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An Analysis of the August 9th 2019 GB Transmission System Frequency Incident

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ABSTRACT

This paper presents an analysis of the August 9th 2019 GB transmission system frequency event which saw 1.1 million customers disconnected from the electricity system. Using publicly available data and dynamic system simulation, a detailed event timeline is presented that very closely matches the observed system response on the day. This allows for an independent assessment of system operation and response services during the incident, and of various uncertainties around what happened. A number of alternative scenarios are modelled that show how better response provision or better adherence of distributed generation to the latest protection setting guidance could have avoided the disconnection of demand. A thorough discussion of the key lessons that can be learned from the system event is given. This identifies issues for multiple stakeholders to address including the Electricity System Operator, Distribution Network Operators, generator owners and regulators.

1 Introduction

At 4:52pm on Friday 9th Aug 2019, the Great Britain (GB) transmission system experienced a single circuit fault caused by a lightning strike that resulted in the unexpected and near simultaneous loss of two large generation sources as well as a large amount of distributed generation (DG). This led to system frequency eventually falling from an initial 50 Hz to 48.8 Hz and triggering, for the 1st time in eleven years, the system operators' under-frequency load-shedding scheme, known as Low Frequency Demand Disconnection (LFDD), which interrupted electricity supply to around 1.1 million customers. The event also triggered disruption to rail networks during rush hour period and impacted critical facilities including an airport and a hospital [1].

One of the key ways of learning from major disturbances is to reproduce them in simulation allowing for a more thorough understanding of underlying causes and a better basis to consider ways to improve system resilience in future, including through the improvement of modelling [2, 3]. Despite the high level of published information on the incident through reports published by the Electricity System Operator (ESO) [4-6] and the British regulator, the Office of Gas and Electricity Markets (Ofgem) [7], there remains a degree of uncertainty around the detail of the extent and timing of generation losses and system responses during the incident. This paper seeks to fill in these gaps in knowledge using a dynamic model of the GB system to provide an independent critical assessment of the response of the system to the event and the lessons that should be learned from it. In addition, the model is used to test two significant hypotheses: that the worst consequences could have been avoided if (i) scheduled frequency containment reserve had delivered fully; or (ii) if DG protection settings had been updated in accordance with new rules approved by Ofgem.

The paper delivers the following key contributions:

- A detailed replication of the chain of events that led to the widespread disruption is presented and compared with phasor measurement unit data provided to the authors allowing for critical assessment of the performance of the system and of the response services procured by the ESO. The results produce a very strong match with the observed system response, providing for new insights into the scale and timing of system losses and delivered response services.
- An assessment of the impact better response provision for frequency containment could have had on the outcome of the incident showing clearly that widespread disconnection could have been avoided if a higher percentage of procured services had delivered.
- An assessment of the role of DG and of protection systems in the event showing that improper operation contributed significantly to the severity of the incident.
- A thorough discussion of the key issues highlighted by the events of August 9th 2019 and the main learning points and recommendations for the ESO and other stakeholders that should be addressed in light of this.

2 Event Background and System Conditions

2.1 Generation Background

The GB electricity system has an annual peak demand of around 60 GW. Available records indicate that, in 2018, it had almost 70 GW of transmission connected generation capacity plus 31.3 GW of DG capacity [8]. In the half hour prior to the event, transmission system demand, i.e. that exported from the transmission system to the distribution networks and directly connected large loads, was approximately 29 GW, typical for the time of day and year. Figure 1 gives a breakdown of the share of 'balancing mechanism unit' (BMU) generation that was online. Each generating unit that participates in the GB balancing mechanism is a BMU. BMUs account for all transmission connected and some, often larger, distribution connected generators on the system. Using available BMU data the authors estimate only 7.4 GW of DG actively participates in the balancing mechanism, 3.1 GW of which is medium to large scale CCGT plant connected at 132kV in England and Wales (and so technically classed as distribution connected). This suggests the large majority of small scale DG, connected at lower distribution level voltages, does not participate in the balancing mechanism and therefore its status is not included in the presented figures.

The figure shows that output was dominated by wind, CCGT (both ~8.5 GW) and nuclear generation (~6.2 GW). When including net interconnector imports (all supplied via HVDC), in total almost 40% of transmission system demand was being met by non-synchronous sources. When including system reserves, which stood at around 4 GW, the total generation capacity available to the transmission system was 32 GW according to [4]. In addition to this, the ESO estimated that around 2 GW each of wind generation and solar power were connected on distribution networks, contributing to meeting total demand but not visible to the ESO [6].

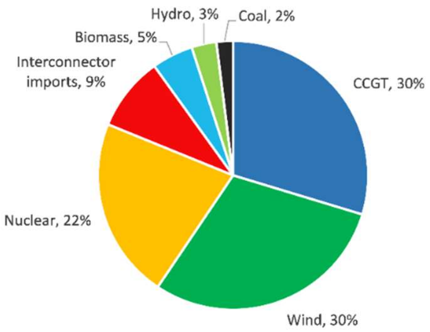

Figure 1 - Share of balancing mechanism unit generation. Adapted from [6]

2.2 Procured System Response Services

The Security and Quality of Supply Standard (SQSS), obliges the ESO in Britain to operate the system such that a 'normal loss of infeed' of up to 1000 MW would not cause system frequency to drop more than 1% below the nominal frequency of 50 Hz, i.e. it should be kept to 49.5 Hz or above. Also, in the event of an 'infrequent loss of infeed' of greater than 1000 MW, system frequency may fall below 49.5 Hz but must be restored to at least that value within 60s [9]. Furthermore, operational practice is to limit the maximum deviation to -0.8 Hz [10]. In addition, there is a practical limit on the system's maximum rate of change of frequency (RoCoF), determined by the threshold at which RoCoF-based loss of main (LoM) protection on DG is triggered .This threshold is currently ±0.125 Hz/s, determined by legacy RoCoF based LoM relays [6, 11]. There is an "Accelerated Loss of Mains Change Programme" underway [12] to implement Engineering Recommendation G99 [13] and change RoCoF settings to 1 Hz/s (relaxed to 0.5 Hz/s for thermal generation). It should also be noted that the LoM protection on some DG is based on vector shift (VS), triggered if the local voltage angle deviates by more than 6° [14]. Because transmission network faults can cause such a deviation, Ofgem outlawed the use of VS-based LoM relays in 2018 [15] and aim to remove existing VS-based LoM protection through the accelerated change programme.

The ESO has asserted that, at the time of the incident on August 9th, the largest single loss of infeed event to which the system was exposed was 1000 MW and that enough frequency containment reserve was being carried to comply with the SQSS [5]. The response of a power system to a 'loss of infeed' frequency event like that on August 9th is determined by a number of factors which relate to both the characteristics of the system at the time and the externally procured services which are designed to keep the extent of the frequency excursion within specified limits. The two key system characteristics that affect frequency response are the system's inertia and the extent to which system demand naturally varies with changes in frequency and therefore helps limit the RoCoF and the extent of the excursion.

The ESO has estimated that system inertia at the onset of the event was close to 220 GVAs, reducing to a minimum of 212 GVAs during the event [6]. This shows that despite the relatively high levels of non-synchronous penetration, system inertia levels were in a normal range and above the threshold of around 200 GVAs below which the ESO may begin to take steps to limit the size of the largest credible "normal" loss risk below 1000 MW. This is based on a simple swing equation calculation, outlined in equation (1), adapted from [16]. This determines that RoCoF, (df/dt), for an instantaneous loss, (ΔP), of 1000 MW on a system with a nominal frequency, (f_0), of 50 Hz and a system inertia, (H_{sys}), of 200 GVAs would be 0.125 Hz/s.

$$\frac{df}{dt} = \frac{\Delta P * f_0}{2 * H_{sys}} \tag{1}$$

Table 1 sets out the frequency containment response services that were procured at the time of the incident [4, 6].

Table 1 - Procured Frequency Response Services during August 9th incident

Response Provision	Procured (MW)
Enhanced	**227**
Dynamic	**595**
- Primary	*564*
- Secondary	*31*
Static Primary (49.6Hz - 1s)	**231**
Static Secondary (49.7Hz - 30s)	**285**
Total	**1338**

The suite of response services that the ESO procures to ensure frequency stability are detailed in [17, 18]. Enhanced response is a fast frequency response service that delivers response with no more than a 0.5s delay and with a 1% droop characteristic such that 100% of response is delivered for a 0.5 Hz frequency deviation. 227 MW of enhanced response, typically delivered from battery energy systems, was contracted on August 9th. Dynamic primary response is defined as a service that is fully delivered within 10s of an event, and sustained for 30s, with an activation delay of up to 2s. Dynamic secondary response is defined as the full delivery of a service within 30s and sustained for 30 minutes. Practically, there is no distinction between both services and both are procured as part of a bundle as the plants that deliver dynamic secondary response also deliver dynamic primary response. At the time of the event the ESO had procured a total 595 MW dynamic response of which 564 MW was contracted to deliver in primary timescales.

Static response services are distinct in that they are triggered at a particular frequency threshold and act discretely rather than following a frequency deviation dynamically. Two static services were in operation on the day of the event, one which is designed to act within 1s of a 49.6 Hz frequency threshold (i.e. in primary response timescales) and a second which is triggered at 49.7 Hz but designed to act within 30s (i.e. in secondary timescales). It can be seen from Table 1 that a total of 1022 MW of enhanced and primary response (static and dynamic combined) had been procured with another 316 MW of secondary response (static and dynamic combined) giving a total response provision of 1338 MW.

3 System Model and Event replication

3.1 Single Bus Frequency Model

The single bus model developed in DigSILENT PowerFactory [19], described and validated in [20] and further applied in [17, 21] is used to replicate and analyse the first 100s of the August 9th 2019 event. On moderately sized island systems such as that in Great Britain, a single bus model is typically sufficient in respect of modelling system frequency response in the event of disturbances and the performance of, or requirements for, frequency response services. Models with greater spatial detail are used to study conditions and faults that are known to give rise to risks of angular instability or where short term regional variations in frequency response are of particular consideration. In this instance, we are concerned with the global frequency response of the GB system to the events of August 9th and so a single bus model is used, in line with the approach of the ESO in its own previous assessment of frequency response [22]. Successful calibration of the model – described in section 3.2 – and its use in testing a number of hypotheses for how the system would have behaved under a set of counterfactual conditions – described in section 4.2 – show the value of the model.

The model allows the convenient representation of bespoke operational conditions and the required range of response providers. The key elements of the model are:

- Frequency responsive synchronous generator: This represents the thermal generation units which operate with headroom to provide the scheduled dynamic response through governor control. A baseline droop characteristic of 4% and a time delay of 1s are assumed with ramp rate limits adjustable to fine tune the rate of response.
- Enhanced Frequency Response (EFR) unit: In line with the defined EFR service and the facilities that won contracts [23], modelled as a battery energy storage system with 1% droop characteristic with ±0.015Hz operational deadband enabling delivery of 100% of given response volume for a 0.5 Hz frequency deviation.
- Frequency non-responsive synchronous generator: This represents the rest of the thermal units on the system for the given scenario. In combination with the frequency responsive generator this is used to accurately represent the power and inertia contribution from thermal generation on the system. In this study the inertia contribution is adjusted to match the stated estimated whole system values given in Appendix M of [6].
- Wind model: A type 3B wind turbine model is used to represent the combined wind generation fleet online at the time of the event. At the time of writing, it is uncommon in GB for wind generation to be used to provide frequency response and none of the reports of the incident mention it. It is therefore assumed that these units provide no frequency response services.
- Non-synchronous element: A negative load injection is used to represent remaining non-synchronous power sources, most notably from solar generation and interconnector imports.
- Demand (power): This load element represents the real power component of transmission system demand. Demand sensitivity – the rate at which demand varies with system frequency – is included in the model and set at 2.5%/Hz [24].
- Demand (inertia): the contribution of demand to whole system inertia is modelled, in line with historical assumptions from the ESO as a motor load with an inertia constant of 1.83s applied to the transmission system demand [20]. It should be noted that this figure includes any contribution from synchronously connected DG.
- Trigger elements: A series of additional trigger elements are used to complete the analysis. Included are generator or load elements to represent stepped or ramped positive or negative power injections. These are either timed in line with known events or, where appropriate, set with reference to frequency or RoCoF thresholds. This allows for the modelling of generation outages, static primary and secondary frequency response services, loss of distributed generation due to the breech of different protection settings and the instigation of the LFDD scheme. In addition, changing system inertia through the event is modelled by switching in and out motor load elements of different inertia contribution at the appropriate times in accordance with figures given in Appendix M of [6].

3.2 Event Replication

To accurately model the totality of the incident a timeline of all events and responses is required. The severity of the event and the subsequent detailed investigations mean that an unusually thorough account of the incident is available in the public domain. Despite this, as illustrated in Table 2, the August 9th incident was multi-faceted and there remains a degree of uncertainty with regard to the exact magnitude or timing of a number of the individual event elements.

For comparative purposes Figure 2 shows the modelled output of the 9th of August event as presented by the ESO in [5], while Figure 3 presents the final results of the event replication process from this work. This involved a number of trials and iterations testing the different uncertainties that were present across 16 unique event stages that have been identified and certain inherent system level input assumptions before the final set of model inputs were adopted. Table 2 describes each of these event stages in more detail indicating the final modelling assumptions regarding the magnitude of events and their timing (trigger time for instantaneous events and start time for continuous events and responses – the latter indicated with an ‘ → ’ symbol). An indication of how much modelling certainty there is at each stage based on the available public data is also given. Where the timing and magnitude of event elements could be derived with high certainty from published information that input data was used directly. Where the certainty of either the magnitude or timing of certain event elements could not be verified with high certainty from the published reports, best estimates were tested and refined across each event stage to deliver the closest possible match between the model replication and real system frequency data. As Figure 3 illustrates, the final modelled results match very closely with real system phasor measurement unit (PMU) data obtained from the time of the event. Indeed, the results shown match the PMU data more closely than the ESO's own published modelling which, for example, shows a several seconds mismatch at the point of the first nadir.

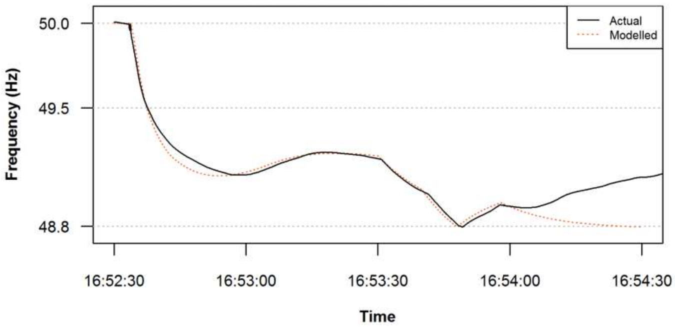

Figure 2 - ESO model output for August 9th event. From [5]

The following paragraphs describe the various phases of the event in more detail.

1) 0-10s

The ESO has reported that a single phase short circuit fault occurred on the 400 kV overhead line between East Socon and Wymondley with roughly a 50% voltage depression in the blue phase at precisely 16:52:33.49 [5]. It was cleared correctly by opening of the circuit breaker at Wymondley 70ms after inception of the fault and after 74ms at Eaton Socon. (The line was returned to service after 20s by the action of delayed auto-reclose). This is not modelled explicitly in the single bus model. However, it did set in motion the chain of events outlined in Table 2. Very soon after onset of the circuit outage we know that the system lost power from both DG – due to the operation of VS LoM protection – and Hornsea offshore wind farm. The VS loss was estimated at 150 MW by the ESO and this figure is used in the model. Hornsea offshore wind farm experienced divergent oscillations of voltage and reactive power in the wake of the circuit outage which, according to Appendix D of [6], triggered the shutdown of individual turbines totalling 737 MW meaning a combined initial loss of 887 MW within the first 250 milliseconds of the onset of the overhead line fault.

Close to 1 second after the onset of the overhead line fault, it appears that the first of three units at the Little Barford CCGT power station was also tripped. 244 MW were lost from Little Barford Steam Turbine 1A due to what seems like an erroneous overspeed signal, apparently also triggered by the initial circuit outage, as detailed in Appendix E of [6]. The precise timing of this is uncertain because although RWE, the owner, has produced what they believe to be an accurate timeline of events at the station, they leave open a ±0.5s window around the mapping of this onto the clock timings used by the ESO [6]. For the model, the mapping of events at Little Barford is determined by matching with observed markers in the PMU data.

This brings the total loss of infeed to 1131 MW, above the 1000 MW "normal" loss risk. This appears to have been enough to breach the 0.125 Hz/s RoCoF threshold which triggered a further loss of distributed generation. The magnitude of this loss was estimated at 350 MW from observations made by the ESO but their own modelling suggested this could have been as much as 80 MW more, totalling 430 MW. Our modelling supports the assessment that at least 430 MW of additional generation must have been lost to recreate the extent of the initial drop in frequency that occurred. It is also possible that more DG was lost due to VS protection and less to RoCoF but the modelling confirms that within the timeframe of around a second as much as 1561 MW of generation is lost to the system in total, with at least 580 MW from DG due to LoM protection.

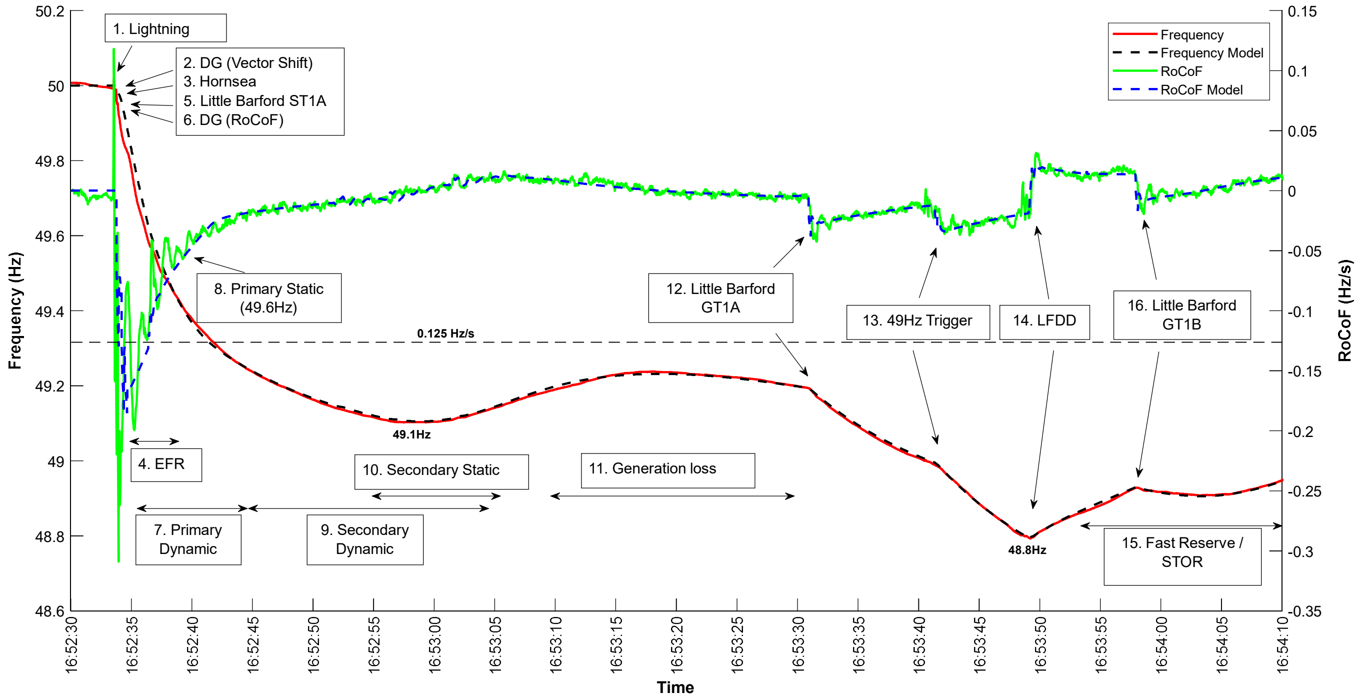

Figure 3 - Measured vs Modelled Frequency and RoCoF traces for 100s of the August 9th incident

Table 2 - Detailed Timeline of loss of infeed events and system responses modelled during the first 100s of the August 9th frequency incident

No.	Event Type	Event	Modelled Time	Modelled loss of infeed / response	Certainty	Comment
1	Trip/Event	Single phase circuit trip	16:52:33.49	N/A	High	Incident initiated by lightning strike and trip of 400 kV East Socon - Wymondley single circuit.
2	Trip/Event	Vector shift trip	16:52:33.70	150 MW	Moderate	Trip of local DG due to vector shift protection. Short delay after circuit outage assumed. Magnitude of 150 MW assumed in line with ESO estimates
3	Trip/Event	Hornsea de-loads	16:52:33.70	737 MW	High	Timing and magnitude of de-load at Hornsea offshore wind farm known with accuracy. Approximated as step change at similar time to Vector shift trip [5].
4	Response	Enhanced Frequency Response	16:52:33.90 →	165 MW	Low	The timing of enhanced frequency response is modelled in line with specifications for the product. The magnitude delivered is uncertain with 227 MW procured. An estimated response of 165 MW is reported in Table 3 of [4], while 94% of an unknown magnitude of validated responders delivered according to Table 5 in [5]. Modelling suggests total delivery in line with the lower end estimate of 165 MW over the course of around 4s.
5	Trip/Event	Little Barford ST1 breaker opens	16:52:34.47	244 MW	Moderate /High	The magnitude of loss from Little Barford Steam Turbine 1A is known with high certainty. RWE's submission in [6] provides a detailed timeline of events at the station under its own timings but there is uncertainty as to precisely how this maps to the ESO's stated timeline. Mapping chosen to fit with observed markers in real data.
6	Trip/Event	RoCoF trips	Automated	430 MW	Low	Triggering of system wide RoCoF protection on DG. The model automates this based on a 0.125 Hz/s threshold with a 0.1 delay. There is low certainty on the magnitude of impacted DG, 350 MW recorded by the ESO but their own modelling suggests 430 MW. The model indicates the loss was in line with the higher estimate, given the previous assumption for loss due to vector shift protection.
7	Response	Primary Response - Dynamic	16:52:34.50 →	484 MW	Moderate	Dynamic primary response is modelled with a 1s delay. The exact level of delivered response is unknown. The ESO reported an estimate of 497 MW in Table 3 of [4] while validated delivery in Table 5 of [5], if covering total procured volume of 543 MW, would indicate 484 MW. The modelling indicates delivery in line with the lower estimate over the first 10s.
8	Response	Primary Response - Static (49.6Hz)	Automated	230 MW	Moderate /high	The timing of static primary response is automated based on when a 49.6 Hz frequency threshold is reached in the simulation. There is moderate certainty as to the magnitude with an estimate of 230 MW in Table 3 of [4], with the majority of this validated in Table 5 of [5]. Procured capacity was 231 MW and modelling suggests almost all static response was delivered.
9	Response	Secondary Response - Dynamic	N/A	N/A	Low /Moderate	Validated frequency response data in Table 5 of [5] indicates ~50 MW of additional secondary dynamic response was provided on top of primary dynamic services in secondary timescales (10-30s into incident). Modelling indicates no net contribution in this phase on top of other inputs. This may have been balanced by an underlying slow reduction in generation output or absorbed into the static secondary response.
10	Response	Secondary Response - Static	16:52:55 →	198 MW	Moderate	Static secondary response is modelled in line with product specifications which state a delivery within 30s of 49.7Hz frequency trigger. This is delivered in line with sample specifications using a 10s ramp after a 20s delay [25]. The exact level of delivered response is unknown. The ESO reported a validated response rate of circa two thirds in Table 5 of [5] whereas 198 MW was estimated in Table 3 of [4] against a total procured volume of 282 MW. The model indicates delivery in line with the estimate of 198 MW.
11	Trip/Event	Generation ramping down	16:53:09 →	6 MW/s	Low	An unexplained drop in frequency occurs in the middle of the event suggesting a slow drop in generation output. The ESO estimates 100 MW over 30s [5]. Modelling assumes 6 MW/s loss of generation over ~20s to match the observed frequency.
12	Trip/Event	Little Barford GT1A breaker opens	16:53:30.90	210 MW	Moderate /High	The magnitude of the loss from Little Barford Gas Turbine 1A is known with high certainty. RWE provide in [6] a detailed timeline of events at the station under its own timings but there is some uncertainty as to precisely how this maps to the ESO's stated timeline. The mapping is chosen to fit with observed markers in real data.
13	Trip/Event	49 Hz trigger point (DG & trains)	Automated	200 MW	Moderate	A combination of DG and system loads (including trains) erroneously tripped off the system when frequency breached 49 Hz. The ESO estimates the net impact of this at 200 MW. The modelling supports this given the system wide assumptions used.
14	Response	LFDD trigger point	Automated	330 MW	Moderate	The LFDD scheme is automated to operate at 48.8 Hz. ESO analysis indicated a net demand loss of 931 MW from the disconnected circuits – Table 6 [4]. Their own analysis estimated an observed impact on the transmission system of 350 MW. Modelling here suggests the net impact could have been closer to 330 MW
15	Response	Fast Reserve / STOR	16:53:53 →	9 MW/s for 10s then 18 MW/s	Low	Modelling indicates an observable increase in generator output from around 80s into the event. This is likely to be from the Fast Reserve service or in combination with Short Term Operating Reserve (STOR) which was instructed on from as early as 30s into event even though it is not obliged to operate for at least 20 mins.
16	Trip/Event	Little Barford GT1B breaker opens	16:53:57.89	187MW	Moderate /High	The magnitude of the loss from Little Barford Gas Turbine 1B is known with high certainty. RWE's submission in [6] gives a detailed timeline of events at the station on their own timings but there is uncertainty as to precisely how this maps to the ESO's stated timeline. Mapping is chosen to fit with observed markers in real data.

This represents a system loss that is well in excess of both the "normal" and "infrequent" loss risks against which the ESO had secured the system. Procured frequency containment services were triggered in this phase with Enhanced Frequency Response the first to respond. The model suggests that 165 MW of response was provided, delivered over the course of around 4s. This is in line with initial estimates from the ESO. The responses detailed in Table 5 of [5] - that the ESO reports as having been validated - appear to show a higher response rate of 94%, but we do not know what proportion of the service providers were validated. Further discussion and analysis of the frequency response services is given in Section 4. Dynamic Primary Response is next to initiate with modelling suggesting around 485 MW was delivered over the course of around 9s. In addition, the model indicates that around 230 MW of Static Primary Response was initiated, assuming a 49.6 Hz trigger point. This means a total frequency response of around 880 MW was delivered within the first 10s of the event. In addition we know that system demand is also sensitive to frequency at an assumed rate of 2.5%/Hz [24]. With system demand of 29 GW and a reduction in frequency over the first 10s of around 0.75 Hz then demand is likely to have dropped by around 540 MW by this stage. Including this with the response provision gives a total system response of up to 1420 MW. This is still short of the total estimated event magnitude of 1561 MW and so, as can be seen in Figure 3, system frequency continues to fall at this point.

2) 10-30s

Although system response in the first 10s of the event was not enough to arrest the fall in frequency, it did slow the RoCoF significantly. Over the course of the following 10s or so, the modelling and PMU measured data suggests that there were likely no other net contributions to frequency response other than the inherent continued slow reduction of system demand in line with the dropping frequency. The next system frequency response contribution observable from measured data is attributable to the static Secondary Frequency Response that was procured. This reacts to a 49.7 Hz frequency threshold but has a response delay of 20s meaning it initiates around 22s into the incident [25]. Modelling tuned to the measured PMU data suggests that around 198 MW were delivered over 10s in line with the ESO's initial estimates. System frequency reaches the first nadir of 49.1 Hz around 24s into the incident, shortly after the Static Secondary Response initiates. The additional response finally brings the total system response above the initial loss of generation and frequency begins rising slowly from the nadir.

Additional dynamic response acting in secondary timescales is also likely to have occurred during this period. The frequency response reported, in Table 5 of [5], to have been validated by the ESO indicates around 50 MW of additional dynamic response could have acted in this period but the PMU data and modelling indicate there was no net impact to this effect on the frequency trace and therefore it is not modelled. This suggests that it could have been absorbed into the modelled Static Secondary Response, estimated at 198 MW, or counteracted by some unnoticed ongoing low level loss of generation in the background or some combination of the two.

3) 30-55s

The influence of the Static Secondary Response continues to be observed beyond 30s with frequency slowly rising up to a new local maximum of a little above 49.2 Hz. However, rather than frequency settling to a new equilibrium it slowly begins to fall again from around 45s into the incident and continues this fall for the remainder of the period. The ESO offers no suggestion of what causes this from the data they have gathered, only to conclude during their own modelling attempt that this is an unexplained gradual loss of generation, estimated to be around 100 MW over 30s. The PMU data and the modelling here indicate that applying a 6 MW/s loss in background generation over 20s from around 37s into the event provides a reasonable match to the observed frequency trace. However, given the lack of data, there is little certainty to this estimate.

4) 55-75s

A second phase of generation losses occurs a little under 1 minute into the incident. In response to the initial outage of the steam turbine unit at Little Barford power station, the two gas turbines at the station went into bypass operation which is designed to allow continued operation. However, an as yet unexplained high pressure fault developed at the station which led to Gas Turbine 1A being tripped from the system about 57s into the event resulting in the further loss to the system of 210 MW. This once again causes a fall in system frequency, with all the procured frequency response services having been exhausted. Over the course of the next 11s frequency drops towards 49 Hz. Despite there being no reason for 49 Hz to trigger the loss of elements from the system, another swathe of losses were seen when a 49.0 Hz threshold is reached. With nothing reported in respect of transmission connected plant, these losses are assumed to have occurred on the distribution system. However, it is reported in [26] that demand from a significant number of trains was lost at this point due to erroneously set internal protection settings. The net effect as observed in the PMU data comes from the loss of several hundred megawatts of DG, also operating on legacy internal protection that, following a system frequency incident in 2008 [27], was recommended not to be used and, in 2019, was banned but is seemingly still in use. Tuning of the model to the measured PMU data suggests there to have been a net loss of 200 MW from the system. Frequency then accelerates further towards the 48.8 Hz LFDD threshold.

5) 75-100s

About 76s into the incident the LFDD scheme is triggered with the ESO suggesting that this resulted in some 931 MW of demand reduction with actions taken across a wide range of distribution network owner areas [5]. However, modelling tuned to the PMU data shows the net impact on the system was closer to 330 MW. If the figure of 931 MW of disconnected load is accurate, this suggests the simultaneous loss of a further 600 MW of DG due to LFDD actions, reducing the intended response by almost two thirds. Despite this, frequency does recover and over the course of the next 8s tracks back up towards 49 Hz. However, around 84s into the incident, a final system loss occurs with the third and final unit at Little Barford, Gas Turbine 1A, being manually tripped from the system in response to the earlier faults that occurred at the plant resulting in the further loss of 187 MW of generation. Frequency drops a little but is arrested at around 48.9 Hz before recovering again towards the end of the simulated period. Modelling indicates that the frequency is stopped from going back towards the LFDD trigger threshold by a combination of the residual effects of the initial LFDD response and an increase in the underlying system generation which is likely to be the result of the operation of Fast Reserve or short term operating reserve (STOR) units ramping up output. Modelling indicates operation of this from around 80s onwards, first at a rate 9 MW/s then at a rate of 18 MW/s from 90s on.

6) Assessment of system assumptions

As well as exploring the magnitude and timing of key incident events, another key aspect that the analysis explored was the validity of the underlying system assumptions on inertia and demand sensitivity. The ESO produced a table charting their calculated system inertia assumptions throughout the event. They have access to a detailed picture of exactly what transmission connected generation was online at the time of the event and with knowledge of the inertia contribution from each unit, are able to generate an accurate picture of the inertia contribution from these generators. However, the ESO has very low visibility of what inertia contributions are made at distribution system level via synchronously connected DG or motor loads so an assumption has to be made. A long standing assumption, known through discussion with industry sources, is that you can approximate this by applying an inertia constant of 1.83s to the magnitude of transmission system demand [20]. While there is no published information on how the ESO has determined their inertia estimates, it remains true that they are in part an estimate rather than a known figure so the validity cannot automatically be assumed. In addition, demand sensitivity - the rate at which synchronously connected loads vary their drawn power in relation to system frequency – is another key system parameter that cannot be directly measured. Another long standing assumption is that demand sensitivity on the GB system can be approximated to be 2.5%/Hz [24].

Each of these assumptions may vary over time depending on the exact composition of demand and DG but there is an underlying received wisdom that over the long term each of these figures should, if anything, be trending down as the proliferation of inverter interfaced generation and loads would dilute the amount of synchronously connected elements. Given this, it is interesting to find that the tuning of modelling to the PMU data for the August 9th incident appears to reinforce the validity of the ESO's inertia estimate and the underlying assumption on demand sensitivity. Lower inertia and reduced demand sensitivity scenarios were tested by the authors but none were able to give a good representation of the observed frequency trace. Particular attention was paid to incident event number 12 in this analysis. Here we have an exact known magnitude of system loss of 210 MW and, in theory, all system response services have already operated so the only variables that should impact the frequency and RoCoF traces would be the system assumptions for inertia and demand sensitivity. The modelling gives a very good approximation to the event when using the standard assumptions presented above, and could not be well represented by other combinations that were tested. This, perhaps surprising, finding is in contrast, for example, to changes made by the Australian system operator who have recently revised their own underlying assumptions for the level of demand sensitivity (or load relief) present in the Australian system from 3%/Hz to 1%/Hz [28]. This change results in a significant increase in the level of frequency response provision that needs to be procured. Further discussion of how the ESO derives these assumptions and the apparent lack of transparency in doing so is given in Section 6.3

4 Frequency Response Performance

4.1 Response Delivered During the Event

One of the key aspects of assessing whether actions of the various parties on which system stability depends, notably the ESO and providers of responses, were adequate on August 9th is to assess the delivery of frequency response against what was procured at the time. As part of their investigation into the event the ESO carried out a process using a combination of internal data and data from providers to try to validate the level of delivered response as detailed in Table 5 of [5]. This analysis found that at least 841 MW of response was delivered in primary timescales (within 10s of the disturbance) and at least 1055 MW in secondary timescales (within 30s). Unfortunately, the analysis only accounted for 91% of the procured primary and secondary response, and did not give a breakdown of which services accounted for the 9% of undocumented response delivery. This means that, despite initial appearances, the data cannot be used to give a definitive answer on exactly how much each frequency response service delivered. Thus, the final figures used in the event replication model for each response service are derived through a combination of the evidence garnered from initial ESO estimates, the ESO's validation process (where helpful), and iterative modelling observations. Table 3 gives an overview of the differences between initial estimates from the ESO in Table 3 of [4], their validation process outlined in Table 5 of [5], and our final modelled estimates. It then compares all of these with the level of procured response.

Table 3 - Comparison of ESO and modelled frequency response delivery estimates with procured volume

Frequency Response	Procured Response 'headroom'	ESO initial estimate	ESO validation	Model estimate
Primary	1022 MW	892 MW (at most)	841 MW (at least)	880 MW
Secondary	1338 MW	1090 MW	1055 MW (at least)	1078 MW

The initial estimates are based on response after 30s. The primary value from the initial estimate is therefore considered an upper estimate whereas the validated response is incomplete so can be considered as a lower bound on delivery. Our modelling suggests that primary response delivered at a rate of around 86.1%, and primary and secondary combined at around 80.6%. These figures remain estimates and a level of additional response could have been masked by underlying losses that were not observed, but it seems likely that they are strongly indicative of the performance of frequency response providers on the day. The ESO stated publicly after the event that it operates a conservative procurement policy which assumes only a 90% delivery rate from response providers [6]. The modelling evidence suggests that the rate of under delivery significantly surpassed this 10% procurement safety margin.

4.2 Alternative Response Scenarios

One key question that can be assessed through use of the model developed by the authors and described Section 3 is the extent to which better performance from frequency response providers would have altered the outcomes and severity of the August 9th incident. Table 4 expands on Table 3 by giving a more detailed comparison of each of the response services that were procured by the ESO at the time of the incident and the model estimated delivery of those response services.

Table 4 - Summary of procured frequency response services and model estimated delivery

Response Provision	**Procured (MW)**	**Model Estimated Delivery**
Enhanced (EFR)	**227**	**165**
Dynamic	**595**	**485**
- *Primary*	*564*	*485*
- *Secondary*	*31*	*0*
Static Primary (49.6 Hz - 1s)	**231**	**230**
Static Secondary (49.7 Hz - 30s)	**285**	**198**
Total	**1338**	**1078**
- *Primary*	1022	880
- *Secondary*	316	198

This can be used to inform an analysis of what impact different response performance scenarios would have had on the trajectory of the event and the extent of the impact. Figure 4 shows the modelled system frequency responses under a range of different response scenarios.

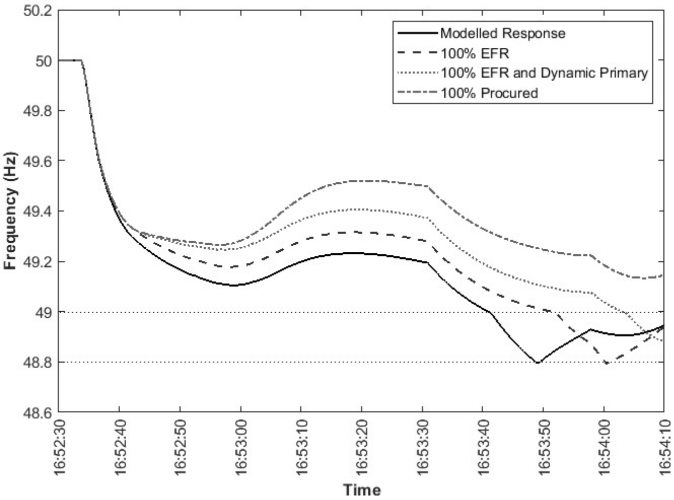

Figure 4 - Modelled system frequency for a range of response scenarios

The enhanced frequency response (EFR) service commenced operation in 2017. Provision was procured through one auction round in which contracts were placed for the delivery of a response with no more than a 0.5s delay and with a 1% droop characteristic such that 100% of response is delivered for a 0.5 Hz frequency deviation. All the contracts were placed with battery storage owners [23]. Both the ESO's analyses and our modelling suggest an aggregate under delivery of EFR, while the ESO's attempted response validation process is inconclusive.

The 1st additional scenario presented here models the full delivery of procured EFR, increasing the total response of that service only from 165 MW to 227 MW, an increase of 62 MW. It is found that this improves the system frequency response but can only delay rather than avoid triggering the LFDD scheme and so, ultimately, the impact of the incident is likely to have been similar under this scenario.

The next scenario modelled the full delivery of both EFR and dynamic primary response (increased from 485 MW to 543 MW[1]), a combined additional response of 120 MW. In this scenario we see that the response is further improved although not enough to avoid breaching the 49.0 Hz threshold which triggers the loss of additional DG. However, the improvement is enough for frequency to reach a new nadir of around 48.87 Hz, just high enough to avoid triggering the LFDD scheme at 48.8 Hz. It is therefore possible that such a response scenario could have avoided the full extent of the consumer impact that was felt on August 9th.

The final scenario models the delivery of all of the procured frequency response, a combined additional response over the original modelled response of around 260 MW. In this case it is shown that frequency never drops as low as the 49.0 Hz threshold and therefore comfortably avoids triggering the loss of further DG and the LFDD scheme. The results show that a better delivery of response provision against that which was procured had the potential to avoid the worst impacts of the 9th August incident.

5 The Role of Distributed Generation

A particular feature of the August 9th incident was the prominent role that DG played in exacerbating an already large power system imbalance. In total across the first 80s of the incident, the authors estimate that, in addition to the loss of 1.38 GW of transmission connected generation, in excess of 1.43 GW of DG disconnected. In the initial phase of outages two large transmission connected sources of power were disconnected in close succession, 737 MW from Hornsea offshore wind farm and 244 MW from Steam Turbine 1A at Little Barford gas fired power station. This combined loss of 981 MW is still within the 1000 MW normal loss risk that the ESO was securing the system against. However, modelling tells us as much as 580 MW of DG was also lost in this initial phase due to the action of Loss of Mains (LoM) protection systems. The ESO estimated that the initial transmission network fault caused the loss of 150 MW of DG due to a voltage angle deviation larger than the threshold for vector shift (VS) LoM protection in the locality of the single circuit outage. Our modelling confirms this to be a reasonable estimate. It was noted in Section 2.2 that VS-based LoM protection is in the process of being removed from the system. It was also noted that DG is not supposed to trip when system frequency drops to 49.0 Hz.

Figure 5 shows what the potential impact of changes to the loss risk of DG throughout the incident might have been. The figure shows that the removal of the VS LoM protection loss risk would likely have had the largest bearing on the extent of the event. Removing this 150 MW loss at the start of the incident means that the system was unlikely to have gone on to

[1] This omits 21 MW of the stated total primary dynamic response. This relates to non-balancing mechanism sources that appear not to have contributed according to Table 5 of [3]

breach the 0.125 Hz/s RoCoF protection threshold. This in itself would have prevented the further loss of up to 480 MW of RoCoF protected DG. The model shows that despite the further loss of the second and third units at Little Barford, the frequency under this scenario would not even have breached the threshold set in the GB Security and Quality of Supply Standard of 49.5 Hz for normal loss risk containment [9].

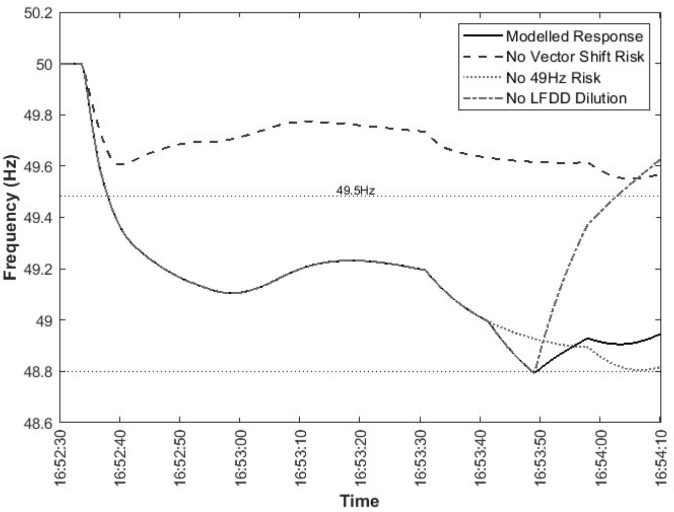

Figure 5 - Modelled response under different distributed generation risk scenarios

Further into the incident, we know that a significant amount of DG also tripped when frequency passed through 49.0 Hz, despite there being no formal system regulations that would require that. The modelled net impact of this, including the disconnection of certain system loads such as a number of trains, was found to be a net loss to the system of 200 MW. A scenario was also considered that removed this 49.0 Hz loss risk from the system. In this case the model suggests that system frequency would very narrowly have avoided triggering the LFDD scheme, though given the remaining modelling uncertainties and how close to the threshold the modelled frequency reached this should not be considered a definitive finding.

It has also been observed through modelling the incident that the disconnection of DG seemingly had a large impact on the effectiveness of the LFDD scheme. Based on Distribution Network Owner (DNO) data, the ESO estimated that 931 MW of demand was shed from the system due to actions taken on distribution feeders acting as part of the LFDD scheme in response to the 48.8 Hz frequency threshold being breached. Similarly, Ofgem quote a net demand shedding of 892 MW in relation to LFDD [7]. Modelling shows us that the net response seen on the transmission system was potentially closer to 330 MW. This suggests as much as 600 MW of mostly unaccounted for DG is likely to have disconnected on these same distribution feeders, acting to significantly dilute the system impact. Figure 5 shows modelling of the scenario where this dilution of the LFDD scheme is not present. It shows that a net response of 931 MW at this stage would have had a significantly greater impact on the system, swiftly bringing frequency back above the 49.5 Hz limit. This would have allowed for a much quicker return to the nominal frequency of 50 Hz, which in reality was only achieved several minutes later through numerous manual instructions from the system operator for increased generator output.

6 Lessons for System Resilience

One important outcome of any major system event is that it sheds a light on areas of weakness and should prompt an assessment of measures that can be taken to improve system resilience in the future. Alongside Ofgem's own review into the incident, two other reviews, one from the UK Government's Energy Emergencies Executive Committee (E3C) and another from the Office of Rail and Road (ORR), examined the August 9th incident to assess performance and understand the lessons that could be learned. These reviews all published reports on the same day in January 2020 [1, 7, 26]. More recently, an overview and discussion of the incident was presented in [29]. Some of the main lessons raised in these reports along with the authors own observations, informed by the analysis carried out in this paper, will now be presented.

6.1 Outage at Hornsea Offshore Wind Farm

According to a report by the owner of Hornsea offshore wind farm, Ørsted, that was submitted to the ESO and published in Appendix D of [6], the loss of 737 MW from Hornsea was attributable to the erroneous performance of power electronic converter control systems on the wind turbines. This meant that instead of riding through the voltage deviation caused by the onshore transmission system fault, both voltage and reactive power at the offshore wind farm went into divergent oscillations eventually causing internal protection systems to operate and disconnect the offshore turbines within ~250ms of the clearance of the onshore network fault. It is reported that Hornsea's owner, Ørsted, and the wind turbine manufacturer, Siemens Gamesa, re-configured the wind turbines' control software on August 10th so that the same problem should not arise at Hornsea again [6]. In acknowledgement of their contribution to the overall event, Ørsted agreed to pay £4.5m in compensation to a voluntary redress fund administered by Ofgem.

The incident at Hornsea leads to wider questions about the behaviour of controllers of wind turbines and power electronics devices more generally. Although it seemed not to have an impact on the event, Hornsea has a very long AC cable connection, more than 120 km, with reactive compensation both at the mid-point and at the point of connection to the main interconnected network. There was an apparent lack of understanding on the part of the ESO with regard to the operation of the wind farm's control systems and their interaction with the rest of the system. Given that Hornsea was only partially constructed and not yet fully commissioned it also raises questions as to how rigorous ESO's processes are for ensuring Grid Code compliance of newly connecting assets. Ofgem explicitly called for improvement in this area when stating "The ESO relied significantly on self-certification by Hornsea 1 for the generator's commissioning process as demonstration of the generator's compliance with the Grid Code, despite the complexity of the connection … We would expect the ESO to review the adequacy of the procedures it carries out and flag potential compliance concerns to Ofgem." [7]. Given that the installed capacity of offshore wind is expected to grow significantly in the coming decades - from around 10 GW in 2020 to 40 GW in 2030 if the UK

Government's target is met [30] - the authors believe it is essential that the ESO ensures there is a better understanding of control system response from newly connecting assets like offshore wind farms and that a rigorous compliance regime is in place to avoid future issues including the risk of common mode failures.

6.2 Outage at Little Barford Gas Power Station

The staggered loss of all three units at the Little Barford CCGT station was another unexpected feature of the August 9th event. In the aftermath of the lightning strike and circuit outage nearby, it is firstly attributable to an apparently erroneous overspeed signal which tripped the first steam turbine unit at the plant. There was then a subsequent failure of the bypass system resulting in a high pressure shutdown of a second unit and the power station operator's decision to manually disconnect the third unit. The reasons behind each of these failures remain unclear. As with Hornsea, the initial lightning strike and circuit outage should not normally have gone on to trigger the losses experienced and RWE, the owner of the power station, similarly agreed to a £4.5m compensation payment to the voluntary redress fund. Ofgem again pointed to a lack of Grid Code compliance testing in the aftermath of a major refurbishment of the plant in 2011/12. This outage again points to deficiencies in assurance of Grid Code compliance, not just for new plant but for existing plant. Consideration should be given to enhanced requirements on generators to prove compliance at ongoing intervals throughout their lifespan and in the aftermath of significant changes such as refurbishment.

6.3 Frequency Response Provision & Security Standards

The combined loss of transmission connected generation and DG within the space of 2s on August 9th (1561 MW) was well in excess of the 'normal loss of infeed' level (1320 MW) specified in the SQSS and the level against which the ESO has reported it was securing the system (1000 MW). Nevertheless, analysis has shown that there was still a significant under-delivery of frequency response compared with what the ESO had procured on the day amounting to 17% of primary response and 14% of secondary response according to Ofgem. This is corroborated by the detailed modelling carried out in this study which also goes on to show that, in spite of the very large initial loss of infeed, had all of the contracted frequency response providers delivered to their agreed level, the system could well have avoided the need for demand disconnection.

The ESO's policy – seemingly not publicly disclosed until after the August 9th event – is to procure frequency response on the assumption that only 90% of it will be delivered [6]. The ESO was able to validate what response was actually delivered from only 91% of providers and only after a detailed subsequent investigation. Ofgem noted that "the ESO has been unable to demonstrate a robust process for monitoring and validating the performance of individual providers" even though frequency response contracts specify payments to providers on the basis of both availability – the initial response 'headroom' – and the volume of energy delivered in response to an event. This is a clear point of improvement that the ESO should look to address at the nearest opportunity, not just to enhance confidence in stable operation of the system but also to ensure that markets for frequency response services are being operated efficiently with clear incentives given to service providers to deliver on promised response provision.

Further, Ofgem goes on to remark that "our assessment of the level of inertia and frequency response held by the ESO prior to this event suggests that there was only a narrow margin for error in securing the system against transmission-connected generator losses alone". In response to this Ofgem has called for a review by the ESO of the SQSS requirements for holding reserve, response and system inertia and whether the requirement to consider the cumulative impact of DG on transmission disturbances should be made explicit.

In its report, Ofgem identified a single point of system failure that would have disconnected significantly more generation than the ESO had secured against. Ofgem estimated that a double circuit fault outage of the Hedon/Saltend North – Creyke Beck transmission route would have resulted in the combined loss of at least 1600 MW of generation when including DG lost due to the action of LoM protection, more than the loss for which the ESO had procured frequency containment reserve. It may be argued that the failure to procure enough reserve for this event was a breach of the statutory requirements expressed by the Security and Quality of Supply Standard (SQSS).

Ofgem has reported that the ESO has an internal policy of fully securing against the most onerous faults only during periods of increased risk to the transmission system (e.g. bad weather, lightning) or when it considers it economic to do so. (It may be recalled that the initial transmission short circuit fault on August 9th was caused by lightning). In its report, Ofgem has recommended a review of "whether it is appropriate to provide flexibility in the requirements in the SQSS for securing against risk events with a very low likelihood, for example on a cost/risk basis" [7].

A degree of flexibility is already built into the SQSS in terms of the authority to tighten security under 'adverse conditions' (such as bad weather) to avoid outcomes from particular contingencies that would normally be allowed, provided there is no economic justification for not doing so. However, there is no provision for relaxation, either of the set of contingencies to be secured against or the consequences to be avoided. The idea of an 'adaptive' security standard where the set of secured events is defined according to the prevailing conditions is not a new one. For example, it was proposed in [31]. Useful theoretical underpinnings and a practical demonstration on the Icelandic system were provided as part of recent European project, GARPUR [32, 33]. However, the GARPUR consortium also noted a key barrier to the application of what it called "probabilistic reliability management methods": the lack of reliable statistical or other data collected by transmission system operators across Europe [34].

One of the most significant responses by the North American regulator to the blackout that affected the North-Eastern US and parts of Canada and disconnected more than 50 million people in August 2003 was a new regulatory requirement on key actors in the sector. This obliged them to collect and process basic reliability data for components of the system and publish annually a raft of what were called 'vital signs' so that trends could be seen [35]. These include emergency alerts, transmission outage rates, protection system performance and reserve margins and go far beyond the rather limited information published by the GB transmission licensees with which Ofgem has seemed content for so long [36]. In order to enable security standards that are more explicit in their treatment of risk, and to be able to better monitor how the network licensees are performing, obligations for collection and publication of data similar to what is obliged in North America are likely to be needed and should be put in place soon.

With suitable work to collect and process key data such as failure rates and repair times for critical equipment types under different conditions and suitable modelling to make use of the data and inform decisions, an 'adaptive' security standard could provide benefits to electricity users through both improving reliability of supply and reducing the cost of balancing services. However, in order to provide confidence to all stakeholders, it is essential that there is greater transparency in how the ESO comes to decisions on system security actions such as the level of frequency containment reserve that is procured and the contingencies that are and are not to be secured.

The ESO should also be more systematic in respect of significant uncertainties, e.g. through testing the sensitivity of modelling results to key assumptions. Another aspect of ESO procedure under question following the August 2019 event centres on their approach to modelling the contribution of demand to both system inertia and system frequency response, both of which influence the requirements for frequency response provision. Ofgem notes that the ESO validated their assumptions on demand contribution to system inertia based on analysis of eight system events from 2016/17 and suggest this is inadequate. They reiterate that this calculation is critical to the evaluation of the RoCoF trigger point and call for it to be "based on a much larger sample of more recent events, to be continuously updated, and to include an adequate margin for error". Despite our modelling of this event suggesting that the ESO estimates for inertia and demand sensitivity were reasonable for this particular event the authors are in agreement that the ESO could be significantly more proactive and transparent in detailing how they come to such assumptions and how they are updated, especially given the rapidly evolving nature of the electricity system and in light of recent reviews of the same phenomena in places like Australia which did lead to significant alterations to the underlying assumptions.

6.4 Loss of Mains Protection

The disconnection of as much as 580 MW of DG on LoM protection was a major influence on the severity of the August 9th incident. The settings of LoM protection represented a known risk. A so-called "Accelerated Loss of Mains Change Programme" began a three year process in May 2019 to try to remove the risk from the system. In light of the August 9th incident, Ofgem recommended a review of the timelines for this programme. In response, the Energy Networks Association gave an update in July 2020 proclaiming that over 4000 individual units with a combined capacity of almost 8 GW had so far been upgraded [12]. This suggests good progress given the estimated combined risk was thought to be around 11 GW, 8.5 GW on vector shift protection and 2.5 GW on RoCoF protection. Swift completion of this programme would be of immediate benefit to system operation, as highlighted in Section 4.2. Nevertheless the programme is not due to complete until 2022 and, given the process is based on an incentive scheme which seeks to drive voluntary participation from owners of DG, there remains the potential that some level of risk will remain in place. How the ESO intends to account for this risk in the interim and potentially longer term remains to be seen. Any residual risk posed by an inability of the programme to deliver full reach should be clearly quantified by the ESO and factored into future security analyses.

6.5 Underfrequency protection

It was noted in Section 3.2 that a significant amount of DG tripped off the system due underfrequency protection set at 49.0 Hz. Such a phenomenon was also observed the last time the LFDD scheme was triggered in 2008 [27]. In the aftermath of that event changes were made to the Distribution Code and Engineering Recommendation G59 to recommend small DGs should not trip on underfrequency unless frequency drops below 47.5 Hz for longer than 20s or 47 Hz for 0.5s [37]. This recommendation only became mandatory in 2019 with the implementation of the Requirements for Generators European Code [38]. Given the evidence of the August 9th event it is clear that the code changes implemented in the aftermath of the 2008 event were not sufficient in enacting the desired change. Further, Ofgem has reported that "Some power electronic interfaced generators may have settings within their internal systems which have been configured by the manufacturer, and as a result are hidden from the DNO or [owners of] generators themselves" [7].

If DG under-frequency protection settings had been compliant with the relevant codes, our modelling has shown that demand disconnection would likely have been avoided on August 9th (See Figure 5). While the very large number of distributed generation sites – more than 3300 just of those with an installed capacity of 1 MW or more [8] - makes compliance testing very challenging, they do all have connection agreements with DNOs that, in theory, could not only stipulate certain performance expectations in line with relevant Engineering Recommendations but also give DNOs the right to enforce them. Ofgem has committed to lead a review of the regulatory compliance and enforcement framework for distributed generators to ensure more reliable and predictable performance going forward. With more than 31 GW of DG already connected in GB, [8], the authors agree this is a required step and would expect new measures that place greater requirements on distributed generation – both that already connected and that which will connect in future – to show greater adherence to guidelines and responsiveness to changes in recommendations than has been evidenced in the past.

The ORR investigation found that power converters on two particular types of train operated by Govia Thameslink in the south-east of England tripped when system frequency dropped to 49.0 Hz [26]. On a number of them, the equipment was locked out until a technician could attend. These trains were therefore stranded and blocked key routes for a number of hours over peak commuting time. The ORR reports that the main regulation states a lower frequency bound for continued operation of 47.0 Hz although an accompanying guidance note permits disconnection at 49.0 Hz. Why this should be the case and whether the network operators were aware of this remains in question. The ORR has recommended rail operating companies to check their trains' protection settings with respect to frequency. The disconnection of trains was a relatively minor element of the August 9th incident from a power system perspective but it arguably contributed most in terms of societal impact. This reflects the importance of understanding and managing the resilience of critical loads that are connected to the system and highlights that the responsibility for this might not always lie with the ESO or DNOs.

6.6 Low Frequency Demand Disconnection Scheme

The analysis in this paper has shown that the impact of LFDD as seen by the transmission system for the August 9th incident was diluted by as much as two thirds compared with the demand that was apparently disconnected. This implies a large amount of unaccounted for DG also tripped off the system. The effectiveness of the LFDD scheme is something which was under consideration prior to the 9th August incident. In 2017 as part of its 'system operability framework' analysis the ESO published a short report into LFDD which concluded that long term trends of increasing distributed generation, lower system inertia and reduced transmission system demand were all likely to be contributing to a reduction in the effectiveness of the scheme and they recommended further review to explore changes to the scheme [39]. Despite this, no changes were made to the scheme in the interim and the August 9th incident was left to expose the reality of the situation. Both Ofgem and E3C make a clear recommendation that a fundamental review of the LFDD scheme should now be carried out citing a specific need to account for the impact of distributed generation. The analysis in this paper makes a clear case that a key priority for this review is to consider how the scheme can be more targeted so as to avoid the disconnection of significant penetrations of DG. Many LFDD relays currently sit on 33 kV distribution feeders. The authors believe an advisable first step would be to undertake an analysis of the contribution that moving LFDD relays to a lower voltage level, for example, 11 kV, could make to minimising the impact of DG on the scheme. Another aspect to consider is how much the consumer should be expected to pay for any improvements.

In addition to the impact of DG other questions were raised around the LFDD scheme. Some DNOs appear not to have met their obligation in terms of the level of demand that was disconnected. Ofgem recommend that the Grid Code should be improved to provide greater clarity on the requirements on DNOs. There were also concerns that some critical infrastructure sites were disconnected as part of the first stage of the scheme including two hospitals and an airport as well as power supplies to a number of rail services. Although backup power supplies operated in the case of the hospitals and airport, Ofgem have recommended that DNOs also review their guidance on treatment of essential loads within the LFDD scheme. The ORR recommended that Network Rail should check and understand the nature of their connections to DNOs' networks.

6.7 Challenges for the Energy Transition

The electricity system is rapidly evolving in different ways many of which present challenges to continued system resilience. High penetration of renewables and reduced system inertia are often cited as key issues but our analysis shows these were not key factors for the 9th of August incident. However, the incident did reveal vulnerabilities in relation to how the system deals with both rapidly increasing levels of DG and converter connected generation. Ofgem reflected that "the ESO could have been more proactive in understanding and addressing issues with distributed generation and its impact on system security" and that "the information DNOs collect and record on distributed generation is variable or severely limited". Many of the DNOs have aspirations to become 'distribution system operators' (DSOs) that take a much more active role in managing power flows and utilising flexibility from generation, storage and flexible demand in real time than is done now [40]. However, this requires much more observability and controllability of distributed resources. It is clear from August 9th that they are far from ready for this, with Ofgem stating that "substantial improvements [are] required in DNOs' capabilities if they are to transition towards playing a more active network management role as DSOs".

Another challenge for system operation going forward is the increasing number of generators or interconnectors that make use of power electronic converters. These allow much greater control flexibility relative to traditional directly connected electrical machines. However, given the wide variety of ways in which the thousands of lines of control software can be written and the intellectual property bound up in it, only the manufacturers know in detail how the converters behave. However, manufacturers generally lack the network operators' models of the wider systems to which they will connect and so cannot be totally sure what the converters will do under all conditions once connected and how they will interact with other equipment.

Grid Code rules are designed to ensure minimum standards are observed and issues avoided, but the behaviour of the wind turbines at Hornsea on August 9th showed that software changes can make a big difference: the version of the software installed at the time (and subsequently replaced) caused unstable responses to the not unusual condition of a voltage depression on the network, to the ultimate detriment of the system as a whole. One key recommendation from Ofgem was that "the ESO, in consultation with large generators and transmission owners, should review and improve the compliance testing and modelling processes for new and modified generation connections, particularly for complex systems". Exactly where responsibility lies for ensuring compliance will be an important issue to address given that DNOs, owners and manufacturers potentially all have an important role to play as well as the ESO.

7 Conclusions

A thorough investigation of what happened during the August 9th 2019 GB system frequency incident has been presented. Despite a large amount of publicly available data, many aspects of the event remain uncertain. Using publicly available data and a dynamic simulation to reproduce observations recorded using a PMU, a precise timeline of the incident has been generated that produces a very strong match to the observed system frequency response. This independent analysis provides new insight into the probable scale and timing of the array of system losses that occurred and system response services that acted on the day.

The modelling is able to confirm that frequency response provision is likely to have fallen within the range that can be inferred from publicly available data. However, it has been shown that this represents a significant under-delivery of frequency response provision relative to what was procured. Further, it has been possible to assess and validate a number of system wide assumptions used by the ESO including inertia estimates and the frequency sensitivity of demand. In this instance the assumptions used appear robust but it would be desirable for the ESO to instigate a transparent process outlining how such assumptions are derived and how they will be updated in time, in light of an evolving system background.

It has been shown that the incident was multi-faceted with a combination of failings involving multiple industry actors. In isolation each of these failings may not have caused any noticeable system disruption but in aggregation they led to the disconnection of 1.1 million customers. Initially, in contradiction to connection requirements, two large generating stations failed to ride through a standard, transient transmission line fault outage. The avoidance of either or both of these failures would have meant no system interruption occurred. Distributed generation has been identified as a major factor in the incident, contributing as much disconnected generation as the transmission system. The severity of the initial N-2 event was exacerbated initially by the operation of LoM protection systems on DG and later by operation of additional protection set at a 49 Hz trigger threshold in error. The analysis reported in this paper has shown that better adherence of DG to the latest protection standards and settings would, in all likelihood, have meant that the Low Frequency Demand Disconnection (LFDD) scheme would not have been triggered. Although the total loss of infeed across the course of the event was well beyond that of a single loss of infeed to which the ESO is obliged to secure the system, it has been shown that a better performance from response providers could also have avoided the disconnection of 1.1 million consumers. Finally, a better targeted LFDD scheme would also have avoided further disconnection of DG and delivered a faster system recovery.

In addition, an overview of the range of lessons that can be taken from the August 9th incident has been presented, capturing points of improvement and recommendations for many electricity stakeholders including the ESO, DNOs, generators and regulatory bodies. The key recommendations are summarised below.

Swift completion of the “Accelerated Loss of Mains Change Programme” would provide immediate benefits to system operation while any inability to achieve full coverage should be clearly quantified by the ESO alongside an assessment of residual risk to system operation and required mitigation strategies. More rigorous compliance testing regimes should be implemented for new and existing plant alike to avoid future outages similar to those experienced at Hornsea offshore wind farm and Little Barford gas-fired power station. Improved monitoring of the delivery of response services should provide a greater incentive for providers to meet contract obligations and improve overall delivery rates. The transparency of the ESO’s frequency response procurement process should be improved to make clear what contingencies are included in the assessment and there should be a demonstrable cost-benefit rationale for any credible contingencies that it decides should not be secured against. More reliable and predictable performance of distributed generators is essential going forward with an enforcement regime required to ensure stricter compliance with the latest connection requirements and recommendations. A more targeted LFDD scheme should be investigated as a priority to reduce the risk that high penetrations of distributed generation act to negate the effectiveness of the scheme during future events.

The electricity sector in Britain has complicated institutional arrangements. In the authors’ view, the August 9th incident shows that responsibilities for ensuring electricity system resilience – preventing, containing and recovering from interruptions to supply arising from disturbances – need to be clarified and applied in a more rigorous way. As E3C’s report noted, essential services that use electricity also need to be helped to understand the extent to which they can depend on a supply from the system and how to survive interruptions.

Delivering a resilient system cost-effectively requires the right mix of operational decisions, control facilities, logistics and assets with the right specifications. Engineering standards, clearly defined roles for the sector’s various licence holders and codes for governing the relationships between them are critical to getting both the engineering and the commercial relationships right among so many different actors. In particular, the set of codes and standards need to be kept fit for the energy system that is coming with clarity on who is responsible for maintaining and enforcing them as knowledge, the system and the assets connected to the system evolve.

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