TRANSPOWER

FSR Indicators: Minimum System Inertia Study

This document presents the results of system operator studies to determine the minimum system inertia threshold for frequency stability in the New Zealand Power System.

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1 Executive Summary

This report presents the findings of frequency studies conducted by the system operator to determine a minimum inertia threshold for the New Zealand Power System (NZPS). The motivation for this work stems from the ongoing decline in system inertia driven by the increasing penetration of inverter-based resources (IBRs) offsetting traditional synchronous generating units. Inertia is diminishing with the retirement of many large rotating machines that store the kinetic energy providing that inertia. This reduces the system's ability to withstand rapid frequency changes, heightening the risk of frequency excursions unless mitigated by frequency management strategies.

System operators worldwide face a similar challenge. AEMO (Australia), ENTSO-E (Continental Europe), EirGrid (Ireland) and ERCOT (Texas, USA) have implemented minimum-inertia requirements or placed constraints on generator outputs to uphold frequency-stability standards. These international precedents underscore the importance of proactive inertia management as part of a comprehensive frequency-control strategy.

In New Zealand, compliance with the Electricity Industry Participation Code (the Code) Clause 7.2A obliges the system operator to maintain frequency within defined secure limits. As inertia levels fall, meeting these statutory requirements will become increasingly difficult under existing reserve-procurement arrangements. The system operator will require supplementary actions to ensure ongoing system security.

In its February 2024 Future Security and Resilience (FSR) consultation, the Electricity Authority (the Authority) identified "managing reduced system inertia" as a key initiative to be finalised by 2029. Planned actions include the development of a low-inertia frequency-reserve strategy, the inclusion of the formal definition of inertia into the Code, the integration of emerging reserve types into procurement and testing frameworks, and the enhancement of operational procedures and analytical tools. A suite of monitoring indicators—tracking inertia from February 2022 through August 2024—has already been established to measure progress.

Key findings of this study include the identification of a critical inflection point between 10,000 MW·s and 15,000 MW·s, beyond which significantly more Instantaneous Reserve (IR) is required to arrest frequency decline after a contingency. Because Battery Energy Storage System (BESS) can respond more rapidly than synchronous machines, a higher inflection point is observed in cases where IR is sourced from BESS. Based on this analysis, the system operator proposes a conservative **minimum system-wide inertia floor of 15,000 MW·s** to preserve frequency stability **for the combined NZPS**. Thresholds are also proposed for each island: **9,000 MW·s for the North Island** and **5,000 MW·s for the South Island**.

In 2024, the recorded minimum inertia levels were 9,109.3 MW·s (North Island) and 4,654.63 MW·s (South Island), indicating that the latter has already breached its minimum threshold, with the former nearing its critical limit. There were only six days in that year when the North Island inertia levels fell below 10,000 MW·s, all occurring during summer and spring under conditions of low load and high wind generation. In the South Island, the inertia threshold was breached on two occasions, both during overnight trough load periods.

In response to these findings, this report recommends the prompt and thorough investigation of mitigations to prevent potential frequency instability in the future under low inertia conditions.

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2 Introduction

As part of the FSR programme, the Authority published a consultation paper titled *The future operation of New Zealand's power system* in February 2024. The paper identifies six key drivers of anticipated changes in New Zealand's power system (NZPS):

- **Generation technology**
- Consumer technology
- Operational technology
- Information technology
- Climate change and extreme weather events
- Electrification of the energy system

The changes in generation technology include the offsetting of synchronous generating units by inverter-based resources (IBR) connected to the grid and/or distribution networks. As this transition happens, system inertia, an inherent characteristic of synchronous machines, is expected to decline. The decline reduces the power system's ability to resist changes in frequency, making it more susceptible to frequency fluctuations. Consequently, without adequate frequency management strategies, the power system may face challenges in maintaining frequency stability.

In the FSR roadmap [1], the Authority identifies 'managing reducing system inertia' as an opportunity/challenge for the NZPS. This involves the following activities:

1) **Creating a frequency reserve strategy to manage low inertia**
2) Defining inertia in the Code and ensuring market systems can accommodate new reserve types
3) Incorporating new reserve types in the Procurement Plan and testing methodology
4) Updating operational procedures and tools.

The Authority projects that this initiative will be complete by 2029. To this end, it has established a set of indicators[1] to monitor evolving opportunities and challenges, including current inertia levels as in Figure 2-1.

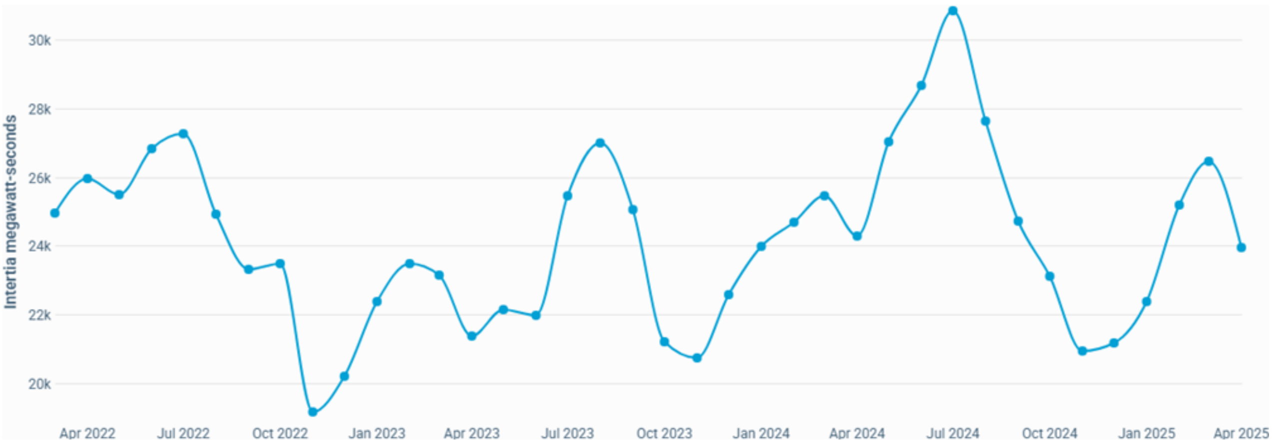

Figure 2-1: Monitoring of NZPS Monthly Average System Inertia Levels from April 2022–April 2025.

The Authority has engaged the system operator to conduct frequency studies to identify the **minimum system inertia threshold**. This threshold will guide inertia monitoring and support the Authority's development of a frequency reserve strategy to address low inertia conditions.

This report, detailing the study requirements and the system operator's findings, is organised as follows:

[1] Future security and resilience indicators | Tableau Public

- Section 3 presents key inertia concepts and a brief of how under frequency events are managed on the NZPS;
- Section 4 presents the study's objectives and the assessment criteria used to determine the minimum inertia threshold;
- Section 5 provides the modelling and tools used, assumptions, methodology and results for each of the studies in this work; and
- Section 6 presents conclusions gathered and recommends mitigation strategies to manage low system inertia scenarios.
- Section 7 to 9 provide additional results and supplementary information to this work.

3 Background

System inertia refers to "the energy stored in the rotating components of generators, motors and other industrial plant as they rotate at a speed that is synchronised to the power system's electrical frequency." [2]

In traditional power systems where the generation mix primarily consists of synchronous generating units, system inertia is provided by the inherent physical characteristics of these rotating machines. Immediately after a loss of large generation/load, the rotating components of these machines initially resist the change in system frequency. The kinetic energy stored in the rotating machines compensates for the power imbalance by supplying additional power to the grid. The reduction in kinetic energy appears as the reduction in the angular velocity of the machine. Since the machines are directly coupled to the grid, this change in angular velocity is reflected in the grid frequency.

The change in the machine's rotor angle with respect to the power imbalance is represented in the linearised swing equation:

$$\frac{2H}{\omega_s}\frac{d^2\delta}{dt^2} = P_m - P_e \tag{1}$$

where H is the inertia constant, ω_s is the rated synchronous speed, δ is the rotor angle and P_m and P_e are the mechanical and electrical power (assuming load damping to be 0). The inertia constant, H, is a fixed value that describes how long the machine could inject energy at its rated electrical output, solely with its stored rotational kinetic energy when initially spinning at nominal speed.

Inertia constants for synchronous machines are typically in the range of 2-8 seconds, with hydro machines having the lowest inertia, and gas machines having the highest per unit of capacity. Hence, the combination of inertia constant and total capacity of online generators determines the total system inertia provided by the generators. Other machines such as synchronous condensers are also capable of providing an inertial response, especially with the addition of a flywheel.

Another factor which contributes to system frequency response and inertia is load contribution. This could be from motors contributing inertia or load disconnecting due to low frequencies. However, for this study, the equation in (1) assumes the load damping coefficient to be 0 i.e. no response of load to the changes in frequency. This is because the inherent and uncontrolled response of load contributes a relatively small increase in how long the system has to respond to a frequency deviation.

Contingency and grid size also contribute to the overall frequency response in an event. Inertia is proportional to grid size, hence the same contingency would have a lower frequency deviation impact on a larger grid than a smaller grid. Contingency size also correlates to rate of change of frequency (RoCoF), also known as $\frac{df}{dt}$, assuming all other factors remain constant. From the time derivative of frequency deviation in (1), the RoCoF for a power system, expressed in Hz/s is then:

$$\frac{df}{dt}\,(RoCoF) = \frac{f_0}{2H_{sys}}\,\Delta P_{sys} \tag{2}$$

where f_0 is the frequency at the time of disturbance, H_{sys} is the system inertia constant (seconds), and ΔP_{sys} represents the power change.

It is worth noting here that when frequency analysis is conducted in power systems simulations, the frequency measurement typically involves analysing the rate of change of the bus voltage angle. At the instant of a contingency tripping, this rate of change becomes negatively infinite due to the supply-demand imbalance. Although this abrupt change may not be visible on the frequency trace within TSAT due to filtering applied to the numerical derivative of the bus voltage angle, a slight negative spike in the frequency measurement does occur at that instant. This brief but sharp fluctuation in frequency can lead to inaccurate RoCoF readings. Therefore, to achieve accurate and reliable measurement, a rolling average window of 500 milliseconds from the time of disturbance is usually selected to calculate the RoCoF [3].

When considering total system inertia, Figure 3-1 portrays the evolution of frequency following a power imbalance occurring at 0 seconds. At time 0^+, the sum of the inertial response of the generators, hence the system, attempts to slow down this decline until the frequency is out of the deadband of the turbine governor, when the primary frequency control is triggered[2]. For this initial response, the larger the system inertia, the more stored kinetic energy is converted to electrical energy, and thus the smaller the RoCoF is at this stage. The inertial response overlapped with primary frequency response arrests the system frequency at its minimum. This then starts to recover as more energy is injected into the system once the secondary and tertiary frequency controls respond.

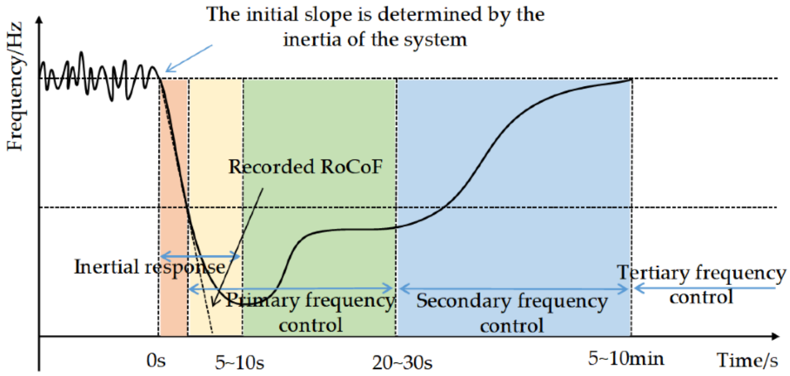

Figure 3-1: Typical Frequency and Frequency Control Timelines upon a Sudden power imbalance [4].

With the drive to promote renewable energy in the generation mix, higher penetration of IBR generation means the total system inertia is decreasing. The generation-demand imbalance then leads to higher frequency deviations, hence a higher RoCoF or a lower minimum frequency (nadir).

Inertia can influence power system characteristics that are not directly related to frequency and RoCoF. One such example is the impact of inertia on rotor angle stability, whereby clusters of synchronous generating units may swing against each other following (small or large) disturbances. An increase in the RoCoF can also result in premature tripping of other generation, leading to cascade failures and premature protection operation. Such contingencies can be prevented by ensuring that the inherent behaviour of synchronous generating units contributing to overall system performance is maintained.

Internationally, several jurisdictions have reported power system events where low system inertia played a critical role. One notable example is the 2016 black system event in South Australia [5]. The incident was exacerbated by a low level of dispatched synchronous generation, which resulted in reduced system inertia and a high RoCoF that exceeded the underfrequency load shedding protection threshold.

To safeguard inertia, different jurisdictions have introduced various solutions. Australia's AEMO has set region-specific minimum inertia thresholds to ensure each region retains sufficient frequency-control capability to operate securely—and, if required, in islanded mode [6]. In Ireland, EirGrid and SONI employ the System Non-Synchronous Penetration (SNSP) limit and the Minimum Number of Conventional Units Online (MUON) requirement to uphold adequate rotational inertia [7]. CAISO, California's ISO, employs a similar constraint called Minimum Online Commitment (MOC) to provide minimum inertia[3].

[2] This could also include Interruptible load as a primary frequency response.
[3] Establishing System Operating Limits for the Operations Horizon

3.1.1 Inertia in the New Zealand Power System

New Zealand operates as a stand-alone power system with no interconnection to other countries, meaning frequency management must be handled entirely within the New Zealand grid. However, the HVDC link between the North and South Islands enables frequency support to be shared across the main islands.

For the NZPS, in the North Island, inertia values range between **9 109.3 MW·s** and **25 743.39 MW·s**, while the South Island exhibits a range from **4 654.63 MW·s** to **11 694.1 MW·s**. When combined, the total system inertia spans from **13 763.93 MW·s** to **37 437.49 MW·s**, as plotted in Figure 3-2 for 2024. The average trend of monthly inertia values is shown in Figure 2-1.

It is important to note that low inertia in the South Island does not necessarily coincide with low inertia in the North Island; one island can experience higher inertia while the other is low, depending on the generation mix present in each island at a given time.

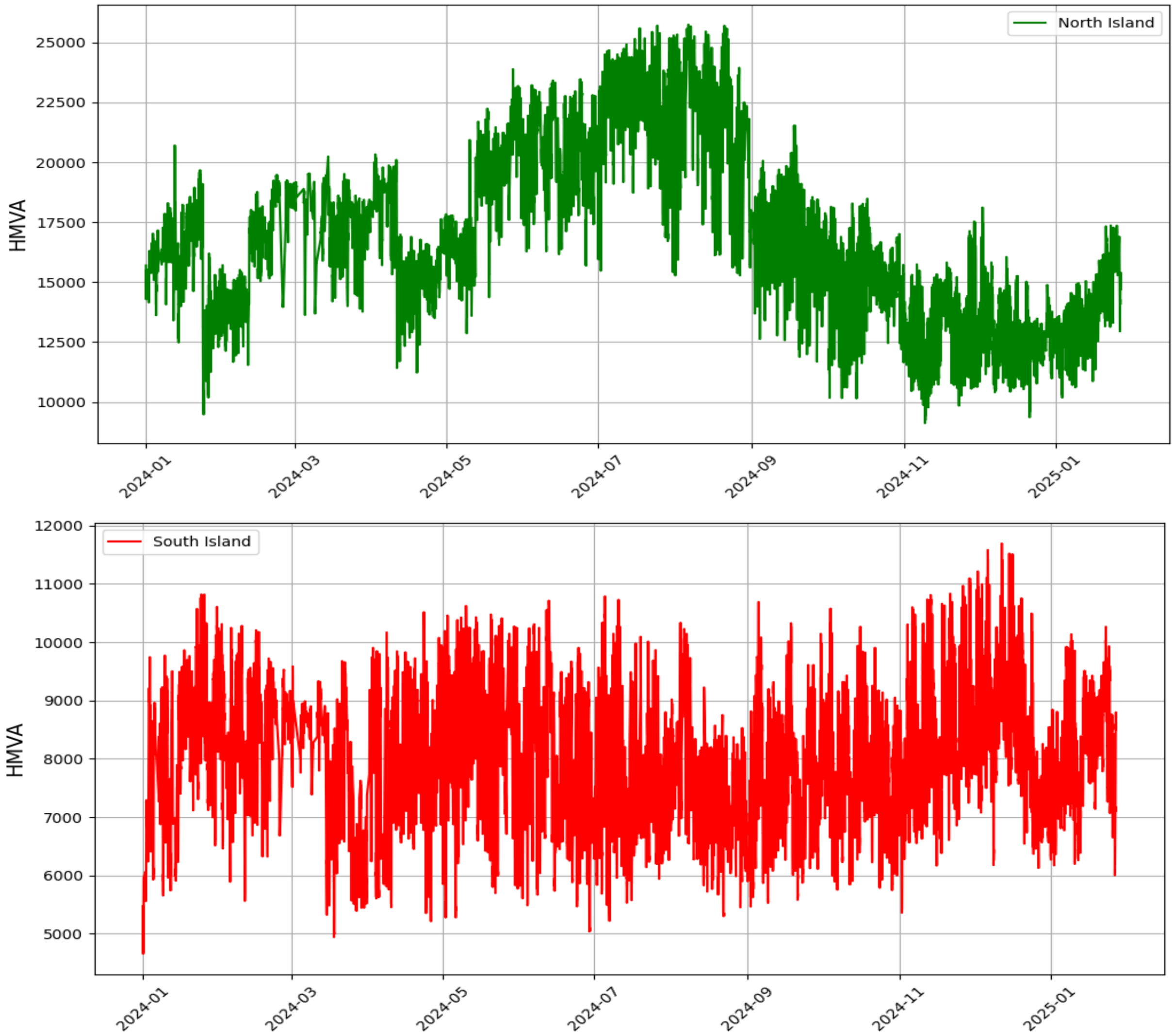

Figure 3-2: Island-based Inertia Levels Between January 2024 and January 2025

The wider distribution of inertia values, as shown by the box and whisker plot in Figure 3-3, reflects the differing generation profiles—most hydro generation is located in the South Island, contributing to more stable inertia levels, while the North Island has a higher proportion of IBRs, leading to greater inertia variability.

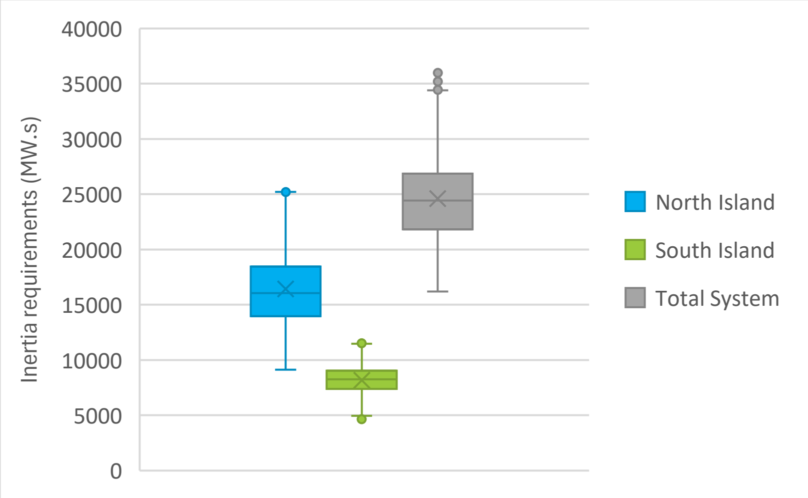

Figure 3-3: Box and Whiskers Plot Showing Distribution of Inertia on each Island and for NZPS Combined (2024)

The Code outlines specific frequency management obligations for the system operator in Clause 7.2A, requiring the management of frequency and the prevention of cascade failures due to frequency excursions or supply-demand imbalances. Additionally, asset owners must contribute the maximum possible injections to keep the frequency within the normal band, as specified in Clause 8.17.

To fulfil the system operator's obligations, several under-frequency management products are procured from the market. This includes fast (FIR) and sustained (SIR) instantaneous reserve (IR) and the Automatic Under-Frequency Load Shedding scheme (AUFLS).

FIR is the additional capacity provided by six seconds (for generation) or 1 second (for interruptible load (IL)) after a contingent event (CE) to stop frequency fall. FIR must be sustained for at least sixty seconds.

SIR is the average additional output (for generators) or the average drop in load (for IL) provided during the first 60 seconds after a CE. SIR is generally required to be sustained for 15 minutes or until instructed otherwise by the system operator.

AUFLS is in place for more severe power system events where frequency falls below a preset threshold to trigger the disconnection of electrical load. AUFLS has recently transitioned to a 4-block scheme; the system RoCoF is now included as a trigger for the fourth block. The performance design of this fourth block [8] is to "electrically disconnect 6% of the demand—

A. 15 seconds after the frequency reduces to, and remains at or below, 47.5 Hz;
B. within 0.3 seconds after the frequency reduces to, and remains at or below, 47.3 Hz; and
C. within 0.3 seconds after the frequency falls, and remains falling at *1.2 Hz/second, and the frequency is below 48.5Hz.*" (emphasis added)

With the IL frequency trigger at 49.2 Hz, the system inertial and instantaneous responses should be adequate to ensure that for contingent events, there is clear discrimination between IL and AUFLS Block 4 specifically.

The system operator employs the Reserve Management Tool (RMT) to ensure that adequate IR is procured for contingent events (subject to being the lowest cost solution) so that the frequency nadir remains above 48 Hz. RMT achieves this by determining the net-free reserves (NFR) required to maintain a secure power system. NFR values are then used to calculate the IR required to ensure the power system remains stable following an under-frequency event. NFR values for each island and risk class (16 combinations) represent system inertia. These NFR values, along with the corresponding IR requirement, are then evaluated iteratively through a combination of the RMT and Scheduling, Pricing and Dispatch application (SPD) tools.

So far, the representation of system inertia through the above tools has sufficed. However, with low system inertia predicted due to the transitioning energy system, the system operator views that the iterative RMT-SPD process needs to be re-evaluated.

4 Study Objectives

At present, there is no obligation on the system operator to procure alternative inertia services or provide an inertia market to maintain a minimum system inertia level. While the system operator can utilise IR to meet the obligations under Clause 7.2A (subject to offer availability), the decreasing proportion of synchronous generating units providing system inertia makes it increasingly challenging to fulfil this requirement.

The purpose of this study is to evaluate the inertia requirements for the NZPS, including the North Island Power System (NIPS) and South Island Power System (SIPS) separately and as a combined power system connected by HVDC.

The key objectives of this study are:

1. Determine the minimum inertia level for:
    a. the combined NZPS; and
    b. NIPS and SIPS individually.
2. Assess whether the above inertia level varies according to the source of IR—specifically synchronous generating units and BESS.

4.1 Assessment Criteria

This is the criteria used to determine the minimum level of inertia required for the power system to remain secure during a specified contingency event. A power system is considered secure post-contingency if it complies with Clause 7.2A(5), which requires system frequency to stay above 48 Hz.

There are three studies proposed as part of this report's scope, each conducted with one of the following:

- Single machine mass model
- TSAT full network model
- RMTSAT full network model

Each study evaluates the amount of IR necessary to arrest frequency decline across a range of inertia levels. The analysis of results seeks to determine whether a inflection point exists—a critical threshold beyond which the IR requirement increases sharply to maintain the required frequency nadir.

This inflection point signifies the minimum inertia level below which the system can no longer support efficient and equitable reserve procurement, indicating a transition from requiring more IR to more inertia.

5 Study Details

This section first outlines the assumptions, tools, and models involved in each of the studies conducted to determine the inertia threshold, followed by a discussion of the corresponding results. Although the frequency stability assessment is a fundamental aspect of power system studies, the system operator has not yet carried out dedicated investigations to determine minimum inertia requirements. As a result, certain assumptions are necessary to guide and streamline the scope of the study. These assumptions help focus the analysis, since it is impossible to capture all system conditions.

While study-specific assumptions are detailed in their respective sections, these are overarching assumptions applied across all studies:

- To facilitate comparison across scenarios with different contingency sizes, results are normalised using an IR:CE ratio, defined as the IR divided by the MW loss of the CE.
- The inertia values specified in this study are observed post-contingency.
- RoCoF is presented in negative values due to the frequency decline from 50 Hz. However, the RoCoF is increasing in absolute value; the more negative, the faster the RoCoF.

5.1 Tools

Power flow and Short-circuit Analysis Tool™ (PSAT), developed by Powertech Lab of Canada, is the power flow tool that was used to create and modify network models in the frequency studies. For the simple mass model study, power flows extracted from the system operator's archive were simplified in PSAT to create a network representation. Afterwards, these were modified to represent the equivalent system inertia. For the full network study, the archived power flows were modified in PSAT as inertia levels were iterated through.

The frequency studies were then carried out in the Transient Security Assessment Tool™ (TSAT), which performs detailed time domain simulations of the power system in root mean square (RMS) quantities. The system operator currently uses TSAT to assess frequency and transient security in real-time operation, helping to ensure the power system can remain stable following credible contingencies. This was used to assess the frequency, voltages and power responses of the model as the selected CE was tripped.

Powertech's Reserve Management Transient Stability Analysis Tool (RMTSAT) was then used to verify the TSAT study results. RMTSAT is the offline tool that presents RMT results for power system studies. As mentioned in Section 3.1.1, RMT is utilised by the system operator to consider system inertia represented through NFR values. It is worth noting that NFR values are very sensitive to system load and dispatched generation that are in SPD real-time schedules, so any significant change to these input conditions can change the NFR significantly. This then changes the IR dispatched in the following solution.

While best efforts were taken to manipulate power flows to match the selected cases and inertia level, then assess the amount of FIR required for each case, the system operator cannot presently replicate the iterative process between SPD-RMT-SPD in all offline study tools.

5.2 Single Mass Model (SMM) Study

In the first study, a single-mass model was used to conduct a quick assessment of frequency stability across different scenarios. The SMM, as shown in Figure 5-1, represents multiple generating units with varying inertia as a single generating unit with equivalent inertia. The model also included an aggregated IBR block. Considering the relationship between real power, frequency and inertia, the SMM effectively solves the energy balance of the power system over time. The SMM is based on the swing equation of the power system and iteratively solves a set of equations to model the behaviour of the system.

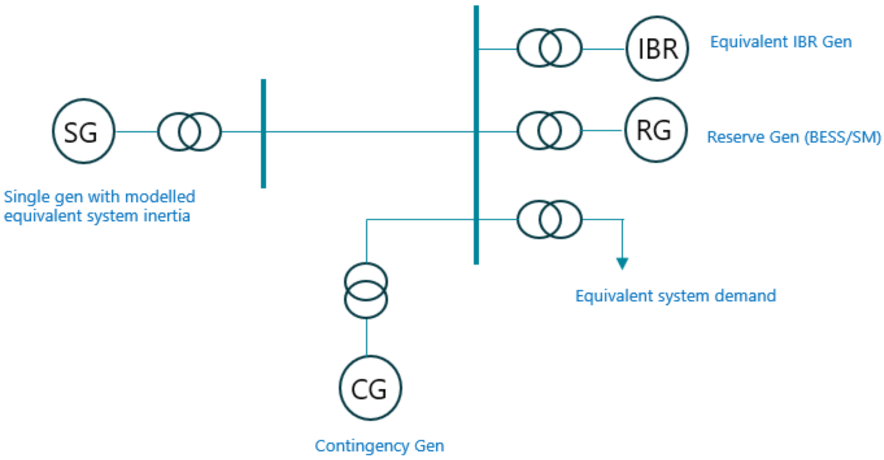

Figure 5-1: SMM Model Representation

The system operator selected online cases to capture different system conditions, as shown in Table 5-1. The systematic scaling of aggregate inertia then produced additional study variants by adjusting the rating of the equivalent generator (SG) and the dispatched output of the aggregated IBR block.

Table 5-1: Details of the Online Cases Used in this Study

Case No	Case Description	System Conditions				
		Inertia (MW.s)[4]	Demand (MW)	ACCE (MW)	IL (MW)	IR:CE[5]
1	Summer trough	20 155	3 098	144	0	1.35
2	Winter peak	32 000	6 455	270	128	0.88
3	Low IBR penetration	28 100	5 059	214	0	1.038
4	High IBR penetration	24 700	4 919	345	94	1.06
5	Under-frequency event	27 900	5 121	217	0	1.01

5.2.1 Dynamic Models

All the synchronous generating units and reactive power compensation devices used in the SMM studies were modelled using generic models obtained from the standard library in TSAT. The same generic governor model is used in scenarios where IR is supplied by a synchronous generating unit. An example of the response observed in this study is in Figure 5-2.

[4] Rounded to the nearest 100s

[5] The IR:CE represents the factor by which the IR must be increased, relative to the CE, to arrest the frequency and restore it to its normal band as per the Code requirements.

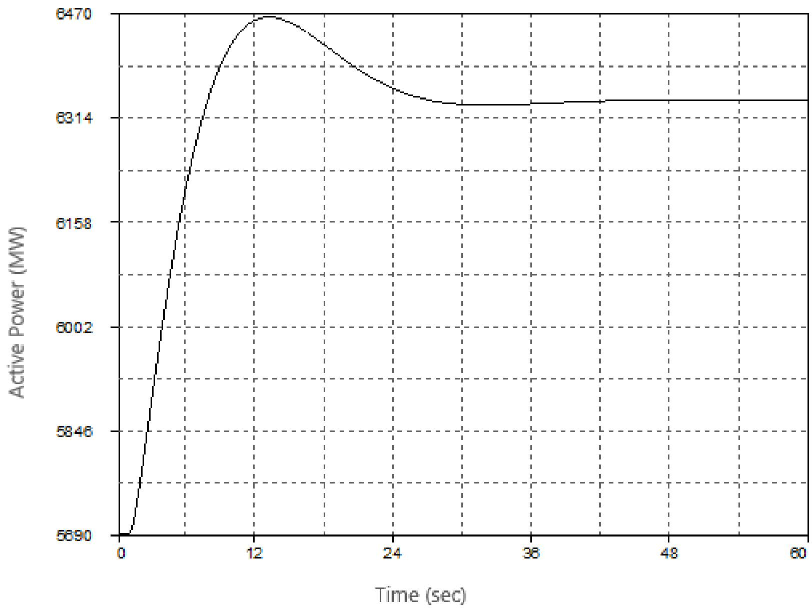

Figure 5-2: Typical SG Active Power Response, Post-CE Tripping at 1sec, for SMM Studies

For this study, we modelled the 'Equivalent IBR Gen' and the Reserve Gen (BESS) with generic renewable RMS dynamic models created by the Western Electricity Coordinating Council (WECC)[6]. The IBR generation was dispatched to the maximum available power, meaning there was no headroom for underfrequency support as is currently seen on the actual power system.

The study did not fully utilise the voltage response of the models. However, reasonable actions were taken to appropriately model the reactive power capability defined in Clause 8.23 of the Code (+50 percent and -33 percent reactive power capability). The high-level control block diagram is shown in Figure 5-3. The detailed generator/converter model, electrical controller model and the plant controller model are REGC_B, REEC_D and REPC_A respectively.

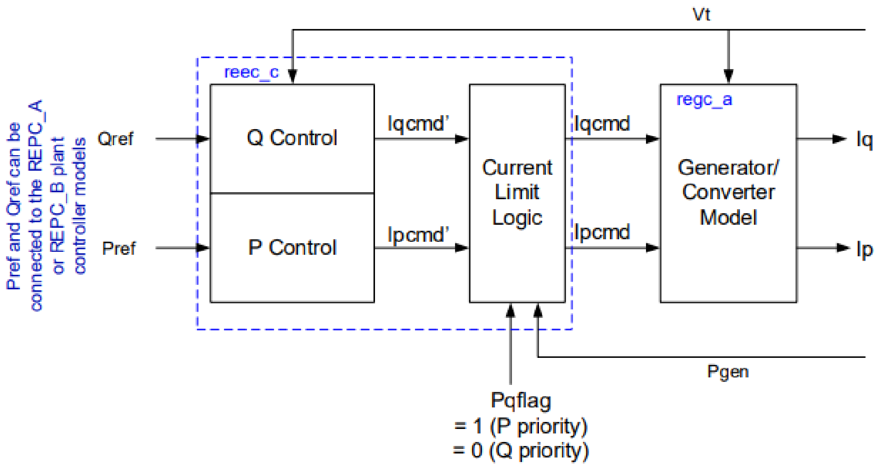

Figure 5-3: Block Diagram for IBR and BESS Dynamic Models[7]

[6] https://www.esig.energy/wiki-main-page/generic-models-wpps/

[7] Image extracted from Model User Guide for Generic Renewable Energy System Models (epri.com)

5.2.2 Assumptions

- The SMM study covers the system inertia for both the NIPS and SIPS combined. This assumes that the HVDC poles are in operation and are modelled as an AC circuit. The HVDC's contribution to inertia is included in the equivalent inertia modelled.
- The contingency considered for these studies is the Alternating Current Contingent Event (ACCE) representing the largest AC risk.
- For an ACCE tripping, the frequency response in the North Island drops lower than in the South Island. This is due to the SIPS ACCE being lower than the NIPS ACCE, and the lower proportion of IBR present in the South Island. Hence, for a worst-case scenario study, only the NIPS ACCE and frequency response was considered.
- IL was modelled in the SMM to match the amount of IL tripped in the full network casefile, if applicable.
- The SMM equivalent inertia was modelled to get the same frequency response as the online cases. Consequently, the modelled system inertia is slightly higher than the actual system inertia. The supplementary inertia includes the contribution of other grid equipment such as motor loads and synchronous condensers.
- In both scenarios—whether the RG is modelled as a synchronous generating unit or a BESS—most of the frequency response is provided by the reserve generator. However, a portion of the response still comes from the generator SG, depending on the available headroom. This behaviour mirrors that of an actual power system, where online generators naturally contribute to frequency deviations regardless of whether they are explicitly dispatched to provide FIR.

5.2.3 Methodology

The system operator selected the scenarios in Table 5-1 to cover varied scenarios, including peak and trough load scenarios, high and low (1%) IBR penetration instances, and an under-frequency event from June 2024. The high-level methodology of this stage of the study was as follows:

1) Model the SMM to align with the frequency parameters observed in the selected online cases. The ACCE in the SMM was then modelled to capture the worst-case scenario i.e. maximum possible active power deviation.
2) Adjust system inertia iteratively by modifying the capacity of the SG and the IBR generator. Additionally, adjust the output of the reactive compensation devices to ensure that reactive limits were adhered to.
3) Model the reserve generator (RG) as a synchronous generating unit, introducing additional inertia into the system. Note: the additional inertia introduced by this generator ranged from 12.5 MW.s to 2500 MW.s for this study. Switch in the RG for iterations that do not meet the frequency obligations until they are satisfied.
4) For the selected CE, extract the following results for both islands:
   - bus frequency (Hz),
   - generator mechanical torque (MW) and
   - generator active power (MW) traces for both islands.
5) Model the RG as a BESS with a 0.4 p.u/sec ramp rate and droop setting of 4%. Note: these parameters were not varied in this study and contributed no additional inertia. Switch in the RG for iterations that do not meet the frequency obligations until they are satisfied.
6) Repeat to analyse all selected system scenarios and the outputs of all connected generators and frequency responses.

5.2.4 Results

For these study cases, the system inertia progressively reduced in steps down to 10% (labelled as 90% decrease in inertia) of the base case level.

Figure 5-4 shows an example of the frequency response for each iteration of the chosen scenarios. For the Low IG penetration case (Case 3) shown, the frequency was arrested above 48 Hz and returned to above 49.25 Hz within 60 seconds. A reserve generator (RG) was introduced at the '40% decrease' case and its output increased as inertia levels were lowered, as shown in Figure 5-5.

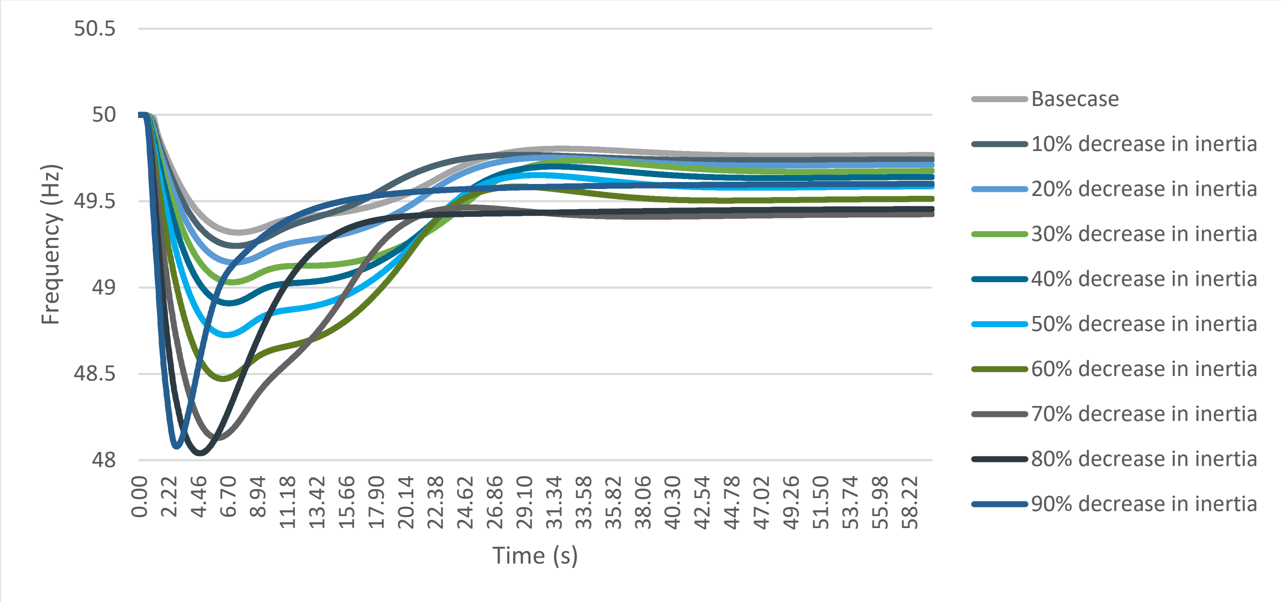

Figure 5-4: Frequency Response after CE Tripping at Reducing Inertia for SMM Case 3, with IR Provided by a Synchronous Generating Unit

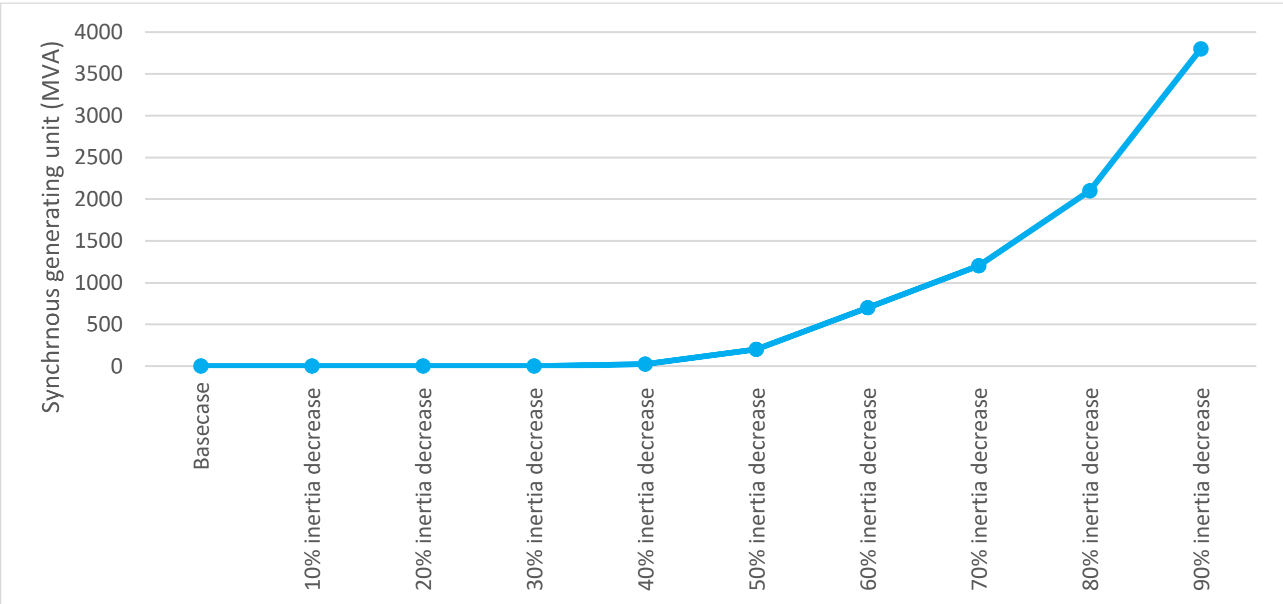

Figure 5-5: Size Variation of Reserve Generator in SMM as a Synchronous Generating Unit for SMM Case 3

As expected, with the reduction in inertia levels, the frequency nadir decreases and the RoCoF increases requiring the RG capacity to be increasing almost linearly. However, as the inertia is reduced to less than 70% of the base case, the size of the generating unit required to maintain frequency stability has to be increased exponentially. Due to this, the frequency restoration is faster and to higher levels than the previous iterations. The trend frequency response for '90% decrease in inertia' is evidence of this in Figure 5-4.

Figure 5-6 and Figure 5-7 below present results for the same scenario above, but with a BESS modelled in the SMM to provide the IR. Due to the BESS' faster response characteristics, the frequency nadir was higher with a lower RoCoF. However, for the '90% decrease' case, the BESS capacity had to be increased drastically to arrest the frequency above 48Hz.

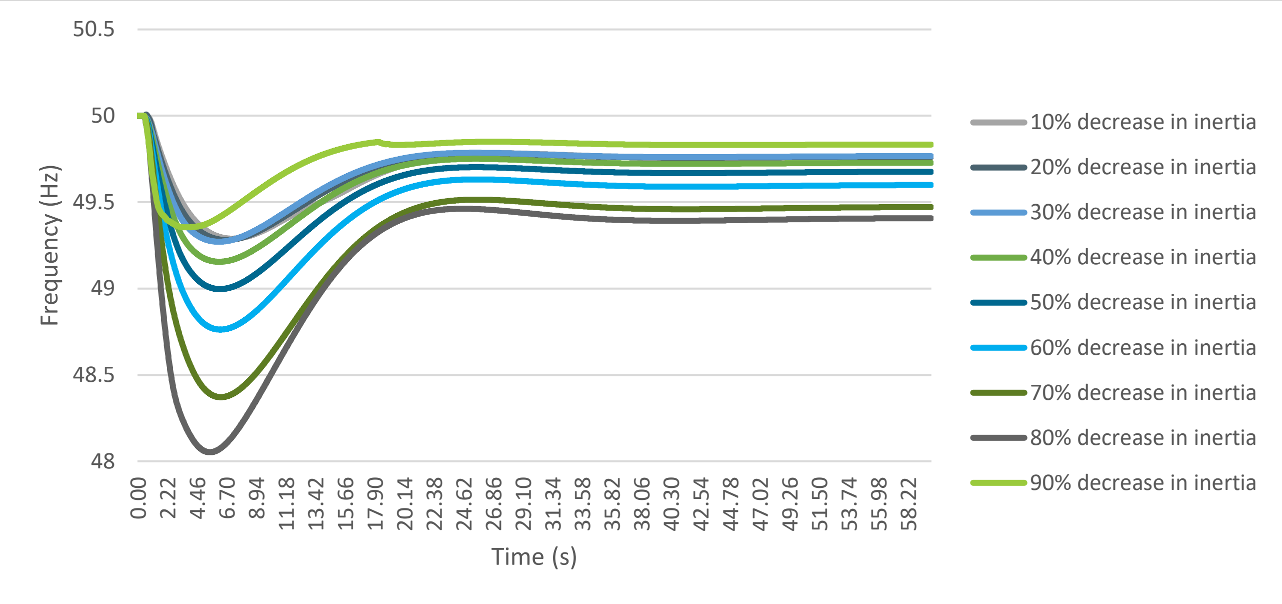

Figure 5-6: Frequency Response after CE Tripping at Reducing Inertia for SMM Case 3 with a BESS Primarily Providing IR

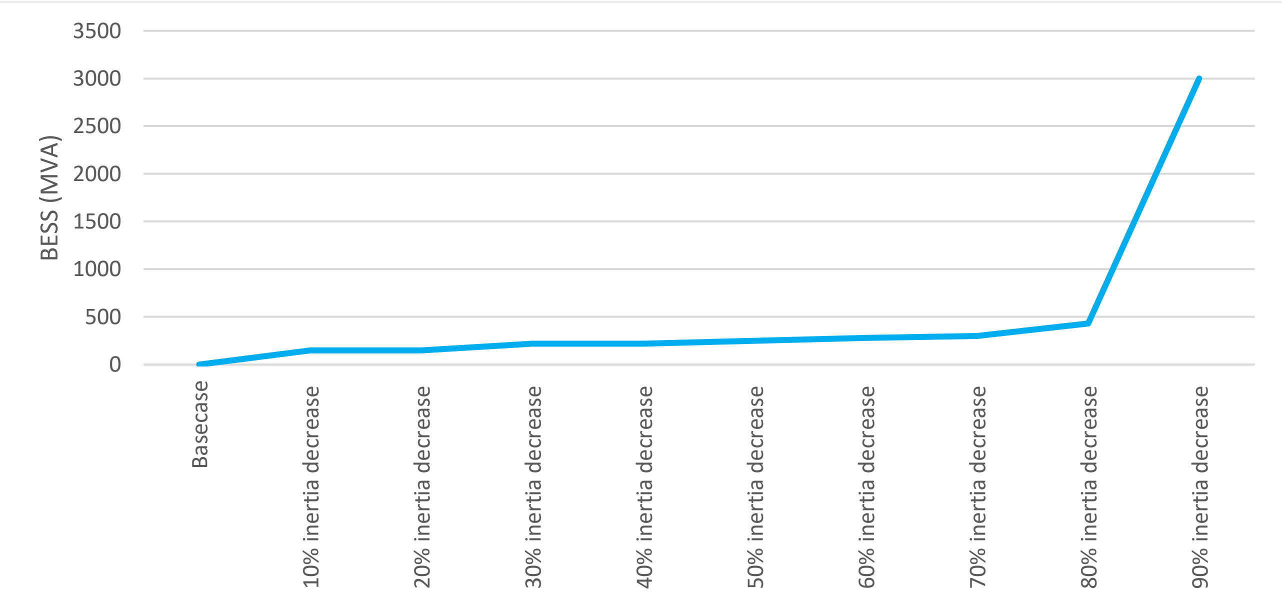

Figure 5-7: Size Variation of Reserve Generator in SMM as a BESS for SMM Case 3

The observations for Case 3 presented above are similar to the other studied scenarios and available in Section 0.

For each inertia level where the frequency requirement was met, the total generator mechanical torque was recorded and IR:CE ratio calculated. The relationship between the inertia requirement and the IR:CE ratio is plotted in Figure 5-8.

The graphs illustrate that as inertia levels decrease, the amount of IR required to stabilise the frequency following the tripping of the modelled ACCE increases slightly until the inertia levels fall within the range of 10,000 to 15,000 MW.s (area shaded in red). Beyond this point, the IR:CE ratio increases significantly across all scenarios, reaching a ratio of 1.9 in the 'Low IBR penetration' case. For this case, it would mean that when the power system inertia level is at 7,300 MW.s, and for a contingency size of 214 MW, 406.6 MW of IR are required to ensure the system remains secure. Similar conclusions can be drawn for other studied cases.

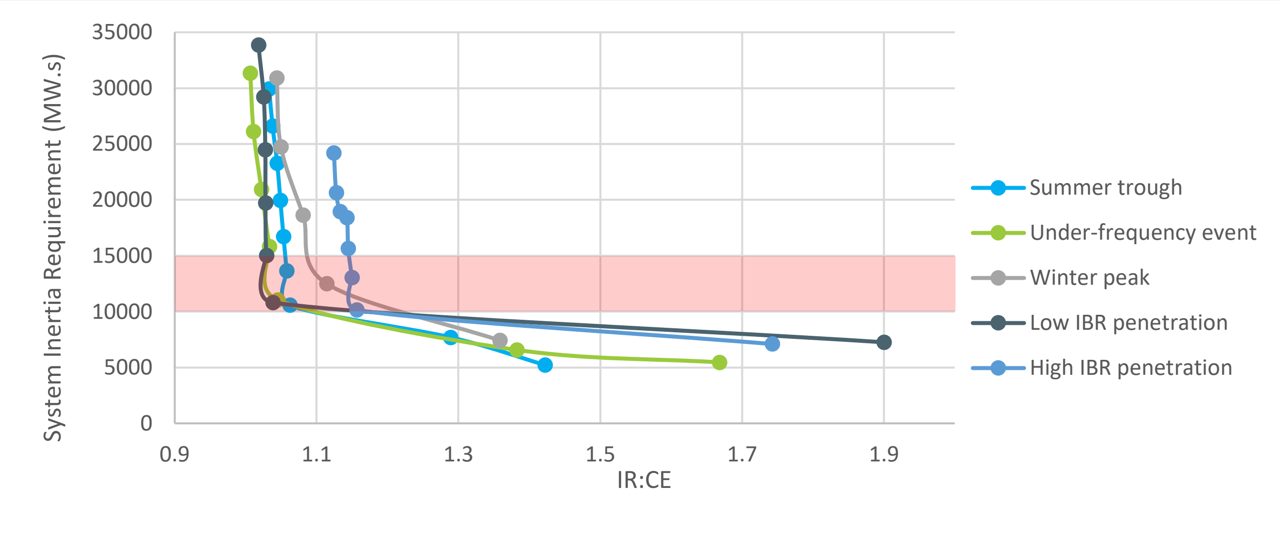

Figure 5-8: Relationship between Inertia Levels and IR:CE ratio with a Synchronous Generating Unit Providing IR

Figure 5-9 shows a similar relationship between inertia levels and the required IR, but the reserve is primarily provided by a BESS. While the IR:CE ratio is comparatively lower when the IR is provided by the BESS, due to the BESS' faster response to the frequency change, the inflection point still occurs within the 10 000 to 15 000 MW.s range.

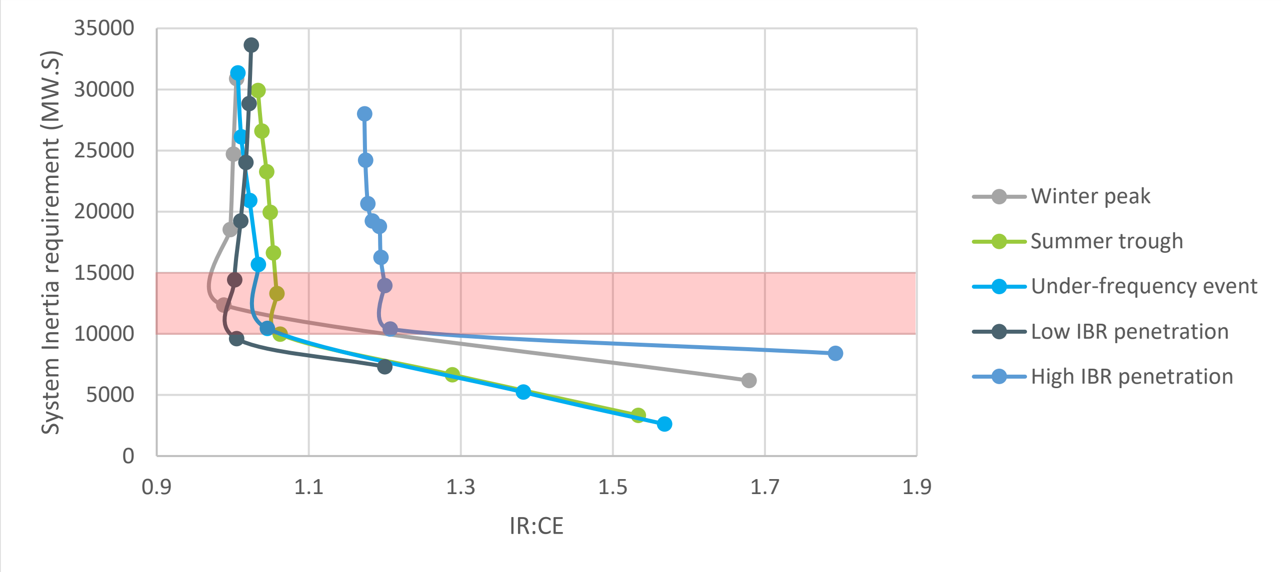

Figure 5-9: Relationship between Inertia Levels and IR:CE ratio with a BESS Primarily Providing IR

Although this study does not establish a specific RoCoF threshold, it includes an analysis of RoCoF across various inertia levels to ensure that, at the minimum selected inertia level, the RoCoF remains above the AUFLS Block 4 trigger threshold of -1.2 Hz/s.

Figure 5-10 and Figure 5-11 below depict the relationship between RoCoF and system inertia levels for each reserve type. As system inertia levels decline, the RoCoF increases exponentially. However, this rate of increase begins to slow once the inertia levels drop below 15,000 MW.s. This trend demonstrates that for inertia levels lower than 15,000 MW.s, even a minor reduction in system inertia leads to a significant rise in RoCoF. Within this range, the sensitivity of RoCoF to changes in inertia becomes more pronounced, indicating a more substantial impact on frequency rate of change with small variations in inertia.

Nonetheless, it is evident that for a CE event, for inertia levels above 10 000 MW.s, the measured RoCoF does not surpass the AUFLS Block 4 trigger. For this breach to occur, system-wide inertia levels would have to be lower than 10 000 MW.s.

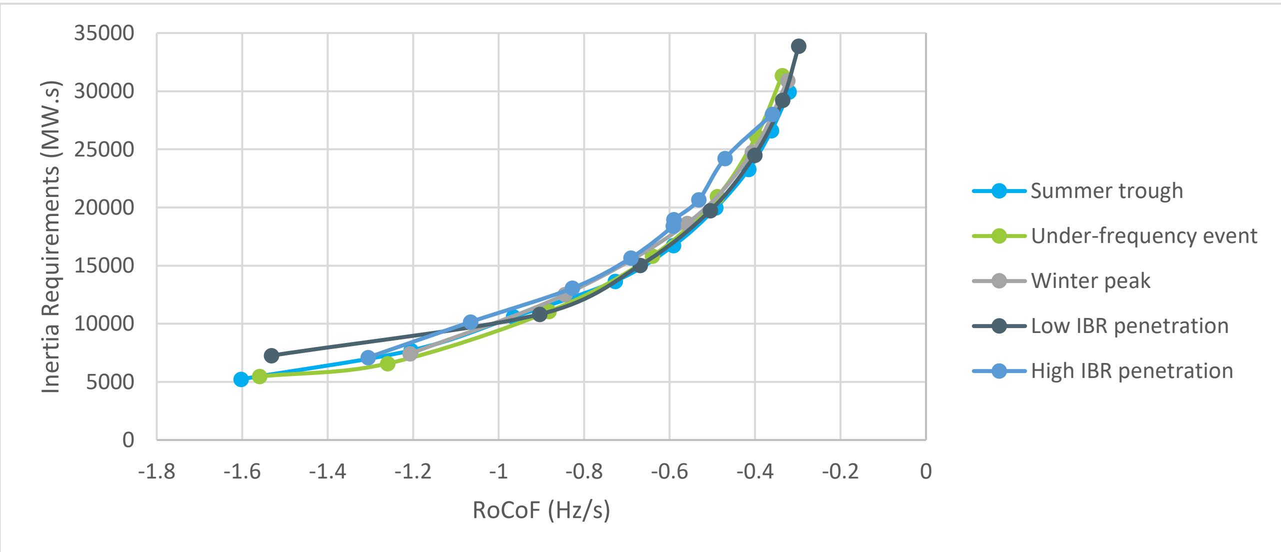

Figure 5-10: Relationship between Inertia Levels and RoCoF with a Synchronous Generating Unit providing IR

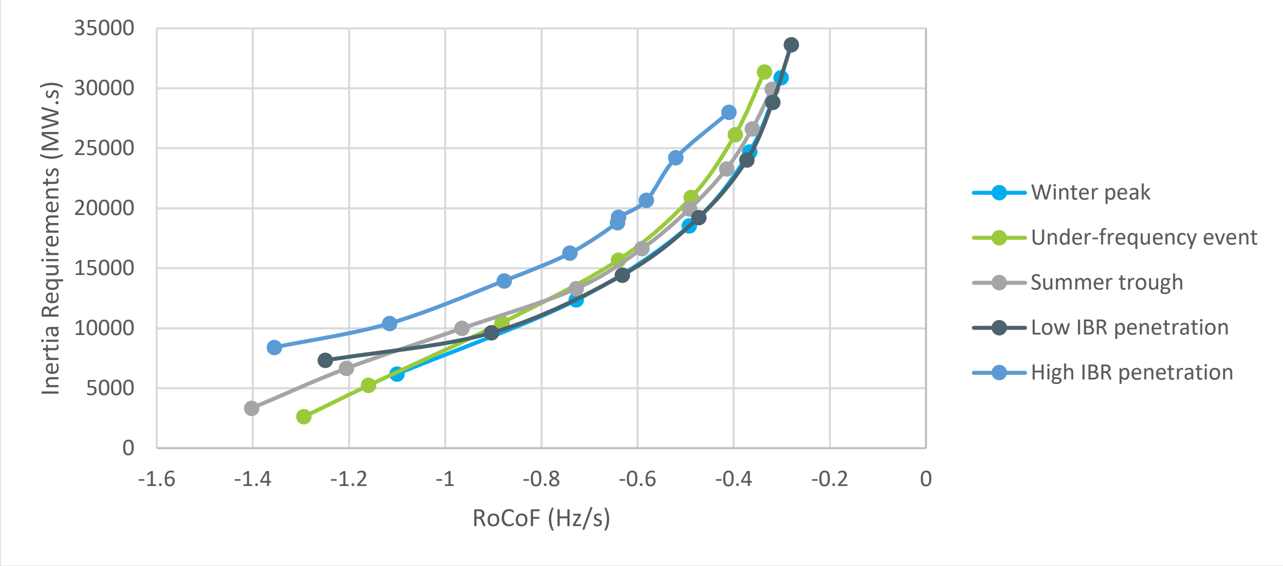

Figure 5-11: Relationship between Inertia Levels and RoCoF with a BESS Primarily Providing IR

5.3 Full Network Study

The system operator scanned system inertia data for 2024 to identify several low inertia cases for further assessment. The second study focused on three low inertia cases that occurred in the periods circled in red in Figure 5-12. The case details are outlined in Table 5-2 below that.

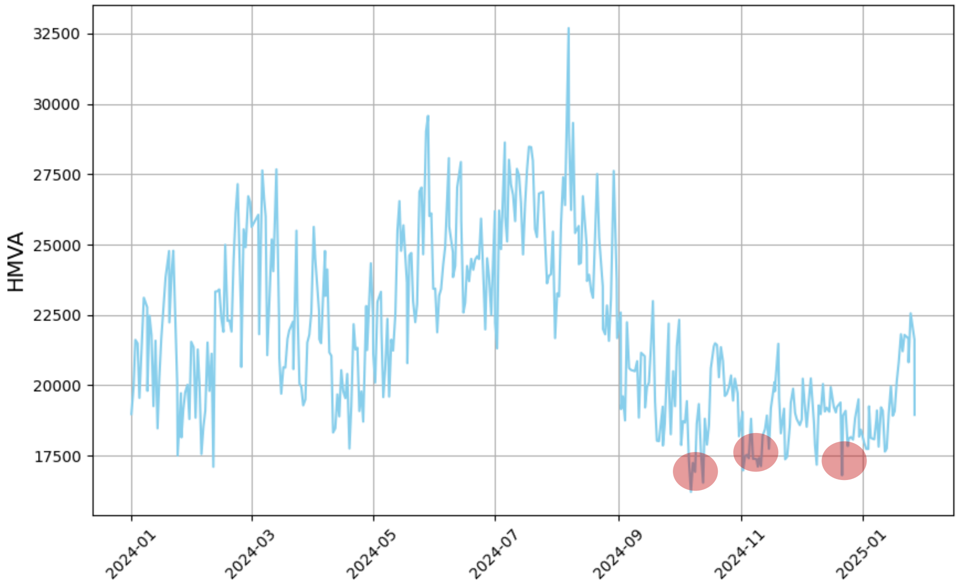

Figure 5-12: Daily Minimum System Inertia for January 2024 to January 2025

Table 5-2: Details of the Online Cases used in the Full Network Study

Case	System Conditions					
	IBR penetration levels (%)	Inertia (MW.s)[8]	Demand (MW)	CE Risk (MW)	IL (MW)	IR:CE[9]
1	35	16 500	3 270	144	36	1.35
2	27	19 450	4 320	206.19	49.34	1.25
3	11	21 900	4 500	134.64	0	1.03

5.3.1 Dynamic Models

To model the dynamic response of the power system during an event, the following dynamic models were used:

- **Generator, governor, exciter:** PSS/E and User-Defined Models (UDM) validated against asset capability statement (ACS) data as part of the system operator's business-as-usual (BAU) and representative of the generating stations' performance.
- **Reactive power compensation devices:** simplified generic UDM models for all static synchronous compensators (STATCOMs) and statis VAR compensators (SVCs).
- **Reserves to manage over/under-frequency:**
  - Interruptible Load modelled to trip at 49.2 Hz with a 1 second delay;
  - Generators modelled using UDM and contracted for Over Frequency Arming (OFA) to trip at specified frequencies.
- **IBR dynamic models:** similar to the models used in the SMM study

5.3.2 Assumptions

- The system operator maintains a robust TSAT library of dynamic models and network configurations to ensure alignment between online results and offline studies, supported by the routine tool use. As a result, the models and data provided by asset owners—through the system operator's ACS database—were not separately verified prior to this study. However, the inertia constants of generators were updated beforehand to align with the latest asset information submitted via the ACS.
- The NI ACCE event was selected as the contingency for analysis.

5.3.3 Methodology

The high-level methodology of this study was as follows:

1. Use the full network power-flow to enumerate all generators that are online and dispatched.
2. Model only the required IBRs at their projected capacity according to the 2023 Transmission Planning report (TPR). This generation (as seen in Table 5-3) is filtered to only include 2028 generation that is currently in the advanced stages of the generation pipeline.

[8] Rounded to the nearest 100 s

[9] The IR:CE represents the factor by which the IR must be increased, relative to the CE, to arrest the frequency and restore it to its normal band as per the Code requirements.

Table 5-3 Modelled IBR generation compared to TPR 2028 generation forecast

Technology	TPR cumulative new generation capacity (MW)	TPR Projected generation in advanced stages (MW)[10]	Total capacity modelled in power flow (MW)
Solar	2 585	927	335.4
BESS	1 735	100	100

3. Generate a succession of power-flows by removing one synchronous generating unit at a time and re-dispatching the displaced active power to an IBR. Note: unlike in the SMM study, the inertia could not be decreased by the same ratio with each iteration. Instead, each step was indicative of a selected synchronous generating unit or generating station being dispatched off.
4. For the selected contingency, extract the following results for both islands:
    a. bus frequency (Hz);
    b. generator mechanical torque (MW); and
    c. generator active power (MW) traces.
5. Use the results to construct system inertia versus Instantaneous Reserve to Contingency Event (IR:CE) ratio plots. Identify the inflection point to determine the threshold at which frequency performance criteria are met.

5.3.4 Results

All reasonable efforts were undertaken to iteratively refine the full network studies, ensuring the frequency nadir reached the target of 48 Hz. However, due to the complexity of manipulating full network cases, some iterations resulted in frequency nadirs greater than 48 Hz, as indicated by the example in Figure 5-13. This has led to a leftward shift in the curves presented in Figure 5-14, illustrating that lower IR:CE ratios are sufficient at reduced inertia levels. The RMTSAT validation study was conducted to address this limitation.

[10] As of June 2025

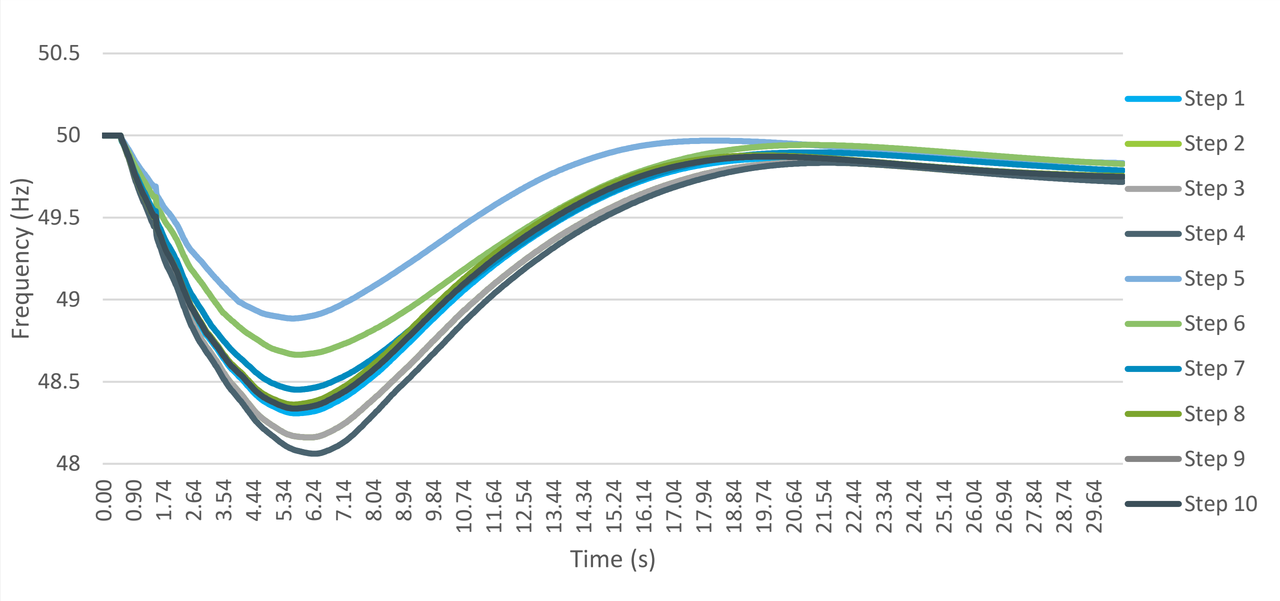

Figure 5-13: Frequency Response after ACCE Tripping in Case 3 with Decreasing Inertia Steps

Figure 5-14 illustrates the relationship between system inertia and the IR required to arrest the frequency nadir at 48 Hz.

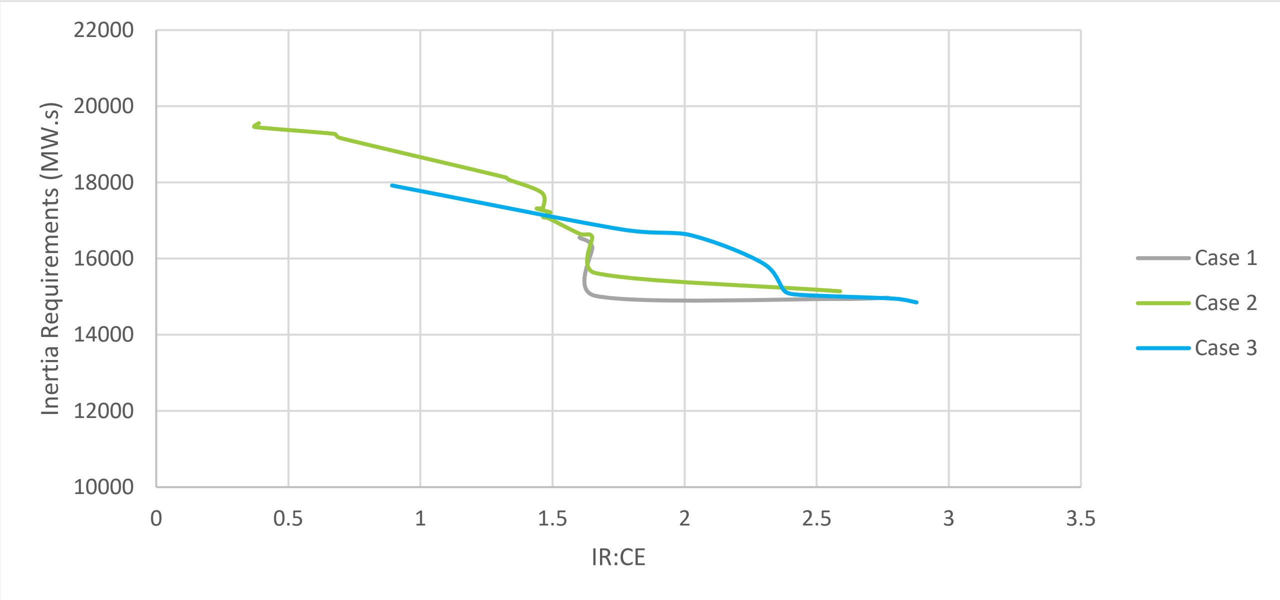

Figure 5-14: Relationship between Inertia and IR required for an ACCE contingency

A distinct inflection point is observed around the 15,000 MW·s mark—specifically:

- Case 1 at 15 021 MW·s;
- Case 2 at 15 600 MW·s; and
- Case 3 at 15 100 MW·s.

This trend supports the conclusion previously established in the SMM study.

Another key conclusion from this analysis is that the decline in inertia beyond the inflection point is almost horizontal compared to a slight incline observed in the SMM studies. This points to the significance of this threshold, highlighting that an even smaller decline in inertia (compared to the SMM study increments) requires a disproportionate amount of IR response to meet the frequency obligations.

5.4 RMTSAT Validation Study

This final study sought to validate the results of the SMM and full network studies above. The system operator used RMT input files that correspond to the full network cases in Table 5-4 below.

Thanks to RMTSAT's ability to specify island-based inertia, this study both verified and determined NIPS and SIPS inertia for a direct current contingent event (DCCE), i.e. the loss of the largest HVDC pole.

Table 5-4: Details of the Online Cases used in the RMTSAT Study

Case	System Conditions					
	Inertia (MWs)[11]	Demand (MW)	HVDC Flow	DCCE Risk (MW)	IL (MW)	IR:CE
1[12]	21 900	4 500[13]	North	206.34	0	0.73
2	16 200	3 714.98[14]	South	240	24.5	0.81

It was necessary to align the input files with the study cases, as RMT files are typically generated online based on a forward-looking near real-time short schedule (NRSS) that may not perfectly match the study scenarios. For this study, the same methodology was followed as for the full network study, with the exception that no new IBR was introduced; instead, existing IBRs were dispatched simultaneously as synchronous generation was displaced.

5.4.1 Assumptions

These are some of the assumptions that informed the processing of the selected RMT cases:

- According to RMT principles, the NFR is a response from the system that is not provided by the instantaneous reserve providers. The NFR for contingent events consists of an inertial response from rotating machines and load damping, uncleared partially loaded spinning reserves (PLSR) from hydro generators in the North Island, and a response from the HVDC. This value could be negative from non-compliant generation sympathetic tripping.
- RMT does not use a full network model and has specific modelling requirements related to scaling of the scheduled reserves.
- The value for tail water depressed (TWD) FIR was amended to 0 for all cases due to a known RMT scaling feature that results in pessimistic FIR values due to assumed TWD contribution. Only FIR contribution from PLSR and IL were considered for the study.
- SIR response is not modelled in RMT currently, so the results show no frequency recovery.

[11] Rounded to the nearest 100s
[12] Same base case as Case 3 in Table 5-2
[13] North Island load is 2 288.77 MW
[14] South Island load is 1 304 MW (excluding TWI load)

- The models used in RMT are routinely maintained and amended like those in TSAT.
- RMT determines that the binding risk for each case in Table 5-4 was not the ACCE, as was considered in the TSAT studies.
- For the island-based inertia, an additional scenario with high HVDC south transfer had to be to be considered to assess the frequency response and inertia in the South Island.

5.4.2 Study Results

Due to RMTSAT's ability to quantify island-based inertia, the system operator both validated the results from the full network study and determined a threshold for each island power system for a DCCE.

Figure 5-15 below compares the results for a scenario (Case 1) previously analysed in TSAT (Case 3). It used the same iterative approach of reducing inertia by deactivating synchronous generating units. In RMTSAT, the study contingency was a DCCE, reflecting how the tool identifies binding risks and solves for the NFR accordingly. By contrast, the TSAT assessment was conducted for an ACCE. While this introduces a discrepancy, the inflection point is 14 948 MW.s and therefore aligned across both TSAT and RMTSAT study results. The RMTSAT result trend does not reflect the leftward shift at inertia levels above the inflection point. This is where the IR:CE is between 0.7 and 0.9, as would be typical of the ratio in the NZPS.

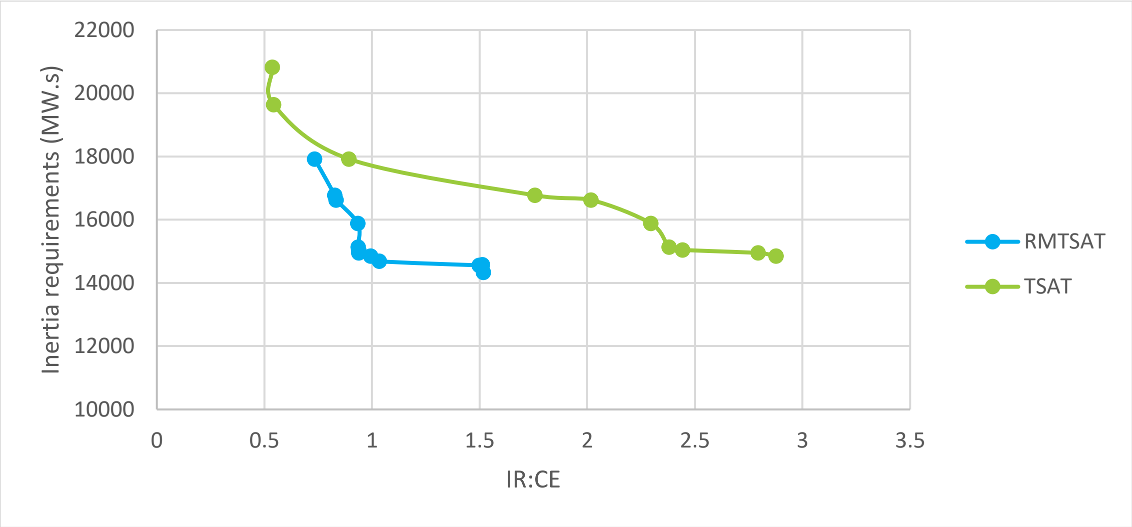

Figure 5-15: Comparison between the Same Case in TSAT and RMTSAT

Figure 5-16 presents results for the same case, focusing solely on the North Island requirements.

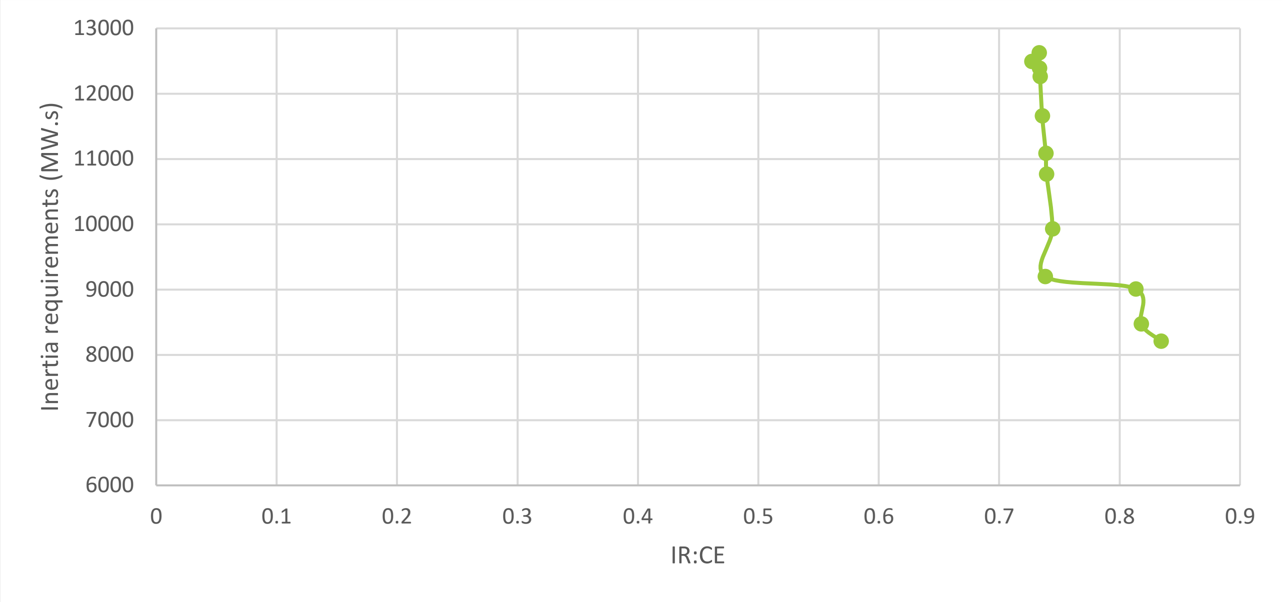

Figure 5-16: Island-based Inertia for the North Island DCCE

To assess the South Island inertia needs under high HVDC southward flow, Case 2 from Table 5-4 was introduced. The outcome of this scenario is shown in Figure 5-17 below.

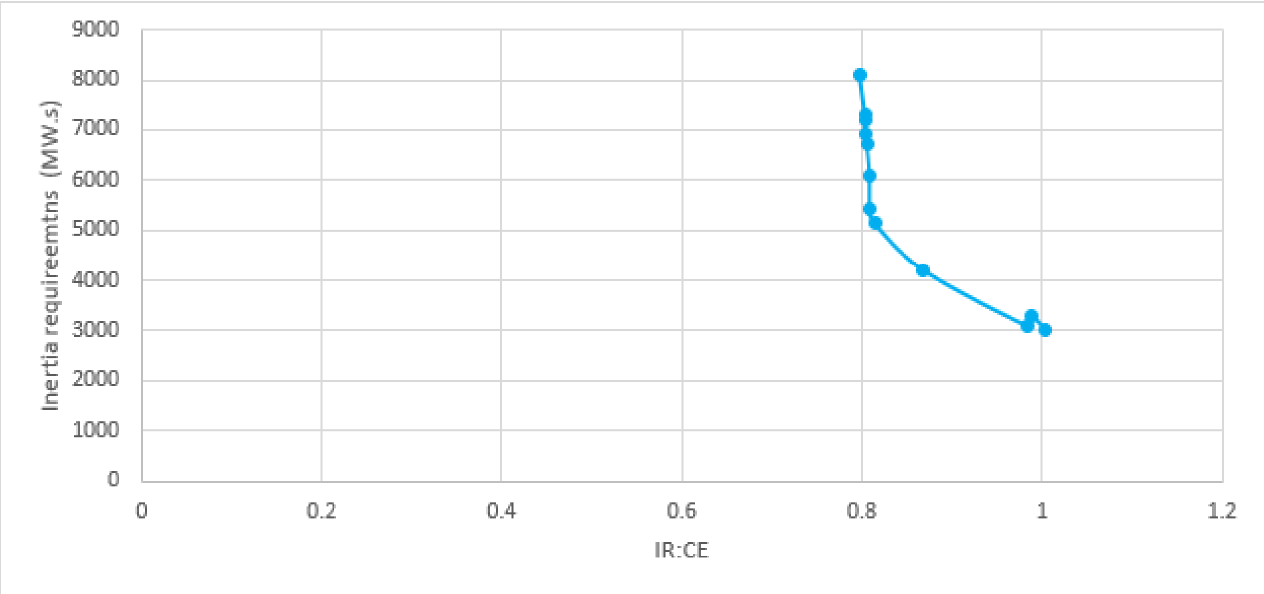

Figure 5-17: Island-based Inertia for the South Island DCCE

6 Conclusion and Recommendations

The minimum inertia threshold identified in this study can be integrated into the 'FSR Indicator – System Inertia' risk monitoring programme to help flag potential frequency instability risks. This threshold could also serve as a reference point for determining the level of IBR penetration at which a revised frequency management strategy may be necessary. To ensure the continued relevance and accuracy of this threshold, periodic studies should be conducted to validate and, if needed, update the minimum inertia requirement.

The system operator draws the following conclusions from the study conducted:

- After a CE tripping, the inflection point whereby significantly more IR is required to ensure a frequency nadir of 48Hz is between **10,000 MW·s** and **15,000 MW·s** for both the synchronous machine and BESS models used in the SMM study**.** The studies with a modelled BESS used as the reserve generator showed slightly higher inflection points compared to studies where IR was delivered by the synchronous generating unit model. Consequently, frequency requirements can be met at lower inertia levels when a larger proportion of IR is provided by IL and BESS rather than when IR is provided by synchronous machines. While the RoCoF recorded for this inertia range increases faster when the inertia level is less than 15 000, it does not surpass the AUFLS Block 4 trigger, -1.2 Hz/s.

- This conclusion is further supported by full network studies conducted for actual low inertia scenarios where the inflection point was just above 15 000 MW.s. This is due to the arresting of system frequency above 48 Hz, hence more than the required IR response from generators was recorded.

- Therefore, based on these observations, a conservative inertia floor of **15,000 MW·s** for both North and South Islands combined would be considered sufficient to maintain frequency stability. Figure 6-1 illustrates how this threshold compares to the combined system inertia observed in 2024. It is worth noting that this figure reflects only the inertia contributed by generation and representation of the contribution of other network devices; the real inertia contribution from loads or other network devices is assumed to supplement this minimum threshold.

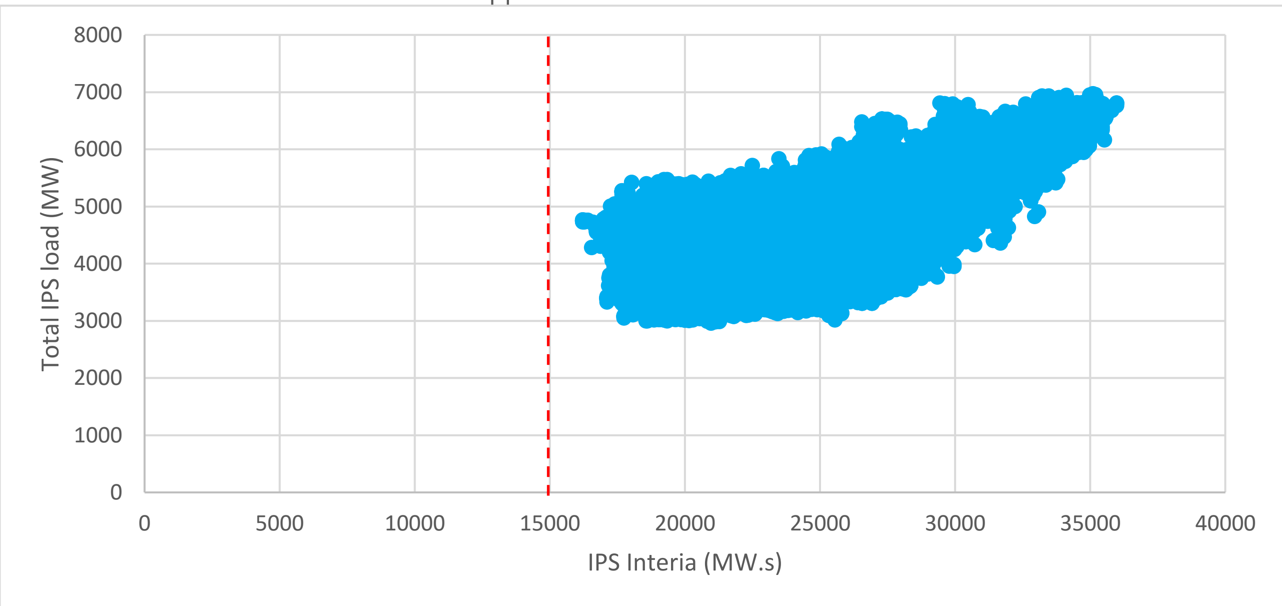

Figure 6-1 Scatter Plot Illustrating the Recommended Inertia Threshold In Relation To The Distribution Of the combined System Inertia Throughout 2024.

When assessed on an island-by-island basis, a conservative threshold identified is approximately **9,000 MW·s for the North Island** (plotted in Figure 6-2) and **5,000 MW·s for the South Island** (plotted in

Figure 6-3). In 2024, the North Island's minimum recorded inertia was 9 109.3 MW·s, while the South Island's was 4 654.63 MW·s. In that year, North Island inertia levels dropped below 10,000 MW·s only on six days, none breaching the 9,000 MW.s recommended threshold, all of which occurred during summer and spring periods characterised by low demand and high wind output. In the South Island, the threshold was exceeded on just two days, both during overnight trough load conditions.

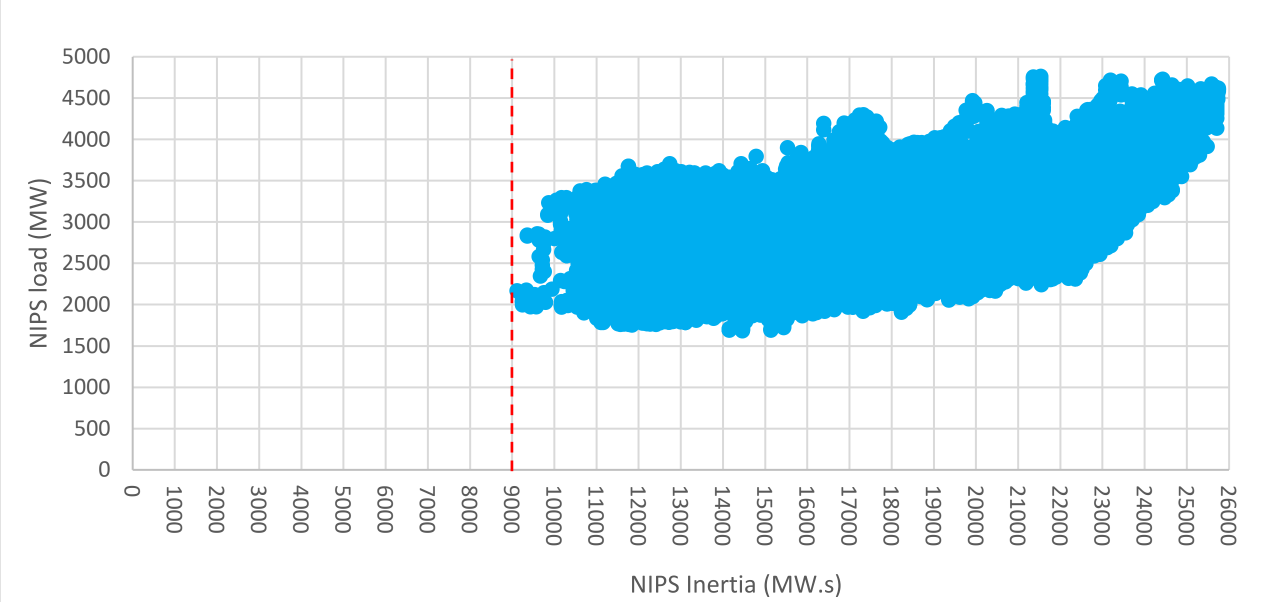

Figure 6-2 Scatter Plot Illustrating the Recommended Inertia Threshold In Relation To The Distribution Of the North Island System Inertia throughout 2024.

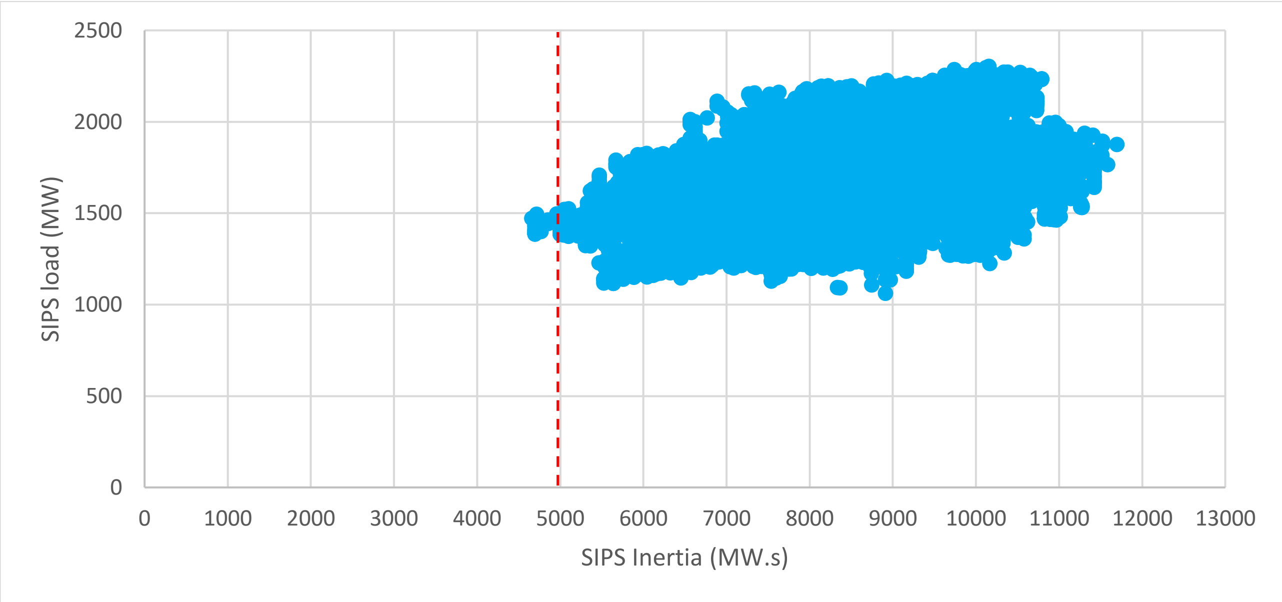

Figure 6-3 Scatter Plot Illustrating the Recommended Inertia Threshold In Relation To The Distribution Of the South Island System Inertia throughout 2024.

- This indicates that the South Island has already fallen below the identified threshold, and the North Island is very close to the limit. Given this situation, there is a need to explore mitigation strategies. To this end, the system operator proposes the following approaches that require investigation to effectively manage low inertia scenarios:

Approach	Description
A	**Decrease IL response time from 1 second to 0.5 second** to enable faster frequency arrest due to load tripping faster when frequency reaches 49.2Hz.
B	**Reduce the binding risk output** to lower the need for additional IR procurement in low inertia scenarios. Currently, the system operator's SPD tool's logic can constrain the binding risk but only based on IR availability and offers. To enable SPD to consider the same logic for low inertia scenarios, boundary conditions can be set up to assess the type of risk, risk generator output and island load. If the boundary conditions are breached, SPD would adjust the binding risk output instead of procuring a disproportionate amount of IR.
C	**Create categories for FIR providers** RoCoF increases with lower inertia levels, hence the frequency nadir is reached at a lower T_{min}. Slower acting types of generation would not be able to provide the same response at a T_{min} of 3 seconds as at 6 seconds. This derating of generation performance could be reflected through an effectiveness factor. For example: at $T_{min} =$ 3 seconds, faster acting products such as BESS and IL have a factor of 1, partially loaded spinning reserves (PLSR) have a factor of 0.8, and tail water depressed (TWD) offers are given a factor of 0.2. At $T_{min} =$ 4 seconds, BESS and IL will still have a factor of 1, while the others will increase slightly as they will be able to reach higher outputs in the additional time. This option would enable SPD to schedule reserves at different inertia scenarios, taking into consideration not only their offer price but also their performance. As SPD does not have visibility of the system inertia, hence T_{min}, similar boundary conditions as specified in the previous recommendation can serve as a proxy to dictate when this categorisation is required. Within these boundary conditions i.e. above the minimum inertia threshold, all reserve types are adequate and thus do not require an effectiveness factor. This approach is primarily beneficial in low inertia scenarios, enabling efficient IR procurement where, depending on cost, more effective reserves are prioritised. This can also provide incentives for asset owners to tune their control systems to provide a faster response, which is beneficial as inertia levels continue to drop. The assessment of reserve types required for this option are already implemented in the current RMT logic. This uses existing asset models and thus would likely not require many software changes. Work will need to be done to determine each effectiveness factor and ascertain its integration into RMT. Further investigation into the SPD-RMT-SPD iterative process is also necessary, particularly with large sudden differences between generation schedules resulting in unexpected negative NFR values without the SPD's retrospective ability.
D	**Lower the minimum allowable frequency for CE in the South Island** to accommodate lower inertia conditions. This gives time for reserves to respond due to less fast acting reserves on the island. This option would require changes to SI AUFLS relays and HVDC FKC controls.
E	**Promote the provision of synthetic inertia by IBRs,** particularly from BESS utilising grid-forming (GFM) inverter technology. The ability of a GFM BESS to deliver synthetic inertial response is influenced by its control system logic, inverter design, and configuration. This

	capability is especially valuable during frequency disturbances as it emulates the inertial behaviour of conventional synchronous machines. Further study needs to be conducted to understand the capability of a GFM BESS to provide synthetic inertia at different operating points and the impact of the contingency size and the RoCoF on its provision, if any.
F	**Introduce a faster reserve product (F-FIR)** whose active power response would be assessed at a lower T_{min}. Faster-responding resources are well-suited to provide this service. This could be verified either through a demonstration of their active power response to a specified frequency deviation (e.g. 0.5 Hz) and a selected ramp rate requirement: using desktop simulations with a validated plant model or through on-site frequency injection testing using a modified curve. Implementing such a product requires market changes, numerous tool and database changes, new reserve performance standards, requirements for high-speed data recording, and a systematic integration with existing frequency management products. The drawback of this option is that, given the current generation in the South Island being primarily composed of synchronous FIR providers, if T_{min} is set to less than 3 seconds, there would be little to no market participation from TWD providers.

7 Other Study Results

7.1.1 Frequency Response

7.1.2 Case 1: Summer Trough

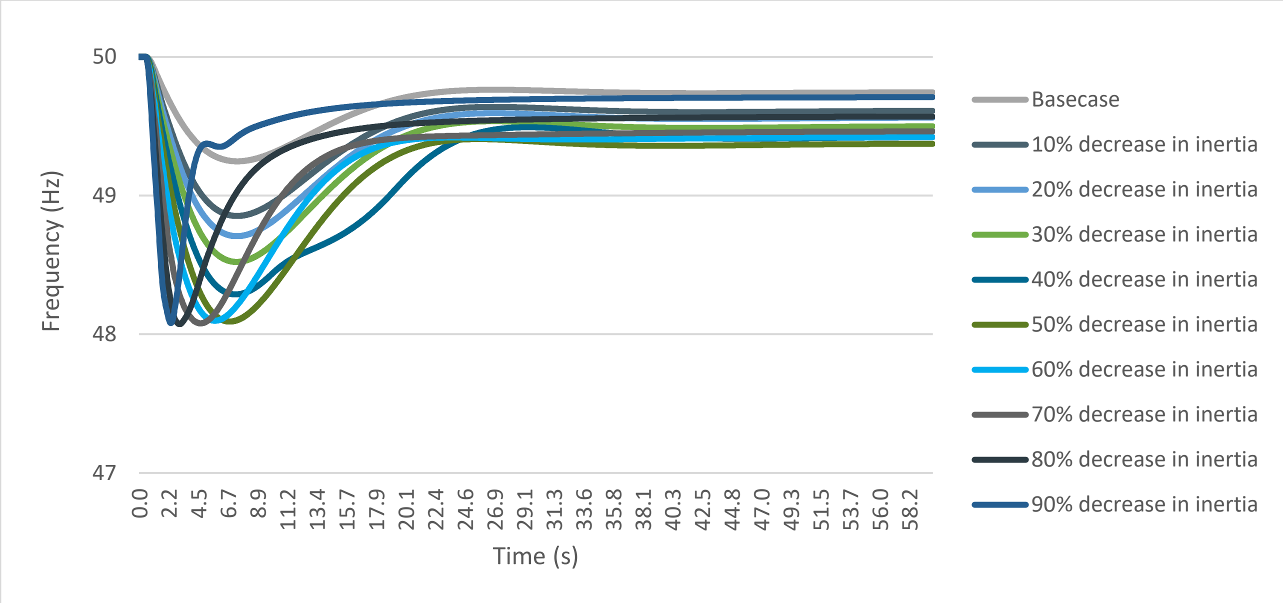

Figure 7-1 Frequency response after CE tripping at reducing inertia, for SMM Case 1 – IR provided by a synchronous generating unit.

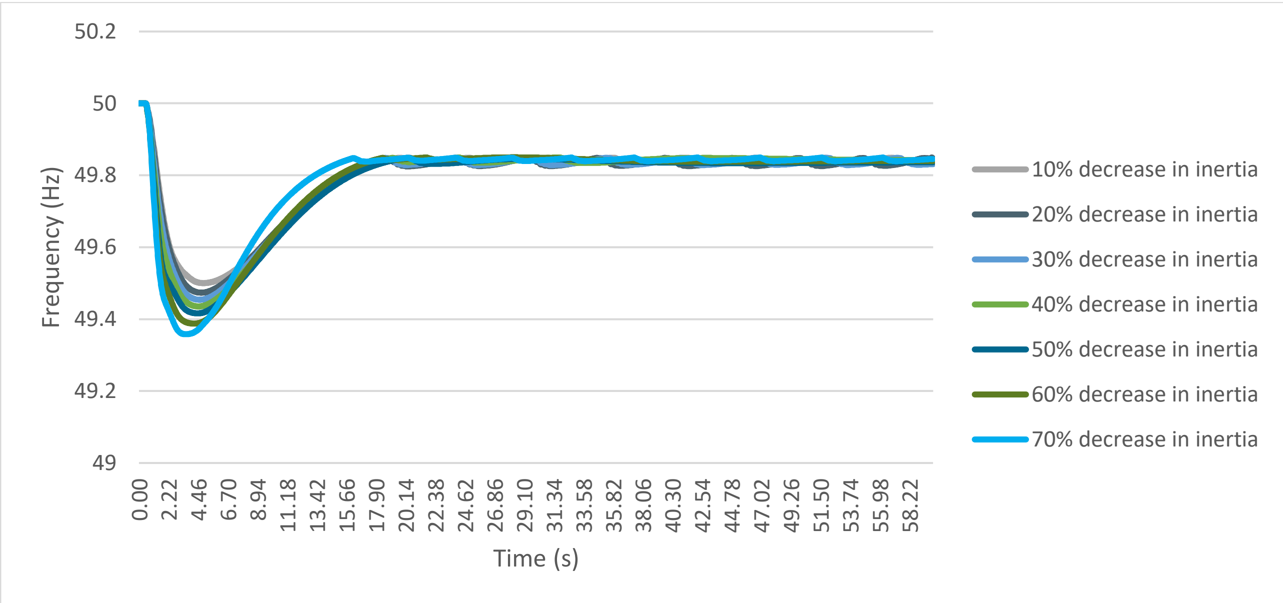

Figure 7-2 Frequency response after CE tripping at reducing inertia, for SMM Case 1 – IR primarily provided by a BESS

7.1.3 Case 2: Winter Peak

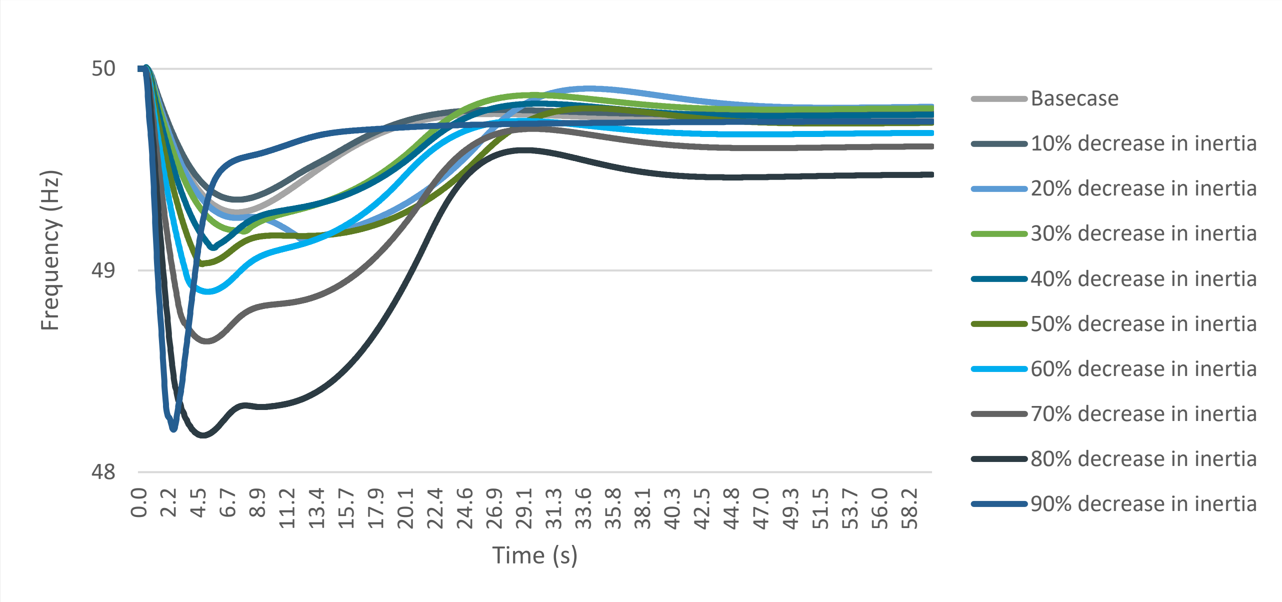

Figure 7-3 Frequency response after CE tripping at reducing inertia, for SMM Case 2 – IR provided by a synchronous generating unit.

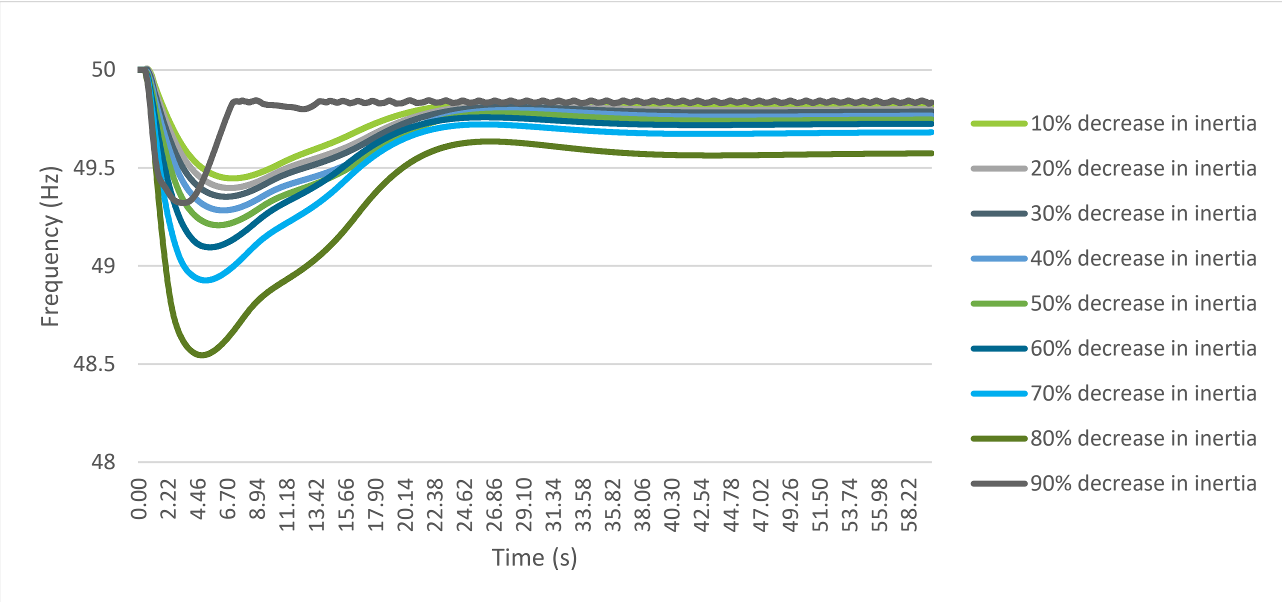

Figure 7-4 Frequency response after CE tripping at reducing inertia, for SMM Case 2 – IR primarily provided by a BESS

7.1.4 Case 3: Low IBR generation

Can be found in Section 5.1.3

7.1.5 Case 4: High IBR generation

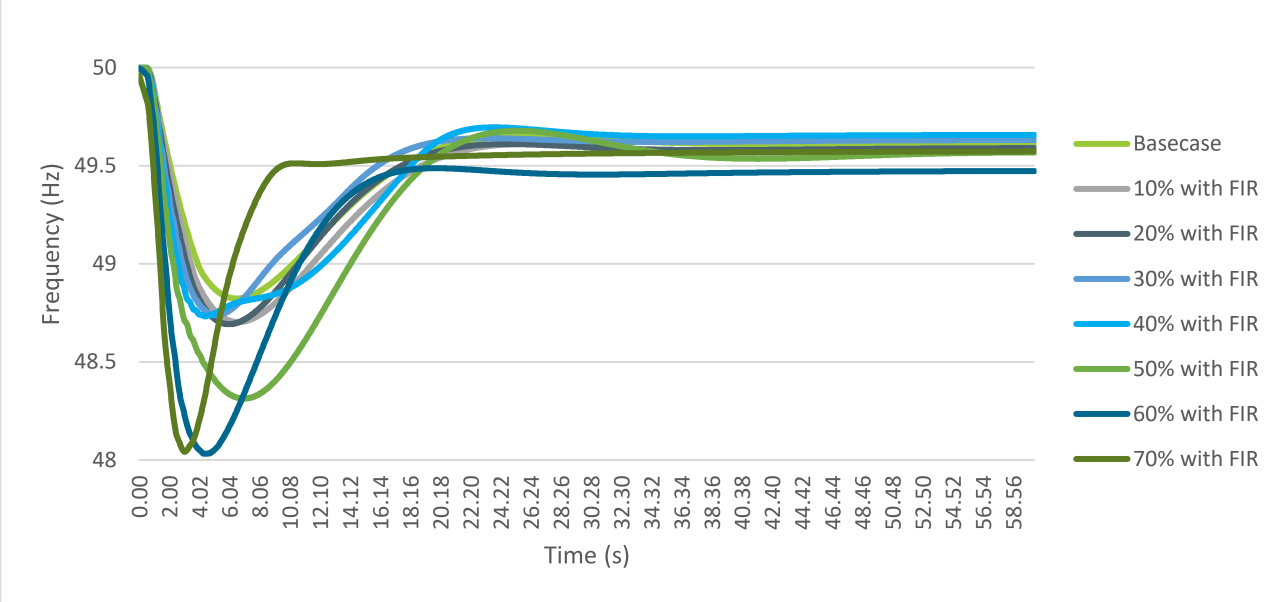

Figure 7-5 Frequency response after CE tripping at reducing inertia, for SMM Case 4 – IR provided by a synchronous generating unit.

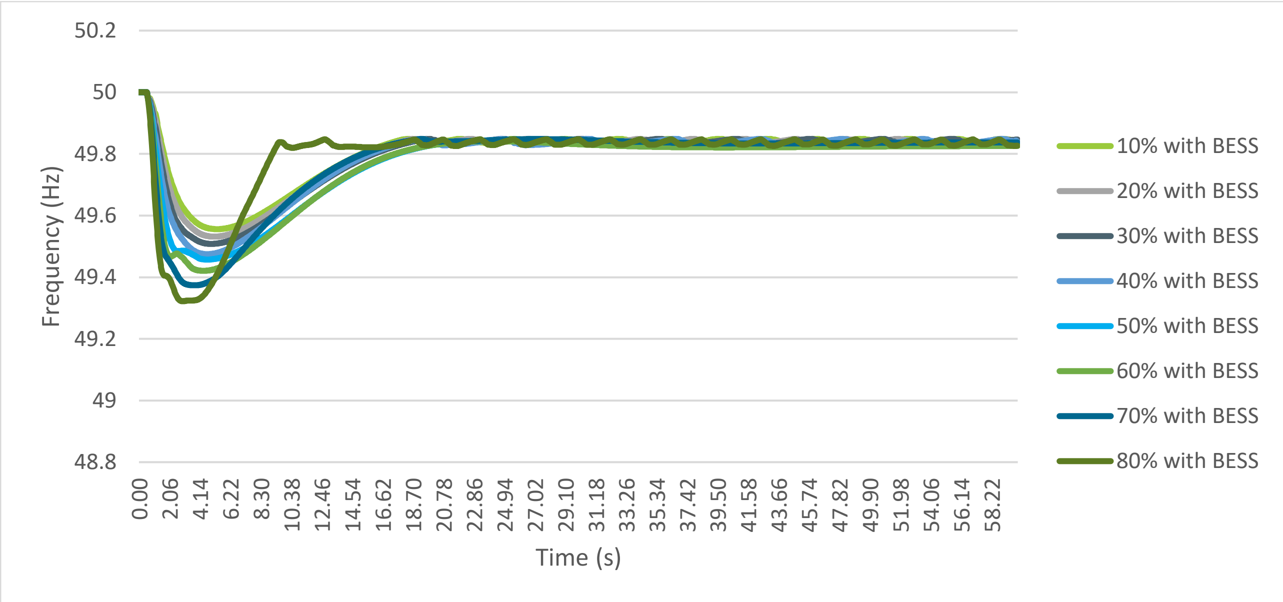

Figure 7-6 Frequency response after CE tripping at reducing inertia, for SMM Case 4 – IR primarily provided by a BESS

7.1.6 Case 5: Under frequency event

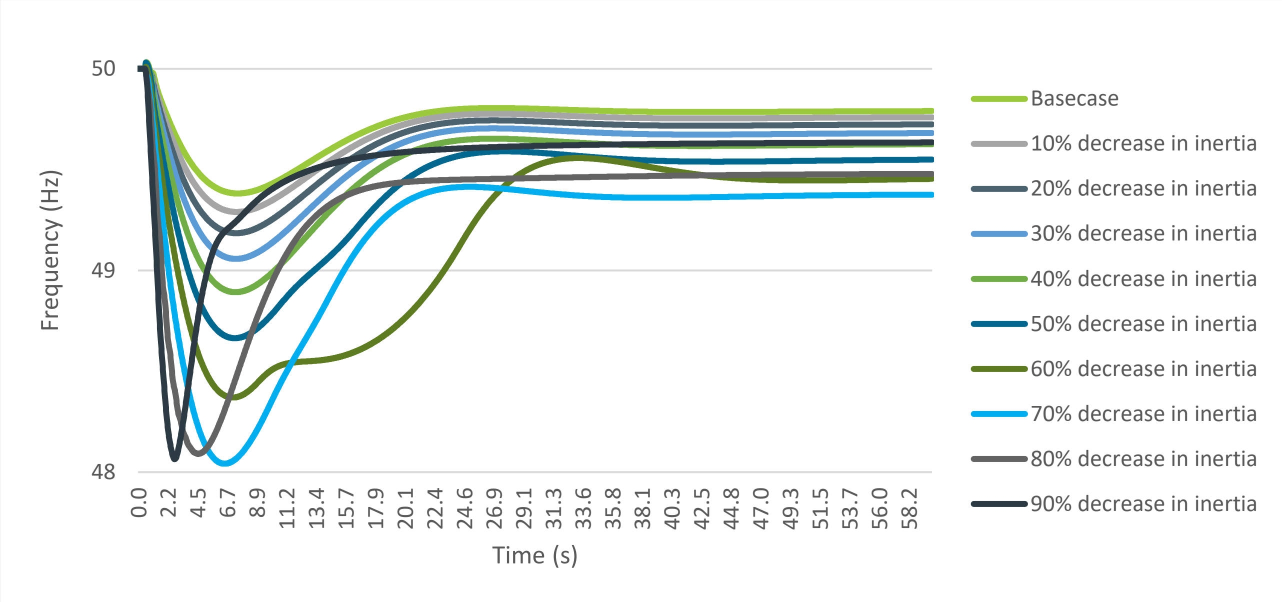

Figure 7-7 Frequency response after CE tripping at reducing inertia, for SMM Case 5 – IR provided by a synchronous generating unit.

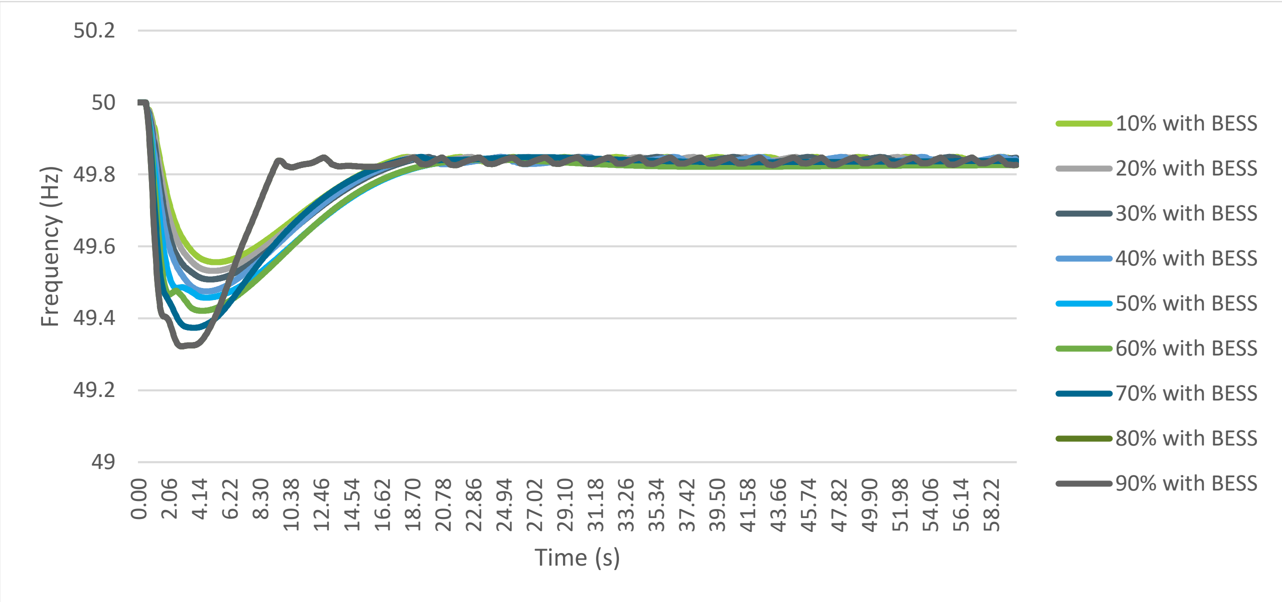

Figure 7-8 Frequency response after CE tripping at reducing inertia, for SMM Case 5 – IR primarily provided by a BESS

7.1.7 Variation in the size of the modelled reserve generator

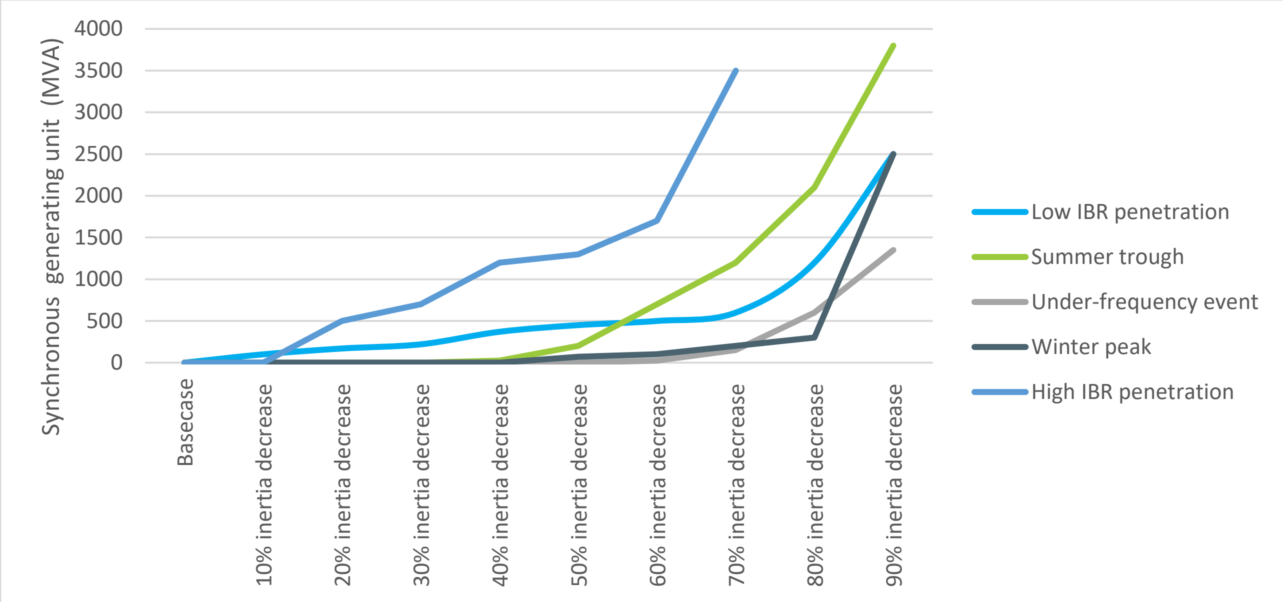

Figure 7-9 Size variation of reserve generator in SMM as a synchronous generating unit for all SMM case studies.

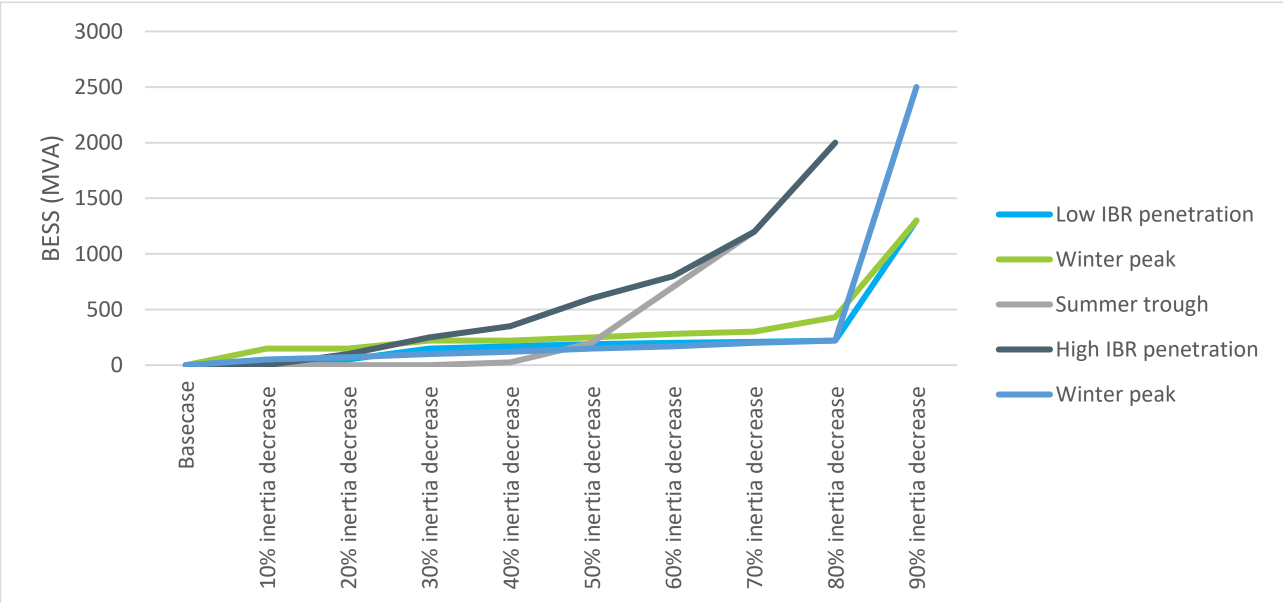

Figure 7-10 Size variation of reserve generator in SMM as a BESS for all SMM case studies.

8 Abbreviations

Abbreviation	Explanation
ACCE	Alternating Current Contingent Event
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
CE	Contingent event
DCCE	Direct Current Contingent Event
EirGrid	Electricity Supply Board (Ireland)
ENTSO-E	European Network of Transmission System Operators
ERCOT	Electric Reliability Council of Texas
FIR	Fast Instantaneous reserve
FSR	Future Resilience and Security
GFM	Grid forming inverter
Hz	Hertz
IBR	Inverter-based Resources
IL	Interruptible Load
IR	Instantaneous Reserves
MOC	Minimum unit commitment
MUON	Minimum Number of Conventional Units Online
NFR	Net-free reserves
NIPS	North Island Power System
NRSS	Near real-time short schedule
NZPS	New Zealand Power System
PLSR	Partially loaded spinning reserve
PSAT™	Power flow and Short-circuit Analysis Tool
RMT	Reserve Management tool
RMTSAT™	Reserve Management Transient Stability Analysis Tool
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SG	Synchronous generator
SIPS	South Island Power System
SIR	Sustained Instantaneous reserve
SMM	Single Mass model
SNSP	System Non-Synchronous Penetration
SPD	Scheduling, Pricing and Dispatch application/tool
The Authority	The Electricity Authority
The Code	Refers to the Electricity Industry Participation Code 2010
TSAT™	Transient Security Assessment Tool
TWD	Tail water depressed
UDM	User-Defined Models
WECC	Western Electricity Coordinating Council

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