Appendices to the Technical Report on the events of 9 August 2019

6 September 2019

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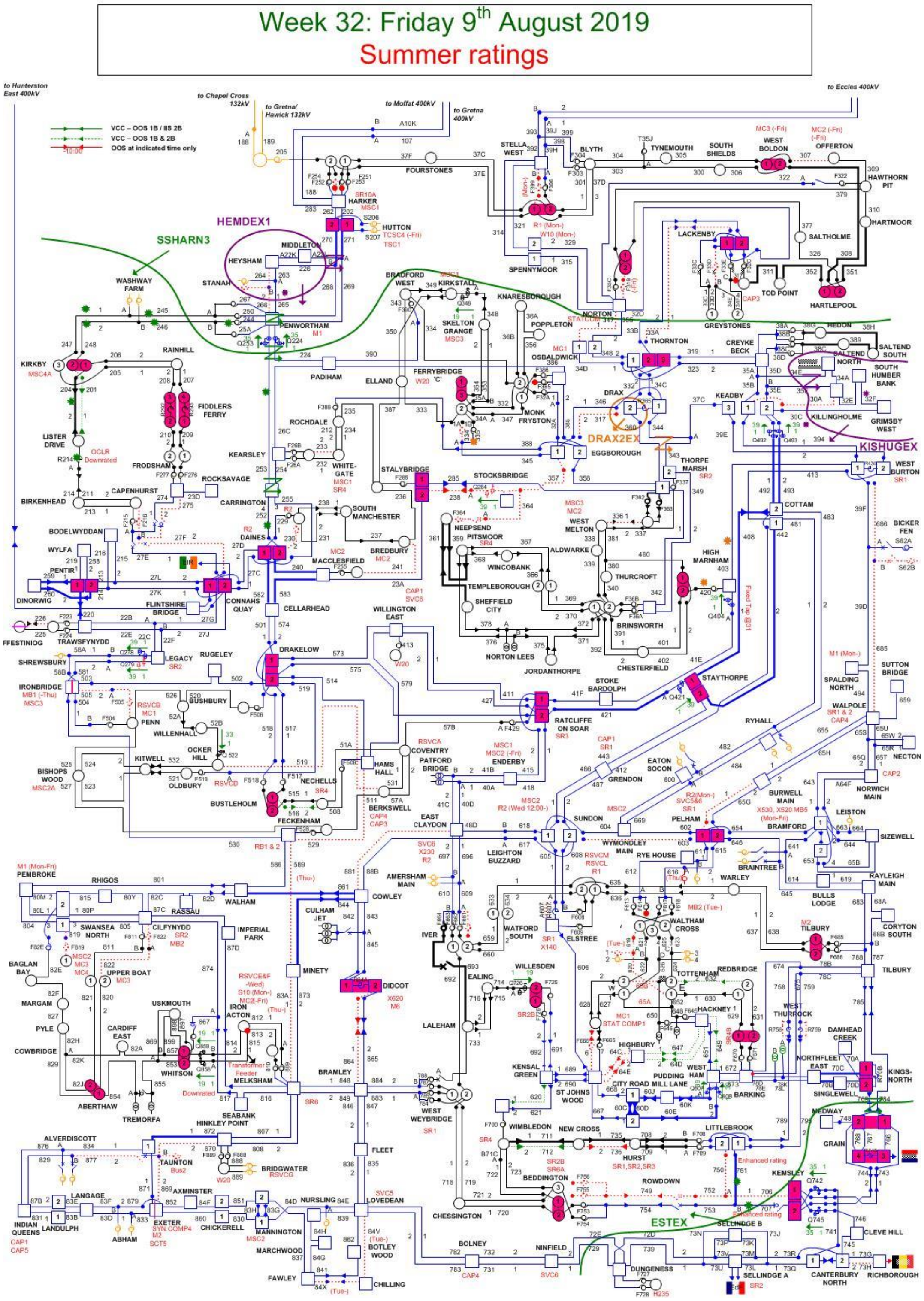
Appendix A - System Conditions Prior to the Incident

This Appendix provides an overview of system conditions on 09 August prior to the incident including: transmission system outages; generation mix on the system; out-turn wind and solar generation; a full list of operational BMUs; an overview of weather on the day.

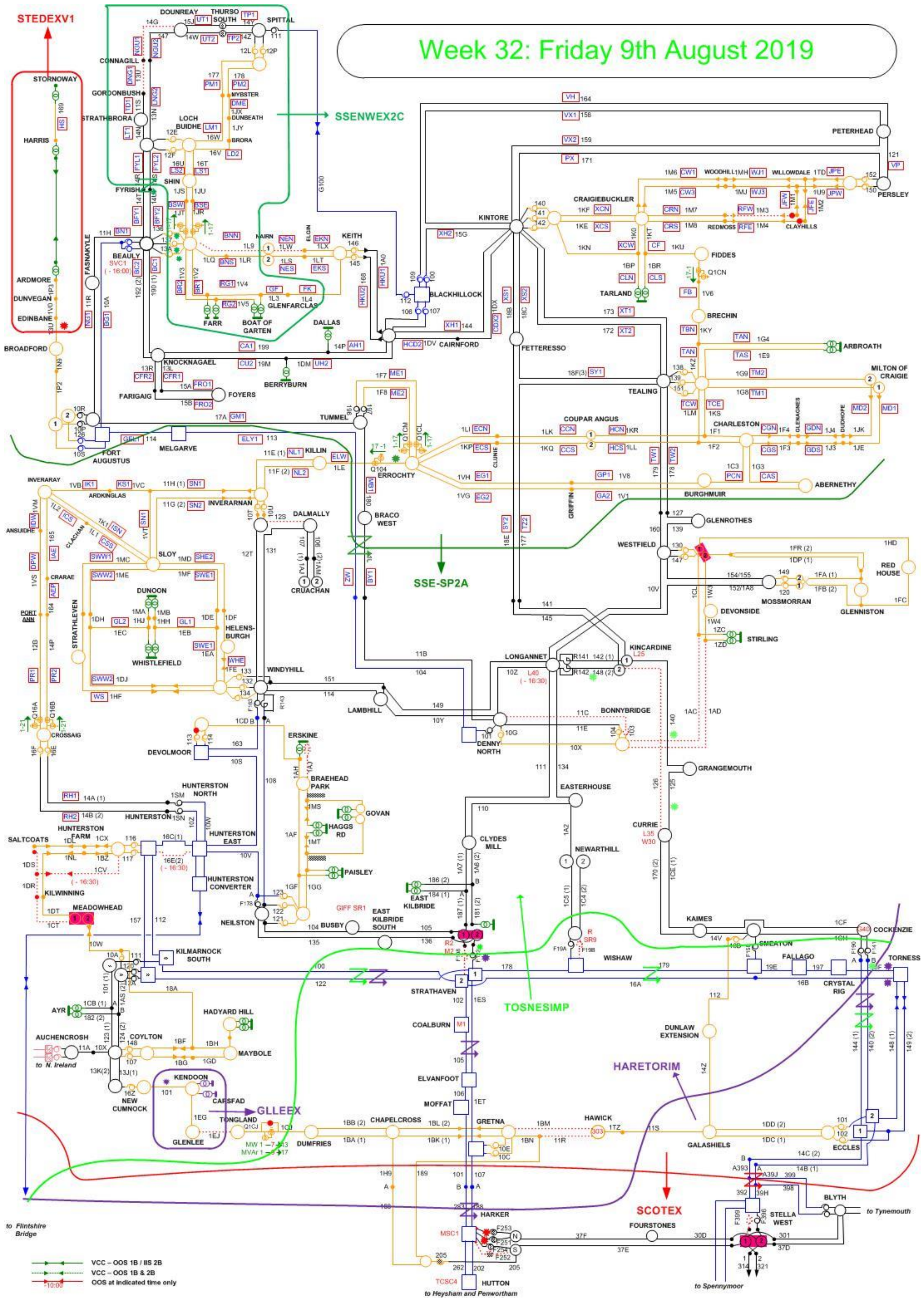
System Diagrams for 09 August 2019

The diagrams below are network representations of the transmission networks in England & Wales and separately Scotland. The different colours of connected lines of blue, black and orange represent the different transmission voltages, 400kV, 275kV and 132kV respectively. Dotted red lines show circuits and equipment which were out of service for Transmission Owner works, either maintenance or construction. The overlaid lines show the active transmission constraints which were being managed on the system.

Transmission System E&W



Transmission System in Scotland



Keys:

400kV circuit

275kV circuit

132kV circuit

Circuit on outage

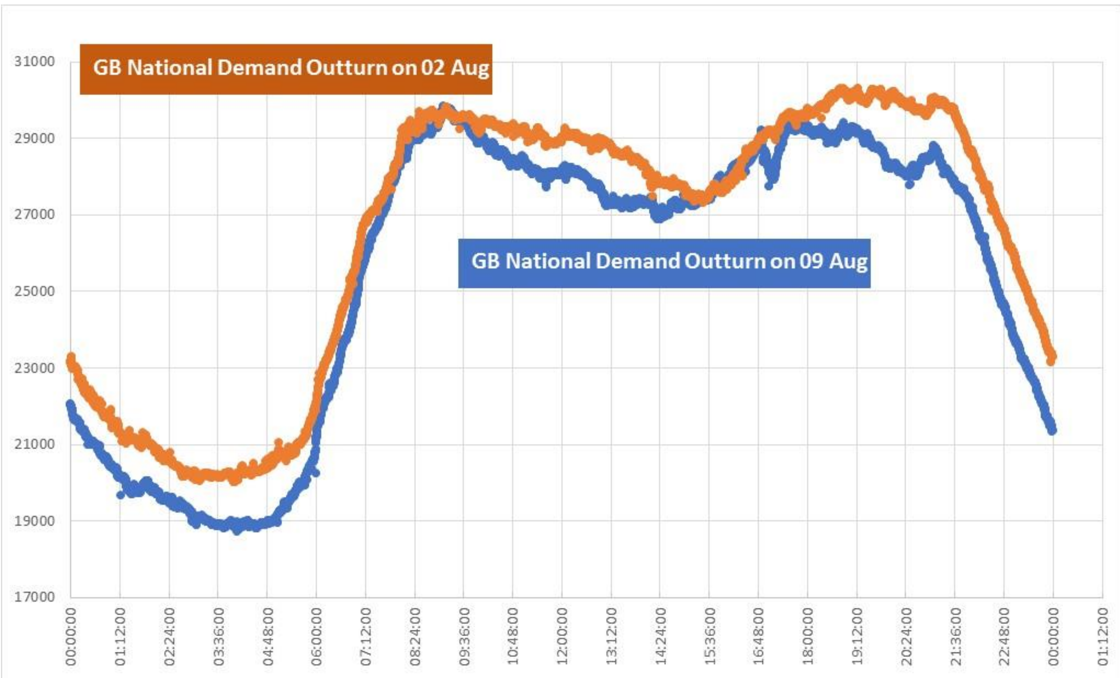
Circuit out of service for voltage control

List of Active Constraints:

England & Wales	Scotland
DRAX2EX	GLLEEX
ESTEX	HARETORIM
HEMDEX1	SCOTEX
KISHUGEX	SSENWEX2X
SSHARN3	SSE-SP2A
	STEDEXV1
	TOSNESIMP

GB Demand Outturn on 9 August

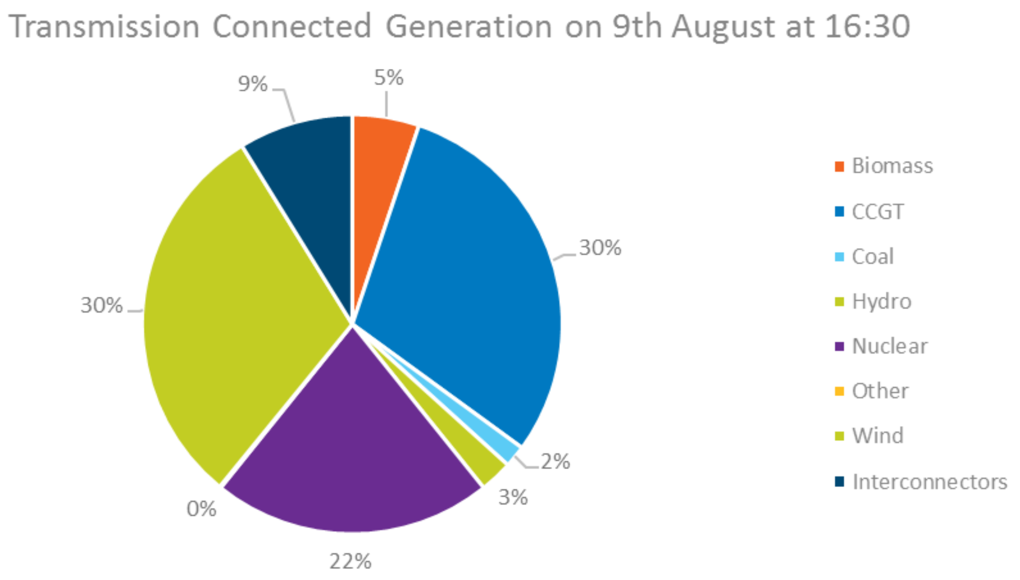
Below is a chart showing the demand for both Friday 9th August and Friday the 2nd August for comparison. The demand profile is similar to other summer days and is in line with normal expectations.



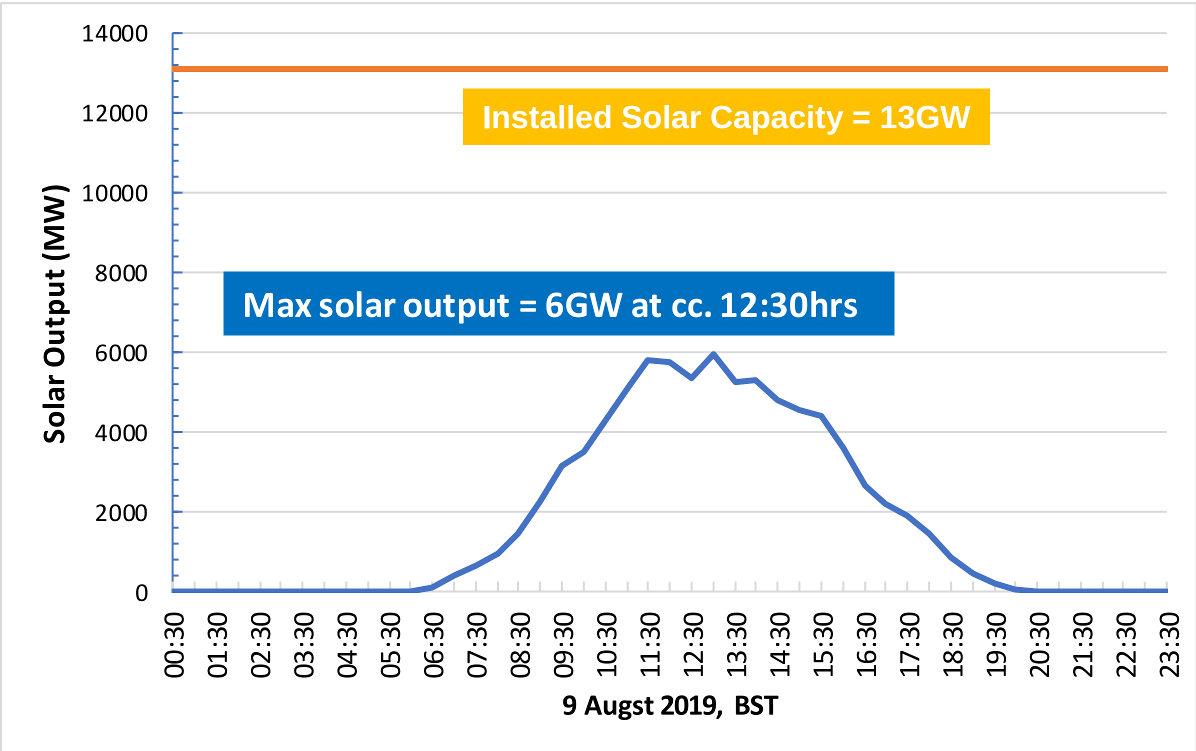
Generation Outputs, Solar and Wind Generation Outputs

The generation mix in the half hour before the event is shown in the pie chart below and is as might be expected for this time of year.

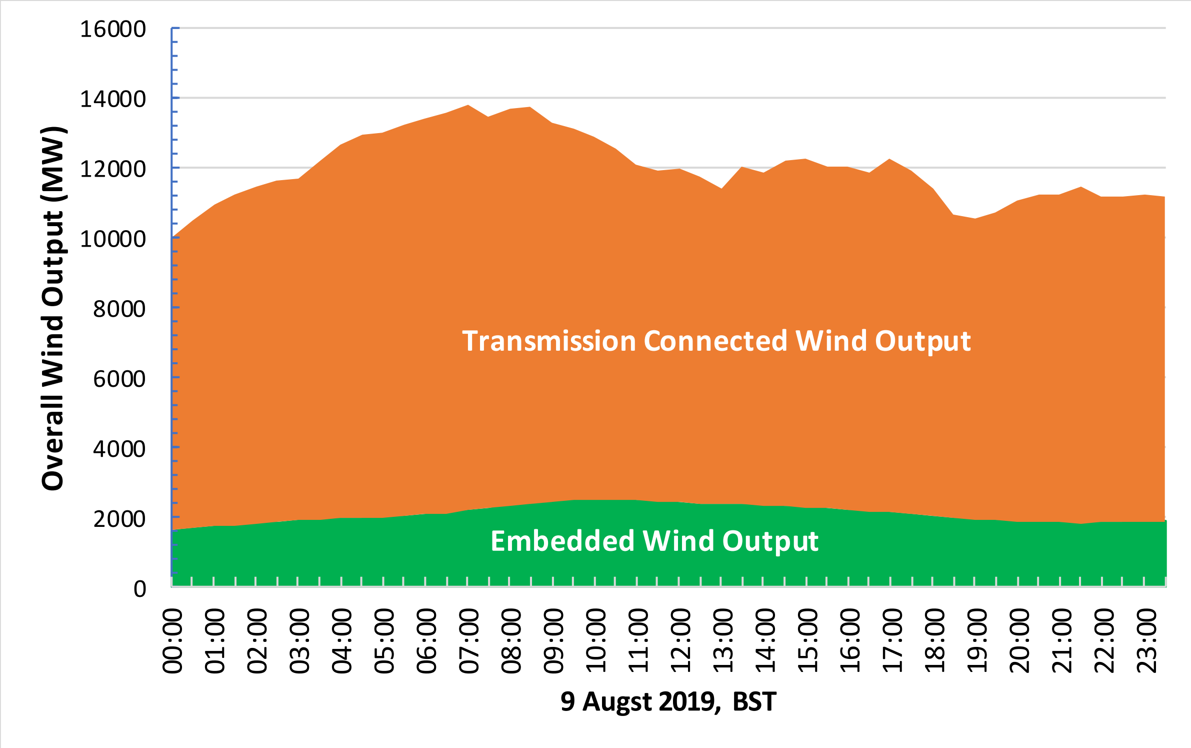
The peak solar output for the day was 6GW which was below the record peak of 9.55 GW on May 14th 2019. The peak wind output of 13.8 GW occurred at 07:00 and was below the record peak of 15.5 GW on 7th January 2019.



Generation Mixture on 9 August 2019



Half Hour – Estimated Average UK Solar Generation Output on 9 August 2019



Half Hour – Estimated Embedded Wind Generation Output on 9 August 2019

List of Operational BMUs on 9 August

The table below provides a list of Operational BMUs on 9 August details all of the Balancing Mechanism Generators which were synchronised and generating at the time of the event. (Excluding interconnectors)

BMU ID	FUEL	Output MW	BMU ID	FUEL	Output MW	BMU ID	FUEL	Output MW
DRAXX-3	BIOMASS	630	AG-ALIM02	OTHER	1	GRGBW-1	WIND	151
DRAXX-4	BIOMASS	618	AG-BUKP01	OTHER	2	GRGBW-2	WIND	165
LNMTH-1	BIOMASS	130	AG-FFLX01	OTHER	1	GRGBW-3	WIND	148
MARK-1	BIOMASS	53	AG-MFLX01	OTHER	2	GRIFW-1	WIND	34
WILCT-1	BIOMASS	30	ARNKB-1	OTHER	8	GRIFW-2	WIND	34
CARR-1	CCGT	182	CRSSB-1	OTHER	3	GYMRO-17	WIND	75
CDCL-1	CCGT	368	EAS-SEL01	OTHER	13	GYMRO-28	WIND	79
CNQPS-1	CCGT	260	ABRBO-1	WIND	88	HADHW-1	WIND	20
FELL-1	CCGT	2	ABRTW-1	WIND	1	HBHDW-1	WIND	2
GRAI-6	CCGT	364	ACHRW-1	WIND	42	HLGLW-1	WIND	24
GRAI-7	CCGT	378	AFTOW-1	WIND	15	HLTWW-1	WIND	33
GRAI-8	CCGT	379	AKGLW-2	WIND	20	HMGTO-1	WIND	103
HUMR-1	CCGT	609	ANSUW-1	WIND	8	HMGTO-2	WIND	101
KEAD-1	CCGT	356	ARCHW-1	WIND	53	HOWAO-1	WIND	70
KLYN-A-1	CCGT	44	ASHWW-1	WIND	7	HOWAO-2	WIND	394

LBAR-1	CCGT	609	ASLVW-1	WIND	8	HOWAO-3	WIND	369
LSTWY-1	CCGT	2	BABAW-1	WIND	45	HRHLW-1	WIND	4
MRWD-1	CCGT	463	BDCHW-1	WIND	24	HRSTW-1	WIND	4
PEMB-21	CCGT	414	BEATO-1	WIND	125	HYWDW-1	WIND	29
PEMB-31	CCGT	397	BEATO-2	WIND	125	KLGLW-1	WIND	136
PEMB-41	CCGT	400	BEATO-3	WIND	160	KPMRW-1	WIND	18
PEMB-51	CCGT	404	BEATO-4	WIND	167	LARYO-1	WIND	90
RDFRB-1	CCGT	3	BETHW-1	WIND	23	LARYO-2	WIND	40
RDFRD-1	CCGT	3	BHLAW-1	WIND	65	LARYO-3	WIND	149
ROCK-1	CCGT	256	BLKWW-1	WIND	12	LARYO-4	WIND	156
RYHPS-1	CCGT	200	BLLA-1	WIND	2	LCLTW-1	WIND	60
SCCL-1	CCGT	160	BLLA-2	WIND	1	LNCSO-1	WIND	115
SCCL-2	CCGT	160	BNWKW-1	WIND	16	LNCSO-2	WIND	125
SCCL-3	CCGT	348	BOWLW-1	WIND	34	MDHLW-1	WIND	70
SHBA-2	CCGT	469	BRBEO-1	WIND	210	MIDMW-1	WIND	13
STAY-2	CCGT	368	BRDUW-1	WIND	13	MILWW-1	WIND	64
STAY-4	CCGT	366	BRYBW-1	WIND	44	MINSW-1	WIND	1
SVRP-10	CCGT	173	BTUIW-2	WIND	13	MKHLW-1	WIND	18
TRFPK-1	CCGT	1	BURBW-1	WIND	42	MOYEW-1	WIND	24
WBURB-2	CCGT	256	CAIRW-1	WIND	40	MYGPW-1	WIND	2
WBURB-3	CCGT	85	CAIRW-2	WIND	36	OMNDO-1	WIND	53
WTRLN-1	CCGT	3	CLDCW-1	WIND	35	PAUHW-1	WIND	63
COTPS-3	COAL	480	CLDNW-1	WIND	43	PNYCW-1	WIND	183
CAS-BEU01	HYDRO	21	CLDRW-1	WIND	23	RCBKO-1	WIND	249
CAS-CLU01	HYDRO	46	CLFLW-1	WIND	7	RCBKO-2	WIND	260
CAS-CON01	HYDRO	74	CMSTW-1	WIND	44	RMPNO-1	WIND	172
CAS-GAR01	HYDRO	32	CNCLW-1	WIND	29	RMPNO-2	WIND	180
CAS-KIL01	HYDRO	23	COUWW-1	WIND	13	RREW-1	WIND	15
CAS-MOR01	HYDRO	34	CRGHW-1	WIND	41	RRWW-1	WIND	22
CLAC-1	HYDRO	40	CRMLW-1	WIND	42	SANQW-1	WIND	11
DINO-5	HYDRO	33	DALSW-1	WIND	3	SHRSO-1	WIND	86
DINO-6	HYDRO	298	DDGNO-1	WIND	60	SHRSO-2	WIND	86
ERRO-1	HYDRO	2	DDGNO-2	WIND	60	STLGW-1	WIND	45
ERRO-3	HYDRO	2	DDGNO-3	WIND	53	STLGW-2	WIND	52
FASN-1	HYDRO	22	DDGNO-4	WIND	63	STLGW-3	WIND	45
FASN2	HYDRO	2	DOREW-1	WIND	91	STRNW-1	WIND	46
FASN-4	HYDRO	7	DOREW-2	WIND	76	TDBNW-1	WIND	1
FFES-3	HYDRO	12	DRSLW-1	WIND	15	THNTO-1	WIND	130

FFES-4	HYDRO	17	DUNGW-1	WIND	87	THNTO-2	WIND	130
FINL-1	HYDRO	17	EDINW-1	WIND	14	TULWW-1	WIND	6
KNLCV-1	HYDRO	23	FAARW-1	WIND	24	TULWW-2	WIND	7
NANT-1	HYDRO	15	FAARW-2	WIND	24	WDNSO-1	WIND	63
HEYM11	NUCLEAR	220	FSDLW-1	WIND	9	WDNSO-2	WIND	63
HEYM12	NUCLEAR	415	GAOFO-1	WIND	75	WHIHW-1	WIND	11
HEYM27	NUCLEAR	647	GAOFO-2	WIND	78	WHILW-1	WIND	8
HEYM28	NUCLEAR	638	GAOFO-3	WIND	76	WHILW-2	WIND	2
HINB-7	NUCLEAR	491	GAOFO-4	WIND	72	WISTW-2	WIND	24
HINB-8	NUCLEAR	482	GDSTW-1	WIND	12	WLNYO-2	WIND	84
HRTL-1	NUCLEAR	577	GLCHW-1	WIND	6	WLNYO-3	WIND	238
HRTL-2	NUCLEAR	578	GLOFW-1	WIND	20	WLNYO-4	WIND	229
SIZB-1	NUCLEAR	590	GLWSW-1	WIND	17	WLNYW-1	WIND	42
SIZB-2	NUCLEAR	190	GNAPW-1	WIND	12	WTMSO-1	WIND	193
TORN-1	NUCLEAR	641	GNFSW-1	WIND	100			
TORN-2	NUCLEAR	641	GNFSW-2	WIND	64			
AG-AFLX01	OTHER	2	GORDW-1	WIND	69			

Weather Forecast

There weather forecast for the day was; Rain, heavy at times, clearing northwards, but persisting in northern and eastern Scotland. A mix of sunny spells, but also some heavy and possibly thundery showers will follow on behind. Feeling warm and humid for many, but increasingly windy.

Lightning Forecasts from Meteogroup on 9 August 2019

ESO obtains information on lightning strikes from the Meteogroup. Lightning risk is provided on a scale of 1-5, with 5 referring to the least risk of lightning (due to the absence of the required weather conditions), and 1 the highest risk. On 9 August from 05:49hrs onwards ESO received email updates on the lightning risk from Meteogroup. The Lightning Risk 1 regions are shown in Table 1. East Anglia was updated to Risk 1 in the update just prior to the incident.

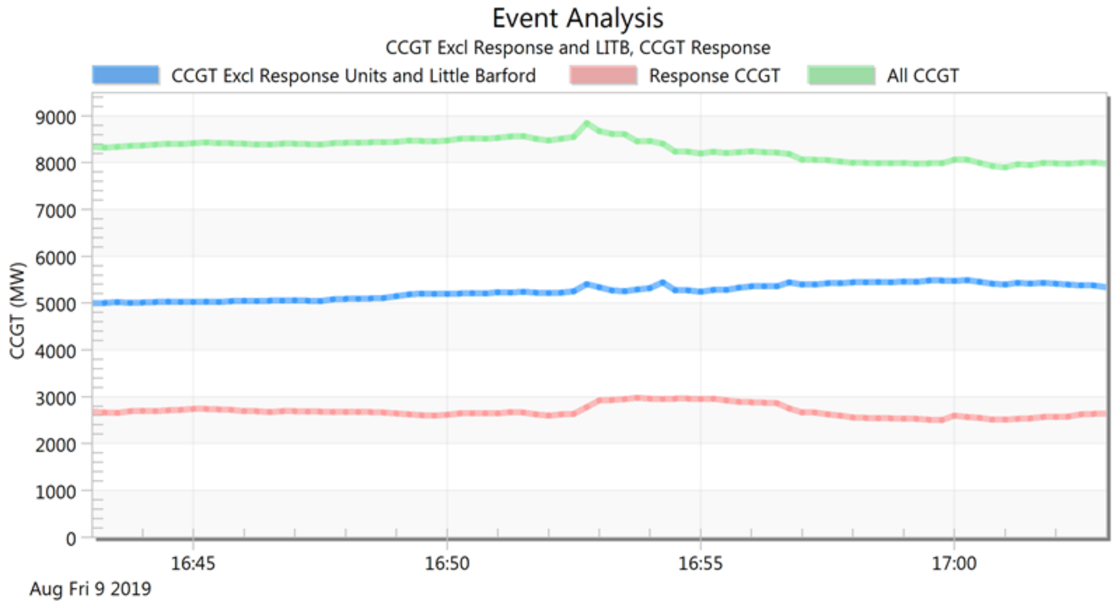
Time of Lightning Update Received	Regions Forecasted with Level 1 lightning risk for the next 24 hours
05:49hrs	North West England, North East England, Midlands / Lincs
08:02hrs	North West England, North East England, Midlands / Lincs, Southern Scotland
12:34hrs	North West England, North East England, Midlands / Lincs, Southern Scotland, North Wales, South Wales
16:44hrs	North West England, North East England, Midlands / Lincs, Southern Scotland, North Wales, South Wales, Northern Scotland, East Anglia, Central South England, South East England

Appendix B – Transmission Connected Generation Performance

This Appendix provides and overview of generation output before, during and after the incident by fuel type. The analysis shows that all plant technologies behaved as expected.

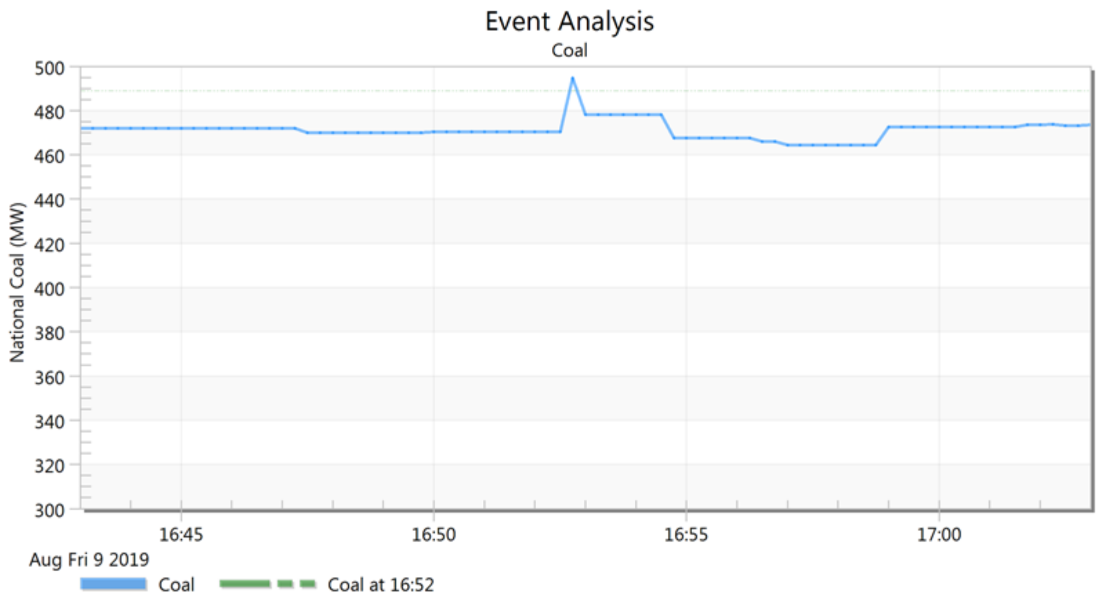
CCGT

From the graph below, it can be seen that excluding the trip of Little Barford, the CCGT fleet (both those in frequency responsive mode and those not) were stable during the event.



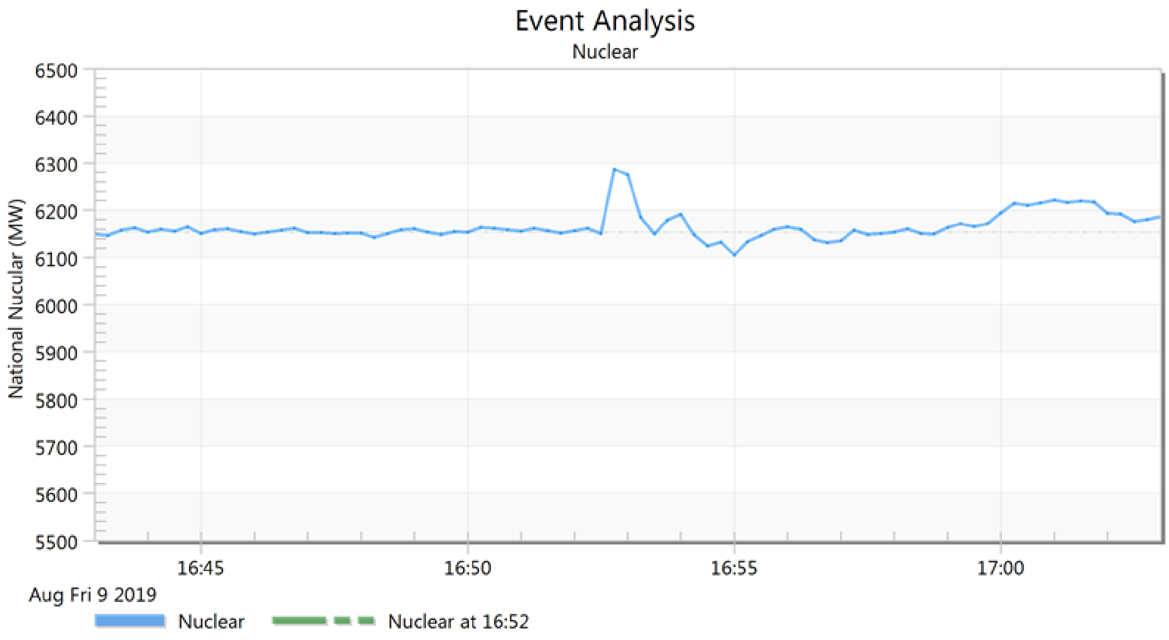
Coal

Coal-fired generation also provided a stable output during the incident.



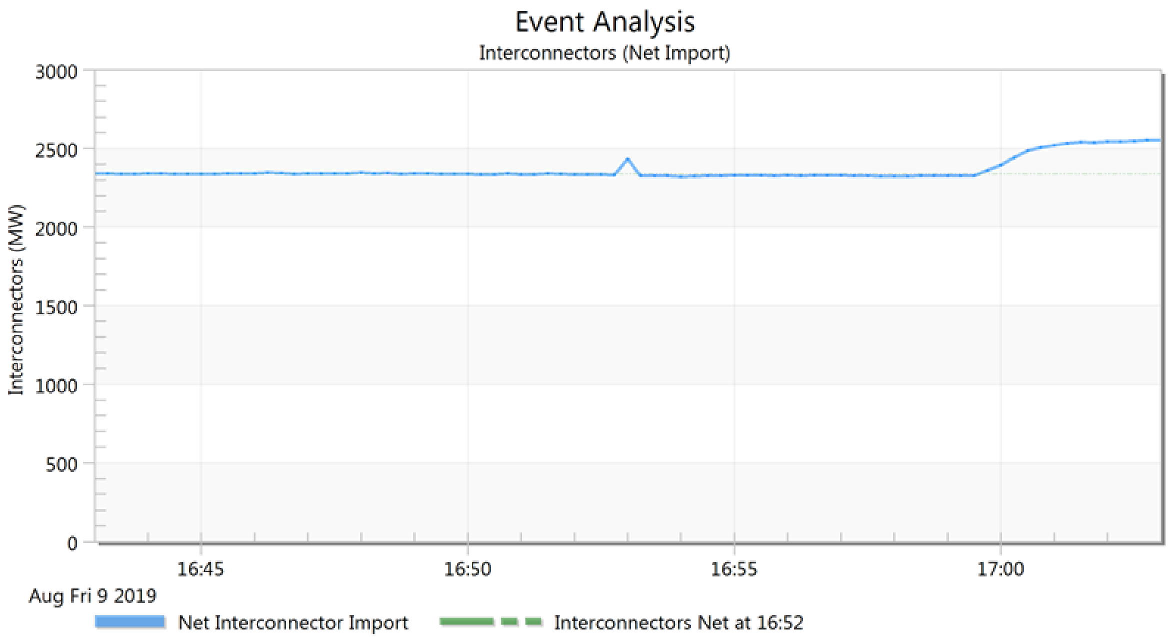
Nuclear

Nuclear generation, although not expected to respond to frequency events, remained stable and in fact provided some additional generation at the start of the frequency dip. In response to a low frequency event, the governor droop characteristics of the nuclear generators mean that all nuclear stations provide an initial increase in output.



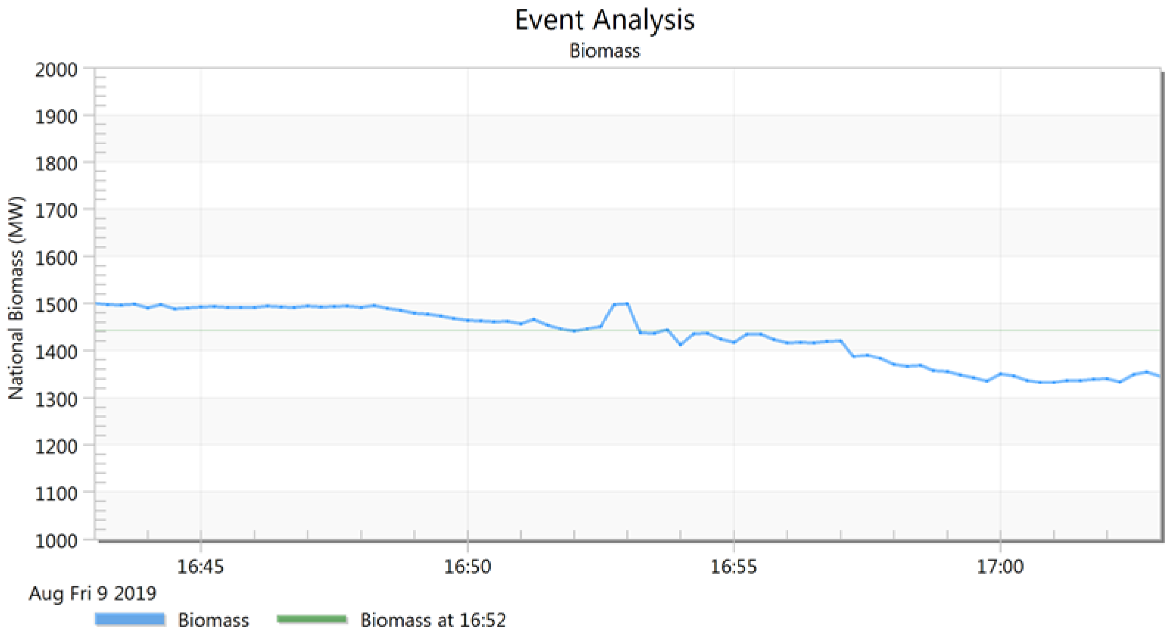
Interconnectors

Interconnector output remained stable during the event.



Biomass

Biomass generation remained stable during the event.



Appendix C - NGET Technical Report

This Appendix contains the independent technical report provided to the ESO by National Grid Electricity Transmission (NGET) into the performance of the England and Wales transmission system on 09 August as part of the detailed investigation into the incident.

National Grid Electricity Transmission (NGET)

Report into the Power Interruption following Generator Trips and Frequency Excursion on 9th August 2019

National Grid Electricity Transmission

Report into the power interruption following Generator Trips and Frequency Excursion On 9th August 2019

Executive Summary

On the evening of Friday 9th August 2019, we experienced significant storms across the UK, resulting in heavy rain and lightning. We have many storms throughout the year and some of these result in lightning strikes to equipment, causing our circuits to switch out to clear the fault. Normally these events pass without further incident. On that evening, there were a series of events that ultimately caused the disconnection of approximately 1 million electricity consumers. This caused significant disruption to both electricity consumers and travellers across Britain.

Following the lightning strike on our Eaton Socon – Wymondley Main circuit, in Hertfordshire at 16.52 our equipment correctly cleared the electrical fault. The network performed as expected and designed. The resulting electrical performance was what we would normally expect with a lightning strike of the magnitude experienced in the area.

The circuit was returned to service 20 seconds later with our automatic Delayed Auto-Reclose system again operating as expected and designed. This action restored the network to its pre-event status.

Since then NGET has spent time establishing the facts associated with the transmission asset performance before, during and after the event. This report explains how the physical transmission system performed that evening.

In summary, our key finding is that the electricity transmission network operated as designed and in line with standards, and specifically:

- At 16:52 on the 9th August 2019 the electricity transmission system saw a lightning strike on the Eaton Socon – Wymondley Main Circuit, 4.5km from Wymondley substation. This caused the middle conductor (blue phase) to fault to the earthed transmission tower causing a voltage transient depression of 50% on blue phase and fault currents of 7kA and 21kA at Eaton Socon and Wymondley Main substations respectively.

- The main protection at Wymondley Main operated in 70ms and the main protection at Eaton Socon operated in 74ms, therefore clearing the fault within the 80ms required in the Grid Code.

- A voltage depression of circa 50% was seen at the fault location on the blue phase which lasted for 100ms in the vicinity of the fault. Further from the fault, voltage dips of 20% were observed with 80ms duration. The voltage depression and duration were as expected for this type of fault.

- All pre-fault and post-fault steady state voltages were within limits required within industry standards and the transient effects during the fault aligned with Grid Code fault ride through requirements. Harmonic and Negative Phase Sequence currents were within limits set out within the relevant standards and codes.

Contents

Main Report Introduction

On Friday 9th August at 16.52 there were a series of events that ultimately caused the disconnection of approximately 1 million electricity consumers.

This report sets out the performance of the National Grid Electricity Transmission (NGET) system assets during the events of 9th August 2019 and explains the post event analysis that has been undertaken to establish the facts associated with the event on the transmission system.

National Grid Electricity Transmission (NGET) is the owner of the high-voltage electricity transmission network, and its associated assets, in England and Wales. Our work involves building and maintaining the electricity transmission network safely, reliably and efficiently. We connect sources of electricity generation, which we do not own, to the transmission network. We then transport the electricity onwards to large directly connected customers such as steelworks, and to distribution network operators, who then transport the electricity onwards again to homes and businesses across Britain.

The report is structured as follows

Part 1: Our transmission system response to a lightning strike on the Eaton Socon – Wymondley Main transmission circuit

Part 2: Communications between NGET, Distribution Network Operators (DNOs) and National Grid ESO during the events of 9th August 2019.

Part 3: Post event analysis we have undertaken to support industry investigation into the events of 9th August 2019.

Part 4: Our findings and next steps.

1. Part 1 - Our transmission system response to a lightning strike on the Eaton Socon – Wymondley Main transmission circuit

1.1 Easton Socon – Wymondley Main Circuit trip

On the afternoon of the Friday 9th August 2019 a number of severe storm systems were passing through the United Kingdom, including the Hertfordshire area. The Eaton Socon – Wymondely Main circuit, is an 400kV (400,000 Volt) double circuit overhead line running from Eaton Socon substation near St Neots in Cambridgeshire; to Wymondley Main substation near Stevenage in Hertfordshire. This circuit runs for just over 35km and is made up of lattice steel towers (pylons), carrying two circuits, each with 3 sets of associated conductors, one each side of the tower as depicted below, and an earth wire at the top of the tower: -

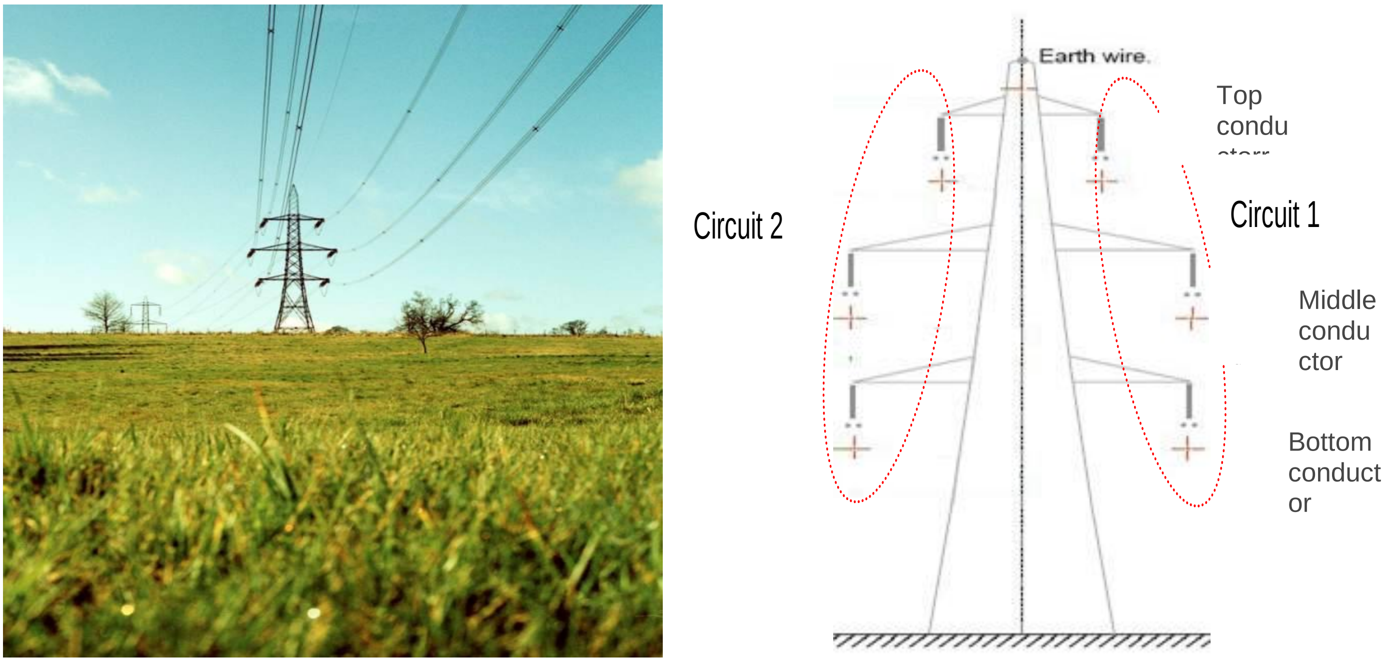


Figure 1.1: Example of a 400kV Double Circuit Tower

At 16.52 there was a storm with lightning and heavy rain in the area around Wymondley Main Substation. A lightning strike hit one of the Eaton Socon – Wymondley Main circuits approximately 4.5km along the circuit from the Wymondley Main substation end. The Electricity Transmission system in the UK is a 3-phase system operating at 50Hz, with each circuit having three wires/conductors. Each of these phases of AC power is given a colour designation of Red, Blue and Yellow to ensure all connections are made consistently.

The lightning struck the middle conductor on one side of the pylon causing an electrical fault between the middle (blue phase) conductor and the tower which is earthed to the ground. During the single circuit electrical fault both the voltage and current flowing in the circuit were affected; the blue conductor phase voltage was reduced by approximately 50% and currents of 21kA (21 thousand amps) were recorded at Wymondley Main and 7kA at Eaton Socon. These voltage and current effects are within the parameters and the design ratings of the transmission system and are not unusual for this type of lightning strike event.

Each of our transmission circuits have protection systems associated with them, the purpose of which is to detect faults on a circuit when they occur and clear them by opening the switches (called circuit breakers), at each end of the circuit. We, like all transmission network users in the UK, are required to ensure that our system meets the requirements of the Grid Code (technical standard). One requirement of the Grid Code (Connection Condition CC.6.2.3.1.1) is that our 400kV primary main circuit breaker protection operates within 80ms to clear electrical faults. In this event the circuit breaker at Wymondley Main substation opened in 70ms and the circuit breaker at Eaton Socon substation opened in 74ms, clearing the fault from the network. Our network operated correctly and entirely as expected.

All transmission network owners in the UK are also required to design their networks to meet the requirements set out with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). This standard requires that the system should remain within specified limits for voltage and that circuit current should not exceed the circuit rating, etc, following a range of defined fault events, including the prolonged loss of two circuits (such as the circuits between Eaton Socon and Wymondley Main described above). This event resulted in the loss of only one of the circuits rather than two, and for a duration of only 20 seconds as our automatic systems then returned it to service correctly in line with the design of those systems (as described below). We saw transient voltages and currents within the Grid Code tolerances and steady state system voltages and currents remained within the limits defined within the NETS SQSS following the event.

1.2 Delayed Auto Re-Close (DAR)

Our transmission system (in line with other similar systems around the world) is designed to automatically return some circuits back to system service following clearance of electrical faults. This is because many of the electrical faults we experience, like lightning strikes, are transient (temporary) in nature. By utilising automatic systems (called Delayed Automatic Re-close – DAR), we can restore the network to its full system resilience as quickly as possible. On the 9th August, the DAR system was available and in service on the Eaton Socon - Wymondley Main circuit and it successfully returned the circuit to service within 20 seconds in line with the design arrangements for the DAR system. This restored the network to the same configuration seen prior to the event. The DAR system in this case again operated exactly as expected and required no further operational intervention or immediate site attendance.

2. Part 2: Communications between NGET, Distribution Network Operators (DNOs) and National Grid ESO during the events of 9th August 2019.

2.1 Transmission Network Control Centre (TNCC) Communications

The Transmission Network Control Centre (TNCC) is part of the NGET business and operates 24/7, 365 days a year to undertake transmission switching as required by the ESO Electricity National Control Centre (ENCC). The TNCC also monitor alarms associated with our transmission assets, and ensures any circuits switched out for maintenance or other works are made safe for personnel to work on them.

As is standard practice the ENCC led the response to the system fault on 9th August. Our TNCC control room communicated directly with the ESO ENCC control room. The Distribution Network Operators (DNOs) also communicated direct with the ENCC. Our TNCC control room received electronic system alarm indications to notify them that the Low Frequency Demand Disconnection (LFDD) scheme – an industry automatic protection mechanism which disconnects demand when system frequency reaches specific pre-determined levels - had operated. This was confirmed by phone with the ENCC and DNOs over a period of 8mins following receipt of the initial alarm indications.

The TNCC control room has responsibility for managing electrical system safety on the National Electricity Transmission System and at the interfaces of our system and those connected to it, and as part of this role operates a phone number to allow the public to notify them of safety concerns that they may have related to our system or assets. On the 9th August and afterwards the TNCC received a number of calls from members of the public using this number to find out information regarding the power interruption. As these calls were not related to a network safety issue, we redirected each call to the Electricity Networks Association (ENA) information "105" number. Phone calls were also received from third party organisations and DNO customers, who were each directed to the relevant body for restoration information.

2.2 Other response and communications

On the evening of the event we established an operational management team to oversee our response to the event. This team led our initial review of how the NGET system had operated during and after the event, and coordinated our collation of information into what had happened. Our operational staff were requested to attend Wymondley Main and Eaton Socon substations to collect data from our systems including protection operating data. Engineers went to both sites and confirmed all assets were operating as normal at each substation and no defects on our assets were identified.

Our overhead line engineers undertook a visual inspection of the Eaton Socon – Wymondley Main overhead line, on the morning Saturday 10th August. No identified defects were observed. Once we established our assets were secure and in normal operation, we switched our focus to post fault analysis of the event itself.

3. Part 3: Post event analysis undertaken by NGET to support industry investigation into the events of 9th August 2019.

Figure 3.0 below shows the relevant section of the transmission system discussed in this report. The location of the lightning strike is indicated to be near to Wymondley Main Substation. For clarity, Little Barford Power Station is connected to the transmission network at Eaton Socon (in Cambridgeshire) substation and Hornsea Offshore Windfarm is connected at Killingholme (in North Lincolnshire).

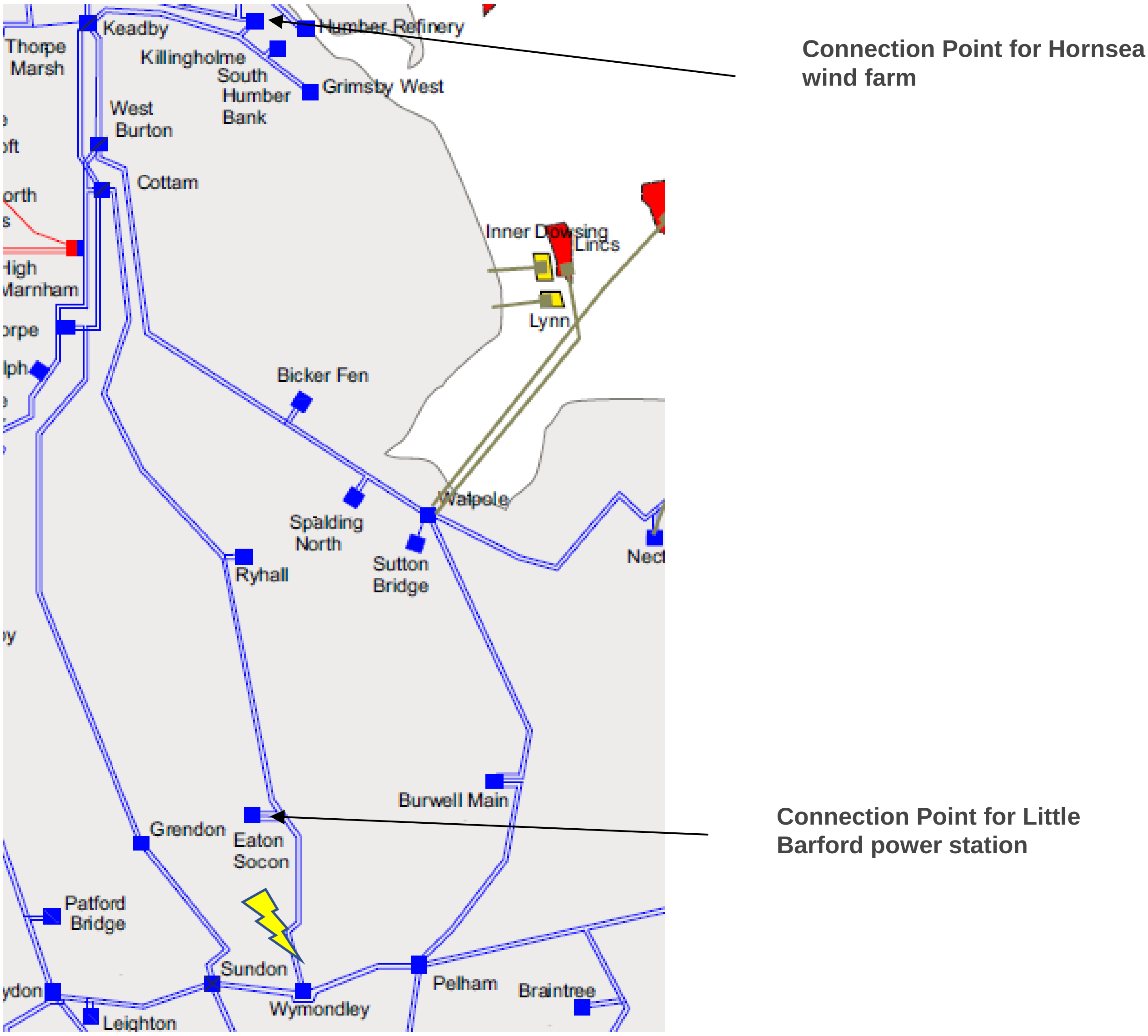


Figure 3.0 Geographic Map Showing NGET Substations and Circuits (in Blue and Red)

3.1 Weather Related Fault Data

3.1.1 MeteoGroup Lightening Activity Recording

Figure 3.1.1 shows lightning activity recorded by MeteoGroup in the vicinity of the Eaton Socon – Wymondley Main circuit. The activity aligns with the protection data indicating the fault was 4.5km from Wymondley Main, just outside Letchworth Garden City. The lightning strike overlay here shows a number of strikes close to our overhead line circuits. One of these strikes is timed at the same time as the fault. As such we can be confident that a lightning strike was the cause of the fault.

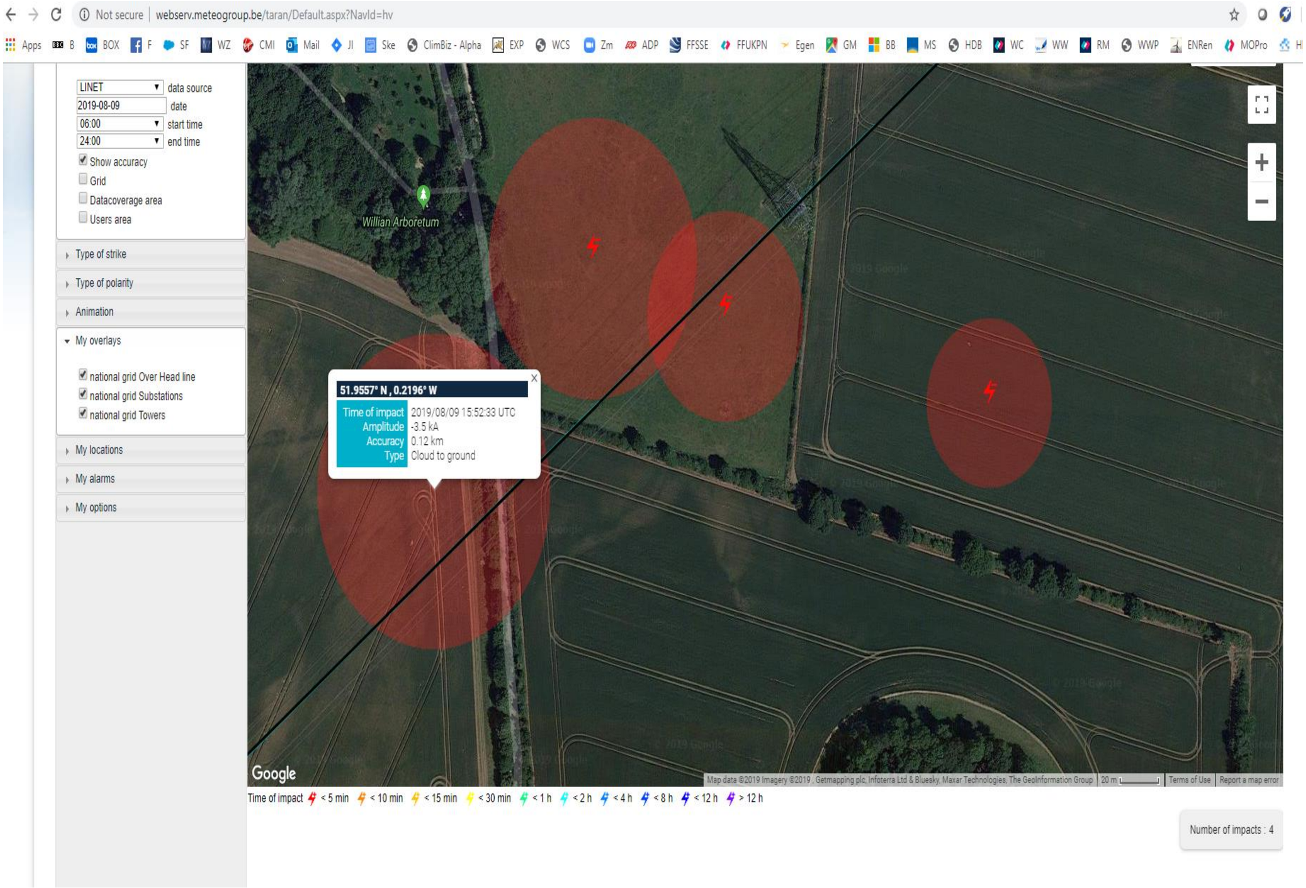


Figure 3.1.1 MeteoGroup Lightning Activity Recordings in the vicinity of Letchworth Garden City.

3.2 Post Event - Protection Analysis

As described in Part 1 of this report the protection systems on the Eaton Socon – Wymondly Main operated as expected and in compliance with the requirements of the Grid Code. The Grid Code Connection Conditions, set the standards by which equipment connected to the transmission system should perform under normal and fault conditions. Grid Code Connection Condition (CC.6.2.3.1.1) require the following fault clearance times for primary protection operation: -

(i) 80ms at 400kV (400,000 volts)

(ii) 100ms at 275kV

(iii) 120ms at 132kV and below

Definition: - Millisecond (ms) 1000th of a second

3.2.1 Eaton Socon Protection Operation.

Figure 3.2.1 shows the operation of the protection at Eaton Socon substation which opened and cleared the electrical fault within 74ms seeing a fault Current 7kA (rms). After a further 20 seconds (outside the timescale of the graph), the circuit was automatically returned to service by DAR.

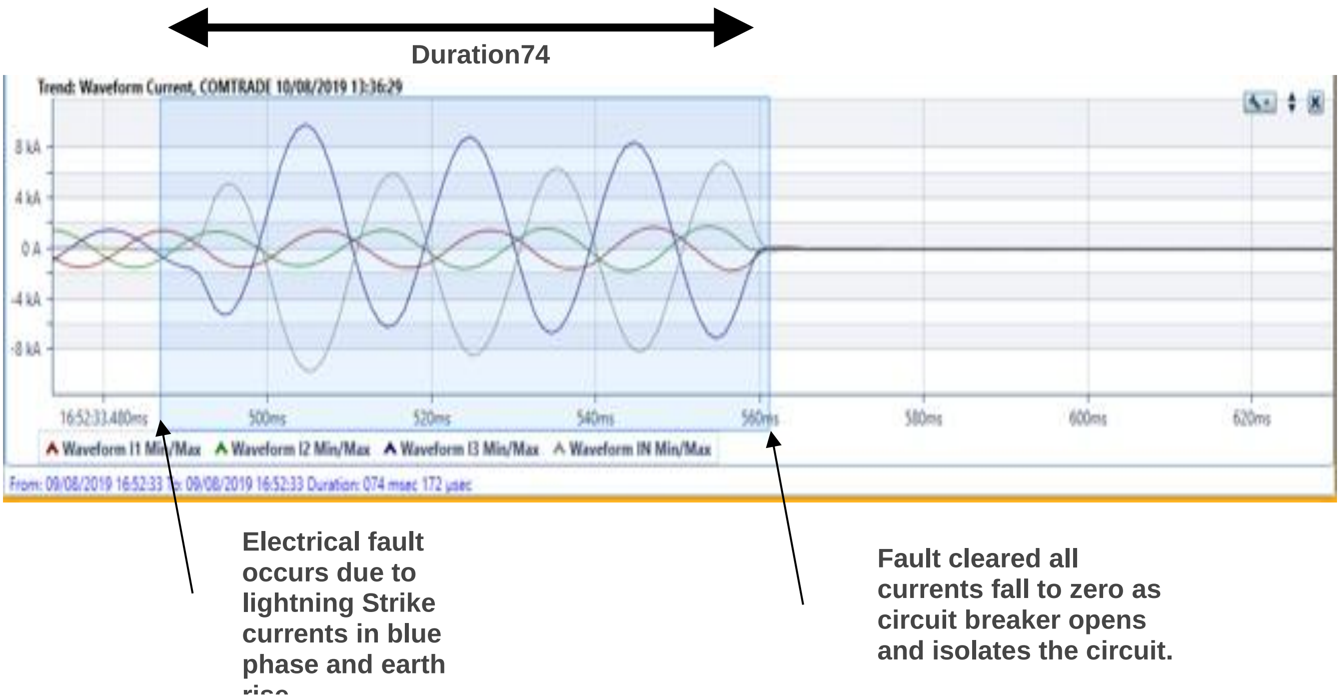


Figure 3.2.1 Eaton Socon, 1st Main Protection Operation.

3.2.2 Wymondley Protection Operation

Figure 3.2.2 below shows the operation of the protection at Wymondley Main substation which opened and cleared the electrical fault within 70ms seeing a fault current of 21kA (rms). After a further 20 seconds (outside the timescale of the graph) the circuit was automatically returned to service by DAR.

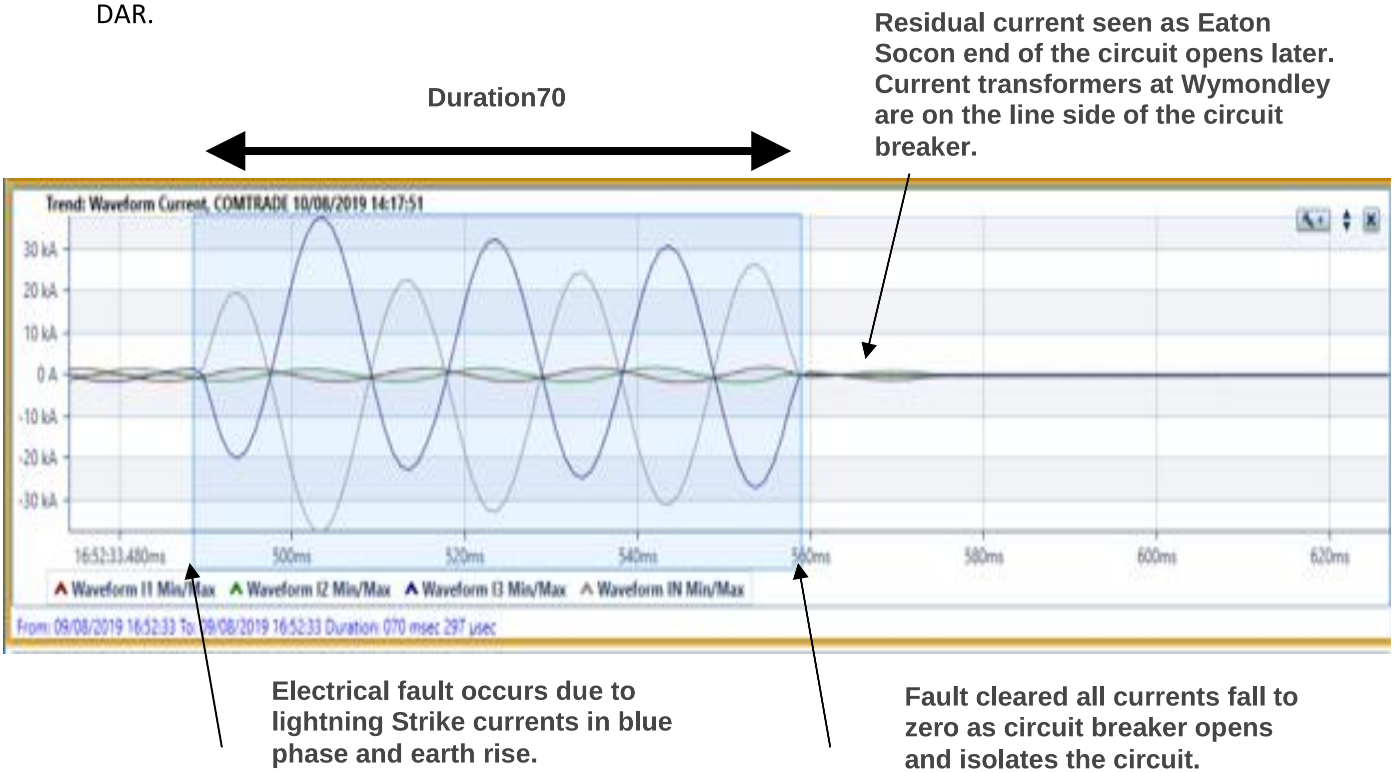


Figure 3.2.2 Wymondley Main, 1st Main Protection Operation

3.2.3 Protection Conclusions

All protection associated with our Eaton Socon – Wymondley Main circuit operated as expected and within the requirements of the Grid Code. All our equipment was operating within our maintenance policy requirements. The operation of both circuit breakers at Wymondley Main and Eaton Socon was as expected, with both operating as designed, clearing the fault currents correctly and within the equipment ratings.

3.3 Power Quality and Monitoring

3.3.1 Power Quality Monitoring at Ryhall 400kV

The following diagrams show transient voltage effects on our transmission system following the fault disturbance to the system caused by the lightning strike. 'Transient' is a term used to describe short duration and quickly changing effects on the system following a fault disturbance such as a lightning strike. These transients are expected and accommodated for in the design of equipment associated with, and connected to, the National Electricity Transmission System.

We have a number of Power Quality Monitors deployed across the system which allow us to monitor actual voltages and currents on the system. One of these monitors is located at Ryhall which is the next substation along from Eaton Socon and is considered to be very close from an electricity connectivity perspective to the fault experienced on the Eaton Socon – Wymondley Main circuit. Our Power Quality Monitors allow us to study voltage and current information following events like those experienced on Friday 9th August 2019.

Figure 3.3.1 below shows the 44% voltage depression on the Blue phase of the circuit experienced at Ryhall. The duration of the event including voltage recovery is 100ms, a waveform typical of the voltage depression and duration expected for this type of fault.

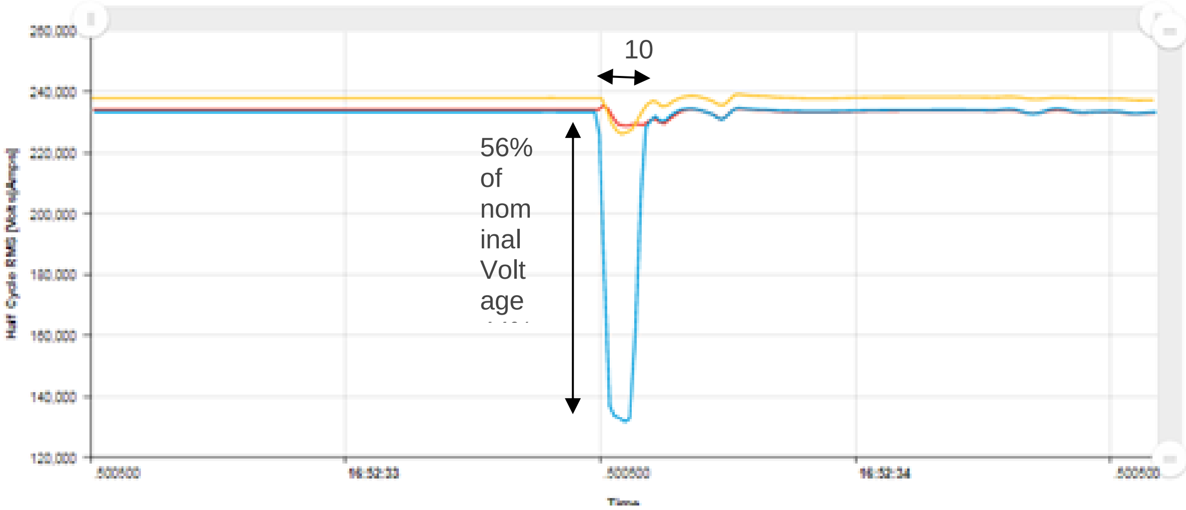


Figure 3.3.1 Voltage Dip at Ryhall 400kV

Figure 3.3.1b below shows the voltage waveform seen at Ryhall 400kV, before, during and after the fault is cleared from the system. The distortions of the voltage wave forms are from the transient disturbance from the lightning strike and transient disturbance from the circuit breaker clearing the fault. Such transient disturbances are expected and not unusual for both instances of lightning and transmission switching.

Figure 3.3.1b – Transient Voltage Waveform Recorded at Ryhall 400kV

Figure 3.3.1c below shows a further small transient event which occurred at Ryhall a minute after the fault. This trace shows effects that are most likely associated with reactive compensation switching on the network which was in response to the fault and is not unusual activity to see on the network following a fault. Reactive compensation is used on the system to manage system voltages, and following a fault this equipment can automatically operate to support network voltages and this operation will typically exhibit the kind of small disturbances like those seen below.

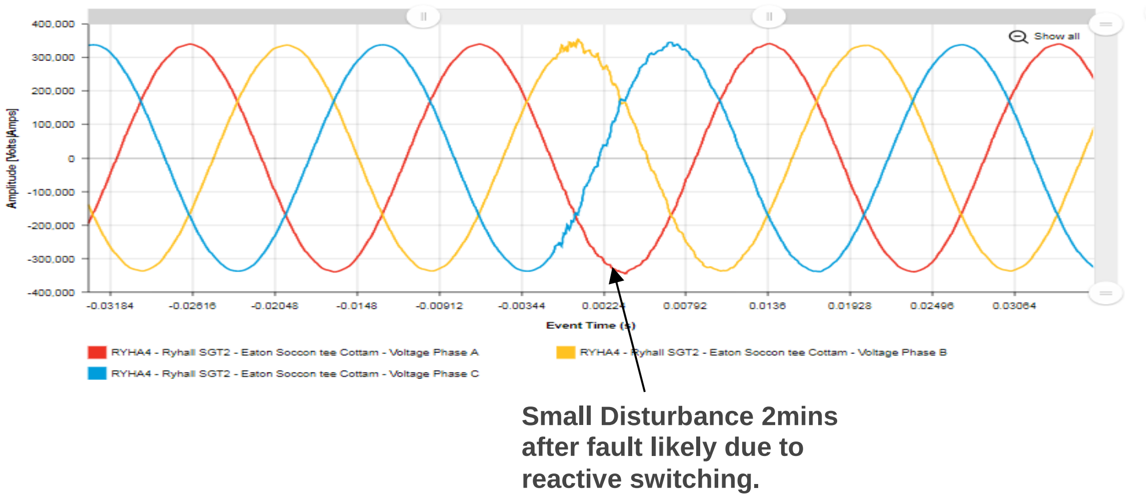


Figure 3.3.1c – Transient Voltage Waveform Recorded at Ryhall 400kV after fault

3.3.2 Power Quality Monitoring at Necton

Necton Substation is located in Norfolk, but electrically is a similar distance away from the fault as Killingholme (where the Hornsea wind farm is connected to the network) and therefore is a good proxy for the voltage dip at that distance from the fault. The Power Quality Monitoring Equipment we have installed close to Killingholme was not available at the time of fault, as it is connected to the Killingholme – Keadby circuit which was out of service for planned maintenance on 9th August. However, the Necton monitoring information will be indicative of that experienced at Killingholme.

Figure 3.3.2 below shows voltage depression of 21% on the Blue phase of the circuit experienced at Necton 400kV. The duration of the event including voltage recovery is 80ms in length and shows how the event becomes less significant due to the electrical impedance over greater distances from the fault location. Again, this dip and duration is as expected for this type of fault.

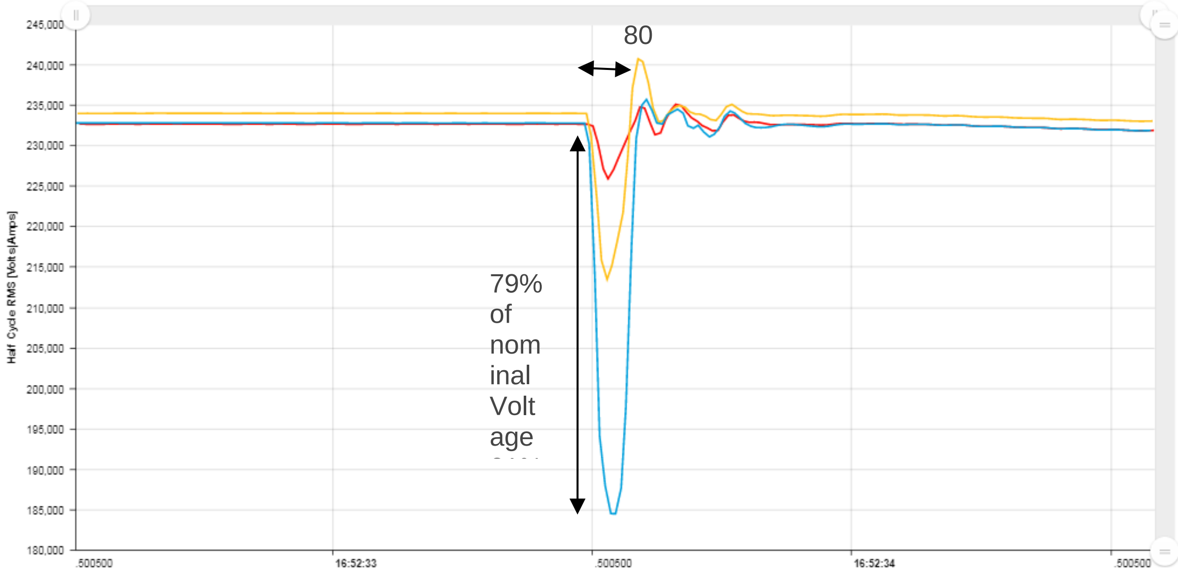


Figure 3.3.2 Voltage Dip at Necton 400kV

Figure 3.3.2b below shows the voltage waveform seen at Necton 400kV, before, during and after the fault is cleared from the system. The distortions of the voltage waveforms are from the transient disturbance from the lightning strike and transient disturbance from the circuit breaker clearing the fault. The second transient seen at Ryhall 400kV likely associated with reactive switching did not register at Necton, as this transient was too small to register at this location.

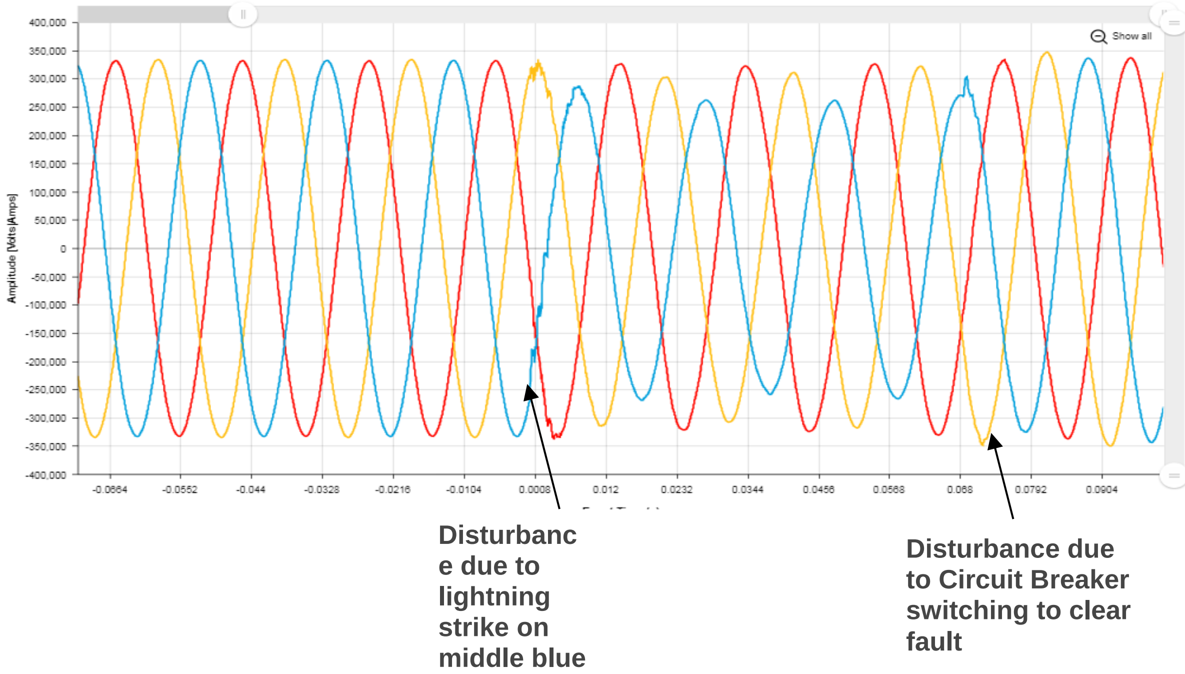
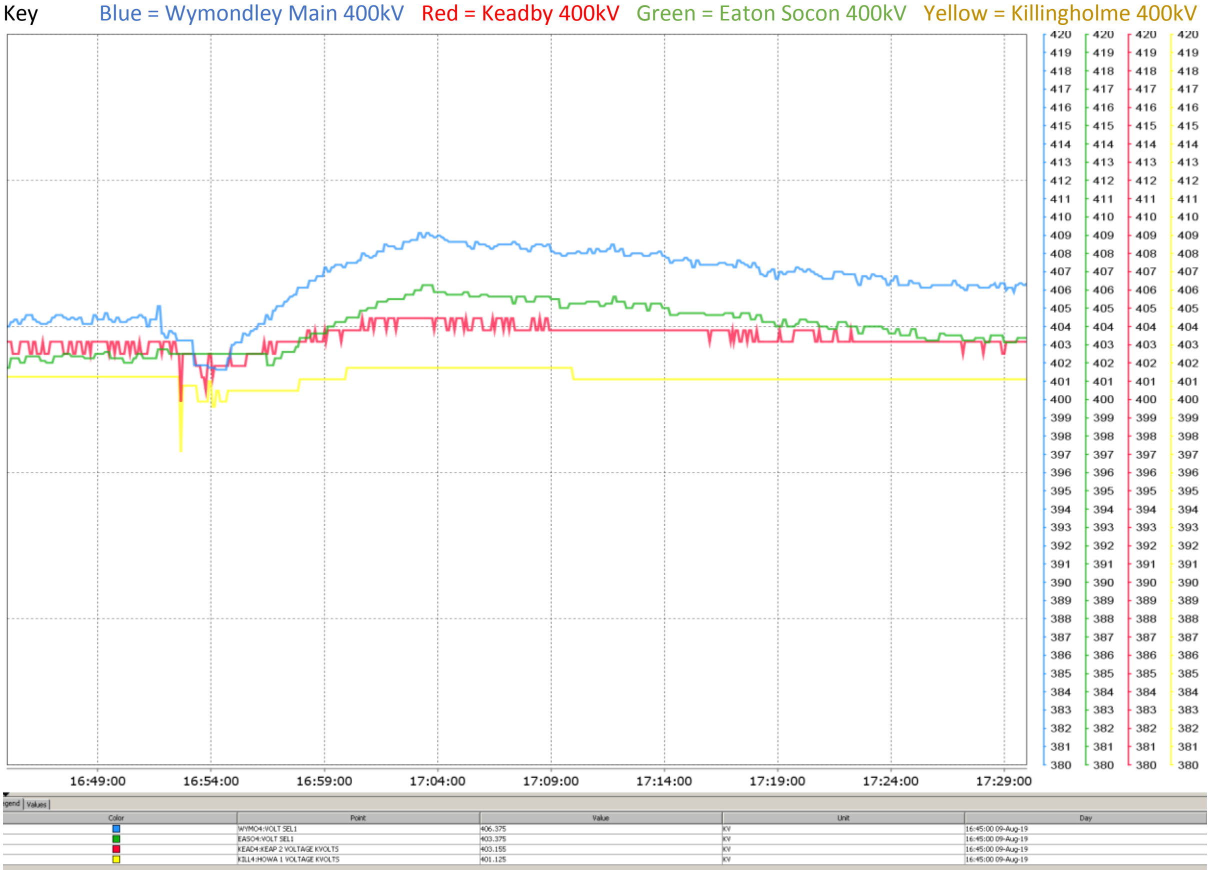


Figure 3.3.2b – Transient Voltage Waveform Recorded at Necton 400kV

3.4 Steady State pre-fault and post-fault voltages

The section above described voltage dips on the system that occur during a fault and which are known as transient effects. When the system is not experiencing a disturbance such as a lightning strike, the system is considered to be operating in a steady state. 'Steady State' is a term used to describe voltages and currents over a longer timescale where changes are slower in nature. Graph 3.4 below shows "static" steady state 3-phase voltages recorded at Wymondley Main 400kV, Eaton Socon 400kV, Keadby 400kV and Killingholme 400kV substations. This trace shows all sites operating as expected and within operational voltage limits (of ±10% 420KV – 380kV) set out in the industry's Security and Quality of Supply Standard (SQSS).



Graph 3.4 Pre-Fault and Post-Fault Steady State Voltages

3.5 Harmonics and Negative Phase Sequence (NPS) Currents

Power electronic equipment can cause distortion to the Alternating Current (AC) waveforms of voltage. These are called 'harmonics' and can cause the waveform to become irregular in shape. This, if not controlled, could cause problems with the quality of electricity supply to homes and businesses. Therefore, harmonics are limited to 3% by Electricity Association (EA) Engineering Recommendation (ER) G5/4 design requirement. On Friday 9th August system harmonics in the area of the event were compliant with these limits at less than 1%.

When the currents in the system become unbalanced between the phases of the three-phase system, negative phase sequence (NPS) currents are generated. NPS currents allowed on the transmission network are limited to 1.5% by the Grid Code to protect customer's equipment. On Friday, the 9th August the NPS levels in the area of the event were within these requirements and did not exceed 0.6%.

Part 4: NGET Findings and Next Steps.

4.1 Report Findings

Our investigation into the events of Friday 9th August 2019 has identified that the electricity transmission network operated as designed and in line with standards, and specifically:

- On the 9th August 2019, the transmission system saw a lightning strike on the Eaton Socon – Wymondley Main Circuit, 4.5km from Wymondley substation. This caused the middle conductor (blue phase) to fault to the earthed transmission tower causing a voltage transient depression of 50% on blue phase and fault currents of 7kA and 21kA at Eaton Socon and Wymondley Main substations respectively.
- The main protection at Wymondley Main operated in 70ms and the main protection at Eaton Socon operated in 74ms, therefore clearing the fault within the 80ms required in the Grid Code.
- A voltage depression of circa 50% was seen at the fault location on the blue phase which lasted for 100ms in the vicinity of the fault. Electrically further from the fault voltage dips of 20% were observed with 80ms duration. The voltage depression and duration were as expected for this type of fault.
- All pre-fault and post-fault steady state voltages were within limits required within industry standard and the transient effects during the fault aligned with Grid Code fault ride through requirements. Harmonic and Negative Phase Sequence currents were all well within limits set out within the relevant standards and codes.

4.2 Next steps

- We will continue to work collaboratively and support all investigations into the power disruption of the 9th August openly and transparently.

Appendix D – Hornsea Technical Report Submitted by Orsted

This Appendix contains the independent technical report provided to the ESO by Orsted into the performance of the Hornsea offshore windfarm on 09 August as part of the detailed investigation into the incident.

Ørsted Technical Report for National Grid ESO on the events of 9 August 2019

Ørsted
5 September 2019, submitted 1606h

Table of Contents

Glossary of Terms

BCA – Bilateral Contract Agreement

EON – Energisation Operational Notification – first milestone in commissioning process

FON – Final Operational Notification – the last milestone in the commissioning process

ION (Part A) Interim Operational Notification (for dynamic reactive compensation on OFTO assets) second milestone in commissioning process

ION (Part B) Interim Operational Notification (to export active power) second/third milestone in commissioning process

NETS – National Electricity Transmission System. In GB this relates to 400kV and 275kV network

OFTO – Offshore Transmission Owner

OTSUA – Offshore Transmission System User Assets

PPM – Power Park Module. These are groups of WTGs on a radial network. 100MW per PPM at Hornsea. Each BMU consists of 4 x PPM

TIP – Transmission Interface Point. This is where the offshore transmission system connects to the National Electricity Transmission System and from where voltage control is mandated

WTG – Wind Turbine Generator

Executive Summary

On 9 August 2019 at 16:52 an unbalanced voltage dip due to an external event occurred at the interface point where Hornsea One connects to National Grid’s 400kV transmission system. Initially the offshore wind farm responded as expected by injecting reactive power into the grid thereby restoring the voltage back to nominal. However, in the following few hundred milli-seconds, as the wind farm active power reduced to cope with the voltage dip and the reactive power balance in the wind farm changed, the majority of the wind turbines in the wind farm were disconnected by automatic protection systems. The de-load was caused by an unexpected wind farm control system response, due to an insufficiently damped electrical resonance in the sub-synchronous frequency range, which was triggered by the event.

Since the event, the control system software has been updated to mitigate the observed behaviour of Hornsea One to stabilise the control system to withstand future grid disturbances in line with grid code and connection agreement requirements.

Hornsea One overview

Hornsea One is an offshore wind farm located 120 km from the Yorkshire coast and is currently under construction offshore. Once completed, it will have a total installed capacity of 1.2GW, comprising of 174 offshore wind turbines rated at 7MW each.

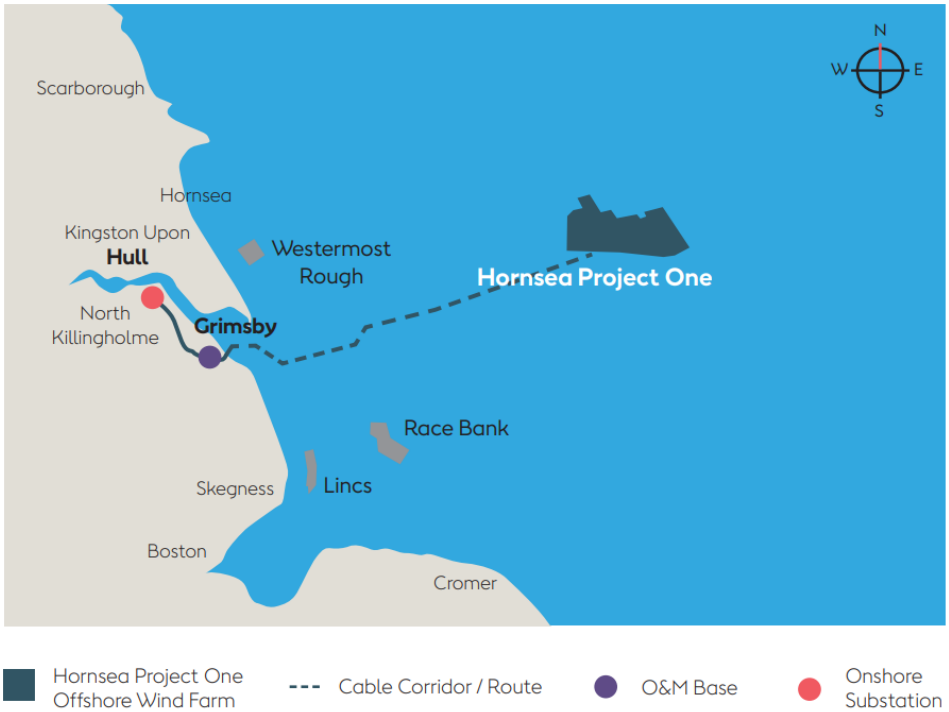


Figure 1: Location of Hornsea One

The entire Hornsea One offshore wind farm consists of three phases, each 400MW in size. This report references each phase as Hornsea 1A, Hornsea 1B, and Hornsea 1C. Each phase connects into its own HVAC Collector Substation, before connecting into a HVAC Reactive Compensation Station located offshore before connecting into an Onshore HVAC Substation, which then subsequently connects into the National Grid Substation at Killingholme.

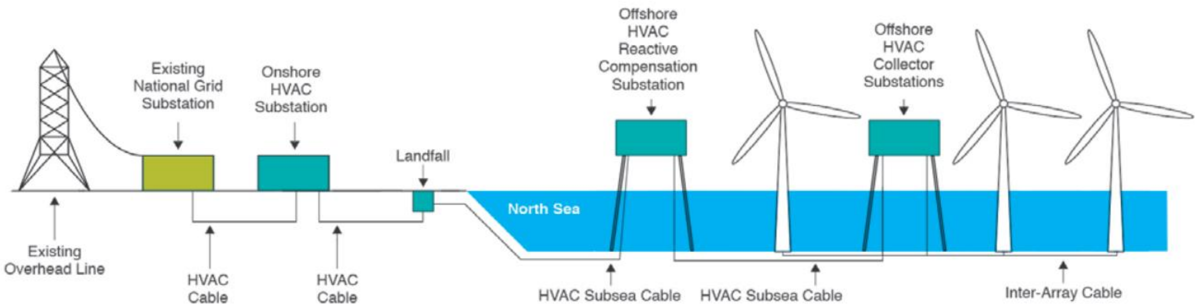
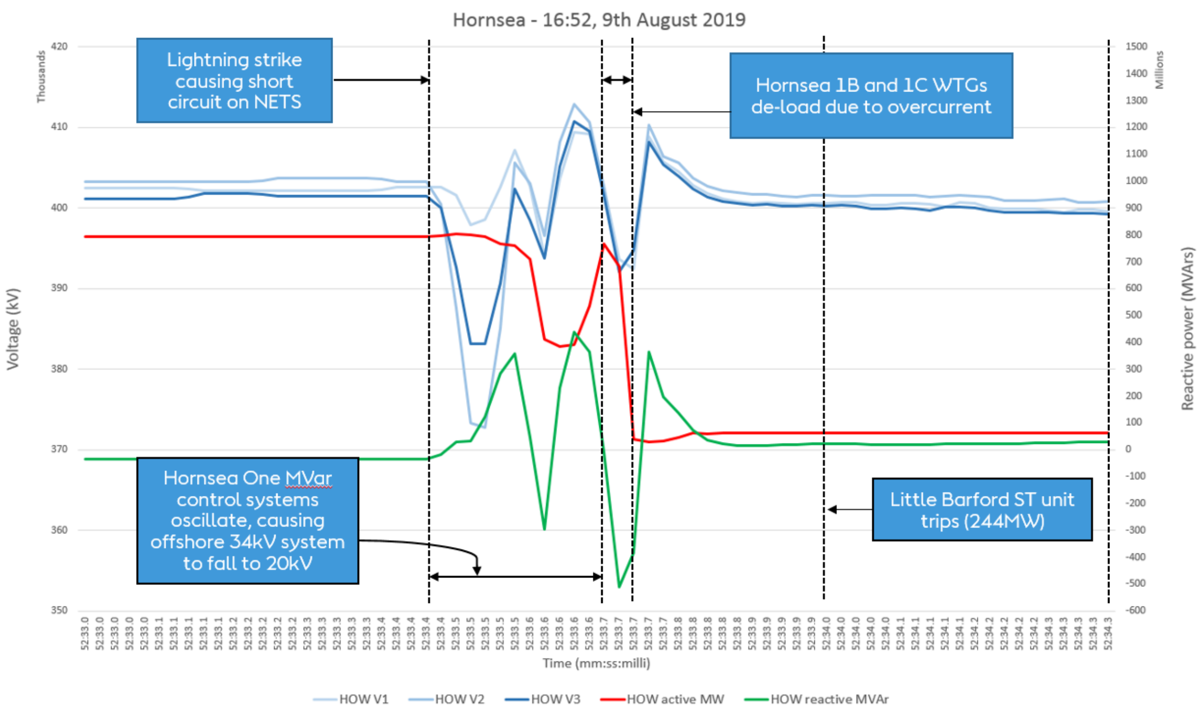


Figure 2: Basic layout description of Hornsea One

Description of events

At 16:52 on the 9 August 2019, Hornsea One de-loaded from 799MW to 62MW in response to a disturbance caused by a circuit trip on the external 400kV network. Despite experiencing unusual conditions at the connection point to grid, it was expected that Hornsea One would withstand the event and remain in operation. Following a detailed and thorough technical investigation the root cause for Hornsea One de-loading has been identified.

At the time in question, Hornsea One's systems identified a weak grid and then detected an unusual voltage disturbance which was subsequently discovered to have been caused by the circuit trip, itself caused by a lightning strike.



1. *Figure 3 – Showing Voltage, Active power (MW) and Reactive power (MVAr) from Hornsea One at the time of the de-load*

Figure 3 (above) shows NETS voltage in the 400kV substation initially steady at ~400kV (16:52:33:000 to 16:52:33:490). A short time[1] before 16:52:33:490 lightning strikes the NETS Overhead Lines (OHL) between Eaton Socon and Wymondley substations. The lightning strike results in a phase to Earth short circuit at exactly 16:52:33:490. This short circuit causes the NETS system to protect itself, clearing the fault by opening circuit breakers and disconnecting the affected line in 74ms.

As can be seen in figure 3 during this time (16:52:33:490 to 16:52:33:700), the Hornsea One reactive compensation control systems initially inject reactive power (leading MVArs) to boost NETS voltage, before a significant oscillation occurs, absorbing reactive power (>300MVAr which depresses NETS and Hornsea One systems

[1] At the time of publishing Ørsted is unaware of the exact time of the lightning strike

voltage to ~394kV) and then injecting MVArs again. As a consequence, Hornsea reduces active power from 799MW to 400MW before returning to 799MW.

As Hornsea One active power output returns to 799MW, so the reactive power output reaches ~0MVAr as it rapidly switches from injection and absorption again (16:52:33:700). Hornsea now absorbs ~560MVAr. In the wind farm 34kV collection cable system the result of this is that the voltage rapidly reduces to 20kV (target voltage 34kV) and all WTGs on Hornsea 1B and Hornsea 1C reduce to 0MW as a result of overcurrent protection in the generators (16:52:33:728 to 16:52:33:835).

Figure 4 (below) depicts the offshore conditions at Hornsea 1B (circuit Z12). Prior to the event, Hornsea 1B is operating at 400MW (maximum capacity for that unit), before the oscillations described earlier begin affecting voltage, reactive power and active power. As a result of the oscillations, Hornsea 1B system voltage falls to ~20kV while attempting to maintain full active power which leads to an overcurrent of each WTG connected to Hornsea 1B and Hornsea 1C at the time. In the event of an overcurrent, the WTGs de-load as part of the industry standard protection system to avoid permanent damage to the generators.

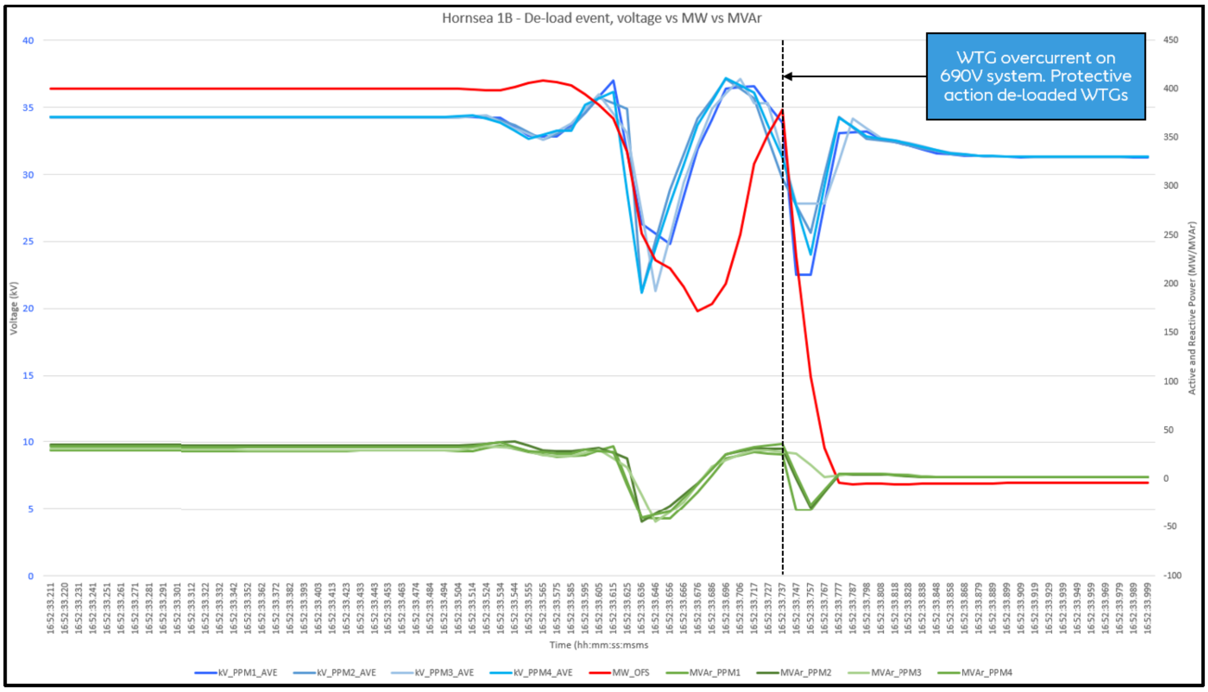


Figure 4 – The de-load of Hornsea 1B due to overcurrent at the WTGs

The protection systems at Hornsea 1B and 1C began de-loading turbines at 15.52.33.728 and completed the de-load at 15.52.33.835, 107ms later. Following the de-load of Hornsea 1B and Hornsea 1C, Hornsea 1A remained in operation at 62MW active power output.

Subsequent to the event in question and as part of this investigation, electrical oscillations at Hornsea One were identified occurring prior to the event (and without causing any de-loading). 10 minutes before, the trace shown in figure 5 (below) can be seen.

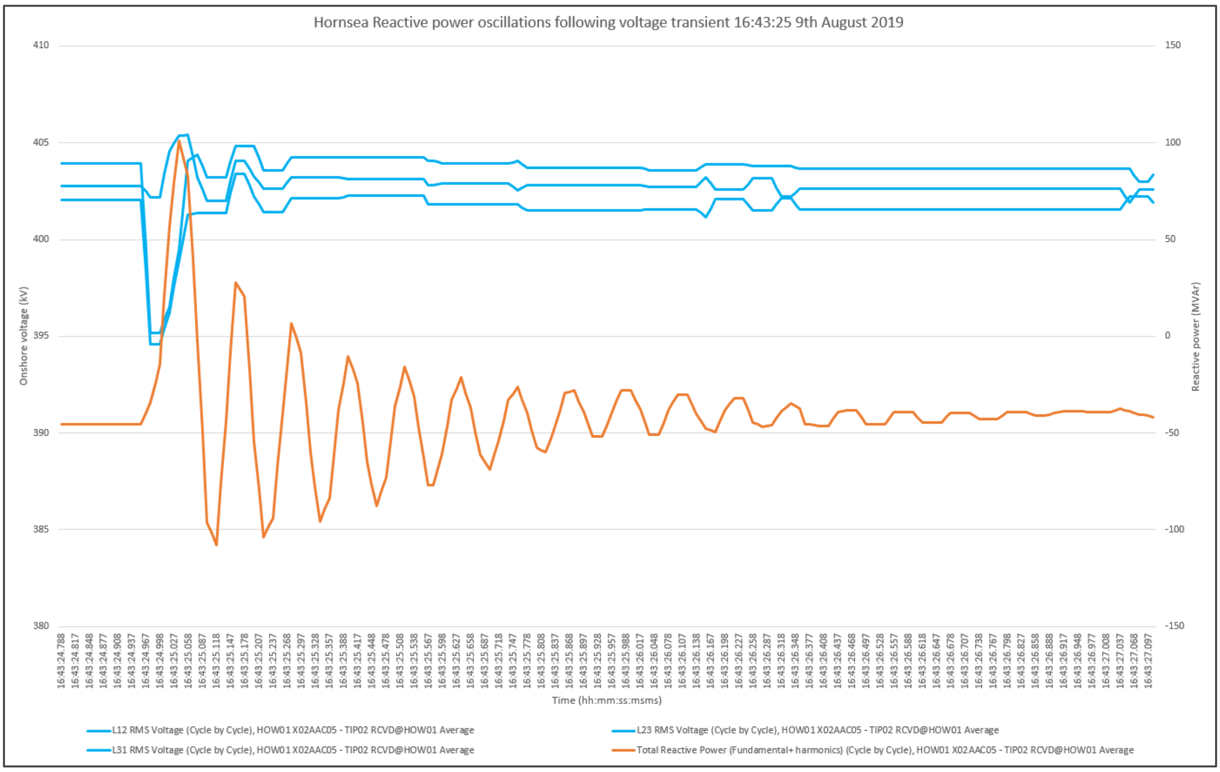


Figure 5 – Showing the reactive power output from Hornsea 10 minutes prior to the event in response to a 2% voltage step change

In this case the response from Hornsea shows a damped oscillatory response from the overall voltage control systems.

Prior to the event, each stage of Hornsea One had been successfully modelled and physically tested in line with all grid code requirements. While the potential for oscillations had been considered, there had been no reason to suggest that Hornsea One would have responded to a fault on the grid in the way that it evidently did.

To the best of Ørsted's knowledge this is the first time such oscillations have led to a de-load of a windfarm. The software update performed on the 10 August 2019 was previously agreed with the manufacturer to address performance improvement opportunities; which included an improved response to grid disturbances in weak grid conditions. This software update mitigates the observed behaviour of Hornsea One stabilising the control system to withstand future grid disturbances in line with grid code and connection agreement requirements.

Conclusion

The de-load was caused by an unexpected wind farm control system response, due to an insufficiently damped electrical resonance in the sub-synchronous frequency range, which was triggered by the initial event.

Appendix E – Little Barford Technical Report Submitted by RWE

This Appendix contains the independent technical report provided to the ESO by RWE into the performance of Little Barford CCGT on 09 August as part of the detailed investigation into the incident.

RWE Preliminary Findings Regarding the Event on 9th August 2019

30th August 2019

Preliminary Findings

The following sequence of events occurred;

Time T = 16:52:34 +/- 0.5seconds

• 110v AC UPS –B- general fault alarm	"T" = 0 mSec
• 110v AC UPS –A- general fault alarm	+003 mSec
• Initiation of ST Control System shutdown	+253 mSec
• ST Generator Breaker Open command	+1.16 Sec
• ST Generator Breaker Open feedback	+1.185 Sec
• GT1A Auto shutdown command	+56.583 Sec
• GT1A Breaker Open feedback	+57.620 Sec
• GT1B Manual shutdown command	+83.897 Sec
• GT1B Breaker Open feedback	+84.613 Sec

Times are recorded in the Station's Sequence of Events system. RWE have confidence in the chronology of the events, further investigation work is required to determine an accurate "T" datum relative to datum used within NGESO report.

Investigation Update

Uninterrupted Power Supply (UPS)

The investigation to date has found that all UPS' at Site have functioned correctly to enable continuity of supply to plant equipment. Relevant OEM's have been engaged and confirmed the units have functioned as expected. Therefore, we do not now believe the UPS' were related to the subsequent trip.

RWE's hypothesis is that the UPS' have initiated a changeover to battery back-up supplies as a consequence of the system disturbance. The exact characteristic of the power supply to the UPS causing it to switch to battery operation is still to be determined and subject to further investigation.

During a forthcoming outage, commencing 6th September 2019, we have requested that the OEM undertakes resilience testing to reaffirm the functionality of the system and cross reference these results to the previously undertaken manufacturing tests (9th November 2017) and commissioning tests (January 2018).

Based on our recent experience at Little Barford, we are confident that the UPS functions as designed, and we are confident in its ability to demonstrate this.

Steam Turbine

Our investigations have confirmed that the Steam Turbine tripped due to a discrepancy in the speed signals after the point of the Transmission System fault clearance.

A comprehensive investigation of hardware, software, fault handling and diagnostic coverage for the conditions, that the ST was subjected to during this rare system disturbance, is ongoing. Additional high-resolution frequency data has been received from NGESO, relevant to Eaton Socon, to assist the investigation.

Gas Turbines

Upon initiation of the Steam Turbine Trip the Gas Turbines went into bypass mode of operation, which is the normal response to allow sustained operation. For reasons presently unknown a high-pressure excursion occurred on GT1A resulting in an automated trip. Given the prevailing conditions all systems functioned as expected. GT1B was manually tripped shortly after as a result of excessive steam pressure.

A physical inspection of the bypass system is now planned during the forthcoming outage in September 2019 to help determine the root cause of the pressure excursions.

END

Appendix F – Govia Thameslink Railway (GTR) technical report

This Appendix contains the independent technical report provided to the ESO by GTR into the impact of the frequency disturbance on their trains on 09 August as part of the detailed investigation into the incident.

Title	Power Surge Disruption on 9th August 2019: Technical Review.
Date	3rd September 2019

Event Summary

1. From information supplied by the National Grid at 1653 on Friday the 9th of August the frequency of the OLE AC voltage supply dropped below 49Hz for 16 seconds. It dropped below 48.89Hz to a minimum of **48.8 Hz** for milliseconds.
2. There was no identified OLE AC Voltage supply interruption.
3. All Desiro City class 700 and 717 units operating on AC Voltage suffered a Protective Shutdown where the converter, known as the 4QC (4 Quadrant Controller) shut down. None of the other AC trains in the GTR fleet suffered any power related issues from this event e.g. Class 387, Class 365, Class 313.
4. In Passenger Service this involved circa 60 units, consisting of Class 700 FLU/RLUs and Class 717, suffering a 4QC lock out.
5. The effect of the 4QC shutting down on the train is that the train switches to battery power which causes a loss of HVAC (fan only fresh air supply), stand by reduced lighting (emergency lighting is activated when battery voltage drops), no at seat power, no PIS displays (audio only from the cab), and no traction power. The GSM-R radio remains active.
6. Following failed attempts to repower the trains, the established first response for a train failing with these symptoms is for the Driver to perform a reboot of the train known as a Battery Reset. This takes approximately 10 minutes.
7. Fleet Control diagnosed the issue quickly and a global GSM-R call was broadcast to instruct drivers to carry out the Battery Reset process.
8. After this 27 of the affected units were recovered.
9. The remaining circa 30 units required the Protective Shutdown to be unlocked by the intervention of a Technician with a laptop attending each unit.
10. There were 17 Technicians available at the time of the event. These 17 were immediately sent to stranded units with laptops and a further 24 technicians were mobilized within the next hour. The trains affected were widely spread geographically and some were not easily accessible.
11. Therefore, this process took some time and resulted in 23 train evacuations and severe levels of service disruption.

Cause

1. The Desiro City from Siemens Mobility is the latest generation software enabled commuter train, so requiring protection against power supply frequency excursions for safety reasons and to protect low power electronics.
2. Siemens Technical Specification for the train states that the train will continue to operate with supply frequency drops down to **48.5Hz** for short periods of time.
3. The NR Electrification System Compatibility document, NR/GN/ELP/27010 *("Guidance for compatibility between electric trains and electrification systems")*, a Manufacturing and Supply Agreement compliance requirement, identifies that the supply frequency can fall to **48.5Hz** in extreme conditions.
4. A review of the Class 700 NoBo design submission (Siemens document A6Z00036309602 item 4.2.8.2.2) shows that compliance with both NR/GN/ELP 27010 and EN 50163 (*Railway Applications – Supply Voltages of Traction Systems*) would be demonstrated.
5. Following investigations, Siemens advised that the supply frequency response of the train was designed to comply with the EN 50163 Clause 4.2 Note 2. This note permits train drives to disconnected at **49Hz**. Use of this supply frequency value in the train design led to the train protectively shutting down its drives when the supply frequency response fell below 49Hz.
6. Importantly Siemens have also clarified that there should not have been a Permanent Lockout on the train following a protective shutdown caused by a supply voltage frequency drop. All trains should have been recoverable via Battery Reset whereas 30 trains were not recoverable. This was not the intended behaviour of the train.
7. Therefore, the affected Class 700 and 717 sets did not react according to their design intent in these circumstances. The risk of this happening was not known prior to the power event on Friday 9 August.
8. Separately as a part of the new TCMS (Train Control Management System) software version 3.27, the ability for the driver to recover from a Permanent Lockout by using the Battery Reset process was removed.
9. On the 9th of August all the units which required a Technician to recover power were at software level 3.27 or above. The 28 units recovered by the driver performing a Battery Reset were at the previous TCMS software level of 3.25 or below.

Conclusion

1. All the Class 700 and Class 717 trains operating on AC suffered a Protective Shutdown of the 4QC controller because of a drop in the supply frequency below 49Hz for 16 seconds.
2. This was not how the train system had been specified to operate. This event should not have caused a Permanent Lockout fault on the trains.
3. The effects of this were exacerbated as the fleet was undergoing a software change, contained in this was a change in functionality removing the Battery Reset remedy for Permanent Lockout events.
4. This meant that the driver could not recover failed trains which were operating on the new software, instead a Technician was required to attend.

Planned Mitigation

1. Siemens are developing a software patch to allow units which protectively shutdown below 49Hz supply frequency to recover themselves without the need of a reboot or laptop when the frequency rises above 49.5Hz.
2. It is not proposed by Siemens or GTR to revert units to previous software versions as there are concerns this could severely impact unit availability. Based on discussions with the National Grid Head of Networks, the risk of frequency excursion dropping below 49Hz before the patch is fully introduced are considered extremely unlikely.
3. In addition to this Siemens will investigate how the train could be made to operate for a short time with supply frequency falling to 48.5Hz.

Appendix G - Compliance Testing for Hornsea and Little Barford

This Appendix provides an overview of the compliance testing process together with an overview of the compliance testing for Hornsea and Little Barford

Overview of the Compliance Testing Process

Generators are responsible for demonstrating and maintaining compliance with the Grid Code both when connecting to the system initially and on an ongoing basis. The process is clearly laid out in the Grid Code in the Compliance Processes and the European Compliance Processes. Compliance is demonstrated through a combination of studies, simulations and testing of the generator.

The ESO runs the compliance process and supports the generator in achieving compliance. For the initial connection of any large[1] or directly connected generator, the generator proceeds through a number of stage gates in the process: energisation stage, interim operational stage and final operation stage. The generator must provide the required compliance evidence at each stage. The ESO is responsible for assessing this information against the Grid Code requirements and issues a notice to proceed through the stage gate if compliance has been met.

If the generator makes any changes to its configuration which may impact compliance, it is responsible for firstly notifying the ESO of the change and then ensuring that it demonstrates compliance. The ESO is not responsible for checking compliance on an ongoing basis. If the operation of a generator is not in line with what is expected, then this will be flagged to the compliance team who will notify the generator to investigate the non-compliance.

If a generator believes it would require more than 84 days to resolve any compliance issues, the ESO issues a Limited Operational Notice (LON) to the generator and work with them to achieve full compliance

Hornsea Compliance Testing

NG ESO and Orsted had 14 face to face operational notification connections compliance meetings between 21/03/2017 and 05/04/2019 to ensure Orsted fully understood the Grid Code requirements for a Hornsea Offshore wind farm to demonstrate.

Orsted provided Grid Code requirement compliance data to NG ESO from 04/08/2017 to 21/06/2019 with the first version of the fault ride through report submitted on 30/04/2018. Following all the compliance data submissions which included all the simulation studies relating to Fault Ride Through, Voltage Control, Frequency Control and Reactive Capability demonstrating that Hornsea complies with the Grid Code through the design of the plant, NG ESO confirmed the compliance data were satisfactory.

Energisation of assets and synchronisation to the NETS occurred as shown below

Activity	Date
Energization of circuit 1	31/10/2018
Energization of circuit 2	28/11/2018
Synchronization of Reactive Compensators	06/11/2018
Synchronization of Module 1	15/07/2019
Synchronization of Module 2	01/02/2019
Synchronization of Module 3	30/04/2019

- Completed Grid Code Compliance Test Dates

[1] The definition of large generator in the Grid Code is: greater that 99.9 MW in England & Wales; greater than 9.9MW in Scottish Hydro Electricity Transmission; greater than 29.9MW in Scottish Power region; 9.9 MW offshore

20% Capacity Voltage Tests	Date of Test	Results sent to NG ESO	Approval by ESO
Hornsea M1_20% Voltage test on Dynamic Reactive Compensator DRC10	15.01.2019	17.012019	17.012019
Hornsea M2_20% Voltage test on Dynamic Reactive Compensator DRC20	15.01.2019	17.012019	17.012019
Hornsea M3_20% Voltage test on Dynamic Reactive Compensator DRC30	15.01.2019	17.012019	17.012019
Hornsea M1/2 20% Voltage test on Dynamic Reactive Compensators DRC10/20 together	15.01.2019	17.012019	17.012019

70% capacity, Limited Frequency sensitive Mode Tests OC5.A.3.3	Date of Test	Approval by ESO
Hornsea M2 70% Frequency test on High Performance Park Pilot (HPPP) 2	25.03.2019	26.03.2019
Hornsea M3 70% Frequency test on High Performance Park Pilot (HPPP) 2	07.06.2019	13.06.2019
Hornsea M1 70% Frequency test on High Performance Park Pilot (HPPP) 2	09.08.2019	23.08.2019

Preliminary Frequency Response Tests OC5.A.3.6.4	Date of Test	Approval by ESO
Hornsea M2 Frequency tests on High Performance Park Pilot (HPPP) 2	25.03.2019	26.03.2019
Hornsea M3 Frequency tests on High Performance Park Pilot (HPPP) 2	07.06.2019	13.06.2019

List of Outstanding Tests

70% capacity, Preliminary Frequency Response Tests on wind farm M1.

100% capacity, Reactive Capability Testing on the 2 Transmission Interface Points CP.7.2.2(a), OC5.A.3.4

100% capacity, Voltage Control Testing on the two connections CP.7.2.2(b), OC5.A.3.5

100% capacity, Frequency Response Testing on the 3 Offshore Wind Farms CP.7.2.2(c) OC5.A.3.6.6.

Further requirements outstanding prior to issuing Final Operational Notification (FON)

Updates to documentation as CP.7.3 most significant items being:

Model verification to demonstrate that the models/parameters reflect the test results CP.7.3.1(c), CP.A.3.7

Update planning code data with final commissioned status. CP.7.3.1(a)

Updated Compliance Statements CP.7.3.1(e)

Little Barford Compliance Testing

Little Barford connected to the transmission network in 1996 prior to the inclusion of the compliance process into the Grid Code however, the compliance process applied to the replacement of gas turbines and associated control systems.

Activity	Date
ESO issued LON for Gas Turbine replacement	06/01/2012
Automatic Voltage Regulator & Power System Stabilizer Tests on GT1A	07/01/2013
Automatic Voltage Regulator & Power System Stabilizer Tests on GT1B	17/01/2013
Automatic Voltage Regulator & Power System Stabilizer Tests on ST10	01/10/2012
Governor Tests	15-19/03/2013
ESO Issued FON	26/04/2013

Appendix H - Managing Frequency with Statutory Limits

This Appendix explains the obligations on ESO for managing frequency within statutory limits as set out in the National Electricity Transmission System Security and Quality of Supply Standard (SQSS). The methodology for determining the largest loss is outlined together with the approach used to calculate the volume of frequency response required to secure that loss. More explanation of Loss of Mains protection systems is also provided.

Security and Quality of Supply Standards (SQSS)

What is the System Security and Quality of Supply Standard**?**

The National Electricity Transmission System Security and Quality of Supply Standard (SQSS) establishes a coordinated set of criteria and methodologies that the ESO uses in planning and operating the national electricity transmission system. Of particular relevance to the events on 9 August, the SQSS sets out the types of event for which the system must be secured (a Secured Event) and the performance of the power system following such a Secured Event – specifically the frequency deviation limits with which the ESO as system operator must comply.

The ESO is the administrator for the SQSS, which it maintains together with other transmission licensees. All changes to the SQSS are subject to industry consultation and approval by Ofgem.

What does the SQSS require?

The SQSS requires the operation of the national electricity transmission system such that it remains secure following the occurrence of any one of a set of potential faults / contingencies (Secured Events) under prevailing system conditions, i.e. conditions on the national electricity transmission system at any given time and will normally include planned outages and unplanned outages.

The SQSS defines two types of Infeed Loss which could result from a Secured Event:

- '*Normal Infeed Loss'*: the maxiumim loss the system should be able to manage without the frequency going below 49.5 Hz (e.g., an interconnector at 1,000MW)
- '*Infrequent Infeed Loss'*: is a higher level of infeed loss dictated by a small number of larger potential losses (e.g., Sizewell at 1,260MW) and for the loss of which the frequency should not go below 49.2 Hz and should recover to 49.5 Hz within one minute.

The SQSS requires the ESO to ensure that, following any Secured Event resulting in a Normal or Infrequent Infeed Loss, the network should remain within the defined standards (e.g., the frequency ranges defined above).

The SQSS anticipates that only one Secured Event would happen at any one time and does not assume multiple Secured Events occurring simultaneously. In engineering terms this is defined as N-1, that is to say, that the network remains secure following one Secured Event.

The Power Infeed Loss is the amount of power infeed that can be lost in one Secured Event. Generally this is either a single large generator, with a single mode of failure such as a single connection to the transmission system or could be two or more smaller generators that are separate but are connected to the rest of the system through an asset treated as a single Secured Event (for example a double circuit overhead line or busbar).

Events of 9 August

The SQSS requires the operation of the national electricity transmission system such that it remains secure following the occurrence of a single Secured Event. The largest single Infeed Loss on the day was 1,000 MW, the loss of a single interconnector.

Little Barford and Hornsea had connections to the network which had a number of degrees of separation from the transmission line that was struck by lighting and tripped and reclosed. As such, the events of the 09 August are considered as three separate (albeit simultaneous) Secured Events, specifically:

- the loss of Hornsea (737MW);
- the loss of Little Barford (641MW); and
- the loss of vector shift generation (150MW).

The total loss seen through the three Secured Events was significantly in excess of the level secured for (1,000MW) at 1528MW.

As the SQSS only requires the system to be operated to be secure for a single Secured Event, events of 09 August represent three separate simultaneous events and which together exceed the requirements of the SQSS in terms of the Infeed Loss that was required to be secured for. In addition to the 1528MW loss, there was also approximately 350MW of embedded generation tripped off on Rate of Change of Frequency protection.

The fact that this loss was greater than the secured level resulted in the excursion of frequency outside normal standards and the automatic tripping of LFDD.

Re-securing the system

The SQSS also sets out that the system should be re-secured as soon as reasonably practicable after the occurrence of a Secured Event. The correct action of automatic frequency response followed by the dispatch of the fastest available services by the control room saw the system re-secured within 5 minutes which we consider to be as quickly as could be reasonably achieved.

How does ESO determine largest loss?

The largest infeed risk as defined in the SQSS is managed in the control room using planning and actual data to identify the largest infeed loss present on the system at that time. As set out above, this is the loss associated with a single Secured Event, in general the largest single generator loss or interconnector loss on the transmission system, or associated loss of the network connecting a large generator that will result from a single Secured Event. It is assessed based on system configuration at the time and the likely effect from these Secured Events.

Additional Considerations relating to loss of mains

In securing for the largest loss, the ESO also takes into account the known protection setting historically specified in the Distribution Code for RoCoF of 0.125 Hz/s. The ESO monitors the potential RoCoF following any infeed loss and seeks to ensure that the system is configured in real-time such that the limit of 0.125Hz/s is not breached for an infeed loss. This is achieved by dispatching generation (increasing inertia), management of response and reduction in size of the potential largest infeed loss.

The ESO also considers the impact of vector shift protection on embedded generation. It assesses the risk and probability of a Secured Event, the cost to secure and the likely level of Vector Shift. Based on this assessment the ESO will secure for the potential cumulative effect of vector shift (e.g., following a transmission fault) and infeed loss where it considers it appropriate to do so.

Calculating the response requirement

The response requirement is the amount of frequency response we need to keep the system within the frequency limits provided above for a Secured Event.

The overall response requirement is calculated, for a given loss, through an internally developed model - the FSE (Frequency Simulation Engine). This model allows the ESO to simulate the frequency for a given system imbalance, system inertia and given response service holdings. The model adopts a pessimistic approach to mitigate the risk that not all units would deliver 100% performance at time of a significant frequency event using the following assumptions:

- The starting frequency is set as 49.9Hz for low frequency response calculation, while in real time it would be generally kept higher. Hence the erosion amount of dynamic response should be less in real time compared to what is modelled.
- The response service is modelled in a way based on their minimum performance requirement. Historical analysis has shown that most units out perform this specification and some units will over deliver.

The models involved in these calculations are regularly calibrated against real system events to confirm that the frequency and response provision worked as expected.

Response provision

Response can be provided from:

- Mandatory Frequency Response (MFR): This can only be provided by synchronised BM units. The requirement for MFR is an obligation of the Grid Code.
- Commercial response contracts: This is the service procured from generation or demand, BM or Non-BM units. The providers are required to deliver the contracted amount of response.

Response Types

The ESO procures two main types of low frequency response, Primary and Secondary;

Primary response- is to contain the fall in frequency following an instantaneous generation loss in addition to the effect from system inertia. It must be delivering it's required output by 10 seconds following the trip and must continue to deliver for a further 20 seconds (30 seconds total)

Secondary response- is to help return the frequency back to within operational limits. It must be delivering it's required output by 30 seconds following the change in frequency and must continue to deliver for a further 30 minutes.

Both Primary and Secondary response can be delivered through two different types of provisions either Dynamic or Static;

Dynamic - Is a continuously provided service to manage the normal fluctuations in the frequency.

Static - Is a service to provide frequency response when the system frequency transgresses the low frequency relay setting on site.

These two types of service can be provided from generation and demand, BM and Non-BM units.

To ensure the quality of steady state frequency control, a minimum amount of dynamic response must be held. The requirement is reviewed continuously to ensure the stable pre-fault frequency management. The minimum dynamic response requirement at the time of the incident was set to 550MW.

Procurement

Whilst it is possible to procure the full frequency response requirement in real time from BM units, it is not generally the most economic way to do so. An optimisation strategy is used to procure various services from different providers at different times to ensure that the base requirement for a period is met. The primary method for this is through the monthly FFR tenders.

Real-time operations

The FSE model is used to create a series of response requirement tables which provide the overall frequency response requirement based on demand, inertia and largest infeed loss. These are used in operational systems to optimise the overall frequency response requirement for 5 minute blocks throughout the day based on the real-time demand, inertia and largest infeed loss. Operational systems are also loaded with the specific contractual arrangements that are already in place for each 30-minute period. The operational tools allow the control room engineers to understand the effectiveness of the products already in place against the overall requirement and set out a residual requirement to be procured in real time through mandatory services.

Managing Rate of Change of Frequency

Approximately 2 GW of small generators are connected to the distribution networks via relays which disconnect the generators if the RoCoF is greater than 0.125Hz/s. These relays are intended to protect these generators against a Loss of Mains event, disconnecting them from the system safely.

As a result, the ESO must keep the RoCoF at less than 0.125Hz/s to prevent loss of this generation.

What determines RoCoF?

If there is a loss of supply on system due for example to a generator or interconnector trip, then the RoCoF is determined by the size of the loss and the inertia of the system.

The greater the size of the loss, the higher the RoCoF and so the ESO plans the system to manage the largest infeed loss that could be experienced at that time. Typically, this loss will be Sizewell (1,260 MW) or an interconnector (1,000 MW).

The greater the inertia on the system, the lower the RoCoF. The inertia of the system is determined by the plant mix connected. The more synchronous machines connected the higher the inertia as non-synchronous (solar and wind) provides little inertia

How RoCoF is managed?

The ESO actively monitors, models and forecasts the RoCoF level for each half-hourly settlement period and ensures that it is maintained lower than the 0.125 Hz/s of the relays.

On days when there are large volumes of renewables and demand is low, the volume of synchronous plant on the system is lower, which reduces the inertia.

If there is not sufficient system inertia to keep RoCoF within limits the ESO has two options

1. Reduce all of the infeed losses to the level where if there is a loss then the RoCoF remains within limits given the inertia
2. Increase system inertia by turning off large amounts of non-synchronous generation and replace it with large synchronous generation

To increase the inertia of the system to allow 1MW more of infeed loss generally requires adding 20 MW of synchronous generation to the system. Option 2 is therefore approximately 10 times more expensive than option 1 and so the approach taken is to reduce the largest loss.

We continuously monitor and update our models to reduce the overall cost of managing the issue. We have also been working with the wider industry for 5 years to change protection settings on the relays to 1 Hz/s.

A further programme to change settings for generators to 1Hz/s has recently been initiated and is expected to run for approximately 3 years.

Managing Vector Shift

Approximately 8.5 GW of small generators are connected to the distribution networks via relays which disconnect the generators if the Vector Shift angle is greater than 6 degrees. These relays are intended to protect these generators against a Loss of Mains event, disconnecting them from the system safely.

What determines Vector Shift?

For Vector Shift, the trigger is not related to system frequency but instead to voltage phase angles. The voltage phase angle change (vector shift) is determined by the severity of the fault, proximity to the fault and the network configuration. In general:

- a three-phase fault is more onerous than a single-phase fault
- a fault in a meshed network is more onerous than in a radial network

How Vector Shift is managed

Faults that could cause a Vector Shift risk are divided in to two types:

- Type A: transmission faults with no coincident loss of BMU infeed (e.g. an overhead line)
- Type B: transmission faults with coincident loss of BMU infeed (e.g. a generator busbar)

The ESO actively monitors, models and forecasts the largest Type A Vector Shift risk (e.g., associated with a fault on a transmission circuit) for each half-hourly settlement period and ensures that the infeed loss associated with this is less than both the largest infeed loss and the RoCoF trigger level.

Type B faults are only secured based on it being economic to do so. There are no practical options for reducing the voltage phase angle change associated with a fault, and hence reducing the size of a Vector Shift infeed loss, and as such the costs of securing for Type B Vector Shift in all circumstances would be prohibitive.

The ESO continuously monitors and updates its models to reduce the overall cost of managing Vector Shift and we have also been working with the wider industry for a number of years to remove Vector Shift as an allowable form of Loss of Mains protection for new generators.

Appendix I – Simulation of the 09 August Event

This Appendix provides simulation results for the 09 August event performed by ESO using an internally developed model.

Simulation of Frequency Trace

The Frequency Simulation Engine (FSE) is used by ESO to calculate the frequency response holding required to keep frequency within limits for a given loss and set of system conditions. This has been used to simulate the 09 August incident to gain a better understanding of the event and demonstrate that the model is suitable for representing the dynamics of the system.

The simulation works by calculating the variance in the frequency caused by any imbalance between generation and demand.

As a first stage in the modelling, FSE has been used to infer the imbalance between supply and demand that would produce the actual frequency curve of the event. This is shown in the figures below.

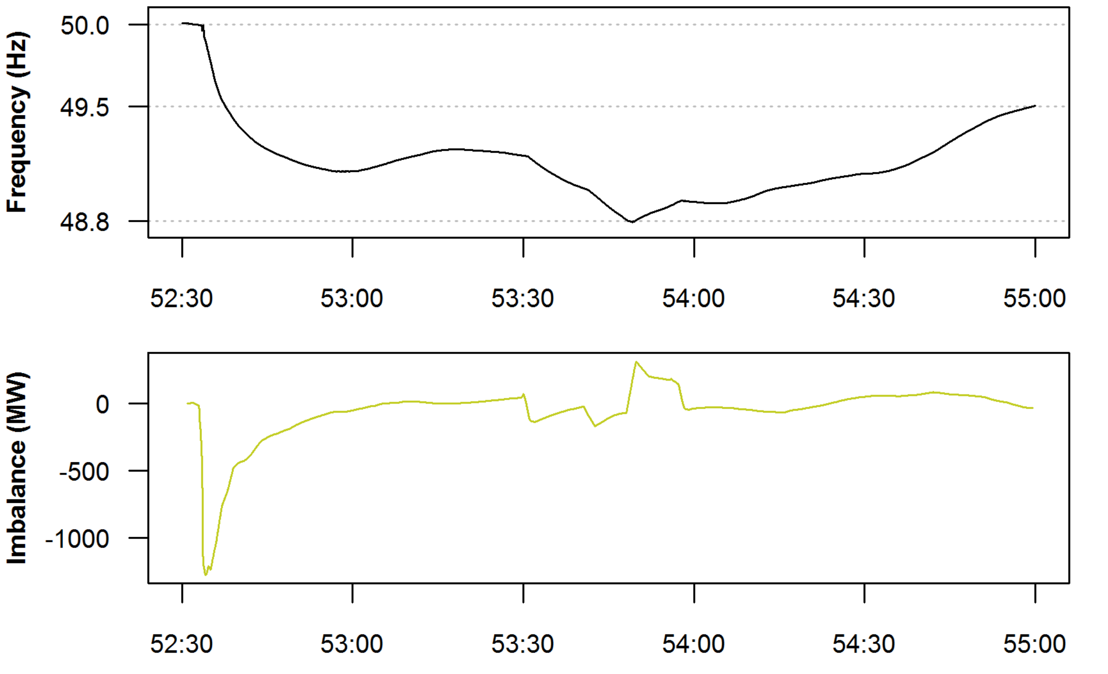


Figure 1 – Frequency Trace of the event and required imbalance to create the trace

The green trace includes the output from the frequency response services as they reacted to the event. Removing these from this imbalance trace gives the solid green line in the following figure. This line represents the changes in underlying supply and demand over time that are required to obtain the out-turn frequency trace.

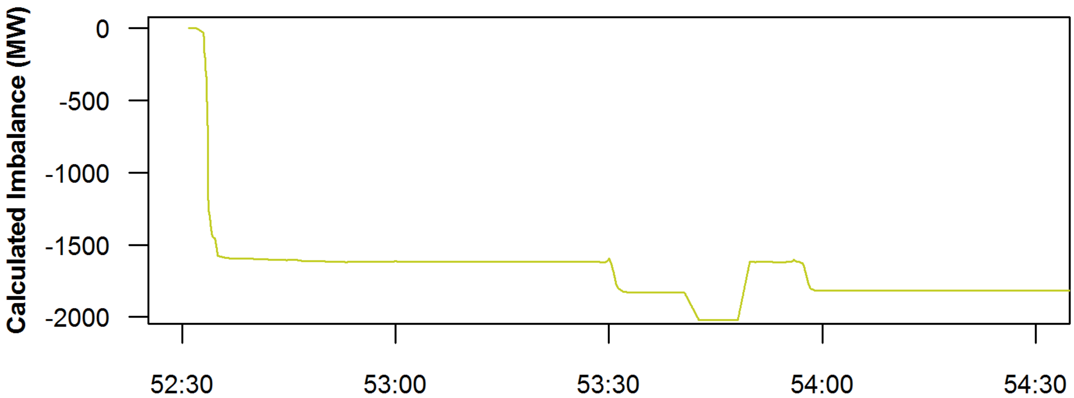


Figure 2 – Imbalance time series with Frequency response removed

An event such as this is complex with many different things happening and so it is unlikely that we can explain all of the movements in the imbalance. It is useful to analyse this trace to understand whether we can infer more about what happened.

Key elements of the trace are due to the known losses at Hornsea and Little Barford together with the embedded generation disconnected through Vector Shift and RoCoF. The loss due to Vector Shift of 150 MW is estimated to have occurred at the time of the circuit trip as highlighted previously. In Section 4.2.3 above it is estimated that, based on the data from DNOs, the volume of embedded generation lost through RoCoF was 350MW while analysis of the simulation data indicates that it may be slightly higher at 430MW.

A 100 MW variation in underlying imbalance which can be attributed to a slight reduction in generation output across the fleet lasting for 30 seconds is also modelled during the return of the frequency.

There is a change in the frequency trace at 49 Hz. A number of asset owners, both demand and generation, have highlighted that under frequency protection operated at this frequency, disconnecting both demand and generation. Analysis of the frequency trace indicates that the net effect of this protection operation was a reduction of generation of 200 MW.

At 48.8 Hz a total of 931 MW of demand was disconnected on LFDD. Our modelling indicates that an additional 581 MW of embedded generation was also disconnected either part of the LFDD scheme or via another mechanism, resulting in a net reduction in demand of 350 MW.

This gives the following inputs for a time series of imbalance

Event	Time	Imbalance Change (MW)
Hornsea One	16:52:33.728	-737
Little Barford ST1C	16:52:34	-244
Loss of Mains – Vector Shift	16:52:34	-150
Loss of Mains - RoCoF	16:52:34	-430
Reduction in generator output over 30 seconds	16:53:10	-100
Little Barford GT1A	16:53:30	-210
Net Change due to protection at 49.0 Hz	16:53:40*	-200
Net demand change at 48.8 Hz	16:53:48*	+350
Little Barford GT1B	16:53:58	-187

Table 1 – Modelled Imbalance Time Series

Factoring in the above changes it is possible to create the simplified imbalance time series below.

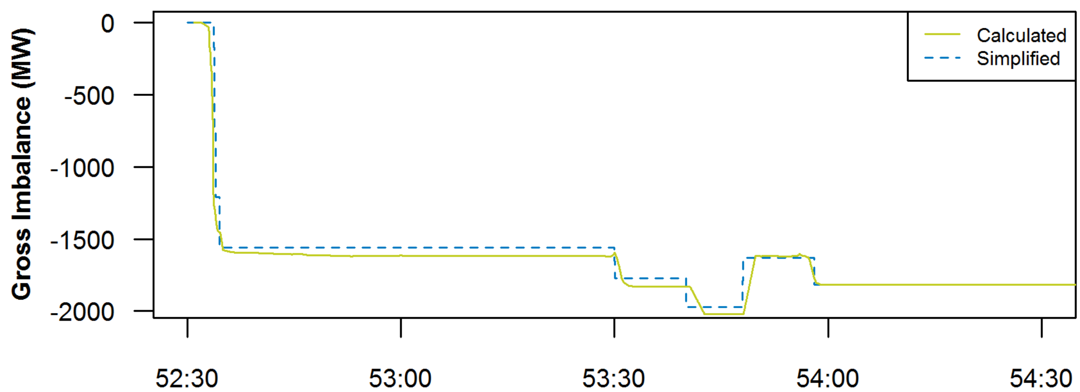


Figure 3 – Imbalance Time Series

Modelled Frequency Trace

Using the imbalance time series data from above it is possible to simulate the frequency to create the dotted blue on the chart below. The black line is the smoothed frequency from the event.

Note: The modelling inputs complete at 16:54 hence the deviation of the trace from this point onwards.

From these results above it can be seen that the model is properly calibrated and capable of recreating the event and correctly modelling the power system and how it responds.

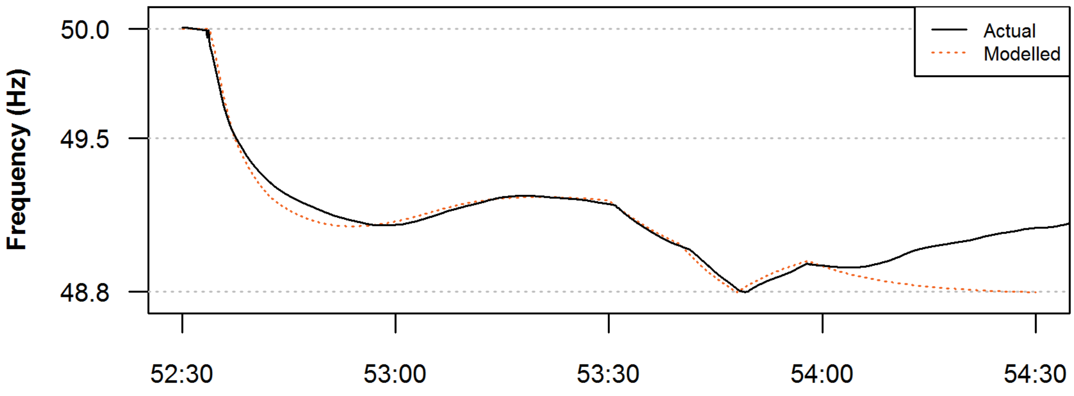


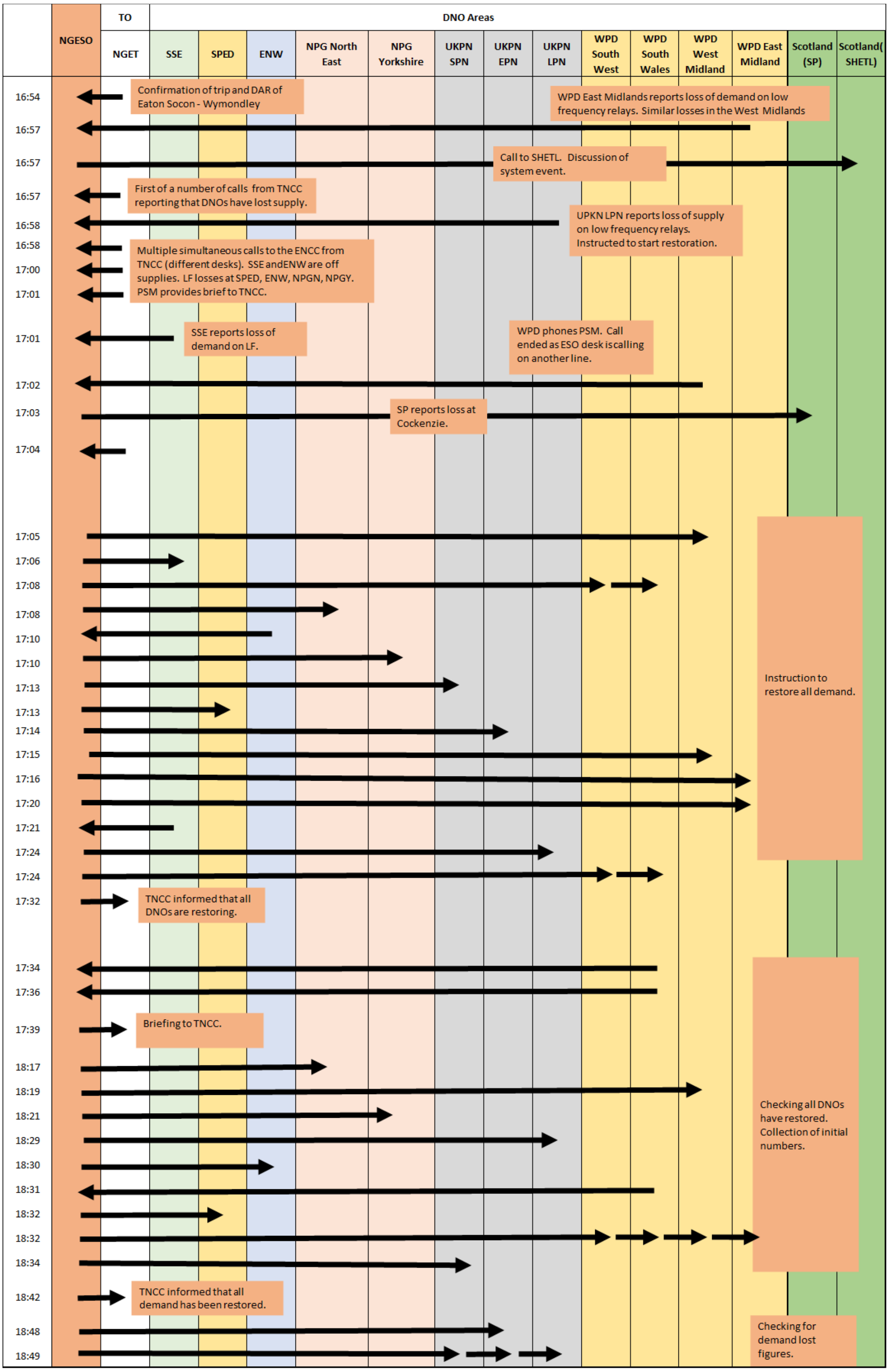
Figure 4 – Frequency Trace of the event vs Modelled Frequency Trace

Appendix J – Operational Calls between ESO Control Room, DNOs and NGET Control Room

This Appendix provides a diagram of all the operational calls between parties during and immediately after the event as the system was returned to normal operation.

Table summaries all operational calls between the ESO control room, DNO control rooms and NGET control room following the power cut event and until all demand were restored on 9 August.

- By 17:04hrs, demand disconnection on individual DNO areas were all communicated to the ESO control room.
- At 17:05hrs, demand restoration instruction commenced from ESO control room to DNOs.
- By 17:16hrs, demand restoration instructions were all initiated to DNOs.
- Since 17:34hrs, communications commenced to check restoration status and collate initial numbers.



Appendix K – ESO Interim Report

This Appendix provides a link to the interim report provided by the ESO to Ofgem on 16 August 2019.

https://www.nationalgrideso.com/information-about-great-britains-energy-system-and-electricity-system-operator-eso

Appendix L – OFGEM Letter Requesting Report

This Appendix contains a letter dated 12 August 2019 from Dermot Nolan, Chief Executive, Ofgem to Fintan Slye, Director ESO requesting a detailed report by the Electricity System Operator into the circumstances that led to the incident and the response from the Electricity System Operator and the wider industry.

Making a positive difference
for energy consumers

Fintan Slye
National Grid ESO
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Date: 12 August 2019

Dear Fintan,

Power failures

Following the power failures on Friday 09 August 2019, Ofgem is requesting a detailed report by the Electricity System Operator into the circumstances that led to the incident and the response from the Electricity System Operator and the wider industry. This should be independently produced and solely approved by the Electricity System Operator.

An interim report should be delivered to Ofgem by 4pm on Friday 16 August 2019 and a final detailed technical report by 4pm on Friday 06 September 2019.

The scope of the report should focus on an explanation of the events of Friday 09 August 2019, the causes of the power failures, the steps taken by the Electricity System Operator in response, and the industry response.

The interim report

The interim report should cover (but not be limited to):

- A detailed timeline of events as they unfolded on 09 August 2019;
- The cause of the incident, including the reasons for, and the implications of, each of the generators coming off the system so quickly;
- The Electricity System Operator's planning assumptions and preparedness for such an incident;
- The Electricity System Operator's response and how this relates to your regulatory and statutory requirements;
- The wider industry response and how the impact of the event was managed – and, in particular, the prioritisation criteria that were applied to curtail demand that was taken off of the system and the implications for wider critical infrastructure;
- Communication by the Electricity System Operator and the wider industry about the incident with Government, Ofgem and the public;
- Your estimate of the customer detriment that occurred as a result of the incident;
- Whether it highlights any systemic issues relating to the evolving generation mix; and
- Any other factors you think are relevant to understanding this incident.

Upon receipt of the interim report we may raise further questions or requests for information or documents in response to any information you provide or as we otherwise consider appropriate.

The technical report

The technical report should give further detailed technical information in response to questions requested for the interim report. It should address any additional query lines that come to light while carrying out this analysis, including from dialogue between Ofgem and the Electricity System Operator (such as following the receipt of the interim report). It should highlight the steps that the Electricity System Operator and industry will be taking or propose taking to resolve similar issues arising on the system in future.

The aim of the report will be to highlight lessons learned, but Ofgem will consider whether further action is appropriate. Please liaise with Jonathan Brearley for further clarification or discussions.

Yours sincerely,

Dermot Nolan
Chief Executive

cc: Jonathan Brearley (Executive Director, Systems and Networks, Ofgem)
Duncan Burt (Operations Director, Electricity System Operator)

The Office of Gas and Electricity Markets
10 South Colonnade, Canary Wharf, London, E14 4PU **Tel** 020 7901 7000 **Fax** 020 7901 7066
www.ofgem.gov.uk

Appendix M – ESO E3C Questions and Answers

This Appendix contains the questions to the ESO from the E3C committee to inform their report together with the answers provided. These answers are all based on the data available to the ESO on 28 August 2019.

1 Do you think the relevant lessons (including lessons around comms) from the 2008 incident and 2013 Christmas storm have been properly implemented?

2008 Event – we believe that the relevant lessons have been properly implemented

The 2008 final report recommended

1. Inclusion of a clear and explicit frequency operation range in the distribution code for small embedded generation.
2. Where reasonably practicable, the inadequate frequency range settings on existing small embedded generation plant should be modified to improve their resilience to frequency excursions
3. Ensure LFDD schemes are not compromised by the presence of low voltage interconnections between substations; primary substation running arrangements; delayed auto reclose on feeders; uninstructed manual restoration of demand
4. With the continued assistance of the Association of Electricity Producers (AEP), establish as far as practicable the timing and cause of any embedded generation losses on the 27 May to further support actions 1 and 2.

The table below outlines the actions taken against each recommendation and our view on the impact in 2019.

	Action Taken	Commentary for 2019
1	The Distribution Code and Engineering Recommendation G59 – Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators, were revised in 2010 (Issue 2) and included an explicit frequency operation range. These requirements became mandatory with implementation of the Requirements for Generators European Code in April 2019	At this stage there is no clear evidence of a general lack of resilience amongst distributed generators to changes in frequency aside from the known issues associated with Loss of Mains protection
2	One of the changes in Issue 2 of ER G59 was a change to the settings for the frequency protection on Distributed Generation (DG). For DG in the range 5 to 50 MW. There was a requirement for these changes in frequency protection to be applied retrospectively, where practicable. Progress was reported regularly to the Distribution Code Review Panel and over 4GW of capacity at risk was addressed	Regular progress reports provided to the DCRP show that this action was implemented and that changes were made at the majority of affected sites. The remaining volume was considered to be immaterial given the effort required to make the changes
3	LFDD performance was reviewed by the E3C Working Group and improvement areas were identified and completed. A Grid Code change (D/09) was also implemented which clarified LFDD requirements	LFDD performance on August the 9th was as expected, demonstrating that necessary lessons have been learnt. We support continued dialogue on LFDD performance to ensure that the scheme remains effective in light of the growth of distributed generation capacity and the deployment of active network management schemes
4	This work was undertaken by the E3C Working Group and used to inform the actions identified above	

2013 event – this event was substantially different

The learnings from Christmas 2013 were predominantly relevant to situations in which consumers experience a lengthy power disruption with uncertainty over restoration timescales. As a result, many findings are not directly relevant to this extent

Many of the recommendations related to communication with customers. The ENA took an action after Christmas 2013 to set up the national power cut helpline number (105) which they now advertise on their website. They published a reminder of this number on their Twitter account during the event on 09 August. As an example of best practice, Northern Powergrid also helpfully provided details of affected postcodes and likely restoration timescales in a single tweet, by 5.14pm on 9th August.

In our preliminary report we have proposed a review of ESO communication processes with industry, Government, Ofgem and media, to support timely and effective communication in any future event

2 What learning can BEIS and energy sector take from the emergency response to the GB power system disruption on Friday 9 August?
3 Are there lessons to be learnt for maintaining wider system resilience?

We have answered questions 2 and 3 together
Our analysis of the events of 09 August is still ongoing. We have issued our interim report and are working towards a final report on 6 September.

Our preliminary findings, as detailed in our interim report, and based on analysis to date, are:

Two almost simultaneous unexpected power losses at Hornsea and Little Barford occurred independently of one another - but each was coincident with a lightning strike on a transmission circuit. As generation would not be expected to trip off or de-load during or following a lightning strike, this appears to represent an extremely rare and unexpected event.

This was one of many lightning strikes that hit the electricity grid on the day, but this was the only one to have a significant impact; lightning strikes are routinely managed as part of normal system operations.

The protection systems on the transmission system operated correctly to clear the lightning strike and the associated voltage disturbance was in line with what was expected.

The lightning strike also initiated the operation of Loss of Mains (LoM) protection on embedded generation in the area and added to the overall power loss experienced. This is a situation that is planned for and managed by the ESO and the loss was in line with our forecasts for such an event.

These events resulted in an exceptional cumulative level of power loss greater than the level required to be secured by the Security and Quality of Standards (SQSS) and as such a large frequency drop outside the normal range occurred.

The Low Frequency Demand Disconnection (LFDD) system worked largely as expected and disconnected approximately 1.1m customers (c. 1GW load).

The system was returned to a stable position in c. 15 minutes and the Distribution Network Operators then quickly restored supplies in c. 30 minutes once the system was returned to a stable position.

Several critical loads were affected for a number of hours by the action of their own systems, in particular rail services.

Our interim report also identified the following areas where further work is required and on-going to have a complete understanding of the event:

Understanding the exact failure mechanisms at Little Barford and Hornsea, building on our current good level of understanding of the timing and levels of the various generation losses; and

Continuing to work with the DNOs to understand fully the demand side impacts, including the demand facilities that were disconnected via the LFDD scheme operation and those that lost supply for other reasons during the event.

Based on our analysis to date, we have identified the following areas where lessons can be learned:

- Communication processes and protocols should be reviewed across ESO, DNOs, TOs, Government, Ofgem and media, to support timely and effective communication in any future event;
- The list of facilities connected to the LFDD scheme should be reviewed to ensure no critical infrastructure or services are inadvertently placed at undue risk of disconnection; and
- The settings on the internal protection systems on electric trains should be reviewed to ensure they can continue to operate through ‘normal’ disturbances on the electricity system.

As we continue our further analysis through the areas of further work above, there may be further areas to highlight.

While the processes and procedures in place on 09 August generally worked well to protect the vast majority of consumers, there was however significant disruption – over 1m customers were without power for up to 45 minutes, rail services were severely impacted and some critical facilities were without power. Therefore, given the expected significant future evolution of the electricity system, and reflecting on the scale of disruption caused to the public, there are some areas where we believe a wider review of policy, processes or procedures may be appropriate. This includes:

- A review of the security standards (SQSS) to determine whether it would be appropriate to provide for higher levels of resilience in the electricity system. This should be done in a structured way to ensure proper balancing of risks and costs;
- A review of the timescales for delivery of the Accelerated Loss of Mains Change Programme to reduce the risk of inadvertent tripping and disconnection of embedded generation, as GB moves to ever increasing levels of embedded generation; and
- Assessing whether it would be appropriate to establish standards for critical infrastructure and services setting out the range of events and conditions on the electricity system that their internal systems should be designed to cater for.

4 What if any improvements to the design of the power system, in particular the LFDD relay settings and generation technical standards could have prevented or further limited the impact of the incident?

The Low Frequency Demand Disconnection (LFDD) system worked largely as expected, providing an important layer of protection for the wider system which should be continued in the future.

A review of how the LFDD is designed would be prudent given the growth of generation embedded in the distribution networks and that during the event some infrastructure such as Newcastle airport and railway signals were disconnected.

LFDD tripping may have the effect of tripping Distributed Energy Resources (DER) situated within the demand block being disconnected by the LFDD scheme. This has the impact of removing both generation and demand at the same time thus potentially reducing the overall effectiveness of the LFDD action. Over time, predicting the overall level of demand that would be lost in a LFDD event consequentially becomes more complex to estimate as DER penetrations increase.

Potential improvements to LFDD relay settings and schemes could be achieved through:

- having more transparency of the LFDD system so that there is general awareness of what can get disconnected
- having more visibility of DER including location, technology and if possible metering to understand what impact DER might have on net load that is disconnected.
- optimising the relay placement on DNO networks. Through analysing the amount and location of DER in LFDD blocks and then placing the LFDD relays where there are lower volumes of DER. It would make the operation of LFDD more effective thus reducing the risk of the requirement for further LFDD operation at lower frequency level(s).

5 Do you believe that the system should be secured against the instantaneous loss of the two largest generators, rather than one, recognising this would incur additional costs to consumers

The standards we have had in place for many years have delivered world class reliability - however for what was a rare event on the 09 August the disruption caused to society was something we would not want repeated and therefore we think a review of the standards for security of supply would be prudent to ensure they are appropriate for society and the economy today and into the future and that they reflect the right balance with the costs to customers.

6 Should there be a minimum requirement for the level of inertia held on the system?

It is our view that the required level of system resilience should be mandated as this is what is important to society. At each point in time the ESO can then optimise the system to deliver this resilience in the most cost-effective manner. The appropriate level of resilience should be considered as part of any review of the standards for security of supply.

Mandating inertia or any of the other system variables rather than the required resilience level could lead to unnecessary costs for consumers.

.

7 From your analysis/information, what embedded generation was lost over this incident. If so, why was it lost?

We estimate that approximately 500 MW of embedded generation was lost in the incident.

The Loss of Mains protections operate in two different modes – Rate of Change of Frequency (RoCoF) and Vector Shift. Both are designed to ensure the safety of the equipment attached via the protection.

The trigger for vector shift protection is not related to system frequency but instead to voltage phase angles being out of alignment (e.g., following a fault). The vector shift protected generation would have therefore been lost co-incident with the transmission system fault.

A RoCoF protection system is designed to disconnect the embedded generation if the RoCoF is greater than a trigger level. As result any RoCoF protected generation would have been lost co-incident with the frequency fall and so occurs after the loss of generation due to vector shift.

The volume has been estimated by analysing the changes in flows between the Transmission Networks and the Distribution Networks using metered data gathered from our IEMS system. At the time of the incident the flow changed. We have corrected this change for the frequency characteristics of demand and allowed for frequency response services in the distribution network. The resulting increase is approximately 500MW. The work we have done previously with DNOs tells us this 500 MW change can be attributed to the loss of embedded generation primarily associated with Loss of Mains Protection (RoCoF and vector shift).

We are continuing further analysis of our own data, also data from our own embedded providers, and DNOs to further establish a more accurate change in the flows in order to give a higher confidence in this number and to determine whether we can a split between RoCoF and Vector Shift connected generation.

8 Are current largest loss of load assumptions fit for purpose in the changing energy system (.i.e more distributed generation, higher penetration of intermittent renewables, larger individual nuclear generators)?

The assessment of infeed loss risks considers the largest infeed loss at a Transmission level and is in line with current security standards.

Given the expected significant future evolution of the electricity system and reflecting on the scale of disruption caused to the public, a review of the security standards (SQSS) should be considered to determine whether it would be appropriate to provide for higher levels of resilience in the electricity system. This should be done in a structured way to ensure a proper balancing of risks and costs

9 In your opinion, were the trips of Hornsea 1 and Little Barford linked to a circuit fault? If so, why?

The two almost simultaneous unexpected power losses at Hornsea and Little Barford occurred independently of one another - but each coincident with a lightning strike. Throughout the incident voltage remained within Grid Code limits. As generation would not be expected to trip off or de-load in response to a lightning strike, this appears to represent an extremely rare and unexpected event. We are continuing to analyse the data for the publication on 06 September.

10 What was the ESO forecast(s) of generation output, broken down by transmission connected and distribution connected, by fuel type, over the six hour period prior to, during and the event?

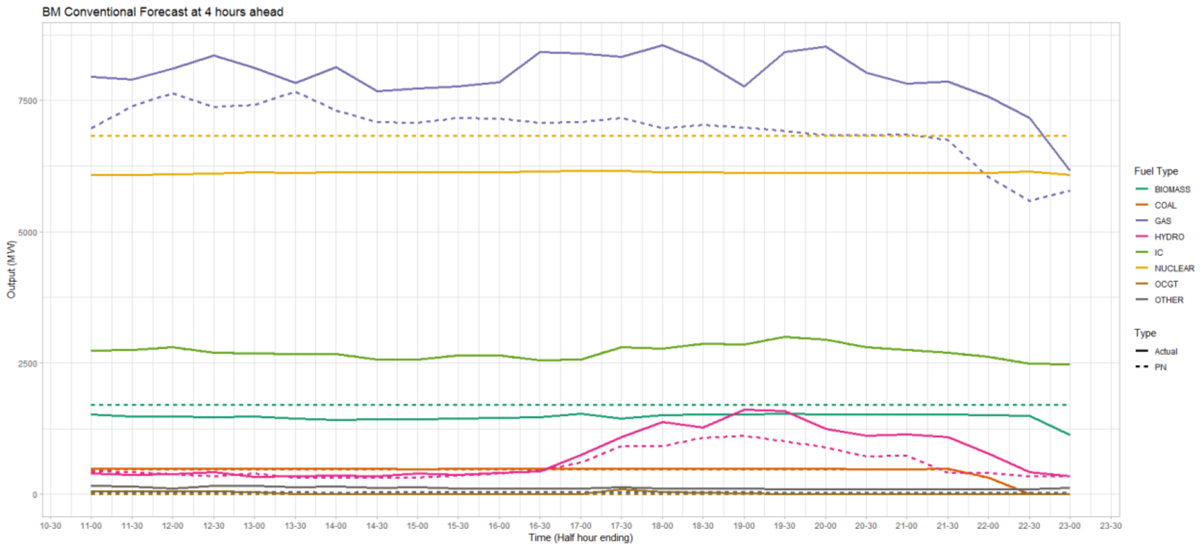
Conventional transmission connected generation provides Physical Notifications (PNs) of output. With the exception of wind generation, this represents their intended generation pattern by settlement period. Wind generation units do provide PNs, but this represents the maximum they could generate if units were operating at full capacity, and so these are not used; instead the ESO makes its own forecasts of output, based on forecast weather conditions. The majority of distribution connected generation provides no indication of proposed output, and no actual output data to the ESO.

For weather driven distribution connected generation (wind and PV/solar) forecast and output values are modelled on relevant weather variables. Forecast and estimated output generation are produced from these models (in the case of PV generation further statistical techniques using a sampling of some selected PV sites is also employed to improve outturn accuracy).

The first graph shows the forecast which is the PN submmited by the generators (dotted) and estimated outturn of conventional transmission generation (solid line) by fuel type at the 4 hour ahead stage.

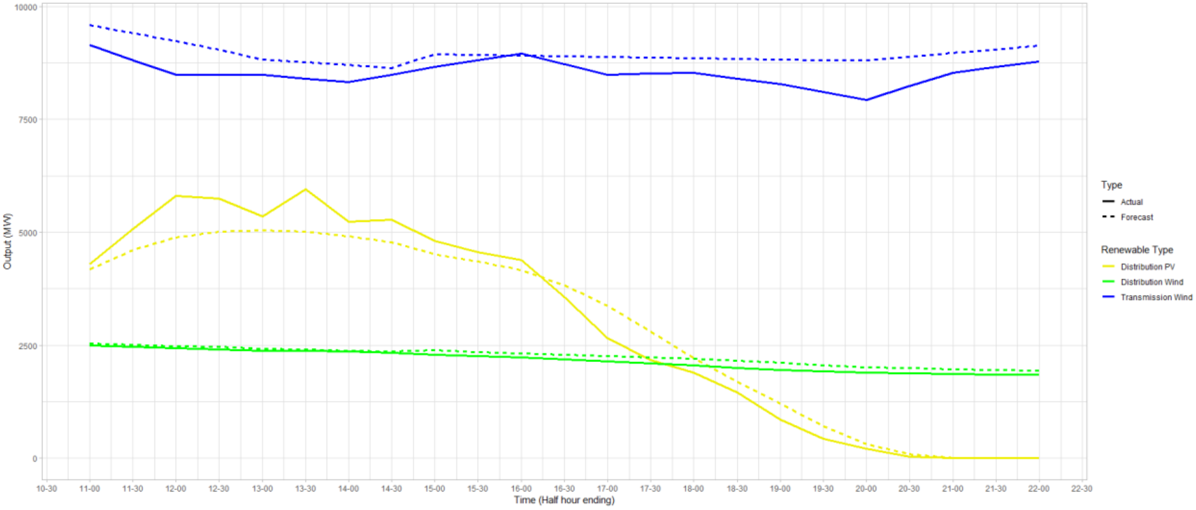
In general actual outturn for conventional generation closely follow PNs. Nuclear ouput is below the PN as nuclear operators tend to keep the PNs for the plant at a maximum level and use the Maximum Export Limit (MEL) to indicate the plant output. Gas (CCGT) plant is the marginal fuel type and is predominantly used by the ESO control room to balance the system: output tends to be higher than the PN, representing the ESO instructions to increase output.

An increase in hydro plant output after the event at 16:53 is clear as the ESO instructs plant to stabilise the frequency and replace missing energy (note: this data is at settlement period resolution).



The second graph shows the forecast and outturn for transmission connected wind and for distribution connected wind and solar (PV). Forecasts were close to out-turn across the day.

Renewable Forecast at 4 hours ahead



11 What's driving their largest loss of load assumption and how do they update the assumptions?

The largest loss of load assumption (largest infeed risk as defined in the SQSS) is managed in the control room using planning and actual data to identify the largest infeed loss present on the system at that time. This involves:

- Identification of the largest infeed risk. Typically, this is the largest single generator loss or interconnector loss on the transmission system, or associated loss of the network connecting a large generator that will result from a single secured event. It is assessed based on system configuration and the likely effect from the credible system faults.
- We also secure the system to within a ROCOF limit of 0.125 Hz/s for the largest credible loss. This means that we identify both the largest loss (as above, but which may take a number of seconds to occur) and also the largest instantaneous loss (the largest secure single loss that can happen instantaneously i.e. for the opening of a circuit breaker)

We then schedule sufficient frequency response to ensure the largest loss is contained to frequency limits (49.5Hz for a normal loss, 49.2 Hz for an abnormal loss) and ROCOF limits of 0.125Hz/s for the greater of the largest loss and the largest instantaneous loss.

We also consider the impact of vector shift protection on embedded generation where appropriate to do so. Furthermore, where there is a higher probability that a large infeed loss may also be associated with significant vector shift protection losses then we manage this for this event even though this is strictly not within the requirements of the security standards.

12 How are largest infeed loss considerations taken into account when determining volumes (and right mix/design of balancing products) that need to be procured in the Ancillary Services Market?

The requirement to secure against the largest infeed loss is the main driver for the volume of frequency response procured.

We procure Frequency Response capabilities through several products; Firm Frequency Response (FFR), Enhanced Frequency Response (EFR) and Mandatory Frequency Response (MFR).

FFR creates a route to market for providers whose services may otherwise be inaccessible. The FFR service gives us and service providers both a degree of stability against price uncertainty under the mandatory service arrangements.

Ahead of time, we procure FFR through competitive tenders for both dynamic and non-dynamic services to ensure that we meet our minimum volume requirements for response driven by the largest infeed loss considerations. Should additional response volume be required on the day then this can be procured through the MFR market.

13 Which services were called upon/utilised to deal with the frequency drop?

Frequency response products were used to arrest the fall of frequency. These can be categorised into dynamic frequency response which is a continuously provided service used to manage the normal second-by-second changes on the system and static frequency response which is typically a discrete service triggered at a defined frequency deviation.

Dynamic frequency response services were

- Firm Frequency Response (FFR): this is tendered for on a monthly basis
- Mandatory Frequency Response: this has similar characteristics as FFR but is provided as an obligation laid out in a generator's connection agreement
- Enhanced Frequency Response (EFR): this is a faster form of FFR

Static frequency response was also available. This reduces demand or increases generation when the frequency hits a trigger limit

A range of reserve services were used to return the frequency to operational limits

- Short Term Operating Reserve: this service typically delivers energy within 20 minutes or less
- Rapid Start: this provides access to energy in less than 2 minutes
- Balancing Mechanism Actions

14 Could the procurement of higher volumes of frequency response have prevented the outage? If yes, what volume of frequency response (and mix of balancing products) and at what cost? What would be the optimal design of frequency products to achieve this?

The procurement of higher levels of frequency response could secure the system against higher infeed losses (e.g., the loss of multiple units). To increase the levels of frequency response today the ESO would need to

1. Contract for more frequency response
2. Redispatch the generation on the system to create the headroom for frequency response. Although significant progress has been made in attracting batteries and demand side response into the market, there is currently not sufficient to provide this extra frequency response and it would need to be sourced from traditional generators synchronised on the system.
3. Further redispatch of the generation on the system to ensure that the inertia is sufficient to maintain RoCoF below trigger levels for this larger loss (i.e., loss of multiple units).

The first action above, contracting for more frequency response, would cost c. £200m per annum, based on the current portfolio of providers and generation mix. The other two actions together would be considerably more expensive (likely several billion pounds). Over a longer timeframe which allows investment these costs can be reduced. Key enablers for achieving this are:

Signalling the need for more frequency response to attract investment in more batteries and other technologies alongside increased demand side response

The 3 year program of work that the ESO has put in place to adjust the settings on the RoCoF relays to make them less sensitive. As a result, less inertia will be required in the future for a given loss.

The development of an inertia market. The ESO is at an early stage in this through its stability pathfinder project

15 How will future ancillary services products/product design help mitigate such incidents in future?

The current set of products and services available is fit for purpose for balancing today's system. Through the Power Responsive campaign over the last 4 years the ESO has transformed the balancing services markets, working closely with industry.

Response and reserve products have historically been provided by traditional generators such as coal and CCGTs which are less frequently synchronised to the system. Supported by the Power Responsive campaign the ESO has been working on simplifying and standardising the products so that they can be provided by a wider range of participants such as DSR and batteries. Central to this work has been our Systems Needs and Product Strategy and the subsequent roadmaps which explained our requirements and provided a basis for working with industry to transform the markets. This work has been extremely successful, increasing the volumes of response and reserve available to manage frequency and driving down costs for consumers. The next phase of the work this year to trial auctions close to real time will allow wind generators and increased volumes to participate.

The generation mix will continue to evolve as we drive towards net zero by 2050 and the ESO has committed to being able to operate the system carbon free by 2025. To achieve this aim, the ESO is working across the wider industry on several initiatives specific to the control and stability of frequency:

- Continuing the reform of response and reserve products to ensure there are no unnecessary barriers to entry for new technologies
- Investigation of a new set of frequency response products which could include a faster acting product.
- Development on an inertia market. We are taking the first step in this inertia through our 'pathfinder' project on stability
- A 3 year Accelerate Loss of Mains Change Program which will reduce the volume of generation at risk of disconnection in response to a large loss has commenced.
- A new inertia monitoring service will give us world leading information on the dynamic characteristics of the system which will feed into the calculation of response and reserve.

16 What was the total capacity of all Primary and Secondary frequency response available; an hour prior to as well as during and after the time of the event; for activation by the ESO?

Below is a table detailing the volumes of frequency response which was instructed by the ENCC at three time points around the event.

		One hour prior to event	Event time	Time after event
Time		15:52	16:52	17:00
Largest gen loss		950	1000	1000
Frequency Response Type		**Low Frequency Holding (MW)**	**Low Frequency Holding (MW)**	**Low Frequency Holding (MW)**
Dynamic	Primary [Secondary]	618[751]	564 [595]	823[1018]
	Enhanced Frequency Response	227 [227]	227 [227]	227 [227]
Static	Primary [Secondary]	231 [231+285]	231 [231+285]	231 [231+285]
Total		**1076[1494]**	**1022 [1338]**	**1281[1761]**

Source of data: NED system

17 Was all the Primary and Secondary frequency response activated by the ESO, and when (in a timeline, prior to, during and after the event) was this done?

Primary and secondary response is either dynamic (responding continuously in line with frequency deviations) or static which is armed at a frequency trigger level. Therefore, both types of response are automatically provided once armed by the Control Room.

The table below highlights the frequency response holding and the current best view of the low frequency response performance, this is subject to change.

Frequency Response Type			**Number of Units**	**Low Frequency Holding**	**Low Frequency Delivered** within 30 seconds of event
Dynamic	Primary [Secondary]	BM	8	284 [325]	266
	Primary [Secondary]	NBM	36	280 [270]	231
	Enhanced Frequency Response	NBM	10	227 [227]	165
Static	Triggered at 49.7 Hz, delivered within 30 seconds	BM	-	-	-
		NBM	19	[285]	198
	Triggered at 49.6 Hz, delivered within 1 second	BM	2	200 [200]	200
		NBM	7	31 [31]	30
Total (Excluding demand effect*)				1022 [1338]	1090

*Demand varies due to frequency, as some devices such as synchronous motors use slightly less power when frequency is slightly low, and vice versa when frequency is slightly high. For 29 GW demand, this effect is approximately 350MW at 49.5 Hz. This effect is unrelated to LFDD.

18 Was there any delay in the provision of Primary or Secondary frequency responses (prior to, during and after the event) to the ESO?

All response is automatically activated by the fall in frequency. The table above highlights the frequency response holding and the current best view of the low frequency response performance. Analysis is ongoing on response performance across the portfolio and the technical report will provide a detailed assessment of this. Note, when calculating the volume of frequency response required to secure the largest loss, a 90% delivery rate is assumed.

19 What's was the total capacity of all other Balancing Mechanism (BM) frequency related capabilities available; an hour prior to as well as during and after the event; for activation by the ESO?

This is not something we routinely record. Below is a table detailing the volumes of frequency response holding in the BM at three time points around the event. This consists of mandatory frequency response (MFR) activated on synchronised generators and static response from interconnectors. The volume of MFR activated on the system is optimised by the ENCC so that the total volume of response held is as close to the target volume as possible.

		One hour prior to event	Event time	Time after event
		15:52	16:52	17:00
Frequency Response Type		**Low Frequency Holding (MW)**	**Low Frequency Holding (MW)**	**Low Frequency Holding (MW)**
Largest loss		**950**	**1000**	**1000**
Dynamic MFR	Primary [Secondary]	338[481]	284[352]	543[748]
Static (Moyle and EWIC)		200[200]	200[200]	200[200]

20 Was all the BM capabilities available activated by the ESO, and when (in a timeline, prior to, during and after the event) was this done?

1,240 MW of actions were taken by the ESO to restore frequency to operational limits, using the following services:

Short Term Operating Reserve

Rapid Start

Balancing Mechanism Actions

Fast Reserve (from BM and non-BM providers).

Immediately following the loss of Hornsea One and Little Barford ST1C various automatic and manual services were initiated to arrest the frequency fall as highlighted in previous questions. The automatic services included static Low Frequency initiated Firm Frequency Responses (FFR) which is designed to be triggered at 49.7Hz, EWIC and Moyle interconnectors being initiated at 49.6Hz and a service contracted with Gas Turbines which was initiated at 49.6Hz and 49.5Hz respectively, depending on the agreement between NGESO and the providers. There were also some manual actions conducted by NGESO control room which included rapid start service being instructed to one Dinorwig unit, instructions to another Dinorwig Unit and two Ffestiniog units from a synchronising position to generating and an additional distribution connected diesel generator. 400MW of short term operational reserve was also instructed. To cover the enduring loss of generation at Little Barford and Hornsea One, Coryton South and Carrington were both instructed by NGESO.

21 Was there any delay in the provision of those BM activated services (prior to, during and after the event) to the ESO?

Please refer to question 18 (response performance) and more information will be available in the technical report.

22 What's was the total capacity of all other, non BM, frequency related capabilities (such as FFR, DSM etc., etc.,) contractually available; an hour prior to as well as during and after the event; for activation by the ESO?

Non-BM participants can provide enhanced frequency response (EFR), dynamic frequency response (FFR) or static frequency response.

Providers of FFR and low frequency static participate in the monthly tenders or the auction trial where the same volume is provided for all settlement periods in an EFA Block. In addition the EFR contracts are for a constant volume. EFA Block 5 when the incident occurred starts at 15:00 and ends at 19:00. As a result, volumes an hour prior, during and after the event are all the same.

	Low frequency contracted (MW) Primary	**Low frequency contracted (MW) Secondary**	**Low frequency contracted (MW) 1s**
EFR			227
FFR dynamic	280	270	
FFR static	0	285	31
Total	**280**	**555**	**258**

23 Was all the other, non BM, frequency related capabilities contractually available activated by the ESO, and when (in a timeline, prior to, during and after the event) was this done?

As per question 17, primary and secondary response is either dynamic (responding continuously in line with frequency deviations) or static which is armed to respond at a frequency trigger level. Both types of response are automatically provided once armed by the Control Room.

24 Are you aware of secondary impacts observed by you or reported to you by third parties?

We are continuing to investigate and any further information will be included in the technical report

25 In your opinion, are there any cost-effective ways in which the impacts of such an event can be addressed?

We support a review of the security standards in light of the impacts of this incident. This review should be carried out in a structured way, properly balancing risk and costs. Any changes should be implemented as soon as possible without incurring unnecessary costs for consumers or industry disruption.

26 In your opinion, are any process/procedural issues that any to be addressed to avoid a repeat of this event or to reduce the impact of such an event.

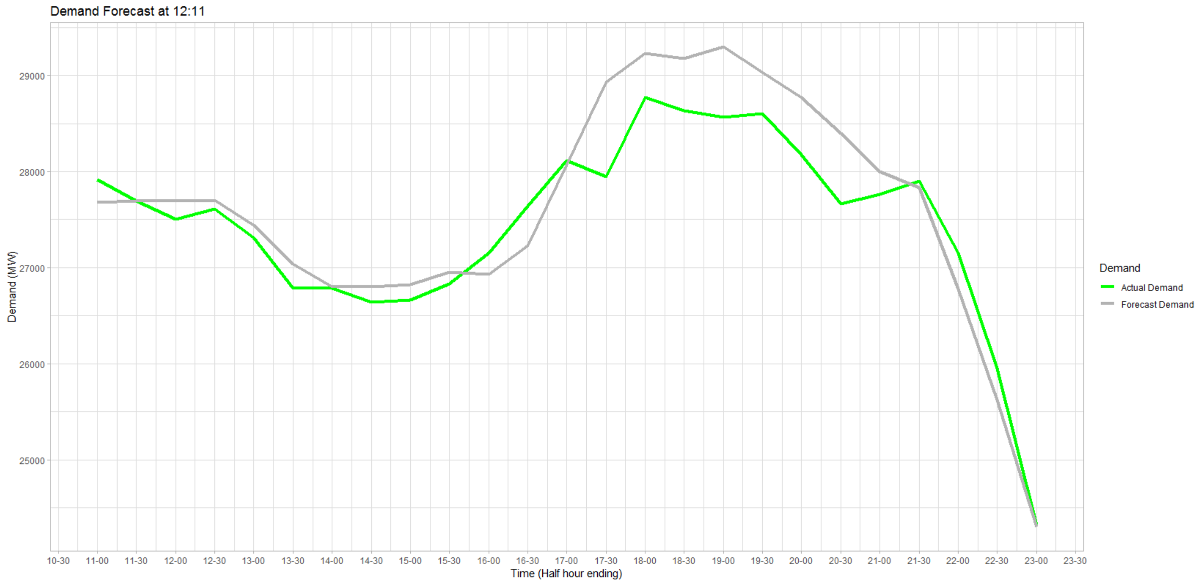
The processes and procedures in place on 9 August worked well. Our analysis is still ongoing and we have outlined our views on this and wider issues in our response to questions 2 and 3 above.

27 Have you taken any defensive measure in the interim to prevent a reoccurrence?

In the days immediately after the event we took the prudent, defensive measure of holding 100 MW more frequency response whilst we analysed the incident. Through our analysis we have gained more confidence in the delivery of frequency response and have now removed this extra holding.

28 What was the ESO demand forecast(s) and actual demand over the six hour period prior to, during and after the event?

The graph shows the half hourly National Demand forecast produced at 12:11 which was used to finalise the sytem operating plan for the early evening.



29 The actual demand trace is a combination of real demand net of distributed generation.

Did the ESO have the right trade-off in cost and risk in balancing the system?

The security of supply standard sets the risk that is acceptable for operation of the transmission system. The ESO operates the system in accordance with this security standard and aims to achieve this standard in the most cost-effective manner for consumers.

30 At around the time of the incident, were there any disturbances/faults on system? Please provide technical details of any relevant faults.

Prior to the event, there were two weather related transmission system faults.

- At 14:23:00, the Harker – Stella West 275kV circuit tripped and was automatically returned to service via Delayed Auto Reclose (DAR) at 14:23:32.
- At 16:43:25, the Blyth – Eccles – Stella West 1 400kV circuit tripped and was likewise returned to service via DAR at 16:43:54.

On both occasions, lightning was observed in the vicinity and the faults were cleared with no adverse effects to the transmission system.

31 Did the GB Transmission System and the DNO networks act as expected during the event?

The transmission system acted as expected. The fault on the Eaton Socon - Wymondley circuit was cleared within 80ms at both ends.

Initial analysis for the Interim Report suggests that the LFDD worked as intended. The ESO is collaborating with DNOs to understand their demand losses and the number of customers disconnected by their LFDD relays operations. An updated position will be provided in 6 September report

32 What is ESO policy on bad weather risk mitigations? Was the weather such on the day that actions were being considered or had been taken?

Weather conditions on 9th August were anticipated and were not unusual. The Met Office had issued yellow warnings of wind for the South West England and South Wales, and yellow warnings of rain for all of England and Wales. Lightning Risk 1 was in place in NW England, NE England and Midlands/Lincs.

The Yellow Warning is the lowest of the 3 Met Office warnings.

NGESO's policy for severe weather, which was not required on the day, requires the Network Planning Access Manager (more than 24 hours ahead and during office hours) or Power System Manager (less than 24 hours ahead or during office hours) to initiate any defensive measures as considered appropriate when in receipt of forecasts of severe weather conditions.

The following is a list of possible defensive measures but is not necessarily exhaustive and all situations are considered on their individual merits:

- Postpone/cancel the release of transmission outages.
- Review the current outage pattern, with particular regard to demand and generation at single circuit risk and active transmission constraints.
- Review the generation pattern and consider the running of strategic generation.
- Recall transmission outages (or accelerate the return) as considered necessary.
- Consider the provision of additional staff at ENCC to handle increased activity.
- Other actions designed to improve the ability of the system to withstand the effects of the severe weather, e.g. can sites normally run split be coupled to improve security?
- Issue a GB Transmission System Warning.

33 Were the communications at ENCC efficient and effective with the DNOs and TNCC, particular during the demand restoration process?

The operational communications between ENCC and TNCC, and between ENCC and DNOs were efficient and effective, during the demand restoration process and in the demand restoration reporting process with the following observations.

Distribution Network Operators (DNOs) incorrectly called the National Grids Electricity Transmission (NGETs) Transmission Network Control Centre (TNCC). The TNCC correctly referred DNO's to the ESO. This did not impact the restoration process.

Indications are that DNOs did ask specific permission of the ENCC to restore demand. While verbal instructions to DNOs to restore demand did not follow agreed phraseology they were clear and understood.

The communication timeline is presented in the table below:

	DNO Areas											
	SSE	SPED	ENW	NPG North East	NPG Yorkshire	UKPN SPN	UKPN EPN	UKPN LPN	WPD SW	WPD South Wales	WPD West Midland	WPD East Midland
When was ESO informed of LFDD	17:00	17:01	17:01	17:01	17:01	17:04	17:04	Approx 17:00	16:56			17:05
When did ESO instruct restoration	17:06	17:13	17:11	17:08	17:11	17:12	17:14	Approx 17:00	17:07		17:18	17.19
When did restoration complete	17:07	17:17	17:17	17:18	17:12	Approx. 17:40			17:30			
When was ESO informed restoration complete	18:30	17:36	18:30	18:18	18:22	18:34	18:33	18:34	18:30			

At 16:56hrs, first report of demand disconnection from DNO was received by ENCC.

At 17:00hrs, the first demand restoration instruction was initiated. The last restoration instruction was sent to WPD East Midland at 17:19hrs. The demand was instructed back in a progressive manner.

At 17:22hrs, ENCC informed TNCC that all DNOs had started demand restoration.

At 17:36hrs, first DNO reported their demand restoration was completed. Last demand restoration report was received by ENCC at 18:34hrs.

Further analysis is still required to understand all aspects of communications will be presented in the 6 September report.

34 There appeared to be delays in escalations to Ofgem & BEIS after LFDD was initiated? Are there any lessons to be learnt?

At 17:10hrs, the ENCC Power System Manager (PSM) reported the incident to the Head of National Control, ESO.

The 1st communication between ENCC PSM and BEIS was at 17:41hrs. At this point the event was generally understood and demand restoration had been initiated. It was also considered unlikely that there would be any further disturbances.

The 1st communication with Ofgem was made just after 18:00hrs with the Director of Operations, ESO.

Further updates to BEIS from the PSM were made at 18:09hrs, 19:29hrs and 19:38hrs respectively.

In the first hour following the event, the level of operational communication was significant. The power system was confirmed to be stable within 15 minutes however the scale of the secondary impact to the end consumers, e.g. the travel disruption, was not clear to ENCC even after the demand restoration was initiated.

Current ESO procedure outlines that following an event of loss of supply, a clear communication to Ofgem & BEIS is essential. The communication is recommended to be initiated as soon as possible, and this procedure is in line with the 'Energy Incident Reporting' requirement set by Ofgem dated in December 2017. It is important in all cases that resolution of the incident remains the primary objective.

35 What issues did you encounter with the public-facing communications by industry, notably in terms of the content and timelines for the messaging?

The public-facing communications did not impact the speed with which the incident was resolved but it did drive a large volume of media queries to the ESO.

The initial communications from some DNOs and rail companies said that the incident had been caused by a National Grid fault. These communications were issued very shortly after the event (from 5.09pm onwards). An example of this was a repeated tweet over the weekend:

"The failure of the UK National Grid caused widespread disruption across the country, not least to your journeys on a Friday evening."

The ESO prepared an external communication seeking to give reassurance to the public which was issued at 18:27 once it was established that the DNOs had reconnected all customers.

The initial statements from some parts of the industry were issued before our statement and without any co-ordination with our comms team.

36 How could these issues be addressed?

These issues could be addressed through an industry-wide review of communication processes to support timely and effective communication in any future event.

37 Explain what customer comms/channels you have in place for: prior, during and post this kind event

Operational Communications

The ENCC has routine operational communication with various customers and stakeholders across the industry. Voice communication is routed through dedicated, resilient communication channels with the standard BT network for backup purposes. Email communication is also routinely used between control rooms for operational purposes.

Day-to-day operational incidents are managed between control staff across control rooms, with escalation to operational managers where required.

SO Communications Document

The ENCC Power System Manager (PSM) and duty officer have access to the SO communications document, which is regularly maintained by the business continuity team. This document holds up-to-date contact information, that can be used during such an event, including: BEIS and OFGEM duty officers; TO and DNO Control Room managers; contacts within generation and supply companies; and internal media and escalation contacts

Incident Management

NGESO has adopted incident and emergency planning processes in line with those used by Government Emergency Services and the Group Crisis Management Framework (GCMF).

Low intensity incidents are managed through normally operating processes, using existing personnel structures.

ENCC Silver Command Centre will be initiated for escalating incidents, which will provide a focal point for internal and external communications with the intention of removing non-operational communication from the ENCC. The Gold, Silver and Bronze incident management structure will be utilised, where appropriate.

GB Transmission System Warnings

Where GB Transmission System Warnings are applicable to System conditions or Events, which have widespread effect, NGESO will in accordance with the Grid Code notify Users by fax:

Fax machines are used for the purpose of issuing GB Transmission System Warnings. These are to be tested periodically to ensure fax machines at both ends of a route and the route itself is in working order. Control Telephony is used for instructing Demand Control and as these are in daily operational use they are not presently tested however, updates to any fall back ‘Control’ phone numbers will be requested at the time of the periodic fax tests

Media / External Communication

NGESO has a dedicated media team. Colleagues from both the ESO and Group function take part in a communications duty rota, so that support is available 24/7.

The NGESO uses media distribution lists, industry stakeholder contacts, website (nationalgrideso.com) and twitter feed (@ng_eso) to communicate regular updates and news.

38 Were there any communicating issues with customers as a result of the GB power system disruption?

There were no communication issues with our customers as a result of the power disruption

39 Were any of your/third-party communication systems affected by the GB power system disruption?

The ESO did not experience any issues in our communication system and we are not aware of any third party communication system problems

40 Do you feel that any leaning points/changes required to how as either yourself or as an industry we communicate to customers prior, during or post this kind of event? If so, please provide details.

The interim report has proposed a review of ESO communication processes with industry, government Ofgem and media which should identify learning points and potential changes.

41 Was ENA comms utilised for support or assistance?

The ESO spoke to the ENA early on the morning of Saturday 10th August. We had a call with them and the DNO's first thing on the morning of Monday 12th August. At this point, we also shared our lines to take with their comms team.

We engaged with the ENA and it's relevant members directly through week commencing 12th August to set out our preliminary technical findings related to the networks and also seek support for providing further technical data for the interim report.

On Monday 19th August, we also spoke with them ahead of the publication of the interim technical report – explaining our comms approach and how we planned to handle the media. We asked for support where they felt appropriate – even if only to retweet any of our statements or suggest other spokespeople that could be offered to the media.

We were also in contact over email throughout.

42 What was the level of system inertia (in VAs) six hour period prior to, during and after the event?

The ESO does not currently measure system inertia directly but instead estimates it using a model. The inertia estimate is derived from the forecasted demand level, embedded solar and wind to continuously estimate the system inertia and the largest loss that needs to be secured in real-time operations. The system inertia (MVAs) 6 hours prior to, immediately prior to, during the event and after the event when frequency returned to normal operations are summarised in the Table below.

Timestamp (hr:min:sec)	**System Condition**	**Inertia (MVA.s)**
11:00	6 hours before the incident	201353
16:52	Immediately prior to the trip	219632
16:52:34	LBAR ST1 trip and 500MW embedded generation loss	216885
16:52:58	LFGT service kicked in	218013
16:53:31	LBAR GT1A trip	216177
16:53:49	LFDD operated, 931MW drop reported from DNOs	214222
16:53:58	LBAR GT1B trip	212386
16:57	Frequency restored with additional units on	215356

43 Were there any areas of concern about compliance testing with generators or OFTOs?

Generators are responsible for demonstrating and maintaining compliance with the Grid Code both when connecting to the system initially and on an ongoing basis. The process is clearly laid out in the Grid Code in the Compliance Processes and the European Compliance Processes. Compliance is demonstrated through a combination of studies, simulations and testing of the generator.

The ESO runs the compliance process and supports the generator in achieving compliance. For the initial connection of any large[1] or directly connected generator, the generator proceeds through a number of stage gates in the process: energisation stage, interim operational stage and final operation stage. The generator must provide the required compliance evidence at each stage. The ESO is responsible for assessing this information against the Grid Code requirements and issues a notice to proceed through the stage gate if compliance has been met.

If the generator makes any changes to its configuration which may impact compliance, it is responsible for firstly notifying the ESO of the change and then ensuring that it demonstrates compliance. The ESO is not responsible for checking compliance on an ongoing basis. If the operation of a generator is not in line with what is expected, then this will be flagged to the compliance team who will notify the generator to investigate the non-compliance.

If a generator believes it would require more than 84 days to resolve any compliance issues, the ESO issues a Limited Operational Notice (LON) to the generator and work with them to achieve full compliance

We are not aware of concerns regarding the compliance testing process.

44 Have there been any issues highlighted during the Generation Compliance process at Hornsea 1 or Little Barford in the past?

There have been no issues highlighted in the generation compliance process at Hornsea 1 or Little Barford in the past.

45 How does ESO test for generator ride-through capability for fault and large/rapid frequency changes?

There are no direct tests for generator ride-through for fault and large frequency changes. This would require application of an intentional fault to the transmission system and could compromise the integrity of the system.

Simulation studies are performed by the asset owner to demonstrate generator ride-through capability for fault and large/rapid frequency changes. The ESO will not issue an Interim Operational Notice to the generator until it has reviewed these studies and determined that they are in line with Grid Code requirements.

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[1] The definition of large generator in the Grid Code is: greater that 99.9 MW in England & Wales; greater than 9.9MW in Scottish Hydro Electricity Transmission; greater than 29.9MW in Scottish Power region; 9.9 MW offshore

46 Are current requirements around the ability to ride through faults on the Transmission & Distribution networks adequate?

To date the ESO has not had concerns regarding requirements for fault ride through.

The conclusions of our full technical report may provide further information

47 What risk mitigations do ESO consider or put in place when large sized (i.e. > 500MW) generator assets, OFTO or Interconnectors are commissioning?

A key risk mitigation is a robust compliance process as described in the answer to question 43.

In planning timescales in the control room, if there is a particular commissioning test which could result in a higher risk of trip for the commissioning plant, the ESO might request that the test is performed outside certain windows such as winter peak to reduce the impact of a trip.

Appendix N – DNVGL Letter

This Appendix contains a letter from DNVGL providing an overview of their role in reviewing the technical report and providing support for the findings and recommendations.

National Grid ESO
Attn. Mr. Criag Dyke
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Workingham
RG41 5BN

DNV GL - Energy

Tel: +31 6 46094857
Email: gerard.cliteur@dnvgl.com

Date:	**Our reference**:	**Your reference**:
2019-09-06	189392-AM 19-2858	

Subject: Technical Report Review

Dear Mr. Dyke,

DNV GL has provided a 'real-time review' service during the production of National Grid ESO's "Technical Report on the events of 9 August 2019", dated September 6, 2019, referred to herein as the 'Technical Report'.

DNV GL's role is further outlined below:

- Starting from a thorough review of the Interim Report dated August 16, 2019, DNV GL has participated in the analysis of the data and drafting of the Technical Report
- Four senior DNV GL staff members specializing in Power System Failure Investigations (highlighted in grey in Table 1) spent two weeks working onsite at National Grid ESO, commencing on August 26, 2019 and ending with the submittal of the Technical Report on September 6, 2019
- The underlying data behind the Technical Report have been requested and received and DNV GL team members have performed independent analysis where necessary to verify results
- Further to above, where necessary, key documents and data have been requested from National Grid ESO and third parties and reviewed by DNV GL as part of the 'real time review'.

DNV GL has as part of its role in this case reviewed, scrutinized, and challenged the assumptions, logic and conclusions as presented by National Grid ESO in the final Technical Report. Such interactions were on an ongoing basis, particularly in the two weeks between 26 August and 6 September 2019, and were based on DNV GL's global experience in performing power failure and outage investigations as a third-party service and DNV GL's staff members' grid expertise in general.

As an analogy, DNV GL looked into National Grid ESO's kitchen and judged the 'ingredients', 'cooking' and 'the dinner itself' when it came to overseeing the data and analysis behind the final Technical Report. Furthermore, DNV GL has aimed to report any key inputs or insights from our work, additional to the contents of the Technical Report, in a supplementary report.

To the best of DNV GL's knowledge, based on our role as outlined above, including independent review and analysis of underlying data, we believe the technical analyses performed by National Grid ESO have been diligent and robust, and we support the findings and recommendations in the National Grid ESO's Technical Report.

Table 1 DNV GL team members

Employee	Role	Discipline
Michael Dodd	Project Sponsor	
Kees-Jan van Oeveren	Project Director	QA
Gerard Cliteur	Project Manager	Overall investigation lead
Daniel Karlsson	Senior Principal	System performance
Lars Messing	Senior Principal	Circuit faults
Henrik Hemark	Senior Consultant	Grid Code
Evert Agneholm	Senior Principal	Frequency Control
Angeliki Gkogka	Consultant	Demand/supply analysis
Mischa Vermeer	Principal Consultant	Remote technical backup
Frederik Groeman	Principal Consultant	System performance, RoCoF schemes
Tim Jesson	Principal Consultant	Grid code, tech compliance
Edgar Goddard	Principal Consultant	Grid Code, SQSS, operations
Ronan McDermott	Senior Consultant	Remote support, report writing QA
Bridget Morgan	Principal Consultant	Grid Code compliance

Sincerely,
For DNV GL Netherlands B.V.

Kees-Jan van Oeveren
Head of Department Asset Management