Security & Quality of Supply Standards

Frequency Risk and Control Policy

December 2020

1. Executive Summary

This *Frequency Risk and Control Policy* document:

- states current *NGESO* policy for frequency risks and controls, and
- provides a baseline for the first edition of the *Frequency Risk and Control Report*

It is written with the intention of providing clarity and transparency to the way *National Grid Electricity System Operator* (*NGESO*) operates the system with respect to frequency control. As such, it is a necessary start-point for the process of developing the first edition of the *Frequency Risk and Control Report*, as outlined and required in the Security and Quality of Supply Standards (SQSS) modification GSR027.

The 2021 edition of the *Frequency Risk and Control Report* will focus on:

- establishing a clear, objective, transparent process for assessing reliability vs. cost of operating the *National Electricity Transmission System* with respect to frequency to ensure the best outcome for consumers
- making the assessment of the risk from the inadvertent operation of Loss of Mains protection transparent
- identifying quick, short-term improvements for reliability vs. cost

This *Frequency Risk and Control Policy* will be superseded by the 2021 edition of the *Frequency Risk and Control Report*.

2. Contents

3. Introduction

3.1. Scope

This *Frequency Risk and Control Policy* document is designed to:

- document current *NGESO* policy for frequency risks and controls, and
- provide a baseline for the first edition of the *Frequency Risk and Control Report*

The 2021 edition of the *Frequency Risk and Control Report* will focus on:

- establishing a clear, objective, transparent process for assessing reliability vs. cost of operating the *National Electricity Transmission System* with respect to frequency
- making the assessment of the risk from the inadvertent operation of Loss of Mains protection transparent
- identifying quick, short-term improvements for reliability vs. cost

Future editions of the *Frequency Risk and Control Report* will then build on that further, addressing further events, impacts and controls.

3.2. Defined terms

This document contains technical terms and phrases specific to *transmission systems* and the Electricity Supply Industry. The meaning of some terms or phrases in this document may therefore differ from the common understanding. For this reason, defined terms from the SQSS have been identified in the text using *blue italics*.

4. Impact of frequency deviations

NB: see **7 Appendix – Impact of frequency deviations** *for more details.*

4.1. What causes frequency deviations?

The frequency of the system will change:

- if generation exceeds demand, then the frequency will rise
- if demand exceeds generation, then the frequency will fall

The size of a frequency deviation is proportional to the size of the mismatch between generation and demand; bigger mismatches lead to bigger and faster deviations.

Transient frequency deviations outside of *steady state frequency* limits only occur if a sufficiently large generation or large demand loss happens over very short timescales[1].

4.2. Considerations

The impact of a *transient frequency deviation* depends on its duration, size and the conditions under which it occurs. Amongst other things, these affect automatic actions taken by equipment on the system, such as protection schemes, the delivery of **Controls** (**Ch 6**), as well as determining the consequences for the electricity system and its users as a whole.

One of the main considerations in this context are the requirements of the Grid Code, including Low Frequency Demand Disconnection (LFDD).

See **7 Appendix – Impact of frequency deviations** for more detail.

4.3. Frequency limits

For events covered by **6.4 Specific NGESO policy**, NGESO applies the following frequency limits to minimise the likelihood of *unacceptable frequency conditions*:

- 49.2Hz as the lower bound for frequency following a Balancing Mechanism Unit (BMU)-only *infeed* loss greater than 1000MW, ensuring frequency returns inside statutory limits within 60 seconds
- 49.5Hz as the lower bound for frequency following an BMU-only *infeed* loss less than or equal to 1000MW
- 50.5Hz for the upper bound of frequency following an BMU-only *outfeed* loss
- 49.8Hz to 50.2Hz for pre-fault frequency, aiming to stay as close to 50.0Hz as is practicable most of the time

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[1] of the order of zero to sixty seconds

5. Events and loss risks

NB: see **8 Appendix – Events and loss risks** *for more details.*

5.1. Events and loss risks

Frequency Risk and Control Policy covers the following six categories of loss risks, all of which are considered by *NGESO*. This includes events on the transmission system which cause the consequential loss of Distributed Energy Resources (DER). The definitions of probability are included in **5.2 Loss risk sizes and likelihoods**.

BMU-only

- an event which only disconnects one or more BMUs
  (no Vector Shift (VS) loss or Rate of Change of Frequency (RoCoF) loss)
- these are caused by faults inside a particular BMU, or particular group of BMUs, which:
  - cause the associated *infeed* or *outfeed* to be disconnected from the transmission system, and
  - do not cause an electrical disturbance which propagates into the distribution networks, causing a consequential VS loss
- without any containment or mitigation controls:
  - *transient frequency deviations* following these events would be very common (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk is be up to 1,400 MW

VS-only

- an event which causes a consequential VS loss
  (no BMU loss or RoCoF loss)
- these are caused by faults on the *National Electricity Transmission System* which:
  - cause an electrical disturbance which propagates into the distribution networks, causing a consequential VS loss, and
  - do not disconnect a particular BMU or group of BMUs from the transmission system
- without any containment or mitigation controls
  - *transient frequency deviations* following these events would be common (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk would be up to 750MW

BMU + VS

- an event which only disconnects one or more BMUs and causes a consequential VS loss (no RoCoF loss)
- these are caused by faults on the *National Electricity Transmission System* which:
  - cause an electrical disturbance which propagates into the distribution networks, causing a consequential VS loss, and
  - do disconnect a specific BMU or group of BMUs from the system due to the design of the network, for example a busbar fault, a generator transformer fault or a double circuit fault where it is the only connection to the network
- without any containment or mitigation controls:
  - *transient frequency deviations* following these events would be rare (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk would be up to 1900 MW

BMU + RoCoF

- a BMU loss which also causes a consequential RoCoF loss (no VS loss)
- without any containment or mitigation controls:
  - *transient frequency deviations* following these events would be very common (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk would be up to 2700 MW

VS + RoCoF

- a VS loss which also causes a consequential RoCoF loss (no BMU loss)
- without any containment or mitigation controls:
  - *transient frequency deviations* following these events would be common (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk would be up to 2100 MW

BMU + VS + RoCoF

- a BMU + VS loss which also causes a consequential RoCoF loss
- without any containment or mitigation controls:
  - *transient frequency deviations* following these events would be rare (see **Figure 1**)
  - as of December 2020, the size of the resulting loss risk would be up to 3300 MW

5.2. Loss risk sizes and likelihoods

Figure 1 shows the relative size and likelihoods of the different loss risks if no mitigations were applied. Key points to note are that:

- BMU loss risks and VS loss risks are much more likely to occur than BMU+VS loss risks, but BMU+VS loss risk have the potential to be much larger
- the impact of consequential RoCoF losses[2], significantly increasing the total loss size for each of the three initial events.

As a framing for the likelihood of causing a *transient frequency deviation*:

high likelihood / common	• occurs more often than once a year
low likelihood / rare	• occurs less often than once in twenty years[3]

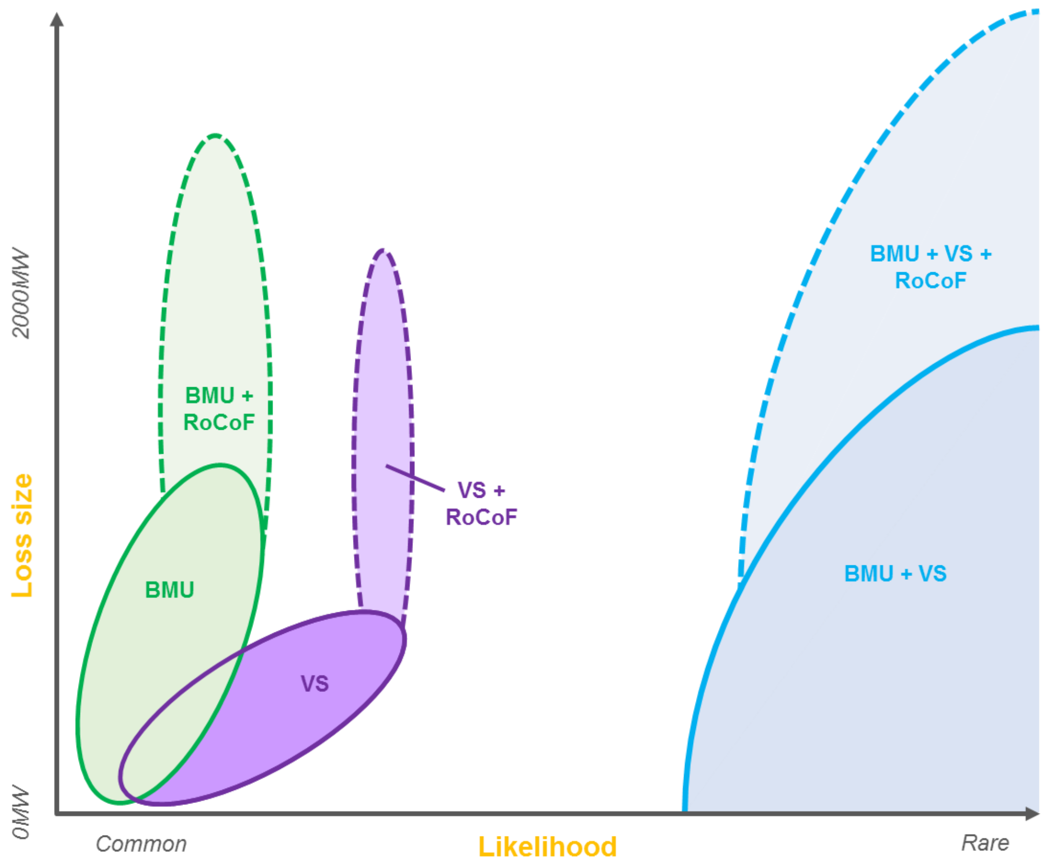

Figure 1 - Relative size and likelihood of loss risks without prior mitigations

[2] *a RoCoF loss cannot happen by itself: there must be an initial 'event', BMU and/or VS loss, to cause a high rate of change of frequency, which then causes the consequential RoCoF loss*

[3] likelihoods are estimated using the statistics produced to support SQSS modification proposal "GSR008: Regional Variations and Wider Issues"

6. Controls

*NB: see **9 Appendix – Controls** for more details.*

6.1. General strategy

There are four main controls for mitigating *transient frequency deviations*:

- holding frequency response
- reducing BMU loss size
- reducing Loss of Mains (LoM) loss size
- increasing inertia

6.1.1. Frequency Response

Frequency response services aim to contain an event or sequence of events by reducing the size of frequency deviations once an event has happened. This is achieved by delivering either more or less power to the system, depending on the direction of the frequency deviation away from 50Hz.

Holding frequency response is the first step in the frequency control strategy, as it mitigates a large proportion of the events which could cause *unacceptable frequency conditions*.

Frequency response is allocated through a number of different means available to the ESO.

6.1.1.1. Historic frequency response services

Historic frequency response services and markets (before the introduction of Dynamic Containment) have been optimised over time to meet the typical largest BMU-only loss risks[4].

This level of frequency response will also cover the VS-only loss risks.

However, the historic frequency response services are not suited to covering BMU+VS loss risks, or any loss risk that also causes a consequential RoCoF loss. This is because the size of these losses is so great, and the rate of change of frequency is so high, that they cannot keep up with the resulting frequency deviation.

6.1.1.2. New frequency response services

The soft-launch of Dynamic Containment in October 2020 is the first of the new frequency response services under the “Response and Reserve Reform” programme. As the supply of Dynamic Containment increases, it will enable frequency response to cover BMU+VS loss risks and any loss risk that also causes a consequential RoCoF loss.

The cost-risk benefit of securing these larger, less frequent loss risks with larger quantities of Dynamic Containment will be assessed in the *FRCR*.

4 typically 1260MW, although sometimes up to around 1400MW for the largest BMU group on a *double circuit overhead line*

6.1.2. Reduce BMU loss size

BMU+RoCoF loss risks have typically been too large to be covered with historic frequency response services from a cost and capability perspective. Taking bids or offers on individual large BMU loss risks decreases their size and prevents the consequential RoCoF losses.

This control is used to mitigate the BMU+RoCoF loss risks for large, flexible BMUs.

6.1.3. Reduce Loss of Mains (LoM) loss size

6.1.3.1. Vector Shift

VS+RoCoF loss risks have typically been too large to be covered and historic frequency response services from a cost and capability perspective. Reducing the size of any consequential VS losses reduces the Rate of Change of Frequency and prevents the consequential RoCoF losses.

6.1.3.2. RoCoF

The historic frequency response services are not suited to covering any loss risk that also causes a consequential RoCoF loss, because the size of these losses is so large and historic frequency response is typically too slow (see **6.1.1.1 Historic frequency response services**).

Reducing the size of any consequential RoCoF losses makes holding frequency response a viable option, especially with the introduction of Dynamic Containment.

6.1.3.3. Accelerated Loss of Mains Change Programme

Reductions in the LoM loss size is achieved by updating the Loss of Mains protection settings on embedded generation to match the latest requirements, through the Accelerated Loss of Mains Change Programme (ALoMCP). This is a one-time fix; when the relay settings are changed the risk of inadvertent tripping for the affected equipment is eliminated.

This control reduces the VS and RoCoF loss sizes, but will not fully mitigate events which includes these consequential DER losses until there is full delivery of the ALoMCP expected in September 2022. However, continued delivery under the programme does reduce how much of the other controls are required.

*NB: see **9.2 Reducing Loss of Mains loss size** for more details.*

6.1.4. Increase inertia

For some loss risks it is not possible to sufficiently reduce the loss size to prevent a consequential RoCoF loss from occurring. Instead, inertia is increased to reduce the Rate of Change of Frequency to prevent a consequential RoCoF loss from occurring.

This control is used to mitigate the BMU+RoCoF loss risks for smaller, inflexible BMUs, and to mitigate VS+RoCoF loss risks.

6.2. Cost vs. risk

As a general principle:

- good-value risks are likely to be those which are lower cost to mitigate or contain, have a high likelihood, or which have a large impact
- poor-value risks are likely to be those which are higher cost to mitigate or contain, have a low likelihood, or which have a small impact

There is a whole spectrum of costs and likelihoods across each of the events.

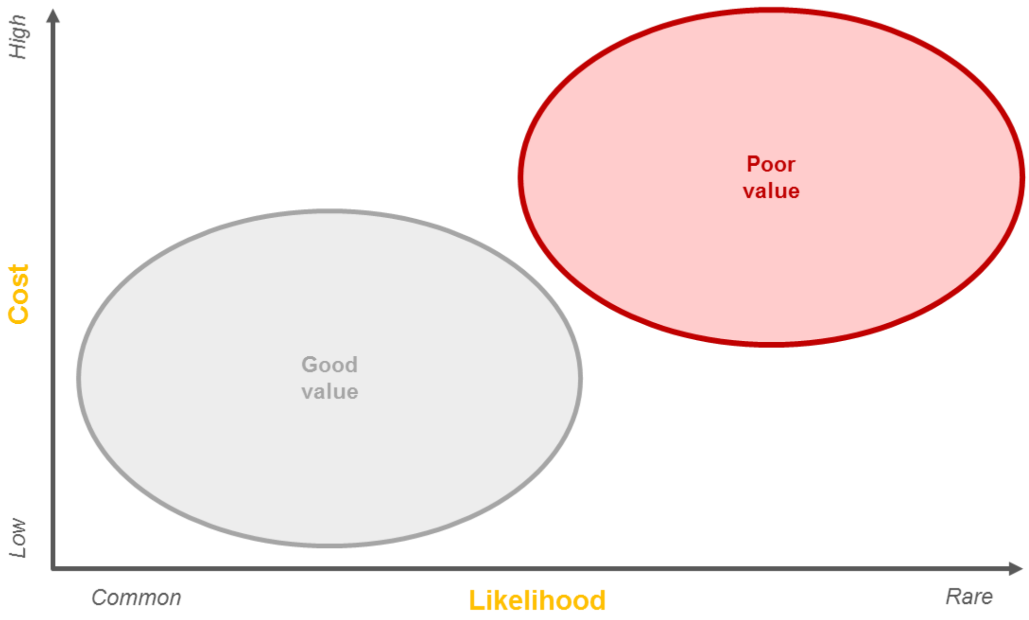

Figure 2 – Illustration of good-value and poor-value risks

6.2.1. Good-value loss risks

In general, BMU-only, VS-only, BMU+RoCoF and VS+RoCoF loss risks fall under the "low cost, high likelihood[5]" section of the cost-risk spectrum, and so they are good value to mitigate[6].

The cost of managing these risks is of the order of £500m per year, and without mitigation the impact of these events could occur multiple times per year.

The costs[7] are:

- £150m per year – provision of frequency response services
- £200m per year – provision of reserve for frequency response services
- £150m per year – reducing BMU loss size and increasing inertia

Accordingly, *NEGSO* mitigate these risks through the actions detailed in **6.4 Specific NGESO policy**.

[5] more than once per year
[6] noting the specific variations in **6.4 Specific NGESO policy**.
[7] based on 2019-20 MBSS

6.2.1.1. Example of good-value loss risks

The following examples of individual BMU+RoCoF and VS+RoCoF loss risks illustrates the relatively low cost and high likelihood.

Loss risk	Category	1-in-x years	Cost per year
Example A	BMU+RoCoF	1-in-1 years	£ 26m
Example B	BMU+RoCoF	1-in-20 years	£ 15m
Example C	VS+RoCoF	1-in-12 years	£ 10m

Table 1 - Examples of good-value loss risks which are mitigated

6.2.2. Poor-value loss risks

The higher cost of fully mitigating BMU+VS and BMU+VS+RoCoF loss risks makes them poor value to mitigate given their low likelihood of occurrence.

Due to the current RoCoF loss size simultaneous loss risks, exacerbated by consequential RoCoF losses, are also higher cost. This combined with their low likelihood means they are poor value to mitigate.

The estimated additional cost of mitigating all identified poor value risks BMU+VS and BMU+VS+RoCoF events are in the region of £1bn per year, approximately doubling current Balancing costs[8], but these events are assessed to occur less than once every 50 years.

Accordingly, *NEGSO* only mitigates these risks through reduction in the LoM loss size which is being progressed through the Accelerated Loss of Mains Change Programme. It will not mitigate these risks in real-time with frequency response, inertia, or reduction in BMU loss size.

6.2.2.1. Example of poor-value loss risks

The following examples of individual BMU+VS and BMU+VS+RoCoF loss risks illustrates the relatively high cost and low likelihood.

Loss risk	Category	1-in-x years	Cost per year
Example X	BMU+VS+RoCoF	1-in-70 years	£ 47m
Example Y	BMU+VS+RoCoF	1-in-75 years	£ 52m
Example Z	BMU+VS+RoCoF	1-in-300 years	£ 38m

Table 2 - Examples of poor-value loss risks which are not mitigated

These poor-value BMU+VS and BMU+VS+RoCoF loss risks are caused by **8.2.2 Transmission network faults**, rather than **8.2.1 BMU faults**.

Section **10 Appendix – worked example of cost vs. risk** explores this in more detail.

[8] based on 2019-20 MBSS

6.3. Overview of NGESO policy

This section outlines *NGESO's* frequency risk and control policy resulting from the assessment of **6.2 Cost vs. risk**. The detailed implementation of this is covered in **6.4 Specific NGESO policy**.

	BMU-only	VS-only	BMU + RoCoF	VS + RoCoF	BMU + VS	BMU + VS + RoCoF
Considered by policy	Yes	Yes	Yes	Yes	Yes	Yes
Mitigated in real-time	Yes	Yes	Yes	Yes	No	No
Main control	Frequency response	Frequency response	Reduce BMU loss size	Inertia	Reduce LoM loss size	Reduce LoM loss size
Additional control	Inertia or Reduce BMU loss size	n/a	Inertia	n/a	n/a	n/a

Table 3 - Overview of NGESO policy

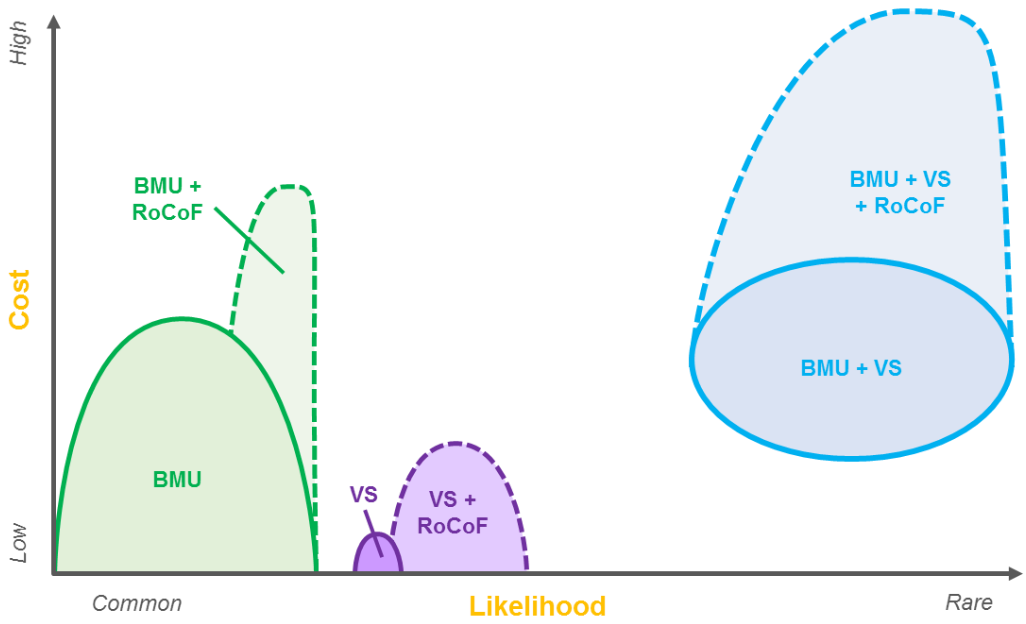

Figure 3 - Likelihood and cost of mitigating different categories of loss risk

6.4. Specific NGESO policy

6.4.1. Frequency response

NGESO will:

a) Infeed losses ≤ 1000MW

- prevent BMU-only, BMU + RoCoF and VS-only *infeed* losses ≤ 1000MW causing a frequency deviation below 49.5Hz
  - if there are no BMU-only or VS-only losses as large as 1000MW, then NGESO may reduce the frequency response requirement to only cover the lower level if it is economic to do so and does not affect other frequency response holding policies[9]

b) Infeed losses > 1000MW

- prevent BMU-only, BMU + RoCoF and VS-only *infeed* losses > 1000MW causing a frequency deviation below 49.2Hz and restore frequency above 49.5Hz within 60s
  - typically 1260MW, although sometimes up to around 1400MW for the largest BMU group on a *double circuit overhead line*
  - if there are no BMU-only or VS-only losses as large as 1260MW, then NGESO may reduce the frequency response requirement to only cover the lower level if it is economic to do so and does not affect other frequency response holding policies[10]

b) Demand losses

- prevent all BMU-only *outfeed* losses causing a frequency deviation above 50.5Hz

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

6.4.2. Inertia

NGESO will:

a) Minimum inertia

- maintain system inertia at or above 140 GVA.s
  - this prevents all BMU-only, VS-only and BMU+VS loss risks up to approximately 700MW from causing a consequential RoCoF loss11

    (as outlined in **6.1.4 Increase inertia**)

9 e.g. if the largest loss in this category was 900MW, then *NGESO* might only cover for a 900MW loss
10 e.g. if there were no losses in this category over 1100MW, then NGESO might only cover for a 1100MW loss
11 for some loss risks, the inertia lost with the event means the threshold is slightly below 700MW

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

6.4.3. Reduce Loss of Mains loss size

NGESO will;

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

6.4.4. Reduce BMU loss size

NGESO will;

a. Infeed loss risks
- not let BMU-only *infeed* loss risks cause a consequential RoCoF loss[12], by taking bids to reduce the *infeed* loss and resulting rate of change of frequency to be below 0.125Hz/s

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[13]
  - 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

6.4.5. Variations to this policy

There are specific, limited variations to these policies based on technical, probabilistic and economic grounds. This includes additional actions where appropriate during times of increased system risk, such as during severe weather, and exceptions where risks cannot feasibly occur[14].

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[12] see **9.2 Reducing Loss of Mains loss size** for more information
[13] 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
[14] e.g. due to the configuration of a BMU making the loss of the whole BMU at once not credible

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7. Appendix – Impact of frequency deviations

7.1. Grid Code

7.1.1. What frequency ranges are prescribed in the Grid Code?

Section CC.6.1.3 of the Grid Code defines how long plant and apparatus is required to remain connected to the system as frequency moves between 47.0Hz and 52.0Hz:

- between 51.5Hz and 52.0Hz: for at least 15 minutes
- between 51.0Hz and 51.5Hz: for at least 90 minutes
- between 49.0Hz and 51.0Hz: continuous
- between 47.5Hz and 49.0Hz: for at least 90 minutes
- between 47.0Hz and 47.5Hz: for at least 20 seconds

However, there are other considerations which mean that using the full range of 47.0Hz to 52.0Hz is not likely to be acceptable.

7.1.2. Low Frequency Demand Disconnection

Low Frequency Demand Disconnection (LFDD) scheme is a set of automatic, frequency sensitive relays designed to disconnect bulk supply points in the DNO networks. The LFDD scheme to limit the fall in frequency of the electricity network during unusual events by disconnecting some electrical demand to ensure the protection of the whole system, but in doing so, some electricity consumers are exposed to the risk of temporary disconnection of their individual supply[15].

The LFDD scheme is managed by the distribution network operators (DNOs) in accordance with the requirements of the Grid Code. In designing their LFDD schemes DNO's endeavour to ensure that disconnection is prioritised appropriately.

The first stage of LFDD is set at 48.8Hz, with eight further stages at intervals down to 47.8Hz.

[15] the precise levels of disconnection at different frequencies and in different geographic areas is defined in the Grid Code table CC.A.5.5.1a

7.2. System Operator Guideline

In 2017 the System Operator Guideline[16] (commonly known as SOGL) enshrined the SQSS implementation of the frequency standards[17].

	CE	GB	IE/NI	Nordic
standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1 000 mHz	1 000 mHz
maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
frequency recovery range	not used	± 500 mHz	± 500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

[16] Regulation EU 2017/1485 establishing a guideline on electricity transmission system operation

[17] Annex III Table 1 Frequency quality defining parameters of the synchronous areas

8. Appendix – Events and loss risks

8.1. What events can cause loss risks?

The large generation and demand losses that lead to transient frequency deviations are generally caused by unplanned events such as *fault outages* on the *national electricity transmission system (NETS)*, or generation sites connected to the *NETS*.

The most common examples of events that drive large changes in frequency are a large *loss of power infeed (infeed)*, such as an importing interconnector or a combined cycle gas turbine (CCGT), or a large *loss of power outfeed (outfeed)*, such as a pump storage unit[18], transmission-connected customer, or an exporting interconnector.

Consequential losses of other DER can also occur following *fault outages* on the *national electricity transmission system*. For example, some types of Loss of Mains (LoM) protection, either Rate of Change of Frequency (RoCoF) or Vector Shift (VS), have been observed to inadvertently operate and cause a loss of Distributed Energy Resources (DER) following events on the transmission system. These events can increase the total *infeed* or *outfeed* loss, and therefore affect the resulting frequency deviation.

Relevant events for which there is a known cause and effect are assessed in the *Frequency Risk and Control Policy*. In most cases these will be foreseen because of well understood features of plant and equipment performance, but, in some cases, they will need to be based on the observation of events that have already occurred.

[18] while pumping

8.2. Transmission-connected events

The SQSS directly defines *secured events* on the *NETS*, both *onshore* and *offshore*, that should not cause *unacceptable frequency conditions*.

The causes of these transmission-connected events can be described as falling in to two categories: BMU faults, and transmission network faults.

8.2.1. BMU faults

These are *fault outages* of a specific *infeed* or *outfeed* that cause the associated generation (production) or demand (consumption) be disconnected from the *NETS*. Examples include CCGT modules, boilers, nuclear reactors, and interconnector imports and exports from *external systems*.

These are covered by the *single generating unit*, *single power park module*, *single DC converter*, *Loss of Power Infeed* and *Loss of Power Outfeed*[19] criteria in the SQSS.

For the purpose of the *Frequency Risk and Control Policy* these are collectively referred to as BMU[20] faults, in line with the Balancing and Settlement Code definitions.

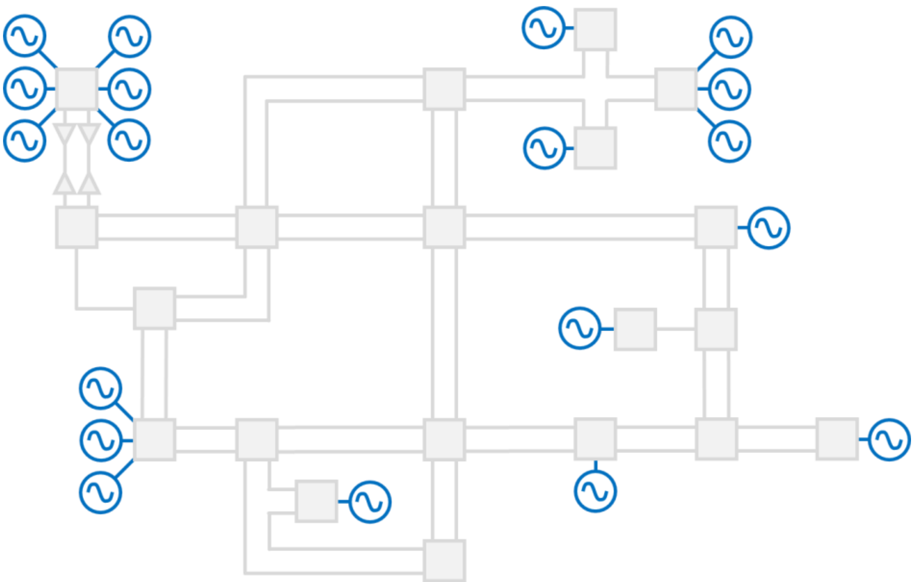

Figure 4 - potential BMU faults on an illustrative network

[19] the term *Loss of Power Outfeed* is introduced in GSR027

[20] https://www.elexon.co.uk/operations-settlement/balancing-mechanism-units/

8.2.2. Transmission network faults

These are *fault outages* on the *NETS* which can disconnect a specific BMU or group of BMU from the system due to the design of the network.

These are covered by the *single transmission circuit*, *single generation circuit*, *busbar / mesh corner* and *double circuit overhead line* criteria in the SQSS.

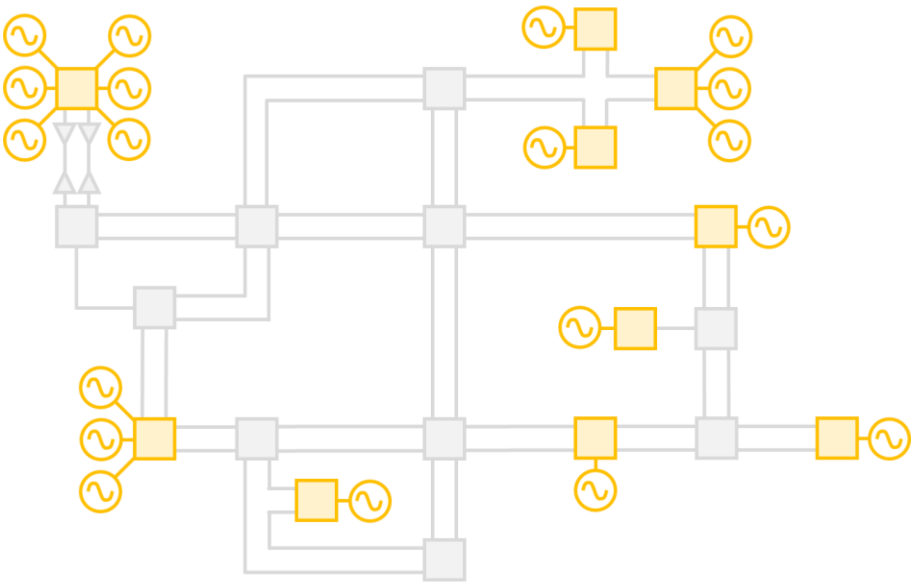

Figure 5 - potential busbar / mesh corner faults on an illustrative network

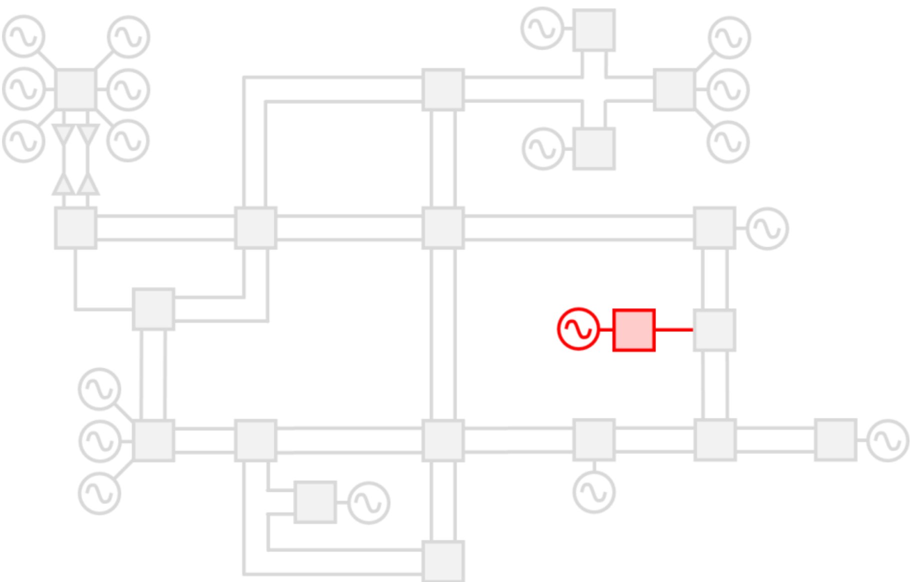

Figure 6 - potential single circuit faults on an illustrative network

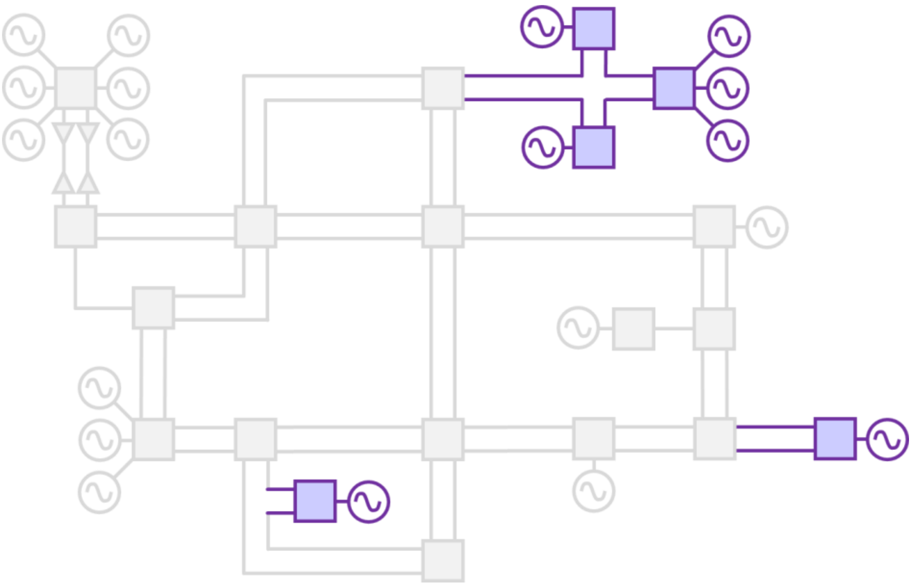

Figure 7 - potential double circuit faults on an illustrative network

8.3. Infeed and outfeed losses

This section sets out the background to the BMU losses and consequential loss of DER which are assessed in the *Frequency Risk and Control Policy*.

8.3.1. BMU losses

These are either:

- equipment failures within a BMU or group of BMUs, and affect only that BMU or group of BMUs.
- *fault outages* on the *NETS* which can disconnect a specific BMU or group of BMUs from the system due to the design of the network.

8.3.2. How big are the BMU loss sizes?

BMU loss sizes currently range from a few MW for the smallest *single generating unit* up to around 1400MW for the largest BMU group on a *double circuit overhead line*.

8.3.3. How likely are BMU losses?

There is a large range in the likelihood of these potential *infeed* and *outfeed* losses, from multiple times per year for a *single generating unit* or a *single DC converter* to one or twice per millennium for the shortest *double circuit overhead line* routes.

8.4. Consequential loss of Distributed Energy Resources

Distributed Energy Resources (DERs) are a significant proportion of the generation feeding the electricity system, and so managing their loss and potential to cause or contribute to *unacceptable frequency conditions* has become important for the overall reliability of the electricity system.

The loss of one individual distribution-connected resource is unlikely to noticeably impact the frequency of the *NETS*. However, the inadvertent operation of some types of Loss of Mains (LoM) protection, either Rate of Change of Frequency or Vector Shift following events on the transmission system can cause the loss of multiple DERs, which can then cause a *transient frequency deviation*.

8.4.1. Why do we have Loss of Mains protection?

Loss of Mains (LoM) protection is designed to prevent the formation of islanded networks following localised faults and is a requirement of the Distribution Code and supporting recommendations for most small generators.

An islanded network is a section of network operating separately from the rest of the network, with its own demand, generation and frequency. This islanding could occur following a fault on the distribution network.

Islanded networks typically have an unstable frequency and alternating current (AC) waveforms, due to the potential for large mismatches between demand and generation and little to no inertia and frequency response for damping. This gives rise to the possibility of equipment in the islanded network being damaged as it tries to stay connected to the rapidly changing frequency, or posing a danger to people who come across on unexpected live network.

It is possible that a stable island forms, if the demand and generation are matched closely enough. If this happens there is a risk of damage to equipment connected to the island, or that when a person comes to fix the initial fault that caused the island to separate, the network will still be live at one end and so pose an electrical danger to that person.

Loss of Mains protection seeks to detect a localised fault that may have led to islanding conditions, and quickly disconnects generation from the network. This prevents the island from forming, as there is no generation to sustain the demand, and removes the electrical risk to people and equipment.

8.4.2. How does Rate of Change of Frequency (RoCoF) protection work?

Islanded networks typically have large mismatches between demand and generation and little to no inertia and frequency response for damping. This means that the frequency in an islanded network changes quickly.

RoCoF protection measures how quickly the frequency is changing; the Rate of Change of Frequency (RoCoF). If the RoCoF exceeds a pre-defined threshold for a certain duration then the protection will activate, disconnecting the generator from the network.

The most sensitive RoCoF protection on the GB system is set at 0.125Hz/s, with little to no minimum duration threshold. There are further tranches of RoCoF relays at other thresholds, e.g. 0.2Hz/s, 0.5Hz/s and 1.0Hz/s, depending on manufacturer settings.

8.4.3. How does Vector Shift protection work?

When an electrical fault occurs, the phase angle between the voltage and current in the AC waveform can change significantly, by many degrees.

Vector Shift (VS) protection measures these phase angle changes. If the phase angle change exceeds a pre-defined threshold for a certain duration then the protection will activate, disconnecting the generator from the network.

The most sensitive Vector Shift protection on the GB system is set at six degrees, with no prescribed duration threshold.

8.4.4. Why has inadvertent tripping of DER become an issue?

Distributed Energy Resources now make up a significant proportion of the electricity generation feeding into the system. This significance, combined with the risk of inadvertent tripping of Loss of Mains protection, means there is a need to include DER in the list of events considered within *Frequency Risk and Control Policy*.

RoCoF has become significant because of the decline in system inertia. Inertia is a measure of the stored energy in a system. This stored energy helps to resist and slow down changes in the frequency. The amount of inertia on the electricity transmission system depends on the level of demand and on the generation-mix that is meeting that demand[21].

The level of transmission-system demand and inertia has decreased markedly over the last decade, as efficiency and environmental targets have led to wholesale change in the generation mix as Great Britain transitions to a low carbon economy.

When inertia is higher the Rate of Change of Frequency on the system following a large generation or demand losses would not exceed 0.125Hz/s, but as inertia has decreased, the same large generation or demand losses could now cause it to exceed 0.125Hz/s if not controlled.

RoCoF protection is now often unable to differentiate between localised events on the distribution networks, for which it should activate, and large events on the transmission network, for which it should not activate.

Vector Shift protection has similar issues with over-sensitivity, with faults on the transmission networks leading to large phase angle changes that propagate down into the distribution networks.

Vector Shift protection is now unable to differentiate between localised events on the distribution networks, for which it should activate, and large events on the transmission network, for which it should not activate.

[21] *see* **9.3 Increasing inertia** *for more detail*

8.4.5. How big are consequential DER loss sizes?

A significant proportion of DER with RoCoF or Vector Shift protection is either wind or solar powered, and so its output changes with the prevailing weather conditions.

The RoCoF loss size does not vary with the location of the event as system frequency is the same across the transmission system[22].

The potential RoCoF loss sizes are forecast to be in the following range, depending on the weather conditions and resulting load factors of DER in that region:

Tranche	Threshold	Loss size
Tranche 1	0.125 Hz/s	250 – 750 MW
Tranche 2	0.200 Hz/s	200 – 625 MW

Table 4 – potential RoCoF loss sizes, as of August 2020

The Vector Shift loss size varies with the location of the event, as the topology of the transmission and distribution networks affects the propagation of the phase angle change.

Examples of the potential Vector Shift loss sizes are forecast to be in the following ranges, depending on the weather conditions and resulting load factors of DER in that region:

Location	Threshold	Loss size
Scotland	6 degrees	20 – 200 MW
South West England	6 degrees	100 – 600 MW
South and Central England	6 degrees	250 – 1000 MW

Table 5 - potential Vector Shift loss sizes, as of August 2020

[22] to a first approximation

8.4.6. How likely are consequential DER losses?

The likelihood of a consequential Loss of Mains loss depends on the likelihood of the preceding *fault outages* happening. This is because:

- For a RoCoF loss to happen there first needs to be a fast change in the frequency. This would be caused by a large, fast, *infeed* or *outfeed* loss during a low inertia period.

  The relationship between inertia, loss size and RoCoF is given by:

$$RoCoF\ [Hz/s]\ =\frac{50[Hz]}{2}\times\frac{loss\ size\ [MW]}{Inertia\ [MVA.s]}$$

  Table 6 shows how different loss sizes can reach the 0.125Hz/s threshold at different inertia levels. Table 7 shows how for the same loss size varying inertia at which the loss occurs will result in different RoCoFs.

Inertia	Loss size	Rate of Change of Frequency
140,000 MVA.s	700 MW	0.125 Hz/s
160,000 MVA.s	800 MW	0.125 Hz/s
180,000 MVA.s	900 MW	0.125 Hz/s
200,000 MVA.s	1000 MW	0.125 Hz/s

Table 6 - relationship between inertia, loss size and RoCoF

Inertia	Loss size	Rate of Change of Frequency
160,000 MVA.s	1000 MW	0.156 Hz/s
200,000 MVA.s	1000 MW	0.125 Hz/s
240,000 MVA.s	1000 MW	0.104 Hz/s

Table 7 - relationship between inertia, loss size and RoCoF

  Without control measures being used by *NGESO*, RoCoF losses could happen multiple times per year.

- For a Vector Shift loss to happen, there needs to be a sufficiently severe electrical fault, such as a phase-to-earth or phase-to-phase fault on an overhead line, cable circuit or busbar.
  These can occur multiple times per year, but the size of the loss varies as in Table 5. The size of the loss typically depends on the location of the fault, the DER output at the time and the impedance of the fault. The likelihood of the largest losses is of the order of once every few years to once every few decades.

9. Appendix – Controls

9.1. Frequency response

9.1.1. Aim

The definition of *unacceptable frequency conditions* refers to *steady state frequency* (49.5Hz to 50.5Hz) and *transient frequency deviations* outside those limits.

NGESO uses operational limits of 49.8Hz to 50.2Hz to keep the frequency near to 50.0Hz most of the time; this is often called “pre-fault frequency” *i.e. before an event has happened*.

This means that when an event happens and causes a *transient frequency deviation*:

- frequency isn’t already close to the edge of the *steady state frequency* limits (49.5Hz to 50.5Hz)
- only a small amount of the frequency response services will have been used to manage “pre-fault” frequency, so it is still available to manage the “post-fault” *transient frequency deviation*

NGESO currently procures two categories of frequency response services;

- dynamic, which delivers proportionally to the frequency deviation
- static, where full delivery is activated when a frequency threshold is passed

9.1.2. Strategy

NGESO meet the above aim through procurement of a variety of *Ancillary Services*, including dynamic and static frequency response, reserve, bids and offers in the Balancing Mechanism, and trading.

All of these are part of controlling *steady state frequency* (keeping frequency near 50.0Hz), but the initial control of a *transient frequency deviation* is achieved with frequency response.

Once the *transient frequency deviation* has been controlled and returned to the *steady state frequency* limits, the other services take over again.

9.1.3. Requirement

NGESO’s frequency response requirements are split into two parts:

- pre-fault frequency – the minimum dynamic requirement
- post-fault frequency – the total requirement (including minimum dynamic)

The total frequency response requirement changes with demand, inertia, the size of potential *infeed* and *outfeed* losses, and the combination of frequency response services that are procured.

Larger losses
- bigger frequency deviations ⇒ more response required
- higher Rate of Change of Frequency ⇒ faster acting response required

Lower demand
- demand changes by 2.5% per Hz with the frequency, assisting with the control of frequency deviations
  → lower demand means this effect is lessened ⇒ greater quantity of response required

Lower inertia
- higher Rate of change of Frequency ⇒ faster acting response required

Combination of response services
- high proportion of slow response services ⇒ more required
  → as each provider will only partly deliver in time for faster frequency deviations
- too much static response can “overreact” to medium-sized events, as it does not deliver proportionally to the frequency deviation, and so can cause its own frequency deviation in the opposite direction

9.1.4. Services

The frequency response requirements are currently met through a variety of services, including: Primary, Secondary and High dynamic, Enhanced Frequency Response, secondary-only static, Low Frequency Static, and Dynamic Low High.

These services have large overlaps in meeting the pre-fault and post-fault requirement, and are not well suited to meet the future operability challenges of lower inertia, lower demand and larger losses.

This is a key driver for *NGESO* transitioning to a new set of frequency response services, such as Dynamic Containment which is designed for controlling *transient frequency deviations*.

9.1.5. Procurement

The baseline, firm requirement for frequency response is procured through tenders and auctions ahead of real-time. Any additional, variable need is currently met through optional services and the mandatory market, as *NGESO* transition to closer to real-time procurement and the new frequency response service suite.

9.1.6. Review

The requirements, controls and procurement are reviewed on a regular basis to determine the best approach, so any change in policy resulting from the *Frequency Risk and Control Report* will feed back in to this cycle.

9.2. Reducing Loss of Mains loss size

9.2.1. Background

A series of Grid Code and Distribution Code modifications have sought to address the inadvertent tripping of DER due to Loss of Mains protection.

Grid Code modification GC0035

The first of these modifications, Grid Code modification GC0035, was approved by Ofgem in 2014 and addressed the inadvertent tripping of RoCoF for generation capacity over 5MW.

The implementation of GC0035 was successfully completed in 2018, but left a remaining RoCoF risk for capacity under 5MW.

In this period, the inadvertent tripping of Vector Shift arose as a new issue on the system.

Distribution Code modification DC0079

The second series of these modifications, Distribution Code modification DC0079, addressed both Vector Shift (all capacities) and the remaining RoCoF capacity less than 5MW.

The deadline for compliance with the retrospective requirements of DC0079 is 01 September 2022. Once DC0079 has been successfully implemented, the threshold for triggering the consequential loss of RoCoF protection will rise to 1.0 Hz/s (sustained over 500ms) and no generation will be allowed to use Vector Shift protection.

This will significantly reduce the risk associated with *transient frequency deviations* due to the consequential loss of DER.

9.2.2. Interim controls

Until the successful implementation of DC0079, there are two main options for reducing the Loss of Mains loss size:

Change LoM relay settings	• prevent the inadvertent trip of Loss of Mains protection by changing the relay settings • this is a one-off fix; when the relay settings are changed the risk of inadvertent tripping for the affected equipment is eliminated[23]
Curtail LoM output	• curtail the output of DER which could inadvertently trip through Loss of Mains protection, to reduce the loss size • this would have to be done on an enduring basis, until the relay settings are changed

[23] at 1.0 Hz/s the frequency would deviate outside of *statutory limits* within 0.5 seconds, meaning that frequency response services would not have enough time to control *transient frequency deviations*. As such, there is no expectation to allow frequency changes to exceed this new Loss of Mains protection threshold.

9.2.3. Change LoM relay settings

The Accelerated Loss of Mains Change Programme (ALoMCP) aims to bring forward the date of full implementation of DC0079 by providing a financial incentive to DER at risk of inadvertent tripping due to LoM protection to change their relay or relay settings ahead of the 01 September 2022 deadline.

This aims to reduce the quantity of controls[24] and amount of time that *NGESO* uses them, reducing costs overall for the end consumer. It should be noted that this saving is only fully realised on completion of the project.

The main programme is run in quarterly windows, with applications from generators processed by DNOs and assessed by *NGESO*. Once accepted, successful applicants then deliver their relay changes in the agreed timescale. The maximum delivery lead time is 9 months, but most are within 3 months. The DNOs then perform validation checks that the work has been carried out successfully, and *NGESO* are notified to allow them to update their assumptions of the remaining capacity at risk of inadvertent tripping.

The Fast Track programme looks to further accelerate this for the highest value relay changes. It follows the same outline process as the main programme and condenses the timescale from months to weeks.

As a rolling programme, at any point in time there are many applicants at various stages of the process from application through to delivery and validation.

9.2.4. Curtail LoM output

NGESO have not followed this option to date, for the following reasons:

Does not address the root cause

- curtailment actions would need to be taken on an enduring basis, costing consumers for a long period of time until the relay setting is changed

Ineffective

- *NGESO* would have to curtail most or all the affected capacity to have a material impact; this would represent a large cost to end consumers, and impose a large distortion to the energy market
- doing only a small proportion of the capacity at risk doesn't solve the problem, as the remaining Loss of Mains loss size would still be large enough to cause a big frequency deviation
- *NGESO* would still have to take the same actions for the other frequency response, inertia and BMU loss size control, so it would not offset existing costs, and would incur more on top

Visibility

- *NGESO* don't have visibility of the affected parties to set up the arrangements with them

[24] inertia, frequency response and BMU loss size

9.3. Increasing inertia

9.3.1. What is inertia?

Inertia is a measure of the stored energy in a system. This stored energy helps to resist and slow down changes in the frequency.

9.3.2. What affects the amount of inertia on the system?

The amount of inertia on the electricity transmission system depends on the level of demand and on the generation-mix that is meeting that demand.

All AC-connected synchronous generation has some level of inertia associated with it, from the rotating machinery that is producing the electricity. This includes biomass, CCGTs, coal, hydro, nuclear, and pump storage.

Other types of generation, connected through converters, traditionally do not have inertia associated with them. This includes renewables like wind and solar, and HVDC interconnectors to other countries. Renewable generation is often at the top of the merit order to run, due to environmental incentives, and interconnector imports are expected when the price in other markets is lower than in GB.

Some sources of demand and some DER also have some level of inertia associated with them. These are also considered in calculating the inertia of the system.

Finally, *NGESO* have access to additional inertia through firm and optional contracts with providers, through programmes like Stability Pathfinder Phase 1.

9.3.3. When do low and high inertia periods occur?

During low demand periods, like the summer minimum or the reduced demand levels during the initial COVID-19 restrictions of 2020, zero-inertia generation is theoretically able to meet a large proportion of demand, and there is little self-dispatch of non-nuclear synchronous generation with inertia.

Low inertia therefore correlates with low demand, high renewable output, and interconnector imports.

During high demand periods, like winter peak, more generation runs to meet the demand. As there is currently insufficient renewable and interconnector capacity to meet the high demand level, a higher proportion of the generation mix has inertia associated with it, as other fuel types have to run.

High inertia therefore currently correlates with high demand, low renewable output, and interconnector exports.

The following figure illustrates this correlation of demand and inertia, with the width of the scatter plot due to different levels of renewable outputs and interconnector flows.

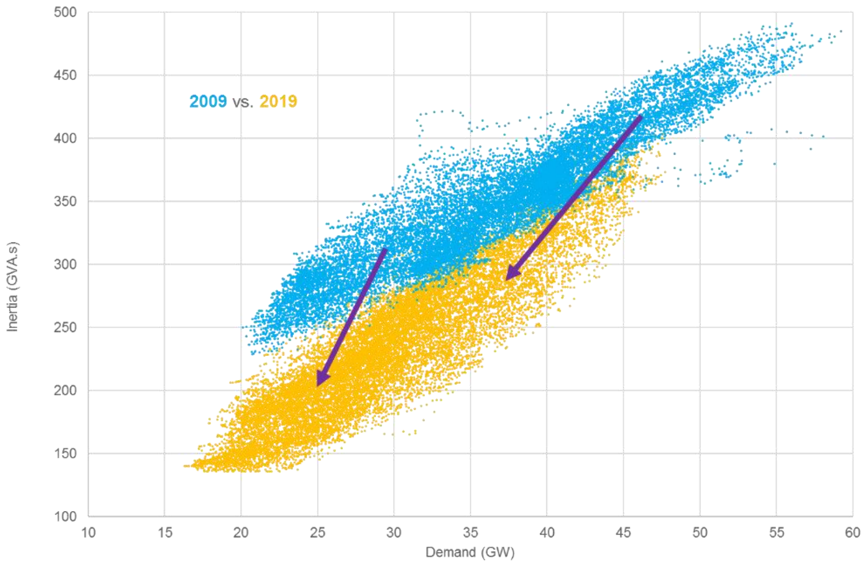

Figure 8 - Inertia vs. demand for 2009 vs. 2019

9.3.4. How to identify the need for additional inertia?

NGESO's forecast of the demand, the market position and Physical Notifications of the expected running of each BMU, and any inertia contracts it has, allows them to estimate the level of inertia that will be on the system.

If this is below required levels, then *NGESO* will take actions to increase the inertia of the system.

9.3.5. How to increase the inertia?

NGESO traditionally increases the inertia of the system by running synchronous units (BMUs) which provide inertia that would otherwise not be running.

This means that they have to buy energy in order to access inertia.

Each BMU comes with:

- a different amount of inertia, set by its electromechanical properties
- a different amount of energy, set by its Stable Export Limit[25]
- a different price for the energy, set by its offer price

Any additional energy that gets bought as a by-product of increasing the inertia must be balanced out with a corresponding quantity of bids (assuming that the market closes balanced, per the cash out incentive).

NGESO must also meet its negative reserve requirements, for real-time management of the frequency within *steady state limits*.

[25] the Stable Export Limit, or SEL, is the minimum power level a BMU can operate at continuously

These bids are therefore mostly taken on BMUs which do not provide inertia, to avoid undermining the initial action to increase inertia and to maintain the negative reserve requirement.

Typically, the bid prices of each fuel type put interconnector bids in merit first, mostly via trades, followed by renewables bids in the Balancing Mechanism.

Further actions are considered as a last resort, for example:

Optional Downward Flexibility Market	implemented as a time-limited measure[26] in 2020, because of the low demand levels brought about by the COVID-19 restrictions
System warnings	such as Negative Reserve Active Power Margin notices, designed to stimulate access to additional downwards flexibility

The optimisation of which BMU to synchronise for inertia must therefore maximise the inertia added whilst minimising the additional energy and associated cost.

Zero-megawatt and minimal-megawatt inertia services through Stability Pathfinder[27] and super-SEL contracts are aiming to reduce the cost and market impact of controlling inertia, by reducing or eliminating the energy component.

[26] expired 25 October 2020
[27] such as synchronous compensators

10. Appendix – worked example of cost vs. risk

This worked example looks at the cost vs. risk calculation for a specific BMU+VS+RoCoF loss risk.

10.1.1. Likelihood of a fault occurring

10.1.1.1. General likelihood of a fault on the network

The typical annual fault rate of different asset types on the network[28] have been taken from information produced to support SQSS modification proposal “GSR008: Regional Variations and Wider Issues”[29]

Table 2-3. England and Wales eight-year period data

Fault (eight-year data)	All	Weather Related	Fault Rate per 100km/year	Fault Rate per total no
OHL SC permanent	18	12	0.1263	
OHL DC permanent*[1]	3	1	0.0435	
OHL SC transient	71	62	0.5061	
OHL DC transient*[1]	4	3	0.0526	
Busbar (app 800 in E&W)	4	1		0.0048
Switchgear*[2]	34	1		0.0149
Transformer circuits	21			0.0091

*1 Fault rate is per route 100Km/year,
*2 All switchgear faults not necessarily a Bus Coupler or Section Switch

Figure 9 - Fault statics from GSR008: Regional Variations and Wider Issues

10.1.1.2. Specific likelihood of the example event

Considering the busbars, switchgear and transformer circuits associated with this example event, this gives the overall likelihood of a transmission network fault which could cause the BMU+VS loss at a rate of 0.01355 events per year.

This equates to 1-in-74 years.

10.1.2. Likelihood of a fault aligning with a RoCoF risk period

In order to cause a consequential RoCoF loss, the BMU+VS loss cause a Rate of Change of Frequency over 0.125Hz/s.

The proportion of time that this condition exists depends on the level of inertia, VS loss risk size and BMU loss size, each of which varies with time of year, market conditions and weather conditions.

On average, the example BMU+VS loss risk is large enough to cause a consequential RoCoF loss in around 40% of all Settlement Periods.

[28] e.g. overhead lines, cables, busbars
[29] https://www.nationalgrideso.com/document/14871/download

10.1.3. Likelihood of causing a transient frequency deviation

The likelihood of a fault occurring to cause this BMU+VS loss risk is assessed at 1-in-74 years. However, it is only large enough to cause a consequential RoCoF loss in around 40% of all Settlement Periods.

To get the overall risk we divide the likelihood of the fault (1-in-74 years) by the exposure (40%). This equates to approximately 1-in-185 years.

10.1.4. Cost of securing the BMU+VS+RoCoF loss

As outlined in **6.1 General strategy**, the lowest cost way of mitigating the risk would be to reduce the BMU loss size to prevent the BMU+VS loss risk from causing a consequential RoCoF loss. This would be less expensive and more feasible then holding more frequency response or increasing inertia.

Taking the typical price of reducing the BMU output for mitigating the BMU+RoCoF loss risk, and the additional volume of bids required to offset the additional VS loss component, the total cost is estimated at £52 million per year.

10.1.5. Overall cost vs. risk assessment

The cost vs. risk calculation for this BMU+VS+RoCoF loss risk results in a low likelihood, at 1-in-185 years, and a high cost, at £52 million per year.

As such, it would represent poor value to the end consumer to mitigate the risk.

This example is typical of the poor value of mitigating all BMU+VS and BMU+VS+RoCoF loss risks, as discussed in **6.2.2 Poor-value loss risks**.

11. Appendix – Glossary

11.1. General

System inertia	a measure of the stored rotational energy in the system (measured in MVA.s). directly affects the rate of change of frequency (df/dt) during a fault

Loss of Mains protection

Loss of Mains protection	protection on DER designed to detect a Loss of Mains condition to prevent the formation of islanded networks for local faults
df/dt	the Rate of Change of Frequency (RoCoF) observed on the electricity transmission system for a particular loss
RoCoF relay	a type of LoM protection which detects whether df/dt has exceed a particular threshold (e.g. 0.125Hz/s), indicating a possible islanding event
Vector Shift (VS) relay	a type of LoM protection which detects whether a sudden change in phase angle has exceed a particular threshold (e.g. 6 degrees), indicating a possible islanding event
RoCoF trigger threshold	the df/dt at which the first RoCoF protection is expected to trip (i.e. 0.125Hz/s)
RoCoF trigger level	the size of imbalance needed to cause df/dt to exceed the RoCoF trigger threshold, thereby tripping RoCoF protection and causing a RoCoF loss

Loss of Mains events

RoCoF loss	the loss of generation from DER due to the inadvertent tripping of LoM RoCoF relays, caused by an event on the electricity transmission system
Vector Shift loss	the loss of generation from DER due to the inadvertent tripping of LoM VS relays, caused by an event on the electricity transmission system
RoCoF loss forecast	the expected size of a RoCoF loss. this is the same nationally, regardless of event location
Vector Shift loss forecast	the expected size of a Vector Shift loss. this varies with the event location