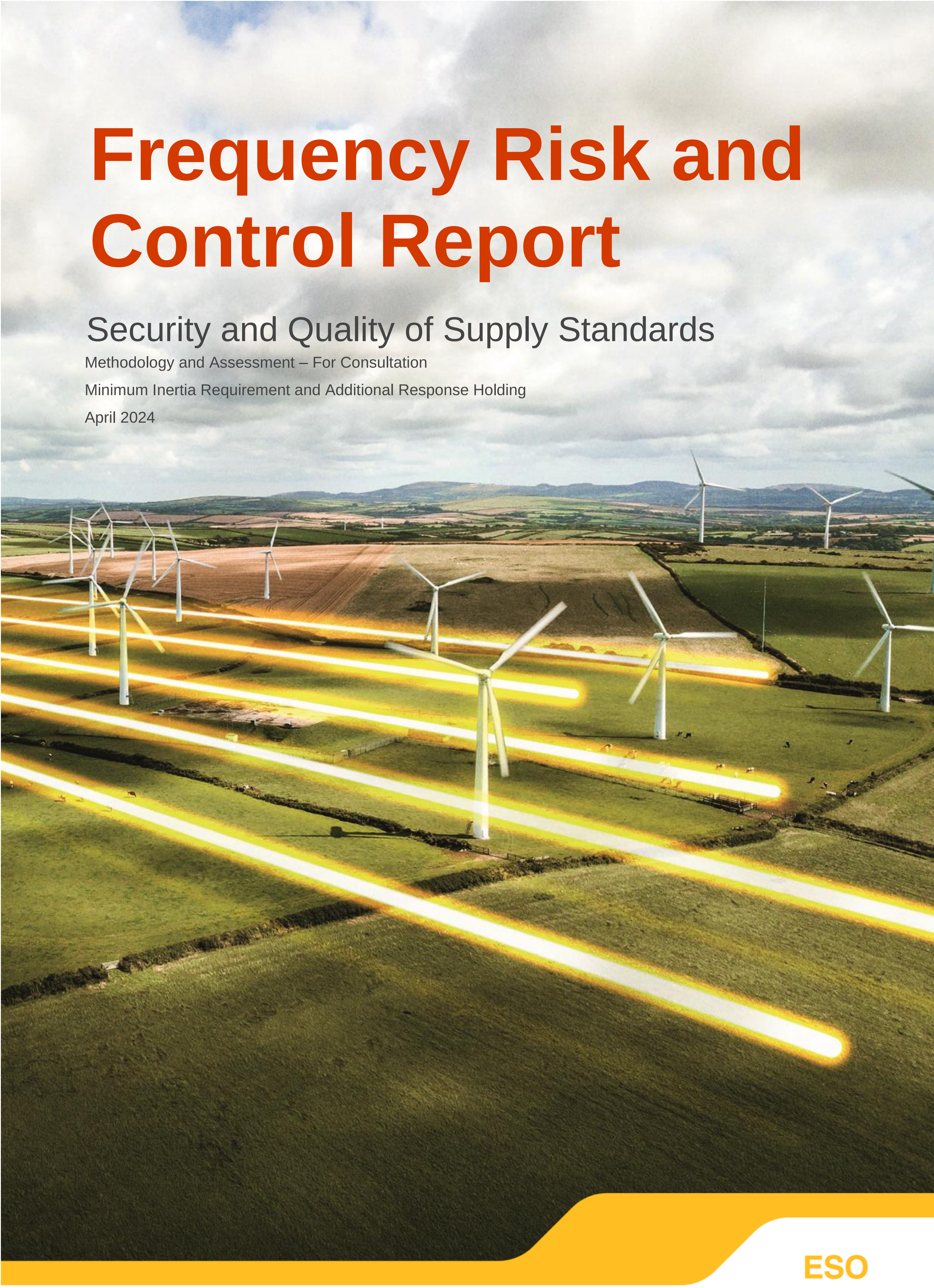
Frequency Risk and Control Report

Security and Quality of Supply Standards

Methodology and Assessment – For Consultation

Minimum Inertia Requirement and Additional Response Holding

April 2024



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1. Foreword

In line with our Security and Quality of Supply Standard (SQSS) requirement, the ESO produces an annual Frequency Risk and Control Report (FRCR) and consults with industry on the methodology and assessment presented within the report.

Large sudden changes in supply and demand can cause the frequency of the GB electricity system to change. This report sets out the parameters for how often, how long and how large those frequency changes should be and sets out the criteria by which we manage these risks.

We have produced FRCR 2024 to cover an extended time horizon - to include the cost vs. risk assessment for both 2024/25 and 2025/26. This 2024 edition of the FRCR concentrates on three main areas: reviewing the minimum inertia policy, assessing the costs and benefits of securing beyond current policy on event categories, assessing the cost and benefits of holding additional response controls, as well as providing an outlook to 2025. The focus of the report is to set the optimal balance between risk and cost, and to ensure the GB system is effectively and appropriately protected from frequency events for the following year. The report aims to improve transparency across industry and stakeholders, setting out clear and objective criteria by which we balance risk and cost to ensure the end consumer receives efficient security of supply.

The policy changes made through FRCR become increasingly significant as the energy system transitions to a low carbon system. The FRCR allows us to regularly review the response, reserve and inertia holdings on the system – parameters that significantly impact our ability to operate a zero-carbon transmission system. This report allows us to work with stakeholders to review and manage emerging risks relating to these areas, helping us operate a secure, cost effective, and zero carbon system of the future.

Since the introduction of FRCR, the report has worked alongside other projects to massively alter how we manage frequency risks on the system. The combined impact of the report recommendations, introduction of our new suite of dynamic response products, implementation of the Accelerated Loss of Mains Change Programme (ALoMCP), delivery of the Stability Pathfinders, and delivery of the Enduring Auction Capability (EAC) have resulted in improved system security and reduced cost in comparison to previous years. Our continued work in these areas should help us to operate a zero-carbon system more frequently in the future and help us reach the government target of continuous zero-carbon operation by 2035. FRCR is integral to achieving these goals as it has reduced the minimum inertia requirement for system operation, going a significant way to operating a secure, zero-carbon electricity system.

This year’s FRCR focuses on maintaining the 120 GVA.s minimum inertia requirement, mitigating all BMU-only infeed and outfeed loss risks, and using frequency response controls to further reduce residual risks to provide better value for consumers.

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. FRCR 2021 established the baseline for cost vs. risk when managing frequency, FRCR 2022 evaluated the consumer benefits of securing simultaneous events, and FRCR 2023 assessed the benefits of reducing the minimum inertia requirement.

We currently have an approved policy to operate the system with a reduced minimum inertia of 120 GVA.s based on the FRCR 2023 recommendation, this is planned to be fully implemented during summer 2024. This 2024 report assesses system risk and cost with a minimum inertia of 120 GVA.s during 2024/25 and 2025/26. In addition, this report explores the benefits of running the system at an inertia level below 120 GVA.s in the future.

In the past several years we have seen the delivery of the Enduring Auction Capability (EAC), the progression of the Stability Pathfinder Projects, the phasing out of Firm Frequency Response (FFR), alongside the overall response market growing for Dynamic Containment (DC), Dynamic Regulation (DR) and Dynamic Moderation (DM). All of the above have fundamentally changed the way we manage system frequency, in terms of reducing the risks on the system, as well as reducing the costs for managing those risks. Due to this growth in the response market, and therefore cost reduction, we can now look at the cost vs. risk benefits of securing beyond current FRCR policy with additional response holdings.

This report represents the first step in our process to secure beyond BMU-only risks and the move towards a future state of securely and economically operating the system carbon free for short periods of time in 2025. It also re-assesses whether the existing policy, not taking additional actions to secure all simultaneous events, still delivers the best value for consumers.

FRCR 2024 Recommendations

- **Maintain the existing minimum inertia requirement at 120 GVA.s**

The minimum inertia requirement under FRCR policy determines the inertia required to managing frequency risks. The report indicates the majority of the benefits are obtained by reducing the minimum inertia requirement from 140 GVA.s to lower levels - there is no increase in the overall system residual risk by operating at reduced inertia levels. However, due to delays in implementing the 120 GVA.s policy that was recommended in FRCR 2023, it is prudent to maintain the minimum inertia requirement at 120 GVA.s to gain more operational experience.

By 2025, the ESO plans to have the capability to operate GB transmission system zero carbon for short periods and reach continuous zero carbon operation by 2035. Further reduction of minimum inertia, from 120 GVA.s to a lower level, paves the foundation and accelerates zero carbon operation. This report highlights that operating at a lower inertia level of 102 GVA.s does not result in a reduction in frequency security. Moreover, there is a potential additional cost saving of £33m and £48m if the minimum inertia requirement is reduced to 110 GVA.s or 102 GVA.s. Subject to system conditions and operational readiness, we may propose operating at these lower inertia levels before completion of FRCR 2025. We will share our operational findings and analysis with industry through subsequent consultation before implementing the lower minimum inertia requirement.

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

Current policy of securing all BMU-only events still presents the best value. Securing against all BMU+VS and simultaneous events would double the spend on DC and require a significant increase in DC capacity - this is not currently available and would put the current market under significant pressure and increase operational risk. Therefore, we do not see value in changing the current policy relating to securing all BMU+VS and simultaneous events as it does not provide value for consumers.

- **Consider additional DC-Low requirement to further reduce residual risks.**

Dynamic Containment (DC) is currently the most cost-effective tool for managing frequency risks; the introduction of Enduring Auction Capacity (EAC) has improved the liquidity of the DC market and driven a cost reduction for procuring the service. Holding additional DC-Low response improves system security. The report verifies that holding an additional 100 MW of DC-Low presents the best incremental risk reduction per extra spend.

Impact of Recommendations

The implementation of this policy in 2024/25 with additional DC-Low holding results in a residual risk of **1-in-29** years risk of a 49.2 Hz event and **1-in-30** years risk of a 48.8 Hz event.

The residual risks have decreased compared to last year's FRCR analysis, with the likelihood of 49.2 Hz events improving from 1-in-17 years in FRCR 2023 to 1-in-29 years in FRCR 2024. The likelihood of 48.8 Hz events happening remains same as last year's analysis. The estimated annual cost of managing frequency risks based on this year's FRCR is £245 million, including the estimated cost for procuring additional DC. This represents a reduction from the previous FRCR's cost estimation of £264 million.

When FRCR 2024 policy is approved, industry will be informed of the implementation through industry forums, such as the Operational Transparency Forum (OTF), prior to go-live.

3. Background

3.1 Purpose

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: *'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 Policy

Current Policy resulting from the approved 2023 FRCR[1] is:

- Maintain the system inertia at a level above the minimum inertia requirement of 120 GVA.s.
- Apply individual loss risk controls to Balancing Mechanism Unit (BMU)-only events to keep resulting frequency deviations within the range of 49.2 Hz and 50.5 Hz.
- Only allow BMU-only infeed loss risks to cause a consequential Rate of Change of Frequency (RoCoF) loss if the resulting loss can be contained within the range 49.2 Hz and 50.5 Hz.
- Do not apply individual loss risk control to BMU+Vector Shift (VS) outage or BMU+VS intact events.
- Do not apply additional system-wide controls to secure simultaneous events.

Frequency Risk and Control Report Methodology

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

Frequency Risk and Control 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 paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS. The SQSS notes that the FRCR will set out those conditions under which unacceptable frequency conditions will not occur.

In 2022, following discussions with the SQSS panel and Ofgem, it was agreed that the 2022 edition of FRCR would combine both the report and methodology into a single consultation. We have continued to apply this approach for successive reports including this one.

This combined report and methodology considers the value proposition of securing beyond the BMU-only events. It will be consulted on between the 10th April 2024 and the 17th May 2024, and a webinar is planned during the consultation period. The final report will be submitted to the Authority for approval by end of June 2024.

3.2 What is the FRCR?

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
- 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.

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[1] FRCR 2023

3.3 What is the report trying to achieve?

In the context of system frequency, there are two key objectives:

- A reliable supply of electricity
- At an affordable cost

There is a balance between these objectives:

- Higher reliability requirements result in higher direct costs to meet those requirements
- Lower reliability requirements result in lower direct costs to meet those requirements but have higher indirect costs and impacts that arise from the lower reliability requirements.

These objectives are formalised through the SQSS and the FRCR. This report provides an assessment and recommendation on the right balance between the two competing objectives of reliability and cost, focusing on the risks, impacts and controls for managing system frequency.

3.4 Levels of impact

This report uses the four levels of impact set out below when assessing the balance between the key objectives. These levels allow for comparison with historic performance:

#	Deviation	Duration	Relevance
H1	50.5 Hz < f	Any	• Above current frequency standards. • Plant performance prescribed in detail by Grid Code, but not tested often in real-life conditions.
L1	49.2 Hz ≤ f < 49.5 Hz	60 seconds	• Current SQSS and System Operation Guideline (SOGL) frequency standards. • Infrequent occurrence, but reasonable certainty over plant performance.
L2	48.8 Hz < f < 49.2 Hz	Any	• Beyond current frequency standards and SOGL, but without triggering Low Frequency Demand Disconnection (LFDD). • Plant performance prescribed in detail by Grid Code, but not tested often in real-life conditions.
L3	47.75 Hz < f ≤ 48.8 Hz	Any	• First stage of LFDD.

3.5 Metrics: What principles can be applied?

At its simplest for each level of impact, good value risks are likely to be those which are:

- Low cost to mitigate, and/or
- Likely to occur, and/or
- Have a large impact.

Poor value risks are likely to be those which are:

- High cost to mitigate, and/or
- Unlikely to occur, and/or
- Have a small impact.

There is a whole spectrum of costs and likelihoods across each of the events, which means that a clear-cut judgement of the balance between reliability and cost can be challenging to reach for one event in isolation. Instead, the FRCR assesses the total risk and total cost across all events. Where risks are deemed to be of poor value and not actively mitigated, the backup measures prescribed through the Grid Code will act to minimise overall disruption to the system should they occur.

3.6 What is meant by reliability?

The SQSS refers to unacceptable frequency conditions as a measure of reliability. This encompasses whether transient frequency deviations outside the range 49.5Hz to 50.5Hz are considered infrequent and tolerable. Whether frequency deviations are acceptable depends on the exact combination of three factors:

1. How often they occur
2. How long they last for
3. How large they are

Each of these measures affects the impact of an event (see section 3.4). For example, larger or longer deviations that happen very rarely might be acceptable, but smaller or shorter deviations that happen very often might not be. The report will define what is considered reasonable as infrequent and tolerable for each of these criteria for transient frequency deviations.

3.7 What drives direct costs?

We use Balancing Services to manage frequency deviations. Some Balancing Services are automatic, like frequency response, others are manually dispatched, such as reserve, the Balancing Mechanism (BM), services to manage inertia or services to pre-emptively decrease the size of potential loss risks. In this document we refer to these Balancing Services as “controls”.

The size, duration and likelihood of transient frequency deviations depend on:

- The size of the event that caused the frequency deviation, and
- How much of each of these controls are used, and the effectiveness of the controls:

Scenario	Direct costs	Frequency deviations
Small event/ more controls	Higher	Shorter, smaller, occur less often
Large event / fewer controls	Lower	Longer, larger, occur more often

The report considers the relevant controls which we currently use to meet our requirements.

3.8 How to set the right balance between reliability and cost?

The methodology sets out an objective and transparent framework for us to assess risks associated with frequency deviations, the events which could cause them, their size, the impacts they have, and the cost and mix of controls to mitigate them. The assessment has been used to determine the appropriate balance between reliability and cost, as described in this report.

Consultation and ongoing engagement with industry stakeholders is key to achieving this openly and transparently. Our role is to analyse the risks, impacts and controls, their impact on reliability and cost, and present a recommendation for where the appropriate balance might lie. This enables the Authority to make an informed decision on the right balance between the reliability of electricity supplies and the cost to end consumers.

4. Scope of FRCR 2024

4.1 Performance review of FRCR 2023

FRCR 2023 recommendation was to reduce the minimum inertia requirement from 140 GVA.s to 120 GVA.s. The policy was approved by Ofgem on the 9th June 2023. The implementation of this policy was delayed due to system events such as the sub-synchronous oscillations during the summer of 2023. Phase 1 of the recommendation, which involved reducing the minimum inertia requirement from 140 GVA.s to 130 GVAs, was implemented on the 28th February 2024. The next phase, Phase 2, which involves reducing further from 130 GVA.s to 120 GVA.s, is expected to be implemented during summer 2024. Following this change, a review of system performance under the recommended reduced minimum inertia will be communicated in subsequent consultations.

4.2 Scope of FRCR 2024

Assessment of the minimum inertia requirement within FRCR policy

The minimum inertia requirement was reduced from 140 GVA.s to 120 GVA.s as part of FRCR 2023 recommendation; we will re-evaluate the current minimum inertia requirement and assess whether it is sufficient to manage the system frequency risks. System risks and costs will also be assessed when running the system with lower inertia levels of 110 GVA.s and 102 GVA.s.

In line with our 2025 zero carbon ambition, our aim is to ensure that the system can operate at a minimum inertia of 102 GVA.s. This is based on an assumed largest loss of 1800 MW and ensures the Rate of Change of Frequency (RoCoF) remains within 0.5 Hz/s. A 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 inertia requirement of 102 GVA.s to meet our 2025 ambition. The 2023 Operability Strategy Report (OSR) discusses our 2025 and 2035 zero carbon goals, detailing how minimum inertia levels effect our zero carbon targets[2].

Assessment of current FRCR policy on loss categories

We are assessing the cost-risk benefits of securing against different defined loss risk categories, including BMU-only, BMU+VS (outage or intact), 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.

Outlook to 2025

FRCR 2024 covers an extended time horizon to assess system risks for multiple years. The outlook to 2025 represents a step towards this future state by assessing the feasibility of further reducing our minimum inertia level beyond one year ahead.

4.3 Main drivers for increasing response holding

Under current system conditions, where the system is becoming more 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. Increasing the volumes held of these new frequency response services will help further mitigate residual risks on the system.

Growth of new suite of dynamic response services

Since their launch in 2021, the design and implementation of these new response markets has provided us with effective frequency control services. The steady growth of the Dynamic Containment (DC), Dynamic

[2] Operability Strategy Report, December 2023

Moderation (DM) and Dynamic Regulation (DR) markets has enabled us to operate the system with a lower minimum inertia requirement.

The increased participation and market outcomes have given us confidence that we have access to sufficient capacity to cover our largest loss risks on the system. This was highlighted in July 2023 when higher-risk system conditions forced us to temporarily increase our DC requirement resulting in the highest volume of DC-Low procured at 1576 MW - significantly higher than our average requirement. As of April 2024, we currently see approximately 5000 MW of participation in the dynamic response auctions of which we secure around 3000 MW in each Electricity Forward Agreement (EFA) block; this clears the vast majority of the requirement for our products.

Enduring Auction Capability

The Enduring Auction Capability (EAC) is our new auction platform which enables us to procure dynamic response services. It allows market providers to access multiple markets at the same time, which improves market access and competition, makes the procurement of balancing services more efficient and allows us to select the option that offers the best value for consumers.

By introducing innovative features such as co-optimisation, stacking and an advanced clearing algorithm, we can allocate resources more efficiently. The new auction platform and market design provides benefits for market participants through the removal of duplicated processes. The EAC also provides a reduction in response service cost, resulting in benefits to end consumers.

5. Methodology

The aim of the methodology is to set out an objective and transparent framework to enable us to assess risks associated with frequency deviations caused by changes in system conditions. The assessment can then determine the optimal policies to operate the system in a balanced security vs. cost manner.

5.1 Methodology description

The methodology used in FRCR 2024 remains largely unchanged from that set out in the previous edition of the FRCR. There have been some adaptations and upgrades made to the methodology to assess the impact of proposed recommendations, such as the functionality of using response as the control to mitigate further risks.

The overall process of the methodology can be summarised in the steps below:

Step 1: Define scenarios

Step 2: Determine system-wide costs for each scenario

Step 3: Determine if targeted actions are required for each event in each scenario

Step 4: Determine overall cost vs. risk trade-off for each scenario

The remainder of this section explains the methodology steps in detail.

Step 1: Set-up scenario

Initially, all inputs are loaded into the model, including costs for response and targeted actions, Loss of Mains (LoM) load factors, fault statistics, forecasted BMU profiles and forecasted system conditions. The relevant updates to the input dataset that is used to represent the system changes expected for 2024/25 and 2025/26 are included and more details can be found in section 5.2.

Baseline system conditions

The analysis uses historic scenarios adjusted for known or expected changes in the coming 12 months to isolate the reliability vs. cost decisions from the impact of these wider changes. Example of adjustments include new connections to the National Electricity Transmission System (NETS) in 2024/25, which represent additional loss risks, and which impact the inertia of the system, as well as up to date RoCoF and Vector Shift (VS) loss risks post ALoMCP.

The analysis is performed as a time series at settlement period granularity. Many of the key inputs such as demand, inertia, BMU loss size, LoM loss size, vary markedly with time; hourly, daily, weekly and seasonally. Analysis of a single point in time, for example winter peak or summer minimum, would not capture the intricacies and interactions or give a true picture of risk exposure. This approach is used by some system operators in other countries but is inappropriate for assessing frequency risks on the GB system.

These are the baseline system conditions against which the different control scenarios are assessed. We will unwind balancing actions from the historic data sets to get a representation of the “market position” for these baseline system conditions.

Define scenario parameters

The main aim of the FRCR 2024 analysis is to assess the impact and benefit of reducing the minimum inertia requirement and improving system security, hence parameters applied within the scenarios are designed to fit that purpose. The assessment has considered the proposed minimum inertia requirement modifications and expected response market sizes. Different scenarios are assessed to determine the impact on the overall cost and baseline level of system risk. LoM capacity post ALoMCP is used for this FRCR analysis for both RoCoF and VS.

Step 2: Determine system wide costs

All frequency response and inertia costs are applied first as they affect all events and loss risks. Costs for inertia are benchmarked against the typical prices achieved through the BM and trading.

The quantity of DC to be procured is calculated based on securing the maximum single BMU loss and any consequential RoCoF loss under the minimum inertia requirement set out in the scenarios - assuming that other response products are in place to mirror the current day-ahead DC auction process.

Once the system-wide controls are in place, the largest securable loss at each settlement period for each frequency threshold will be assessed, i.e. 50.5 Hz, 49.5 Hz, 49.2 Hz or 48.8 Hz. These figures allow us to assess (based on estimated BMU profiles) how often an event would be under risk by comparing the profile of that event against the relevant largest securable loss. With this assessment, it can be concluded how much residual risk would remain after spending system wide costs. It should be noted that the resulting costs are based on current system and market conditions and hence are purely indicative. They are not forecast costs for 2024 and 2025 as outturn costs might well change due to factors such as pricing, behaviour and forecast uncertainty.

Step 3: Determine if targeted actions are required

Targeted control actions are considered after evaluating which event is under which type of frequency risk. Two control actions are considered in the FRCR 2024 model: **BM Control** to reduce the loss size and **Response Control** to further increase response holdings.

- **BM Control** action is to instruct relevant BMU(s) to adjust their output(s) so that they become securable. The cost incurred involves the Bid Offer Acceptances (BOA) price to reduce the loss size as well as the re-positioning price for other BMU's to compensate. Both reduction and re-positioning prices are dependent on the BMU MW size and system conditions.
- **Response Control** action is to quantify the additional DC requirements to cover the loss size.

The analysis goes through the list of events in each scenario, assessing if their profiles are within the largest securable loss, and applying the two loss control approaches to mitigate risks.

Step 4: Determine the overall cost vs. risk trade-offs for each scenario

Determine costs of targeted actions

The cost for each targeted action is calculated for each event.

Calculate residual risk

Due to the physical constraints on BMUs, such as inflexible plant or other industrial processes, there may still be some periods which can't be mitigated by individual loss risk actions. A second assessment is conducted to evaluate how often each event is at risk of causing each of the impacts after both the system-wide and individual loss risk controls are applied. This is used to calculate the residual risk.

Calculate risk reduction

The risk reduction achieved is calculated by applying the individual loss risk control and comparing the baseline risk (after system-wide controls) to the residual risk (after system-wide and individual loss risk controls).

Each event is ranked for risk reduction and the cost of applying the individual loss risk controls (in terms of the cost per avoided event), giving a "value for money" ranking. This allows the identification of a boundary between events which are of good value to secure and those which are not. The **cost per avoided event** is used at this boundary to determine the rate of occurrence of simultaneous events that would represent good value to secure. Additionally, the costs for system-wide controls and individual loss risk controls, as well as the residual risk under different minimum inertia requirements can be compared and analysed.

5.2 Input dataset and model updates

The assessment requires data to assess the cost vs. risk of different scenarios. The inputs are based on historical data from April 2022 to March 2023. We adjusted to account for known changes to the system. The dataset and model have been updated as listed below.

FRCR Methodology 2021[3] discussed the reasons not to use Value of Lost Load (VoLL), which "*represents the value that electricity users attribute to security of electricity supply and the estimates could be used to provide a price signal about the adequate level of security of support in GB*"[4], as the cost metric in FRCR analysis. This year our understand remains that VoLL is not appropriate for frequency control policy assessment. FRCR analysis considers balancing costs including spends in frequency response, inertia and BM actions to reduce loss size / re-position, to evaluate system security and total benefits. Therefore, the cost per avoided event is used to determine which events would represent good value to secure. We continue exploring other metrics and approaches to better value cost vs. risks and will implement into future FRCR analysis.

Cost assumptions	
BM actions	The cost of BM actions considers the average prices during 2023/24, including Bid (to take a BMU from Physical Notification (PN) towards Stable Export Limit (SEL)), Offer (from PN towards Maximum Export Limit (MEL)), and De-sync (from SEL to 0). Prices are categorised per fuel type and nuclear is assumed to be inflexible.
Response service	The cost for response services takes the average prices against different Electricity Forward Agreement (EFA) blocks for each service during 2023/24, when EAC went live in November 2023. Response products are Dynamic Containment (DC), Dynamic Regulation (DR), Dynamic Moderation (DM) and Static response. The daily auction results regarding volume and price are published on our data portal[5].
Inertia	The cost for accessing additional inertia is achieved by converting the required volume of inertia into the volume of energy that needs to be repositioned.
Risks	
BMU fault rate	For BMU-only events this is based on the fuel-type breakdown statistics. Typical BMU fault rate is considered to be between 0.04% per year and 8.8% per year, derived from historical trip events in past 3 years.
Network equipment fault rate	For BMU+VS events caused by transmission network failure, different types of assets are considered, e.g. Over Head Lines (OHLs), cables, single-circuit fault, double-circuit fault, busbars and mesh corners. Failure rates are updated from historical failures in past 3 years.
New connections	The list of loss events is updated to include new connections with estimated loss profiles and estimated fault rates based on historical data.
Loss of Main risks	LoM risk profile post ALoMCP completion is used with adequate margins considered in the model. Estimated sizes of remaining RoCoF loss are between 20 MW and 90 MW for 0.125 Hz/s tranche. For 0.2 Hz/s tranche, the size is between 10 MW and 40 MW. The estimated

[3] Frequency Risk and Control Report Methodology 2021
[4] Value of Lost Load (VoLL)
[5] Enduring Auction Capability (EAC) auction results

	maximum RoCoF loss size is 130 MW. The estimated maximum VS loss size is 130 MW following a transmission fault.
Response Holdings	
Pre-fault response	330 MW of DR and 150 MW of DM are used as the pre-fault response. Dynamic Firm Frequency Response (FFR) which has been phased-out by Nov 2023.
Post-fault response	For each of the inertia levels assessed, the DC holding volume is determined at the day-ahead stage, for all EFA blocks the following day. Three factors determine the DC holding volume: • system conditions including demand and inertia, • the expected largest loss considering consequential RoCoF loss, • volume of other response holding before DC auction, for example, static response holding is assumed to be 250 MW.
Contribution of stability workstream	FRCR 2024 assessment will be effective for the period April 2024 to March 2025. Contributions from Stability Pathfinder Phase 1 and Phase 2 are considered in the analysis. Stability Pathfinder Phase 3 and Stability Y-1 deliveries are not considered.
Other Updates and Assumptions	
Pre-fault frequency	FRCR 2024 model is updated to reflect average frequency deviation at pre-fault.
Inertia Baseline	Updated inertia forecast profile based on system condition changes for 2024/25 and 2025/26.
Other causes of distribution resource losses	Other failure mechanisms that could impact the size and likelihood of infeed losses, e.g. Fault Ride Through (FRT), are assumed compliant in FRCR analysis. We understand FRT issues are under clarification and resolved via measures introduced in GC0151[6]. Other failure mechanisms are managed via ESO's operational policy and will be further assessed in subsequent FRCR.

[6] GC0155: Clarification of Fault Ride Through Technical Requirements

5.3 Event categories

FRCR 2024 continues considering three categories of loss risks including:

BMU-only	• an event that disconnects one or more BMUs, and may or may not also cause a consequential RoCoF loss (no VS loss) • caused by a **Loss of Infeed** or **Loss of Outfeed**
BMU + VS (outage or intact)	• an event that disconnects one or more BMUs and causes a consequential VS loss, and may or may not also cause a consequential RoCoF loss • caused by **fault outages** of **primary transmission equipment** on the **National Electricity Transmission System (NETS)** (i.e. a **single transmission circuit**, a **busbar** or **mesh corner**, or a **double circuit overhead line**) • Trip rate for an event will normally be increased under outage condition compared to that under intact condition. It is also considered to involve number of days of planned/unplanned outage to evaluate the severity.
Simultaneous Event	• an event that disconnects two BMUs at the same instant and may or may not also cause a consequential RoCoF loss. • The analysis focuses on a total loss made up of BMU-only events occurring at the same time instant as this represents the most onerous condition from a response perspective.

FRCR 2022[7] explained the definition of simultaneous events and detailed the statistical approach to quantify the likelihood and size of the simultaneous events, where,

- 1-in-10 years risk of a median (50% of total loss size) simultaneous event,
- 1-in-20 years risk of an upper quantile (75% of total loss size) simultaneous event,
- 1-in-30 years risk of the peak (maximum total loss size) simultaneous event.

FRCR 2024 updated the sizes of the above three categories of simultaneous events by going through every combination of two BMU-only events (around 4000 pairs) and adding the consequential RoCoF losses. This year, we consider the median, upper quantile and peak simultaneous event to reach the value of, 1.5 GW, 1.8 GW and 3 GW respectively. Operational experience (around 1.5 GW loss in 2008 blackout event, around 1.9 GW loss in 2019 power cut event and around 1.7 GW in 2023 simultaneous event) has indicated simultaneous events have occurred less frequently than we assume in the model. The statistical summary of simultaneous events occurrence with their loss sizes remains a good representation of system risks for FRCR 2024.

5.4 Controls

There are four main controls for mitigating transient frequency deviations – these are set out below. FRCR 2024 analysis explores the value that can be gained through increasing **Response Control** to mitigate further risks.

- **Response Control**: Response Control refers to the holding of frequency services that are automatically activated by a frequency measurement to determine an appropriate change in active power. Procuring additional response volumes help to secure higher loss sizes.
- **BM Control**: BM Control aims to reduce the output of the BMU such that if there is a unit failure it will not result in the frequency dropping below the agreed upon threshold. Since the implementation of the previous FRCR, the number of actions required to reduce loss size to manage RoCoF risks, has reduced significantly.
- **Reducing LoM Loss Size**: as a consequence of the ALoMCP completion, the capacity of Distributed Energy Resources (DERs) at risk of disconnection from the operation of Loss of Mains (LoM) relays

[7] FRCR 2022 Report and Methodology

has decreased significantly. This has an impact on the quantity of frequency response that needs to be procured. The up-to-date LoM loss size has been considered in FRCR 2024.

- **Increasing inertia**: action can be taken to increase system inertia in order to slow down the frequency fall following a loss of generation. Initiatives such as the Stability Pathfinder provide extra inertia on top of the inertia that is naturally provided by the system. If necessary, we will synchronise additional units to increase inertia on the system to meet the operational policy of 120 GVA.s minimum inertia. In the FRCR model, increasing inertia will only be considered when the pre-set minimum inertia is not met. This control method will not be assessed as an action to mitigate beyond BMU-only risks in the FRCR 2024 model.

6. Assessment and results

This chapter reviews the key areas in FRCR 2024: minimum inertia requirements, securing different loss categories, and benefits of additional response control, while providing an outlook to 2025/26. 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 considerations if necessary. This analysis drives the recommendation which is presented at the end of each sub-section.

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. This assessment covers inertia levels of 140 GVA.s, 120 GVA.s, 110 GVA.s 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 vs. cost

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
49.2 Hz event	1-in-27 years	1-in-27 years	1-in-27 years	1-in-27 years
48.8 Hz event	1-in-30 years	1-in-30 years	1-in-30 years	1-in-30 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 risk is calculated as the probability of all the unsecured events that could trigger 49.2 Hz or 48.8 Hz frequency deviations after controls are applied.

Under different minimum inertia requirements, results show that there would be no additional risks to the system as the residual risks for 49.2 Hz events would remain at 1-in-27 year under different minimum inertia levels. This risk remains the same at lower minimum inertia levels due to an increase in response holding to contain the same largest BMU-only risks; currently we procure sufficient response to meet the increased requirement. As a result, changing the minimum inertia requirement does not impact our risk profile for securing against a 49.2 Hz event.

Differing the minimum inertia requirement does not impact the risk profile for 48.8 Hz events – this is largely driven by the underlying assumption made within the FRCR modelling of a 1-in-30 year risk of a peak simultaneous event (referenced in 5.2 above).

The FRCR 2023 assessment, under 120 GVA.s inertia levels, estimated the system residual risk would be 1-in-17 year for 49.2 Hz events. Compared with this year's result, 1-in-27 year risk to see a 49.2 Hz event, the improvement in system residual risk under the same inertia level is mainly driven by the completion of the ALoMCP and the increase in response requirements due to system condition changes between last year and this year.

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*)	£374m	£242m	£209m	£193m
Cost to meet minimum inertia (this element is included in system wide cost)	£194m	£62m	£29m	£13m
Cost for Dynamic Containment (this element is included in system wide cost)	£51.83m	£51.98m	£52.06m	£52.12m
Incremental saving		**£132m**	**£33m**	**£16m**

The table above 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 a changing 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 increase associated with DC.

In 2024, with the implementation of 120 GVA.s minimum inertia policy, we estimate that a total saving of £132m can be achieved if we move from 140 GVA.s to 120 GVA.s. A further saving could be achieved if we operate at reduced inertia levels, below 120 GVA.s. Compared to 120 GVA.s, an estimated further cost saving of £49 million is expected when operating at 102 GVA.s. When reducing inertia from 120 GVA.s to lower levels, the incremental DC volume increase in each reduction step is estimated around 50 MW – this is achievable based on the current DC market capacity.

The cost saving between 140 GVA.s and 120 GVA.s was estimated as £65m in FRCR 2023. The increase in cost saving when operating at 120 GVA.s is mainly driven by the natural reduction in system outturn inertia when meeting energy requirements as the energy system transitions to a low carbon system. Meeting a higher inertia requirement, e.g. 140 GVA.s, results in higher costs. Increased cost saving encourages us to operate the system at a lower inertia level while continuing to prioritise system security.

6.1.2 Additional Considerations: minimum inertia requirements below 120 GVA.s

Analysis indicates that an additional £33m could be saved if we reduce the minimum inertia requirement to 110 GVA.s. Another £16m could be saved if we further reduce inertia to 102 GVA.s. There is no reduction in the overall system risks by operating at an inertia level lower than 120 GVA.s. It is likely that system events that cause frequency deviates outside of 48.8 Hz under 102 GVA.s would also result in a frequency deviate outside of 48.8 Hz under a higher inertia level of 120 GVA.s. Our past operational experience verifies the effectiveness of Low Frequency Demand Disconnection (LFDD), under lower inertia levels our analysis shows LFDD will remain highly effective.

However, the implementation of 120 GVA.s, as recommended by FRCR 2023, has been delayed due to various reasons. It is important to gain operational experience associated with operating the system at 120 GVA.s before we reduce minimum inertia below 120 GVA.s. Therefore, for the period covered by this report, 2024/25, we consider that 120 GVA.s is the optimal level of inertia to apply.

This change to system operation represents the first stage in our ambition to operate the system at lower inertia levels, to help meet our zero carbon ambitions.

We will closely monitor system performance at 120 GVA.s and continually review our studies to ensure we understand wider system impact and future system inertia needs. Depending on system conditions and balancing service market movement during 2024/25, we will lead on proposing a further reduction to minimum inertia levels before the completion of FRCR 2025. We will share operational findings and provide analysis with industry through subsequent consultation before we implement the lower minimum inertia requirement.

In terms of system operability, there are interactions between reducing minimum inertia level and other system operability workstreams, for example, inertia levels directly impact system voltage and stability. 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.

During summer 2023, we experienced the sub-synchronous oscillation events - an example of the interactions between several operability workstreams. Our extensive investigation found no evidence to suggest that the cause of these events is directly linked to system inertia. However, we will continue to solve any future challenges associated with zero carbon operation, ensuring we understand the operability requirements and how these operability challenges interact.

6.1.3 Recommendations

Based on the assessment conducted, we are recommending to continue with the minimum inertia requirement of 120 GVA.s.

Depending on system conditions and market movement during 2024/25, we will recommend further reducing the minimum inertia level if we are operationally ready – this will be done through subsequent consultation. We will engage with industry to clarify system impacts and communicate the implementation plan before the system moves to a new lower inertia level.

6.2 Assessment of securing additional event categories

Current policy focuses on securing BMU-only events. In this section we focus on the impacts and benefits of securing additional event categories, including BMU+VS and simultaneous events. The primary objective of this assessment is to determine the optimal approach regarding each event categories to understand if there is any additional value in changing the existing policy of securing all BMU-only events.

6.2.1 System residual risks vs. cost

This section evaluates the risk vs. cost using Response Control and BM Control to secure the remaining event categories, i.e. BMU+VS (outage), BMU+VS (intact) and Simultaneous events. Driven by the increase in the DC market capacity and the launch of the Enduring Auction Capability (EAC), we have observed a lower cost for procuring our response services. This cost reduction presents an opportunity to use additional Response Control to mitigate the system risks beyond BMU-only events with little additional cost implications.

The assessments were conducted for 2024/25, with BM Control and Response Control both applied individually to mitigate beyond BMU-only events. The system residual risks and additional cost associated are concluded in the below table.

Event category	BM Control		Response Control	
	Residual risk	Additional costs	Residual risk	Additional cost
BMU-only	1-in-27 year	£0	1-in-27 year	£0
BMU+VS (outage)	1-in-27 year	£925k	1-in-27 year	£35k
BMU+VS (intact)	1-in-28 year	£22m	1-in-28 year	£838k
Simultaneous event	N/A	N/A	1-in-9999 year	£37m

*minimum inertia requirement is 120 GVA.s

BM Control and Response Control can both be utilised to mitigate BMU+VS (outage) or BMU+VS (intact) events and the system residual risk stays the same. However, it is not possible to use BM Control to mitigate all simultaneous events due to the high loss level for peak simultaneous events, shown as “N/A” in the table.

The current policy of securing all BMU-only events has achieved a balance between cost and risk, where system residual risk remains 1-in-27 year. By securing all BMU-only events, the majority of the BMU+VS and simultaneous events are automatically covered. This indicates that we are capable of mitigating around 96.30% of system risks, leaving around 3.70% uncovered. However, it would be struggling to fully mitigate the remaining 3.70% of risk by applying Response Control as the volume of DC required is beyond the current market capacity; we would need approximately 1.6 GW of DC to cover BMU+VS events and 3 GW of DC to cover simultaneous events.

For the additional cost, Response Control offers significantly higher cost-effectiveness compared to BM Control. To mitigate all BMU+VS events, the estimated cost for Response Control is around £840k, whereas the cost for BM Control would be around £22m; this cost is only indicative as it is based on current DC average price assumptions which may fluctuate.

	Cost for system-wide controls (*include inertia and all response costs*)	**Additional Cost for BMU+VS (outage)**	**Additional Cost for BMU+VS (intact)**	**Additional Cost for simultaneous events**
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**

*minimum inertia requirement is 120 GVA.s for FRCR 2023 and FRCR 2024

The above table 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 three years’ FRCR reports. By applying Response Control as the additional measure to mitigate BMU+VS risks, estimated additional costs are around £840k, 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 there is potential for exploring further utilisation of DC to mitigate additional risks.

6.2.2 Recommendations

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

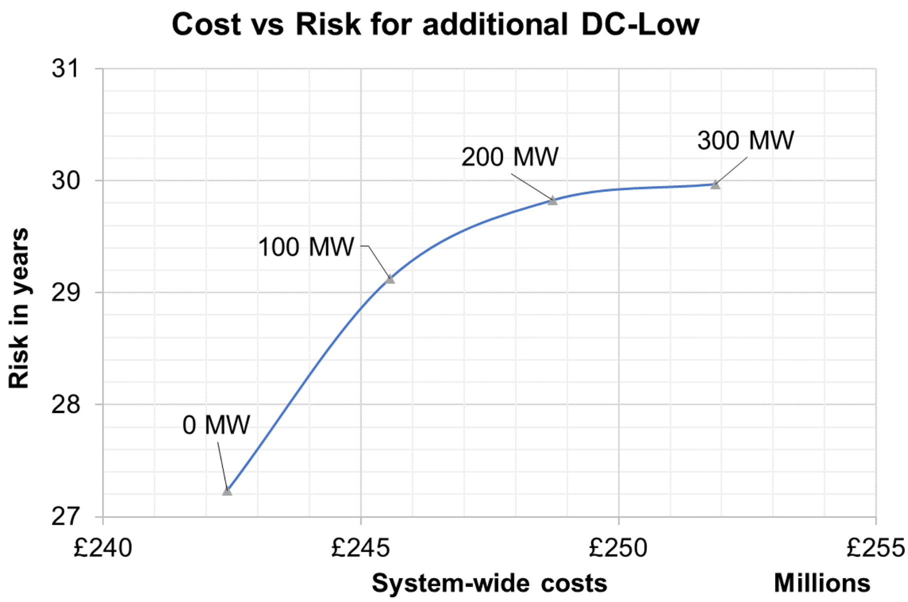
However, it would be struggling to fully secure all BMU+VS risks by applying Response Control. This is mainly because significant DC capacity would be required to mitigate all these risks, and this capacity is not always available in the current market. Further analysis would be necessary to fully understand the impact to the response market following any requirement increase and fluctuation. Due to the large benefits experienced by applying Response Control, an alternative approach of holding a fixed additional volume of DC is proposed and assessed in 6.3.

6.3 Assessment of additional DC-Low holding

Analysis in 6.2 indicates Response Control is a cost-effectiveness tool for mitigating beyond BMU-only risks. This section assesses different potential options for holding additional DC-Low.

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 of 100 MW, 200 MW and 300 MW are considered. Analysis indicates that the system risk reduction is most significant when increasing DC-Low holdings from 0 MW to 100 MW. Beyond this initial increment, the marginal benefits decrease with each 100 MW of DC-Low increase, while costs rise at a comparable rate. The following table compares system residual risks and cost under three scenarios: BMU-only, BMU-only with 100 MW additional DC-Low, and BMU-only with 200 MW additional DC-Low. All analysis is based on the latest market data and does not consider the price changes associated with requirement increase.

Option	Extra cost on top of £242m	Residual risk	Reduced risks per year
BMU-only (current policy)	£0	1-in-27 year	N/A
100 MW additional DC-Low	**£3.15m**	**1-in-29 year**	**0.24%**
200 MW additional DC-Low	£6.31m	1-in-30 year	0.32%

Holding an additional 100 MW of DC-Low yields a modest improvement in risk mitigation, accompanied by an incremental expenditure of £3.15m and a reduction in residual risk to 1-29 year. However, holding the 200 MW additional DC-Low offers only a slight further decrease in risk, albeit at twice the expense.

6.3.2 Recommendations

Based on the findings, this section recommends overholding 100 MW of DC-Low as an optimal level that effectively balances cost with risk mitigation. We recommend overholding an additional DC-Low requirement of up to 100 MW; adjusting our daily DC operation and procurement. We will continue monitoring market impact following the change before proposing any further alterations to the DC-Low requirements.

The recommendation of overholding additional volumes of DC provides a modest risk improvement but signifies the importance of increased system security.

Increasing our DC-Low holding has the potential to further grow the response market. As our largest loss size increases, with sites such as Hinkley-C power station connecting to the network, 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.

6.4 Outlook to 2025/26

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 continuous zero carbon electricity system by 2035. This FRCR explores managing frequency risks with the system conditions expected in 2025/26. The results obtained from the analysis are preliminary. A more comprehensive assessment will be conducted in FRCR 2025 considering additional operational experiences and improved foresight of system conditions, to drive appropriate future frequency control policy.

6.4.1 Minimum inertia requirements

The impact of the current FRCR policy (see appendix 9.2) on the residual risk for 2025/26 is set out below. In the 2025 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.

Scenario	120 GVA.s	102 GVA.s
49.2 Hz event	1-in-27 year	1-in-27 year
48.8 Hz event	1-in-30 year	1-in-30 year

Varying the minimum inertia in 2025 would not pose additional risks to the system, as the residual risks for 49.2 Hz and 48.8 Hz events would remain the same in 2025 compared to 2024 analysis.

Scenario	120 GVA.s	102 GVA.s
Cost for system-wide controls (*NB: system wide controls include inertia and all response costs)*	£256m	£199m
Cost to meet minimum inertia this element is included in system wide cost	£135m	£78m
Overall saving		**£57m**

The table above shows the costs and potential savings that could be achieved with a minimum inertia of 102 GVA.s in 2025 before any further individual loss risk controls are applied. With full implementation of the 120 GVA.s minimum inertia policy, we estimate that a total saving of £57m can be achieved by moving from 120 GVA.s to 102 GVA.s. This figure has slightly increased compared to the 2024 analysis (£49m). The cost saving increase between 2024 and 2025 is mainly due to changing system conditions; system inertia is anticipated to decrease in 2025 which will likely result in higher inertia costs to meet the same inertia requirement.

6.4.2 Securing additional event categories

The table below shows the system residual risk and costs of a 102 GVA.s minimum inertia policy in 2025, when securing beyond BMU-only events.

Event category	BM Control		Response Control	
	Residual risks	Additional costs	Residual risks	Additional costs
BMU-only	1-in-27 year	£0	1-in-27 year	£0
BMU+VS (outage)	1-in-27 year	£1m	1-in-28 year	£38k
BMU+VS (intact)	1-in-28 year	£25m	1-in-28 year	£912k
Simultaneous event	N/A	N/A	1-in-9999 year	£36m

*minimum inertia requirement is 102 GVA.s

To secure all BMU+VS events (outage and intact) by applying BM Control, it will cost an additional £25m. The resulting residual risk would slightly improve from 1-in-27 year of securing BMU-only events to 1-in-28 year.

With Response Control, an additional spending of £912k 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-28 year. Response Control shows higher cost-effectiveness when compared to BM Control. However, the volume of DC required to fully mitigate BMU+VS risks remains approximately 1.6 GW, matching the 2024 analysis.

6.4.3 Additional DC-Low holding

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

Option	Extra cost on top of £199m	Residual risk	Reduced risks per year
BMU-only	£0	1-in-27 year	N/A
100 MW additional DC-Low	**£3.15m**	**1-in-29 year**	**0.26%**
200 MW additional DC-Low	**£6.31m**	1-in-30 year	0.32%

This 2025 analysis shows similar results to the 2024 analysis, verifying that the residual risk reduction is most effective when increasing DC-Low holding from 0 MW to 100 MW. System risk has improved from 1-in-27 year to 1-in-29 year, with an extra cost of £3.15m per annum. In this analysis the additional cost of DC remains the same with the price assumed to be unchanged from 2024 to 2025.

7. Conclusions

7.1 Recommendation

The recommendation within this report is:

- Maintain the minimum inertia requirement at 120 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 DC-Low control to increase system security and grow market.

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

7.2 Implementation

We plan to further reduce the minimum inertia requirement to 120 GVA.s in summer 2024 – we will continually monitor system conditions and performance at this minimum inertia level. We recommend maintaining the 120 GVA.s minimum inertia policy until we have gained further operational experience. Subject to system conditions and operational readiness, we may propose operating at lower inertia levels, such as 110 GVA.s or 102 GVA.s, before completion of FRCR 2025. Before further reducing our minimum inertia policy, we will share our operational findings and analysis with industry through subsequent consultation. We will engage with industry to clarify system impacts and communicate the implementation plan before making further changes to this policy.

We are recommending that the DC-Low requirement increases by up to 100 MW; based on current market liquidity we foresee no issues with implementing this change. Pending approval from Ofgem, we will communicate the implementation of the additional holding through the Operational Transparency Forum (OTF) or similar platforms - providing at least five working days' notice via our normal forecasting and communication routes.

8. Future considerations

There are various events, loss risks, impacts and controls which are not explicitly considered in this edition of the report. They will be prioritised for future inclusion in future reports, based on consultation with the industry and the Authority. Such examples are described in the following section.

8.1 Events and loss risks

Events associated with lower system inertia and short circuit level: The change in the likelihood of existing events or new events created due to the increasing penetration of renewable generation connected to the whole system.

Weather conditions: The change in the likelihood of events during adverse conditions. The key complexity is how to quantify the increase in risk.

New causes of events: Such as Active Network Management schemes (AMNs), single control points for multiple-BMUs, IP risks. More work is required to understand and quantify these events.

Generation connections: Assets owned by generators that connect them to the NETS, but which are not covered by the SQSS e.g., short double circuit routes from a power station to a substation.

New causes of distributed resource losses: Any new causes that come to light as the power system evolves.

New infeed and outfeed losses: Approach to better forecast the running-pattern and reliability of new future new interconnectors, offshore wind and nascent technologies.

Impact of system conditions in the run-up to an event: How this impacts on the ability of the system to cope with events e.g., more onerous starting frequency, sustained high or low frequency and the impact on energy-limited controls.

Fault Ride Through (FRT): The FRT issues are under clarification and being resolved via measures introduced in GC0151 and will be further assessed in subsequent FRCR where appropriate.

Simultaneous events: Review and better quantify the probability of faults forming simultaneous events.

8.2 Impacts

Multiple stages of LFDD: Exploring whether events could cause more than one stage of LFDD, and how often this could happen. This would include the duration of LFDD events and the time taken to recover. Considering wider consequence when a LFDD event is triggered.

Further investigation of high frequency deviations: The ESO has explored the benefits of relaxing the high frequency limits to align with low side. Potential benefits are identified as, reduced response cost for high frequency response and allowing larger demand connections including future interconnectors. Due to its technical complexity and consequential effects that could affect the whole electric industry when implementing the change, FRCR 2024 does not propose any change on high frequency side. We will keep this under review in the future.

8.3 Controls

New Response and Reserve services: Future technologies and services developed under the Response and Reserve roadmap. Cost assessment of new technologies and services are to be considered.

Other Response service: How Limited Frequency Sensitive Mode (LFSM) from response services impact response requirements under different system conditions.

Further reduction of minimum inertia requirement: We will continue to review our minimum inertia requirement in order to help achieve our zero carbon operation ambition.

8.4 Metrics

Other approaches to valuing cost vs. risk: Whether there are other projects, initiative or research which can help to inform the metrics and the tolerability of events to end consumers.

Ongoing updates: Regularly updating the metrics to incorporate the effect of changes in the value of security of supply as electricity demand changes e.g., due to the electrification of heat, electric vehicles or production of green hydrogen.

Implementation: The time and costs associated with implementing a change in policy.

8.5 Analysis and data

Improvements in statistical data inputs: Whether there is the opportunity for better quality or more accurate input data on the probability of the various types of faults, and how to reflect any uncertainties. Whether to model a range of possible weather scenarios to understand the variance this introduces.

Improvements in operation monitoring: We are developing new operational tools and processes to improve our real-time visibility of system performance including system frequency, inertia etc. Improved monitoring will help promptly initiate adjustment of operation policy and be used as inputs for future FRCR analysis.

Collaboration with other system operability workstreams: We will continue looking into FRCR future policy and implementation of frequency management in collaboration with other power system operability areas to understand wider system impacts, i.e., voltage control, fault level requirements, system restoration requirements.

9. Appendices

9.1 List of Abbreviations

Abbreviation	Definition
ALoMCP	Accelerated Loss of Main Change Programme
ANMs	Active Network Management schemes
BMU	Balancing Mechanism Unit
BOA	Bid Offer Acceptance
BP	Business Plan
CCGT	Combined Cycle Gas Turbine
DC	Dynamic Containment
DER	Distributed Energy Resources
DM	Dynamic Moderation
DR	Dynamic Regulation
EAC	Enduring Auction Capability
EFA	Electricity Forward Agreement
ESO	Electricity System Operator
FES	Future Energy Scenarios
FFR	Firm Frequency Response
FRCR	Frequency Risk and Control Report
FRT	Fault Ride Through
LFDD	Low Frequency Demand Disconnection
LoM	Loss of Mains
MEL	Maximum Export Limit
NETS	National Electricity Transmission System
OHL	Over Head Line
OSR	Operability Strategy Report
PN	Physical Notification
RIIO	Revenue = Incentives + Innovation + Outputs
RoCoF	Rate of Change of Frequency
SEL	Stable Export Limit
SOGL	System Operation Guideline
SQSS	Security and Quality of Supply Standards
VS	Vector Shift

9.2 FRCR April 2023 Policy

Reduce Loss of Mains loss size:

The ESO will

a) Accelerated Loss of Mains Change Programme (ALoMCP)

Update operational tools with latest programme delivery, as a reduction against the initial baseline capacity estimate at the start of the programme.

Inertia

The ESO will:

a) Minimum inertia

Maintain system inertia at or above 120 GVA.s. This prevents all BMU-only, VS-only and BMU+VS loss risks up to approximately 600 MW from causing a consequential RoCoF loss[8].

b) Largest VS-only loss risk

Ensure system inertia is maintained at or above the level that will prevent the largest VS-only loss from causing a consequential RoCoF loss.

Frequency Response

The ESO will:

a) Infeed losses

Prevent BMU-only and VS-only infeed losses causing a frequency deviation below 49.2 Hz and restore frequency above 49.5 Hz within 60 seconds.

b) Demand losses

Prevent all BMU-only outfeed losses causing a frequency deviation above 50.5 Hz.

Prevent the loss of Super Grid Transformer supplies to Distribution Networks causing a frequency deviation above 50.5 Hz[9].

NB: VS-only losses can't cause outfeed losses, only infeed losses.

Reduce BMU loss size

The ESO will

a) Infeed loss risks

Allow BMU-only infeed loss risks to cause a consequential RoCoF loss where the resulting loss can be contained to 49.2Hz. If the resulting loss cannot be contained to 49.2Hz, then two approaches are taken. 1: take bids to reduce the BMU-only infeed loss to prevent a frequency deviation below 49.2Hz, either by preventing the consequential RoCoF loss or reducing the overall BMU+RoCoF loss; 2: increase response holding to contain the overall BMU+RoCoF loss

b) Outfeed loss risks

Consider allowing BMU-only outfeed loss risks to cause a consequential RoCoF loss, as the two losses will partially offset each other[10]

- This is only permissible if the resulting high frequency and/or low frequency deviations are acceptable
- If they are not acceptable, then do not let BMU-only outfeed losses cause a consequential RoCoF loss, by taking offers to reduce the demand loss

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[8] for some loss risks, the inertia lost with the event means the threshold is slightly below 600 MW.

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[10] the BMU-only outfeed loss would make frequency rise, but the consequential RoCoF loss would make the frequency fall, so the net effect of the combined loss is smaller.

Variations to this policy

There are specific, limited variations to these policies based on technical, probabilistic and economic grounds, applied under paragraphs 5.11.2 and 9.4.2 of the SQSS. This includes additional actions where appropriate during times of increased system risk, such as during severe weather, and exceptions where risks cannot feasibly occur[11] .

The FRCR is an assessment of all events across the past year, made using assumptions as to the likelihood and impact to system security based on the controls the ESO expects to have available. If there are circumstances whereby a specific event would lead to overall system risk being significantly different to the expected case, the ESO reserves the right to take actions to ensure that system risk remains in line with the risk appetite outlined in the FRCR.

If and when this occurs, and as appropriate, the ESO will inform the Authority of such actions after they have been taken, and report relevant details in the following FRCR process.

[11] e.g., due to the configuration of a BMU making the loss of the whole BMU at once not credible