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9 August 2019 power outage report

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This report sets out the key findings to date, outcomes and next steps from our investigation into the power outage that occurred on 9 August.

In the report we:

- identify the circumstances and causes of the outage;
- set out our assessment of the key issues, and the outcomes of our investigation into certain licensed parties' compliance with their obligations;
- identify the lessons to be learned by the energy sector to improve the resilience of Great Britain's electricity network; and
- recommend actions to implement the lessons learned.

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Executive Summary

On Friday 9 August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply. Several other services were disrupted due to the affected service providers' own safety systems or problems with their back-up power supplies. The rail services were particularly affected with more than 500 services disrupted. The security and reliability of energy supply is a key consumer outcome for the sector, a principal objective for Ofgem as the energy regulator, and an important consideration for the future in an evolving electricity system. We have used our statutory powers to establish the circumstances and causes of the outage and the lessons that can be learned to improve the resilience of Great Britain's energy network, and to investigate the compliance of the key licensed parties involved with their licence and code obligations. This report sets out our key findings to date, outcomes, and next steps.

Circumstances and causes of the power outage

- A lightning strike caused a routine fault on the national electricity transmission system which was rectified very shortly after.
- A number of small generators connected to the local distribution network (known as distributed generation) disconnected[1] automatically immediately following the lightning strike.
- Two large generators - Hornsea 1 Limited, (operated by Ørsted), and Little Barford power station, (operated by RWE Generation UK plc) - experienced technical issues near-simultaneously and were unable to continue providing power to the system.
- As a result of this combined loss of generation, the system frequency fell rapidly, causing a larger volume of distributed generation to disconnect from the system.
- These combined power losses went beyond the back-up power generation arrangements that the Electricity System Operator (ESO) had in place to keep the system stable.
- Demand disconnection was therefore triggered to contain the power outage.
- The system was restored within 45 minutes, and the Distribution Network Operators (DNOs) generally disconnected and reconnected customers as expected.
- Two DNOs (Eastern Power Networks plc and South Eastern Power Networks plc, owned by UK Power Networks) reconnected customers in England before the

[1] 150MW of distributed generation.

required instructions from the ESO and this could have jeopardised recovery of the system.
- The most significant impacts on the rail sector occurred, in particular, when certain Govia Thameslink Railway trains shut down and became stranded due to the configuration of their own on-board automatic safety systems, and this caused other services to be cancelled or delayed.

Compliance, voluntary action and enforcement

Some licensees do not appear to have met their licence and code requirements and the event highlights the importance of robust industry compliance processes.

- Hornsea 1 Limited and RWE Generation UK plc have each acknowledged the role they respectively played in contributing to the outage, and agreed to make voluntary payments of £4.5m each to the Energy Industry Voluntary Redress Scheme.
- Eastern Power Networks plc and South Eastern Power Networks plc have each acknowledged a technical breach of their requirements and agreed to make voluntary payments of £1.5m in aggregate to the Energy Industry Voluntary Redress Scheme.
- We consider these actions to be an appropriate resolution in the circumstances of each case given our preliminary findings on the parties' performance, their cooperation during our investigation, and commitment to mitigating the issues identified.

We have not identified any failures by the ESO to meet its requirements which contributed to the outage. We will continue to review the ESO's current application of the security standards it is required to meet. Alongside this review, the security standards themselves should also be reviewed, as part of our recommended actions set out below. If we identify instances in which the ESO has failed to meet its requirements, we will take the necessary action.

In investigating compliance, we have focused on the key licensed parties involved in the outage. Under current legislation, smaller generators are able to generate without a licence from us and we address this issue in our lessons learned regarding distributed generation.

Lessons learned and recommended actions

It is essential that the energy sector learns the lessons provided by the event on 9 August to reduce the risks of it reoccurring. This report therefore focuses on these lessons and sets out our recommended actions for maintaining the resilience of the electricity system.

The actions relate to:

- System security:
    - reviewing the standards that the ESO is required to operate to for securing the electricity system against credible disruptive events;
    - improving the transparency of the processes the ESO uses for estimating requirements for back-up arrangements to replace power losses and for validating the performance of providers of back-up power;
    - improving the robustness of the processes for testing compliance of generators with a technical industry code, and the ESO's approach to carrying out those processes and modelling the performance of complex generators.
- Distributed generation:
    - reviewing the timetable and scope of planned industry changes to the sensitivity of distributed generators' protection settings to the impacts of network disturbances;
    - reviewing the regulatory and compliance framework for distributed generation and options to strengthen it, including consideration of licensing smaller generators which would require government action;
    - considering options to improve the real-time visibility of distributed generation for DNOs and the ESO.
- Demand disconnection arrangements:
    - reviewing the effectiveness of demand disconnection arrangements; and
    - considering requirements on network and system operators regarding customer treatment during outages.

In addition, we have identified a number of issues with the ESO's existing processes and procedures for managing system operation in highly complex and changing conditions. Given the changes which are required in the energy system to achieve Net Zero we believe that the core roles of the system operators are worthy of review. Hence, we have committed in our forward work plan to a strategic system operation review from January 2020. The concerns raised by our investigation into the events of 9 August 2019 and associated lessons learned will inform that work. We will also work closely with BEIS ahead of its position paper on system governance in 2020.

We have supported the government's Energy Executive Emergency Committee's (E3C) review of the power failure and, where appropriate, our recommended actions involve the E3C or joint working with the Department of Business, Energy and Industrial Strategy to ensure a consistent approach across the energy sector. The major impacts of the outage were on services in other sectors, particularly the rail sector, due to the affected providers' lack of resilience to the disturbance. Whilst we do not have formal powers outside of the energy sector, it is important that all sectors learn the lessons from the event and we have liaised with the Office of Rail Regulation in this regard.

1. Introduction

Context and related publications

1.1. On Friday 9 August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply. Significant disruptions were experienced in other services, including in the transport and water sectors, due to the affected service providers' lack of resilience to the disturbance. The security and reliability of energy supply is a key consumer outcome for the sector and a principal objective for Ofgem as the energy regulator.

1.2. The Electricity System Operator (ESO) operates the national electricity transmission system, ensuring the real-time balancing of supply and demand and maintaining the integrity and security of the system. Given its role, and the information it possesses, the ESO provided a report describing and explaining the events of the 9 August power outage. Following the ESO's submission of an interim report[2] on the outage, we identified areas which needed to be investigated further using our statutory powers. We launched an investigation with three key purposes: (i) establish the circumstances and causes of the 9 August power outage, assessing whether we agree with the ESO's explanation; (ii) establish what lessons can be learned to improve the resilience of Great Britain's energy network; and (iii) assess whether the key licensed parties involved complied with their licence and code obligations.

1.3. With regards to the third aim above, the key licensed parties involved in the outage were: the ESO – National Grid ESO, the transmission network owner in England and Wales - National Grid Electricity Transmission (NGET), the 14 distribution network operators (DNOs)[3], and generation licensees - RWE Generation UK plc[4] (owner and operator of Little Barford power station) and Hornsea 1 Limited[5] (operated and co-owned by Ørsted). Our investigation has focused on evidence related to (i) whether the ESO met its licence obligations to secure the electricity system against the loss

[2] https://www.ofgem.gov.uk/system/files/docs/2019/08/incident_report_lfdd_-_summary_-_final.pdf
[3] There are 14 DNO licensees that belong to 6 company groups: namely Electricity North West Limited, Northern Powergrid, Scottish and Southern Energy, SP Energy Networks, UK Power Networks and Western Power Distribution.
[4] Referred to as 'RWE Generation' in the rest of this document.
[5] Referred to as 'Hornsea 1' in the rest of this document.

of generation supplies; (ii) whether the relevant generators met their requirements with respect to the impacts of the transmission fault on their generation assets; and (iii) whether the DNOs complied with their Low Frequency Demand Disconnection (LFDD) obligations and the circumstances leading to the loss of power to essential services[6].

1.4. This report follows the ESO's final report[7] and summarises the key findings, outcomes, and next steps from our investigation to date. In developing these findings we have gathered information from the licensed parties set out in 1.3 above, conducted site visits and interviews, and commissioned an external technical report on the factual information we obtained[8].

1.5. We have assessed the circumstances and causes of the event. We have also reviewed the evidence, and reached final outcomes in respect of our investigation into certain licensed parties' compliance with their licence and code obligations.

1.6. We have identified key issues related to the resilience of Great Britain's electricity network, and emerging lessons learned for the sector. The security and reliability of our power supply are key considerations for the future in a changing energy system. This report therefore focuses on the areas the industry needs to address to reduce the risks of the event reoccurring. We have set out our recommended actions and steps to achieve this.

1.7. We have liaised with the rail regulator (Office of Rail and Road) on the impacts of the power outage on trains and the rail network. We have additionally supported the government's Energy Executive Emergency Committee's (E3C) review of the power failure[9]. The E3C's final report identifies lessons learned, summarises the actions already taken by industry and also recommends further actions to maintain security and integrity of the energy network. Our report is aligned with the E3C's report in its account of the events of 9 August and the underlying facts. Our lessons learned and recommended actions to implement them are also aligned but go beyond those set out by the E3C in some areas. This is because our investigation has a unique

[6] Essential service' is used in this report to refer to important services used daily by the general public as well as critical industries such as airports.
[7] https://www.ofgem.gov.uk/system/files/docs/2019/09/eso_technical_report_-_final.pdf
[8] We expect to published this external report once we have concluded all aspects of our investigation.
[9] https://www.gov.uk/government/publications/great-britain-power-system-disruption-review

purpose of assessing the role of the energy market participants in the events of the 9 August. As such, our technical assessment of evidence we gathered using our statutory powers yielded detailed findings and some additional lessons learned.

Your feedback

1.8. We believe that feedback is at the heart of good policy development. We are keen to receive your comments about this report. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall process of this report?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Are its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send any general feedback comments to August2019PowerOutage@ofgem.gov.uk.

2. The 9 August power outage

This section explains the relevant roles and responsibilities of the key parties referred to this report. It also sets out the circumstances, causes and consequences of the event, and summarises our assessment.

Overview

2.1. The ESO is responsible for operating, planning and directing the flow of electricity on the national electricity transmission system, and for protecting its security and integrity[10]. One of the important ways in which it does this is by taking actions to balance electricity demand and generation in real-time. The frequency of the system varies constantly depending on the imbalance between supply and demand. Balancing actions limit changes in frequency, and enable the national electricity system to operate steadily at around 50 hertz (Hz).

2.2. The ESO is required to keep the frequency close to 50Hz for credible disruptive events, such as large generators disconnecting from the system or faults occurring on the system. If a more significant event occurs, and the ESO is unable to manage it through balancing actions then, as a last resort, demand customers can be automatically disconnected from the local distribution networks (under Low Frequency Demand Disconnection) in order to prevent a partial or total shutdown of the national system.

2.3. On Friday 9 August 2019, the back-up power the ESO was holding[11] was insufficient to balance the system against the combined loss of two large generators and a large amount of distributed generation, following a lightning strike on the transmission system. Automatic demand disconnection was therefore triggered. This was carried out successfully and the effects of the event were contained. However, this last

[10] Table 1 below specifies the obligations referred to in this report.
[11] The term 'holding' is used in this document to refer to back-up power generation that can be activated through the ESO's contracts with balancing service providers, as opposed to physical power generation assets owned or operated by the ESO.

resort outcome was unexpected and it is important that we review the circumstances to mitigate the risks of it reoccurring in similar circumstances.

Box 1: Key parties

Ofgem - the Office of Gas and Electricity Markets (Ofgem), supporting the Gas and Electricity Markets Authority (GEMA), regulates the electricity and downstream natural gas markets in Great Britain. Changes to licensing for parties carrying out licensable activities under the Electricity Act 1989 (the Act), and changes to the other codes and standards, can be approved by the Authority. It can also make enforcement decisions against parties who have breached their licence obligations.

BEIS – the Secretary of State for the Department for Business, Energy and Industrial Strategy shares the Authority's principal objective under the Act.

Energy Emergencies Executive Committee (E3C) - is a partnership between government, the regulator and industry which co-ordinates resilience planning across the energy industry.

National Grid ESO (ESO) – is responsible for the operation of the national electricity transmission system and real-time balancing of electricity generation with demand, amongst other obligations set out in its licence.

National Grid Electricity Transmission (NGET) – is the onshore transmission network owner in England and Wales, responsible for building and developing the transmission infrastructure, as set out in its licence.

Generators – larger generators generally use the transmission network to transport the electricity they produce provided they are licensed to do so by Ofgem. Smaller generators connected to the distribution network (also known as distributed generators) are generally not licensed.

Distribution Network Operators (DNOs) – DNOs plan, develop and operate local electricity distribution networks according to their licence.

Table 1: Roles, responsibilities and specific obligations

Role	Responsibilities	Specific obligations discussed in this report
The ESO	System operator, responsible for the secure operation of the national electricity transmission system and real-time balancing of electricity generation with demand. The ESO has obligations in its licence, the Security and Quality of Supply Standard (SQSS), the Grid Code, the System Operator-Transmission Owner Code and the Connection and Use of System Code (CUSC).[12]	The SQSS specifies the minimum standards for planning and operating the national electricity system, including frequency and voltage control standards[13]. The Grid Code sets out the technical requirements for connecting to and using the national electricity system, and it specifies the procedures the ESO must use to ensure transmission network users can meet the requirements of the code.
Transmission network owner	Onshore transmission network owners are responsible for building and developing the onshore transmission infrastructure in specified areas according to their licence.	NGET is required by its licence to plan and develop the transmission network in England and Wales in line with the SQSS. It must also work with the ESO under the System Operator-Transmission Owner code (STC).

[12] Licence condition C17 of the ESO licence requires it to '(a) plan, develop and operate the national electricity system co-ordinate and (b) direct the flow of electricity onto and over the national electricity transmission system, in accordance with the National Electricity Transmission System Security and Quality of Supply Standard version 2.4, together with the STC, the Grid Code or such other standard of planning and operation as the Authority may approve from time to time…'.
[13] The Electricity Safety, Quality and Continuity Regulations (ESQCR) sets the frequency and voltage ranges the system should operate within.

Role	Responsibilities	Specific obligations discussed in this report
Generators	Generators can connect and use the transmission network if they are licensed by Ofgem, requiring them to comply with the Grid Code and CUSC, and have entered into a bilateral connection agreement with the ESO. Generators connected to the distribution network (also known as distributed generators) are generally not licensed and are generally required to comply with the Distribution Code through their connection agreement with their local Distribution Network Operator[14].	The Grid Code requires generators to have specific voltage control and frequency control capabilities, and to follow certain procedures during and after a network fault. The Distribution Code covers the technical aspects relating to the connection and use of the electricity distribution licensees' distribution networks. It specifies procedures for distribution network planning and operational purposes in normal and emergency circumstances.
DNOs	DNOs plan, develop and operate local electricity distribution networks in specific areas according to their licences. DNOs are responsible for having the Distribution Code in place and must also comply with Grid Code requirements, for example, on demand disconnection.	Grid Code Operating Code (OC) No 6, (Demand Control) describes the Low Frequency Demand Disconnection (LFDD) arrangements DNOs are required to have in place.

[14] Some licence exempt distributed generations with a capacity between 50MW and 100MW in England and Wales or greater than 30MW in Southern Scotland or greater than 10MW in Northern Scotland also have to comply with sections of the Grid Code.

Box 2: Managing system frequency

System frequency is continuously changing second-by-second (in real-time) according to the balance between total system demand and generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises. The SQSS sets out the minimum standards for managing system operation, including managing frequency variations. Where there is a significant loss of power generation, sufficient power reserves must be available and activated to replace the lost power quickly enough to shore up the fall in frequency so that the frequency standards are met. The initial power reserves, known as frequency response, act automatically to rapidly inject additional power as system frequency falls. The ESO can also manually instruct additional reserves to help frequency recover. Frequency response is provided by an increase in the power output from generators, interconnectors, and storage providers. It can also be provided by network users who can offer a temporary demand increase/decrease.

'Inertia' is a form of frequency response which is inherently provided by large rotating plant, synchronised to the system. When the frequency of the system falls, these generators slow down. Their stored rotational energy is automatically transferred to the power system. The total 'system inertia' helps to counteract changes in system frequency. We consider that the ESO should ensure there is sufficient system inertia to manage frequency variations in line with its obligations, and avoid a domino effect of distributed generation losses, described directly below.

Generators connected to the local distribution system have protection settings which automatically disconnect them when the rate of change of frequency (RoCoF) exceeds a limit. This is a form of 'loss of mains' protection, designed to stop these generators from continuing to operate when they may have been isolated from the main electricity system and may otherwise compromise the safety of the distribution network. Some older generators with capacity under 5MW are highly sensitive to frequency changes. The ESO's management of system frequency therefore considers this 'RoCoF limit' since the loss of distributed generation from a rapid fall in system frequency could exacerbate the issue. Another form of loss of mains protection ('vector shift') responds to voltage changes. This can cause distributed generators to trip automatically for nearby network faults that cause a voltage change. The ESO describes the loss of distributed generation from this mechanism as normal and expected for a lightning strike on a transmission line.

Summary of the event

2.4. Following our review and comparison of the evidence we gathered from the different parties involved, we have established a sequence of events that occurred on 9 August 2019. In summary, this sequence generally aligns with the sequence of events described in the ESO's published reports, and also referred to in the E3C's interim report[15].

2.4.1. At 16:52:33 on Friday 9 August 2019, a lightning strike caused a fault on the Eaton Socon – Wymondley 400kV line. This is not unusual and was rectified within 80 milliseconds (ms)[16].

2.4.2. The fault affected the local distribution networks[17] and approximately 150MW of distributed generation disconnected from the networks or 'tripped off' due to a safety mechanism known as vector shift protection.[18]

2.4.3. The voltage control system at the Hornsea 1 offshore wind farm did not respond to the impact of the fault on the transmission system as expected and became unstable. Hornsea 1 rapidly reduced its power generation or 'deloaded' from 799MW to 62MW (a reduction of 737MW).

2.4.4. Very shortly after, the steam unit at Little Barford power station in Bedfordshire (244MW) disconnected from the transmission system. The speed sensors on the steam turbine produced a discrepancy, initiating its automated control system to shut the unit down.

2.4.5. The events above resulted in a cumulative power loss of more than 1,130MW of generation within around 1 second of the fault.

2.4.6. The level of power loss (or increase in net demand on the electricity system) caused the frequency of the electricity system to fall at a rate of change of frequency (RoCoF) above 0.125Hz/s. Some distributed generators operating

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[15] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/836626/20191003_E3C_Interim_Report_into_GB_Power_Disruption.pdf

[16] Electrical faults are abnormal deviations in voltage and current which can cause damage to equipment and safety risks as well as reliability issues with the electricity system. Disrupting or breaking the flow of current through the relevant circuit through fault clearing devices can minimise these risks.

[17] The fault induced a shift in the voltage waveform – the shape that the voltage within a circuit cycles in, over time – known as a vector shift.

[18] Under the circumstances, distributed generators tripped but were not disconnected from the network at any point. Vector shift protection is no longer permitted for distributed generators connected after 1 February 2018.

under legacy Distribution Code requirements have loss of mains protection mechanisms triggered by RoCoF set at this rate. As a result, an estimated 350-430MW of distributed generation tripped off unnecessarily, based on information provided by the ESO[19].

2.4.7. The cumulative loss of generation at this point was around 1,500MW. The ESO has informed us that it held sufficient frequency response and reserve for a 1,000MW generation loss.

2.4.8. Frequency response was activated. The frequency fall was arrested 25 seconds after the fault at 49.1Hz, and then started to recover, plateauing after 45 seconds at 49.2Hz; this is below the minimum frequency level of 49.5Hz set in the SQSS for the type of transmission network fault that occurred.

2.4.9. There was a reduction in frequency equivalent to a 100MW reduction in generation or increase in demand over 30 seconds. The ESO has stated that during this time there were a number of movements in both demand and generation but it is unable to precisely point to the source of change.

2.4.10. Around a minute after the fault, one of the gas turbines at Little Barford (210MW) was shut down for safety due to too much steam pressure in its pipework.

2.4.11. There was a further net reduction in generation of 200MW at 49Hz[20]. Some distributed generators tripped due to protection mechanisms set to activate when the frequency falls to 49Hz, and this could be the cause of the net reduction in generation observed. The cumulative loss of generation at this point was at least 1,990MW.

[19] This has been inferred by the ESO from a 500MW increase in transformer loadings at the interface with the distribution network. The ESO estimated 150MW of vector shift distributed generation tripped and attributed the remainder to RoCoF. Further ESO modelling suggests the total loss of distributed generation from vector shift and RoCoF could have been up to 580MW. It has not been possibly to fully validate with the DNOs as they also do not monitor output from distributed generators in real-time.
[20] This figure is net of demand disconnection, such as trains and large industrial customers we are aware of.

2.4.12. System frequency continued to fall, dropping below 48.8Hz. This triggered DNOs to disconnect approximately 5% of demand to balance the electricity system and restore its frequency, known as 'Stage 1 of Low Frequency Demand Disconnection (LFDD)'. 892MW of net demand was disconnected in total from the local distribution networks.

2.4.13. The ESO reported that the net demand reduction seen by the transmission system was only 350MW. This indicates that approximately 550MW of additional distributed generation was lost at this point. The reasons for this need to be better understood and addressed to avoid it happening again.

2.4.14. System frequency started to recover following the LFDD, increasing above 48.8Hz within 200ms.

2.4.15. The second gas turbine at Little Barford (187MW) was manually tripped by plant staff around a minute and a half after the fault due to safety concerns.

2.4.16. System frequency continued to recover as the ESO instructed additional frequency response and reserve, returning to 50Hz within 5 minutes of the fault. All electricity supplies were restored through the local distribution networks within 45 minutes of the fault.

Consequences of the event

2.5. In total, 892MW of net demand was disconnected from the local distribution networks as a result of LFDD, representing approximately 4% of national demand and affecting 1.15 million customers. Some essential service providers were directly disconnected as part of Stage 1 of the LFDD and disrupted as their back-up power supply arrangement were not effective. Other services were affected indirectly because the providers' own safety systems were configured to automatically disconnect when system frequency fell.

2.6. In the transport sector, 29 Govia Thameslink Railway (GTR) Class 700 and 717 trains shut down and became stranded when the system frequency fell below 49Hz due to their own on-board automatic frequency protection systems. Two Class 387 trains were also trapped by the stranded units, and altogether passengers had to be safely evacuated from 30 trains.

2.7. Traction supply standards in the rail sector specify a lower operating limit of 47Hz, however, they also refer to a narrower range of 49Hz – 51Hz within which the trains are required to operate normally. Outside this range, they are permitted to reduce their performance or disconnect, and the protection settings for the units affected on 9 August appear to be based on this interpretation of the standards. Some of these protection settings were reset by the driver but 22 permanently locked out and had to be reset by a technician, which was the main cause of disruption to rail lines into St Pancras International and King's Cross. A software update is being introduced to these trains so that they can be automatically reset if the frequency drops below 49Hz in the future.

2.8. The traction supplies to the Wirral line on Merseyrail were disconnected as a result of SP Energy Networks' LFDD operations. Three Transport for London stations and eight signalling sites at rural locations across England and Wales were also thought to have been affected by LFDD operations, although traction supplies were unaffected.

2.9. As a result, there was significant disruption to the rail network, with 371 services cancelled and 220 part cancelled. Affected passengers were entitled to claim compensation through the normal process.

2.10. Newcastle airport was disconnected as part of LFDD. The E3C has reported that standby generation was in place and power restored within minutes at Newcastle airport. It has also reported that a second airport switched to its back-up power supplies without issue although it was not affected by LFDD.

2.11. In other essential services, two hospitals were disconnected as part of the LFDD and their back-up generators were activated. The E3C has reported that two other hospitals were disconnected by their own safety systems but switched to back-up generation. Some water pumping stations were disconnected as part of the LFDD. The E3C has reported that their back-up supplies were not connected automatically and, as a result, several thousand customers experienced some disruption to their running water supply.

Our assessment of the event

2.12. The lightning strike caused a fault on the transmission system which is not unusual. A number of small distributed generators disconnected automatically following the lightning strike as their protection settings responded to the impact of the fault on network characteristics. Two large generators near-simultaneously experienced faults and were unable to continue providing power to the system after the lightning strike. Transmission-connected generators have a requirement to remain connected and continue providing power to the system following faults on the transmission network. The combined loss of generation from both of those stations contributed to the power outage. The loss of generation from those power stations and distributed generators caused the system frequency to fall rapidly, and a larger volume of distributed generation subsequently disconnected due to their protection mechanisms. The combined power losses went beyond the automatic reserves being held by the ESO. Under these circumstances, the need for demand disconnection to protect the system was inevitable.

2.13. The major impacts of the event were on other sectors, particularly the rail sector, due to the affected providers' lack of resilience to the disturbance. The impacts on GTR rail services, for example, should not have occurred and would have been avoided if the trains had automatically reset when the frequency returned to normal. The impacts on all essential services should have been avoided by those services ensuring they had effective back-up arrangements. It is important that all sectors learn the lessons from this event. Nonetheless, within the energy sector, our expectation is that DNOs should consider how to avoid disconnecting critical sites during the early stages of LFDD.

2.14. The actions taken by the ESO to restore power supplies during and immediately after this event proved effective, especially considering the severity and scale of the power outage. As a result, the system was restored within 45 minutes and importantly, the overall integrity of the system was maintained and further disconnections were avoided. The outage highlights the risks and challenges of managing system security and stability in the evolving electricity system, as well as the importance of robust industry processes.

2.15. The electricity system is characterised by lower system inertia caused by replacement of large synchronous thermal generation by a mix of smaller scale renewable generation on the distribution networks and large scale non-synchronous plant on the transmission network, with limited inherent inertial response. The increasingly significant volume of generation connected to the local distribution networks also means that its performance in response to network disturbances is increasingly important for the operation of the national electricity transmission system, and this proved significant in the outage on 9 August.

2.16. Some distributed generators are reported to have erroneously tripped at 49Hz and this highlights the importance of compliance with the Distribution Code. The sensitivity of distributed generators protection settings is being addressed by an ongoing industry programme but this event shows that changes must cover all sensitive settings and be completed in a timely and effective manner.

2.17. In addition, the ESO could have been more proactive in understanding and addressing issues with distributed generation and its impact on system security. Uncertainty in the volume and causes of distributed generation losses highlight this issue. We need to understand how the ESO considers the impacts on the total system in carrying out its system balancing role in more detail and how this could be improved going forward, given the increasing impact of distributed generation on the security of the system as a whole.

2.18. More broadly, the ESO, and DNOs (particularly as they transition towards Distribution System Operator roles) need to adapt to changes in the system characteristics. The trends underpinning these changing characteristics are persistent and considered an important part of the future energy system in the context of the drive towards decarbonisation. It is therefore essential that the sector learns the lessons from the 9 August power outage, and takes steps to maintain the resilience of the system in the face of a changing mix of generation and demand.

3. Key findings

This section sets out our key findings in relation to the issues which contributed to the power outage or which increase the risks of similar occurrences. These findings support the outcomes and next steps of our investigation into the key licensed parties' compliance with their licence and code obligations, which are set out in Section 4. These findings also support the lessons learned and recommended actions set out in Section 5.

The ESO

Box 3: Regulation of the ESO

One of our statutory duties is to regulate persons or bodies involved in electricity transmission activities, including the ESO. We exercise these duties in a manner which protects the interests of consumers. We regulate the ESO's revenue directly through decisions on its funding model and incentives framework. The incentives framework is designed to encourage the ESO to proactively respond to system challenges and maximise consumer benefits across the full spectrum of its roles beyond baseline requirements prescribed in its licence.

Given the ESO's unique role in managing the operation of the national electricity transmission system, and the need to use information from parties across the energy industry to carry out this role, it is well positioned to develop proposals for adapting the systems to the changing generation mix. Moreover, we would expect the system operator to proactively take actions to this effect.

Box 4: National Electricity Transmission System Security and Quality of Supply Standard (SQSS)

The SQSS sets out the minimum standard that the ESO is required to use for planning and operating the national electricity system. It contains limits on frequency variations for various disruptive, credible events such as large generators disconnecting from the system or faults occurring on the transmission network (for example, faults on a single circuit or double circuit overhead line). Specifically, the SQSS requires frequency to stay above or equal to 49.5Hz or that any fall below that level should be recovered within 60 seconds for such events. The ESO is required to secure the system by holding reserves so that the frequency limits are not breached for these events.

The SQSS requires that the system is secured against the loss of the largest amount of power feeding into it following a credible fault event. This loss of power infeed risk can vary depending on the operation of the largest power sources connected to the system.

Overview

3.1. We have not identified a direct causal link to suggest that any failures by the ESO to meet its requirements were responsible for the power outage. The ESO performed well in restoring the system given the amount of generation that was lost. We also note that Great Britain has one of the most reliable electricity systems in the world with comparatively few outage events impacting consumers. However, we have identified a number of issues with the processes and procedures the ESO uses to manage system operation which need to be addressed to reduce the risks of future events occurring. These issues relate to robustness, transparency, and interpretation of regulatory requirements. The processes and procedures relate to: the ESO's interpretation and application of the SQSS; estimating and holding inertia and frequency response needed to meet its requirements; and ensuring generators meet the requirements of the Grid Code.

3.2. The ESO does not consider it is required to secure against distributed generation losses under the SQSS. However, for some faults and in some instances the ESO does secure against distributed generation losses. We will continue to review the ESO's current application of the SQSS, and if we identify instances in which the ESO has failed to meet its requirements, we will take the necessary action.

Key findings

Applying the SQSS

3.3. The ESO is not required to secure the system against the near-simultaneous loss of the two large generators that lost power on 9 August. The largest instantaneous risk of transmission power infeed loss at the time was presented by a group of three generators near Saltend with a net export of 969MW[21]. The ESO also informed us that it was holding power reserves against the slightly higher figure of a 1,000MW power loss on 9 August.

[21] The ESO took balancing action to reduce the total output of the Saltend group of generators to 969MW. This was based on its assessment that some curtailment was needed to remain below the RoCoF trigger level for distributed generation.

3.4. Independently from the fault that occurred on 9 August, we noted that a simultaneous potential fault on both circuits of the 275kV Hedon/Saltend North – Creyke Beck double circuit overhead line would have led to the loss of the Saltend group of generators and distributed generation losses from vector shift protection mechanisms. The combined generation losses would have resulted in additional distributed generation losses and a total generation loss of at least 1,600MW[22]. This loss would have exceeded the amount of back-up power the ESO was holding, causing the frequency to drop below standards, and could have resulted in a similar power outage to the one that occurred on 9 August.

3.5. The loss of distributed generation following transmission faults is a known risk to the ESO. The ESO follows an internal policy of only securing against both transmission-connected generation losses *and* distributed generation losses from vector shift protection mechanisms for credible transmission network faults during periods of increased risk to the transmission system (e.g. bad weather, lightning) or when it considers it economic to do so. In effect, the ESO applies an economic and risk-based assessment of potential faults in considering whether to account for the impacts of distributed generation when securing the system. We will continue to review the ESO's current application of the SQSS security requirements to ensure the ESO's judgements in securing the system appropriately balance the costs and risks to consumers. This review will be carried out alongside a review of the requirements themselves. If we identify instances in which the ESO has failed to meet its requirements, we will take the necessary action.

Estimating and holding inertia and frequency response and reserves needed to meet requirements

3.6. 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. There was also a high level of sensitivity to small changes in key assumptions. The ESO's internal processes for estimating the impact of distributed generation on requirements, in

[22] The additional distributed generation losses would have occurred because the trigger level for RoCoF protection mechanisms would have been exceeded.

particular, do not appear sufficiently robust given the marginal levels of system inertia and poor performance of frequency response providers on the day.

3.7. We have found this uncertainty is compounded by the lack of granular and accurate information available to the ESO on distributed generators' operational characteristics and performance in response to network faults. The current processes for data availability, adequacy and communication between DNOs and the ESO are insufficient to enable the ESO to fully consider the impacts on the total system in carrying out its balancing role. We acknowledge that the ESO has had difficulty in obtaining accurate data on distributed generation. However, in our view the ESO could have been more proactive in raising the issue of distributed generation impacts on system security with the regulator and industry parties.

3.8. We have also identified potential issues in how the ESO models the contribution of demand response to system inertia – the ESO used 8 sample events in 2016/17 (when demand and system inertia was higher) to build a model which it validates against actual system events. Given the importance of this modelling in calculating the RoCoF trigger level, we would have expected the contribution of demand response to system inertia to be modelled based on a much larger sample of more recent events, to be continuously updated, and to include an adequate margin for error to minimise the possibility of the RoCoF trigger being exceeded for the loss of the largest power infeed.

3.9. The overall performance of frequency response providers was generally inadequate. This includes mandatory frequency response providers that are required to provide automatic frequency response by the Grid Code and commercial frequency response providers. Primary response providers (required to deliver a response within 10s) under-delivered by 17% and secondary response providers (required to deliver a response within 30s) under-delivered by 14%. Mandatory response providers, and commercial Fast Frequency Response providers of dynamic primary response (required to provide a continuous, proportional response to the change in frequency) performed particularly poorly, under-delivering by approximately 25% respectively. The ESO has informed us that it has initiated formal processes under the contracts in response to any under-delivery.

3.10. We have also found examples of reserve and response services providers who were disconnected by LFDD, and were therefore unable to provide the service. This is an area which needs addressing and we would like to see more industry engagement particularly between the ESO, DNOs and generators on the impacts of distributed generation for restoring system stability. It is particularly important as the disconnection of balancing service providers can significantly undermine the recovery of the system frequency.

3.11. In our view, the ESO has been unable to demonstrate a robust process for monitoring and validating the performance of individual providers, including mandatory providers. It is also unclear how such material under-delivery is accounted for in the ESO's operational planning, how it is addressed on an ongoing basis to ensure delivery of these vital services, and furthermore, whether this represents value for money for consumers.

3.12. We do not believe that better response and reserve delivery would have been sufficient to prevent demand from being disconnected for this event. However, this is a significant finding given frequency response and reserve are vital balancing services that the ESO must continually procure to secure the system, and expenditure on these accounted for £132m worth of balancing service charges in 2018/19.

Ensuring generators meet the requirements of the Grid Code

3.13. We have not found any evidence to suggest the ESO has failed to meet its requirements under the Grid Code in this area. The ESO was not aware of any potential compliance issues with Hornsea 1 or Little Barford ahead of the event. However, the processes the ESO used to check their respective compliance with the Grid Code do not appear to be sufficiently robust. 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. Following Little Barford's major refurbishment in 2011/12, the ESO relied on the RWE's confirmation that the modifications had not impacted the generator's compliance with the Grid Code requirements for generators to remain stable following network faults. No independent compliance testing or verification was carried out.

3.14. In addition, we have found limitations in the ESO's understanding of Hornsea 1's control system and the interaction between its onshore and offshore arrangements. This limited understanding impaired the ESO's view of Hornsea 1's performance after it was impacted by the fault.

3.15. Lastly, the ESO allowed both Hornsea 1 and Little Barford to reconnect to the transmission system without taking adequate steps to determine the root cause of each failure. In the case of Hornsea 1, this meant the wind farm was reconnected to the system and returned to service following confirmation from the generator that the faulted equipment had been removed from service but before the full root cause analysis had been completed. We have concerns about this approach, particularly when Hornsea 1 was still going through Grid Code compliance processes for commissioning generators and had just suffered technical issues which contributed to the widespread power outage.

3.16. The Grid Code procedures which the ESO is required to follow for checking generators' compliance with the code may need to be clarified and strengthened. Our findings also suggest the ESO's approach to following the procedures is not sufficiently considered and proactive given the increased complexity of the system. We would expect the ESO to review the adequacy of the procedures it carries out and flag potential compliance concerns to Ofgem.

NGET

3.17. The lightning strike caused a fault on one of the overhead lines of the Eaton Socon – Wymondley Main (400kV) circuits. NGET's transmission system protection assets automatically rectified the fault, tripping the overhead line. Another NGET system returned the overhead line to service within 20 seconds.

3.18. Evidence NGET has submitted to us shows its fault clearance times for the two circuit breakers were under 75ms, and that the voltage remained within a range of 390kV to 410kV following the fault. The evidence suggests that NGET's transmission assets performed as expected based on its Grid Code and SQSS requirements.

Hornsea 1

Overview

3.19. Hornsea 1 is a 1,200MW capacity offshore wind farm, located 120km from Yorkshire coast. It is operated and co-owned by Ørsted. The wind farm consists of three modules of 400MW capacity, and a complex offshore transmission system links it back to the 400kV Killingholme onshore substation of the national electricity transmission system. On 9 August, two of its modules were fully installed and the third was partially installed; it therefore had declared a total 800MW power export capability. Hornsea 1 was progressing though the Grid Code compliance process and had fulfilled the necessary requirements to export on an interim basis. Hornsea 1 deloaded following the lightning strike due to a technical fault with the wind farm, and this contributed to the power outage.

Key findings

3.20. Hornsea 1's two fully operational modules deloaded from around 737MW to zero generation automatically after the lightning strike, whilst its remaining module continued to generate at 62MW. This occurred after the network fault on the Eaton Socon-Wymondley circuits had been rectified.

3.21. We have found that the wind farm's onshore control system operated as expected when the system voltage dipped concurrently with the lightning strike. The offshore wind turbine controllers, however, reacted incorrectly to voltage fluctuations on the offshore network following the fault. This caused an instability between the onshore control system and the individual wind turbines. The instability triggered two modules to automatically shut down. In investigating the issues internally, Ørsted identified that this stability issue with its voltage control system had occurred around ten minutes prior to the incident on 9 August but had not caused de-loading at that time.

3.22. We have also identified from the information Ørsted provided to us that modelling it carried out with its equipment manufacturer prior to 9 August suggested that there were performance issues with the voltage control system with Hornsea 1 operating at its full planned 1,200MW capacity. These issues were not discussed with the ESO. The manufacturer proposed a software update to mitigate these issues which Ørsted informed us it had planned to carry out on 13 August but implemented on 10 August immediately following the event. The issue on 9 August occurred when the wind farm reached generation of 799MW. Prior simulations and discussions had not foreseen such issues would occur at this capacity, nor that the windfarm would become unstable and de-load, even at full load.

3.23. We have also found issues with Hornsea 1's communication with the ESO. Hornsea 1 did not notify the ESO directly when the wind farm deloaded by 737MW. The wind farm then began its process of starting up two of its modules (temporarily) without any coordination with the ESO whilst the ESO was attempting to respond to the generation losses it was aware of.

3.24. The Grid Code requirements on generators' responses to network faults, known as Fault Ride Through requirements, are fundamental to the security and resilience of the power system. The Grid Code requires that generators must remain connected and transiently stable following a fault on the transmission system, with power output recovering to at least 90% within 0.5 seconds. Hornsea 1 has acknowledged that it did not meet this requirement, having deloaded following the fault[23]. In addition, Hornsea 1 has accepted that it did not meet the Grid Code requirement to have an overall voltage control system which appropriately dampens or limits swings[24].

Little Barford

Overview

3.25. Little Barford is a 740MW combined cycle gas turbine power station, located in Bedfordshire. It is owned and operated by RWE Generation. It is connected to the national transmission system at the Eaton Socon 400kV substation. The station has two gas turbines and one steam turbine which were all operating on 9 August. It was commissioned in 1995 and went through a major upgrade in 2011/12.

3.26. As set out above, Fault Ride Through requirements are fundamental to the security and resilience of the power system. However, Little Barford's generators did not continue providing power to the system following the lightning strike, and this contributed to the power outage.

Key findings

3.27. Little Barford's steam turbine was generating 244MW when it tripped, within 1 second of the lightning strike. Around a minute after the fault, one of the gas turbines which was generating 210MW tripped. Around 30 seconds after that, the

[23] Grid Code Connection Condition CC. 6.3.15.1
[24] Grid Code Connection Condition CC. A.7.2.5.2 Voltage Control (Oscillations)

other gas turbine was manually shut down by plant staff, bringing the total loss of generation to 641MW.

3.28. We have established that the steam turbine tripped initially because of a discrepancy in the three independent speed sensors on the turbine. This discrepancy exceeded the tolerance of the control system, causing the generator to automatically shut down. The root cause of the discrepancy in the speed sensors has not been established.

3.29. Following the steam turbine trip, the pressure in Little Barford's steam system rose and its safety systems automatically shut down one of the gas turbines due to excessive pressure in the steam bypass. The steam system pressure continued to rise after this and the plant operators made the decision to manually trip the other operational gas turbine due to safety risks. The root cause of these high pressure conditions has not been established. Given the sequence of events and in absence of an established root cause, it is our preliminary view that the steam turbine's anomalous speed readings and the resulting trip were due to the transmission network fault following the lightning strike. RWE Generation has acknowledged the role it played in contributing to the power outage by not continuing to provide power to the system following the fault.

Distributed generation

Box 5: Distributed generation

Distributed generation is also known as embedded generation. It refers to electricity generating plant that is connected to a distribution network rather than the transmission network. There are many types and sizes of distributed generators but they generally generate under 100MW and are not generally licensed. They are required to enter into bilateral connection agreements with local DNOs and to comply with the Distribution Code. Consequently, they are not subject to the licence obligations and Grid Code obligations of larger, transmission-connected generators.

Over recent years we have witnessed a significant growth in the number of generators connecting to the distribution network, driven by decarbonisation initiatives and evolving technology. There was around 25GW of recorded distributed generation capacity connected to Great Britain's electricity distribution networks in 2018[25]. The Grid Code requires DNOs to send data on historic and forecast demand on their local networks to the ESO to inform the investment planned by the

[25] National Grid ESO Future Energy Scenarios July 2019

ESO to comply with the SQSS. This data includes information on distributed generators' unique identifiers, capacity and loss of mains protection settings. It also includes demand profiles for particular demand scenarios at substations, exclusive of distributed generation.

Overview

3.30. Our lower bound for total estimated distributed generation lost across the event is 1,300MW, and the loss could be as high as 1,500MW. There is a significant possibility that this volume is in excess of the transmission connected generation lost during the event. This underscores the changes that Great Britain's electricity system is facing and the importance of understanding the role of distributed generation in the energy mix and the control of the electricity system. Our findings on the causes of the distributed generation losses also highlight the importance of compliance with the Distribution Code, and the need to strengthen and clarify the regulatory framework for these generators to meet current and future electricity system needs.

Key findings

3.31. At least 500MW of distributed generation is estimated to have been lost due to loss of mains protection settings (RoCoF and vector shift) in the first second after the fault. The high sensitivity of these protection settings is a known and expected issue that is being addressed by the industry. However, some generators with capacities greater than 5MW were reported to have de-loaded during the event and the cause of this is still to be determined precisely. These generators' RoCoF protection settings should have been changed following Distribution Code modifications made in 2014[26].

3.32. Additionally, in excess of 200MW of distributed generation tripped off when system frequency reached 49Hz[27]. Changes were made to the Distribution Code which reduced the frequency level triggering under frequency protections to 47Hz permitted for distributed generators with capacities greater than 5MW from August

[26] https://www.ofgem.gov.uk/publications-and-updates/changes-distribution-code-and-engineering-recommendation-g59-frequency-changes-during-large-disturbances-and-their-impact-total-system
[27] It is possible that significantly more than 200MW of distributed generation tripped off at this point as the modelling is net of demand that was simultaneously disconnected such as the trains.

2010. It is possible that the frequency protection settings on some generators were not changed in line with these Distribution Code requirements.

3.33. We have also received information suggesting that some of the distributed generation losses may have been due to internal control systems that cause these generators to deload in response to frequency drops. 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 generators themselves. These settings could explain the loss of further distributed generators when the system frequency dropped below 49Hz.

3.34. Generators' compliance processes should ensure that they make any changes necessary to ensure that the electricity system operates in an effective and secure fashion. At this stage, it is reasonable to assume that these processes have not been effective in all cases. This is particularly concerning given we have recently approved a Distribution Code modification enabling additional changes required to distributed generators' protection settings[28]. It would be equally concerning if there are internal protection systems that are unknown to the DNOs and the generators themselves.

3.35. We are continuing to review the behaviour of distributed generation during the event. It has been brought to our attention that certain licensed distributed generators tripped due to their protection settings, and we have therefore included our next steps with regards to such parties in Section 4 of this report.

DNOs

Overview

3.36. We have found that most DNOs would appear to have met the requirements in the Grid Code regarding low frequency demand disconnection. However, we found some issues with essential services being disconnected, and found areas for improvement in the LFDD arrangements. We have also found concerning evidence that some DNOs disconnected distributed generation via LFDD that was providing either

[28] https://www.ofgem.gov.uk/publications-and-updates/distribution-code-dc0079-frequency-changes-during-large-disturbances-and-their-impact-total-system-phase-4-dcrp1808

frequency response or reserve services. We have found that most DNOs reconnected customers as required but found issues with two DNOs which could potentially have jeopardised the recovery of the system.

3.37. We also found that the information DNOs collect and record on distributed generation is variable or severely limited. As a result, the exact causes and timeline of the incident cannot be fully established and this highlights the substantial improvements required in DNOs' capabilities if they are to transition towards playing a more active network management role as Distribution System Operators (DSOs).

Key findings

Some DNOs disconnected less than 5% of demand as specified on winter peak for Stage 1 of the LFDD

3.38. The Grid Code (Operating Code 6) requires each DNO in England and Wales to have LFDD equipment in place to disconnect a maximum of 60% of demand (measured at winter demand). This equipment should operate in stages to disconnect a given percentage of supply once certain frequencies are reached. The Grid Code requirements contain an accuracy tolerance for the frequency levels and a time delay permitted for different LFDD equipment, depending on its installation date.

3.39. On 9 August, the system frequency fell below 48.8 Hz which triggered Stage 1 of the LFDD. This required 5% of winter peak demand to be disconnected. On average, the DNOs disconnected an estimated 4% of demand as measured prior to the event, and some disconnected significantly less than 5%. Overall, the activation of Stage 1 of the LFDD scheme successfully assisted in stabilising the national system frequency. However, the DNOs did not all achieve the 5% demand reduction and this could have undermined the frequency stabilisation and required further LFDD stages.

3.40. There are several explanations provided for the lower levels of demand disconnection. The principal cause appears to be the technical specification of some LFDD relays which prevented them from activating. These relays would have activated if the frequency had dropped marginally lower and the Grid Code permits this margin of error. Another cause may have been the disconnection of significant volumes of distributed generation as part of the LFDD operation which lowered the net demand reduction. The Grid Code does not currently regulate the disconnection of distributed generation through LFDD, and this issue is addressed in Section 5 of this report.

DNOs have an inconsistent approach to disconnecting essential services as part of LFDD

3.41. On 9 August, several essential service providers (such as hospitals and airports) were disconnected as part of LFDD. There is no obligation on DNOs to refrain from disconnecting such providers in their LFDD requirements, and it would be difficult to do so in all circumstances for such rare and short lived events. This is because the LFDD equipment does not operate at an individual site level and so isolating particular sites is generally unfeasible. Individual customers operating essential services should therefore maintain and operate back-up power supplies to deal with the power outages. Disruptions experienced at the sites of essential service providers directly impacted by the power outage were generally caused by failures in their back-up power arrangements.

3.42. However, we have found that DNOs have significantly different approaches to evaluating which areas to disconnect during Stage 1 of the LFDD, depending on the type of sites embedded within them. Some DNOs, for example, give more consideration to the impact of supply losses in different areas compared to others.

DNOs reconnected demand without instruction from the ESO

3.43. Our findings on the DNOs' reconnection of demand following Stage 1 of LFDD suggest that they generally performed as expected. However, Eastern Power Networks plc and South Eastern Power Networks plc (both owned by UK Power Networks) reconnected sites without being told to do so by the ESO, and acknowledge that they do not appear to have technically met the requirements of the Grid Code[29]. These instances were caused by the configuration of the DNOs' operational systems. The system frequency was successfully restored to 50Hz following the LFDD activation on 9 August. However, the premature demand

[29] Grid Code Operation Code 6.6.4

reconnection by Eastern Power Networks plc and South Eastern Power Networks plc could potentially have jeopardised this outcome.

3.44. SP Distribution erroneously disconnected 22MW in Scotland when system frequency fell below 48.8Hz and reconnected customers without informing the ESO. As SP Distribution is part of the SP Transmission network area, it is not required by the Grid Code to disconnect demand until frequency reaches 48.5Hz. The demand disconnection occurred due to an incorrect setting in the DNO's LFDD equipment. Since SP Distribution was not responding to an LFDD event in this case, it does not appear to have contravened the Grid Code in its disconnection or prompt reconnection of demand without informing the ESO[30].

DNOs are unable to consistently provide comprehensive and accurate information on distributed generators' characteristics and dynamic performance

3.45. Most of the DNOs only record information on generation volumes on their networks on a half-hourly basis, obscuring shorter-term events such as the 9 August power outage. This is due to their policies on data collection and recording of generation on their networks. The majority of the data DNOs have provided to us therefore only gives a partial view of which distributed generators tripped off or reduced output on their networks at different times in response to the fault. As a result, we cannot ascertain the resulting volumes of generation output lost at different locations or the cause of these losses with confidence from the information DNOs have provided[31]. Although some DNOs collect more granular information, all DNOs require a detailed understanding of their networks if they are to transition to DSOs, and the policies they currently employ do not provide this.

[30] DNO performance on customer interruptions is measured and factored in to an incentive scheme as part of price control arrangements.
[31] We have been able to ascertain the distributed generation losses described in section 2 based on our validation of the frequency event modelling carried out by the ESO.

4. Compliance, voluntary action and enforcement

This section sets out the outcomes and next steps in relation to our findings in Section 3 on licensed parties' compliance with their obligations.

Closed issues

4.1. RWE Generation and Hornsea 1 have each acknowledged their role in contributing to the power outage by not continuing to provide power to the system following the lightning strike. Each licensee has agreed to make a voluntary payment of £4.5m to the Energy Industry Voluntary Redress Scheme in recognition of the role it played in contributing to the power outage.

4.2. Eastern Power Networks plc and South Eastern Power Networks plc have each acknowledged their technical breaches of their Grid Code requirements by reconnecting customers without being told to do so. The licensees have agreed to make voluntary payments of £1.5m in aggregate to the Energy Industry Voluntary Redress Scheme in recognition of their actions which could have potentially jeopardised recovery of the system[32].

4.3. We consider the acknowledgements and voluntary payments above an appropriate resolution in the circumstances of each case. Based on our preliminary assessment of the licensees' compliance with their obligations, we consider their response to be proportionate to the nature and impact of the incident. In addition, the parties have cooperated fully with our investigation and shown commitments to mitigating the issues identified. We also note and appreciate that following the event Hornsea 1, Eastern Power Networks plc and South Eastern Power Networks plc have already implemented measures to prevent reoccurrence of the issues identified and supported sharing lessons learned to benefit the wider industry.

[32] Each licensee has agreed to make a voluntary payment contributing to the £1.5m aggregate payment in proportion to power (in MWs) that each disconnected prematurely. Eastern Power Networks has therefore agreed to pay £1.45m and South Eastern Power Networks has agreed to pay £0.05m.

4.4. We acknowledge that some parties have different interpretations to ours as to extent of any breaches and that in agreeing voluntary resolution, we make no formal legal determination on those matters.

4.5. We are not pursuing our investigation into the actions of NGET or any other DNOs as they appear to have met their obligations.

Additional issues

4.6. We will continue to review the ESO's current application of the SQSS security requirements. This review will be carried out alongside a review of the requirements themselves. If we identify instances in which the ESO has failed to meet its requirements, we will take the necessary action.

4.7. Our investigation has focused on the key licensed parties involved in the outage. We are continuing to review the behaviour of distributed generators during the event and will consider whether it is appropriate to open investigations into any licensed parties' compliance with Distribution Code requirements regarding distributed generators' protection settings.

5. Lessons learned and recommended actions

This section sets out the lessons learned and our recommended actions from the findings in Section 3 on the key issues which contributed to the power outage or which increase the risks of similar occurrences. Where appropriate, actions have been aligned with recommendations in the E3C's report to ensure a consistent approach.

The ESO

Lessons learned

Updating the SQSS

5.1. Our findings show that the SQSS should be updated periodically to reflect changing system security risks and requirements. It may be necessary to consider standards for assessing explicitly the risk-weighted costs and benefits of securing the system for certain events, including simultaneous generator losses, and whether the SQSS remains fit for purpose with respect to the impact of distributed generation. This would provide greater transparency and assurances on how the ESO is managing these issues.

5.2. The ESO has a unique role in operating and managing the national electricity transmission system taking into account the total system effects of its actions. We would therefore expect it to take a more proactive approach in bringing forward proposed changes to established practice, for example in the SQSS. In doing so, it should recognise the changing nature of the system, and smart, flexible and innovative ways that are now available for managing it.

Estimating and holding inertia, frequency response and reserves needed to meet requirements

5.3. Our findings in this area show that the methodologies the ESO uses for estimating inertia, frequency response and reserve requirements should be reviewed to ensure they are sufficiently robust to known uncertainties. As part of this, the underlying planning assumptions regarding the impact of fault events on distributed generation and the adequacy of information exchanges between the ESO and other parties which underpin these assumptions should be tested.

5.4. In addition, the ESO's process for validating the performance of both mandatory and commercial frequency response providers must be made more robust to enable it to take action against those providers that fail to deliver when a frequency event occurs. The process by which the ESO's operational planning assumptions take into account uncertainties in delivery by frequency response and reserve providers, including distributed generators covered by LFDD arrangements, should also be tested.

Ensuring generators meet the requirements of the Grid Code

5.5. Our finding in this area is that the ESO should have a more considered and proactive approach to compliance testing for new and modified generation connections, underpinned, where necessary, by changes to the Grid Code. Where the ESO is connecting complex power systems to the network, it must be capable of modelling their performance when the network is disturbed. In addition, its process for understanding and ensuring the issues behind fault-related outages prior to reconnecting generators should be made more robust.

The ESO's structure and governance framework

5.6. The event has underlined the importance of the ESO's role at the heart of a highly complex and changing electricity system. It is required to make increasingly complex judgements on which actions provide the best value to consumers in the short and long-term. In the context of this increased complexity of the system, we have identified a number of issues with the ESO's existing processes and procedures for managing system operation which need to be addressed. Further improvements to the ESO's structure and governance framework should be considered in order to meet the challenges of the energy transition.

Recommended actions

5.7. *Action (1):* The ESO, in consultation with the industry, should undertake a review of the SQSS requirements for holding reserve, response and system inertia.

5.7.1. This review should consider:

- the explicit impacts of distributed generation on the required level of security
- whether it is appropriate to provide flexibility in the requirements for securing against risk events with a very low likelihood, for example on a cost/risk basis
- the costs and benefits of requiring the availability of additional reserves to secure against the risk of simultaneous loss events

5.7.2. The ESO, as the party required to operate to the standard, should carry out this review and raise modification proposals to the SQSS Panel by April 2020. This would provide the appropriate channels for industry scrutiny and transparency, and for an ultimate Ofgem decision on any required changes to the standard.

5.8. *Action (2):* The ESO should consider and come forward with recommendations to improve the transparency of real-time operational requirements and its holding of reserve, response and system inertia, and review its procedures for holding balancing service providers to account for delivery of balancing services.

5.8.1. We expect the ESO will provide more visibility to the industry on how secure the system is and which services are being used to provide that security. Additionally, given the issues we have identified with the ESO's management of balancing service providers' performance and the significant expenditure on these services, we expect it to strengthen their processes for holding providers to account. We also expect it to report against key performance indicators to demonstrate the effectiveness of these process improvements. The ESO should report its progress on this action to Ofgem on a quarterly basis.

5.9. *Action (3):* 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.

5.9.1. The ESO, as the owner of these compliance testing and modelling processes, is best placed to carry out this review. It should report progress on this action to the E3C by April 2020.

5.10. *Action (4):* Our current investigation should inform Ofgem's review of the ESO's structure and governance framework.

5.10.1. Given the changes which are required in the energy system to achieve Net Zero we believe that the core roles of the system operators are worthy of review. Hence, we have committed in our forward work plan to a strategic system operation review from January 2020. The concerns raised by our investigation into the events of 9 August 2019 and associated lessons learned will inform that work. We will also work closely with BEIS ahead of its position paper on system governance in 2020. If, during the course of the strategic review, we find identify further relevant information regarding the ESO's compliance with any of its obligations, then pursuing additional measures, including enforcement action remains an option.

Distributed generation

Lessons learned

The various protection mechanisms for distributed generation are critical for national system operation.

5.11. The event showed that whilst each distributed generator that de-loaded or tripped may have been small, large volumes of distributed generation behaving in unison can have major impacts on the system. Understanding the behaviour of these generators is critically important for managing the risks to consumers of demand disconnection in a cost-effective manner, and this requires detailed knowledge of their operation and design.

5.12. The protection settings on distributed generation should be addressed as a matter of urgency. This requires undertaking research to establish whether power electronic interfaced generators have internal settings making them sensitive to frequency fluctuations.

The compliance framework for ensuring smaller distributed generators meet the technical requirements of their connection agreements and the Distribution Code must be made more robust.

5.13. When changes are made to the Distribution Code or any other technical requirement to allow the safe and secure operation of the electricity system, these changes must be implemented. There is a possibility that in this case two such long-standing changes required by the Distribution Code were not made in all cases, and this shows that the related regulatory framework should be clarified and strengthened.

Recommended actions

5.14. *Action (5):* The ESO and DNOs through the Energy Networks Association (ENA) should review the timescales for the Accelerated Loss of Mains Change Programme, and consider widening its scope to include distributed generation that unexpectedly disconnected or deloaded on 9 August.

5.14.1. Given the large volume of distributed generation loss was a key driver of the power outage and some of these losses were unexpected, it is vital that the issues are fully understood and that required changes are delivered as quickly as possible. The ENA should put forward recommendations to the E3C by April 2020.

5.15. *Action (6):* Ofgem and BEIS should undertake a joint review of the regulatory compliance and enforcement framework for distributed generators.

5.15.1. This review should explore options for setting and enforcing technical requirements on these generators, including consideration of licensing smaller generators which would require government action. It should take into account any assessments of the current monitoring and enforcement processes undertaken by the E3C. Ofgem and BEIS should engage the industry in Spring 2020.

5.15.2. Given that changes to long-standing Distribution Code requirements governing distributed generators' protection settings do not appear to have been complied with, and the volume of distributed generation continues to increase, it is important and urgent that we assess clear options for setting and enforcing technical requirements.

DNOs

Lessons learned

The effectiveness of LFDD arrangements

5.16. The Grid Code should be more specific on the level of demand disconnection required as an outcome of each stage of the LFDD scheme. As part of this, the arrangements should consider how the allocation of demand disconnection at different stages would impact distribution generation, including distributed generators providing frequency response and reserve services. This consideration impacts the net demand disconnection achieved, and the appropriateness of using winter peak demand as a basis for disconnection requirements. The technical specifications for LFDD equipment should be also reviewed to ensure disconnection can occur effectively, and options explored for technology which would allow for more targeted disconnection of non-essential load.

DNOs' approaches to disconnecting sites providing essential services

5.17. Based on our key finding above, there is room for improvement in how DNOs consider which sites to disconnect. Further requirements or guidance on DNOs' LFDD obligations in the Grid Code would help to ensure a more consistent and proportionate approach to disconnecting essential service providers. There would also be merit in DNOs making their customers more aware of the potential for load shedding for major incidents, and the need for customers to ensure that they have in place back up generation that is regularly tested.

Collection and recording of data on distributed generation

5.18. The DNOs lack of consistent and complete information on the operational characteristics and performance of distributed generators in response to the network fault, demonstrates the scale of the visibility issue surrounding distributed generation. Significant improvements are required in the data availability, adequacy and communication between the DNOs and the ESO to support management of system operation. DNOs must have a much more detailed understanding of their networks in order to more actively manage them as they transition towards becoming DSOs.

Recommended actions

5.19. *Action (7):* E3C, through the DNOs and the ENA, should undertake a fundamental review of the LFDD scheme.

5.19.1. This review should consider:

- the impact of distributed generation on the scheme
- options for short-term and long-term improvements
- the interactions between the scheme and balancing service provision
- options for improving the granularity of the scheme using technology to better target non-essential loads
- guidance on the treatment of essential loads.

5.19.2. The E3C should report progress on this action to Ofgem and BEIS on a quarterly basis.

5.20. *Action (8):* Ofgem, as part of the DSO key enablers work, should consider options to improve the real-time visibility of distributed generation to the DNOs and the ESO.

5.20.1. This review should consider modifications to industry codes and the distribution licences, and requirements for investment in real-time monitoring and control systems. It is timely to consider moving to more granular operational monitoring of distributed generation, given the issues identified in our findings on the lack of visibility of distributed generators' performance on 9 August, and given DNOs are required to operate networks with more active storage, generation and demand. There are synergies with our DSO key enablers work so it is appropriate to include this action within the scope of that programme.

Network and system operators

Lessons learned

Quality of service obligations

5.21. The outage revealed lessons learned for the LFDD arrangements specifically as set out above. However, more broadly, there is merit in introducing specific regulatory obligations on all network companies to provide an appropriate quality of service to customers during power or gas outages which they can be held accountable for.

Recommended actions

5.22. *Action (9):* Ofgem should consider introducing a new licence obligation for network companies and operators for emergency or load shedding.

5.22.1. This obligation could be part of a broader obligation for network companies and operators to treat customers fairly. It should encompass obligations to:

- treat customers fairly during emergency outage or load shedding situations
- avoid disruptions to essential services where possible, keeping them informed and providing support or alternative arrangements
- restoring power in a reasonable timescale.

6. Conclusions and next steps

Overview

6.1. Through our investigation into the 9 August power outage, we have established the sequence of events, circumstances and causes. We have identified that the near-simultaneous deloading that occurred at the Hornsea 1 wind farm and outage that occurred at Little Barford power station, in combination with the loss of smaller distributed generators, triggered the outage. The ESO and DNOs' actions related to the event were generally effective in restoring the system promptly.

Compliance, voluntary action and enforcement

6.2. Some licensees do not appear to have met their licence and code requirements and the event highlights the importance of robust industry compliance processes. Hornsea 1 and RWE Generation have acknowledged their respective roles in contributing to the power outage by not continuing to provide power to the system following the lightning strike. DNOs, Eastern Power Networks plc and South Eastern Power Networks plc, have acknowledged their reconnection of customers without being told to do so by the ESO is a technical breach of their requirements and could potentially have jeopardised recovery of the system. We consider these acknowledgements and the voluntary payment agreements these licensees have entered into to be an appropriate resolution in the circumstances of each case.

6.3. We are not pursuing investigations into the actions of NGET or any of the other DNOs as they appear to have met their obligations.

6.4. We will continue to review the ESO's current application of the SQSS security requirements. This review will be carried out alongside a review of the requirements themselves. If we identify instances in which the ESO has failed to meet its requirements, we will take the necessary action.

6.5. We are continuing to review the performance of distributed generation during the event and will consider whether it is appropriate to open investigations into any licensed parties' compliance with the Distribution Code requirements regarding distributed generators' protection settings.

Lessons learned and recommended actions

6.6. The table below summarises the lessons learned and our recommended actions for implementing them.

Table 2: summary of lessons learned and recommended actions

Parties	Lessons learned	Recommended actions
ESO	The SQSS should be updated periodically to reflect changing system security risks and requirements, and the ESO should take a more proactive approach in proposing changes.	Action (1): the ESO, in consultation with the industry, should undertake a review of the SQSS requirements for holding reserve, response and system inertia. It should raise modification proposals to the SQSS Panel by April 2020.
	The methodologies the ESO uses for estimating inertia, frequency response and reserve requirements and its processes for holding balancing service providers to account for their performance should be reviewed to ensure they are sufficiently robust.	Action (2): the ESO should consider and come forward with recommendations to improve the transparency of real-time operational requirements and its holding of reserve, response and system inertia, and review its procedures for holding balancing service providers to account for delivery of balancing services. It should report its progress to Ofgem on a quarterly basis.
	The ESO's approach to compliance testing for new and modified generation connections should be more considered and proactive, and where the ESO is connecting complex power systems to the network, it must be capable of modelling their performance when the network is disturbed. In addition, the ESO's process for understanding and ensuring the issues behind fault-related outages prior to reconnecting generators should be made more robust.	Action (3): 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. The ESO should report its progress to the E3C by April 2020.
	Further improvements to the ESO's structure and governance framework should be considered in order to meet the challenges of the energy transition.	Action (4): Our current investigation should inform Ofgem's review of the ESO's structure and governance framework from January 2020.
Distributed generation	The various protection mechanisms for distributed generation are critical for national system operation.	Action (5): The ESO and DNOs through the Energy Networks Association (ENA) should review the timescales for the Accelerated Loss of Mains Change Programme, and consider widening its scope to include other distributed generation that unexpectedly disconnected or deloaded on 9 August. The ENA should put forward recommendations to the E3C by April 2020.

Parties	Lessons learned	Recommended actions
Distributed generation (continued)	The compliance framework for ensuring smaller distributed generators meet the technical requirements of their connection agreements and the Distribution Code must be made more robust.	Action (6): Ofgem and BEIS should undertake a joint review of the regulatory compliance and enforcement framework for distributed generators. Ofgem and BEIS should engage the industry in Spring 2020.
DNOs	The Grid Code should be more specific on the levels of demand disconnection required at each stage of LFDD, taking into account the impacts of distributed generation. The specifications for LFDD equipment and the technology options should also be reviewed. Guidance or further obligations would help to ensure a more consistent approach amongst DNOs to disconnecting sites providing essential services and communicating with them beforehand.	Action (7): The E3C, through the DNOs and ENA should undertake a fundamental review of the LFDD scheme. The E3C should report its progress to Ofgem and BEIS on a quarterly basis.
	Significant improvements are required in the data availability, adequacy and communication between the DNOs and the ESO on the performance of distributed generation.	Action (8): Ofgem, as part of the DSO key enablers work, should consider options to improve the real-time visibility of distributed generation to the DNOs and the ESO.
Network and system operators	Regulatory obligations should be put in place to ensure network companies can be held accountable for providing an appropriate quality of service to customers during power or gas outages.	Action (9): Ofgem should consider introducing a new licence obligation for network companies and operators for emergency or load shedding.