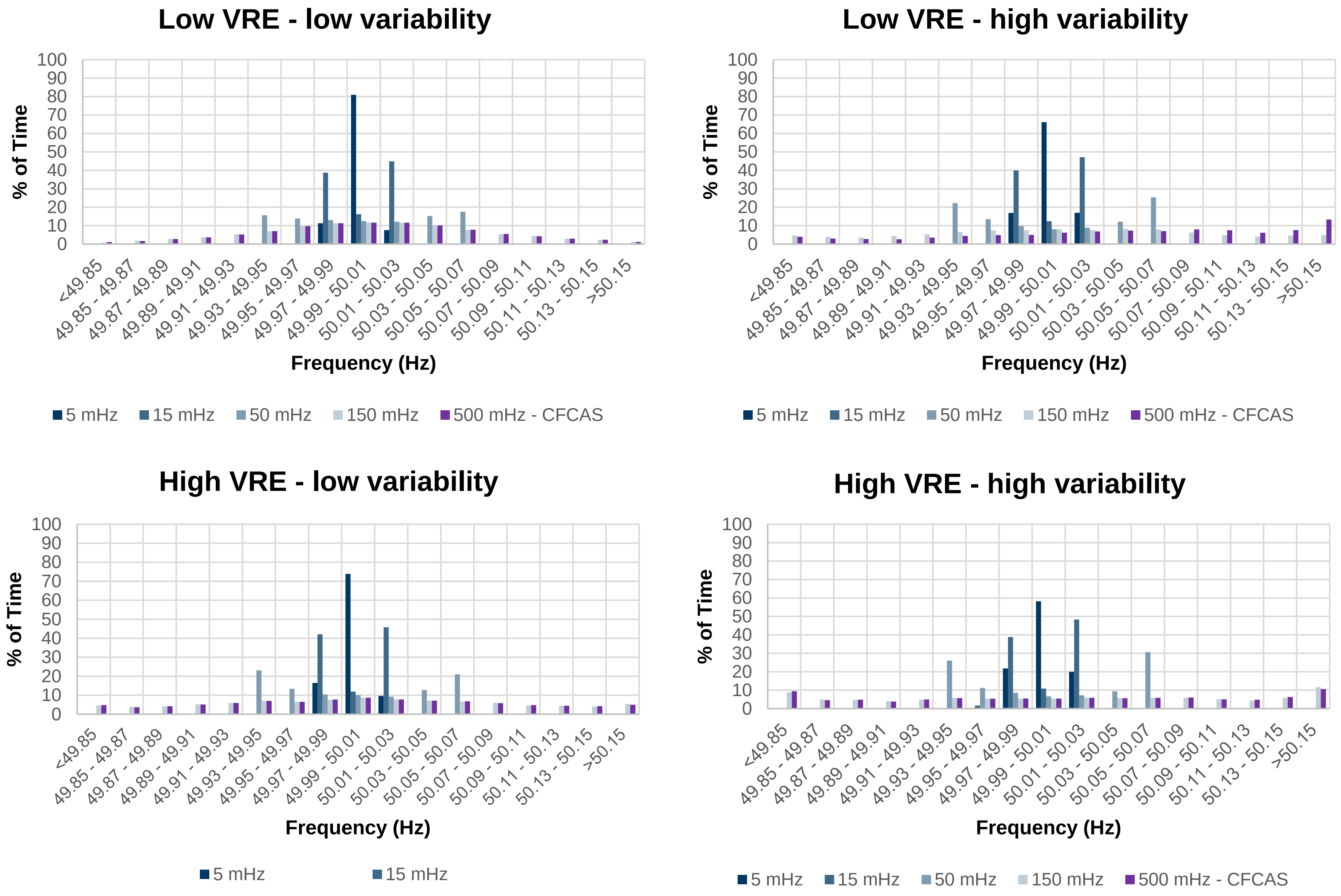

Figure 8 – Frequency distribution across the extremes of the dispatch and forecast error scenarios, for different PFCB settings in 2022

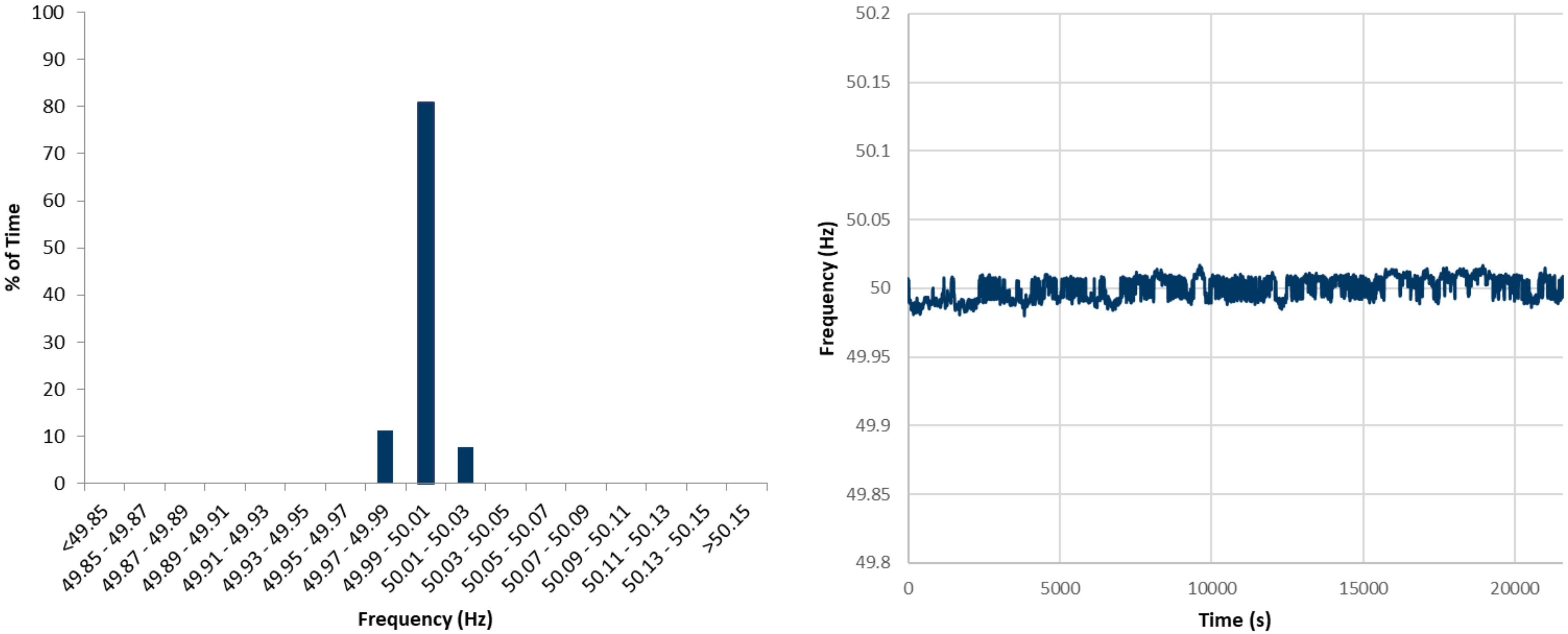

Figure 9 – Frequency distributions – low VRE dispatch case – low forecast variability – 5 mHz deadband

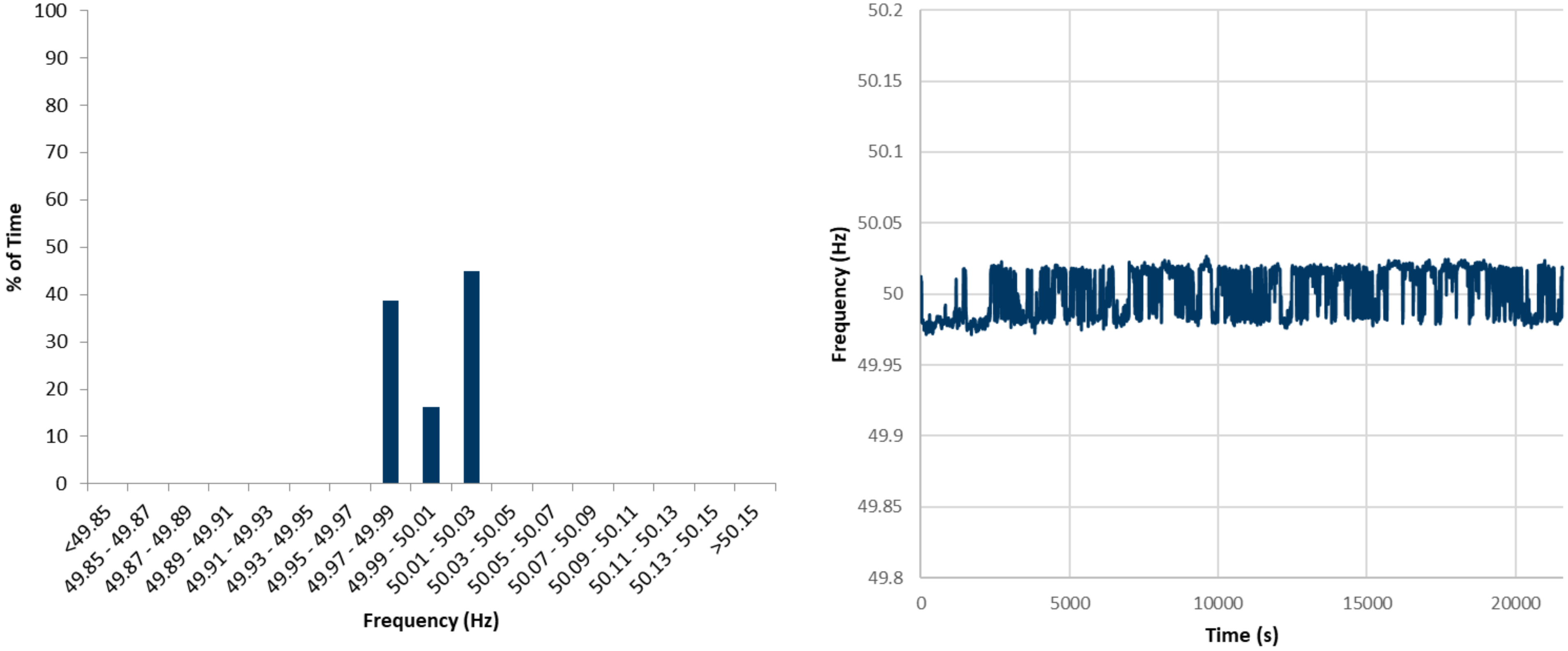

Figure 10 – Frequency distributions – low VRE dispatch case – low forecast error – 15 mHz deadband

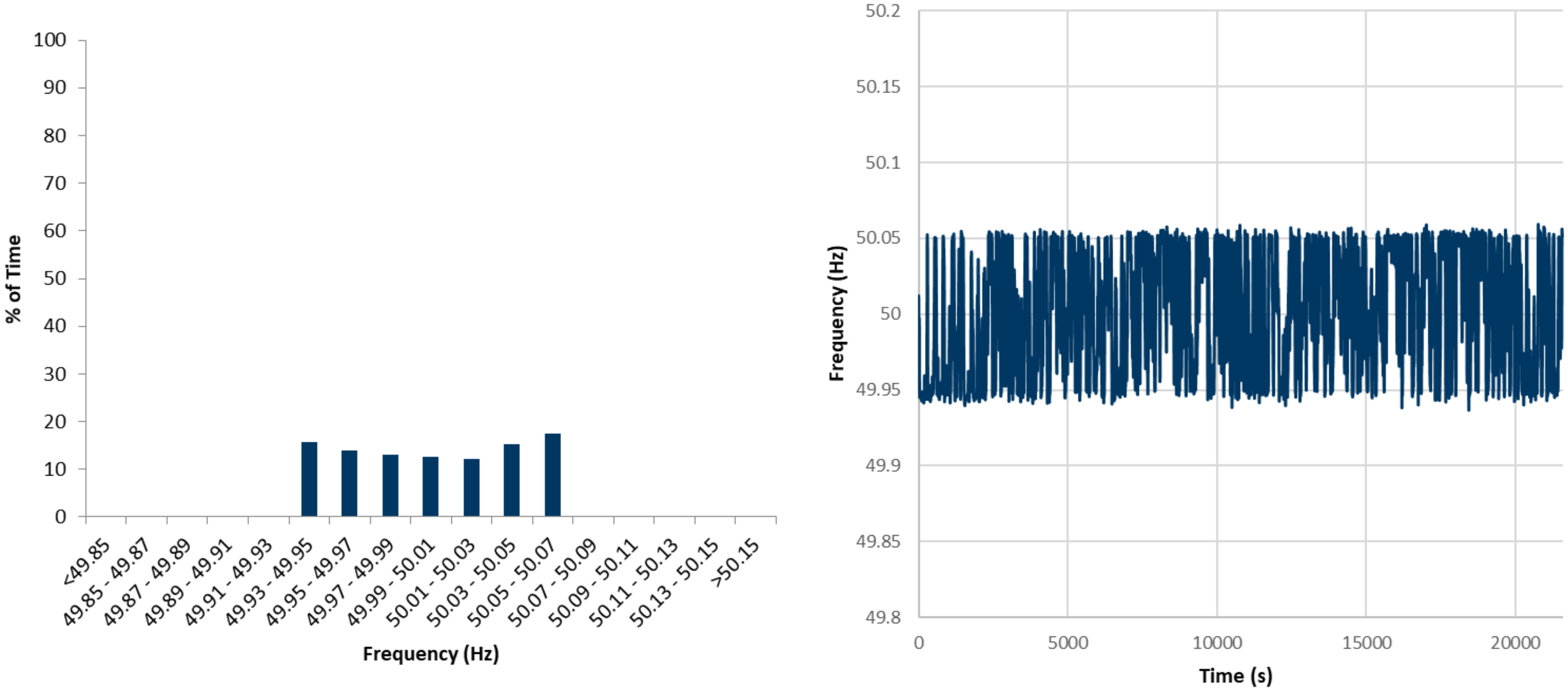

Figure 11 – Frequency distributions – low VRE dispatch case – low forecast variability – 50 mHz deadband

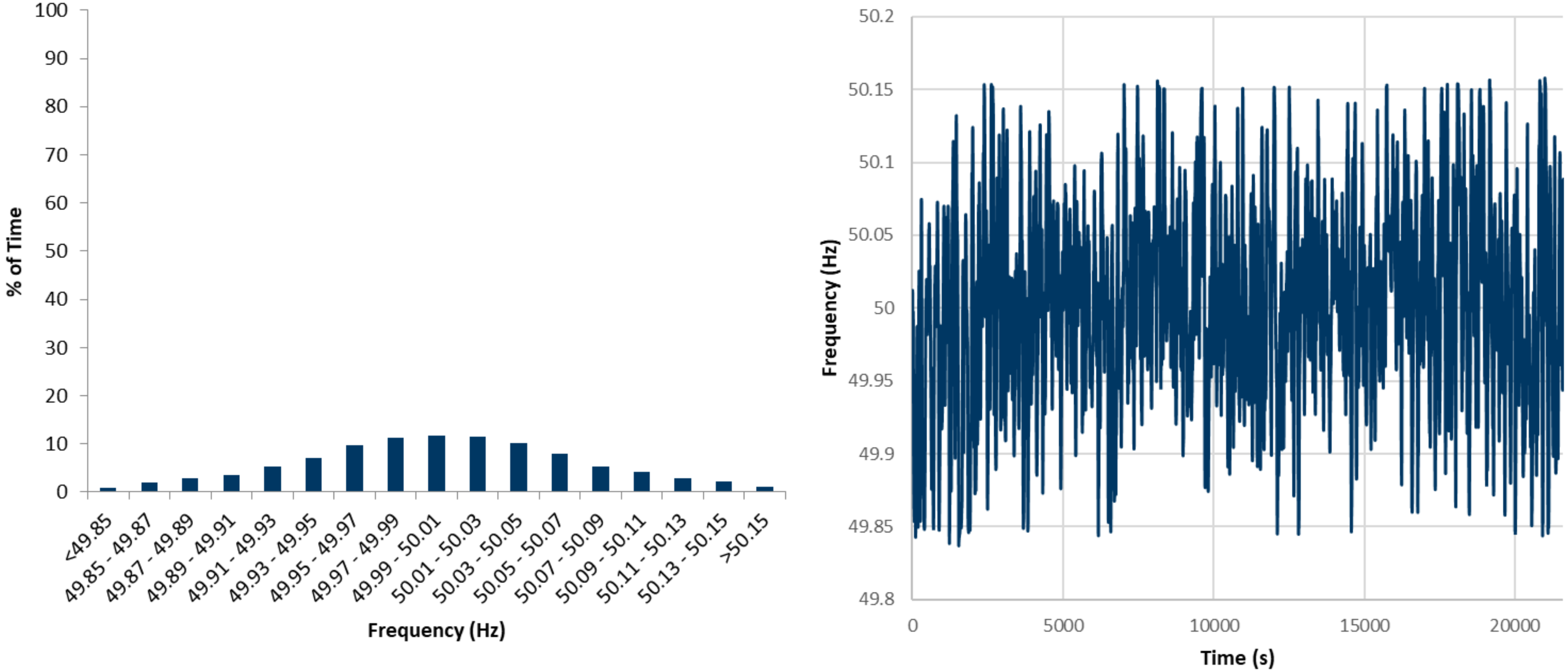

Figure 12 – Frequency distributions – low VRE dispatch case – low forecast error – 150 mHz deadband

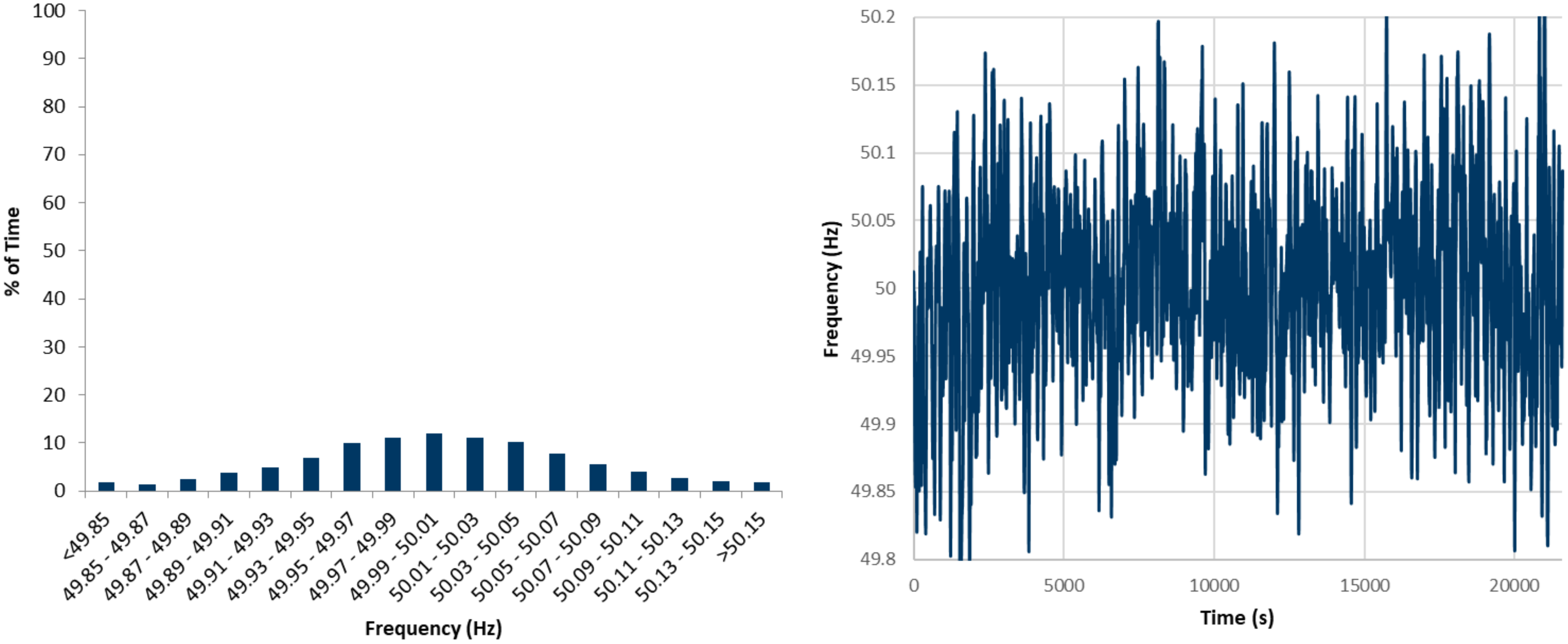

Figure 13 – Frequency distributions – low VRE dispatch case – low forecast error – 500 mHz deadband with no C-FCAS

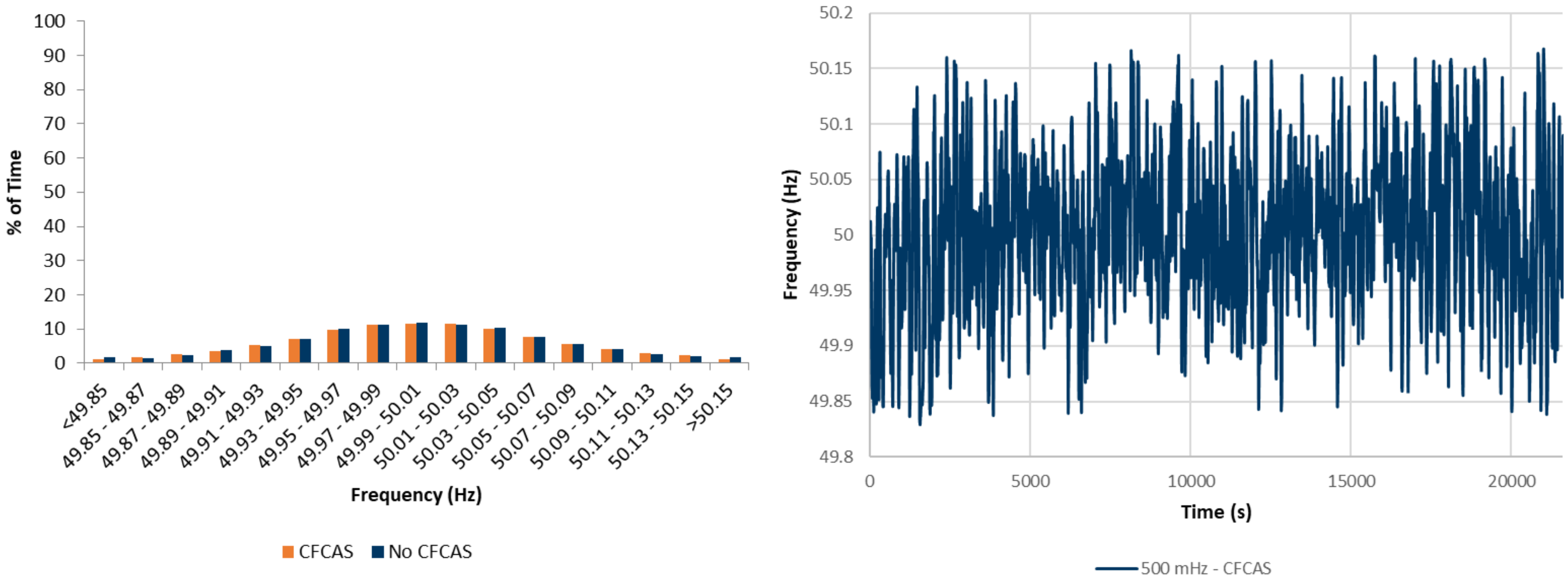

Figure 14 – Frequency distributions – low VRE dispatch case – low forecast error – 500 mHz deadband – with and without C-FCAS

4.1.2 Impact of disabling 50% of responsive plant

Case 2 of the Task 1a studies was simulated to assess the impact of disabling the PFR response of generators. To accomplish this, governors were disabled for ~50% of the total capacity of the generation in each dispatch case that contributed both raise and lower PFR capability. Coal and other synchronous plant were disabled, and no inverter-based resources had their frequency control systems disabled in this scenario. A comparison between case 1 – showing the frequency regulation of the NEM with 100% of generators providing a PFR response consistent with the specified deadband, and case 2 – showing the frequency regulation of the NEM with 50% of generators by capacity providing a PFR response can be seen in Figure 15 for the high renewable high variance scenario.

An analysis of the results obtained shows that when 100% of plant in the power system provides PFR:

- The overall quality of frequency regulation is improved, with maximum and minimum frequencies observed of ~50.03 and ~49.97 Hz across the 6-hour period.
- Less variation is seen, with frequency excursions outside of the deadband occurring less often.
- No excursions outside of the NOFB were observed.
- The frequency distribution is skewed above 50 Hz, in line with the forecast error data over this period, where a positive skew was observed.

When only 50% of plant in the power system frequency are providing a frequency response:

- The overall quality of frequency regulation is worse, with maximum and minimum frequencies observed of ~50.06 and ~49.89 Hz across the 6-hour period.
- More variation is seen, with frequency excursions outside of the deadband more often.
- No excursions outside of the NOFB were observed.
- More extreme frequency excursions are observed on the under-frequency side which is consistent with reduced levels of PFR raise capability with governors on synchronous generators disabled.

With 50% of plant on the system providing PFR the frequency remained within the NOFB, even for the highest variance set of forecast error data. However, frequency excursions on the under-frequency side were observed that were closer to breaching the NOFB, compared to the 100% scenario.

While synchronous generators are typically dispatched below 100% capacity and have governors capable of adjusting their active power output both upwards and downwards, renewable generators are typically dispatched at the maximum level of active power they are capable of generating given energy availability. This means that while renewable generators are capable of responding to over frequencies by reducing their output, they cannot respond to under frequencies by increasing their output above their previous dispatch level. This behaviour worsens frequency regulation for under frequency events and is likely to become an increasing issue for the NEM in the future, as more renewable generation is connected and dispatched displacing synchronous generation.

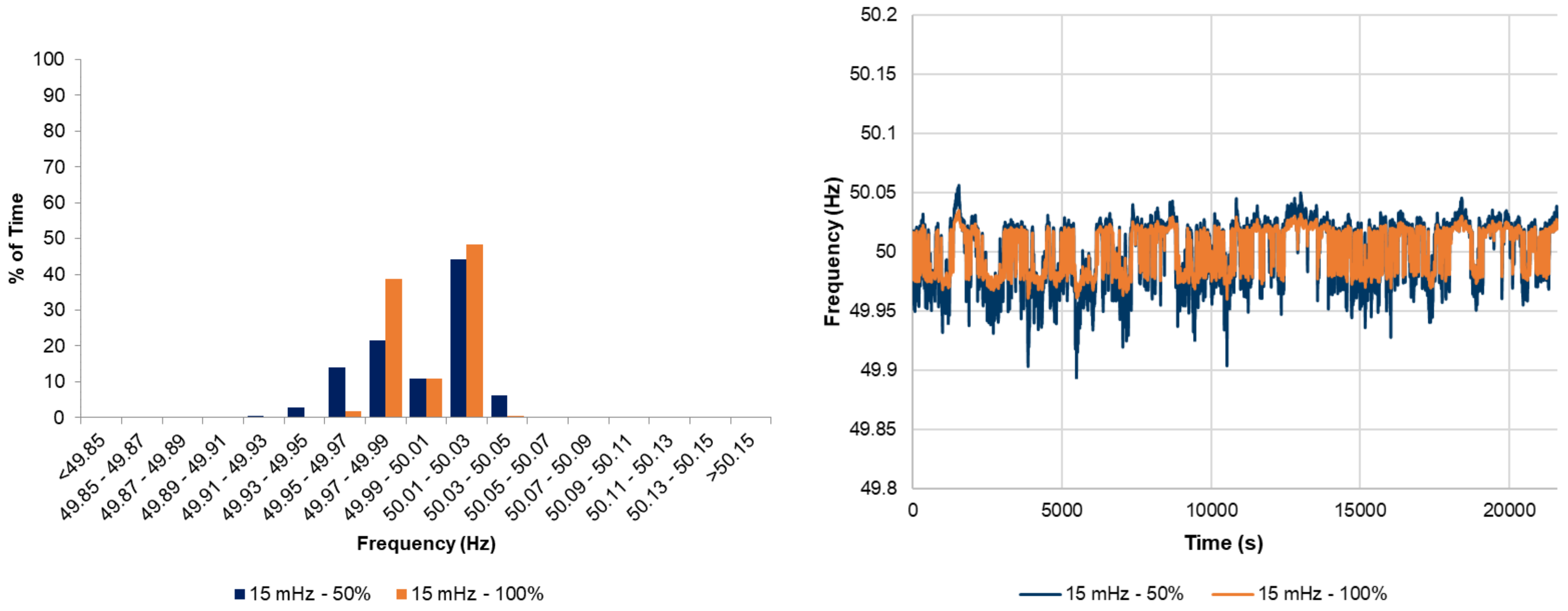

Figure 15 – Frequency distributions - high VRE, high forecast error – 15 mHz deadband – 50% and 100% of generators in frequency control mode

4.1.3 Impact of forecast error

A comparison of the impact of forecast error variability is shown in Figure 16 for a +/-50 mHz deadband scenario. The frequency distribution for the maximum and minimum levels of forecast error and their impact on the low VRE case have been shown. Conclusions regarding the impact of forecast error are as follows:

- Both the low and high forecast error study results are skewed to the outer limits of the deadband with the high error results increasing the proportion of time spent at these outer limits (in excess of 45% of the time)
- Historic levels of forecast variability observed in the NEM during the period between 1 and 15 September 2021, do not result in significant frequency excursions beyond the edges of the deadband under normal conditions.
- System dispatch conditions and deadband settings are significantly more influential over the observed frequency distribution than the level of forecast error.

High variability in forecast error represents a worst-case for normal system operation but does not significantly impact frequency regulation compared to other variables including changing the mixture of plant dispatched and their deadband and governor settings. Although the selection of the forecast error trace did impact the frequency distribution skew, it did not significantly change the simulated frequency distribution.

Major forecast errors caused by weather events are of increasing concern to power system operators. The impact of a cloud cover event resulting in a rapid reduction in output across a large or several large PV solar installations could have a more significant impact on NEM frequency. A similar impact could be observed from load changes due to events impacting rooftop PV. The impact of these large events will become increasingly part of “system normal” operation as more renewable generation is connected to the NEM, and security standards should reflect this change.

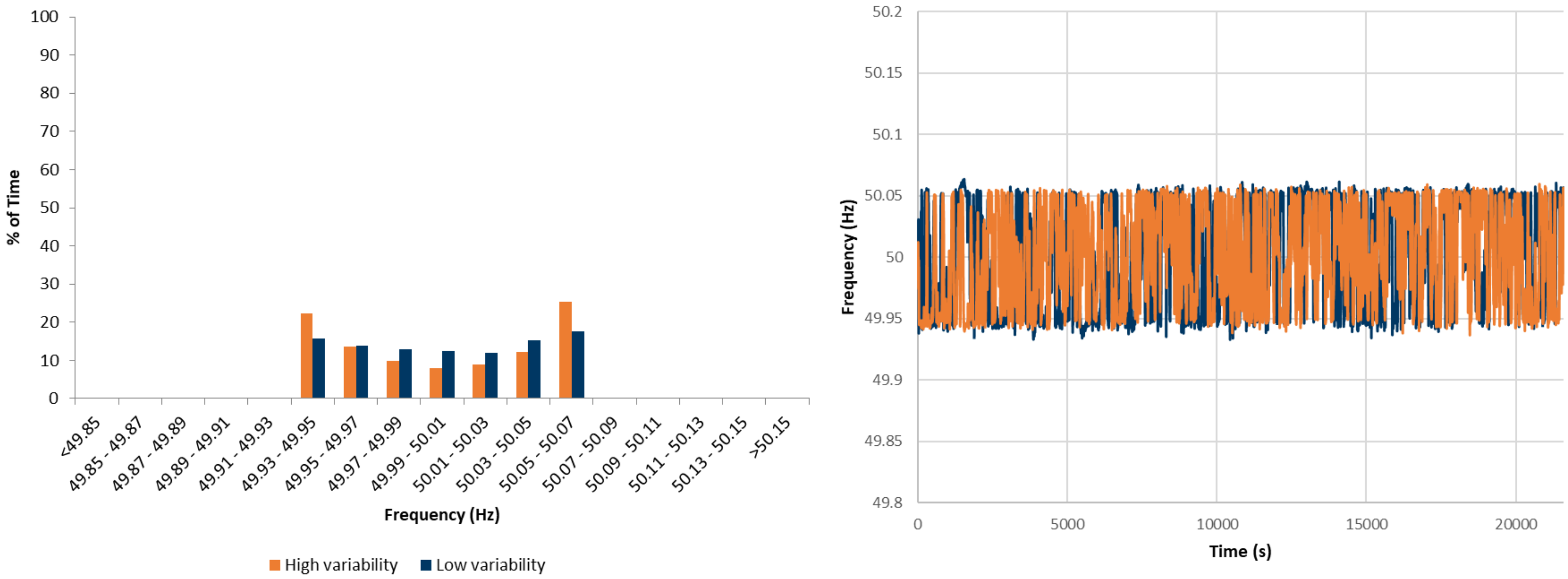

Figure 16 – Frequency distributions – low VRE dispatch case – 50 mHz deadband – high and low forecast error comparison

4.1.4 Impact on utilisation of AGC dispatched R-FCAS providers

The AGC system implemented on the NEM dispatches R-FCAS generators every 4 seconds to balance the system between dispatch intervals, which allows for load changes and forecast errors to be compensated over time. Without the regulation service, the system would be unable to follow load changes effectively, and this would result in significant frequency errors over time. AGC also currently has the secondary function of correcting frequency time error, which it does by regulating system frequency marginally higher or lower to correct the aggregate time error.

The DIgSILENT model had a representation of the AGC system used by AEMO to follow load on the NEM between dispatch periods, by providing dispatch instructions to R-FCAS enabled generation. All studied deadbands, forecast variations, and dispatch scenarios were assessed for their impact on the utilisation of R-FCAS generators controlled through AGC.

General trends were observed with the dispatch of the AGC controlled R-FCAS providers in response to different deadbands and forecast error. The trends observed were as follows:

- For a wider PFCB, the AGC dispatched R-FCAS providers are forced to respond more actively to attempt to maintain frequency, requiring more movement from the R-FCAS plant and a wider range of movement.
- For a higher variance forecast error, the AGC dispatched R-FCAS plant responds more significantly than for a lower variance forecast error.
- In isolation the response of AGC dispatched R-FCAS plant is unable to prevent frequency variations exceeding the NOFB under normal operation when the PFR deadbands are set outside the NOFB.

Figure 17 shows a specific comparison made to assess how AGC active power output varies when both a 15 mHz and 500 mHz deadband were modelled, this plot shows that:

- For a 15 mHz deadband minimal variation in active power output from R-FCAS providers occurs with a maximum range of 73.3 MW observed.
- For a 500 mHz deadband the variation in active power output from R-FCAS providers increases significantly with a maximum range of 302.4 MW.

The difference in active power output between the two deadbands modelled is significant, with a wider deadband resulting in significant variation in active power output from R-FCAS plant.

Greater movement is observed from the AGC dispatched R-FCAS plant in the 500 mHz deadband study as the AGC system attempts to use R-FCAS plant to compensate for the relaxed deadbands. Although R-FCAS capacity remains necessary to balance the system between dispatch intervals, due to its relatively slow action it is unable to regulate frequency as tightly as a system in which AGC is complemented by narrow band PFR response.

As a modification to DIgSILENT's original model, GHD tested the impact of incorporating newer technologies such as BESS, which are presently being used on NEM to provide R-FCAS. There was no material impact from incorporating these new technologies into the model, although it was noted that the BESS was less likely to overshoot setpoints than other technologies, the difference in terms of frequency control was not material.

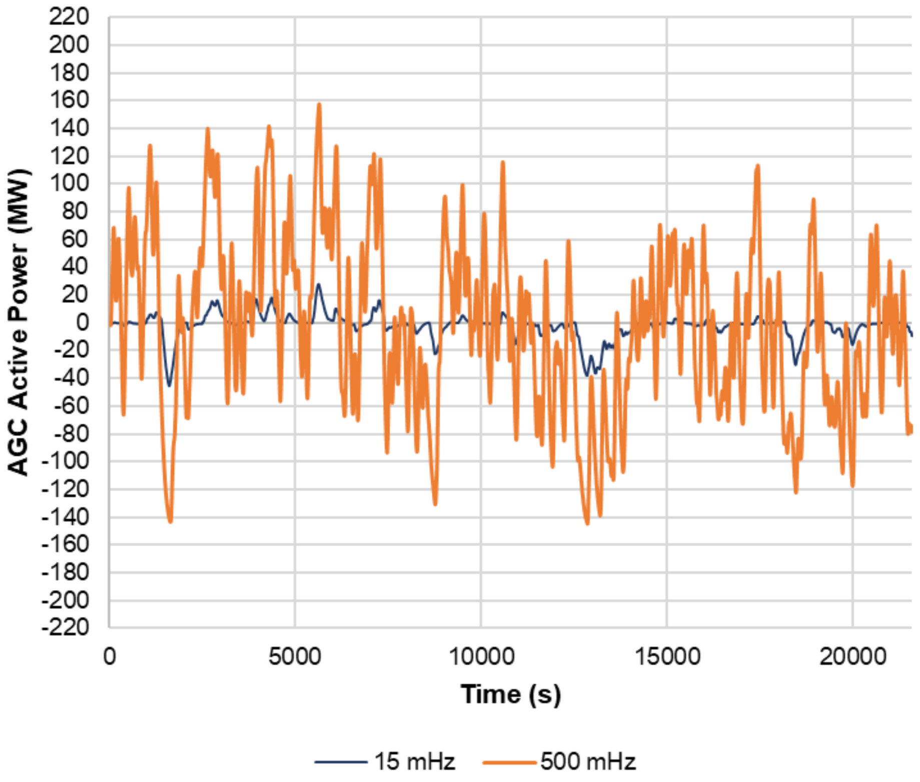

Figure 17 – High renewables case – high forecast error – 15 mHz and 500 mHz comparison

4.1.5 Impact of a detuned AGC

The widening of the PFCB significantly increased the maximum movement per 5-minute interval required from AGC controlled R-FCS plant. As the increased response was not driving a noticeable improvement in frequency regulation, it was considered desirable to test the impact of de-tuning the AGC. The reduction in the proportional gain applied to the AGC resulted in a decreased utilisation of the R-FCAS plant controlled by AGC across all scenarios studied, however, impacts were different depending on the PFCB selected. A comparison of AGC response for a 15 mHz deadband, and a 150 mHz deadband can be seen in the following figures.

A review of the below figures leads to the following conclusions:

- Reducing the AGC proportional gain can result in a substantial reduction in utilisation in R-FCAS plant during normal operation, provided the PFCB setting remains narrow.
- Reducing the AGC proportional gain does not substantially impact R-FCAS utilisation when the PFCB setting are wider.

The “assist” and “emergency” gains in the AGC model were not altered in these detuning studies. With a wide PFCB setting, the frequency deviation was often large enough to activate the “assist” loop within the AGC. This meant that even with the detuning of the AGC, wide PFCB settings resulted in similar levels of utilisation of AGC dispatched R-FCAS plant. While in theory the “assist” and “emergency” proportional gains parameters could similarly de-tuned, this may have other impacts outside of normal operation, such as impacting frequency recovery after contingency events.

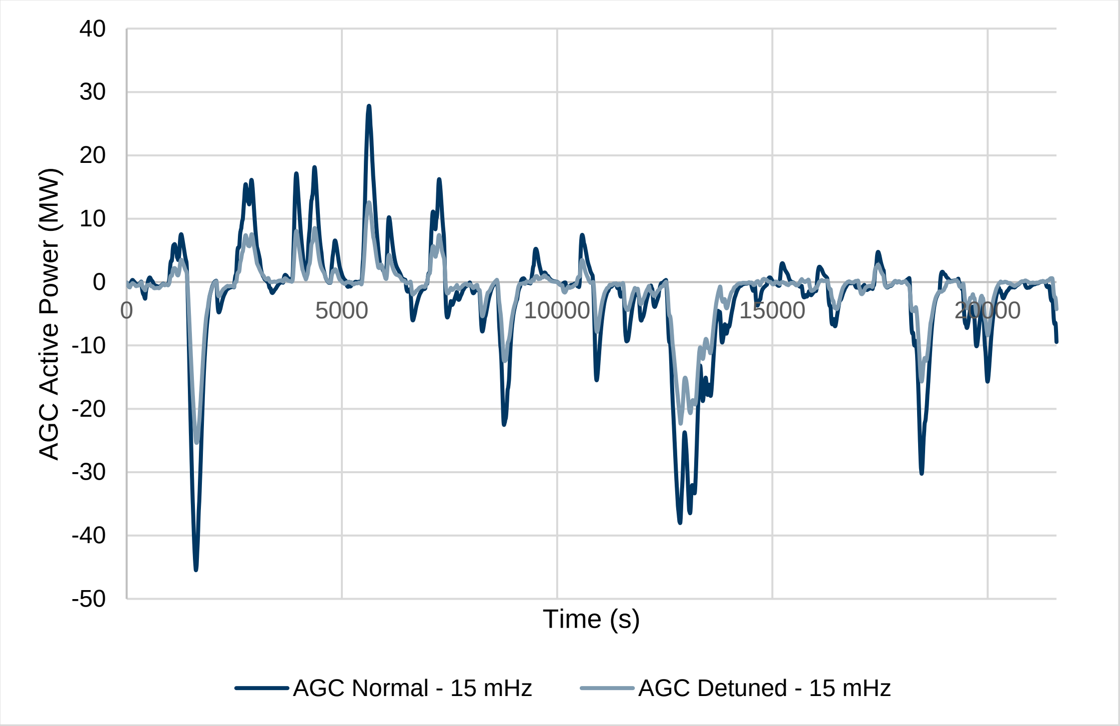

Figure 18 – AGC detuning comparison - 15 mHz PFCB

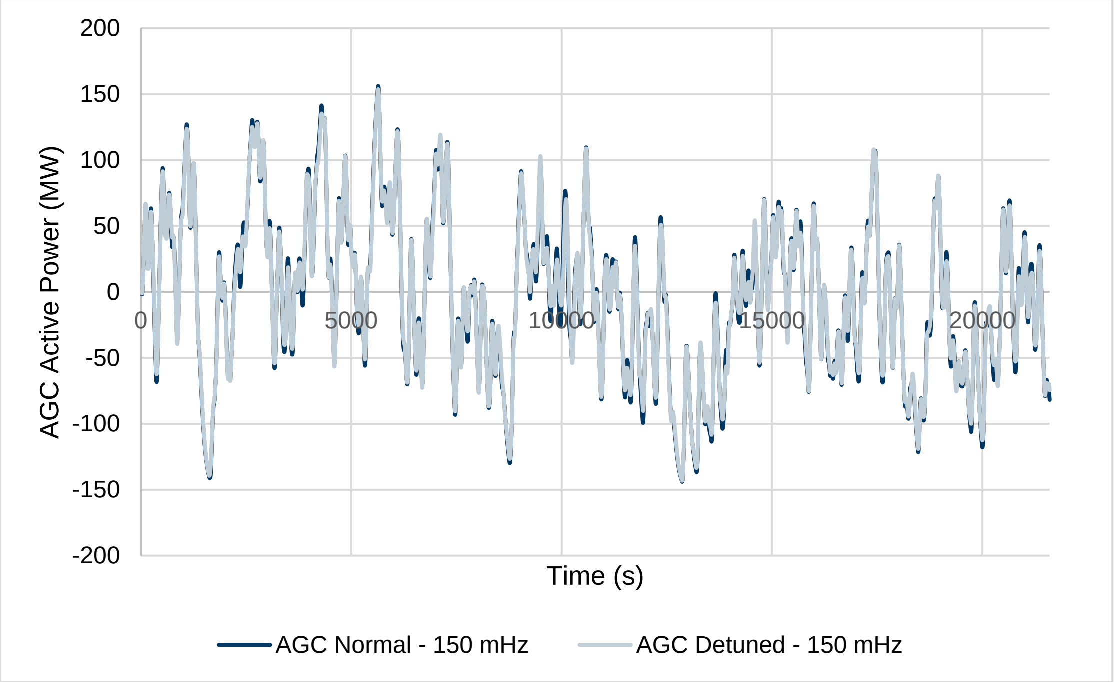

Figure 19 – AGC detuning comparison - 150 mHz PFCB

4.1.6 R-FCAS utilisation costs

Using the costing methodology set out in Section 3.1.5, the impact of PFCB settings on R-FCAS utilisation costs have been assessed. Increased utilisation results in significantly increased costs, due to the maximum levels of R-FCAS movement required being significantly greater. Therefore, wider PFCB settings reflected in wider PFR deadbands result in significantly higher costs attributable to R-FCAS utilisation.

Our modelling has assumed that the required amount of F-CAS service enabled by AEMO remains constant regardless of the PFCB settings.

Table 7 shows the R-FCAS costs assessed using the modelling results for the high forecaster error simulations utilising the high renewable generation scenario in the 2022 study year.

Table 7 – Annualised R-FCAS costs - high forecast error, high renewables scenario

PFCB Setting	5 mHz	15 mHz	50 mHz	150 mHz
Cost of regulation enablement	$90,772,580	$90,772,580	$90,772,580	$90,772,580
Cost of regulation work done	$292,091	$2,011,962	$14,204,266	$21,209,258

The following assumptions were built into the calculation of the costs in Table 7:

- 6 hour forecast error period costs were multiplied by 1460 to produce an annual cost.
- Regulation enablement costs were based on actual NEM costs for the 6-hour 2021 period that the forecast error was based on.
- Regulation work done costs were calculated as per the costing methodology in Section 3.1.5.

The table shows that with a narrow PFCB, R-FCAS utilisation is reduced, as PFR acts to keep frequency closer to 50Hz which reduces the requirement for AGC to respond. However, under a wider PFCB, R-FCAS utilisation increases significantly, with all available capacity often being used.

Table 8 shows the R-FCAS costs assessed using the modelling results for the AGC detuning sensitivity.

Table 8 – Annualised R-FCAS cost - high forecast error, high renewables scenario – AGC detuned

PFCB Setting	5 mHz	15 mHz	50 mHz	150 mHz
Cost of regulation enablement	$90,772,580	$90,772,580	$90,772,580	$90,772,580
Cost of regulation work done	$249,974	$1,065,921	$9,383,608	$20,656,044
% Reduction in “work done” cost	-14%	-47%	-34%	-3%

Detuning AGC resulted in the most significant reductions in costs of R-FCAS utilisation with the existing PFCB. With an extremely narrow PFCB, R-FCAS utilisation costs are minimal regardless of the AGC tuning. With the wide 150 mHz PFCB setting, R-FCAS costs are minimally impacted by the modelled detuning as AGC operates in “assist” and “emergency” mode the majority of the time. This finding suggests that there could be some financial benefit to de-tuning AGC under a PFR incentives framework, however, this benefit would be maximised under the existing PFCB setting.

4.2 Impact of PFCB on PFR utilisation

Under the mandatory PFR requirements currently implemented on the NEM, there is a requirement for generators to provide a frequency response from a governor or frequency controller. This action can cause generators to move marginally from their setpoints under normal system conditions. This movement affects generation technologies differently, but can have the following impacts:

- Loss of energy generated by wind & solar generators which are typically dispatched at rated capacity where possible, and therefore can only provide a downward frequency response.
- Wear and tear on synchronous generators due to speed changes and actuator movement due to governor action.
- Loss of warranted cycling capacity on BESS due to the energy requirements of providing a PFR response.

The impact of PFR requirements can be measured on a system wide basis to assess how specific PFCB settings impact different types of generators and energy storage systems, and how specific PFCB settings impact the aggregate response required from all generators and energy storage systems. The system wide impacts are measured using the following metrics:

- Aggregate levels of system PFR movement – This refers to the total level of generator movement under any given scenario due to the imposition of a specific PFCB. This metric includes responses from PFR, and C-FCAS holding generators, and therefore can be considered to represent a total of system wide response due to primary frequency controller action.
- Movement per technology type – this analysis breaks out the movements undertaken by individual classes of generators and storage throughout a scenario, indicating how different technologies with different frequency control settings respond given a PFCB requirement.

4.2.1 Technology comparisons

The impact of different PFCB settings on individual technologies has been assessed by undertaking an analysis of the movement of generators and storage throughout the simulation from their original setpoints in terms of megawatt hours, weighted by installed capacity of each type of generation and storage. The results of this analysis are shown in Figure 20 which shows generator movements weighted by capacity for each technology type dispatched in the high renewables scenario, with high forecast error variability and existing PFCB settings. This analysis has led to the following findings:

- Primary frequency response action is dominated by the response from BESS, which has the most significant response as a proportion of installed capacity. Figure 20 demonstrates that with the PFCB set to 15 mHz the BESS provide a response greater than 0.9% of installed capacity over 40% of the time, in contrast other generation technologies provide a response which is less than 0.15% of capacity 10% of the time.
- Renewable generators such as PV and wind contribute least to PFR. This is primarily due to the assumption that energy source availability means that PV and wind are unable to respond to under frequency movements, instead responding only to over frequencies. These generators were modelled with a 5% droop, and so would not respond to incidents any faster than equivalent synchronous plant.

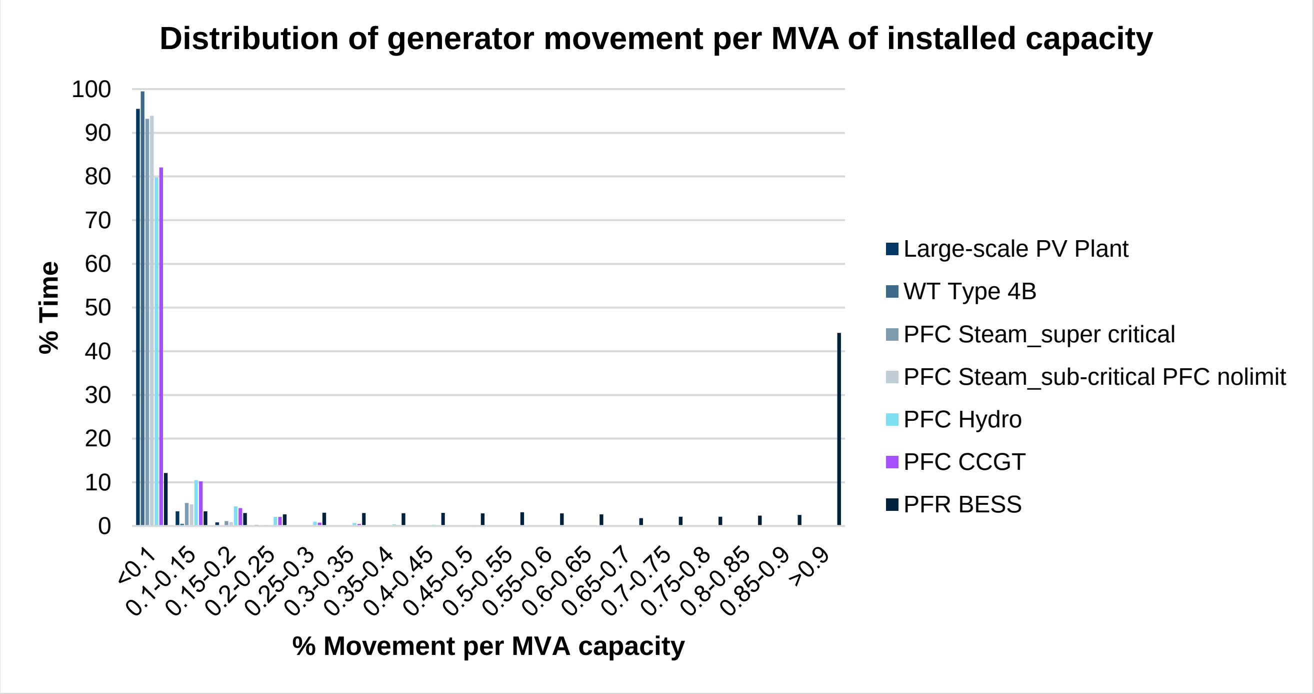

Figure 20 – Generator movements throughout simulation as a % of rating dispatched in model – 15 mHz PFCB

An alternative method of measuring contribution from technologies to PFR duty is to look at the energy used across time intervals to provide a PFR response. A measurement of energy used divided by the total capacity dispatched shows the same outcome as an analysis focused on bi-directional movements. BESS dominate the response in terms of energy served, with wind and solar farms lagging synchronous generators. An example of this analysis is shown in Figure 21.

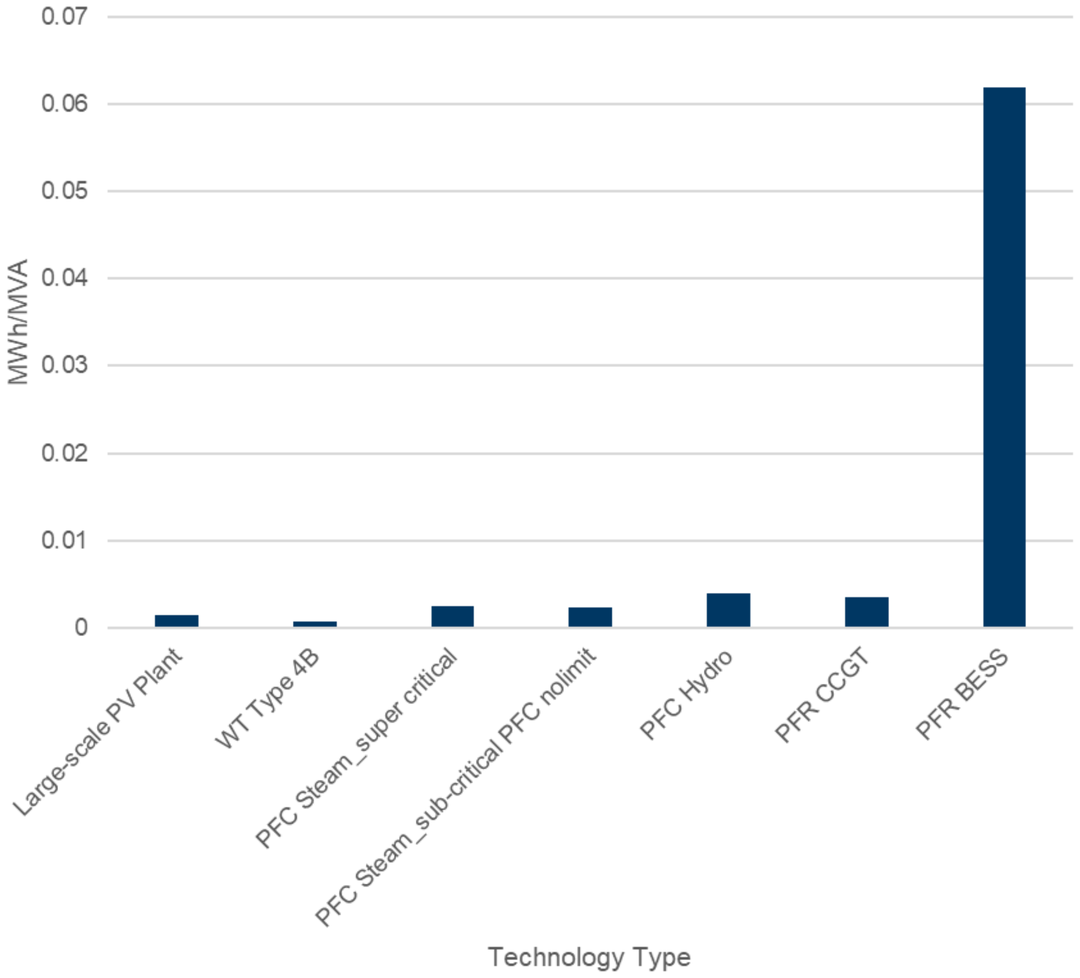

Figure 21 – 2022 High forecast error, high renewable scenario – PFR duty in MWh/MVA – 15 mHz PFCB

The response of individual generator types is primarily due to the function of the specific controller settings chosen for each generator, as well as some inherent characteristics such as inertia. BESS, which were modelled with a droop setting of 2.5% and with no synchronous inertia, responded most aggressively to frequency deviations as a function of capacity.

Synchronous plant was modelled with a droop setting of 5% on average and therefore provide less PFR response per MVA of installed capacity than the BESS.

The assessed PFR movement for synchronous generators reflects the total movement produced the combination of the inertial response to any frequency change and the response provided by governor action. The different synchronous generator technologies deliver slightly different PFR movement when expressed in MWh/MVA of installed capacity.

Unlike inverter connected generation, synchronous generation also moves marginally in response to frequency changes inside the PFCB, as the change in frequency will inherently impact active power output due to the marginal electrical torque change impacting the generator.

Finally, renewable generators, which as modelled did not respond to under frequency deviations and responded to over frequency deviations with the same droop setting as synchronous plant, moved the least of all generator types, being unimpacted by either frequency changes inside the PFCB, and under frequencies.

While the chosen frequency controller parameters are appropriate for representing an aggregated simplified model of the NEM, this analysis should highlight to regulators and policymakers the importance of specific controller settings on the impact felt by individual plant and generators, which may be set up with a wide range of settings when providing a mandatory requirement. While setting minimum performance standards is an appropriate strategy to ensure an adequate level of performance from plant, the impact of a requirement is felt unevenly by plant with different controller settings.

A sensitivity study was undertaken to determine the impact of the BESS droop setting on its PFR response. The results of the study are shown in Figure 22.

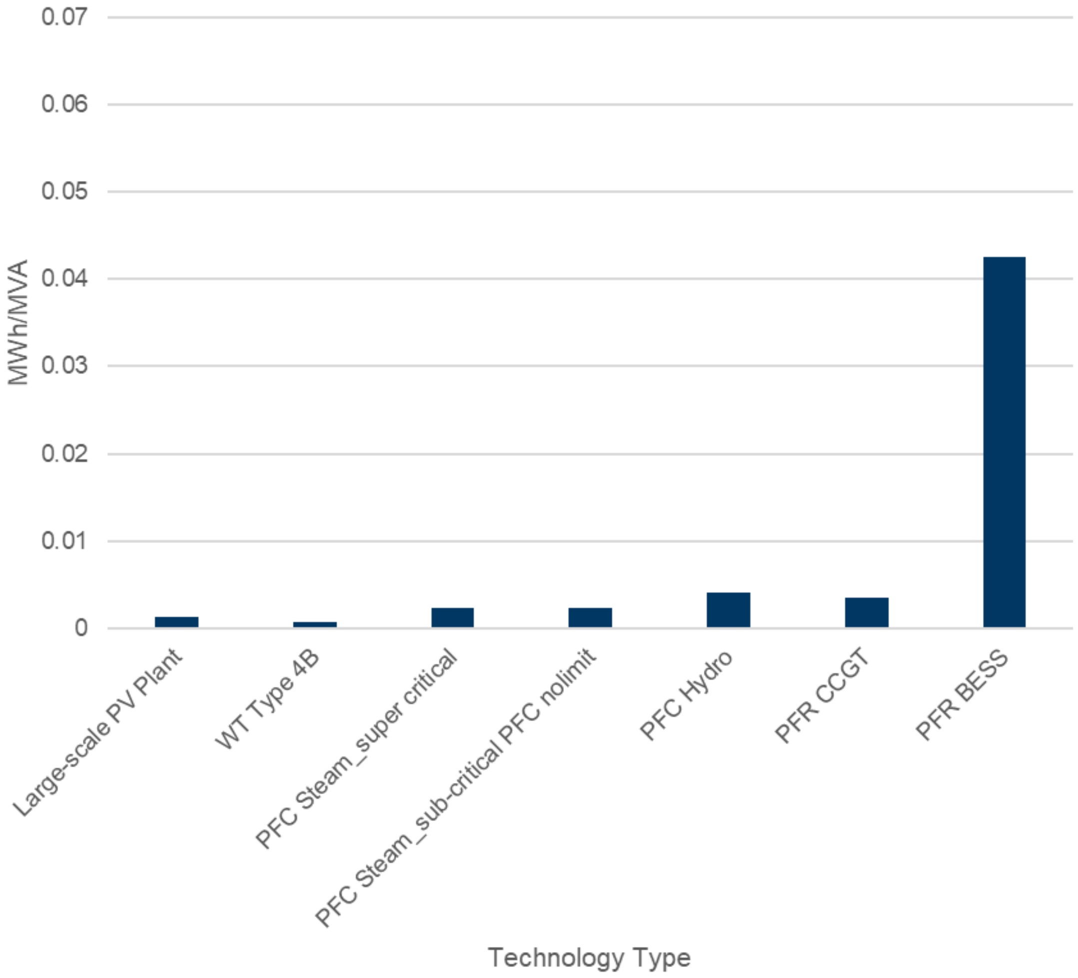

Figure 22 – 2022 High forecast error, high renewable scenario – PFR duty in MWh/MVA – BESS droop set to 5%

Figure 22 shows that with a 5% droop the BESS continue to be overrepresented as a function of PFR response. This is due to a combination of inherent BESS characteristics, as well as some assumptions made in modelling, including:

- BESS inherently have double the equivalent capacity of other technologies, due to their ability to charge and discharge, effectively acting as a load.
- This analysis has assumed that all BESS capacity dispatched for PFR would be available for a PFR response – this is unlikely to be how BESS operators would set up their plant in reality.
- BESS have no restrictions in operation due to charge / discharge limits in this analysis – this is unlike other generation types which may be limited in terms of the range that they can realistically move when providing PFR.

4.2.2 System wide PFR duty

The impact of different PFCB settings on the PFR movements on a system wide basis has also been subject to analysis. The results of this analysis for each deadband setting for the Low VRE – low forecast error scenario is shown in Figure 23. The figure shows the aggregate duty measured across all generators and BESS providing a

PFR response, as measured by the sum of a maximum positive or negative movement during each 5-minute interval across the 6-hour period.

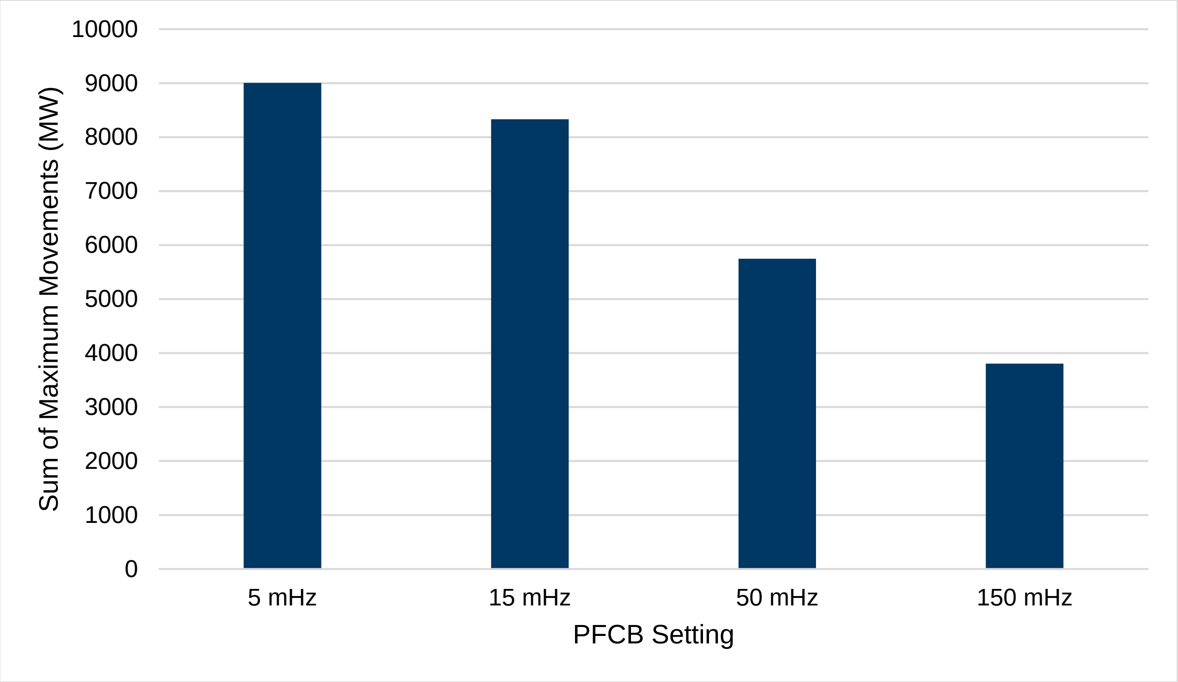

Figure 23 – System wide duty across 6 hours – low renewables – low error

Figure 23 shows that the PFCB setting significantly impacts the total movement generators perform in response to frequency changes. Wider PFCB settings reducing the PFR duty while also reducing the ability to tightly control frequency at close to 50 Hz. The reduction in aggregate PFR duty across the generation fleet will result in a reduction in costs to generators providing a PFR response, provided that deadbands are being set consistently across generators.

The metric being used in this case to estimate “duty” is consistent with a metric that can be costed and compensated through the upcoming PFR incentives framework. However, it may not be consistent with true costs generators experience from a PFCB setting, which could be based on:

- Wear and tear due to “mileage” based on the total movement up and down due to governor actions and frequency variations.
- Energy throughput resulting in loss of warranted cycles from BESS.
- Loss of revenue from dispatch changes below a target setpoint (for renewable generators providing a one-way PFR response only)

The metric used is most suitable for determining how generators will be able to recover their costs due to a PFCB setting via the PFR incentives framework and is therefore a suitable framework for this analysis. However, an understanding of how the PFR incentives framework relates to true costs experienced by generators is necessary to understand whether this framework is likely to be successful in encouraging generators to provide sufficient PFR response.

4.2.3 PFR duty costs

Using the costing methodology set out in section 3.1.5, the impact of PFCB settings on PFR utilisation has been costed. With wider PFCB settings the aggregate PFR duty is reduced providing significantly reduced PFR costs. In contrast, wider PFCB settings were shown in section 4.1.6 to deliver in significantly higher costs attributable to R-FCAS. The PFR costs calculated for the 2022 study case modelling high forecast error and high renewable generation are shown in Table 9.

Table 9 – Annualised PFR cost figures - high forecast error, high renewables scenario

PFCB Setting	5 mHz	15 mHz	50 mHz	150 mHz
Cost of PFR work done	$32,057,817	$30,183,249	$24,399,127	$17,767,429

The assumptions made for this costing were identical to those made to estimate the cost of R-FCAS utilisation.

Table 9 shows that a narrow PFCB materially increases the utilisation of PFR and therefore costs attributable to the provision of PFR. However, it should be noted that the reduction in PFR costs do not outweigh the increased costs due to utilisation or R-FCAS, as seen in section 4.1.6.

This analysis, while preliminary and subject to change due with the price of PFR payments, suggests that the estimated market size means that generators including BESS will be fairly compensated for providing a PFR response, and will be able to cover costs based on current prices for frequency regulation in the NEM.

Adequacy of BESS PFR revenue

Additional analysis we performed to consider whether the calculated PFR payments that underpin the estimate of PFR costs were likely to provide adequate compensation for a BESS providing PFR. This was of interest as BESS is likely to play a significant role in the provision of PFR in the future and there is a concern that a BESS has a limited number of warranted charge/discharge cycles and therefore it is important the PFR revenues provide sufficient complesation to account for the utilisation of warranted cycles in the provision of PFR.

The analysis examined share of the PFR revenue allocated to BESS providing PFR response in the Power Factory model. The PFR revenue was assessed to determine whether PFR incentives payouts would be enough to meet the levelized costs of energy for the BESS.

The analysis considered the BESS levelized cost of energy, derived for information published in the 2022 AEMO Integrated System Plan. This analysis modelled the impact of a mandatory PFR requirement by measuring energy throughput for the modelled BESS providing PFR using that to determine the annual PFR payment. The annual payment was expressed as a PFR revenued per warranted cycle used to provide PFR and that was compared with the levelized cost calculated from the BESS cost data included in the 2022 ISP.

Table 10 shows the levelized cost per cycle determines from the BESS cost data in the 2022 ISP and the revenue per BESS cycle determined from our analysis of the PowerFactory modelling results for the higher VRE dispatch, high variability scenario in 2022. The analysis shows that, based on historical prices paid for frequency regulation in September 2021, payments were likely to be sufficient for BESS to recover their levelized costs.

Table 10 –BESS PFR revenue and levelised cost – 2022 high forecast error, high renewables scenario, 15mHz deadband

Levelised cost per warranted cycle 2022 ISP BESS costs	PFR revenue per warranted cycle
$233 (1MW and 1MWh)	$622

4.3 Power system resilience

4.3.1 Frequency resilience studies – Load shedding events

Studies were undertaken to determine the impact of a wider PFCB on power system resilience to contingency events. Non-credible contingency events were considered in this analysis, assuming that credible contingencies would be secured by C-FCAS in line with current security standards. A brief description of the contingency events studied using the multi-regional model are as follows:

- QNI tripping – The QNI was tripped when carrying 1200 MW exporting from Queensland to New South Wales. The objective of this study was to test the resilience of the power system with regards to an over frequency in QLD and an under frequency in the remainder of the NEM due to the trip, and to test the impact of the modified PFCB.

- Heywood tripping – The Heywood interconnector was tripped when carrying 600 MW exporting from Victoria to South Australia. The objective of this study was to test the resilience of the power system with regards to an under frequency in SA due to the trip, and to test the impact of the modified PFCB.
- Loy Yang A tripping – This event was simulated by tripping multiple coal units generating 1300 MW in the NSW – Victoria region of the model. The objective of this study was to test the resilience of the power system with regards to an under frequency, and to test the impact of the modified PFCB.
- Large load tripping - This event was simulated by applying a step load change of ~600 MW in the NSW – Victoria region of the model. The objective of this study was to test the resilience of the power system with regards to an over frequency, and to test the impact of the modified PFCB.

Individual under frequency load shedding blocks were specifically modelled in PowerFactory in line with data provided by AEMO in order to understand the volume of load likely to be tripped during a non-credible contingency event. These blocks were separated on a state-by-state basis in the model.

The results of the non-credible contingency studies are shown in the Figure 24 to Figure 27.

The results of the non-credible contingency studies show a significant change in the frequency response across the scenarios. The main change in system behaviour across the events are:

- Frequency nadirs – for all events, nadirs are significantly worse in the 500 mHz deadband case.
- Frequency recovery – for all events, frequency recovery is significantly worse in the 500 mHz deadband case.
- Impact on islanded regions – for both islanding events, the frequency performance in both the islanded region and the remainder of the NEM is worse with a wider PFCB.

The trends seen across the scenarios are to be expected based on the impact of a wider PFCB on frequency control during normal conditions. With a wider PFCB, generators will take significantly longer to respond to frequency changes, waiting for frequency to fall further, and will provide less of their reserve capacity for an equivalent sized trip, due to droop response being calculated from outside the deadband for governors and frequency controllers. In turn, this also has an impact of turning events which the current mainland NEM would easily ride through, i.e., the loss of a 600 MW interconnector, into more significant frequency events. This increases the likelihood of load shedding due to less significant events which would not currently result in load shedding.

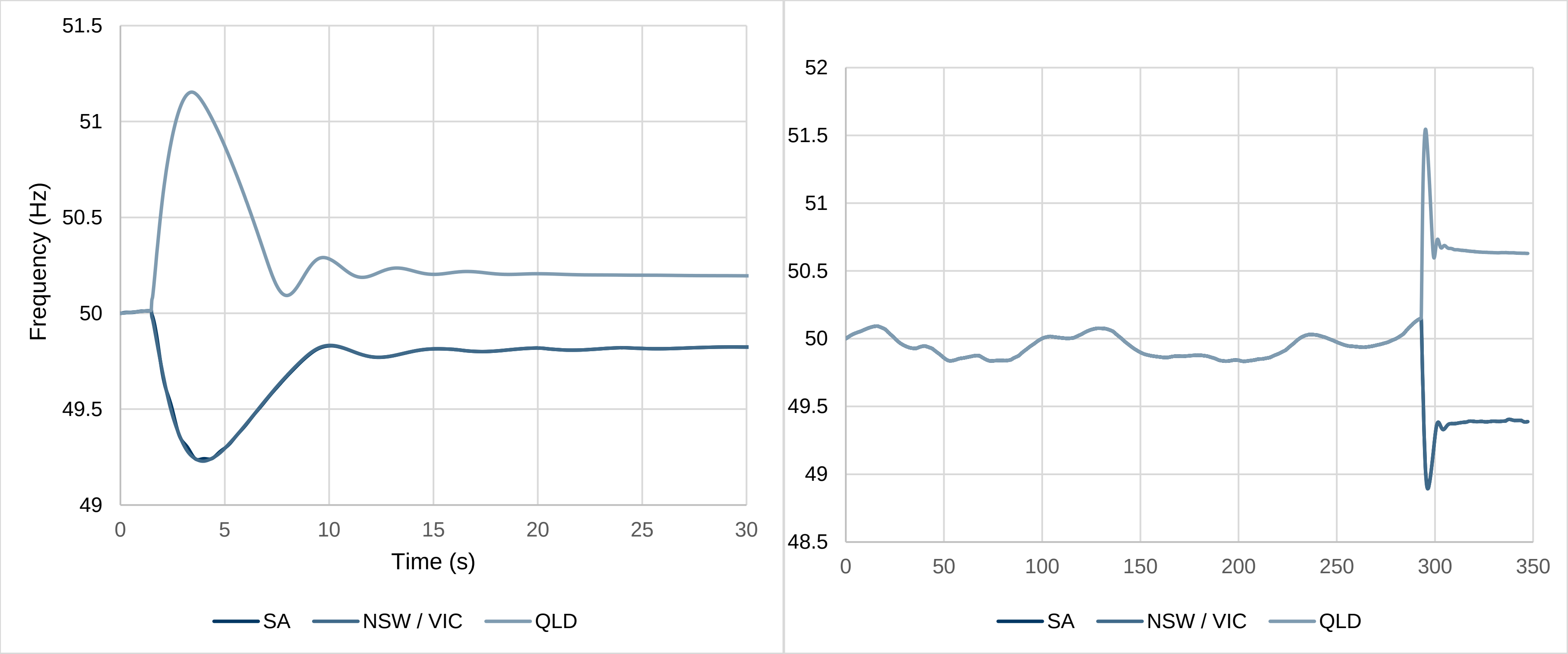

Figure 24 – Frequency response – Queensland – New South Wales interconnector trip modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands)

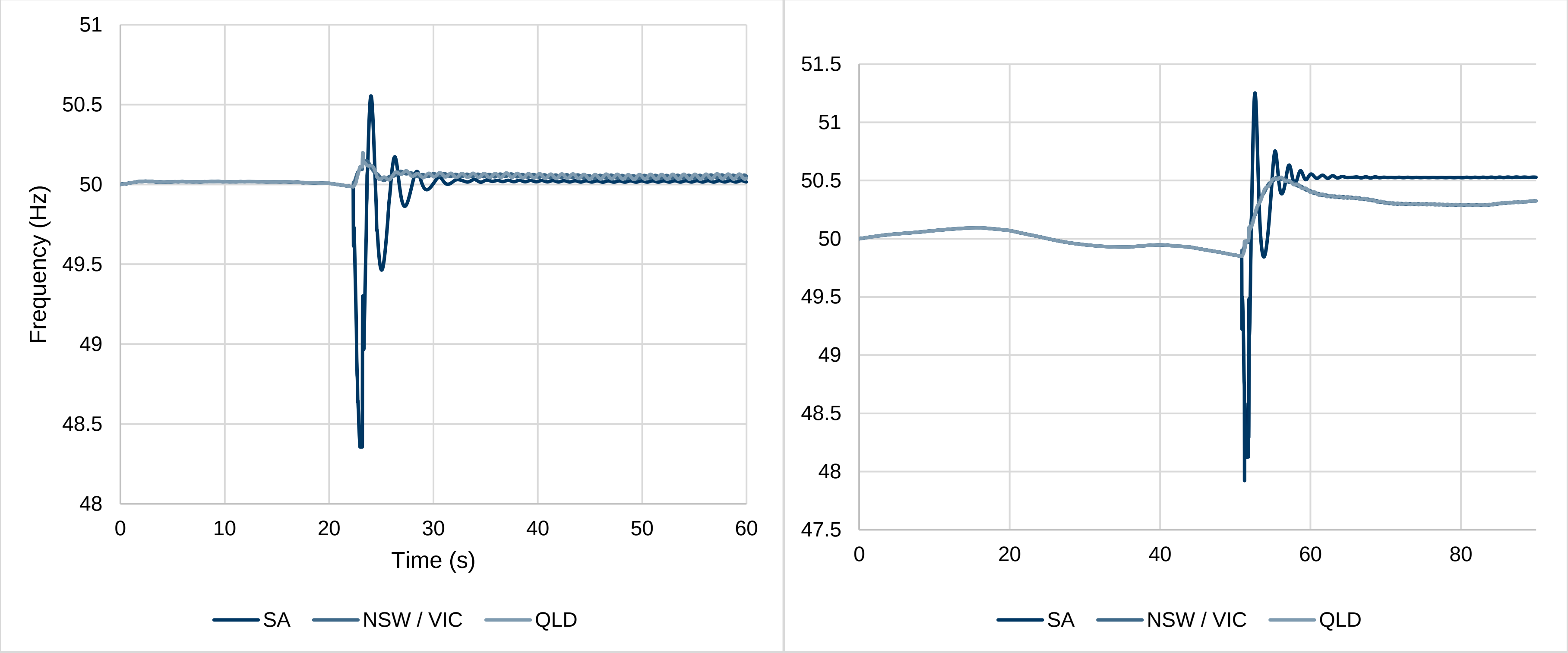

Figure 25 – Frequency response – Heywood interconnector trip modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands)

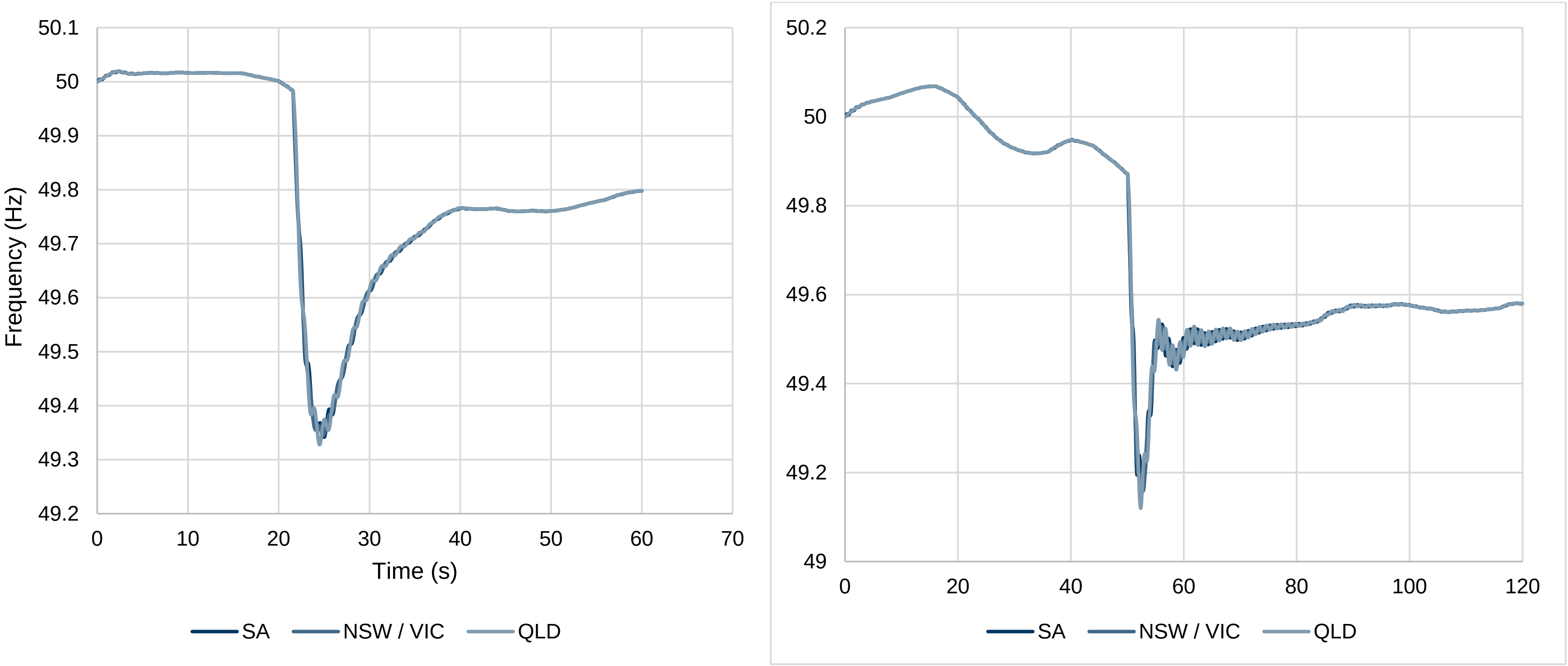

Figure 26 – Frequency response – Loy Yang generator trip of 1130 MW modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands)

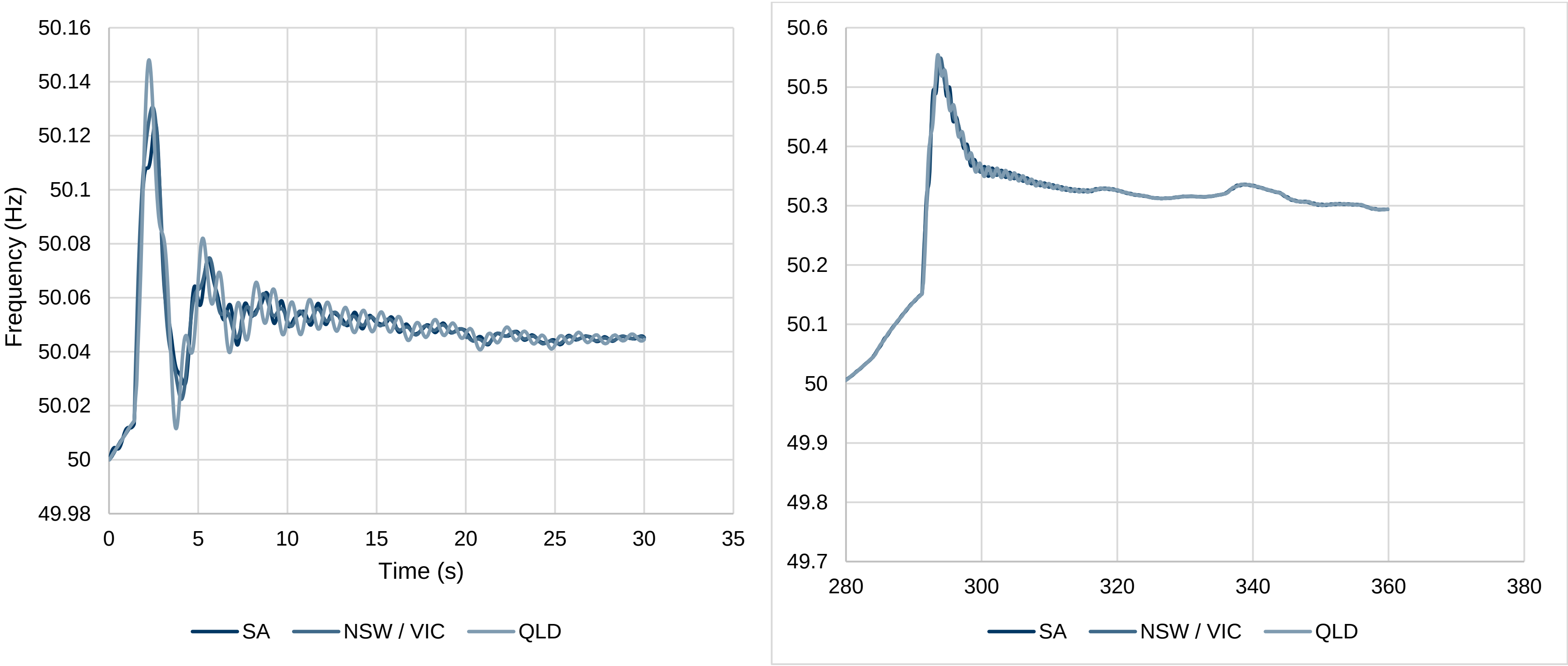

Figure 27 – Frequency response – 600 MW load trip modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands)

4.3.2 Frequency resilience studies - Resynchronisation

A further six-hour study was undertaken using the multi-region model to assess the impact of the 15 mHz and 500 mHz PFCB settings on the ability to resynchronise two islands. The study involved running the model with the QNI open. Power system islands can only be resynchronised when system voltages and frequencies at connection points are close enough to allow breakers to close without damage. This requires careful monitoring of the voltages and frequencies on each island to determine conditions are right for resynchronization. The success criteria for these studies were chosen to be when power system island frequencies were within 0.01% of each other, equivalent to 2 mHz. The results of this study are shown in Table 11 below and Figure 28.

Table 11 – Resynchronisation results - 2022

Deadband	Success criteria met during 6-hour interval?	Number of times success criteria met?	% Of time success criteria met
15 mHz	Yes	2114	39%
500 mHz (inc 150 mHz C-FCAS)	Yes	296	5.5%

It can be seen from the results in the table that a smaller deadband is significantly more likely to allow for system frequencies in islands to be close to each other to support successful synchronisation.

The probability of successful resynchronisation of islands decreased with a wider PFCB. Table 11 indicates that increasing the PFCB to ±500 mHz could make it 7 times less likely that islanded regions could be quickly resynchronised. A similar degradation in the ability to reschronise systems would be expected with a PFCB of ±150 mHz as the results presented in 4.1.1 demonstrate that C-FCAS generators with a deadband of ±150 mHz act to provide a similar frequency distribution for PFCB of ±500 mHz or ±150 mHz.

The load shedding costs shown in Figure 30 assume all load is restored with one hour of the contingency, which is unlikely to be achieved if synchronisation is delayed. A wider PFCB may therefore result in synchronisation delays which increase costs due to load shedding.

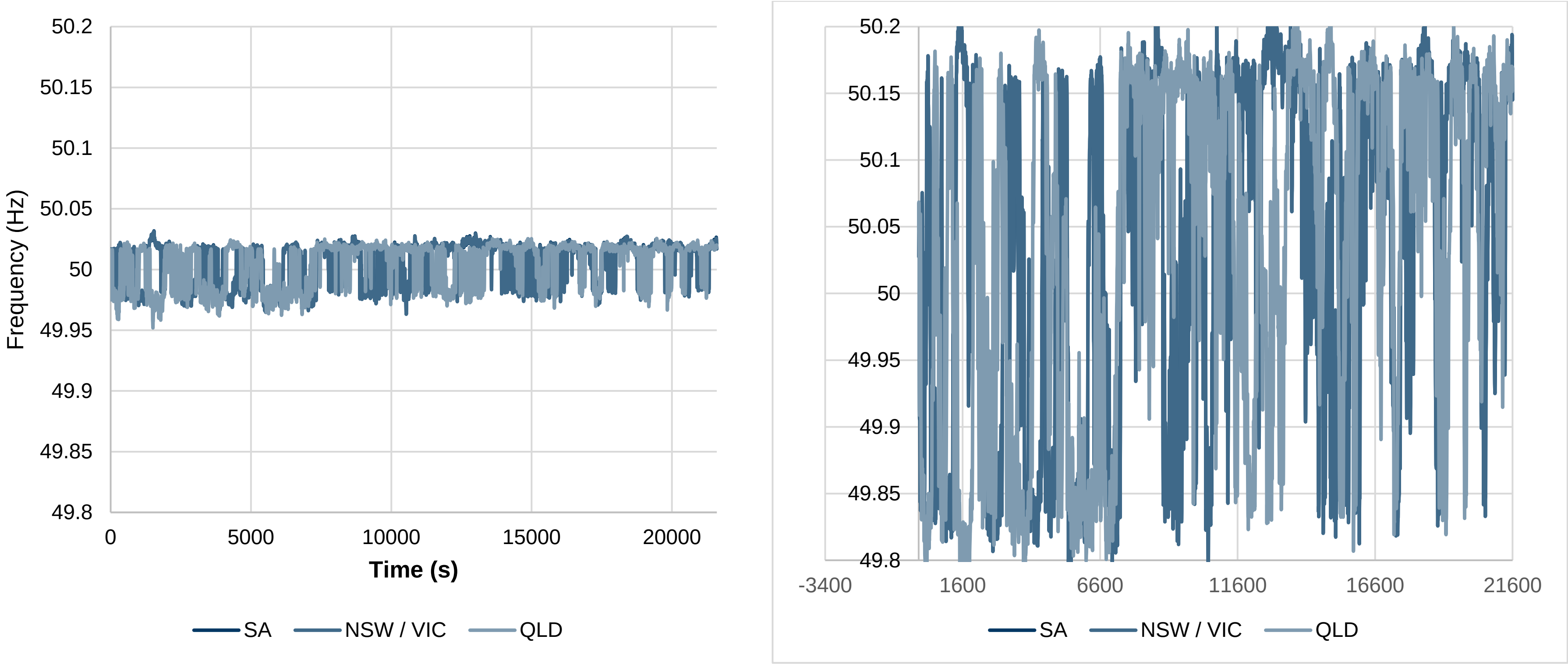

Figure 28 – Frequency response – Queensland – New South Wales interconnector separated

4.3.3 Frequency resilience studies – Loss of SCADA

A final study attempted to determine the impact of losing control of SCADA systems controlling AGC on the NEM, by disabling the AGC model in DIgSILENT and running a 6-hour simulation to determine the impact on the frequency distribution across the 6-hour interval. A comparison of the frequency distribution seen for a 15 mHz PFCB with and without AGC is shown in Figure 29.

The loss of AGC had a minor impact on power system frequency during GHD's simulation, however it is worth noting that because no load changes have been simulated across the 6-hour interval beyond forecast errors, that the capacity reserved for AGC would normally have a more significant impact in preventing PFR reserves being exhausted. In terms of frequency resilience across a period with no significant load changes, and where these reserves are not exhausted, the loss of AGC study produce the following findings:

- Frequency remains controlled by PFR and did not drift far from the edge of the PFCB even with AGC diabled.
- Frequency drifts further from 50 Hz across the time interval with AGC diabled.

The analysis found that the loss of AGC did not significantly impact system resilience when sufficient headroom and foot-room exists on generation with a mandatory PFR requirement to manage forecast errors. However, this analysis did not account for load changes, and therefore may not capture the potential impact if there was no AGC capacity available combined with a lack of available room for movement from dispatched generation on the NEM.

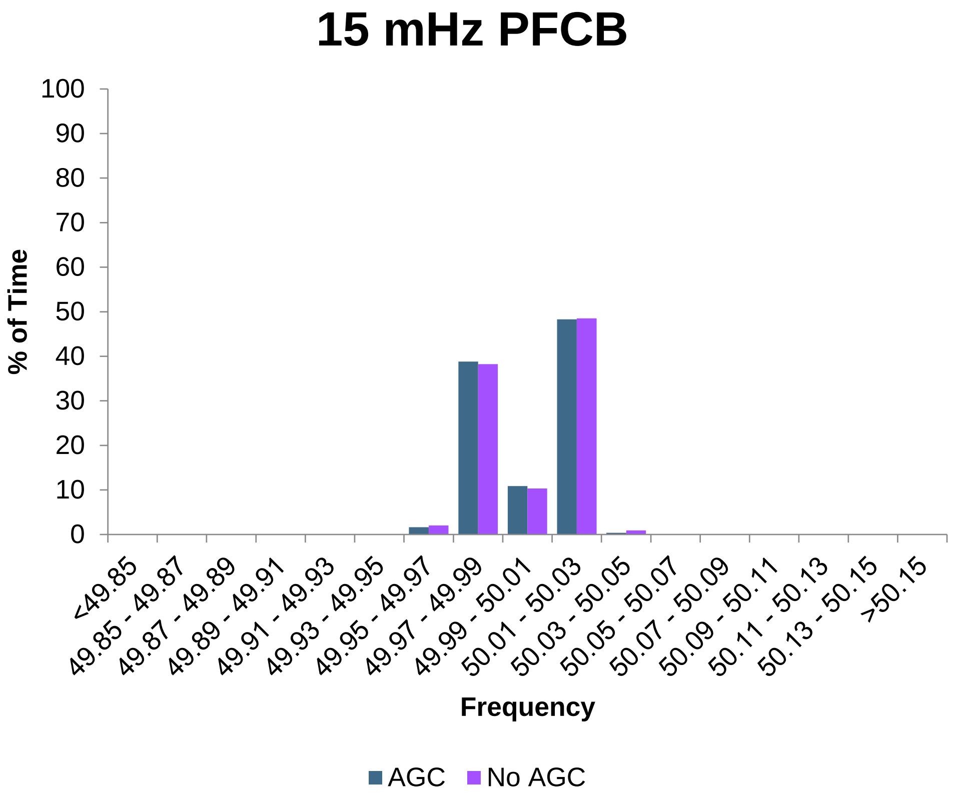

Figure 29 – Loss of SCADA - frequency distribution comparison

4.3.4 Valuing resilience

The cost of a reduction in power system resilience can be obtained by valuing the increased potential for load shedding using a VCR metric, which quantifies the cost to consumers from a supply interruption. The cost of reduced resilience in the case of each event studied can therefore be valued by determining the increased amount of load shedding with different PFCB settings and valuing it in line with the methodology specified in Section 3.2.4.

Figure 30 dispalys the estimated costs of load shedding for various events simulated with 15 mHz and 500 mHz PFCBs.

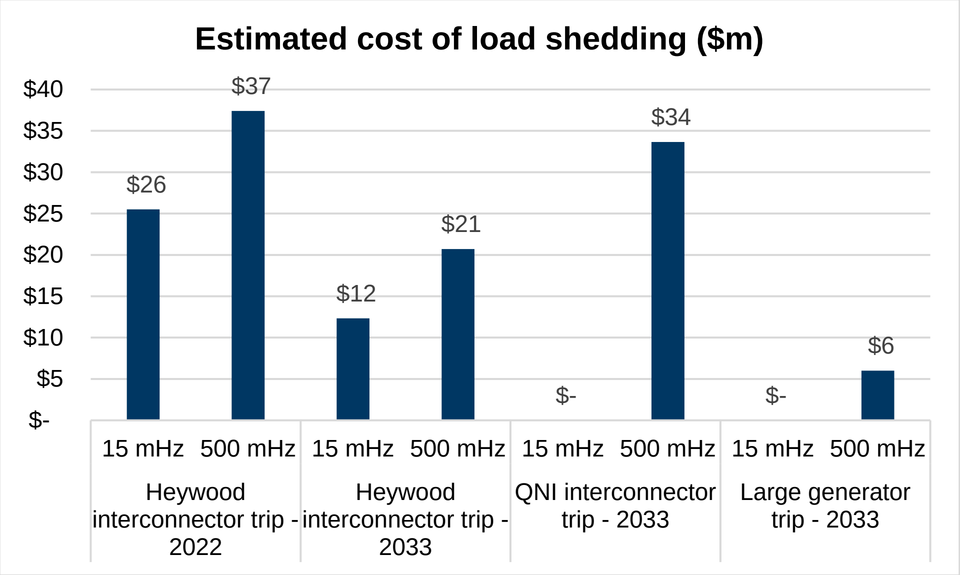

Figure 30 – Estimated resilience costs due to load shedding following contingency events

A national load-weighted VCR of 42.52 $/kWh was applied, and a minimum outage duration of one hour was assumed. For further details, please refer to section 3.2.4 and Appendix B.

The results in Figure 30 show that there is a significant resilience impact from widening the PFCB. With C-FCAS machines tuned to respond only at the edge of the NOFB, significantly more load shedding results from the same contingency events, resulting in a higher amount of unserved energy to customers.

The conclusions from this analysis are as follows:

- Reduced reliability carries implicit costs for consumers in terms of unserved energy
- Precise probability of these costs being incurred cannot be quantified, but the value of a single non-credible contingency event can exceed annual savings in PFR movement from a widened PFCB.
- Costs of non-credible contingencies will significantly increase if load cannot be restored in a timely manner. The results presented in section 4.3.2 demonstrate that a wider PFCB may significantly reduce the likelihood of successfully resynchronising islands after a contingency event. Delays in resynchronising could prolong load shedding beyond the 1 hour assumed, further increasing the resilience benefit provided by a narrow PFCB.

The resilience costs shown in Figure 30 derive from comparing the results of simulations of various contingency events with the current PFCB settings and with a PFCB of ±500 mHz and C-FCAS provided operating with deadbands set to ±150 mHz. As noted in Section 4.1.1 the frequency distribution under normal system conditions with a PFCB of ±500 mHz and active C-FCAS generators is very similar to that achieve with a PFCB of ±150 mHz. This means that the frequency immediately prior to any contingency is likely to be as distant from 50 Hz with a PFCB of ±500 mHz or ±150 mHz.

While a contingency event is likey to start with the frequency the same distance from 50 Hz the response observed to a large contingency event may differ, depending on the PFR capacity available to respond to the under-frequency:

- With a PFCB of ±500 mHz, there would be no PFR immediately following the contingency except that provided by the C-FCAS generators. PFR from other providers would begin once the frequency fell below 49.5Hz.
- With a PFCB of ±150 mHz, there would be an immeditate response from CFAS and PFR providers once the frequency fell below 49.85Hz.

This means that the amount of load shedding could be different for the two scenarios, with a PFCB of ±150 mHz potentially resulting in less load shedding. This will be the case where the region experiencing the underfrequency has a large amount of PFR raise capability available.

The results in Figure 30 for contingencies involving the trip of the Heywood interconnector are likely to provide a reasonable estimate for the resilience benefit gained by maintaining the existing PFCB as compared to widening the band to ±150 mHz. This because the resilience benefit is calculated for a contingency involving the trip of the Heywood interconnector and there is a limited amount of PFR raise available within South Australia. This means that the frequency nadir will mainly be influenced by the pre-contingency deviation from 50 Hz.

5. Findings of 2033 studies

5.1.1 Frequency distribution - 2033

Frequency distribution studies for 2033 considered the cases described in Table 3 against one dispatch case and three forecasting error variations. The frequency regulation achieved in the 2033 scenarios changed compared to the 2022 scenarios, primarily due to the lack of synchronous plant present on the power system. However, under the assumptions made for our study, with adequate raise PFR available from curtailed inverter connected generation, the trends observed across scenarios remain similar, with some minor differences, which are noted below:

- Frequency controllers on inverter connected plant control frequency to the outer limit of their deadband the majority of the time, rather than attempting to control frequency back to 50 Hz, resulting in more time spent at the extremes of a deadband relative to the 2022 scenario.
- Tighter frequency regulation is more achievable on a system dominated by inverter connected generation, with inverter connected frequency controllers able to respond quicker than synchronous generator governors.
- More extreme differences between scenarios have been noted due to the lower inertia, as frequency is controlled more precisely to the edge of each deadband.

It should be noted that the 2033 studies as modelled frequency control systems as used in present inverter controller technologies. Inverters have not been primary providers of frequency response on the majority of synchronous power systems, and therefore frequency controls developed for power systems dominated by synchronous plant may not be suited for inverter dominated low inertia power grids. Innovations such as virtual synchronous machines will likely result in frequency control requirements closer to those achieved on the current power system.

The trends noted from the 2033 studie do not change the conclusions of this analysis. More significant in terms of changes impacting this analysis will be the future price of frequency regulation, and the prices that can be recovered by generators under the PFR incentives arrangement.

5.1.2 Frequency resilience studies – 2033

The results observed in the 2022 scenarios hold as valid observations in 2033, and primarily show that:

- Frequency nadirs – for all events, nadirs are significantly worse in the 500 mHz deadband case.
- Frequency recovery – for all events, frequency recovery is significantly worse in the 500 mHz deadband case.
- Impact on islanded regions – for both islanding events, the frequency performance in both the islanded region and the remainder of the NEM is worse with a wider PFCB.

It has been noted that frequency resilience in 2033 was not always worse than in 2022, despite a significant reduction in synchronous inertia across the scenarios. This was due to a significantly increased level of PFR available from inverter-based resources such as BESS, with control settings providing a faster frequency response than traditional synchronous plant. It is anticipated that due to the performance capabilities of these plant, the power system performance for non-credible contingencies could in some cases be improved despite a lower level of synchronous inertia being available.

Two figures showing the performance of the power system in 2033 are shown below. Figure 31 shows an event which increases in severity, the trip of the QNI, primarily due to the extremely high RoCoF generated by the large magnitude of the contingency, causing tripping in NSW and VIC.

Under a 15 mHz deadband, the power system avoids load shedding, although some damped oscillatory instability is observed. Under the wider deadband condition, a significant amount of load shedding was observed, with no frequency recovery. This event would also cause over frequency generator shedding in Queensland if such a scheme were to be implemented as it is in South Australia.

Figure 32 shows an event which appears less severe in 2033 than in 2022, the trip of the Heywood interconnector, primarily due to the increased levels of PFR available from inverter-based resources. However, no frequency recovery is observed for the 500 mHz case even when delayed load shedding is triggered.

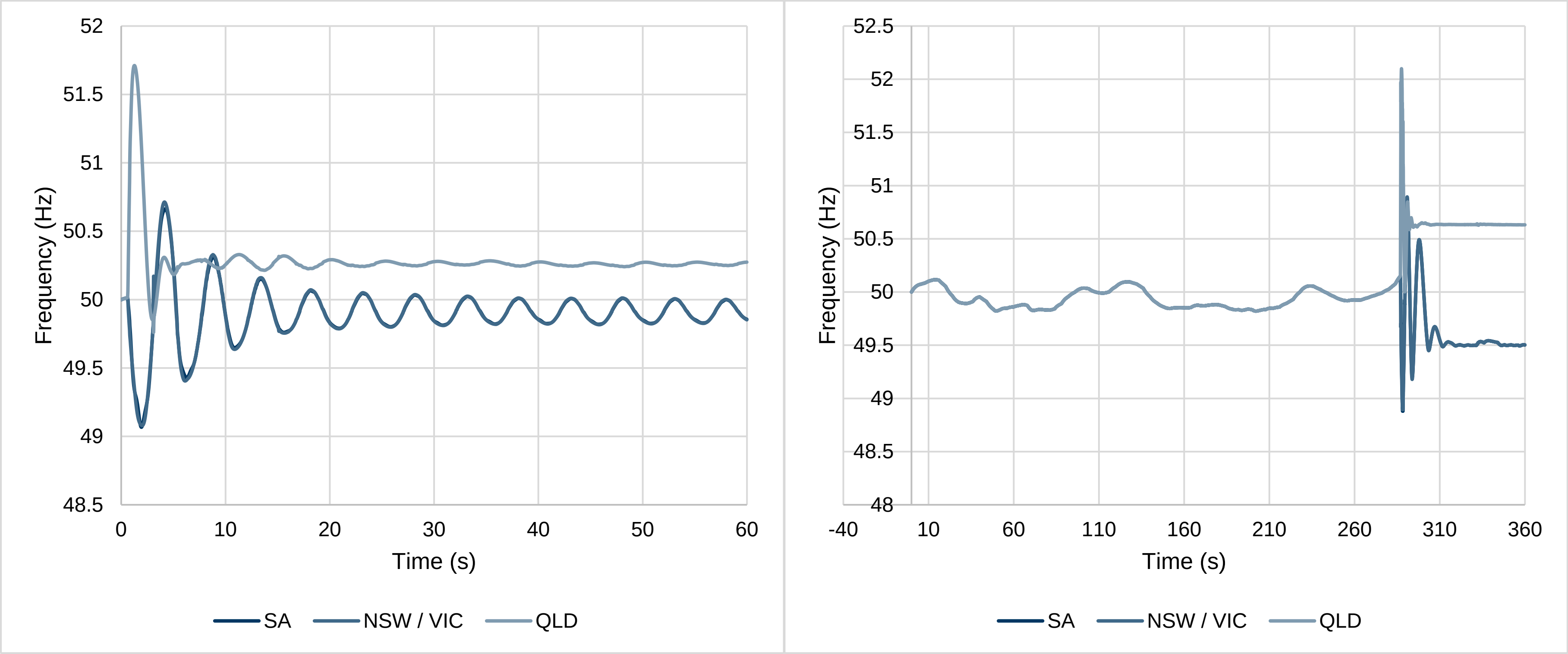

Figure 31 – Frequency response – Queensland – New South Wales interconnector trip modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands) – 2033 scenario

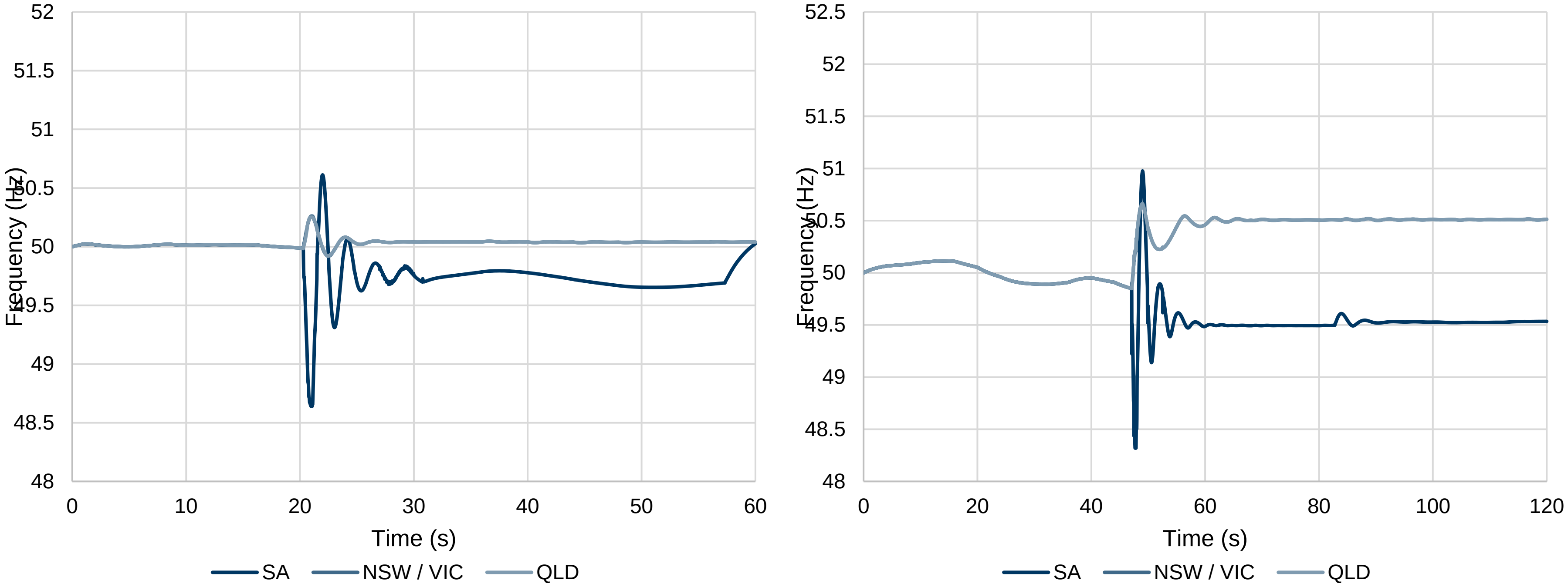

Figure 32 – Frequency response – Heywood interconnector trip modelled with deadband limits of 15 mHz and 500 mHz (including C-FCAS generators at 150 mHz deadbands) – 2033 scenario

5.1.3 Frequency resilience studies – Resynchronisation – 2033

Resynchronisation in 2033 was impacted by the PFCB in a similar manner to that observed in 2022. Overall probability of resynchronisation in 2033 increased with a narrow deadband and decreased with a wider deadband compared to 2022.

Table 12 – Resynchronisation results - 2033

Deadband	Success criteria met during 6-hour interval?	Number of times success criteria met?	% Of time success criteria met
15 mHz	Y	2454	45.4%
150 mHz	Y	220	4.1%

It can be seen from the results in Table 12 that a smaller deadband is significantly more likely to allow for system frequencies in islands to be close to each other to support successful synchronisation. The results in 2033 indicate a 10x greater likelihood of successful resynchronisation with a narrow PFCB.

6. Conclusions

The total energy requirement to administer PFR is relatively small, but the selection of the PFCB has material impact on both generators and consumers. These impacts include:

- Wear and tear on generators due to movements and speed changes impacting synchronous generators.
- Energy throughput impacting battery warranties
- Lost energy impacting renewable generation providing a response below their output.
- Unserved energy impacting consumers due to decreased system resiliency.

The selection of the PFCB setting also impacts the ability to maintain frequency within the NOFB specified in the FOS. The optimal setting of the PFCB should consider the materiality of the costs attributable to generators, relative to the costs of increased or decreased resilience on the power system.

A summary of the impacts of several of the PFCB settings modelled by this analysis can be seen in Figure 33 for the high forecast error, high VRE scenario in 2022, and in Figure 34 for the 2033 high forecast error scenario.

Annual costs for the NEM have been extrapolated based on 6-hour periods which may not represent the variability likely across a year. Considering the range of annual costs estimated from analyais of different 6 hour periods may provide a more informed view of the potential variation in annual costs with different PFCB settings. A comparison between the annual costs under normal operation for the different combinations of VRE dispatch and forecast error variability considered in the 2022 simulations can be seen in Figure 35. The difference in costs between the scenarios takes into account the differences in the simulated work done by PFR and R-FCAS providers and the difference in the R-FCAS enablement for the period in different historiacal 6 hour periods. Total annual costs under normal operation for a 15 mHz deadband vary between $65m and $123m across these scenarios.

As a reference, historical regulation costs in the NEM range from $4.6m in 2013 to $126.8m in 2019, with an average over the years 2019-21 of $93m[10]. The analysis included in the AEMC's PFR incentive arrangements final determination expected the scale of gross frequency performance payouts to be in the order of $90m per year[11], falling within the range of scenarios considered by GHD in this analysis.

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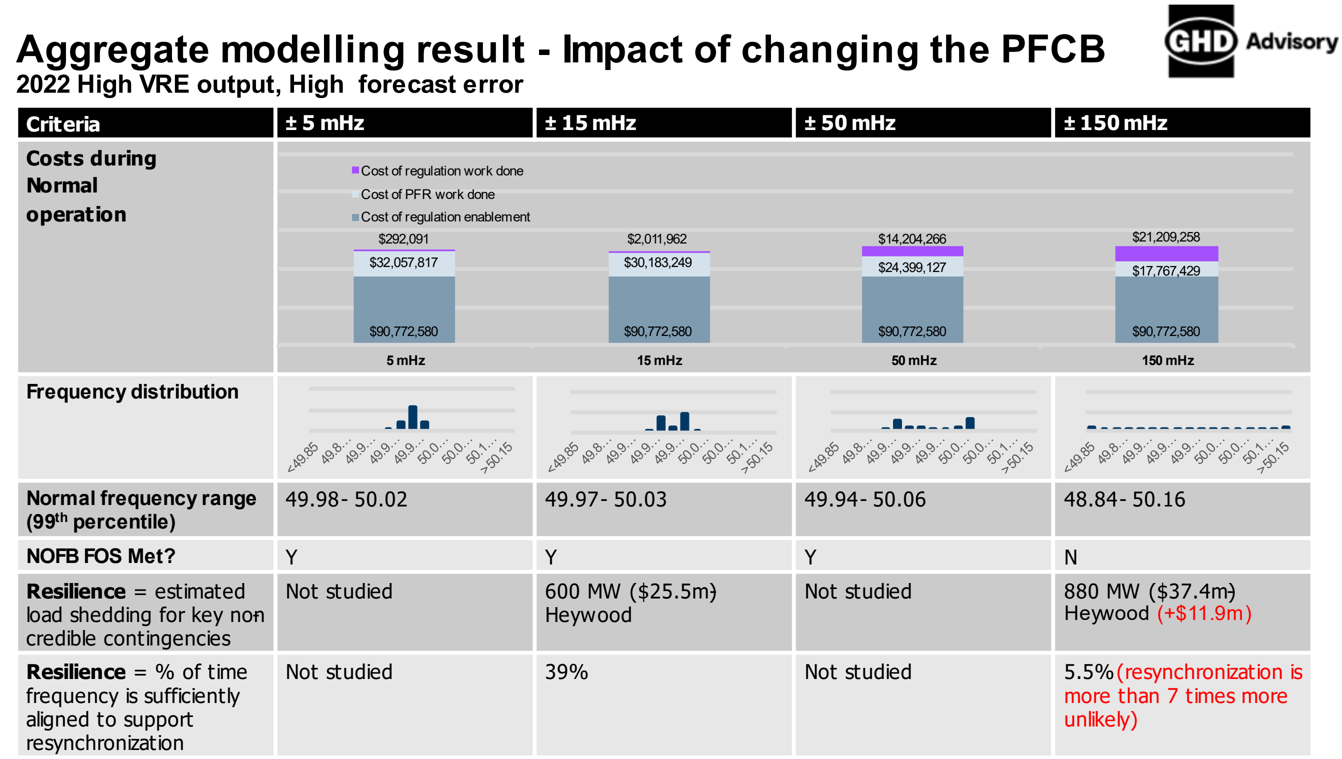
[10] Appendix E of the PFR Incentive Arrangements Final Determination. Available at **Primary frequency response incentive arrangements | AEMC**

[11] Page 74 of the PFR Incentive Arrangements Final Determination. Available at **Primary frequency response incentive arrangements | AEMC**

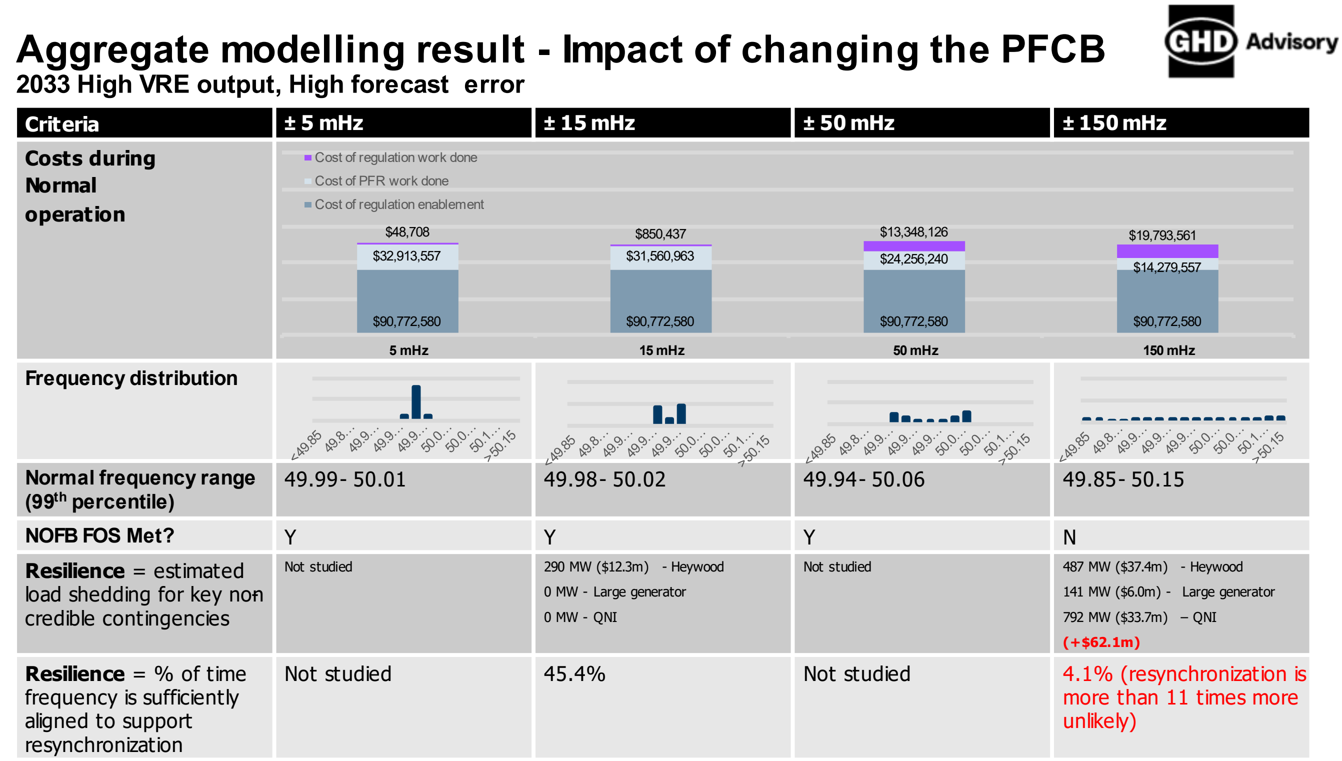


Aggregate modelling result - Impact of changing the PFCB

2022 High VRE output, High forecast error

Criteria	± 5 mHz	± 15 mHz	± 50 mHz	± 150 mHz
Costs during Normal operation				
Frequency distribution				
Normal frequency range (99th percentile)	49.98- 50.02	49.97- 50.03	49.94- 50.06	48.84- 50.16
NOFB FOS Met?	Y	Y	Y	N
Resilience = estimated load shedding for key non credible contingencies	Not studied	600 MW ($25.5m) Heywood	Not studied	880 MW ($37.4m) Heywood (+$11.9m)
Resilience = % of time frequency is sufficiently aligned to support resynchronization	Not studied	39%	Not studied	5.5% (resynchronization is more than 7 times more unlikely)

Figure 33 – Summary of modelling results for 2022 high VRE, high forecast error scenario



Aggregate modelling result - Impact of changing the PFCB

2033 High VRE output, High forecast error

Criteria	± 5 mHz	± 15 mHz	± 50 mHz	± 150 mHz
Costs during Normal operation				
Frequency distribution				
Normal frequency range (99th percentile)	49.99- 50.01	49.98- 50.02	49.94- 50.06	49.85- 50.15
NOFB FOS Met?	Y	Y	Y	N
Resilience = estimated load shedding for key non credible contingencies	Not studied	290 MW ($12.3m) - Heywood 0 MW - Large generator 0 MW - QNI	Not studied	487 MW ($37.4m) - Heywood 141 MW ($6.0m) - Large generator 792 MW ($33.7m) – QNI **(+$62.1m)**
Resilience = % of time frequency is sufficiently aligned to support resynchronization	Not studied	45.4%	Not studied	4.1% (resynchronization is more than 11 times more unlikely)

Figure 34 – Summary of modelling results for 2033 high VRE, high forecast error scenario

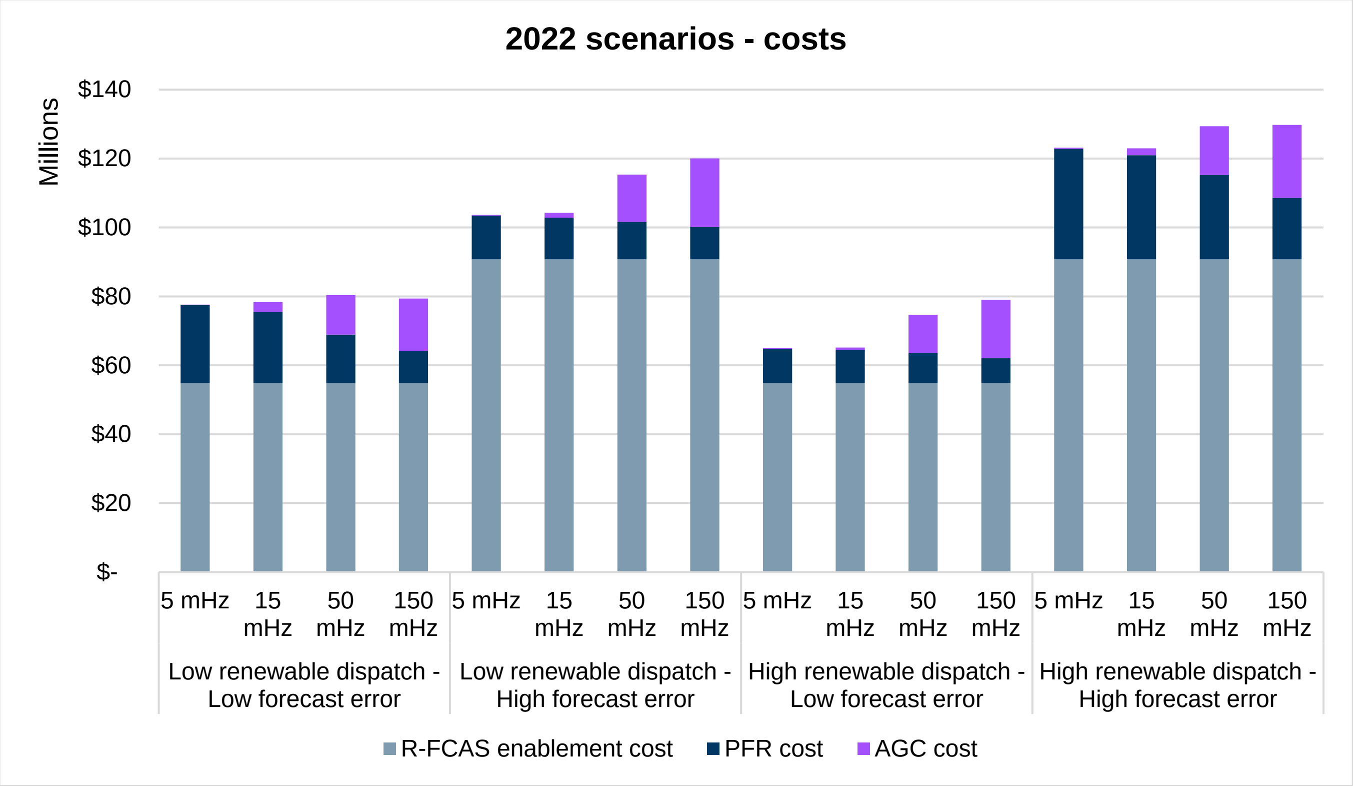


Figure 35 – Annualised costs – comparison of the lowest and highest variability scenario for 2022

The analysis undertaken shows that regardless of the assumptions around generation dispatch, the following conclusions hold.

- Widening the PFCB reduces the quality of frequency regulation and increases the risk that the frequency will move outside of the NFOB
- Widening the PFCB reduces the PFR response required from generation, reducing overall cost due to PFR.
- This reduction is offset due to increased utilisation of R-FCAS, which increases its work done to attempt to keep frequency close to 50 Hz.
- Widening the PFCB reduces the quality of frequency regulation, resulting in an overall reduction in power system resilience under contingency events.
- The reduction in power system resilience is a significant material cost in terms of increased risk of load shedding and unserved energy.
- Widening the PFCB also decreases the likelihood of successful resynchronisation in the case of islanding events, which could have further impacted on unserved energy, although this impact has not specifically been costed.

The analysis presented in this report demonstrates that while the total energy required to administer PFR is relatively small, the selection of the PFCB can impact generators, and consumers via system resiliency. The selection of the PFCB also impacts the ability to maintain frequency within the NOFB specified in the FOS. The optimal setting of a PFCB should consider the materiality of the costs attributable to generators relative to the costs of increased or decreased resilience of the power system. Based on the results of the analysis, there is no compelling reason to move away from the current PFCB in 2022, as there have been no substantial reductions in costs to consumers identified, and a significant reduction in power system resilience is observed as the PFCB is widened.

However, this analysis relies on historical pricing data to determine likely payments under the PFR incentives arrangements scheme. Due to the uncertainty in the future around the pricing of these payments, the impacts of the aggregate costs to administer a PFR requirement may change. On this basis, this could result in a need to review the PFCB setting after the PFR incentives scheme is implemented on the NEM, and more pricing data is available.

Appendices

Appendix A

Task 1a results

This appendix provides a complete set of all Task 1a modelling results, supplementing the results included in the body of the report.

A-1 Frequency distribution graphs 2022 – Low VRE – Medium forecast error

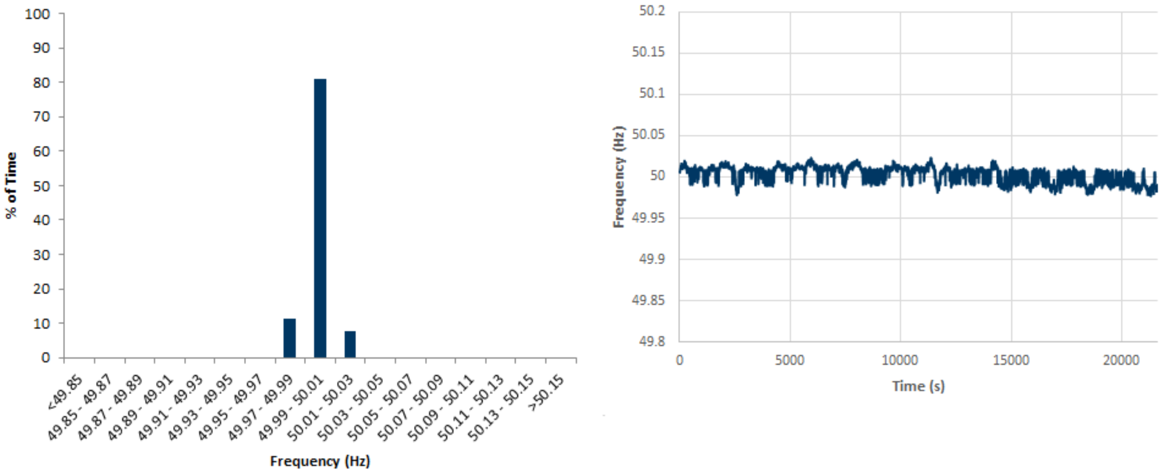


Figure 36 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 5 mHz deadband

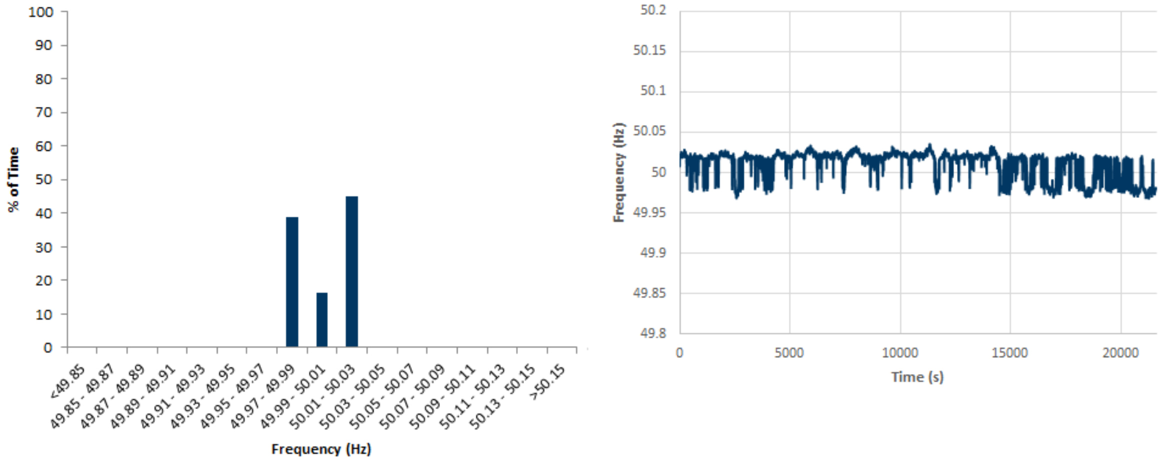


Figure 37 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 15 mHz deadband

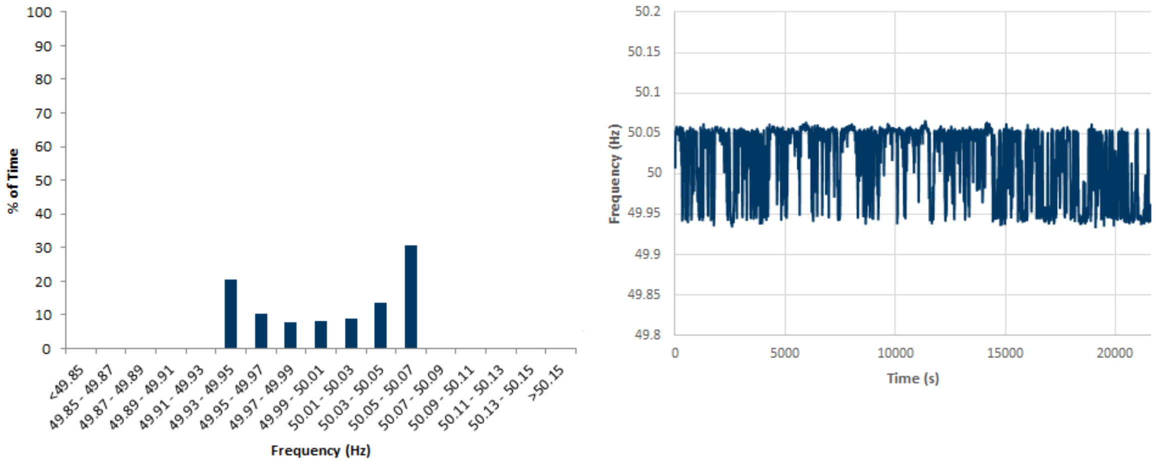


Figure 38 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 50 mHz deadband

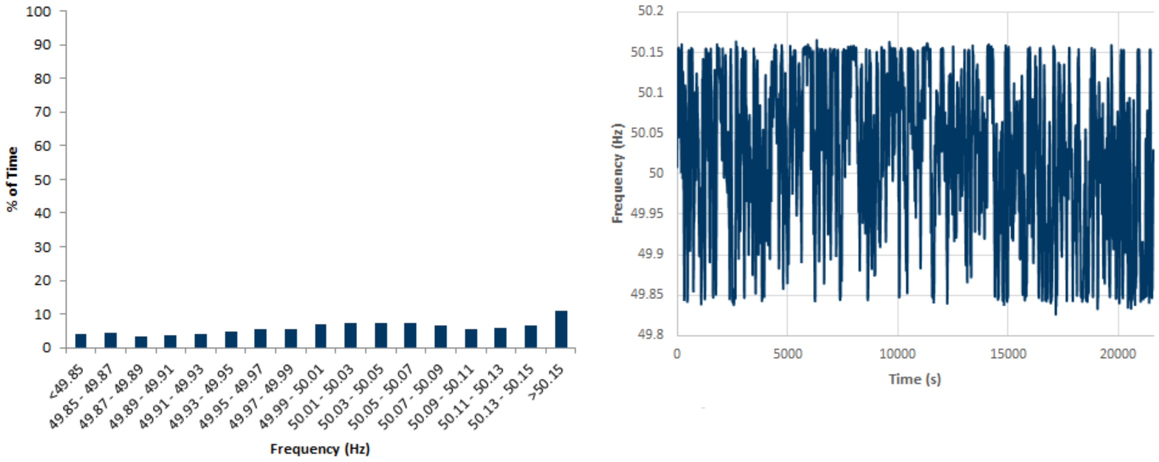


Figure 39 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 150 mHz deadband

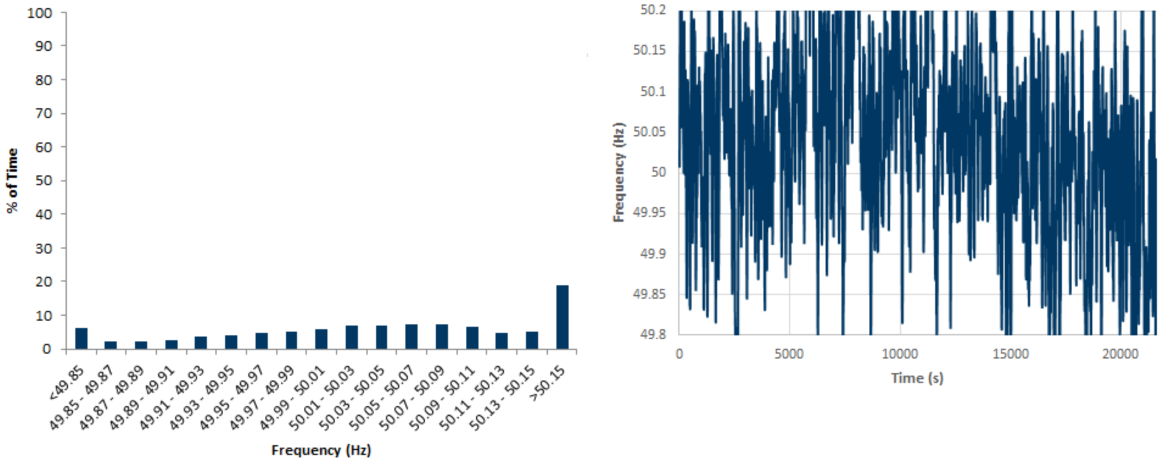


Figure 40 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 500 mHz deadband with no C-FCAS

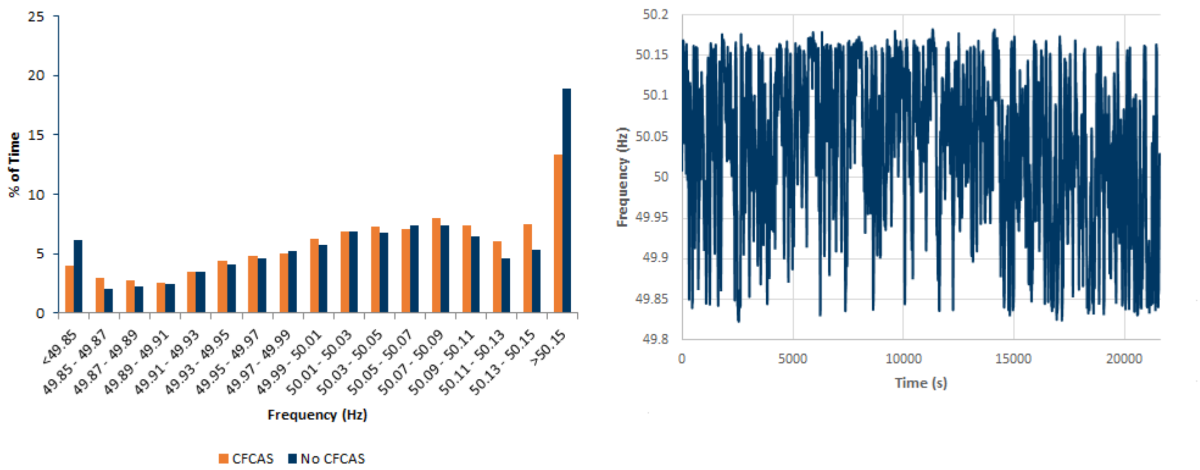


Figure 41 – Frequency distributions – Low VRE 2022 case – Medium forecast variability – 500 mHz deadband with and without-C-FCAS

A-2 Frequency distribution graphs 2022 – Low VRE – High forecast error

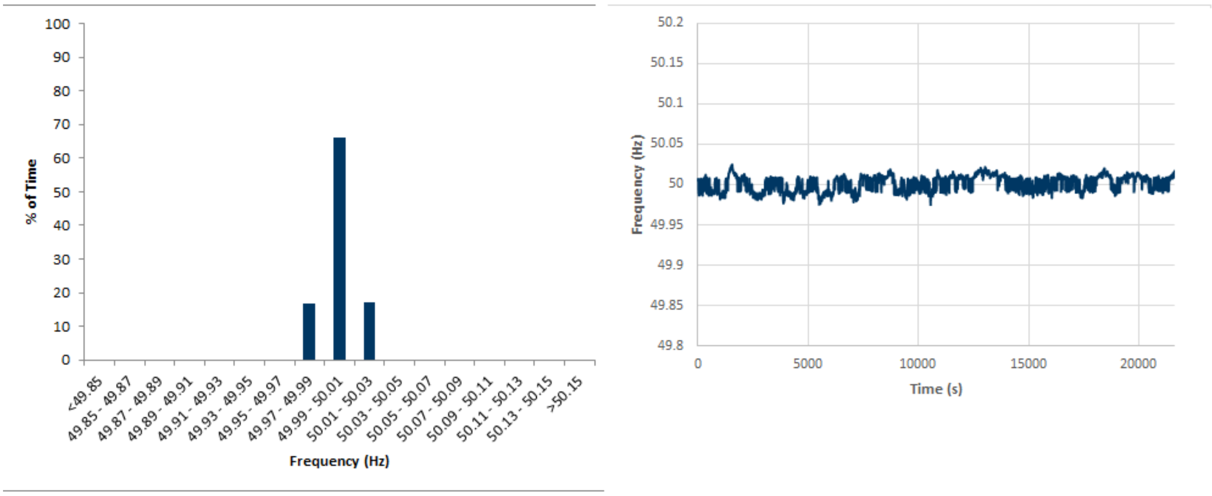


Figure 42 – Frequency distributions – Low VRE 2022 case – High forecast variability – 5 mHz deadband

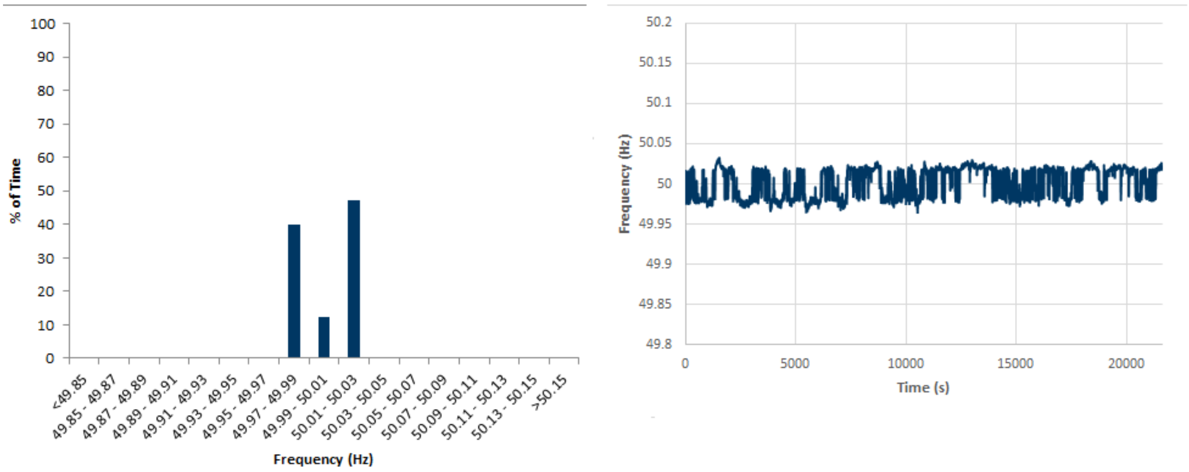


Figure 43 – Frequency distributions – Low VRE 2022 case – High forecast variability – 15 mHz deadband

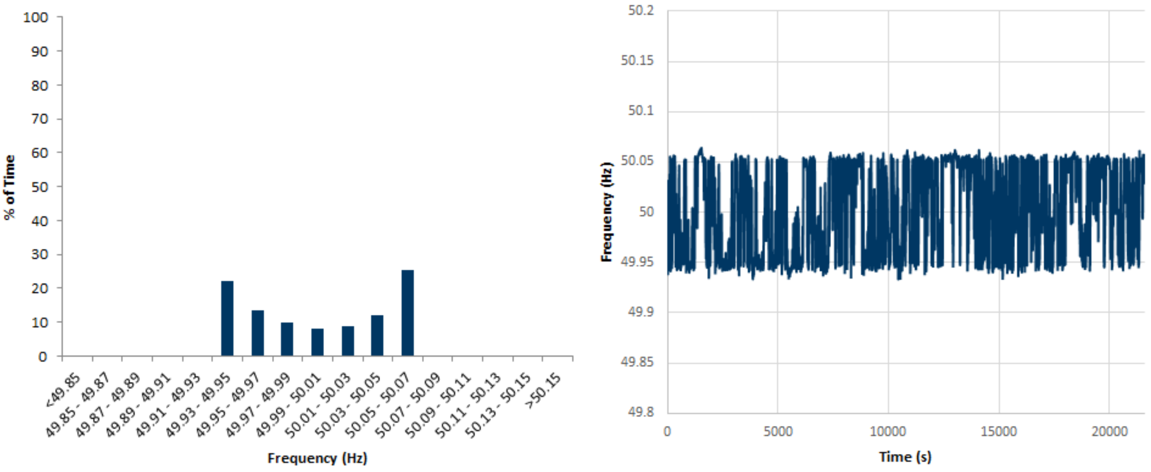


Figure 44 – Frequency distributions – Low VRE 2022 case – High forecast variability – 50 mHz deadband

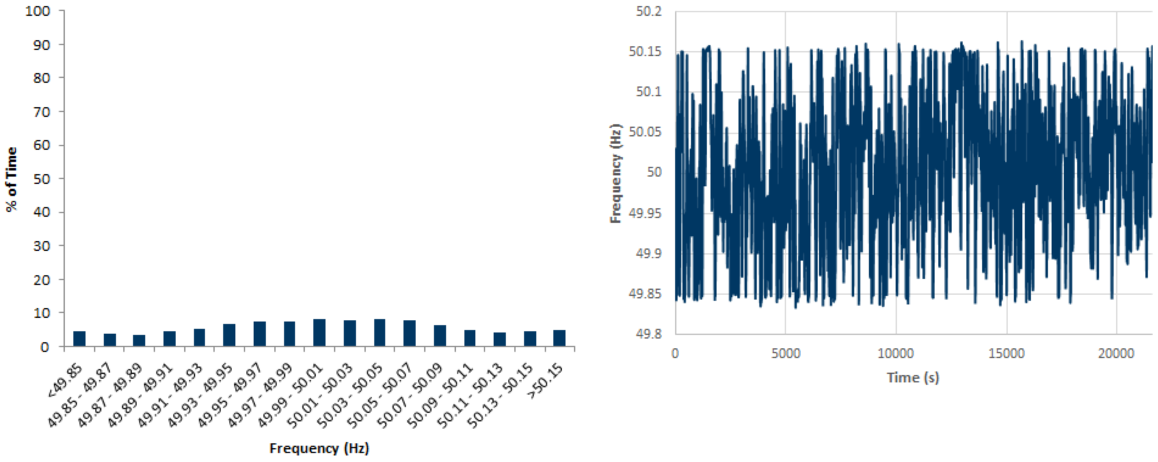


Figure 45 – Frequency distributions – Low VRE 2022 case – High forecast variability – 150 mHz deadband

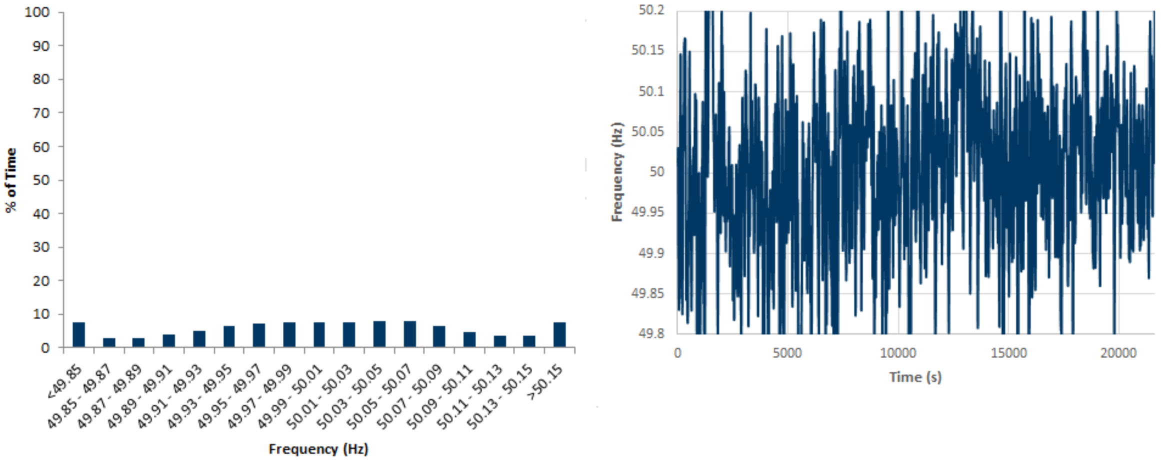


Figure 46 – Frequency distributions – Low VRE 2022 case – High forecast variability – 500 mHz deadband with no C-FCAS

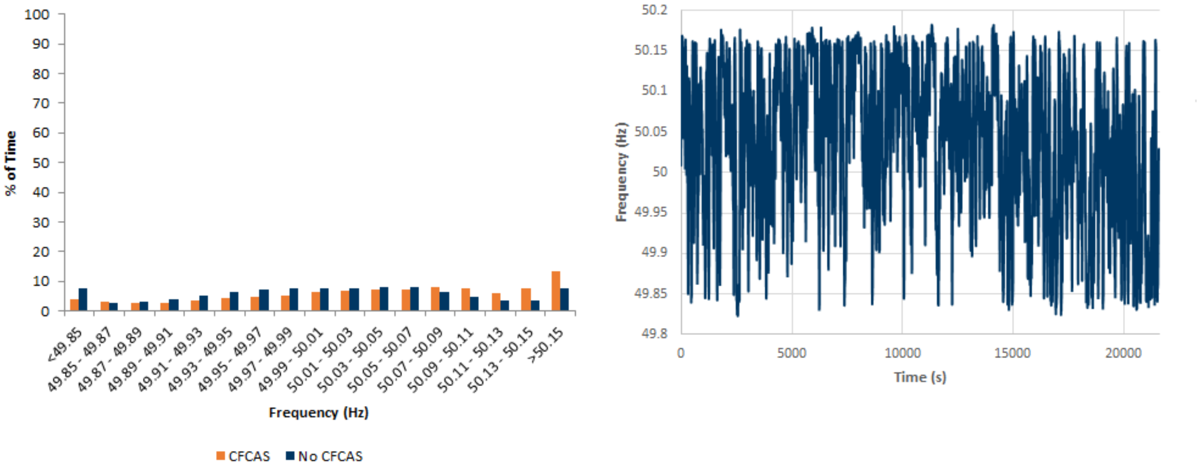


Figure 47 – Frequency distributions – Low VRE 2022 case – High forecast variability – 500 mHz deadband with and without-C- FCAS

A-3 Frequency distribution graphs 2022 – High VRE – Low forecast error

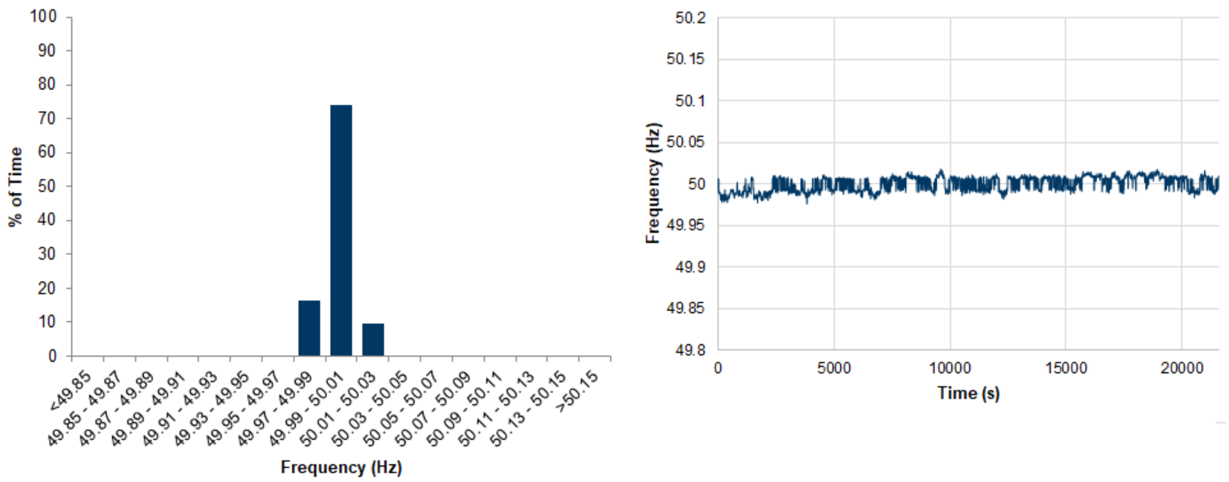


Figure 48 – Frequency distributions – High VRE 2022 case – Low forecast variability – 5 mHz deadband

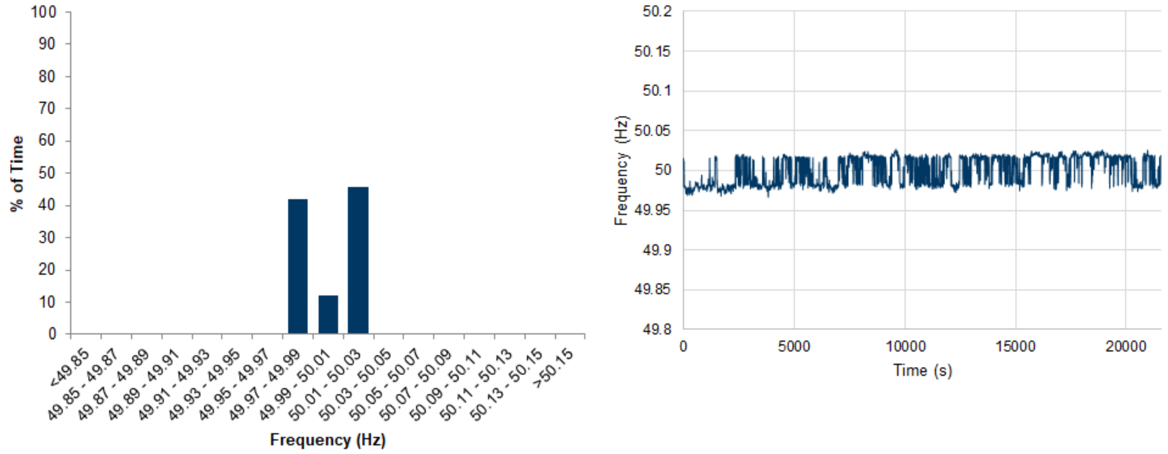


Figure 49 – Frequency distributions – High VRE 2022 case – Low forecast variability – 15 mHz deadband

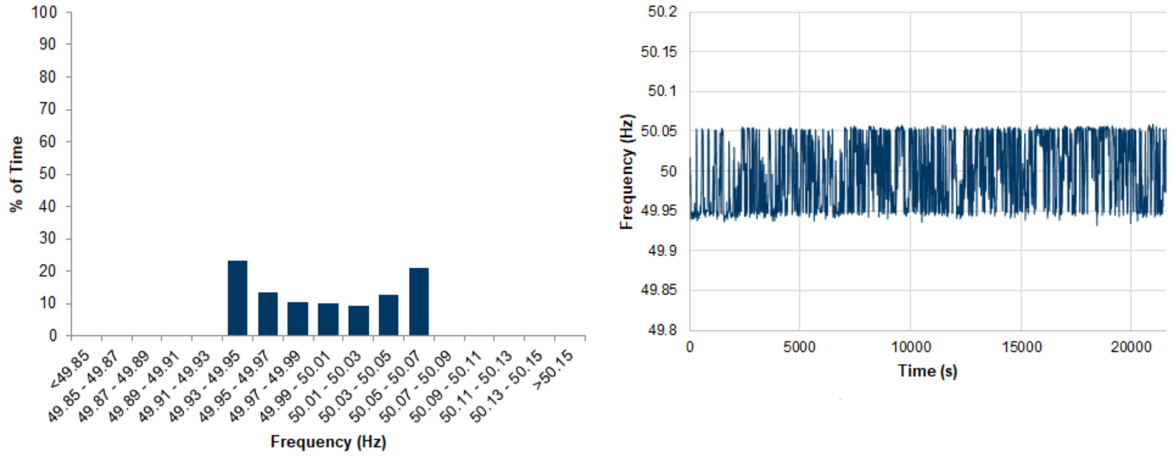


Figure 50 – Frequency distributions – High VRE 2022 case – Low forecast variability – 50 mHz deadband

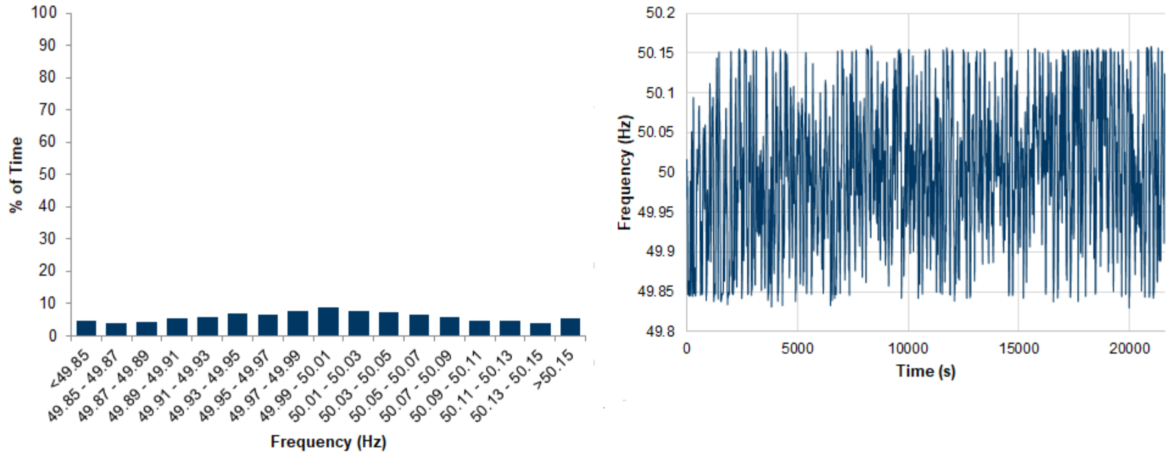


Figure 51 – Frequency distributions – High VRE 2022 case – Low forecast variability – 150 mHz deadband

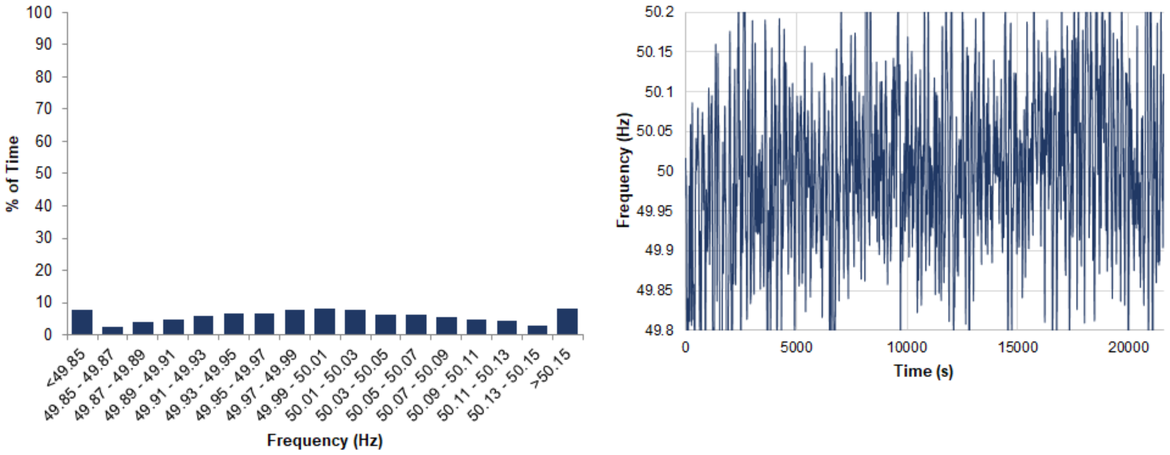


Figure 52 – Frequency distributions – High VRE 2022 case – Low forecast variability – 500 mHz deadband no C-FCAS

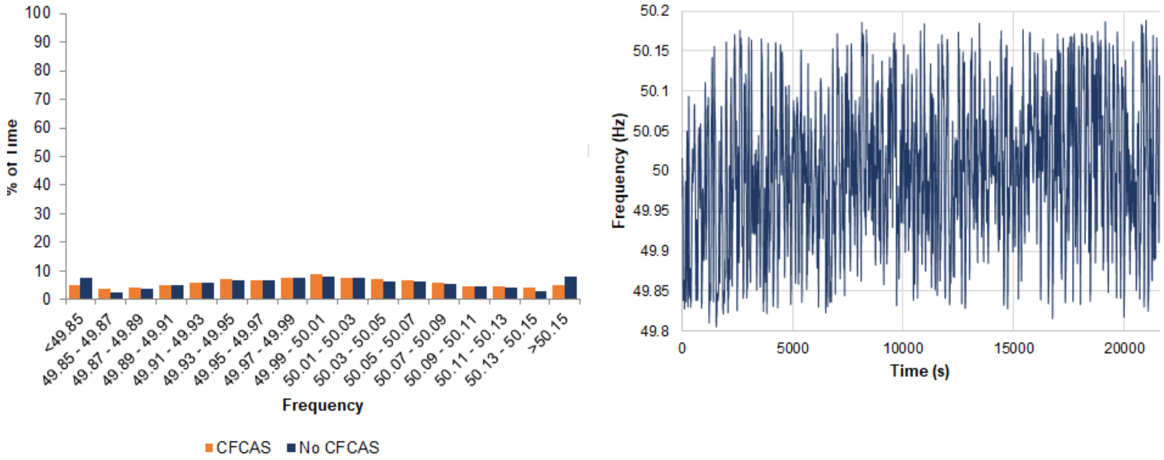


Figure 53 – Frequency distributions – High VRE 2022 case – Low forecast variability – 500 mHz deadband with and without-C-FCAS

A-4 Frequency distribution graphs 2022 – High VRE – Medium forecast error

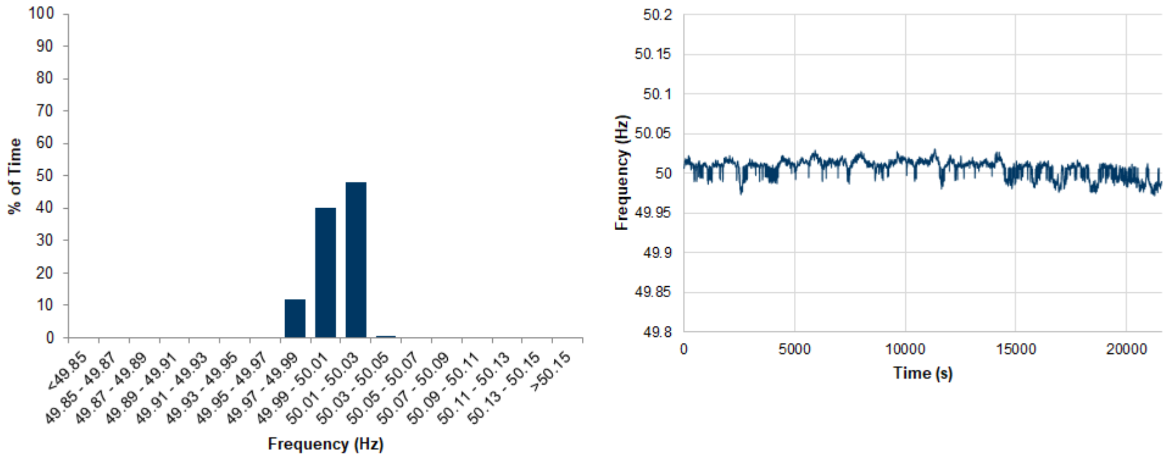


Figure 54 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 5 mHz deadband

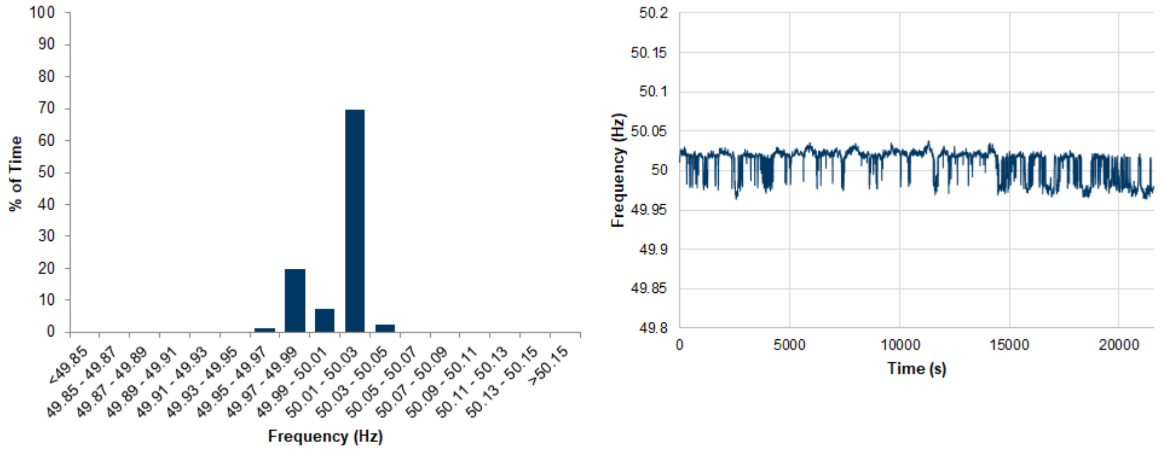


Figure 55 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 15 mHz deadband

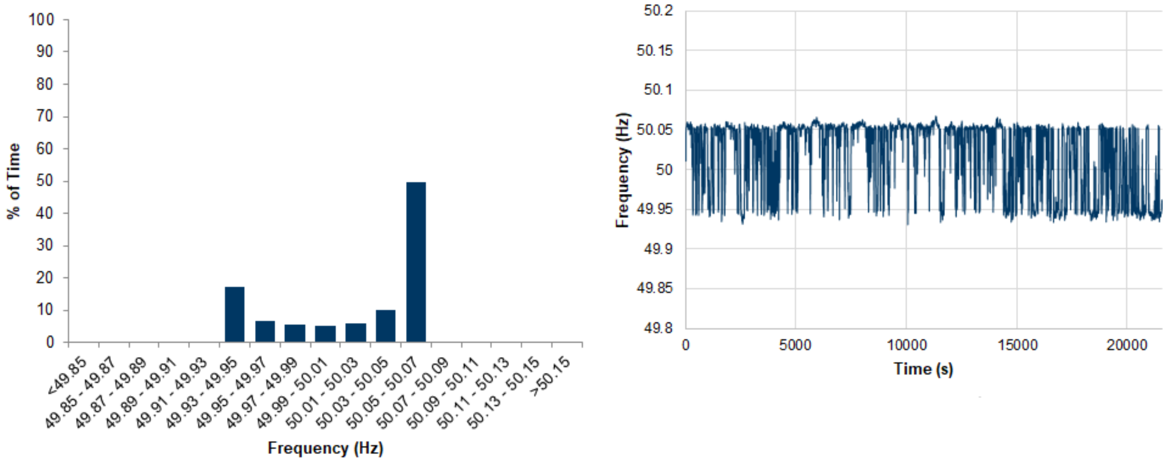


Figure 56 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 50 mHz deadband

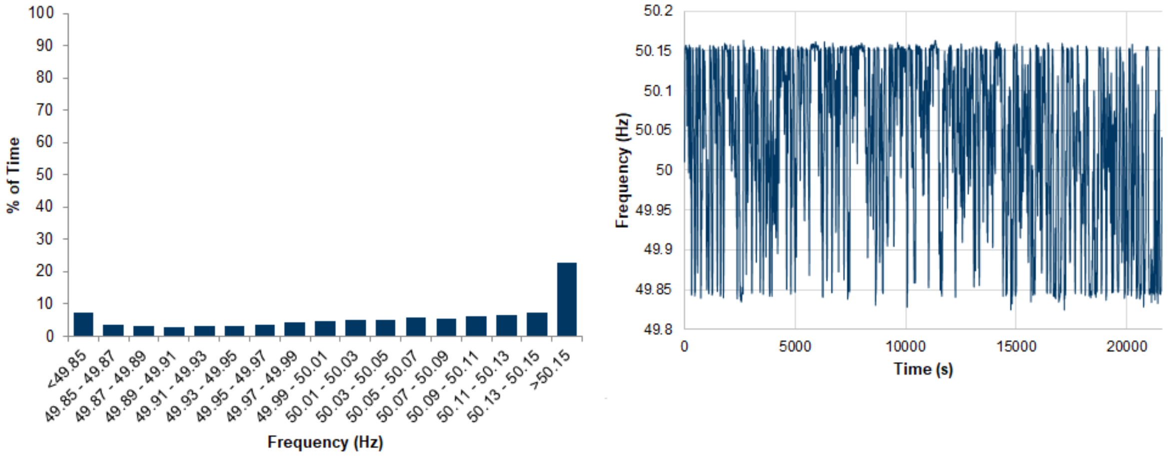


Figure 57 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 150 mHz deadband

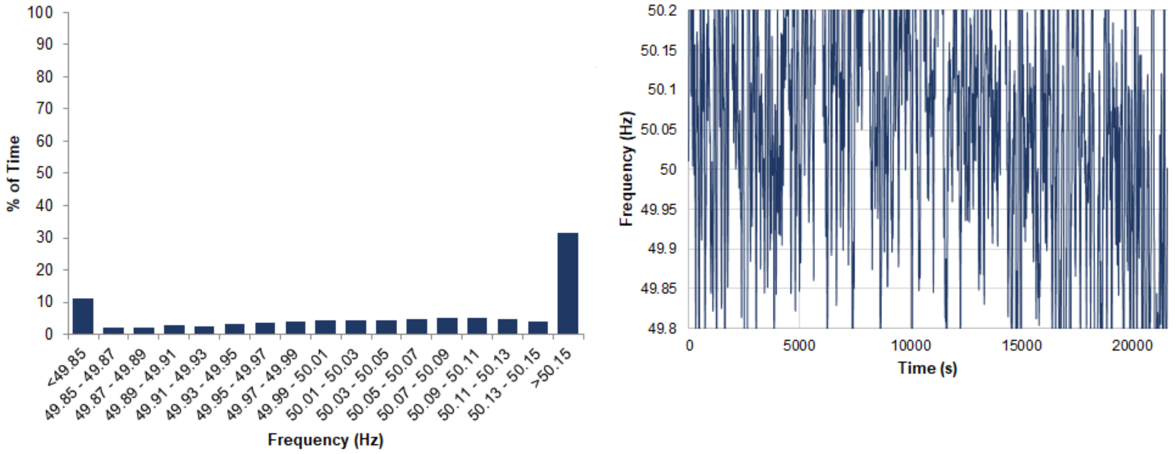


Figure 58 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 500 mHz deadband no C-FCAS

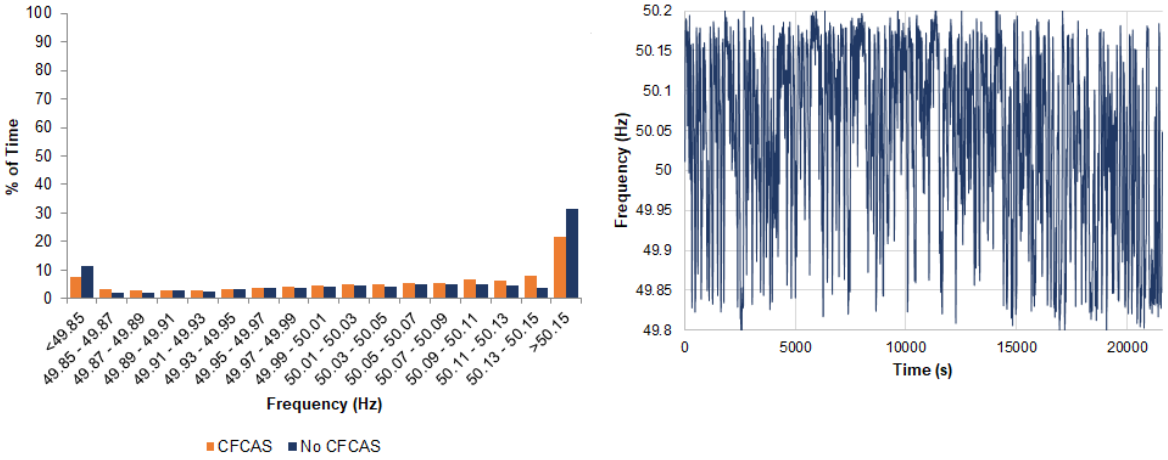


Figure 59 – Frequency distributions – High VRE 2022 case – Medium forecast variability – 500 mHz deadband with and without C-FCAS

A-5 Frequency distribution graphs 2022 – High VRE – High forecast error

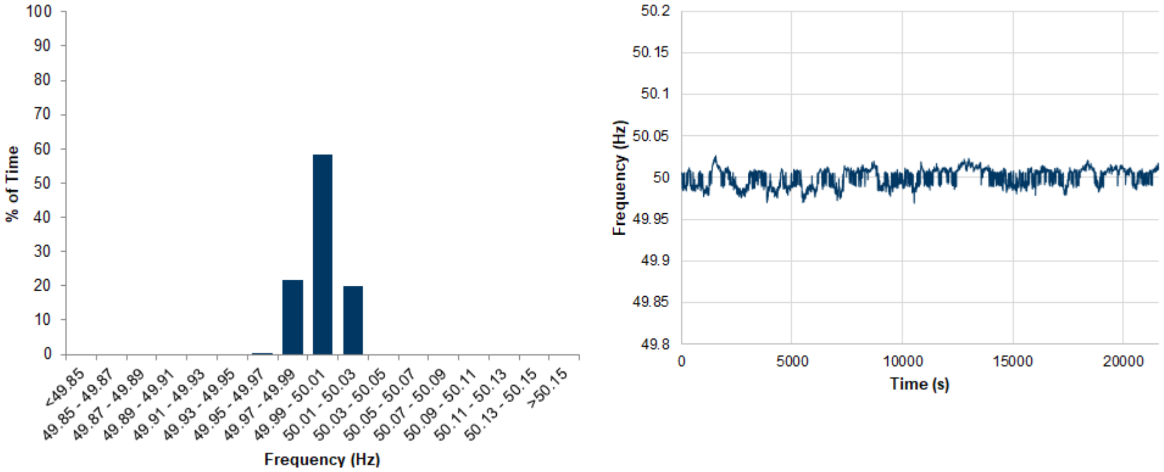


Figure 60 – Frequency distributions – High VRE 2022 case – High forecast variability – 5 mHz deadband

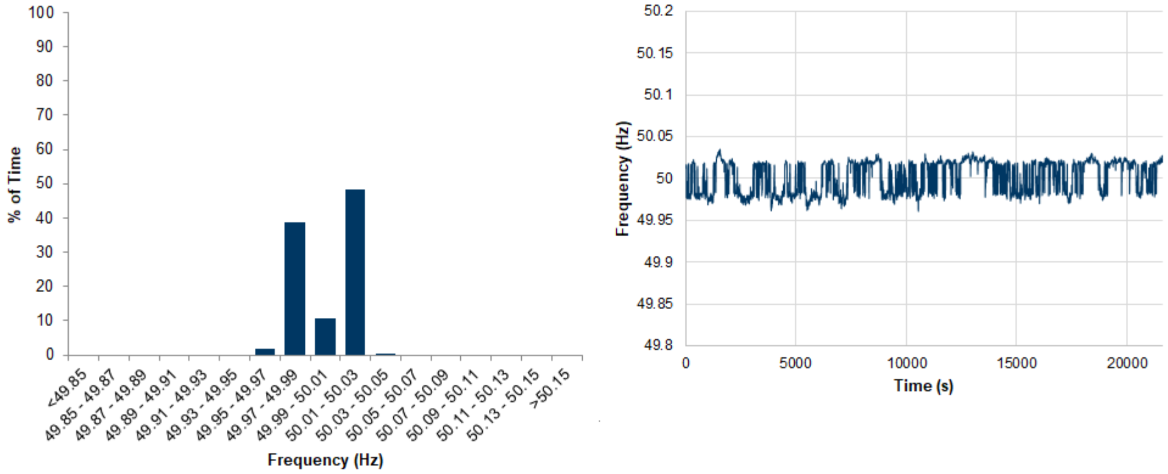


Figure 61 – Frequency distributions – High VRE 2022 case – High forecast variability – 15 mHz deadband

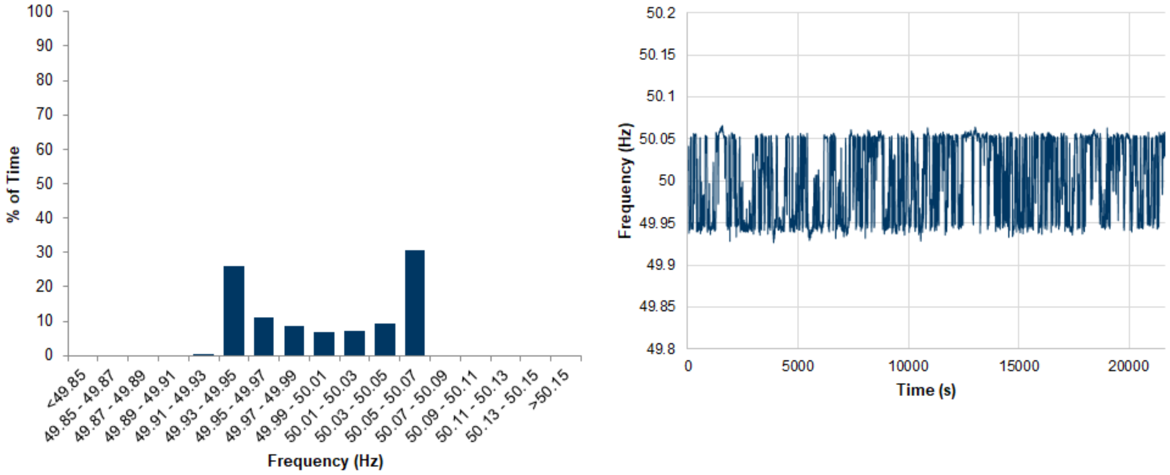


Figure 62 – Frequency distributions – High VRE 2022 case – High forecast variability – 50 mHz deadband

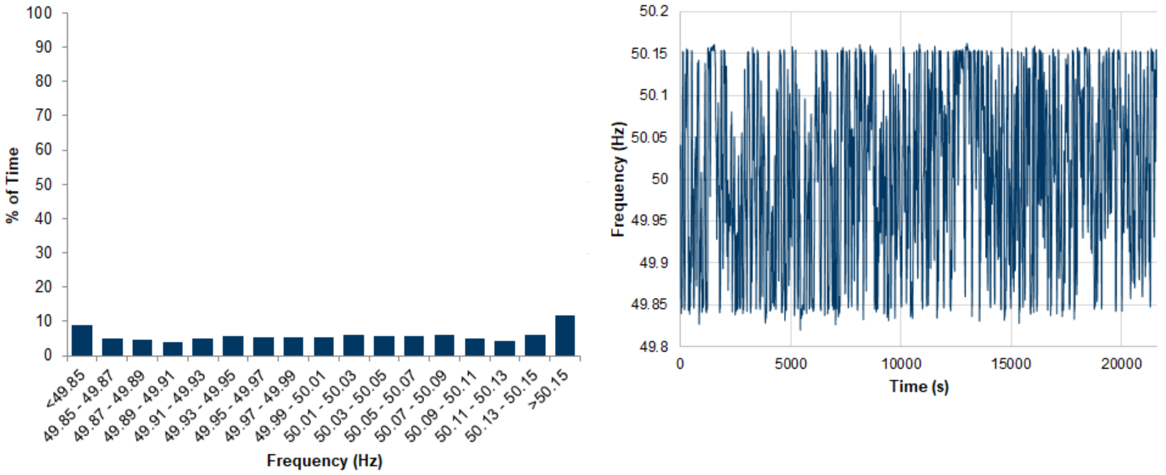


Figure 63 – Frequency distributions – High VRE 2022 case – High forecast variability – 150 mHz deadband

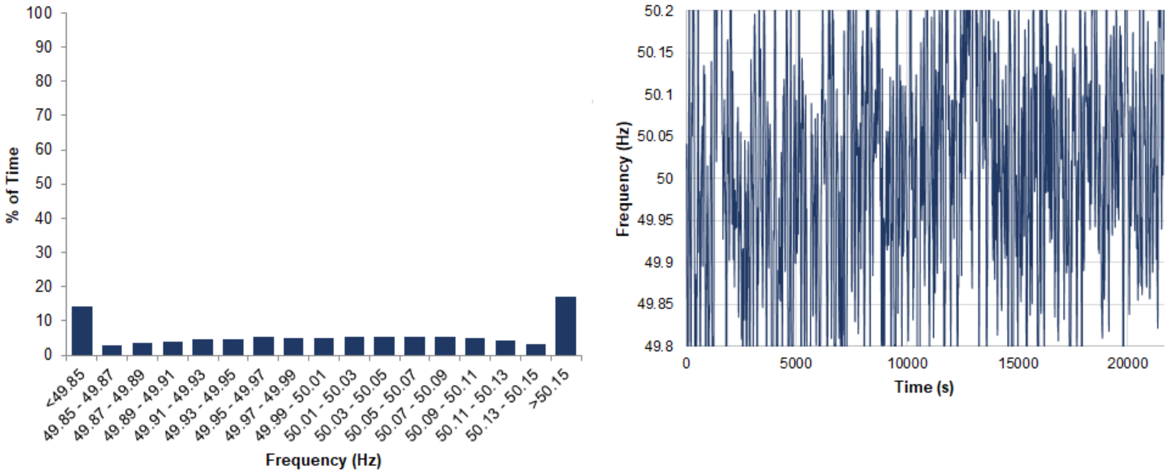


Figure 64 – Frequency distributions – High VRE 2022 case – High forecast variability – 500 mHz deadband no C-FCAS

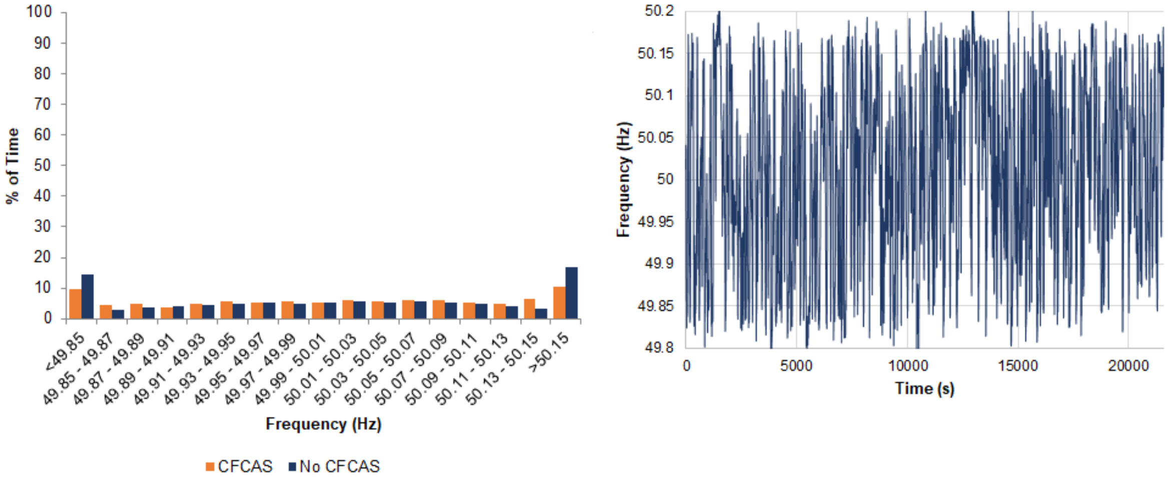


Figure 65 – Frequency distributions – High VRE 2022 case – High forecast variability – 500 mHz deadband with and without C-FCAS

A-6 Frequency distribution graphs 2033 – High VRE – Low forecast error

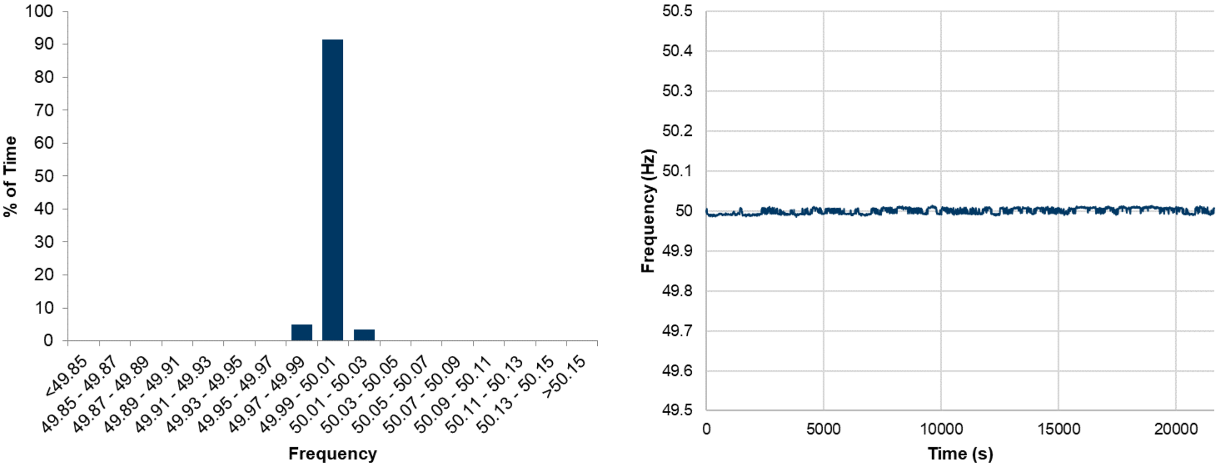


Figure 66 – Frequency distributions – High VRE 2033 case – Low forecast variability – 5 mHz

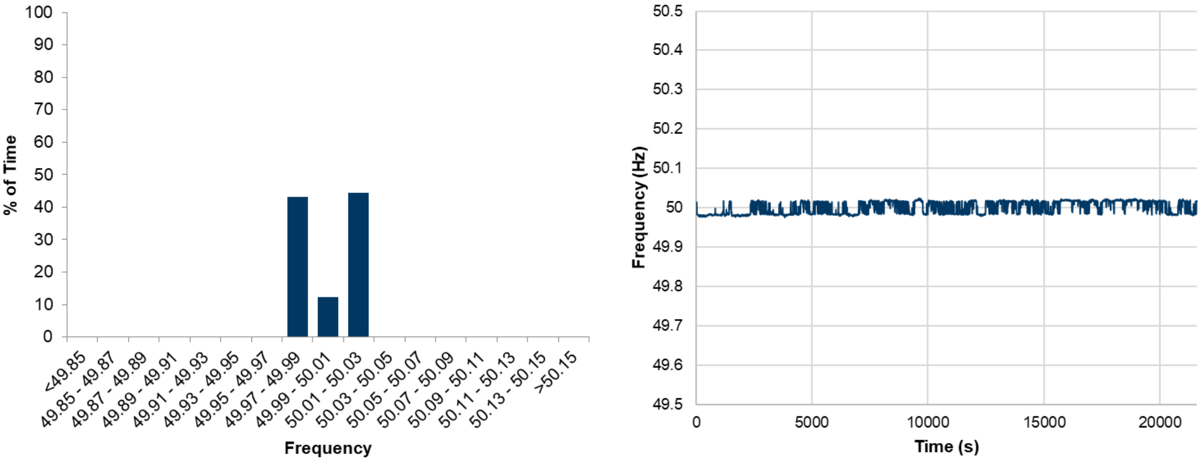


Figure 67 – Frequency distributions – High VRE 2033 case – Low forecast variability – 15 mHz

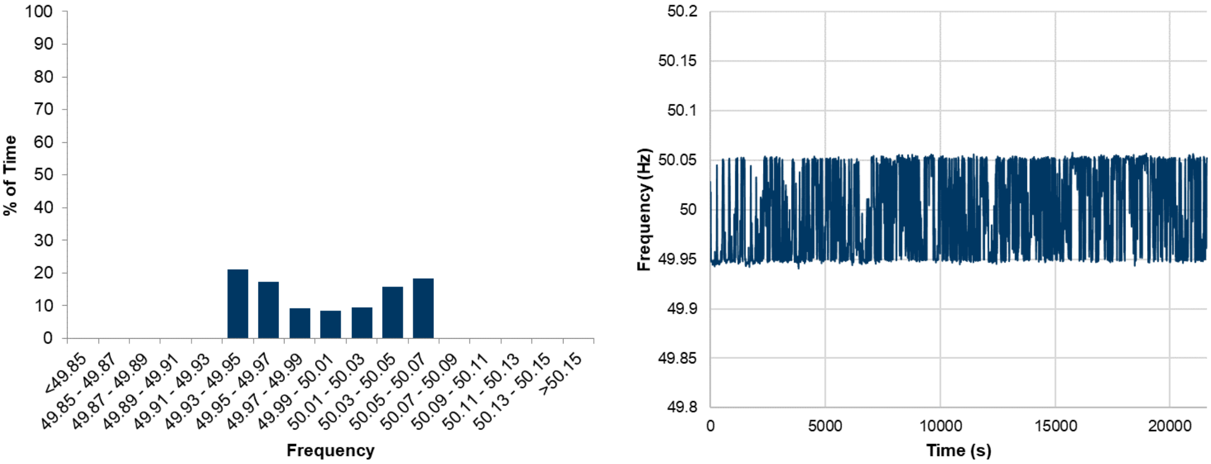


Figure 68 – Frequency distributions – High VRE 2033 case – Low forecast variability – 50 mHz

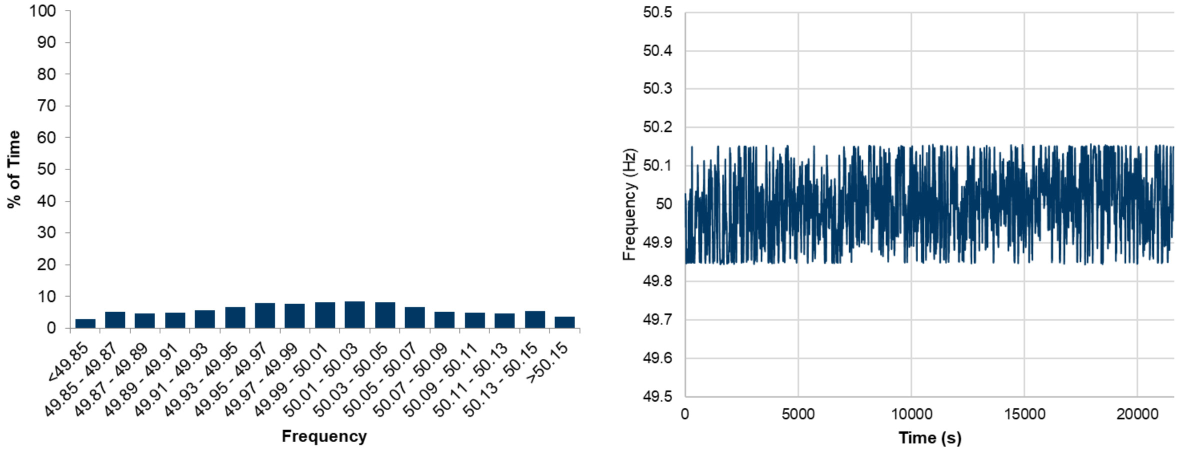


Figure 69 – Frequency distributions – High VRE 2033 case – Low forecast variability – 150 mHz

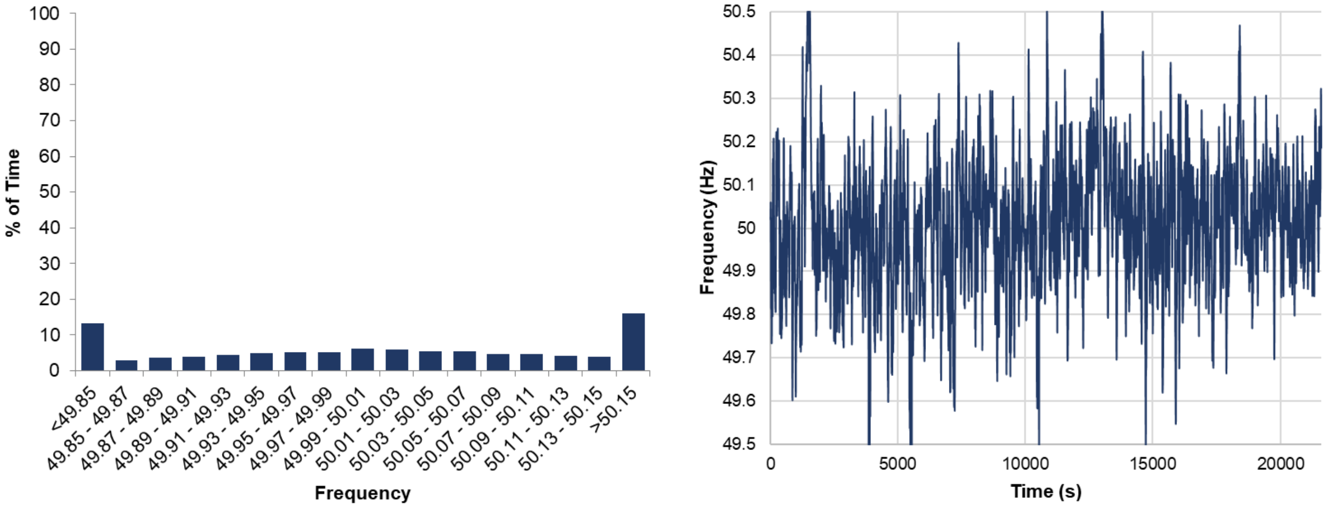


Figure 70 – Frequency distributions – High VRE 2033 case – Low forecast variability – 500 mHz deadband no C-FCAS

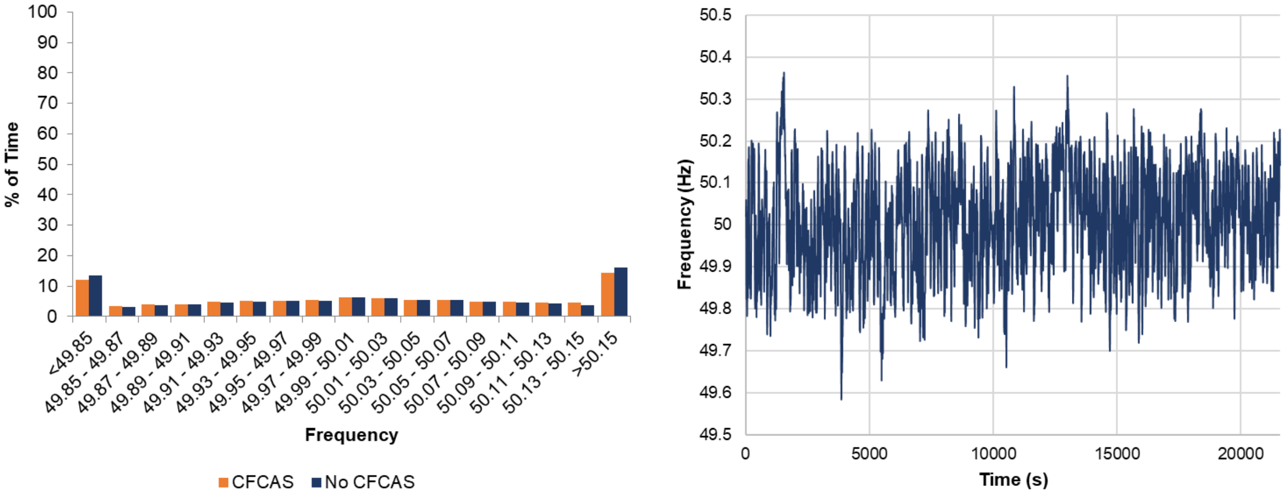


Figure 71 – Frequency distributions – High VRE 2033 case – Low forecast variability – 500 mHz deadband with and without C-FCAS

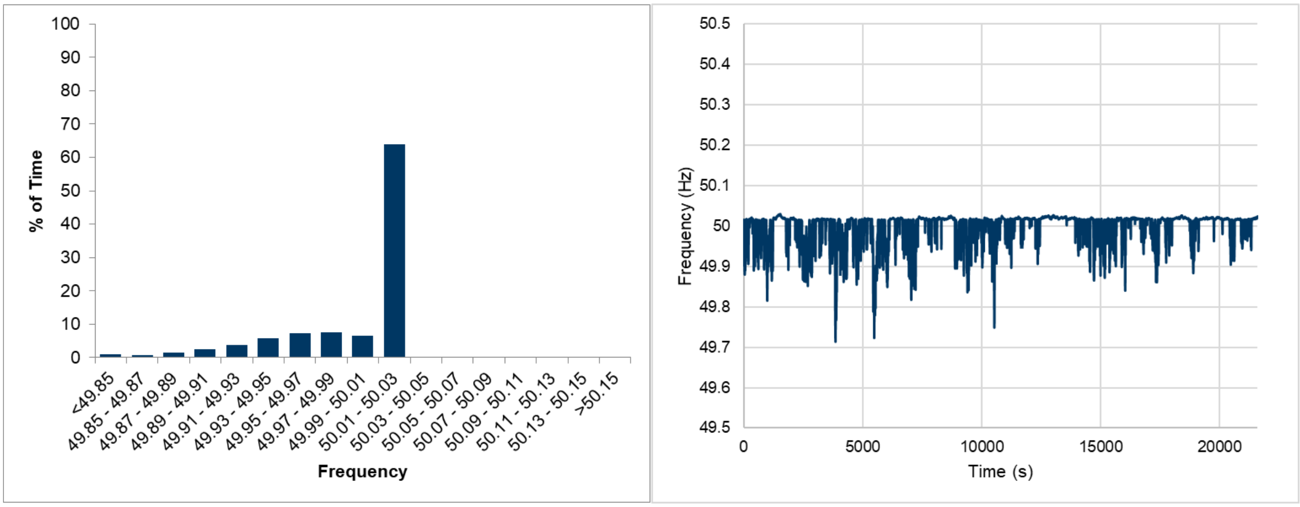


Figure 72 – Frequency distributions – High VRE 2033 case – Low forecast variability – 15 mHz with 50% non-responsive

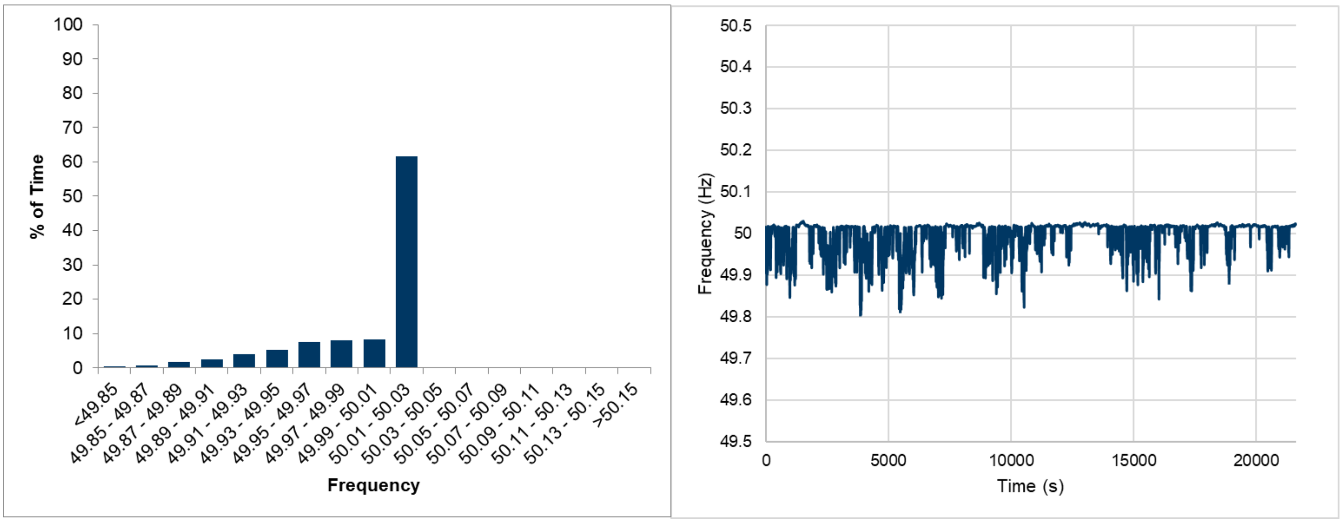


Figure 73 – Frequency distributions – High VRE 2033 case – Low forecast variability – 30% of PFR providers have 15 mHz deadbands and 70% have 150 mHz deadbands

A-7 Frequency distribution graphs 2033 – High VRE – Medium forecast error

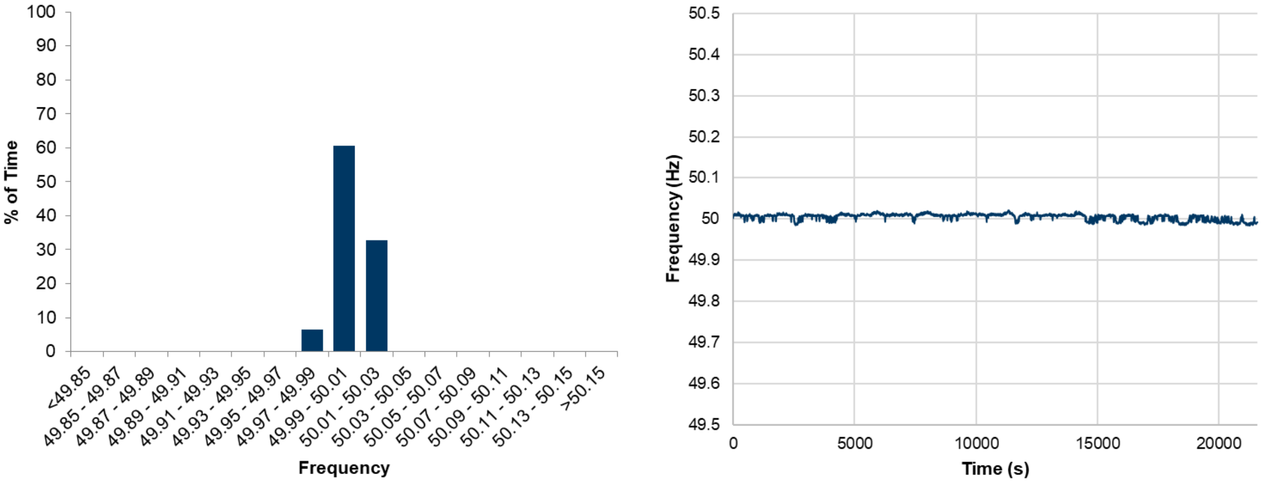


Figure 74 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 5 mHz

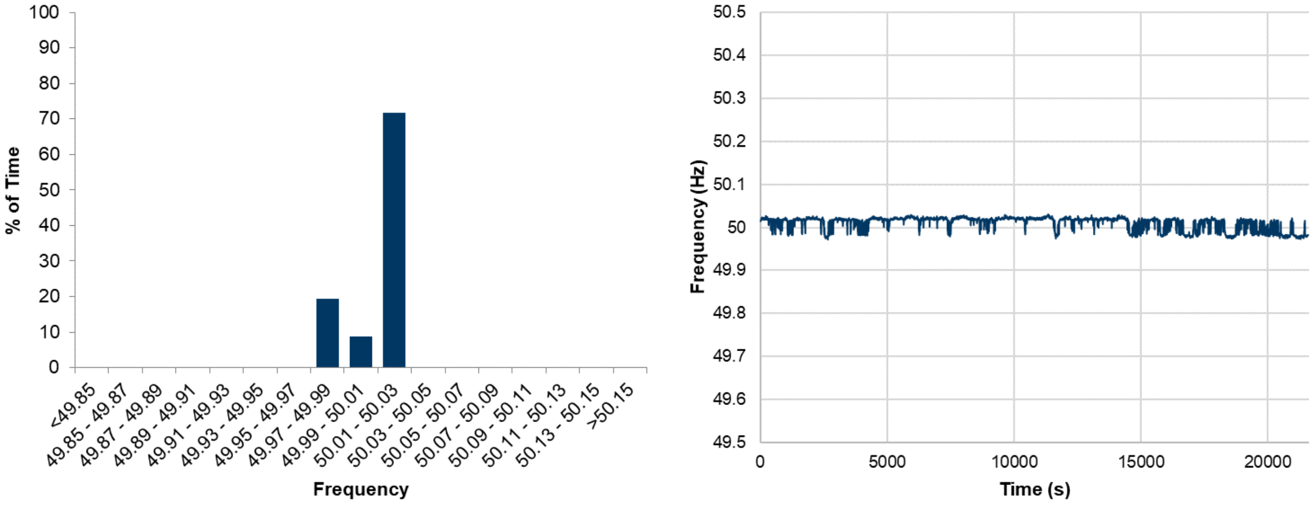


Figure 75 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 15 mHz

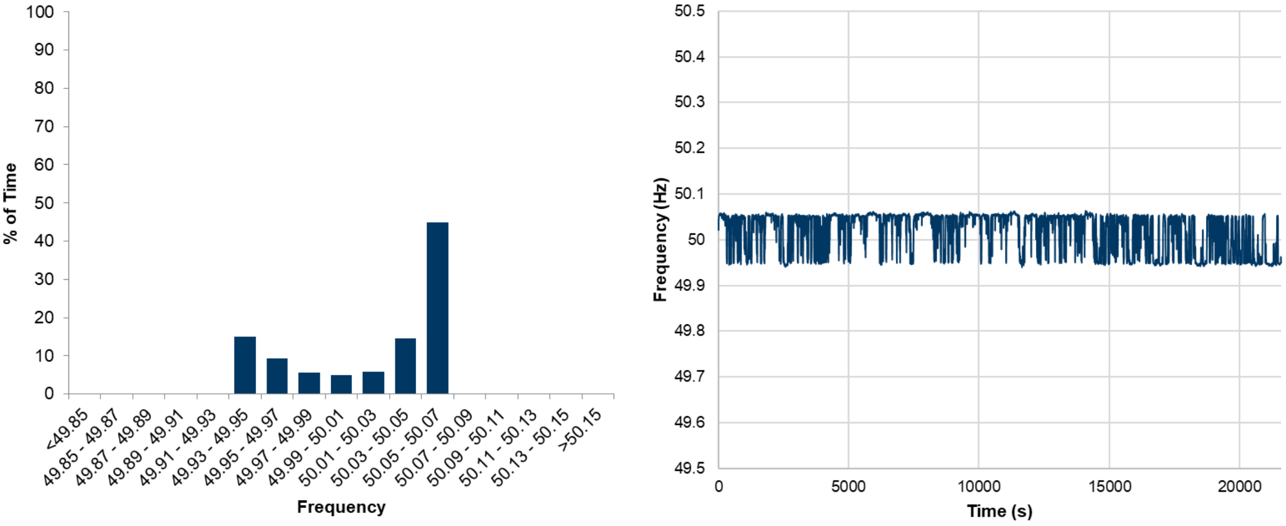


Figure 76 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 50 mHz

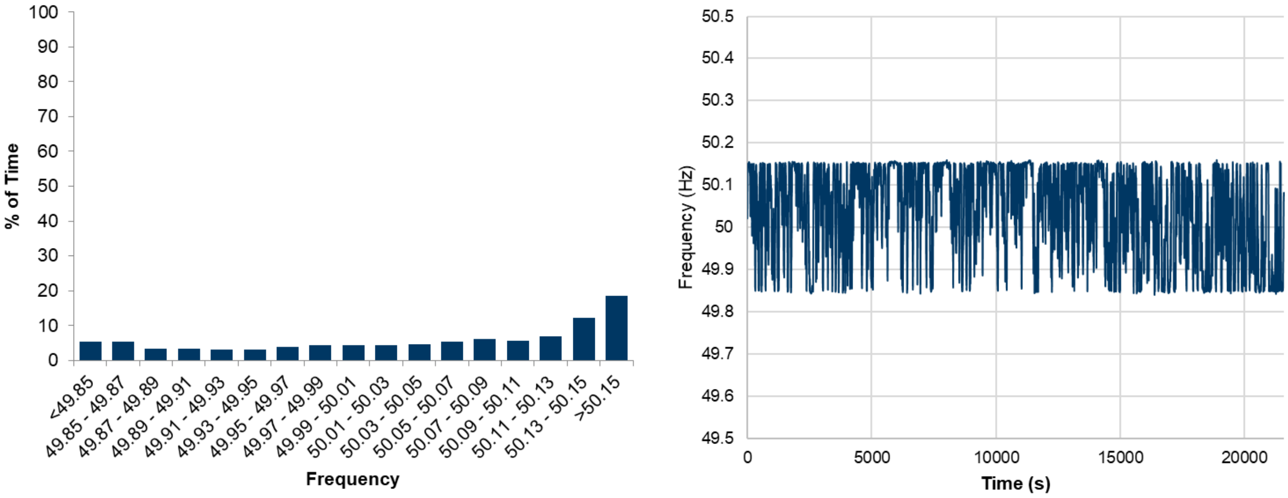


Figure 77 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 150 mHz

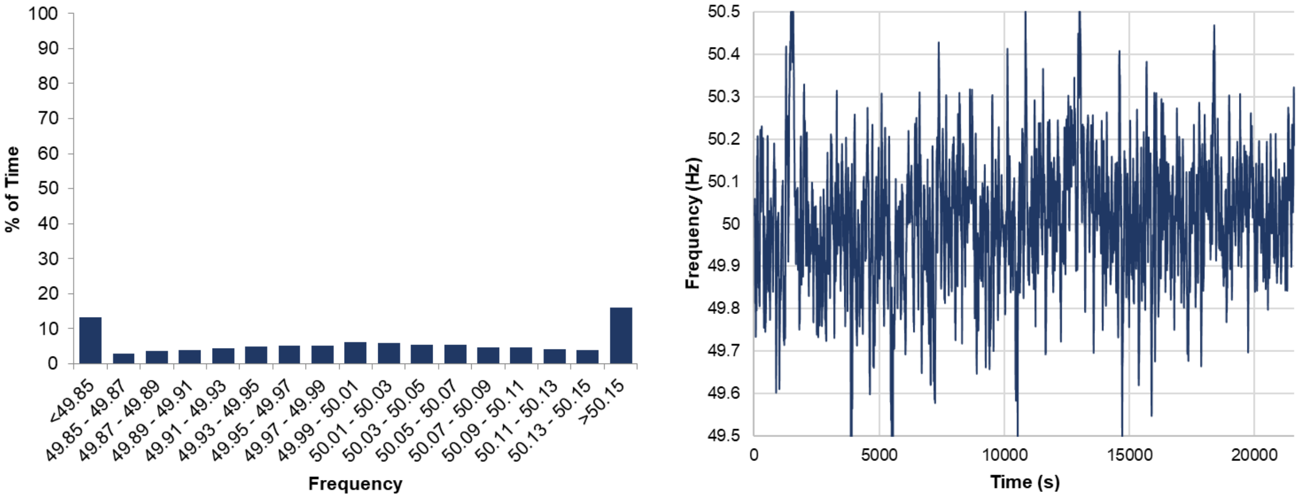


Figure 78 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 500 mHz deadband no C-FCAS

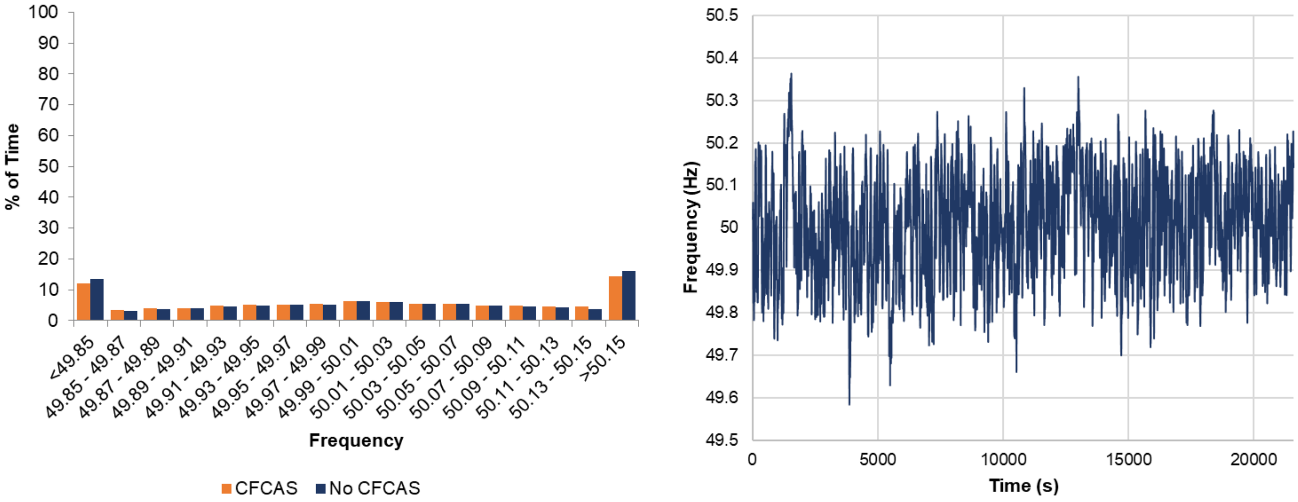


Figure 79 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 500 mHz deadband with and without C-FCAS

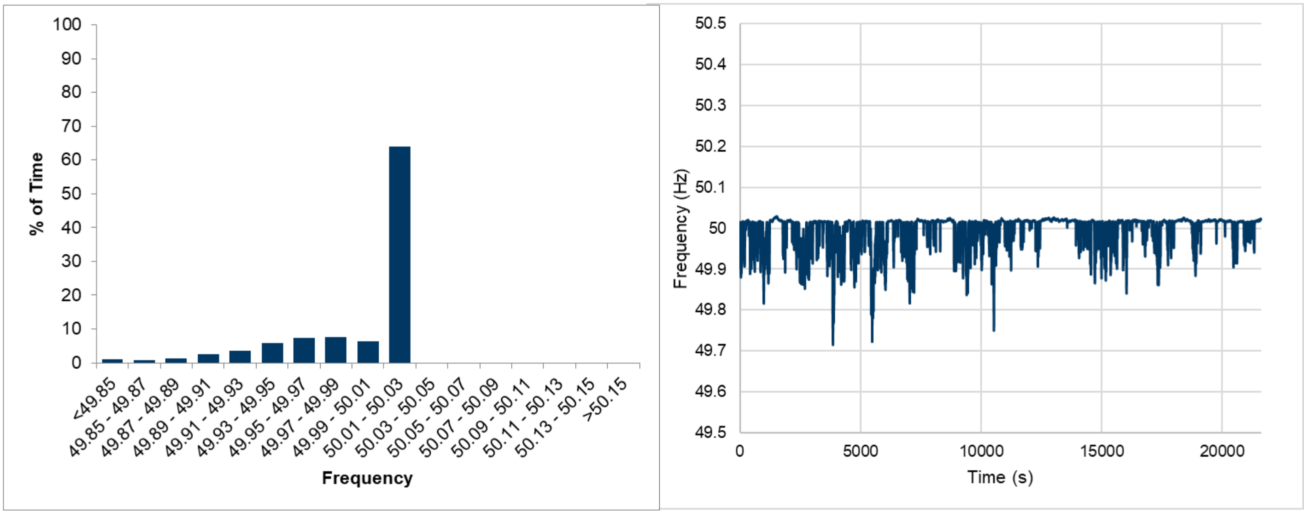


Figure 80 – Frequency distributions – High VRE 2033 case – Medium forecast variability – 15 mHz with 50% non-responsive

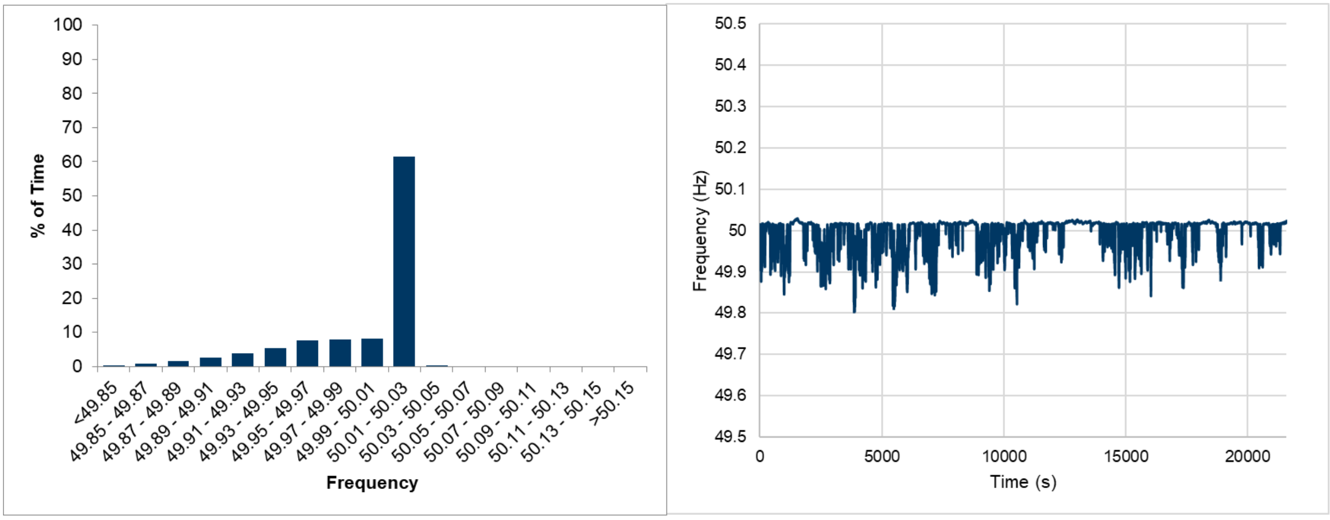


Figure 81 – Frequency distributions – High VRE 2033 case – Medium forecast variability – – 30% of PFR providers have 15 mHz deadbands and 70% have 150 mHz deadbands

A-8 Frequency distribution graphs 2033 – High VRE – High forecast error

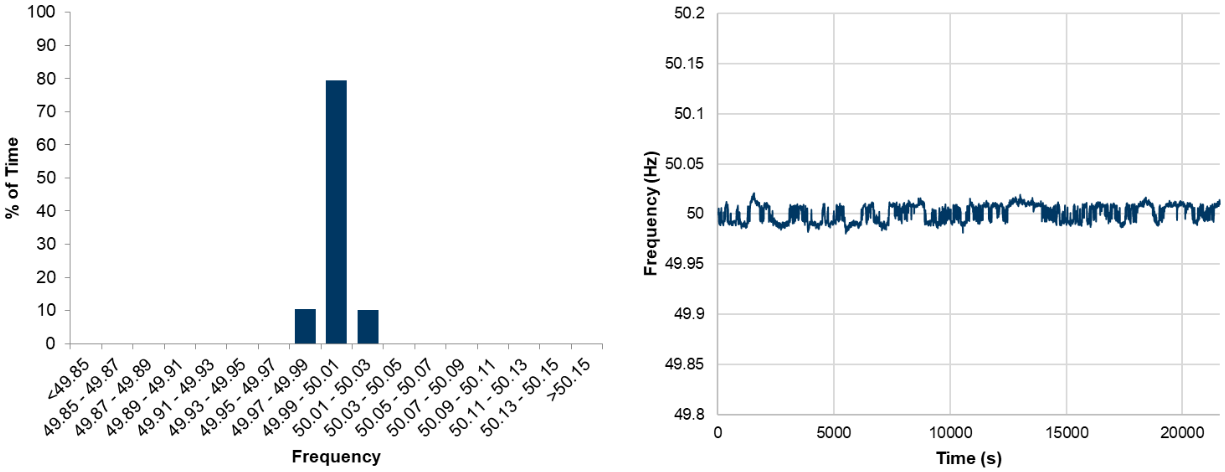


Figure 82 – Frequency distributions – High VRE 2033 case – High forecast variability – 5 mHz

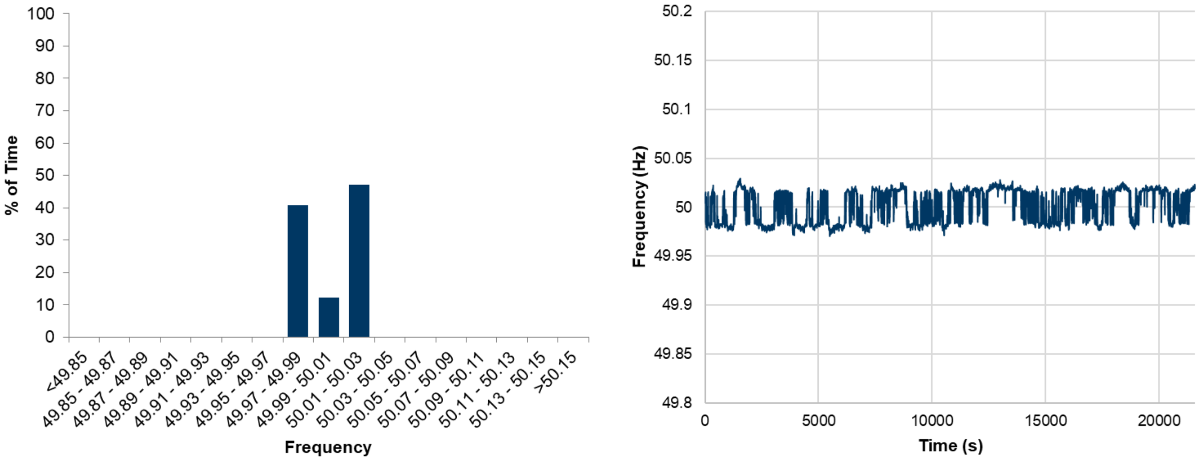


Figure 83 – Frequency distributions – High VRE 2033 case – High forecast variability –15 mHz

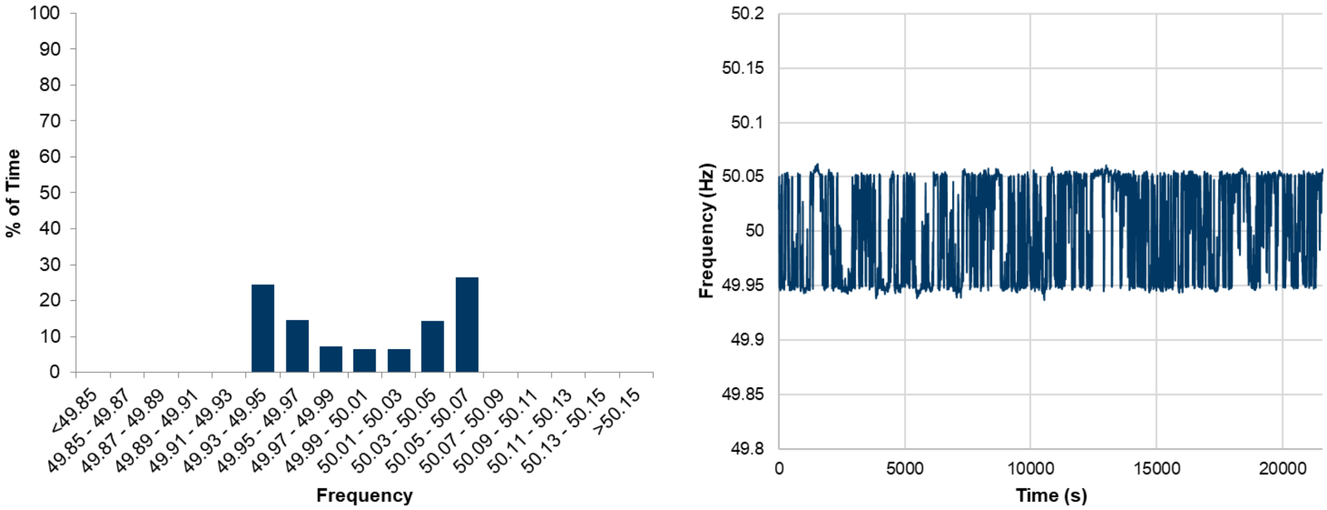


Figure 84 – Frequency distributions – High VRE 2033 case – High forecast variability – 50 mHz

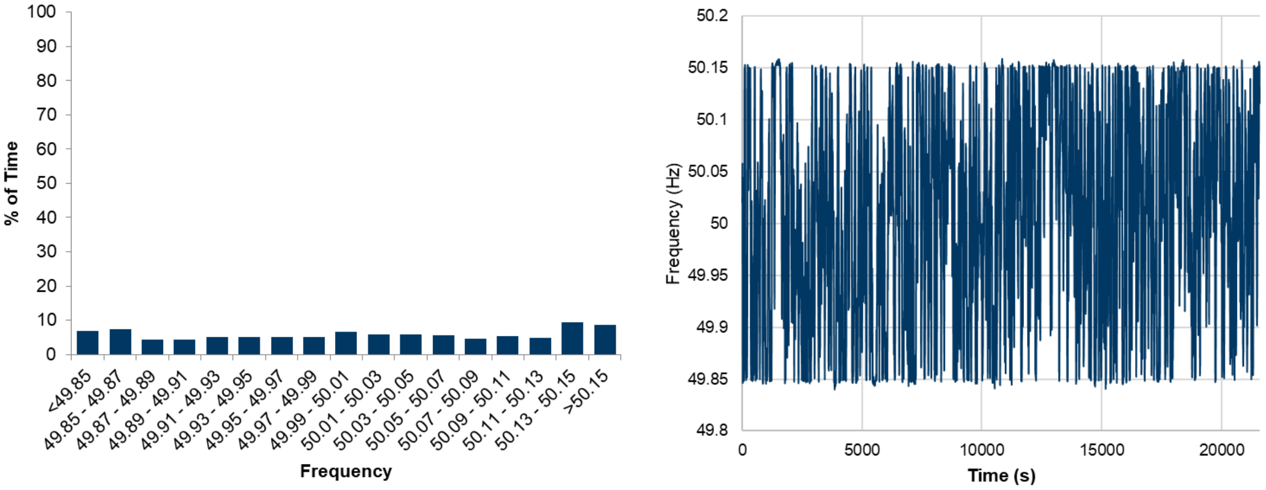


Figure 85 – Frequency distributions – High VRE 2033 case – High forecast variability – 150 mHz

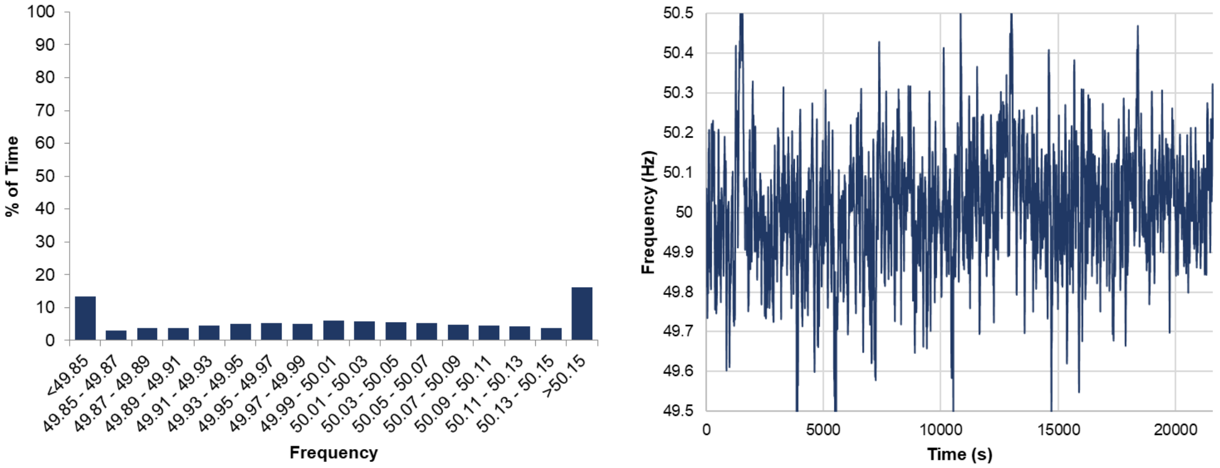


Figure 86 – Frequency distributions – High VRE 2033 case – High forecast variability – 500 mHz deadband no C-FCAS

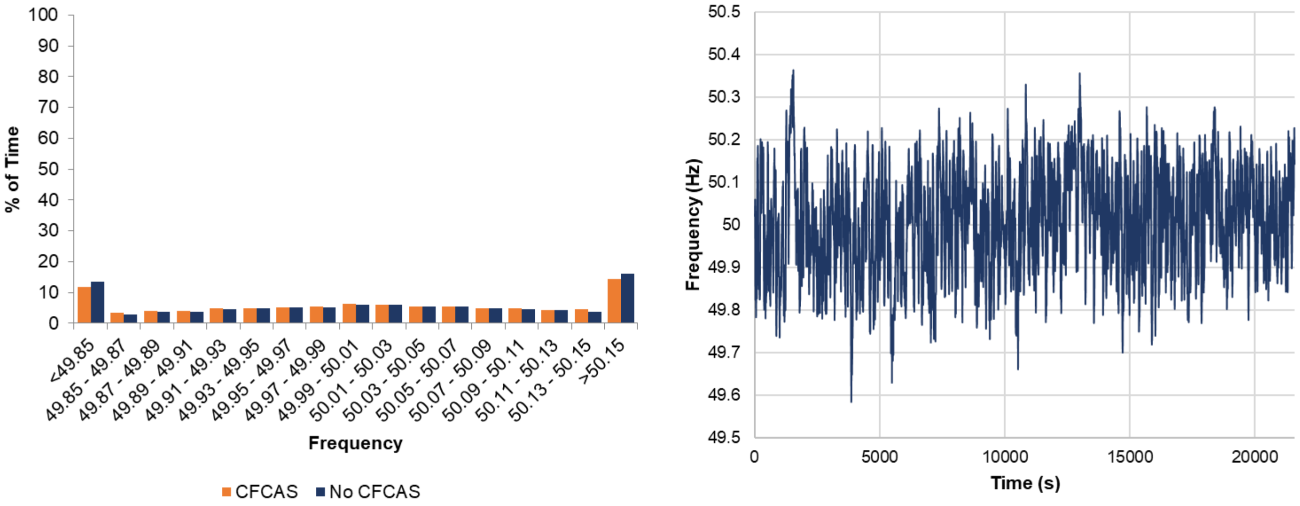


Figure 87 – Frequency distributions – High VRE 2033 case – High forecast variability – 500 mHz deadband with and without C-FCAS

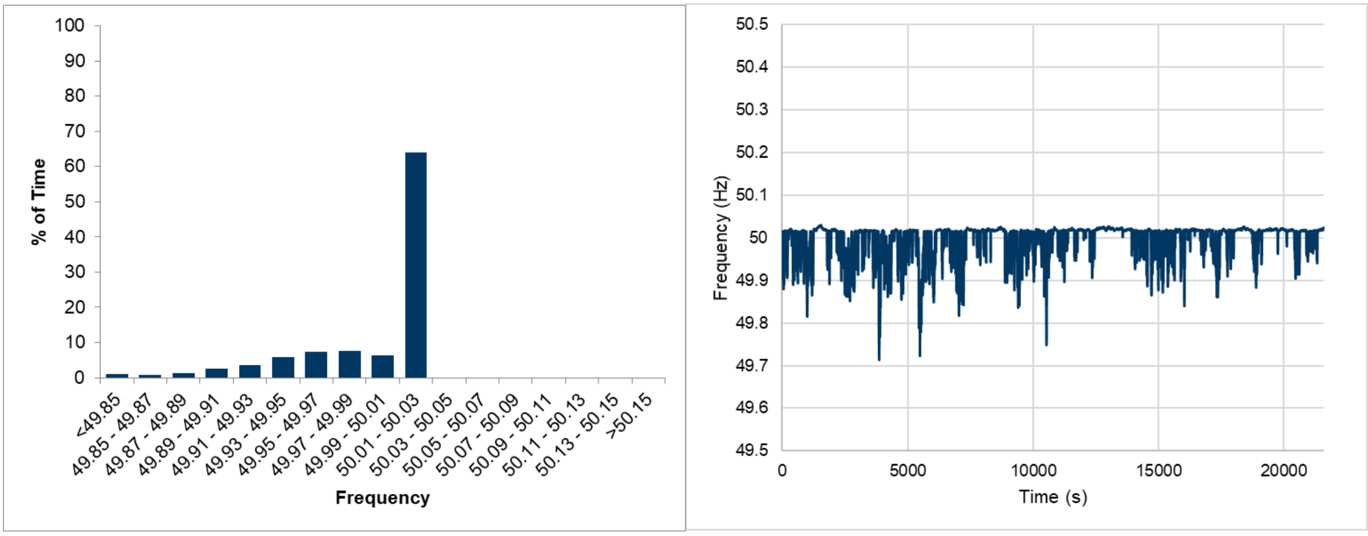


Figure 88 – Frequency distributions – High VRE 2033 case – High forecast variability – 15 mHz with 50% non-responsive

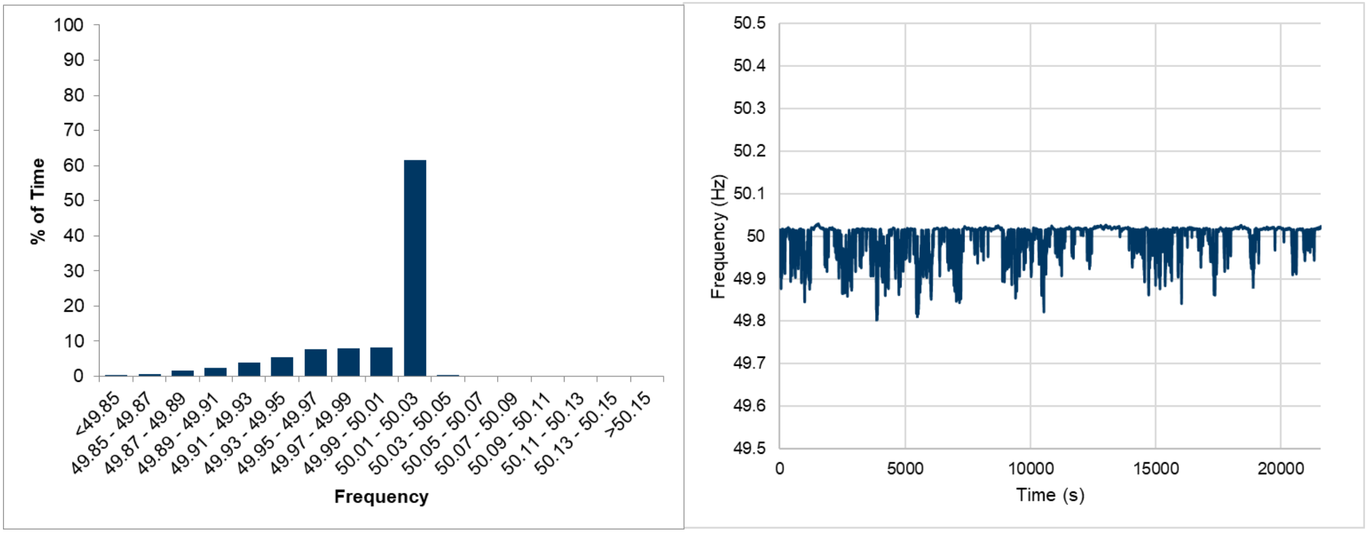


Figure 89 – Frequency distributions – High VRE 2033 case – High forecast variability – – 30% of PFR providers have 15 mHz deadbands and 70% have 150 mHz deadbands

Appendix B

Task 1b results

This appendix provides a complete set of all Task 1b modelling results, supplementing the results included in the body of the report.

B-1 Cost of load shedding results

A summary of the events causing load shedding in the 2022 and 2033 scenarios studied can be seen in Table 13.

Table 13 – Load shedding cost impact

Scenario	Deadband (mHz)	Total load shed (MW)	Unserved energy (kWh)	Total cost ($m)	Cost difference vs 15 mHz ($m)
Heywood interconnector trip - 2022	15	600	600,000	$25.51	$11.90
Heywood interconnector trip - 2022	500	880	880,000	$37.41	
Heywood interconnector trip - 2033	15	290	290,100	$12.33	$8.37
Heywood interconnector trip - 2033	500	487	487,000	$20.70	
QNI interconnector trip – 2033	15	0	-	$0.00	$33.66
QNI interconnector trip – 2033	500	792	791,700	$33.66	
Large hydro generator trip - 2033	15	0	-	$0.00	$6.01
Large hydro generator trip - 2033	500	141	141,300	$6.01	
An outage duration of one hour was assumed in all cases.					
As discussed below, a NEM-wide load-weighted VCR of 42.52 $/kWh was applied for all shed loads.					

An outage duration of one hour was selected after consultation with AEMO. We understand that this is a reasonable minimum timeframe to assume for the restoration of load following a large contingency resulting in UFLS. In reality, it is reasonable to expect that the larger the quantity of load shed, the greater the time required to restore all loads fully. This would result in greater costs. However, for uniformity, we have assumed a consistent outage duration across the scenarios.

As discussed in section 3.2.4, load-weighted Value of Customer Reliability (VCR) metrics have been applied to estimate the cost of the shed load. The AER developed the VCR framework[12]. The 2019 NEM VCR figures developed by the AER were adjusted by the CPI to develop a load-weighted VCR value for 2021. This cost was applied across all scenarios.

Table 14 – VCR value

Year	$/kWh
2019 AER NEM VCR	40.99
2021 CPI adjusted NEM VCR	42.52

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[12] Refer to table 5.22 in the December 2019 AER publication **Final report on VCR values** and **AER - 2021 VCR Annual Adjustment**

B-2 2022 – 15 mHz results

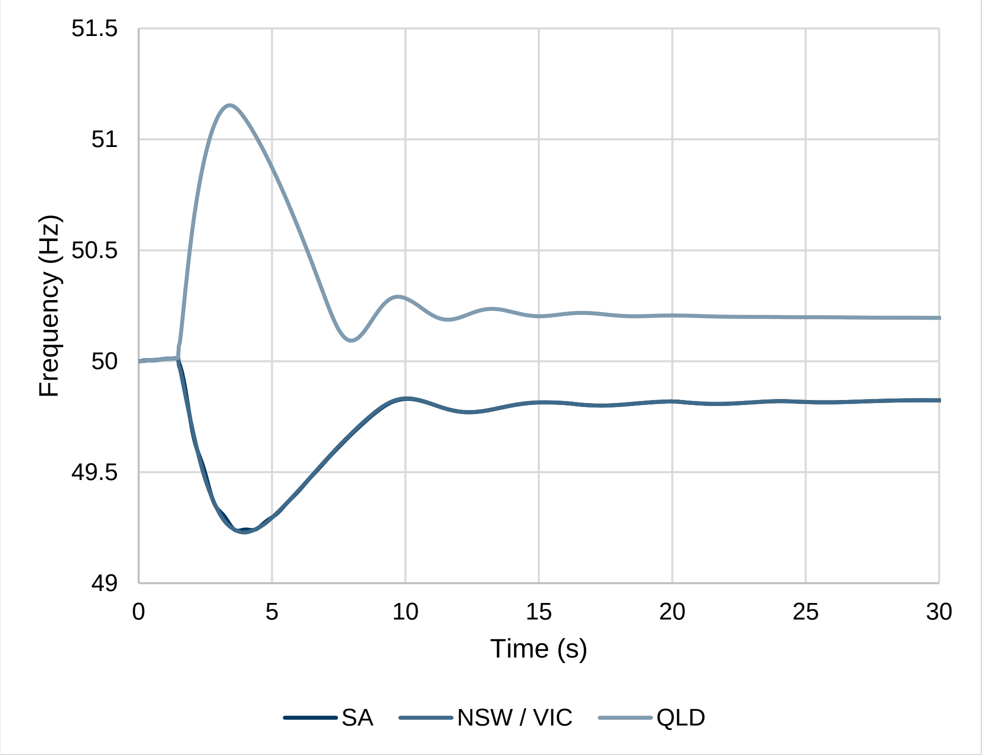

Figure 90 – QNI trip - 15 mHz PFCB - frequency

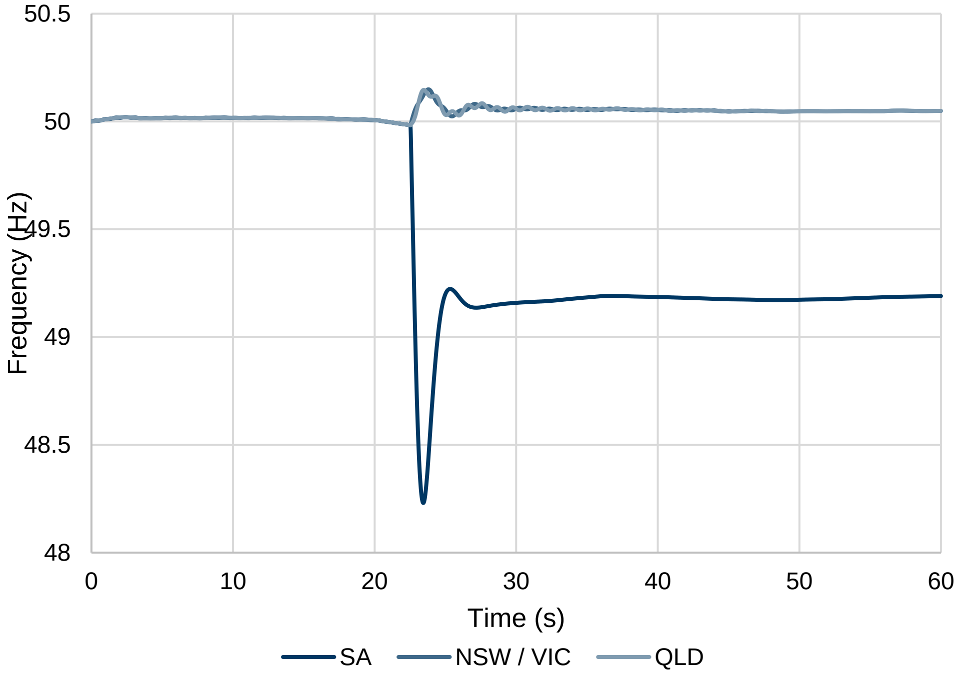

Figure 91 – Heywood trip - 15 mHz PFCB – frequency

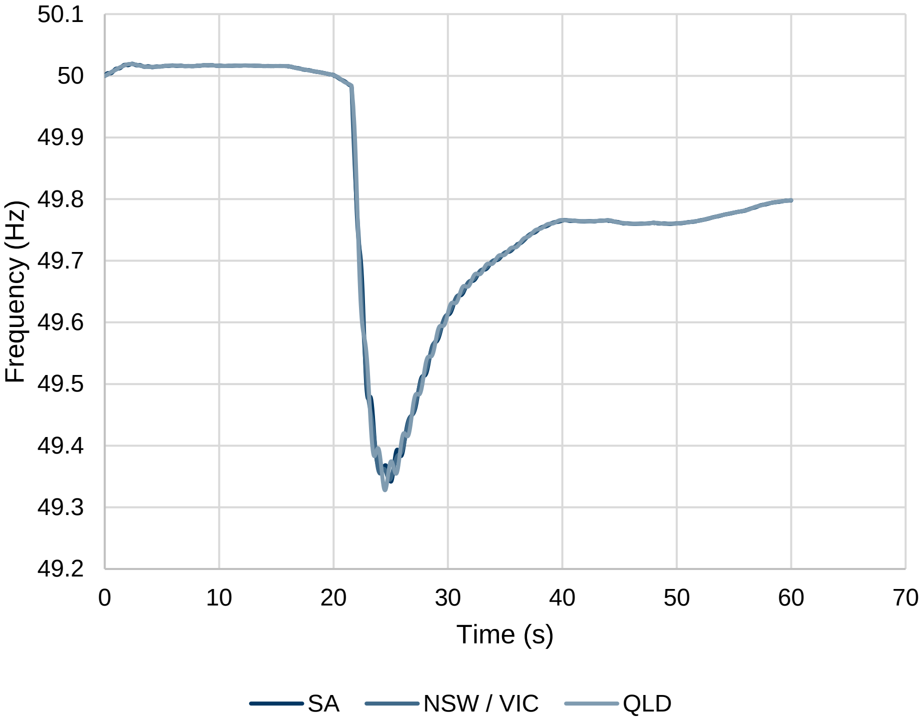

Figure 92 – Loy Yang A trip - 15 mHz PFCB – frequency

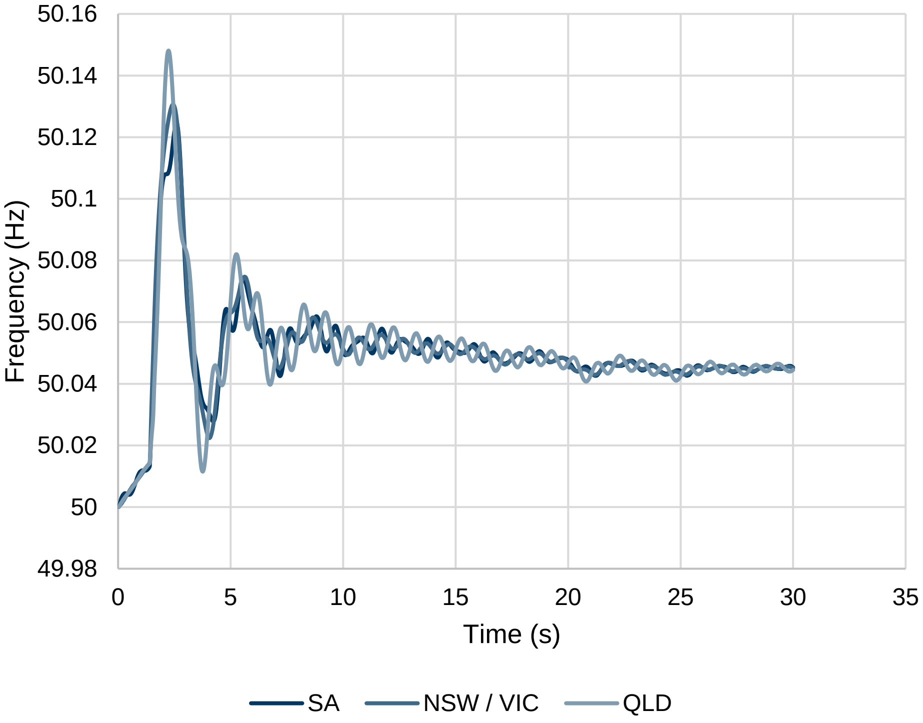

Figure 93 – 600 MW load trip - 15 mHz PFCB – frequency

B-3 2022 – 150 mHz results

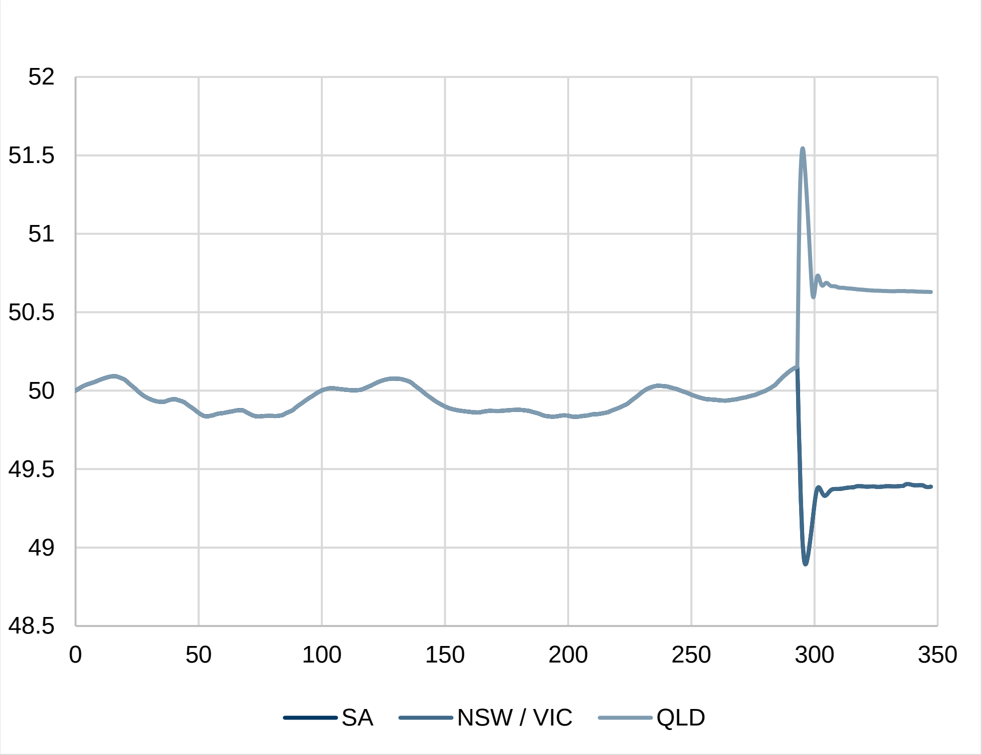

Figure 94 – QNI trip - 150 mHz PFCB – frequency

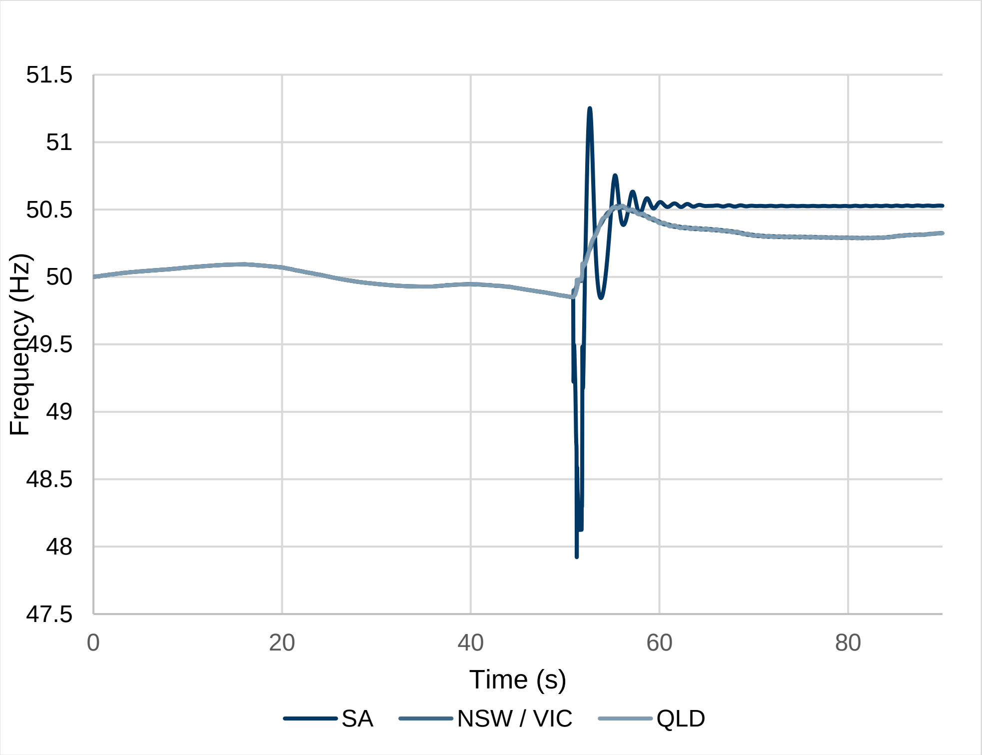

Figure 95 – Heywood trip - 150 mHz PFCB – frequency

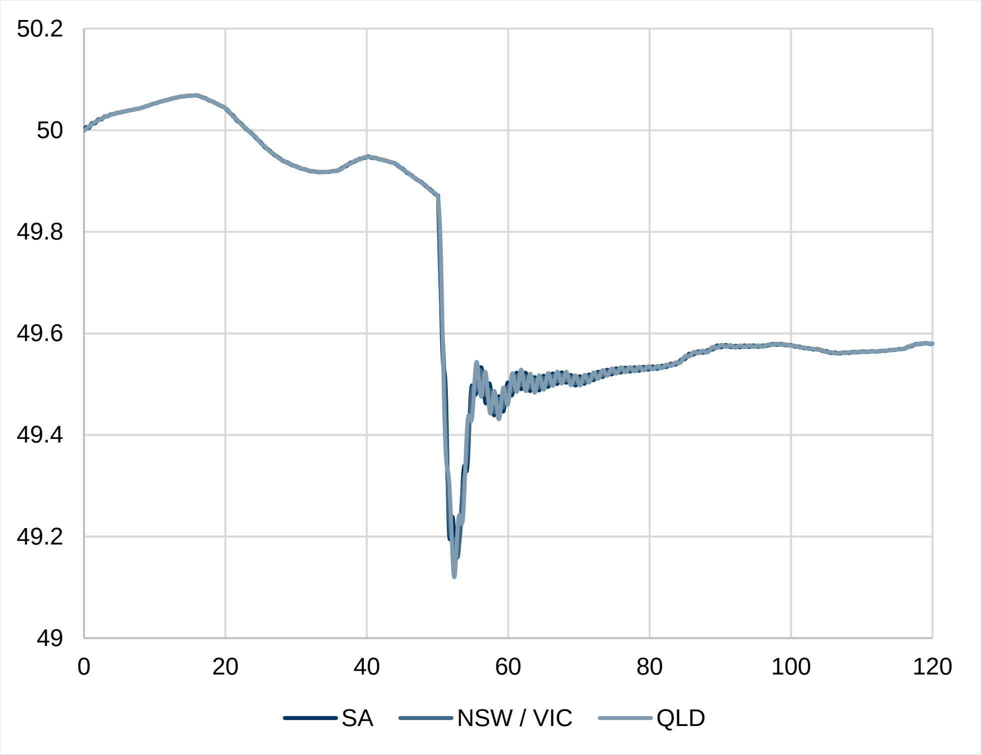

Figure 96 – Loy Yang A trip - 150 mHz PFCB – frequency

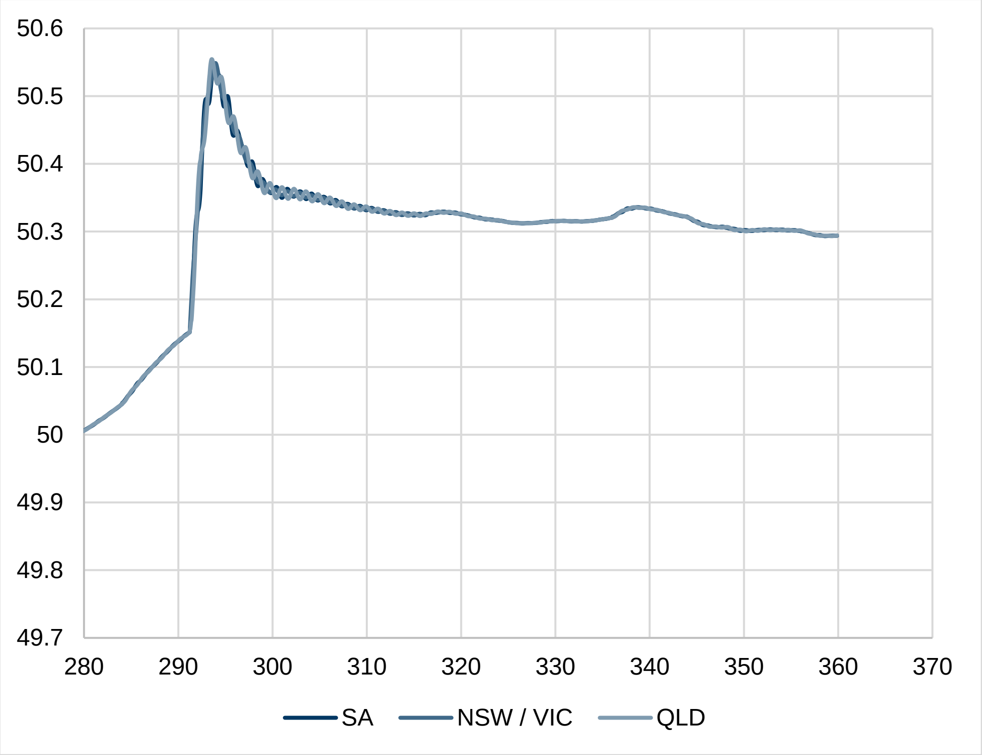

Figure 97 – 600 MW load trip - 150 mHz PFCB – frequency

B-4 2033 – 15 mHz results

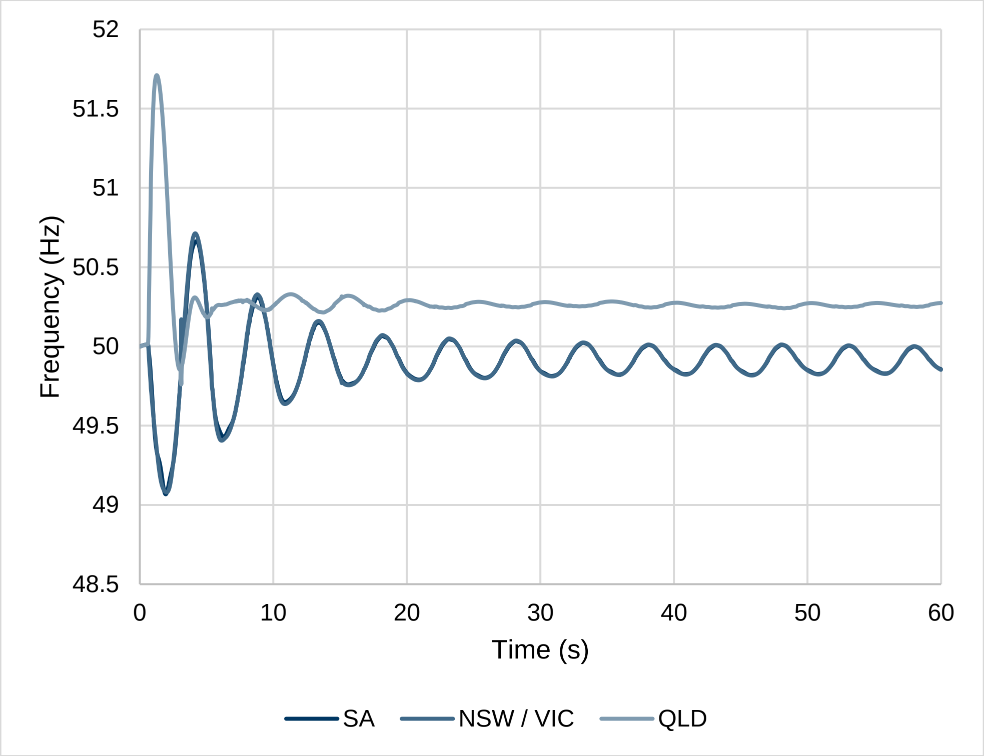

Figure 98 – QNI trip - 15 mHz PFCB – frequency – 30% of VRE provide raise and lower PFR

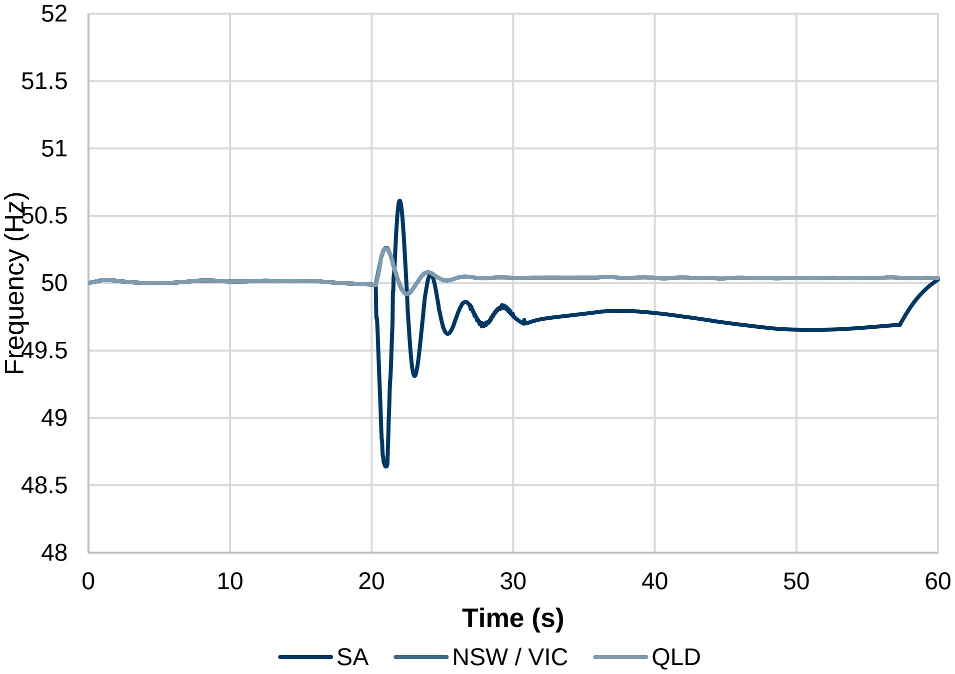

Figure 99 – Heywood trip - 15 mHz PFCB – frequency – 30 % of VRE provide raise and lower PFR

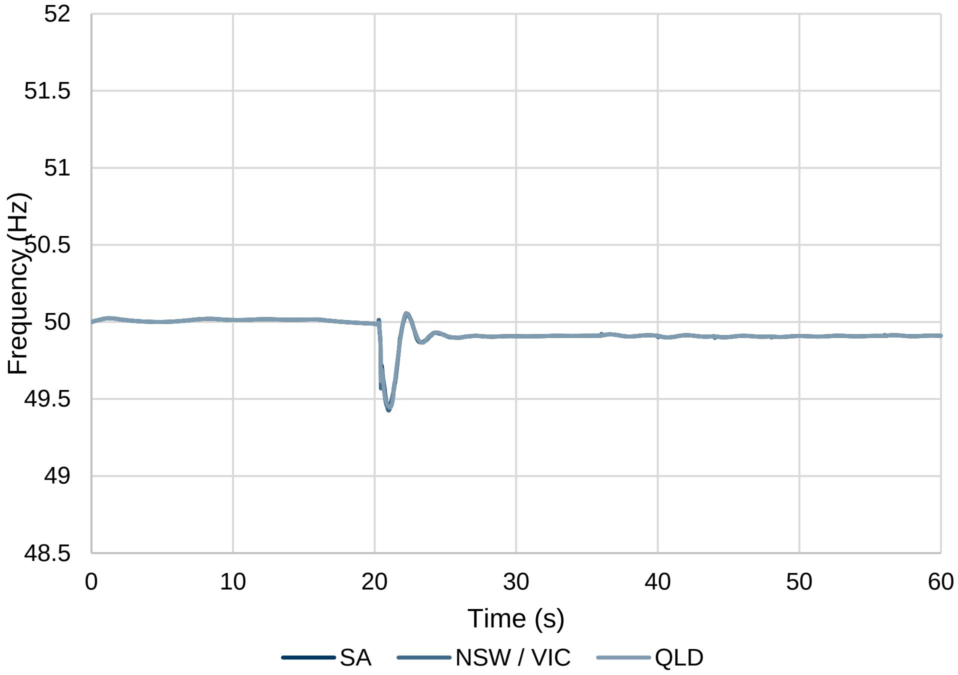

Figure 100 – Loy Yang A trip - 15 mHz PFCB – frequency – 30% of VRE provide raise and lower PFR

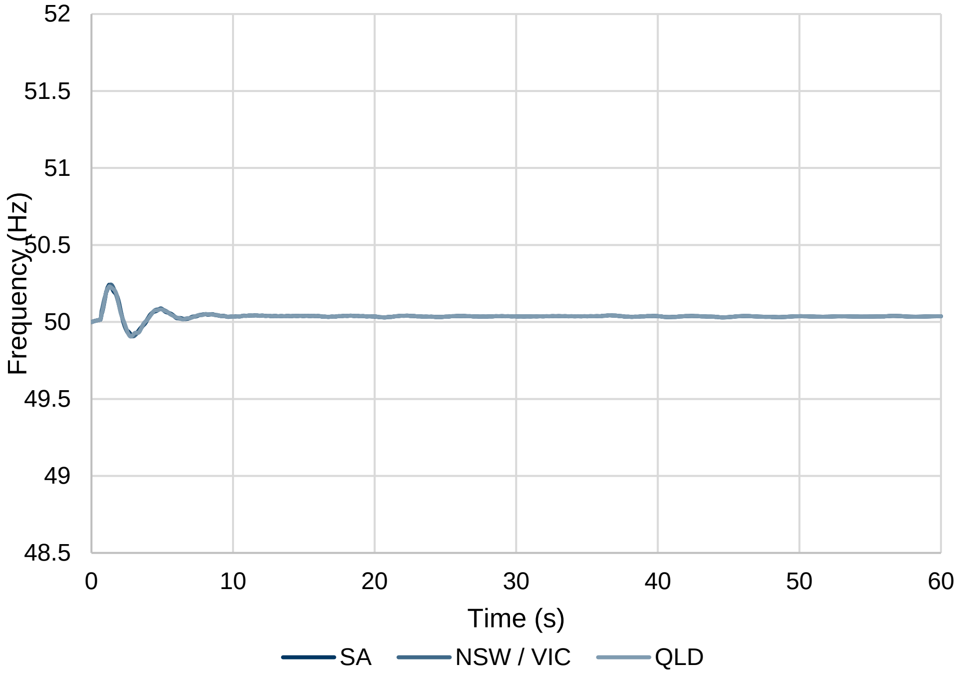

Figure 101 – 600 MW load trip - 15 mHz PFCB – frequency – 30% of VRE provide raise and lower PFR

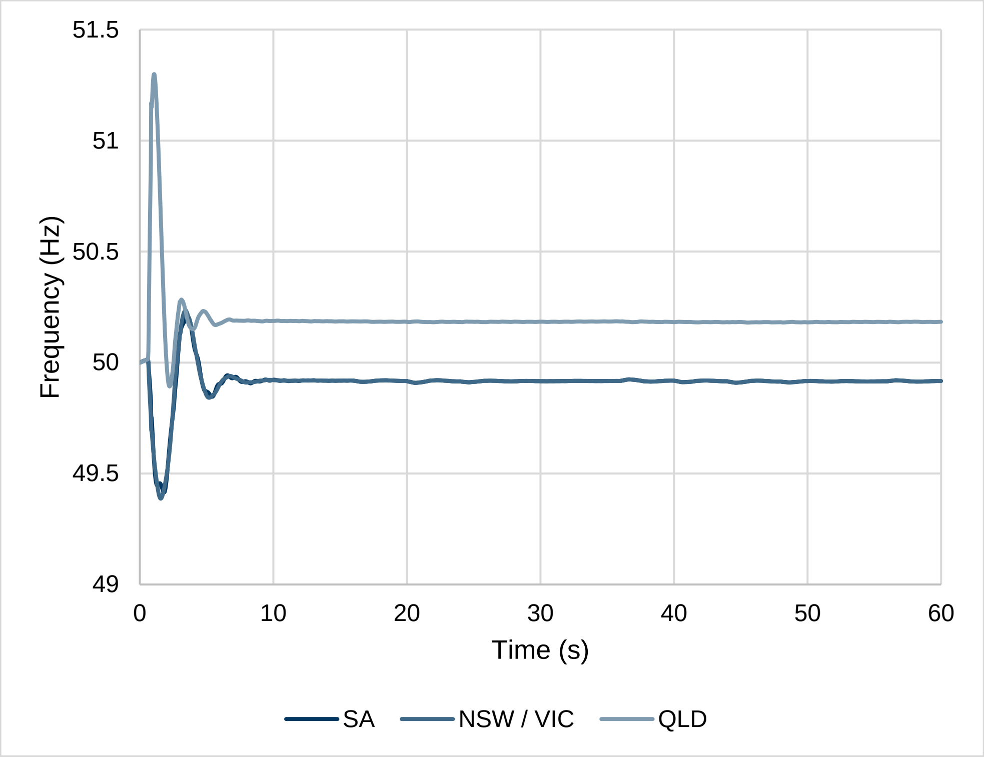

Figure 102 – QNI trip - 15 mHz PFCB - 50% of VRE provide raise and lower PFR

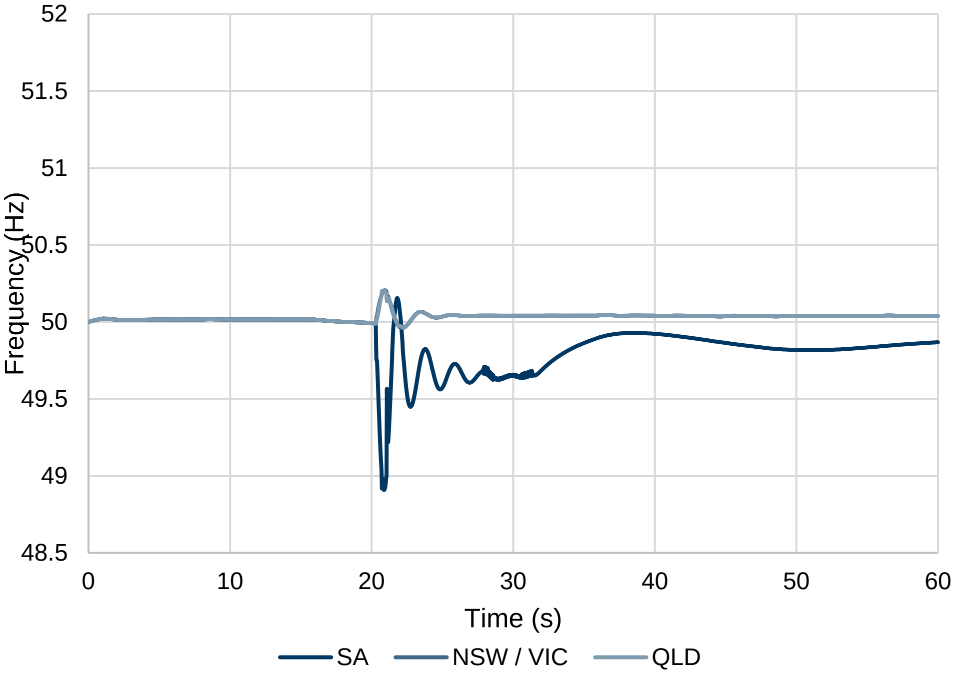

Figure 103 – Heywood trip - 15 mHz PFCB - 50% of VRE provide raise and lower PFR

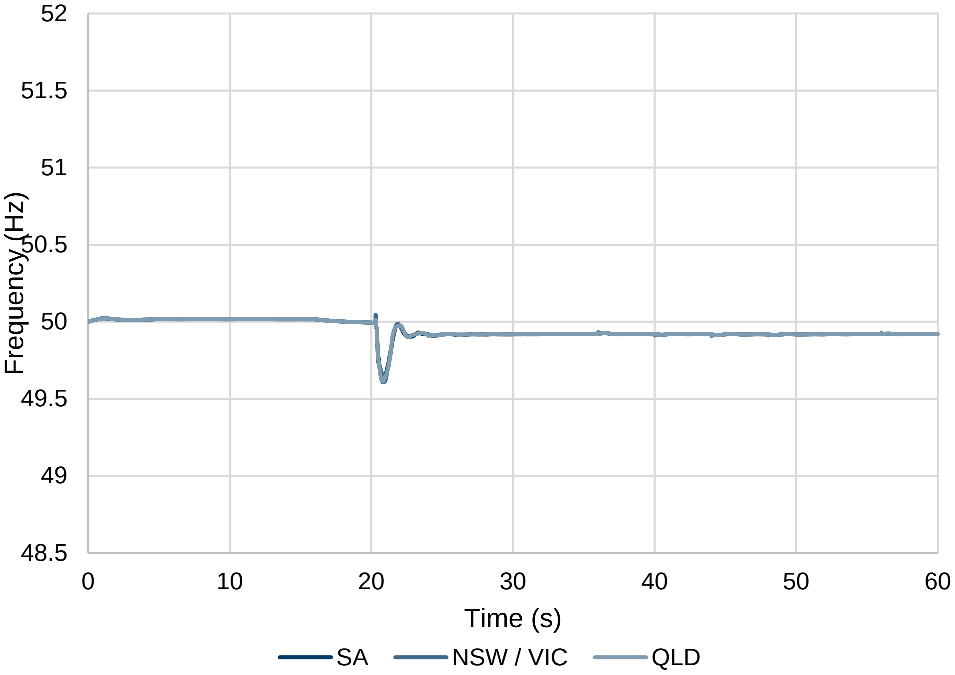

Figure 104 – 1300 MW Hydro trip - 15 mHz PFCB - 50% of VRE provide raise and lower PFR

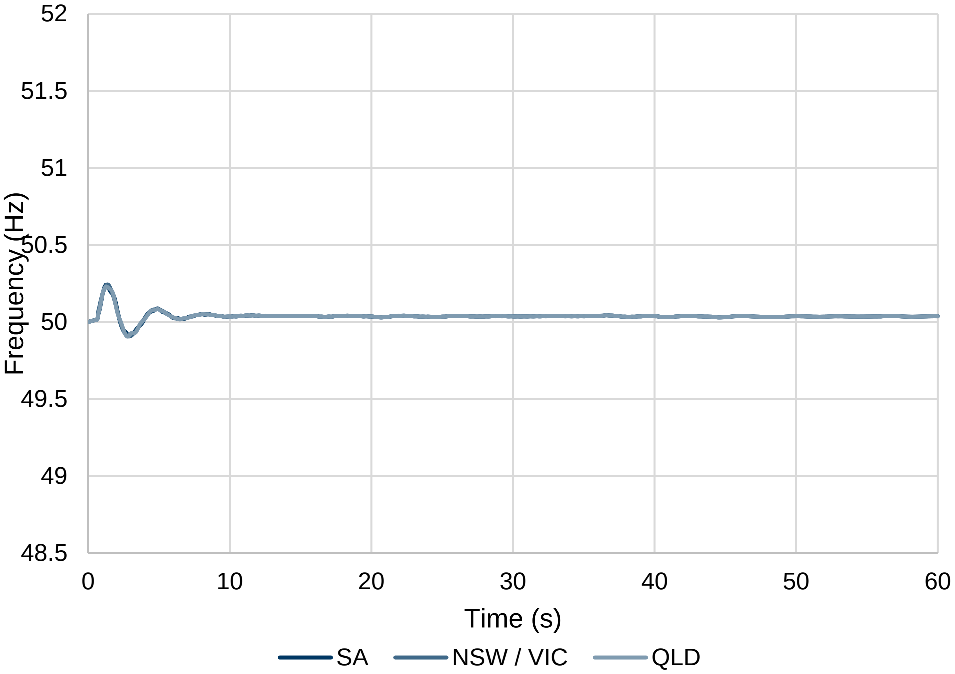

Figure 105 – 600MW load trip - 15 mHz PFCB - 50% of VRE provide raise and lower PFR

B-5 2033 – 150 mHz results

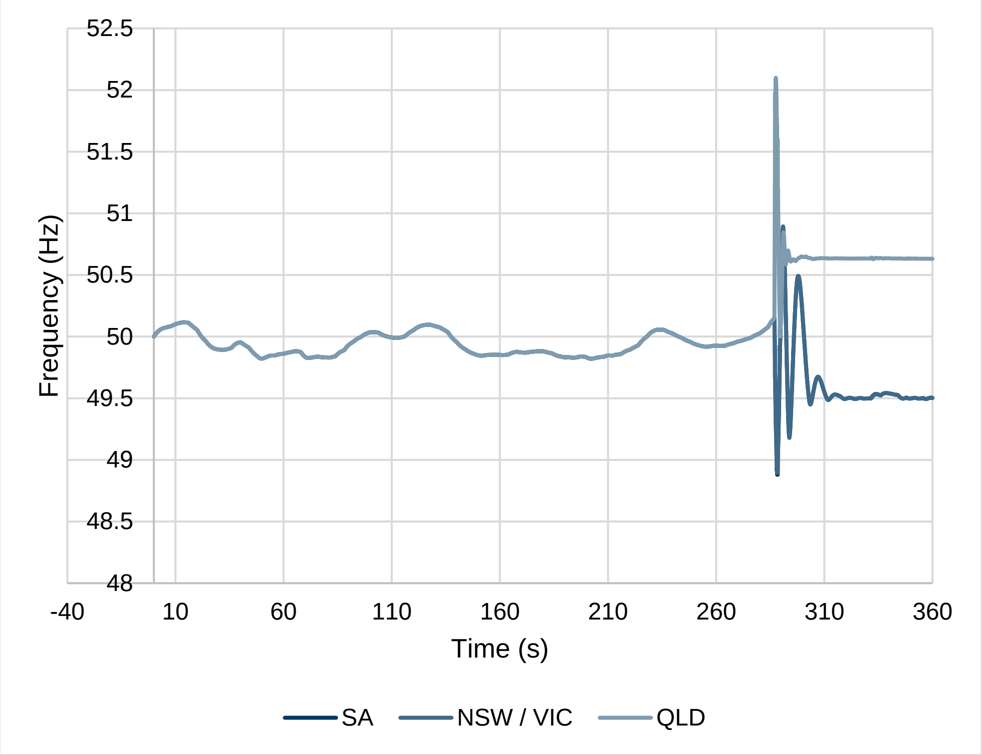

Figure 106 – QNI trip - 150 mHz PFCB – frequency – 30% of VRE provide raise and lower PFR

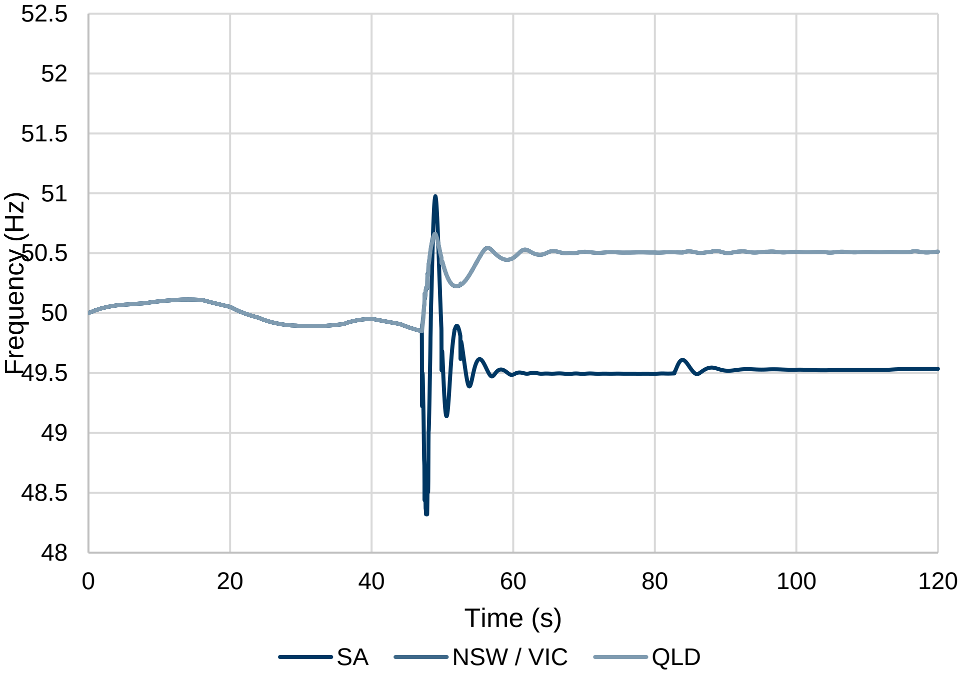

Figure 107 – Heywood trip - 150 mHz PFCB – frequency – 30 % of VRE provide raise and lower PFR

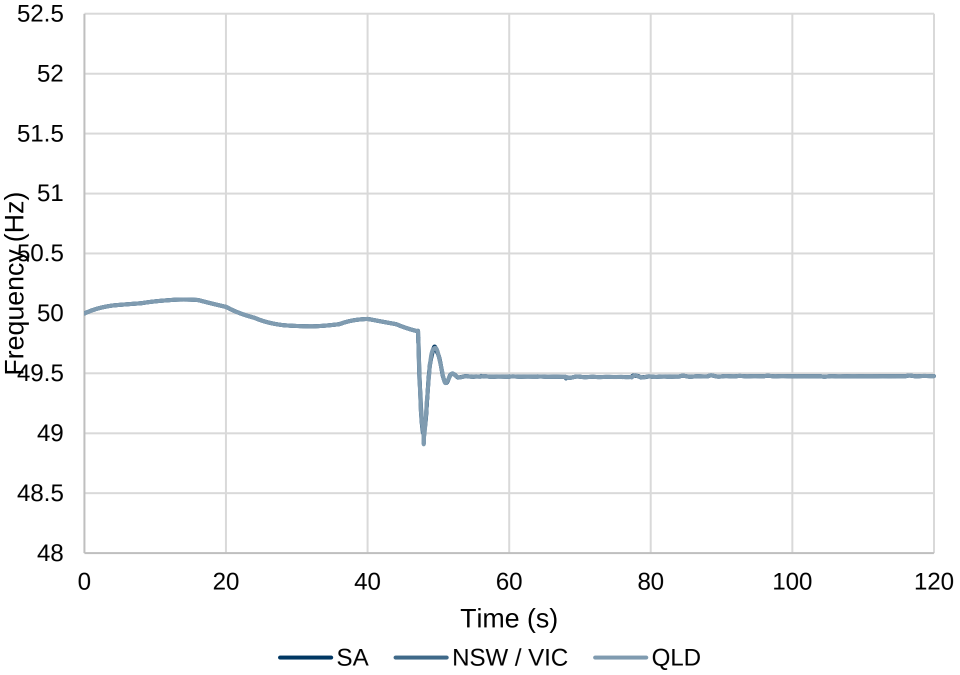

Figure 108 – Loy Yang A trip - 150 mHz PFCB – frequency – 30% of VRE provide raise and lower PFR

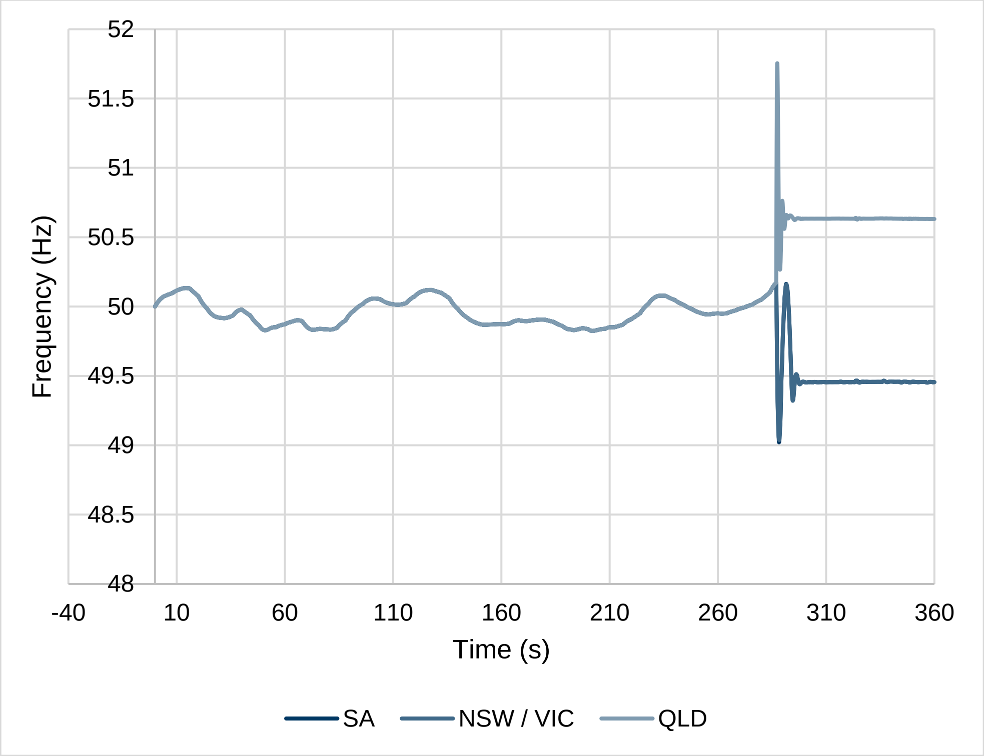

Figure 109 – QNI trip - 150 mHz PFCB - 50% of VRE provide raise and lower PFR

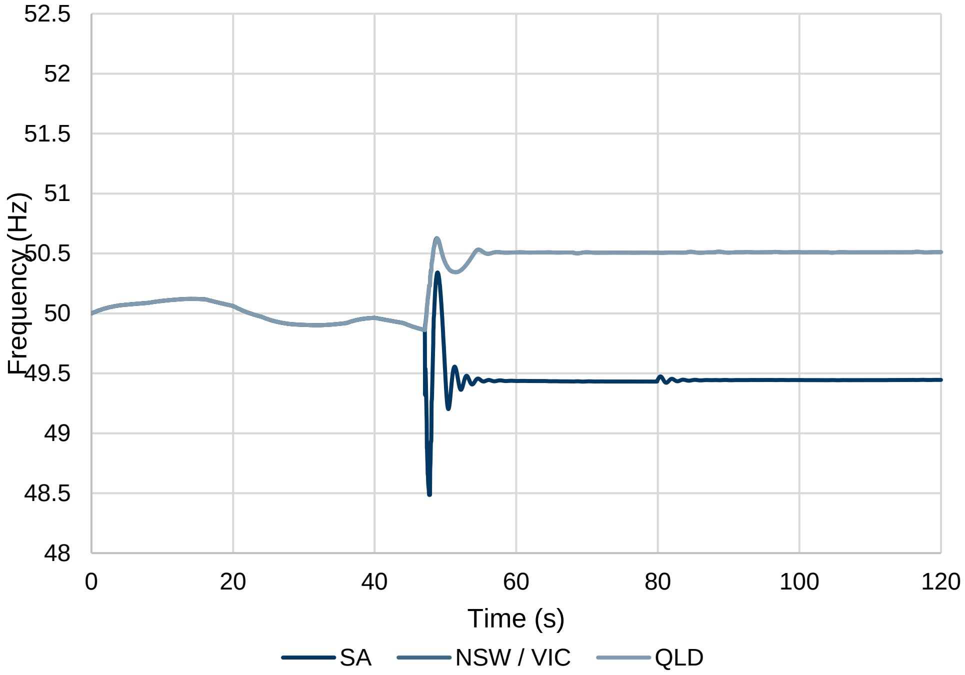

Figure 110 – Heywood trip - 150 mHz PFCB - 50% of VRE provide raise and lower PFR

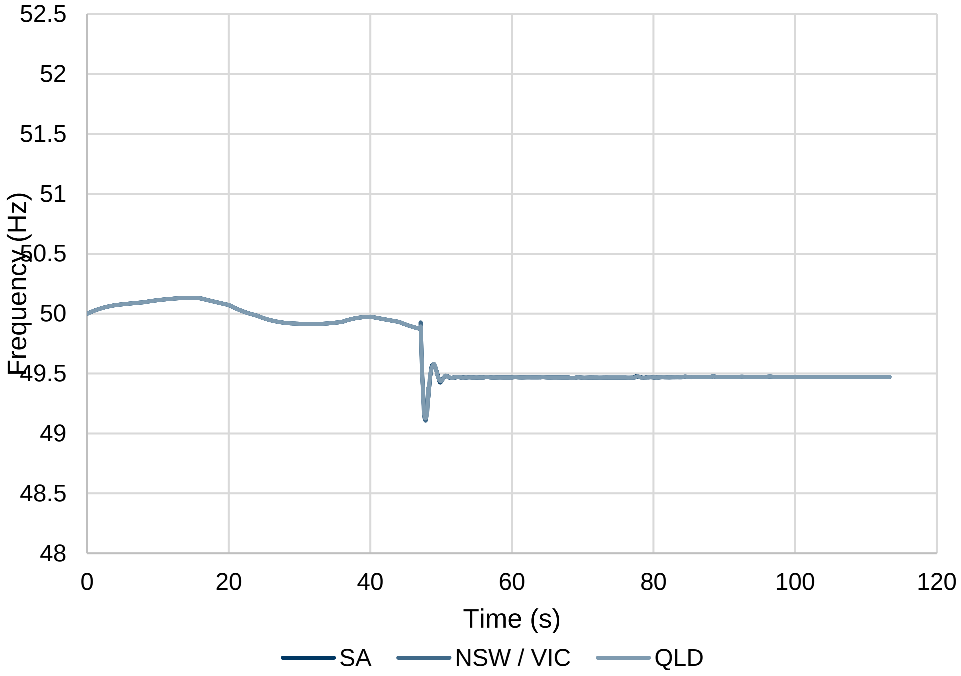

Figure 111 – 1300 MW Hydro trip - 150 mHz PFCB - 50% of VRE provide raise and lower PFR

Appendix C

Controller modelling details

C-1 PowerFactory frequency controller details

This appendix provides details of the frequency controller models included in the PowerFactory modelling across all generation types represented in the simulation studies. Where parameters have been varied due to the change in the PFCB requirement or due to differences across technology types, the description “Varied” has been included instead of the parameter number.

Coal Governor – Sub/Super Critical – BBGOV1

Name	Value	Unit	Description
fcut	**Varied**	[pu]	Dead Band of Speed
Ks	25	[pu]	Speed Gain
Kls	0.1	[pu]	PI Controller Limiter
Kg	0.01	[pu]	PI Gain
Kp	1	[pu]	Controller Gain
Tn	10	[s]	Controller Time Constant
Kd	1	[pu]	Second Controller Gain
Td	0.2	[s]	Second Controller Time Constant
T4	1	[s]	High Presure Time constant
K2	0.6	[pu]	Intermediate Pressure Factor
T5	10	[s]	Intermediate Pressure Time constant.
K3	0.3	[pu]	Low Presure Factor
T6	1	[s]	Low Presure Time constant.
PN	0	[MW]	Turbine Rated Power(=0->PN=Pgnn)
Switch	1	[0/1]	Electric Power Selector
T1	5	[s]	Power Feedback Time constant.
Pmin	**Varied**	[p.u.]	Minimum Gate Limit.
Pmax	**Varied**	[p.u.]	Maximum Gate Limit.

Hydro Governor – IEEE Hydro2

Name	Value	Unit	Description
Db	**Varied**		
Trate	0	[MW]	Turbine rated power (0 => Trate=Prated of SG)
K	25	[p.u.]	Governor gain
T1	1	[s]	Governor lag time constant
T2	0.5	[s]	Governor lead time constant
T3	1.5	[s]	Gate actuator time constant
Tw	3	[s]	Water starting time
P_min	**Varied**	[p.u.]	Gate minimum
P_max	**Varied**	[p.u.]	Gate maximum

Gas Governor – CCGT / OCGT - GAST

Name	Value	Unit	Description
R	0.05	[pu]	Speed Droop
db	**Varied**		
T1	0.4	[s]	Controller Time Constant
T2	0.1	[s]	Actuator Time Constant
T3	3	[s]	Compressor Time Constant
AT	1	[pu]	Ambient Temperature Load Limit
Kt	2	[pu]	Turbine Factor
Dturb	0	[pu]	frictional losses factor pu
PN	0	[MW]	Turbine Rated Power(=0->PN=Pgnn)
Vmin	0	[pu]	Controller Minimum Output
Vmax	1	[pu]	Controller Maximum Output

Inverter Based Resource Frequency Controller – BESS/PV/Wind – REPC_A

Name	Value	Unit	Description
Rc	0	[p.u.]	Line drop compensation resistance
Xc	0	[p.u.]	Line drop compensation reactance
Tfltr	0.02	[s]	Voltage and reactive power filter time constant
Tp	0.25	[s]	Active power filter time constant
db	0.002	[p.u.]	Deadband in reactive power or voltage control
Kp	1	[p.u./p.u.]	Volt/VAR regulator proportional gain
Ki	5	[p.u./p.u.]	Volt/VAR regulator integral gain
Vfrz	0.7	[p.u.]	Voltage for freezing Volt/VAR regulator integrator
Tft	0	[s]	Plant controller Q output lead time constant
Tfv	0.05	[s]	Plant controller Q output lag time constant
Kc	10	[p.u.]	Reactive droop gain
FrqFlag	1		Active power control: 0 = disabled, 1 = enabled
RefFlag	0		: 0 = reactive power control, 1 = voltage control
VcmpFlag	0		0 = reactive droop, 1 = line drop compensation
fdbd1	**Varied**	[p.u.]	Frequency deadband downside
fdbd2	**Varied**	[p.u.]	Frequency deadband upside
Ddn	**Varied**	[p.u./p.u.]	Down regulation droop gain
Dup	**Varied**	[p.u./p.u.]	Up regulation droop gain
Kpg	0.1	[p.u./p.u.]	Real power control proportional gain
Kig	1	[p.u./p.u.]	Real power control integral gain
Tlag	0.1	[s]	Plant controller P output lag time constant
emin	-0.5	[p.u.]	Minimum Volt/VAR error
Qmin	-0.313	[p.u.]	Minimum plant reactive power command
femin	-99	[p.u.]	Minimum power error in droop regulator

Pmin	**Varied**	[p.u.]	Minimum plant active power command
emax	0.5	[p.u.]	Maximum Volt/VAR error
Qmax	0.313	[p.u.]	Maximum plant reactive power command
femax	99	[p.u.]	Maximum power error in droop regulator
Pmax	**Varied**	[p.u.]	Maximum plant active power command

Appendix D

Review of historical incidents

D-1 Frequency of multiple contingency events in the NEM

GHD has reviewed the NEM system incident reports published by AEMO since 2016 to understand the frequency of multiple contingency events that lead to either separation of regions or disconnection of substantial amounts of load. The table below lists the identified multiple contingency events that resulted in a significant frequency change, the trip of a substantial amount of load, or the separation of a region from the rest of the NEM.

Table 15 shows that there have been eight such events over the past eight years. This indicates that the frequency of such events is approximately once every year. Resilience benefits offered by narrower PFCB, therefore, have the potential to accrue about once every year.

Table 15 – Historical multiple contingency events leading to substantial loss of load or separation

Year	Date of Incident	Description of Incident
2016	28/9/2016	South Australia System Black
2018	25/8/2018	QLD and SA separation following the trip of multiple transmission circuits
2019	16/11/2019	SA and VIC separation following the trip of multiple transmission circuits
2020	4/1/2020	NSW and VIC separation following multiple contingencies resulting from bushfires
2020	31/1/2020	SA and VIC Separation after multiple transmission circuits tripped during a major weather event
2021	25/5/2021	Trip of multiple generators in Queensland
2022	1/1/2022	Trip of multiple potlines at Bell Bay
2022	14/10/2022	Landslip leads to multiple transmission lines tripped in Tasmania

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