Addressing more frequency variability in New Zealand's power system

Consultation paper

25 June 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority (Authority) is reviewing the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). The Authority is undertaking this review as part of our Future Security and Resilience (FSR) work programme. ‘Common quality’ means those elements of the quality of electricity conveyed across New Zealand’s power system that cannot be technically or commercially isolated to an identifiable person or group of persons. The common quality requirements in the Code are foundational to the safe and reliable supply of electricity to consumers.

Through a combination of one-on-one engagement and formal consultation with interested parties, the Authority has identified seven key issues with the common quality requirements in Part 8 of the Code.

We are publishing a suite of consultation papers on matters relating to five of these seven key issues. This paper contains short listed options to address Issue 1, which relates to frequency. Another paper contains short listed options to address Issues 2, 3 and 4, which relate to voltage. A third paper discusses Issue 5, which relates to harmonics. A fourth paper provides an overview of, and context for, the consultation suite.[1]

Later in 2024 we plan to consult with interested parties on addressing Issues 6 and 7. Issue 6 relates to the provision of information to network operators and Issue 7 relates to ensuring that Code terminology appropriately enables technologies.

Issue 1

The first key identified issue with the common quality requirements in Part 8 of the Code is as follows:

> *An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the ‘normal band’ of 49.8–50.2 Hertz (Hz), which is likely to be exacerbated over time by decreasing system inertia*. (**Issue 1**)

Addressing Issue 1 in a timely manner is consistent with our statutory objectives. The Authority wants the Code’s common quality requirements to enable evolving technologies, particularly inverter-based resources. Examples of inverter-based resources include solar photovoltaic generation, wind generation, and battery energy storage systems.

We see these technologies as a key enabler of:

(a) consumers having more choice and flexibility around their electricity use and supply

(b) the electrification of parts of New Zealand’s economy, such as transportation and heating.

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1 Overview and context for the consultation suite: https://www.ea.govt.nz/documents/cqrconsultationcoverpaper

Paper 2: Addressing larger voltage deviations and network performance issues in New Zealand’s power system: https://www.ea.govt.nz/documents/cqrconsultationpaper2

Paper 3: The governance and management of harmonics in New Zealand’s power system: https://www.ea.govt.nz/documents/cqrconsultationpaper3

In addition to providing opportunities, these technologies do, however, pose some challenges. In particular, we expect that co-ordinating the real-time operation of New Zealand's power system to supply electricity to consumers at the level of reliability they want will become more difficult over the coming years. This increased difficulty will be the result of evolving technologies enabling a significant increase in variable and intermittent generation and an increase in bi-directional electricity flows.

We want to address the key identified common quality issues in a manner that promotes reliability of electricity supply for consumers. We also want to address these issues in a way that promotes competition in, and the efficient operation of, the electricity industry. We see this as critical to promoting innovation in affordable electricity-related services.

Options to help address Issue 1

The Authority has considered a range of options to help address Issue 1 and is proposing we investigate further the following three short listed options:

(a) Option 1: Lower the 30 megawatt threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations (AOPOs) and technical codes in Part 8 of the Code.

(b) Option 2: Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

(c) Option 3: Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

The Authority wishes to highlight we are considering other options to help address Issue 1. These options are part of other work programme initiatives underway, or planned to be underway, in the Authority.

Currently, the Authority is focussing on options with a shorter Code development timeframe. Once time and resources permit, we will turn our focus to options that would need a longer period to develop and implement in the Code.

The Authority has benefitted greatly from input we have received from the Common Quality Technical Group and the system operator. The Common Quality Technical Group is supporting our evaluation of options to help address the identified key common quality issues. The knowledge and experience of its members collectively ranges from the operation of the power system at both the transmission and distribution levels to the operation of generation and demand-side management technologies.

Your feedback is welcomed

The Authority welcomes feedback from interested parties on the options described in this paper.

The Authority acknowledges the content of this consultation paper is technical and has allowed for an 8-week consultation period. During the consultation period the Authority will be available to hold individual and group briefings with interested stakeholders.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. Through a combination of one-on-one engagement and formal consultation with interested parties, the Electricity Authority (Authority) has identified seven key issues with the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). ‘Common quality’ means those elements of the quality of electricity conveyed across New Zealand’s power system that cannot be technically or commercially isolated to an identifiable person or group of persons.

1.2. The purpose of this paper is to consult with interested parties on three options the Authority considers should be investigated further to help address the first of the seven key common quality issues:

> *An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the ‘normal band’ of 49.8–50.2 Hertz (Hz), which is likely to be exacerbated over time by decreasing system inertia*. (**Issue 1**)

1.3. A more detailed explanation of Issue 1 can be found in section 3 of the 2023 Issues paper for the Authority’s review of common quality requirements in Part 8 of the Code. This review is part of our Future Security and Resilience (FSR) programme of work. An overview of the FSR programme can be found on our website at Future security and resilience | Our projects | Electricity Authority (ea.govt.nz).

1.4. The Authority considers we should investigate further the following three options to help address Issue 1:

(a) Option 1: Lower the 30 megawatt (MW) threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations (AOPOs) and technical codes in Part 8 of the Code.

(b) Option 2: Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

(c) Option 3: Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

1.5. These options rank higher than several alternative options we have assessed – please refer to Appendix A.

1.6. The Authority notes we have workstreams outside the FSR programme that are looking at other options we consider would help address Issue 1. Examples of options being considered outside the FSR programme include:[2]

(a) Lowering the minimum frequency keeping threshold below 4MW and having a national market for frequency keeping.

(b) Allocating frequency keeping costs to the causers of frequency deviations.

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[2] See Table 4 in Appendix A of this paper.

(c) Removing the obligation on the system operator to eliminate from the power system any deviations from New Zealand standard time caused by variability in system frequency.

1.7. The Authority also notes that, within the next 12–24 months we plan to consider some options to address Issue 1 that currently are on hold. Currently, we are focussing on options that have a shorter Code development duration. Once time and resources permit, we will turn our focus to options that would need a longer period to develop and implement in the Code. This approach is enabling us to progress options that can deliver 'quicker wins' ahead of options that require a longer gestation, and which are not necessarily needed within the next five years.[3]

1.8. Lastly, we note there are interdependencies within the three short listed options, with more than one option likely to be needed to address Issue 1. There are also interdependencies between these short listed options and some of the options being considered in workstreams outside the FSR work programme. We are carefully managing such interdependencies.

This paper is part of a suite of common quality consultation papers

1.9. The Authority is publishing a suite of consultation papers on matters relating to five of the seven key common quality issues identified in the 2023 Issues paper. This consultation suite contains:

(a) an overview of, and context for, the consultation suite

(b) options to help address a frequency-related key common quality issue (Issue 1)

(c) options to help address three voltage-related key common quality issues (Issues 2, 3 and 4)

(d) a discussion on the governance and management of harmonics, which are part of a harmonics-related key common quality issue (Issue 5).

1.10. As noted above, this consultation paper sets out options to help address Issue 1. The other papers, which are being published alongside this one, are available at

(a) Overview and context for the consultation suite: https://www.ea.govt.nz/documents/cqrconsultationcoverpaper

(b) Paper 2: Addressing larger voltage deviations and network performance issues in New Zealand's power system: https://www.ea.govt.nz/documents/cqrconsultationpaper2

(c) Paper 3: The governance and management of harmonics in New Zealand's power system: https://www.ea.govt.nz/documents/cqrconsultationpaper3

How to make a submission

1.11. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to fsr@ea.govt.nz with "Consultation Paper—Addressing more frequency variability in New Zealand's power system" in the subject line.

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3 See Appendix A of this paper.

1.12. If you cannot send your submission electronically, please contact the Authority (at fsr@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.13. Please note the Authority intends to publish all submissions we receive. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.14. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.15. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.16. Please deliver your submission by 5pm on Tuesday 20 August 2024.

1.17. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority (at fsr@ea.govt.nz or 04 460 8860) if you do not receive electronic acknowledgement of your submission within two business days.

2. An overview of Issue 1

Introduction

2.1. The proportion of variable and intermittent generation operating on New Zealand's power system is expected to increase over the next 5–10 years as more wind generation, solar photovoltaic generation, and energy storage systems connect. This is likely to cause more variability in frequency within the range of 49.8–50.2Hz, which is the range the system operator must maintain frequency within other than for momentary fluctuations (defined in the Code as the 'normal band').[4]

2.2. More frequency variability within the normal band would make it more challenging for the system operator to continuously balance the demand for, and supply of, electricity conveyed across the transmission network.

2.3. For consumers, more frequency variability within the normal band might cause their electrical equipment to operate sub-optimally. In this way, more frequency variability within the normal band would be expected to impose economic costs on consumers. Consumers might also be adversely affected economically by the additional costs associated with the system operator managing system frequency (eg, procuring additional instantaneous reserve to cover for less automatic response from generating units to changes in frequency).

More frequency variability from an increasing amount of variable and intermittent resources, exacerbated by decreasing system inertia

2.4. Compared with international jurisdictions, New Zealand operates a small power system with a small generation base and relatively low inertia. This means:

(a) a small imbalance between electricity demand and supply can cause frequency to deviate outside the normal band of 49.8–50.2Hz

(b) changes in system frequency are much faster than in larger power systems with higher system inertia.

2.5. Wind generation is highly intermittent, which can lead to generation output varying quickly due to wind gusts and potentially shutting down due to low or high wind speed.

2.6. The intermittency of solar photovoltaic generation is also affected by weather – mostly from cloud movement.[5] In addition, solar photovoltaic generation is affected by its daytime-only nature.

2.7. Intermittency of electricity generation output caused by clouds and wind creates difficulty for the system operator in predicting the amount of generation needed from

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4 The Code requires the system operator to maintain frequency within 0.4% of 50Hz (ie, 49.8–50.2Hz), except for momentary fluctuations. In the case of momentary fluctuations, the system operator must not let frequency drop below 45Hz in the South Island and 47Hz in the North Island, and must return frequency to at least 49.25Hz within 60 seconds. The Code does not specify equivalent upper bounds on frequency fluctuations.

5 See Transpower New Zealand Limited, 2017, Effect of Solar PV on Frequency Management in New Zealand.

one hour to the next in order to balance electricity demand and supply across the power system. The short-term (second-to-second) balancing of generation with electricity demand is also affected by fast changes in wind speed or cloud movement.[6] This presents a real challenge for the system operator to maintain frequency within the normal band.

2.8. Material increases in behind-the-meter generation also makes system frequency more variable and uncertain:

(a) as net load (ie, as measured on the network side of an installation control point) becomes more variable and elastic/flexible, and

(b) as this generation and distribution network-connected wind generation and solar photovoltaic generation displace the dispatch of synchronous machine-based generation that contributes to frequency regulation capability and system inertia.

2.9. Exacerbating this problem of more frequency variability within the normal band are:

(a) the behaviour of some existing generation in assisting the system operator to manage frequency

(b) the expected relative increase in variable and intermittent generation that either is not required to comply with the frequency-related obligations in Part 8 of the Code or which receives a dispensation from needing to comply with these obligations

(c) the expected fall in system inertia as large thermal generating stations are retired over the coming years, replaced by inverter-based generation.

2.10. The next three subsections expand on these points.

Some existing generation behaviour does not assist in managing frequency

2.11. The behaviour of some existing generation does not assist the system operator in managing frequency. The system operator is observing the following behaviours amongst generating stations:

(a) Wind, geothermal, solar photovoltaic, and run-of-river hydro generating stations will typically generate as much output as allowed by the fuel source. Therefore, this generation usually has no ability to increase its megawatt output to support the system operator in managing under-frequency, but can reduce output to support the system operator in managing over-frequency.

(b) More and more generators are applying frequency dead bands to their generating units. The system operator advises this is degrading the system operator’s ability to manage frequency within the normal band and also adversely affecting the system operator’s management of momentary fluctuations.

2.12. Moving forward this will exacerbate the problem of more frequency variability within the normal band caused by increasing amounts of variable and intermittent generation on the power system.

[6] In some instances, cloud movement can cause a fast fluctuation in active power output from solar photovoltaic generation.

More generation will not have to comply with frequency-related obligations

2.13. Absent a change to the Code, over time the percentage of generation capacity required by the Code to assist in maintaining frequency within the normal band is expected to fall – at least for the foreseeable future. This is based on the following expectations:

(a) There will be a proportional increase in the number of generating stations exporting less than 30MW to a network. This expectation is based on the falling cost of solar photovoltaic generation technology and battery energy storage system technology. These technologies lend themselves to smaller-scale installations deployed in a distributed manner across New Zealand's distribution networks for economic and resource availability reasons.

(b) For the foreseeable future, the system operator will continue to grant dispensations to generating stations that have, or will have, assets or a configuration of assets that do not comply with a frequency-related asset owner performance obligation (AOPO) or technical code in Part 8 of the Code. This expectation is based on the system operator continuing to expect that granting such dispensations will not affect the system operator's ability to continue operating the existing power system and meeting its principal performance obligations (PPOs).[7]

2.14. In accordance with clause 8.38 of the Code, the Authority could, upon receiving an application from the system operator, direct generating stations exporting less than 30MW to a network to support system frequency in the same way as larger exporting generating stations. We could do this if we were satisfied there would be a benefit to the public. However, doing this on a station-by-station basis would be expected to have relatively higher transaction costs than reducing the 30MW threshold if we considered such a reduction would have a benefit to the public.

2.15. The system operator can decline to grant generating stations a dispensation from the frequency-related obligations in Part 8 if the system operator:

(a) reasonably expected it could not continue operating the existing power system and meeting its PPOs, or

(b) could not readily quantify the costs on other persons of the dispensation.[8]

2.16. However, the system operator is expected to continue granting dispensations from the frequency-related obligations in Part 8 to non-synchronous generating stations for the foreseeable future. This is because of:

[7] See clauses 8.29 and 8.31 of the Code. Clause 8.31 says the system operator must grant such dispensations if the system operator—
(a) reasonably expects it can continue operating the existing power system and meet its PPOs, and
(b) can readily quantify the costs on other persons of the dispensation.

[8] An asset owner must pay readily identifiable and quantifiable costs borne by others as a result of a dispensation granted to that asset owner. In practice, it is difficult to identify such costs reliably and accurately. Therefore, typically the system operator does not include a cost allocation in a dispensation. A notable exception is a dispensation from certain generator obligations relating to under-frequency, where the Code sets out the cost allocation formula for non-compliant generators.

(a) the characteristics of these non-synchronous generating stations (eg, being unable to maintain pre-event output during a contingent event), and

(b) the likelihood that granting a dispensation to an individual non-synchronous generating station is unlikely to prevent the system operator from operating the existing power system and meeting its PPOs.

2.17. At some point the system operator would be expected to stop granting these dispensations, because the cumulative effect of doing so would be likely to prevent the system operator operating the existing power system and meeting its PPOs. Therefore, there is an inherent upper bound on the amount of generation that will not have to comply with frequency-related obligations.

A fall in system inertia will exacerbate the problem of more frequency variability

2.18. Variable and intermittent inverter-based resources that provide little or no system inertia are, in many cases, replacing thermal generation in New Zealand.[9] This reduction in system inertia means system frequency will change more rapidly in response to supply/demand imbalances. This in turn requires, for a given level of demand, an increased supply of resources for frequency keeping (including more frequency control system response), instantaneous reserve, and potentially automatic under-frequency load shedding (AUFLS).[10]

2.19. Moving forward, a fall in system inertia will exacerbate the problem of more frequency variability within the normal band caused by increasing amounts of variable and intermittent generation on the power system. A fall in system inertia will also exacerbate the rate of change of frequency and the frequency excursion size for an extended contingent event, such as tripping the largest connected generating station or both poles of the high voltage direct current (HVDC) link.

2.20. Currently, there is no specific procurement of, or payment for, inertia. Nor are generating stations that do not provide inertia allocated some proportion of the cost of procuring instantaneous reserve and frequency keeping.[11]

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9 The Authority notes this is distinct from variable and intermittent resources being built to meet increased electricity demand.

10 AUFLS is the automatic shedding of electrical load when frequency falls below a pre-set level or falls at a pre-set rate.

11 An inverter-based resource that uses a ‘grid-forming’ inverter can provide ‘synthetic’ inertia. This inverter forms a voltage angle independently of the network to which it is connected and controls its output voltage so as to synchronise with, and remain synchronised with, the network. To date, most inverters installed in New Zealand have been a ‘grid-following’ inverter. This type of inverter tracks the voltage angle of the network to which it is connected, to control the output of the inverter-based resource and thereby remain synchronised with the network.

3. Short listed options to help address Issue 1

3.1. The Authority has considered a range of options to help address Issue 1. We have benefitted greatly from input we have received from the Common Quality Technical Group and the system operator.

3.2. After much consideration, we have settled on a short list of three options we consider should be investigated further to help address Issue 1. These are outlined in sections 4, 5, and 6 of this paper.

3.3. The options are a subset of a longer list of options we have assessed against evaluation criteria. The evaluation criteria draw from the key principles guiding the consideration of options to help address issues identified in our review of common quality requirements in Part 8 of the Code. The evaluation criteria are listed in the overview and context for the consultation suite. Appendix A contains the other options we considered and decided not to short list.

4. Option 1: Require smaller generating stations to comply with frequency-related obligations

4.1. Under option 1, clause 8.21 of the Code would be amended to lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code. The lower threshold would apply to existing and new generating stations.

4.2. Part 8 of the Code contains AOPOs that specify the contributions generators must make to maintaining frequency in the normal band. Clause 8.17 of the Code sets out the overarching requirement on generators to:

> "*make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to within the normal band)*".

4.3. Clause 8.17 also requires such contributions to be assessed against the technical codes in Schedule 8.3 of Part 8, which include the requirement on generators to:

(a) ensure that each of their generating units has a speed governor (the purpose of which is to automatically adjust the generating unit's output in response to changes in system frequency)

(b) agree speed governor settings with the system operator.[12]

4.4. Governors are standard features of conventional synchronous machine-based generating technologies powered by hydro, steam and gas turbines. The collective response of generating units operating under governor control is an essential part of normal frequency management. It acts in the first instance to limit system frequency changes due to imbalances between generation and demand.

How generating unit speed governors help maintain frequency

A generating unit's speed governor regulates the amount of primary energy supply to a turbine (eg, hydro, gas, or steam) in response to variations in the power system's frequency. This adjusts the generating unit's output, with the amount and rate of adjustment determined by the size of frequency variation and the speed governor's characteristics and settings. Thus, a speed governor will typically respond to a fall in system frequency by automatically increasing the generating unit's output, and vice versa.[13] This action helps to stabilise (and potentially restore) system frequency movements away from 50Hz.

Generating units that use inverters when functioning do not use speed governors. Instead, they use electronic frequency control systems to adjust the generating unit's output in response to changes in system frequency.

4.5. In the early years of wind generation technology, wind turbines typically did not have the capability to support system frequency. However, modern inverter technology means that wind turbines, along with solar photovoltaic generation and battery energy

12 See clause 5(1) of Technical Code A of Schedule 8.3.

13 Energy storage systems and demand response can provide similar functionality.

storage systems (in both charging and discharging mode) can provide frequency control. Therefore, these technology types can assist to limit system frequency changes due to imbalances between generation and demand, in the same way that conventional synchronous generation can.

4.6. Through its ability to provide 'synthetic' inertia, inverter-based generation that uses a 'grid-forming' inverter would also assist to limit system frequency changes due to imbalances between generation and demand.

The 30MW threshold was not expected to be fixed forever

4.7. It is useful to understand why 30MW of a generating station's output was selected as the threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code. It is also important to understand that this threshold was not meant to be fixed forever. Rather, at the time the threshold was established, the expectation was that it might change at some point in time.

4.8. The 30MW threshold was developed more than 20 years ago, prior to the Code and its predecessor, the Electricity Governance Rules 2003. The threshold was established through an industry working group process that developed common quality rules for an enforceable industry rulebook.

4.9. Originally, it was proposed that generating stations with a *capacity* (as opposed to an *output*) of less than 5MW would be exempt from complying with frequency-related AOPOs and technical codes. The 5MW threshold carried over the requirement in place at the time under Transpower's 'Common Quality Obligations'. Under this original proposal, the intention was to subsequently undertake appropriate economic analysis to determine whether the 5MW, or some other, threshold was appropriate.

4.10. Alternative proposals at the time included:

(a) no exemption threshold, with the system operator assessing each generating station against criteria to establish whether full compliance with the common quality technical obligations was warranted

(b) all generation connected to a distribution network being exempt from complying with the common quality technical obligations

(c) all generation connected to a distribution network being exempt from complying with the common quality technical obligations unless a (clearly prescribed) cost-benefit test triggered the application of frequency-related common quality technical obligations.

4.11. Some stakeholders raised concerns with 5MW being used for the threshold for complying with frequency-related AOPOs and technical codes. These concerns related to:

(a) the apparent absence of any cost-benefit justification for using 5MW

(b) the potential compliance cost for existing generating stations if 5MW were to be adopted[14]

(c) the use of 5MW being likely to impose significant costs on distributed generation, which could impede the development of distributed generation.[15]

4.12. As a result of these concerns, 5MW was revised up to 30MW. In addition, the basis for the threshold was changed from a generating station's capacity to its 'nominal net export'. The rationale for this was that the sudden loss of a site with matched generation and load during an under-frequency event would not affect common quality whereas the sudden loss of a site exporting electricity would.[16]

4.13. The threshold was applied to a generating station rather than a generating unit because 'common mode failure' was of most concern in relation to the performance of generating equipment during under-frequency events. Applying the threshold to a generating station also avoided the risk of large generating stations being exempt from the frequency-related AOPOs and technical codes because they comprised many smaller generating units.

4.14. Setting the threshold at 30MW net export was intended to result in two or three larger on-site generating stations needing to comply with the frequency-related AOPOs and technical codes. It was believed these on-site generating stations would otherwise be likely to island[17] during an under-frequency event. This would result in a net public cost, associated with procuring instantaneous reserve (generation reserve and/or interruptible load) to cover the net injections at risk of islanding.

4.15. This change to the basis of the threshold meant an industrial site with on-site generation capacity of 30MW or more did not need to comply with the frequency-related AOPOs and technical codes, provided the export of surplus electricity from the site was less than 30MW.

4.16. Pending a proper evaluation of an appropriate megawatt level or a longer-term approach, the system operator had to make the case for assets with a nominal net export of less than 30MW being required to comply with any of the frequency-related AOPOs and technical codes. It was considered likely that compliance with some obligations would be appropriate for generating stations below the excluded generating station threshold. An example was the provision of information to establish common mode failure risks, which the system operator could use for system planning purposes.

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14 Although 5MW was an existing threshold in Transpower's Common Quality Obligations, there was no effective means of enforcing some generators' compliance with certain provisions in the Common Quality Obligations. Therefore, using 5MW for the threshold in the proposed new industry rulebook had cost implications for some generators, in that common quality requirements could now be enforced.

15 *ibid*

16 The Authority notes another rationale would be to lower compliance costs for businesses with on-site generation that is integral to their industrial processes.

17 'Islanding' is the term used to describe the electrical disconnection (tripping) of a generating station and any load it supplies that is behind its point of connection to a network. This tripping is often done via automatic protection relays in response to large (under) frequency excursions on the power system. Reasons why some generating stations island during a frequency excursion include avoiding damage to generating equipment and/or to avoid disruptions to business processes at the point of connection (eg, industrial or manufacturing processes).

A power system study recommends a threshold of 5MW

4.17. The Authority has engaged the system operator to undertake a power system study investigating whether, with the expected uptake of variable and intermittent generation over the coming years, the threshold for automatically excluding generating stations from the frequency-related AOPOs and technical codes should be amended.

4.18. The system operator's recommendation after completing this study is to lower the 30MW threshold to 5MW. Attached as Appendix C is the report for this study.

4.19. Lowering the threshold would:

(a) improve the performance of frequency across the power system during a 'contingent event' on the power system[18]

(b) reduce the risk of generation electrically disconnecting from the power system during a contingent event (secondary tripping[19]). This is because all generating units above the lower threshold would be expected to ride through an under-frequency event.

4.20. These two outcomes, in turn, would reduce the amount of under-frequency reserve procured by the system operator in order for the system operator to plan to comply, and comply, with its PPOs.

4.21. The power system study considered several thresholds (20MW, 10MW, 5MW, 0MW) for the year 2035. The study found the first 10MW reduction in the threshold (ie, 30MW to 20MW) delivered a relatively larger improvement in frequency performance, and a relatively greater reduction in required under-frequency reserve, than the second (ie, 20MW to 10MW) and third (ie, 10MW to 0MW) incremental reductions of 10MW.

4.22. Unsurprisingly, 0MW was the threshold delivering the best frequency performance in a contingent event. However, the improvement in the frequency performance[20] relative to the frequency performance under the 5MW and 10MW thresholds was found to be small.

4.23. The system operator notes the 5MW threshold performed only slightly better in the system studies than the 10MW threshold. The system operator gives two reasons for this:

(a) The number of generating stations with a capacity below 5MW is high – ie, more than 50% of the generating stations below 10MW have a capacity under 5MW.

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18 A 'contingent event' is an event affecting the power system where the impact, the probability of occurrence, and the estimated costs and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event. See clause 12 of the Policy Statement, which is incorporated by reference in the Code under clause 8.10.

19 'Secondary' or 'sympathetic' tripping of a generating unit occurs when the generating unit's protection equipment disconnects the unit from the network because of a disturbance on the network to which the unit is connected.

20 As measured by the frequency nadir/lowest point.

(b) With only 20% of the generation below a threshold being tripped in the studies, the total megawatt amount tripped for the 5MW and 10MW threshold cases differs by only 12MW in the summer cases and 14MW in the winter cases.[21]

4.24. The system operator has recommended a 5MW threshold instead of a 10MW threshold because:

(a) a 5MW threshold results in a lower risk of secondary tripping in a contingent event or an extended contingent event

(b) a 5MW threshold 'future proofs' against the uptake of distributed generation with an output of 5–10MW (eg, distributed solar photovoltaic generation)

(c) a 5MW threshold should not impose significant costs on generating stations because technology used in new generating units, regardless of size, is designed to have the capability to ride through an under-frequency event and remain connected for a specified period for the frequency thresholds specified in the Code.[22]

4.25. The Authority notes we have not yet formed a view on an appropriate threshold and welcome your feedback on this.

The frequency support obligations should apply to existing generating stations and energy storage systems

4.26. The Authority considers the frequency support obligations under the first frequency-related option should apply to both new and existing generating stations and energy storage systems that export at or above the revised threshold. We expect these resources would incur little or no capital cost complying with the requirement because synchronous machine-based generating technology and standards-compliant inverter technology have incorporated the necessary frequency control capabilities for years.

4.27. Generation owners and energy storage system owners who could not or chose not to fully comply with the frequency support obligations would have the option of applying to the system operator for a dispensation from full compliance.

4.28. Dispensations are conditional on asset owners paying any identifiable costs incurred by the system operator as a result of their non-compliance. In this respect, dispensations would allow generation asset owners and energy storage system owners to avoid excessive or uneconomic upgrade costs, while requiring owners to pay for any additional costs their non-compliance imposed on others. The dispensation process ensures that exacerbators pay for the costs they impose on others by ensuring that they internalise those costs. Allocating costs in this way promotes productive efficiency and efficient levels of reliable supply of electricity.

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21 See p. 26 of the system operator's frequency study 2, attached as Appendix C.

22 The Authority notes that thermal generation in New Zealand is connected in the North Island, which has a frequency threshold of 47Hz for an under-frequency event, as opposed to the threshold of 45Hz in the South Island.

Should ‘virtual power plants’ be treated consistently with single site generating stations?

4.29. A virtual power plant is an aggregation of the capacities of multiple smaller generating, or demand-side management, technologies for the purpose of participating as a single ‘virtual’ generating station or ‘virtual’ load in the wholesale electricity market.

4.30. The Authority’s preliminary thinking is that ‘virtual power plants’ / ‘virtual generating stations’ with a common control system should have the same frequency-related AOPOs placed on them as for generating stations located at a single site. This is because the effect on frequency, for example, on a 20MW virtual generating station is likely to be similar to the effect on frequency of a generating station of the same size that is located at a single physical location.

4.31. The Authority welcomes feedback on this preliminary thinking. The Authority also welcomes feedback on the extent to which it is desirable to align the AS/NZS 4777.2 standard with the Code’s requirements for generating stations to support frequency during under-frequency events.

Summary of the key pros and cons of option 1

Pros

4.32. The system operator’s study shows the key technical benefit of reducing the 30MW threshold – improved frequency performance during a contingent event on the power system.

4.33. The study also highlights a key economic benefit from a lower threshold – relatively lower procurement costs for under-frequency reserve.

Cons

4.34. For owners of (single site and virtual) generating stations below the 30MW threshold but equal to or above a new lower threshold, there will be the cost associated with ensuring their asset complies with the technical requirements in Part 8 of the Code and undertakes commissioning and routine testing in accordance with Part 8. This cost could be lowered by, for example, placing less onerous testing requirements on the asset owner.

4.35. There will be costs related to dispensations if some generating stations below the 30MW threshold but equal to or above the new lower threshold cannot comply with the technical requirements in Part 8 of the Code and undertake commissioning and routine testing in accordance with Part 8. These costs will relate to the asset owner seeking a dispensation and the system operator considering the dispensation.

4.36. For some consumers with on-site generation integral to their industrial processes, the obligation for the generation to remain connected during an under-frequency excursion may result in on-site processes being disrupted by the frequency excursion. This would depend on the sensitivity of the on-site processes to variations in frequency.

Q1. Do you agree the Authority should be short listing for further investigation the first frequency-related option to help address Issue 1? If you disagree, please explain why.

Q2. What do you consider to be the main benefits and costs associated with the first frequency-related option?

Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?

Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an under-frequency event for six seconds?

5. Option 2: Introduce a maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve

5.1. Under option 2, clause 5 of Technical Code A of Schedule 8.3 of the Code would be amended to set a permitted maximum dead band beyond which a generating unit would have to contribute to frequency keeping and instantaneous reserve. This obligation would apply to existing and new generating units.

5.2. As noted above in paragraph 4.2, Part 8 of the Code contains AOPOs that specify the contributions generators must make to maintaining frequency in the normal band. The AOPO approach currently is to require a pool of generating units to be fitted with speed governors that, when dispatched for energy and instantaneous reserve, maintain an acceptable level of power system stability and frequency quality.

5.3. Clause 8.17 of the Code sets out the overarching requirement on generators to:

> "*make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to within the normal band)*".

5.4. Clause 8.17 also requires such contributions to be assessed against the technical codes in Schedule 8.3 of Part 8, which include the requirement on generators to:

(a) ensure that each of their generating units has a speed governor (the purpose of which is to automatically adjust the generating unit's output in response to changes in system frequency)

(b) agree speed governor settings with the system operator.[23]

5.5. However, currently this clause is silent on whether a generator can apply a dead band setting to a speed governor, thereby halting the generating unit's frequency response within that band.

5.6. Under option 2, the permitted maximum dead band would be measured across the entire generating unit, rather than as an input parameter for the governor/inverter. The permitted maximum dead band would be expressed as an amount (in Hz) above and below 50Hz.

'Dead band', 'Permanent droop' and 'Gain'

A frequency 'dead band' in a generating unit's frequency control system halts the generating unit's frequency response within that band. This reduces the generating unit's response to frequency deviations. A dead band can be inherent in moving parts – a generating unit with an inherent dead band will not respond, at least immediately, to small changes in system frequency. A dead band can also be a settable parameter – a frequency control system with a dead band setting of ± 0.1Hz will not respond until system frequency is lower than 49.9Hz or higher than 50.1Hz.

The 'permanent droop' of a frequency control system is a mechanism to change the apparent set point for the output of a generating unit as a proportional response to changes

[23] Clause 5(1) of Technical Code A of Schedule 8.3.

in frequency. If system frequency rises beyond the set point frequency (50Hz), the permanent droop of the frequency control system reduces the apparent set point for generating unit output. Similarly, if system frequency falls below 50Hz, the frequency control system increases the apparent set point for generating unit output.

The droop percentage refers to the percentage change in frequency that is necessary to cause the output of the generating unit to change from zero output to full output. For example: the set point of a generating unit with 7% droop will increase from no output to full output if the frequency decreases by 7%: the set point of a generating unit with 5% droop will increase from no output to full output if the frequency decreases by 5%.

It is important to note that droop itself is only acting to change the apparent generating unit output set point. Droop does not reflect how long the generating unit will take to reach that point. This is determined by the collective effects of the droop, gain, and dynamic characteristics of the generating unit.

'Gain' is a settable parameter for frequency control systems that affects how quickly a generating unit will move to its new output. The speed of this movement can also be affected by the ramping characteristics of the generating unit.

Previously the Authority has proposed a maximum dead band of ± 0.025Hz

5.7. In 2014, the Authority consulted on a Code amendment proposal to clarify generators' obligations to contribute to maintaining frequency in the normal band. Included in that Code amendment proposal was a permitted maximum dead band of ± 0.025Hz around 50Hz.[24]

5.8. The size of the proposed maximum dead band was based on a recommendation from the system operator in 2011, following a study modelling the effects of several dead bands (0.025Hz, 0.05Hz, 0.1Hz). The 2011 study was in response to feedback from generators. They had noted that many generating units had a small inherent dead band of around 0.01–0.025Hz. This made it impossible for them to comply with an interpretation of the Code under which generating units were to operate with no dead band.[25]

5.9. For each of the modelled dead bands, the system operator's 2011 study looked at two things:

(a) the total response of all generating units[26] to a frequency deviation within the normal band

(b) the stability of generating units' governors.

5.10. The study showed that:

(a) as expected, a generating unit's response to a frequency deviation within the normal band decreased as the permitted maximum dead band increased, but

24 Electricity Authority, June 2014, Normal frequency asset owner performance obligations, Consultation paper.

25 System operator, 28 September 2011, TASC-011: Normal Frequency Review, Version 02.

26 Separately for the North Island and South Island.

that the power system's response to the frequency deviation would not be unduly affected by a small maximum dead band

(b) the modelled dead bands had minimal effect on the stability of grid-connected generating units' governors, as compared to having no permitted maximum dead band at all.[27]

5.11. In submissions on the 2014 Code amendment proposal the Authority received feedback from several generators saying the proposed dead band was too narrow. This feedback was received in relation to various generating technology types – co-generation, combined cycle gas turbine (CCGT), geothermal, hydro, and wind.[28]

5.12. Generators submitted that a permitted maximum dead band of ± 0.025Hz around 50Hz would require either:

(a) dispensations from the system operator, or

(b) significant capital expenditure to make generating units compliant, along with significant operating and maintenance expenditure because of increased wear and tear of the generating units.

5.13. For example, Meridian Energy said that, in the absence of dispensations, it would need to incur millions of dollars of cost and foregone revenue in attempting to comply with the proposed maximum dead band.[29]

A capability market for control response, subject to costs and practicality

5.14. In late 2014, the Authority decided to reconsider options for procuring governor response. This was due to feedback received on the June 2014 consultation paper and due to information from the system operator's frequency-related developments that was relevant to the frequency-related AOPOs. In particular, the system operator was observing that the operation of 'multiple provider frequency keeping' (MFK) and the HVDC link's 'frequency keeping modulation control' (FKC)[30] was appearing to result in generating units with responsive frequency control systems being more active in responding to frequency deviations.[31]

5.15. Subsequently these early observations were confirmed – the introduction of FKC and MFK had resulted in a change to normal frequency management. Some of the frequency keeping duty of contracted frequency keeping providers had moved to the inherent response of frequency control systems. In 2018 the Authority decided new arrangements should be developed to replace the performance obligations for generating unit governor response.[32]

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27 System operator, 28 September 2011, TASC-011: Normal Frequency Review, Version 02, p. 4 and p. 14.

28 Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations, Consultation Response Paper, Appendix A.

29 *Ibid*

30 See paragraphs 6.3 to 6.13 of this paper for an explanation of FKC and MFK.

31 Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations. Consultation response paper, p. 28.

32 Electricity Authority, 18 September 2018, Normal Frequency Management Decision Paper.

5.16. The Authority decided that, subject to costs and practicality, the new arrangements should be in the form of a capability market for governor response (and other future forms of control response). Using a tender-based procurement approach, the system operator would procure adequate resources through the capability market to maintain system security and an acceptable level of frequency quality.[33]

5.17. However, the Authority also decided to pause further development of a capability market for control response until the outcomes of several Authority projects could be taken into account. These projects were:

(a) Enabling new generating technologies to participate in the wholesale market.

(b) Identifying whether there are effective arrangements in place for equal, or open, access to transmission and distribution electricity networks.

(c) Identifying and addressing barriers to consumers using electricity or electricity services provided by more than one party at the same time, at the same location.

(d) Improving the efficiency of distribution pricing.

(e) Implementing a default distribution agreement template in Part 12A of the Code.

5.18. We considered that accounting for the outcomes of these projects would potentially improve the level of participation of alternative technologies in the capability market for control response (eg, battery energy storage systems and demand-side response).[34]

5.19. In the meantime, we have commenced initial scoping for a review of the purpose and effectiveness of the frequency keeping ancillary service.[35]

A maximum dead band is desirable at least until a capability market for control response

5.20. Although the Authority has decided new arrangements should be developed to replace the existing performance obligations for generating unit governor response, we consider a permitted maximum dead band in the Code would be desirable. This is for the reasons set out in the problem definition (refer to paragraph 2.11). We consider a clearly specified maximum dead band would help with both maintaining frequency within the normal band and managing the quality of frequency within the normal band.

5.21. A permitted maximum dead band may still be needed for system security reasons if a capability market for control response were to be implemented. As we noted in our 2018 decision, removing the governor response requirement would be an untested approach. It is probable that a minimum response to changes in frequency would be required of at least some generating units not participating in the capability market.[36] This would need to be considered during the design and implementation of any such market.

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33 Electricity Authority, 18 September 2018, Normal Frequency Management Decision Paper, p. 3.

34 Electricity Authority, 18 September 2018, Normal Frequency Management Decision Paper, p. 3.

35 See paragraph 3.17 of the Authority's Peak Capacity consultation paper.

36 Electricity Authority, 18 September 2018, Normal Frequency Management Decision Paper, p. 17.

Should the maximum dead band be based on the technology of the generating station?

5.22. An argument can be made that the size of any permitted maximum dead band should depend on the technology of the generating station. Technology-based dead bands reduce total operating and maintenance costs across the pool of generators by causing generating units with lower operating and maintenance costs to contribute more to frequency management than generating units with higher costs. Theoretically, technology-based maximum dead bands should improve the reliability of the power system by improving the reliability of generating units that face relatively more wear and tear under a narrow maximum dead band (eg, thermal generating units).

5.23. Such an approach would appear to be broadly consistent with how governors are currently set for each technology class—which appears to broadly reflect their relative costs of providing frequency response. Several submissions on the Authority's 2014 and 2017 normal frequency management consultations supported normal frequency management standards on generating units that were appropriate to the technical capabilities of the generating unit.[37]

5.24. However, we note this approach has the potential to distort decisions made about different generation technologies – in relation to investment, design, operation, and refurbishment. We note that many overseas jurisdictions make little distinction between the expected capabilities of different generation technologies.

5.25. A second order consideration is that varying the permitted maximum dead band based on generation technology could result in generating stations that are more responsive to changes in frequency being off their dispatched quantities more often and/or by larger amounts. We have received feedback in the past that this has implications for a generator's compliance with the Code. The system operator, who monitors compliance with dispatch instructions, has indicated to us that it considers the level of effort in monitoring these generators' compliance with dispatch instructions is similar to that involved in monitoring other generators' compliance with dispatch instructions.[38]

Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.

Should a permitted maximum dead band be linked to droop and gain settings?

5.26. A generating unit might comply fully with a permitted maximum dead band requirement but contribute less to normal frequency management than a generating unit that does not comply fully. A generating unit might not comply with the maximum dead band requirement for frequency control systems but otherwise be more

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37 Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations, Consultation Response Paper, Appendix A.

Electricity Authority, 18 September 2018, Summary of submissions – Normal frequency management strategic review.

38 Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations, Consultation Response Paper, pp. 14–15.

responsive to changes in frequency in the normal band. This might be due to a lower droop setting than the generating unit that complies with the maximum dead band requirement.

5.27. Specifying in the Code the dead band, droop, and gain settings for individual generating units' frequency control systems is impracticable. The Authority considers a more effective approach is to include a permitted maximum dead band in the Code, alongside the existing droop range (of 1–7%), and for generators with non-compliant generating units to engage with the system operator via the dispensation and/or equivalence processes. This will enable the parties to determine dead band, droop, and gain settings that best enable the system operator to plan to comply, and to comply, with its PPOs.

5.28. We note this is consistent with the typical practice historically for generators to work with the system operator to implement settings for frequency control systems that provide stable operation when their generating stations are operated within an islanded load. The settings reflect inherent differences in capability (eg, hydro generating units usually have lower droop settings than geothermal generating units).

What about widening the normal band?

5.29. If a maximum dead band were to be specified in the Code, then one might expect frequency management to be easier for the system operator if the normal band were to be widened (eg, 49.7–50.3Hz). Widening the normal band might also be expected to reduce frequency keeping procurement costs relative to keeping the normal band at 49.8–50.2Hz.

5.30. The Authority notes, however, both outcomes would be contingent upon generators not widening the dead bands in place for their generating stations in response to the widening of the normal band (eg, to reduce wear and tear).

5.31. A survey undertaken in 2003 suggested that if the normal band were to be widened, most of the demand side of the electricity industry would probably be indifferent. However, some generators would be likely to incur costs, due to mechanical wear and tear and generating unit efficiency reductions because of free governor action.[39] An industry working group estimated at the time that the costs of widening the normal band to ±0.3Hz would be approximately $20m p.a.[40] Identified costs included:

(a) greater free governor action increasing generating unit wear and tear (due to continual cycling of equipment)

(b) efficiency losses (by forcing generating units away from optimal loading)

(c) implementation, overhead and transaction costs.[41]

5.32. The Authority's predecessor, the Electricity Commission, commenced a project in 2007 to review the normal frequency band. However, this project was put on hold the following year, pending completion of a project looking at generation fault ride through

39 Grid Security Committee Secretariat, September 2003, Frequency Quality Survey, cited in Electricity Commission, 20 November 2006, Common Quality Development Plan: Evaluation of Options, p. 15.

40 Frequency Development Working Group, 2003, cited in Electricity Commission, 20 November 2006, Common Quality Development Plan: Evaluation of Options, p. 36.

41 Ibid, pp. 13–14.

asset owner obligations.[42] This latter project resulted in amendments to the Code in late 2016.[43]

5.33. The Authority has undertaken a high-level assessment of widening the normal band. We note this option is relevant to all three of the short listed options discussed in this paper. We consider widening the normal band is feasible but may be expensive to implement, based on the earlier consideration of this option, albeit over 20 years ago.

5.34. We expect there would be a long implementation, as physical power system trials would be needed to evaluate the extent to which widening the normal band would affect normal frequency management, including the procurement of frequency keeping ancillary services. The potential effects on instantaneous reserve requirements would also need to be considered. More fast instantaneous reserve may be required to arrest an under-frequency event quicker.

5.35. Also, we consider there would be a moderate risk of unintended consequences – in relation to the operational effect on some generation and frequency-sensitive loads.

5.36. System trials would enable industry participants to provide feedback to the Authority on the costs and benefits of any wider normal band under consideration.

Q6. Do you consider the Authority should be short listing the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.

Power system studies recommend a permitted maximum dead band of 0.1Hz

5.37. The Authority has engaged the system operator to undertake two power system studies investigating the effects of different frequency response dead bands on:

(a) managing frequency within the normal band

(b) managing frequency after a contingent event has occurred (ie, managing frequency outside the normal band).

5.38. The first study has assessed how different maximum dead bands within the normal band affect the operation of MFK used to maintain frequency within the normal band. The system operator has concluded that enforcing a maximum dead band across all generating units may result in the existing MFK band of ±15MW continuing to be appropriate through until at least 2035. In contrast, a permitted maximum dead band across new generating units only may necessitate a widening of the MFK band of ±15MW sooner than 2035, as more variable and intermittent generation connects to the power system.

5.39. The second study has assessed how different maximum dead bands within the normal band affect the amount of instantaneous reserve needed to keep frequency above 48Hz during a contingent event. The system operator has concluded that the effect of a permitted maximum frequency dead band on instantaneous reserve requirements is insignificant.

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42 Electricity Commission, 20 November 2008, Common Quality Advisory Group: Common Quality Key Work Stream Update, p. 2.

43 See clauses 8.25A, 8.25B, 8.25C and 8.25D of the Code.

5.40. The system operator's recommendation after completing these studies is:

(a) to implement a permitted maximum dead band of ± 0.1Hz around 50Hz for any new generating units

(b) to maintain existing dead band settings for already-commissioned generating units.

5.41. Attached as Appendix C and Appendix D are the reports for these studies.

The Authority considers a maximum dead band should account for inherent dead bands

5.42. An inherent dead band in generating units means it is impractical and/or expensive for generators to comply with a permitted maximum dead band that is too narrow. As noted above in paragraph 5.22, there is also the possibility that an overly-narrow maximum dead band would cause a sufficient increase in the wear and tear of some generating units as to decrease their reliability (eg, thermal generating units).

5.43. The Authority considers any permitted maximum dead band should not be less than the inherent dead band in generating units connected to the power system, as specified by the original equipment manufacturer.

5.44. We acknowledge this requires a trade-off in terms of frequency quality, but we consider the costs of complying with a Code-mandated maximum dead band that falls within an inherent dead band would outweigh the benefit for frequency sensitive load. As generators have pointed out in the past, the cost of complying could come to many millions of dollars.[44]

5.45. Conversely, on the benefit side our understanding is that modern equipment and appliances typically are not degraded by 'noisy' frequency oscillation around 50Hz, provided this is kept within a reasonably narrow band. The current normal band of 49.8–50.2Hz specified in the Code is considered an appropriately narrow band.

A maximum dead band should apply to existing generating stations and energy storage systems

5.46. The Authority considers a maximum dead band should apply to both new and existing generating stations and energy storage systems. We expect these resources would incur little or no capital cost complying with the requirement because of our proposal for any dead band to account for inherent dead bands.

5.47. Generation owners and energy storage system owners who could not or chose not to fully comply with a maximum dead band would have the option of applying to the system operator for a dispensation from full compliance.

5.48. As noted in paragraph 4.28, dispensations are conditional on asset owners paying any identifiable costs incurred by the system operator as a result of their non-compliance. In this respect, dispensations would allow generation asset owners and energy storage system owners to avoid excessive or uneconomic upgrade costs, while requiring owners to pay for any additional costs their non-compliance imposed

44 Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations, Consultation Response Paper, Appendix A.

on others. The dispensation process ensures that exacerbators pay for the costs they impose on others by ensuring that they internalise those costs. Allocating costs in this way promotes productive efficiency and efficient levels of reliable supply of electricity.

Summary of the key pros and cons of option 2

Pros

5.49. The narrower a permitted maximum dead band, the better the quality of frequency (ie, the closer frequency is to 50Hz).

5.50. A narrower permitted maximum dead band could improve the amount of spinning reserve some generating units could offer.

Cons

5.51. Even if a Code-mandated permitted maximum dead band allowed for inherent dead bands, specifying a maximum dead band in the Code that is narrower than the existing dead band in place for a generating unit would be expected to increase the operating and maintenance expenditure associated with the generating unit.

Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why.

Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?

Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?

6. Option 3: Procure more frequency keeping and instantaneous reserve under status quo arrangements

6.1. Under option 3, the system operator would, under the status quo Code arrangements:

(a) procure more frequency keeping ancillary services, via MFK, to help manage frequency within the normal band (49.8–50.2Hz)

(b) procure more instantaneous reserve:

(i) to keep frequency above 48Hz for contingent events, and

(ii) to keep frequency above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

6.2. We have included this option in the short list of options to help address the frequency-related issue despite this option requiring no changes to the Code. This is because a Code-mandated maximum dead band beyond which a generating station must contribute to supporting frequency has implications for the system operator's procurement of frequency keeping, via MFK, and instantaneous reserve. The system operator expects the MFK frequency keeping band may need to widen over the coming years because of variable and intermittent generation causing more frequency variability within the normal band. This widening of the MFK frequency keeping band may not be as large if there is a permitted maximum dead band on all generation in the vicinity of ± 0.1Hz.

The maintenance of frequency using multiple frequency keeping providers

6.3. Frequency keeping providers (frequency keepers) are generating stations that respond to changes in system frequency by adjusting their output to return frequency to 50Hz. Frequency keeping is a common feature of electricity markets around the world.

6.4. Since 2013 (in the North Island) and 2014 (in the South Island), multiple generating stations have been able to provide frequency keeping within the same 30-minute trading period. This service is referred to as ‘multiple provider frequency keeping’ (MFK).[45]

6.5. Generating stations selected to provide the MFK service in a trading period increase or decrease their output in response to a central control signal sent by the system operator. Such changes in output are co-ordinated via the system operator’s MFK control, to correct frequency deviations or system time error.[46] The system operator selects MFK providers, by island, in accordance with MFK market offers.

45 Internationally, frequency keeping is often called ’frequency regulation service’, with providers co-ordinated via automatic generation control, which is similar to the MFK function in New Zealand. Automatic generation control is also used for dispatch purposes in some electricity markets.

46 Prior to 1 July 2013 for the North Island and 4 August 2014 for the South Island, station-based control systems were used to manage frequency in the normal band.

6.6. MFK requirements can be influenced by:

(a) the choice of energy dispatch interval[47]

(b) the amount of response of frequency control systems on the power system.

6.7. Frequency control systems generally are capable of providing a faster frequency response than MFK. However, the extent and speed of the response of frequency control systems depends on the particular technology and how the frequency control mechanism is configured. Real time energy dispatch is the slowest mechanism, while MFK responds continuously within the timeframe between fast inverter control system response and real time energy dispatch.

6.8. The system operator also procures back-up single provider frequency keeping (back-up SFK) services in each island. This is in case the MFK system is unavailable. Providers tender a constant fee for availability, with the system operator able to call on them if MFK systems are unavailable. Providers that are called upon by the system operator receive their offered price.

6.9. A single back-up SFK provider is used rather than two (island-based) back-up SFK providers during any period when MFK is not operating but the HVDC link's frequency keeping modulation control (FKC) is (see paragraphs 6.12 to 6.13). Otherwise, the island-based back-up SFK providers would 'fight' each other to maintain frequency across both islands. Island-based back-up SFK providers are used if there is a loss of both MFK and FKC.

Frequency keeping quantities have been relatively low for some time

6.10. Prior to May 2016 the system operator procured 75MW of frequency keeping—25MW in the South Island and 50MW in the North Island.

6.11. These megawatt quantities represent the megawatt band within which frequency keepers ramped their megawatt set points up and down (ie, ±50MW in the North Island and ±25MW in the South Island).

6.12. In January 2015, FKC was brought into full operational use. FKC varies the active power on the HVDC link to tie together the North Island and South Island frequencies. This followed trials in late 2014. FKC has allowed MFK and instantaneous reserve to be shared between the North Island and South Island.

6.13. The use of FKC has changed frequency management in the following ways:

(a) The system operator has been able to reduce the quantity of frequency keeping it procures nationally via MFK from 75MW to 30MW (15MW in each island[48]) without causing any material deterioration in the quality of system frequency.

(b) More of the work of managing frequency has shifted from frequency keeping providers contracted via MFK to the inherent response of frequency control systems. This is because the speed of response of FKC and the frequency

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47 At regular intervals, the system operator determines generating station dispatch trajectories to meet expected generation requirements to balance electricity supply and demand across the transmission network during the next five-minute interval. Usually this is every five minutes.

48 Ie, the megawatt band within which frequency keepers ramp their megawatt set points up and down is now ±15MW in the North Island and ±15MW in the South Island.

control systems of generating units is faster than the speed of the MFK controls.[49]

Frequency keeping and instantaneous reserve quantities under option 3

6.14. As noted above in paragraph 6.1, under option 3 the system operator would procure more frequency keeping, via MFK, and instantaneous reserve.

6.15. The system operator expects that, over the coming years, it will need to procure more frequency keeping, via MFK, and that the MFK frequency keeping band may need to widen. This will be to help manage more frequency variability within the normal band from an increasing amount of variable and intermittent resources, exacerbated by decreasing system inertia.[50] The first study contained in the report attached as Appendix D sets out the basis for this expectation. As noted in paragraph 6.2, any such widening of the MFK frequency keeping band may not be as large if there is a permitted maximum dead band on all generation in the vicinity of ± 0.1Hz.

6.16. The system operator also expects it will need to procure more instantaneous reserve over the coming years, to help manage frequency variability within the normal band from an increasing amount of variable and intermittent resources, exacerbated by decreasing system inertia. The first study contained in the report attached as Appendix C provides the basis for this expectation.

Summary of the key pros and cons of option 3

Pros

6.17. Given the absence of a capability market for control response (frequency control system response and other (future) forms of control response), option 3 improves transparency around the economic cost of normal frequency management. Generators whose generating stations provide frequency keeping via MFK can factor into their offers such costs – for example:

(a) generating unit wear and tear

(b) efficiency losses due to generating units operating away from their optimal loading.

6.18. Currently, some of the costs associated with the frequency response provided by frequency control systems are hidden or opaque (eg, they are factored into a generator’s energy offers in the wholesale electricity market). Therefore, an increase in the cost of frequency keeping and instantaneous reserve under this option may not represent an increase in incremental cost. Instead, this increase may be a reassignment of costs.

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49 Some shift in frequency management duty towards generating units’ frequency control systems occurred with the implementation of MFK in mid-2013, due to MFK being a slower form of control than the station-based frequency control that pre-dated MFK.

50 See p. 47 of the of the system operator’s frequency study 2, attached as Appendix D, and recalling this is the frequency-related issue we would like to address via the options set out in this paper.

Cons

6.19. Under option 3 there will be the incremental cost of procuring additional frequency keeping, via MFK, and instantaneous reserve.

6.20. Option 3 on its own does not promote the system operator's ability to manage frequency within the normal band as much as would a combination of option 2 and option 3. This is because option 2 is expected to result in generating units' frequency control systems providing more frequency support than at present, due to the speed of response of frequency control systems being faster than the speed of the MFK controls.

6.21. This technical drawback of option 3 may have an economic cost, associated with the degradation of equipment and appliances. However, this cost would be negligible in relation to modern equipment and appliances that generally do not degrade as a result of some increase in relatively minor frequency fluctuations outside the normal band.

Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?

Appendix A Assessment of options

A.1. The Authority has assessed options to help address Issue 1 against seven evaluation criteria. These criteria are drawn from:

(a) the Code amendment principles in the Authority's consultation charter[51]

(b) the Market Development Advisory Group's recommended principles to guide the development of proposals for the FSR work programme[52]

(c) the Market Development Advisory Group's recommended principles to guide the design of Code arrangements for new generating technologies in the wholesale electricity market.[53]

A.2. Our consultation on this options paper provides an opportunity to test our initial assessment with interested parties.

A.3. Table 1 summarises our initial assessment of the three short listed options discussed in this paper:

(a) Option 1: Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code.

(b) Option 2: Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

(c) Option 3: Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

A.4. Although option 3 is simply the system operator continuing to operate under existing regulatory mechanisms, we have included an assessment of it, for completeness.

51 See Electricity Authority I Consultation Charter 2024.

52 As the Market Development Advisory Group had not prepared recommended principles at the time, we used the proposed principles set out in its 6 December 2022 'Library of options' paper on price discovery in a renewables-based electricity system (see Electricity Authority I MDAG Library of options paper). However, we note the set of recommended principles aligns with the set of proposed principles (see Electricity Authority I MDAG Final recommendations report).

53 Market Development Advisory Group, June 2020, Enabling participation of new generating technologies in the wholesale electricity market – Market Development Advisory Group recommendation to Authority Board (see Electricity Authority I MDAG recommendations paper on enabling new generating technologies).

Table 1: Assessment of short listed frequency options against evaluation criteria

	Evaluation criterion	Assessment of frequency option 1	Assessment of frequency option 2	Assessment of frequency option 3
1.	*The option is feasible / implementable with little or no risk of unintended consequences*	The option is moderately feasible with a low risk of unintended consequences.	The option is feasible with uncertain risk of unintended consequences.	The option is strongly feasible with no risk of unintended consequences.
2.	*The option is consistent with the Authority's statutory objectives*	The option promotes one or more limbs of the Authority's statutory objective (reliability and efficiency).	The option promotes one or more limbs of the Authority's statutory objective (reliability and efficiency).	The option promotes one or more limbs of the Authority's statutory objective (competition, reliability and efficiency).
3.	*The option promotes competitive neutrality amongst technologies / fuels*	Yes. The option is neutral as to which technology (synchronous / inverter-based) and fuel type can provide the required service / output.	Yes. The option is neutral as to which technology (synchronous / inverter-based) and fuel type can provide the required service / output.	Somewhat. Geothermal generation, in particular, is not as conducive to frequency keeping operations as other generation technologies (eg, hydro) because of reduced efficiency and higher operating and maintenance costs when providing frequency keeping services.
4.	*The option signals full costs and benefits*	Somewhat. The option entails non-marginal-cost pricing with some costs allocated to some causers.	Somewhat. The option entails non-marginal-cost pricing with some costs, in the form of additional frequency support ancillary service costs, allocated to some beneficiaries (ie, purchasers).	Somewhat. Marginal cost pricing exists to the extent that reserves and energy are co-optimised in the wholesale electricity market. Non-marginal cost pricing exists to the extent that: a) additional frequency support ancillary service costs are allocated to some beneficiaries (ie, purchasers)

				b) instantaneous reserve costs are allocated to causers of under-frequency events.
5.	*The option is a market-based approach*	No. The option is not a market-based / tender-based approach to providing the required service / output.	No. The option is not a market-based / tender-based approach to providing the required service / output.	Yes. The option is a market-based approach to providing the required service / output, to promote innovation and transparency of the full costs and benefits of an option / solution.
6.	*The option is output-based rather than prescriptive*	No. The option is prescriptive as to what a participant must do / provide to achieve the common quality outcome. A dispensation to a participant will impose costs on other participants.	No. The option is prescriptive as to what a participant must do / provide to achieve the common quality outcome. A dispensation to a participant will impose costs on other participants.	Somewhat. Theoretically it is possible for industry participants to decide how best to achieve the outcome.
7.	*The option is durable*	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years.	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years. This option may not be durable if the dead band is set at a level that necessitates a frequency keeping requirement that exceeds the amount of frequency keeping capability.	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years.

A.5. To arrive at the three shortlisted options to help address the identified frequency issue, the Authority assessed a 'long list' of options against the first of the seven evaluation criteria—ie, *the option is feasible / implementable with little or no risk of unintended consequences*.

A.6. The Authority removed from the long list those options we considered feasible but:

(a) expensive or which have a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)

(b) expensive and which have a long implementation and/or a significant risk of unintended consequences (>5 years to change the Code, >7 years to change assets, >$100m implementation cost).

A.7. The reason for this approach was to enable options that can deliver 'quicker wins' to be progressed ahead of options that require a longer gestation, and which are not necessarily needed within the next five years.

A.8. The Authority is not discarding all of the options removed from the long list. Rather, we are deferring further consideration of some of them for the time being. We plan to return to these within the next 12–24 months.

A.9. Table 2 shows the options we removed from the long list.

Table 2: Options removed from the long list of frequency-related options

	Option	Assessment
1.	Resources (e.g. generating stations, battery energy storage systems) must make available X% of maximum rated capacity to support frequency in under-frequency events.	The option is expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost). The unintended consequence is that the cost of wholesale electricity would increase, which could exceed the benefit from reducing instantaneous reserve costs.
2.	Establish a new ancillary service market product for 1 second reserve.	The option is expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost).
3.	Establish a new ancillary service contract for inertia (accommodating both synchronous and synthetic inertia).	The option is expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost).
4.	Widen the normal band, since electrical appliances can operate within a frequency range that is wider than 50Hz ± 0.2Hz.	The option is expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost).

		The risk of unintended consequences is the key issue here – in relation to the operational effect on some generation and frequency-sensitive loads, and on the system operator’s management of under-frequency events (eg, higher procurement costs for fast instantaneous reserve).
5.	Require / incentivise improved forecasting by generators. (Refer to MDAG’s options paper for price discovery in a renewables-based electricity system, and the Authority’s issues and options paper on a review of forecasting provisions for intermittent generators in the spot market.)	Out of scope. Part of the Authority’s review of forecasting provisions for intermittent generators in the wholesale electricity spot market.
6.	Increase, from 45Hz to 47Hz, the minimum frequency at which South Island generation assets must remain synchronised for 30 seconds following an under-frequency event.	The option is expensive <u>or</u> has a long implementation <u>and/or</u> a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost). Expected benefits of this option include greater competition in the supply side of the wholesale electricity market and possibly a reduction in the risk of extended supply shortages during dry years. However, amongst other things, raising to 47Hz the minimum frequency at which South Island generation assets must remain synchronised for 30 seconds following an under-frequency event would require a change to the design of the AUFLS regime for the South Island and to the system operator's system tools (eg, the Reserve Management Tool). The system operator would need to also procure more reserves to cover HVDC extended contingent events. This option requires significant investigation and would have a long implementation.

A.10. The Authority retained in the long list those options we considered to be:

(a) strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)

(b) moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)

(c) feasible with uncertain risk of unintended consequences.

A.11. Table 3 shows the options we retained from the long list.

Table 3: Options retained from the long list of frequency-related options

	Option	Assessment
1.	Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related AOPOs and technical codes in Part 8 of the Code.	The option is moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost).
2.	Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.	The option is feasible with uncertain risk of unintended consequences.
3.	Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.	The option is strongly feasible with no risk of unintended consequences (no changes to the Code or to assets, negligible implementation cost).
4.	Lower the minimum frequency keeping threshold below 4MW and have a national market for frequency keeping.	The option is moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost).
5.	Allocate frequency keeping costs to the causers of frequency deviations.	The option is moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost).
6.	Put in place ramping limits on generation plant and load for post-disturbance or change-of-MW output (eg, due to wind gusts or cloud covering).	The option is moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost).
7.	Review the dispensation and equivalence arrangements framework (for frequency obligations).	The option is feasible with uncertain risk of unintended consequences.
8.	Remove the obligation on the system operator to eliminate from the power system any deviations from New Zealand standard time caused by variability in system frequency.	The option is moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost).

A.12. The Authority evaluated these eight options against the remaining six evaluation criteria referred to at the start of this appendix. Table 4 shows why we are consulting on only three of these eight options—a combination of considering an option in another Authority workstream and deferring an option for later consideration.

Table 4: Options retained from the long list of frequency-related options but not short listed

	Option	Assessment
1.	Lower the minimum frequency keeping threshold below 4MW and have a national market for frequency keeping.	Over the next 12–24 months, the Authority plans to look at the regulatory settings for encouraging competition in frequency regulation services as part of a separate project to the review of common quality requirements in Part 8 of the Code. This option will be considered as part of the work to be undertaken in that separate project.
2.	Allocate frequency keeping costs to the causers of frequency deviations.	The Authority is looking at the regulatory settings for allocating frequency keeping costs as part of a separate project to the review of common quality requirements in Part 8 of the Code. This option will be considered as part of the work to be undertaken in that separate project.
3.	Put in place ramping limits on generation plant and load for post-disturbance or change-of-MW output (eg, due to wind gusts or cloud covering).	This option will be considered as part of the consideration of a new frequency-related ancillary services (eg, 1 second reserve / synthetic inertia). The option should include ramping limits on load as well as generation (noting such ramping limits exist now for distributors turning on ripple-controlled load).
4.	Review the dispensation and equivalence arrangements framework (for frequency obligations).	The Authority will add a project to review the dispensation and equivalence arrangements to its prioritisation of projects for the financial year 1 July 2025 – 30 June 2026. Therefore, no consideration of this option is needed as part of the review of common quality requirements in Part 8 of the Code.
5.	Remove the obligation on the system operator to eliminate from the power system any deviations from New Zealand standard time caused by variability in system frequency.	The Authority will progress this option by including it in the Authority's review of the system operator's PPO reporting requirements. This review is being undertaken over the next 12–24 months.

Q11. Do you have any comments on the Authority’s assessment of options to help address Issue 1 identified in our 2023 Issues paper?

Appendix B Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree the Authority should be short listing for further investigation the first frequency-related option to help address Issue 1? If you disagree, please explain why?	
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	
Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?	
Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an under-frequency event for six seconds?	
Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	
Q6. Do you consider the Authority should be short listing the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	
Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why.	

Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	
Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	

Appendix C Report on frequency power system studies 1 and 3

Part 8 Review: Frequency Studies (1 and 3)

Study 1: Lower the 30 MW threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations (AOPOs).

Study 3: Set a permitted dead band beyond which a generating station must contribute to instantaneous reserve and investigate if more instantaneous reserve is required to keep frequency above 48 Hz during contingent events.

Version: 5

Date: June 2024

1 Executive Summary

As part of its Future Security and Resilience (FSR) project, the Electricity Authority (Authority) is investigating potential changes to the management of frequency and voltage across New Zealand's power system. This is to address key identified issues from an increasing amount of variable and intermittent resources on the system.

This report covers two of three sets of frequency studies undertaken by Transpower, as system operator, to assist the Authority and industry stakeholders in their consideration of potential options to help address the following identified issue relating to frequency:

An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic (PV) generation, is likely to cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

In addition to the overall increase in variable and intermittent resources, there is expected to be a proportional increase in generating stations exporting less than 30 MW. This threshold is significant to the system operator as it serves to define the export capacity of an excluded generating station.

Under the Electricity Industry Participation Code (Code), excluded generating stations are exempt from frequency obligations specified in the Code. These exemptions mean that excluded generating stations are not required to support the frequency for an event on the power system and can disconnect from the network to which they are connected if an event arises. An excluded generating station is exempt from the following clauses in the Code:

1. Clause 8.17: Contribution by injections to overall frequency management
2. Clause 8.19: Contributions to frequency support in under-frequency events

Secondary tripping/disconnection of generation is a real risk, as experienced by overseas jurisdictions. For the system operator to meet its principal performance obligations (PPOs), sufficient analysis must be carried out to understand this risk and to enable appropriate technical requirements to be specified to manage the risk.

A proportional increase in generating stations exporting less than 30 MW may require the system operator to procure additional instantaneous reserve (IR) to mitigate any residual risk, and ensure the system operator can meet its PPOs.

Findings

This report contains the following findings:

1. *Reducing the 30 MW excluded generating station threshold*
   The study shows that reducing the MW threshold has a positive impact on the power system's frequency response. The study found that a 5 MW threshold performs slightly better than a 10 MW threshold, as most generating stations that are considered in the study and rated below the 10 MW threshold are also rated below the 5 MW threshold. Imposing a 5 MW threshold will ensure secondary tripping risk can be addressed adequately.
2. *Battery Energy Storage Systems (BESS) providing an additional 15% of fast instantaneous reserve (FIR)*
   This study showed that BESS is effective but needs to have the correct droop settings and performance requirements.
3. *Inverter Based Resource (IBR) generating stations operating with 10% generating headroom*
   This study showed that IBR generating stations can assist in frequency management if operated with generating headroom. This solution may have an economic impact on the generating station owner.

Recommendations

We recommend reducing the 30 MW threshold for excluded generating stations to 5 MW. Reducing the excluded generating station threshold to 5 MW will enforce frequency obligations on a larger pool of generating stations connected to the power system. This would positively support frequency, assist in overall frequency management, and avoid the need to schedule relatively more reserves for the electricity market.

Contents

2 Definitions and Abbreviations

Definitions

Term	Explanation
Code	Refers to the Electricity Industry Participation Code

Abbreviations

Abbreviation	Explanation
ACCE	Alternating Current Contingent Event
ACS	Asset Capability Statement
AGC	Automatic Governor Control
AOPO	Asset Owner Performance Obligation
AUFLS	Automatic Under-Frequency Load Shedding
BESS	Battery Energy Storage System
CQTG	Common Quality Technical Group
EMI	Electricity Market Information
FIR	Fast Instantaneous Reserve
FKC	Frequency Keeping Control
GIP	Grid Injection Point
GXP	Grid Exit Point
IBR	Inverter Based Resource
IL	Interruptible load
IR	Instantaneous Reserve
OCGT	Open Cycle Gas Turbine
OFA	Over Frequency Arming
POC	Point Of Connection
PPO	Principal Performance Obligations
PV	Photovoltaic
REEC	Renewable Energy Electrical Controller
REGC	Renewable Energy Generator Converter
REPC	Renewable Energy Plant Controller
RMT	Reserve Management Tool
SPD	Schedule, Pricing and Dispatch
SPS	Special Protection Scheme
STATCOM	STATic synchronous COMpensator
SVC	Static Var Compensator
TPR	Transmission Planning Report
WECC	Western Electricity Coordinating Council
WiTMH	Whakamana i Te Mauri Hiko

3 Introduction

3.1 Purpose and overview of the frequency studies

As part of its Future Security and Resilience (FSR) project, the Electricity Authority (Authority) published an Issues Paper in 2023 titled "Future Security and Resilience – Review of common quality requirements in Part 8 of the Code"[1]. The Issues Paper identified seven key common quality issues. The first of these issues was related to frequency:

An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic (PV) generation, is likely to cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

This report covers two of three sets of frequency studies undertaken by Transpower, as system operator, to assist the Authority and industry stakeholders in their consideration of potential options to address this issue.

3.2 Expected changes in generation

The New Zealand power system is currently dominated by synchronous machine-based generation which produces approximately 90% of the energy delivered across the transmission network. The number of Inverter-Based Resources (IBR), such as wind and solar photovoltaic (PV) generation and Battery Energy Storage Systems (BESS), is expected to increase in the coming years, displacing some of the existing synchronous machine-based generation. This view is very much aligned with the connection requests made to Transpower for IBR and the expected, and regularly signalled, retirement of large synchronous thermal generation. The increase in solar PV generation is expected to include a rapid increase in behind-the-meter solar PV generation, as the technology becomes more affordable.

The increase in IBR availability and lower marginal operating costs compared with thermal generation, and at times hydro generation, means that IBR generation is likely to comprise a significant portion of the generation operating in the future.

One of the significant operational differences between synchronous machine-based generation and wind or solar PV generation is the variability and intermittency of the latter's generation output. This can cause an imbalance between generation and load in real time, impacting the system frequency.

The technologies used for IBR bring about other operational differences – particularly the ability of the IBR to remain connected and synchronised with the power system. In short, the increase in IBR will impact the system operator's ability to manage system frequency.

3.3 Managing system frequency

New Zealand maintains a nominal frequency of 50 Hz across the power system. Maintaining this frequency is necessary to avoid damage to equipment connected to the power system, avoid cascade failure due to equipment disconnection, and maintain the frequency time error.

The Electricity Industry Participation Code (Code) requires the system operator to maintain the frequency within a 'normal band' of 49.8 Hz to 50.2 Hz, other than for momentary fluctuations. To maintain and manage the system frequency, the New Zealand power system depends on generator dispatch, frequency keeping services, and asset owner performance obligations (AOPOs) on generators to both ride through frequency fluctuations and to help maintain system frequency by automatically changing their generation output in response to changes in system frequency.

[1] Link to Electricity Authority Issues Paper: [Part 8 common quality requirements | Our consultations | Our projects | Electricity Authority (ea.govt.nz)]

Managing frequency through generator dispatch and procurement of instantaneous reserve: The system operator is responsible for dispatching generation on a five-minute basis, to balance generation and demand so as to maintain frequency. To restore frequency during momentary fluctuations, the system operator also procures IR, which is a mixture of additional reserve capacity and interruptible load. The collective response of the generators must return frequency to at least 49.25 Hz within 60 seconds, with the frequency not permitted to go below 45 Hz in the South Island and 47 Hz in the North Island.

Frequency keeping: One or more generators provides a frequency keeping service (Multiple Provider Frequency Keeping (MFK)) by varying the output of their generating unit(s) in response to frequency keeping control signals issued by the system operator. The generators providing this service use automatic governor controls (AGC), where a central controller can calculate the required power (MW) to maintain the frequency and time error within a required target, which is normally limited to within a regulation control band. New Zealand uses a high voltage direct current (HVDC) frequency keeping control (FKC) mechanism to help keep frequency in the normal band within the North and South Islands. FKC is an operating mode of the HVDC link that continuously varies the HVDC power transfer to maintain the same frequency in the North and South Islands, essentially sharing the frequency keeping reserve across the islands.

Maintaining frequency through obligations on generation asset owners: Part 8 of the Code contains AOPOs that specify the contributions generators must make to maintaining frequency in the normal band. To maintain frequency in the normal band, these obligations require that generating units must ride through contingent events and ensure their governors (or equivalent control systems) automatically respond to changes in system frequency.

Generating stations that export less than 30 MW to the transmission network or to a local (distribution) network[2] do not have to support system frequency in the same way as generating stations exporting 30 MW or more. These are referred to as 'excluded generating stations' in the Code (see clause 8.21). This creates somewhat of an incentive for generators to build generating stations that export less than 30 MW.

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in **Technical Code A** of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** that exports less than 30 **MW** to a **local network** or the **grid**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in **Technical Code A** of Schedule 8.3.

Impact of a frequency dead band: A frequency dead band is a band of frequency in which the generator's frequency control system[3] does not respond to changes in frequency. The Code does not stipulate frequency dead band settings. A narrow dead band reduces the costs of reserve procurement, but the narrower the dead band, the higher the equipment lifecycle costs for generating units due to more active frequency response.

[2] The Code defines a 'local network' to mean the lines, equipment and plant that are used to convey electricity between the transmission network and one of the following: (a) an embedded generator: (b) an embedded network: (c) an installation control point (ICP).

[3] By 'frequency control system' we mean a speed governor for synchronous machine-based generating units and a frequency controller for IBR. At the time of writing this report, the term governor is still used in the code. The term governor is used in this document when referring to the code.

3.4 Assessing the impact of a changing generation mix

Whilst managing system frequency with *current* levels of variable and intermittent generation that uses IBR is manageable, the expected significant increase in IBR will create challenges for managing system frequency under the current regulatory arrangements.

The Authority, in collaboration with the system operator and a technical group the Authority has established to provide advice on the Code's common quality requirements (the Common Quality Technical Group (CQTG)), scoped the following studies.

Study 1: This study assesses the potential future impacts on system frequency in New Zealand from a proportional increase in the number of excluded generating stations for which the frequency-related AOPOs set out in clauses 8.17 and 8.19 of the Code do not apply. The study extends to determining an appropriate (export[4]) MW threshold to enable the system operator to continue to meet its Principal Performance Obligations (PPOs). The engineering studies assess:

1. How different MW thresholds for excluded generating stations can affect frequency management outside the normal band.
2. The impact on frequency management if excluded generating stations do not remain connected during an under-frequency event for the time periods specified in clause 8.19 of the Code.

Study 2: This study assesses:

1. The impact of increased intermittent IBR generation on frequency within the normal band and on frequency keeping, and
2. The impact of implementing a frequency dead band on the width of the MFK frequency keeping band needed to maintain frequency within the normal band.

Study 3 This study assesses how different frequency dead bands affect the amount of IR needed to keep frequency above 48 Hz during a contingent event.

Studies 1 and 3 are the focus of this report. A separate report has been prepared on Study 2.

3.5 High level study approach

Power system frequency studies use dynamic tools that simulate the frequency response of a model of the power system to various system events. For these studies we used the same tools that we use for real-time system operation for:

1. Power flow analysis (to check that the dispatched generation and loading for our studies was plausible and within operating limits); and
2. The dynamic studies that enable us to study frequency changes following simulated tripping of generation.[5]

The high-level approach for these studies involved:

1. Establishing demand and generation inputs and assumptions for a 2035 future New Zealand power system.
2. Setting up and testing a **model of the power system** to represent the current and 2035 New Zealand power system, including dynamic models for elements of the power system such as synchronous machine-based generating stations and IBR.
3. Establishing assumptions for generation scheduling, contingencies, and reserve management.
4. Setting up and running **study cases** to test the frequency responses.

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[4] Clause 8.21 specifies an excluded generating threshold which relates to export and not capacity.

[5] These tools are PSAT and TSAT respectively – software developed by Powertech Lab, Canada.

4 Understanding the Future Power System

Forecasts predict substantial growth in New Zealand's electricity demand, with consequential increases and changes in generation sources, and investment and changes in infrastructure. We have based our view of generation, demand, and network infrastructure for a 2035 future New Zealand power system on the following forecasts and data.

Transpower's 2020 Whakamana i Te Mauri Hiko (WiTMH) report, with updated data from the March 2023 WiTMH monitoring report. These reports have been well socialised, and the base 'accelerated electrification' scenario should be familiar to industry participants. We have based our generation and demand assumptions on these reports. Using these reports enables us to draw from Transpower's most recent (2023) Transmission Planning Report for data on demand forecasts, timing and location of generation investment, and future changes likely to be made to the transmission network.

2023 Transmission Planning Report (TPR). This report sets out the likely need for future transmission projects and incorporates input and review by industry. We have used this report for demand data inputs and for future network configuration and infrastructure upgrades. The TPR forecasts are aligned with the 2020 WiTMH report.

Asset Capability Statement (ACS) and dispensation data. This is data on current, installed generation. We used this data:

1. To understand the current proportion of generation under the 30 MW 'excluded generating station' threshold, the proportion that is connected within distributor networks rather than being transmission connected, and the existing frequency-related dispensations.
2. To inform assumptions about these proportions for the future (2035) projection.
3. To provide frequency-response parameters (such as trip timings) for our modelling.

4.1 Whakamana i Te Mauri Hiko projections

The 2020 WiTMH report is used to inform the amount and type of generation we expect to see in 2035. The 2020 WiTMH report uses an 'Accelerated Electrification' scenario as its base scenario, with a variation ('the Tiwai Exit scenario') which assumes the same accelerated electrification without the Tiwai aluminium smelter as a consumer. Table 1 and Figure 4-1 show the generation capacity by type extracted from the 2020 WiTMH report.

The studies in this report:

1. Use the 2023 TPR forecast, which aligns with the Tiwai Exit scenario for 2035. Impacts of not including Tiwai in the study are:
    a. The alternating current contingent event (ACCE) risk is not impacted, as this is dependent on generation output.
    b. There is reduced load in the lower South Island, which allows for increased north power flows across the HVDC link. However, because an extended contingent event (ECE) risk is not studied, the exclusion of Tiwai has minimal impact on a frequency study where the ACCE risk is studied.
2. Uses the March 2023 WiTMH monitoring report's forecast of utility-scale (i.e. large-scale or grid-scale) solar PV generation.
3. Uses the 2023 TPR's projections of the likely timing and location of generation.

Table 1: Generation capacity by technology type

Technology	Gen Capacity by Type [GW]
Hydro	5.50
Wind	2.90
Geothermal	1.70
Distributed Solar	1.70
Utility Solar	1.00
Gas	1.40
Coal	0.00
Other	0.30
Total	14.50

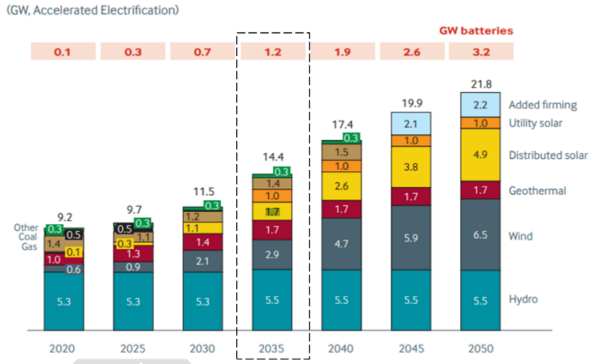

Figure 4-1: Generation capacity by type from WiTMH with focus on 2035

Figure 4-2 is from the March 2023 WiTMH monitoring report and shows how the projections for distributed and utility-scale solar PV generation to 2030 have changed.

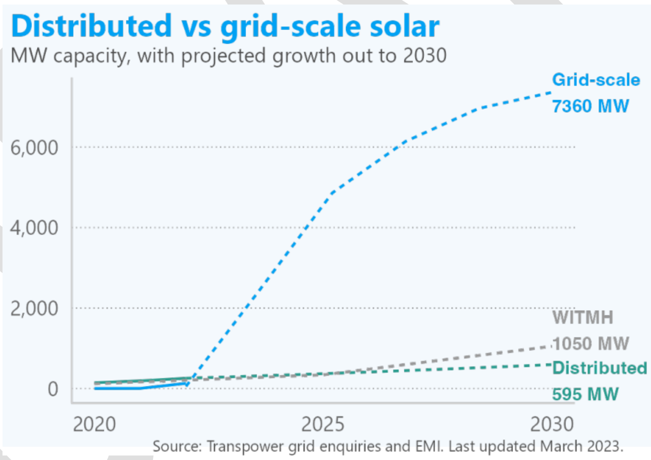

Figure 4-2: March 2023 WiTMH monitoring report forecast on distributed and utility-scale solar

These solar projections show a significant uplift by 2030, particularly in utility-scale solar. For the frequency studies, we have dispatched utility-scale solar to values greater than those stated in the 2020 WiTMH report and have used the 2035 TPR data, which aligns with the distributed solar[6] forecast in the March 2023 WiTMH monitoring report.

4.2 Transmission planning report projections

The purpose of the TPR is to model a possible future New Zealand power system and identify transmission investment needs for the future. The 2023 TPR uses the Tiwai Exit scenario from the 2020 WiTMH report, with the underlying load projection following the Accelerated Electrification scenario but excluding Tiwai.[7] We have

[6] Distributed solar is used to mean solar connected to low voltage (LV) networks e.g. roof top PV.
[7] Noting the TPR makes further projections out to 2035.

used the 2023 TPR's demand projections and likely timing and location of generation for our studies, as well as the forecast transmission investments.

However, it is worth noting three aspects of the 2023 TPR's approach to demand forecasting.

4.2.1 The TPR's demand forecast takes account of some generation

The net TPR demand forecast is inclusive of some generation. The gross demand forecast disaggregates some generation. This gross demand forecast was used in the casefiles. This enabled existing generation that is modelled now in our dynamic studies to be dispatched on/off. Distribution-connected solar PV generation and BESS ('distributed solar' and 'distributed BESS') were not modelled separately.

4.2.2 The TPR's use of prudent and expected demand projections

The TPR uses a combination of prudent and expected forecasts of electricity demand. The prudent demand forecast adds demand to the forecasted expected demand, to account for higher growth in the first seven years (accelerating transmission investment needs in these years). Thereafter the forecasted demand growth returns to forecasted expected demand. For our frequency studies, the TPR's expected demand data was used to project the demand to 2035.

4.2.3 The TPR's demand scenarios

There are various seasonal and within-day demand scenarios in the TPR (i.e. 'Summer Midday/Peak', 'Shoulder Midday/Peak' and 'Winter Midday/Peak'). We used 'Summer Midday' and 'Winter Peak' forecasts of demand to reflect the network extremes of peak demand (Winter Peak) and peak IBR injection (Summer Midday).

4.3 Summary demand assumptions for the 2035 case

The demand projection for the 2035 casefile is important as generation would need to be dispatched to meet this demand. The 2020 WiTMH report outlines demand growth. The TPR projections align with this report where the underlying load projection follows the Accelerated Electrification scenario but excludes Tiwai.

For these studies, we used the 2023 TPR projections. Table 2 shows TPR demand projections and the demand modelled in the frequency studies.

Table 2 Modelled demand compared to TPR demand projections

	Scenario	TPR Net Demand [MW]	Gross Demand (excl. embedded generation) [MW]
Modelled demand (based on 2023 TPR)	Summer Midday	3544	4271
	Winter Peak	8394	9293

4.4 Summary generation assumptions for 2035 case

4.4.1 Summary of high-level installed generation assumptions

Table 3 compares the existing generation, the expected generation retirements, the projected generation capacity in the 2020 WiTMH report and the capacity modelled in our 2035 casefile.

Table 3 Expected generation capacity and modelled capacity

Technology	Asset Capability Statement [MW]	Retired by 2035 [MW]	WiTMH 2020 Report [MW]	Capacity Modelled (Casefile) [MW]
Hydro	5545	0	5500	5978
Geothermal	1137	0	1700	2151
Thermal	2349	1863	1400	1067
Thermal (Cogen)	219	0	-	240
Other	-	-	0	0
Wind	1015	137	2900	3248
Solar	2	0	1050	2585
BESS	0	0	400	1219.76
EG/DG	-	-	-	231.08
Total	10267.917	1999.97	12950.3	16719.71

4.4.2 Modelling distributed solar

Distributed solar was revised down from 1,700 MW to 595 MW for 2030 in the March 2023 WiTMH monitoring report. Distributed solar is embedded in the 2023 TPR load projections. Analysing the TPR forecast for distributed solar, we see the forecast for 2030 contains 613.5 MW of distributed solar. This is close to the March 2023 WiTMH monitoring report, and hence the forecasts align. The March 2023 WiTMH monitoring report forecasts project out only to 2030. We assume that the trend observed in the 2023 TPR forecast continues and hence the modelled distributed solar is as shown in Figure 4-3 and Table 4.

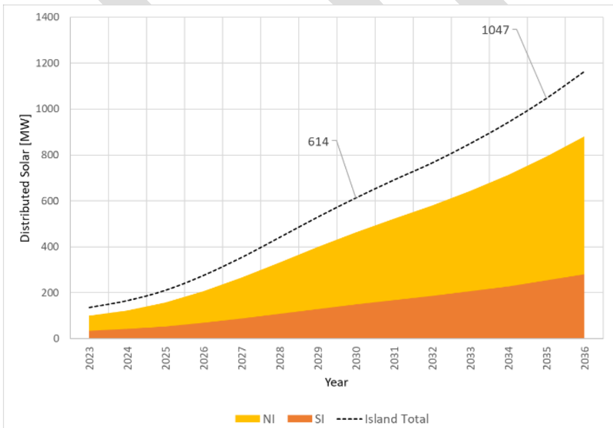

Figure 4-3: Distributed solar modelled on the midday case through the TPR forecast

Table 4: 2030 and 2035 Dist. Solar

	NI	SI	Total
2030	464	150	614
2035	793	254	1047

Distributed solar is the sum of commercial (malls, factories, office buildings etc.) and residential solar PV installations. We assume that most, if not all, of distributed solar installations are less than 5 MW. Table 5 shows the 2022 data for total capacity installed, average installed capacity, new average capacity. This data was extracted from the Authority's Electricity Market Information (EMI) website as at October 2023.

Table 5: 2022 Statistics of distributed solar on the NZ network

	Date	Total Capacity Installed [MW]	Avg. Capacity Installed [kW]	Avg. Capacity - New Installations [kW]
Residential Solar	31/03/2022	155	4	6
Small, Medium Enterprises	31/03/2022	32	15	22
Commercial	31/03/2022	27	18	36
Industrial	31/03/2022	26	23	39
Total ICP installation		240		

4.4.3 Analysis of current generation from ACS data and dispensations data

The Code requires asset owners[8] to provide Transpower, as system operator, with asset capability statements that provide information on current installed generation. As system operator we also hold information on dispensations granted to generators. We have analysed this data to help inform our assumptions for future generation and to provide some parameters for our generation modelling.

Current proportions of generation under the 30 MW excluded generating station threshold

Excluded generating stations make up 4.3 % (280 MW) of the current grid capacity (10,267 MW). Generating stations with dispensations against clauses 8.19(1) and 8.19(3) of the Code make up 17.1 % of the North Island grid capacity, and 5.5 % of the South Island grid capacity, this is shown in

[8] Someone who owns equipment or plant that is connected to or forms part of the transmission network, including in the case of Part 8 of the Code:
(a) equipment or plant that is intended to become connected to the transmission network, and
(b) equipment or plant of an embedded generator.

Table 6 and Table 7. Having a dispensation does not mean that the generating station will trip during an event. Some dispensations are granted due to an inability to sustain pre-event MW output. This will create a shortfall in generation during an event. A table of generating stations and associated dispensations can be found in the appendix of this report.

Most excluded generating stations in the ACS data do not have tripping frequency data, therefore the actual trip settings are unknown.

Table 6: North Island Generating Stations above and below the 30 MW threshold

Station Size	Number	Rated Capacity [MW] (% of Island)	Dispensation[9] [Stations]	Frequency-related Dispensation Capacity [MW](% of Island)
< 30 MW (Excluded)	30	280 (4.3 %)	-	-
> 30 MW	50	6225 (95.7 %)	7	1111
Total	80	6505	7	1111 (17.1 %)

Table 7: South Island Generating Stations above and below the 30 MW threshold

Station Size	Number	Rated Capacity [MW](% of Island)	Dispensation [Stations]	Frequency-related Dispensation Capacity [MW](% of Island)
< 30 MW (Excluded)	27	160 (4.25 %)	-	-
> 30 MW	16	3603 (95.75 %)	4	208
Total	43	3763	4	208 (5.5 %)

Table 8 gives an indication of generation, above and below the 30 MW threshold, that is transmission connected. The data shows that for generating stations with rated capacity equal to or greater than 30 MW, 5.93 % and 3.35 % in the North Island and South Island respectively are not grid connected. For generating stations less than 30 MW, less than 1% are grid connected. Hence it is assumed that new generation < 30 MW will not be grid-connected. This simplifies assigning the inverter voltage control strategies (reactive power support) for the dynamic files used in the 30 MW threshold study[10].

Table 8: Table showing the number of generating stations above and below 30 MW that are grid connected and embedded

	NI				SI			
	Number	MW (% of Island)	MW Cap ≥ 30 MW (% of Island)	MW Cap < 30 MW (% of Island)	Number	MW (% of Island)	MW Cap ≥ 30 MW (% of Island)	MW Cap <30 MW (% of Island)

[9] Dispensations can be against a single generating unit in a generating station.

[10] The IBR voltage control strategies do not impact the frequency study greatly but are set up using this assumption.

Transmission-Connected Stations[11]	43	5895 (89.39 %)	5865 (88.93 %)	30 (0.46 %)	15	3488 (92.69 %)	3477 (92.40 %)	11 (0.29 %)
Distribution-Connected Stations[12]	37	700 (10.61 %)	450 (6.82 %)	250 (3.79 %)	28	275 (7.31 %)	126 (3.35 %)	149 (3.96 %)
Total	80	6595	6315	280	43	3763	3603	160

[11] Our assumption is that if the "Network Connection" data in the ACS refers to Transpower as the network connection, then the generating station has a point of connection (POC) to the transmission network, with the remaining generating stations having a POC to a distributed network.

[12] Based on the definition of 'Grid' and 'Point of Connection' in Part 1 of the Code.

5 Asset and Network Modelling

5.1 Network configuration

This section describes how we configured the transmission network for the study.

In the study case:

1. All transmission-connected generating stations are modelled as individual generating stations at their grid injection point (GIP).
2. Some distribution-connected generating stations are modelled as individual generating stations at their grid exit point (GXP)
3. Some distribution-connected generating stations are modelled as a single aggregated generating station at the GXP, with its export netted off the load at the GXP. This is because distribution networks and secondary networks are not modelled.

Figure 5-1 shows the typical connection of generation to the power system. Figure 5-2 shows how generation is aggregated and modelled on the casefile.

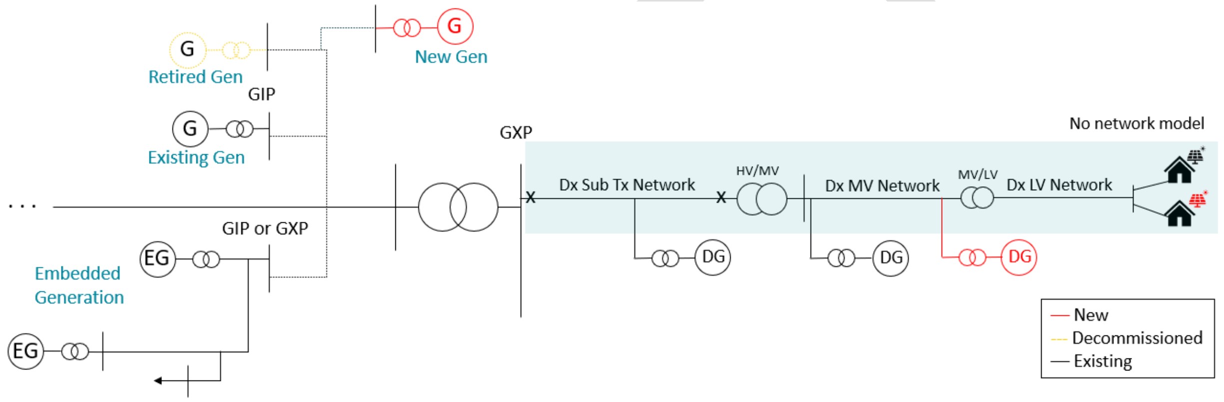

Figure 5-1: Typical connection of generation to part of a network

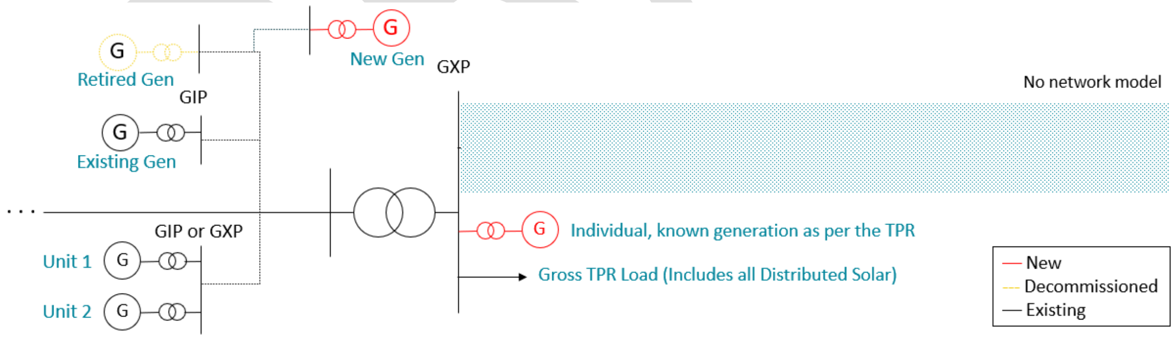

Figure 5-2: Casefile representation of how generation is connected on the network

5.2 Infrastructure upgrades

One of the outcomes of the TPR is to identify infrastructure upgrades. At the time we commenced our frequency studies, the 2023 TPR study was not finalised. Therefore, the 2035 casefile included the upgrades identified in the 2022 TPR. The difference in identified upgrades in the 2022 and 2023 TPRs has minimal impact on the frequency studies.

5.3 Dynamic models

To model the dynamic response of the power system during an event, the following dynamic models are used to express the behaviour of the system over time.

1. **Generator, Governor, Exciter:** PSS/E and User-Defined Models (UDM) are used. These models were validated against ACS data and are representative of the generating stations' performance.
2. **Reactive power compensation devices**: Simplified generic UDM models were used for all static synchronous compensators (STATCOMs) and static Volt-Amps reactive (VAr) compensators (SVCs). Controllable shunt capacitors are placed in/out of service depending on the bus voltage in the power flow. The Upper North Island Reactive Power Controller is not modelled. This scheme is in place to assist in voltage management in the case of High Impact, Low Probability (HILP) events such as an HVDC bipole trip.
3. Reserves to manage over/under-frequency:
    a. <u>*Interruptible Load:*</u> Interruptible load is modelled to trip at 49.2 Hz with a 1 second delay.
    b. <u>*Over Frequency Arming (OFA):*</u> Generators contracted for OFA will trip at specified frequencies and are modelled using a UDM. A list of contracted OFA generators for the North Island and South Island can be found in this report's Appendix (in the section 'Asset and Network Model' under *B1. Dynamic* models). In the North Island, all generators except for Te Mihi are armed.
    c. <u>*Automatic Under-frequency Load Shedding (AUFLS):*</u> New Zealand is currently transitioning from a 2-block AUFLS scheme to a 4-block scheme, which is scheduled to be completed in 2025. The 4-block scheme is modelled in the casefile.
4. **Special Protection Scheme (SPS) to trip excluded generating stations:** An SPS was used to monitor the bus frequency at the point of connection for the IBR, and trip a specified IBR plant at frequencies 48.7 Hz and 48.2 Hz with a time delay of 10 cycles and a breaker delay of 5 cycles.
5. IBR Dynamic Models:
    a. The Western Electricity Coordinating Council (WECC) Generic Renewable Energy Models[13] were used to model the dynamic response of wind, solar and BESS. The Plant Controller (REPC_A), Electrical Controller (REEC_D), and Generator (REGC_B) models were used.
    b. Each IBR generating station is configured for over- and under-frequency management and dispatched to the maximum available power. This means there is no headroom for under-frequency support (as currently seen on the power system), but the functionality remains.

6 Scenarios: Scheduling, Contingencies, and Reserves

6.1 Generation scheduling scenarios

The dispatch philosophy used in the studies is to dispatch generating stations with the lowest offers first (i.e. geothermal, wind and solar, hydro, thermal). There are a few generation scenarios considered for the studies.

1. **Winter Peak:** This is a network maximum loading scenario.
2. Summer midday is the period where solar irradiance and hence solar penetration is at its yearly peak. The summer midday base case can potentially see the highest IBR penetration on the network. Different summer midday scenarios are considered:
    a. **Summer Midday (SM):** Summer midday is the base summer midday case aligning with the generation growth expectations in the March 2023 WiTMH monitoring report.
    b. **SM_Low Wind SYNC Replaced:** High solar, low wind where wind generation is replaced by synchronous machine-based generation (typically hydro[14]). Low wind is modelled between 200 MW and 250 MW.

[13] Models were tested separately to assess their performance and suitability for the study. Generic models were used and no alignment to vendor-specific parameters was considered, in order to keep the models neutral.
[14] See section 6.2 for an explanation of the selection of generating stations for reserve management.

c. **SM_low Wind SOLAR Replaced:** High solar, low wind where wind generation is replaced by solar generation. For summer midday this is a highly probable case.
d. **SM_Low Solar, Low Wind:** This is a high synchronous machine-based generation case that has been considered.
e. **SM_SensUP20_GS:** This is a sensitivity case where a 20% increase in utility-scale solar is considered.

Table 9 shows the dispatched generation in MW for each scenario.

Table 9: Dispatched Generation for each Scenario

	Winter Peak	Summer Midday (SM) [MW]	SM_Low Wind SYNC Replaced [MW]	SM_Low Wind SOLAR Replaced [MW]	SM_Low Wind Low Solar [MW]	SM_SensUP 20_GS [MW]
Hydro	4394	760	1919	796	2501	735
Geothermal	1472	600	684	559	704	539
Thermal	789	360	360	360	405	360
Thermal (Cogen)	89	135	118	99	99	99
Other	68	30	38	30	56	30
Wind	2479	1239	232	257	237	1379
Solar	0	1143	943	2185	229	1143
BESS	268	0	0	0	0	0
EG/DG	231	138	138	138	138	138
Total	9790	4404	4432	4424	4369	4423

6.2 Contingency and reserve management

The contingency considered for the 2035 study is an ACCE where the largest generator is tripped on the network for all scenarios (ACCE = 447 MW in Winter Peak, and ACCE = 360 MW in summer midday). This event was kept constant throughout the studies, except for the 2023 case where the contingency is selected based on the operating conditions.

IR is generating capacity or interruptible load available to operate automatically in the event of a sudden failure of a large generator or the HVDC link. For reserve management, clause 7.2A of the Code requires the system operator to schedule sufficient IR such that the frequency remains above 48 Hz and returns to above 49.25 Hz for a contingent event. This frequency range is sufficient to test the impact of excluded generating stations on IR. The reserves in the study case were scheduled to meet these requirements.

For each study case IR was modelled using partially loaded spinning reserve (PLSR) and tail water depressed (TWD), interruptible load, AUFLS, and energy storage systems. For the study, the mechanical power of a generator is used to quantify the FIR contribution due to the frequency response of generators. Some scenarios in the study modelled the impact of IBR response to under-frequency separately.

The dispatch philosophy for reserves used in the studies is to dispatch the lower offers first, where thermal offers are generally lower for reserve when compared to hydro. SPD/RMTSAT will attempt to co-optimise energy and reserve dispatch such that the least cost solution is implemented. Scheduling reserve is a manual process for the study where this philosophy was considered.

7 Study Assumptions

Generation and demand forecasts

1. It is sufficient to align the study to only the WiTMH and TPR reports as these documents consider multiple sources and have been consulted on with a wide range of industry stakeholders.
2. The 2023 TPR demand projections will be sufficient to represent the loading for a future case, and so the TPR assumptions are adopted in the study.

Network upgrades

1. The 2022 TPR infrastructure upgrades are sufficient as these were the best estimate of a future case at the time the casefiles were developed. The difference in identified upgrades in the 2022 and 2023 TPRs has minimal impact on the frequency studies.

Generation parameters

1. New generation has been dispatched at 90% of the MVA rating. Generation with a POC to the transmission network needs to have the capability to provide reactive power support to the transmission network as per the Code requirements. In practice, this can be achieved by commissioning additional reactive support devices or making use of the generator's capability.

Generation dispatch

1. Wind and solar will be dispatched at 100% of available capacity. No consideration is given to wind availability as it is assumed that wind generating stations will operate at maximum available power.
2. Wind and solar are modelled to provide no inertia to the power system.
3. For the Winter Peak case, it is assumed that there is no generation from solar, as there is little or no solar radiation at the time of the system peaks.
4. Winter Peak has no solar injection, while Summer Midday is expected to have a high amount of solar injection due to solar irradiance peaking around midday.
5. Hydro generation can be partially loaded to a minimum of 70-75% and thermal generation partially loaded to 80% when providing reserve.
6. The order of generation in the generation supply stack will generally not change between 2023 and 2035, i.e. geothermal, wind and solar will remain as the lowest bids in the supply stack in 2035.

Use of dynamic models

1. Existing dynamic models extracted from the online case are sufficient to model the power system's behaviour, as these align to generator asset owner data provided to the system operator.
2. For other equipment with no explicit/detailed models, generic models are sufficient to model the power system's behaviour.

Other

1. No new market products are modelled in detail as this is outside of the study's scope.
2. The power system analysis tools initialise the frequency at 50 Hz. It is adequate to use this starting frequency for all simulations noting that the frequency can be slightly different at the time an ACCE occurs. The average frequency (frequency time error) can be corrected through energy dispatch in real time.

8 Studies, Results, and Observations

8.1 Study 1: impact of lowering the 30 MW threshold on frequency response

This study assesses the impact on managing system frequency in New Zealand due to clauses 8.17 and 8.19 of the Code not applying to excluded generating stations. The study extends to determining an appropriate MW threshold where generating stations below this threshold do not have significant impact on the system operator's ability to meet its PPOs. The engineering studies assess:

1. How different MW thresholds for excluded generating stations can affect frequency management outside the normal band.
2. The impacts on frequency management if excluded generating stations do not remain connected during an under-frequency event for the time periods specified in clause 8.19 of the Code.

8.1.1 Methodology

A 2023 study case provides a baseline and demonstrates current behaviour. A series of study cases were then run for the scheduled generation scenarios for a 2035 casefile, to investigate the impacts on frequency of changes in the power system.

Casefile preparation:

1. 2023 casefile: Extract an online case for Summer Midday and Winter Peak.
2. 2035 casefile:
    a. Forecasting the casefile such that there is alignment between the TPR report, the 2020 WiTMH report and the March 2023 WiTMH monitoring report.
    b. Create various generation mix scenarios according to the generation scheduling scenarios documented in the previous sections of this report.

Study process:

For each study, the largest generator across both islands is tripped as the ACCE.

Following an ACCE for the **2023** cases:

1. The current system response is observed. In 2023 there is no additional generation, and no additional secondary tripping is considered.

Following an ACCE for the **2035** cases:

1. 20%[15] of new[16] excluded generating stations are tripped, where 50% of these generators are tripped at a frequency of 48.7 Hz and the remaining 50% is tripped at a frequency of 48.2 Hz, with a time delay of 10 cycles and breaker operation delay of 5 cycles.
2. Step 1 is repeated with a reduced threshold and the frequency and mechanical power is observed.
3. Additional scenarios are run to complete the study:
    a. With a large uptake of distributed solar expected, it is acknowledged that the tripping of distribution generation affects common quality on the transmission network, and so 20% of the distributed solar is tripped to show the impact.

[15] Odessa Disturbance 1: 1,112 MW of a total of 4,533 MW of (pre-disturbance) generation exhibited active power reduction (25%). Odessa Disturbance 2: 1,711 MW of a total of 8,740 MW of (pre-disturbance) generation exhibited active power reduction (19.5%). To be conservative, we have chosen to use 20% of generation tripped in the study.

[16] Only new excluded generation is tripped as the performance of existing generation is known.

b. Impact of procuring an additional 15% of FIR using BESS is assessed. In this study, the droop is changed to show the performance of BESS with varying droop settings.
c. 20% of dispatched wind and solar generation was dispatched to provide 10% generating headroom. This was to show the impact of IBR responding to under-frequency events.

8.1.2 Study case details

2023 Casefile – baseline study case

This casefile provides a status quo baseline study case, which demonstrates the current behaviour of the power system under a Peak Winter and Summer Midday scenario.

2035 Casefile study cases – impact of different excluded generating station thresholds, across the six generation schedule scenarios described in section 6.1 of this report:

Study case 0: No Trip: No excluded generating station trips.

Study case 1: 30 MW Threshold: 20% of excluded generating stations below 30 MW are tripped.

Study case 2: 20 MW Threshold: 20% of excluded generating stations below 20 MW are tripped.

Study case 3: 10 MW Threshold: 20% of excluded generating stations below 10 MW are tripped.

Study case 3A:[17] 5 MW Threshold: 20% of excluded generating stations below 5 MW are tripped.

Study case 4: An additional 20% of distribution-connected generation is tripped: Impact of tripping Distributed Solar *in addition to* 20% of excluded generating stations at the 5 MW threshold.

2035 Casefile study cases – impact of BESS providing FIR across the six generation schedule scenarios described in section 6.1 of this report.

Study case 5: BESS to provide 15% of FIR: BESS supplies an additional 15% of FIR to the power system, with varying droop settings, and with 20% of excluded generating stations below 30 MW tripped.

2035 Casefile study cases – impact of wind and solar providing headroom across the six generation schedule scenarios described in section 6.1 of this report.

Study case 6: 20% of wind and solar generation provides frequency reserve: 20% of dispatched wind and solar generating stations are dispatched to 90% of available power to provide headroom for under-frequency response. This is completed using the 30 MW excluded generating station threshold.

8.1.3 Observations

For the cases, we are looking first at the frequency response. It is a Code requirement for the system operator to ensure that, for the island in which the contingent event takes place, the frequency remains above 48 Hz. We are also looking at the size of the modelled FIR required to restore frequency to the normal band.

In these studies, we look at the individual mechanical power of each generating station modelled in the casefile. The individual response of the generating stations is summed to obtain a total generation response, to quantify the FIR contribution due to generator response in the system. The FIR contribution due to generator response is summed with the interruptible load tripped, to ascertain the modelled FIR.

Baseline scenario: the 2023 casefile

Summer Midday Case: A 2023 online case was used, dated 31 January 2023 at 13:30. This represents a Summer Midday case for the present power system.

Winter Peak Case: A 2023 online case was used, dated 10 August 2023 at 19:01. This represents a Winter Peak case for the present power system.

[17] This study case was added after the development of the high-level scope reviewed by the CQTG.

Results, findings, and observations

The North Island and South Island frequency response due to an ACCE is shown below in Figure 8-1 and Figure 8-2. In each case the frequency remains above 48 Hz and returns to the normal band as expected. The South Island frequency does not drop as far as the North Island frequency. The ACCE risk in the South Island is smaller than that in the North Island, as shown in Table 10. This is the case for all the studies in this report. Therefore, for the remainder of these results, only the North Island frequency and North Island ACCE are considered. In addition, the forecast uptake of IBR in the South Island is much lower than in the North Island.

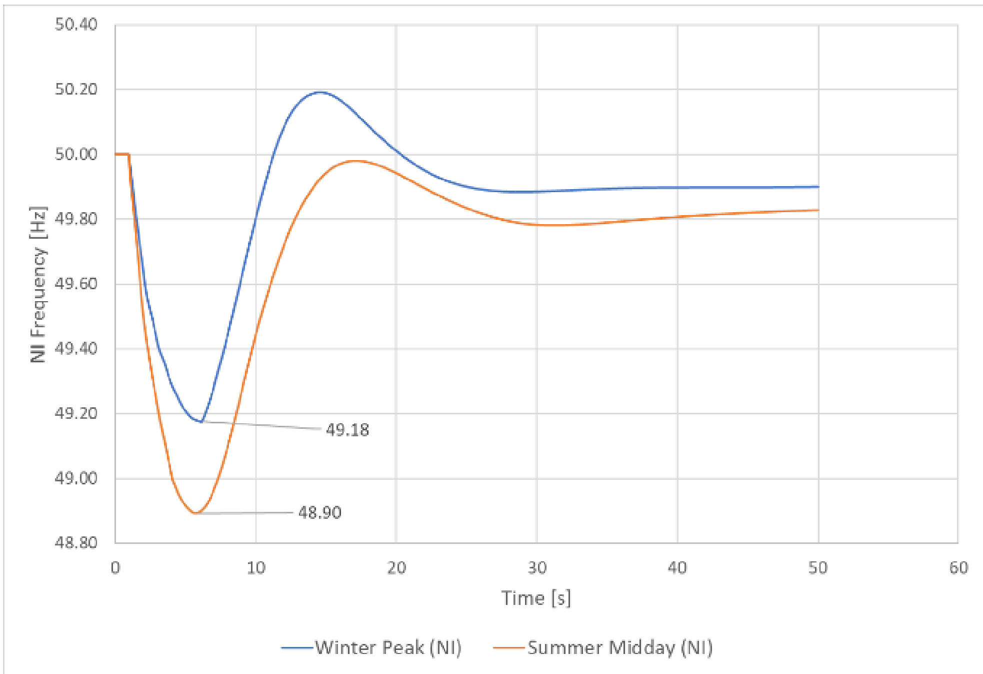

Figure 8-1: Frequency response after an ACCE for the North Island

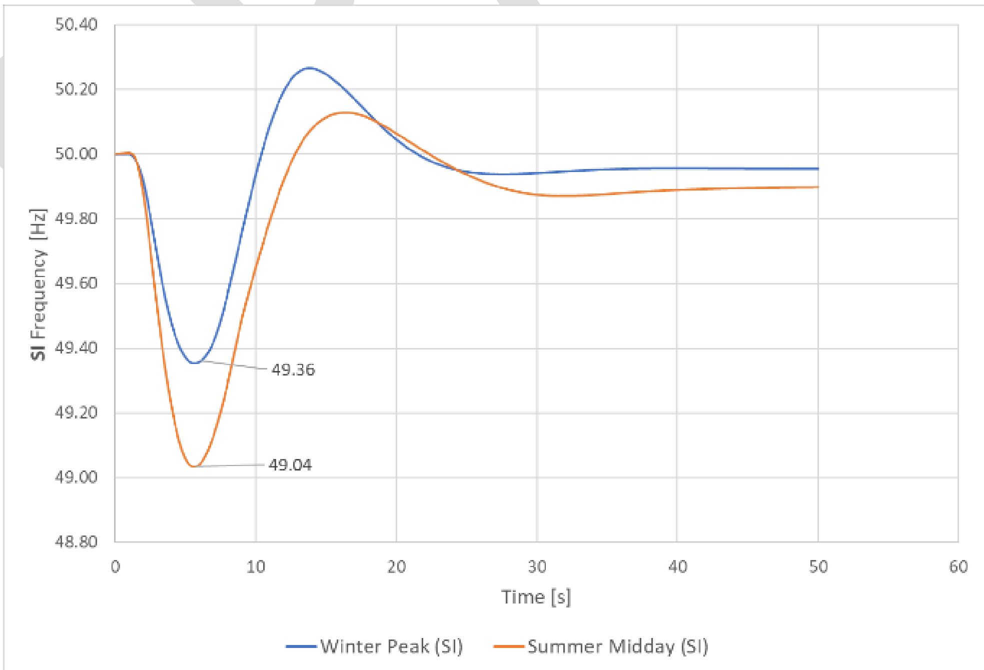

Figure 8-2 Frequency response after an ACCE for the South Island

Table 10 shows the ACCE risk in each island for the 2023 Summer Midday and Winter Peak cases.

Table 10: ACCE risk in each Island

Case	Island	Generator	Dispatched MW
Summer Midday	NI	Huntly 5	335
Summer Midday	SI	Manapouri 2	119
Winter Peak	NI	TCC	312
Winter Peak	SI	Manapouri 4	124

Figure 8-3 and Figure 8-4 show both the frequency and mechanical power for winter peak and summer midday and are a useful demonstration of how we use the results to calculate FIR.

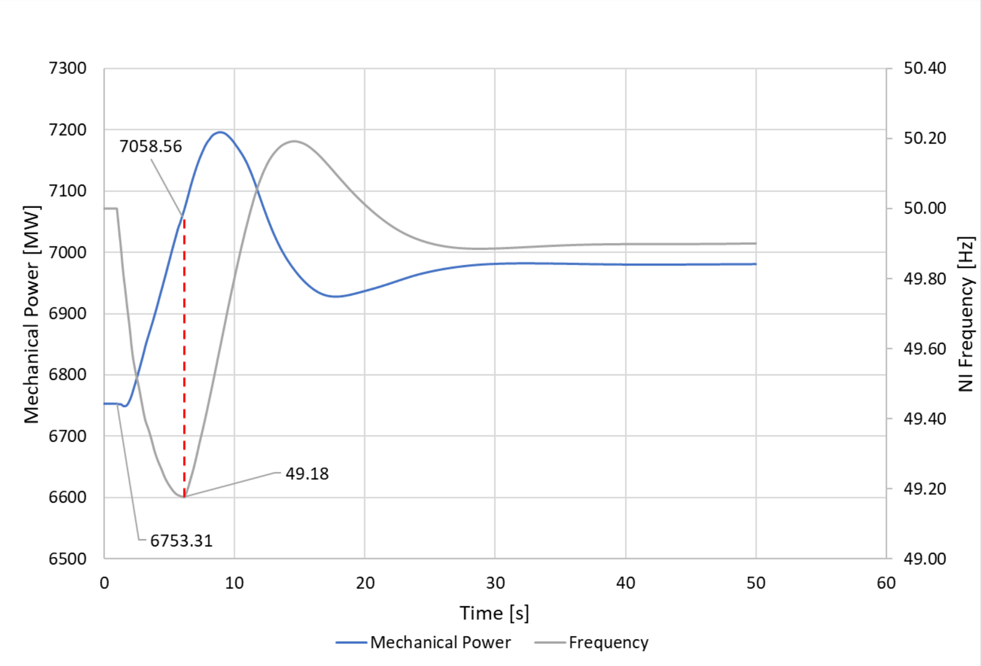

Figure 8-3: Frequency and Mechanical Power plot for 2023 winter peak for a North Island ACCE

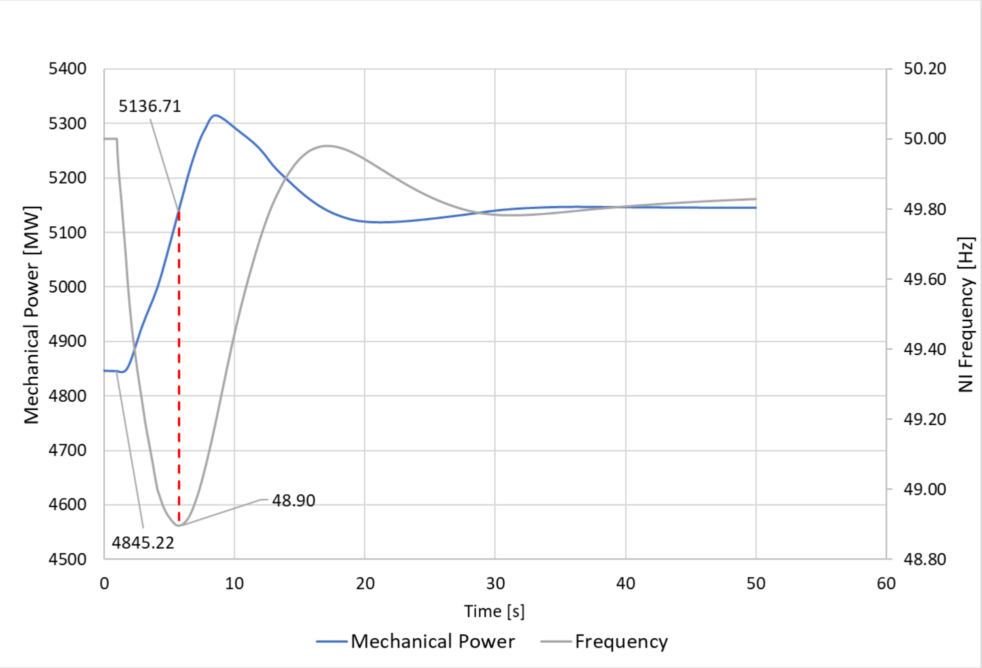

Figure 8-4: Frequency and Mechanical Power plot for 2023 Summer Midday for a North Island ACCE

Using the lowest point in the frequency fluctuation to select the mechanical power value, Table 11 shows the $\Delta P_{Mechanical}$, interruptible load, estimated FIR, ACCE and the FIR/ACCE ratio. The FIR/ACCE ratio shows that the required FIR was higher than the contingency size to arrest the fall in frequency and restore frequency to the normal band.

Table 11: Estimated FIR for the Winter Peak and Summer Midday for 2023

	$\Delta P_{Mechanical}$ [MW]	IL [MW]	Est. FIR [MW]	ACCE [MW]	FIR/ACCE
Winter Peak	305	79	384	312	1.23
Summer	291	54	346	335	1.031

Table 12 shows the system inertia for the 2023 study cases. These provide useful comparisons for the 2035 study cases, which see significant drops in inertia.

Table 12: System Inertia for the 2023 cases

Scenario	Inertia [MVAs]
Winter Peak	28775
Summer Midday	23596

Study cases 0, 1, 2, 3, & 3A: the impact of different thresholds for the 2035 cases

These study cases analyse the impact of different excluded generating station thresholds, across the six scheduled generation scenarios described in section 6.1 of this report.

The six scheduled generation scenarios were considered with the same contingency applied. Table 13 shows the ACCE (contingency size) and associated generators for the 2035 case, where the ACCE is chosen as the generator with the largest MW export in the power flow file.

Table 13: Generators selected for the ACCE for the 2035 case

Case	Island	Generator	Dispatched MW
Summer Midday	NI	Huntly 5	360
Summer Midday	SI	Solar_AVI_1	222
Winter Peak	NI	Huntly 5	447
Winter Peak	SI	Kaiwera Downs	200

The frequency plots for each scenario in Figure 8-5 show that the reserves were scheduled such that the minimum frequency is between 48.1 Hz and 48.2 Hz.

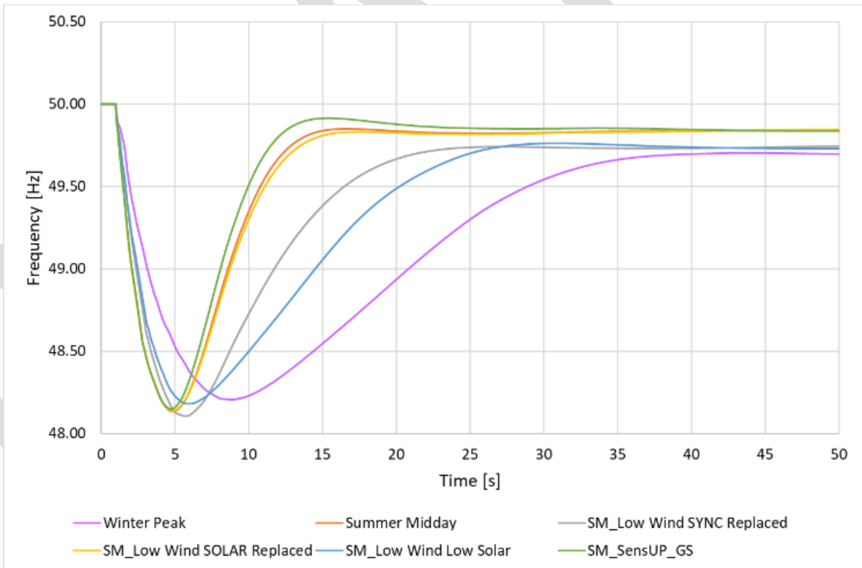

Figure 8-5: No Trip frequency for different scenarios

Figure 8-5 also shows a varying rate of change of frequency (ROCOF) for the scheduled generation scenarios. This can be attributed to the system inertia. Table 14 shows, in descending order, the system inertia for each of the generation mix scenarios. All cases show a decrease in inertia compared to the 2023 cases in Table 12.

Table 14: System inertia for each generation mix scenario

Scenario	Inertia [MVAs]
Winter Peak	26406

Scenario	Inertia [MVAs]
Summer Midday_Low Wind Low Solar	14455
Summer Midday_Low Wind, Replaced with synchronous generation	12973
Summer Midday_Sensitivity Case with 20% increase in grid-solar	10559
Summer Midday Base Case	10537
Summer Midday_Low Wind, replaced with solar	10537

Table 15 shows the calculated amount of generation that should be tripped (20% of Total Capacity), and compared to generation that was tripped on during the study for summer and winter. This serves as a confirmation the 20% of excluded generation below a threshold is tripped as prescribed in the study scope.

Table 15: MW values of tripped generation

	Summer Midday			Winter Peak		
Threshold	Total Capacity of Gens < 30 MW	20% of Total Capacity	MW Tripped on casefile	Total Capacity of Gens < 30 MW	20% of Total Capacity	MW Tripped on casefile
5	58	12	11	53	12	12
10	117	23	23	117	23	27
20	300	60	61	300	60	63
30	522	104	108	522	104	107

Frequency results, with the different excluded generating station thresholds

The following six figures show the frequency results for each scenario, with 20% of 'excluded generating stations' tripping for different thresholds.

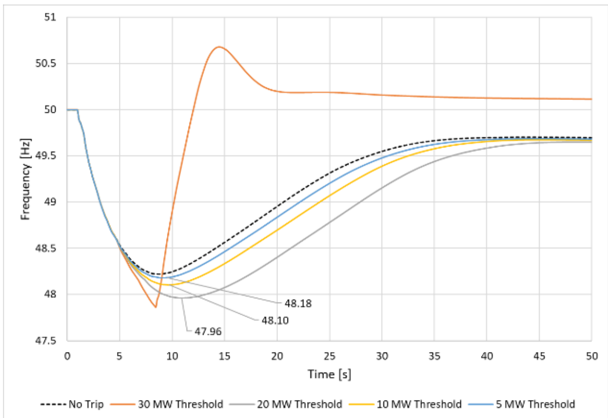

Figure 8-6: Winter Peak

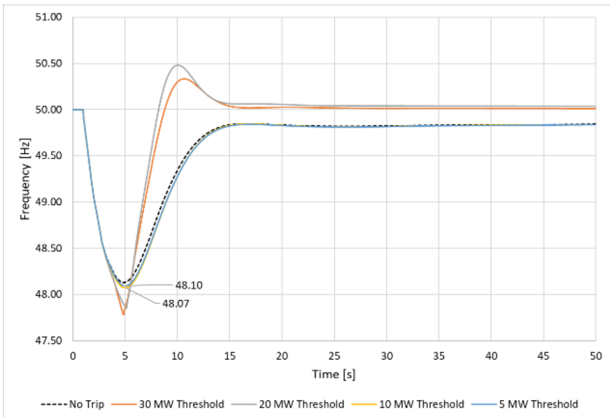

Figure 8-7: Summer Midday

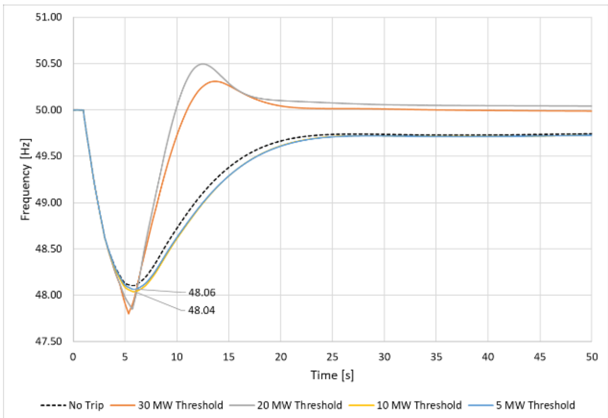

Figure 8-8: Summer Midday – Low Wind, replaced with synch

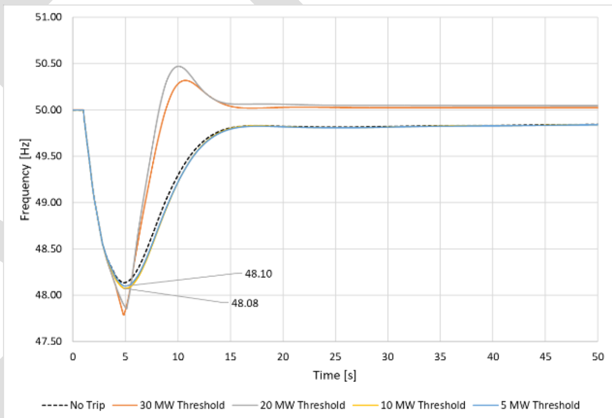

Figure 8-9: Summer Midday – Low Wind, replaced with solar

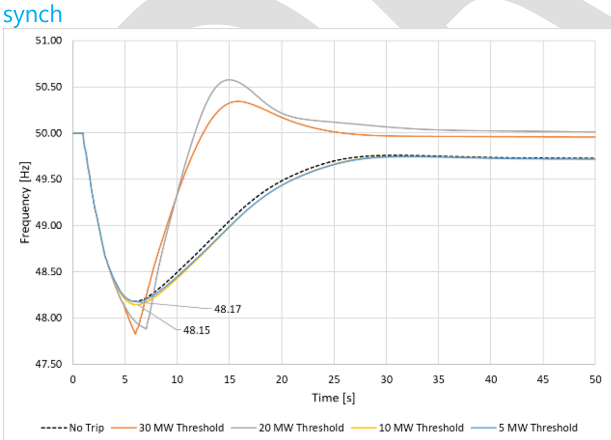

Figure 8-10: Summer Midday – Low Wind Low Solar

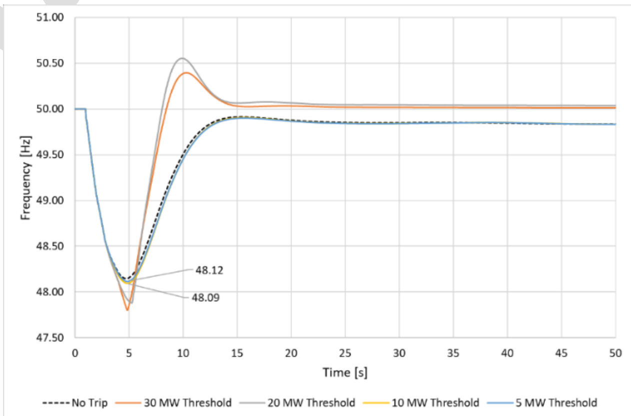

Figure 8-11: Summer Midday – 20% increase in grid solar

For each case, reducing the threshold reduces the impact on the minimum frequency point, without scheduling additional reserves. This is expected as the amount of MW tripped for a reduced threshold scenario is lower.

For all cases, the 20 MW and 30 MW threshold study cases do not retain frequency above 48 Hz and so AUFLS demand was tripped. The first AUFLS block is triggered and tripped at 47.9 Hz. When the AUFLS demand is tripped, there is a sharp turn in frequency and the frequency recovers. For a contingent event, the system operator must ensure that the frequency remains above 48 Hz. Hence, the scenarios where AUFLS demand has tripped indicate that the system operator may need to procure more reserves to ensure it plans to comply with its PPOs.

For the 5 MW and 10 MW thresholds, the frequency is retained above 48 Hz, where the 5 MW threshold performs slightly better than the 10 MW threshold for all scenarios. The key reasons for the 5 MW threshold performing only slightly better than the 10 MW threshold are:

1. The number of generating stations with a capacity below 5 MW is high – i.e. more than 50% of the generating stations below 10 MW have a capacity of less than 5 MW.
2. With only 20% of the generation below a threshold being tripped, the total MW tripped for the 5 MW and 10 MW threshold cases differ by only 12 MW in the summer cases and 14 MW in the winter cases. This is compared to larger differences between the 10 MW and 20 MW threshold cases (37 MW for the summer case 36 MW for the winter case) and the 20 MW and 30 MW threshold cases (37 MW for the summer case 36 MW for the winter case). Table 15 shows the MW tripped values for excluded generation for each threshold.

Mechanical Power Results

The mechanical power shown is the sum of the individual contributions of the modelled generating stations on the power system and is an indication of the MW provided to the power system through governor response in response to frequency fluctuations. Figure 8-12 shows the mechanical power required for each of the different excluded generating station MW thresholds. For the 30 MW case, AUFLS operated, altering the required mechanical power from generating stations. For this case, just over 600 MW of AUFLS demand tripped, causing a quick frequency recovery and overshoot, as observed earlier in Figure 8-6. The governor controls responded to this change in frequency and therefore are not a good indication of the FIR response for an ACCE event, as the governors in the system are responding initially to an ACCE and thereafter to an AUFLS event, to stabilise the frequency.

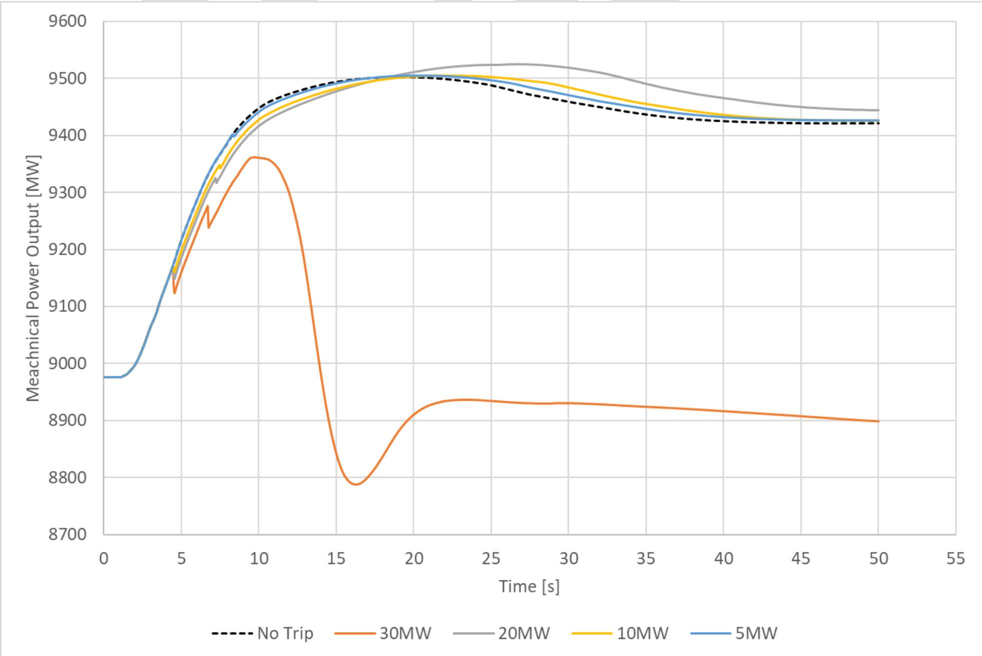

Figure 8-12: Winter Peak Mechanical Power for all Thresholds in the Winter Peak case

To better view the results, the mechanical power for the 30MW threshold scenario is removed and the frequency results are superimposed, this is shown in Figure 8-13. This figure shows that the mechanical power taken at the minimum frequency point for each scenario is reasonably similar, where Table 16 and Table 17 show the minimum frequency point and associated mechanical power at that point. So, to retain the same frequency performance (i.e. similar minimum frequency points), more FIR would need to be procured under higher excluded generating station thresholds. The amount of FIR required to retain the frequency performance would be equal to at least the amount of MW tripped for that threshold. If the FIR/ACCE ratio is used, the maximum FIR to be procured can be approximately 23% higher than the contingency size, if the 2023 FIR/ACCE ratio is used.

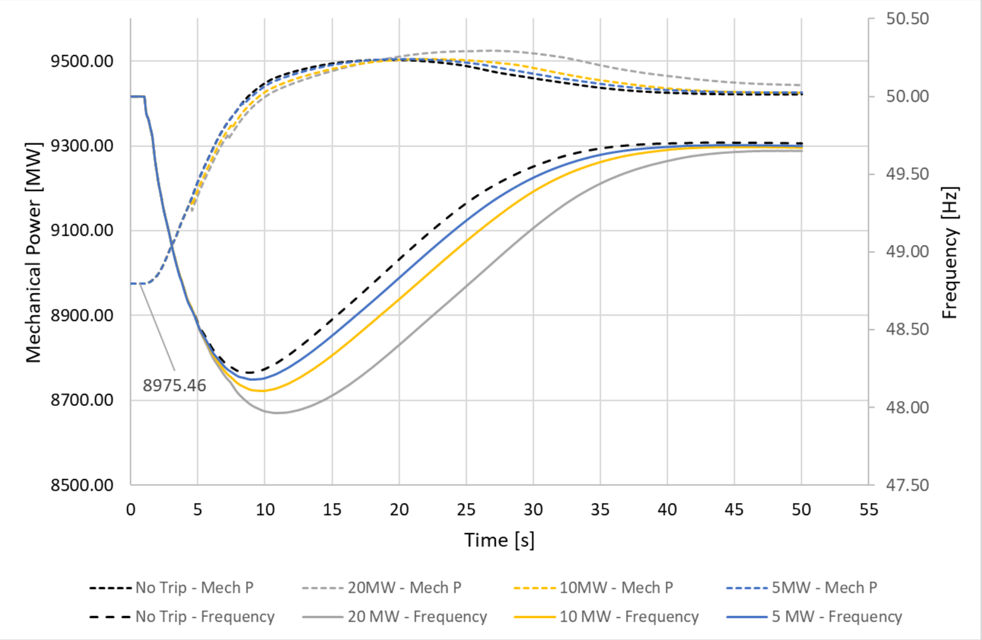

Figure 8-13: Frequency and associated mechanical torque for Winter Peak

Table 16: Minimum frequency and associated mechanical power for the Winter Peak case

Threshold	Frequency [Hz]	Mechanical Power [MW]	Tripped Generation [MW]	Difference in Mech P from No trip Scenario
No Trip	48.22	9419.6	0.0	0.0
5 MW	48.18	9418.3	10.8	1.3
10 MW	48.10	9423.1	22.7	3.5
20 MW	47.96	9432.1	60.6	12.5

For completeness, the Summer Midday mechanical power and frequency plot is shown in Figure 8-14 for cases that do not trip AUFLS, with similar results observed to the Winter Peak cases that do not trip AUFLS.

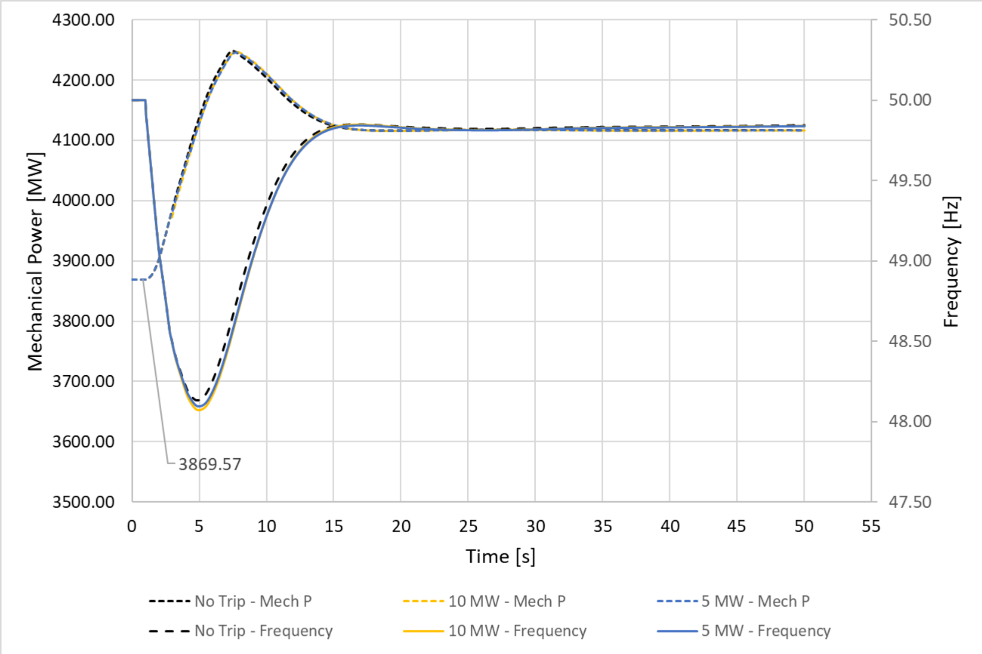

Figure 8-14: Frequency and associated mechanical torque for Summer Midday

Table 17: Minimum frequency and associated mechanical power for the Summer Midday case

Threshold	Frequency [Hz]	Mechanical Power [MW]	Tripped Generation [MW]	Difference in Mech P from No trip Scenario [MW]
No Trip	48.13	4128	0	0
5 MW	48.10	4128	10.8	-0.67
10 MW	48.07	4128	22.7	-0.27

Table 18 shows the $\Delta P_{Mechanical}$, interruptible load, estimated FIR, and the ACCE contingency size for the Winter Peak and Summer Midday no trip cases. Additionally, the ratio of FIR to contingency size shows the amount of FIR required is more than the contingency size – i.e. 15.8% and 2.4% more in winter and summer respectively. The FIR/ACCE ratio is broadly comparable to the 2023 case shown in Table 11 (Winter Peak (2023) = 1.23 and Summer Midday (2023) = 1.031). For the 2035 Winter Peak case, to increase the FIR/ACCE ratio to 1.23, would require the procurement of an additional 35 MW of reserve. This would increase the minimum frequency point, but not to the 2023 level, as the system inertia is lower in 2035.

Table 18: Estimated FIR for the Winter Peak and Summer Midday 2035

	$\Delta P_{Mechanical}$ [MW]	Interruptible Load [MW]	Est. FIR [MW]	ACCE [MW]	FIR/ACCE
Winter Peak	444	74	518	447	1.158

Summer Midday	259	110	369	360	1.024

Study case 4 – testing the impact of an additional 20% of distributed solar tripping

There is no explicit data on forthcoming distribution-connected generation investment or future connection of distribution-connected generation to the study horizon of 2035. Arguably some of the modelled new generation could be connected to a distribution network – i.e. commercial and residential solar. For case study 4, 20% of the connected distributed solar is tripped in addition to 20% of excluded generating stations under a 5 MW threshold.

Results, findings, and observations:

The total distributed solar modelled in the North Island is 793 MW, so 20% of this value is 158 MW. For the study, an additional 150 MW of generation is tripped in the North Island and the impact on frequency observed. Figure 8-15 shows that AUFLS[18] has operated for the summer case with the additional trip. In the winter case it is assumed that there is no solar dispatched, hence the results do not change.

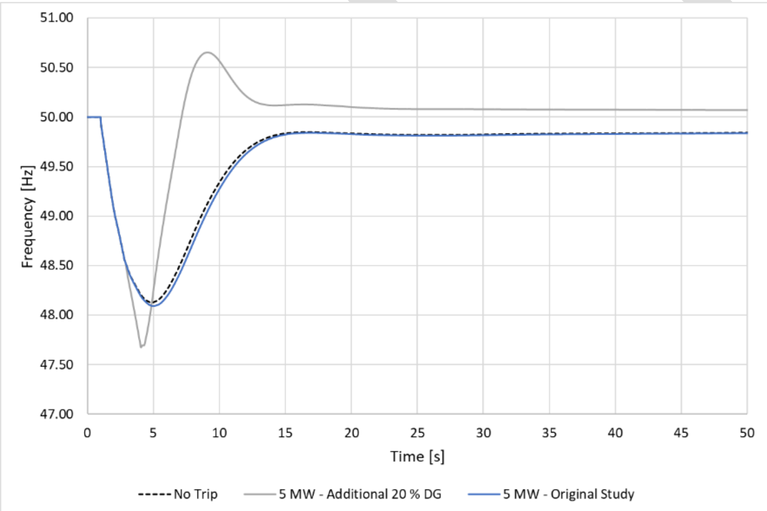

Figure 8-15: Impact of tripping 20% of distributed solar in addition to excluded generating stations

Study case 5 – the effectiveness of procuring additional BESS as reserve

Table 19 shows the capacity of BESS plants to be used to provide an additional 15% of FIR to the power system. Approximately 77 MW and 55 MW of BESS is added as additional reserve for winter and summer respectively.

Table 19: BESS Plants used to provide FIR

Case	Generator Name	Dispatch [MW]	Capacity [MW]	Additional 15% of FIR [MW]
Winter Peak	BESS A	0	41	77
Winter Peak	BESS B	0	38	

[18] Total load shed (Summer Midday) = 566 MW.

Case	Generator Name	Dispatch [MW]	Capacity [MW]	Additional 15% of FIR [MW]
Summer Midday	BESS C	0	58	55

In the IBR controls for frequency response, a power reference with respect to a change in frequency is informed by the droop setting and the proportional integral (PI) controller in the control path. The IBR plant will then ramp to the new specified power reference which is limited by the ramp rate. IBR plants were set to ramp at 0.2 pu/s and kept constant at this value throughout the study. The speed at which a BESS responds is important, hence part of the study focused on the droop setting of the BESS plants providing FIR – i.e. 4%, 2% and 1% with the ramp rate limits of BESS only increased from 0.2 pu/s to 0.4 pu/s. The ramp rate was retained at 0.4 pu/s while the droop was varied to show the impact of different droop settings. Studying the features of BESS was out of scope for this study, and so other BESS capabilities were not considered.

Results, findings, and observations

The following results show the effect of having different droop settings for BESS for the Winter Peak and Summer Midday scenarios for the 30 MW threshold. Figure 8-16 and Figure 8-17 show the frequency profile for Winter Peak and Summer Midday respectively. Overall, the frequency improves with the additional BESS reserve on the network. The performance or speed of the supplied reserve impacts the frequency performance. Figure 8-18 and Figure 8-19 show the impact of a reduced droop setting, where the lower droop setting improves the BESS response (i.e. faster response). In the Winter Peak case, the BESS plant reaches its installed capacity, which limits the output.

In the Summer Midday case, the frequency fall is arrested before 48.2 Hz. Recall, the case studies were set up so that 20% of excluded generating stations below a threshold were tripped. Of the 20%, half are triggered to trip at 48.7 Hz and the remaining 50% are triggered to trip at 48.2 Hz. Due to the frequency not falling to 48.2 Hz for the Summer Midday case, 50% of the selected excluded generating stations (approximately 50 MW) do not trip. This results in a higher minimum frequency point with approximately 55 MW of additional BESS reserve.

Further studies can be completed to assess changes in other parameters on BESS performance. As there are no specified droop settings or other regulated performance requirements for BESS, it is difficult to quantify the support BESS would provide. At a minimum, the additional reserve that would need to be procured would be between the range of 103% to 125% of the tripped MW for excluded generating stations. This range is an estimate and is based on the scenarios selected for the 2023 winter peak and summer midday cases, and is dependent on system conditions. FIR/ACCE ratio for the study is calculated in Table 11.

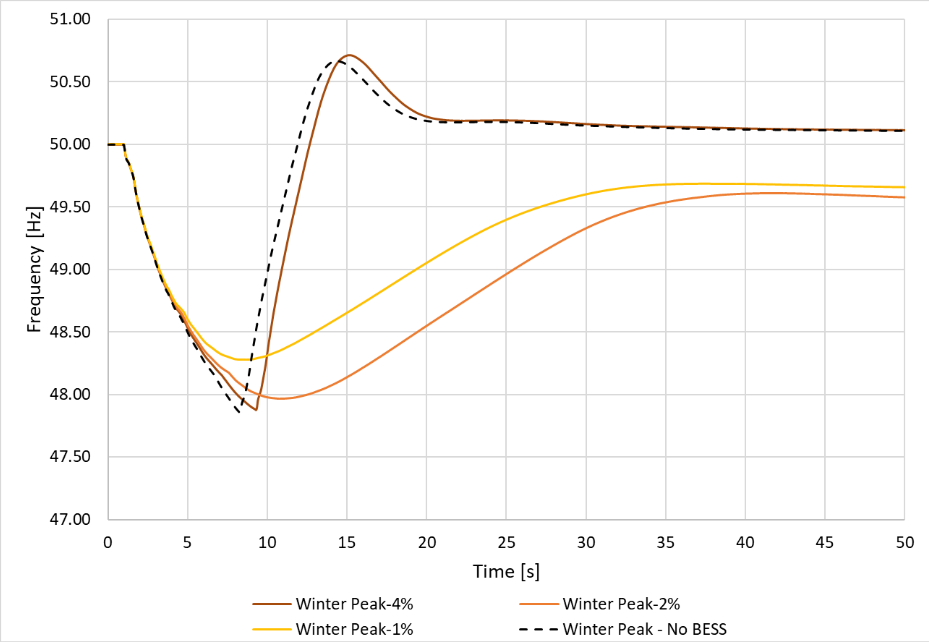

Figure 8-16: Frequency with 15% BESS as additional FIR at a 40%/sec ramp rate at different droop settings for Winter Peak

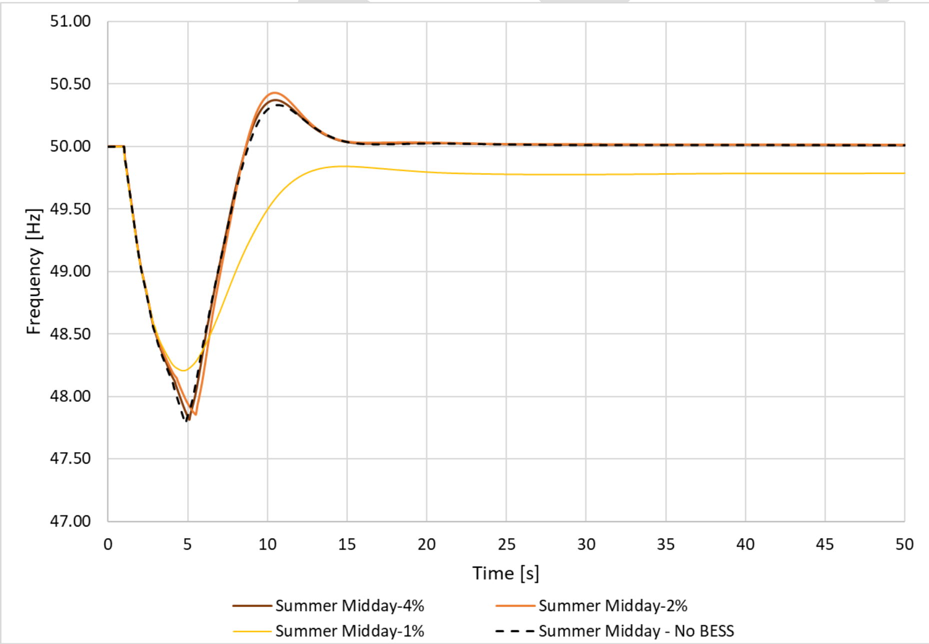

Figure 8-17: Frequency with 15% BESS as additional FIR at a 40%/sec ramp rate at different droop settings for Summer Midday

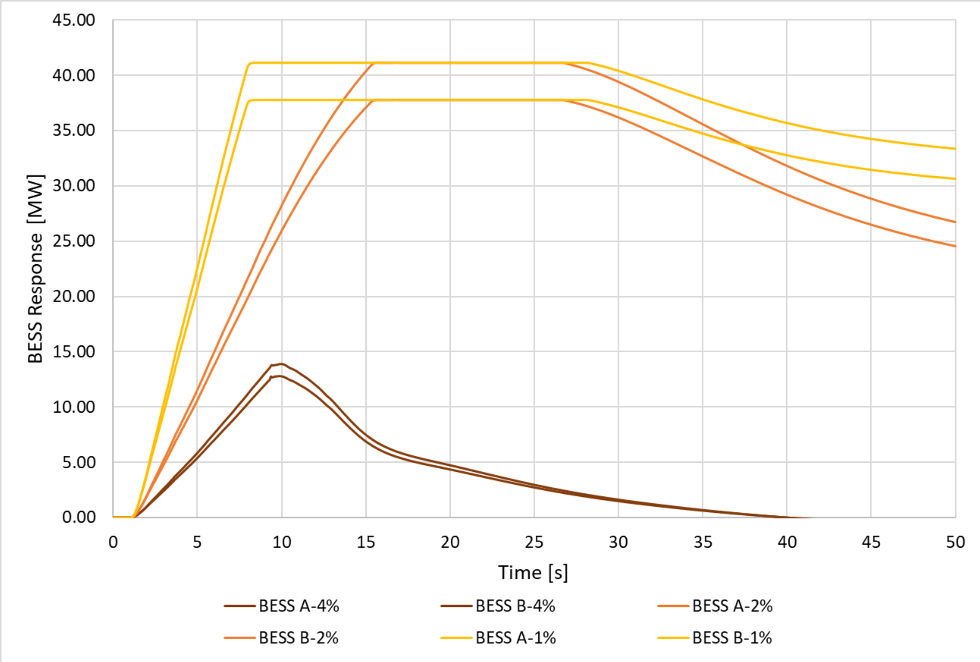

Figure 8-18: Winter Peak BESS response

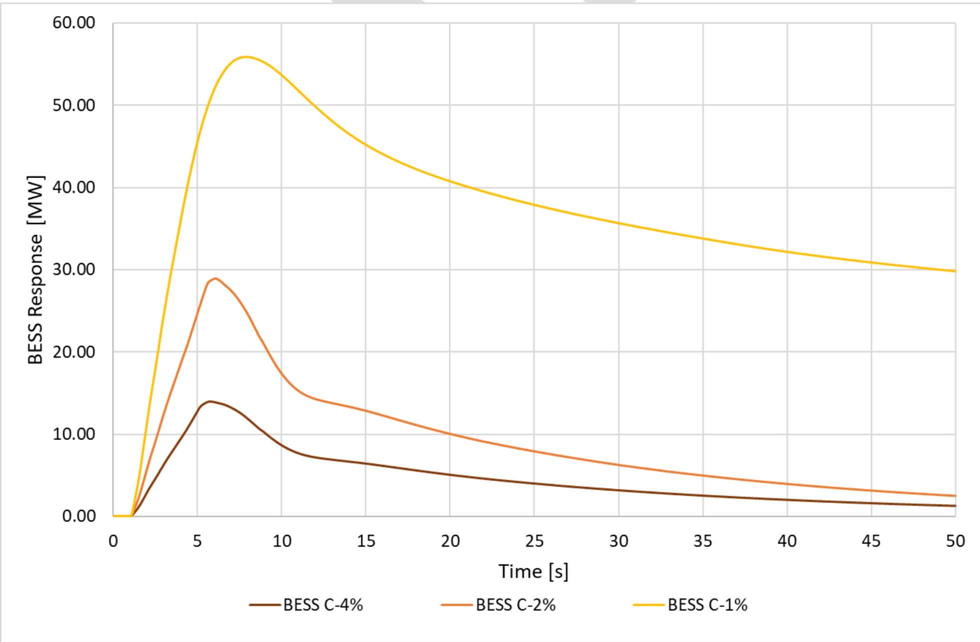

Figure 8-19: Summer Midday BESS response

Study case 6 - the effectiveness of 20% IBR with headroom

To set up the case, 20% of dispatched IBR generating stations were set to have 10% operating headroom. Only solar and wind IBR generating stations were considered in this study. Table 20 shows the MW values for the dispatched wind and solar IBR generation, 20% of the dispatched wind and solar IBR generation, and the MW capacity of generating stations modelled with 10% headroom. The generating stations dispatched to 90% of their total capacity are shown in the column labelled "Modelled Headroom (MW)". Therefore, in Winter Peak, 490 MW of IBR generation is modelled to have 49 MW of headroom available to respond to under-frequency events. Note other generation needs to be dispatched to make up for the headroom, and so the headroom can be seen as additional reserve on the power system.

Table 20: Dispatched IBR per scenario, 20% of dispatched, Modelled

Scenario	IBR Technology	Dispatched IBR [MW]	20% IBR [MW]	Modelled Headroom [MW]
Winter Peak (WP)	Wind	2479	496	490
	Solar	0	0	0
Summer Midday (SM)	Wind	1239	248	241
	Solar	1143	229	220
SM_Low Wind SYNC Replaced (Low wind replaced with Synchronous generation)	Wind	232	46	75
	Solar	943	189	195
SM_Low Wind SOLAR Replaced (Low wind replaced with solar generation)	Wind	257	51	50
	Solar	2185	437	447
SM_Low Wind Low Solar	Wind	237	47	72
	Solar	229	46	46
SM_SensUP20_GS (Sensitivity Case with 20% increase in grid-solar)	Wind	1379	276	276
	Solar	1143	229	220

Each generation mix scenario has different combinations of IBR penetration. The frequency and active power output of IBR generating stations are shown in Figure 8-20 and Figure 8-21 for the Winter Peak case and the Summer Midday case respectively. These figures show that the selected IBR generating stations responded to an under-frequency event.

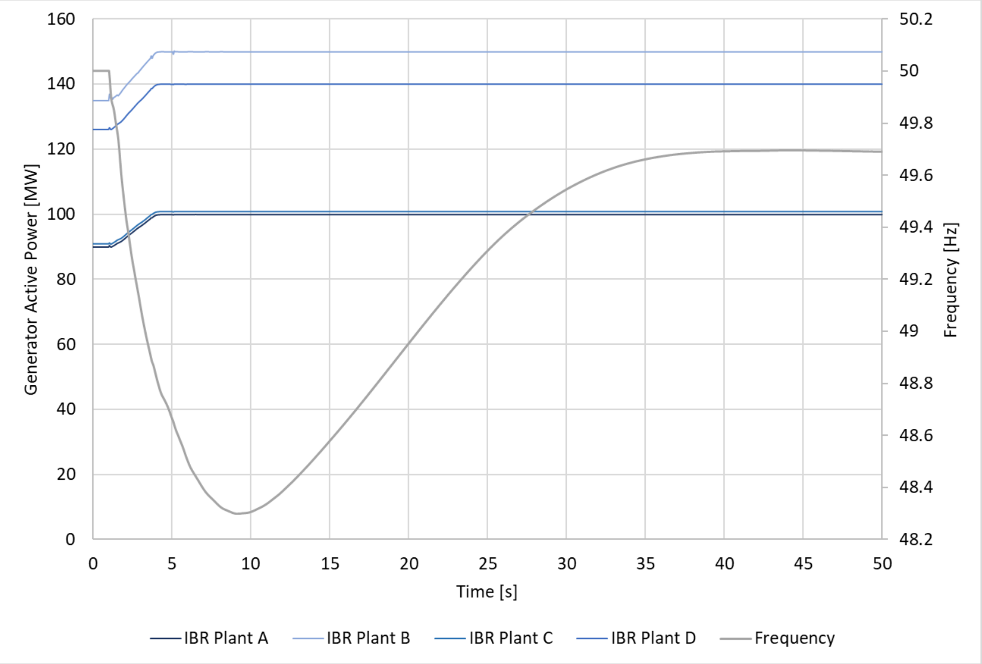

Figure 8-20: Frequency and IBR plant active power for the Winter Peak case

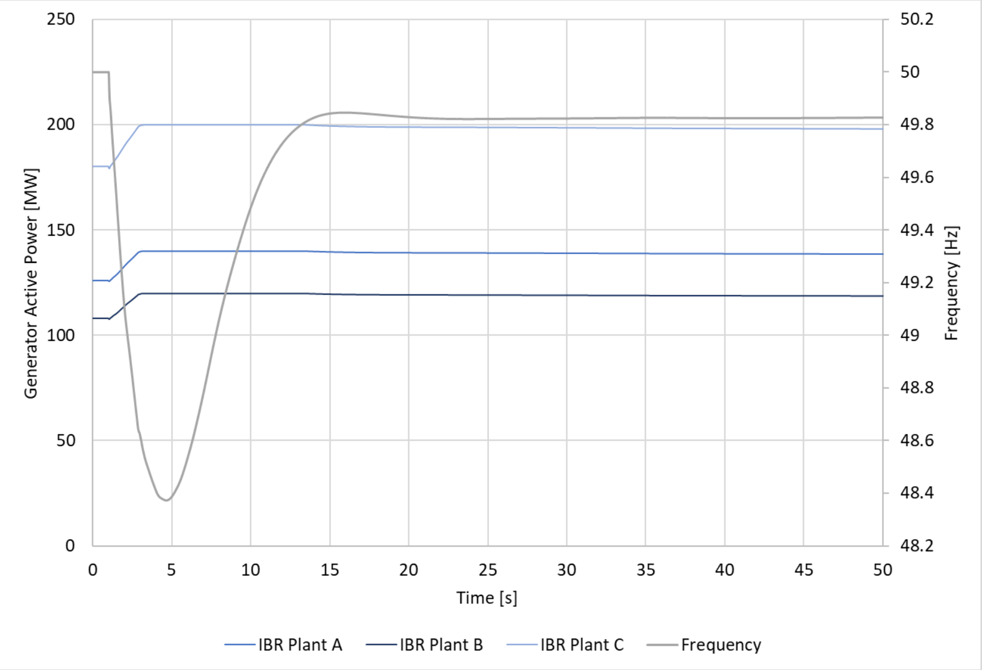

Figure 8-21: Frequency and IBR plant active power for the Summer Midday case

For each generation mix scenario, the following figures show the frequency response under the following headroom scenarios:

1. **No Trip_NO Headroom**: This shows a case under which no excluded generating stations trip.
2. **No Trip_Headroom**: This shows a case where no excluded generating stations trip and 20% of the dispatched IBR generating stations operate at 10% headroom.
3. **30 MW Threshold_NO Headroom**: This shows a case where the 30 MW threshold is retained, and IBR generating stations do not operate with headroom (per previous cases).
4. **30 MW Threshold_Headroom**: This shows a case where the 30 MW threshold is retained and 20% of the dispatched IBR generating stations operate at 10% headroom.

The frequency curves in Figure 8-23, Figure 8-25, Figure 8-27 show that IBR headroom improves the frequency performance for cases with high IBR penetration. This is to be expected as there is more MW availability from IBR generation and hence higher MW response on the power system to support the frequency. This additional MW response would need to be reconciled through the energy market processes. In contrast, the frequency curves in Figure 8-24 and Figure 8-26 show that additional MW support from IBR generation is not effective under a lower level of IBR penetration on the power system, which results in AUFLS operating.

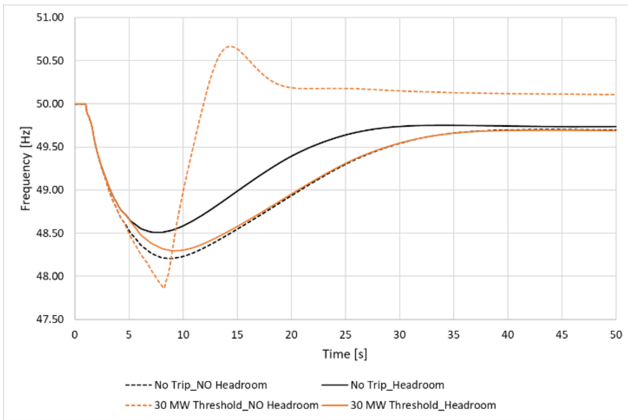

Figure 8-22: Winter Peak

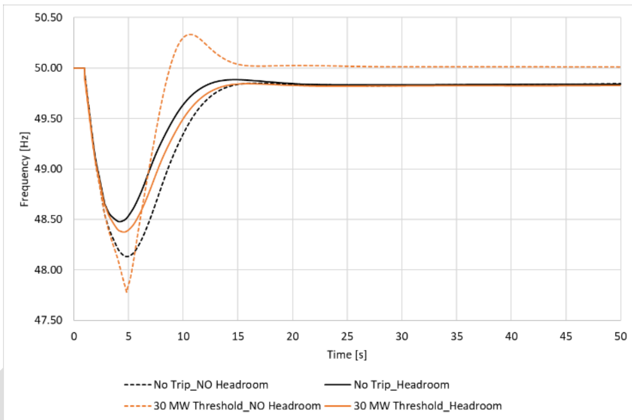

Figure 8-23: Summer Midday

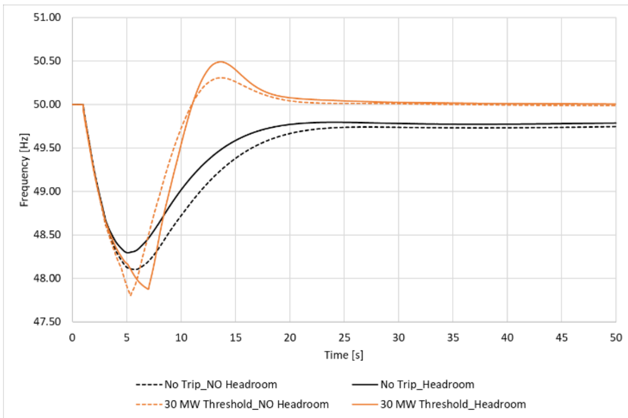

Figure 8-24: Summer Midday_Low Wind SYNC Replaced

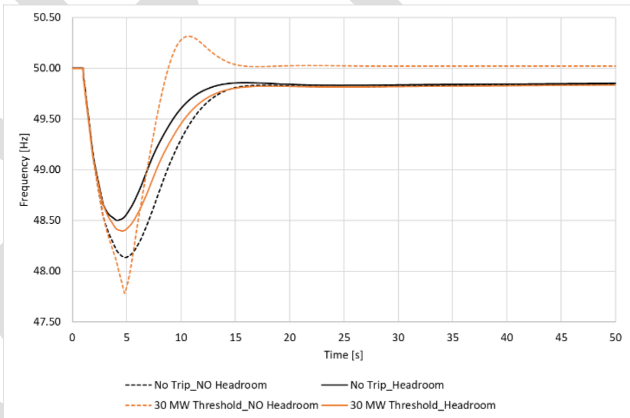

Figure 8-25: Summer Midday_Low Wind SOLAR Replaced

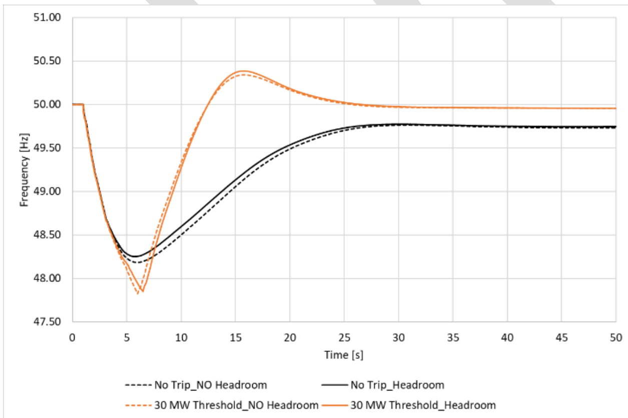

Figure 8-26: Summer Midday_Low Wind Low Solar

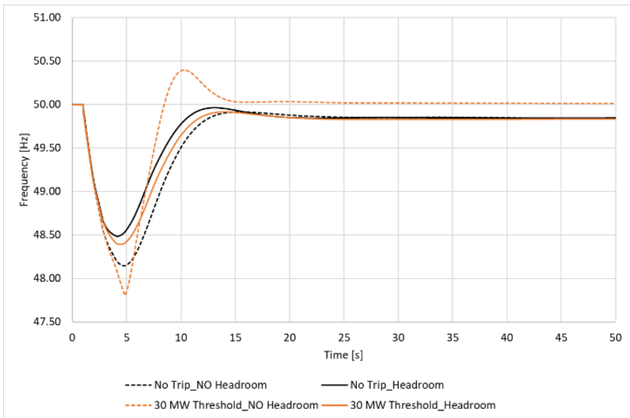

Figure 8-27: Summer Midday_SensUP20_GS

8.2 Study 3: impact of implementing a frequency dead band on instantaneous reserve

Study 3 assesses the impact of implementing a set frequency dead band on IR.

Study 2 assesses the impact of implementing a set frequency dead band on new generating stations. In study 2 various dead bands are studied – i.e. ± 0.015 Hz, ± 0.05 Hz, and ± 0.1 Hz.

Study 3 uses dead bands of ± 0.015 Hz and observed dead bands to test the impact of these dead bands on IR. The impact on IR is linked to study 1 in the following ways:

1. The casefiles setup is the same and hence the casefiles used in study 1 are adapted for study 3.
2. Study 1 and study 3 assess the impact on frequency.

Secondary tripping due to a proportional increase in the number of generating stations smaller than 30 MW would trigger the procurement of additional reserves so that the system operator can plan to comply with its PPOs. The implementation of a set dead band is expected to change generation response times in accordance with the set frequency dead band. This change in generation response may have an impact on IR, hence this study assesses the impact of implementing a set frequency dead band on IR.

8.2.1 Additional study assumptions

1. Geothermal generation does not provide reserves due to operating at maximum available output.
2. Wind and solar generation will operate at maximum available output.
3. A set dead band will be applied to new generation only, and existing generation will retain its existing frequency dead band setting.

8.2.2 Methodology

Utilise casefiles from study 1 with different frequency dead band settings for study 3.

8.2.3 Study case details

Two study cases are run:

Study case 1: Retain the existing frequency dead band trends (Status Quo):

1. Open cycle gas turbine (OCGT) = ± 0.1 Hz
2. IBR = ± 0.15 Hz.

Study case 2: Apply a frequency dead band of ± 0.015 Hz:

1. OCGT = ± 0.015 Hz
2. IBR = ± 0.015 Hz.

8.2.4 Observations

After running the study for two different dead band settings, the following has been observed.

1. Figure 8-28 shows there is an insignificant impact on frequency.
2. Figure 8-29 shows that OCGT generation with a smaller dead band will respond sooner. The difference in time between the response curves is insignificant. This figure also shows there is no response from a single IBR generating station, which applies to all modelled IBR generation. This is due to all IBR generation being modelled as operating at maximum available output.
3. Figure 8-30 shows a zoomed-in profile of the frequency response curve for winter and summer where the frequency dead band is retained. Overlaid on this figure are different frequency dead band setpoints. A frequency dead band setting affects the time at which a generator starts to respond. Figure 8-30 shows that for different dead band settings, the time at which generators start to respond in this study is under 0.5 seconds.

Figure 8-28: Frequency response with different dead band settings

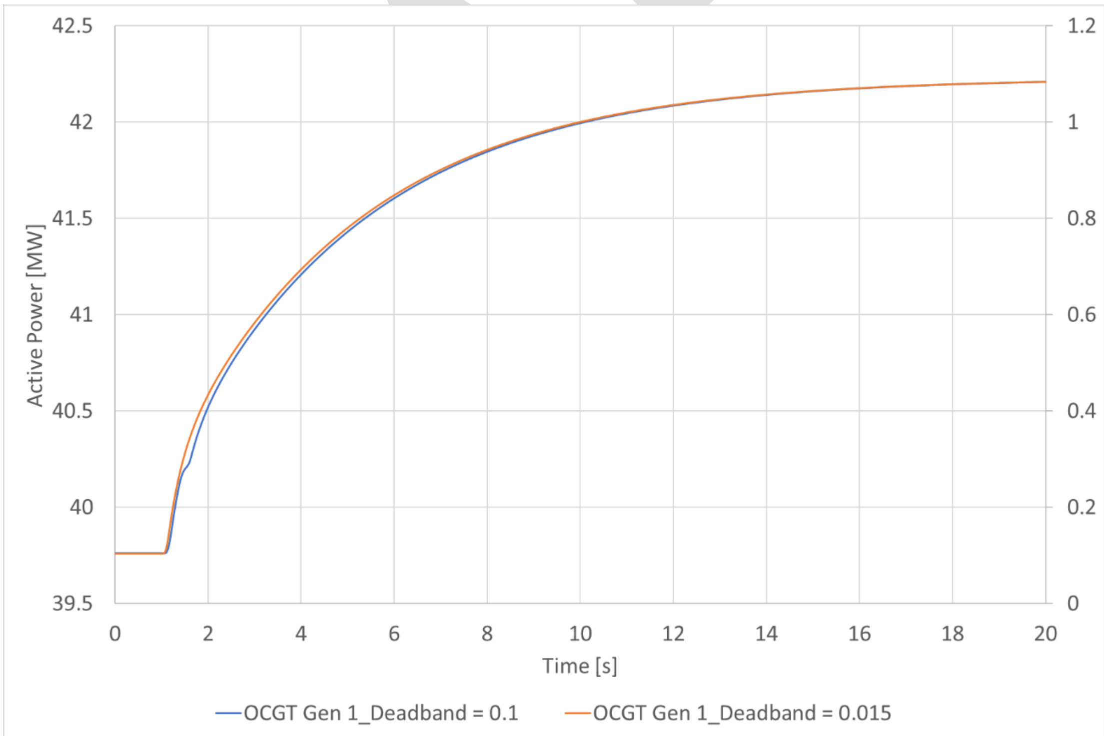

Figure 8-29: First 20-seconds of an OCGT generator responding to under-frequency

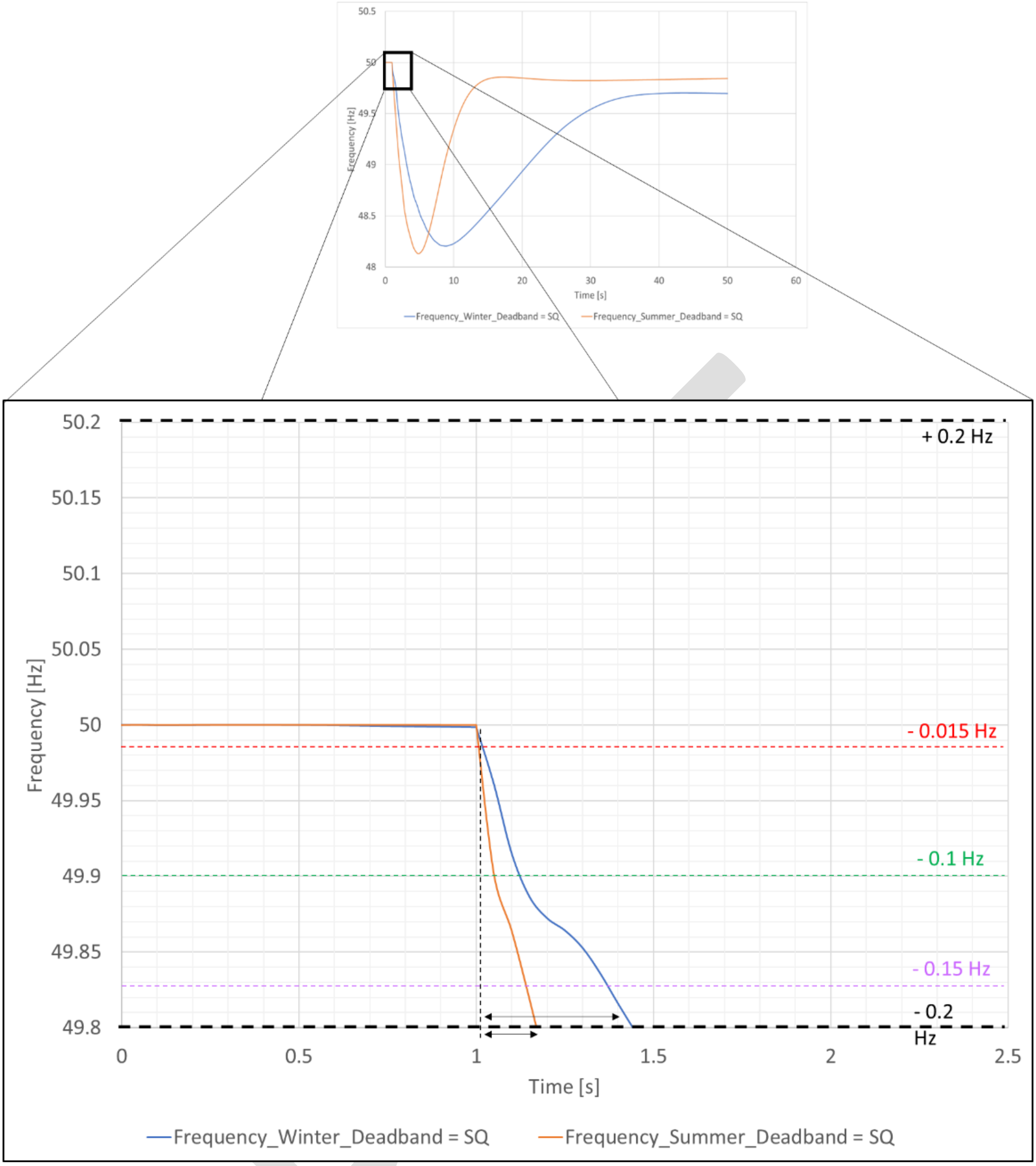

Figure 8-30: Zoomed frequency profile overlayed with frequency dead band setpoints

9 Findings and Recommendations

9.1 Study 1: impact of lowering the 30 MW threshold on frequency response

Findings

Study cases 1, 2, 3, 3a: comparing different excluded generating station thresholds

With the identified generation expected to be commissioned by 2035, study cases 1, 2, 3 and 3a show that tripping generating stations below 30 MW can adversely affect the frequency performance of the power system. The results are impacted by the number of generating stations below the threshold. Reducing the excluded generating station threshold improves the frequency performance without requiring the procurement of additional reserves.

Study case 4: the impact of tripping from residential and commercial solar

Study case 4 shows that tripping distributed solar has a significant impact on frequency. The results show that frequency trip settings for distributed solar need to be consciously set because of the potential effect on system frequency.

Study case 5: the effectiveness of procuring additional BESS as reserve

The study shows that additional BESS providing FIR can usefully support frequency. The study also shows the impact of the droop settings on the BESS response. Further studies would need to be undertaken to assess the full capability of BESS. As there are no specified droop settings or other performance requirements for BESS, it is difficult to quantify the support BESS would provide.

Study case 6: the effectiveness of 20% IBR with headroom

Study case 6 shows that implementing headroom on IBR generating stations is effective when there are sufficient IBR generating stations online. The study is high level and provides an indication of the impact on frequency. To investigate this as an option, further studies would need to be undertaken to decide the optimal headroom threshold and economic impact on the generation owner.

Overall conclusion

With a lower excluded generating station threshold, the study showed:

1. The secondary tripping is reduced.
2. The minimum frequency is improved without the requirement to procure more reserves.

Table 21 shows the MW tripped in addition to an ACCE. Using the FIR/ACCE ratio established in the study, the required additional FIR can be calculated based on the studied scenarios.

Table 21: MW Tripped and potential additional IR requirements

Study	MW Tripped	Required additional FIR
Study case 1 (30 MW)	108	1.03 to 1.23 times MW tripped
Study case 2 (20 MW)	61	1.03 to 1.23 times MW tripped
Study case 3 (10 MW)	23	1.03 to 1.23 times MW tripped

Study	MW Tripped	Required additional FIR
Study case 3a (5 MW)	11	1.03 to 1.23 times MW tripped
Study case 4 (20% DG)	N/A	N/A
Study case 5 (15% BESS FIR)	108	1.03 to 1.23 times MW tripped, with correct performance requirements
Study case 6 (Headroom)	108	Inconclusive, needs further impact analysis

The performance of an excluded generating station threshold is impacted by the size and number of generating stations below the threshold. Figure 9-1 shows the size of generating stations modelled in the study, overlaid by different threshold values. A proportional increase in smaller-sized generating stations would increase secondary tripping, which could possibly require the system operator to increase the procurement of reserves so as to plan to comply, and comply, with its PPOs.

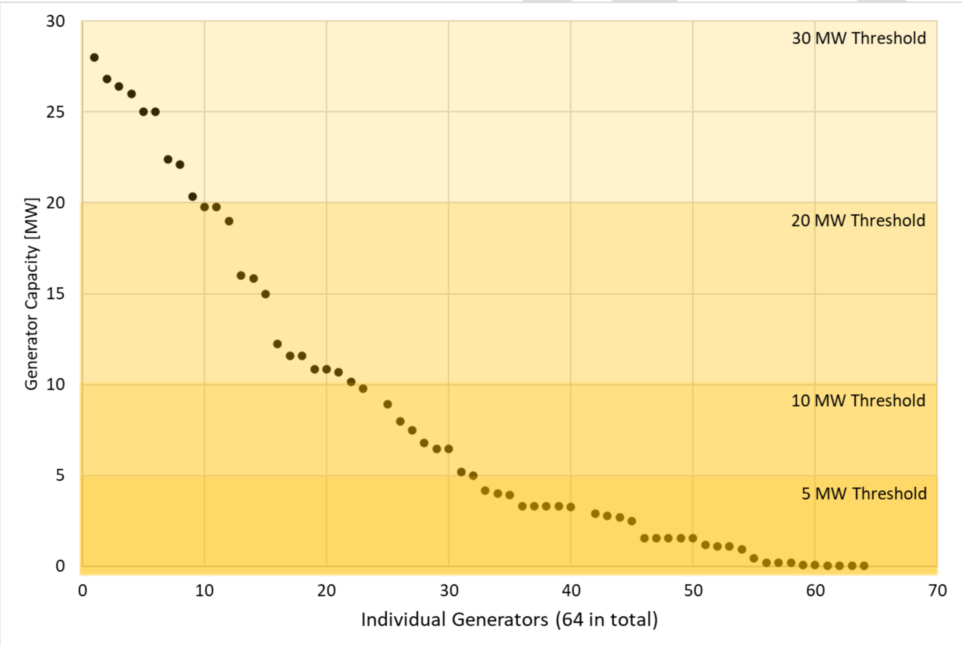

Figure 9-1: Generators below 30 MW modelled in the 2035 case

Recommendation

Change Clause 8.21 in the Code to implement a 5 MW threshold for excluded generating stations.

1. Choosing to reduce the excluded generating station threshold is expected to reduce the need for the system operator to schedule additional reserve to cover the risk of more secondary tripping of excluded generating stations in the coming years.
2. Amending the Code to stipulate a new excluded generating station threshold would help to support the system frequency in under-frequency events, by requiring more generating stations to maintain their pre-event output and remain synchronised with the power system.

The rationale for choosing the 5 MW threshold is as follows:

1. A 5 MW threshold would enforce frequency obligations on a wider pool of generating stations wishing to connect to the power system.
2. The 5 MW threshold has performed slightly better than the 10 MW threshold in the studies. The reason why the performance of the 5 MW threshold is only slightly better than that of the 10 MW threshold is because most generation below 10 MW is also below 5 MW in this study.
3. This option positively impacts the frequency performance by tripping the lowest amount of MW, and hence the reserve requirements would be the lowest, which has a positive impact on the wholesale electricity market.
4. The performance of any set threshold depends on the number of generating stations that are below that threshold and connected to the power system. The 5 MW threshold is therefore more robust against future uncertainties.

9.2 Study 3: impact of implementing a frequency dead band on instantaneous reserve

Findings

1. There is no improvement in the frequency curve. This is due to insignificant change in response to new generating units.
2. The impact of a frequency dead band on IR is insignificant.

Recommendations

1. No recommendation.

References

[1] Electricity Authority, "Electricity Industry Participation Code", 2010. Online: [Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz)]

[2] Transpower New Zealand Limited, "Whakamana i Te Mauri Hiko, Empowering our Energy Future", March 2020. Online: [Whakamana i Te Mauri Hiko - Empowering our Energy Future | Transpower]

[3] Transpower New Zealand Limited, "Whakamana i Te Mauri Hiko, monitoring report", March 2023. Online: [Transpower releases March Whakamana i Te Mauri Hiko monitoring report | Transpower]

[4] Transpower New Zealand Limited, "Transmission Planning Report", 2022

[5] Transpower New Zealand Limited, "Transmission Planning Report", 2023

[6] Transpower New Zealand Limited, "Policy Statement", 2022. Online: [Policy statement | Transpower]

Appendix

A. Asset capability statement analysis

The following provides a visual representation of Clause 8.19 (1) and (2) in Part 8 of the Code.

8.19 Contributions to frequency support in under-frequency events

(1) Subject to subclause (3), each **generator** must at all times ensure that, while **electrically connected**, its **assets**, other than any **excluded generating stations**, contribute to supporting frequency by remaining **synchronised**, ensuring that each of its **generating units** can and does, at a minimum, sustain pre-event output—

- (a) at all times when the frequency is above 47.5 Hertz; and
- (b) for at least 120 seconds when the frequency is 47.5 Hertz; and
- (c) for at least 20 seconds when the frequency is 47.3 Hertz; and
- (d) for at least 5 seconds when the frequency is 47.1 Hertz; and
- (e) for at least 0.1 seconds when the frequency is 47.0 Hertz; and
- (f) at any frequencies between those specified in paragraphs (b) to (e) for times derived by linear interpolation.

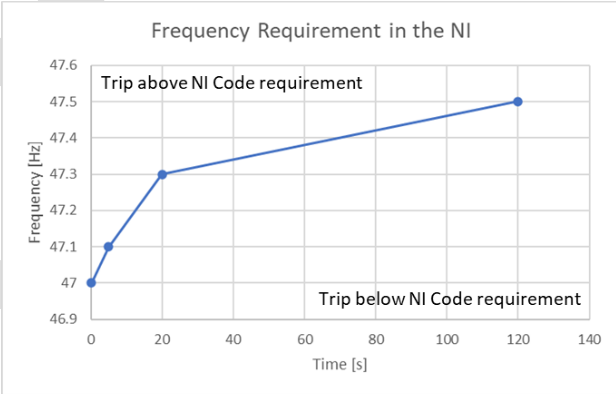

Figure 0-1: Visual Representation of clause 8.19 for frequency requirements in the North Island

(3) Each South Island **generator** must ensure that each of its **assets**, other than excluded **generating units**, remains **synchronised**, and can and do, at a minimum, sustain pre-event output—

- (a) at all times when the frequency is above 47 Hertz; and
- (b) for 30 seconds if the frequency falls below 47 Hertz but not below 45 Hertz.

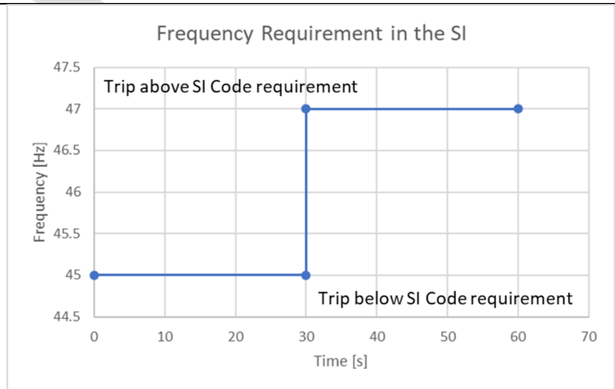

Figure 0-2: Visual Representation of clause 8.19 for frequency requirements in the South Island

Table 22: List of generating stations and generating units that have dispensations

Station	Island	Equipment	Gen Size	Obligation	Pre-event	Freq	Description
Huntly	NI	Unit 6	63.5	Part 8, Subpart 2, 8.19(1) - Generators (contributions to frequency support in the case of under-frequency events)	x		The plant is not capable of meeting the requirement. The output of unit 6 reduces by 6.1 MW during an under-frequency event. Additional IR will be needed to cover this shortfall.
Huntly	NI	G5	474	Part 8, Subpart 2, 8.19(1) - Generators (contributions to frequency support in the case of under-frequency events)		x	Due to plant characteristics and frequency protection settings, the 400 MW combined cycle gas turbine unit: - cannot sustain pre-event output at all times above 47.5 Hz; and - can only remain synchronised for a maximum of 20 seconds when the frequency remains at 47.5 Hz or below.
Te Rapa	NI	All units	49.6	Part 8, Subpart 2, 8.19(1) - Generators (contributions to frequency support in the case of under-frequency events)		x	Insufficient response to under-frequency.
Mahinerangi Wind Farm	SI	All units	37.5	Part 8, Subpart 2, 8.19(3)(b) - For 30 seconds at minimum South Island frequency		x	This rule requires that generators remain synchronised and sustain pre-event output for 30 seconds if the frequency falls below 47 Hz but not below 45 Hz. The wind turbines cannot achieve this and will trip in 0.2 seconds if the frequency goes below 47 Hz.
White Hill	SI	All units	58	Part 8, Subpart 2, 8.19(3)(b) - For 30 seconds at minimum South Island frequency		x	This rule requires that generators remain synchronised and sustain pre-event output for 30 seconds if the frequency falls below 47 Hz but not below 45 Hz. The wind turbines cannot achieve this and will trip in 0.2 seconds if the frequency goes below 47 Hz.
Taharoa	NI_	All		Clause 8.19 (1) (c), (d), (f)			Did not get commissioned
TCC	NI	All Units	500	Part 8, Subpart 2, 8.19 (1)((b) and (f)) - Contributions to		x	TCC protection setting for low frequency trip 1 cannot meet the requirements of 120 seconds at 47.5 Hz. TCC is operationally limited to a 20 second time delay for frequencies equal to 47.5 Hz to 47.3 Hz.

Station	Island	Equipment	Gen Size	Obligation	Pre-event	Freq	Description
				frequency support in the case of under-frequency events			
Junction Road	NI	G72	63.5	8.19(1) Contributions to frequency support in under-frequency events.	x		Unit cannot sustain pre-event output during an under-frequency event.
Junction Road	NI	G71	63.5	8.19(1) Contributions to frequency support in under-frequency events.	x		Unit cannot sustain pre-event output during an under-frequency event.
McKee	NI	G61	64.5	8.19(1) Contributions to frequency support in under-frequency events.	x		Unit cannot sustain pre-event output during an under-frequency event.
McKee	NI	G62	64.5	8.19(1) Contributions to frequency support in under-frequency events.	x		Unit cannot sustain pre-event output during an under-frequency event.

B. Asset and network modelling

B1. Dynamic models

Table 23: Contracted generators for OFA

Island	Trip Frequency [Hz]	Generator
South	53	AVI G1, G2, G3, G4 MAN G1, G2, G5, G7
South	53.5 & 54	CYD G1, G2, G3, G4, BEN G1, G2, G3, G4, G5, G6 MAN G3, G4, G6
North	51.2	THI G1, G2, KAG U1
North	51.4	NAP G1
North	51.6	MOK STG10

C. Model performance

Once the model was set up, it was tested to assess its performance. The following results are shown:

1. **Voltage and thermal loading**: Voltage and thermal loading indicate that the dispatched generation and loading is plausible and within operating limits. Outcome: The voltage and thermal loading were acceptable, showing a plausible power flow.
2. **Non-Disturbance**: This is a pre-study check to ensure that the modelled generating stations on the power system are stable before an event on the system is studied. Outcome: All scenarios displayed a stable non-disturbance rotor angle and speed deviation for 10 seconds.
3. **Interruptible Load:** Interruptible load forms part of FIR and remains constant throughout the simulation. Typical values are between 70 MW and 120 MW. Outcome: Tripped interruptible load is shown in Table 25.
4. **ROCOF**[19]: The minimum frequency is modelled so that it is similar for each scenario. The ROCOF is monitored as AUFLS block 4 can be triggered to trip on ROCOF if the ROCOF is greater than -1.2 Hz/s and below 48.5 Hz. Outcome: ROCOF is less than 1 Hz/s, as shown in Table 25.
5. **WECC Models**: Voltage step and frequency response tests were conducted to ensure that these models are suitable for the study. A subset of the frequency results is shown as these are more applicable to this study. Outcome: Models are satisfactory for use in the study.

The following figures show the results.

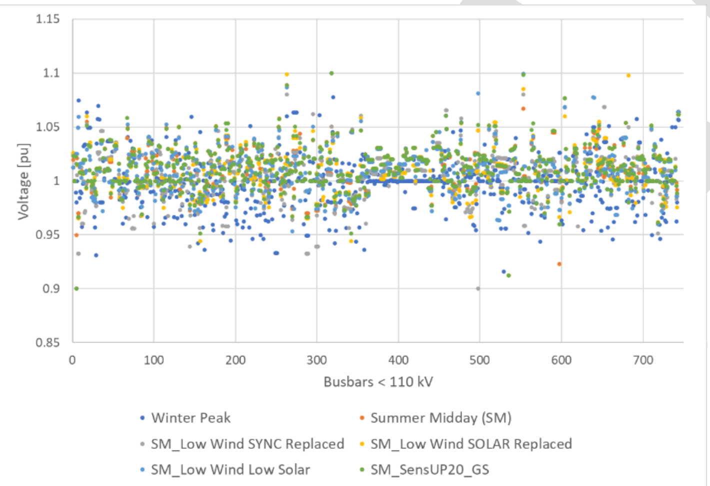

Figure 0-3: Voltages of busbars < 110 kV in the casefiles

Voltage < 110 kV:
These voltages are acceptable, there are a few voltages that are close to 1.1 pu. These do not affect the study as they are MV terminal voltages. (Figure 0-3)

[19] ROCOF is synonymous with df/dt.

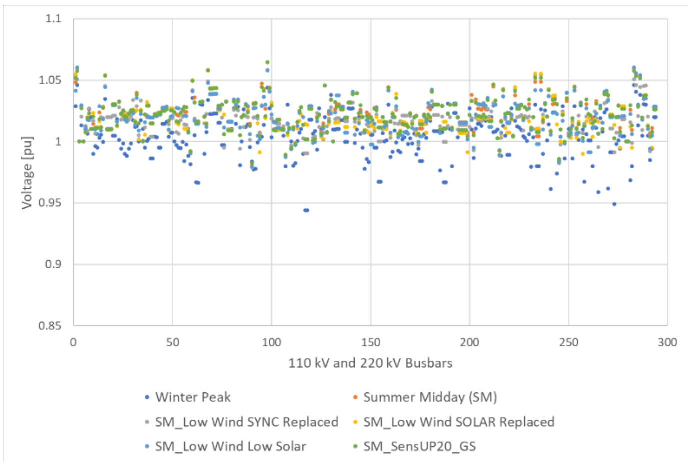

Figure 0-4: 110 kV to 220 kV busbar voltages

110kV ≤ Voltage ≤ 220 kV:

The system operator keeps transmission voltages well within ±10%. It is noted that the voltage is not severely impacted by an ACCE when compared to a short circuit fault or extended contingent event (ECE). (Figure 0-4)

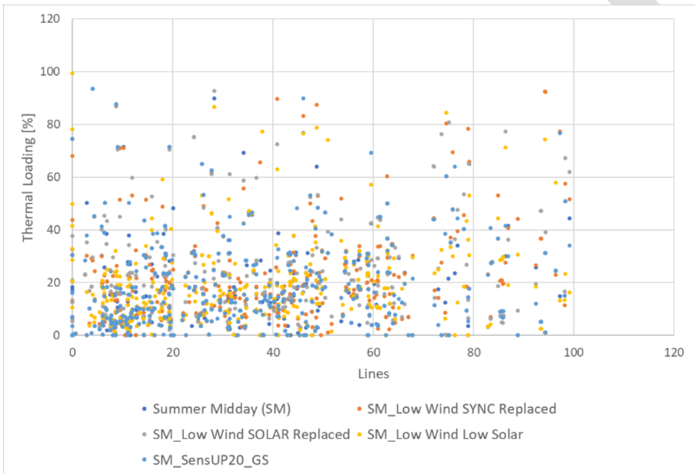

Figure 0-5: Thermal loading of the networks

Figure 0-5 shows the loading is below 80% for the majority of lines. Table 24 shows the number of lines loaded above 90% for each scenario.

Table 24: Number of lines loaded above 90%

Scenario	Loading > 90%
Winter Peak	10
Summer Midday (SM)	1
SM_Low Wind SYNC Replaced	2
SM_Low Wind SOLAR Replaced	1
SM_Low Wind Low Solar	1
SM_SensUP20_GS	1

Table 25 shows the modelled interruptible load and ROCOF trip for each scenario, where the ROCOF was assessed on the initial downward fall in frequency.

Table 25: Modelled interruptible load trip and ROCOF for each scenario

Scenario	IL [MW]	ACCE [MW]	ROCOF
Winter Peak	73.81	447	> -1 Hz/s
Summer Midday (SM)	109.84	360	> -1 Hz/s
SM_Low Wind SYNC Replaced	109.84	360	> -1 Hz/s
SM_Low Wind SOLAR Replaced	109.84	360	> -1 Hz/s
SM_Low Wind Low Solar	109.84	360	> -1 Hz/s
SM_SensUP20_GS	109.84	360	> -1 Hz/s

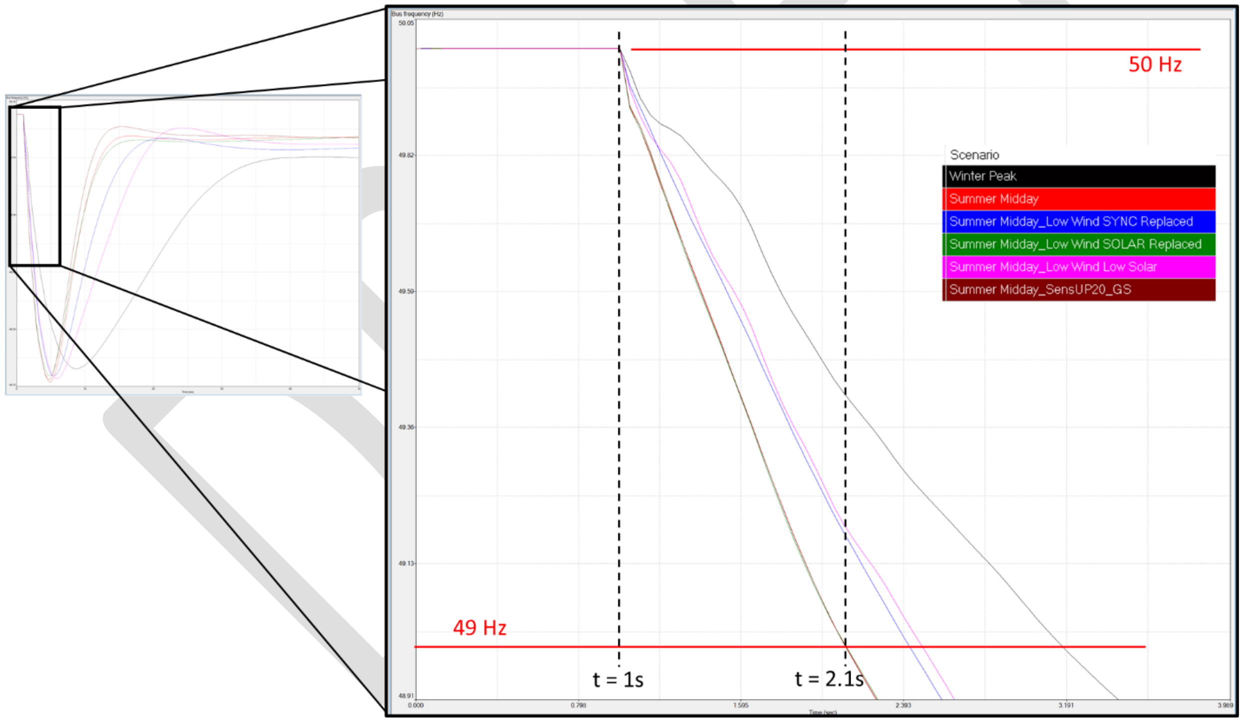

Figure 0-6: Figure showing the ROCOF.

C1. Performance of the WECC models

The WECC Generic Renewable Energy Models were used to model the response of IBR plants. The performance of these models is shown in more detail in this section as IBR plants behave differently to synchronous machines.

C2. Field configuration vs model representation

For a study, the detailed plant configuration or an aggregated representation of the plant can be modelled. In system-wide modelling, it is common practice to represent and model an aggregated plant, and this is how IBR plants are modelled in the casefile. Figure 0-7 shows how the generator and inverters are aggregated and modelled using the WECC Generic Renewable Energy Model.

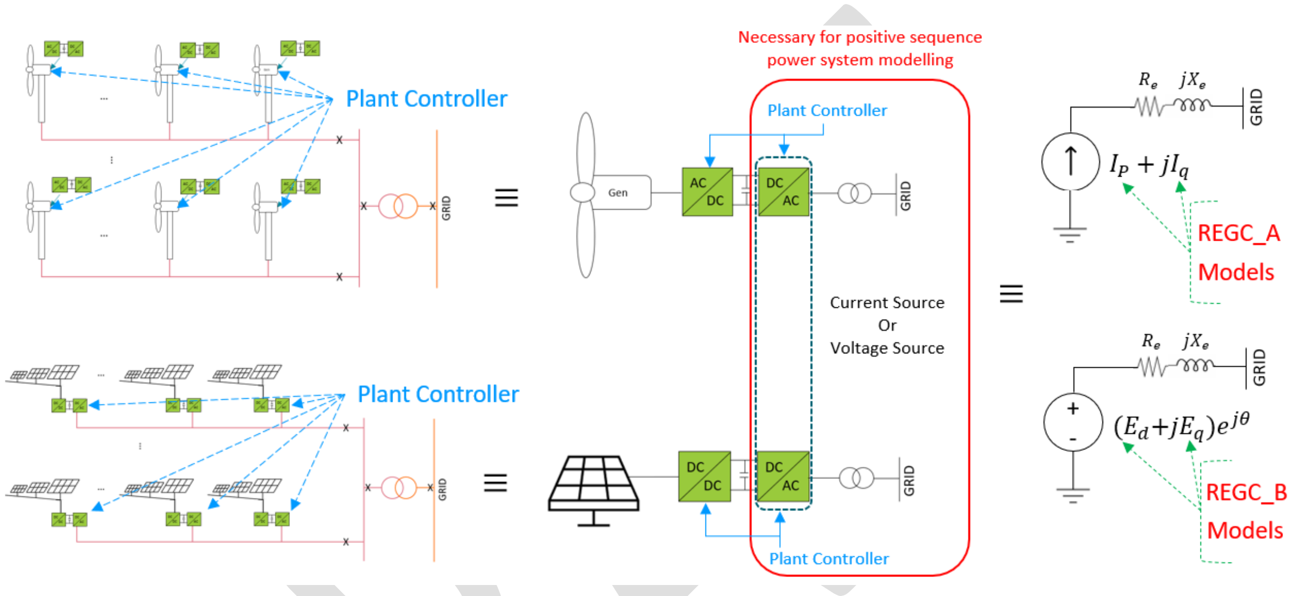

Figure 0-7: Field vs Model Representation, including the WECC representation of the generator converter model.

In PSAT, a generator connected to an 11 kV bus and step-up transformer connected to the transmission network is used to model the generator. The dynamic behaviour of the generator is modelled through the WECC Generic Renewable Energy Model. The WECC models utilised are:

1. **Generator Converter Model**: REGC_B was chosen because this model is more numerically stable at a lower short circuit ratio (SCR) when compared to the REGC_A model. This is a voltage source model.
2. **Electrical Controls**: REED_D was chosen as this is the latest approved model and can be used to model wind, solar PV and BESS. The REEC_A model is primarily used for wind and solar PV only and the REEC_C model is designed for BESS and hybrid solar PV-BESS systems.
3. **Plant Controller**: The REPC_A model is an optional model when using the WECC approach to modelling IBRs. This model was used because the frequency response functionality is modelled in it.

The models were tested to assess their voltage and frequency response. The voltage response of the model is not fully utilised in this study as the system voltage does not vary as much for an ACCE when compared to a faulted condition. However, reasonable model control parameters were applied.

Frequency response is modelled through the REPC_A and REEC_D models. Model control parameters are used to apply a droop characteristic and ramp rate. The droop characteristics are used to generate a new Pref (active power reference signal) for the generation plant based on the change in frequency. The ramp rate serves to limit the MW progression of the plant to the new Pref. This control action is also determined by the parameters in the PI controller of the frequency control path. This can be seen in Figure 0-8

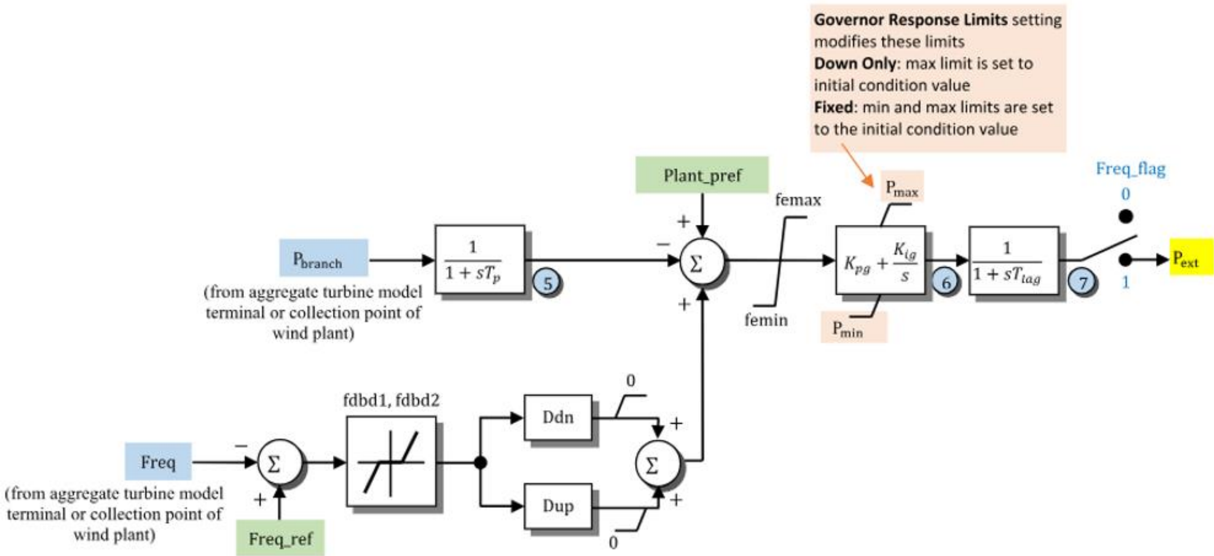

Figure 0-8: Controls of the REPC_A model related to frequency control of the IBR plants modelled

There are two ramp rates modelled, an operational ramp rate (REEC_D) and a transient recovery ramp rate (REGC_B). The operational ramp rate is set to 0.2 pu/s (or 20 %/s) and manages the rate at which the plant would ramp to new Pref values under steady state and under-frequency conditions. The transient recovery ramp rate is set to 1 pu/s (or 100 %/s), which specifies that the IBR plant ramps to 100% of the output after a fault on the network.

WECC Generic Renewable Energy model tests show the plant responding to under- and over-frequency. Initially a frequency step response test was completed and thereafter a test on the whole system. These results are shown in the following figures. For the frequency response test, the frequency follows the error until the controller reaches Pmax. Due to the control action of the integrator in the controls, when the error reaches zero (but not negative), the output of the integrator slows the response.

Figure 0-9 to Figure 0-12 show the results of the frequency response test.

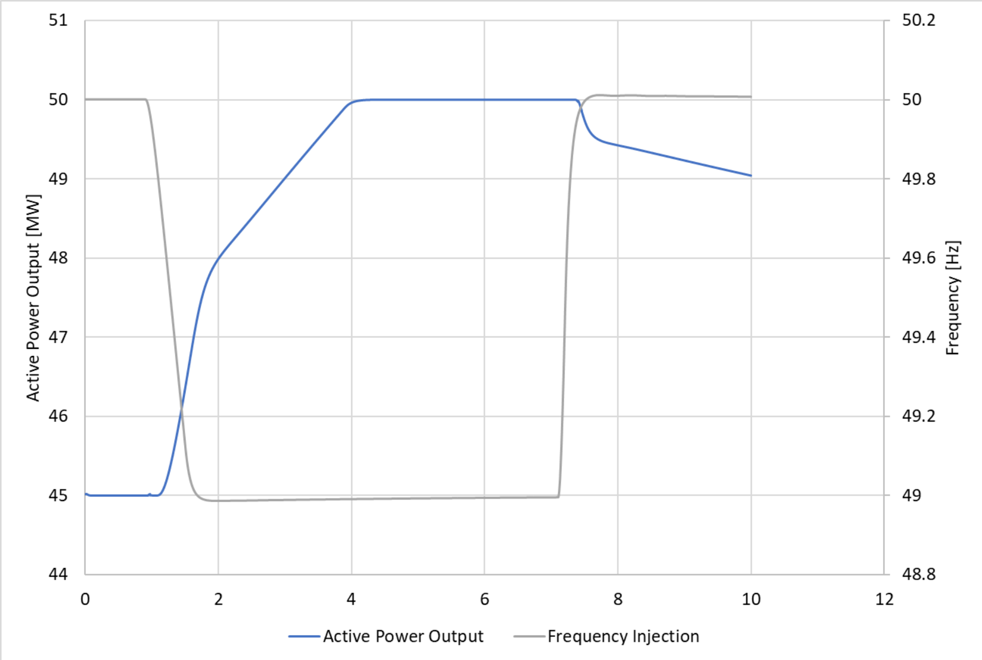

Figure 0-9: Frequency Step Response test for under-frequency

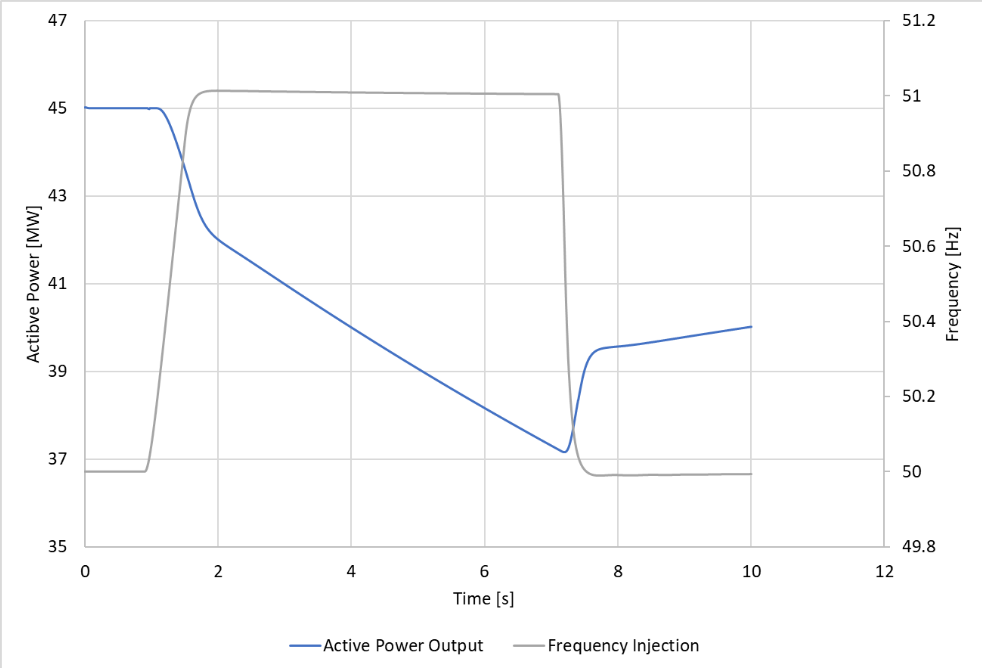

Figure 0-10: Frequency Step Response test for over frequency

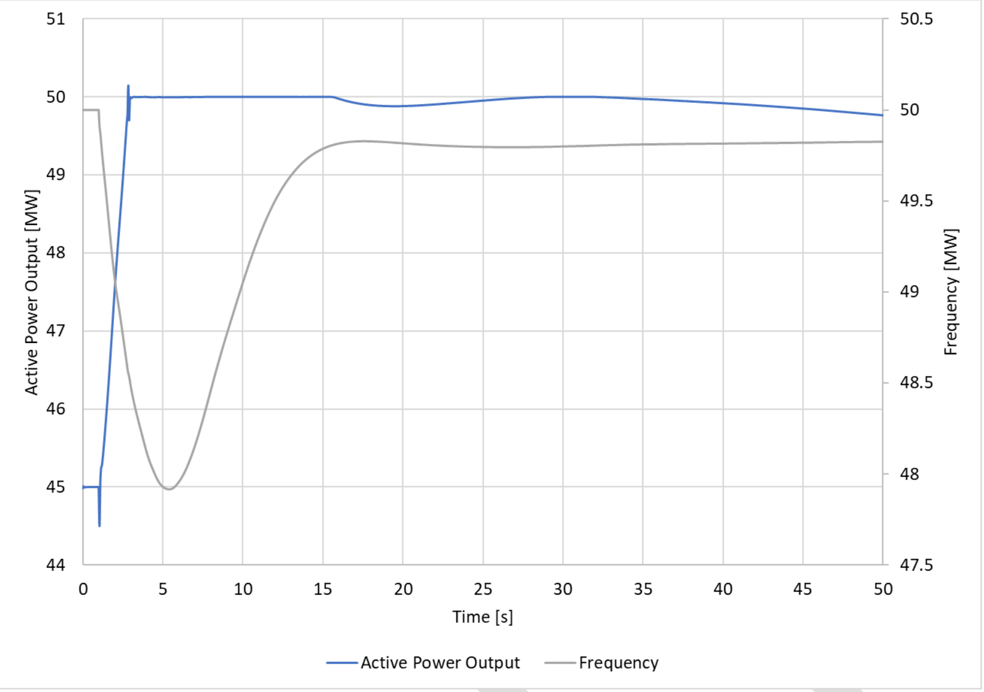

Figure 0-11: Under-frequency support tested on the whole system with an ACCE

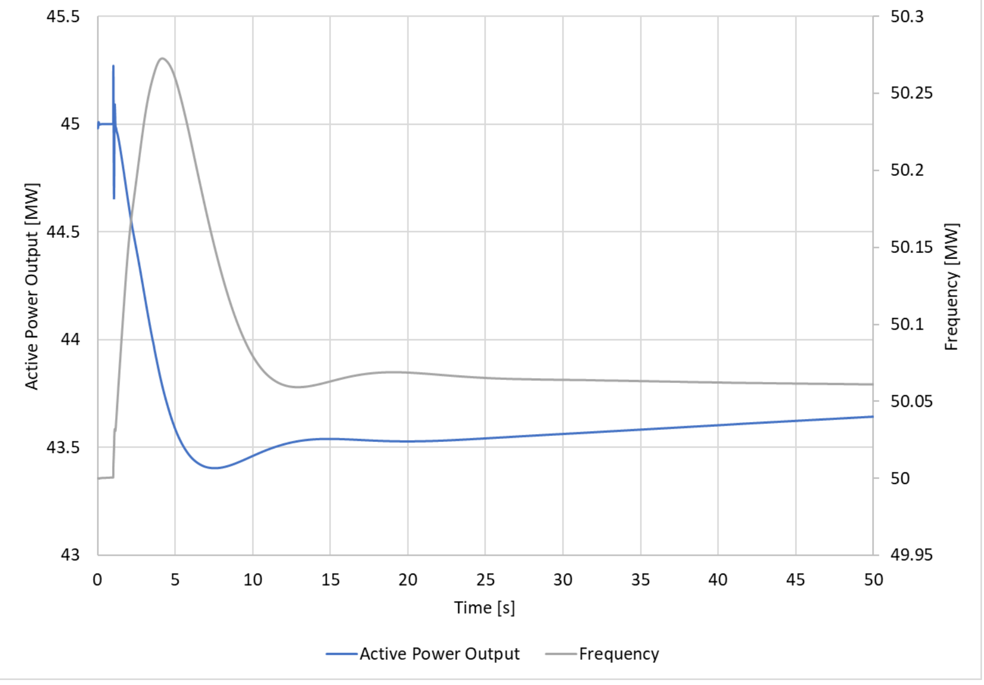

Figure 0-12: Under-frequency support tested on the whole system with load rejection at Penrose

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Appendix D Report on frequency power system study 2

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Part 8 Review: Frequency Studies (2a and 2b)

Study 2a: Assess the impact of increased intermittent generation on frequency within the normal band and on frequency keeping.

Study 2b: Assess the impact of implementing a frequency dead band on frequency within the normal band.

Version: 4

Date: June 2024

1 Executive Summary

As part of its Future Security and Resilience (FSR) project, the Electricity Authority (Authority) is investigating potential changes to the management of frequency and voltage across New Zealand's power system. This is to address key identified issues from an increasing amount of variable and intermittent resources on the system.

This report covers a set of frequency studies undertaken by Transpower, as system operator, to assist the Authority and industry stakeholders in their consideration of potential options to help address the following identified issue relating to frequency:

An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic (PV) generation, is likely to cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

Intermittent generation is usually associated with wind and solar PV generation. Changes in weather conditions can cause generation output to fluctuate. This in turn causes an imbalance in generation and load, resulting in frequency varying.

The frequency keeping ancillary service procured by the system operator helps to manage this imbalance, so that system frequency stays within the range of 49.8 – 50.2 Hz (the 'normal band').

Part 8 of the Electricity Industry Participation Code 2010 (Code) requires generating units to support frequency as follows:

1. Clause 8.17: *"…make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to within the normal band)"*.

The Code is silent on whether a generator can apply a dead band setting to a generating unit to manage the generating unit's response to changes in frequency. A generating unit's ability to change its active power output to maintain frequency within the normal band will be reduced, or even removed, depending on the size of any dead band applied to the generating unit.

The set of studies reported on in this report investigate the effects of differing dead bands on the management of frequency and on frequency keeping.

Overall conclusion

This report contains the following conclusions:

1. Implementing a frequency dead band that is narrower than the normal band has a positive impact on frequency regardless of whether the dead band applies to existing and new generation or just new generation.
2. There is better frequency management and more even sharing of generation MW response when a prescribed frequency dead band is applied to existing and new generation. Applying a prescribed frequency dead band to existing generation may have the following implications:
    a. An adverse financial impact due to wear and tear, especially for thermal and geothermal generating units.
    b. Potentially a material one-off volume of testing and modelling activities, since any upgrade to a control system, including changing a control system setting to alter a dead band setting, would require generators, in conjunction with the system operator, to re-commission the control system.[1]

[1] Schedule 8.3, Technical Code A, clause 2(6)(a) of the Code states that each asset owner must provide a commissioning plan or test plan when changes are made to assets that alter a control system, including a change to a control system setting.

3. When compared to a baseline, applying a dead band to new generation results in generation frequency response being better shared between hydro generation and intermittent wind and solar PV generation because the latter has a relatively lower dead band than they would otherwise have.
4. Generating units operating at their maximum output will not provide the upward frequency regulation needed for a negative/downward frequency deviation even if the generating units have a reduced dead band. Frequency keeping generating units will have to provide more upward frequency regulation, causing them to hit the upper limit of the frequency keeping band more often.
5. The system operator may need to review the +/- 15 MW frequency keeping band, as a result of the increasing proportion of intermittent generation connected to the power system.

Recommendations

We recommend implementing a dead band of ±0.1 Hz for new generating units connecting to the power system. Existing generating units connected to the power system can maintain their current dead band settings.

The set of studies in this report show that implementing a dead band of ±0.1 Hz for newly commissioned generating assets can assist in regulating system frequency within the normal band. A dead band setting lower that ±0.1 Hz performed only marginally better when applied to new generating units only.

We expect new IBR generation and other generation types will be able to meet a prescribed dead band of ±0.1 Hz. The majority of new generation expected to come online in New Zealand in the future is inverter-based. We assume that similar generating technology would be used in New Zealand as is used in Australia, which has a dead band of ±0.015 Hz in its National Electricity Rules.

Contents

2 Definitions and Abbreviations

Definitions

Term	Explanation
Frequency fluctuation	frequency fluctuation means a deviation in frequency outside the normal band
Frequency keeping	frequency keeping means an ancillary service that maintains the system frequency within the normal band
Frequency keeping unit	frequency keeping unit means any equipment that provides frequency keeping services
Normal Band	normal band means a frequency band between 49.8 Hertz and 50.2 Hertz (both inclusive)
Code	Refers to the Electricity Industry Participation Code

Abbreviations

Abbreviation	Explanation
ACS	Asset Capability Statement
AGC	Automatic Governor Control
AO	Asset Owner
AOPO	Asset Owner Performance Obligation
CCGT	Combined Cycle Gas Turbine
CQTG	Common Quality Technical Group
EMS	Energy Management System
FKC	Frequency Keeping Control
GXP	Grid Exit Point
HPF	High Pass Filter
IBR	Inverter Based Resource
IIBR	Intermittent IBR (used in scenario naming and figures)
MCO	Maximum Continuous Output
MFK	Multiple Frequency Keeping or Multiple Provider Frequency Keeping
NI	North Island
NREL	National Energy Renewable Laboratory
OCGT	Open Cycle Gas Turbine
PPO	Principal Performance Obligation
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SFK	Single Frequency Keeping or Single Provider Frequency Keeping
SI	South Island
SO	System Operator
SQ	Status Quo

3 Introduction

3.1 Purpose and overview of the frequency studies

As part of its Future Security and Resilience (FSR) project, the Electricity Authority (Authority) published an Issues Paper in 2023 titled "Future Security and Resilience – Review of common quality requirements in Part 8 of the Code"[2]. The Issues Paper identified seven key common quality issues. The first of these issues was related to frequency:

An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic (PV) generation, is likely to cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

This report covers frequency studies undertaken by Transpower, as system operator, to assist the Authority and industry stakeholders in their consideration of potential options to address this issue.

3.2 Expected changes in generation

The New Zealand power system is currently dominated by synchronous machine-based generation which produces approximately 90% of the energy delivered across the transmission network. The amount of Inverter-Based Resources (IBR), such as wind and solar photovoltaic (PV) generation and Battery Energy Storage Systems (BESS), is expected to increase in the coming years, displacing some of the existing synchronous machine-based generation. This view is very much aligned with the connection requests made to Transpower for IBR and the expected, and regularly signalled, retirement of large synchronous thermal generation. The increase in solar PV generation is expected to include a rapid increase in behind-the-meter solar PV generation, as the technology becomes more affordable.

IBR generation is defined as generation that is connected to the power system using a power electronic inverter or inverter technology. Wind and solar generation are examples of intermittent IBR generation due to the fluctuating nature of their generating power source.

The increase in IBR availability and lower marginal operating costs compared with thermal generation, and at times hydro generation, means that IBR generation is likely to comprise a significant portion of the generation operating in the future.

One of the significant operational differences between synchronous machine-based generation and wind or solar PV generation is the variability and intermittency of the latter's generation output. This can cause an imbalance between the generation and load in real time, impacting the system frequency.

3.3 Managing system frequency

New Zealand maintains a nominal frequency of 50 Hz across the power system. Maintaining this frequency is necessary to avoid damage to equipment connected to the power system, avoid cascade failure due to equipment disconnection, and maintain the frequency time error.

The Electricity Industry Participation Code (Code) requires the system operator to maintain the frequency within a 'normal band' of 49.8 Hz to 50.2 Hz, other than for momentary fluctuations. To maintain and manage the system frequency, the New Zealand power system depends on generator dispatch, frequency keeping services, and asset owner performance obligations (AOPOs) on generators to both ride through frequency fluctuations and to help maintain system frequency by automatically changing their generation output in responses to changes in system frequency.

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[2] Link to Electricity Authority Issues Paper: [Part 8 common quality requirements | Our consultations | Our projects | Electricity Authority (ea.govt.nz)]

Managing frequency through generator dispatch and procurement of instantaneous reserve: The system operator is responsible for dispatching generation on a five-minute basis, to balance generation and demand so as to maintain frequency. To restore frequency during momentary fluctuations, the system operator also procures instantaneous reserve (IR), which is a mixture of additional reserve capacity and interruptible load. The collective response of the generators must return frequency to at least 49.25 Hz within 60 seconds, with the frequency not permitted to go below 45 Hz in the South Island and 47 Hz in the North Island.

Frequency keeping: One or more generators provides a frequency keeping service (Multiple Provider Frequency Keeping (MFK)) by varying the output of their generating unit(s) in response to frequency keeping control signals issued by the system operator. The generators providing this service use automatic governor controls (AGC), where a central controller can calculate the required power (MW) to maintain the frequency and time error within required target, which is normally limited to within a regulation control band. New Zealand uses a high voltage direct current (HVDC) frequency keeping control (FKC) mechanism to help keep frequency in the normal band within the North and South Islands. FKC is an operating mode of the HVDC link that continuously varies the HVDC power transfer to maintain the same frequency in the North and South Islands, essentially sharing the frequency keeping reserve across the islands.

Maintaining frequency through obligations on generation asset owners: Part 8 of the Code contains AOPOs that specify the contributions generators must make to maintaining frequency in the normal band. To maintain frequency in the normal band, these obligations require that generating units must ride through contingent events and ensure their governors (or equivalent control systems) automatically respond to changes in system frequency.

Generating stations that export less than 30 MW to the transmission network or to a local (distribution) network[3] do not have to support system frequency in the same way as generating stations exporting 30 MW or more. These are referred to as 'excluded generation stations' in the Code (see clause 8.21). This creates somewhat of an incentive for generators to build generating stations that export less than 30 MW.

> 8.21 Excluded generating stations
>
> (1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in **Technical Code A** of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** that exports less than 30 **MW** to a **local network** or the **grid**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in **Technical Code A** of Schedule 8.3.

Impact of a frequency dead band: A frequency dead band is a band of frequency in which the generator's frequency control system[4] does not respond to changes in frequency. The Code does not stipulate frequency dead band settings. A narrow dead band reduces the costs of reserve procurement, but the narrower the dead band, the higher the equipment lifecycle costs for generating units due to more active frequency response.

[3] The Code defines a 'local network' to mean the lines, equipment and plant that are used to convey electricity between the transmission network and one of the following: (a) an embedded generator: (b) an embedded network: (c) an installation control point (ICP).

[4] By 'frequency control system' we mean a speed governor for synchronous machine-based generating units and a frequency controller for IBR. At the time of writing this report, the term governor is still used in the code. The term governor is used in this document when referring to the code.

3.4 Assessing the impact of a changing generation mix

Whilst managing system frequency with *current* levels of variable and intermittent generation that uses IBR is manageable, the expected significant increase in IBR will create challenges for managing system frequency under the current regulatory arrangements.

The Authority, in collaboration with the system operator and a technical group the Authority has established to provide advice on the Code's common quality requirements (the Common Quality Technical Group (CQTG)), scoped the following studies.

Study 1: This study assesses the potential future impacts on system frequency in New Zealand from a proportional increase in the number of excluded generating stations for which the frequency-related AOPOs set out in clauses 8.17 and 8.19 of the Code do not apply. The study extends to determining an appropriate (export[5]) MW threshold to enable the system operator to continue to meet its Principal Performance Obligations (PPOs). The engineering studies assess:

1. How different MW thresholds for excluded generating stations can affect frequency management outside the normal band.
2. The impact on frequency management if excluded generating stations do not remain connected during an under-frequency event for the time periods specified in clause 8.19 of the Code.

Study 2: This study assesses:

1. The impact of increased intermittent IBR generation on frequency within the normal band and on frequency keeping, and
2. The impact of implementing a frequency dead band on the width of the MFK frequency keeping band needed to maintain frequency within the normal band.

Study 3: This study assesses how different frequency dead bands affect the amount of instantaneous reserve needed to keep frequency above 48 Hz during a contingent event.

Study 2 is the focus of this report. A separate report has been prepared on Studies 1 and 3.

3.5 Background to Study 2

The system operator has the obligation to maintain frequency within the normal band, to restore frequency to the normal band after a frequency fluctuation and to correct the frequency time error. Frequency keeping is an ancillary service whereby generators with capable generating units are contracted by the system operator to provide frequency keeping. There are two types of frequency keeping services – MFK and Single Provider Frequency Keeping (SFK). MKF is the primary frequency keeping service. It was fully implemented in 2014.

Under MFK, the total frequency keeping band is allocated to the providers, with the system operator monitoring the system frequency and sending regular signals to the selected frequency keeping units to adjust their generation accordingly.

SFK is the backup service for when MFK is not available. With SFK only one generator can be selected in each island and needs to have the capability to provide frequency keeping across the entire frequency keeping band. With SFK, the generator relies on its own frequency keeping logic to control the generating unit's response to changes in system frequency, with some manual intervention to correct the frequency time error. Due to the almost instantaneous nature of governor response, SFK is faster than MFK, since there are no communication delays associated with signals being received from the system operator.

The frequency keeping band is the total MW required across the frequency keeping units in order to maintain frequency within the normal band. These units can move from their energy dispatch set points according to the system operator's regulation control signal, which is limited by the frequency keeping band. Generally, the

[5] Clause 8.21 specifies an excluded generating threshold which relates to export and not capacity.

frequency keeping band is fixed per trading period and is the same for each island. The following table shows the MW frequency keeping bands:

Table 1: MW bands for different frequency types

Island	FKC	MFK	SFK
NI	ON	± 15 MW	N/A
SI	ON	± 15 MW	N/A
NI	OFF	± 25 MW	±25 MW
SI	OFF	± 25 MW	±25 MW

As noted above, the amount of wind and solar PV generation is expected to increase in the coming years, bringing with it increased intermittency of generation output and thereby more variability in system frequency. Study 2 investigates the impact, in 2035, of this expected increase in intermittent generation. As also noted above, the aim of the study is to assess:

1. The impact of increased intermittent IBR generation on frequency within the normal band and on frequency keeping, and
2. The impact of implementing a frequency dead band on the width of the MFK frequency keeping band needed to maintain frequency within the normal band.

3.6 High level study approach

Frequency keeping is a form of tertiary frequency control, restoring frequency to the normal band post a frequency fluctuation. Under normal operating conditions, frequency keeping serves to continuously maintain frequency within the normal band by managing short term imbalances between generation and load. Hence a quasi-dynamic simulation is required – i.e. the time frame for the study needs to be longer than that for dynamic studies which study the moments post a significant event on the power system. This study is run using Matlab/Simulink for a study period of 3 hours (i.e. 6 trading periods).

This will be a comparative study where the high-level approach for these studies is:

1. Establishing **assumptions for a 2035 future New Zealand power system** using an existing knowledge base.
2. Setting up and testing a **model of the power system** to represent the current and 2035 New Zealand power system.
3. Collecting and processing existing data to represent intermittent **IBR generation characteristics**.
4. Using data to pass through the Matlab/Simulink Model to **simulate frequency responses**.

Results Analysis:

1. To best visualise the results, a combination of Microsoft Excel and Python programming is used. Using Python modules, a normalised probability density function is plotted (this is the same as a normal distribution). This is best for visualising changes around a mean (e.g. frequency). A flatter, wider distribution curve represents a dataset with a higher standard deviation from the mean value, indicating that the data is more spread out. The term variability or variance in data is used to describe how the data is spread out, as depicted in Figure 3-1. For each of the curves, the x axis depicts the data in its recorded units (frequency in Hz and active power in MW) and the y axis represents the probability density. For a probability density function, the area under the curve sums to 1 and represents total probability.

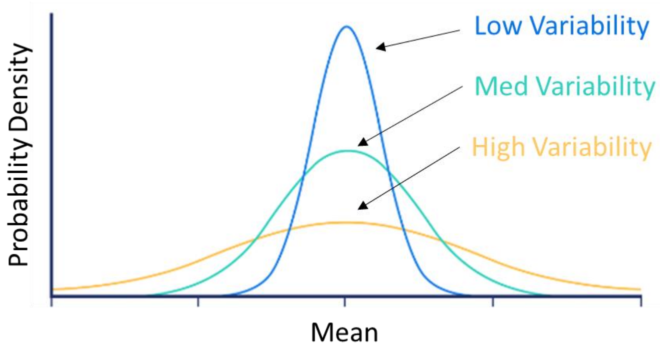

Figure 3-1: Normal distribution curve explained

1. A histogram is used to visualise the MFK results data. The data is plotted in 1 MW bin sizes where the number of times a data point appears in the specified bin is indicated on the y-axis (i.e. count).

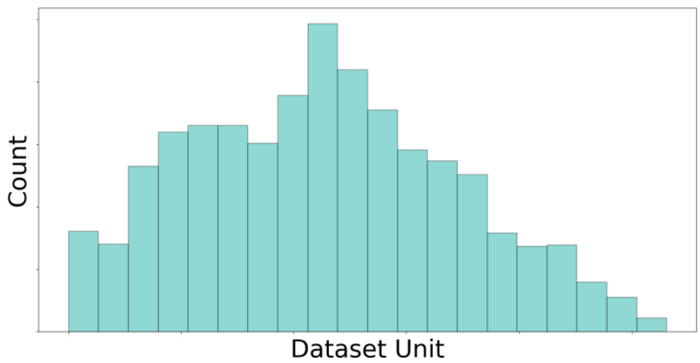

Figure 3-2: Histogram curve explained

4 Understanding the Future Power System

This section unpacks existing and expected future wind and solar generation connections to the New Zealand power system. In this section the following are shown:

1. **Current generation installed capacity**: The existing wind and solar PV generation and the percentage of total installed generation capacity that it comprises.
2. **Existing intermittent generation**: The difference between synchronous machine-based generation and wind generation, highlighting intermittency.
3. **Impact of existing wind generation on frequency**: The impact of wind generation on frequency, with links back to study cases in the Authority's 2023 Issues Paper.
4. **Impact of aggregated solar plants**: The difference between the solar output profile in a localised area and the aggregated solar PV output over a larger geographical area. This section is incorporated in the report to firm up assumptions since there is a lack of commissioned utility-scale (i.e. large-scale / grid-scale) solar generating stations.

4.1 Current generation installed capacity

At the time of writing this report, no plant information (PI) data on solar PV generation in New Zealand is available. The table below shows that nearly 10% of installed generating capacity in New Zealand is wind. In section 4.3.2 (Forecasted Wind and Solar), wind generation grows to approximately 3.6 times its existing installed capacity and solar PV generation becomes established at approximately 3,631 MW. Transpower's 2020 Whakamana i Te Mauri Hiko (WiTMH) report estimates that solar generation could be as high as 7,360 MW in 2030.

Table 2: 2023 Asset Capability Statement (ACS) data on existing generation
(Note: some wind farms may have been commissioned since the extraction of this data)

Technology	Installed Capacity [MW]	% of total installed capacity
Wind	1,015	10%
BESS	0	0.00%
Solar	2	0.02%
Thermal	2,349	23%
Geothermal	1,137	11%
Hydro	5,545	54%
Cogeneration	219	3%
Total	10,268	-

4.2 Existing intermittent generation

The word *intermittent* means "occurring at irregular intervals; not continuous or steady".

When referring to intermittent generation this report refers to generation that relies on a resource that is not stored and varies over time in an unpredictable manner, resulting in generation output that is:

1. variable and uncertain,
2. not fully dispatchable.

This study considers wind and solar PV generation as intermittent generation.

This section highlights the difference between the active power output of intermittent wind generation and synchronous machine-based hydro and thermal generation. Active power data from generating stations in operation is used. Figure 4-1 shows the month of October 2023, while Figure 4-2 shows a day in October 2023. These figures showcase the intermittency of wind generation compared to synchronous generation.

As wind and solar PV generation increases, synchronous machine-based generation may be displaced. This can impact the operation of the power system in the following ways:

1. Traditional synchronous machines, which are generally predicable and dispatchable, may be less available as a mechanism to support/manage system frequency.
2. Fast ramping and unpredictable changes in wind and solar PV generation output disrupts the generation/demand balance, causing frequency to vary.

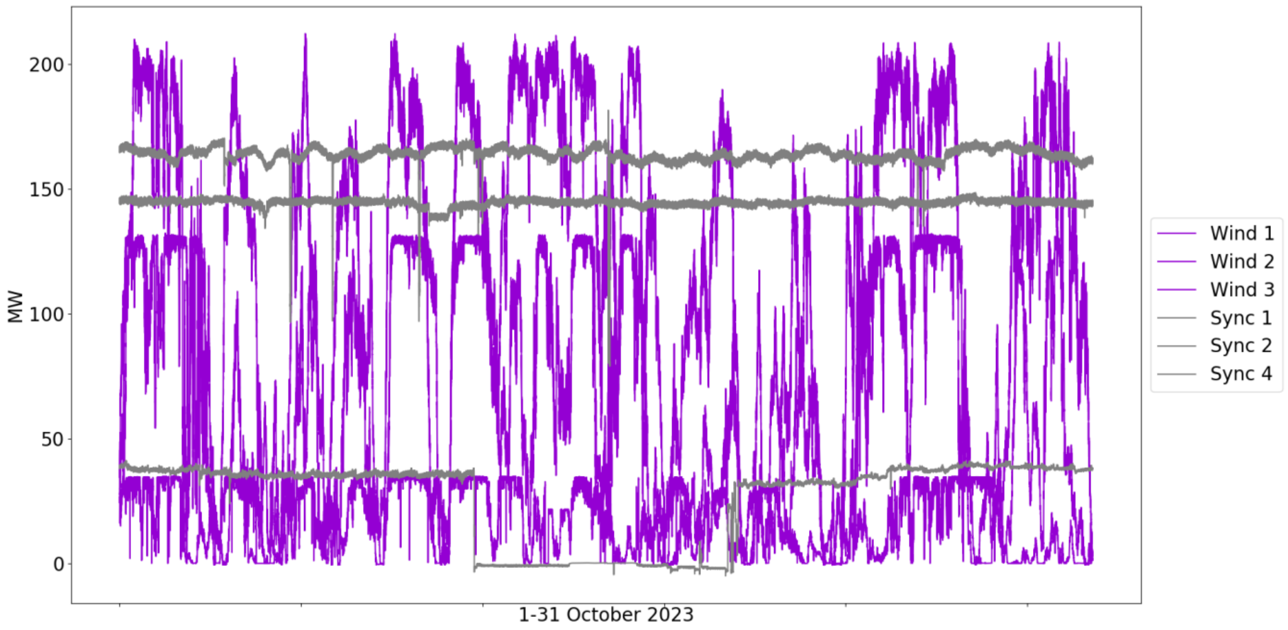

Figure 4-1: Wind and Synchronous Generation for October 2023

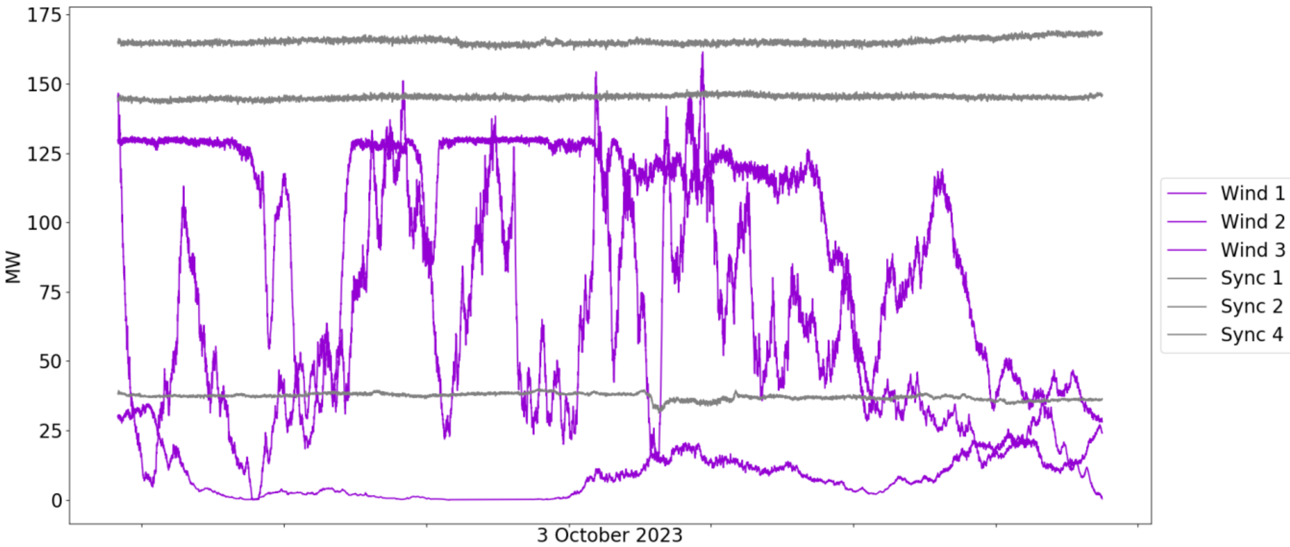

Figure 4-2: Wind and Synchronous Generation for 3 October 2023

4.3 Impact of existing wind generation on frequency

Case studies discussed in the Authority's 2023 Issues paper

A case study observing the impact of wind on frequency was completed for the Authority's 2023 issues paper: *Future Security and Resilience - Review of common quality requirements in Part 8 of the Code*. In Appendix A of this report, various scenarios show how wind generation can adversely affect frequency quality.

4.3.1 Additional data analysis for 2023

In addition to the data analysed for the case studies in the Authority's 2023 issues paper, further 2023 data (1 January 2023 to 30 November 2023) was analysed in a slightly different way to assess if the trend noted in the issues paper persists. Key points to note on the methodology followed are:

1. Wind capacity in the North Island is greater than that in the South Island. Hence, the 'high wind' scenario and the 'low wind' scenario are based on North Island wind generation only. The analysis looks at wind as a percentage of generation that is online at any point in time.
    a. High wind > 20 % of overall generation.
    b. Low wind < 5 % of overall generation.
2. Filtering data based on the percentage of wind generation online means:
    a. The data would be a series of "sectioned" data stitched together over a period.
    b. Each "section" of data varies depending on the dispatched values for wind. Generation is dispatched every 5-minutes and so the smallest "section" of data is expected to be at least 5-minutes, with a few outliers.

The following figures (Figure 4-3, Figure 4-4, Figure 4-5) show:

1. The entire 2023 frequency dataset from 1 January 2023 to 30 November 2023.
2. The subset of the 2023 frequency dataset where wind generation is more than 20 % of total generation.
    a. The normal distribution curve shows more variation in frequency compared to the normal distribution curves for the entire 2023 frequency dataset and with wind generation <5%.
3. The subset of the 2023 frequency dataset where wind generation is less than 5% of total generation.
    a. The normal distribution curve shows less variation in frequency compared to the normal distribution curves for the entire 2023 frequency dataset and with wind generation <5%.

This aligns with the study case in the Authority's 2023 issues paper, and supports the notion that wind and solar PV generation (which is also intermittent) may cause higher frequency fluctuations.

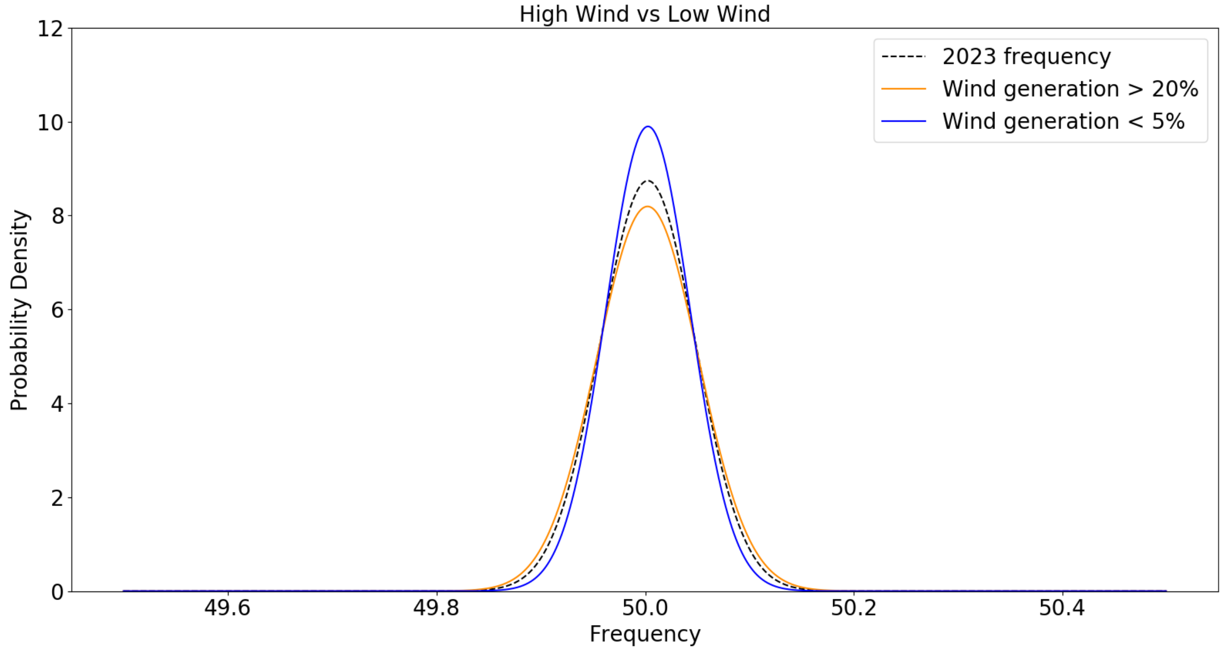

Figure 4-3: Normal distribution for frequency comparing high and low wind generation. Similar trends are observed for summer and winter

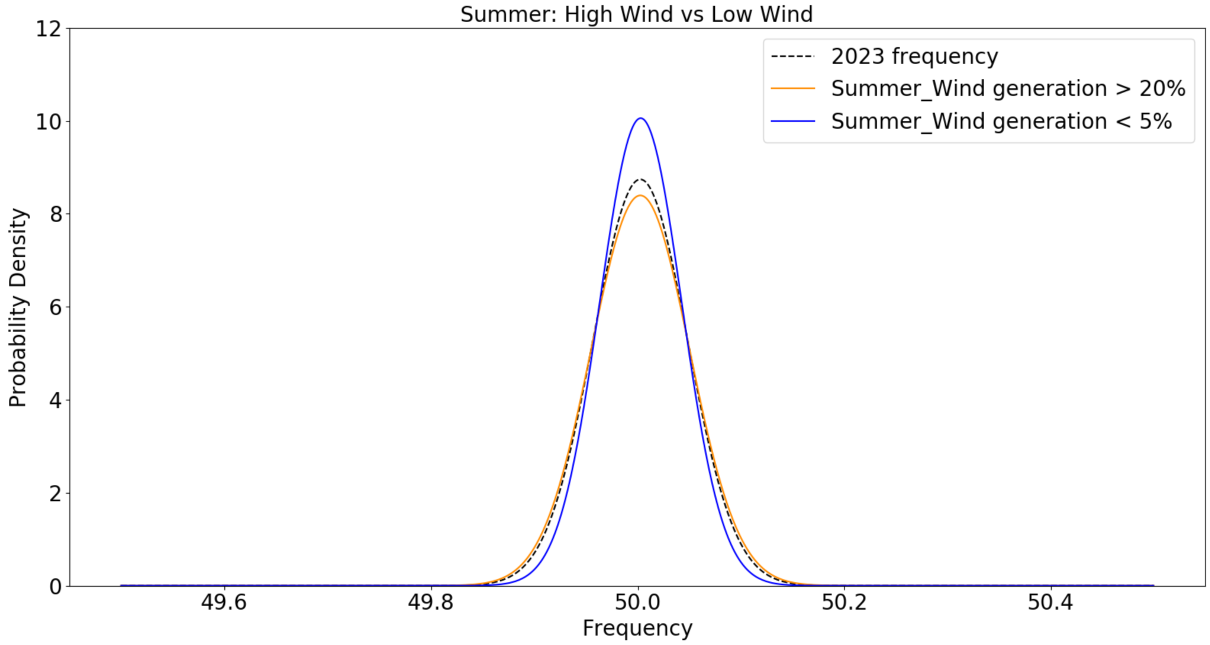

Figure 4-4: Normal distribution for frequency comparing high and low wind generation in SUMMER

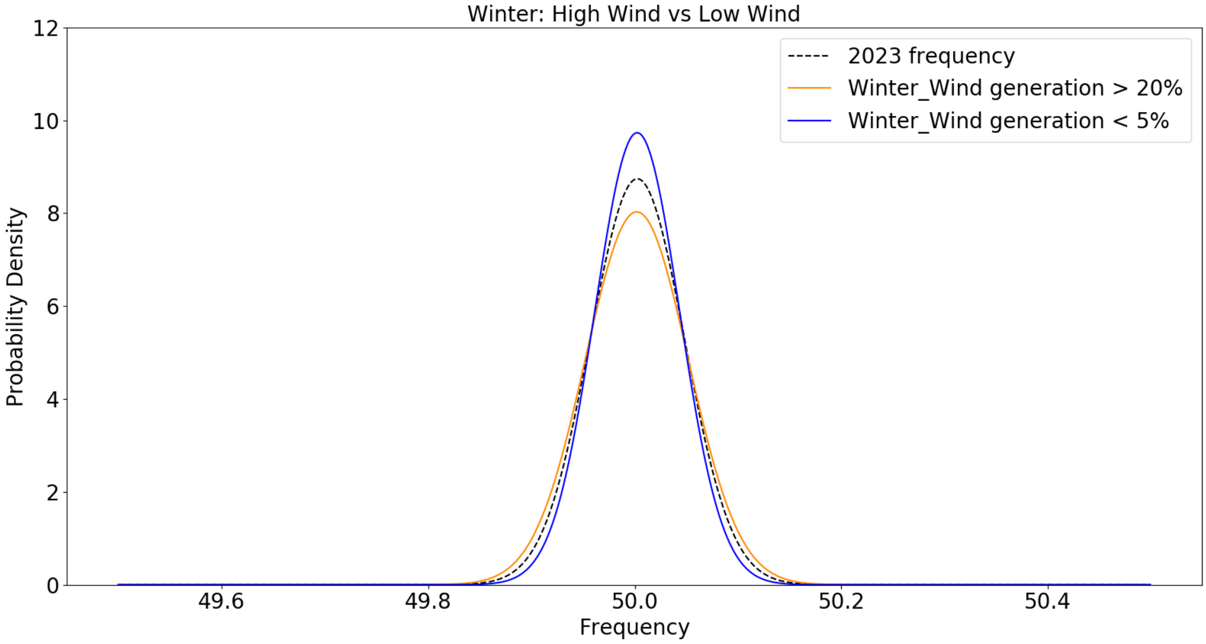

Figure 4-5: Normal distribution for frequency comparing high and low wind generation in WINTER

4.3.2 Forecasted Wind and Solar

Increases in frequency fluctuations are expected in the future due to an increase in wind and solar PV generation connected to the power system. The following tables show indicative numbers for wind and solar PV generation to be connected to the transmission network in 2025, categorised by region. These numbers align to the following publications:

1. The 2020 WiTMH report,
2. The March 2023 WiTMH monitoring report, and
3. The 2023 Transmission Planning Report.

Table 3: Forecasted distributed and utility-scale solar generation classified per regional boundary

Region	Distributed Solar	Utility Scale Solar	Regional Total	Regional Total / Island Total [%]
Northland Region	58	227	285	10%
Auckland Region	296	278	574	20%
Waikato Region	105	964	1069	37%
Bay of Plenty Region	82	74	156	5%
Hawke's Bay Region	61	400	461	16%
Taranaki Region	28	192	220	7%

Region	Distributed Solar	Utility Scale Solar	Regional Total	Regional Total / Island Total [%]
Manawatū-Whanganui Region	56	0	56	2%
Wellington Region	108	0	108	4%
Nelson & Tasman Region	11	0	11	2%
Marlborough Region	19	50	69	10%
West Coast Region	7	0	7	1%
Canterbury Region	165	400	565	80%
Otago Region	34	0	34	5%
Southland Region	18	0	18	3%
Total	1047	2585	3632	-
NI Total	793	2135	2928	-
SI Total	253	450	703	-

Table 4: Forecasted and existing wind generation classified per region.

Region	Wind (New)	Wind (Existing)	Regional Total	Regional total / Island Total [%]
Northland Region	225	0	225	7%
Auckland Region	0	0	0	0%
Waikato Region	326	64	390	13%
Bay of Plenty Region	0	0	0	0%
Hawke's Bay Region	50	0	50	2%
Taranaki Region	0	133	133	4%

Region	Wind (New)	Wind (Existing)	Regional Total	Regional total / Island Total [%]
Manawatū-Whanganui Region	1511	523	2034	67%
Wellington Region	15	211	226	7%
Nelson & Tasman Region	0	0	0	0%
Marlborough Region	0	0	0	0%
West Coast Region	0	0	0	0%
Canterbury Region	172	0	172	28%
Otago Region	150	44	194	31%
Southland Region	200	58	258	41%
Total	2649	1033	3682	-
NI Total	2127	931	3058	-
SI Total	522	102	624	-

4.4 Impact of aggregated solar PV generation

When the incident solar irradiation on solar panels in a solar PV generation station differ at a point in time, the power output of each solar panel differs. The aggregated solar generation output is much less peaky due to non-coinciding peaks and troughs of the output power of each panel. The difference in incident solar irradiation between solar panels is due to partial shading, which can be caused by, inter alia:

1. The panels or solar PV generation station spanning a large geographical area,
2. Cloud movement.

Total (island-wide) power output of solar PV generation is impacted by the location of solar generating stations and cloud movement[6]. The coincidence of solar PV generation output affects the overall "peakiness" of an island-wide solar generation profile. It is expected that island-wide solar generation profiles will be smoother than localised solar generation profiles. To showcase this, we analysed 5-minute time series data supplied by Solar Zero. This data showed the following:

<u>Total solar for the North Island vs total solar in Vector's area of supply (AOS):</u>

[6] There may be correlation between wind and cloud movement, however the analysis of cloud movement across New Zealand and its correlation with wind is out of scope for this study.

1. Figure 4-6, Figure 4-6, and Table 5 (NI vs Vector AOS) show that at the same point in time, the change in power for localised plants (Vector AOS) is higher than the aggregated solar generation profile.
2. The Auckland region has the largest installation of rooftop solar for Solar Zero. The curves show that clusters of solar generating stations in a localised area can have a material influence on the aggregated solar PV generation profile.

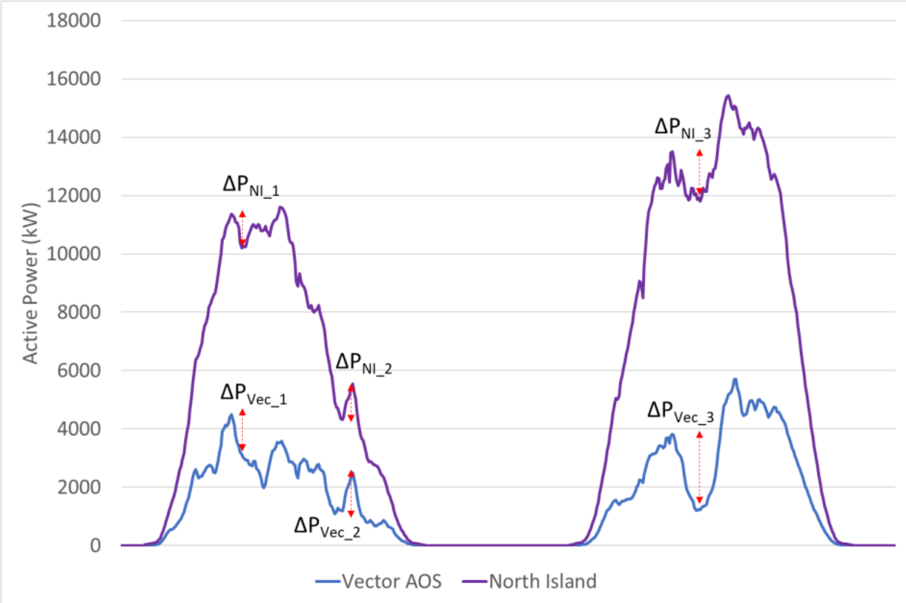

Figure 4-6: North Island vs Vector AOS

Table 5: the change in power at different points on Figure 4-6 and Figure 4-6

	Active power	
x	ΔP_{NI_x}	ΔP_{Vec_x}
1	1,082	1,523
2	1,229	1,308
3	1,703	2,468

5 Asset and Network Modelling

5.1 Model configuration

This section outlines how the model is arranged and provides some details around its structure.

5.1.1 Overall Model (North Island, South Island, HVDC)

Figure 5-1 shows the connection between the main blocks in the model (i.e. the North Island (NI), the South Island (SI), and the HVDC link). The load and wind/solar PV data for each island are used as inputs. The output frequency from each island is fed back into the HVDC link. The following sections provide further detail on each block.

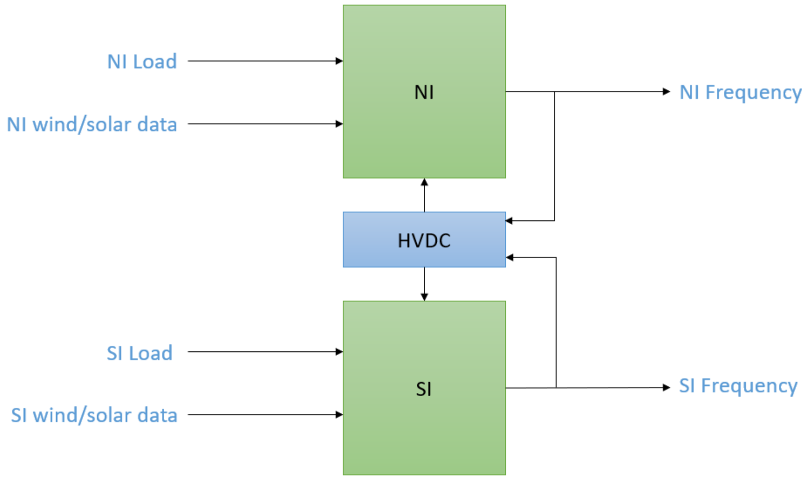

Figure 5-1: Overview of the blocks in the model

The following figure is a control block diagram representation of the study model. Further expansion of the model is shown in subsequent figures.

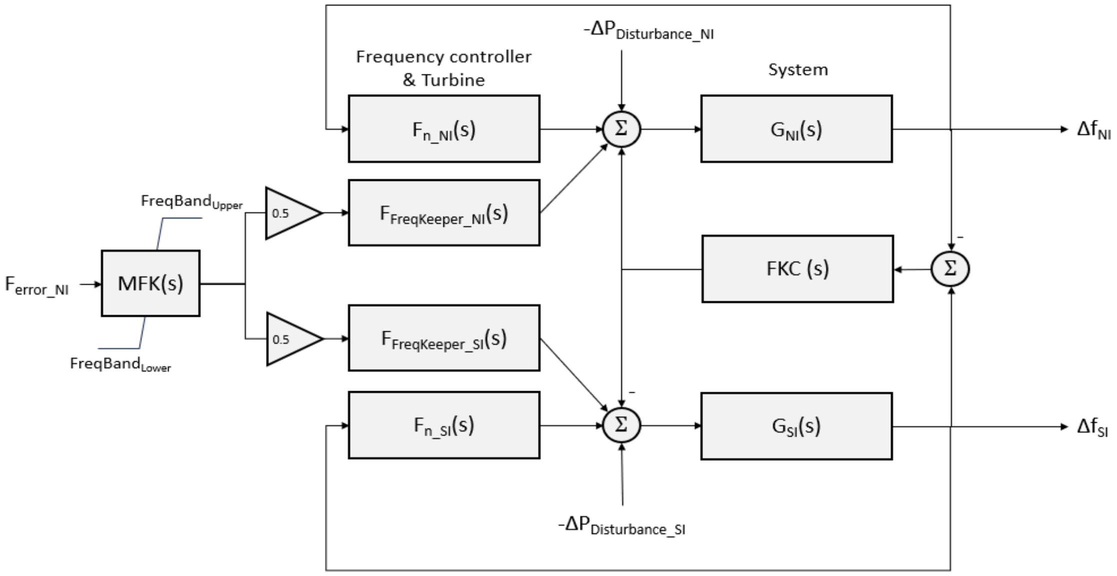

Figure 5-2: Control block representation of the study model

Each block represents a transfer function that models the behaviour of each component in the power system.

$G_{XX}(s)$	• The transfer function modelling the **power system** response to changes in demand and generation for the NI and SI.
$F_{n\_XX}(s)$	• The transfer function modelling the **generation** response to changes in frequency for generation in NI and SI. • Multiple aggregated models are used to differentiate the response of generation by type (n).
$F_{FreqKeeper\_XX}(s)$	• The transfer function modelling the **frequency keeping unit** response to changes in MFK regulation control signal.
MFK(s)	• The transfer function modelling/calculating for the **MFK regulation control signal** in response to a frequency error (error from 50 Hz).
FKC (s)	• The transfer function modelling the **FKC** response of the HVDC link in response to a frequency error between the NI and SI.

The following block diagrams show further detail on the signal flow in the simplified NI and SI model.

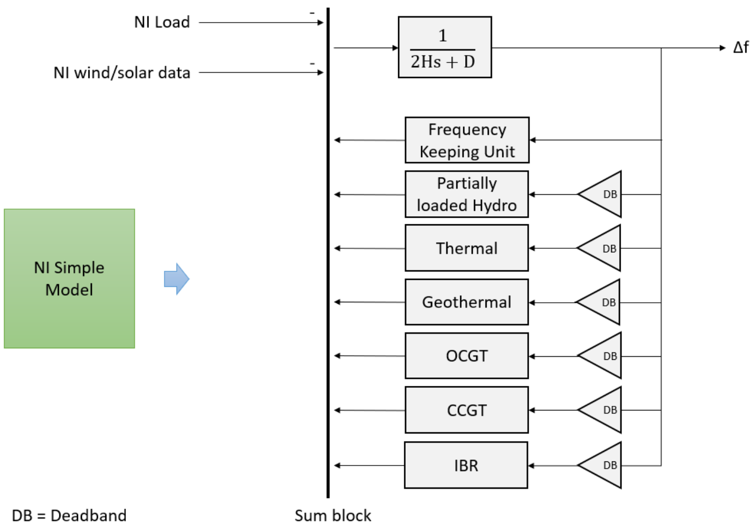

Figure 5-3: Further details on the NI model

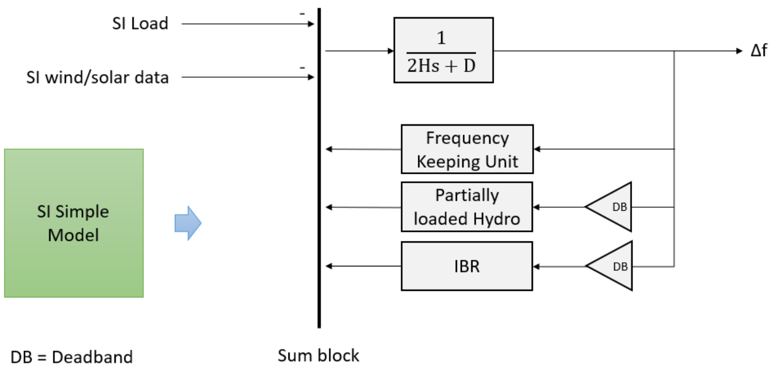

Figure 5-4: Further details on the SI model

5.1.2 Model Limitations

The Matlab/Simulink model accurately models the response of each generation type and the power system. The limitation in the model is the use of an aggregated model to model the response of all generation classified as a certain type. There is no ability to model the diversification in the generating stations' responses when parameters change from one generating station to another. This limitation does not take away from the study results.

6 Scenarios

6.1 High-level scenarios considered

For Study 2 the level of intermittency inside the 5-minute dispatch window is considered. Hence, there are two main scenarios – High Intermittency (HI) and Low Intermittency (LI). The total number of scenarios are as follows:

Study Case 1: Winter (No Solar PV generation output)

1. Scenario 1: Status Quo (2023)
    a. High Intermittency
    b. Low Intermittency
2. Scenario 2: 2035 Lower intermittent IBR (IIBR) wind and solar PV generation export (Lower IIBR case)
    i. High Intermittency
    ii. Low Intermittency
3. Scenario 3: 2035 Higher intermittent IBR wind and solar PV generation export (Higher IIBR case)
    i. High Intermittency
    ii. Low Intermittency

Study Case 2: "What if" analysis on the impact of solar PV generation on frequency keeping.

6.2 Generation mix

The winter generation mix, which has zero solar PV generation, was used due to the limitations with solar PV generation data. This creates a viable case in which trends for other scenarios that include solar PV can be derived. The generation mix data for 2023 was informed by the generation online for a day in July 2023, and the 2035 winter generation mix was informed by the analysis conducted in frequency Study 1. The information on frequency dead bands was sourced from ACS data, which has limitations with its accuracy due to a lack of information.

	Status Quo 2023 - Winter			2035 - Winter		
Generation types modelled	Maximum Continuous Output [MW]	Output [MW]	Dead band [± Hz]	Maximum Continuous Output [MW]	Output [MW]	Dead band [± Hz]
NI_CCGT	0	0	0.1	474	340	0.1
NI_OCGT	378	221	0.1	378	321	0.1
NI_Geo	1195	904	0.195	1773	1472	0.195
NI_Hydro	1076	946	0.03	1761	1553	0.03
NI_IIBR	392	392	0.15	2129	2129	0.15
NI_Thermal	550	251	0.195	550	351	0.195

	Status Quo 2023 - Winter			2035 - Winter		
Generation types modelled	Maximum Continuous Output [MW]	Output [MW]	Dead band [± Hz]	Maximum Continuous Output [MW]	Output [MW]	Dead band [± Hz]
NI_Ungov	565	296	x	565	346	x
SI_Hydro	3217	2494	0.03	3140	2840	0.03
SI_IIBR	100	100	0.15	350	350	0.15
SI_Ungov	105	82	x	105	82	x

7 Study Assumptions

For the study, the following assumptions are made:

Input data:

1. Synchronous machine-based generating stations will not have high variability around the dispatch set point. Hence a change in wind/solar PV generation and load are sufficient model inputs to model the impact on frequency within the normal band.
2. Wind generation profile characteristics depend on weather/climate patterns. These display the intermittency characteristics independent of the time of day/year.
3. Higher wind/solar PV export will result in higher intermittency.
4. The 2035 load profile is affected by changes in load throughout the day. These changes are assumed to be the same as the 2023 load profile.
5. The total capacity of intermittent wind and solar PV generation is assumed to be the same as for the frequency Study 1.

Multiple frequency keeping:

1. MFK is currently the primary mechanism of frequency keeping and assumed to be retained as the primary method in 2035. Hence scenarios that consider SFK and automatic governor control (AGC) are not considered in this study.
2. The MFK regulation control signal will be split equally across the North and South Islands, and the split is retained for all scenarios.
3. The frequency keeping band baseline is ±30 MW which is split equally between the North and South Islands.
4. FKC will be available and enabled for all scenarios. The HVDC transfer limitation is retained as is.

Wind/solar PV generation:

1. It is assumed that intermittent wind and solar PV generation technology will operate with no generation headroom (i.e. at maximum active power output). Hence this generation only responds to over frequency.
2. A default frequency dead band setting for intermittent wind and solar PV generation is set to ± 0.15 Hz – i.e. we assume there is no dead band stipulated in the Code.

Other:

1. All dead band test settings are arbitrary, with the lowest dead band test setting aligning with the response requirement in Australia's National Electricity Rules. It is assumed that similar generating technologies with similar performance capabilities will be used across the Australasian energy sectors.

7.1 Study limitations

The following limitations are noted in the study.

1. The network model used is a simplified representation of the power system. There are aggregated generation models, which impact the total generation response.
2. The input data for the study impacts the frequency response results observed. There are many factors that influence the input profile for intermittent wind and solar PV generation. These include, but are not limited to,:
   a. The correlation between intermittent wind and solar PV generating stations (i.e. coinciding generation peaks and troughs).
   b. The correlation of intermittent wind and solar PV generating station output over a significantly large area that can be influenced by weather patterns (e.g. cold fronts).
   c. The correlation between wind generating station output and solar PV generating station output (e.g. a windy day may correlate with a high passing cloud).

d. The smoothing effect of solar panels in a solar PV generating station with a large geographical footprint, and the correlation and/or smoothing of total generation between multiple solar PV generating stations.[7]

e. The cumulative impact of the intermittency from distribution-connected solar PV generation will impact the distribution load profile, possibly causing it to vary more. The 'duck effect' may also cause a perceived load ramp during the day, which can also influence frequency when energy demand is being managed.

To accurately assess the impact of these factors is difficult and requires an immense amount of data analysis and scenarios to be run, which is out of scope for this project. Running a conservative study with existing data may be a more sensible approach to getting an indication of future trends in frequency keeping. Nevertheless, the results of this study can be used to infer trends with greater/lower intermittency.

3. Frequency dead band data is not accurate due to inconsistencies in how this technical parameter is provided/collected through the ACS information provision process.

[7] Solar radiation data from NIWA was analysed and showed high variations in solar PV generation. However, without the smoothing effect of individual panels in a solar farm and other intermittent solar PV generation, the NIWA data could not be used. NREL data was also sourced, but the resolution was too high (at 5 minutes).

8 Studies, Results and Observations

8.1 Study 2a: Assess the impact of increased wind and solar PV generation on frequency keeping

Problem Statement:

Increased wind and solar PV generation may cause an increased imbalance between generation and load due the intermittent nature of the generation source. This increased generation and load imbalance is expected to cause higher variation of frequency within the normal band.

Overall Objective:

Perform a comparative study to assess the impact on frequency keeping due to an increase in wind and solar PV generation on the New Zealand power system.

8.1.1 Methodology

With the use of Matlab/Simulink, power system frequency response to a specified input can be simulated. The Matlab/Simulink model is representative of the generation on New Zealand's power system.

Generation Mix:

1. The data was sourced from existing generation dispatch data for July 2023 and expected future generation, informed by frequency Study 1 as outlined in section 6.2 (Generation mix).

Inputs:

1. A sample of 3-hour, 1-second PI data for wind generation and load is extracted from the system operator's historian database. These are calculated PI tags derived from measured PI tags:
    a. SI total load
    b. NI total load
    c. SI total wind
        i. High Intermittency
        ii. Low Intermittency
    d. NI total wind
        i. High Intermittency
        ii. Low Intermittency

    When extracting the data, the NI profile was used as a reference due to the higher installed capacity of wind in the NI, which will have a higher impact on the shape of the total wind profile for a specific scenario. The corresponding profile in the SI is extracted for that same 3-hour period. Hence, the SI profiles may not adhere to "high intermittency" or "low intermittency" due to the wind behaviour at the moment in time.
2. The 1-second data is passed through the high-pass filter with cut-off frequency ω = 0.008 rad/s. This value was iteratively chosen so that the model is best calibrated with existing data. This serves to remove the dispatch portion of the signal, which eliminates the need to re-dispatch generation after every 5 minutes in the simulation. The re-dispatch of generation has the potential to skew the results if not done correctly.
3. The output of the high-pass filter is a time series dataset with 1s intervals, which serves as the input to the power system model. The frequency response every second is then observed.

Generating the 2035 profiles:

1. A sample of 1-second PI data for wind generation was extracted for periods of high intermittency and low intermittency and used for the 2023 simulations. The same curve was normalised by establishing the capacity of connected windfarms generating at that point in time. This extracts the profile of wind generation. Multiplying the per-unitised profile by the future wind capacity, a 2035 profile is generated. This profile is limited by the existing wind patterns and does not cater for possible change in these in

the future. Nor does this profile account for changes to the intermittency of wind generation in the future because of changes to the location of wind generating stations. However, higher intermittent wind generation export is expected to cause higher variations in the generation profile, and hence this mention is sufficient to ascertain a trend.

The following figure summarises how data flows through the models:

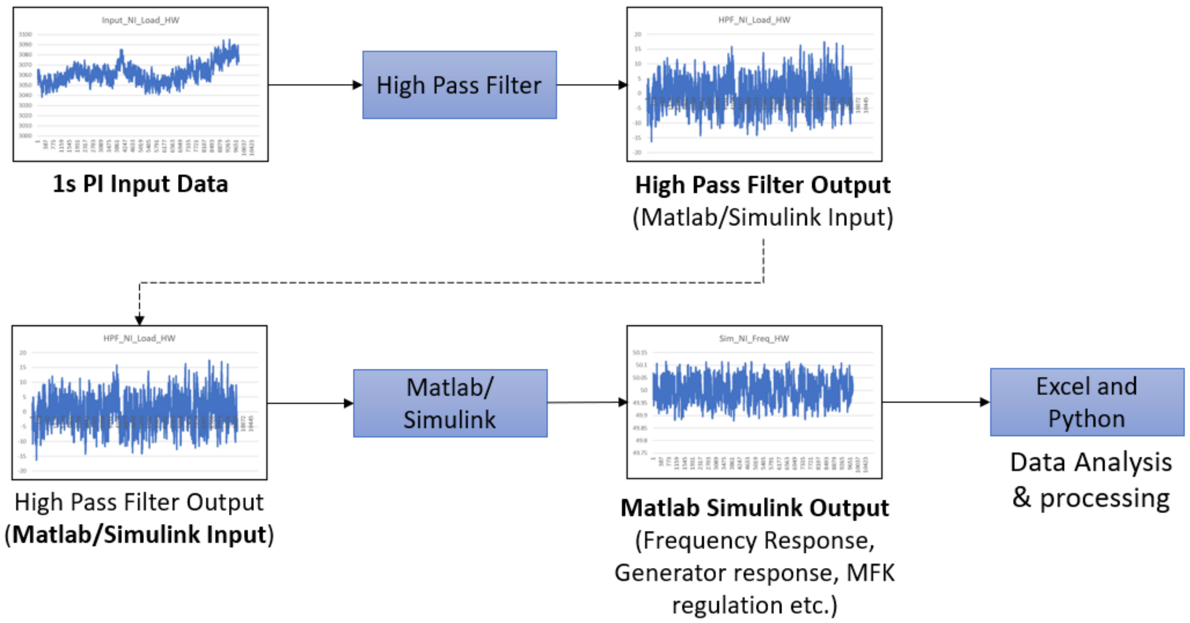

Figure 8-1: Flow of data through the models

Study case details

Study Case 1: Winter (No Solar)

1. **Scenario 1: 2023, Status Quo:** Model the 2023 response with high and low intermittency. This is the baseline used for comparison to the 2035 study cases.
2. **Scenario 2: 2035, Lower IIBR wind generation export:** Model the 2035 response with low IIBR wind generation export showcasing a lower intermittency.
3. **Scenario 3: 2035, Higher IIBR wind generation export:** Model the 2035 response with high IIBR wind generation export showcasing a higher intermittency.

Study Case 2: Impact of Solar profiles

1. **Scenario 1**: What-if analysis on the impact of solar PV generation on frequency keeping.

8.1.2 Observations: Study 2a, study case 1

The following section outlines the results and observations for each of the studies. The layout of the results is as follows:

Study Case 1: Winter Peak (No Solar)

1. 2023 total load and wind PI data compared to the output signal of the High-Pass Filter.
2. 2023 simulated results compared to the PI data for frequency and the MFK regulation control signal.
3. 2023 simulated results compared to the 2035 results for frequency, the MFK regulation control signal, and generation response.

Study Case 2: Impact of Solar profiles

1. Observation of an existing New Zealand solar farm being commissioned.
2. Possible correlation of wind and solar PV generation in 2035.
3. Use of study case 1 to inform the impact of combined wind and solar PV generation on frequency keeping.

Results/Observations of Study Case 1: Winter Peak (No Solar)

<u>2023 total load and wind PI data compared to the output signal of the High Pass Filter:</u>

A 3-hour, 1-second PI data for load and wind is passed through the High Pass Filter for the North Island (NI) and South Island (SI). It is observed that the NI load data has a higher variance than the SI load. This is a known characteristic of the New Zealand power system. Additionally, wind MW data for the NI has a higher variance when compared to the SI. This could be due to a lower installed capacity of wind in the SI compared to the NI, and/or the different wind conditions in the NI and SI because the same timestamp was used to extract the data in each island.

<u>Input vs output of the High Pass Filter for 2023:</u>

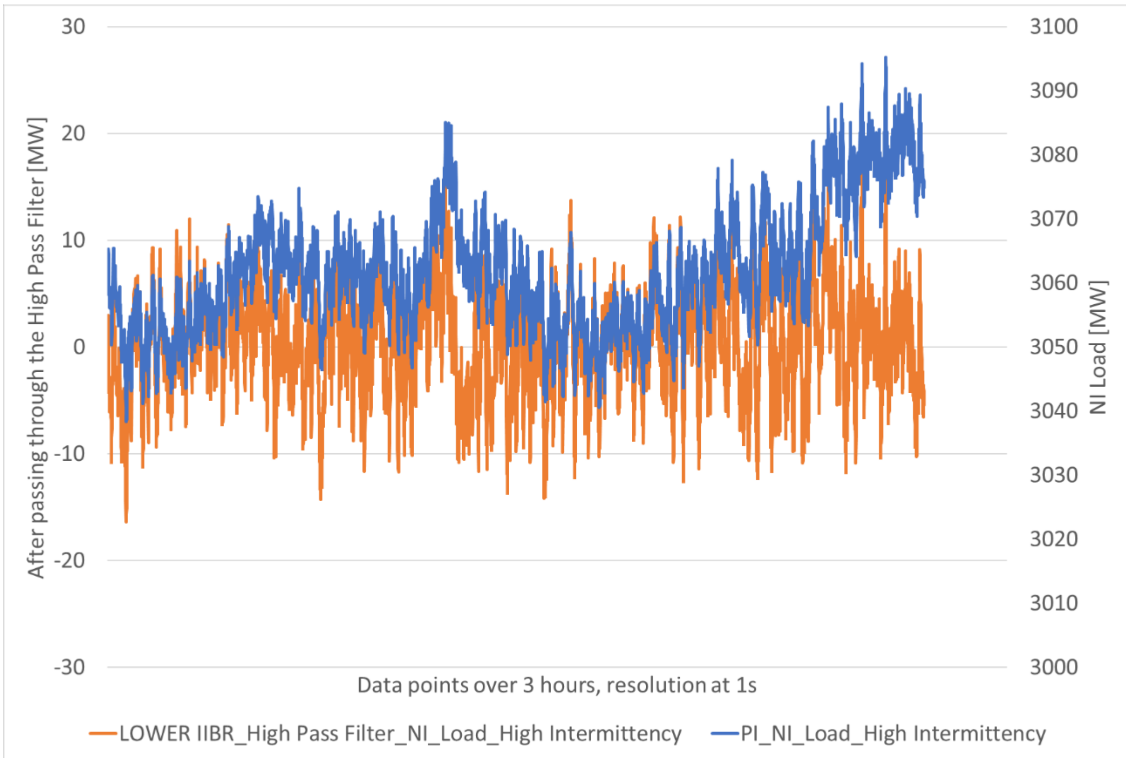

Figure 8-2: PI load data passed through the High Pass Filter for the NI

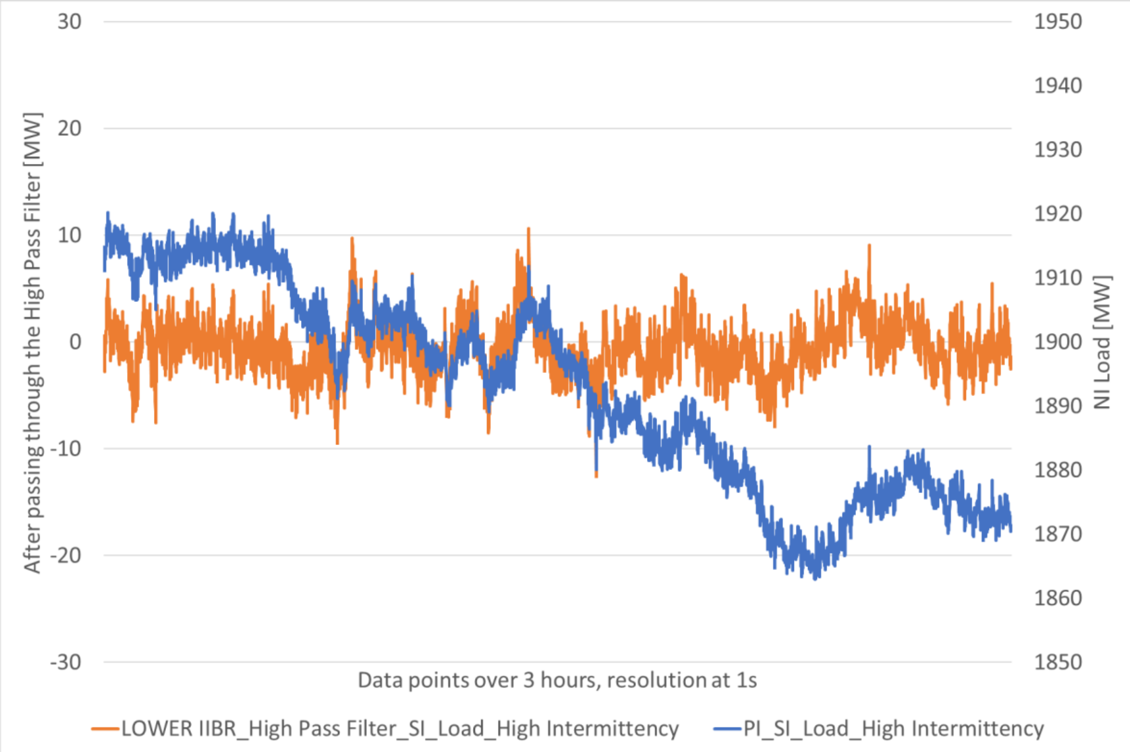

Figure 8-3: PI load data passed through the High Pass Filter for the SI

<u>2023 simulated results compared to the PI data for frequency:</u>

For the actual PI data for the NI and SI, it is observed that the frequency for the SI is managed slightly better. This could be due to:

1. The higher amount of hydro generation with low or no dead bands. On-site governor response due to system frequency changes is much faster than the MFK response because there are communication transport delays with MKF due to the MW regulation control signal being sent from a central source.
2. Lower variance in load and wind generation data in the SI compared to the NI.

Figure 8-4 and Figure 8-5 show the same trend in actual and simulated distributions (i.e. the SI frequency is regulated better than the NI frequency). The difference between the NI and SI frequency is higher in the actual compared to the simulated, which could be due to the interaction of the HVDC link's FKC functionality in the model.

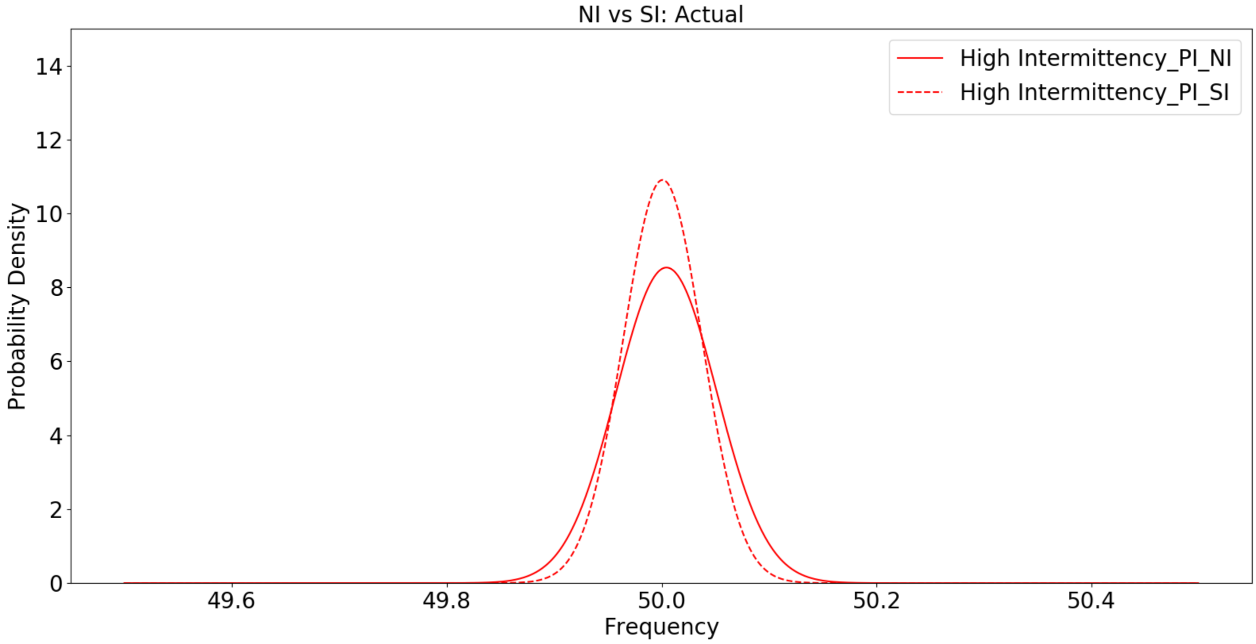

Figure 8-4: NI vs SI PI frequency data showing better regulation on the SI

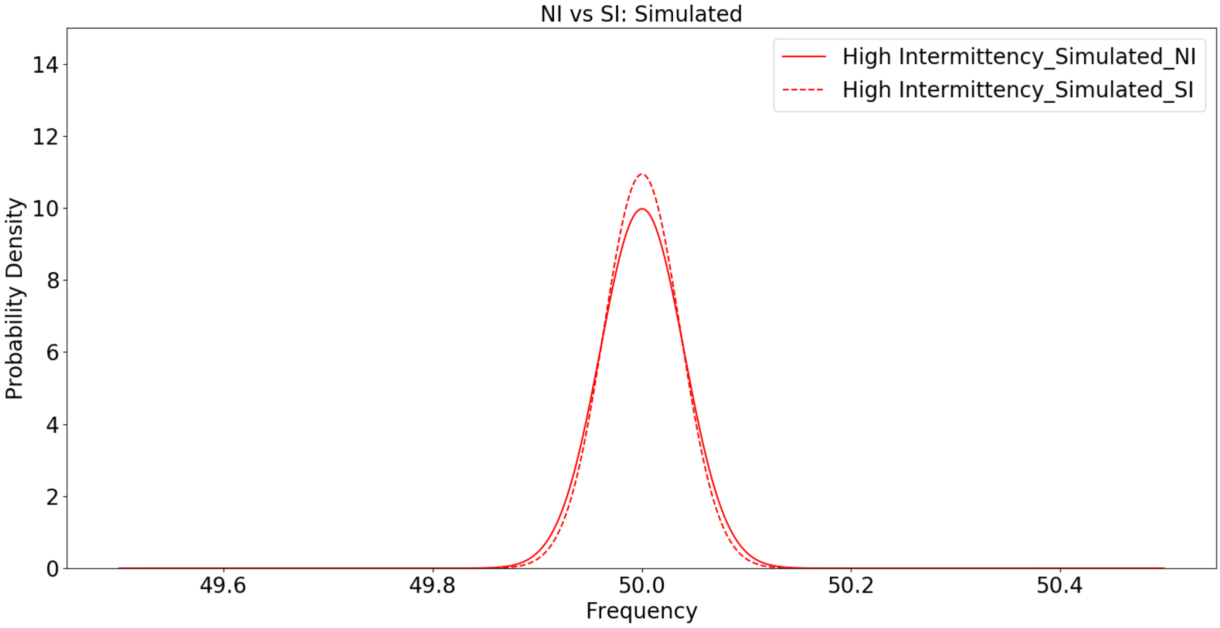

Figure 8-5: NI vs SI simulated frequency data showing better regulation in the SI

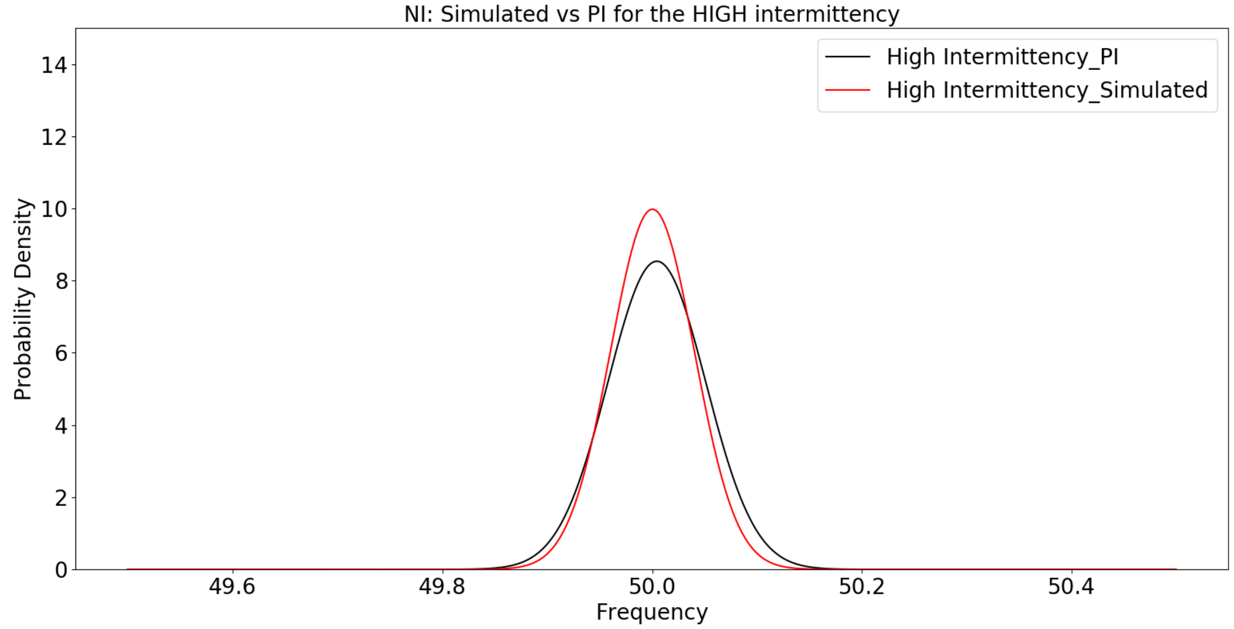

Figure 8-6: Simulated vs PI for high intermittency

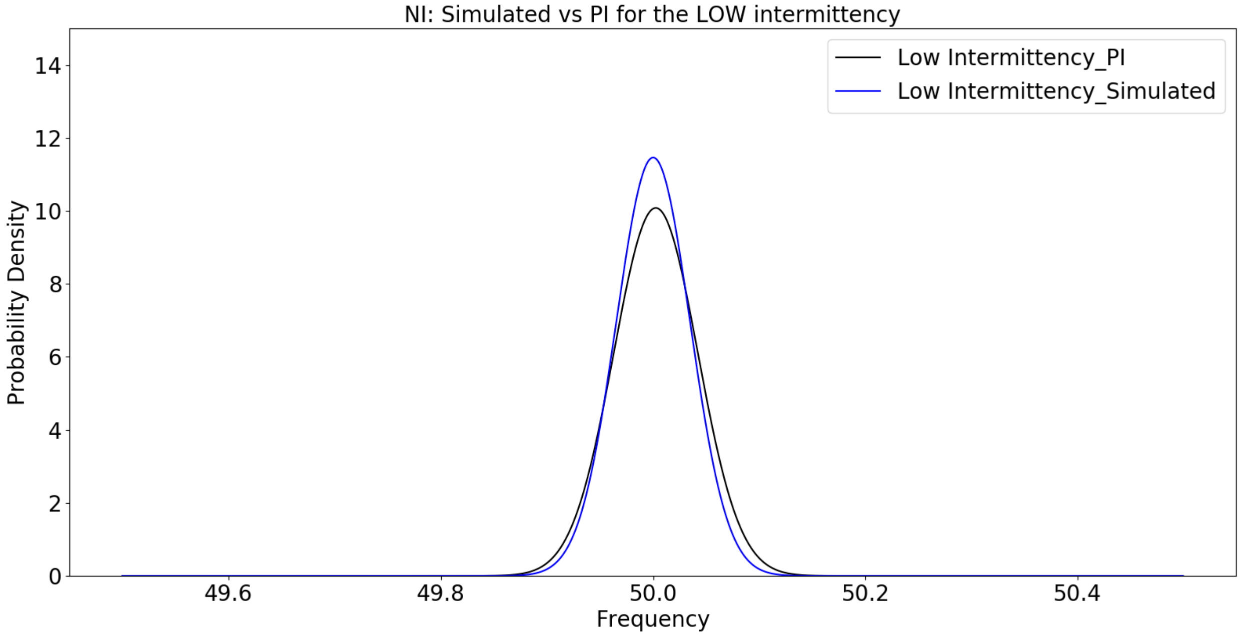

Figure 8-7: Simulated vs PI for low intermittency

For all results, the high intermittency frequency cases have a higher variance than the lower intermittency cases. This is illustrated in Figure 8-8 to Figure 8-11. These figures show that the model follows existing trends well. We note that, although the Matlab/Simulink model is a simplified representation of the New Zealand power system, its response and the results are acceptable.

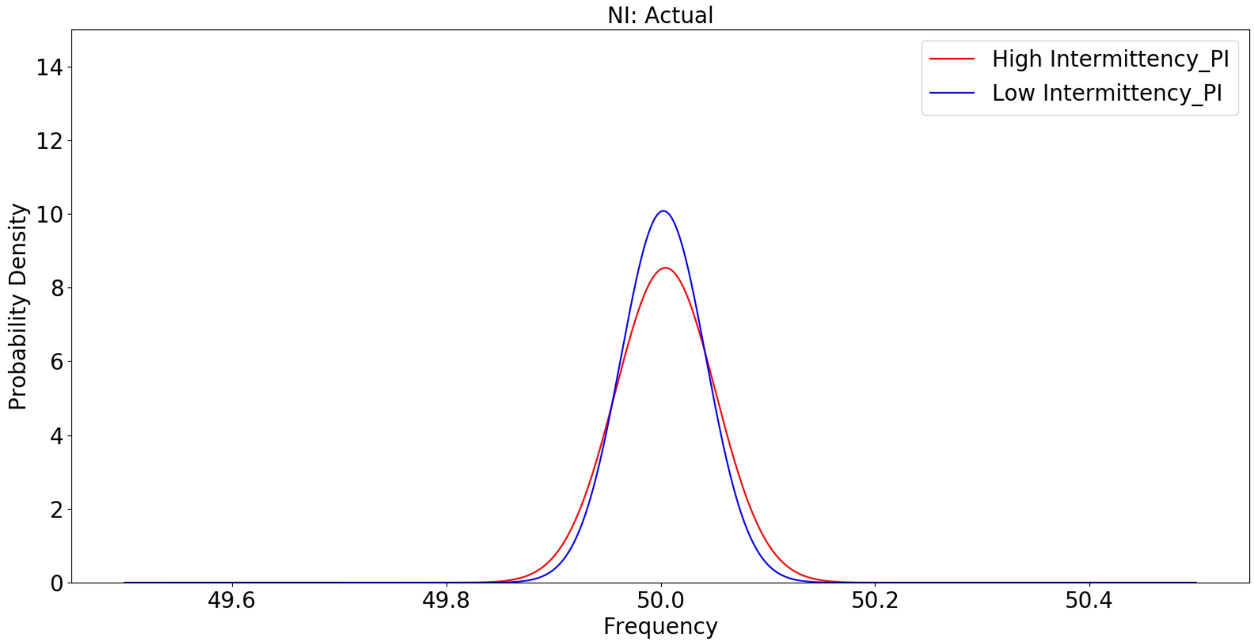

Figure 8-8: NI PI frequency data for high and low intermittency

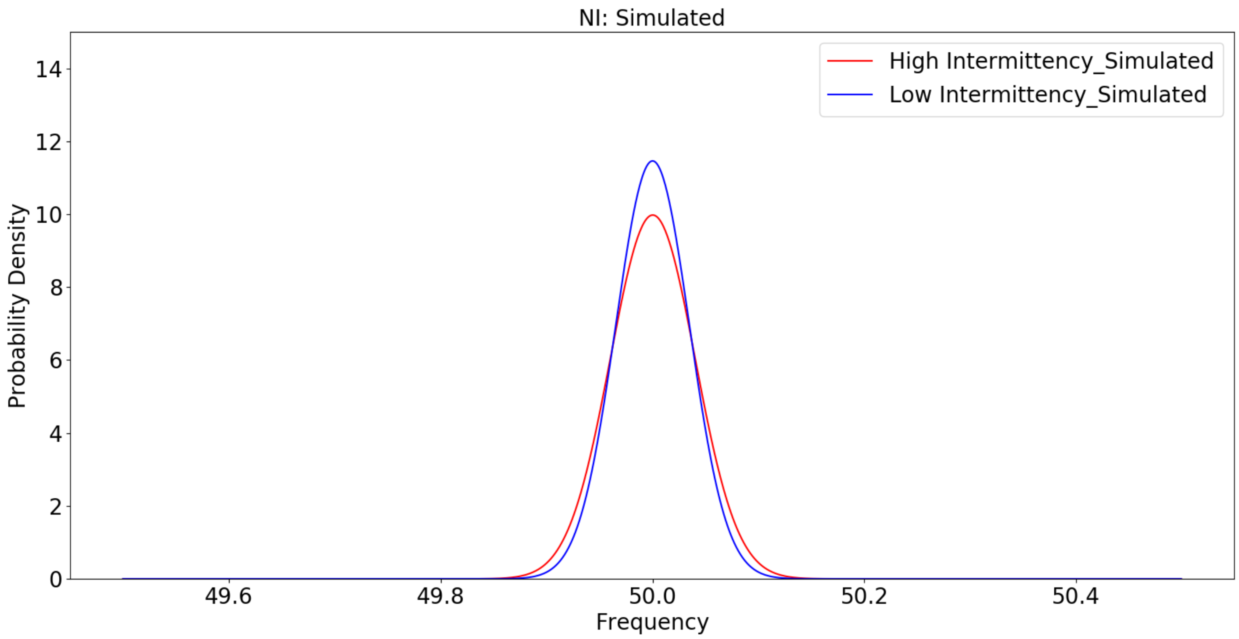

Figure 8-9: NI simulated frequency data for high and low intermittency

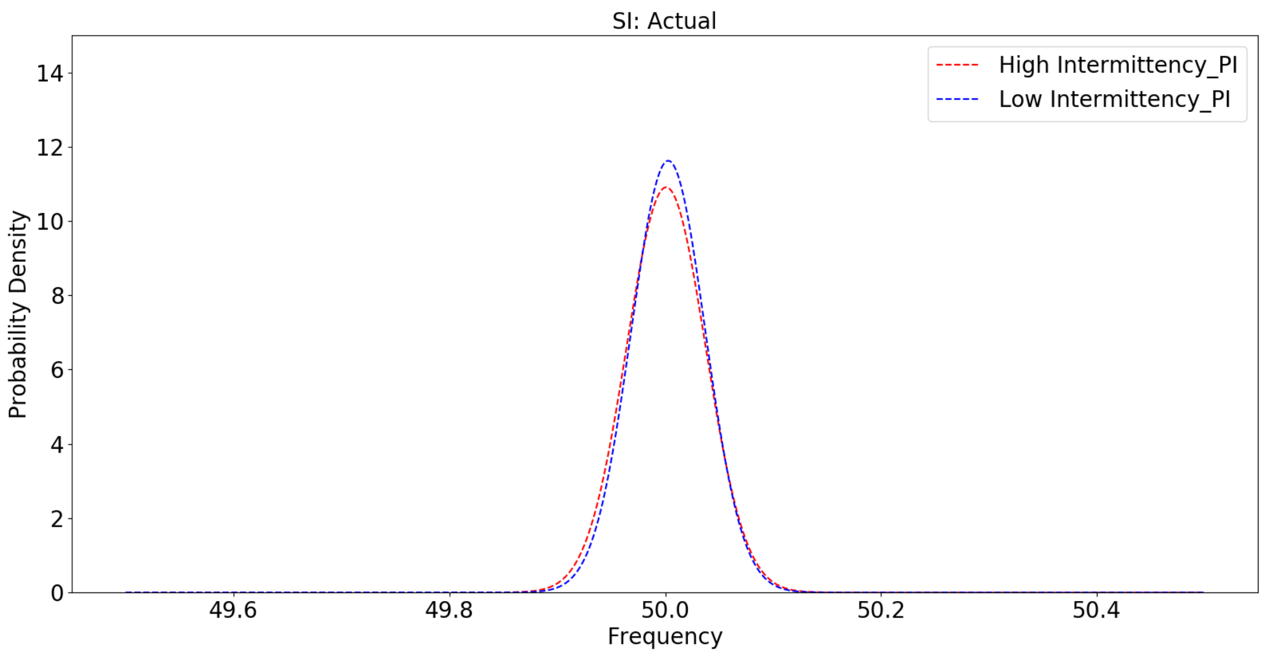

Figure 8-10: SI PI frequency data for high and low intermittency

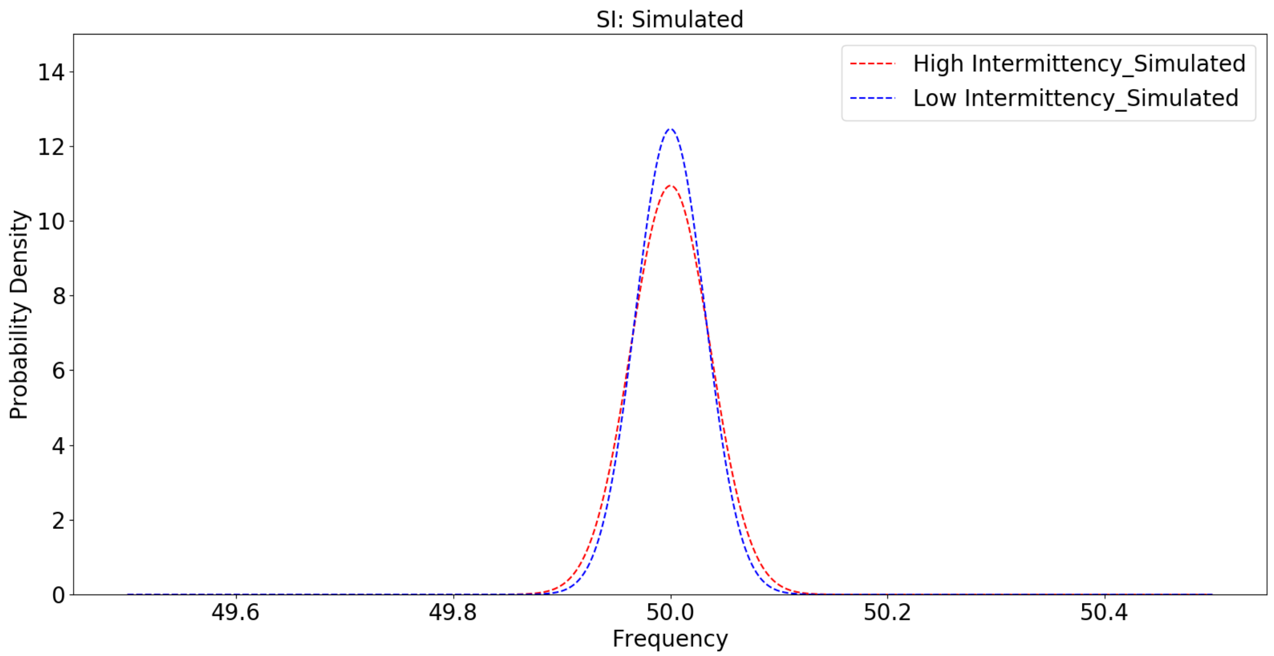

Figure 8-11: SI simulated frequency data for high and low intermittency

<u>2023 simulated results compared to the PI data for the MFK regulation control signal:</u>

MFK regulation control signals are MW values calculated by a central controller in the SCADA/Energy Management System (EMS). The power system-wide values are limited to 30 MW with the signal split equally between the NI and SI. There central controller's functionality allows for it to use different proportions across the islands, but this is not commonly used. All simulations undertaken in this study case use a 50/50 split of the MFK regulation control signal across the NI and the SI.

Figure 8-12 and Figure 8-13 show, respectively, the actual MFK signal extracted from PI and the MFK signal produced by the model. The trends observed in both curves are the same – i.e.:

1. At low intermittency of generation there is less variance in the results data for the MFK curve, indicating less MW frequency regulation is required at low intermittency of generation.
2. For high intermittency of generation there is higher variance in the results data for the MFK curve compared to low intermittency of generation, showing more MW are required to manage frequency.
3. For both the PI data and simulated results, at low intermittency of generation, the curve shows there is a tendency to absorb MW (i.e. the mean is negative). This trend is also observed in the simulated results.

Although the simulated MFK regulation control signal results show a higher variance, the actual machine MW response is what affects the frequency of the power system. The consistency in the trends shows that the model is reliable and can be used in a comparative study for 2035.

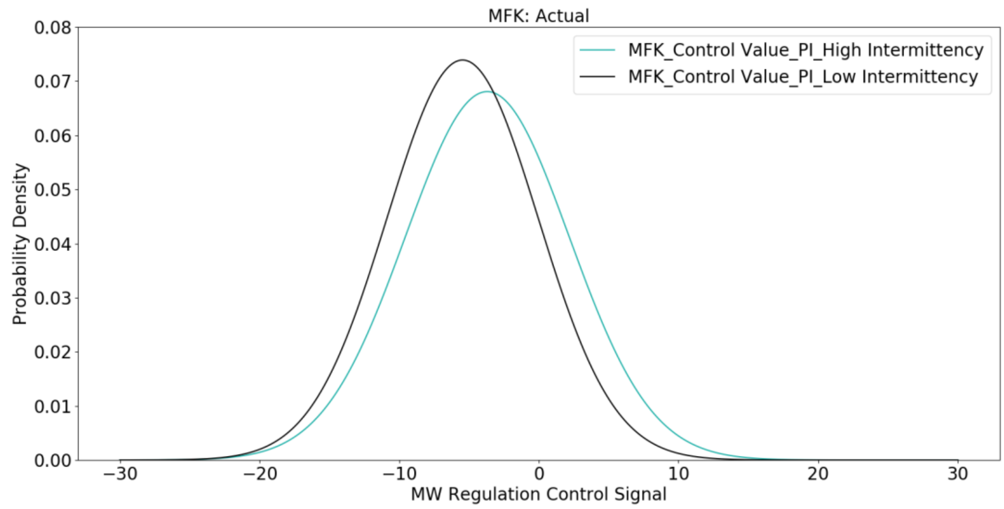

Figure 8-12: MKF regulation control signals for the NI extract from PI

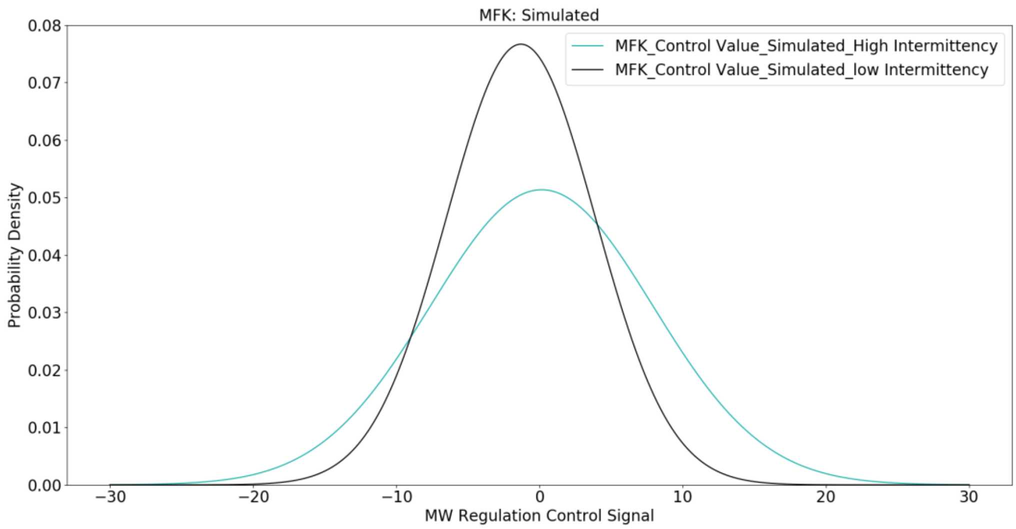

Figure 8-13: Simulated MFK regulation control signals for the NI

2023 simulated results compared to the 2035 results for the frequency, MFK regulation control signal and generation response:

The 2023 (Status Quo) PI data and simulated results have shown consistency in the trends and so the 2023 simulated results will be used for comparison with the 2035 simulated results. The 2035 load data is assumed to have the same behaviour as the 2023 load data.

Input vs output of the High Pass Filter for 2035 wind profiles:

The 2035 wind generation profile data is generated by normalising the 2023 wind generation profile data and then multiplying this normalised data by the installed capacity of wind generation expected to be generating during a 2035 winter peak day. The input profiles are shown in Figure 8-14 to Figure 8-15. A summarised normal distribution of the input data is shown from Figure 8-16 to Figure 8-19. Note the 2035 winter peak day generation mix was informed by frequency Study 1, where the total MW dispatched for wind generation is 2,478.73 (split into 2,128.73 MW for the NI and 350 MW for the SI). The wind was scaled in 2 scenarios, which cover a potential range of intermittent IBR generation export levels in the future generation mix:

1. Lower levels of wind generation export. This scenario is named “Lower IIBR” in results and refers to low levels of intermittent IBR generation export.
   a. NI wind approximately 45% of projected wind.
   b. SI wind at approximately 30% of projected wind.
2. Higher levels of wind generation export. This scenario is named “Higher IIBR” in results and refers to high levels of intermittent IBR generation export.
   a. NI wind approximately 100% of projected wind.
   b. SI wind at approximately 100% of projected wind.

For the **lower IIBR case**, the input MW profile has the following characteristics:

1. For the high generation intermittency case there is
   a. A peak variation of ± 50 MW, with an average variation of ±12 MW for the NI.
   b. A peak variation of ± 15 MW, with an average variation of ±4 MW for the SI.
2. For the low generation intermittency case there is
   a. A peak variation of ± 15 MW, with an average variation of ±3 MW for the NI.
   b. A peak variation of ± 20 MW, with an average variation of ±4 MW for the SI.

For the **higher IIBR case**, the input MW profile has the following characteristics:

1. For the high generation intermittency case there is
   a. A peak variation of ± 100 MW, with an average variation of ±28 MW for the NI.
   b. A peak variation of ± 25 MW, with an average variation of ±6 MW for the SI.
2. For the low generation intermittency case there is
   a. A peak variation of ± 25 MW, with an average variation of ±7 MW for the NI.
   b. A peak variation of ± 25 MW, with an average variation of ±6 MW for the SI.

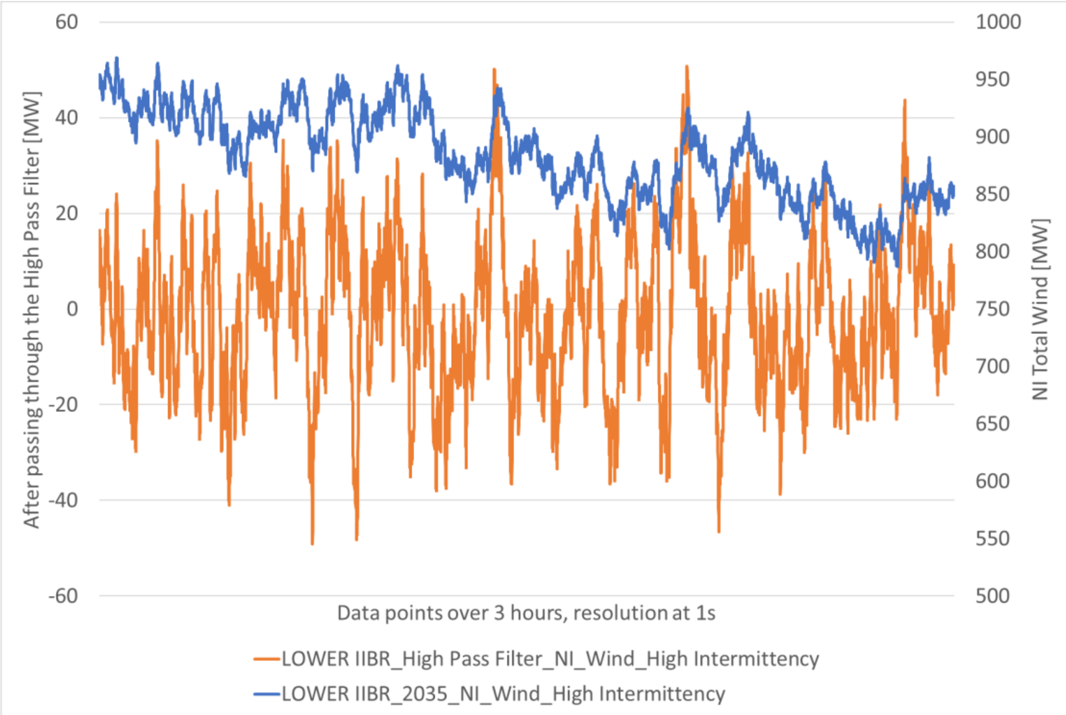

Figure 8-14: LOWER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the NI for the High Intermittency case

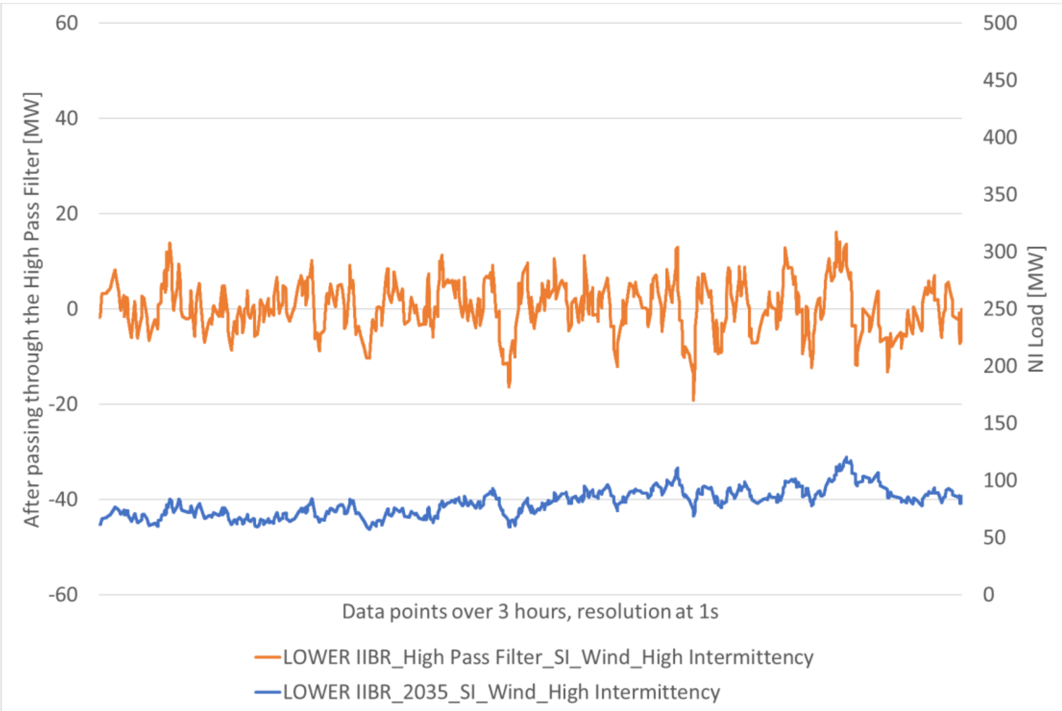

Figure 8-15: LOWER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the SI for the High Intermittency case

To summarise, the data of the input profiles was used to generate the following normal distributions for the NI and SI. The curves show that in the future cases, IBR generation exhibits increased variance in its output (i.e. increased intermittency).

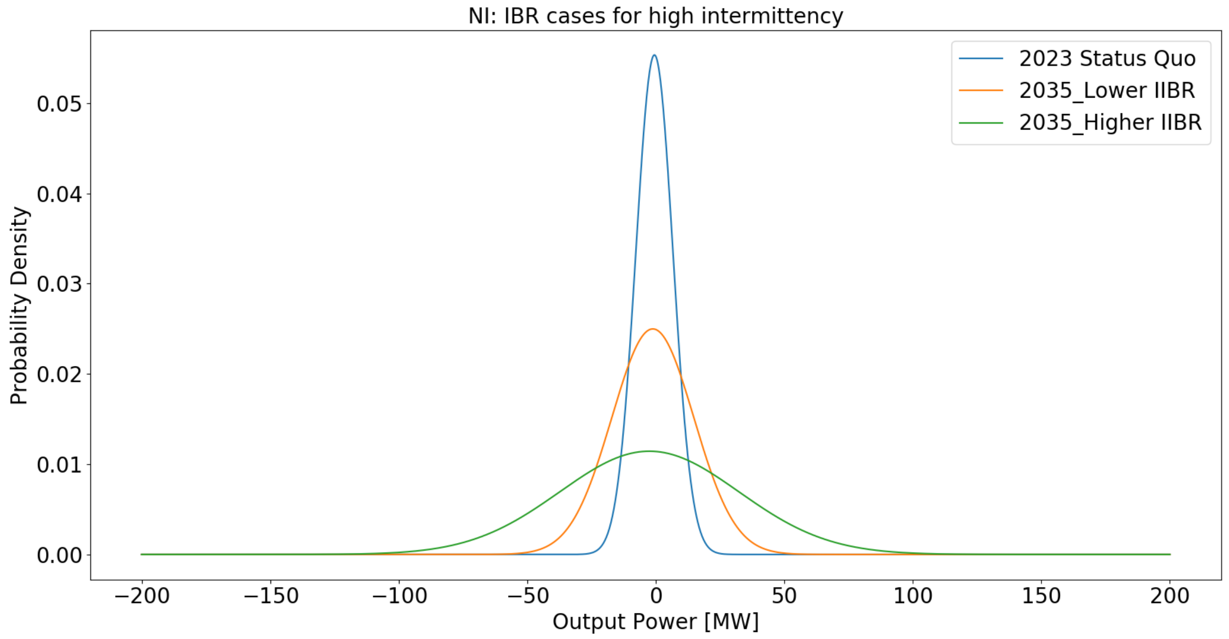

Figure 8-16: NI input profiles represented on a normal distribution curve for high intermittency

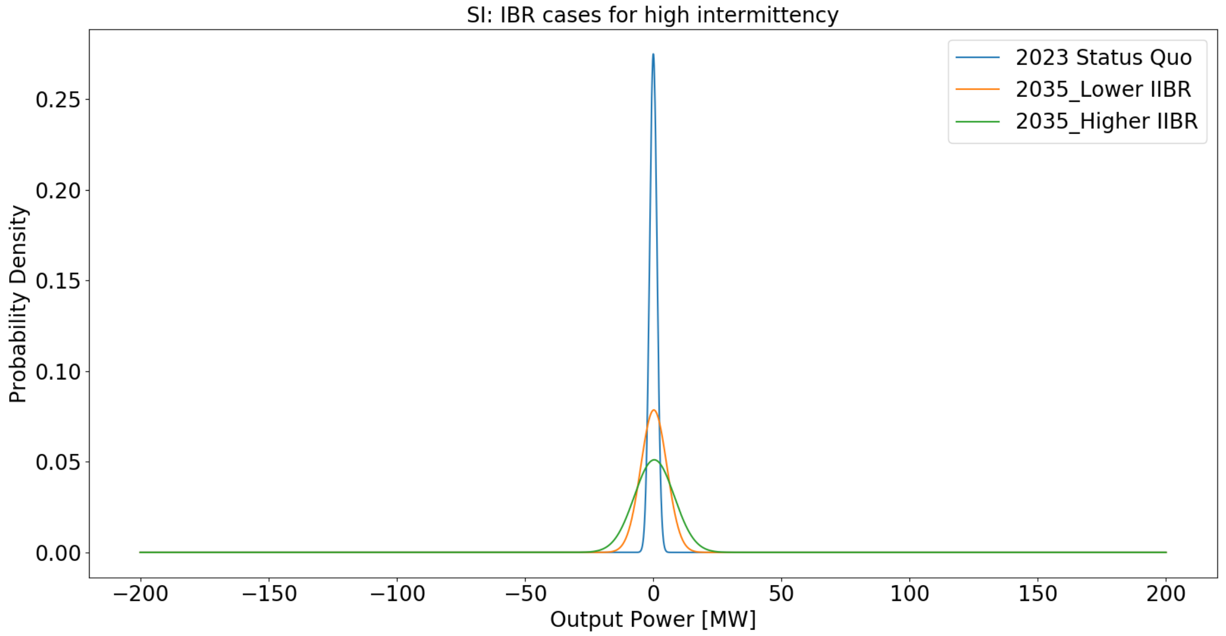

Figure 8-17: SI input profiles represented on a normal distribution curve high intermittency

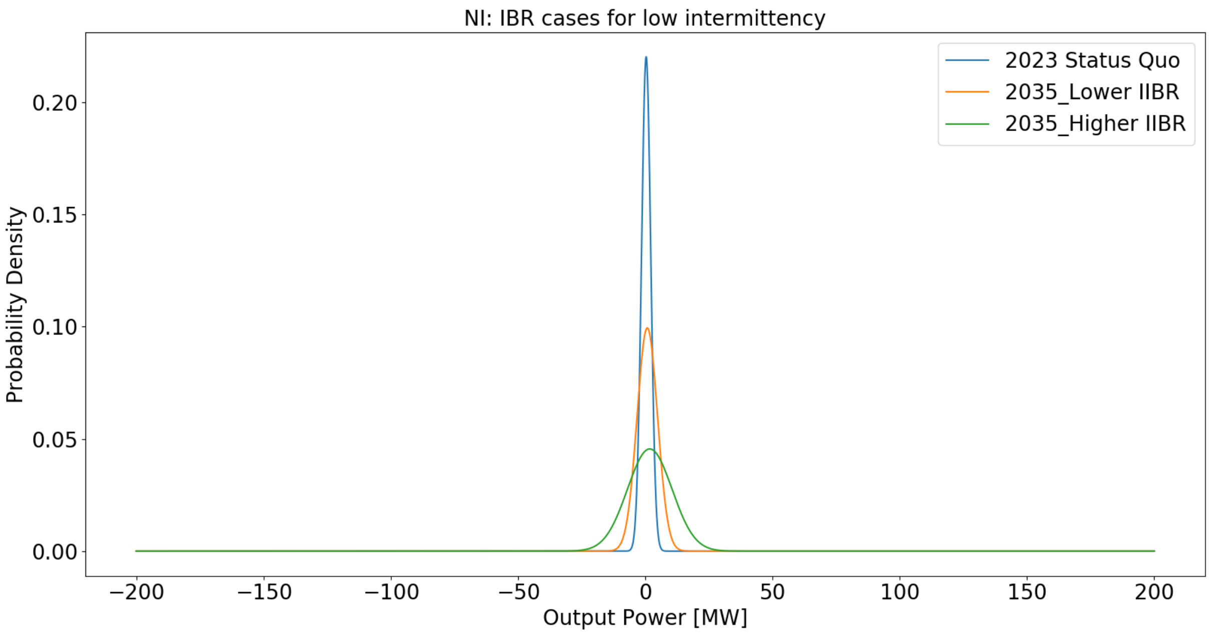

Figure 8-18: NI input profiles represented on a normal distribution curve for low intermittency

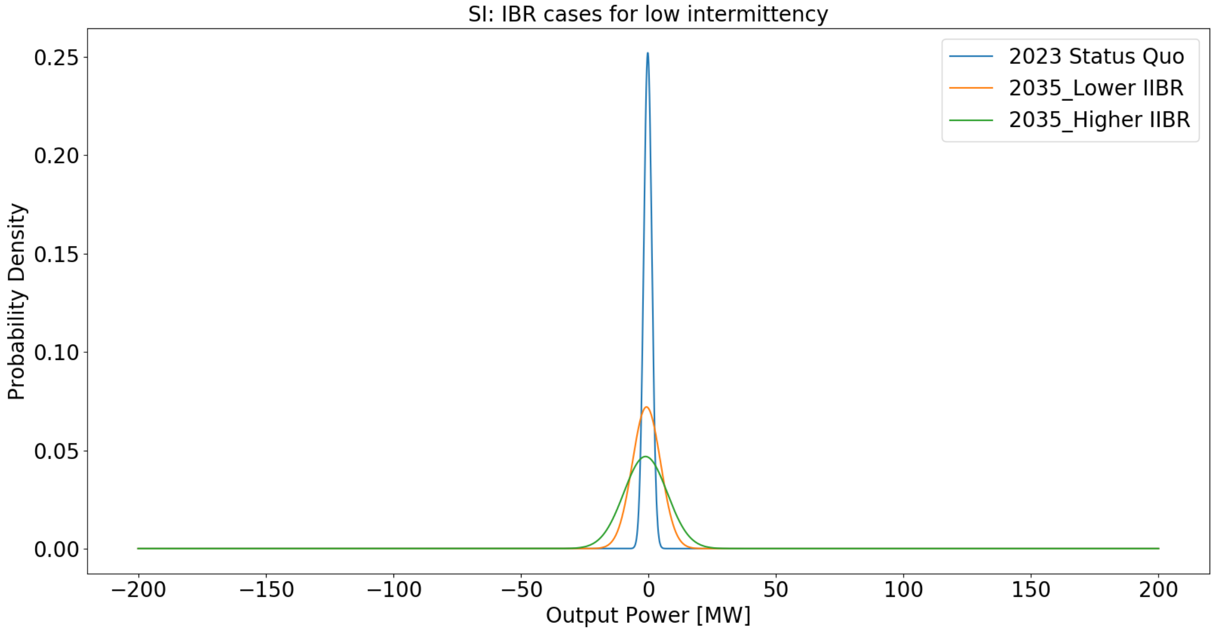

Figure 8-19: SI input profiles represented on a normal distribution curve for low intermittency

Frequency results with 2035 wind profiles:

The normal distribution for frequency in 2023, 2035_Lower IIBR and 2035_Higher IIBR is shown in Figure 8-20 to Figure 8-23 for the high and low intermittency cases. In Figure 8-24, all the normal distribution curves are illustrated in one graph, and distinctly show that the frequency is managed better under lower intermittency.

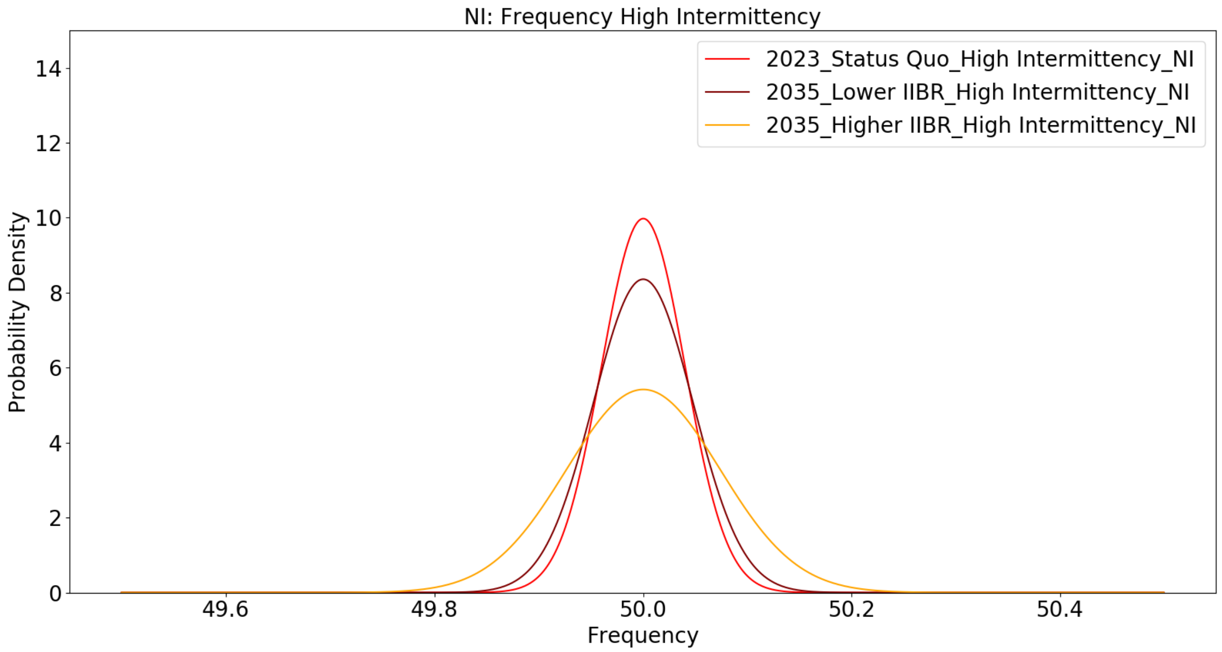

Figure 8-20: Frequency for 2023, 2035 lower IIBR and 2035 Higher IIBR for the High Intermittency case in the NI

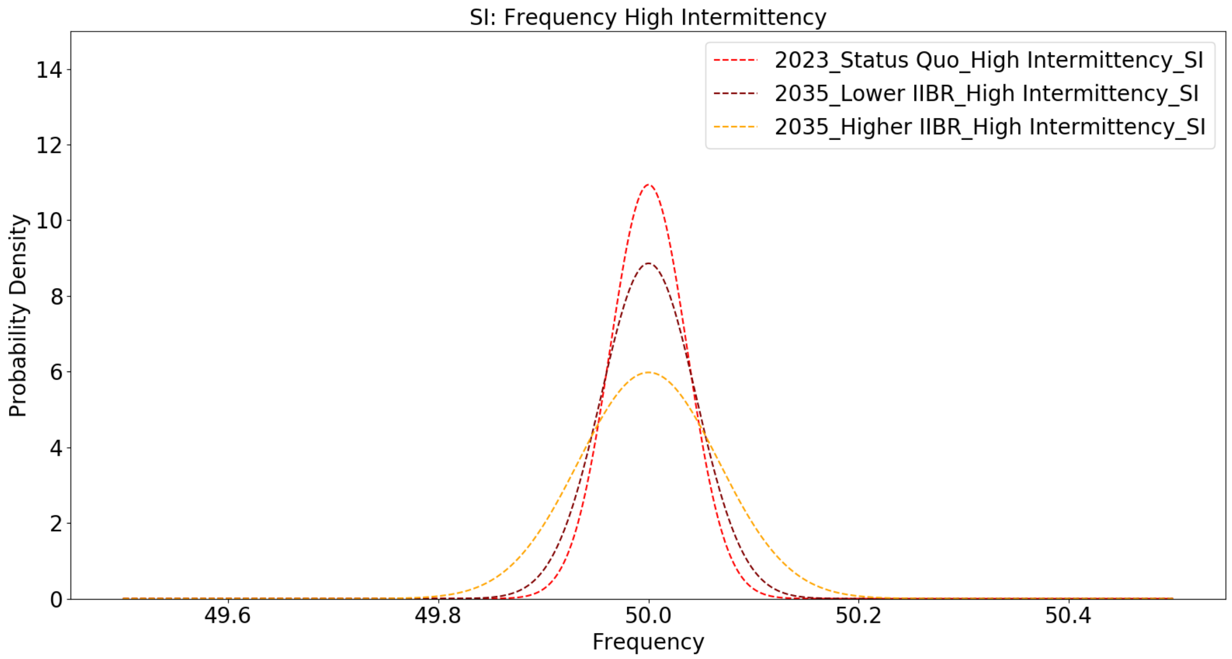

Figure 8-21: Frequency for 2023, 2035 lower IIBR and 2035 Higher IIBR for the High Intermittency case in the SI

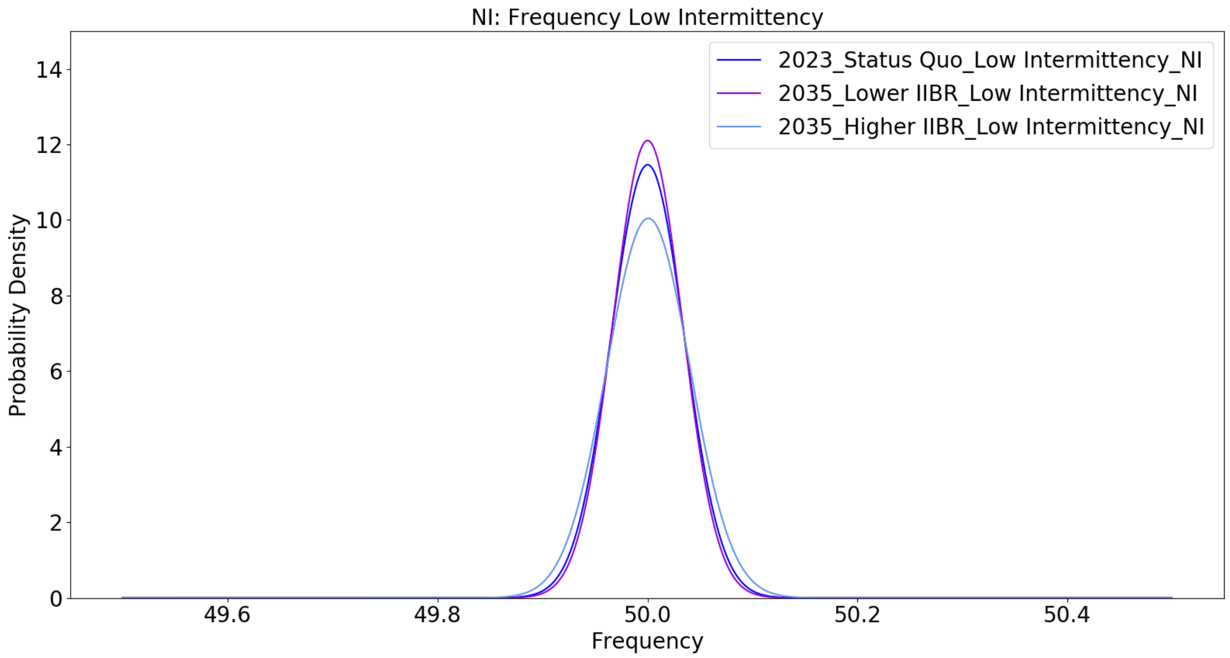

Figure 8-22: Frequency for 2023, 2035 lower IIBR and 2035 Higher IIBR for the Low Intermittency case in the NI

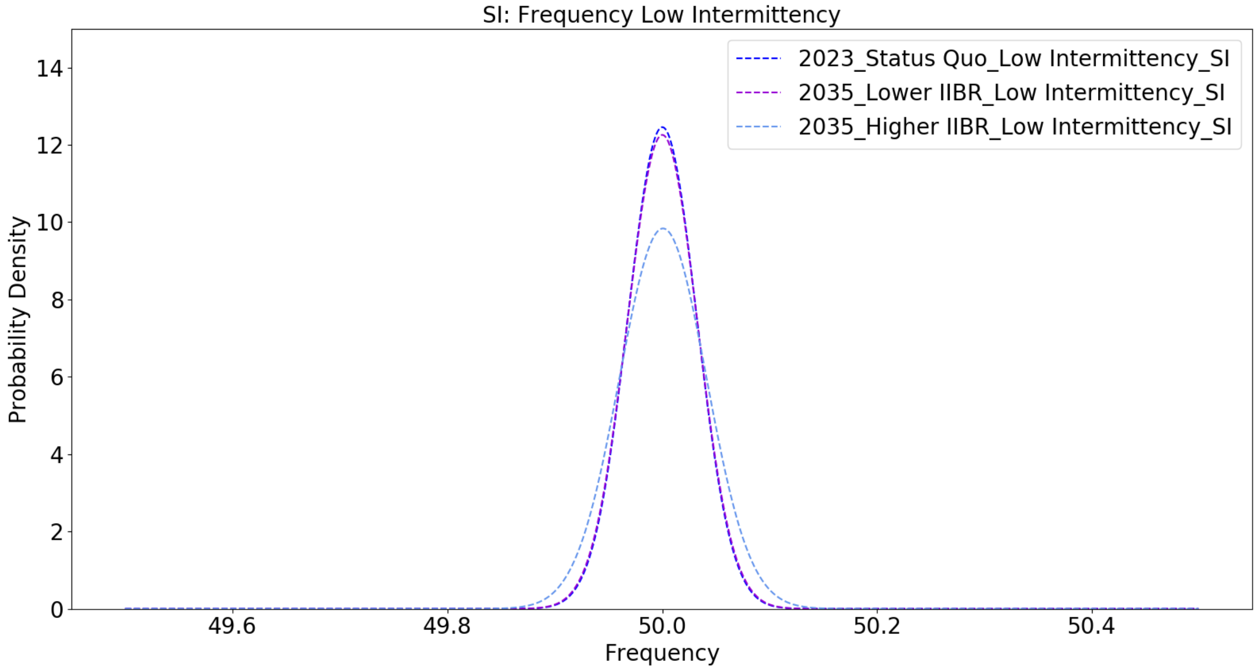

Figure 8-23: Frequency for 2023, 2035 lower IIBR and 2035 Higher IIBR for the Low Intermittency case in the SI

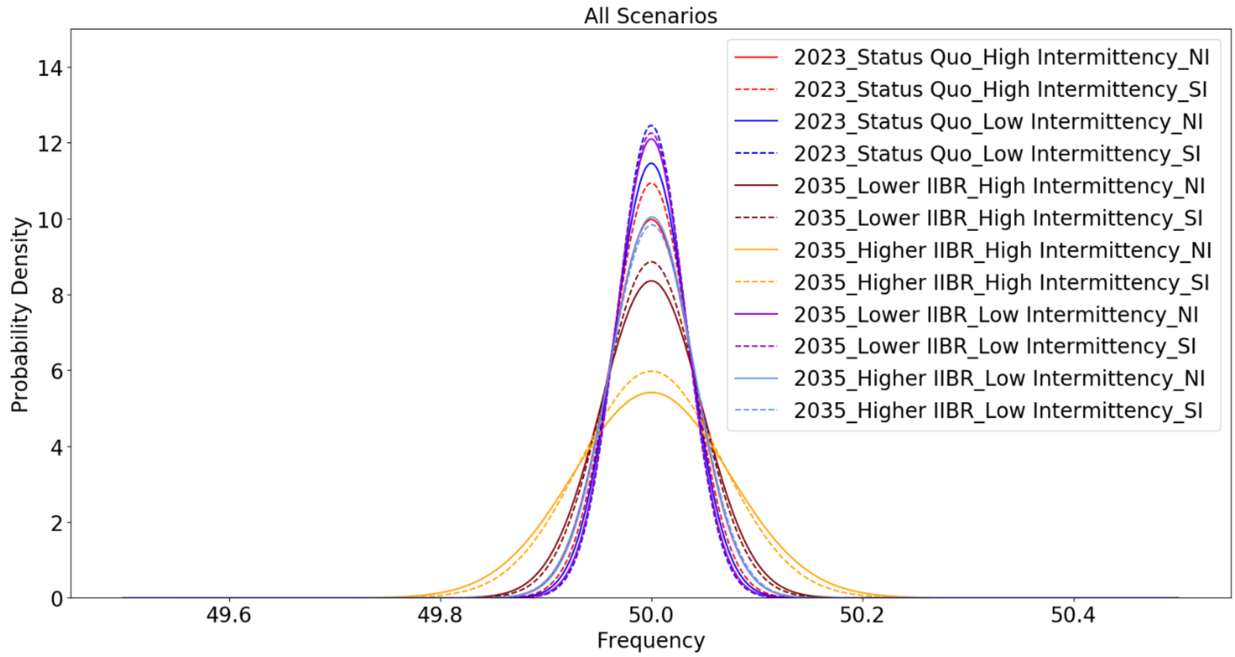

Figure 8-24: All normal distribution curves shown in one figure

<u>MFK results with 2035 wind profiles:</u>

Figure 8-25 shows the normal distribution curve for the MFK regulation control signal simulated output for 2023 and 2035. This graph shows the following:

1. A higher variance in the MFK regulation control signal in the high intermittency cases (the green hues) when compared to the low intermittency cases (black/grey/brown hues). This higher variance indicates that as the intermittency of generation increases, the MFK regulation control signals increase. This increase in the MFK regulation control signal will require the frequency keeping unit to respond over a wider MW range in order to manage frequency.
2. It is noted that although there is an increase in the MFK regulation control signal, the frequency has not improved to the levels observed in 2023.
3. Figure 8-26 shows the simulated MFK regulation control signal. This graph shows that the MFK regulation control signal has reached its limit of 15 MW multiple times for a single island, as the intermittency increases. This is an indication that the 30 MW frequency regulation band over the NI and SI will need to be increased as intermittent generation increases.

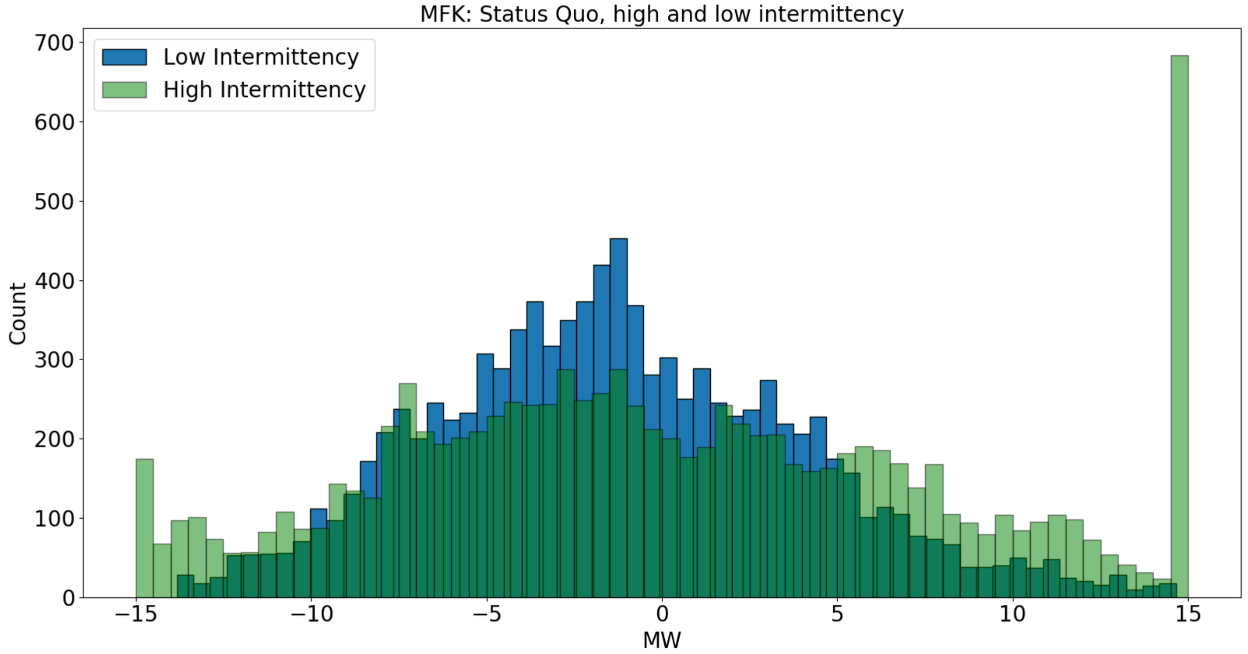

Figure 8-25: Histogram for MFK simulated results for 2023(Status Quo)

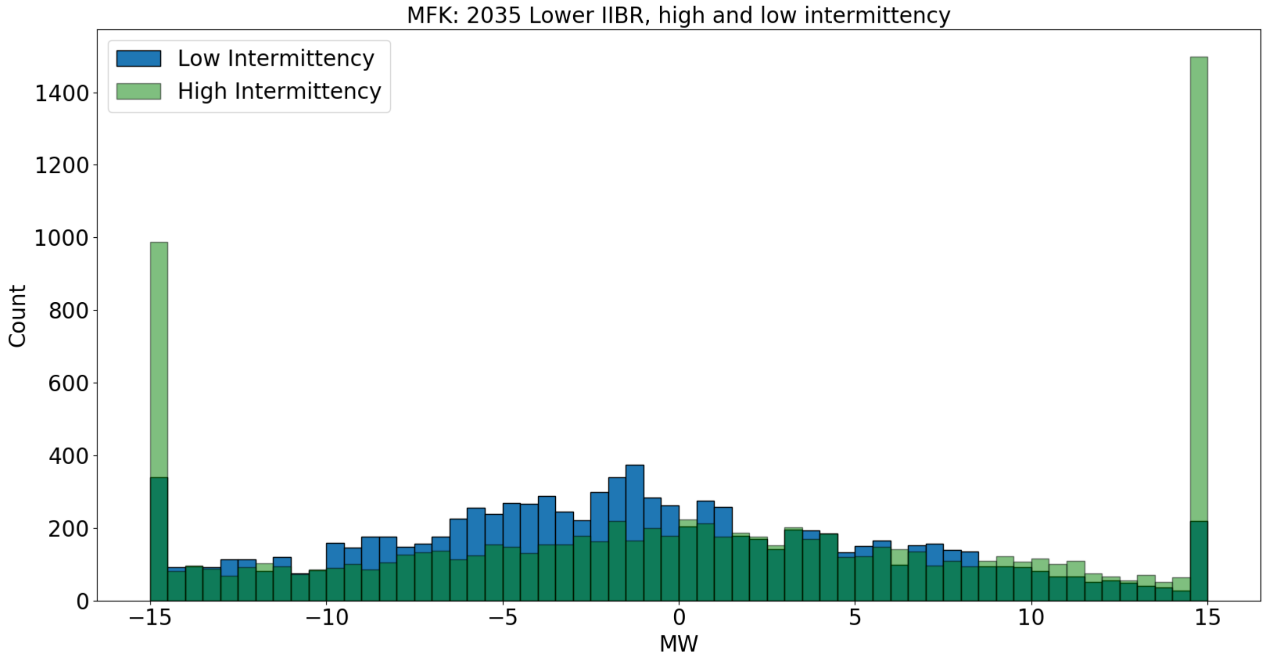

Figure 8-26: Histogram for MFK simulated results for 2035, LOWER IIBR

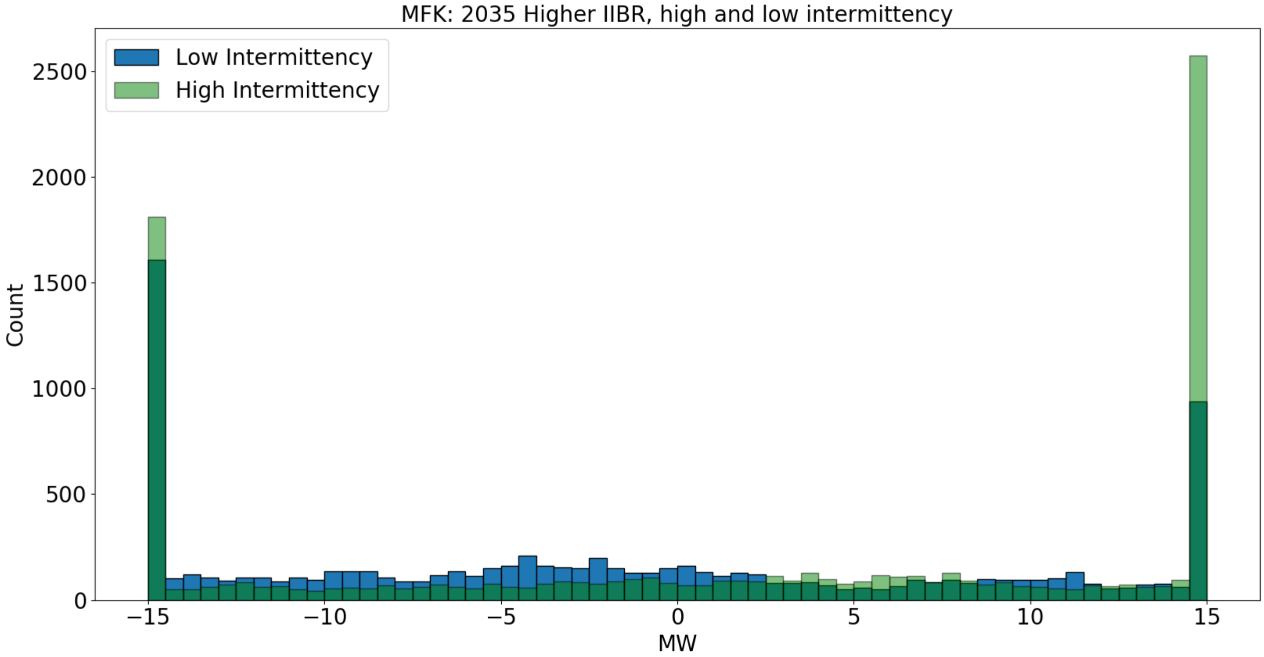

Figure 8-27: Histogram for MFK simulated results for 2035, HIGHER IIBR

<u>Generator response results with 2035 wind profiles:</u>

In the power system, generators with speed governors have the capability to change their MW output to manage or respond to frequency changes outside their frequency dead band. The results in Figure 8-28 and Figure 8-29 show the combined response of generators in the model as intermittent generation increases, and as compared to the simulation response in 2023. Results show that as intermittent generation increases, so does the response of generating units with speed governors. This is attributed to the higher frequency variance in the normal band expected with more intermittent generation.

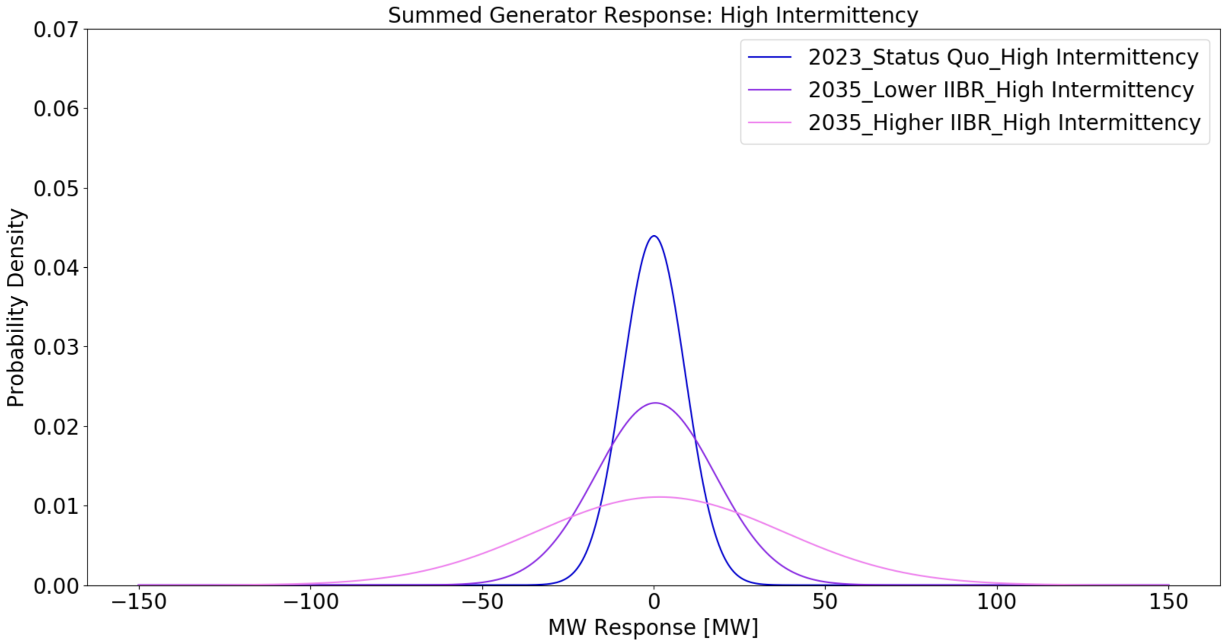

Figure 8-28: Combined generator response in the simulation for the high intermittency case

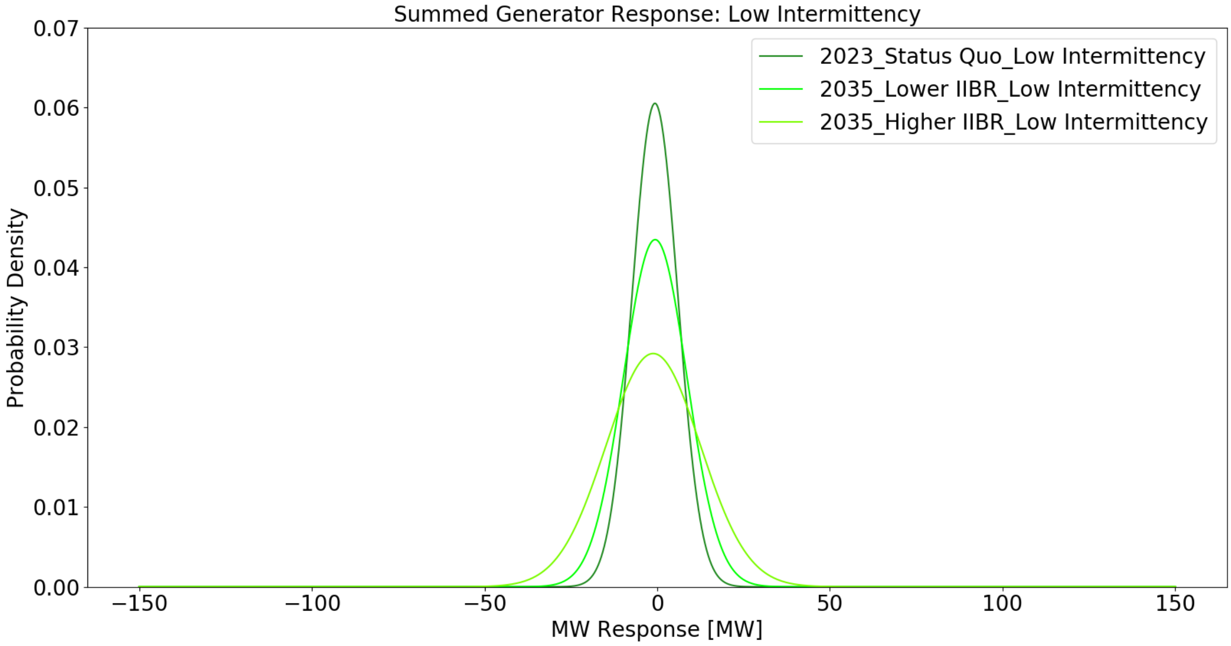

Figure 8-29: Combined generator response in the simulation for the low intermittency case

Observations show the following:

1. A very high combined response of generating units with speed governors – i.e. 100 MW at times for the *2035_Higher IIBR_High Intermittency* scenario. This equates to 1% of dispatched generation in the study case. In the *2023_Higher IIBR_High Intermittency* scenario, the combined response of generating units with speed governors is 0.43% of dispatched generation.
2. In the case where generating units are responding with large MW movement, the generation owner may find that this has an adverse impact on their assets and may deploy mitigation measures such as (increased) dead bands, or seek to recover increased maintenance costs through higher energy bids.

8.1.3 Observations: Study 2a, study case 2

Solar PV generation is generation with an intermittent source like wind generation. The output of solar PV generation varies with the variation of incident solar irradiation on the solar panels. Figure 8-30 illustrates this varying active power output, where high levels of cloud movement change the active power output of the generating station, causing a highly intermittent generation profile. The profile of a single solar farm cannot be used effectively due to the following:

1. Solar panels dispersed over a wide geographical area will provide a smoothing effect due to partial clouding of sections of panels. Hence, the generation profile from a small solar farm can be different to that of a large solar farm.
2. In addition to the smoothing effect within a solar farm, the coincidence of other solar farms connected to the power system impact the total solar PV generation profile. The coincidence of solar itself is reliant on the cloud movement from one area to another.
3. Distribution-connected solar PV generation will also impact the load profile at the GXP nearest (electrically) to the solar farm.

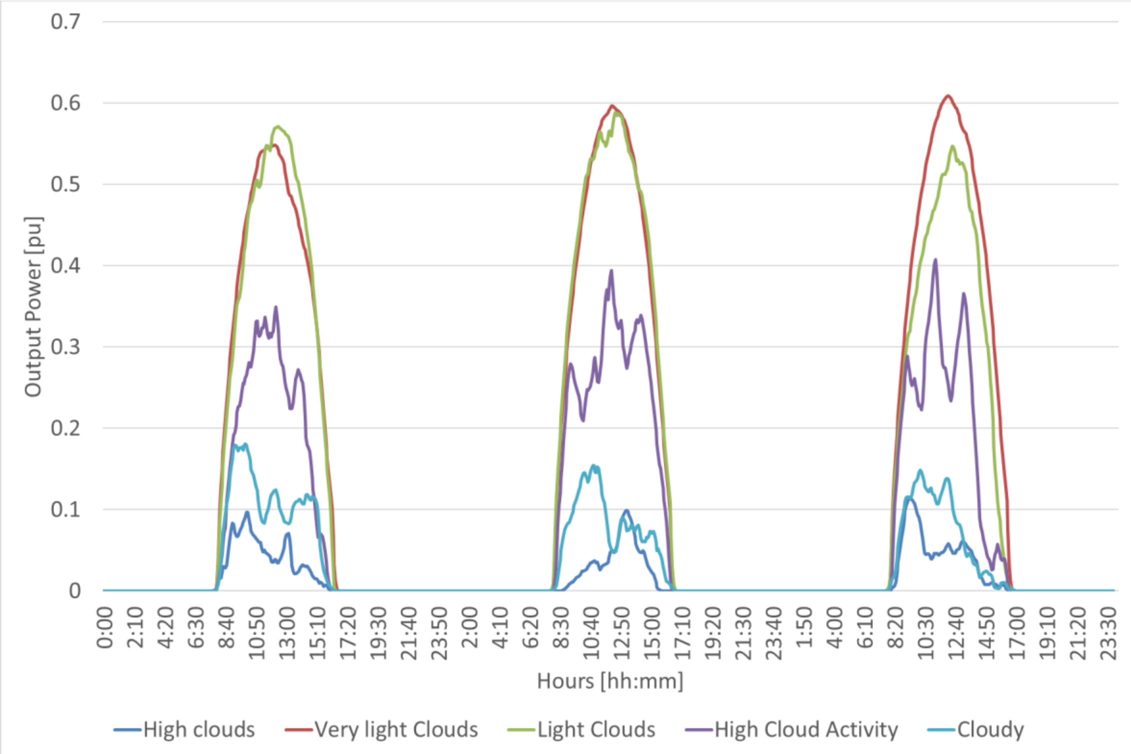

Figure 8-30: Illustration of varying solar output for varying cloud activity (Data Source: NREL)

<u>Observations from a New Zealand solar farm being commissioned:</u>

To illustrate that solar PV generation can impact frequency, the active power output of a single solar farm and the MFK regulation control signal using PI data are analysed. The following are observed:

Figure 8-31 shows the following:

1. The variation in solar PV generation output from 1 February 2024 to 20 February 2024.
2. There are more days with intermittent solar PV generation. Some days show a higher positive frequency regulation from frequency keeping units during the period of solar PV generation.
3. Days 1 to 3 display solar PV generation that is more intermittent than days 4 to 6.

Figure 8-32 compares the MFK regulation control signal for days 1 to 3 and days 4 to 6. The following are observed:

1. The MFK data has a higher spread between ±15 MW for the higher intermittency case (days 1 to 3) compared to days 4 to 6.
    a. This means that there is a higher variation in the MFK regulation control signal in the days with higher intermittency compared to the days with lower intermittency.
    b. This is due to the frequency keeping units compensating for drops in the active power output of the solar farm.
2. The curve does not show a severe impact, which is due to the solar generation output being less than 25 MW.
3. Limitations of this analysis:
    a. The dataset is limited to 3 weeks.
    b. The output power of the solar generating station is less than 25 MW, and there is no way to trend the impact of higher integration of solar generation into the power system.
    c. Various other factors that can influence frequency and frequency keeping are not considered.

The general observation is that frequency keeping is impacted by intermittent solar generation.

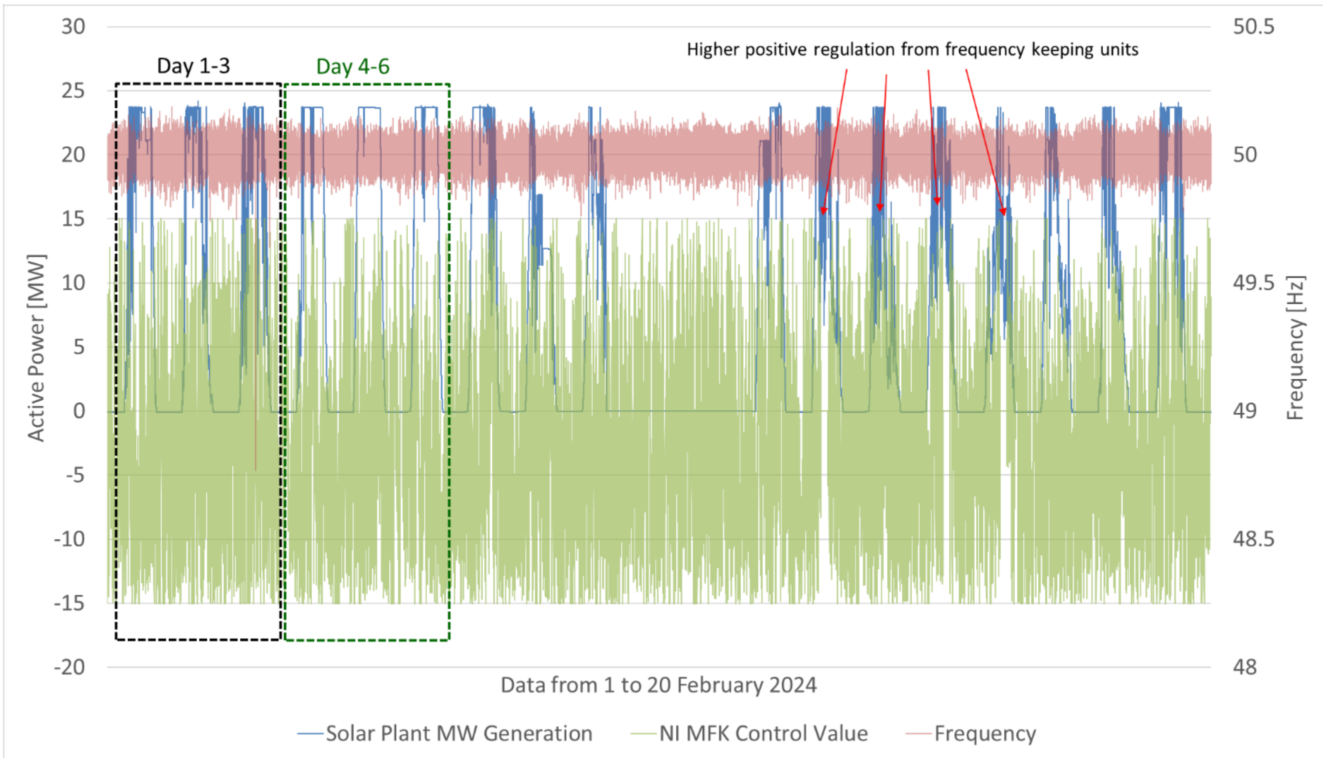

Figure 8-31: Solar farm active power output, the frequency and MFK regulation control signal sent to the frequency keeping unit

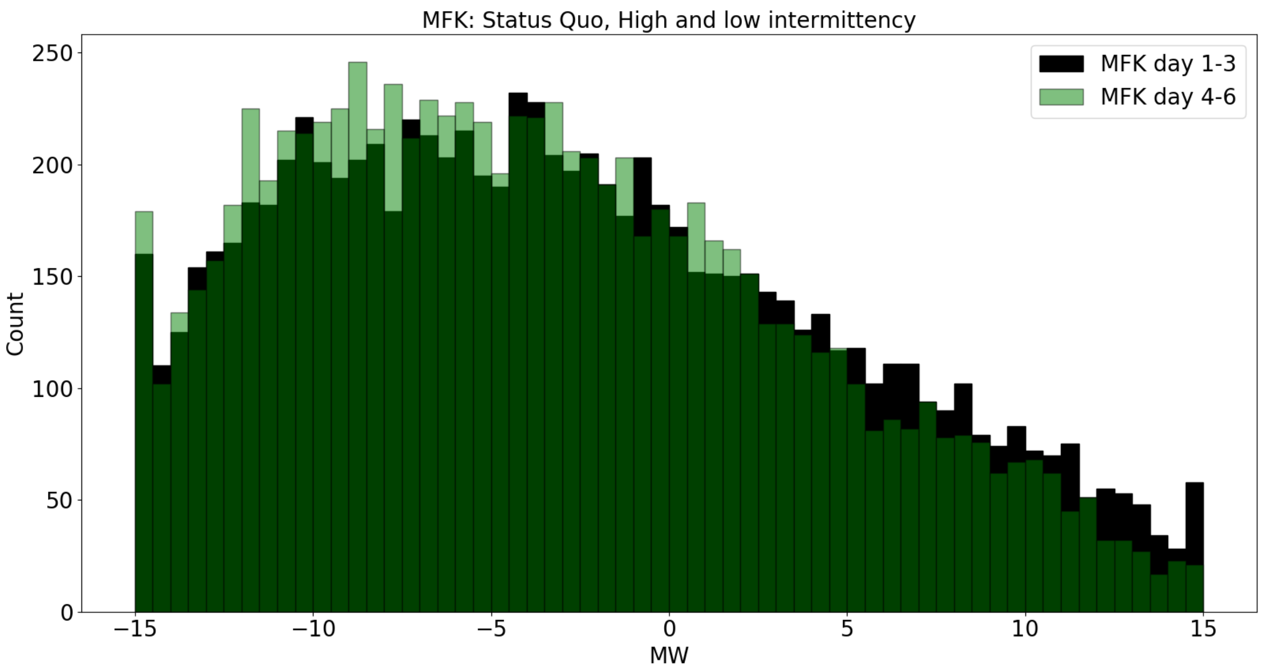

Figure 8-32: MFK signal comparison for days 1 to 3 and days 4 to 6

Possible correlation of wind and solar PV generation profiles in 2035:

In addition to considering solar PV generation profiles on their own, consideration needs to be given to the correlation of wind and solar PV generation profiles. The correlation can be impacted by, inter alia:

1. The frequency and magnitude at which the source (wind and solar) changes. This can impact the overall profile of the intermittent generation.
2. The correlation between certain climate events, which may lead to high or low correlation of wind and solar generation profiles.

Studying the potential correlation of wind and solar PV generation profiles in New Zealand is out of scope for this study. We have listed this as a limitation of the study. However, during daylight hours, there are various possibilities for the correlation of wind and solar PV generation profiles.

There are several considerations when generating a profile for intermittent wind and solar PV generation, such as the limitations discussed in section 7.1 (Study limitations). Studying weather patterns that impact generation output and the coincidence of power output from wind and solar generation, is out of scope for this study. We note a lack of accuracy in the intermittent generation profile can adversely impact the results/conclusions of a study.

Using the analysis from study case 1 and the assumptions made around the correlation of intermittent generation impacting the level of intermittency, the following can be reasoned:

1. Higher intermittency due to high correlation of wind and solar PV generation will cause higher variation in the intermittent generation profile and hence a higher variation in frequency, thereby increasing the need for a higher frequency keeping band.
2. Lower intermittency due to moderate/low correlation of wind and solar PV generation will vary the frequency less than the scenario in point 1.
3. Limitation: the extent of correlation of wind and solar PV generation cannot be studied.

Even in the absence of 2035 solar profiles, due to the inability to accurately estimate the frequency and magnitude of solar variation for New Zealand for utility-scale and distributed small-scale solar PV generation, we still expect that these variations in generation will at times exacerbate the profiles of intermittent generation and GXP load[8]. These variations in the profiles of intermittent generation and load will increase the need for a higher frequency keeping band.

8.2 Study 2b: Assess the impact of implementing a set frequency dead band on frequency quality within the normal band

Problem Statement: The Code does not stipulate a frequency dead band. This enables generation owners to set wide frequency dead bands for their generating units.

Overall Objective: To study the impact of implementing a frequency dead band on the width of the MFK frequency keeping band, with the objective of recommending a frequency dead band for inclusion in the Code.

8.2.1 Methodology

The methodology to run this part of the study aligns to Study 2a, with the following distinctions:

Inputs: These inputs are the same inputs used for Study 2a, but only the high intermittency input profiles are used for this Study 2b.

[8] From a system operator perspective, distributed solar PV generation will impact the load profile at the GXP, and utility-scale solar PV generation will impact total wind and solar profiles.

Changing the frequency dead band:

1. The frequency dead band was changed in the following steps:
    a. Baseline: Use frequency dead bands applied to the current system for years 2023 and 2035.
        i. Frequency Dead band = Status quo estimate.
    b. Set the dead band for existing and new generation connected to the power system.
        i. Frequency Dead band = 0.1
        ii. Frequency Dead band = 0.05 (50% of the first estimate)
        iii. Frequency Dead band = 0.015 (Aligns with the frequency dead band set in Australia's National Electricity Market).
    c. Set the dead band for only new generation connected to the power system.
        i. Frequency Dead band = 0.1
        ii. Frequency Dead band = 0.05 (50% of the first estimate)
        iii. Frequency Dead band = 0.015 (Aligns with the frequency dead band set in Australia's National Electricity Market).

Tools

1. Matlab/Simulink
2. Spyder
3. Microsoft Excel

Steps and procedures

1. Use the wind data profiles in Study 2a to obtain the 2023 and 2035 results with a frequency dead band equal to the status quo estimate.
2. Set the dead band across all generating stations as stated in the methodology.
3. Set the dead band across new generating stations as stated in the methodology.
4. Analyse the results.

Study cases and scenarios to consider

Study Case 1: Baseline - Use frequency dead bands applied in the current power system for years 2023 and 2035.

1. **Scenario 1**: *2023_Existing Gen_Status Quo*: Model the frequency response to a high intermittency profile where all generation has frequency dead bands equal to our estimate of status quo dead bands.
2. **Scenario 2**: *2035_Existing & New Gen_Status Quo*: Model the 2035 frequency response to a high intermittency profile where all (i.e. existing and new) generation has frequency dead bands equal to our estimate of status quo dead bands. This simulates a "do nothing" scenario where we assume existing frequency dead band trends apply in 2035.

Study Case 2: Set the dead band for existing and new generation connected to the power system.

1. **Scenario 1**: *2035_Existing & New Gen_0.1*: Model the 2035 frequency response to a high intermittency profile where existing and new generation has a frequency dead band equal to 0.1 Hz.
2. **Scenario 2**: *2035_Existing & New Gen_0.05*: Model the 2035 frequency response to a high intermittency profile where existing and new generation has a frequency dead band equal to 0.05 Hz.
3. **Scenario 3**: *2035_Existing & New Gen_0.015*: Model the 2035 frequency response to a high intermittency profile where existing and new generation has a frequency dead band equal to 0.015 Hz.

Study Case 3: Set the dead band for new generation connected to the power system.

1. **Scenario 1**: *2035_ New Gen_0.1*: Model the 2035 frequency response to a high intermittency profile where new generation has a frequency dead band equal to 0.1 Hz.
2. **Scenario 2**: *2035_ New Gen_0.05*: Model the 2035 frequency response to a high intermittency profile where new generation has a frequency dead band equal to 0.05 Hz.
3. **Scenario 3**: *2035_ New Gen_0.015*: Model the 2035 frequency response to a high intermittency profile where new generation has a frequency dead band equal to 0.015 Hz.

The following table shows the modelled frequency dead band for each study case and scenario, with the green cells indicating a change from the baseline for the frequency dead band setting.

Table 6: Modelled frequency dead band for each generation type for each scenario

Generation types	Baseline [± Hz]	Study case 2 frequency dead band [± Hz]			Study case 3 frequency dead band [± Hz]		
	SQ	0.1	0.05	0.015	0.1	0.05	0.015
NI_CCGT	0.1	0.1	0.05	0.015	0.1	0.1	0.1
NI_OCGT	0.1	0.1	0.05	0.015	0.1	0.1	0.1
NI_Geo	0.195	0.1	0.05	0.015	0.195	0.195	0.195
NI_Hydro	0.03	0.03	0.03	0.015	0.03	0.03	0.03
NI_IIBR	0.15	0.1	0.05	0.015	0.1	0.05	0.015
NI_Thermal	0.195	0.1	0.05	0.015	0.195	0.195	0.195
SI_Hydro	0.03	0.03	0.03	0.015	0.03	0.03	0.03
SI_IIBR	0.15	0.1	0.05	0.015	0.1	0.05	0.015

8.2.2 Studies, Results, and Observations

This section outlines the results for study case 1, study case 2 and study case 3.

Study Case 1: Baseline - Use frequency dead bands applied to the current system for years 2023 and 2035.

Study case 1, 2035 results are the same as the results for study 2a, study case 1, scenario 3. This is because the same model parameters were used in both simulations. The results show:

1. There is a higher variation in the frequency in 2035, with an increased response from MFK due to the higher intermittency input profile.

Frequency results are shown in Figure 8-33 and Figure 8-34.

MFK results are shown in Figure 8-25 and Figure 8-26 (in the previous study).

To compare the change in dead band settings in 2035, the 2035 baseline scenario is used as a baseline in the following figures.

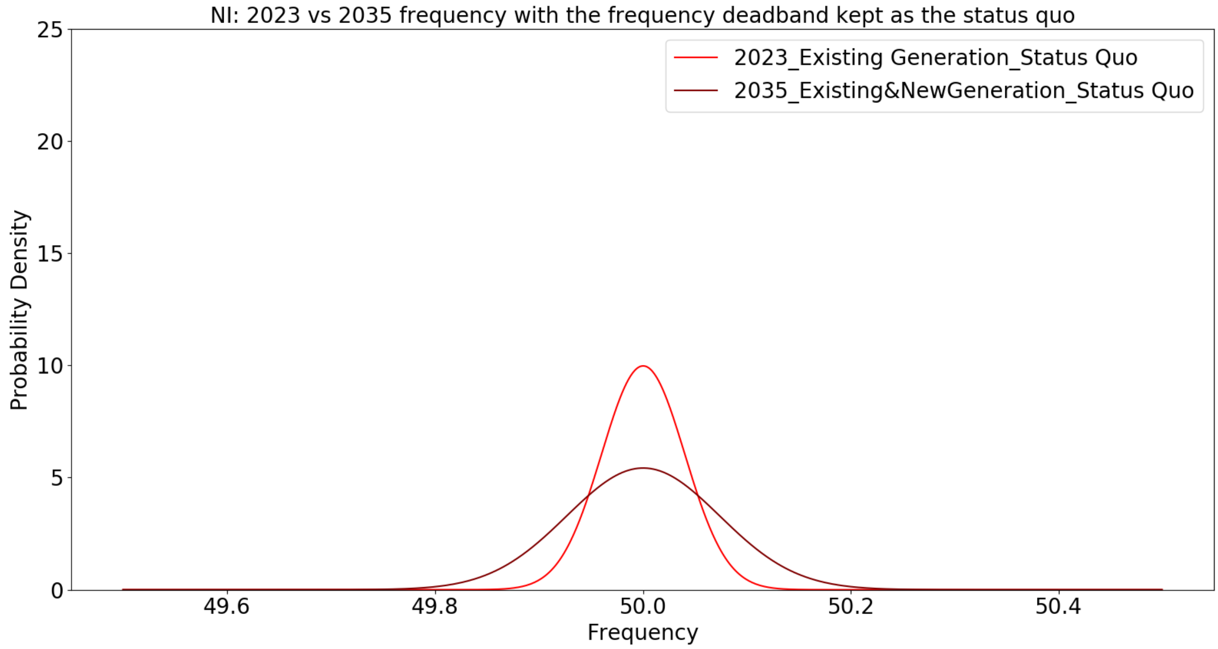

Figure 8-33: Baseline 2023 vs 2035 for the North Island

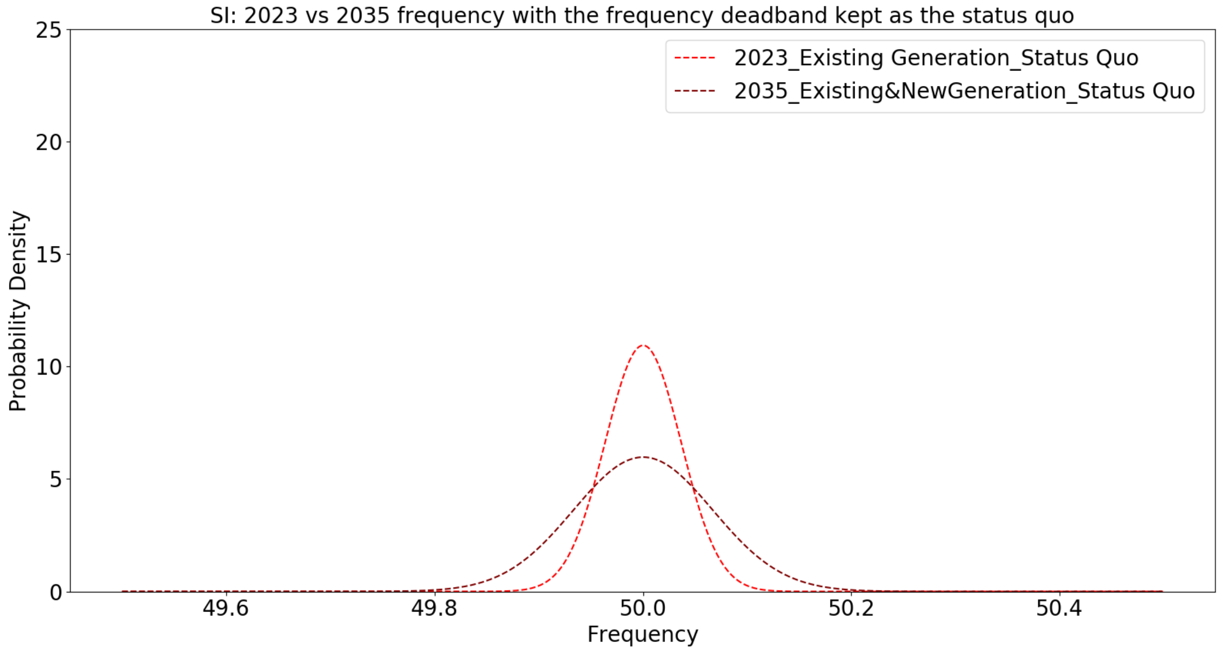

Figure 8-34: Baseline 2023 vs 2035 for the South Island

Study Case 2: Set the dead band for existing and new generation connected to the power system.

The frequency dead band for new and existing generation was changed as indicated in Table 6. The frequency and the response from generating stations connected to the power system are shown in this section, with additional results in the Appendix of this report.

System frequency is managed by generators responding to variations in frequency. The results are structured to show the:

1. frequency response,

2. generation response, and
3. MFK response.

Study case 2: Frequency response

Study case 2 results in Figure 8-35 and Figure 8-36, which show that as the frequency dead band decreases, the variance in the frequency results is reduced, indicating that the frequency is being better managed.

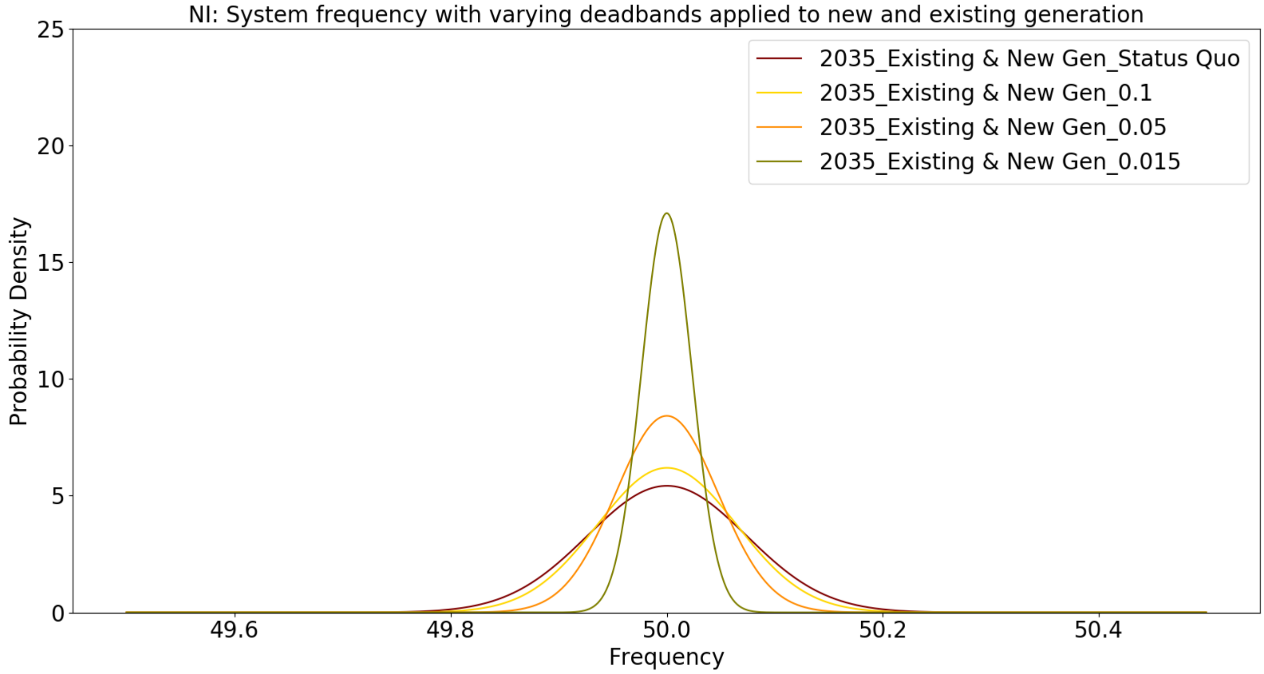

Figure 8-35: System frequency for the NI for study case 2

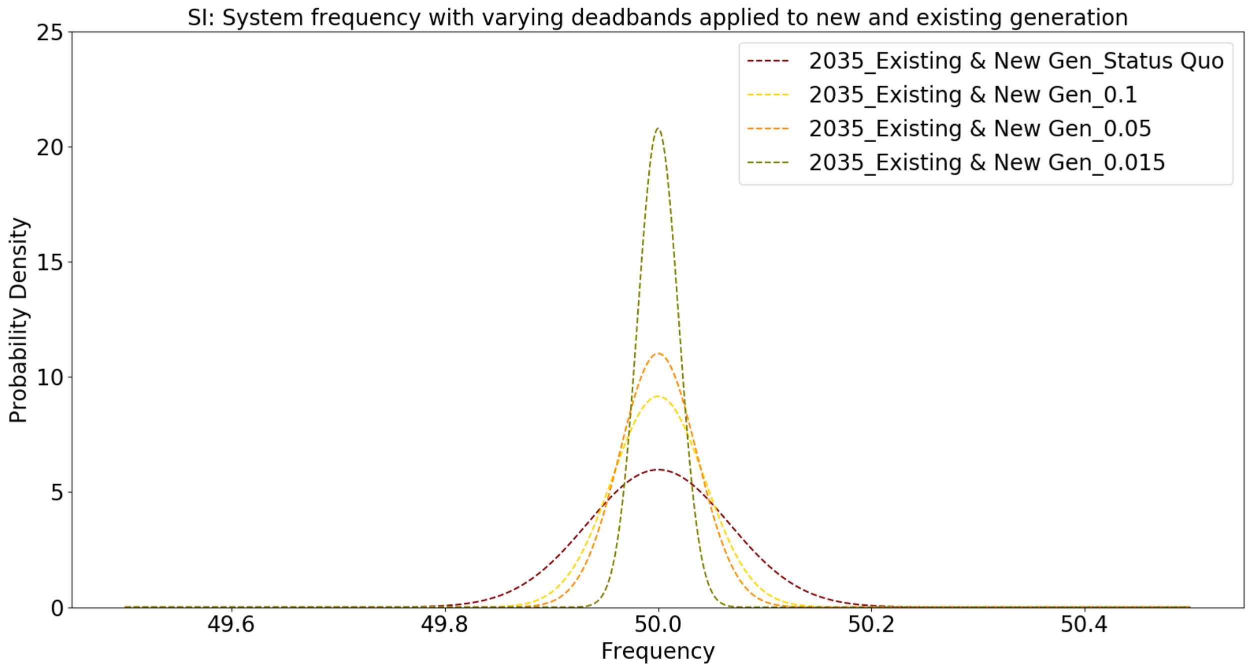

Figure 8-36: System frequency for the SI for study case 2

Study case 2: Generation response

A reduction in the frequency dead band of a generating unit connected to the power system would solicit a response sooner from that generating unit. In the Matlab model, an aggregated generation model per generating unit type was used where the active power response for each aggregated model was recorded in 1 second intervals. Using this dataset of active power results, the standard deviation was calculated. The standard deviation in statistics is the average amount of variability or variance in a dataset. Hence, this represents the average active power contribution of the generating unit in response to changes in system frequency.

The average active power response from each aggregated generation model is depicted in two bar graphs, and shows the following:

1. Figure 8-37 plots the standard deviation for each aggregated generation model. This figure shows that a decrease in the frequency dead band would increase the response of some generation and decrease the response of other generation. The reason for this is that generation, such as NI hydro, have an existing modelled frequency dead band that is lower than the test frequency dead band for that scenario. Hence, the response from hydro is seen to decrease when the response from other generation is observed to increase. See Table 6: Modelled frequency dead band for each generation type for each scenario
2. Figure 8-38 shows the average active power response from generation as a percentage of the total average active power response for each scenario. This figure shows that generation response is shared more evenly across all generation types as the frequency dead band decreases.
3. Detailed diagrams showing the MW response for each generation type for each scenario for study case 2 can be found in the Appendix.
   A limitation of the study is having an aggregated generation model for each generating unit type. This means that the diversity in the response of different generating units/stations is not captured in the results. This does not take away from the results and their conclusion. This is because there is significant detail in the aggregated generator models, the HVDC link model, and the MFK model to study the impact on frequency in the normal band.

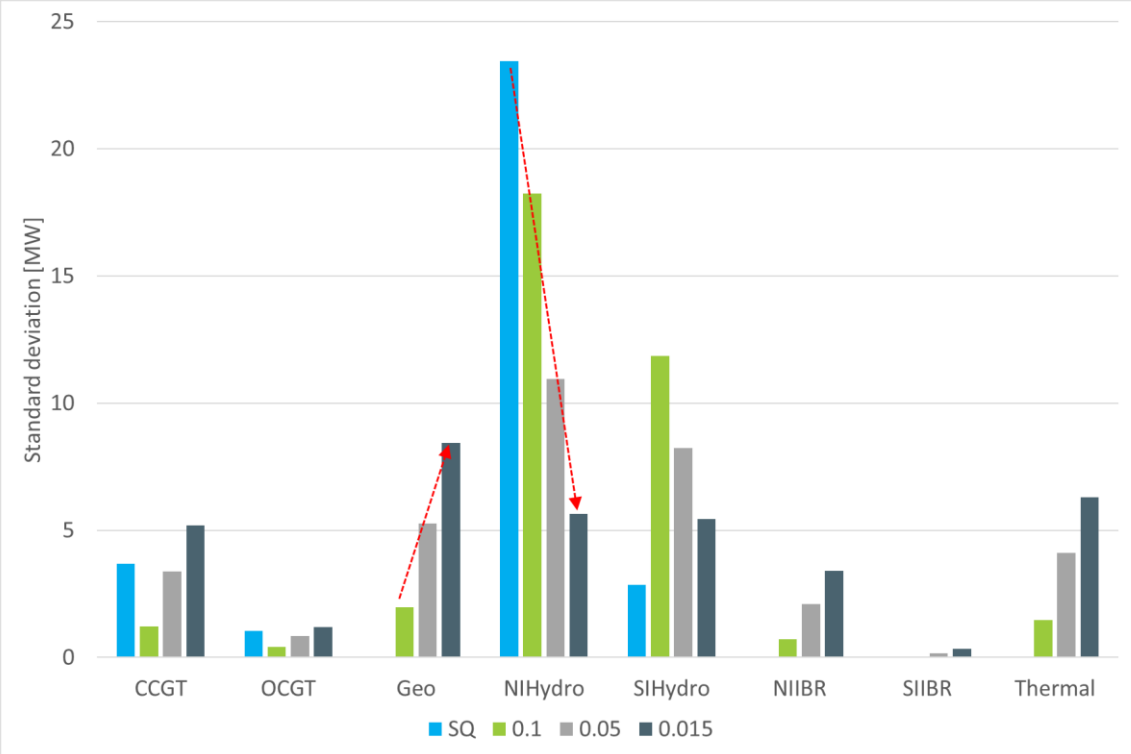

Figure 8-37: Average generation response to different frequency dead band sizes for study case 2

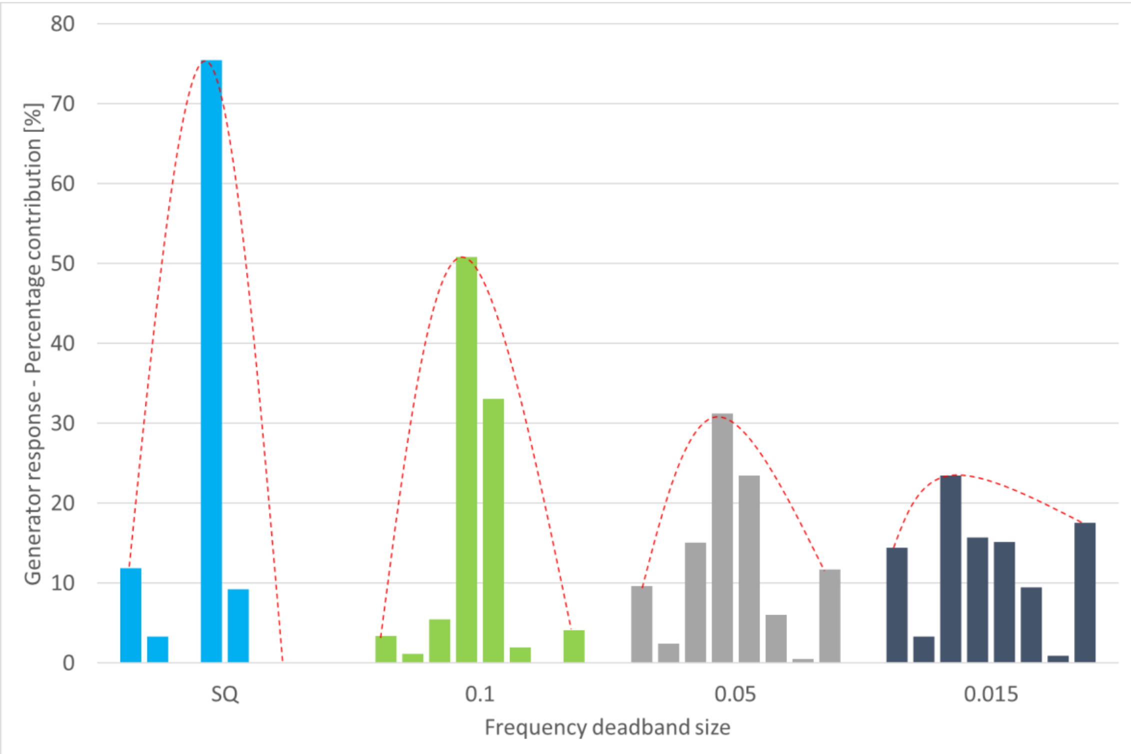

Figure 8-38: Average generation response as percentage of the total average response for study case 2

Study case 2: MFK regulation control

The MFK Controller:

1. The system frequency target is 50 Hz. After the frequency error is fed into the MFK controller, the regulation control signal is then determined and sent to the frequency keeping units for each island.
2. The centralised MFK controller is slower than the local governor response of synchronous machines or frequency control logic of inverters.

The results for the MFK response are shown in the following figures. These results show the following:

1. The spread in the MFK regulation control signal results change as the frequency dead band decreases – i.e. it is spread better between ±15 MW. This indicates that there is a reduced required response from frequency keeping units to manage the frequency. This is due to setting a lower dead band across existing and new generation, which elicits an active power response from existing and new generation.
2. The system frequency is better regulated under the scenario of a dead band equal to ±0.015 Hz, even with a reduced MFK regulation control signal. This is due to the increased generation response of all generation types in the system.

The spread in the results shows that a movement towards more positive MFK frequency regulation – i.e. the frequency keeping unit, on average, injects MW into the transmission network.

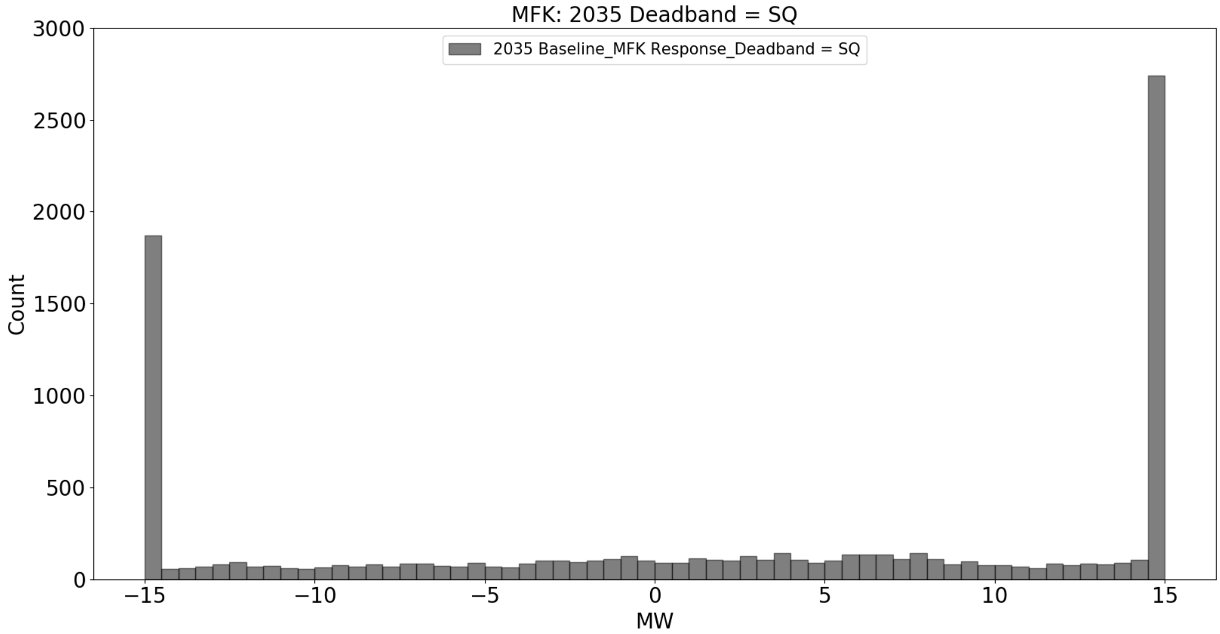

Figure 8-39: Histogram showing the MW Regulation control signal for study case 2 where the dead band trend is retained

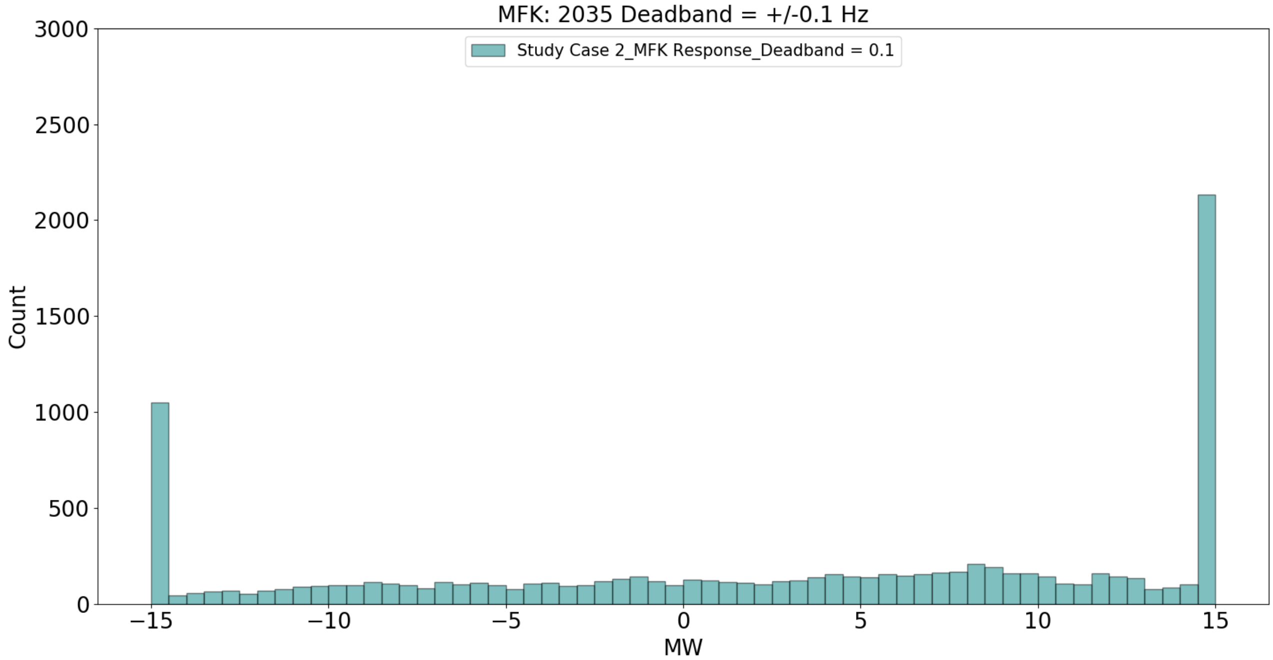

Figure 8-40: Histogram showing the MW Regulation control signal for study case 2 where the dead band = ±0.1 Hz

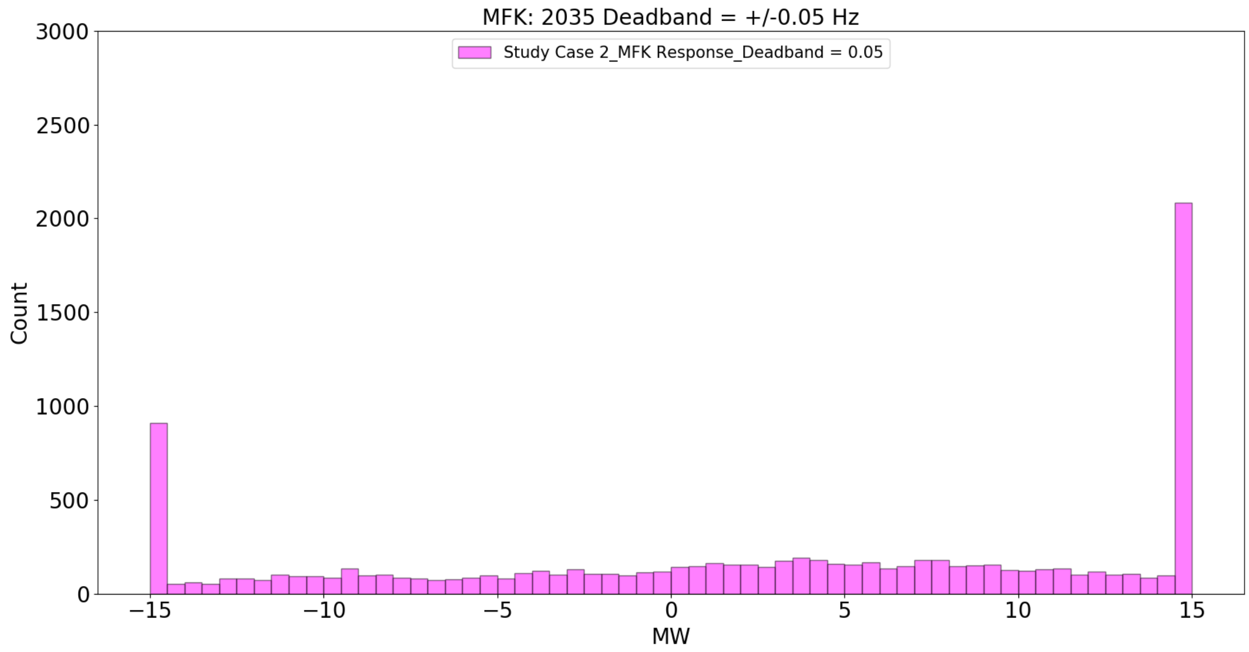

Figure 8-41: Histogram showing the MW Regulation control signal for study case 2 where the dead band = ±0.05 Hz

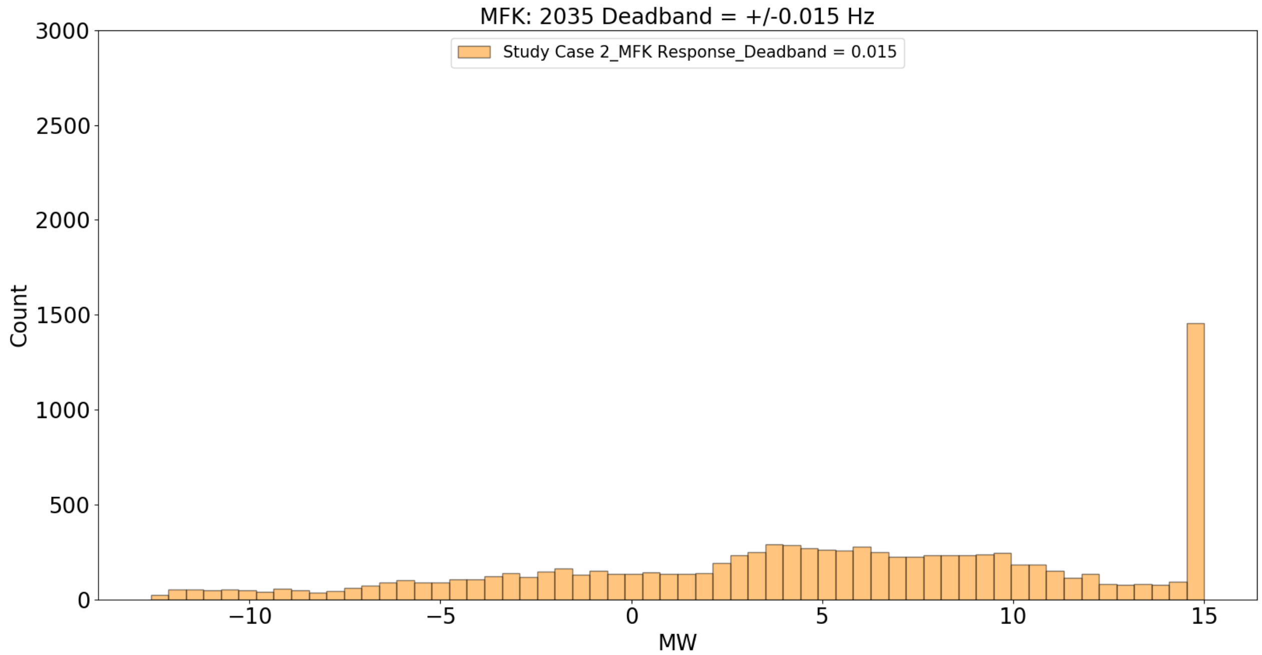

Figure 8-42: Histogram showing the MW Regulation control signal for study case 2 where the dead band = ±0.015 Hz

Study Case 3: Set the dead band for new generating units connected to the power system

In study case 2, existing and new generation was subjected to a set dead band. Study case 3 assumes the grandfathering of any frequency dead bands in place for existing generating units, with a frequency dead band set for new generation only, as indicated in Table 6. Additional results showing the generation response can be found in the Appendix of this report.

This section outlines the frequency results, with these results compared to study case 2.

Study case 3: Frequency

For both the NI and SI, Figure 8-43 and Figure 8-44 show that as the frequency dead band decreases, the variance in the frequency results is reduced indicating that the frequency is being better managed, but only marginally.

The observed system frequency for study case 3 is shown on the graph to the same scale for the x and y axes as for study case 2. This enables both figures to be compared in isolation. In addition, Figure 8-45 and Figure 8-46 plots the frequency results for study cases 1, 2 and 3. From these figures the following can be observed:

1. Implementing a frequency dead band has a positive impact on frequency regardless of whether it is implemented on existing and new generation or new generation only.
2. In study case 3, where the frequency dead band was implemented on new generation only, the frequency variation is higher than in study case 2. This indicates better frequency management occurs under study case 2.
3. There is a slight offset to the left in the normal distribution curve for frequency in study case 3 compared to study case 2. The fact that this offset is to the left indicates that the frequency is managed/maintained slightly below 50 Hz. This is due to:
    a. The downward-only frequency regulation behaviour of intermittent wind and solar PV generation due to this generation operating at maximum available power.
    b. The MFK MW regulation control value reaching its limit of 15 MW in each island, which is caused by the downward-only frequency regulation behaviour of intermittent wind and solar PV generation. This can also impact the variation in frequency.
4. A limitation in the study results is that, due to aggregated models for generation, only intermittent wind and solar PV generation was considered as “new generation”. However, this does not take away from the results, as intermittent wind and solar PV generation makes up the majority of new generation expected to be commissioned between now and 2035.

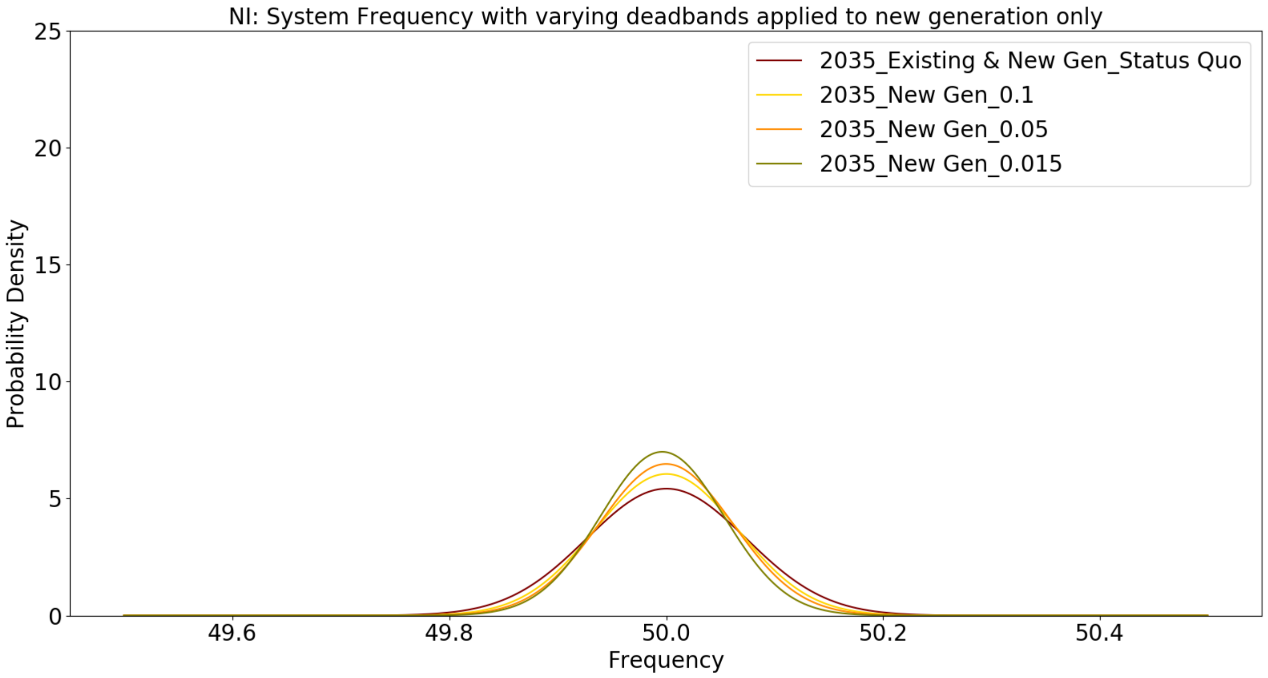

Figure 8-43: System frequency for the NI for study case 3

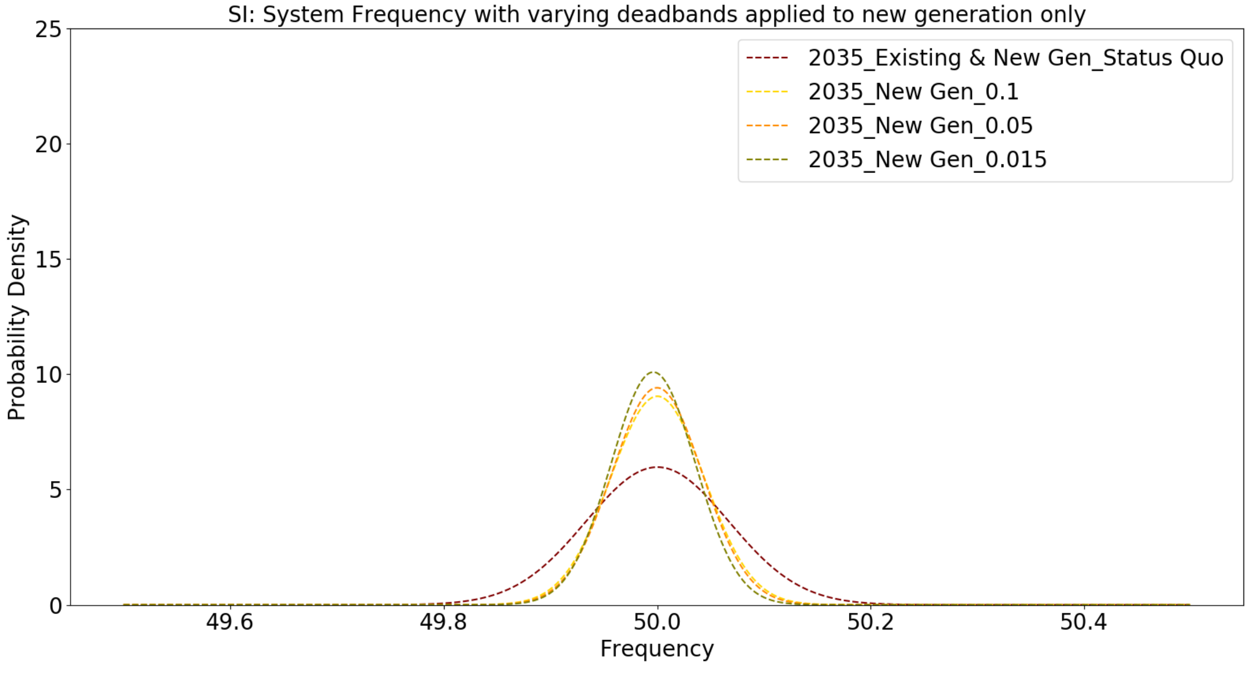

Figure 8-44: System frequency for the SI for study case 3

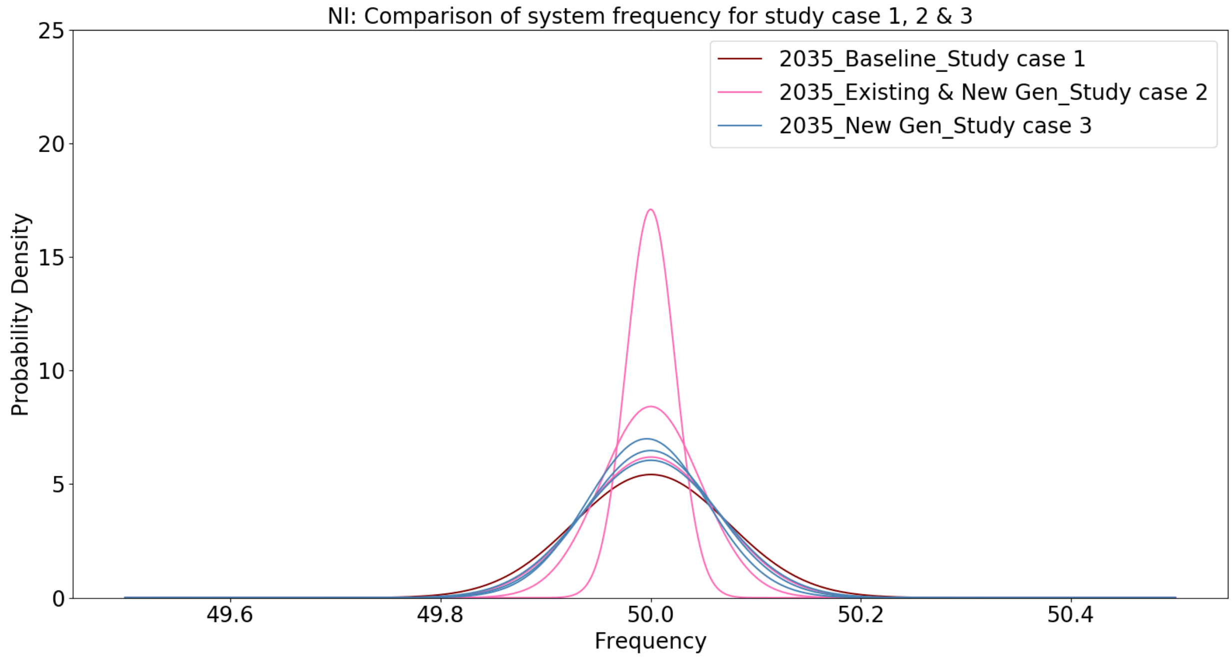

Figure 8-45: System frequency observed for study case 1, 2 and 3 for the NI

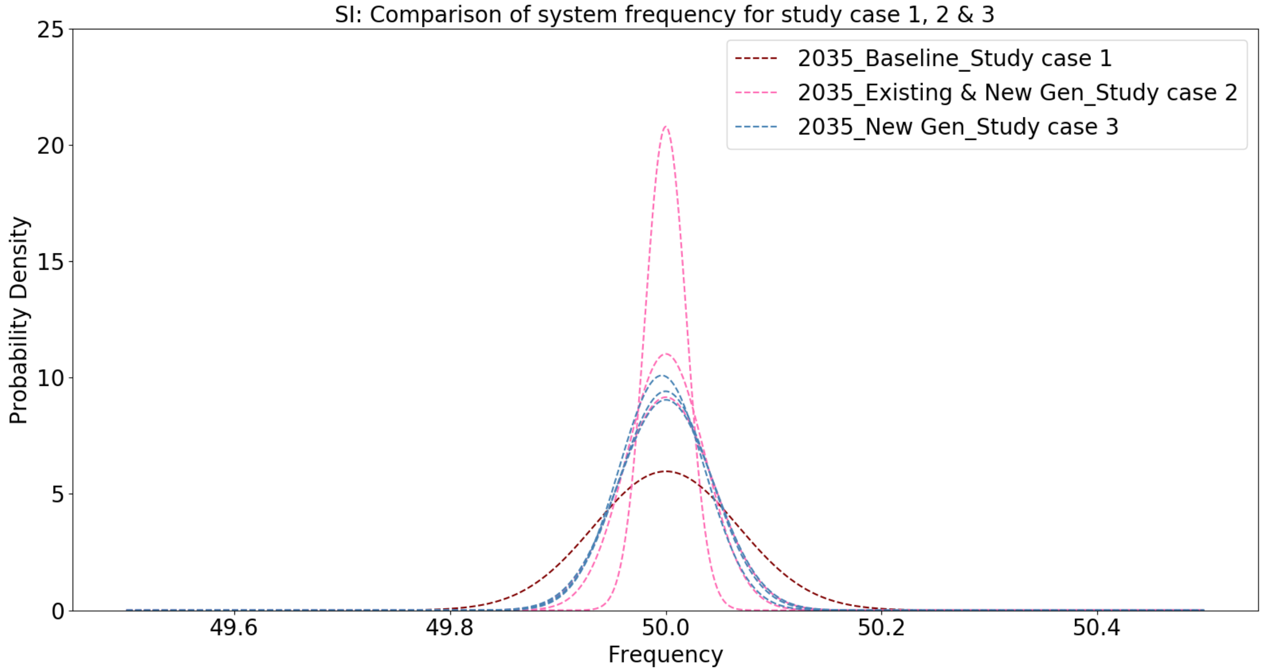

Figure 8-46: System frequency observed for study case 1, 2 and 3 for the SI

9 Findings and Recommendations

9.1 Study 2a: Assess the impact of increased wind and solar PV generation on frequency keeping

Findings

Study case 1: Winter (No Solar)

1. The variability of frequency increases with increased wind and solar PV generation due to higher intermittency.
2. The existing MFK MW regulation band reached its limits, indicating that there is a requirement to increase the frequency keeping band from 30 MW.
3. There is a heavy reliance on generating unit response (other than the frequency keeping unit) to assist in managing frequency within the normal band. There is no certainty in the actions generation owners will take to mitigate any adverse impact on their assets. This could improve/exacerbate the issue.

The study covers a range of wind export scenarios that show the adverse impact of increased intermittency on frequency management.

Study Case 2: "What if" analysis on the impact of solar PV generation on frequency keeping.

Study case 2 exposes the limitations in creating a total generation profile for wind and solar PV generation. It is expected that a higher proportion of intermittent generation on the power system will cause more variability in the profiles of intermittent wind and solar PV generation and GXP load. The level of variance is attributed to several contributing factors, as discussed in study case 2. However, the observations made in study case 1 show that higher variability in intermittent generation adversely impacts frequency, and therefore these conclusions are adopted for study case 2.

Recommendations

Studies strongly indicate that the variability of frequency within the normal band will increase with increased intermittent generation. There is a requirement to further increase frequency management efforts, which includes increasing the frequency keeping band from the current 30 MW.

9.2 Study 2b: Assess the impact of implementing a set frequency dead band on frequency quality within the normal band

Findings

Study Case 1: Baseline - Use frequency dead bands applied to the current system for years 2023 and 2035

1. If the frequency dead band is not stipulated in the Code and we retain the trend seen in the frequency dead bands set by generation owners, we expect to see a relative decrease in frequency quality in the normal band in 2035.
2. *Impact to frequency keeping band:* Increase the upper and lower limit of the frequency keeping band.

Study Case 2: Set the dead band for existing and new generation connected to the power system

1. A reduction in the frequency dead band results in frequency being better managed compared to the baseline – i.e. the lower the dead band, the better the frequency management.
2. Frequency management is dependent on the MW generation response in the power system.
3. Applying a frequency dead band across existing and new generation causes the generation response to be shared across all generation types more evenly – i.e. a decrease in hydro generation response is supplemented by an increase in the response of other types of generation. This is due to hydro generation currently having a low dead band, while applying a new relatively lower dead band across other existing generation and new generation.

4. There is a slight reduction in the MFK regulation control signal due to the increased response from existing and new generation, as a result of the dead band being decreased.
5. The average MFK regulation control signal becomes marginally more positive, indicating that frequency keeping is required to inject more MW into the transmission network as the dead band decreases. This is due to the increased downward-only response from wind and solar PV generation.
6. *Impact to frequency keeping band:* Do not need to change the frequency keeping band.

<u>Study Case 3: Set the dead band for new generation connected to the power system</u>

1. Frequency is better managed, when compared to the baseline, due to a reduction in the frequency dead band – i.e. the lower the dead band, the better the frequency management.
2. Frequency is maintained slightly below 50 Hz, because the average upward frequency regulation is lower than the average downward frequency regulation. This is due to the combination of:
    a. Intermittent wind and solar PV generation only regulating frequency downwards as these forms of generation only operate at maximum available power.
    b. The frequency keeping band reaching its limit of 15 MW in each island in the study, limiting the upward frequency regulation of the frequency keeping unit.
    c. Existing frequency dead bands reducing the response of existing generation with headroom capacity (i.e. with the ability to regulate frequency upwards).
3. Generation response is shared more evenly between hydro and intermittent wind and solar PV generation only when compared to the baseline. Other generation types barely respond due to high initial dead band settings that are not changed.
4. The average MFK regulation control signal becomes significantly more positive, indicating that frequency keeping is required to inject more MW into the transmission network as the dead band decreases. This is due to the increased downward frequency regulation response from intermittent wind and solar PV generation and reduced response from existing generation.
5. *Impact to frequency keeping band:* Increase the upper limit only of the frequency keeping band.

Overall conclusion

The following conclusions are made after considering the results of the studies:

1. Implementing a frequency dead band that is narrower than the normal band has a positive impact on frequency regardless of whether the dead band applies to existing and new generation or just new generation.
2. When compared to a baseline, applying a dead band to new generation results in generation frequency response being better shared between hydro generation and intermittent wind and solar PV generation because the latter has a relatively lower dead band than they would otherwise have.
3. Generating units operating at their maximum output will not provide the upward frequency regulation needed for a negative/downward frequency deviation even if the generating units have a reduced dead band. Frequency keeping generating units will have to provide more upward frequency regulation, causing them to hit the upper limit of the frequency keeping band more often.
4. The system operator may need to review the +/- 15 MW frequency keeping band as a result of the increasing proportion of intermittent generation connected to the power system.
5. There is better frequency management and more even sharing of generation MW response when a prescribed frequency dead band is applied to existing and new generation. Applying a prescribed frequency dead band to existing generation may have the following implications:
    a. An adverse financial impact due to wear and tear, especially for thermal and geothermal generating units
    b. Potentially a material one-off volume of testing and modelling activities, since any upgrade to a control system, including changing a control system setting to alter a dead band setting,

would require generators, in conjunction with the system operator, to re-commission the control system.[9]

Recommendation

The studies showed that implementing a dead band of ±0.1 Hz for newly commissioned generating units can assist in regulating system frequency within the normal band. A dead band setting lower than ±0.1 Hz only performs marginally better when applied to new generating units only. We expect new IBR technology and other generation types could meet a prescribed dead band setting of ±0.1 Hz.[10]

Hence, we recommend implementing a dead band of ±0.1 Hz for new generating units connecting to the power system. Existing generating units connected to the power system can maintain their current dead band settings.

[9] Schedule 8.3, Technical Code A, clause 2(6)(a) of the Code states that each asset owner must provide a commissioning plan or test plan when changes are made to assets that alter a control system, including a change to a control system setting.

[10] The majority of new generation expected to come online in New Zealand is inverter-based, and it is assumed that similar generating technologies with similar performance capabilities will be used across the Australasian energy sectors. The lowest studied dead band is ±0.015 Hz, which aligns with the dead band requirement in Australia's National Electricity Rules.

References

[1] Electricity Authority, "Electricity Industry Participation Code", 2010. Online: Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz)

[2] Transpower New Zealand Limited, "Whakamana i Te Mauri Hiko, Empowering our Energy Future", March 2020. Online: Whakamana i Te Mauri Hiko - Empowering our Energy Future | Transpower

[3] Transpower New Zealand Limited, "Whakamana i Te Mauri Hiko, Monitoring Report", March 2023. Online: Transpower releases March Whakamana i Te Mauri Hiko monitoring report | Transpower

[4] Transpower New Zealand Limited, "Transmission Planning Report", 2022

[5] Transpower New Zealand Limited, "Transmission Planning Report", 2023

[6] Transpower New Zealand Limited, "Policy Statement", 2022. Online: Policy statement | Transpower

Appendix

A. Additional curves for the input and output of the High Pass Filter

This section shows the original PI data which has been passed through the High Pass Filter to produce the High Pass filter curves for the remaining scenarios not shown in the report. The High Pass filter curves are used as input signals to the Matlab model.

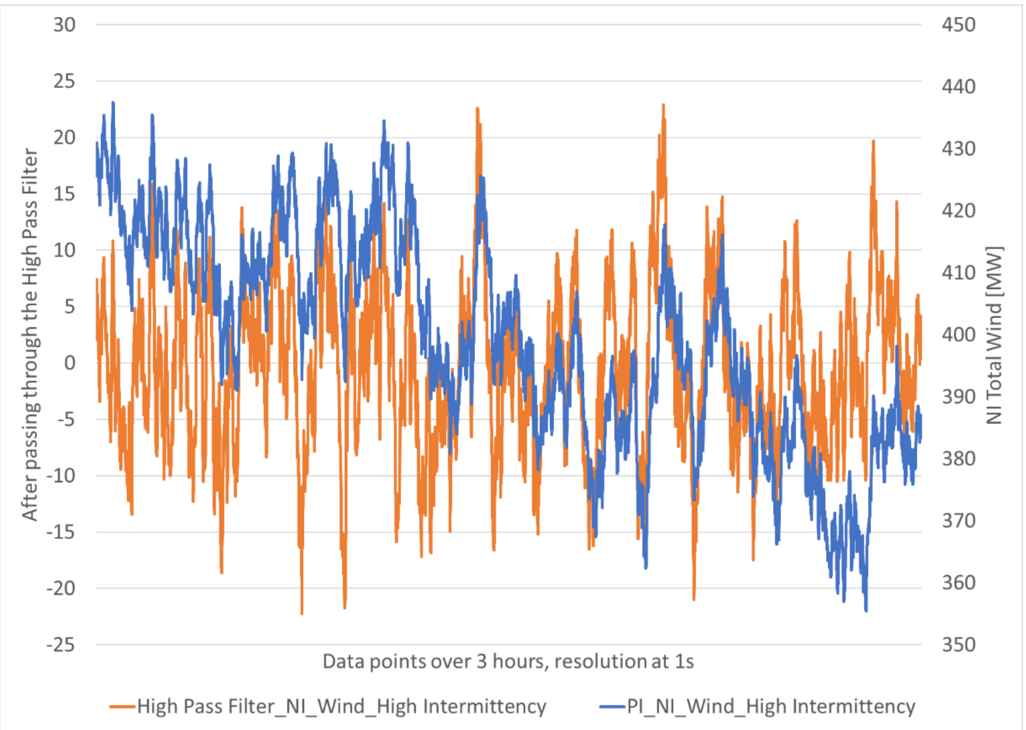

Figure 0-1: PI wind data passed through the High Pass Filter for the NI for the high Intermittency case

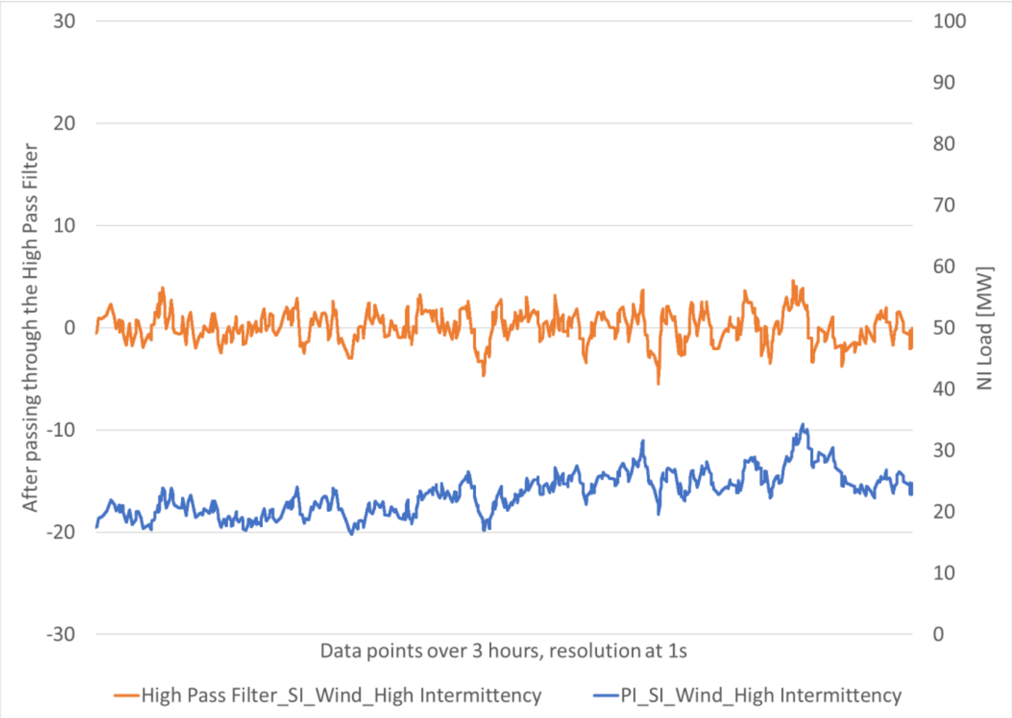

Figure 0-2: PI wind data passed through the High Pass Filter for the SI for the high Intermittency case

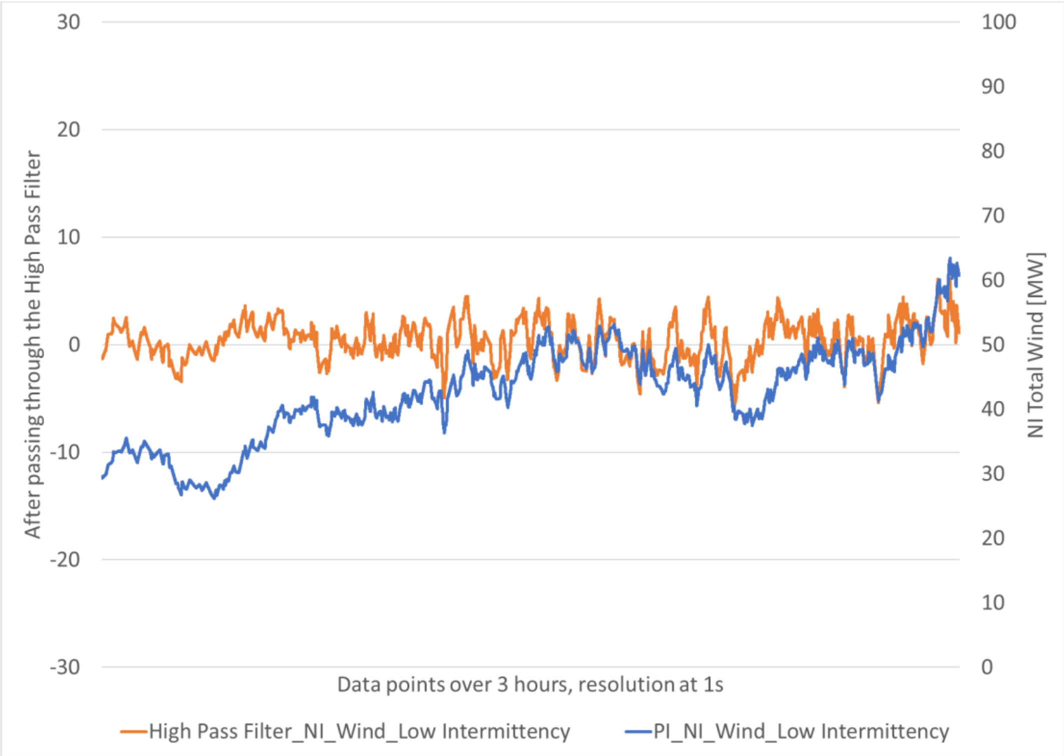

Figure 0-3: PI wind data passed through the High Pass Filter for the NI for the low Intermittency case

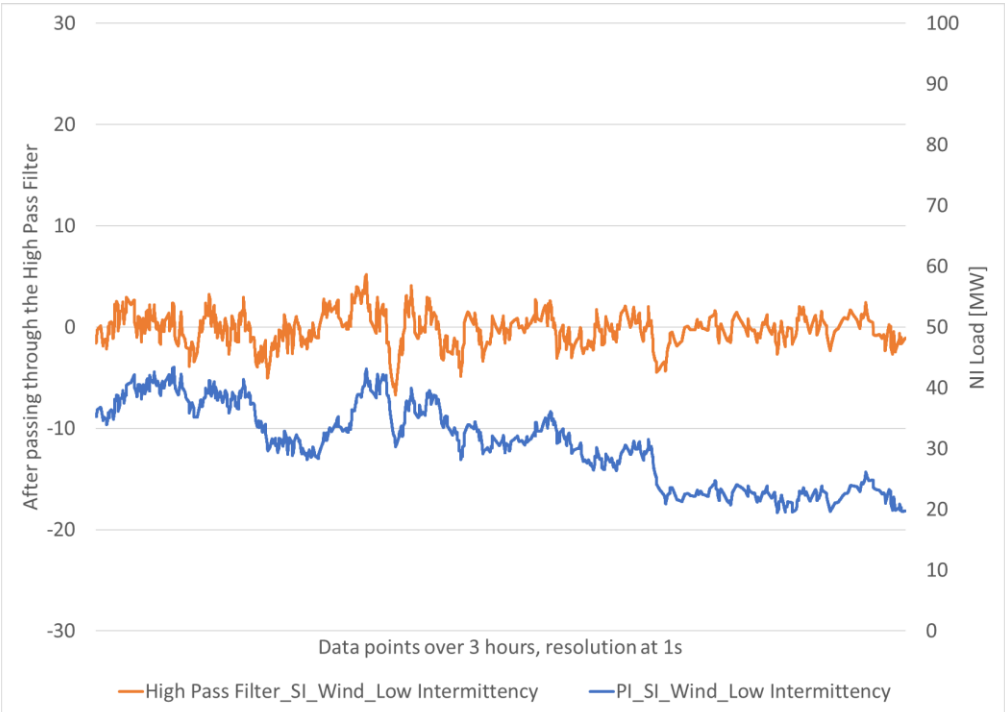

Figure 0-4: PI wind data passed through the High Pass Filter for the SI for the low Intermittency case

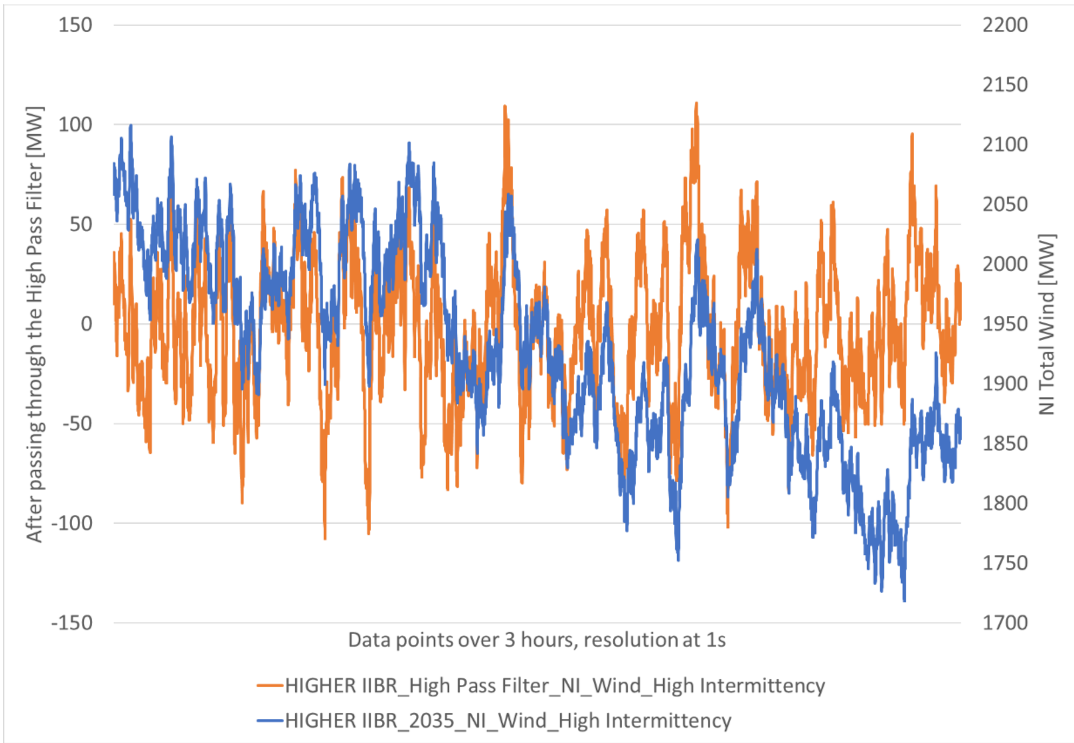

Figure 0-5: HIGHER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the NI for the High Intermittency case

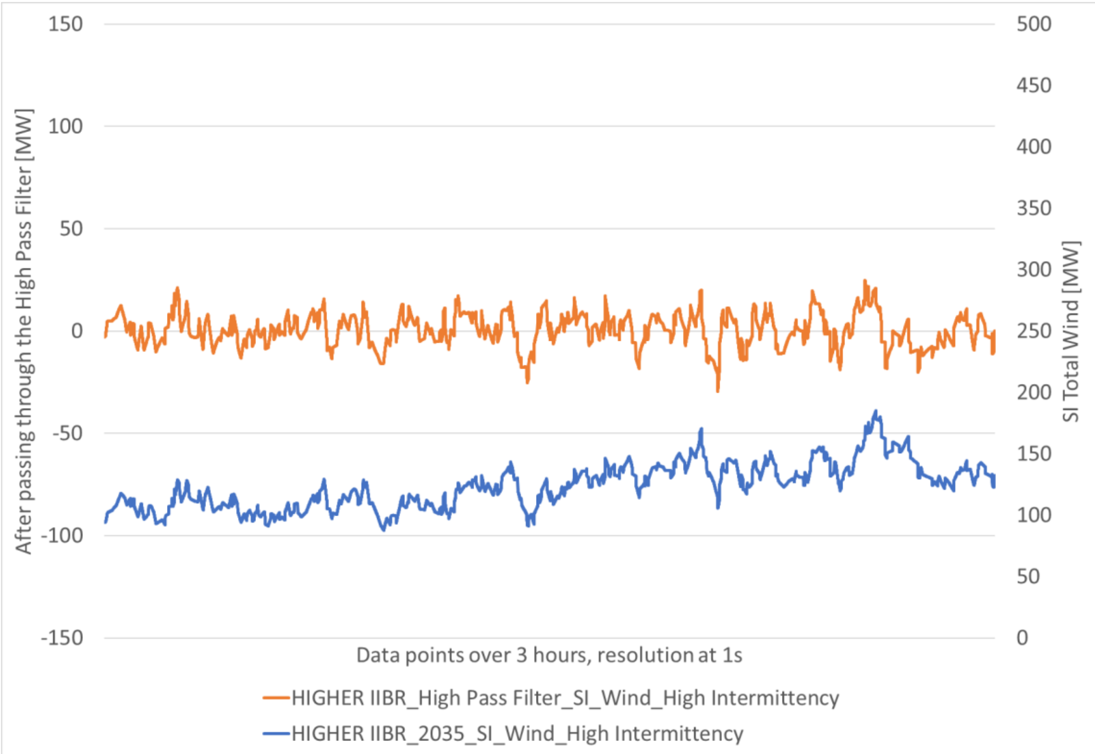

Figure 0-6: HIGHER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the SI for the High Intermittency case

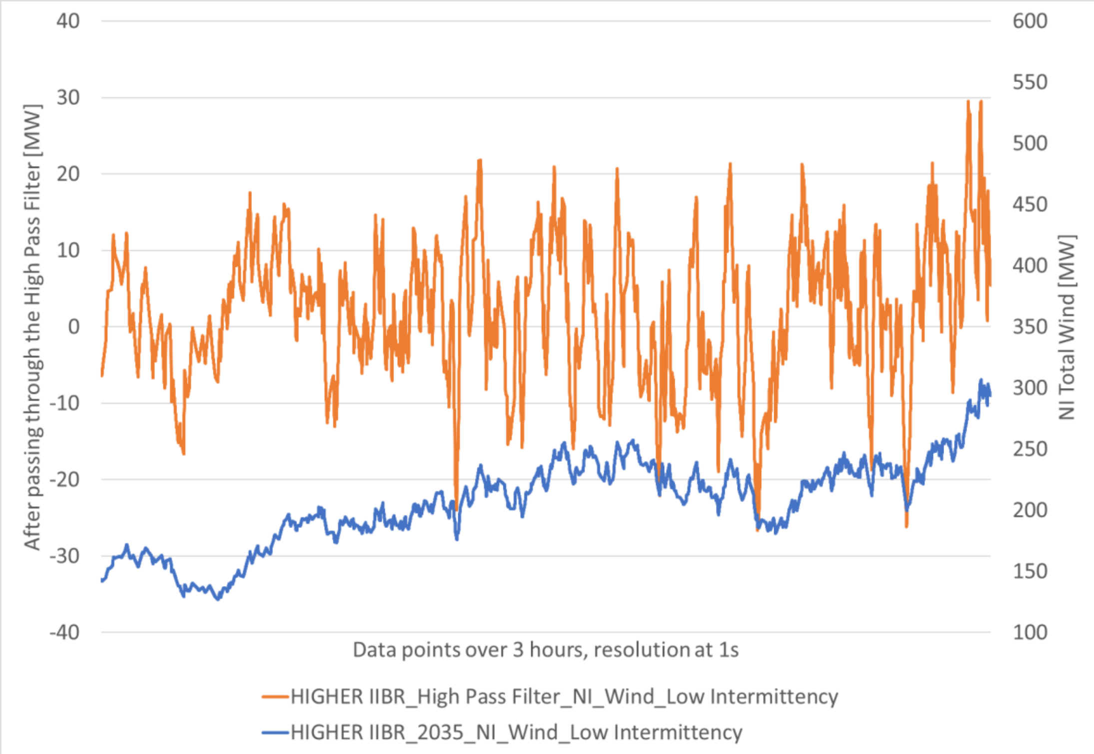

Figure 0-7: HIGHER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the NI for the Low Intermittency case

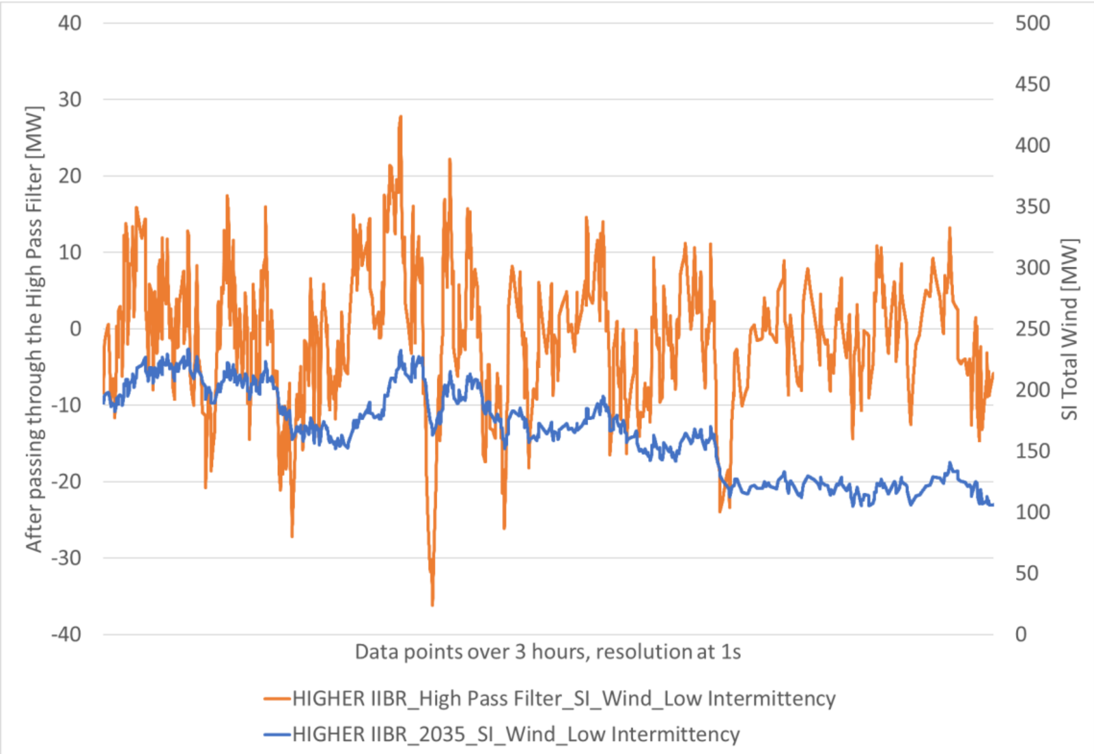

Figure 0-8: HIGHER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the SI for the Low intermittency case. case

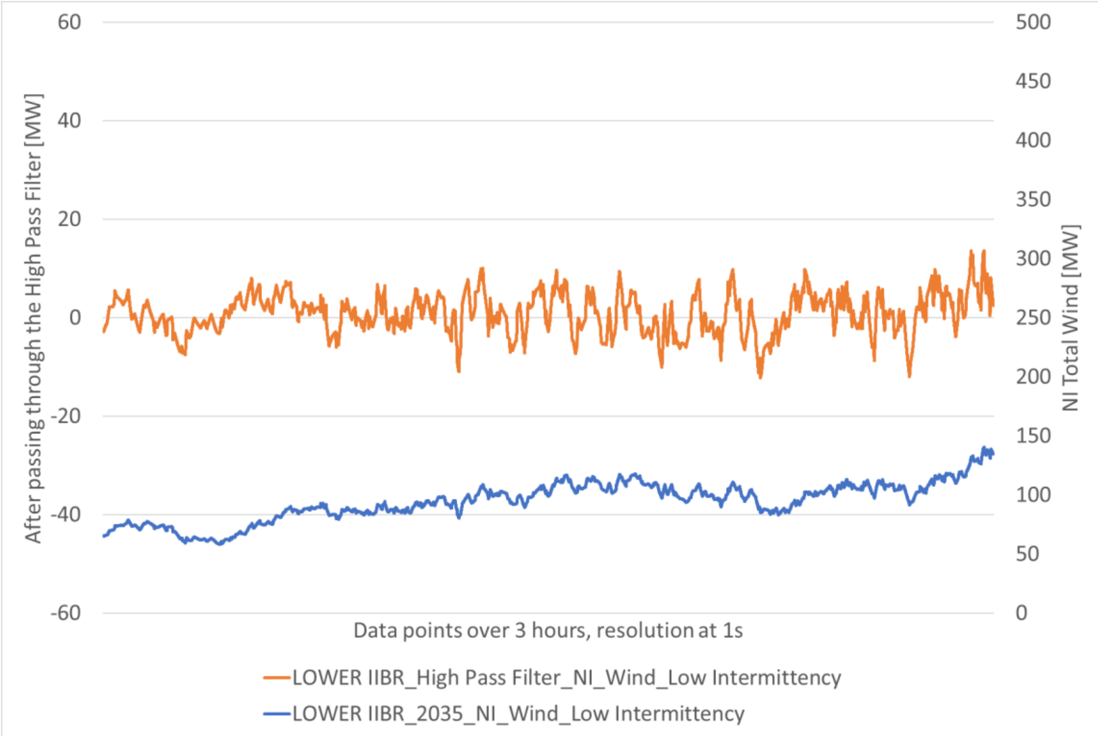

Figure 0-9: LOWER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the NI for the Low Intermittency case

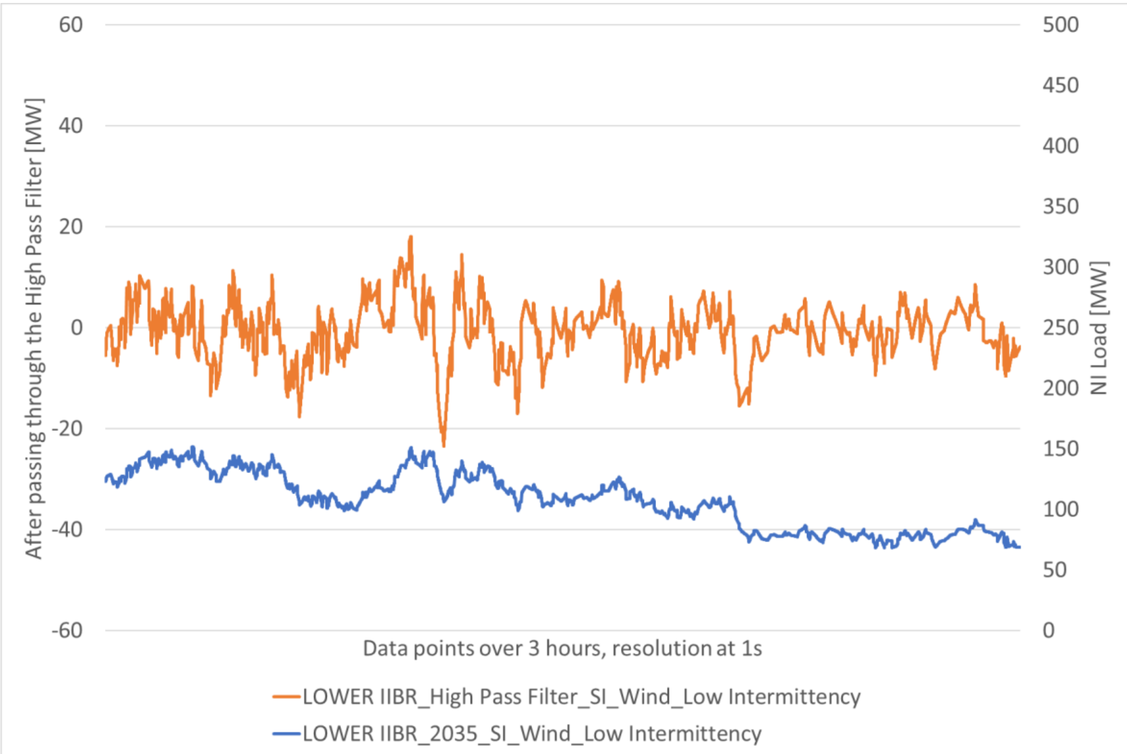

Figure 0-10: LOWER IIBR: Generated wind profile data for 2035 passed through the High Pass Filter for the SI for the Low intermittency case. case

B. Detailed graphs of the generator response: Study case 2

The following curves show further details on the MW response of the generation modelled in Matlab for study case 2. There is a MW response curve and a normal distribution curve to depict the response. The response is summarised in the report under 'Study Case 2: Set the dead band for existing and new generation connected to the power system.'.

For each aggregated generator model, the following are observed for a decrease in the frequency dead band:

1. CCGT: There is an initial decrease in response, and then an increase in response.
2. OCGT: There is an initial decrease in response, and then an increase in response.
3. Geothermal: Shows an increase in response.
4. NI Hydro: Shows a decrease in response.
5. SI Hydro: There is an initial increase in response, and then a decrease in response.
6. Thermal: Shows an increase in response.
7. NI IIBR Wind: Shows an increase in response.
8. SI IIBR Wind: Shows an increase in response.
   Note that the response of intermittent IBR wind generation is only in the negative MW direction, indicating that there is only a reduction in the intermittent IBR wind generation output to support frequency. This is shown as a left displacement in the normal distribution curve. Intermittent wind generating stations operate at maximum MW availability with no headroom to inject MWs into the power system to support the frequency. Hence the only MW support expected from intermittent wind generating stations is when the frequency moves above the upper limit of the frequency dead band.

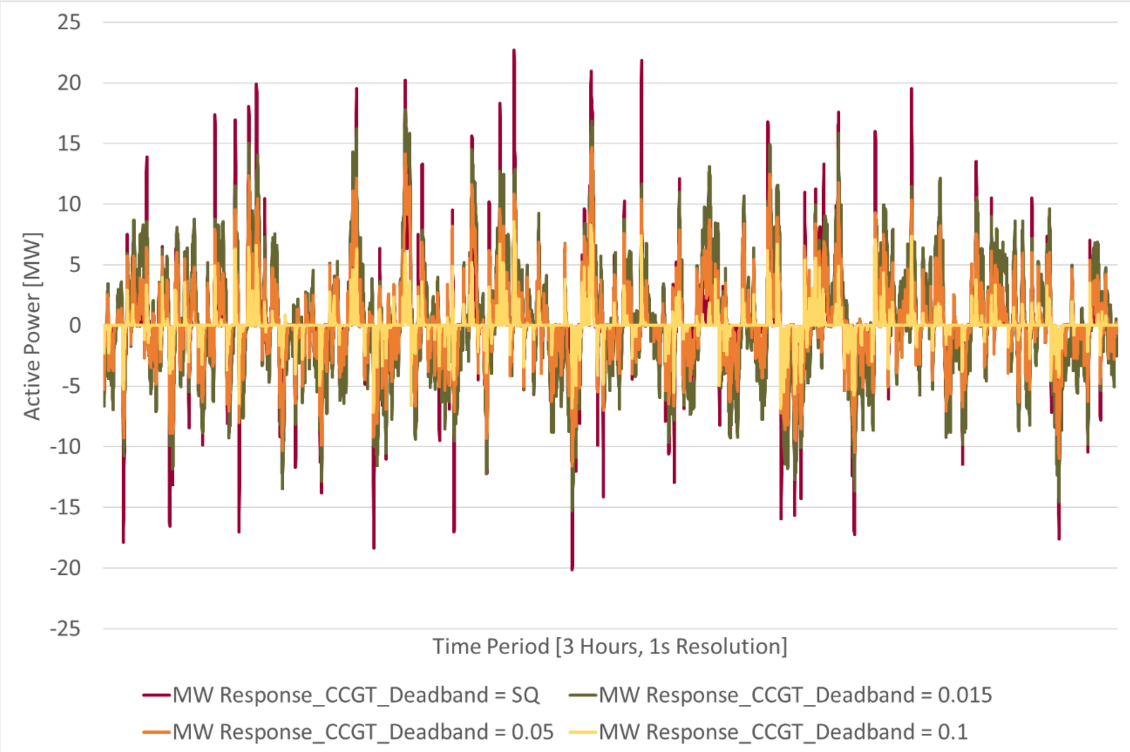

Figure 0-11: Study case 2, MW Response over time

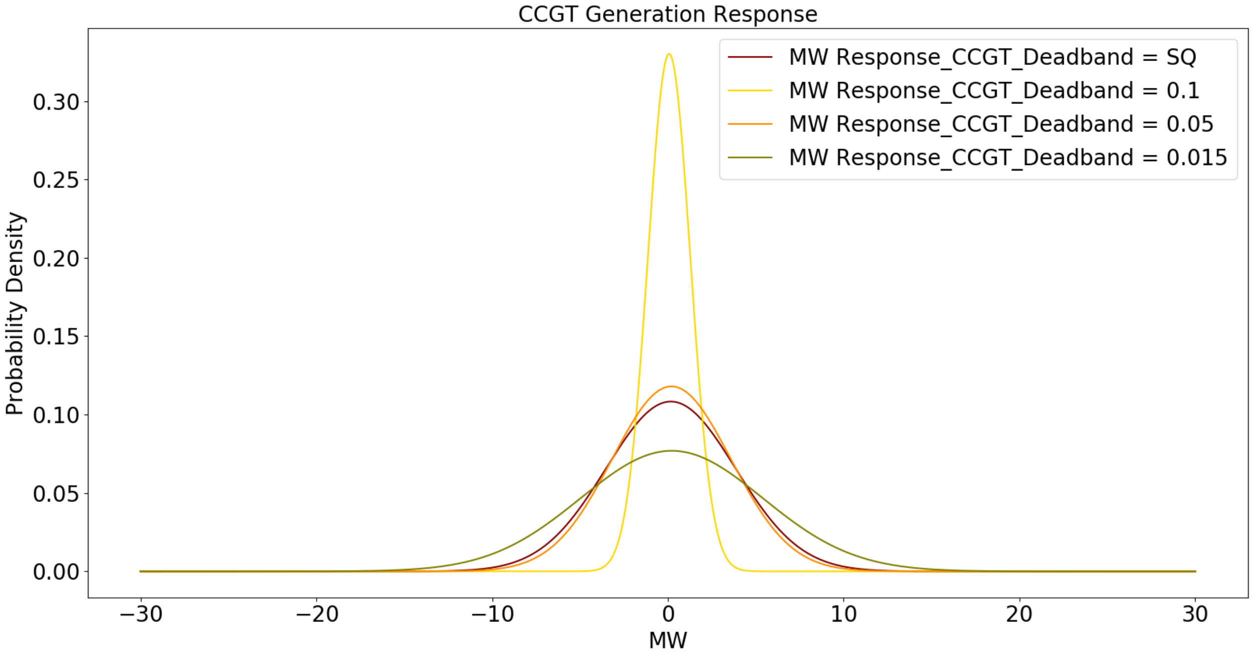

Figure 0-12: Study case 2, Normal Distribution for the MW response

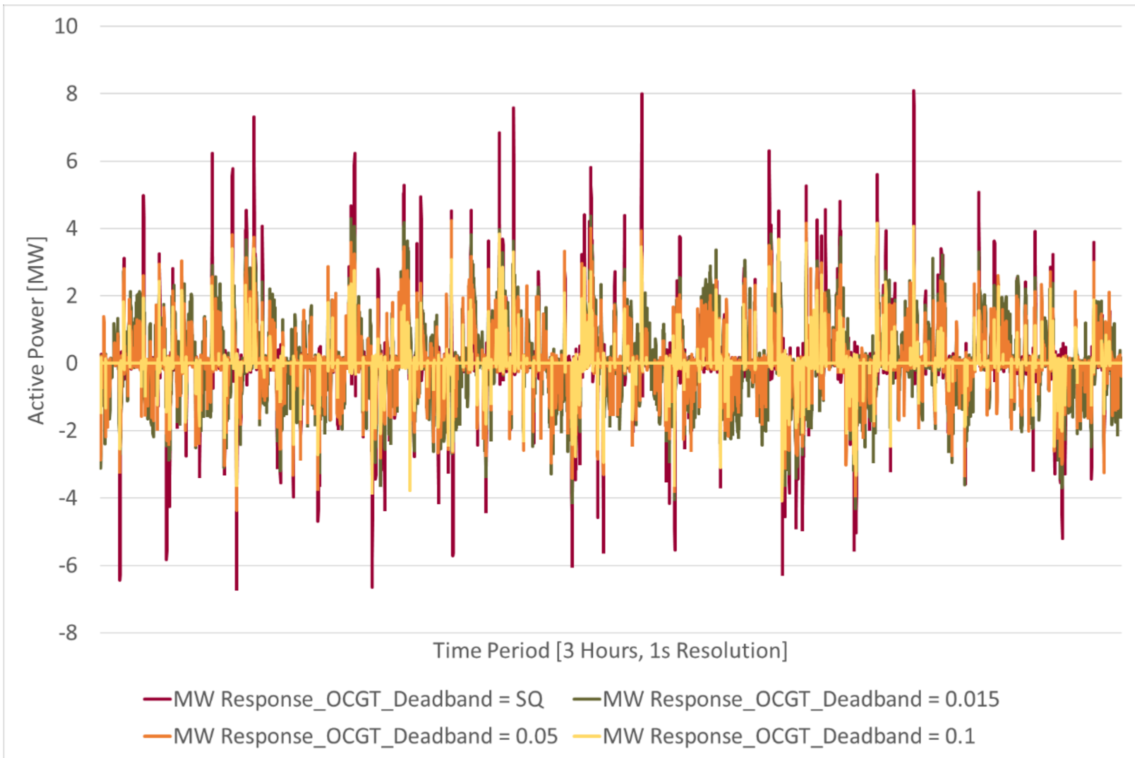

Figure 0-13: Study case 2, MW Response over time

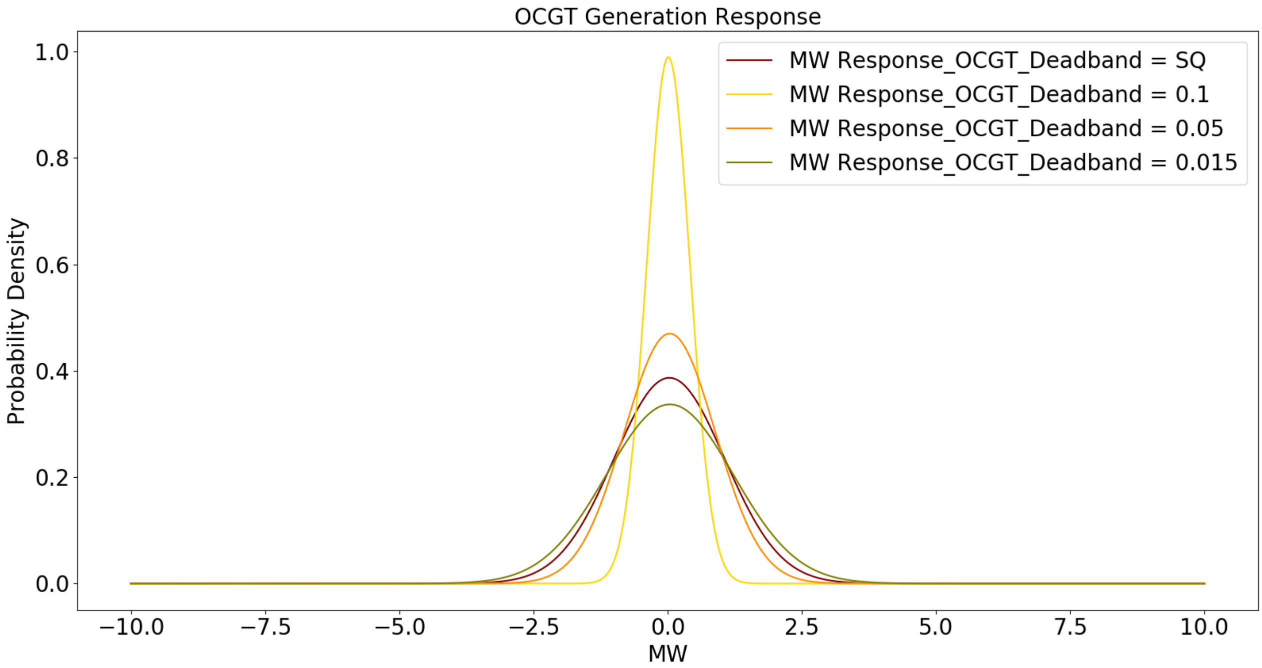

Figure 0-14: Study case 2, Normal Distribution for the MW response

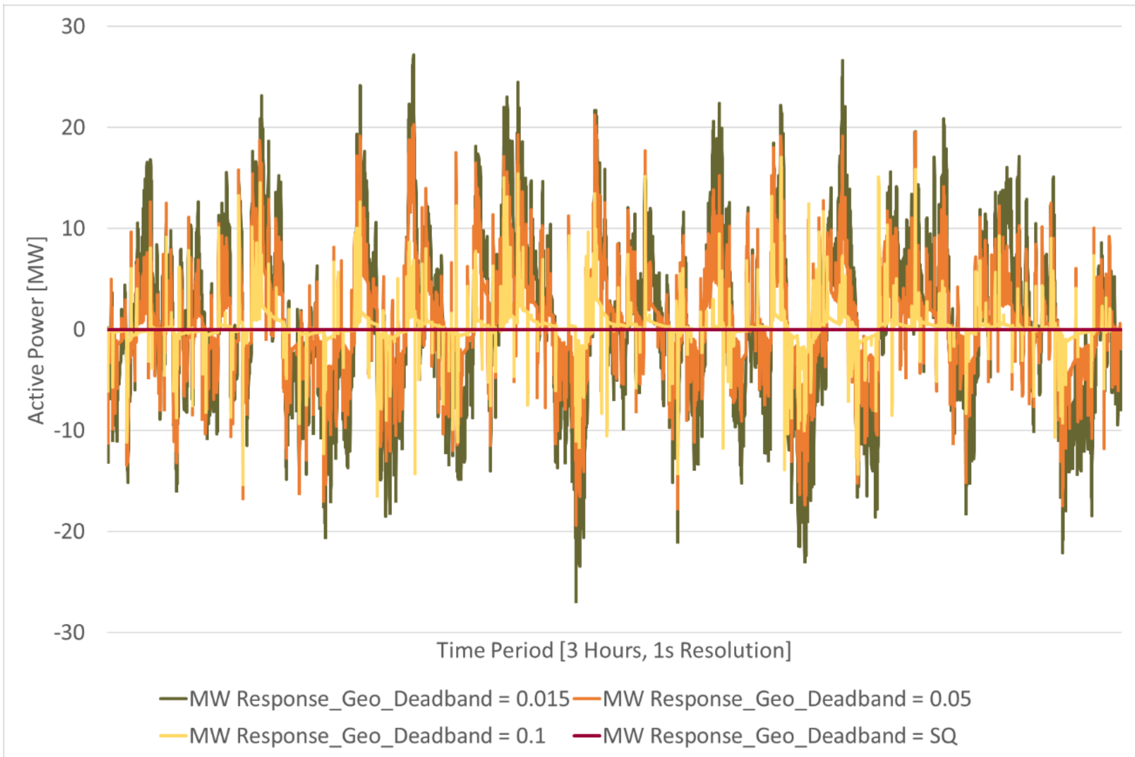

Figure 0-15: Study case 2, MW Response over time

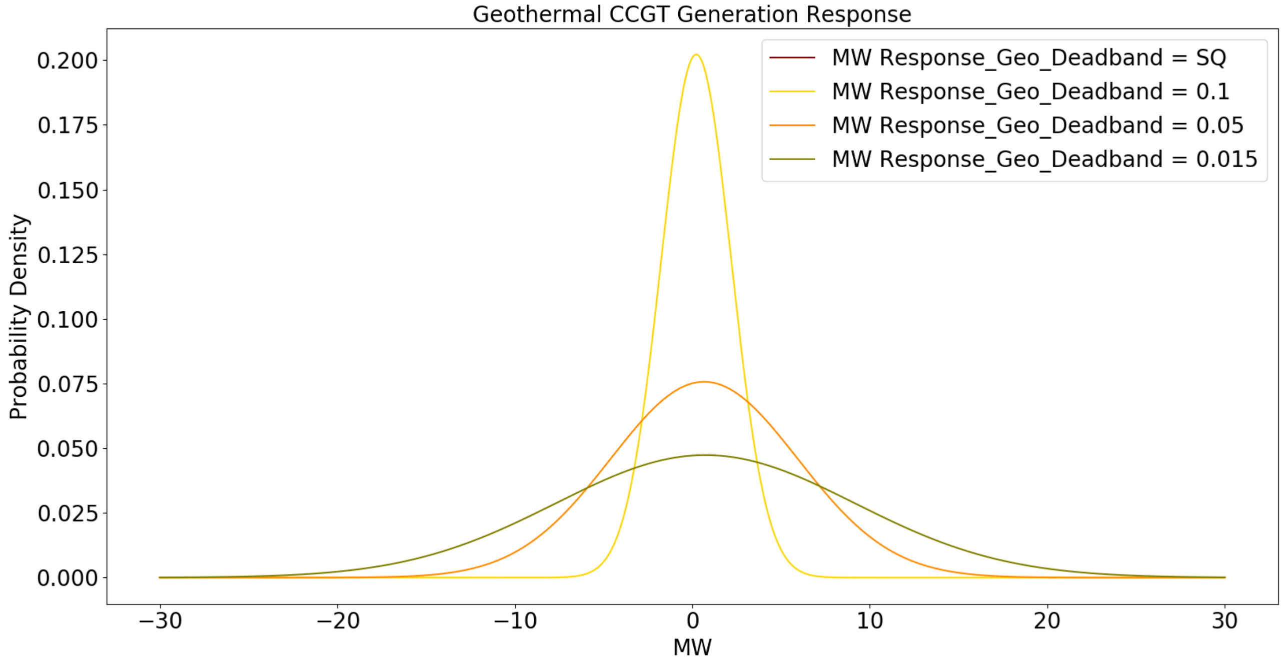

Figure 0-16: Study case 2, Normal Distribution for the MW response

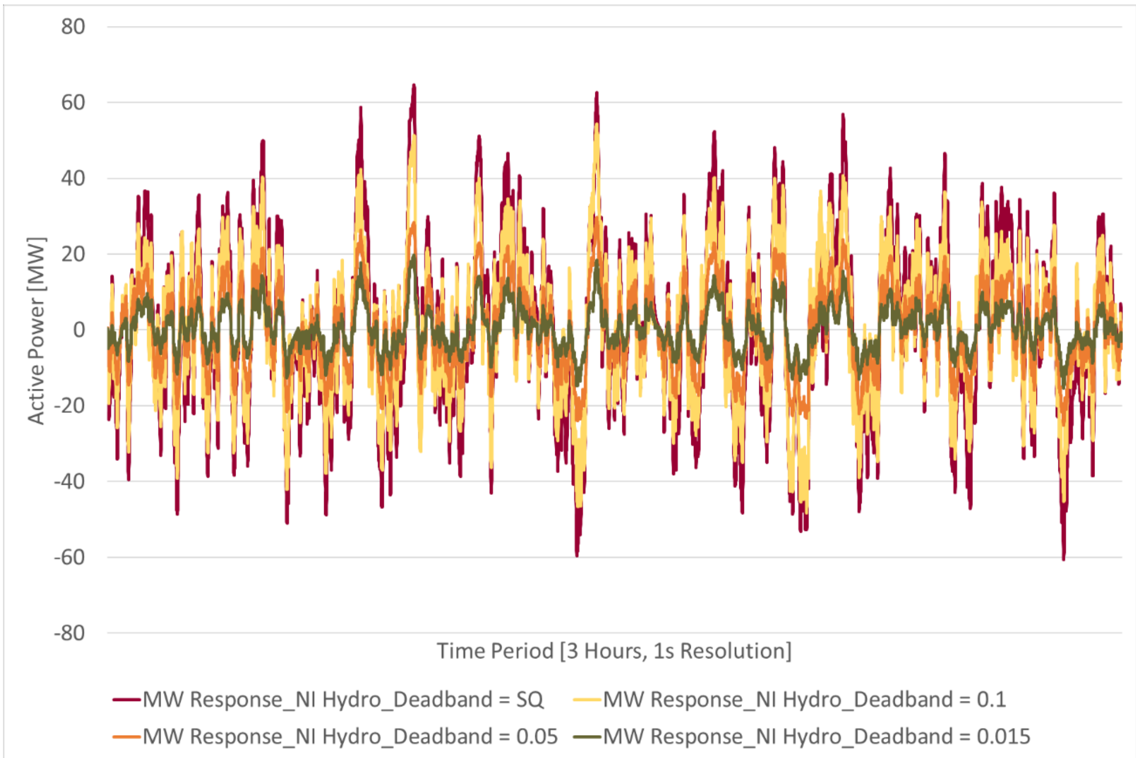

Figure 0-17: Study case 2, MW Response over time

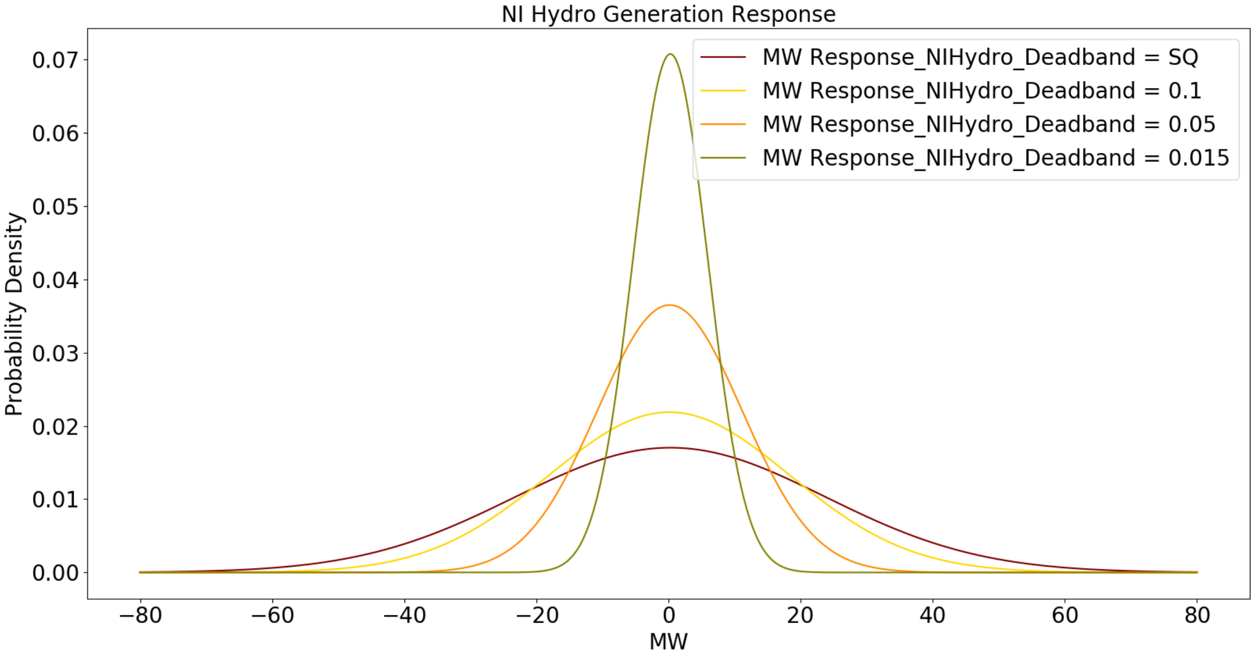

Figure 0-18: Study case 2, Normal Distribution for the MW response

Figure 0-19: Study case 2, MW Response over time

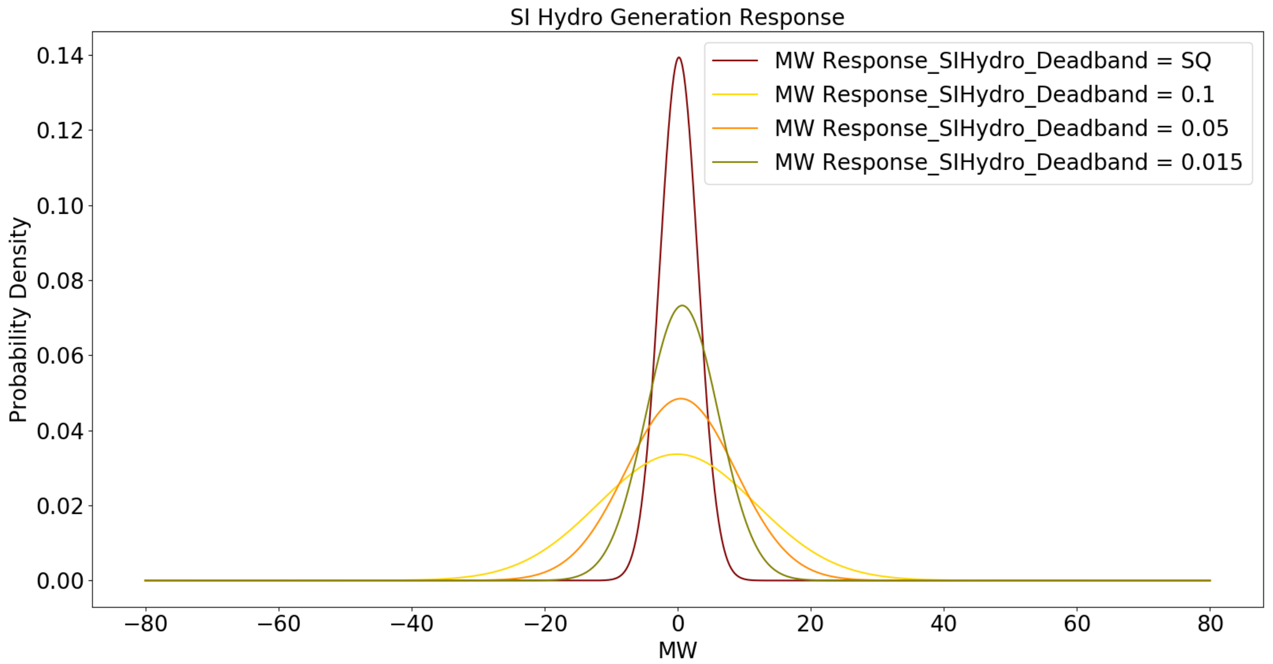

Figure 0-20: Study case 2, Normal Distribution for the MW response

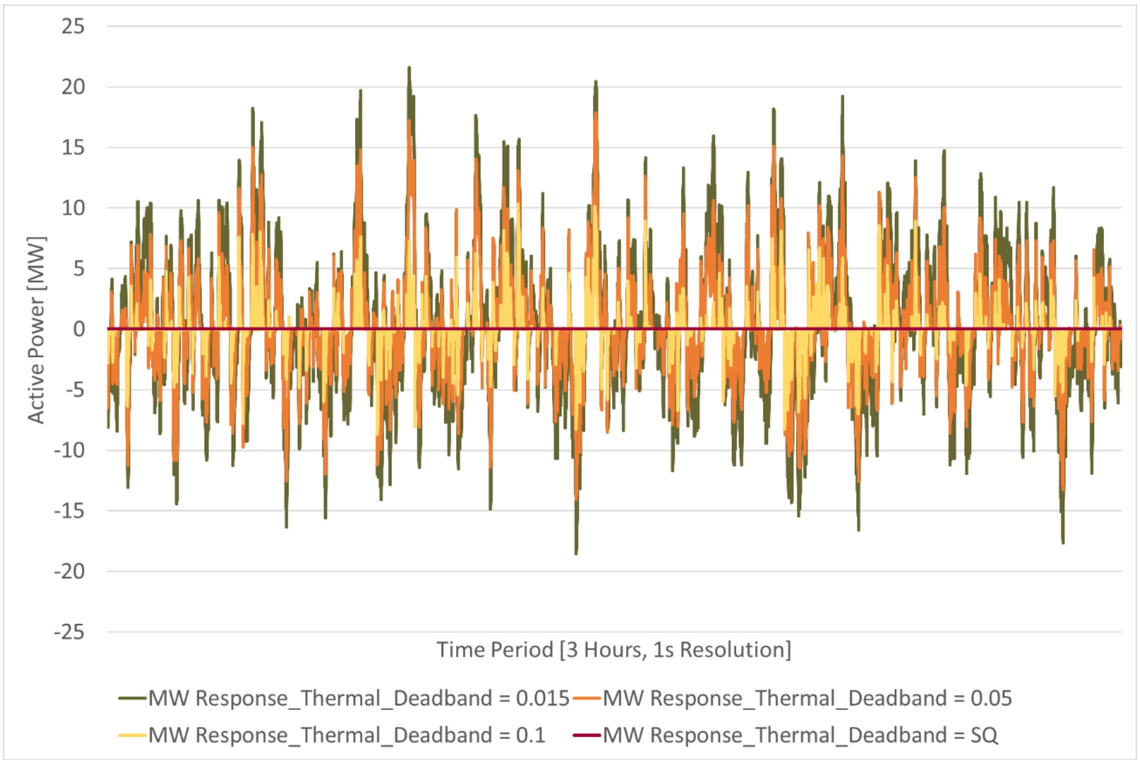

Figure 0-21: Study case 2, MW Response over time

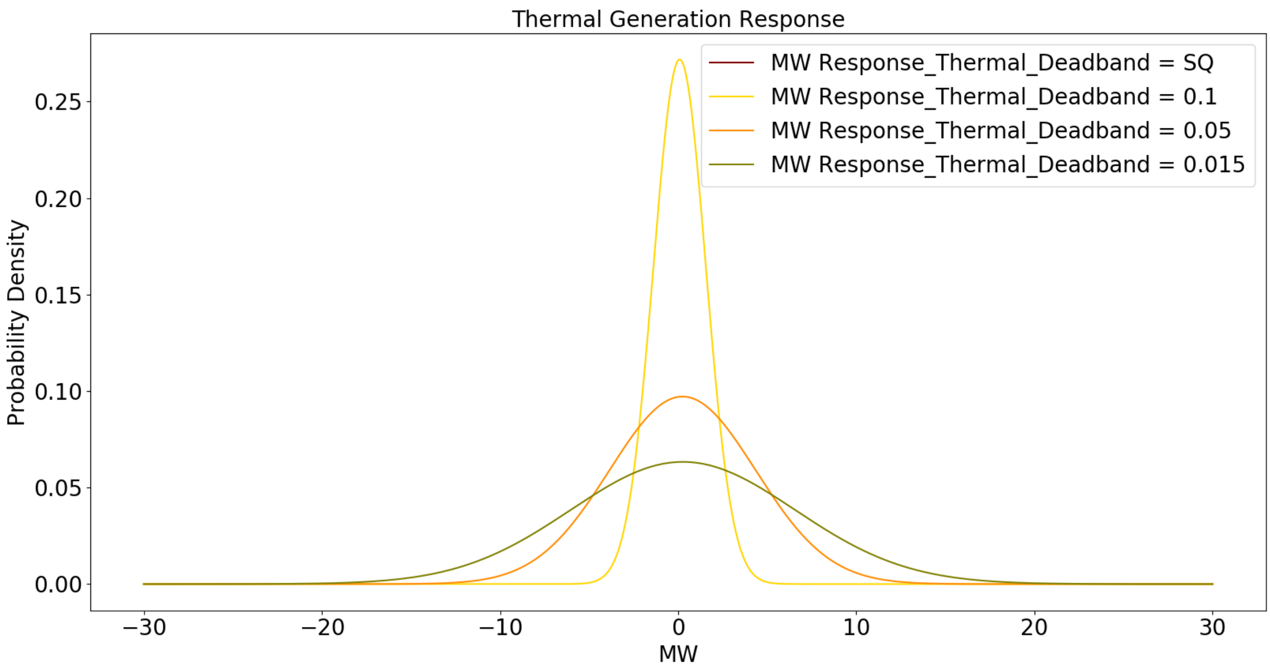

Figure 0-22: Study case 2, Normal Distribution for the MW response

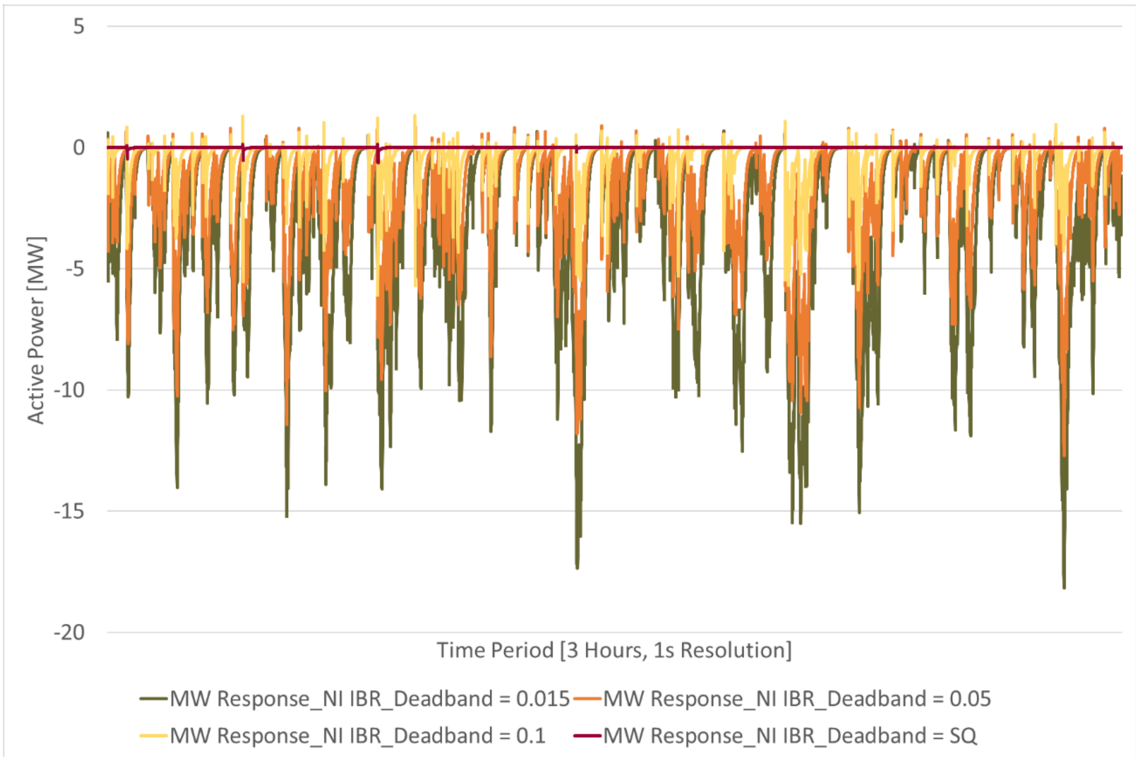

Figure 0-23: Study case 2, MW Response over time

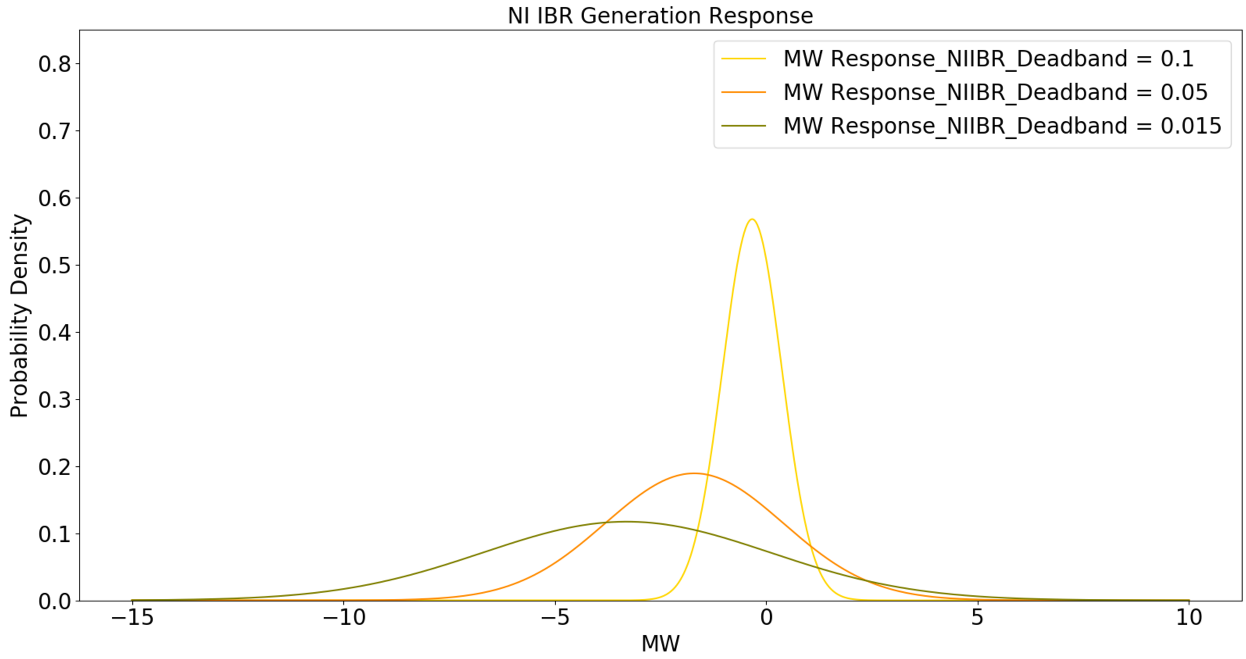

Figure 0-24: Study case 2, Normal Distribution for the MW response

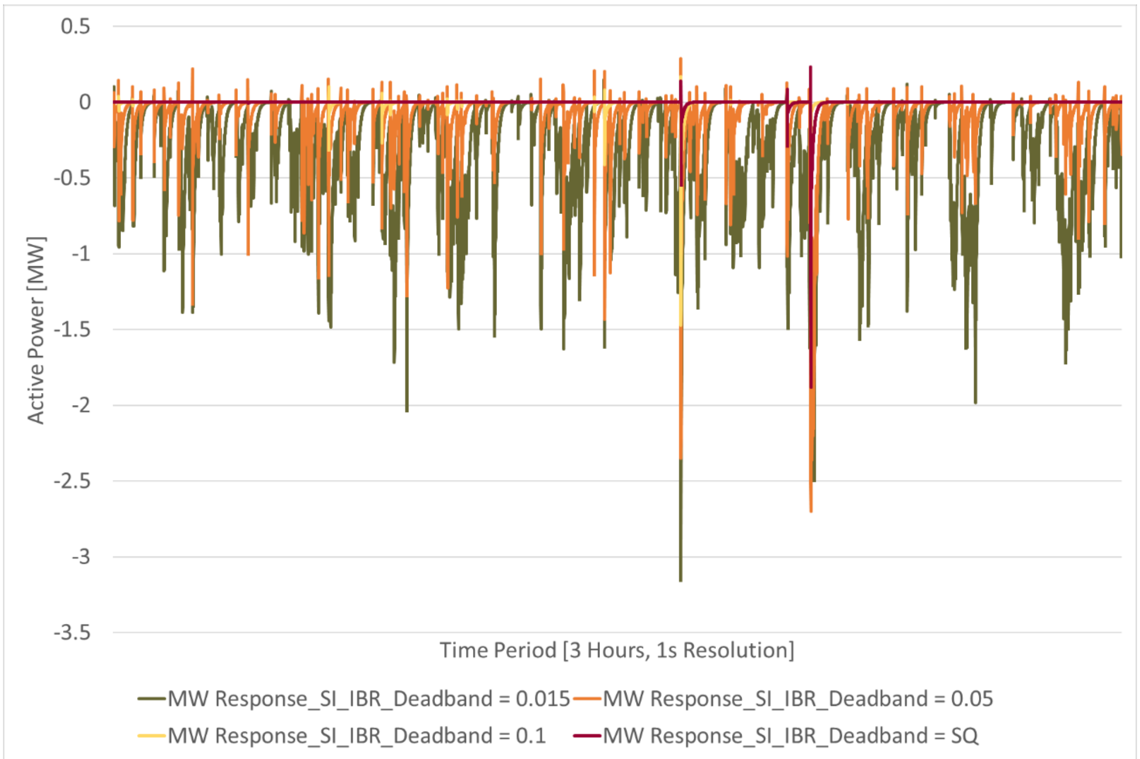

Figure 0-25: Study case 2, MW Response over time

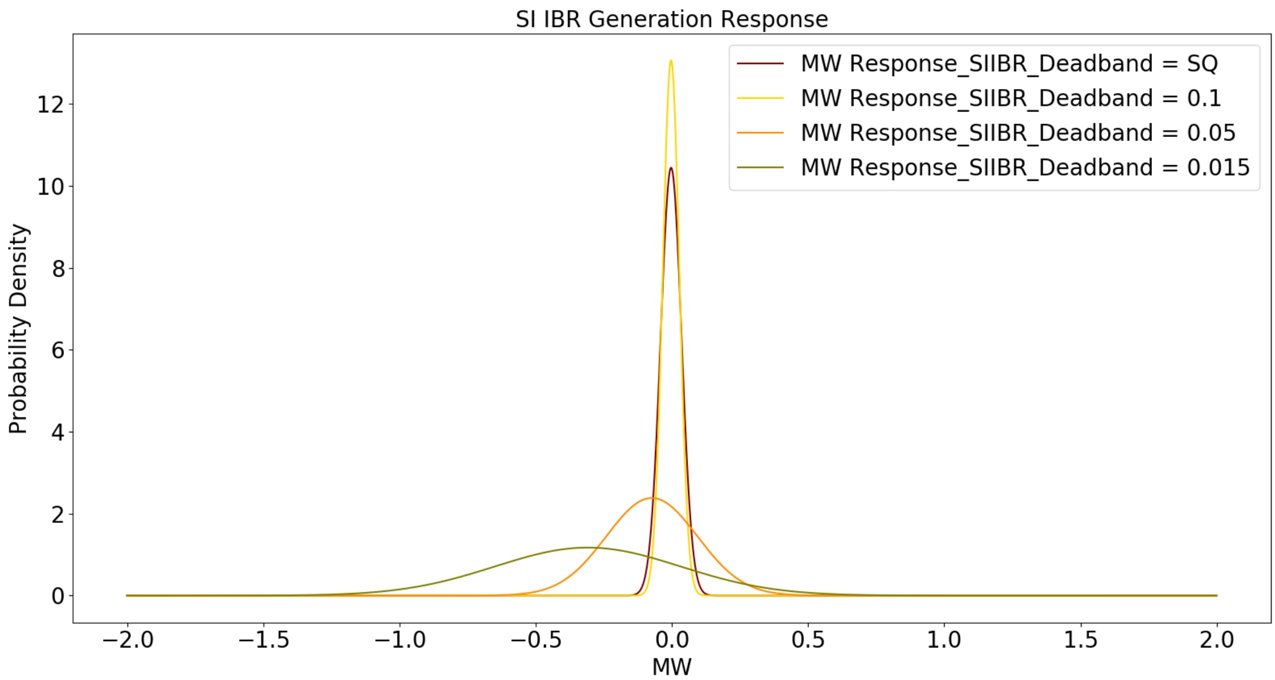

Figure 0-26: Study case 2, Normal Distribution for the MW response

C. Detailed graphs of the generator response: Study case 3

The following curves show further details on the MW response of the generation modelled in Matlab for study case 2. There is a MW response curve and a normal distribution curve to depict the response. The response is summarised in the report under 'Study Case 3: Set the dead band for new generating units connected to the power system'.

For each aggregated generator model, the following are observed for a decrease in the frequency dead band of new generation only:

1. CCGT: A reduction in the MW response, with a slight displacement to the right of the normal distribution curve as the frequency dead band decreases.
2. OCGT: A reduction in the MW response, with a slight displacement to the right of the normal distribution curve as the frequency dead band decreases.
3. Geothermal: No response, as the frequency dead band setting is ± 0.195 Hz and frequency does not vary beyond these limits.
4. NI Hydro: A reduction in the MW response, with a slight displacement to the right of the normal distribution curve as the frequency dead band decreases.
5. SI Hydro: There is an initial increase in response, and then a reduced response as the frequency dead band decreases. There is also a displacement to the right of the normal distribution curve.
6. Thermal: No response, as the frequency dead band setting is ± 0.195 Hz and the frequency does not vary beyond these limits.
7. NI IIBR Wind: Shows an increase in response, with a displacement to the left of the normal distribution curve as the frequency dead band decreases.
8. SI IIBR Wind: Shows an increase in response, with a displacement to the left of the normal distribution curve as the frequency dead band decreases.

Implementing the frequency dead band setting in the study applies directly to the intermittent IBR wind generation. This generation operates at maximum available output and can only support the frequency when the frequency moves above the upper limit of the frequency dead band. This would solicit a response from other generators to support the frequency in the other direction. The overall frequency mean is less than 50 Hz for study case 3 because generation other than intermittent IBR wind generation has a higher frequency dead band and so is not responding as frequently to move frequency back to a mean of 50 Hz.

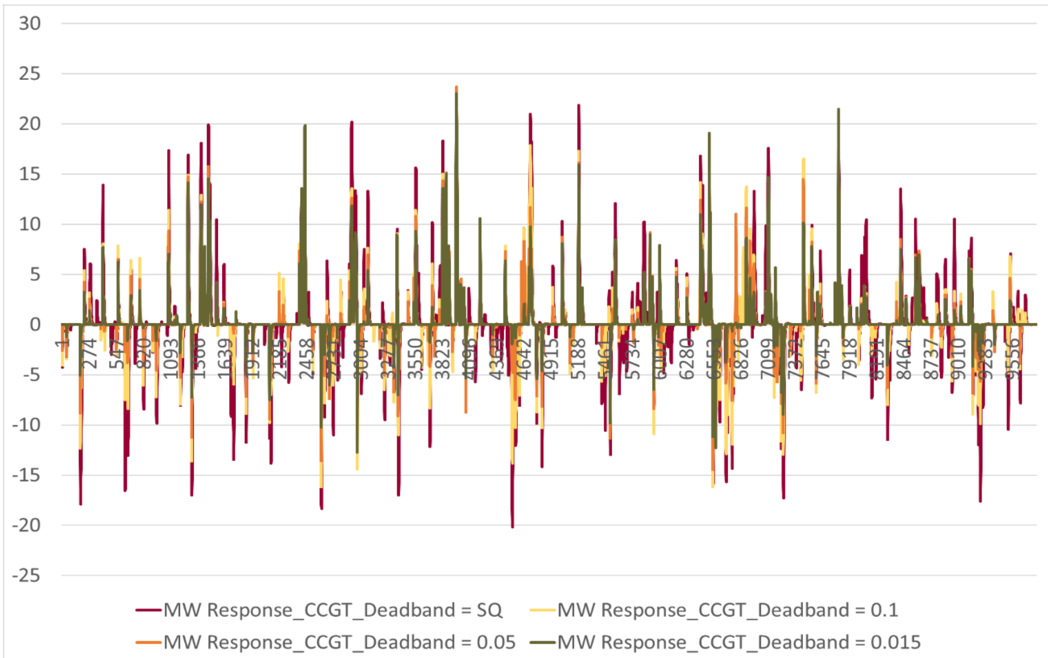

Figure 0-27: Study case 3, MW Response over time

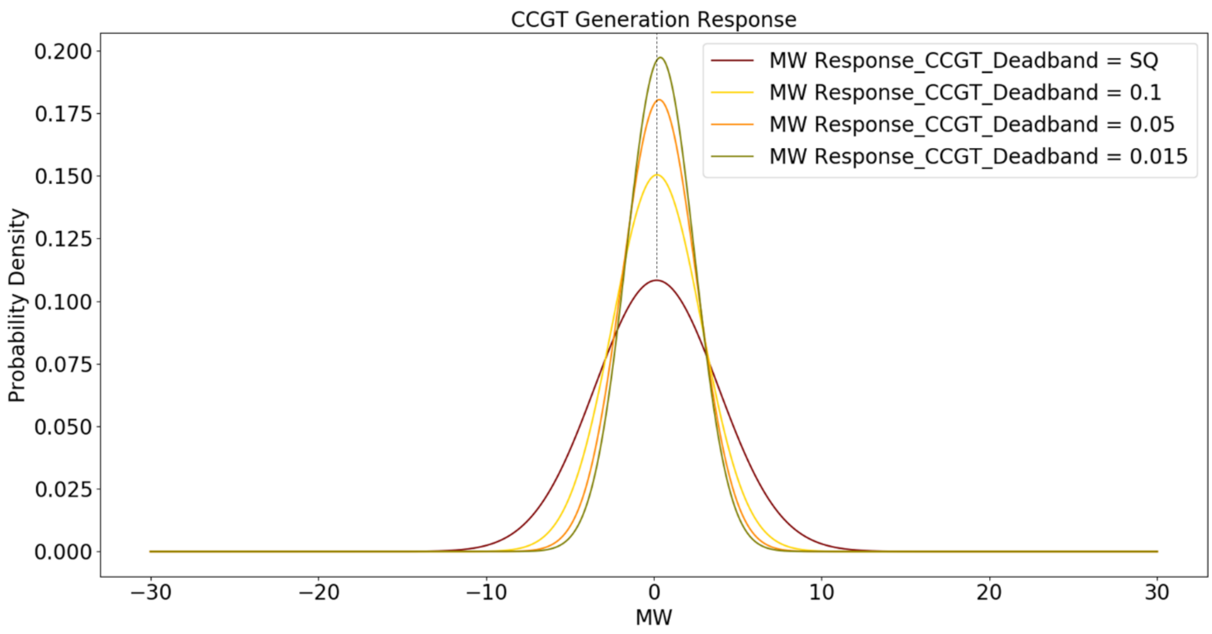

Figure 0-28: Study case 3, Normal Distribution for the MW response

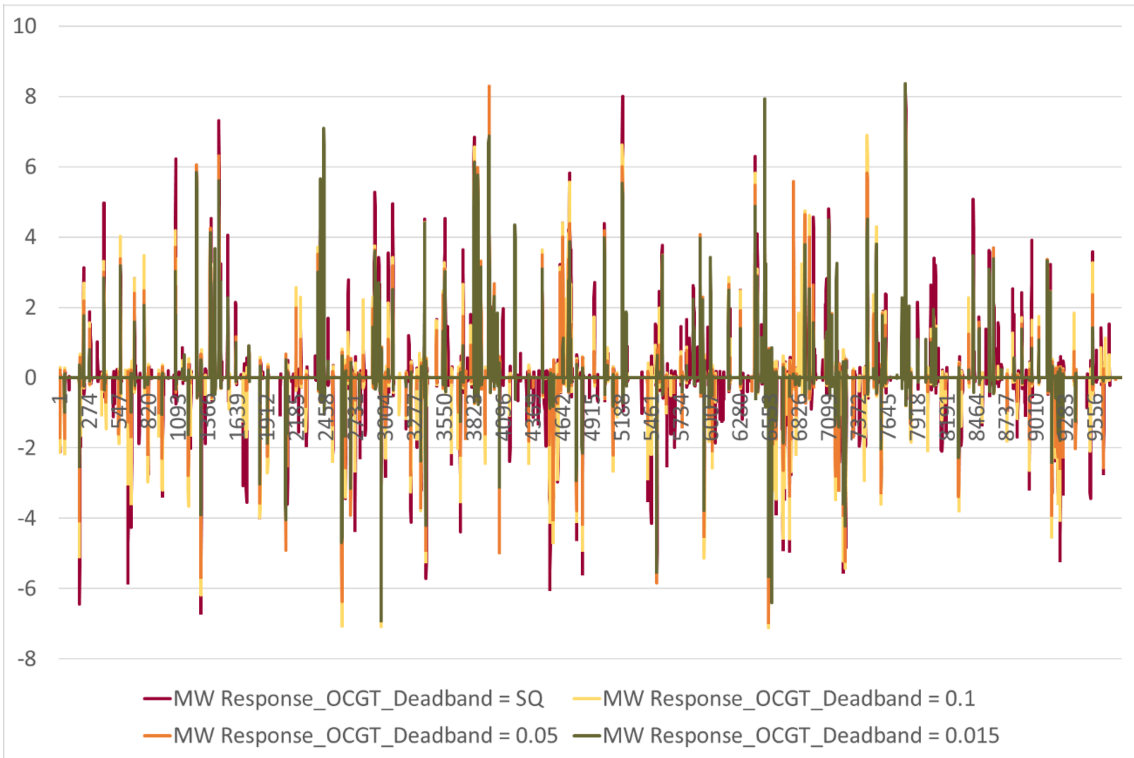

Figure 0-29: Study case 3, MW Response over time

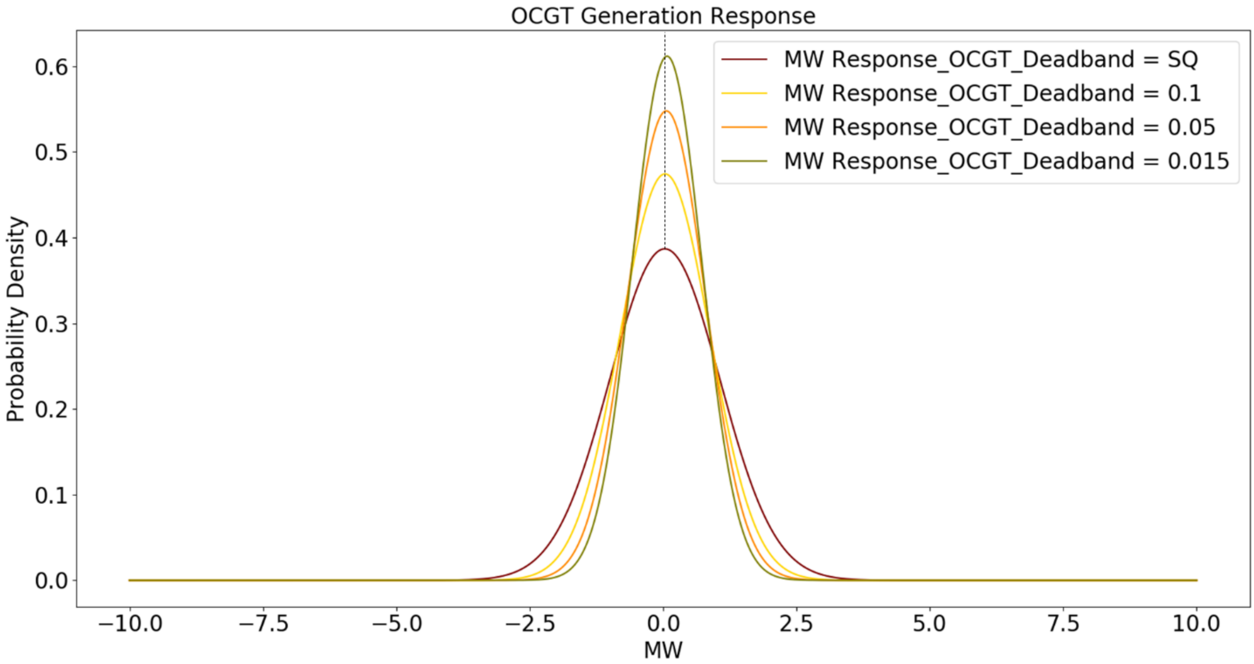

Figure 0-30: Study case 3, Normal Distribution for the MW response

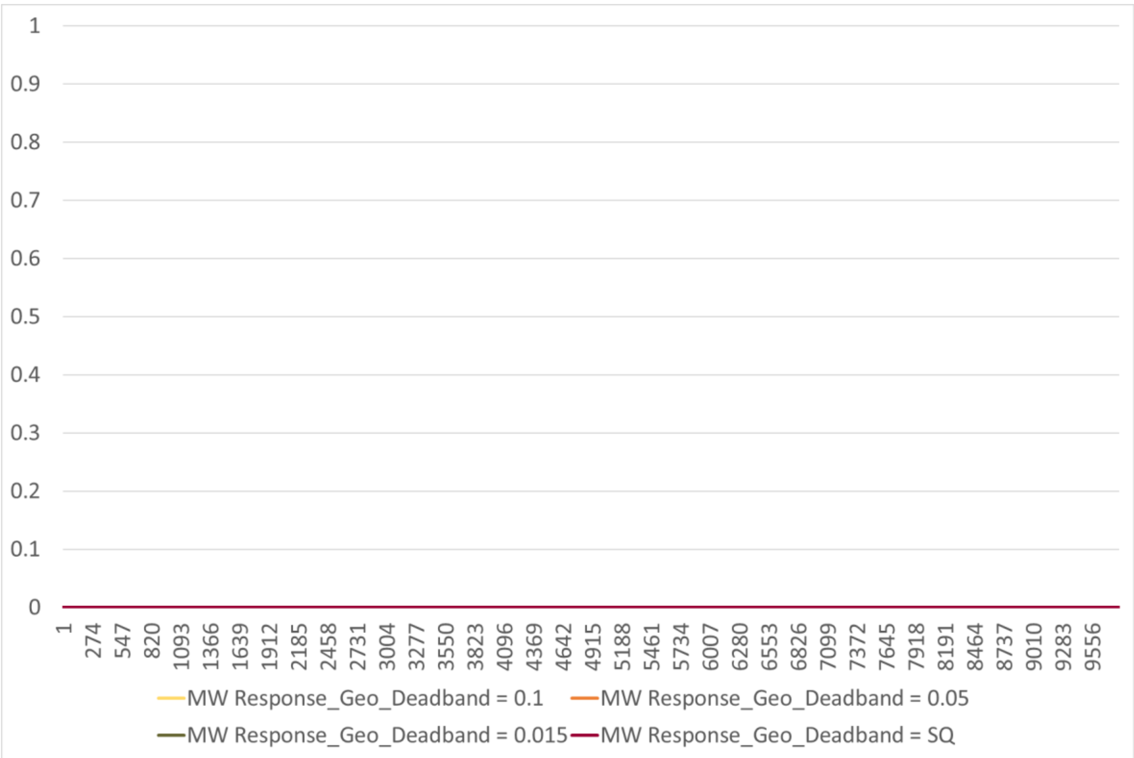

Figure 0-31: Study case 3, MW Response over time (no response observed)

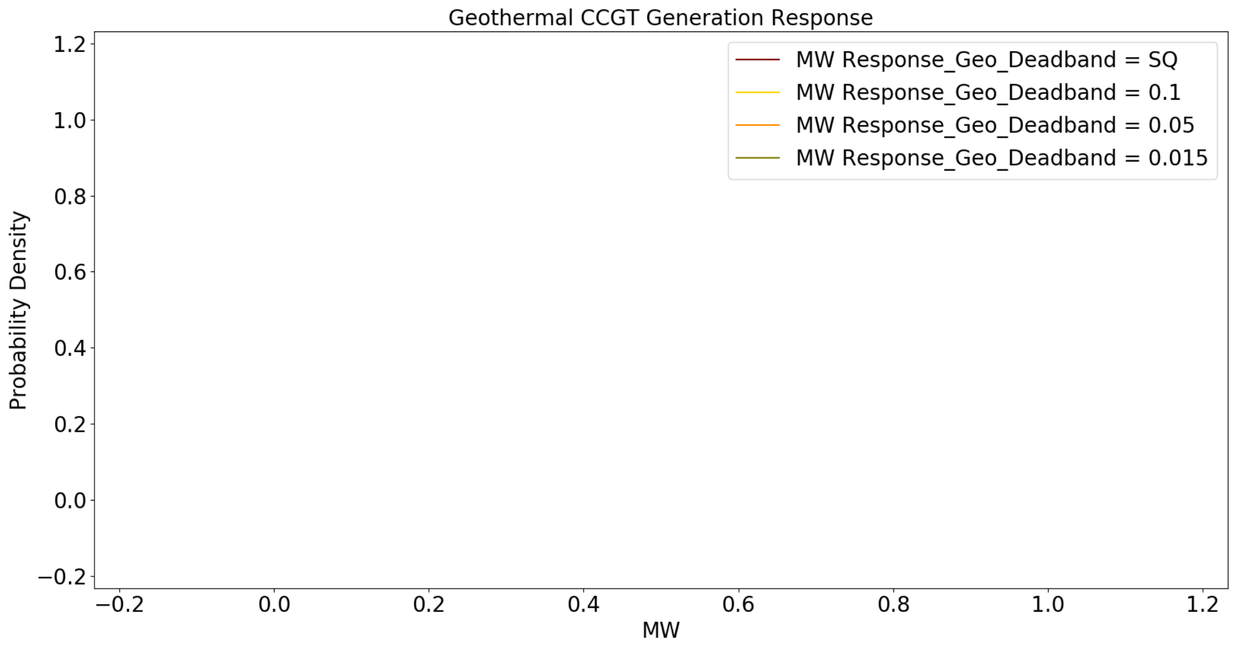

Figure 0-32: Study case 3, Normal Distribution for the MW response (no response observed)

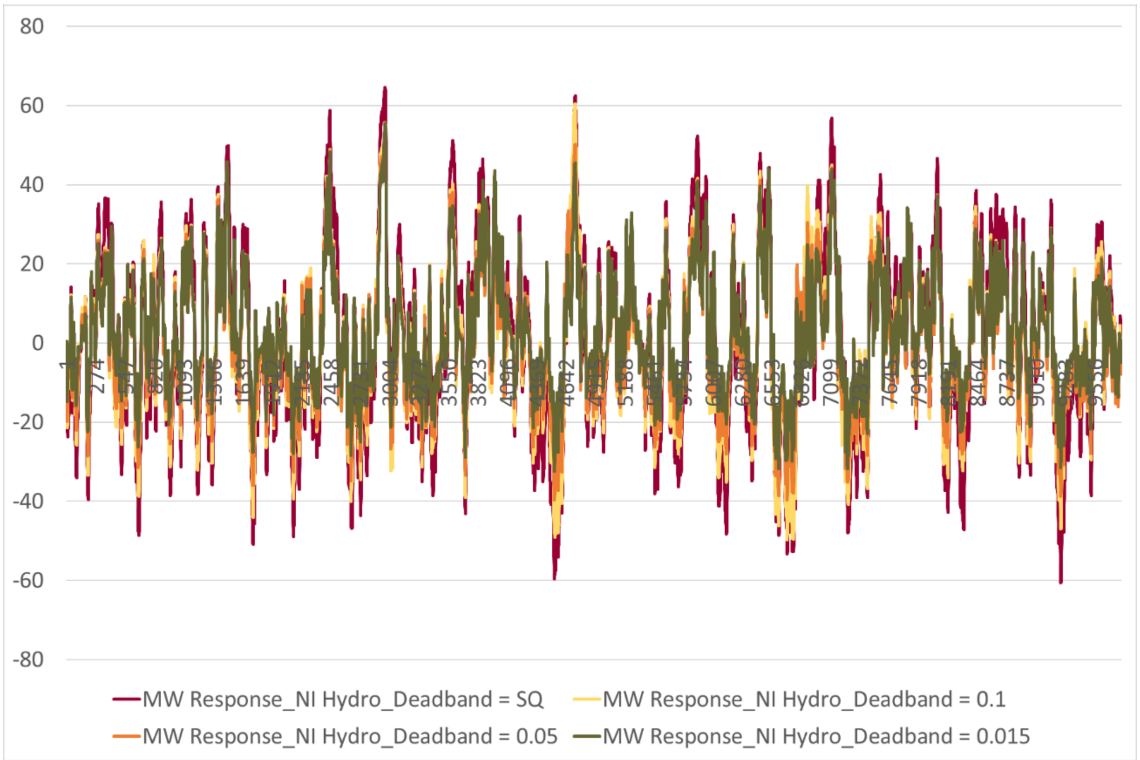

Figure 0-33: Study case 3, MW Response over time

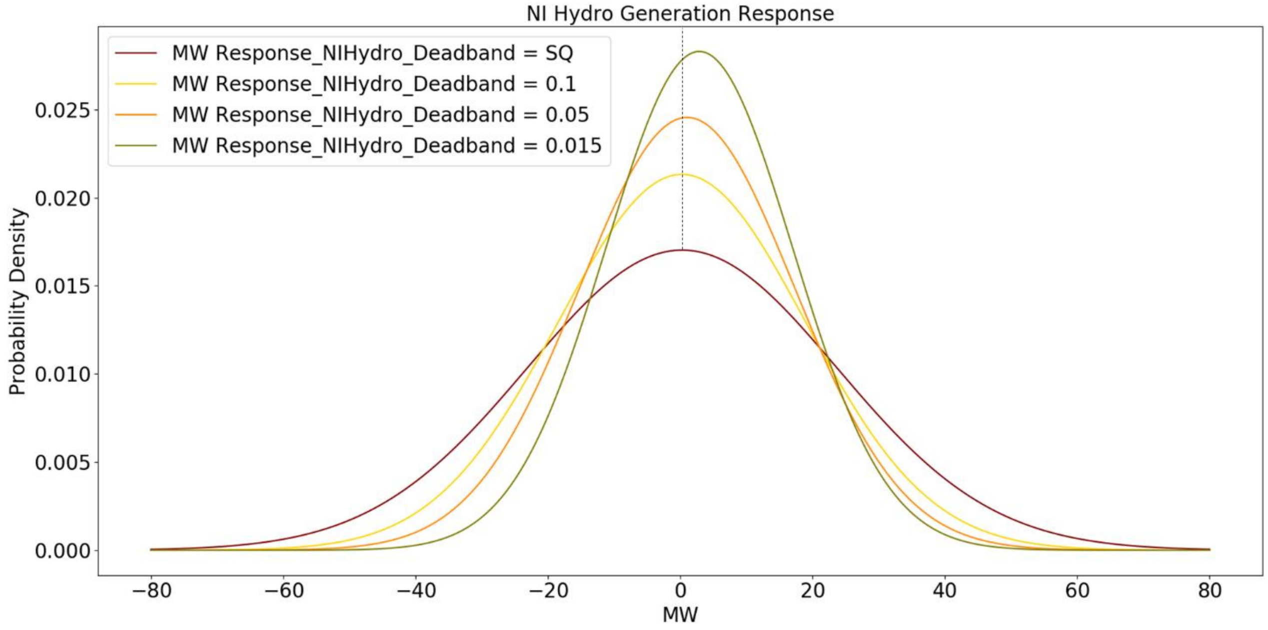

Figure 0-34: Study case 3, Normal Distribution for the MW response

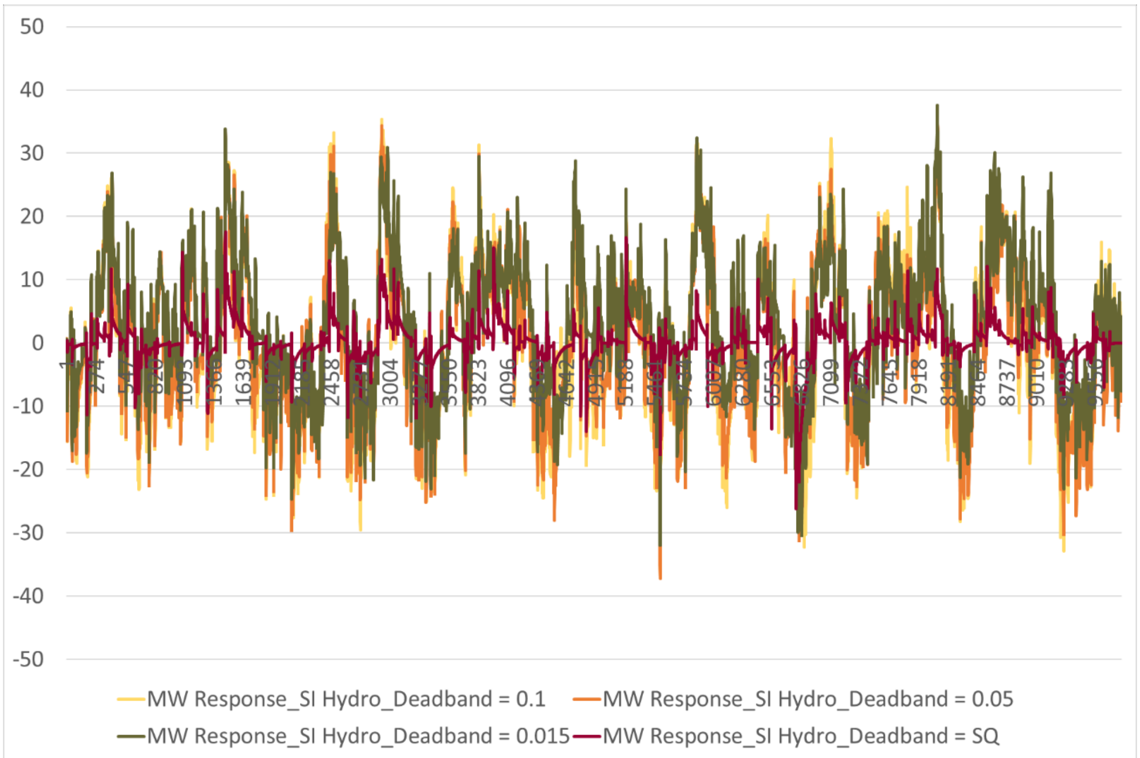

Figure 0-35: Study case 3, MW Response over time

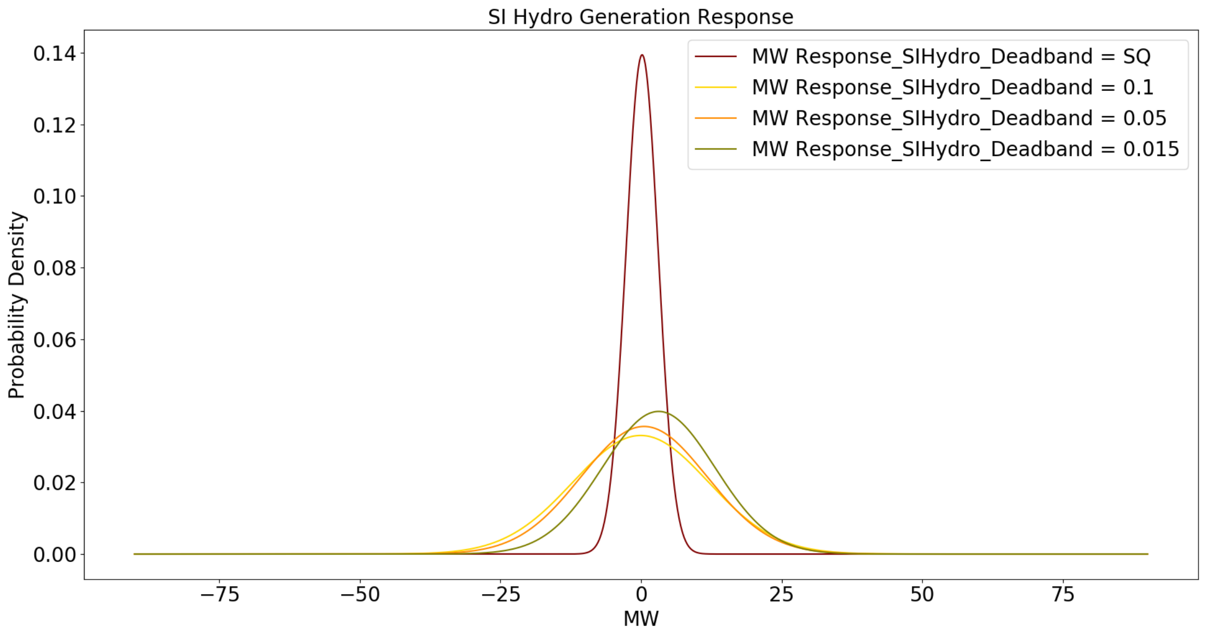

Figure 0-36: Study case 3, Normal Distribution for the MW response

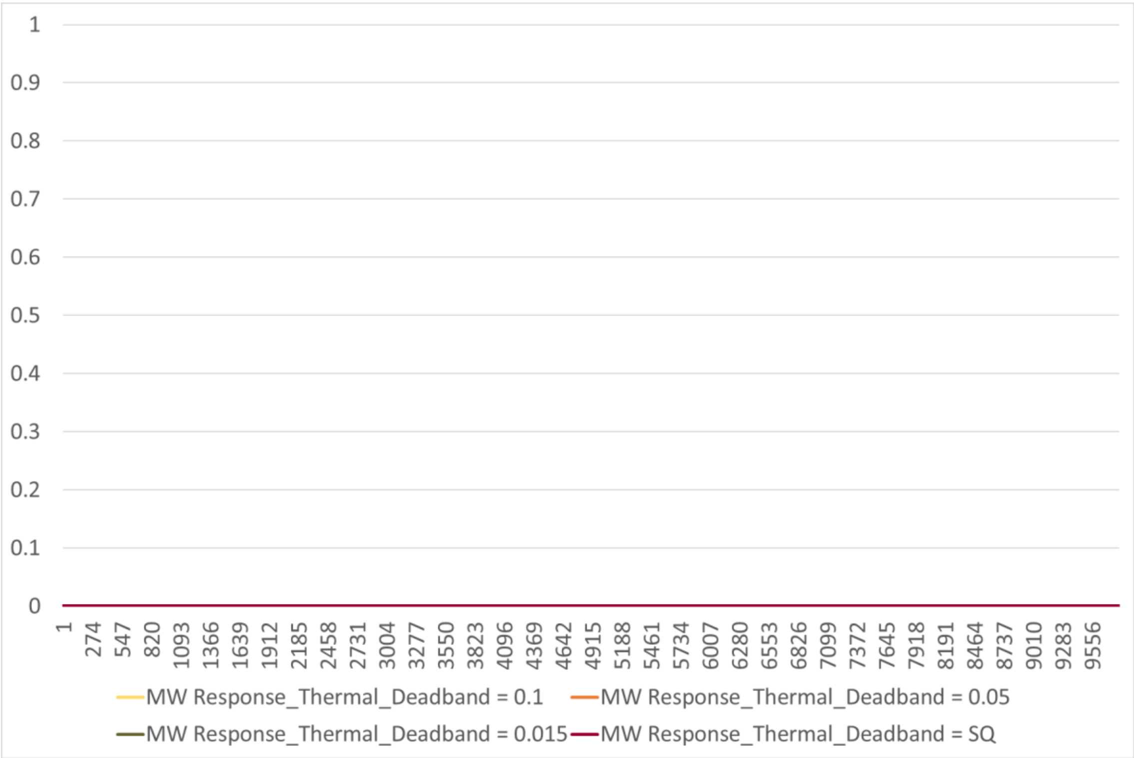

Figure 0-37: Study case 3, MW Response over time (no response observed)

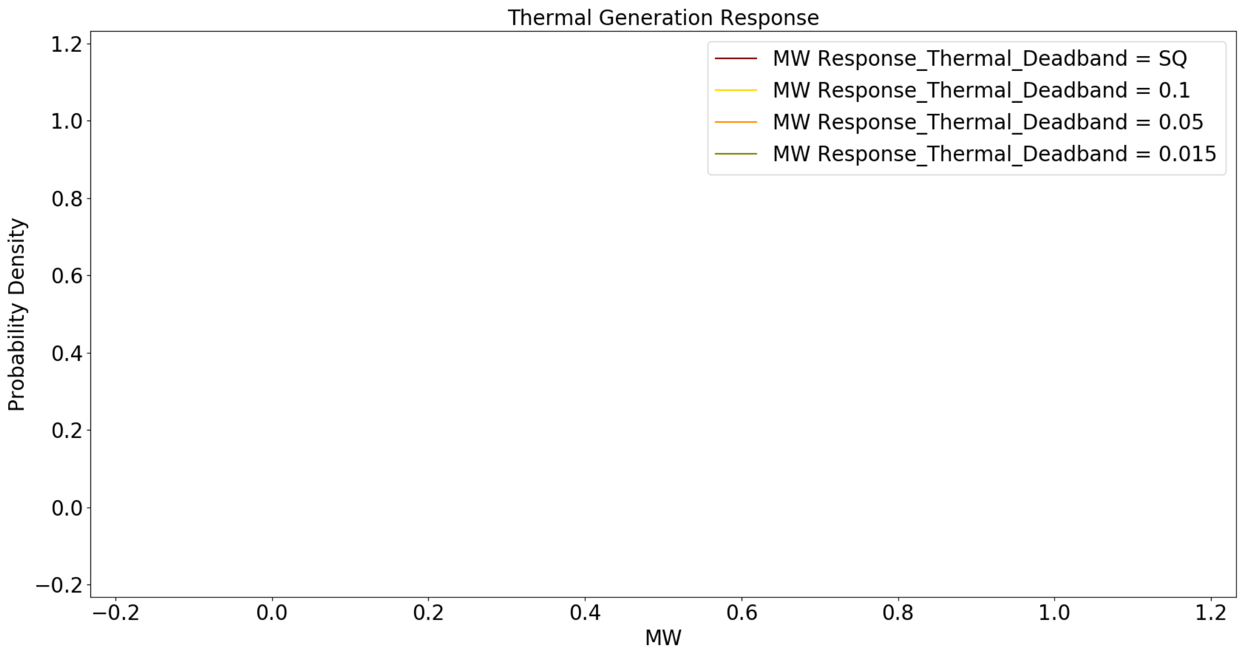

Figure 0-38: Study case 3, Normal Distribution for the MW response (no response observed)

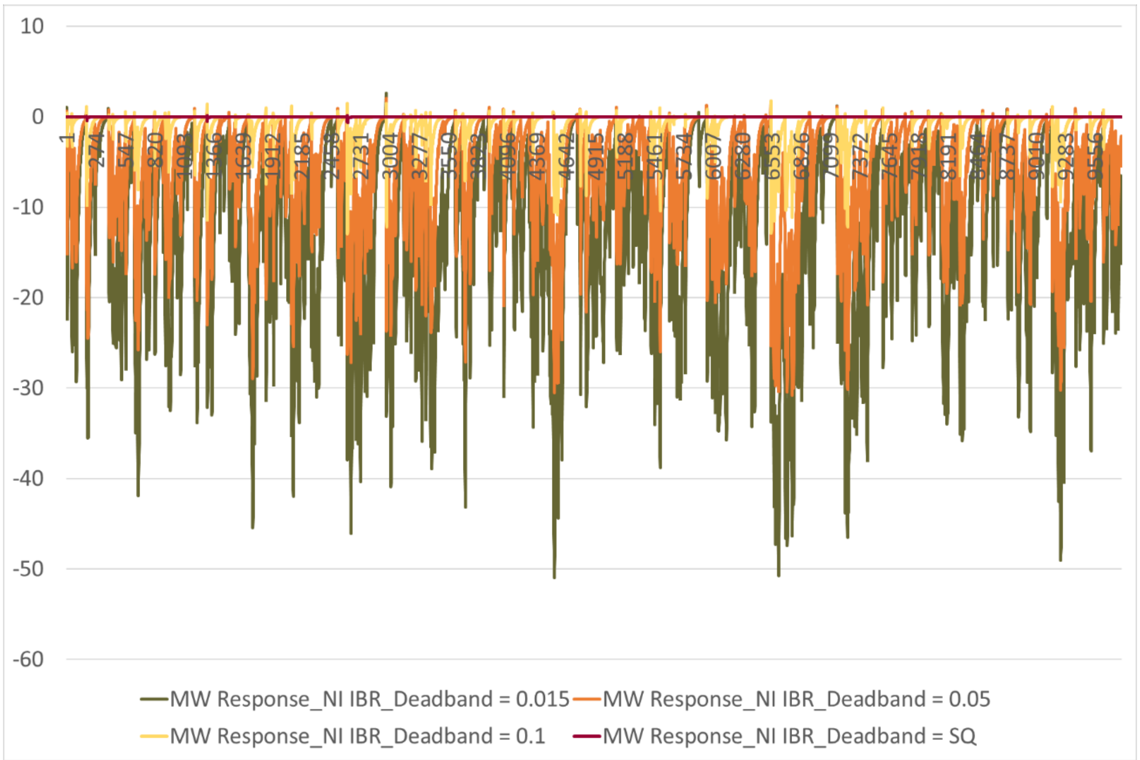

Figure 0-39: Study case 3, MW Response over time

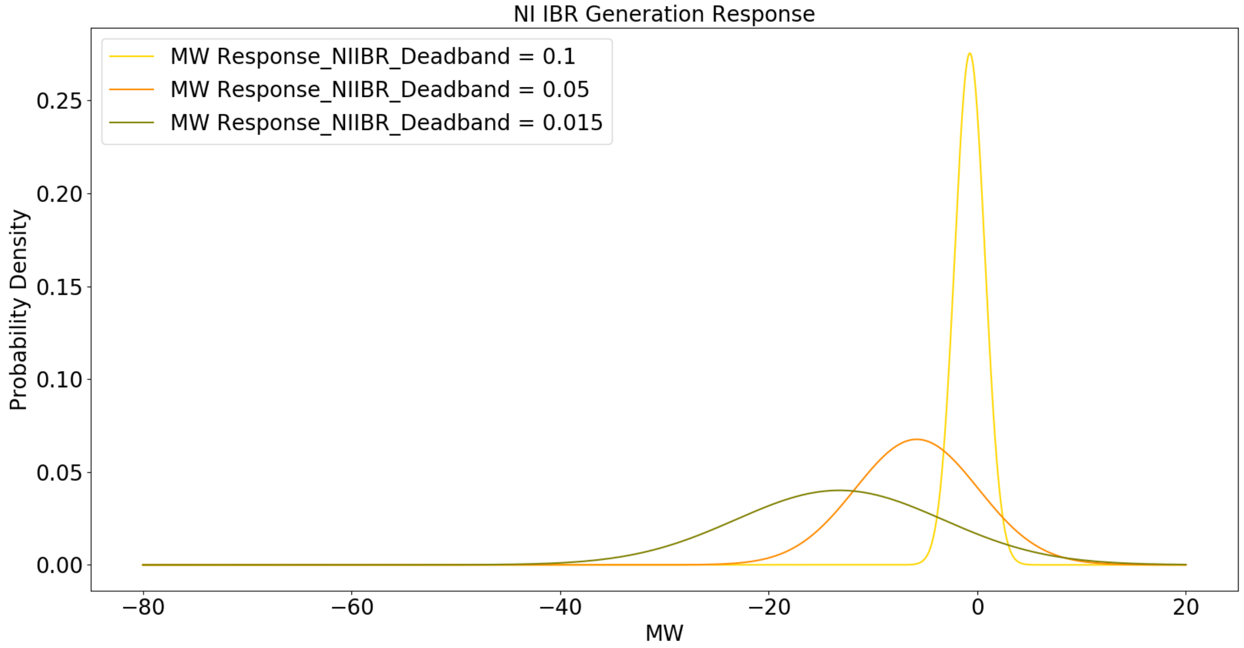

Figure 0-40: Study case 3, Normal Distribution for the MW response

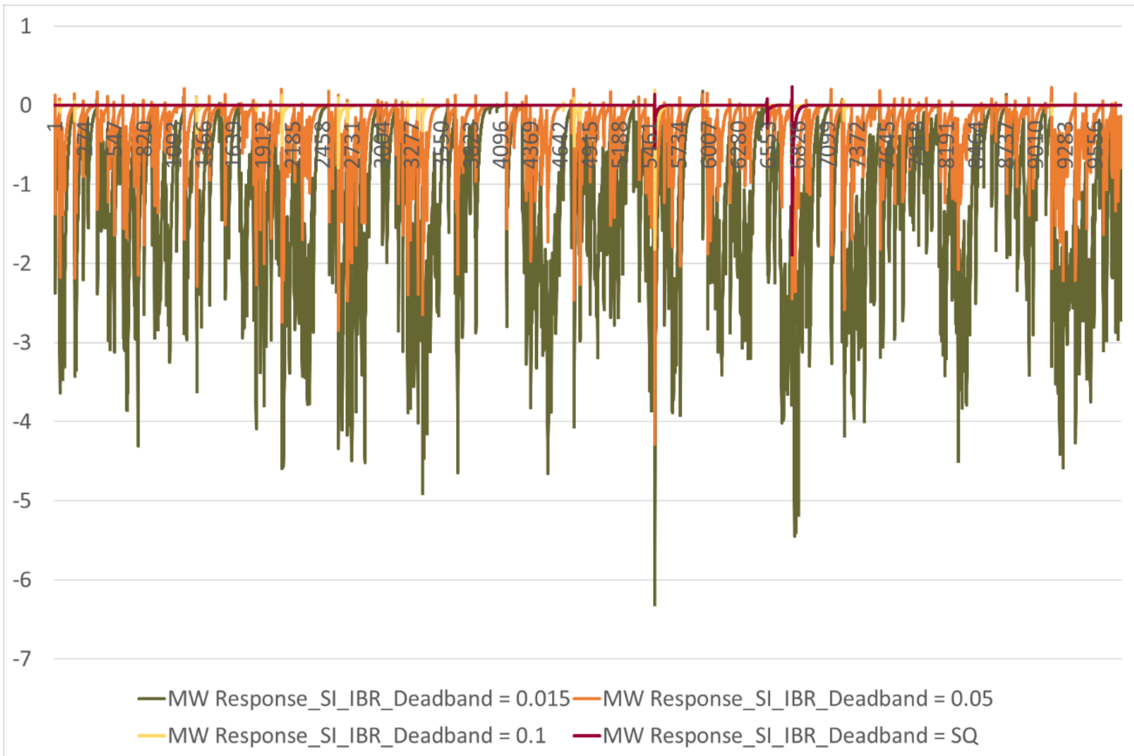

Figure 0-41: Study case 3, MW Response over time

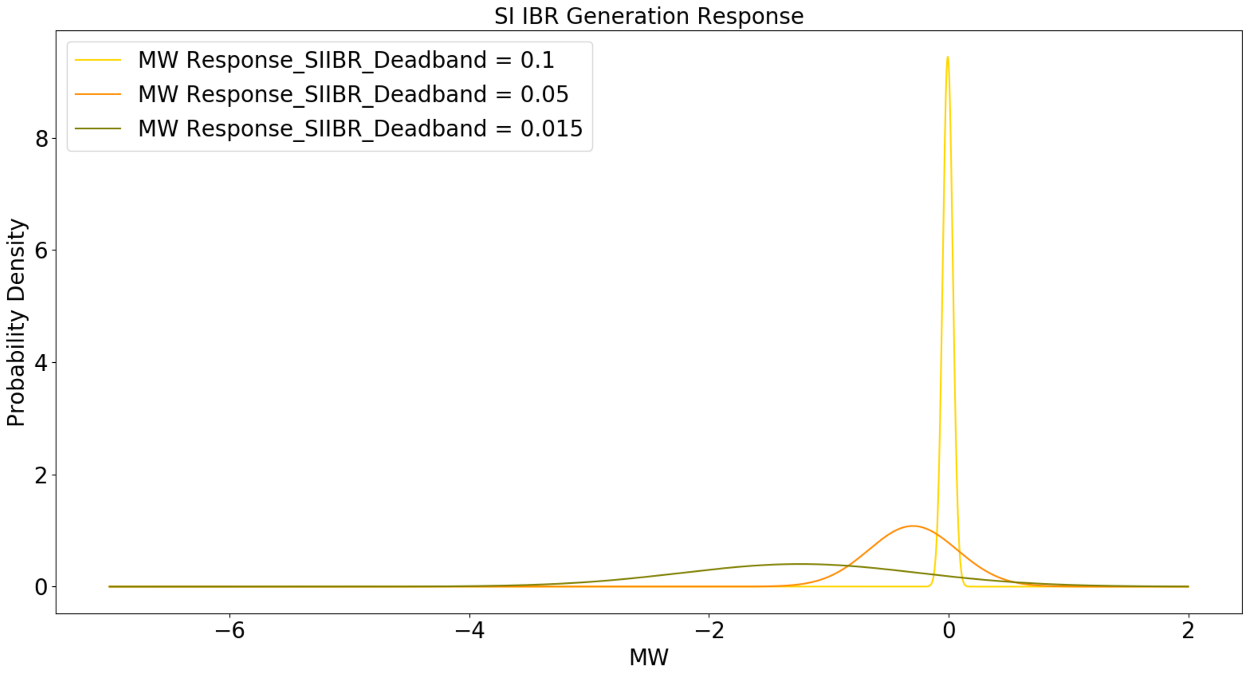

Figure 0-42: Study case 3, Normal Distribution for the MW response

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