Operating a Zero Carbon GB Power System in 2025: Frequency and Fault Current

Frequency Stability

Contributors

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Contents

1 Executive Summary

GB is driving towards a zero-carbon grid that translates to a power system that is tending towards lower inertia, with synchronous generators being displaced by non-synchronous generators. The inherent benefits that synchronous generators provide the power system, particularly in terms of frequency and voltage stability, are also being displaced as a result. This report presents the details of an assessment concerning future frequency response services in a zero-carbon GB power system in 2025. In particular, existing and proposed future frequency responses are compared and tested in a range of scenarios to investigate the impact to both frequency behaviour and the maximum amount of non-synchronous power that can be dispatched at a given time. Regarding the provision of future frequency response services by 2025, potential providers and upgrades are also considered.

1.1 Key Findings

- Existing services are adequate for containing events that result in a 0.125 Hz/s RoCoF but they are inadequate for normal loss risk frequency conditions at 0.5 Hz/s and all loss risk frequency conditions at 1 Hz/s. The ESO's proposed frequency response products, as they are defined, are adequate for both 0.125 Hz/s and 0.5 Hz/s, but inadequate for normal loss risk frequency conditions at 1 Hz/s; at this low inertia there is also an increased risk of frequency instabilities that depends on the specific control design deployed and how much faster the service activates compared to the delay defined in the requirements.

- Thresholds of 79 GVAs and 60 GVAs were identified as a boundary beyond which the risk of instability increases for containing 1.32 GW and 1 GW normal loss risks. Inertia data from the ESO suggests that this boundary occurs up to about 1% of the year in 2025, but in a 44% average penetration of non-synchronous generation in 2030 the boundary can occur up to 22% of the year. This risk can be remedied by introducing a definition for a service that activates within 250 ms of the event, such as the Improved Frequency Containment service demonstrated.

- The Improved Frequency Containment service can be deployed in tandem with the ESO's proposed services, and can tolerate deactivation after the initial response period; however, it is shown that in some instances this would require an additional secondary service to keep frequency within acceptable limits. Other fast-acting services like synthetic inertia can also provide benefits to containment, but the service definitions will need to include limitations to any recovery period.

- The system non-synchronous penetration limit is mostly limited by the RoCoF limit, however, once the changes to the setting take place (expected by 2022) there is minimal impact to the SNSP trends when comparing existing and proposed frequency response services. This is primarily due to the limiting constraint of baseload power supply from nuclear power plants.

- It is likely that synchronous generators will continue to participate in the frequency response market after the ESO replaces existing services with the proposed services, with the most likely product being Dynamic Regulation. Non-synchronous technologies are uniquely suited to fast response services such as Dynamic Moderation and Dynamic Containment, but the inclusion of storage can improve the certainty of power availability and compliance with service definitions, while also offering a route to surpass limitations if VSM is also deployed.

1.2 Recommendations

- In light of the upcoming deployment of Dynamic Containment frequency response service, with an expected initial reserve of 250 MW of a target 1 GW and a unit cap of 50 MW, non-synchronous providers may consider existing and mature control strategies that will allow compliance with service definitions. Although not essential for Dynamic Containment, a hybrid with energy storage offers improved power availability certainty.

2 Frequency Management in GB

The Security and Quality of Supply Standard (SQSS) defines conditions such as normal and infrequent loss risks, as well as unacceptable frequency conditions [1]. Table 2.1 is extracted from [1] and it provides definitions for the aforementioned conditions.

Table 2.1: Definition of conditions extracted from [1].

Normal Loss Risk	That level of loss of power in-feed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5 Hz. Until 31st March 2014, this is 1000 MW. From April 1st 2014, this is 1320 MW, however as described in [2] the practical normal loss risk is still currently 1000 MW.
Infrequent Loss Risk	That level of loss of power in-feed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5 Hz to 50.5 Hz for more than 60 seconds. Until 31st March 2014, this is 1320 MW. From April 1st 2014, this is 1800 MW, however as described in [2] the practical infrequent loss risk is still currently 1320 MW.
Unacceptable Frequency Conditions	These are conditions where: i) the steady state frequency falls outside the statutory limits of 49.5 Hz to 50.5 Hz; or ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5 Hz to 50.5 Hz within 60 seconds. Transient frequency deviations outside the limits of 49.5 Hz and 50.5 Hz shall only occur at intervals, which ought reasonably be considered as infrequent. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which National Grid ESO shall adjust from time to time to meet the security and quality requirements of this Standard.

The loss limits were changed because in 2011 an SQSS review of infeed losses determined that the old limits were no longer consistent with the range of technologies available to developers, and presented itself as a barrier to the connection of planned large generating plants – including new nuclear units with capacities up to 1800 MW. The decision was further justified by an Ofgem impact assessment associated with large nuclear plants, indicating carbon savings, wholesale price impact, etc., details on the review of infeed losses in GB are available in [3]. While this review was motivated by planned new connections of large nuclear power plants, at the time of writing, none of those planned new plants have been connected to the power system. The changes to the SQSS permits larger units or connection designs, such that a single event could cause loss event larger than those under the previous loss risk definitions. In addition to Hinckley C nuclear power plant, other examples include the North Sea Link 1400 MW HVDC interconnector [4] due to be completed in 2021, and potentially, large offshore wind farm connections. The ESO interprets its obligations pertinent to frequency response in [5], which is diagrammatically illustrated in Figure 2.1.

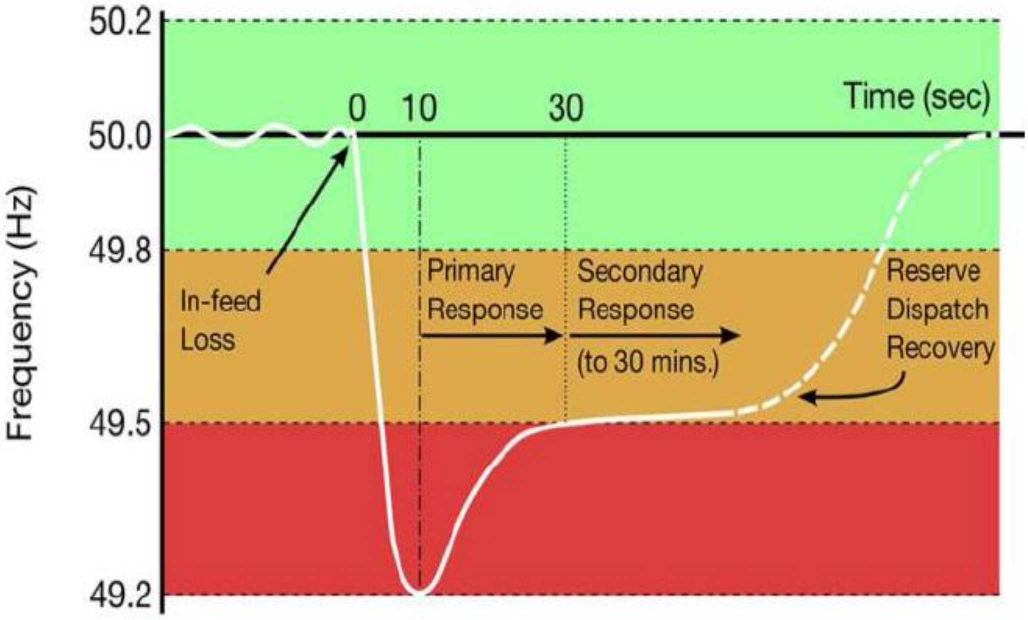


Figure 2.1: Diagrammatic representation of energy response for a maximum loss of in-feed event [6]. Green – normal operating conditions, Amber – normal loss conditions, Red – infrequent loss conditions.

Under normal operating conditions frequency can deviate from nominal 50 Hz by ±0.2 Hz, a limit referred to as the operational limit (49.8 Hz – 50.2 Hz), however, during a loss event a larger frequency excursion can occur. A loss event within the definitions of a normal loss risk must be contained within the statutory limit, i.e. 49.5 Hz – 50.5 Hz, if the loss causes frequency to exceed this limit then frequency must take no longer than 60 seconds to recovery to within statutory limits. There are other thresholds that apply for larger excursions of frequency from 50 Hz, which requires additional actions in order to manage frequency. The Low Frequency Demand Disconnection (LFDD) threshold starts at 48.8 Hz[1], and as the name implies, it is the disconnection of demand in order to prevent frequency collapse. The full spread of the LFDD thresholds as they apply to the three GB Transmission Operators (TOs), National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT) and Scottish Hydro Electric Transmission Plc (SHET), is available in [7].

There are also conditions relating to how quickly the system frequency changes, i.e. the RoCoF. These conditions, as set at the time of writing, are stated in [8]. Prior to the settings in [8], the RoCoF setting was 0.125 Hz/s; however, in a low inertia power system a credible loss of infeed or demand event would lead to a higher RoCoF. The consequence of the higher RoCoF under the previous 0.125 Hz/s setting is the increased risk of unintended operation of RoCoF LoM protection in distributed generation [9, 10], especially at higher loss risks and/or low inertia. The unintended operation of these relays could lead to a cascading effect, increasing the risk of exceeding the threshold for LFDD triggers [11]. To reduce the risk of unintended operation of these relays, the new LoM settings were written into the Engineering Recommendation G59 (now superseded by G99) [8]. It is stated in [8] that on or after the 1st of August 2016, most generators greater than or equal to 5 MW in capacity must operate using a RoCoF relay setting of 1 Hz/s and 0.5 s delay, with synchronous generators commissioned before the 1st of August 2016 permitted to use a 0.5 Hz/s setting. Generators with registered capacity less than 5 MW that were commissioned on or after 1st of February 2018, must operate using a RoCoF relay setting of 1 Hz/s and 0.5 s delay, while generators commissioned before the 1st of February 2018 with a registered capacity less than 5 MW are permitted to use a setting no lower than the original 0.125 Hz/s and not greater than 1 Hz/s with a 0.5 s delay. However, Engineering Recommendation G99 specifies a 1 Hz/s setting with a 0.5 s delay for RoCoF based LoM protection relays. At the time of writing, there remains about 2 GW of distributed generation using relays that could activate if RoCoF exceeds 0.125 Hz/s [12]. However, there are plans in place to update the LoM protection settings by 2022 [13].

[1] 48.8 Hz in the NGET transmission area, 48.5 Hz in SPT area and 48.6 Hz in SHET area [15].

3 Frequency Response in GB

When it comes to managing frequency and securing for credible loss events, both RoCoF limits and acceptable frequency conditions must be considered, and suitable actions need to be taken by the ESO in order to be compliant. One of such actions, is the scheduling of energy reserves held and delivered by participating providers in order to contain and restore a frequency excursion. At the time of writing, the ESO utilises four services described in Table 3.1 and illustrated in Figure 3.1.

Table 3.1: Overview of Frequency Response Services [14, 15].

Service Name	Compliance Definition
Primary Frequency Response (PFR)	Full delivery of active power response no more than 10 seconds after the event with a maximum 2 second delay and sustained for a further 20 seconds. It is the dominant means of containing frequency excursions caused by loss of infeed events.
Secondary Frequency Response (SFR)	Full delivery of active power response no more than 30 seconds after the event and sustained for 30 minutes. It plays a vital role in restoring frequency excursions caused by loss of infeed events.
High Frequency Response (HFR)	Full delivery of active power response no more than 10 seconds after the event with a maximum 2 second delay and sustained indefinitely. It is the dominant means of containing frequency excursions caused by loss of load events.
Enhanced Frequency Response (EFR)	Full delivery of response for a 0.5 Hz change from nominal 50 Hz frequency and sustained for 15 minutes, with the capability to fully deliver response within 1 second. This supplementary service for both loss of infeed and loss of load events.

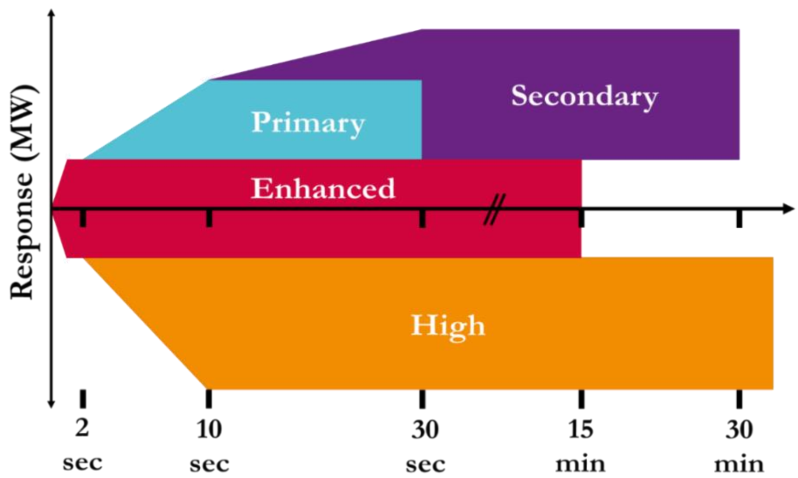
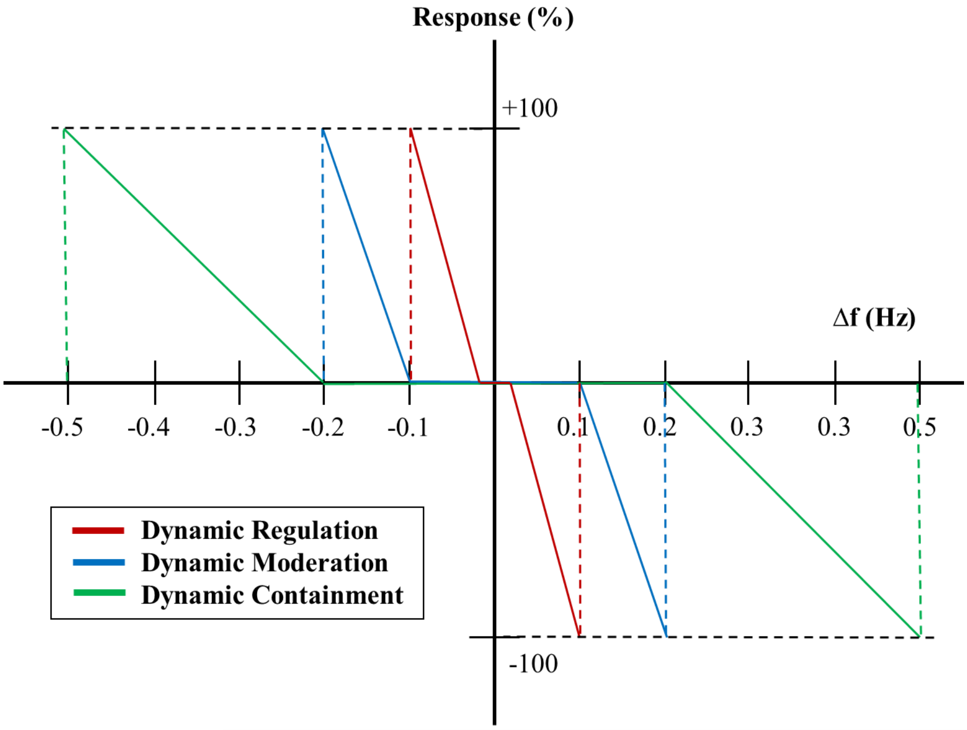


Figure 3.1: Current GB frequency response services [14].

With the exception of EFR (a solely dynamic service), these responses can be dynamic or static. Dynamic frequency responses are services that continuously track frequency changes to provide a proportional response. Static frequency responses are discreet responses to frequency deviations when a frequency threshold[2] is exceeded. Figure 3.2 shows the definitions for future frequency response services proposed by the ESO in [16] and [17].



	Operational Range (-ve dev)	Operational Range (+ve dev)	Max Lag (s)	Max Ramp (s)	Duration (mins)
Dynamic Regulation	0.015 – 0.1		2	8	∞
Dynamic Moderation	0.1 – 0.2		0.5	0.5	20
Dynamic Containment	0.2 – 0.5	0.2 – 0.5	0.5	0.5	20
Static Containment	0.3 – 0.5	0.3 – 0.5	1	N/A	30

Figure 3.2: ESO's draft future frequency response services [16] [17].

According to National Grid ESO, Dynamic Containment will be the first of their proposed products that will be introduced, where assets will be permitted to aggregate within a single GSP. The goal is to procure 1 GW of this product for both low and high frequency events but are expecting an initial 250 MW, with a unit cap of 50 MW. Although this service cannot be stacked with existing products, the ESO aims to maximise stacking opportunities with the rest of the new products; however, they will not permit payment for the same MW/MWh twice [18].

The deadbands for Dynamic Moderation and Dynamic Containment can be used alongside historical 1 second frequency data from the ESO to estimate the number of deadband violations from 2014 to 2019. The results of this study are depicted in Figure 3.3 as yearly totals and Figure 3.4 as monthly totals. The study indicates that the power system is becoming increasingly volatile with more deadband (i.e. the deadbands proposed for Dynamic Moderation and Dynamic Containment) violations occurring in recent years than observed historically.

[2] Based on the details presented in [20], the threshold for static Primary response in 49.6 Hz and the threshold for static Secondary response is 49.7 Hz.

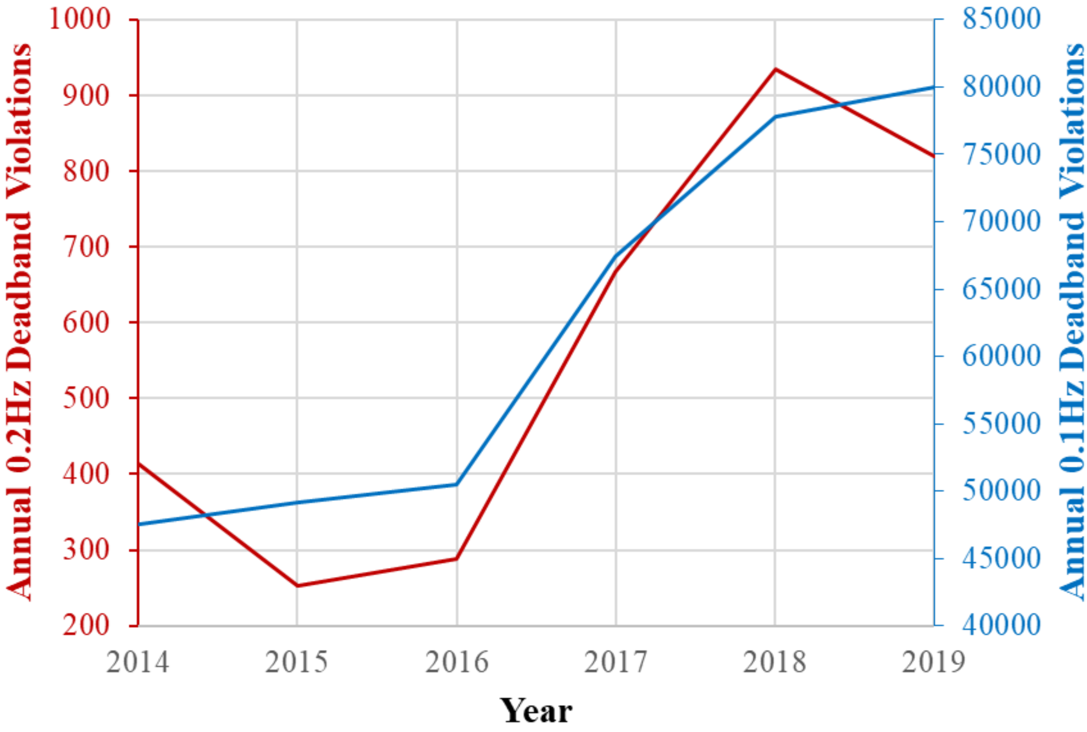


Figure 3.3: Annual violations for 0.1Hz and 0.2Hz deadbands [19].

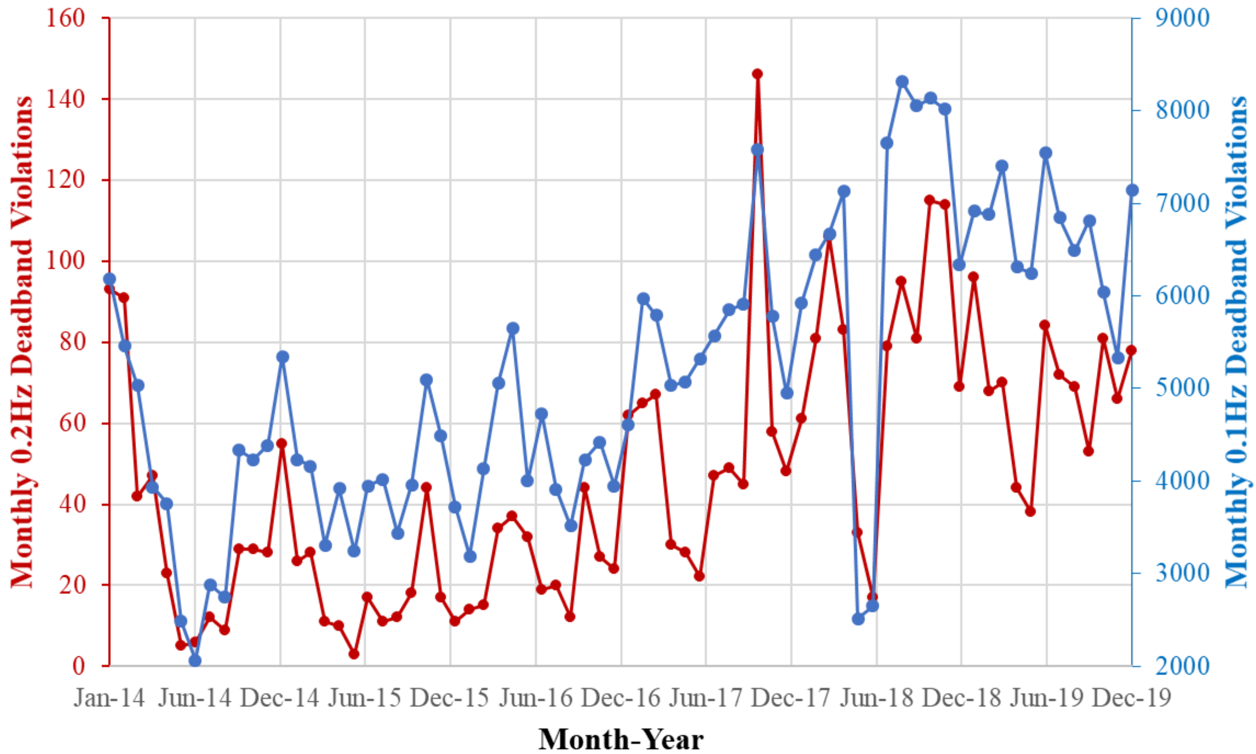


Figure 3.4: Monthly violations for 0.1Hz and 0.2Hz deadbands [19].

4 Power System Model and Validation

A simplified single bus transmission model (SBM) and a frequency studies tool (FEROS) are used in this report. The SBM [20], shown in Figure 4.1, is used to model of GB power system in DigSILENT PowerFactory [21], and FEROS is a tool that is used to operate the model and conduct system studies.

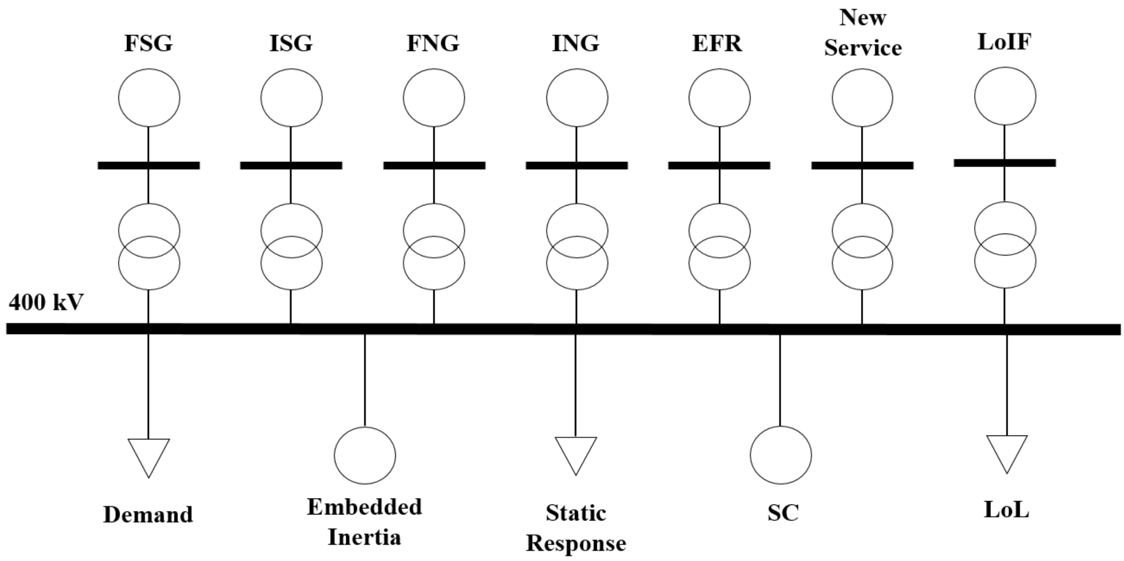


Figure 4.1: Single bus model.

The SBM neglects the spatial distribution of generators and loads, and treats them as being connected to a single busbar. It is an aggregation of elements in the power system based on how they respond to frequency events, allowing for convenient representation of operational conditions and response providers whilst maintaining a reasonably accurate assessment of system frequency behaviour during a loss event. The FSG (Flexible Synchronous Generator) and FNG (Flexible Non-synchronous Generator) elements of the model are the generation elements that provide active power response to a frequency imbalance via controller actions. As a synchronous machine, FSG also provides an inertial response to the frequency event, while FNG does not. The ISG (Inflexible Synchronous Generators) and ING (Inflexible Non-synchronous Generators) elements of the model are generation elements with no controller action in response to a frequency event, however, ISG does provide an inertial response. It should be noted that FNG and ING can also include interconnector imports when applicable to the scenario. Within the dispatch, an inertia constant of 6 seconds is assumed for all gas units and 4 seconds for all other synchronous generators. The EFR and Static Response elements represent their corresponding frequency services, while SC allows representation of Synchronous Compensators. The Demand element refers to demand on the transmission system, i.e. the power exported from the transmission network, and includes pumped hydro, interconnector exports and net unmetered embedded generation. The default value for the sensitivity of demand to frequency changes is 2.5%/Hz [14]. The Embedded Inertia element represents the inertia associated with synchronous machines (generators and motors) operating within the distribution network. Based on discussions with industry experts embedded inertia is assumed to be equivalent to an inertia constant of 1.83 seconds as applied to the total transmission system demand. A loss of infeed event is represented by the LoIF element and a loss of load event is represented by the LoL element. It should be noted that dynamic Secondary response, as defined in GB today, is the extended delivery of Primary response, no 'secondary-only' dynamic frequency response product or service exists. In practice, dynamic Primary and Secondary responses are delivered by the same plant; the provider delivers a response that meets the requirements of both services. Therefore, unless otherwise stated, the modelling methodology used in this report assumes no distinct dynamic Secondary response product or service.

The SBM has been used to replicate the frequency event that occurred in Britain on the 9th of August 2019 as detailed in [22]. The public report of the event provides unusually complete details of the magnitude and timing of the loss events, the system conditions during the event and the magnitude of the frequency response that was provided by the GB ESO. The 9th of August event is simulated by applying these known parameters to the model alongside the underlying assumptions of the SBM. Although the default assumption for dynamic Primary response are its statutory requirements, in replicating the event, the speed of delivery of dynamic Primary response is tuned given knowledge from discussions with industry experts that the real-world delivery of the service usually slightly outperforms the statutory requirements. All other responses are modelled in line with their statutory definitions. The results of the simulation are compared with real 1 second frequency data from the time of the event in Figure 4.2. It is found that the comparative frequency and RoCoF traces of the simulated event are in close agreement with the real system measurements, which acts as a strong validation of the model's ability to accurately replicate system frequency.

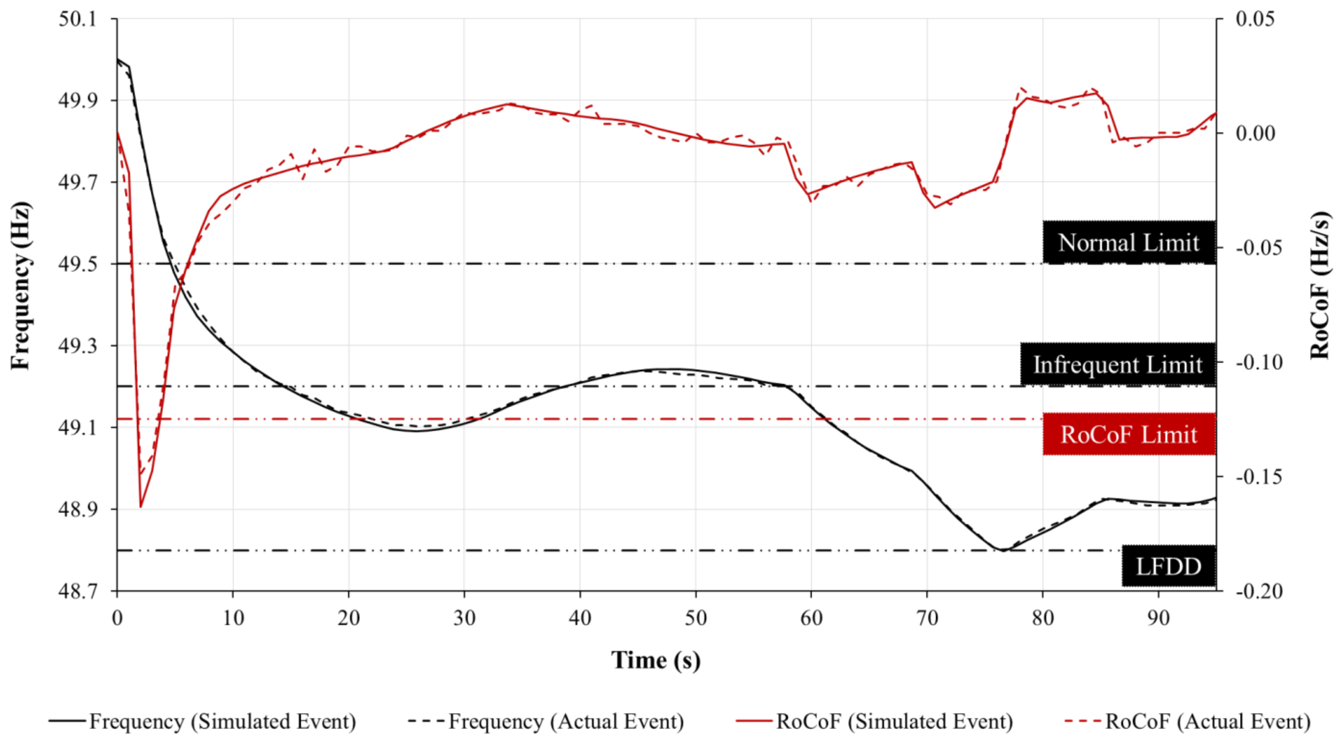


Figure 4.2: Replicating the 9th of August 2019 event.

Figure 4.3 shows how the frequency behaviour during the 9th of August 2019 event would be impacted if all the scheduled response, was delivered. The results indicate that if all the response scheduled to be delivered during the event had been delivered, the events would have been contained within the infrequent los risk frequency conditions. An overview of both scenarios is presented in Table 4.1.

Table 4.1: Scheduled and Delivered Frequency Response

Scenario	Demand (GW)	Inertia (GVAs)	Static PFR (MW)	Static SFR (MW)	Dynamic PFR & SFR (MW)	EFR (MW)
Delivered	29	220	230	198	480	165
Scheduled			231	285	565	227

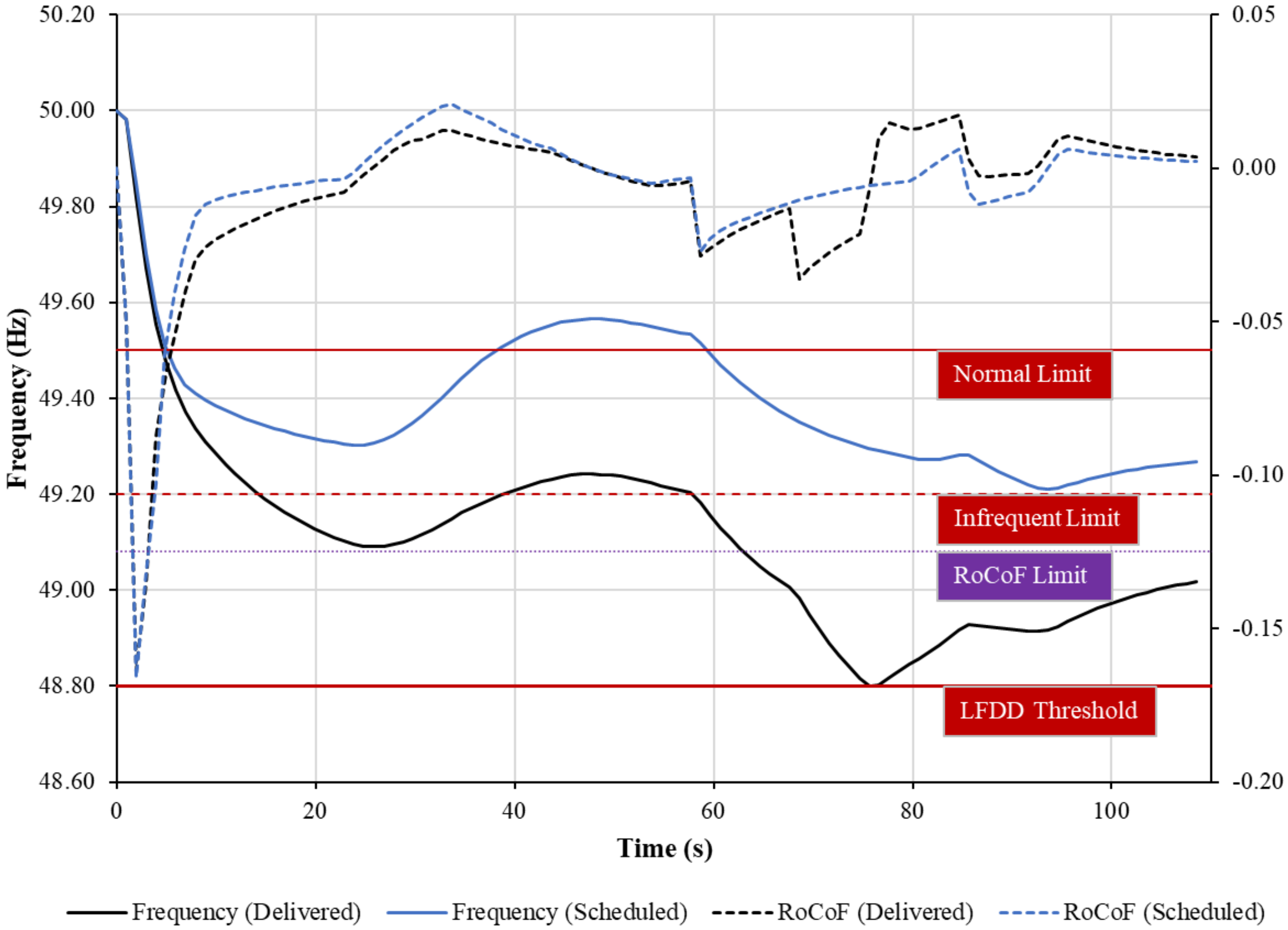


Figure 4.3: Plots comparing the scenarios from Table 4.1.

Unless otherwise stated the subsequent studies and results presented in this report use the tuned SBM (Figure 4.2) to simulate the GB power system in 2025, with the following assumptions made:

- the loss of infeed[3] is simulated as a single instantaneous[4] loss of power supply such that frequency is contained within acceptable frequency conditions as detailed in Table 2.1;
- demand is modelled as total demand in the power system including exports;
- dynamic response services are simulated as defined, with 227 MW of EFR dispatched;
- it is assumed that Primary response is delivered by gas and hydro plants in the FSG element of the model, and frequency is contained using the least response reserve holding as estimated by FEROS;
- the flexible synchronous generator is modelled as 70% loaded with 30% headroom for delivery of response;
- generation background is based on the GB ESO's Two Degrees future energy scenario in [22];
- average availability of nuclear plants is assumed to be 77% for older plants and 95% for the newer plants [23];
- in the initial dispatch of each scenario, baseload power supply (met by nuclear) is first in the merit order;

[3] In the studies presented in this report, the results of loss of load events are roughly equivalent to the results for the loss of infeed events, and as a result only loss of infeed events will be investigated. The main distinction between the two is the loss of demand sensitivity in a loss of load event that is absent in a loss of infeed event, however, at 2.5%/Hz this is equivalent to between 12.5 MW for a normal loss event at a 1 GW loss risk and 36 MW for an infrequent loss event at a 1.8 GW loss risk. Since dynamic Secondary response is modelled as an extension of dynamic Primary response, the modelled service is the low frequency equivalent of dynamic High frequency response. All other dynamic services have symmetrical components, and static response services exist for both high and low frequency events.

[4] This differs from the chain of events simulated loss that was used to tune the model.

- if an inertia target is used then flexible synchronous generation is dispatched next in the merit order until the inertia (and power demand) target is reached, if all flexible synchronous generation has been used and the inertia target has not been reached, then inertia is increased by dispatching the remaining synchronous generation and, if required, additional inertia via synchronous compensation. If the inertia target has been reached but power demand isn't balance then the shortfall is met by non-synchronous dispatch;

- if instead a non-synchronous dispatch is the target, then non-synchronous power is dispatched next in the merit order until the target has been achieved, if the power demand has not been reached then flexible synchronous generation is dispatched next and, if required, inflexible synchronous generation is next in the merit order; and

- when frequency response reserve is being optimised, each scenario is re-dispatched to allow for the provision of dynamic Primary and Secondary response via the flexible synchronous generator. However, this optimisation is constrained by the fixed baseload of minimum nuclear power supply, any defined minimum non-synchronous penetration or inertia target, and the available flexible synchronous generation background.

5 Assessing Future Frequency Response Services

Scenarios based on inertia values, shown in Table 5.1, were derived using the swing equation [24], loss risks and the RoCoF limits. The distinction between embedded inertia and generation inertia is ignored in this study, and instead inertia values represent total system inertia. It is also important to note that all scenarios assume a demand of 30 GW, and RoCoF and load shedding schemes are deactivated. Static Primary and Secondary response are assumed to be available at 250 MW each, with the service definitions delivered as modelled in the tuned single bus model.

Table 5.1: Scenarios devised to test the future frequency response concept.

Scenario	RoCoF Limit (Hz/s)	Loss Risk Limit (GW)	Inertia (GVAs)	Frequency Condition
1	0.125	1	200	Normal loss
2		1.32	264	Infrequent Loss
3		1.32	264	Normal loss
4		1.8	360	Infrequent Loss
5	0.5	1	50	Normal loss
6		1.32	66	Infrequent Loss
7		1.32	66	Normal loss
8		1.8	90	Infrequent Loss
9	1	1	25	Normal loss
10		1.32	33	Infrequent Loss
11		1.32	33	Normal loss
12		1.8	45	Infrequent Loss

Existing and proposed dynamic frequency response services are tested and compared using the scenarios in Table 5.1. The studies presented are for 60 second simulations to represent the window for compliance with the SQSS requirements presented in Table 2.1, as a result frequency containment is only valid for a simulation that reaches a new steady state at frequency greater than or equal to 49.5 Hz.

As expected, it can be seen in Figure 5.1, that existing services are sufficient for frequency events when the power system is constrained within existing RoCoF limits. However, in Figure 5.2, it is observed that existing services are inadequate for normal loss risk frequency conditions as the power system tends towards 0.5 Hz/s RoCoF. Lastly, as the power system tends towards 1 Hz/s (in Figure 5.3), existing services become inadequate. This supports previous work, and indeed the direction of the industry; i.e. the increasing need for faster than traditional dynamic frequency response services for power systems tending towards lower inertia.

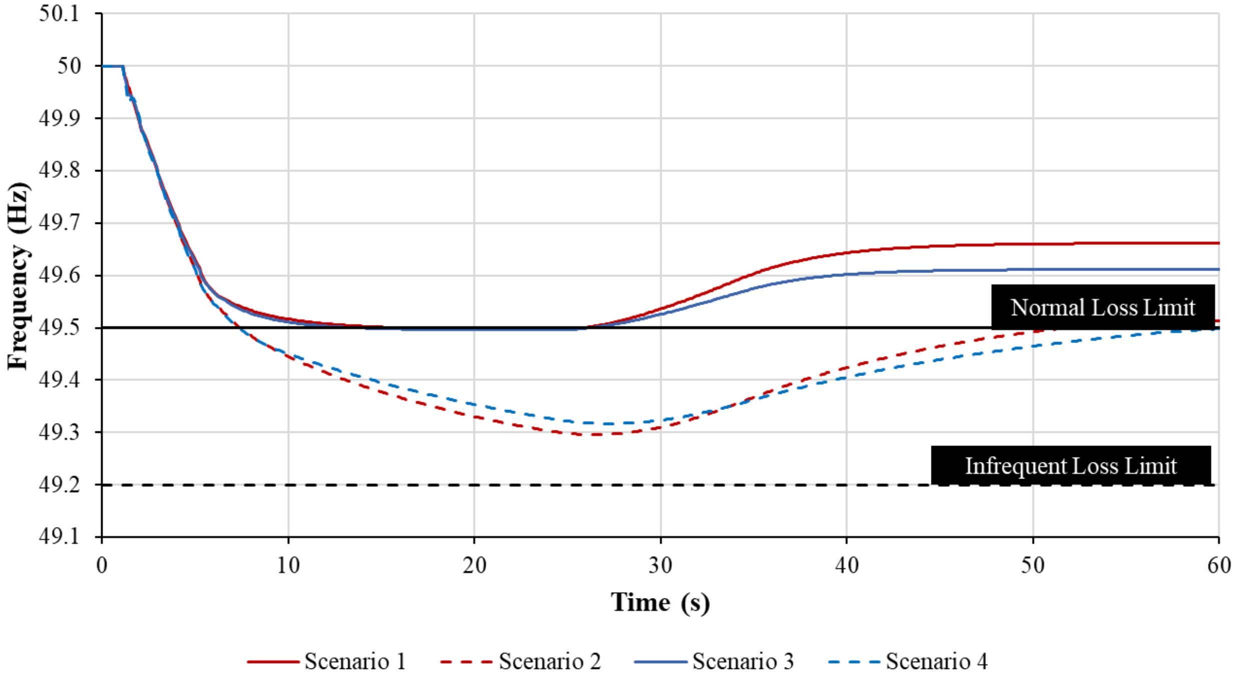


Figure 5.1: Frequency plots for both pairs of loss risks at 0.125 Hz/s RoCoF limit (Existing services).

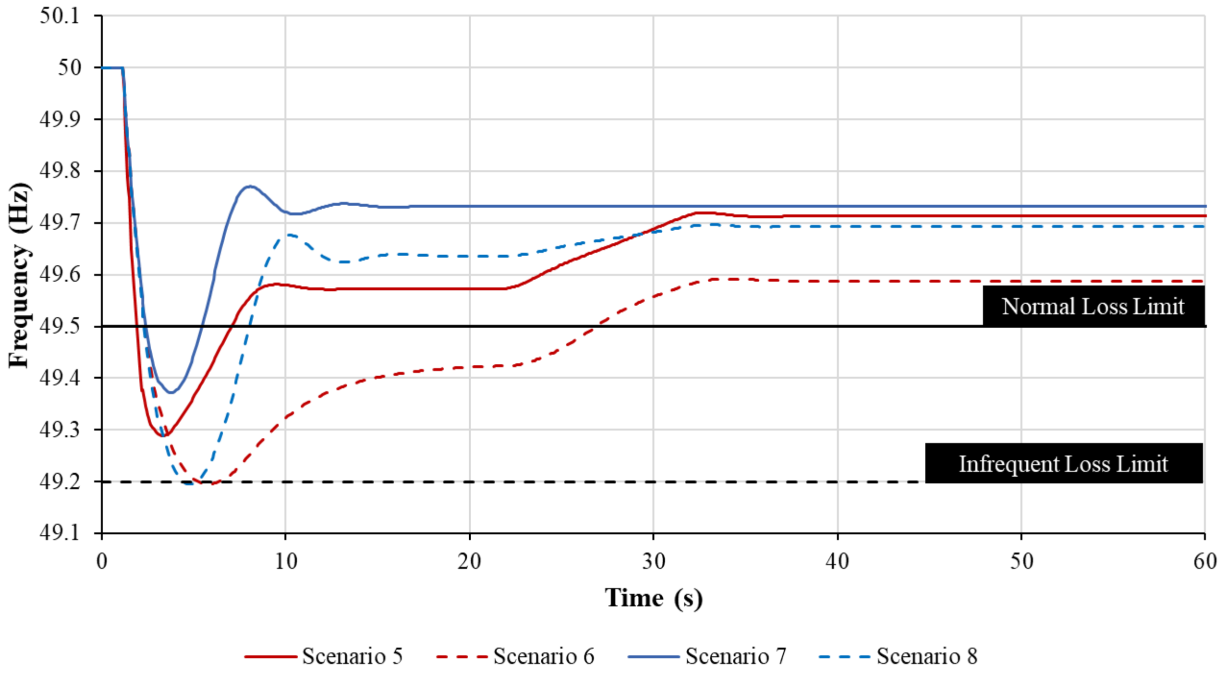


Figure 5.2: Frequency plots for both pairs of loss risks at 0.5 Hz/s RoCoF limit (Existing services).

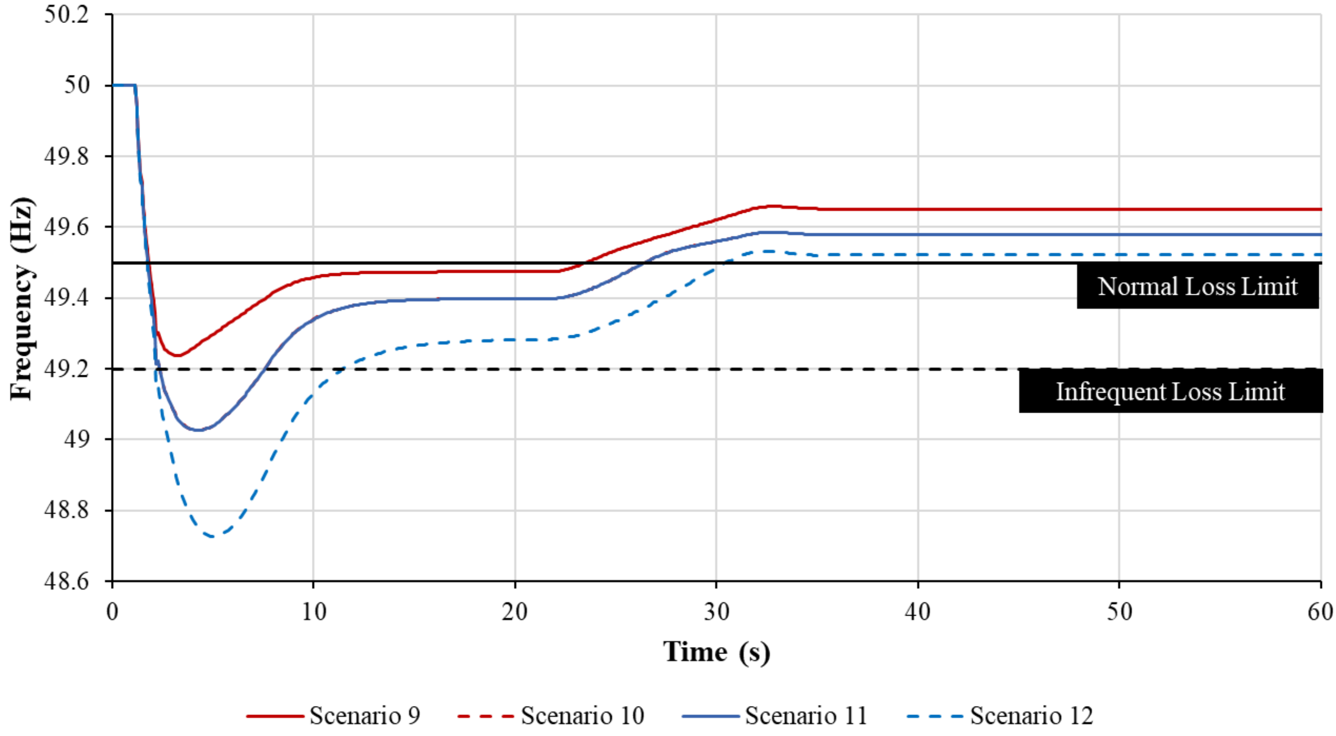


Figure 5.3: Frequency plots for both pairs of loss risks at 1 Hz/s RoCoF limit (Existing services).

The GB ESO proposed a suite of dynamic frequency response services, designed to be improve on existing services. The performance of these services, as they are defined, can be considered by utilising the scenarios in Table 5.1; however, the 0.125 Hz/s scenarios can be ignored since existing services are sufficient and there is accelerated programme in place to update the settings of legacy RoCoF relays before 2025.

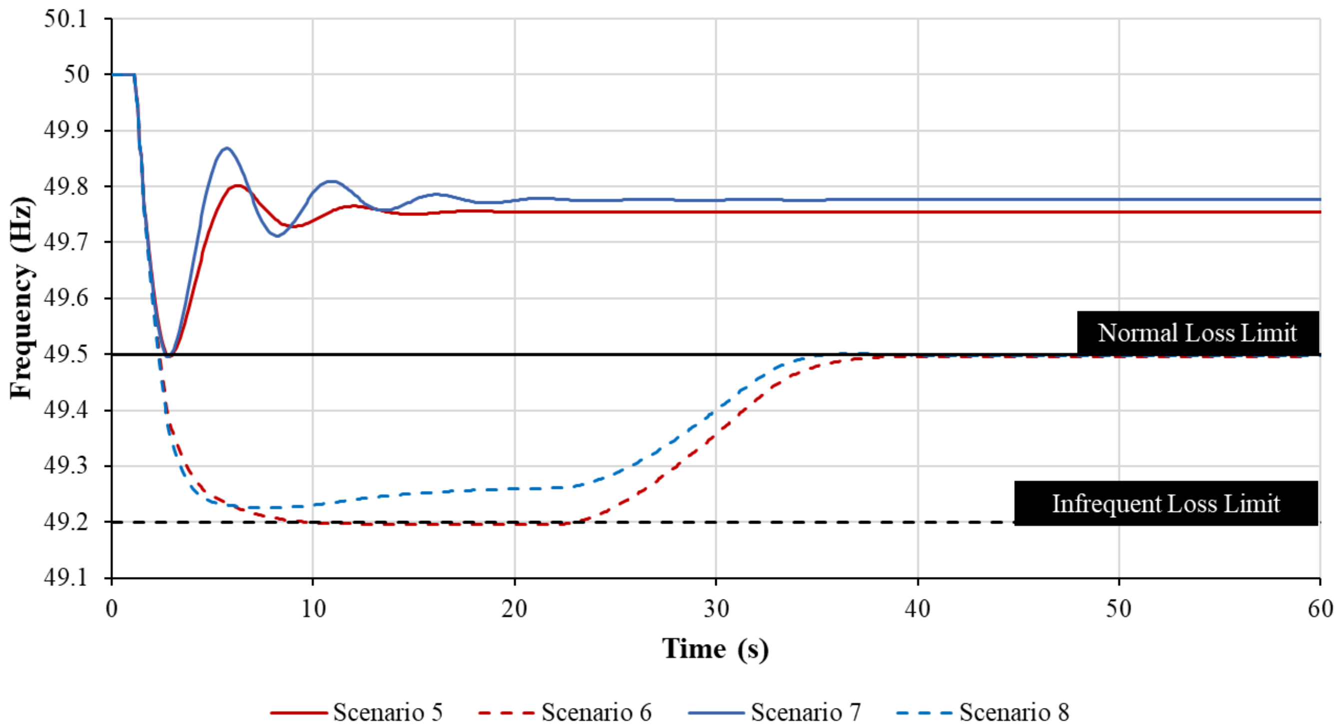


Figure 5.4: Frequency plots for both pairs of loss risks at 0.5 Hz/s RoCoF limit (ESO draft proposal services).

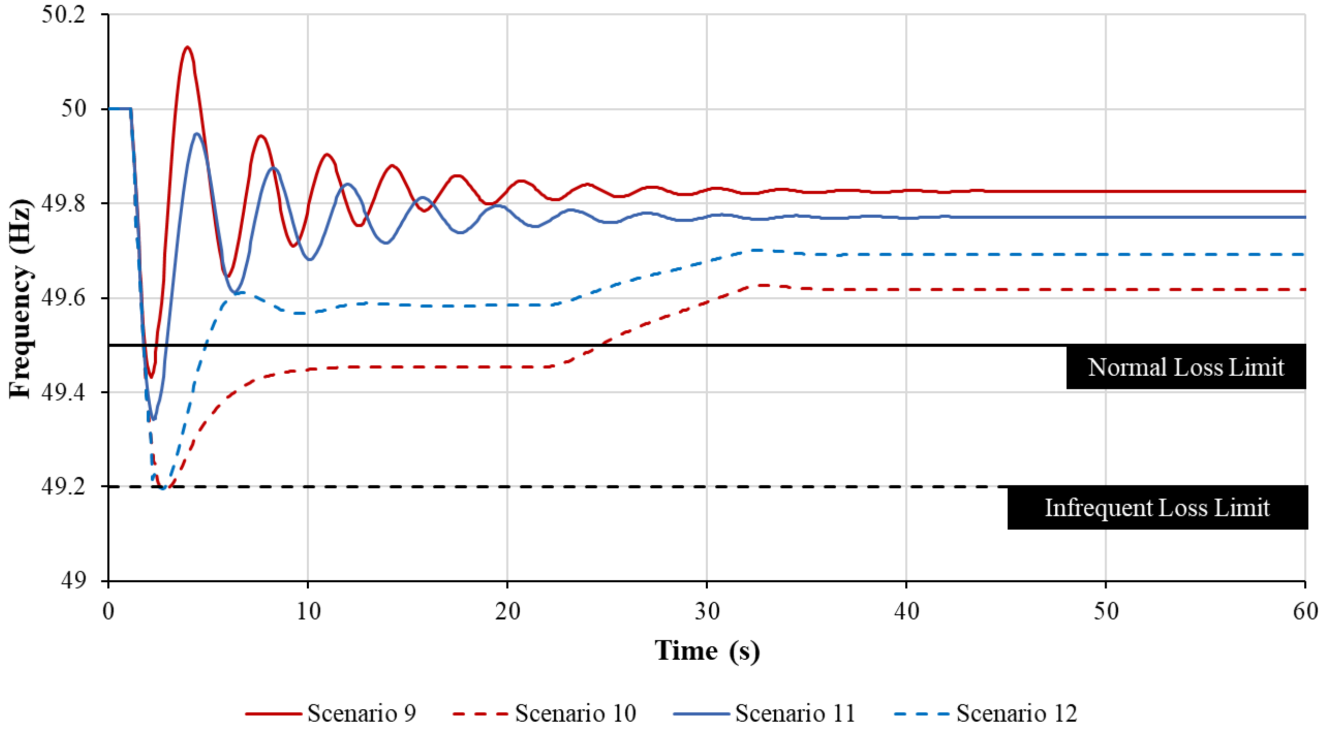


Figure 5.5: Frequency plots for both pairs of loss risks at 1 Hz/s RoCoF limit (ESO draft proposal services).

Comparing the plot for existing and proposed services (Figure 5.2 and Figure 5.4, and Figure 5.3 and Figure 5.5), it is evident that the services proposed by the ESO are a significant improvement to the existing services[5], and while there is some oscillation when addressing a normal loss risks, there is also strong damping[6]. A key factor influencing the appearance of the oscillations in these simulations is how quickly the event needs to be contained in relation to the detection and activation delay of the frequency response services. In Figure 5.5, increasing the response reserve in scenarios 9 and 11 would also dramatically increase the oscillations observed, since the service isn't acting quickly enough; i.e. the events must be contained within 0.5 s and the delay of the fastest service is 0.5 s. The dampened oscillations observed (e.g. Scenarios 5 and 7 in Figure 5.4 with a 1 s containment time and scenarios 9 and 11 in Figure 5.5 with a 0.5 s containment time) indicate a starting point beyond which the risk of containment failure and frequency instability increases. Further study shows that the boundary occurs when frequency needs to be contained to within 0.5 Hz of nominal 50 Hz frequency in less than 1.2 seconds, equivalent to 60 GVAs or 79.2 GVAs for a 1 GW or 1.32 GW normal loss risk, respectively. The data presented in the system operability framework (SOF) 2016 report indicates that across all four future energy scenarios the minimum inertia is about 70 GVAs across all four scenarios in 2025/26. This indicates that while it is unlikely for the boundary to occur for 1 GW normal loss risk, it can occur up to 1.3% of the year in 2025/26[7] for a 1.32 GW normal loss risk. Looking ahead to 2030 using data from Antares based on a European market dispatch in hourly resolutions for a high wind[8] scenario (with wind displacing gas), it is observed that with the inclusion of embedded inertia (at the assumed inertia constant) it is unlikely that there would be an instance where the power system is dispatched at less than 60 GVAs of inertia. However, when embedded inertia is excluded the likelihood of the boundary occurring increases to about 16% of the year, as depicted in Figure 5.6. On the other hand, it is observed that with the inclusion of embedded inertia the power system is dispatched at less than 79.2 GVAs of inertia about 1% of the year, which increases to 22% of the year when embedded inertia is excluded.

[5] When simulating the ESO's proposed services, dynamic Primary response is replaced by Dynamic Regulation as it is defined with the worst-case delivery of the service assumed, i.e. with a 2 second delay and 8 second delivery.

[6] It is acknowledged that improvements to the control strategy deployed could provide even stronger damping, but this does not represent a worst-case scenario and therefore simplified active power controllers that do the minimum required to comply with the definition of the frequency response services are deployed in these studies.

[7] 0.59% of the year in No Progression, 0.95% of the year in Slow Progression, 1.29% of the year in Gone Green and 1.32% of the year in Consumer Power.

[8] An average of 43.87% of non-synchronous generation across every hour of the year with an hourly minimum of 4.25% and maximum of 92.98%. In terms of system non-synchronous penetration this is an average of 40% with a minimum of 4.27% and a maximum of 89.76%.

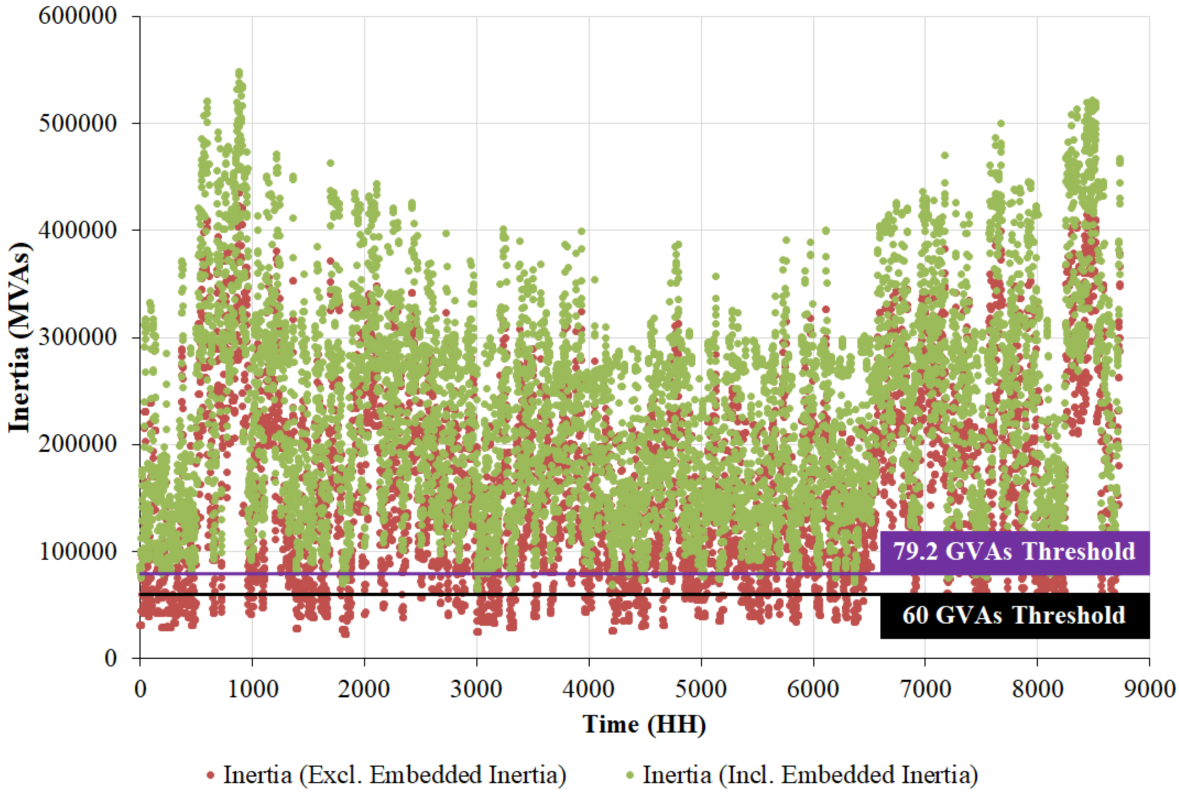


Figure 5.6: Inertia dispatched in 2030 for a high wind penetration scenario based on market dispatch.

It is reiterated that the defined boundary does not necessitate containment failure or instability, but rather it identifies a point beyond which the risk or one or both increases. The likelihood of this risk can be mitigated by improved control topologies[9] (details of which fall beyond the scope of present work), they can also be remedied if the proposed services activate quicker than defined, or if a fast-acting frequency response service is defined. The value in the provision of fast-acting frequency response is in RoCoF containment, or more precisely in slowing down RoCoF until slower frequency response services can activate. A fast-acting response could be an inherent characteristic of the power system e.g. synchronous inertia, or it could be dispatchable reserve such as synthetic inertia (SI), or some other fast-acting frequency response product.

5.1 Fast Acting Dispatchable Frequency Response Services

A simplified synthetic inertia service is modelled to investigate the impact of the recovery period and fast-acting service on frequency containment. This synthetic inertia service is defined as a service that fully activates in 250 ms, sustains delivery for 1 s and recovers for 20 seconds without exceeding -5% of the active power response delivered, as illustrated in Figure 5.7.

The subsequent plots show the results of studies conducted for scenarios 5, 6, 9 and 10[10] using the ESO's proposed services and 150 MW of synthetic inertia as it is defined in Figure 5.7. From Figure 5.8 and Figure 5.9 it can be seen that as the inertia reduces the positive impact of a synthetic inertia service increases, with the most dramatic improvement observed in scenario 9 of Figure 5.9. It is also observed that at the relatively higher inertia of 66 GVAs in scenario 6 (Figure 5.8), the recovery period of synthetic inertia has a detrimental impact on overall frequency containment. The results suggest the value of this sort of service, and while the recovery period could have a detrimental effect, constraints could be imposed to produce a service definition that minimises any detrimental impact on frequency containment, while maximising the benefits of the service.

[9] E.g. improved damping could be used to reduce oscillations.
[10] At 50 GVAs, 66GVAs, 25 GVAs and 33 GVAs respectively.

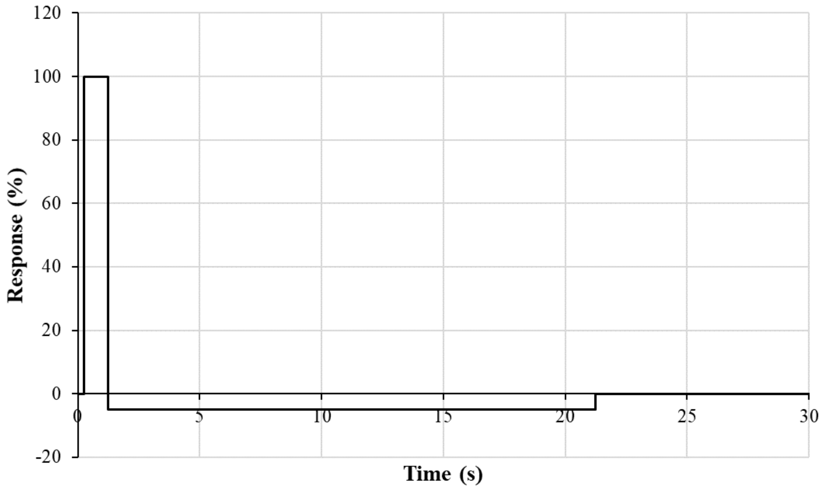


Figure 5.7: Simplified definition of a controlled synthetic inertia profile.

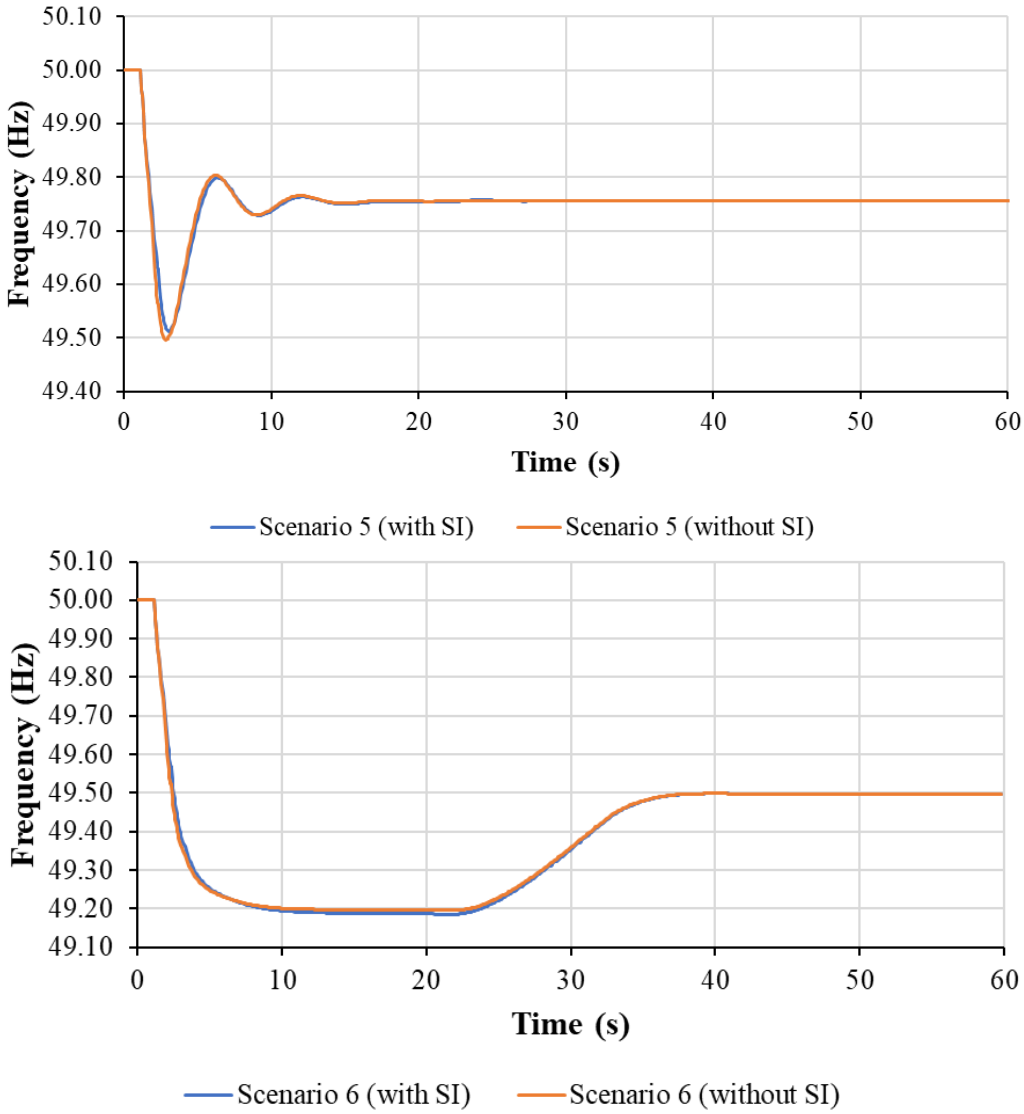
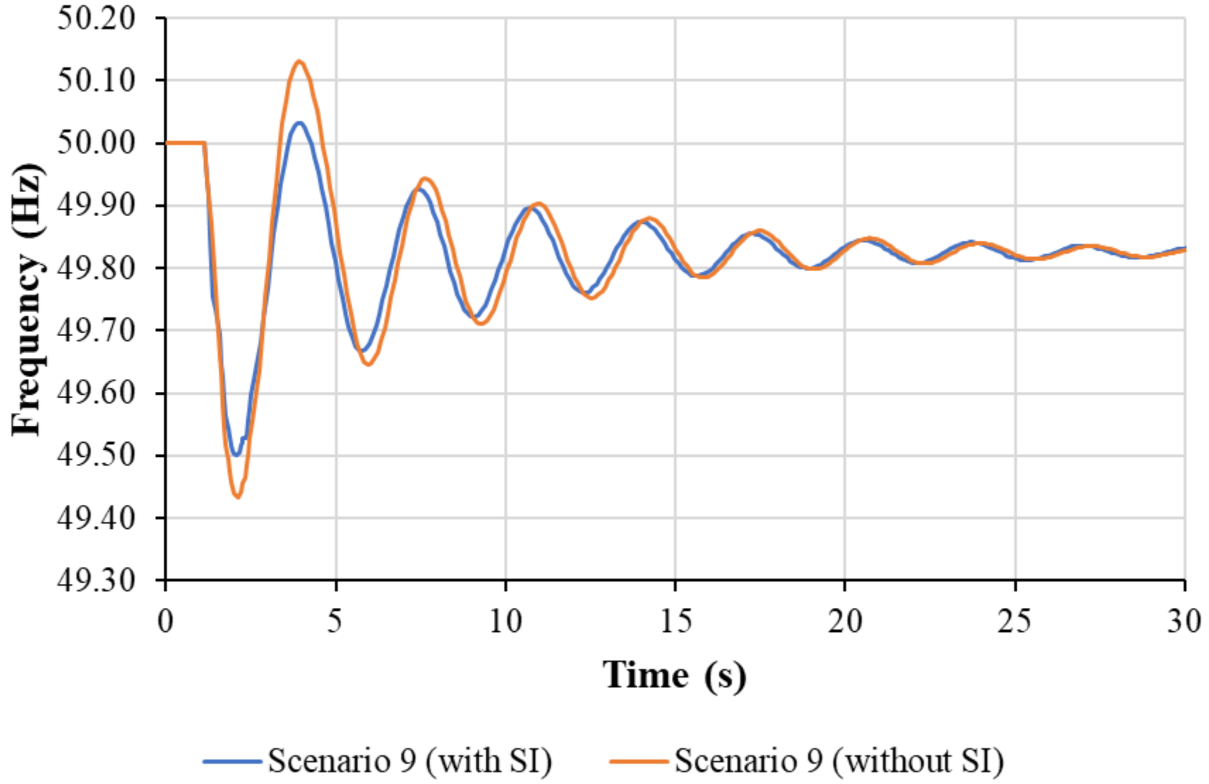


Figure 5.8: The impact of 150 MW of synthetic inertia with a controlled recovery period on normal and loss risks for a 0.5 Hz/s RoCoF limit.



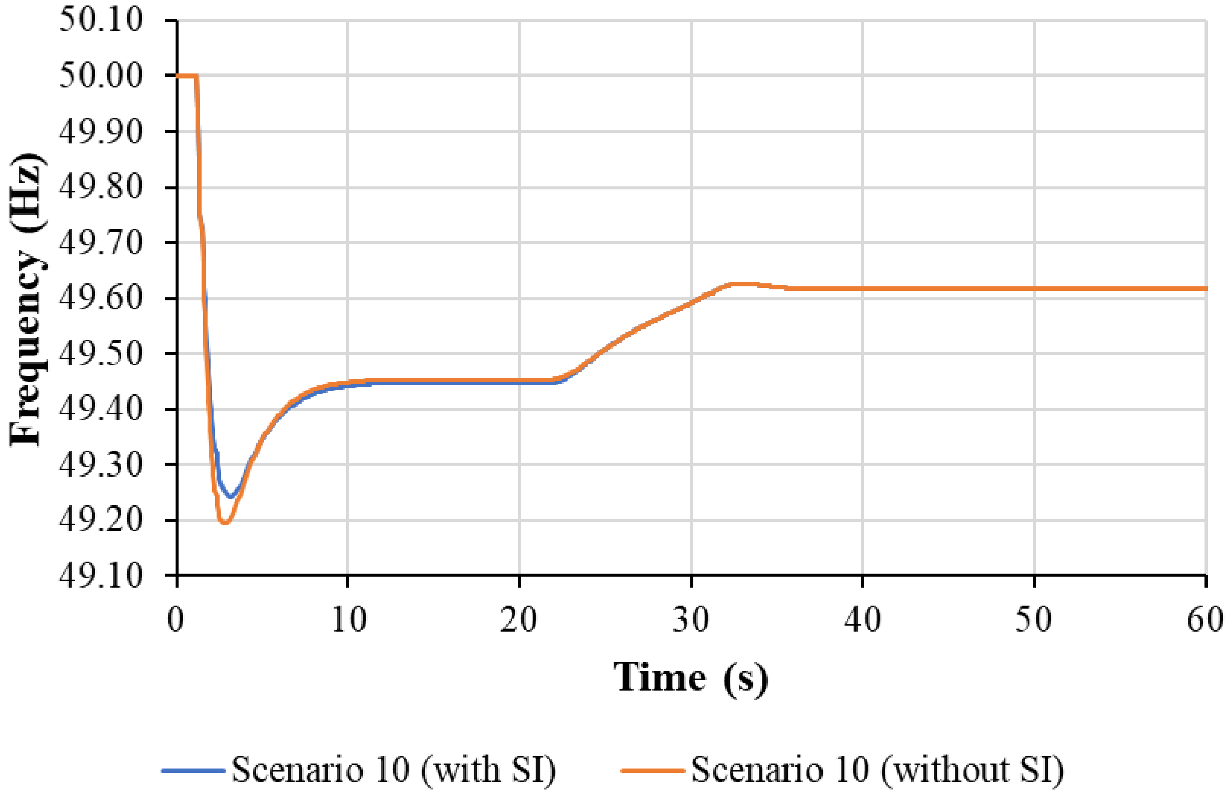


Figure 5.9: The impact of 150 MW of synthetic inertia with a controlled recovery period on normal and loss risks for a 1 Hz/s RoCoF limit.

Although the deployment of 150 MW synthetic inertia, in addition to the proposed ESO services, was able to improve frequency containment in scenario 9 (see Figure 5.9), the service had only minimal impact on damping the oscillatory behaviour. Synthetic inertia is a fast-acting frequency response service and therefore capable of reducing the amplitude of the oscillation (as observed in the initial swing), however, since the service isn't sustained and is only available for 1 second the impact is restricted.

A hypothetical service called Improved Frequency Containment (IFC) illustrates impact of a fast-acting sustained service via the results presented in Figure 5.10. IFC is defined as a frequency response service with a deadband of 0.015 Hz, and a 250 ms detection and activation delay. IFC is designed to fully deliver response up to 500 ms of the event, such that 100% of the response is delivered for a 0.5 Hz frequency deviation. This service is sustained for the duration of the simulation but it is also capable of deactivation. In this study a controller deactivation, when simulated, occurs after response has been sustained for 30 seconds at a rate no faster than 0.05 pu/s[11]. Figure 5.10 shows a comparison of the performance of frequency response services in scenario 9, where the ESO services refer to Dynamic Regulation, Dynamic Moderation and Dynamic Containment services.

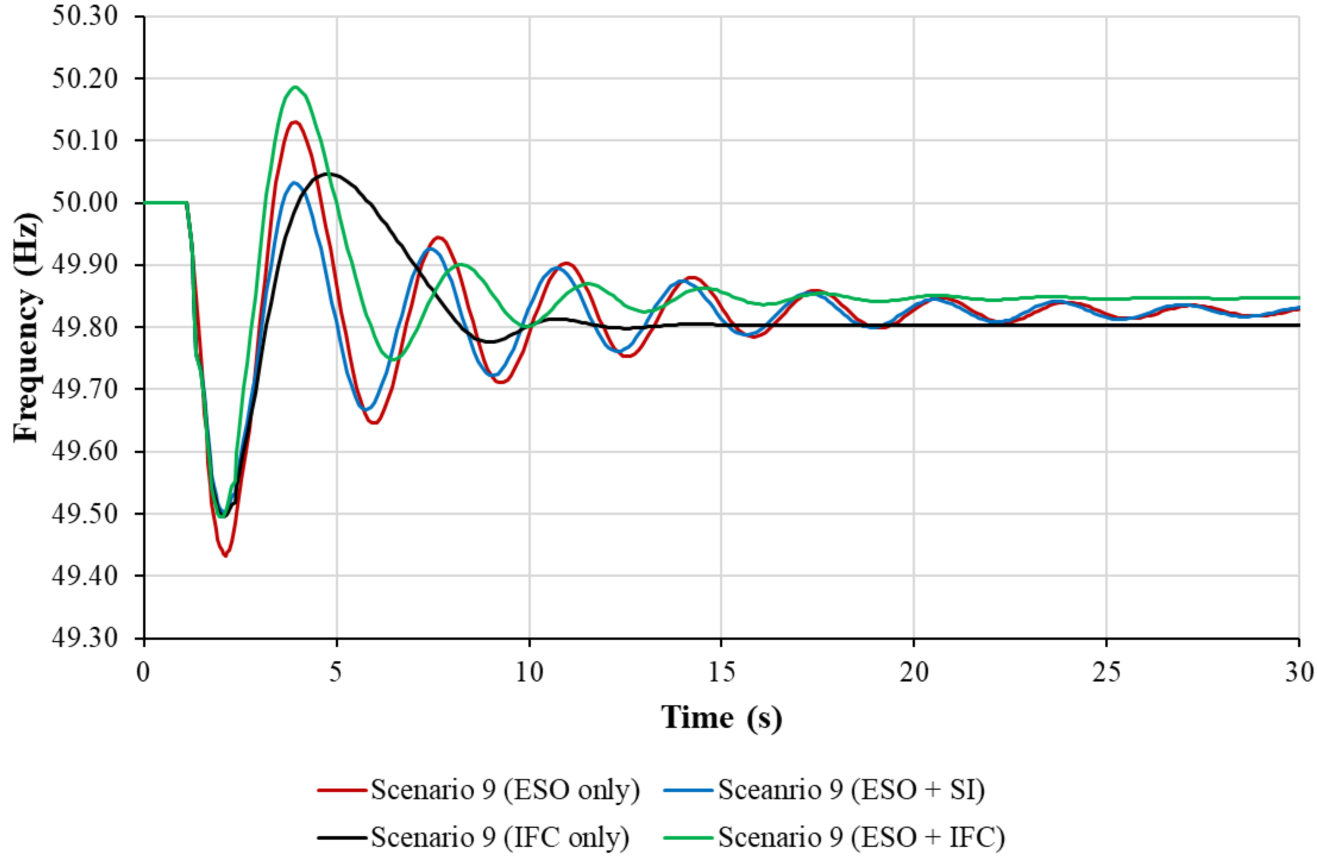


Figure 5.10: Modified versions of scenario 9 showing the performance of frequency response services for a normal loss event[12].

It is observed that in comparison to the ESO's proposed future frequency response services alone (red line), the inclusion of the fast-acting services (SI and IFC) to the ESO's services improves frequency containment in scenario 9, however, unlike SI (blue line), IFC (green line) exhibits strong damping when used alongside the ESO's proposed services. When deployed alone, i.e. used as a frequency response service alongside only EFR and static responses, the IFC service (black line) is capable of containing the event and quickly damping out the initial overshoot[13].

[11] This ramp down rate also applies when the service reduces response delivered even if the minimum sustain time hasn't elapsed.
[12] The services depicted in these plots are used alongside EFR and static response as they were originally dispatched in scenario 9.
[13] It should be noted that in all cases, dynamic response services use simplified active power controllers that meet minimum service definition requirements.

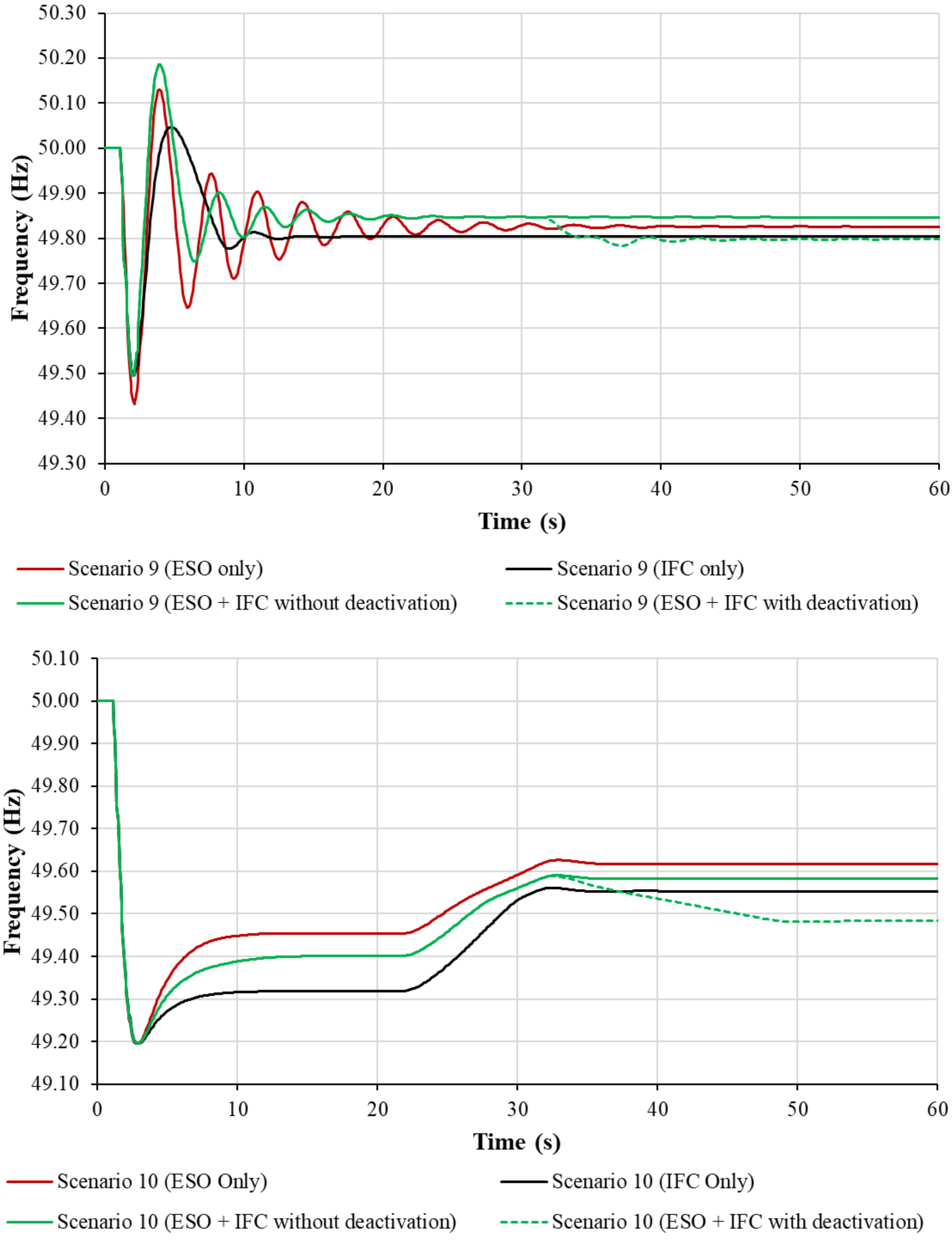


Figure 5.11: Comparing the performance of services using scenarios 9 and 10.

In the comparisons done for using scenarios 9 and 10, the IFC-only simulations require less active power reserve to contain the event than the ESO's proposed services; about 17% for the normal loss risk and about 26% for the infrequent loss risk. It is also observed from Figure 5.11 that when paired with the ESO's proposed services, frequency behaviour during a normal loss event is still acceptable when IFC deactivates after 30 seconds of response delivery, since the loss of IFC is balanced by other active services, but the impact of the deactivation is more dramatic in the infrequent loss event (scenario 10) than in normal loss event (scenario 9). It should be noted that when IFC is deployed as the sole (or major) dynamic response service, any deactivation would need to be balanced by a supplementary secondary service. Further work on the IFC service should consider a deactivation definition linked to Fast Reserve[14], with a deactivation ramp down rate that is sufficiently defined to facilitate the handover of service requirements.

5.2 System Non-Synchronous Penetration Limits

At present, non-synchronous dispatch limits in the GB system are defined in terms of inertia, which is calculated via the swing equation [25]. In Ireland, the non-synchronous dispatch is managed using the System Non-Synchronous Penetration (SNSP) ratio [26]. The Irish system operator, EirGrid, has an operational policy that limits the proportion of demand that can be met at any one time from non-synchronous sources based on the SNSP, set in 2018 to 65% [27]. The SNSP limit is the SNSP ratio that if exceeded would lead to a breach of frequency and RoCoF limits, unless corrective actions are taken by the system operator. Equation (1) defines the SNSP ratio, where 'Total Demand' includes interconnector exports, and 'NSG' refers to non-synchronous generation. It should be noted that this metric makes assumptions on the inertia and frequency response dispatched in the power system.

$$SNSP = \frac{NSG + Imports}{Total\ Demand} \qquad (1)$$

The scenarios presented in Table 5.1, for normal and infrequent loss risk events, has been adapted to facilitate the SNSP studies presented in this section. The 12 scenarios in Table 5.2 are used to investigate both the existing and future services proposed by the ESO. Instead of an inertia constraint, as is used in the previous studies, each scenario is dispatched for a given level of demand and non-synchronous power dispatched, so that a spread is achieved that included multiple demand levels with each level considering a range of non-synchronous power dispatch.

Table 5.2: Scenarios devised to investigate the impact of the services on non-synchronous penetration limits.

Scenario	RoCoF Limit (Hz/s)	Loss Risk Limit (GW)	Frequency Condition
1	0.125	1	Normal loss
2		1.32	Infrequent Loss
3		1.32	Normal loss
4		1.8	Infrequent Loss
5	0.5	1	Normal loss
6		1.32	Infrequent Loss
7		1.32	Normal loss
8		1.8	Infrequent Loss
9	1	1	Normal loss
10		1.32	Infrequent Loss
11		1.32	Normal loss
12		1.8	Infrequent Loss

The study presented in this section is concerning the system non-synchronous penetration limits of the GB power system in 2025, where the following assumptions have been made:

- the loss of infeed is simulated as an instantaneous loss of power supply such that frequency is contained within acceptable frequency conditions as detailed in Table 2.1;
- demand is modelled as total demand in the power system including exports;

[14] Or a future service that replaces the functions of Fast Reserve.

- the distinction between embedded and generation inertia is ignored, and embedded inertia is not explicitly modelled;
- the inherent frequency response of total system demand (demand sensitivity) is applied as 2.5%/Hz of total system demand;
- dynamic response services are simulated as defined, with 227 MW of EFR dispatched;
- static response services are simulated as applied in the tuned SBM model with a fixed availability of 250 MW each for Primary and Secondary static response;
- the delivery of Primary response is simulated as applied in the tuned SBM model;
- it is assumed that Primary response is delivered by gas and hydro plants in the FSG element of the model, and frequency is contained using the least response reserve holding as estimated by FEROS;
- the flexible synchronous generator is modelled as 75% loaded with a 25% headroom for delivery of response;
- generation background is based on the GB ESO's Two Degrees future energy scenario in [22];
- average availability of nuclear plants is assumed to be 77% for older plants and 95% for the newer plants [23];
- in the initial dispatch of each scenario, baseload power supply (met by nuclear) is first in the merit order;
- a non-synchronous dispatch is a defined constraint, so non-synchronous power is dispatched next in the merit order until the target has been achieved, if the power supply does not meet demand then flexible synchronous generation is dispatched next and, if required, inflexible synchronous generation is next in the merit order; and
- when frequency response reserve is being optimised each scenario is re-dispatched to allow for the provision of Primary, Secondary and High frequency response via the flexible synchronous generator. However, this optimisation is constrained by: the amount of frequency response that the flexible synchronous generator must hold as reserve in the headroom; the fixed baseload of minimum nuclear power supply; the defined minimum non-synchronous penetration; and the available flexible synchronous generation background.

Using these assumptions 24 scenarios were simulated (12 scenarios for existing frequency response services and 12 for future frequency response services) for a demand and non-synchronous dispatch range of 20 – 70 GW. The results of this study are presented in Figure 5.12 to Figure 5.17, where the solid lines are trends for normal loss events, the broken lines are trends for infrequent loss events, the red lines are trends for the current normal and infrequent loss risk pair (1 GW and 1.32 GW), and the blue lines are trends for the future normal and infrequent loss risk pair (1.32 GW and 1.8 GW). Considering these plots, it can be seen that there is little difference between the trends of the 0.5 Hz/s RoCoF limit and 1 Hz/s RoCoF limit, while there is a significant different between the 0.125 Hz/s RoCoF limit and the other two limits. A few factors limit the penetration of non-synchronous power dispatch including: minimum baseload power from nuclear plants; available energy responses and flexible synchronous plant; acceptable frequency conditions; and RoCoF limits.

At the lower RoCoF limit of 0.125 Hz/s, the RoCoF limit is the dominant constraint across the trends, however, once this limit is relaxed the scenarios can be pushed to the maximum penetration of non-synchronous power dispatch, limited by the availability of frequency response reserve, minimum baseload power from nuclear power plants, and the capability of the scenario to contain the event within acceptable frequency conditions[15]. It should be noted that the oscillations previously observed are ignored as a constraint in these studies. It is recommended that while the system non-synchronous penetration (SNSP) trends produced in Figure 5.12 to Figure 5.17 consider frequency containment, further consideration should include the risk of frequency instabilities, as well as a broader representation of the range of factors influencing the likelihood of containment. That said, simplified mathematical relationships can be employed

[15] It should be noted that 60 seconds as a fixed value was chosen for simplicity and while it does not reflect the total time available for acceptable behaviour for an infrequent frequency event, it is considered sufficient for the purposes of this study.

to determine the peaks and troughs that would likely be exhibited due to a given loss for a given dispatch of inertia and response (see [28]).

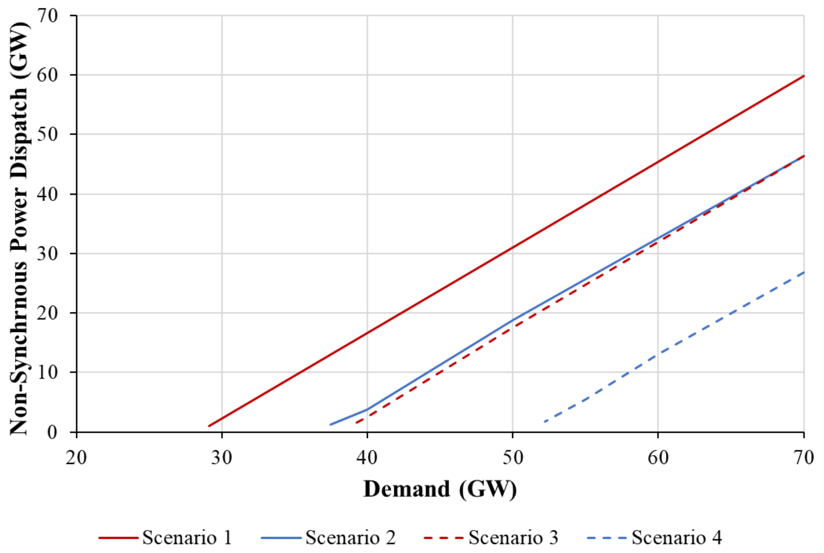


Figure 5.12: Scenarios 1 – 4 for a 0.125 Hz/s RoCoF limit using existing frequency response services.

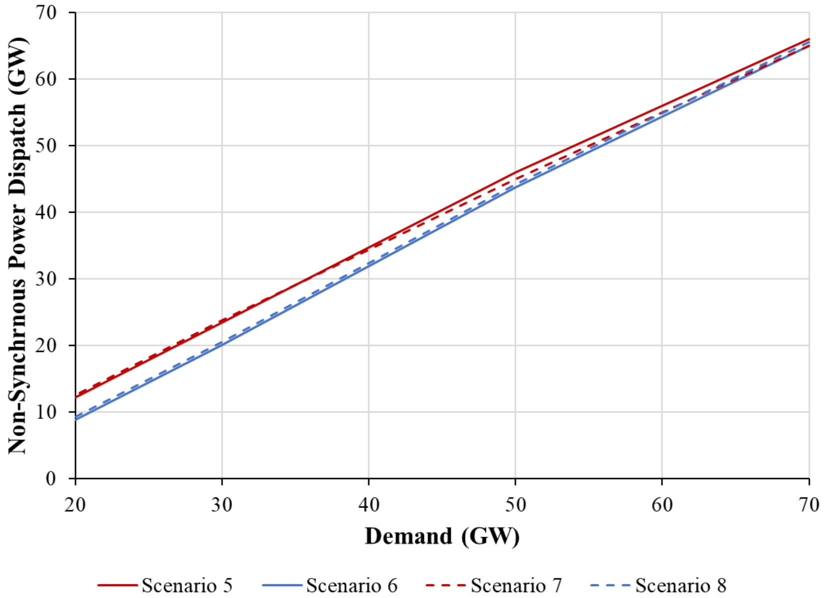


Figure 5.13: Scenarios 5 – 8 for a 0.5 Hz/s RoCoF limit using existing frequency response services.

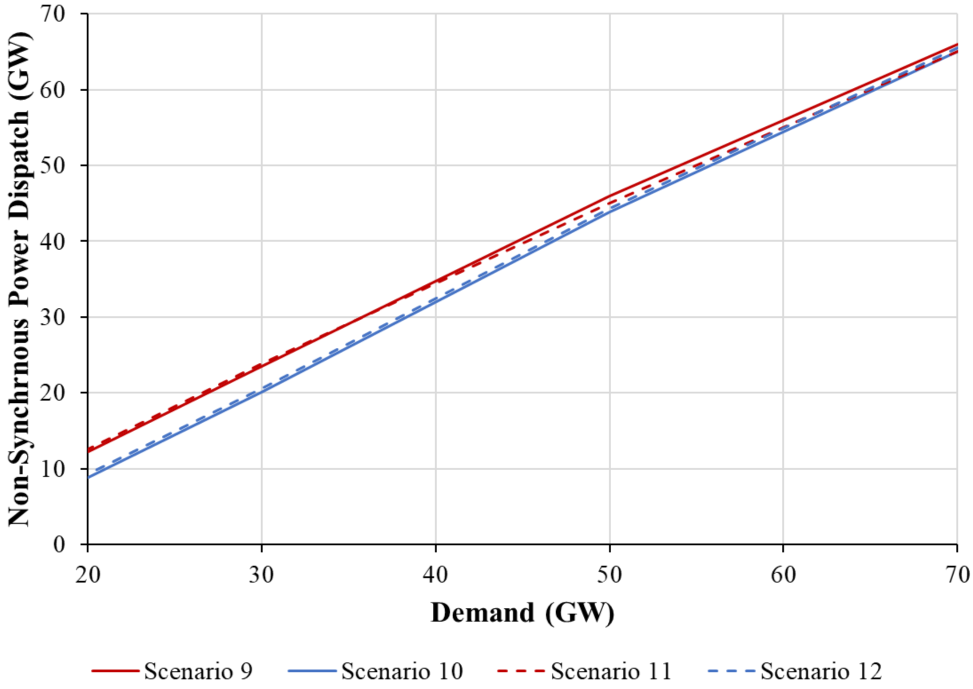


Figure 5.14: Scenarios 9 – 12 for a 1 Hz/s RoCoF limit using existing frequency response services.

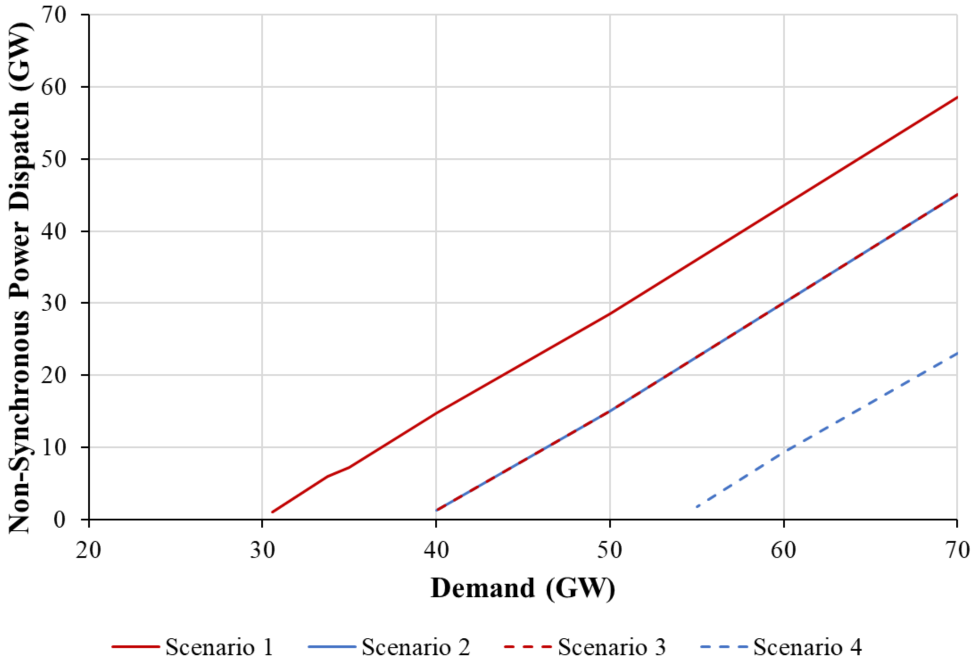


Figure 5.15: Scenarios 1 – 4 for a 0.125 Hz/s RoCoF limit using ESO's future frequency response services.

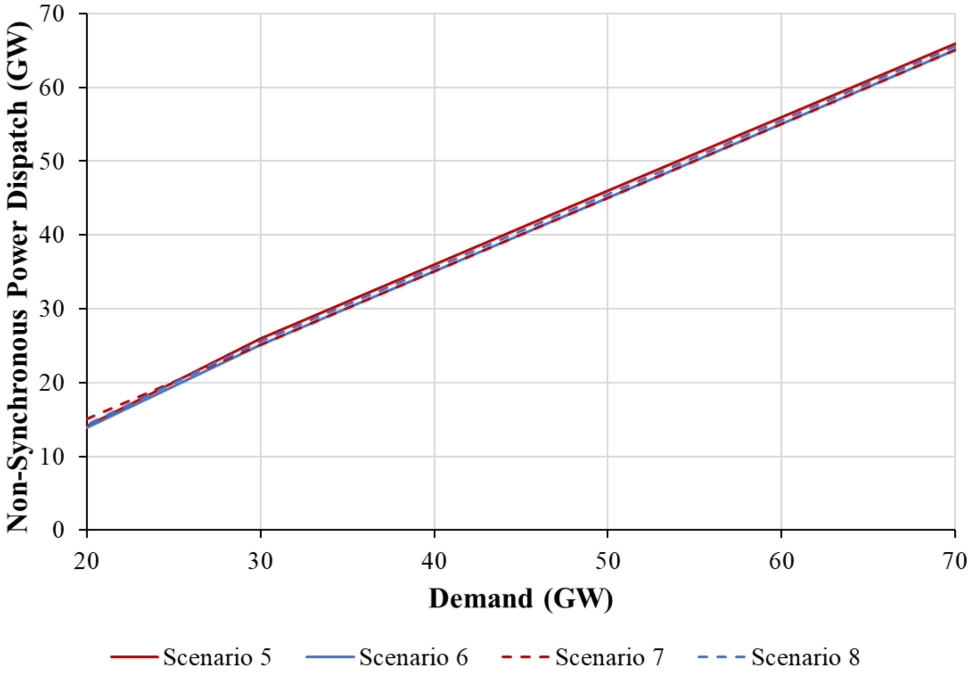


Figure 5.16: Scenarios 5 – 8 for a 0.5 Hz/s RoCoF limit using ESO's future frequency response services.

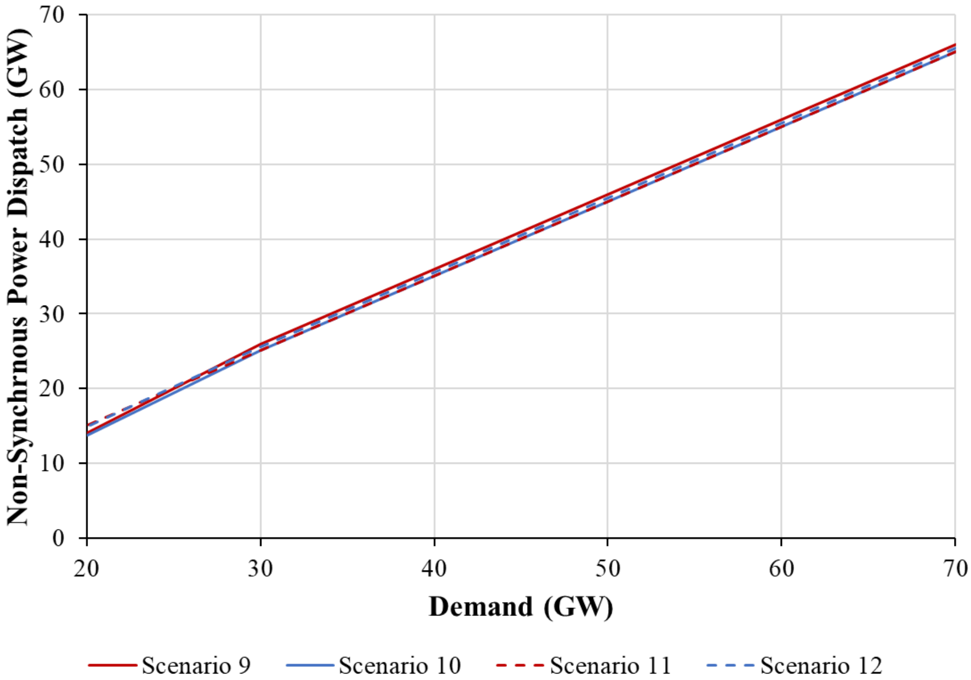


Figure 5.17: Scenarios 9 – 12 for a 1 Hz/s RoCoF limit using ESO's future frequency response services.

6 Potential Technologies for the Provision of Response

Traditionally synchronous generations have been the main source of energy responses to frequency disturbances, with all plants providing inertia and some plants also providing dynamic Primary, Secondary and High frequency response, and it is likely that synchronous plants would continue to participate in future frequency response services via products like Dynamic Regulation. Non-synchronous generators can and do participate in frequency response, however variable resource technologies such as wind and solar, require shorter tender horizons for higher predictability of power output, and the ESO has taken steps towards addressing this barrier to participation. Wind currently participates in dynamic Primary, Secondary and High frequency response via the MFR market, suggesting that the technology can accommodate a sustained response for 30 minutes (under the Secondary response definitions).

The capability to provide fast and fast-acting response services gives non-synchronous technologies a favourable position in the provision of future frequency response services, particularly with the ESO's proposed Dynamic Moderation and Dynamic Containment products. Based on the current participation in the MFR market, wind is technically capable of sustaining a response, to meet both Dynamic Moderation and Containment services, as they are currently defined[16]. However, a hybrid solution would better place the wind plant to deliver either service, potentially opening access to other ancillary products and improve power output certainty. Although the converter may be capable of responding quickly enough to meet the requirements for Dynamic Moderation and Dynamic Containment, there is the question of where the energy comes from; this gap can be met by deploying storage.

6.1 Energy Storage

Developments such as the EFR tender indicate that battery energy storage systems (BESS) are mature enough to participate as providers of a frequency response service, giving a strong indication as to their future potential as a viable technology for the delivery of future frequency response services.

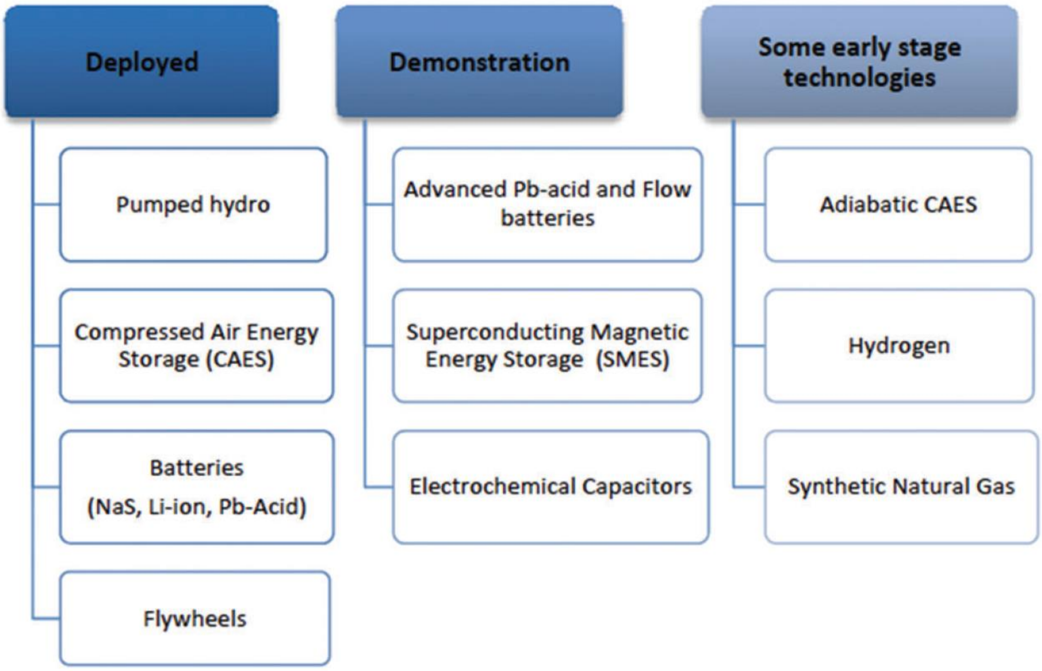


Figure 6.1: Development maturity of major electrical storage technologies towards large-scale deployment [29].

From Figure 6.1, the most likely technologies to provide grid scale services by 2025 would be one of the four in the 'deployed' branch, where broadly speaking (to varying degrees) anyone of those technologies could deliver future frequency response services. These technologies are already deployed around the world and are thus viable for deployment for 2025. The benefits of different storage technologies are presented in Table 6.1, while Figure 6.2 shows a generalised chart on usage (see also [30] for summary of characteristics). Deploying energy storage as a hybrid solution would provide a useful place to store energy during curtailment and make energy available to respond to a frequency

[16] It should be noted that EFR is comparable to Dynamic Containment (the future frequency response service that the ESO plans to introduce first).

events minimising ‘headroom’ requirements. That said, there are non-trivial additional costs associated particularly with installation, a cost-benefit analysis would be required to determine the commercial viability of the hybrid.

Table 6.1: Storage technologies and applications as of 2004 [31].

Full Power Duration of Storage	Applications of Storage and Possible Replacement of Conventional Electricity System Controls.	Biomass.	Hydrogen. Electrolysis +Fuel Cell	Large Hydro	Compressed Air Energy Storage (CAES)	Heat Or Cold Store + Heat Pump.	Pumped Hydro	Redox Flow Cells.	New And Old Battery Technologies	Flywheel	Superconducting Magnetic Energy Storage (SMES)	Supercapacitor	Conventional Capacitor or Inductor
4 Months	Annual smoothing of loads, PV, wind and small hydro.	✓	✓	✓									
3 Weeks	Smoothing weather effects: load, PV, wind, small hydro.	✓	✓	✓									
3 Days	Weekly smoothing of loads and most weather variations.	✓	✓	✓	✓	✓	✓	✓					
8 Hours	Daily load cycle, PV, wind, Transmission line repair.	✓	✓	✓	✓	✓	✓	✓	✓				
2 Hours	Peak load lopping, standing reserve, wind power smoothing. Minimisation of NETA or similar trading penalties.	✓	✓	✓	✓	✓	✓	✓	✓				
20 Minutes	Spinning reserve, wind power smoothing, clouds on PV		✓	✓	✓	✓	✓	✓	✓	✓			
3 Minutes	Spinning reserve, wind power smoothing of gusts.		✓				✓	✓	✓	✓			
20 Seconds	Line or local faults. Voltage and frequency control. Governor controlled generation.							✓	✓	✓	✓	✓	✓

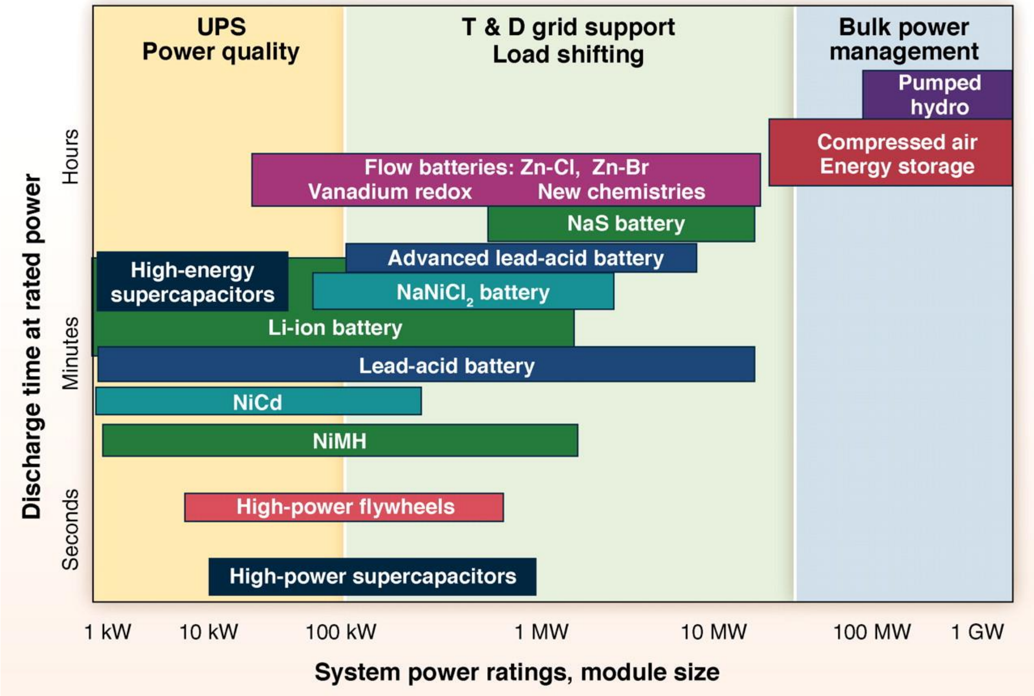


Figure 6.2: Generalised comparison of discharge time and power rating for various energy storage technologies. (The comparisons are of a general nature because several of the technologies have broader power ratings and longer discharge times than illustrated) [29].

6.2 Synchronous Compensators

Synchronous compensators (SCs) are inherently unloaded synchronous machines that is considered to have the potential to offer, among other benefits, a boost to system inertia and an increase to system fault level [32]. In [33], SCs are considered to have the potential to address RoCoF issues, regional stability, voltage management, and reduce the risk of loss of commutation in LCC HVDC links. It is an established technology, which could be purchased for purpose or retrofitted by taking advantage of synchronous plants scheduled for decommissioning. The benefits of deploying synchronous compensators to the power system are widely known since they are synchronous machines. The ESO's recent stability pathfinder [34] provided a route to market for the deployment of synchronous compensators (and the operation of existing synchronous generators in compensation mode). The results of the accepted tenders indicate that about 20% of the total 17 GVAs[17] will be deployed by summer of this year, for contracts spanning almost 6 years – made up of one pumped storage plant and two CCGTs. The other accepted bids have a start date for March/April 2021 and while the technology type isn't explicit in the tender results the 'XXXX' in the unit IDs could imply new builds and may include synchronous compensators. Operators of non-synchronous technologies can deploy synchronous compensators at their sites, providing access to the benefits of a 'nearby' synchronous machine, including inertia, improvement to power quality and overloading capability.

6.3 Virtual Synchronous Machines

A virtual synchronous machine (VSM) control algorithm is one that emulates the properties of traditional synchronous machines. There are different types of VSM and they can be classified based on the control algorithm employed and how the synchronous machine model is applied on the voltage source converter controllers [35]. In [36] the authors discuss a trial involving the use of VSMs in a wind park owned and operated by Scottish Power Renewables. The 23-turbine, 69 MW Dersalloch park in Scotland (direct-drive full-converter) ran in grid-forming mode for approximately 6 weeks and varied levels of inertial contributions were investigated. Key findings from the trials that will be summarised below.

It was observed that when exposed to a small phase step (0.2-0.4 degrees) the VSM has a response similar to that of a synchronous machine, however, for large phase steps in excess of 5-10 degrees (depending on the pre-existing power output) additional intervention is required to avoid over-currents. On the 31st of May 2019 the IFA tripped and the GB power system experienced a loss of about 1 GW, with RoCoF peaking at about -0.11 Hz/s and a frequency drop of nearly 0.5 Hz. At this time the wind farm was operating at a VSM setting of 4 seconds inertia constant, with a power output of about 50 MW of the 69 MW capacity. In this instance windspeed was falling, with power output falling at a rate of about 200 kW/s, but during the study there was no evidence of a recovery period. It was observed that the windfarm ramped up to deliver roughly 1.2 MW, offering an additional 0.1% of the available GB system inertia. On the 12th of June 2019 a similar event occurred with IFA resulting in a peak RoCoF of about -0.08 Hz/s and a frequency drop of about 0.35 Hz, however, this time the windfarm was configured with VSM inertia setting of 7.5 seconds. In comparison to the previous event, it is found that although the RoCoF is smaller the response is larger as a result of the larger inertia constant. However, the dropping background windspeed acts to counter some of the response (see Fig. 3 in Figure 6.3). In both events, it is shown that the VSM, being inertia based, reduces power as RoCoF becomes positive during network recovery. On the 20th of June 2019 another event occurred (the cause is not described) resulting in a peak RoCoF of about -0.06 Hz/s and a frequency drop of -0.4 Hz. In this instance wind speed is increasing, on average, across the wind farm – the windfarm performed as expected and delivered an active power response.

In addition to these actual events a third event is simulated, with a RoCoF of -1 Hz/s and a frequency drop of 3 Hz, while the VSM inertia constant is configured to 8 seconds. The main take away from this test was that there limits to what can be achieved with a wind turbine, even with VSMs, without additional energy storage or pre-event curtailment. In addition, operating at high inertia values without additional energy stored besides the rotor can be counterproductive. In an attempt to deliver a peak response of about 1 MW each, the reducing rotor speeds of the turbines being simulated caused the controllers to reduce the reference power and in turn reduce the absolute power infeed as the event unfolded; this is a 'recovery period' during which power output is reduced until rotor speed recovers. The authors highlight that one of the turbines had its rotor speed fall so low that the turbine cut-out. Aside from additional storage, curtailment and submaximal power tracking, the authors also suggest the inclusion of the capability to alter the VSMs inertia constant in real-time, so that the inertia constant can be high at appropriate wind and rotor speeds, and a tapered reduction when wind and rotor speeds are lower. It should be noted that the turbine's ability to respond is extremely small when the turbines are operating at very low or zero power. Furthermore, the application of a VSM controller is not exclusive to wind farms, the algorithms can be applied other power electronic devices such as batteries as investigated in [37].

[17] 17355.205 MVAs of inertia procured

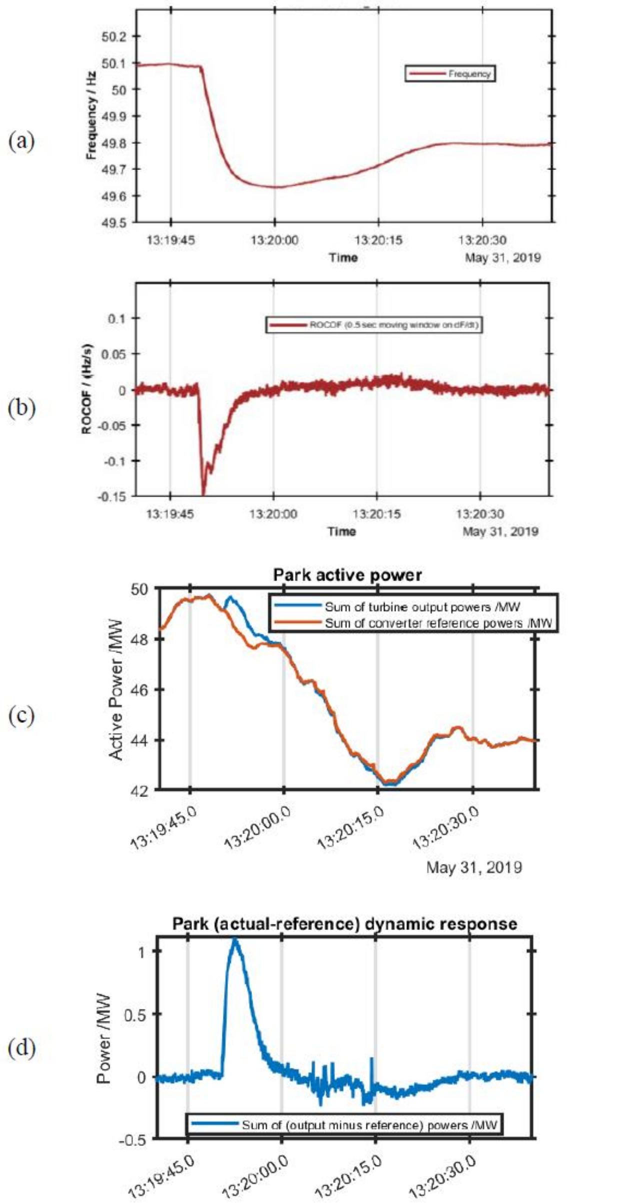


Fig. 2. Response to IFA trip with windpark H = 4 s. (a) SPR 33kV PQ analyser frequency. (b) SPR 33 kV PQ analyser ROCOF (c) Park output power and reference (d) Park output power minus reference

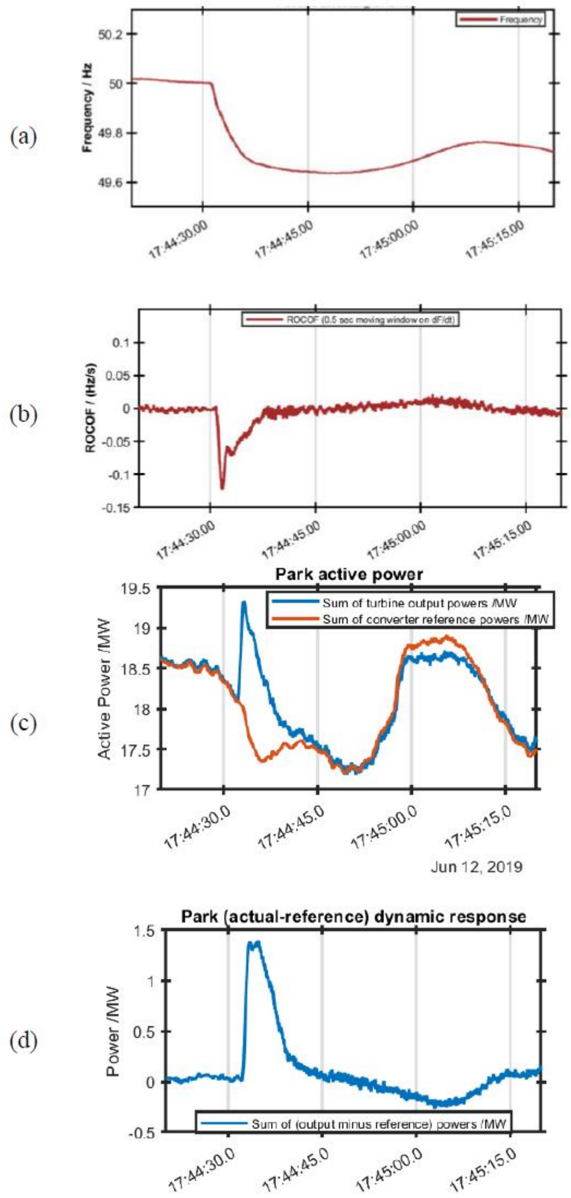


Fig. 3. Response to IFA trip with windpark H = 7.5 s. (a) SPR 33kV PQ analyser frequency. (b) SPR 33 kV PQ analyser ROCOF (c) Park output power and reference (d) Park output power minus reference

Figure 6.3: Plots for windfarm behaviour during IFA events [36].

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