System Rate of Change of Frequency

A GHD survey of international views

The Australian Energy Market Commission

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→ **The Power of Commitment**

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The Power of Commitment

Executive Summary

GHD has prepared independent advice to inform the Reliability Panel's review of the Frequency Operating Standard (FOS) for the National Electricity Market (NEM). Our advice is intended to help inform the Panel's consideration of the following high-level questions:

– How should limits on the post-contingent Rate of Change of Frequency (RoCoF) be specified in the NEM Frequency Operating Standard (FOS)?
– Should the NEM FOS specify a maximum permissible size for a credible single contingency event?
– What is the value of maintaining a limit on frequency time error in the NEM FOS?

Our advice has been developed through a review of relevant literature and consideration of feedback obtained through a survey of national and international power system operators and coordinators. This report is subject to and must be read in conjunction with the limitations set out in section 1 and the assumptions and qualifications contained throughout the Report.

Survey Coverage

Figure 1 illustrates the power systems included in the survey. The purple areas indicate the regions covered by a regional coordinator (NERC for the USA) or an international coordinator (ENTSO-E for Europe). Pink areas signify where we have received a survey response from the relevant power system operator. This includes:

– AEMO for the Wholesale Electricity Market (WEM) in Western Australia
– National Grid ESO for Great Britain
– EirGrid for Ireland
– Hawaii Electric and KIUC for the Hawaiian Islands
– Coordinador Eléctrico Nacional for Chile

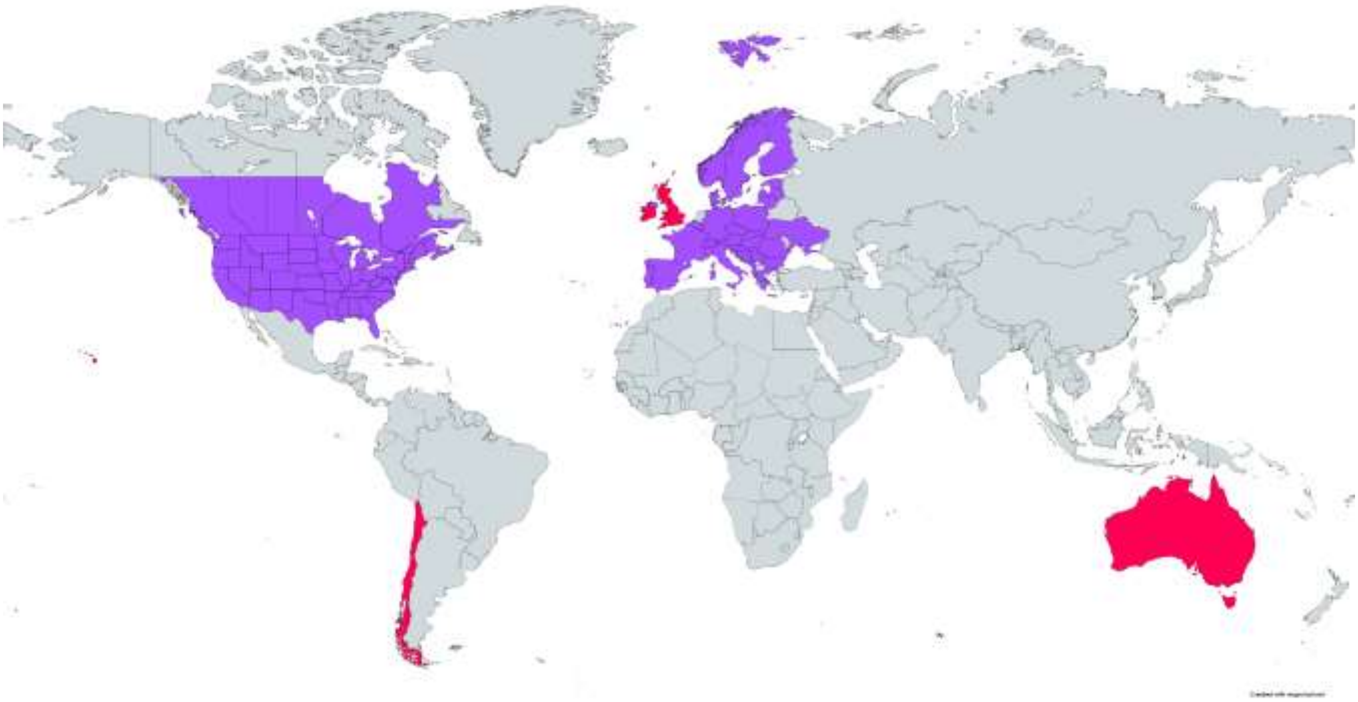

Figure 1 Map illustrating surveyed power systems

Key Findings and Advice

RoCoF

The existing NEM FOS is silent on RoCoF and does not include any requirement to control RoCoF within a specified limit. The absence of a specified RoCoF limit in the FOS creates some doubt regarding the RoCoF that AEMO should seek to maintain following contingency events.

The survey responses indicate that power system vulnerability to higher RoCoF events is a global concern for power system operators. The key observations derived from the survey are listed in Table 1 and grouped under three topics:

- Experience with high RoCoF events
- RoCoF ride-through requirements
- Operational RoCoF standards and control measures

Table 1 Survey findings – RoCoF

RoCoF Topic	Summary of Findings
Experience with high RoCoF events	– Smaller power systems, like those on the Hawaiian islands, have experienced the highest RoCoF. – For larger networks, like the European interconnected system, the highest RoCoF events are expected following events that lead to the formation of islands that are separated from the primary interconnected system. – ENTSO-E review of global experience with high RoCoF events suggests that emergency controls like UFLS may not manage to prevent blackouts if RoCoF exceeds 1 Hz/s measured over 500 ms.
RoCoF ride-through requirements	– It is common for grid codes to specify RoCoF ride-through capability requirements for generating systems. Those ride-through requirements are generally much higher than the RoCoF levels typically observed for credible contingency events. – System operators are concerned that legacy generators may not be able to comply with the RoCoF ride-through requirements expressed in grid codes and that failure to ride-through could further exacerbate a RoCoF event. – Of the entities surveyed, only EirGrid had direct experience investigating generator ride-through capability. – Aside from the Loss of Mains (LoM) issue in Great Britain and the trip of a small liquid fuelled synchronous generator in Hawaii, no survey respondents were able to identify actual events where a large utility-scale generating system tripped due to experiencing high RoCoF. – AEMO has confirmed that the LoM issue experienced in Great Britain and Ireland is unlikely to exist in the NEM.
Operational RoCoF standards and control measures	– A number of system operators consider the operational needs for limiting RoCoF to maintain power system security. However, the Western Australia South West Interconnected System (SWIS) is the only power system that has a safe RoCoF limit specified in a FOS or equivalent regulation. – The Western Australia Electricity Market (WEM) FOS specifies a safe RoCoF limit of 0.25 Hz over any 500 ms period for the SWIS. AEMO-WA is required to perform reasonable endeavours to maintain this safe RoCoF level for events that split the SWIS into islanded power systems. – None of the respondents identified plans to modify existing FOS or equivalent regulations to include a specific RoCoF requirement. However, many expressed interest in the outcome of the Reliability Panel's review of the NEM FOS.

RoCoF Topic	Summary of Findings
	– Specifying a safe RoCoF limit in the NEM FOS in a similar manner to the WEM FOS may assist in maintaining system security and provide better guidance for market participants regarding the RoCoF they should experience. – Many system operators apply operational practices in order to maintain RoCoF within historically acceptable levels. For example, EirGrid developed the Look Ahead Security Assessment Tool that assesses future RoCoF and nadir in real time. – If a safe RoCoF limit is to be included in the NEM FOS, the operating practices adopted in other jurisdictions may help inform an appropriate initial setting.

Our findings indicate that it is prudent to consider the security implications of RoCoF. Both Western Australia and Ireland measure RoCoF over a 500 ms rolling window. Western Australia's limit is 0.25 Hz over 500 ms (0.5 Hz/s). Ireland's limit is 0.5 Hz over 500 ms (1 Hz/s). In addition, ENTSO-E has produced advice based on a review of historical incidents that emergency control schemes may not be able to prevent blackouts if RoCoF exceeds 0.5 Hz measured over 500 ms (1 Hz/s).

Largest Contingency

The survey identified that different approaches are adopted to manage the size of the largest credible contingency, including:

– Hawaii Electric: A standard connection process for generating units less than 20 MW discourages larger unit sizes.

– AEMO WA: While there is no specified limit for the largest acceptable credible contingency, energy dispatch in the WEM allows for co-optimisation to constrain generation to reduce the contingency size and the associated cost of procuring contingency reserves – where this leads to a lower cost outcome. This practice will likely discourage connections that increase the size of the largest credible contingency.

– National Grid ESO: This is the only survey respondent that has specified the largest permissible credible contingency size in technical regulations. The Security and Quality of Supply Standard (SQSS) was amended on 1 April 2014, increasing the maximum contingency size expressed as the maximum infeed loss from 1320 MW to 1800MW [1].

As no operators (except National Grid ESO) have a contingency size specified in a standard, and none are considering changing this, the survey feedback does not provide evidence to support the inclusion of a limit on the largest credible contingency size in the NEM FOS. The economic and security trade-offs are potentially better managed through other grid connection processes. We note that AEMO and transmission network operators manage the size of connecting generators through the connections process by considering the impact on inter-regional power transfer.

Frequency Time Error

The survey responses support the following key findings regarding frequency time error:

– Only the WEM in Western Australia and the NEM specify an explicit frequency time error limit in the applicable frequency operating standard:
  - WEM – time error <10 s for 99% of the time over any rolling 30 day period
  - NEM – time error <15 s

– Most of the respondents currently correct time error, either because it's perceived to be operational best practice or for legacy reasons. A review completed by NERC in 2015 recommended ceasing time error correction, and it appears that the practice is in the process of being suspended in North America [2].

– All survey respondents agree that an accumulated time error is unlikely to impact customers adversely. NERC completed an industry survey in 2008, supporting this view [3].

The review of time error correction completed by NERC across the period from 2008 to 2015 suggests that there may be little value in continuing to correct time error in the NEM. However, experience in Hawaii suggests that even if the requirement to control to a particular time error is removed from the NEM FOS, there could still be value in monitoring time error. Investigating the observed trends might highlight a need to adjust frequency control settings.

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1. Introduction

1.1 Purpose of this report

The AEMC is coordinating the delivery of independent advice prepared by GHD to inform the Reliability Panel's review of the Frequency Operating Standard (FOS) for the National Electricity Market (NEM). This independent advice complements related advice provided by the AEMO as well as analysis undertaken by the AEMC. GHD's advice and analysis will help inform the Panel's determination when considering the following high-level question:

»How should limits on post-contingent Rate of Change of Frequency be specified in the Frequency Operating Standard?«

As extensions of this work, the following high-level questions are also explored:

1. Should the NEM FOS specify a maximum permissible size for a credible single contingency event?
2. What is the value of maintaining a limit on frequency time error in the NEM FOS?

This advice is informed by a review of relevant literature, as discussed in section 2.2, and a survey of system operators, as discussed in section 3. We anticipate that the AEMC may publish this report to allow feedback from interested parties to inform the Reliability Panel's review of the NEM FOS.

1.2 Terminology used in this report

Abbreviations and terms common throughout this report are introduced in Table 2 below.

Table 2 Acronyms and abbreviations

Abbreviation	Description
AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
DC	Direct Current
DER	Distributed Energy Resource
DNSP	Distribution Network Service Providers
FOS	Frequency Operating Standard
GHD	GHD Pty Ltd
GPS	Generator Performance Standards
Hz	Hertz
ISP	[AEMO] Integrated System Plan
IBR	Inverter Based Resource
ms	Millisecond
nadir	The frequency nadir is the lowest frequency reached following a contingency event
NEM	National Electricity Market
NER	National Electricity Regulation
PV	Photovoltaic

Abbreviation	Description
SQSS	Security and Quality of Supply Standard for the Great Britain National Electricity Transmission System
RoCoF	Rate of Change of Frequency
UFLS	Under Frequency Load Shedding
VRE	Variable Renewable Energy
WA	Western Australia
WEM	Wholesale Energy Market

1.3 Scope and limitations

This report: has been prepared by GHD for The Australian Energy Market Commission and may only be used and relied on by The Australian Energy Market Commission for the purpose agreed between GHD and The Australian Energy Market Commission as set out in section 1 of this report.

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

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

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

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

GHD has prepared this report on the basis of information provided by The Australian Energy Market Commission and others who provided information to GHD (including Government authorities), which GHD has not independently verified or checked beyond the agreed scope of work. GHD does not accept liability in connection with such unverified information, including errors and omissions in the report which were caused by errors or omissions in that information.

1.4 Assumptions

GHD has assumed that information provided by each system operator is correct. The information provided was not independently verified.

2. Context

2.1 The Frequency Operating Standard

The existing NEM FOS is silent on RoCoF and does not include any requirement to control RoCoF within a specified limit. The absence of a specified RoCoF limit in the FOS creates some doubt regarding the RoCoF that AEMO should seek to maintain following different types of contingency events.

The existing NEM FOS specifies limits for the acceptable frequency variation under specified conditions or following specified events. For instance, the NEM FOS requires that, following a separation event on the mainland, the frequency be contained within the 49.0 Hz to 51.0 Hz band. While this does not explicitly limit the RoCoF experienced during a separation event, it could be argued that the standard implies that the RoCoF experienced is manageable, avoids worsening of the disturbance, and allows for available controls to contain the frequency disturbance within the range specified in the NEM FOS.

Including a specific RoCoF limit within the NEM FOS may assist AEMO in managing system security by providing a more explicit basis for setting requirements for service to achieve the RoCoF limit. This approach may also help stakeholders to understand the RoCoF limits and ride-through requirements expected in the NEM.

Generator Performance Standards (GPS) specify the requirement for generating systems to maintain continuous, uninterrupted operation in response to frequency disturbance. Schedule S5.2.5.3 of the National Electricity Rules (NER) specifies that to meet the:

– Automatic access standard: A generating system must remain in continuous, uninterrupted operation unless RoCoF exceeds 4 Hz/s for more than 0.25 s, 3 Hz/s for more than 1 s, or other such range as determined by the Reliability Panel.
– Minimum access standard: A generating system must remain in continuous, uninterrupted operation unless RoCoF exceeds 2 Hz/s for more than 0.25 s, 1 Hz/s for more than 1 s, or other such range as determined by the Reliability Panel.

While generator RoCoF ride-through requirements are specified in Schedule S5.2.5.3 of the NER, there have been few instances where the NEM frequency has actually varied at a rate that approaches those requirements. As such, there is a lack of empirical evidence confirming how the power system would perform if exposed to a high RoCoF consistent with the generator ride-through requirements.

2.2 Observations from document review

GHD has reviewed the following documents to help inform our consideration of the need for a RoCoF limit to be included in the NEM FOS and potential options for setting such a standard:

– GE Energy Consulting report titled "Advisory on Equipment Limits associated with High RoCoF" [4]
– ENTSO-E guidance document titled "Rate of Change of Frequency (RoCoF) withstand capability" [5]
– AEMO report titled "Fast Frequency Response Implementation Options: Technical advice on the development of FFR arrangements in the NEM" [6]
– Other documents related to the AEMC fast frequency response rule change, as are relevant [7]
– Documents published with the WEM FOS review. Including the:
    - Energy Transformation Taskforce information paper titled "Revising Frequency Operating Standards in the SWIS" [8]
    - Changes to the WEM rules for the new WEM FOS [9]
    - AEMO guidance document titled "Rate of Change of Frequency Sensitive Equipment" [10]

The GE Energy Consulting report [4] presents information on technology-specific issues that might impact the ability of network equipment and generating equipment to ride-through high RoCoF events. The report suggests that the highest risks associated with RoCoF ride-through may be coupled with the performance of gas turbines. Concerns relate to the potential for a RoCoF event to rapidly change the speed of the gas turbine and destabilise the fuel combustion process and thereby potentially trip the generator.

The report notes that the actual vulnerability of a particular generator will depends on many factors including the operating conditions at the time of the RoCoF event, the design of the gas turbine, the design and tuning of the gas turbine control system and the gas turbine protection and trip settings. The report identifies that while grid codes, such as the NER, often specify ride-through requirements over 2 Hz/s, there is a lack of empirical experience confirming the ability to ride through such events. Historically, power systems have tended to operate with significant levels of synchronous inertia, which means that the RoCoF following contingency events is well below the ride-through levels specified in grid codes. The GE report cautions against assuming that a generator will be able to meet its ride-through requirement unless that level of performance has been validated via modelling or testing. The report indicates that the cost of such testing could be significant (costing more than $1m).

The ENTSO-E guideline on RoCoF withstand capability makes a similar point stating, “the main concerns of thermal power generating modules about high RoCoF are instability and reduced life time of their assets (both electrical and mechanical) due to wear and tear. Since df/dt capability was not a design requirement historically, no specific design criteria or controller system features to counter high df/dt events as well as no protection scheme to disconnect purely due to df/dt measurements have been reported to ENTSO-E” [5]. This report by ENTSO-E provides guidance regarding the setting of RoCoF ride-through requirements in grid codes. The guideline suggests the following minimum RoCoF ride-through standard:

– ±2 Hz/s for a moving average of 500 ms window
– ±1.5 Hz/s for a moving average of 1000 ms window
– ±1.25 Hz/s for a moving average of 2000 ms window

We have specifically included in the survey questions seeking to understand whether the various system operators can identify RoCoF events that led to the tripping or disconnection of generators at levels below the RoCoF ride-through setting of the relevant grid code. We have also sought to understand the applicable RoCoF ride-through requirement for each power system covered by the survey.

The AEMO technical advice submitted to the AEMC to assist with its consideration of the FFR arrangements for the NEM [6] identifies that inertial support and FFR both provide a valuable response. However, they are fundamentally different and should not be combined into the same service. The AEMO technical advice identifies that FFR can be classified into various forms of response, including:

– An inertial-like service, such as the synthetic inertia provided by a wind farm or a battery energy storage system operating to emulate the inertial response from a synchronous generator, and
– A service operating as a fast-acting contingency frequency control ancillary service (CFCAS) that provides a rapid and sustained response to a frequency disturbance.

As illustrated in Figure 2, the inertial response assists in controlling RoCoF but does not provide a sustained injection of active power and therefore does not explicitly work to correct the frequency disturbance. The sustained response from the CFCAS like FFR works to counter the frequency disturbance.

This observation is important as it identifies the potential value of including a specific RoCoF requirement in the NEM FOS. If such a requirement was included in the NEM FOS, it might provide a more explicit means for AEMO to identify the need for inertia and inertia-like FFR services.

The revisions recently introduced into the FOS for the Wholesale Electricity Market (WEM) in Western Australia recognise the value of including a RoCoF requirement. As noted in the changes to the WEM Rules [9], the WEM FOS now includes the following RoCoF requirements:

– Safe RoCoF limit for intact system = 0.25Hz over any 500 ms period[1]
– Safe RoCoF limit for islands within the SWIS = 0.25Hz over any 500 ms (reasonable endeavours)

Several changes are being implemented in the WEM, including the implementation of security-constrained dispatch and a new Essential System Services (ESS) framework. The new ESS framework includes the procurement of RoCoF control services. As reported in the AEMO guidance on RoCoF sensitive equipment [10], it is expected that AEMO will procure RoCoF control service to ensure that:

– the RoCoF is restricted to below the Safe RoCoF Limit; and

[1] This is equivalent to limiting RoCoF to 0.5 Hz/s measured over 500 ms

– minimum frequency requirements are maintained by allowing a trade-off between the amount of reserve required and the amount of inertia on the power system.

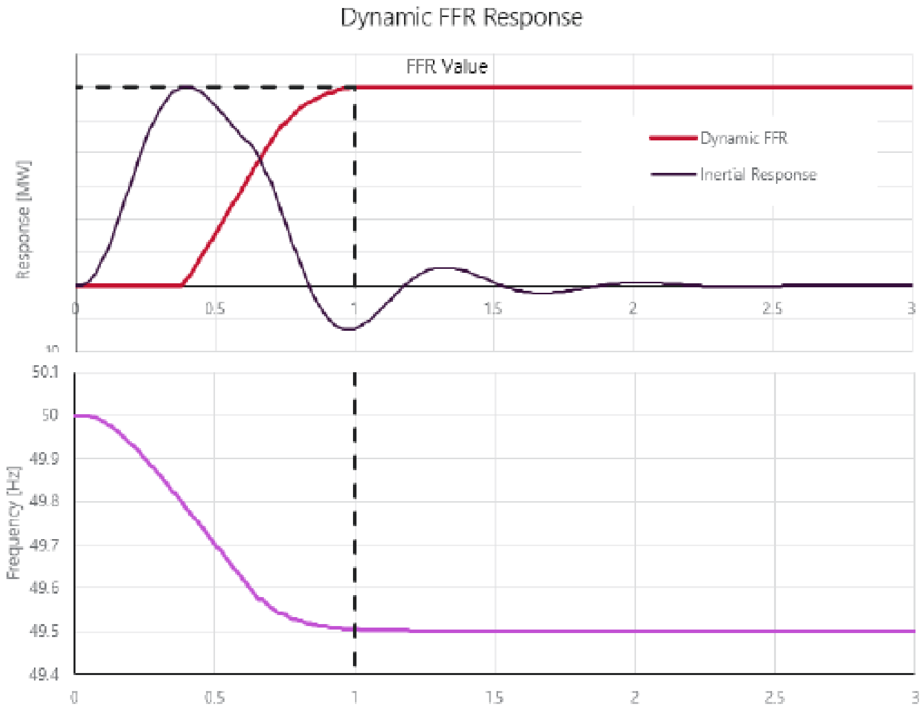


Figure 2 ***Comparing CFCAS-like FFR and inertial response [6][2]***

The cost of procuring RoCoF control services will be recovered by applying a causer pays approach, in which costs are recovered from those facilities with a RoCoF ride-through capability lower than a benchmark set by AEMO and referred to as the RoCoF Ride-Through Cost Recovery Limit.

The survey is designed to understand whether system operators seek to maintain a particular RoCoF limit and the measures adopted to control RoCoF.

A number of the reference documents raise concerns regarding the appropriate measurement of RoCoF. Key issues raised include:

– The potential for transients and voltage waveform distortion to result in the erroneous measurement of frequency and rate of change of frequency.
– Recognition that the RoCoF is unlikely to be uniform at all locations across the power system during large frequency disturbances. This is illustrated in Figure 3, which shows frequencies measured at different locations in Great Britain for a significant power system disturbance in 2012.
– The choice of measurement window may exacerbate issues with more significant variations, likely with shorter measurement windows.
– While a shorter window length may risk distortion, too long a measurement window allows primary frequency response to influence the measured frequency change and hence the detected RoCoF.

To help inform the Reliability Panel on RoCoF measurement practices, the survey includes questions that explore how system operators approach the measurement of RoCoF.

[2] Reproduction of Figure 7, titled “intertial response example” from the AEMO technical advice on the development of FFR arrangements in the NEM.

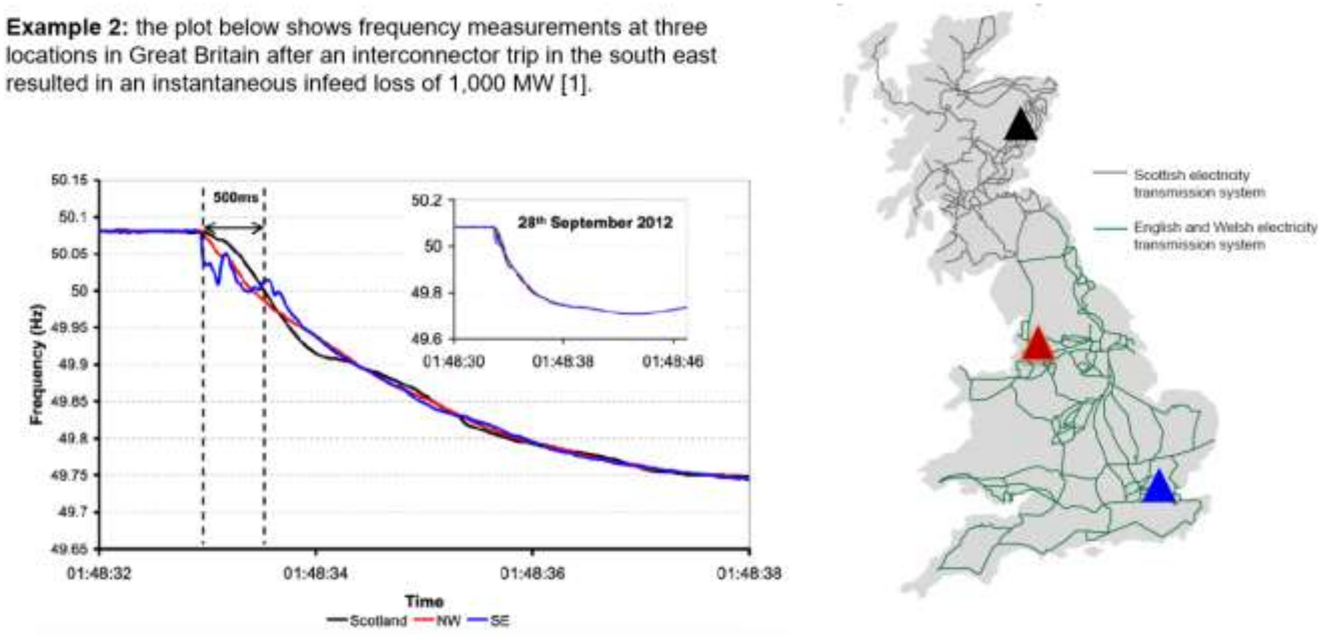


Figure 3 Frequency variation at different locations in the Great Britain Power system (Sourced from National Grid ESO [11])

In addition to seeking feedback on the approach to managing RoCoF, questions have been added to the survey that explore operator practices for:

– The specification of the largest contingency that can be accommodated within the specified power system. The questions seek to understand whether, via connection processes, grid codes, or other means, system operators enforce a limit on the size of the largest single contingency that can connect to their power system.
– The management of frequency to control the amount of frequency time error. The NEM FOS specifies that the accumulated time error for the interconnected mainland system must be contained to 15 seconds. To achieve this requirement, AEMO regularly uses the AGC system to correct the time error. The survey will explore whether it remains common practice for system operators to monitor time error and intervene to correct any accumulating error.

3. Survey development

Figure 4 illustrates the process followed to develop and execute the survey of system operators.

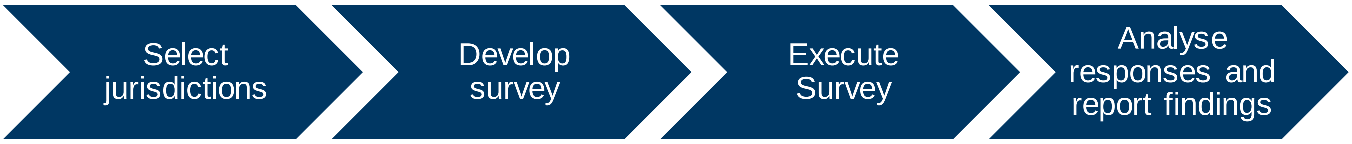


Figure 4 Survey process

The process involved the following phases of work:

- The first phase involved the selection of the set of power systems and system operators invited to participate in the survey, as discussed in Section 3.1
- The second phase involved developing the survey questions, as discussed in Section 3.2
- The next phase involved circulating the survey and arranging interviews with the various system operators, as discussed in Section 3.3
- The last step in the process involves documenting the information obtained through the survey. Section 4 summarises the information obtained from each survey respondent, while Section 5 presents key conclusions drawn from considering all survey responses

3.1 Jurisdiction selection

The following set of jurisdictions was identified through discussion with the AEMC and AEMO. The aim was to include in the list entities that met one of the following criteria:

- Is known to have already experienced high RoCoF events or actively engaged in activities to control RoCoF. Entities meeting this criterion included EirGrid and the Hawaiian System Operators
- Known to have a RoCoF limit specified in its frequency operating standard or equivalent regulations. AEMO, in its role as WEM system operator, met this criterion
- Entities involved in the operation of a significant power system that is experiencing increasing levels of renewable generation, the retirement of synchronous generation, and are concerned with managing increasing RoCoF. Entities meeting this criterion included ENTSO-E, National Grid ESO, NERC and the Coordinador Eléctrico Nacional

Figure 5 illustrates the power systems that were included in the survey. The purple areas indicate the regions covered by an international coordinator or authority. Pink areas signify where we have received a survey response from the relevant power system operator. This includes:

- AEMO for the WEM
- National Grid ESO for Great Britain
- EirGrid for Ireland
- Hawaii Electric and KIUC for the Hawaiian Islands
- Coordinador Eléctrico Nacional for Chile

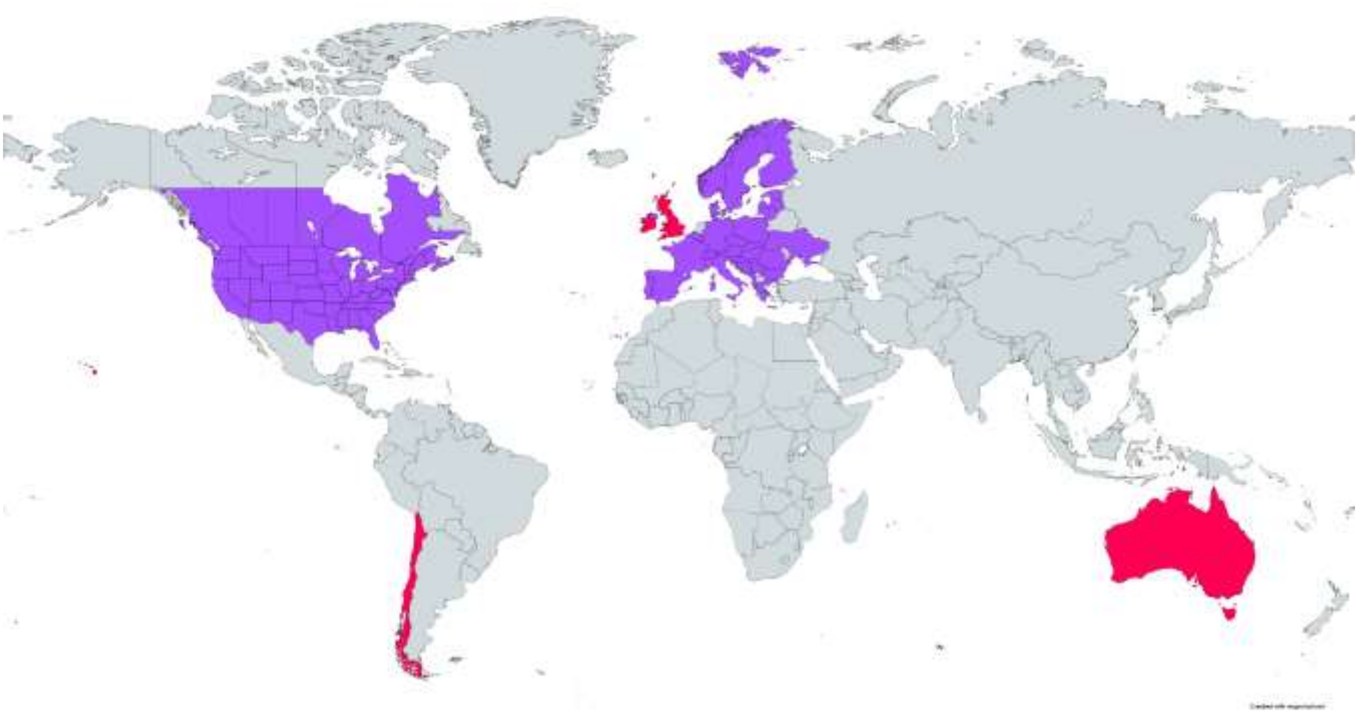


Figure 5 *Map illustrating surveyed jurisdictions*

3.2 Development of survey questions

GHD developed an initial set of survey questions to address the key areas of concern highlighted in Section 2.2. The survey was refined after considering feedback provided by the AEMC and AEMO. The resultant survey questions appear in Appendix A and are organised to address the key topics illustrated in Figure 6.

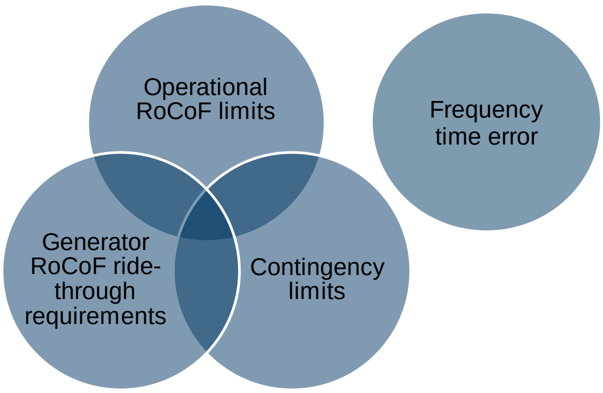


Figure 6 *Illustration of the relationship between survey topics*

Broadly, the questions intend to understand, for each power system:

– The experience with high RoCoF events
– How RoCoF ride-through requirements for generators are specified
– If any RoCoF-triggered protection issues have been observed
– Whether power system security standards specify a RoCoF limit and the processes used by the system operator to control the RoCoF to remain within the specified limit
– Whether the system operator expects to see changes in processes for managing RoCoF introduced in the future and the triggers to introduce those changes

For contingency limits, the questions revolve around whether a largest credible contingency size is specified in grid codes or other regulations and how those limits are enforced.

Finally, we queried whether operators monitor frequency time error and whether they take any action to correct observed errors and control the size of the error to a particular limit.

3.3 Survey execution

Ahead of issuing the survey, GHD contacted each entity to identify the appropriate recipient and confirm the willingness of each entity to respond to the survey.

Surveys were emailed to all recipients in early August 2022. GHD then organised an interview with each recipient of the survey. The interviews were arranged as a virtual meeting and provided the opportunity to review the survey responses and clarify the information provided in each response. The Interviews were completed across August and early September 2022.

Through the interviews, GHD was also able to gain access to additional supporting documents, further elaborating points made on the initial survey response.

Revised versions of the survey responses were provided to each respondent after the interview to allowf for confirmation that all clarifications had been appropriately captured.

4. Survey results

This section presents key findings from the survey, including insights gained through the interviews with survey recipients. As the survey responses contain confidential information, they are not included in this report.

4.1 Europe

4.1.1 Power system overview

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association for the cooperation of the European transmission system operators (TSOs). The 39 member TSOs representing 35 countries are responsible for the secure and coordinated operation of Europe's electricity system, the largest interconnected electrical grid in the world.

Figure 7 Map highlighting ENTSO-E member countries [12]

ENTSO-E and its members ensure the security of the interconnected power system. ENTSO-E also works to coordinate the development of the European interconnected electricity markets [13]. The European TSOs operate independently and are responsible for their respective jurisdictions [12].

The European Union has set ambitious net greenhouse gas emissions reduction targets. Notably, this includes a 55% reduction in emissions by 2030 compared with 1990 and to be climate-neutral by 2050 [14]. As a result, a dramatic increase in Variable Renewable Energy (VRE) is occurring across most member countries as the energy sector seeks to move away from fossil fuel based generation. Consequently, inertia is reducing and will continue to decrease. ENTSO-E has, for some time, been considering the challenge of operating a low inertia power system with an increased potential for high RoCoF events.

Two key RoCoF focus areas for ENTSO-E include:

- Ensuring appropriate RoCoF ride-through requirements are set through the various European grid codes, and
- Providing guidance for assessing the vulnerability of the power system to high RoCoF events. This work is focussed on considering whether existing emergency control schemes can minimise the risk of blackouts should portions of the grid become disconnected from the rest of the European synchronous grid.

4.1.2 Findings

The key results of the survey are summarised below.

4.1.2.1 RoCoF

Operational RoCoF limits

ENTSO-E has reviewed several actual events that resulted in the separation of synchronous grids into disconnected islands. The review considered the RoCoF experienced and whether the available emergency control schemes, such as UFLS, were able to arrest the change in frequency and prevent a blackout. The study is documented in the ENTSO-E report titled "Inertia and Rate of Change of Frequency" [15].

A key finding of the report is that events resulting in RoCoF values higher than 1 Hz/s, measured over 500 ms, can compromise the ability of emergency controls to prevent a blackout. Consequently, a RoCoF greater than 1 Hz/s is currently regarded as potentially not manageable. For consistency, ENTSO-E measures RoCoF over a 500 ms rolling average.

ENTSO-E recommends that member TSOs identify potential separation events and assess the RoCoF likely to be experienced. Should the RoCoF be predicted to exceed 1 Hz/s, TSOs are encouraged to review the adequacy of emergency controls and/or take operational measures to reduce the expected RoCoF. ENTSO-E expects that the 1 Hz/s threshold may remain for some time, and it may be able to be lifted in the future. However, that would require redesigning emergency controls across the European grid, which is a significant undertaking.

Generator RoCoF ride-through capability

The 1 Hz/s safe RoCoF limit recommended by ENTSO-E is lower than the generator ride-through requirements specified in many of the grid codes for the countries forming the Continental European grid. Typically, those grid codes identify ride-through requirements in the range of 2 to 2.5 Hz/s [16, Sec. RfG – Frequency Issues, rows 17–20].

Turbine manufacturers have noted that ensuring compliance with a ride-through greater than 1-2 Hz/s over 500 ms is challenging. Performing studies and creating and implementing a mitigation plan to ensure compliance with more onerous RoCoF ride-through requirements can alone cost up to 5% of plant CAPEX to complete [17].

4.1.2.2 Largest contingency

ENTSO-E does not have a specified largest contingency size. Therefore, generator connection sizes are not restricted.

Across Europe, TSOs may implement operational restrictions to reduce the contingency size to maintain system security. One known example occurs where, due to limited interconnection, a dynamic limit is implemented to adjust the maximum contingency size.

4.1.2.3 Frequency time error

Two control centres oversee frequency monitoring within the Continental European grid. These control centres communicate directly with the TSOs to control the frequency and may also monitor and correct time error. However, there does not appear to be any specific time error requirement in the relevant frequency standards.

ENTSO-E did not identify that a frequency time error would have any detrimental impact on electricity consumers.

4.2 Great Britain

4.2.1 Power system overview

National Grid ESO is the system operator for the interconnected synchronous system spanning the islands of Great Britain. Ireland and Northern Ireland form a separate power system which is operated by EirGrid, as discussed in section 4.3.

Figure 8 ***Map highlighting Great Britain***

As an island, the network is more exposed to RoCoF events than the nearby, larger European system. However, because it is larger than the transmission network in Ireland and Northern Ireland, RoCoF is not as great a concern as it is for Great Britain's close neighbour.

Presently, six subsea interconnectors exist with a combined capacity of 6 GW. These interconnectors are the:

- IFA to France (2 GW)
- IFA2 to France (1 GW)
- BritNed to the Netherlands (1 GW)
- Nemo Link to Belgium (500 MW)
- Moyle to Northern Ireland (500 MW)
- East-West to the Republic of Ireland (500 MW)

Many more interconnectors are proposed, and seven, totalling 8.5 GW, are in development and planned for completion by the end of 2025 [18].

While Great Britain still has a significant proportion of synchronous generation, strict emissions reduction targets are set, and the generation mix is increasingly trending towards renewable sources. The dominant form of VRE is expected to be wind. RoCoF is considered and will increasingly be a challenge.

4.2.2 Findings

The key results of the survey are summarised below.

4.2.2.1 RoCoF

Operational RoCoF limits

No operational or legislated limit for RoCoF is in place. Instead, National Grid ESO completes an annual Frequency Risk and Control Report (FRCR) [19]. This report considers the security of the system and balances the cost efficacy of securing the system for particular contingencies against the risks poses by those. The FRCR considers combinations of contingency events that may produce a high RoCoF. While there is no explicit standard to maintain RoCoF below a certain level, the requirement to update the FRCR annually is specified in the Security and Quality of Supply Standard (SQSS).

Generator RoCoF ride-through capability

The Distribution Code of Licensed Distribution Network operators of Great Britain specifies a requirement for embedded generation to ride through 1 Hz/s over a 500 ms rolling average [20].

The Grid Code specifies requirements for transmission-connected generators [21]. Transmission-connected generation is required to ride through RoCoF events provided the RoCoF does not exceed 1 Hz/s over a 500 ms period. However, National Grid ESO notes that some legacy wind farms have lower RoCoF ride through capability, and these generators are not expected to ride-through high RoCoF events.

Observed high RoCoF events

Reportable events are published on the National Grid website [22].

On 9 August 2019, an event occurred which resulted in a significant amount of embedded VRE generation being disconnected [23]. Investigation of the event identified that a substantial amount of embedded VRE generation (20 GW) was fitted with Loss of Mains (LoM) protection that would disconnect the generation if RoCoF exceeded 0.125 Hz/s. During the event on 9 August 2019, a portion of the Great Britain power system experienced RoCoF >0.125 Hz/s and this resulted in the disconnection of embedded generation. The LoM protection is a connection requirement in Great Britain, intended to disconnect generation within portions of the power system that become disconnected from the rest of the network.

In response to the 9 August 2019 event, the National Grid ESO and the Energy Networks Association ran a program titled the Accelerated Loss of Mains Change Programme (ALoMCP) [24], [25]. This program followed a retrospectively applied new requirement in the Distribution Code. All generators were required to ensure compliance with the revised LoM protection settings. The revised LoM requirement was for protection to be set above 1Hz/s. The program offered funding to some generators to assist with upgrades where required. Following the conclusion of the ALoMCP, the risk of embedded VRE generation inadvertently becoming disconnected has been significantly reduced, with less than 2 GW of generation with legacy LoM settings remaining.

Experience reported by Electricity North West, a distribution system operator in Great Britain, indicates that the investigations undertaken by its customers to allow the change to the LoM protection cost over £1m [26]. The LoM program was designed to change LoM protection so that it does not operate unless RoCoF exceeds 1 Hz/s over 500 ms. This is a substantial increase from the previous 0.125 Hz/s LoM settings.

4.2.2.2 Largest contingency

The SQSS specifies 1800 MW as an infrequent infeed loss risk and requires that no single contingency exceeds this loss of infeed [27]. This was increased in 2014 from 1320 MW to correspond with the addition of a new, large nuclear generating unit.

4.2.2.3 Frequency time error

Frequency time error is not tracked or corrected.

4.3 Ireland

4.3.1 Power system overview

The transmission networks of Ireland and Northern Ireland are interconnected. Together, they form the Synchronous System of Ireland and Northern Ireland that EirGrid operates via EirGrid TSO in Ireland and SONI TSO in Northern Ireland. The system is run as a single market. While Ireland and Northern Ireland are members of ENTSO-E, the Eirgrid operated network is not yet directly connected to the continental European grid.

Figure 9 ***Map highlighting Ireland and Northern Ireland***

Two HVDC connectors exist, and both provide a connection to Great Britain. These are the 500 MW HVDC Moyle interconnector [28] to Scotland and the 500 MW HVDC East to West interconnector [29] to Wales. Two new, larger interconnectors are in development. These will connect to Great Britain (500 MW) and France (700 MW). The development of additional interconnectors will drastically increase the level of interconnection between systems.

Significant renewable generation targets of 40% by 2020 and 80% by 2030 have been set. Most of the 2020 renewable generation is provided by wind sources. It is expected that a significant increase in wind and solar generation will be required to meet the target of 80% renewables by 2030.

EirGrid indicated that it is presently possible for the transmission system to operate with up to 75% of the generation provided by VRE sources. A method called System Non-Synchronous Penetration (SNSP) is employed to facilitate this. By 2030, EirGrid has a target of being able to operate the system at 95% VRE.

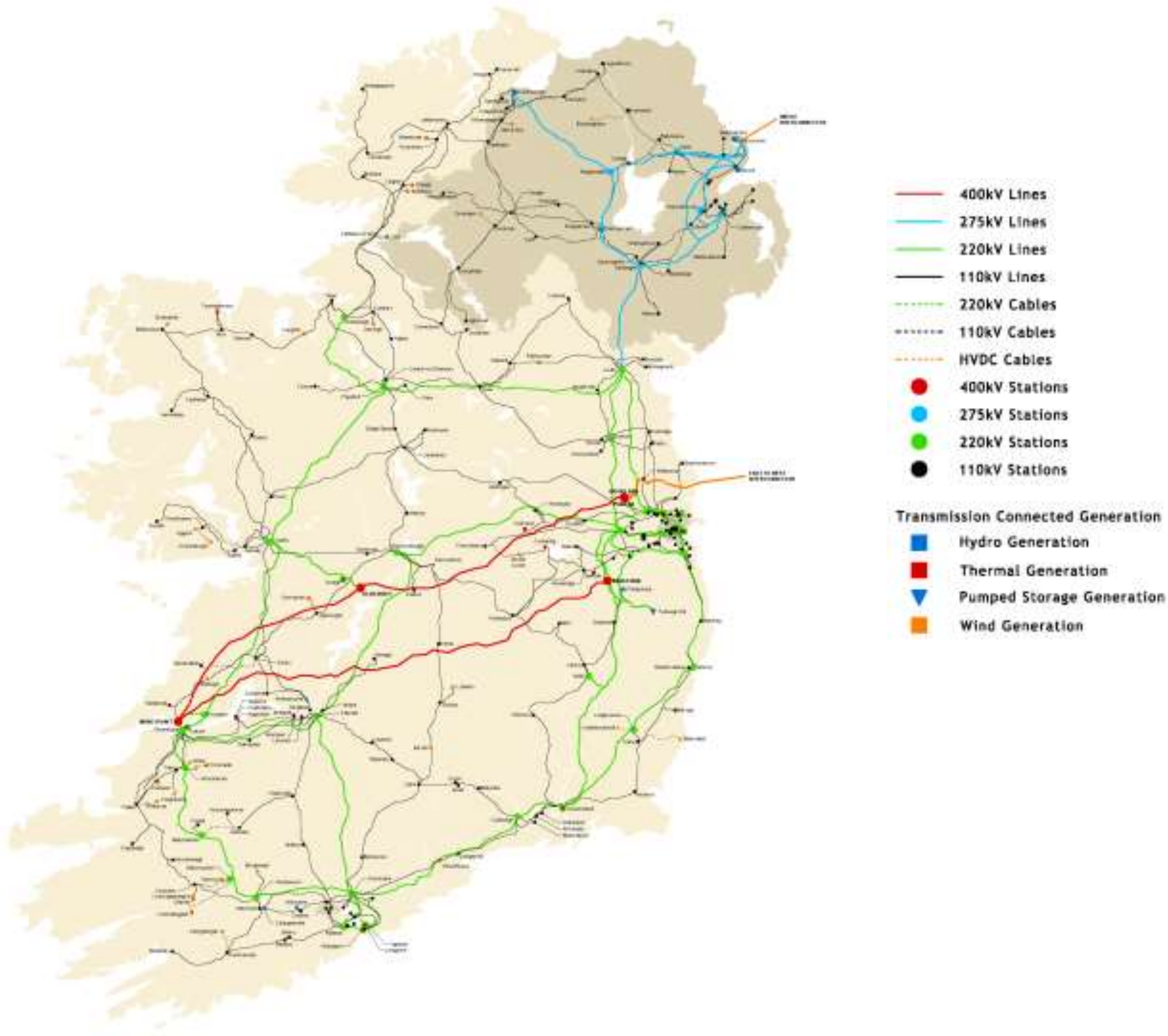


Figure 10 *EirGrid transmission and interconnector map. Figure sourced from EirGrid [30]*

4.3.2 Findings

The key results of the survey are summarised below.

4.3.2.1 RoCoF

Operational RoCoF limits

While EirGrid has not observed events that led to high RoCoF levels, studies considering RoCoF have been occurring for over ten years. Early in this program, RoCoF was identified as a potential future concern. As a result of studies in this program, a RoCoF limit is in use. This was initially 0.5 Hz/s over a 500 ms rolling window. However, this has been increased to 1 Hz/s over a 500 ms rolling window on a trial basis.

The 0.5 Hz/s limit was imposed while EirGrid worked with existing generators to verify their ability to ride through higher levels of RoCoF [31]. Based on the extensive testing undertaken, EirGrid is now satisfied that the operational RoCoF limit can be increased to 1 Hz/s over a 500 ms rolling window on a trial basis.

To support operators, EirGrid developed the Look Ahead Security Assessment Tool. This tool does a real-time assessment of system security and future generation schedules for both RoCoF and nadir. Operators employ this tool to ensure compliance with security standards.

Fast Frequency Response (FFR) services are procured, as required, to ensure the stability of the system. In addition, options for inertial support, including synchronous condensers and grid-forming IBRs, are being considered for future use.

Generator RoCoF ride-through capability

New generator connections are required to comply with the ENTSO-E RoCoF ride-through guidance of 2 Hz/s measured over 500 ms [5].

At the distribution level, Loss of Mains (LoM) protection was identified as at risk of operating during RoCoF events. This led to a change in the protection settings to prevent this from occurring.

4.3.2.2 Largest contingency

EirGrid does not have a specified maximum contingency size.

Operational reserves are sized to cover the largest credible contingency event. Presently, the largest contingency possible is the loss of a 500 MW interconnector. The largest contingency size will increase to 700MW when a planned new interconnection is commissioned. EirGrid is satisfied the benefits offered by greater interconnection capacity outweigh the costs of the additional system services required to cater for that greater contingency size.

4.3.2.3 Frequency time error

EirGrid control centres have a time error clock. Operators strive to keep this within 10 seconds by running the frequency higher or lower as needed. This intervention is done manually by operators.

Time error correction is considered to be a historical operational best practice. It is not required by any standard. Operators commonly view frequency time error as now being less important than in the past.

4.4 Chile

4.4.1 Power system overview

The Sistema Eléctrico Nacional (SEN) transmission grid in Chile is operated by the Coordinador Eléctrico Nacional (the Coordinador).

The SEN serves 98.5% of the population, and the Coordinador manages 649 companies. This includes generators, private transmission networks, distribution networks, energy storage facilities, and complimentary services.

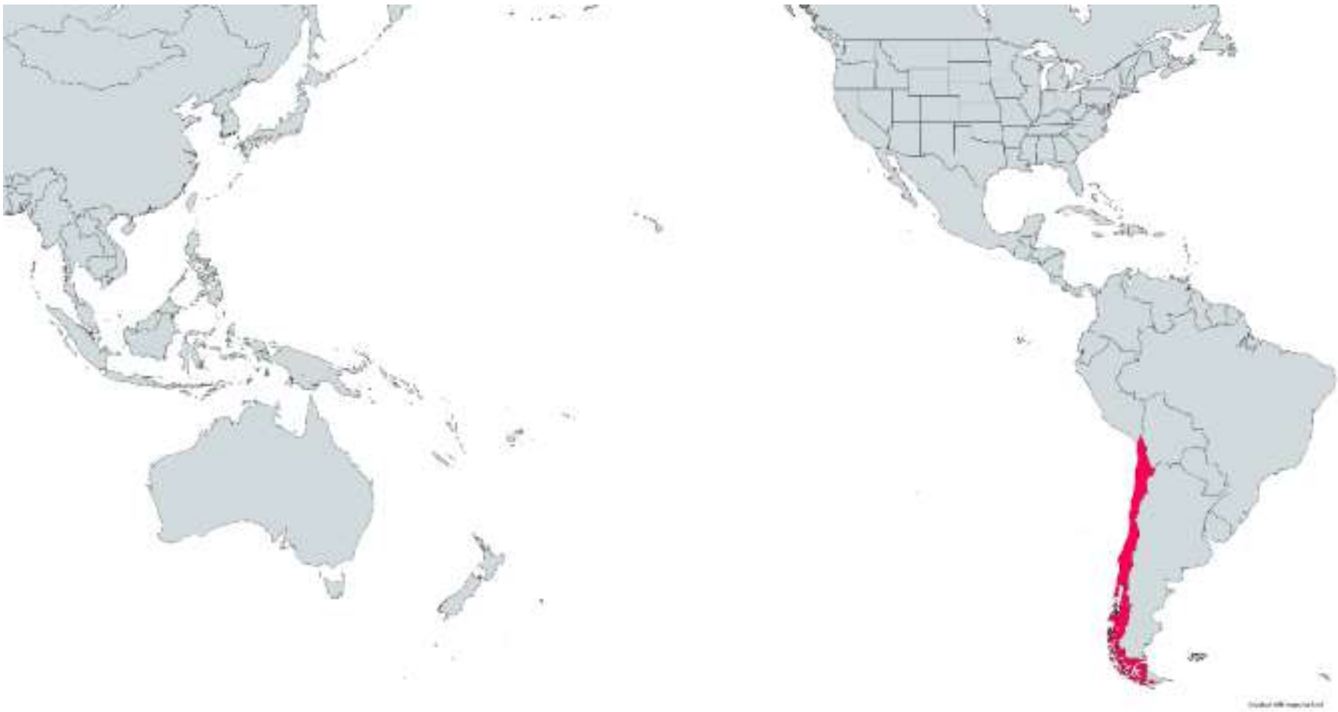


Figure 11 Map highlighting Chile

While this system does have one large 345 kV AC interconnector with Argentina and several smaller unregulated interconnectors, these do not contribute to the frequency control of the system. In addition, two smaller isolated systems (the Aisén and Magallanes systems at 64 MW and 107 MW, respectively) exist in Chile, but these are not considered in this discussion.

The SEN has an installed capacity of almost 31 GW and a span covering 3,100 km. It was selected for inclusion in the survey as it has some distinct similarities to the NEM. Notable among these is that both systems are long and 'stringy', and both are experiencing a rapid PV generation uptake.

Figure 12 Map of the SEN transmission network. Figure sourced from GENI [32]

4.4.2 Findings

The key results of the survey are summarised below.

4.4.2.1 RoCoF

Operational RoCoF limits

No operational RoCoF limit is in place for the SEN. System services are being considered to assist with maintaining system strength. If those services are provided by synchronous generators (such as hydro), then they will, by default, provide inertia.

Generator RoCoF ride-through capability

The Chile Grid Code requires all generating plant (regardless of technology) to ride-through RoCoF events of 2 Hz/s over a 500 ms period. However, this ride-through requirement is not explicitly tested during generator commissioning. Instead, generators are tested for frequency ride-through over defined timeframes. As such, confidence around RoCoF ride-though is limited.

Despite this, there have been no observations of generator tripping due to RoCoF. For the discussed system events, tripped generation was predominantly a result of under or over frequency relay operation. UFLS blocks (discussed in the next section) operated as intended, arresting the falling frequency.

RoCoF triggered UFLS

The SEN has two UFLS schemes. The first has six stages. The second is designated for extreme events and has three stages.

Stages 5 and 6, as seen in Table 3, are triggered by a combination of frequency threshold and RoCoF values.

Table 3 SEN UFLS scheme (provided by the Coordinador)

Stages	Setting	Demand [%]
Stage 1	48.9 Hz	2
Stage 2	48.7 Hz	3
Stage 3	48.5 Hz	4
Stage 4	48.3 Hz	6
Stage 5	49.0 Hz; -0.6 Hz/s	5
Stage 6	48.8 Hz; -0.6 Hz/s	5
Total		**25**

The special scheme for extreme events has three settings, all triggered at the same frequency threshold but by differing RoCoF values.

Table 4 SEN UFLS scheme for extreme events (provided by the Coordinador)

Stages	Setting	Demand [MW]
Stage 1	49.5 Hz; -0.9 Hz/s	159
Stage 2	49.5 Hz; -1.2 Hz/s	204
Stage 3	49.5 Hz; -1.9 Hz/s	281

4.4.2.2 Largest contingency

No largest contingency limit is defined for the SEN. Presently, the largest single unit is 400 MW. If a new connection seeks to exceed this, then studies will occur to assess the potential impacts. If increased frequency control reserves are required, then the generator may be constrained if necessary to optimise the cost of energy and system services.

4.4.2.3 Frequency time error

Time error is not tracked, and correction is not performed.

4.5 The United States of America

4.5.1 Power system overview

The North American Electric Reliability Corporation (NERC) coordinates six major interconnected regions.

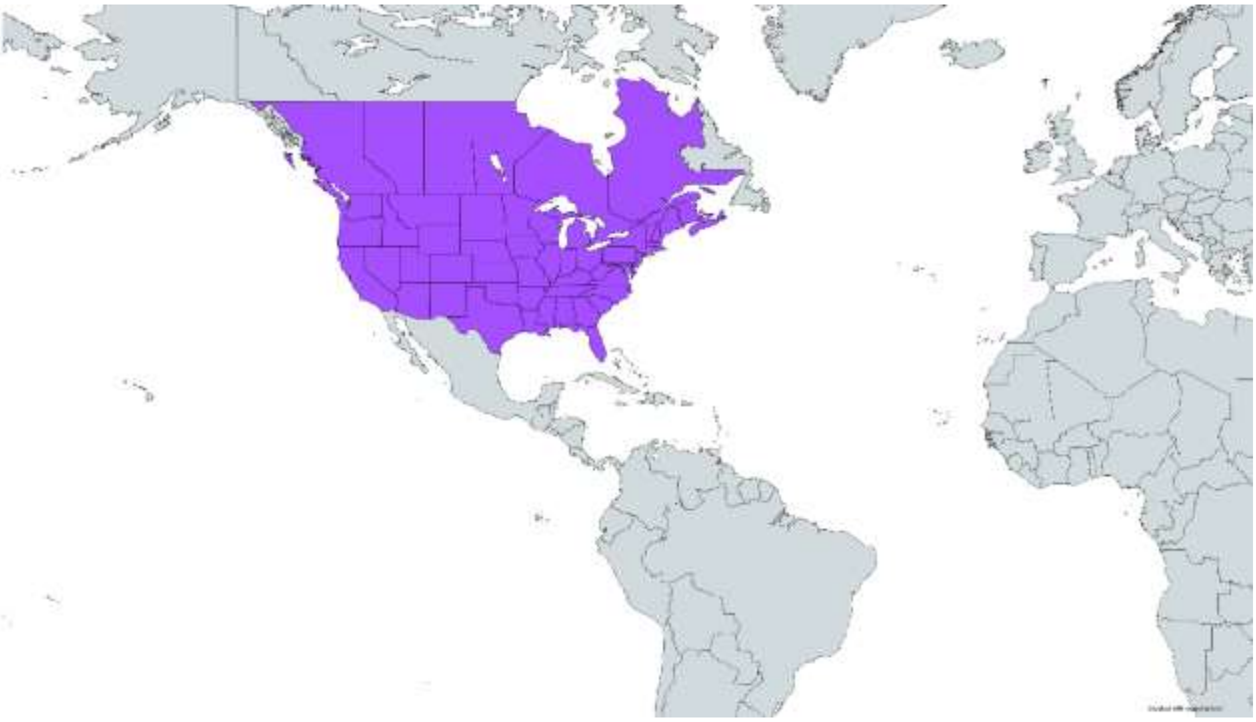


Figure 13 Map highlighting the NERC interconnected systems

Within regions, the transmission networks are highly interconnected, and renewables are yet to have a significant depth of penetration. The exceptions to this are Texas and California. Both states have considerable PV generation. However, California is heavily interconnected, whereas Texas is less so. As such, while the entire system was discussed in our interview, a particular focus was given to Texas.

4.5.2 Findings

The key results of the survey are summarised below.

4.5.2.1 RoCoF

High RoCoF events

Due to the vast scale of the network and because the generation mix is dominated by synchronous sources, a “high RoCoF” event is yet to occur.

The largest recorded RoCoF event is -0.2 Hz/s, measured over 500 ms. This occurred in Texas after multiple generators tripped offline.

NERC was not able to identify any events where the RoCoF resulted in a generator tripping.

Operational RoCoF limits

No operational RoCoF limits are in place.

NERC considers a “high RoCoF event” to be greater than 1 Hz/s measured over a rolling 500 ms window.

Generator RoCoF ride-through capability

Small generator requirements

For small generators of nameplate capacity less than 20 MW and excepting inverters rated for less than 10 kW, the Small Generator Interconnection Agreement applies [33]. This connection agreement calls upon relevant IEEE standards. This therefore includes IEEE 1547, which specifies a RoCoF requirement for DER [34]. This requirement varies from 0.5 to 3 Hz/s depending on certain criteria. The averaging window that applies is 100 ms.

Large generator requirements

For generators with a nameplate capacity greater than 20 MW, PRC-024-3 applies [35]. No RoCoF ride-through requirement exists in the standard. However, generators must remain online, provided the frequency stays within the specified limits. Hence, it is implied that a large generator should ride through any RoCoF event as long as the frequency remains within the bounds of the standard.

4.5.2.2 Largest contingency

The Grid Code and standards do not specify any limit for the largest loss of generation that can occur for a credible single contingency event.

4.5.2.3 Frequency time error

Frequency time error is currently monitored and corrected by a designated operator (the Reliability Coordinator) in each region [36], [37].

The existing NERC standards require time error correction to be initiated or terminated based on the limits specified in Table 5.

Table 5 Current time error correction settings for North America [38]

Time (seconds)	Initiation			Termination		
	East	West	ERCOT	East	West	ERCOT
Slow	-10	-2	-3	-6	+/-0.5	+/-0.5
Fast	+10	+2	+3	+6	+/-0.5	+/-0.5

NERC has initiated a review of manual time error correction, including issuing a survey seeking industry feedback on the proposal to cease applying time area correction. The review's findings are documented in a white paper [39], [40]. The white paper includes a recommendation that time error correction is ceased. Key reasons for the change include:

– A finding is that manual time error correction does not support the reliability of the power system. This finding appears to be based on observations that frequency seems to be further from 60 Hz while time error correction is being made
– A finding that grid frequency is not the appropriate source for alignment to official time and that are other more appropriate sources available
– Recognition that other standards provide an adequate specification of frequency control requirements

The survey reported in the white paper was issued in 2008 [3]. A summary of historical time error correction practices accompanied the survey and concluded that there does not appear to be any continuing need for time correction.

The information on the NERC website suggests that the recommendations in the white paper were endorsed for adoption in 2015, and manual time correction is being removed [2].

4.6 Hawaii Electric

4.6.1 Power system overview

Hawaii Electric manages four isolated systems across four separate islands. The generator mix is predominantly synchronous steam units with a mixture of IBR generators. These systems are relatively small, with the O'ahu power system being the largest, with a peak demand of approximately 1.2 GW [41].

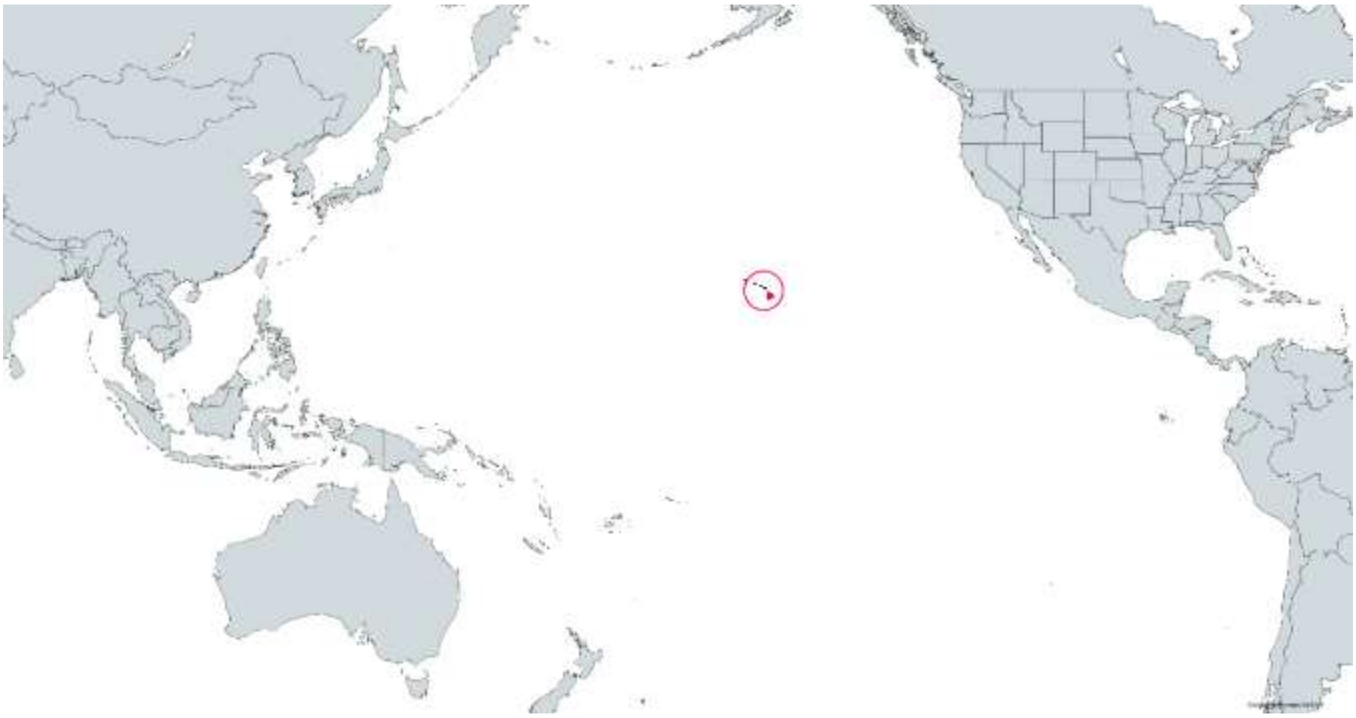


Figure 14 Map highlighting Hawaii Electric operated islands

4.6.2 Findings

A general increase in RoCoF has been observed, and many stability studies have been completed to analyse the present and future effects as IBR penetration increases. These findings will be discussed below.

4.6.2.1 RoCoF

Operational RoCoF limits

A formally defined RoCoF limit does not exist for the Hawaii Electric operated grids. Instead, Hawaii Electric controls the dispatch of generation to avoid situations where RoCoF leads to unstable outcomes when a contingency event occurs, such as if the frequency decline could not be arrested by the available primary frequency response and UFLS. Power system simulations exploring frequency stability determine the need to constrain generation dispatch. In extreme cases, those simulations identified the potential for RoCoF to reach 5 Hz/s following contingency events, depending on the level of inertia.

A load tripping (UFLS) scheme was established to trigger at a RoCoF of -2 Hz/s as a means of speeding up the under frequency protection, rather than waiting for the frequency trip-point. This was intended to provide more effective under frequency protection for the faster RoCoF conditions, thereby raising the nadir. A delay of 3 cycles was assigned. However, the scheme did not function as intended, as accurately measuring RoCoF is challenging, and measurement devices incorrectly triggered protection for non-contingency events. Hence, it has now been disabled. The unexpected operation of the scheme was triggered when a transmission breaker opened. The rapid change in power flow caused a shift in the voltage angle. As a result, the RoCoF UFLS relay interpreted the rapid change in angle as a RoCoF event and the load tripped, despite no actual RoCoF event occurring. i.e., this was a false positive.

The RoCoF based trip scheme was applied as it was anticipated that it could act more swiftly than a frequency triggered tripping scheme. By operating more rapidly, an improved nadir could be achieved, and the scheme could be more effective. However, given the challenges experienced with accurate RoCoF detection, an adaptive under frequency scheme has been derived where the block size is proportional to system demand. Blocks are dynamically populated with circuits based on real-time measurements. This scheme was necessary as circuit loads are greatly affected by DER. This scheme does not include RoCoF based tripping.Hawaii Electric is of the view that great care is needed when measuring RoCoF. 250 ms is used as a standard measurement time window when considering RoCoF, with RoCoF measurements made using phasor measurement units.

Generator RoCoF ride-through capability

New small-scale generators have a RoCoF ride-through requirement. This requirement has not been implemented retrospectively. Specifically, for DER, this is 3 Hz/s over a 0.1 second measurement period. Hawaii Electric observes that 3 Hz/s is, or will be, insufficient. Simulations indicate that RoCoF can be steeper than this. Hawaii Electric is investigating increasing the requirement to 5 Hz/s in the future.

One challenge concerning generator RoCoF ride-through was experienced several years ago after certain high-inertia synchronous steam generators were removed from routine operation. The remaining General Electric LM2500 units operating with liquid fuels, therefore, responded proportionally to the system's faster RoCoF and in accordance with the existing droop settings. A cascade event occurred on one island following a unit trip, as three generating units tripped on over-temperature protection. Investigation revealed that the increased RoCoF resulted in a more rapid increase in the active power requirements from units to align with the existing primary droop setting. Hawaii Electric observed this behaviour across three LM2500 units over two sites. This was rectified by programming a fuel valve limiter to avoid flooding the combustion chamber of LM2500 units following a sudden change in the required generation output. A key learning of Hawaii Electric's experience is that increased system RoCoF will reveal operational concerns that may not be apparent in desktop studies. This example is one of the few recorded instances where a synchronous unit was unable to ride through a RoCoF event.

Outside of this example, no problems with RoCoF ride-through were observed, and synchronous generators are expected to ride through high RoCoF events.

4.6.2.2 Largest contingency

Hawaii Electric does attempt to limit the largest credible generator contingency via the connection process. The limit is enforced through the planning criteria. However, the potential for legacy distributed resources tripping as a consequence of a disturbance is considered to be a greater risk than the trip of a single generating unit.

Hawaii Electric works with prospective generators that wish to connect where they would increase the size of the largest credible contingency. Procurement limits may be introduced, or an additional transmission line may be required. Regardless, a performance standard must be negotiated with Hawaii Electric.

4.6.2.3 Frequency time error

Time error measurement and correction are still in place. Hawaii Electric questions the value of continuing to perform time error correction. However, there is a perception that customers continue to value it.

With increasing IBR penetration, the generator's primary frequency response is more heavily relied upon. Hawaii Electric has had to increase the no-control dead band as it was experienced that marginal errors were being chased when taking frequency correction action.

4.7 Kauai Island

4.7.1 Power system overview

The Kauai Island Utility Cooperative (KIUC) operates the Kauai Island electricity grid. For this relatively small system, KIUC forms the role of generation, transmission, distribution, and system operator.

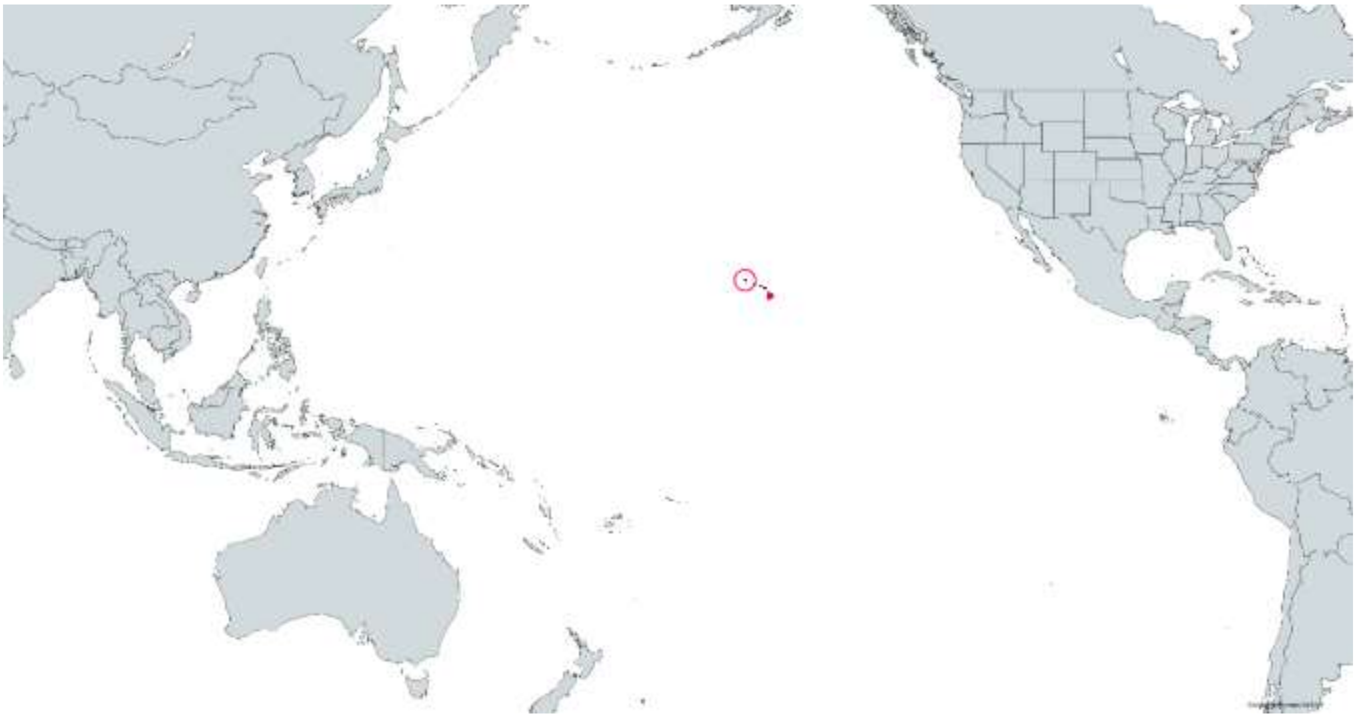


Figure 15 Map highlighting Kauai Island

The average energy demand on the KIUC system is about 50 MW. Generation is a mix of synchronous generation in the form of fossil fuel, biomass, and hydroelectric, and variable renewable generation in the form of solar and BESS. During the daytime, it is typical for this system to operate with 80% or more of the generation from IBRs.

4.7.2 Findings

The key results of the survey are summarised below.

4.7.2.1 RoCoF

Operational RoCoF limits

The largest single generator is 27 MW. Due to the relatively small scale of the grid, and the proportionally substantial size of the largest generator, historically, loss of generation events leads to high RoCoF. This has been dramatically helped by the addition of Battery Energy Storage Systems (BESS) over the last five years.

Operationally, RoCoF is not actively restricted or managed. There is no standard limiting RoCoF. KIUC regularly performs studies to consider all aspects of power system security, including frequency control, system strength, and RoCoF.

No RoCoF triggered protection scheme exists.

KIUC considers “high RoCoF” to be events greater than 10 Hz/s. Presently, KIUC does not have a standard defined timeframe for measuring RoCoF.

Generator RoCoF ride-through capability

Generators have a RoCoF ride-through requirement as part of the connection agreement. The value of this requirement is not publicly available.

Synchronous generators do not have a RoCoF requirement. However, KIUC has not observed issues with synchronous plant tripping due to RoCoF. While the synchronous generators do appear to have specific protection that responds to high RoCoF events, they may trip for large frequency deviations from 60 Hz.

4.7.2.2 Largest contingency

No largest contingency limit is specified by any standard. However, a 20 MW maximum limit is defined operationally. There is one 27 MW generating unit which is very large relative to the system. The loss of this unit is considered non-credible as, with the scale of the system, it is not feasible to manage.

The island has a large quantity of PV generation. While rare, KIUC has experienced variation in generation caused by intermittent cloud cover that approached or exceeded the defined contingency limit.

While new connections greater than 20 MW are allowed, they require an interconnection agreement. Therefore, KIUC does not presently consider it likely that new generators larger than 20 MW will seek a connection.

4.7.2.3 Frequency time error

KIUC tracks time error and does correct it. A traditional automated AGC was previously employed. However, this has been replaced with an in-house control system to control the increasing renewable generation mix more effectively. Typically, a positive time error accumulates during the day when there is an excess of PV and this corrects in the afternoon through to the evening as PV drops off.

There is an internal discussion about the merit of correcting time error. There may be value in continuing to track time error as an indicator of system performance and simply resetting the counter periodically. However, no firm view has been established.

4.8 Western Australia

4.8.1 Power system overview

The Wholesale Electricity Market (WEM) operates across the South West Interconnected System (SWIS), which supplies electricity to over 1.1 million Western Australian households and businesses each year. The SWIS is not connected to any other major Australian grids, and like the NEM, AEMO operates the WEM.

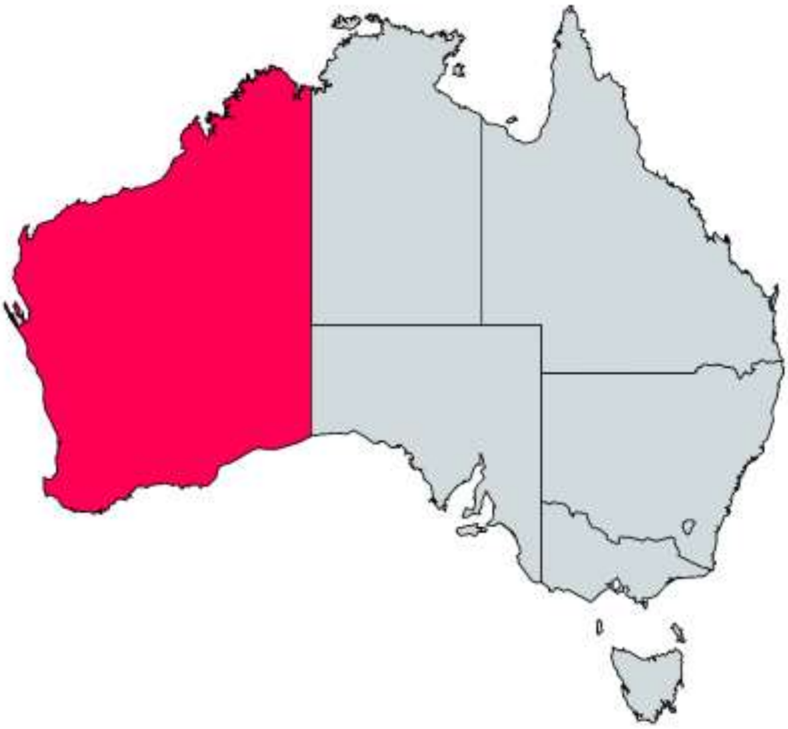


Figure 16 Map highlighting Western Australia

Table 6 summarises the key characteristics of the WEM.

Table 6 Power system characteristics – WEM [42], [43]

Characteristic		Value	Comment
Demand	Minimum demand	742 MW	Recorded on 11 September 2022
	Peak demand	4006 MW	Recorded on 08 February 2016
Annual (dispatchable) generation	Total	17,545 GWh	During 2020/21
	Variable generation	5,060 GWh (28.8%)	
	Non-variable	12,485 GWh (71.2%)	
Installed capacity	Total	6,066 MW	As of May 2022.
	Variable generation	1,197 MW (19.7%)	
	Non-variable generation	4,869 MW (80.3%)	
Non-dispatchable rooftop solar	Installed capacity	1,421 MW	
	Annual generation	1,984 GWh	

4.8.2 Findings

The key results of the survey are summarised below.

4.8.2.1 RoCoF

Operational RoCoF limits

Western Australia is the only surveyed jurisdiction with a legislated operational RoCoF limit. Presently, the RoCoF Safe Limit is considered to be 0.25 Hz/s measured over 500 ms [9, Ch. Appendix 13]. This may be gradually increased via a rule change if AEMO is satisfied that higher levels of RoCoF can be managed. This assessment would need to consider both generator ride through capability and the ability of emergency control schemes to accommodate a higher RoCoF.

Some context surrounds this number. The WEM is currently in a transition period and plans to introduce fully co-optimised Security Constrained Economic Dispatch (SCED). This is tentatively scheduled for late 2023. Some rules are already in place and others will come into force later. As an example, a revision of the FOS was completed in February 2022, and this includes the RoCoF Safe Limit discussed above. This will also define the service quantities for a RoCoF Control Service (RCS) market. However, this market does not yet exist.

Operationally, RoCoF is tracked with the Real Time Frequency Stability (RTFS) tool. This allows the control room to simulate and predict frequency performance following a credible event. A “high RoCoF” event is considered to be greater than 0.25 Hz/s when measured over 500 ms (0.5 Hz/s).

Generator RoCoF ride-through capability

The WEM Rules [9, Ch. A12.7.3.2] specifies a minimum generator performance standard for RoCoF ride through and the ESS Accreditation Standards, section 2.34A, also require generators to ride-through RoCoF events that:

a. reach 2 Hz/s over 250 milliseconds during the disturbance; or
b. reach 1 Hz/s over 1 second during the disturbance.

The WEM Rules [9, Ch. A12.7.2.2] specifies an ideal generator performance standard that requires generators ride-through RoCoF events that:

a. reach 4 Hz/s over 250 milliseconds during the disturbance; or
b. reach 3 Hz/s over 1 second during the disturbance.

These rules do not apply retrospectively, and AEMO considers that legacy generation poses the highest risk of tripping during high RoCoF events. Additionally, some concern was expressed in that commissioning tests may not recreate the true stress of RoCoF events.

To date, AEMO has not identified units in the SWIS that tripped as a result of a high RoCoF. However, the largest RoCoF event experienced in the SWIS was 0.44 Hz/s. There is a risk that legacy generators may trip in the 0.5-1.0 Hz/s range. Participants generally do not know the capability of their plant, and OEMs may not be able to assist with determining the maximum RoCoF capability.

4.8.2.2 Largest contingency

The WEM does not have a specified largest maximum contingency. However, due to the co-optimisation of both energy and reserve dispatch, large generation connections may be constrained to minimise the total system costs.

4.8.2.3 Frequency time error

Frequency time error is automatically corrected in the WEM. Operators do not actively monitor it and in present operational memory (approximately 20 years), manual intervention has never been required.

The WEM Rules specify the time-error correction requirement under clause 3B.3.1.

5. Conclusion and recommendations

5.1 RoCoF

The Survey responses support several key observations concerning each of the following topics:

– Experience with high RoCoF events
– RoCoF ride-through requirements
– Operational RoCoF standards and control measures

Those observations are summarised in Table 7 and elaborated in the following sections.

Table 7 Key findings - RoCoF

RoCoF Topic	Summary of Findings
Experience with high RoCoF events	– Smaller power systems, like those on the Hawaiian islands, have experienced the highest RoCoF. – For larger networks, like the European interconnected system, the highest RoCoF events are expected following events that lead to the formation of islands that are separated from the primary interconnected system. – ENTSO-E review of global experience with high RoCoF events suggests that emergency controls like UFLS may not manage to prevent blackouts if RoCoF exceeds 1 Hz/s measured over 500 ms.
RoCoF ride-through requirements	– It is common for grid codes to specify RoCoF ride-through capability requirements for generating systems. Those ride-through requirements are generally much higher than the RoCoF levels typically observed for credible contingency events. – System operators are concerned that legacy generators may not be able to comply with the RoCoF ride-through requirements expressed in grid codes and that failure to ride-through could further exacerbate a RoCoF event. – Of the entities surveyed, only EirGrid had direct experience investigating generator ride-through capability. – Aside from the Loss of Mains (LoM) issue in Great Britain and the trip of a small liquid fuelled synchronous generator in Hawaii, no survey respondents were able to identify actual events where a large utility-scale generating system tripped due to experiencing high RoCoF. – AEMO has confirmed that the LoM issue experienced in Great Britain and Ireland is unlikely to exist in the NEM.
Operational RoCoF standards and control measures	– A number of system operators consider the operational needs for limiting RoCoF to maintain power system security. However, the Western Australia South West Interconnected System (SWIS) is the only power system that has a safe RoCoF limit specified in a FOS or equivalent regulation. – The Western Australia Electricity Market (WEM) FOS specifies a safe RoCoF limit of 0.25 Hz over any 500 ms period for the SWIS. AEMO-WA is required to perform reasonable endeavours to maintain this safe RoCoF level for events that split the SWIS into islanded power systems. – None of the respondents identified plans to modify existing FOS or equivalent regulations to include a specific RoCoF requirement. However, many expressed interest in the outcome of the Reliability Panel’s review of the NEM FOS. – Specifying a safe RoCoF limit in the NEM FOS in a similar manner to the WEM FOS may assist in maintaining system security and provide better guidance for market participants regarding the RoCoF they should experience.

RoCoF Topic	Summary of Findings
	– Many system operators apply operational practices in order to maintain RoCoF within historically acceptable levels. For example, EirGrid developed the Look Ahead Security Assessment Tool that assesses future RoCoF and nadir in real time. – If a safe RoCoF limit is to be included in the NEM FOS, the operating practices adopted in other jurisdictions may help inform an appropriate initial setting.

5.1.1 Experience with high RoCoF events

Respondents identified varying levels of experience with high RoCoF events. Generally, the highest observed RoCoF events occurred in smaller isolated power systems, with lower levels of RoCoF experienced in larger systems. For example, KUIC indicated that their power system had experienced RoCoF events exceeding 10 Hz/s. This contrasts starkly with NERC's large interconnected power systems, such as the Eastern Interconnection, Western Interconnection and Texas Interconnection, which advised that, to date, the most severe RoCoF observed in their system was -0.2 Hz/s, although the largest RoCoF experienced on the Quebec Interconnection is -0.9 Hz/s.

For the larger interconnected systems, high RoCoF is expected to be triggered by the events that also cause a separation or islanding event. The RoCoF experienced in the islanded system is likely to be much higher than in the rest of the interconnected system. The severity of the RoCoF will depend on the type of generation, the inertia within the island at the time of the separation event, and the power imbalance caused by the separation. As separation events will generally involve multiple contingencies, the system security criteria usually require a best endeavours approach that recognises that some degree of power disruption may be necessary to manage those events. However, there is an expectation that emergency controls such as UFLS should act to prevent a total system collapse or blackout, particularly where the island represents a substantial portion of the power system.

ENTSO-E has completed a review of global events that resulted in high RoCoF being experienced following an islanding event [15]. The study identified an islanding event culminating in a RoCoF of less than 0.5 Hz/s over 500 ms. The emergency control schemes managed the event, arrested the frequency disturbance and prevented a system-wide blackout. Conversely, where the RoCoF exceeded 1 Hz/s, a system blackout occurred. ENTSO-E suggests that TSOs consider 1 Hz/s measured over 500 ms as the RoCoF threshold that should trigger a careful review of the ability of emergency control schemes to manage a potential islanding event.

5.1.2 Generator RoCoF ride-through requirements

The survey responses confirm that it is common practice for grid codes or equivalent regulations to specify RoCoF ride-through requirements for generating systems. The only exception to this rule was in North America, where standards such as those produced by the IEEE are relied on to specify technical requirements for smaller generating systems. The NERC standard (PRC-024) applies to larger generators. While the IEEE standard 1547 for distributed inverter-connected small generating systems included RoCoF ride-through requirements, the NERC Standard PRC-024 does not explicitly mention RoCoF. PRC-024 requires generators to remain online, provided frequency stays within limits specified in PRC-024 for the relevant portion of the North American power system. Hence it is implied that a large generator should ride through any RoCoF event provided the frequency stays within the specified limits. Figure 17 illustrates the frequency limits specified for large generators connecting to the transmission system in Texas operated by ERCOT.

Table 8 lists the RoCoF ride through requirements identified by each survey respondent.

Table 8 Generator RoCoF ride through requirements

Survey Respondent	RoCoF Ride Through Requirement	
	Minimum	Maximum
ENTSO-E[1]	±2 Hz/s for a moving average of 500 ms window ±1.5 Hz/s for a moving average of 1000 ms window ±1.25 Hz/s for a moving average of 2000 ms window	

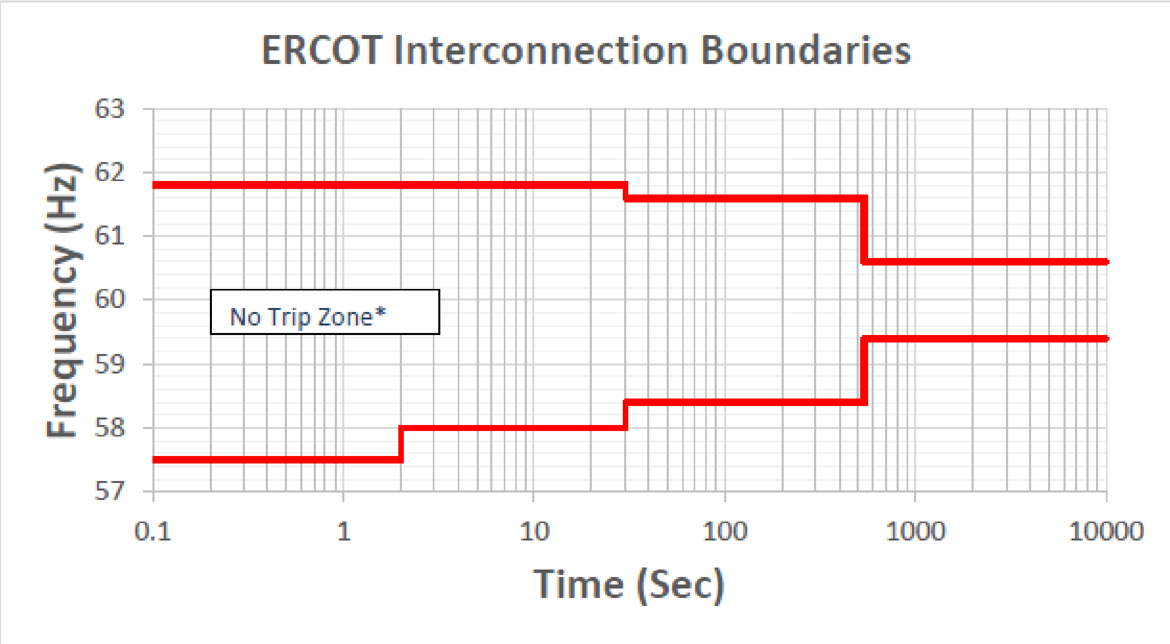
EirGrid, Ireland	±1 Hz/s for a moving average of 500 ms window	
National Grid, Great Britain	±1 Hz/s for a moving average of 500 ms window	
NERC	±0.5 Hz/s [2]	±3.0 Hz/s [2]
Hawaii Electric[3]	±3.0 Hz/s	
KIUC	Not specified in publicly available documents	
Coordinador Eléctrico Nacional, Chile	±2 Hz/s for a moving average of 500 ms window	
AEMO WEM WA[4]	±4.0 Hz/s over 250 ms ±3.0 Hz/s over 1000 ms	±2.0 Hz/s over 250 ms ±1.0 Hz/s over 1000 ms
NEM[5]	±4.0 Hz/s over 250 ms ±3.0 Hz/s over 1000 ms	±2.0 Hz/s over 250 ms ±1.0 Hz/s over 1000 ms
1) While each European TSO is free to specify individual RoCoF ride through requirements, the range shown is that published in the ENTSO-E guidelines [5].		
2) NERC adopts IEEE 1547 requirements for small DER, with no requirement specified for larger generating systems. IEEE 1547 specifies that the average change in frequency must be measured over at least 100ms.		
3) Hawaii Electric indicated that increasing the ride through requirement to 5 Hz/s should be considered.		
4) WEM Rules clause A12.7.2.2 and A12.7.3.2		
5) NER Clause S5.2.5.3		

The generator ride-through requirements specified in most grid codes are generally much higher than the RoCoF levels typically observed for credible contingency events. This means that system operators lack sufficient empirical evidence to be confident regarding the RoCoF ride-through capability for existing or legacy generating systems. Various studies have identified potential issues that may arise during high RoCoF events and impact the ability of the generating system to ride through those events. One study undertaken by GE Energy Consulting for AEMO reported particular vulnerabilities for gas turbine generators [4]. Apart from EirGrid, most survey respondents identified concerns regarding whether legacy generators could be relied upon to comply with the RoCoF ride-through requirements expressed in grid codes. Failure to ride through could exacerbate a RoCoF event.

EirGrid addressed this problem by testing and validating the legacy generation fleet in a workstream known as the DS3 Programme. That process has been running for many years. As a result, EirGrid has gained sufficient confidence that the existing generating fleet should be able to ride through a 1 Hz/s RoCoF event and is therefore planning to relax the operational RoCoF target from 0.5 Hz/s to 1 Hz/s measured across 500 ms.

While many respondents expressed concerns regarding the ability of generators to ride-through high RoCoF events, aside from the LoM issue in Great Britain and the trip of a small liquid fuelled synchronous generator in Hawaii, none of the respondents could cite an event where a generator had been observed to trip due to high RoCoF.

A sequence of events in 2019 in Great Britain resulted in a RoCoF which exceeded the setting used by embedded generating systems to detect a LoM [23]. In this event, the RoCoF resulted in the LoM protection disconnecting embedded generation, which exacerbated the event. AEMO has confirmed that the LoM issue experienced in Great Britain and Ireland is unlikely to exist in the NEM.



** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[9]	≤57.5	Instantaneous[9]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Figure 17 Frequency limits specified for large generators connected to the ERCOT systems (Sourced from PRC-024-3 [35])

5.1.3 Operational RoCoF standards and control measures

Many system operators surveyed consider the need to limit RoCoF to achieve power system security. Specific examples include that:

- Hawaii Electricity implicitly considers the RoCoF in the frequency stability assessment performed to assess the adequacy of frequency controls. The aim is not to keep RoCoF below a specific threshold but to ensure that the combination of available control measures can suitably manage any expected disturbance.
- EirGrid has completed testing and modelling activities across much of the generation fleet and, through that process, has determined a level of RoCoF that they are confident connected generators can ride though. That target RoCoF of 1 Hz/s over a 500 ms rolling window is used when determining the amount of inertia and fast frequency service to dispatch.
- ENTSO-E has provided guidance suggesting that TSOs should assess whether separation events are likely to result in a RoCoF above a "safe level" of 0.5 Hz measured across 500 ms (1 Hz/s). If the safe level is likely

to be exceeded, it is recommended that the TSO investigate the adequacy of existing emergency control schemes.

– National Grid ESO is required to undertake an annual review to determine which events it should secure against. This process considers the consequence of not securing an event, the likelihood of it occurring, and the cost of procuring the services necessary to secure the event.

Out of all respondents, only AEMO (WEM) must meet a safe RoCoF limit specified in a FOS or equivalent regulation. The WEM FOS specifies a safe RoCoF limit of 0.25 Hz over any 500 ms period for the South West Interconnected System (SWIS) and requires AEMO to use reasonable endeavours to maintain this safe RoCoF level for events that spilt the SWIS into islanded power systems.

None of the respondents identified plans to modify an existing FOS or equivalent regulations to include a specific RoCoF requirement.

Specifying a safe RoCoF limit in the NEM FOS may provide several benefits, including:

– Assisting AEMO in identifying the requirement for a specific service or operational measures to maintain RoCoF below the safe level. If the safe level is set at an appropriate threshold, this process should reduce the risk of legacy generators failing to ride-through RoCoF events, thereby exacerbating a RoCoF event. This process can potentially improve the operator's ability to manage system security.
– Providing market participants with greater confidence regarding the RoCoF they are likely to experience when connected to the NEM.

If a safe RoCoF limit is to be included in the NEM FOS, then the operating practices adopted in other jurisdictions may help inform an appropriate initial setting. The setting would likely need to be revised over time as more experience is gained regarding the ride-through capability of existing plant and equipment.

5.2 Largest contingency

The survey responses support a number of key observations with respect to the specification of a limit for the largest acceptable single contingency. Those observations are summarised in Table 9.

The survey feedback suggests that it may not be appropriate to expand the NEM FOS to include a limit on the largest contingency size as the economic and security trade-offs are potentially better managed through other grid connection processes.

GHD notes that the process for establishing a generator connection already requires a generator to negotiate performance standards. Schedule S5.2.5.12 of the NER specifies the generator performance standard with respect to the impact on network capability. The automatic access standard requires that the generating system be designed such that its connection will not result in a reduction of any inter-regional or intra-regional power transfer capability. The minimum access standard allows some level of reduction in transfer capability provided that it does not result in a reduction in the ability to supply customer load and that any reduction in the ability to transfer power into a region is less than the sent-out capacity of the generating system.

A generator is expected to achieve performance as close as possible to the automatic access standard. It will be refused connection if it cannot achieve a level of performance consistent with the minimum access standard. This connection process would appear to restrict the creation of larger credible contingencies if doing so would impact the ability to supply existing customers.

Table 9 Key findings – Largest contingency

Topic	Summary of Findings
Largest contingency limit	– Aside from Great Britain, no jurisdictions formally specify a largest contingency limit in their security standards. The Great Britain SQSS specifies 1800 MW as an infrequent infeed loss risk and requires that no single contingency exceeds this loss of infeed. The threshold was increased from 1320 MW to 1800 MW on 1 April 2014 [1]. – Of relevance and noted by AEMO (WEM), the optimisation performed by the market dispatch engine may choose to constrain a larger generator if that results in the least cost dispatch outcome considering the co-optimised energy and essential system service markets. This naturally incentivises generators to avoid a connection that would increase the size of the largest credible contingency. – Some smaller systems informally discourage relatively large connections through more onerous connection processes. For example, in Hawaii, a large generator would need to follow a bespoke, negotiated connection process, whereas a smaller generator can connect via a standard connection agreement. – EirGrid reports that they have approved the development of a new HVDC link that will increase the size of the largest single contingency. The benefits of the larger capacity link outweighed the costs of procuring additional RoCoF and frequency control services.

5.3 Frequency time error

The survey responses support several key observations concerning the management of frequency time error. Those observations are summarised in Table 10 and Table 11.

Table 10 Key findings – Frequency time error

Topic	Summary of Findings
Time error monitoring	– Some survey respondents reported that time error was monitored, while others identified that time error was ignored. Some track error as a performance metric. Further information is provided in Table 11
Time error impact	– All survey respondents agree that a time error is unlikely to impact customers adversely. In addition, NERC completed an industry survey in 2008 which supports this view.
Time error correction and specification	– Only the WEM and the NEM specify an explicit frequency time error limit in the applicable frequency operating standard: • WEM – time error <10 s for 99% of the time over any rolling 30 day period • NEM – time error <15 s – Most of the respondents currently correct time error, either because it's perceived to be operational best practice or for legacy reasons. A review completed by NERC in 2015 recommended ceasing time error correction, and it appears that the practice is in the process of being suspended in North America [2].

Table 11 Summary of survey responses

Operator	Monitors time error	Actively Corrects
AEMO WEM	Time error monitored	Accumulating errors corrected via AGC to meet performance specified in WEM Rules
Coordinador Eléctrico Nacional for Chile	Not monitored	No corrections applied
EirGrid	Monitored via time error clock	Actions taken to keep time error within 10 seconds
NERC	Balancing authorities currently monitor time error	Current practice is to correct time error. However, a 2015 review endorsed removing manual time error correction
Hawaii Electric	Monitors	Automatically corrects but do not appear to have a prescribed standard
KIUC	Monitors and investigates any trends such as times of day where errors accumulate	Automatically corrects but do not appear to have a prescribed standard
National Grid ESO	TBC	No corrections applied
ENTSO-E	Not responsible for frequency control or time error monitoring	Not responsible for operational frequency control or time error correction

The review of time error correction completed by NERC across the period from 2008 to 2015 suggests that there may be little value in continuing to correct time error in the NEM. However, experience in Hawaii suggests that even if the requirement to control to a particular time error is removed from the NEM FOS, there could still be value in monitoring time error. Investigating the observed trends might highlight a need to adjust frequency control settings.

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Appendices

Appendix A

Survey questions

SURVEY: RoCoF, contingency size and time error in frequency operating standards

Background

Maintaining a secure and reliable power system requires the system operator to maintain appropriate control of power system frequency both in a steady state and following contingency events. In the Australian National Electricity Market (NEM), the power system frequency is required to be maintained within the limits specified in the NEM Frequency Operating Standard (FOS). The Reliability Panel appointed by the Australian Energy Market Commission (AEMC) determines the FOS, on the advice of AEMO, and is required to review the FOS from time to time to ensure it continues to specify appropriate frequency limits. On 28 April 2022, the Reliability Panel published an issues paper to commence consultation on the review of the NEM FOS.

GHD is assisting the AEMC with the review of the NEM FOS and is seeking, through this survey, to understand the approaches adopted in other power systems. The following matters are to be considered:

The method used to specify limits for the Rate of Change of Frequency (RoCoF).

Whether frequency operating standards or other power system security standards place limits on the maximum allowable generator contingency size.

Whether frequency operating standards or other power system security standards place limits on the maximum allowable time error.

The desire to decarbonise the power system is driving investment in renewable generation connected to the NEM. Most new generators are inverter-connected wind and solar farms. New renewable generation is replacing thermal generation, reducing the level of synchronous generation connected to the NEM. This is increasing the likelihood of rapid changes in frequency following contingency events.

Currently, the NEM FOS does not set any specific limits for RoCoF, although the generator technical requirements discussed in the National Electricity Rules do require generating systems to ride through RoCoF events. The current review of the NEM FOS will consider whether there is a need to specify RoCoF limits within the FOS and how those limits should be determined, particularly regarding the timeframe over which the RoCoF is measured.

Survey Scope and Approach

The following pages include the questions that we are seeking to answer via the survey. After issuing the survey we will arrange a virtual meeting with each of the survey recipients to discuss the response to each question and to understand relevant power system parameters to help compare the practices in the different power systems surveyed and the NEM.

Appendix 1 provides summary information on the NEM. We will seek a similar level of detail on the surveyed power systems to facilitate our comparison.

Survey Questions – RoCoF

Question 1 – Operational experience of high RoCoF events

What are some examples of the highest RoCoF levels observed in your system?

Specifically, were changes to security standards, protection, generating, or load schemes implemented because of the RoCoF?

Can you provide a list of the type of generating units that were operating at the time, and successfully rode through those high RoCoF events (and whether there were any that did not successfully ride through)?

Are there any incident reports available for these events?

What level of RoCoF do you consider as being a "high RoCoF" event? (e.g., >1 Hz/s when measured across 250 ms?)

Can you direct us to any publicly available reports that you would recommend as providing a useful investigation of "high RoCoF" events?

What lessons were learned from the observed response to the event? Specifically, were changes to security standards, protection, generating, or load schemes implemented because of the RoCoF?

Question 2 – Technical requirements for Generation equipment

Do you currently specify a requirement for generators to have the capability to ride through a prescribed level of RoCoF during power system disturbances?

Where is that requirement specified and what is the ride-through requirement?

What is your understanding of RoCoF ride-through capability for different generation technologies?

In terms of RoCoF ride-through capability, what differences are you aware of for new vs legacy generation plant?

Question 3 – Interaction with protection schemes

Do you have protection schemes that will operate during high RoCoF events? For example, Under Frequency Load Shedding (UFLS) based on a RoCoF trigger, loss of mains, etc. Can you describe those schemes and the settings that relate to RoCoF?

Question 4 – System limits or standards for RoCoF

Do you currently specify RoCoF limits in power system security standards? If so, where are those limits specified and how are the limits specified?

How is the measurement of RoCoF specified? i.e., over what timeframe is RoCoF assessed?

What process/or reasons lead you to use your RoCoF measurement approach? Do you have any operational experiences with different RoCoF measurement timeframes?

Are the RoCoF measurement timeframes aligned with any RoCoF triggered relays in the field?

Question 5 – Operational tools to manage RoCoF

What measures or controls are currently implemented to manage RoCoF? For example, perhaps very fast frequency response, generation constraints, scheduling of synchronous inertia, management of contingency sizes, and/or use of synthetic inertia.

Question 6 – A view to the future

What is your view of the future challenges and changes in relation to the management of RoCoF in your power system? Do you expect the need to specify RoCoF limits or implement RoCoF controls to increase in the future? Do you plan to make any changes to your current arrangements over the next 5-10 years? What would trigger a change to the current approach?

Survey Questions – Largest Contingency Limits

Question 7 – Management of the largest credible contingency size

How do you manage the maximum “design event” or "largest credible risk” for your power system? Do you currently enforce a limit on the maximum size of a contingency for the purpose of connection of new generators and/or for the operation of the system? Are inter-trip schemes used to reduce the impact of credible contingencies?

Question 8 – Specification of largest contingency limit

If a limit is currently enforced, where is that limit specified? i.e., in power system security standards. How was the limit determined and what is the current setting?

Survey Questions – Time Error

Frequency-time error tracks how well frequency is controlled against the nominal system value. As technology advances, fewer devices appear to be sensitive to frequency-time error. Therefore, it seems appropriate to consider whether a time error remains a useful measure to include in a FOS.

Question 9

Do your power system security standards currently specify a frequency-time error requirement? How is that specified? What action is taken if there is a breach of the frequency-time error specification? Do you perform time error correction, and if so, what drives the need for this action?

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