

Public

# Frequency Risk and Control Report

Security and Quality of Supply Standard

The Report – For Approval

Minimum Inertia Requirement and Additional Response Holding

May 2025

Public

## Contents

<b>1. Foreword.....</b>	<b>3</b>
<b>2. Executive summary.....</b>	<b>4</b>
<b>3. Background.....</b>	<b>8</b>
3.1 Overview.....	8
3.2 FRCR objectives.....	9
<b>4. Scope of FRCR 2025 .....</b>	<b>10</b>
4.1 Assessment of FRCR policy on minimum inertia requirement .....	10
4.2 Assessment of FRCR policy on loss categories .....	10
4.3 Assessment of FRCR policy on additional Dynamic Containment.....	10
4.4 Outlook to 2026/2027 .....	11
<b>5. Performance review of previous inertia requirement reduction.....</b>	<b>12</b>
5.1 System inertia .....	12
5.2 System events .....	13
<b>6. Assessment and results .....</b>	<b>16</b>
6.1 Assessment of minimum inertia requirements .....	16
6.2 Assessment of securing additional event categories .....	18
6.3 Assessment of additional Dynamic Containment – Low response .....	21
6.4 Additional considerations.....	23
6.5 Outlook to 2026/27 .....	25
<b>7. Conclusions .....</b>	<b>28</b>
7.1 Recommendation.....	28
7.2 Implementation.....	28
7.3 Consultation Summary.....	29
<b>8. Future Considerations .....</b>	<b>40</b>
8.1 FRCR forward looking.....	40
8.2 FRCR future governance .....	41
<b>9. Appendix .....</b>	<b>42</b>
9.1 Case studies on historical events.....	42

Public

## 1. Foreword

In 2024, the Great Britain electricity system celebrated a remarkable achievement by completely phasing out coal from its power system and reaching 95% zero-carbon operation for a brief period. This milestone underscores the power of world-leading engineering and innovation in the industry.

During the past few years, significant advancements have been realised through the Accelerated Loss of Mains Change Programme (ALoMCP) and the Stability Pathfinder Projects including the advancement of Grid Forming technology. The phase-out of the dynamic Firm Frequency Response (dFFR), the expansion of the market for Dynamic Containment (DC), Dynamic Regulation (DR), and Dynamic Moderation (DM), and the co-optimisation of Ancillary Services via the Enduring Auction Capability (EAC) also marked a significant shift in the energy landscape.

As GB moves towards operating a safe, secure, affordable and fully clean power system, we face substantial challenges. In accordance with the Security and Quality of Supply Standard (SQSS), the National Energy System Operator (NESO) produces an annual Frequency Risk and Control Report (FRCR) and consults with the industry on its assessments. Its previous recommendations along with the introduction of new dynamic response services have greatly enhanced system security, reduced costs, and will contribute to enablement of the Government's 2030 Clean Power Action Plan.

- FRCR 2021 established the baseline for cost vs. risk in frequency management;
- FRCR 2022 evaluated the consumer benefits of securing simultaneous events;
- FRCR 2023 assessed the benefits of reducing the minimum inertia requirement;
- FRCR 2024 assessed the benefit of using additional response to secure beyond BMU-only events whilst operating the system at the reduced minimum inertia level.

The FRCR 2025 proposes to further reduce the minimum inertia requirement, mitigate all BMU-only loss risks, and apply additional frequency response controls to reduce residual risks, ultimately providing better value for consumers and maintaining system security. The consultation period for the FRCR 2025 was held from 3 March 2025 to 7 April 2025.

Public

## 2. Executive summary

The requirement for a Frequency Risk and Control Report (FRCR) was introduced following the approval of Security and Quality of Supply Standards (SQSS) modification GSR027.

This 2025 FRCR report assesses system risk and cost, at a minimum inertia of 102 GVA.s during 2025/26 and 2026/27. This report represents our continued effort to secure beyond BMU-only risks and to deliver NESO's 2025 ambition for zero carbon operation. The report also re-assesses whether the existing FRCR policy, of not taking additional actions to secure all simultaneous events, still delivers the best value for consumers.

### FRCR 2025 Recommendations

- **Reduce the minimum inertia requirement from 120 GVA.s to 102 GVA.s**

The minimum inertia requirement under the FRCR policy refers to the minimum inertia required at national level to manage frequency risks. The report indicates there are significant cost benefits obtained by reducing the minimum inertia requirement from 120 GVA.s to the lower level of 102 GVA.s. There is no tangible increase in the overall system residual risk by operating at this reduced inertia level with the recommended increase in dynamic response procurement, and this reduction supports the delivery of 2025 zero carbon operation and 2030 clean power targets. The estimated cost saving from the inertia requirement reduction is **£96m per year**.

- **Secure all Balancing Mechanism Unit (BMU) only risks and do not apply additional actions to mitigate all BMU plus Vector Shift (BMU+VS) or simultaneous events**

The current frequency risk control policy of securing all BMU-only events still presents the best value. Securing against all BMU plus VS does not improve system security significantly but requires procuring a substantially uneven DC requirement across the year. Securing simultaneous events would require a significant increase in procured DC capacity. This volume is not currently available and would place the current market under significant pressure, while increasing operational risk and cost. Therefore, we do not see value in changing the current policy relating to securing all BMU plus VS or simultaneous events as it does not provide good value for consumers.

- **Procure additional Dynamic Containment -Low (DC-L) service to further reduce residual risks**

Public

Dynamic Containment (DC) is currently the most cost-effective method for managing post-fault frequency risks. Market growth and the introduction of Enduring Auction Capability (EAC) have improved the liquidity of the DC market and driven a cost reduction for procuring the service. Holding additional DC-Low response improves system security and signals the market to further grow its capacity in meeting future system needs. The report verifies that holding an additional 200 MW of DC-Low, presents the best value for consumers.

### Impact of Recommendations

The implementation of this policy in 2025/26 with additional DC-Low holding, results in a residual risk of a **1-in-23** years occurrence of a 49.2 Hz event and **1-in-30** years occurrence of a 48.8 Hz event. ([Table 6](#) in [Section 6.3.1](#))

The residual risks have increased compared to last year's FRCR analysis, with the likelihood of 49.2 Hz events moving from 1-in-29 years in FRCR 2024 to 1-in-23 years in FRCR 2025. The likelihood of 48.8 Hz events happening remains the same as last year's analysis, with the recommendation of the addition of 200MW DC. The main cause of the risk change for the 49.2 Hz event and 48.8 Hz is a review of simultaneous events, which shows a higher probability of these events occurring in our model. We believe this is more representative of our operational experiences. More information can be found in the **Handbook** Section 5.4.

The estimated annual cost of managing frequency risks based on FRCR 2025 recommendations is £173 million. This includes a £96 million cost saving from reducing the minimum inertia requirement resulting in cost of £170 million for BMU only and an extra £3.2 million cost for procuring additional DC. If the FRCR 2025 policy is approved by Ofgem and implemented, the industry will be informed of the implementation plan through industry forums, such as the Operational Transparency Forum (OTF), before going live.

### FRCR 2025 Integrated Technical Review

In November 2024, the SQSS Panel discussed the need for external assurance of FRCR 2025. In January 2025, NESO proposed an integrated technical assurance approach whereby Accenture would perform an independent review, using NESO prepared test

Public

criteria, of the end-to-end FRCR report creation process, with oversight provided by NESO's functionally independent Engineering Assurance Team. This was implemented with the aim to minimise any delay to the FRCR 2025 timeline.

Phase 1 covered up to and including the development of the policy recommendations (included in this version for consultation). Testing was performed by Accenture using tests provided by NESO's Engineering Assurance Team to assess that the FRCR process has been followed correctly. Having performed a challenge and review of the output from Accenture's testing, NESO's Engineering Assurance Team are satisfied that a rigorous process has been followed in: responding to detailed feedback from industry on the methodology; applying the methodology both in terms of sourcing and processing key supporting datasets; running the model, the outputs from which are reproducible and have been subject to expert challenge and review; and developing policy recommendations from the model outputs. Validation of the coding of the FRCR model was beyond scope as this would introduce a very significant delay in the process.

Phase 2 covered the processing of feedback from industry consultation on the draft FRCR 2025 report, including re-running of the FRCR model to include results and additional levels of DC-Low overholding.

Assurance reports from NESO's Engineering Assurance Team, covering Phases 1 and 2, will be published along with the FRCR 2025 suite of documents on the NESO website.

### Engagement Summary

FRCR 2025 has increased its industry engagement this year following industry feedback from FRCR 2024, with the aim of promoting a greater understanding of how the FRCR recommendations are produced, through the data used and the modelling undertaken during the process. This year has seen NESO undertake three webinars. In addition to the recommendation webinar, this year included a webinar of the data used and a webinar on how FRCR is modelled. The webinars respectively had 43, 51, 61 people registered of which 26, 34, 32 attended with a total of 42 questions raised during the webinars, with 69% of questions answered live during the webinars and the remaining 31% being followed up after the event.

NESO also invited industry to comment on the FRCR 2025 recommendations via a consultation process, running for 5 weeks from the 3 March to the 7 April, which was

Public

extended from 31 March to allow for more responses. The consultation resulted in seven responses, with all seven responses being discussed directly with the respondents by the 25 April and all responses published on the NESO website with the final submission to Ofgem.

Public

## 3. Background

### 3.1 Overview

The requirement for a Frequency Risk and Control Report (FRCR) was introduced following the approval of Security and Quality of Supply Standard (SQSS) modification GSR027: *'Review of the NETS SQSS Criteria for Frequency Control that drive reserve, frequency response and inertia holding on the GB electricity system in 2020'*. There are three main documents in the FRCR process which link together as follows:

#### **Frequency Risk and Control Report (Report)**

The report sets out the assessment results of the operational frequency risks on the system. It includes an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system. It confirms which risks we will or will not secure operationally in line with the expectation set out under the SQSS. The SQSS notes that the FRCR will set out those conditions under which unacceptable frequency conditions will not occur.

#### **Frequency Risk and Control Report Methodology (Methodology)**

The methodology sets out what will be assessed, how it will be assessed and the format of the outputs. The methodology (v3) inputs include: impacts, events and loss risks, controls, and metrics for reliability vs. cost.

#### **Frequency Risk and Control Report Data Handbook (Handbook)**

The handbook is designed to be used as a reference to provide a detailed explanation of how the data has been collected and used in the FRCR process. Furthermore, the handbook offers guidance on interpreting the results. It also includes case studies and examples to illustrate the application of the methodology, thus serving as a comprehensive guide for stakeholders involved in the process.



Public

### 3.2 FRCR objectives

The FRCR sets out the results of an assessment of the operational frequency risks on the system which includes:

- the magnitude, duration and likelihood of transient frequency deviations,
- the forecast impact of these deviations,
- the cost associated with securing the system for these deviations, and
- confirms which risks we will or will not secure operationally under paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS.

These objectives are formalised through the Security and Quality of Supply Standard (SQSS) and the FRCR **Methodology**. This report provides an assessment and recommendation on achieving the right balance between the competing objectives of reliability and cost, focusing on the risks, impacts, and controls for managing system frequency.

The detailed methodology is outlined in the Methodology document, which offers an objective and transparent framework for assessing the risks associated with frequency deviations, identifying the events that could cause them, their magnitude, the impacts they have, and the cost and mix of controls needed to mitigate them.

Consultation and ongoing engagement with industry stakeholders are crucial for achieving this balance openly and transparently. Our role is to analyse the risks, impacts, and controls, and their effects on reliability and cost, and to present a recommendation on the appropriate balance. This enables the Authority to make an informed decision on balancing the reliability of electricity supplies with the cost to end consumer.

Public

## 4. Scope of FRCR 2025

### 4.1 Assessment of FRCR policy on minimum inertia requirement

The minimum inertia requirement was reduced from 140 GVA.s to 120 GVA.s as recommended in FRCR 2023. We have re-evaluating the current minimum inertia requirement and assessing whether it is sufficient to manage the system frequency risks. System risks and costs have also be assessed when running the system with lower inertia levels of 110 GVA.s and 102 GVA.s.

The minimum inertia of 102 GVA.s is based on a future largest loss of 1800 MW and ensures the Rate of Change of Frequency (RoCoF) remains within 0.5 Hz/s. An 1800 MW loss would require 90 GVA.s of inertia to ensure RoCoF remains within 0.5 Hz/s. This assumes a loss of approximately 12 GVA.s of inertia from the 1800 MW unit. This results in the pre-fault minimum inertia requirement of 102 GVA.s. The 2025 Operability Strategy Report<sup>1</sup> (OSR 2025) discusses our zero carbon operation goals by end of 2025 and the delivery of clean power by 2030, detailing how the reduced minimum inertia levels interact with overall operability challenges. The 2025 OSR was published in March 2025.

### 4.2 Assessment of FRCR policy on loss categories

We have assessed the cost-risk benefits of securing against different loss risk categories, namely BMU-only, BMU+VS (under outage or intact system conditions), and simultaneous events.

The analysis includes an assessment of the cost-risk benefits associated with applying additional controls, such as holding additional response, to further mitigate risks beyond the current policy of securing BMU-only events. This assessment aims to determine the effectiveness and efficiency of these additional measures in reducing risks and optimising the cost-risk balance.

### 4.3 Assessment of FRCR policy on additional Dynamic Containment

Under current system conditions, with increased system dynamic with less inertia, it is cost-effective to use the new suite of dynamic response services to manage the system. The new suite of dynamic response services has a fast-acting capability which ensures that the system remains stable and reliable at a reasonable cost.

As of February 2025, we currently see approximately 5000 MW of participation in the dynamic response auctions of which we secure around 2000 MW in each Electricity

---

<sup>1</sup> [Operability Strategy Report 2025](#)

Public

Forward Agreement (EFA) block. Starting from last FRCR, the steady growth of the DC, DM and DR markets has enabled us to think beyond securing BMU-only events as we recommended additional 100 MW DC-low in FRCR 2024. The FRCR analysis will assess the potential benefits of holding additional DC-Low response to further mitigate residual risks on the system this year, refer to [Section 6.3](#).

#### **4.4 Outlook to 2026/2027**

Since FRCR 2024, FRCR study covers an extended time horizon to assess system risks for multiple years. This forward-thinking approach ensures that potential future challenges and opportunities are thoroughly evaluated. Looking ahead to 2026/2027, the outlook has delved into how the proposed policy is expected to perform beyond just the next year.

Public

## 5. Performance review of previous inertia requirement reduction

The FRCR 2023 recommendation was to reduce the minimum inertia requirement from 140 GVA.s to 120 GVA.s. The recommended policy was approved by Ofgem on the 9 June 2023. The implementation of this policy was delayed due to system events such as the Sub-Synchronous Oscillations (SSO) during the summer of 2023.

Phase 1 of the implementation, which reduced the minimum inertia requirement from 140 GVA.s to 130 GVA.s, was implemented on 28 February 2024. Phase 2, which reduced the requirement further from 130 GVA.s to 120 GVA.s, was implemented on 19 June 2024.

Following these changes, a performance review of the system with reduced minimum inertia was conducted and presented at the NESO Operational Transparency Forum (OTF) on 29 January 2025<sup>2</sup>. The performance review of the inertia requirement reduction is included in this report. The main content of the review consists of three parts. The first part demonstrates how the system inertia has changed after the implementation. The second part reviewed system events that have happened after the change. The last part details the balancing cost savings resulting from the policy.

### 5.1 System inertia

The system inertia from January to December 2024 is plotted in Figure 1, showing the system daily maximum and minimum inertia over time and the 7-day average inertia.

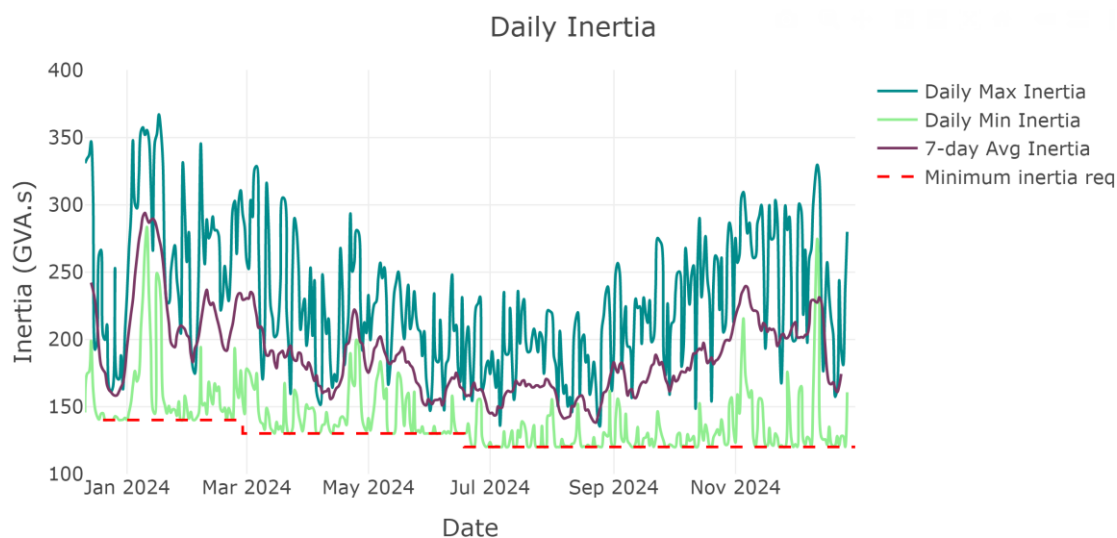


Figure 1 Daily inertia data in 2024

<sup>2</sup> [Operational Transparency Forum 29.01.25](#)

Public

Following the policy implementation, we have seen more occasions when the system outturn inertia is at, or close to, the lower minimum requirement although distinct seasonal patterns remain. Figure 1 Daily inertia data in 2024 illustrates these trends.

As an example, Figure 2 provides a breakdown of inertia from 19 to 25 of August 2024. In this figure, the blue line represents the stability pathfinder phase 1 units, the orange line represents inertia from the market, the green line is the inertia from additional machines synchronised for voltage management, and the purple line indicates the actions taken by NESO to bring the inertia up to the minimum required level.

As demonstrated in both figures, the system inertia is always managed above the minimum inertia requirement. For detailed inertia calculation and assumptions please refer to the **Methodology** and **Handbook**.

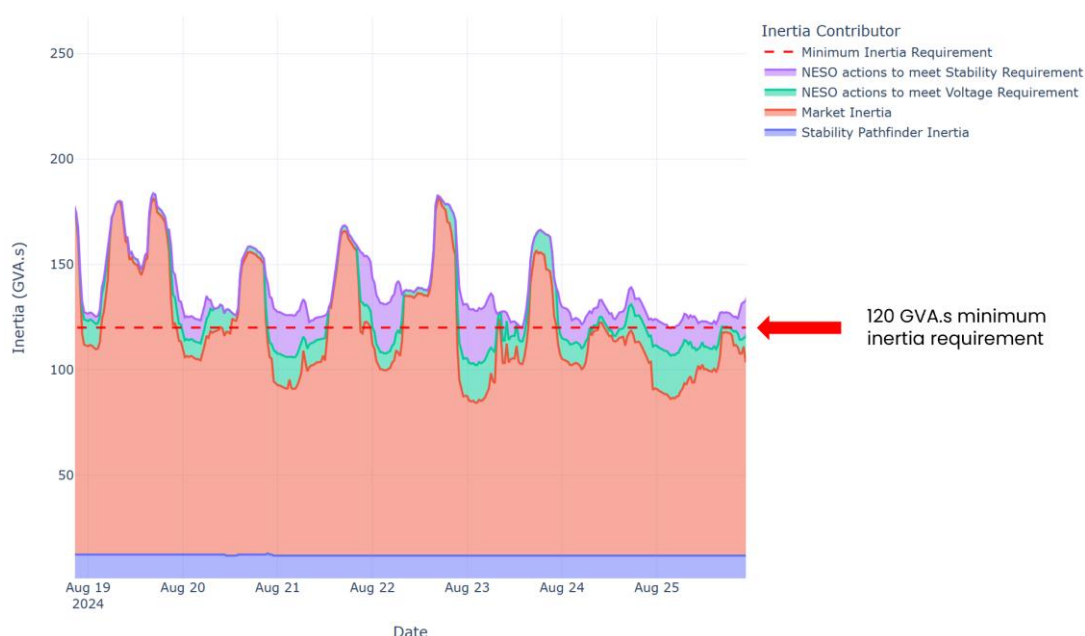


Figure 2 Inertia breakdown for a week in August 2024

## 5.2 System events

By the end of 2024 since implementing the lower minimum inertia policy, there were no reportable frequency events in the GB system, where the system frequency excursions outside statutory limits, i.e. a range of 49.5 Hz to 50.5 Hz, for 60 seconds or more, according to the Transmission Licence Standard Condition C17: Transmission System Security Standard and Quality of Service<sup>3</sup>. After implementing the lower minimum inertia

<sup>3</sup> past Transmission performance report (C17) can be found from NESO [website](#).

Public

policy, there was no increasing trend observed in frequency events<sup>4</sup> based on Grid Code – OC3 reporting criteria. During those events the system and response services performed as expected, and the events were not initiated, caused or related to the lower system inertia policy.

We observed a few Sub-Synchronous Oscillation (SSO) events on the Transmission System in Scotland in 2024. During one of the events, system inertia was recorded at 125.6 GVA.s which was close to the 120 GVA.s minimum requirement. For the remaining events, national inertia was much higher than the minimum level. Our investigation finds no correlation between lower system inertia and the SSO events. NESO has other workstreams actively addressing this issue to ensure that any potential impacts are thoroughly evaluated and managed.

We also conduct reviews and investigations following significant events to ensure that the analysis tools, data, and assumptions remain appropriate, and that the frequency policy remains effective. Further hypothetical analysis has been undertaken to ascertain whether large losses that were observed could be managed with the lower minimum inertia of 102 GVAs. The results of this analysis can be found in the [Appendix](#).

Following the implementation of the lower minimum inertia policy, we have accordingly increased DC-Low and DC-High procurement volumes. We have observed increased capacity and adequate liquidity in the ancillary service market, which is helping us manage system frequency effectively.

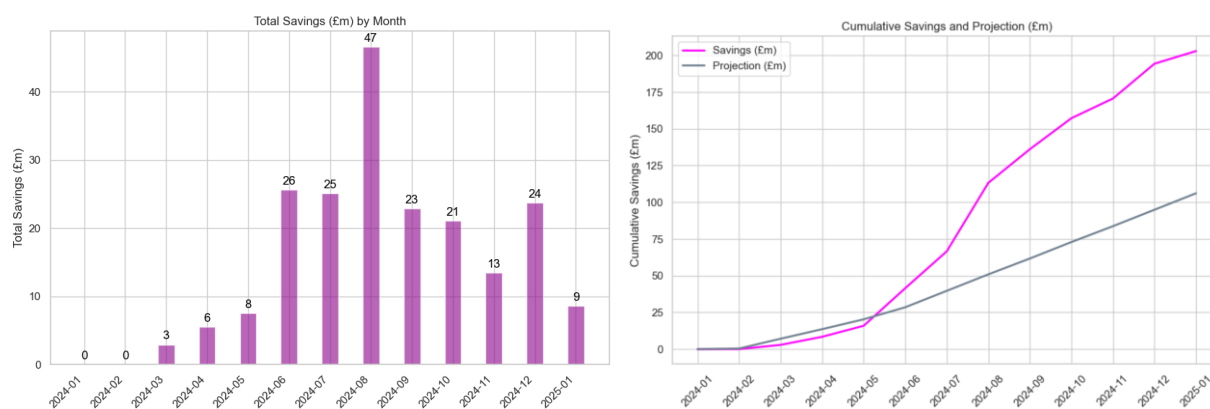
### 5.2.1 Balancing cost saving

This section presents the balancing cost savings from reducing the inertia requirements. We used counterfactual calculations to estimate costs if the minimum inertia remained at 140 GVA.s. Savings result from needing fewer additional inertia machines. The figure below shows monthly and cumulative savings compared to FRCR 2024 projections.

---

<sup>4</sup> events that meet GC105 and GC151 criteria are published on NESO [website](#).

Public



*Figure 3 Savings from inertia requirement reduction*

By January 2025, cost savings totalled over £200 million, that is well above the FRCR 2024 projection. Please note, in the FRCR model we consider average offer and bid price from historical data and adjust by gas and electricity prices, whilst actual balancing costs are used in the counterfactual calculation. Therefore there may be a difference between the actual savings and the projection. For more details on the cost calculations, please refer to the OTF material<sup>5</sup>.

<sup>5</sup> [Operational Transparency Forum 29.01.25](#)

## 6. Assessment and results

This chapter reviews the assessment carried out in FRCR 2025: minimum inertia requirements, securing different loss categories, and benefits of securing additional event categories while providing an outlook to 2026/27. Table 1 below presents the current policy alongside the potential policy evaluated in this report.

*Table 1 Current policy vs. Tested policy in FRCR 2025*

	Current policy	Tested policy
Minimum inertia requirement	120 GVA.s	140, 120, 110 and 102 GVA.s
Secured Loss group	BMU-only	BMU-only, BMU + VS (outage and intact), Simultaneous event
Additional DC-Low response	100 MW	0, 100, 200 and 300 MW

Each section within this chapter includes analysis, results and recommendations for each of the key areas. The analysis in each section focuses on the system residual risks, costs, and additional DC-Low response.

### 6.1 Assessment of minimum inertia requirements

This section assesses the impacts and benefits of operating at different minimum inertia requirement levels, including the legacy 140 GVA.s (before FRCR 2023), current 120 GVA.s (after FRCR 2023) and potential new levels at 110 and 102 GVA.s. The primary objective of this assessment is to understand the residual risks and overall costs associated with each of these inertia levels.

#### 6.1.1 System residual risks

*Table 2 System residual risks*

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
49.5 Hz event	2.84 times per year	2.85 times per year	2.85 times per year	2.85 times per year
49.2 Hz event	1-in-7.40 years	1-in-7.28 years	1-in-7.25 years	1-in-7.24 years
48.8 Hz event	1-in-26.09 years	1-in-25.89 years	1-in-25.83 years	1-in-25.83 years
50.5 Hz event	1-in-78.96 years	1-in-78.99 years	1-in-79.04 years	1-in-79.06 years

The table above shows the system residual risks under different minimum inertia requirements when fully mitigating all BMU-only infeed and outfeed loss risks. A residual



Public

risk is calculated as the probability of all the unsecured events that could trigger 49.5 Hz, 49.2 Hz, 48.8 Hz or 50.5 Hz frequency deviations after controls are applied.

It is evident from the table that the residual risks for each frequency event scenario remain consistent across all levels, despite the differences in the minimum inertia required. This implies that DC is effectively balancing the variations in inertia requirements.

Comparing the residual risks to the FRCR 2024, there has been a notable change in the risk associated with the 49.2 Hz frequency event without considering the additional DC procurement. Previously, the risk of encountering a 49.2 Hz event was estimated to be 1-in-27 years, and it has now increased to 1-in-7.3 years. Similarly, the residual risk of a 48.8 Hz event is increased from 1-in-30 years from 2024 assessment to 1-in-26 years.

This shift is primarily due to a comprehensive review of simultaneous events occurring between 2019 and 2024. The probability of these simultaneous events has been recalibrated from the previous estimate of 1-in-20 years to 1-in-1.3 year for upper quantile simultaneous events. This updated probability reflects a more frequent occurrence of simultaneous events, leading to a considerable change in the risk assessment. More information can be found in Section 5.4 in the **Handbook**.

Despite the updated event probabilities, it is important to note that the FRCR policy mandates securing all BMU-only events. Consequently, the response holding remains consistent level with FRCR 2024 and is not impacted by the updated probability of simultaneous events. This means that the system's security has not been diminished compared to previous years' assessment; instead, the probability data in the model has been updated to reflect the most recent event data.

### 6.1.2 System overall cost

Table 3 Cost breakdown under different minimum inertia requirements

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
Cost for system-wide controls (NB: system-wide controls include inertia and all response costs)	£524m	£266m	£198m	£170m
Cost to meet minimum inertia (this element is included in system wide cost)	£455m	£196m	£128m	£101m
Cost for Dynamic Containment (this element is included in system wide cost)	£24.3m	£24.5m	£24.6m	£24.6m
<b>Incremental saving</b>		<b>£258m</b>	<b>£68m</b>	<b>£28m</b>

Public

The table below shows the costs and potential savings that could be achieved across the different minimum inertia requirements when fully mitigating all BMU-only infeed and outfeed loss risks.

When assessing the cost impact of changing the minimum inertia requirement, only the costs of DC and inertia are impacted. All other system wide costs, such as DR, DM and static response, remain unchanged. Increasing the DC requirements results in higher DC-related costs, and increasing the inertia also leads to higher inertia-related costs. Since DC is a more effective tool for managing frequency risks, the cost savings achieved by reducing inertia are significantly greater than the cost increases associated with DC increases.

With the current 120 GVA.s minimum inertia policy, we have calculated that a total saving of £258m has been achieved as we moved from 140 GVA.s to 120 GVA.s. Compared to 120 GVA.s, an estimated further cost saving of £96 million is expected if operated at 102 GVA.s. When reducing inertia requirement to 102 GVA.s, the additional DC volume to maintain the system security is not significant. The total additional cost is estimated around £22k per year which indicates DC is highly cost effective.

### 6.1.3 Recommendations

Analysis indicates that an additional £96m could be saved if we reduce the minimum inertia requirement to 102 GVA.s. There is no reduction in the overall system risks by operating at an inertia level at 102 GVA.s. It is likely that system events that cause frequency deviations outside of 48.8 Hz under 102 GVA.s would also result in frequency deviations outside of 48.8 Hz under a higher inertia level of 120 GVA.s. Hence the residual risk of 48.8Hz events remains largely the same under various inertia conditions.

The implementation of 120 GVA.s, as recommended by FRCR 2023, has been enabling us to gain experience associated with operating the system at a lower inertia level from 2024. Therefore, for the period covered by this report, 2025/26, we consider that it is beneficial to further reduce the minimum inertia to 102 GVA.s. This change represents our continued effort to operate the system at lower inertia levels, to help meet our zero carbon ambitions.

Based on the assessment conducted, we are recommending a reduction in the minimum inertia requirement from 120 GVA.s to 102 GVA.s.

## 6.2 Assessment of securing additional event categories

Current policy focuses on securing BMU-only events with their consequential RoCoF loss. In this section we review the impacts and benefits of securing additional event categories, including BMU+VS and simultaneous events under reduced inertia

Public

requirement. The primary objective of this assessment is to determine the appropriate approach regarding event categories to understand if there is any additional value to secure beyond BMU-only events under the recommended reduced minimum inertia level of 102 GVA.s. The analysis focuses on system residual risks and cost-benefit considerations.

### 6.2.1 System residual risks vs. cost

This section evaluates the risk vs. cost of using Response Control to secure the remaining event categories, i.e. BMU+VS (outage), BMU+VS (intact) and Simultaneous events. As mentioned in [Section 4.3](#), the cost reduction of procuring DC presents an opportunity to use additional Frequency Response Control to mitigate the system risks beyond BMU-only events with little additional cost.

FRCR analysis compared BM Control and Response Control to mitigate beyond BMU-only events. It was concluded that Response Control offers significantly higher cost-effectiveness compared to BM Control. From this year's assessment, only Response Control is considered to assess beyond BMU-only events.

To mitigate all BMU+VS events, the estimated additional cost for Response Control is around £278k on top of the total cost under 102 GVA.s of £170m, whereas the additional cost for securing all simultaneous events would be around £20m. The system residual risks and additional costs associated are concluded in the below table.

*Table 4 Risk and cost for different risk categories at 102 GVA.s*

Event category	Response Control		
	Residual risk for 49.2 Hz event	Residual risk for 48.8 Hz event	Additional cost per year
BMU-only	1-in-7.24 years	1-in-25.83 years	£0
BMU+VS (outage)	1-in-7.25 years	1-in-25.84 years	£14k
BMU+VS (intact)	1-in-7.26 years	1-in-25.84 years	£278k
Simultaneous event	0 times per year*	0 times per year*	£20m

\*all risks are being covered in the FRCR analysis

The current policy of securing all BMU-only events has achieved a balance between cost and risk, where system residual risk remains 1-in-7 years. By securing all BMU-only events, the majority of the BMU+VS and simultaneous events are naturally covered. The total system security, when assessing system residual risks at 49.2 and 48.8 Hz is not improved significantly following applying additional response controls to mitigate all BMU+VS events.

Public

However to fully secure BMU+VS or simultaneous events, due to the volatility in the event profile in some circumstances we would need up to 3 GW DC holding which is much beyond the current market available capacity and DC price may fluctuate significantly.

### 6.2.2 Historic trend of securing additional event categories

The table below shows the evolution of the cost of securing BMU-only as well as the additional cost of securing BMU+VS (outage), BMU+VS (intact) and simultaneous events in the latest four years' FRCR reports.

Table 5 Comparison of cost in mitigating all risks across different FRCR years

	<b>Cost for system-wide controls</b> <i>(include inertia and all response costs)</i>	<b>Additional Cost for BMU+VS (outage)</b>	<b>Additional Cost for BMU+VS (intact)</b>	<b>Additional Cost for simultaneous events</b>
FRCR 2022 (using BM Control)	£330m	£57m	£1.4b	£370m
FRCR 2023 (using BM Control)	£264m	£13m	£306m	£321m
FRCR 2024 (using Response Control)	£242m	£35k	£838k	£37m
<b>FRCR 2025</b> (using Response Control)	<b>£170m</b>	<b>£14k</b>	<b>£280k</b>	<b>£20m</b>

\*minimum inertia requirement is 120 GVA.s for FRCR 2023 and FRCR 2024, and 102 GVA.s for FRCR 2025

By applying Response Control as the additional measure to mitigate BMU+VS risks, the estimated additional costs are around £280k in FRCR 2025, which is significantly lower than previous years' estimates. This highlights the cost-effectiveness of using DC as a tool for managing frequency risks within the current system and market conditions. These results suggest further utilisation of DC to mitigate additional risks is highly favourable.

### 6.2.3 Recommendations

Securing to BMU-only events continues to present the best cost-risk balance. Considering the high cost-effectiveness of DC, there is a potential to utilise DC to address risks beyond BMU-only events and improve overall system security.

However, we would struggle to fully secure all BMU+VS risks by applying Response Control. This is primarily because significant and fluctuated DC volumes would be required to mitigate these risks due to the volatility in the event profile, and this capacity is not always available in the current market. The large fluctuations in DC volume also

Public

present uncertainty to the market, which could cause unexpected shortfalls in the service procurement and result in increased operational risks. In addition, further analysis is necessary to fully understand the complexity of transmission system conditions that could lead to the BMU+VS events as well as their impact on the increased response requirement.

Instead, an alternative approach of holding a fixed additional volume of DC is proposed and assessed in the section below. This approach is straightforward and can leverage the benefits of Response Control.

### 6.3 Assessment of additional Dynamic Containment - Low response

Analysis in [Section 6.2](#) has indicated that Response Control is a cost-effective tool for mitigating beyond BMU-only risks. In this section, we will evaluate various options for holding additional DC-Low response. Our assessment will consider the potential benefits and drawbacks of options of holding additional DC-Low response under the 120 and 102 GVA.s inertia requirements. By exploring these options, we aim to develop a comprehensive approach that balances cost and reliability.

#### 6.3.1 System residual risks vs. cost

To find the optimal volume of additional DC-Low, a set of scenarios with different volumes of DC are studied with the risk vs. cost results presented. Additional DC-Low requirements ranging from 0 to 500 MW, in increments of 50 MW, are considered. The associated system risk and cost are presented below.

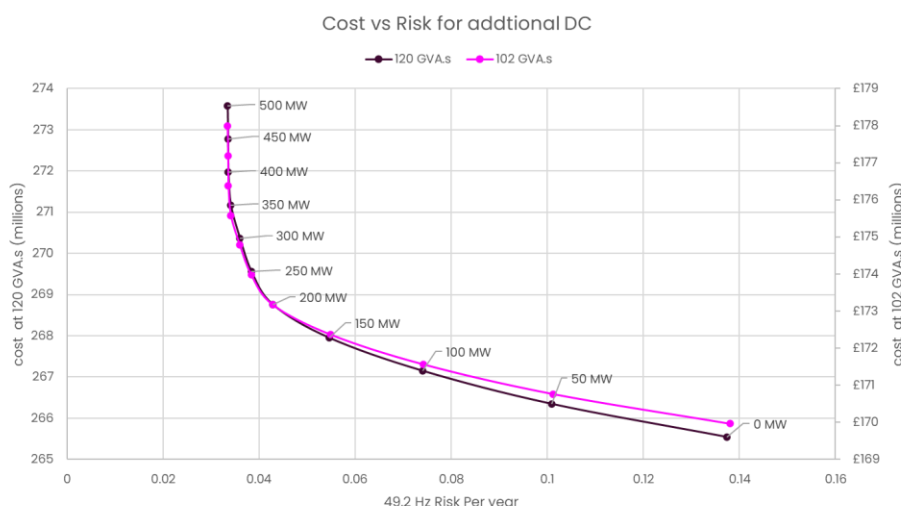


Figure 4 Cost vs risk with additional Dynamic Containment - Low

Public

The cost and residual risk of the different scenarios are shown in Figure 4 under 120 and 102 GAV.s inertia requirement. An indicative curve is interpolated between the data points as well. It indicates that the system risk reduction is most significant when holding an additional 200 MW of DC-Low response both under 120 and 102 GVA.s inertia requirements.

Beyond this increment, the marginal benefits decrease significantly with 300 MW of DC-Low, while costs rise at a comparable rate. The Table 6 below presents more details by compares system residual risks and cost under three scenarios: BMU-only, BMU-only with 100 MW, 200 MW, 300 MW and 400 MW additional DC-Low at 102 GVA.s inertia requirement. All analysis is based on the latest market data and does not consider the price changes associated with the required increase.

*Table 6 Cost vs risk with additional DC-Low response for 49.2 Hz event at 102 GVA.s*

Option	Extra cost	Residual risk (49.5Hz)	Residual risk (49.2 Hz)	Residual risk (48.8Hz)
BMU-only (baseline policy)	£0	2.85 times per year	1-in-7 years	1-in-26 years
100 MW additional DC-Low (FRCR 2024 policy)	£1.61m	2.56 times per year	1-in-13 years	1-in-29 years
200 MW additional DC-Low	£3.23m	1.85 times per year	1-in-23 years	1-in-30 years
300 MW additional DC-Low	£4.84m	0.5 times per year	1-in-28 years	1-in-31 years
400 MW additional DC-Low	£6.45m	0.05 times per year	1-in-30 years	1-in-32 years

The additional cost and the updated residual risk have been calculated and are presented in the table. Holding an additional 200 MW of DC-Low provides enhanced risk mitigation, with an associated incremental expenditure of £3.23 million and a reduction in the residual risk of a 49.2 Hz event to a 1-in-23 years from 1-in-7 years, making it the most balanced option. However, increasing the DC-Low to 300 MW and beyond results in only a marginal further decrease in risk with higher cost. The impact of additional DC-Low holding on the risks of 49.5 Hz and 48.8 Hz events is also shown in the table showing good value for consumers in managing these risks.

### 6.3.2 Recommendations

Based on the findings, we recommend holding an additional DC-Low requirement of 200 MW. Holding additional volumes of DC provides a great system security improvement with a small amount of extra DC cost.

Public

Increasing our DC-Low holding can also help further grow the response market. As our largest loss size increases, with sites such as Hinkley-C power station connecting to the network in the future, we will see a significant increase in DC requirements to cover a larger individual loss. By proactively expanding our DC holding capacity, we are not only making our system more secure but also stimulating the market to expand its capabilities prior to this increasing largest loss size. This is crucial for ensuring that we are capable of managing an 1800 MW loss size on the network in the near future.

## 6.4 Additional considerations

### 6.4.1 Effect of Limited Frequency Sensitive Mode – Over frequency

In FRCR 2025, the Limited Frequency Sensitive Mode – Over frequency (LFSM-O) is included in the model. The impact of LFSM-O is presented in this section. The Limited Frequency Sensitive Mode – Under frequency (LFSM-U) however is not considered as LFSM-U would only be expected to be delivered when the system frequency is below 49.5 Hz and the generator has available head room. Noting that this requirement generally applies only to plants connected to the system on or after April 2019, and concluded purchase contracts for major plant items on or after May 2018, and that, in the main, most plants are operating at maximum capacity, its impact on overall system performance is almost negligible. The detail of modelling the LFSM-O can be found in the FRCR **Handbook** Section 3.1.3.

*Table 7 Risk with and without LFSM-O for 50.5 Hz event*

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
50.5 Hz event	1-in-78.96 years	1-in-78.99 years	1-in-79.04 years	1-in-79.06 years
50.5 Hz event with LFSM-O	1-in-85.58 years	1-in-85.23 years	1-in-85.29 years	1-in-85.30 years

It can be observed from the table that LFSM-O can reduce the system's residual risk of 50.5 Hz events at various inertia levels. It is important to note that the baseline recommendation of FRCR 2025 is established without considering LFSM-O volumes. Analysis including LFSM-O represents NESO's initial attempt to quantify the impact of LFSM, and it is anticipated that the capacity of LFSM-O will enhance risk mitigation. We view LFSM-O as an additional layer of protection beyond the FRCR policy. The capacity of LFSM-O therefore is not considered in NESO's model in determining response service daily auctions but works as additional layer in real-time operation. LFSM capacity and modelling could be further reviewed following frequency events in the future.



### 6.4.2 Effectiveness of low frequency demand disconnection (LFDD)

The first stage of low frequency demand disconnection (LFDD) starts at 48.8 Hz and then subsequent stages apply in the range 48.8 Hz – 47.8 Hz. Under a 102 GVA.s system condition and to initiate a 48.8 Hz deviation, we would have an infeed loss at least 2000 MW. As illustrated in Table 2, the probability of a 48.8 Hz event or an LFDD event occurrence remains at approximately a same level regardless the minimum inertia level, i.e. 1-in-25.89 years under 120 GVA.s and 1-in-25.83 years under 102 GVA.s.

The previous two occurrences of LFDD happened on 27 May 2008 and 9 August 2019 over a decade apart. These are the only two LFDD events since GB electricity industry privatisation in 1990. The limited operational experience however verifies the effectiveness of LFDD operation, including, relay<sup>6</sup> triggering setting and time delay. Past experience indicates there is no unnecessary delay in causing the frequency to drop further or mal-operation leading to frequency overshooting post fault.

### 6.4.3 Wider system operability considerations

When running the system at the inertia of 102 GVA.s, a largest loss of 1800 MW would result in a RoCoF of 0.5 Hz/s. The ALoMCP has significantly reduced the risk of inadvertent tripping of embedded generation where the majority of RoCoF relay settings is now at 1 Hz/s. Following the trigger of 1 Hz/s RoCoF at a system inertia of 102 GVA.s, it is expected most of the embedded generation would start to trip based on their LoM protection settings. This would result in a national-wide power outage scenario. However, to initiate a 1 Hz/s RoCoF event under the proposed 102 GVA.s inertia level, the system would need an infeed loss of 3.3 GW. This level is far greater than the current largest loss we aim to secure and is much higher than any of the historical simultaneous events that we have observed. Proposing 102 GVA.s inertia requirement and limiting the post-fault RoCoF to 0.5 Hz/s provides a security “buffer” under current and foreseen system conditions.

In terms of wider system operability, there are interactions between reducing the minimum inertia level and other system operability areas. Our Operability Strategy Report (OSR) looks at these interactions and considers the wider impact of lower inertia levels on all operability workstreams. We are developing new operational strategies, tools and processes to ensure we have visibility and can manage these challenges in a coordinated manner.

<sup>6</sup> LFDD relays have a requirement to be tested under Energy Networks Association (ENA) technical specification 48-6-5 Issue 1. [Grid Code CC/ECC Appendix 5](#).



Public

We will continue to solve any future challenges associated with zero carbon operation (for example, through the use of Grid Forming technologies and other tools), ensuring we understand the operability requirements and how these operability challenges interact.

## 6.5 Outlook to 2026/27

By the end of 2025, we aim to operate the electricity system at zero carbon for short periods of time, helping us move towards a clean power system by 2030 and go beyond. This FRCR also explores managing frequency risks with the system conditions anticipated in 2026/27. The results obtained from the analysis are preliminary. A more comprehensive assessment will be conducted in future FRCRs considering additional operational experiences and improved foresight of system conditions, to drive appropriate future frequency control policy.

### 6.5.1 Minimum inertia requirements

The impact of the current FRCR policy on the residual risk for 2026/27 is set out below. In the 2026/27 outlook, the assessment focuses on 120 GVA.s and 102 GVA.s minimum inertia policies. When securing BMU-only risks, the residual risks at different minimum inertia levels are shown in the table.

*Table 8 System residual risk in 2026/27*

Scenario	120 GVA.s	102 GVA.s
49.5 Hz event	3.48 times per year	3.49 times per year
49.2 Hz event	1-in-10.71 years	1-in-10.70 years
48.8 Hz event	1-in-27.94 years	1-in-27.87 years
50.5 Hz event	1-in-88.21 years	1-in-88.28 years

It should be noted that varying the minimum inertia in 2026/2027 would not pose additional risks to the system, similar to the analysis for 2025/26. Additionally, the residual risks for 49.2 Hz and 48.8 Hz events are reduced in 2026 compared to 2025. This improvement is due to differences in event profiles between the two years driven by new connections to the system in 2026. The actual risk in 2026 will be reassessed in next year's FRCR as more accurate and updated data becomes available.

Public

Table 9 Cost breakdown in 2026/27

Scenario	120 GVA.s	102 GVA.s
Cost for system-wide controls (NB: system wide controls include inertia and all response costs)	£324m	£258m
Cost to meet minimum inertia this element is included in system wide cost	£255m	£188m
<b>Overall saving</b>		<b>£67m</b>

The table above shows the costs and potential savings that could be achieved with a minimum inertia of 102 GVA.s in 2026 when securing all BMU-only events. We estimate that a total saving of £67 million can be achieved by moving from 120 GVA.s to 102 GVA.s, with a total spending of £258 million at 102 GVA.s. This total spend figure has increased compared to the year 2025 (£170 million at 102 GVA.s). This is mainly due to higher cost to meet the minimum inertia requirement, while system inertia provided by synchronising units is expected to further reduce in 2026.

### 6.5.2 Securing additional event categories

The table below shows the system residual risk and costs of a 102 GVA.s minimum inertia policy in 2026, when securing beyond BMU-only events.

Table 10 Risk and cost for different risk categories in 2026/27 at 102 GVA.s minimum inertia

Event category	Response Control	
	Residual risks	Additional costs
BMU-only	1-in-10.70 years	£0
BMU+VS (outage)	1-in-10.72 years	£13k
BMU+VS (intact)	1-in-10.74 years	£261k
Simultaneous event	0 times per year*	£20m

\*all risks are being covered in the FRCR analysis

With Response Control, an additional spending of £274k on top of the cost of securing BMU-only events allows us to manage all BMU+VS risks, resulting in a similar residual risk of 1-in-11 years compared to 2025 result. However, as discussed in [Section 6.2](#), fully mitigating BMU+VS risks is challenging due to the volatility in the event profile. Therefore, it is still preferable to use a fixed additional DC-Low response to further mitigate residual system risk.

### 6.5.3 Additional DC-Low holding

The table below provides a comparison of the risk vs. cost for holding different volumes of additional DC-Low in 2026. Similarly to 2025 analysis, 100, 200 and 300 MW of additional DC-Low volumes are considered under the 102 GVA.s minimum inertia policy.

*Table 11 Cost vs risk with additional DC-Low response for 49.2 Hz event in 2026/27*

Option	Extra cost on top of £258m	Residual risk (49.2 Hz)	Reduction in risk per year
BMU-only	£0	1-in-10.70 years	N/A
100 MW additional DC-Low	£1.61m	1-in-19.9 years	4.04%
200 MW additional DC-Low	£3.23m	1-in-27.25 years	1.27%
300 MW additional DC-Low	£4.84m	1-in-28.65 years	0.17%

This 2026 analysis shows similar trends to the 2025 analysis, verifying that the residual risk reduction is most effective when increasing DC-Low holding from 0 MW to 200 MW. System risk has improved from 1-in-11 years to 1-in-27 years, with an extra cost of £3.23m per annum. The reduction in risk per year is the difference in residual risk between each option. In this analysis the additional cost of DC remains the same with the price assumed to be unchanged from year 2025.

Public

## 7. Conclusions

### 7.1 Recommendation

The recommendations within this report are:

- Reduce the minimum inertia requirement to 102 GVA.s.
- Secure all BMU-only events to keep resulting frequency deviations within 49.2 Hz and 50.5 Hz.
- Do not apply additional controls to secure all BMU+VS and simultaneous events.
- Apply additional 200 MW DC-Low control to increase system security and grow the market.

The analysis shows that the recommended policy represents good value for GB consumers. The recommendation to hold additional volumes of DC-Low enhances overall system security by enabling us to secure beyond BMU-only risks. Holding additional volumes of DC-Low helps us further grow the response market in preparation for securing the future largest loss of 1800 MW.

### 7.2 Implementation

The reduction of the minimum inertia requirement will be implemented following Ofgem's approval in a phased manner. The initial stage will lower the minimum inertia requirement to 110 GVA.s, followed by a second stage that will further reduce it to 102 GVA.s. We will gain operational experiences following the first stage of the reduction. There will be a minimum interval of five weeks between the two stages to allow adequate time for observation of the changes.

We also recommend an increase in the DC-Low requirement by 200 MW. Based on current market liquidity, we anticipate no issues with implementing this adjustment.

Upon receiving approval from Ofgem, we will announce the implementation through the OTF or separate webinars, providing at least five working days' notice via our standard response service forecasting and communication channels.

#### **Variations to this policy**

There are specific, limited variations to these recommended policies where approved, based on technical, probabilistic and economic grounds, applied under paragraphs 5.11.2 and 9.4.2 of the SQSS. This includes additional actions taken by NESO, where

Public

appropriate, during times of increased system risk, such as during severe weather, and exceptions where risks do not feasibly occur under normal prevailing conditions<sup>7</sup>.

### 7.3 Consultation Summary

The FRCR 2025 consultation was issued on 3 March 2025, closed on 7 April 2025 (extended from 31 March 2025) and received seven responses. We acknowledged all constructive comments to the consultation and offered the opportunity to arrange follow-up meetings with relevant specialists to address their concerns regarding the FRCR 2025 consultation responses. The discussion covered not only FRCR policies but also system operability, compliance, Grid Code Modification, innovation research, the operational changes to mitigate risks.

The consultation responses are summarised below, and the full responses can be found on our website.

*Table 12 Response summary – preparation and general feedback*

Questions	Response summary
Do you agree that the FRCR 2025 has been prepared appropriately? Please elaborate	<p><b>Agreement:</b>            Several agree that the FRCR 2025 has been appropriately prepared, acknowledging the independent reviews and consultation processes positively. One response welcomes the additional resources provided, such as the Data Handbook and webinars.            A few suggestions about specific aspects, such as further exploration of SSO events, lower inertia, more comprehensive reviews and validation of assumptions, methodologies, and models.</p> <p><b>Disagreement:</b>            One respondent disagrees with the preparation of the FRCR 2025, citing a lack of confidence in the risk analysis related to simultaneous, cascading events.</p> <p><b>No Comment:</b> one left no comment</p>

<sup>7</sup> e.g., due to the configuration of the network making the loss of the whole BMU at once not credible.

Public

<p>Do you believe there has been sufficient industry engagement in preparing FRCR 2025? Please specify further suggestions</p>	<p><b>Agreement:</b> One respondent agrees on sufficient engagement but notes limited interaction. Another sees improvement but suggests earlier engagement and more webinars. A third recommends enhancing transparency by publishing questions and responses. Concerns: One mentioned this is a complex modelling area NESO must consider the extent to which any industry party can provide effective engagement.</p> <p><b>Disagreement:</b> One respondent stated “No”. NESO understand the reason is that the respondent suggests further engagement to be more interactive.</p> <p><b>No Comment (Cannot Decide):</b> One respondent is aware of the consultation and associated webinar but cannot judge the level of engagement across the wider industry. One left no comment.</p>
<p>Overall, do you agree that the FRCR 2025 represents the appropriate level of development in determining the way that the NESO will balance cost and risk in maintaining frequency security while operating the system at a reduced inertia down to 102 GVA.s?</p>	<p><b>Agreement :</b> Some respondents see good development in balancing cost and risk. Another agrees with the risk-reward approach but cites uncertainties and suggests considering regional inertia differences. One indicates probable agreement but highlights the complexity and need for deeper understanding. Another respondent suggests evaluating the policy against historical events to assess its robustness, implying current measures might not be sufficient (post engagement, we addressed his questions/concerns).</p> <p><b>Disagreement:</b> One respondent strongly opposes the reduction of inertia, citing increasing frequency excursions, insufficient power backup, and potential security of supply issues. Another respondent states “No”.</p> <p><b>No Comment (Cannot Decide):</b> One respondent notes the complexity of the work and cannot comment.</p>

Public

Table 13 Response summary – Policy Proposal

Questions	Response summary
Do you agree with the recommendation to: Reduce minimum inertia requirement down to 102 GVA.s	<p><b>Agreement:</b> 2 responses agree with suggesting a slower reduction.</p> <p><b>Concerns:</b> One concern requests assessing regional RoCoF risks with industry involvement. The other concern is also around the uneven regional inertia distribution and RoCoF.</p> <p><b>Disagreement:</b> One response had strong disagreement with the reduction. This is understood related to wider operability issue and CP30 target.</p> <p><b>No Comment (Cannot Decide):</b> One felt unable to decide due to the complexity and lack of understanding. One believes risk determination should be by NESO and Ofgem.</p>
Do you agree with the recommendation to: Secure all BMU-only events (including consequential RoCoF)	<p><b>Agreement:</b> 3 responses agreement with the recommendation based on risk and cost data, with a suggestion to review the risk of VS events based on regional inertia levels. One response believes FRCR report sets out the justification.</p> <p><b>Concerns:</b> One concern around the definition of BMU-only event (We clarified during the engagement and updated in the report)</p> <p><b>Disagreement:</b> No direct disagreements expressed.</p> <p><b>No Comment (Cannot Decide):</b> 3 responses. one feels unable to decide due to the complexity and lack of understanding and one left no comment</p>
Do you agree with the recommendation to: Procure additional DC-Low service provision by 200 MW	<p><b>Agreement:</b> 4 responses including 2 requesting further analysis to validate the robustness of the 200 MW. Opinion changed to agree post engagement.</p> <p><b>Disagreement:</b> No direct disagreements expressed.</p> <p><b>No Comment (Cannot Decide):</b> 3 responses. 1 mentioned no confidence in the analysis to respond due to wider operability concerns.</p>
Do you have any other comments to the recommendations?	Reference to specific comments in attached documents or reports.

Public

Table 14 Response summary – Future work and Governance

Questions	Response summary
In your view, what should the future FRCR focus on?	<p>The responses underscore the need for future FRCR work to focus on the broader impacts of increased renewables and inverter-based resources.</p> <p>There is a call for further analysis on managing simultaneous events, potentially through increased Dynamic Containment (DC) capacity as battery storage expands.</p> <p>Additionally, concerns about risk quantification, regional inertia, and the implications of network expansion, including new nuclear facilities and offshore hubs, highlight the importance of considering technological advancements and regional variations to enhance system reliability and resilience.</p>
Do you foresee any issues that may arise from moving the obligation to produce the FRCR to a NESO License Condition rather than an Annex to the NETS SQSS?	<p>The majority of respondents express concerns about transferring the obligation to produce the FRCR to a NESO License Condition. While some do not foresee immediate issues, they emphasize the importance of maintaining robust scrutiny and governance. There is a general consensus that any changes should not diminish industry oversight or the quality of recommendations.</p>
If the obligation to produce FRCR and the governance rules surrounding that process are moved to NESO's License, do you believe that the NETS SQSS Panel should continue to provide oversight?	<p>Most responses support the continued oversight of the FRCR by the NETS SQSS Panel, even if the obligation moves to NESO's License.</p>



Public

If you answer to Question 16 is "Yes" to what extent should this oversight be? For example, should it include technically assessing the recommendations and approving/rejecting it, or should it be limited to confirming that the governance process and methodology has been followed correctly?

Regarding the extent of oversight, the responses vary. Some suggest that oversight should include a thorough technical assessment of the recommendations, while others highlight the need for a balance between detailed technical assessments and confirming adherence to governance processes. There is a shared belief that oversight should ensure the effectiveness of the FRCR process and adapt to transitional changes in the power system.

Key questions and concerns based on industrial responses are summarised below. Table 15 provides the updates made according to the consultation feedback. Table 16 summarises NESO's response to future FRCR work questions and concerns. Finally, we also received questions that sit outside the FRCR scope, and those questions and responses are presented in Table 17. The Detailed response to each respondent can be found on our website under the FRCR section.

*Table 15 Updates on the FRCR 2025 document following consultation*

Updated Document	Updates
<b>FRCR25 Report</b>	Updated report rewording, verb tense and typos.
	Conducted hypothetical analysis to review 2019, 2023 and 2025 simultaneous events and include them in Appendix 9.1
	Included higher granularity and extended the volumes in DC-L incremental analysis in 6.3.
	Included Engagement Summary and Updated Accenture's work in Executive Summary
	Presented Consultation summary in 7.3
	Updated the residual risk to "0 times per year" when simultaneous events are fully secured. Explained all risks are being covered in FRCR analysis in this scenario.

Public

	Included as statement that NESO conducts review and investigations following significant events to ensure our analysis tools, data, and assumptions remain appropriate and that frequency policy remains effective, serving as a form of assurance, in Chapter 5.
	Indicated in 6.4.2 LFDD relays have a requirement to be tested under Energy Networks Association (ENA) technical specification 48-6-5 Issue 1.
<b>FRCR Methodology v3</b>	Clarified v3 methodology document has no material change from v2 but streamlined to reflect current analysis.
	Update BMU-only event definition to clarify there could be sit includes exceptional cases, where more than one BMU are disconnected, where the generating units are fed by a common energy source.
	Included LFSM-O consideration
<b>FRCR Data Handbook</b>	Explained recorded transmission events are from 3 <sup>rd</sup> party data and there is similar data available in GC0151 reports.
	Corrected date of 2023 Simultaneous event to 22 December 2023
	Explained in 6.4 how does FRCR consider historic simultaneous high-frequency events.
	Update BMU-only event definition to clarify there could be sit includes exceptional cases, where more than one BMU are disconnected, where the generating units are fed by a common energy source.

Table 16 Summary of NESO responses on future FRCR work

Areas	Suggestions / Concerns	NESO Actions / Response
<b>Preparation and Engagement</b>	Early engagement and notice, e.g. when consultation was delayed due to assurance work being introduced, could help manage their workload.	NESO will explore other approaches to improve the engagement and obtain industry's feedback.
	Consider different approach to get industrial feedback out of traditional consultation process due to the complexity of this topic.	

Public

	<p>2026 to consider holding a face-to-face workshop with the opportunity to raise questions. This should facilitate better stakeholder engagement.</p> <p>NESO to consider more interactive engagement with industry in future FRCRs.</p>	
<b>Governance</b>	<p>Can the SQSS Panel appoint an independent review within FRCR process?</p> <p>Considering an independent technical analysis of specific parts of the assessment or conducting "spot checks" across the entire FRCR model and analysis.</p>	<p>NESO will collate all the feedback and discuss with the Panel. For future FRCR, the requirement of an independent technical review or the continuous engineering assurance will be clarified with the SQSS Panel.</p>
<b>Future FRCR work</b>	<p><b>FRCR to consider a tolerance level for LFDD</b>, e.g. 48.85 Hz, vs, required in GC as the worst-case scenario to minimise the system impact if a LFDD event happens.</p> <p><b>FRCR forward-looking</b> to consider future and emerging risks in the model.</p> <p>To consider <b>uncertainties and variance from data inputs</b>, e.g. in the simultaneous statistical analysis for a better understanding of risk sensitivity.</p>	<p>We will consider this in future FRCR. The tolerance band needs to be carefully defined.</p> <p>While FRCR is primarily backward-looking, it does incorporate forward-looking elements to manage emerging risks, however the lack of data for new risk is challenging to be incorporated into FRCR model.</p> <p>New risk should be prevented through other workstreams, compliance process, as an example, instead of using FRCR to cover the risk, with more response hold.</p> <p>We will explore this new methodology in the future. This can be extended to other analysis in FRCR model, if not only in the simultaneous analysis.</p>

Public

	<b>To model LFSM-U operation</b>	We will explore the modelling of LFSM-U by reviewing historic events and investigate LFSM-U capacities from battery storage and interconnectors.
	<b>Extension of FRCR analysis time horizon</b> and its strategic direction.	If a long-term time horizon is intended for FRCR to consider, the methodology will need to be revised. Operability strategy is currently set out in different publications where a longer-term view is presented. We will discuss this with the SQSS Panel and run a separate consultation to shape the future FRCR work if needed.
	National HVDC centre suggested FRCR policy to align with the approach taken to voltage stability within the SQSS <b>by introducing a “Frequency containment margin”</b> .	We recognised this is a huge piece of work which might need a separate industry mandate and would need substantially more resource and time of NESO’s and from the industry. We will explore this further.

Table 17 Summary of NESO responses on questions outside of FRCR scope

Topic	Comments / Concerns	NESO Actions / Response
<b>Operability</b>	How flexible FRCR is to assess and align emerging system operability risk?	Wider system risk should be prevented through other workstreams, compliance process, as an example, instead of using FRCR to cover the risk, with more response hold.
	FRCR methodology needs to be updated to reflect and better model the risks from fast changing power systems.	If FRCR methodology needs to be changed following the review, we will consider wider industry engagement and run separate consultation.

Public

	Wider concerns about future operability, economic running of rare used generators and reliance on renewables for meeting CP30 target.	NESO will organise a separate meeting, inviting CP30 team, to further discuss those questions.
	Does NESO have any projects using AI to enhance system performance understanding, such as analysing TO asset behaviours during system events with lower inertia levels.	Both NESO and SHETL are checking with their innovation team to see any existing project and future collaborating potentials.
	Regional RoCoF assessment, Regional inertia and system operability	We will be running an industry workshop to collate wider views and opinions about regional inertia and regional RoCoF. In the meantime, we are following system events to understand better the impact from regional inertia and regional RoCoF. Additionally, we are engaging with industry to develop GFM compliance requirement and market development.
	Suggest that stand-alone simulations estimating current connected device tolerances to the expected transient frequency and phase angle jumps under low inertia conditions are used to anticipate the limits to next stage FRCR action.	We will continue reviewing the grid following converter behaviours (including within transient time frames) following any significant system events to explore the impact from regional inertia.
	concerns about the lack of explicit requirements for vector shift fault ride-through capability.	Whilst acknowledged the concern, we clarified the risks should be managed via Grid Code modification and compliance route. The discussion on fault ride-through requirements is included in industry engagement sessions when addressing Grid Forming Technology (GFM).

Public

<b>LFDD</b>	Concerns about wider system security and economic impacts following a LFDD event	NESO Restoration and Resilience to follow
	LFDD relay effectiveness – Some LFDD relays are very old from a higher inertia and lower RoCoF.	This is out of FRCR scope and is included in ENA Technical Specification 48-6-5 Issue 1 dated 2005 “ENA Protection Assessment Functional Test Requirements – Voltage and Frequency Protection” requirement on LFDD testing to be carried out every 3 years. This is referred by GC/ECC CC.A 5.4.1. This information is also included in the main report.
	Current LFDD relay tolerance setting vs. GC requirement needs to be reviewed	This is out of FRCR and shall be initiated and led by the other workstream.
<b>Data Transparency &amp; Engagement</b>	One comment highlighted the importance of making NESO’s ongoing work, e.g. event review and updated report, GFM development, regional inertia and RoCoF monitoring, and data more visible to the industry.	We acknowledged the comment and will continue being transparent.
	How NESO engages with industry to tackle long-term system changes and risks?	We will feedback to NESO senior management team and discuss with Ofgem

Based on the consultation results, most of the responders agree FRCR 2025 was prepared and engaged with industry adequately and demonstrates NESO’s appropriate development in managing GB frequency. There are some concerns in the 102 GVA.s policy recommendation which are understood, related to regional inertia and RoCoF management. We believe they are out of FRCR’s immediate scope and NESO has initiated the work with the industry, e.g. GFM expertise group, to tackle the issues in longer term. We will continue monitoring and analysing regional operability issues following system events, and introduce mitigations as needed. Concerns with the BMU-

Public

only event and additional 200 MW DC-L response holding were addressed following the post consultation engagement.

As a national policy we are comfortable with our analysis, supported by Accenture's technical review hence we recommend the SQSS Panel to approve the FRCR 2025 policy. We acknowledge that regional operability will be monitored during implementation.

Public

## 8. Future Considerations

### 8.1 FRCR forward looking

In past FRCR editions we explained various events, loss risks, impacts and controls that could be considered in future FRCR modelling and assessments and these will still be valid future considerations following FRCR 2025. In addition to these considerations, there are other strategic directions that future FRCR could prospectively explore to tackle fast-changing system conditions. This section provides our initial thoughts on some potential areas for future FRCR work.

- **Simplified analysis**

Following the ALoMCP, the risk of inadvertent tripping of embedded generation has significantly reduced to a very low level by changes their protection settings and type. System security caused by transient frequency deviation becomes much less sensitive to unexpected LoM operations. This change enables the FRCR analysis to shift from a loss-risk-profile per settlement-period based calculations to a capacity-based analysis. This new approach would significantly simplify the calculation process and reduce computational capacity requirements when proposing new frequency control policies.

However, this approach is outside the currently agreed FRCR Methodology and hence requires industrial consultation and SQSS Panel approval, in accordance with the FRCR governance process.

- **Unified loss risk policy**

Based on the simplified analysis, a future FRCR policy would not differentiate the approach of securing loss risk categories, such as BMU only, BMU + VS, and simultaneous events. Instead, the FRCR policy would recommend securing a loss risk up to a certain level.

To effectively conduct the analysis and implement this policy, NESO will need to modify its existing operational tools, and develop new tools and models to enhance operational awareness. This will ensure that the loss risk from individual BMUs or from a NETS group can be effectively monitored and controlled. The frequency control analysis could necessarily expand to include transmission security discussions, for example, to clarify operational policy in securing switch faults. The FRCR may help to inform those developments that would be formalised in the SQSS and where necessary the other industry codes. This approach and its methodology will require careful feasibility assessment within NESO and with the industry.



Public

### • **Interaction between national inertia and regional inertia**

As we explained in Chapter 5, since implementing the 120 GVA.s minimum inertia policy, we have observed Sub-Synchronous Oscillation (SSO) events in the Scotland network. Our investigations found no correlation between lower overall system inertia and the initiation of these SSO events. Local inertia reduction, however, can have a negative impact on SSO events and other system operability issues such as the secondary effect of reducing the Short Circuit Level (SCL) and the inherent damping provided by synchronous generation at local levels. Several projects and programmes have been initiated by NESO and collaborated with the industry to address these challenges. More details can be found in OSR 2024 which will be published by end of March 2025. In the future, the frequency control workstream, collaborating with wider operability workstreams in NESO, would like to explore and investigate the following areas:

- Regional inertia monitoring and modelling,
- Interaction between regional inertia and system strength, and
- Regional frequency response requirements and procurement policy.
- Highlight the work completed in other areas such as Grid Forming.

We acknowledge the difficulties in exploring these areas. Some of the areas are neither within the scope of current FRCR Methodology nor the original purpose of the SQSS modification GSR027. We would like to initiate discussions with the industry, start with innovation feasibility studies, and allocate appropriate workstreams in leading the development before these can be incorporated into future FRCR policy development. We welcome your views on the future work of FRCR and the development of the GB frequency management policy.

## **8.2 FRCR future governance**

Appendix H of the Security and Quality of Supply Standards (SQSS) sets out the process for production of a periodic FRCR report, detailed requirements and obligations on parties involved in this process. Under this arrangement, the SQSS Panel is required to review and approve the FRCR Methodology and the annual FRCR Report before NESO subsequently submits it to the Authority.

As part of FRCR 2024, a number of SQSS Panel members suggested that the obligation to produce the FRCR may better fit under a new NESO License Condition rather than an Annex to the SQSS. This is due to the fact that the SQSS sets the principles and the rules of planning and operation but does not detail how they are discharged. To address this, NESO are intending to engage with the Authority, the SQSS Panel, and the wider industry to consider this.

Public

We are seeking your preliminary views about this proposal which are also specifically included as consultation questions.

- Do you foresee any issues that may arise from moving the obligation to produce the FRCR to a NESO Licence Condition rather than an Annex to the NETS SQSS?
- If the obligation to produce the FRCR and the governance rules surrounding that process are moved to NESO's Licence, do you believe that the NETS SQSS Panel should continue to provide oversight?
- If your answer to above question is yes, to what extent should this oversight be? For example, should it include technically assessing the recommendations and approving/rejecting it, or should it be limited to confirming that the governance process and methodology has been followed correctly?

We welcome your views to shape the future FRCR governance and its process. We note that any formal change will need to progress through the normal governance route and your responses to these consultation questions are intended to be informative only, with the aim being to improve the FRCR process in the future.

## 9. Appendix

### 9.1 Case studies on historical events

#### 9.1.1 Case study 1 – impact of the minimum inertia policy on 14th March 2025 event.

System inertia was reported as 276.4 GVA.s at the time of the event. The minimum inertia requirement was set at 120 GVA.s. Since the total system inertia was 276.4 GVA.s, which

Public

exceeded the minimum requirement, no additional actions were necessary to increase the system inertia. We can now consider several hypothetical questions:

- ***What if the minimum inertia requirements during the event was 102 GVA.s instead of 120 GVA.s?***

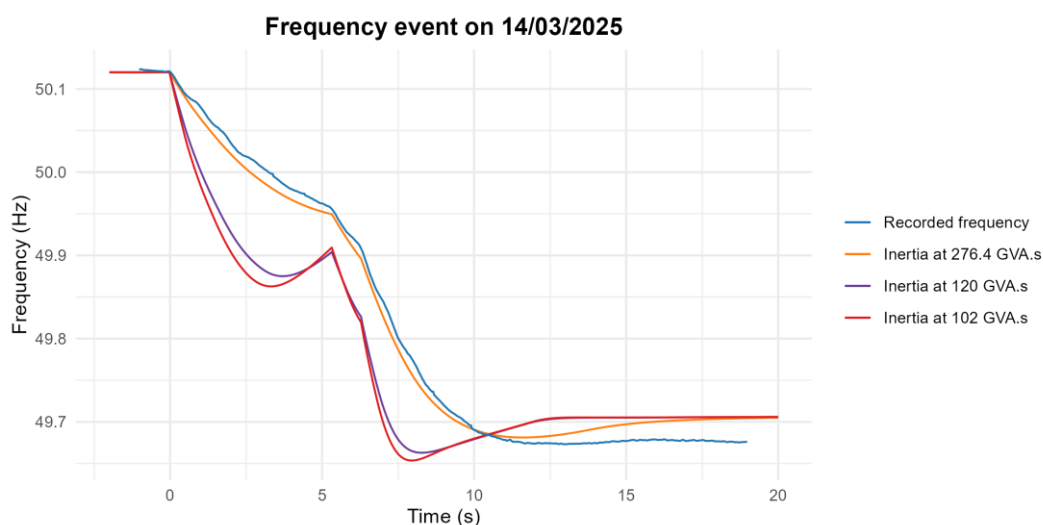
Since the minimum inertia requirement sets only the bottom threshold and does not intentionally reduce inertia, the total system inertia of 276.4 GVA.s satisfies both the 102 GVA.s and 120 GVA.s minimum requirements. Therefore, there would be no expected differences in this event if the minimum inertia requirement were lowered to 102 GVA.s.

However, there would be some difference if the system raw inertia were below the threshold where additional actions are needed.

- ***What if the minimum inertia requirements during the event was 102 GVA.s instead of 120 GVA.s, AND system raw inertia was below the threshold***

If the system's raw inertia falls below the threshold, additional actions would be needed to meet the minimum inertia requirements. Response holdings would be adjusted according to the inertia to ensure that the largest infeed loss can be accommodated. In this scenario, the Dynamic Containment holding would remain unchanged because the static Firm Frequency Response (sFFR) holding of 185 MW did not meet the requirement of 250 MW, necessitating additional Dynamic Containment to fulfil the recovery requirement.

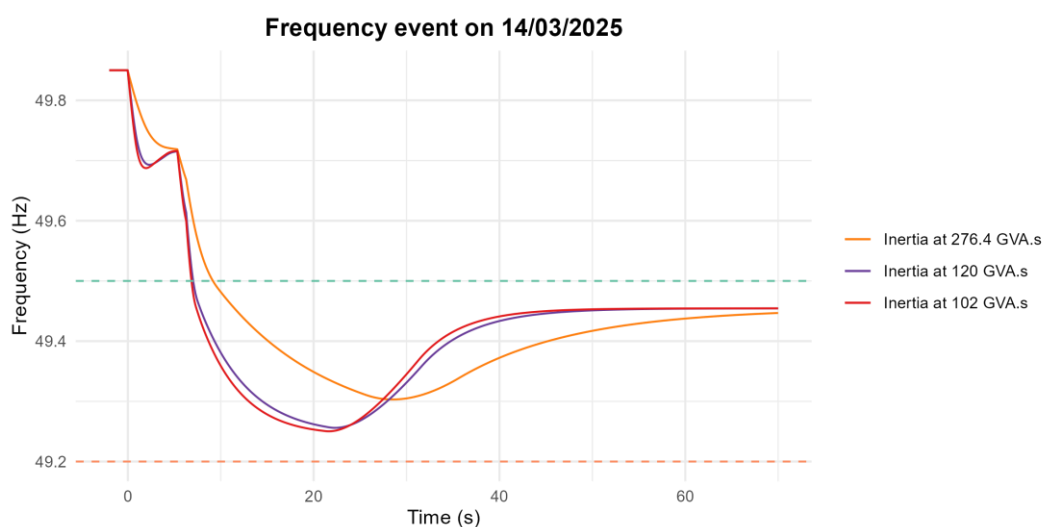
The figure below illustrates the expected frequency curves when the system inertia is either 120 GVA.s or 102 GVA.s. With lower system inertia, the frequency nadir will decrease but will still be contained within 49.5 Hz, while the stabilised frequency remains consistent.



Public

- **What if the minimum inertia requirements during the event was 102 GVA.s instead of 120 GVA.s, AND system raw inertia was below the threshold, AND initial frequency was 49.85 Hz instead of 50.12 Hz.**

The initial frequency of this event was 50.12 Hz which provides a certain level of buffer to this event. The worst-case scenario would be considering 49.85 Hz as the initial frequency which is implemented in the response calculation process. The figure below shows the expected frequency curves if initial frequency was 49.85 Hz.



The frequency drop can be contained before 49.2 Hz, i.e. no LFDD risk for the worst-case scenario. However, the frequency struggles to recover within 49.5 Hz in 60 second since this event is not a secured loss. If this is the case, Control Room will need to instruct reserve products to bring frequency back within 49.5 Hz and the operational limit.

Note: LFSM-U is not included in the study, with LFSM-U the frequency deviation will be further reduced.

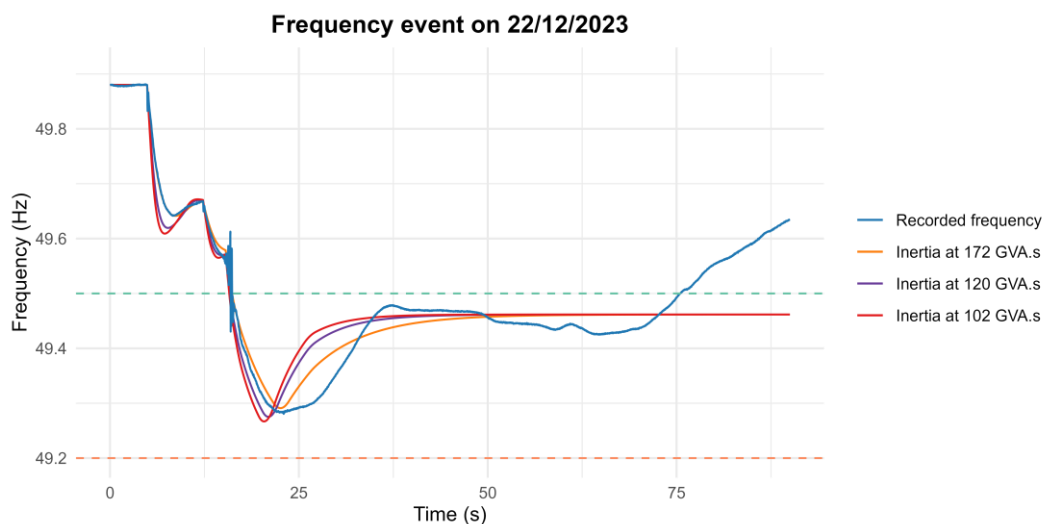
### 9.1.2 Case study 2 – impacts of the minimum inertia policy on 22nd Dec 2023 event.

System inertia was reported as 172 GVA.s at the time of the event. The minimum inertia requirement was set at 140 GVA.s. Since the total system inertia was 172 GVA.s, which exceeded the minimum requirement, no additional actions were necessary to increase the system inertia.

Simulations were conducted for the following hypothetical scenarios:

- 172 GVA.s (actual system inertia)
- 120 GVA.s (inertia policy implemented in 2024)
- 102 GVA.s (reduced inertia level)

Public



The Frequency nadir difference between the 172 and 102 GVAs scenario is 0.026 Hz. None of the scenario will lead a breach of 49.2 Hz threshold. The minimum frequency at 102 GVA.s inertia level is 49.27 Hz.

At the time of the event, the live frequency control policy was FRCR 2023, which did not require any additional Dynamic Containment beyond the standard requirements. FRCR 2024 recommended holding an additional 100 MW of Dynamic Containment Low, while FRCR 2025 proposes holding an additional 200 MW. Increasing Dynamic Containment holdings would improve the frequency nadir.

### 9.1.3 Case study 3 – impact of the minimum inertia policy on 9th August 2019 event.

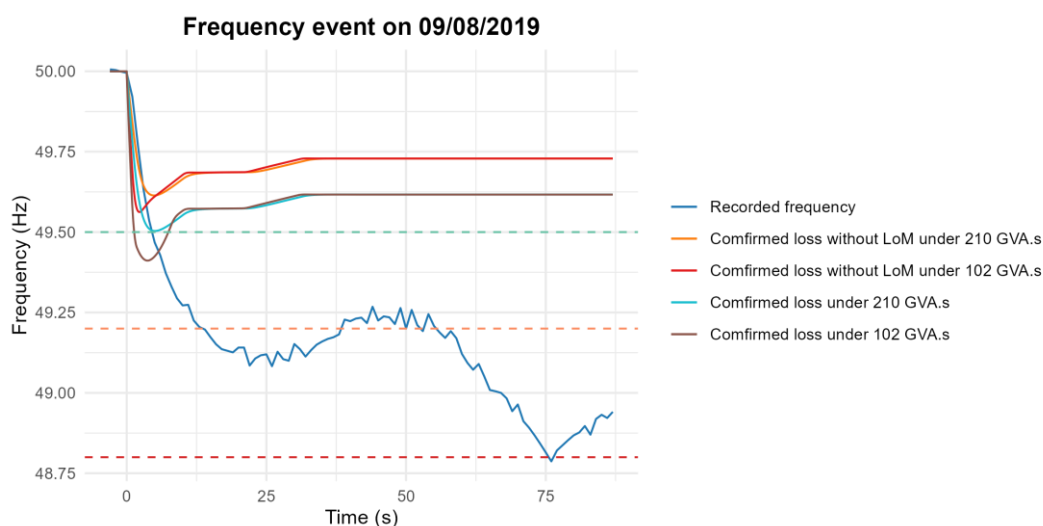
System inertia was reported as 210 GVA.s at the time of the event. The minimum inertia requirement was set at 140 GVA.s. Since the total system inertia was 210 GVA.s, which exceeded the minimum requirement, no additional actions were necessary to increase the system inertia.

The ways of managing frequency risks have changed significantly since the time of the event. The Accelerated Loss of Mains Change Programme (ALoMCP) was introduced to reduce the consequential Loss of Mains (LoM) risks. Dynamic Containment service was introduced as a fast-acting response service to arrest the frequency drop.

Public

Simulations were conducted for the following hypothetical scenarios. In the simulations, response holdings are assumed to align with the current frequency control policy, i.e. FRCR 2024.

- Confirmed loss without LoM under 210 GVA.s (Post ALoMCP with the actual inertia of the event)
- Confirmed loss without LoM under 102 GVA.s (Post ALoMCP with the reduced inertia level)
- Confirmed loss under 210 GVA.s (Pre-ALoMCP with the actual inertia of 210 GVA.s)
- Confirmed loss under 102 GVA.s (Pre-ALoMCP with the reduced inertia level)



Additional simulations were performed for the worst-case scenario, where the initial frequency dropped from 50 Hz to 49.85 Hz. With the help of Dynamic Containment, the frequency drop can be arrested before 49.5 Hz.

Public

