

## **NATIONAL GRID**

### **Report of the National Grid Investigation into the Frequency Deviation and Automatic Demand Disconnection that occurred on the 27<sup>th</sup> May 2008**

**Issued: February 2009**

This report has been produced by National Grid to record the findings of an investigation into an event causing the operation of the National Low Frequency Demand Disconnection Relays and subsequent recovery of demand. The purpose of the report is to enable National Grid to identify (as far as possible) the cause or causes of the incident and any implications for the operation of the transmission system. The purpose of the report is not, however, to identify legal liability; therefore the data and information contained within it have not been compiled in accordance with rules of evidence and cannot be seen as determining either the Company's or an individual's legal liability.

All references in this document to "National Grid" refer to National Grid Electricity Transmission plc, the electricity transmission licence holder.

## **PREFACE**

This document is based upon the report (the “E3C Task Group Report”) provided to the Department of Energy and Climate Change (“DECC”) by the Energy Emergency Executive Committee (“E3C”) Task Group established to oversee an industry investigation into the electricity supply losses of 27<sup>th</sup> May 2008. The E3C Task Group was chaired by DECC with representatives from DECC, Ofgem, National Grid, each of the electricity distribution licence holders and the Association of Electricity Power Producers. A separate review of the E3C Task Group Report was commissioned by DECC from an industry expert from academia. The E3C Task Group provided independent scrutiny of the technical investigation into the events of 27<sup>th</sup> May 2008 undertaken by industry and led by National Grid. The overall purpose of the E3C Task Group was to ensure that, through cross industry participation, the loss of supply events on 27<sup>th</sup> May 2008 were fully investigated and the Secretary of State could be provided with appropriate information on the incident in accordance with the requirements of the Electricity, Safety Quality and Continuity Regulations (“ESQCR”) 2002.

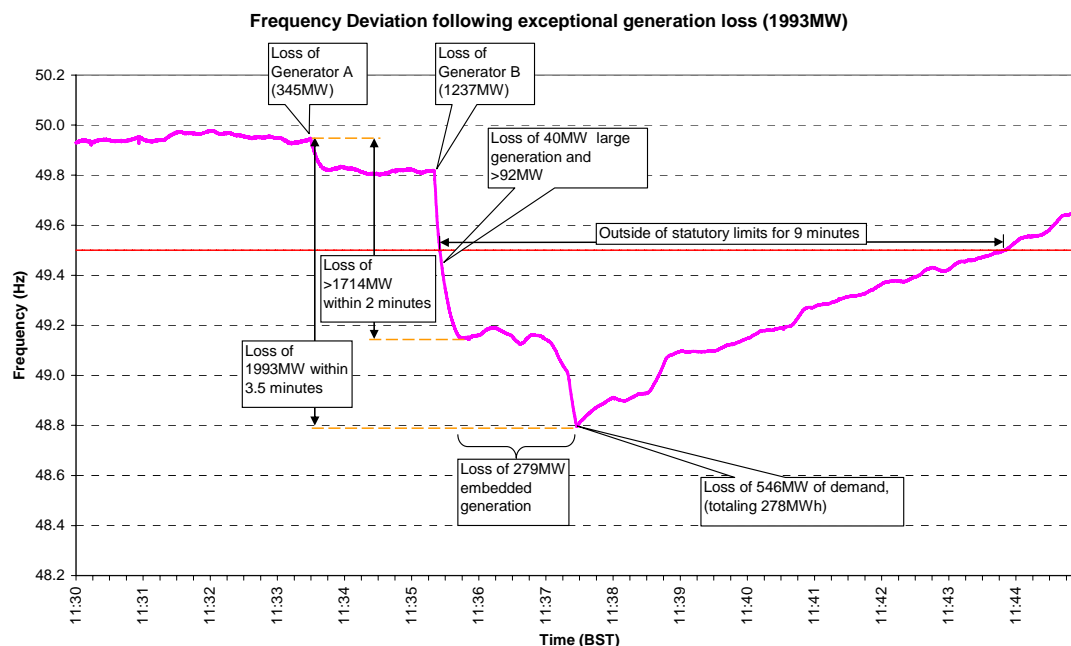
The E3C Task Group Report included confidential information obtained under or by virtue of the National Grid Electricity Transmission plc Transmission Licence and from commercially sensitive Ancillary Services Contracts. Whilst the Utilities Act 2000 prohibits the disclosure of such information subject to limited exceptions, National Grid’s disclosure of such information to the E3C Task Group was to enable the Secretary of State to investigate the incident under ESQCR 2002 and so satisfied one of the relevant exceptions to the prohibition in the Utilities Act 2000. Given that no such relevant exception applies in relation to the publication of this report, where appropriate this report either makes business specific data anonymous or aggregates it so that the obligations on non disclosure of information under statutory, regulatory or contractual obligations are satisfied. The findings, conclusions and recommendations of the E3C Task Group Report did not contain any confidential information and are accordingly presented here in full. Some other minor changes have been made to improve the clarity of the report.

## 1 EXECUTIVE SUMMARY

Prior to the day of the 27<sup>th</sup> May 2008, the forecast demand and generation levels were recorded as being healthy and not at all unusual. The events that occurred throughout the day, both before and after the automatic disconnection of demand event, which are described in this report, make 27<sup>th</sup> May exceptional on two counts. Firstly, the loss of demand as a result of the operation of National Low Frequency Demand Disconnection scheme relays is exceptional in historical terms and secondly the total level of generation lost within such a short period is also unusual.

On the morning of 27<sup>th</sup> May, the near simultaneous loss of generation at Generator A and Generator B power stations occurring at 11:34 and 11:36 respectively, as well as unexpected associated losses immediately after Generator B of two Large generators and some embedded generation, totalling some 1714MW resulted in an initial drop in system frequency to 49.15Hz. The frequency oscillated around this level for about 1.5 minutes then fell to 48.9Hz when a further sharper drop to 48.795Hz occurred. Data received by the Distribution Network Operators indicates that the unexpected tripping of a further amount of embedded generation, estimated to be around 279MW, although it is possible that the full extent of embedded generation tripping could be greater than this, contributed to this last drop in frequency.<sup>1</sup>

These events resulted in system frequency being outside of National Grid's operational criteria and statutory limits for 11 and 9 minutes respectively.



Given the drop in frequency, and in order to prevent wide scale losses of supply, a number of automatic low frequency relays (part of the National Low Frequency Demand Disconnection Scheme) operated successfully at 48.8Hz to arrest the fall and in doing so disconnected some 546MW of demand (estimated as some 550,000 consumers). Following this National Grid, in conjunction with the market, were able to recover the system frequency and instructed all affected DNOs to restore the automatically disconnected demand within a range of 20 to 40 minutes, although given the actions needed by some DNOs some consumers were off supply for up to 63 minutes.

<sup>1</sup> The data available to the DNOs from embedded generation is considered incomplete and variable in quality. The assessment of embedded generation losses is discussed in Section 4.3.

The total amount of generation loss was around 1993MW within 3.5 minutes compared to the maximum secured credible generation loss on the day of 1260MW. The exceptional loss of this amount of generation, together with the pattern of significant other within day plant losses led to a tight supply margin position throughout the afternoon which required the issue of system warnings by National Grid under the Grid Code, namely notices for both High Risk of Demand Reduction (HRDR) and Demand Control Imminent (DCI).

In order to achieve the necessary generation/demand balance a number of DNOs were instructed to apply demand control throughout the afternoon and over the evening peak, as a result of which normal operating margins were re-established by early evening. System conditions for the remainder of the week were normal.

This report seeks to give a summary of the events of the day and the performance of the Transmission system, Generation and the Distribution Networks.

The key findings of this report are:

- The exceptional loss of some 1714MW in 2 minutes, which is a rare random event, led to the operation of National Low Frequency Demand Disconnection scheme at 48.8Hz, shedding 546MW of demand, totalling 278MWh.
- Simulation has shown that the loss of Generator A and Generator B, excluding the other related losses, are sufficient in themselves to cause the frequency to fall below 48.8Hz and therefore initiate the National Low Frequency Demand Disconnection scheme. Although the loss of embedded generation in this instance did not initiate low frequency demand disconnection, in slightly different circumstances it may do so.
- A significant temporary and unexpected response to the fall in frequency from some generation helped temporarily limit the initial fall in frequency following the Generator B loss.
- The unexpected loss of a significant amount of small embedded generation resulted in a total loss of some 1993MW in 3.5 minutes. This indicates that there is a significant amount of small embedded generation that may not remain connected to the system down to 47Hz, and therefore may contribute adversely to low frequency events.
- The Low Frequency Demand Disconnection Scheme protected the overall system from the exceptional generation loss as designed and prevented a wide scale shutdown.
- The levels of generation losses within day were significantly greater than the 1 day in 365 Loss of Load Expectation level, and would only be expected once every 4 to 5 years.
- Demand Control was applied as would be expected given the level of generation losses to restore frequency response to resecure the system and subsequently meet peak demand later in the day.
- Generation subject to the Grid Code and Ancillary Services Contracts met the overall requirements of frequency response and Short Term Operating Reserve.
- The actions taken by National Grid and the DNOs were appropriate and minimised the disruption to consumers.
- In overall terms transmission connected generation, the LFDD scheme, and Demand Control performed as expected and any individual under performance is not considered material in the effective operation of the system. Actions have been taken bilaterally with specific generators and other actions to address specific issues will be progressed via the existing governance route of the Grid Code Review Panel.

The key recommendation from this report is that the Grid Code Review Panel, in conjunction with the Distribution Code Review Panel and the Association of Electricity Producers, considers the need for a clear and explicit frequency range requirement on small embedded generation plant and that the two codes aligned as far as reasonably practicable.

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## 2 INTRODUCTION

On the 27<sup>th</sup> May 2008 an exceptional loss of some 1582MW of generation within two minutes (11:34 and 11:36) for unrelated reasons, as well as the immediate loss of 40MW of large generation and some 92MW of embedded generation, totalling 1714MW, resulted in a major system frequency disturbance. The immediate effect of this loss was to take the system out of normal operating conditions. This, together with a subsequent further loss of some 279MW of embedded generation eventually led to the operation of automatic low frequency relays to preserve the integrity of the wider electricity system. As a consequence 546MW of demand was automatically disconnected at approximately 11:38.

This exceptional total generation loss of some 1993MW within 3.5 minutes, coupled with the pattern of other within day losses led to a shortage of generation, the use of system warnings by National Grid under the Grid Code and the application of demand control across up to nine DNOs' regions at any one time.

This report provides a summary of events and conclusions based on available information as of 3<sup>rd</sup> October 2008. National Grid will continue to work with the industry concerning lessons to be learnt for the future. Further work will be taken forward through the Grid Code Review Panel (GCRP).

### 3 27<sup>TH</sup> MAY SEQUENCE OF EVENTS

#### 3.1 Background

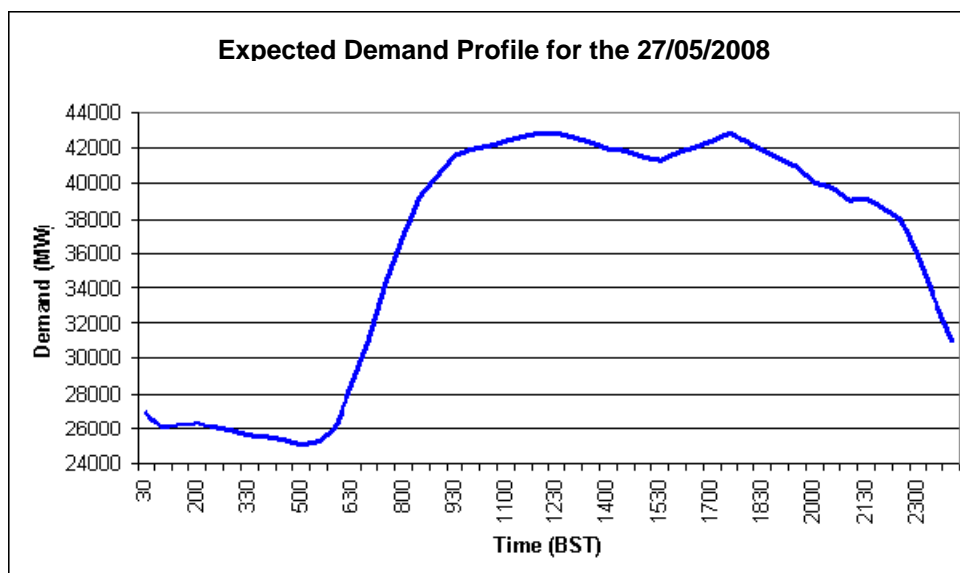
This report deals predominantly with the events close to real time as this is the time frame relevant to the events of 27<sup>th</sup> May 2008. National Grid undertakes a wide range of planning and analysis of system security at longer lead times and provides a range of information to the market through established mechanisms (e.g. Generation Margin reports and the Winter and Summer Outlook reports).

Within shorter term timescales, the Electricity National Control Centre (ENCC) from approximately 11:00 at the day-ahead stage, based on initial submissions from Generators, monitors and takes appropriate action to ensure that the operating conditions for the following day are within the required operating standards.

Figure 1 below summarises the shape of the demand curve for Tuesday 27<sup>th</sup> May. The forecast Peak demand was 43GW, at 17:00, with the lunchtime peak being slightly lower at 42.2GW at approximately 12:15. Planned operating conditions, based on information received from suppliers and generators, together with the anticipated configuration of the Transmission system were within normal operating parameters in the period leading to the event.

There were few active Transmission constraints that would significantly impact generation operation. The primary exception being the capability on that day across the Scotland-England border which would limit the maximum export to England to 1000MW due to planned outage works. However, forecast flows were within acceptable limits.

**FIGURE 1**



#### 3.2 Operating Margins and Generation Availability

Figure 2 summarises the generation plant available to meet the peak lunchtime demand from the day ahead to 4 hours ahead of real time, when the requirement for the “contingency reserve” margin is reduced to zero. From 4 hours ahead of real time, the generation/demand uncertainty is managed by utilising short term operating reserve, regulating reserve and/or frequency response reserve, described in detail in Appendix 1.

Generation plant known to be available to synchronise and achieve full output by the lunchtime peak demand is also indicated in Figure 2. It should be noted that National Grid might be required to intervene to retain this capability to synchronise within the required timescales. Figure 2 also indicates the required “contingency reserve” margin at the identified times.

FIGURE 2

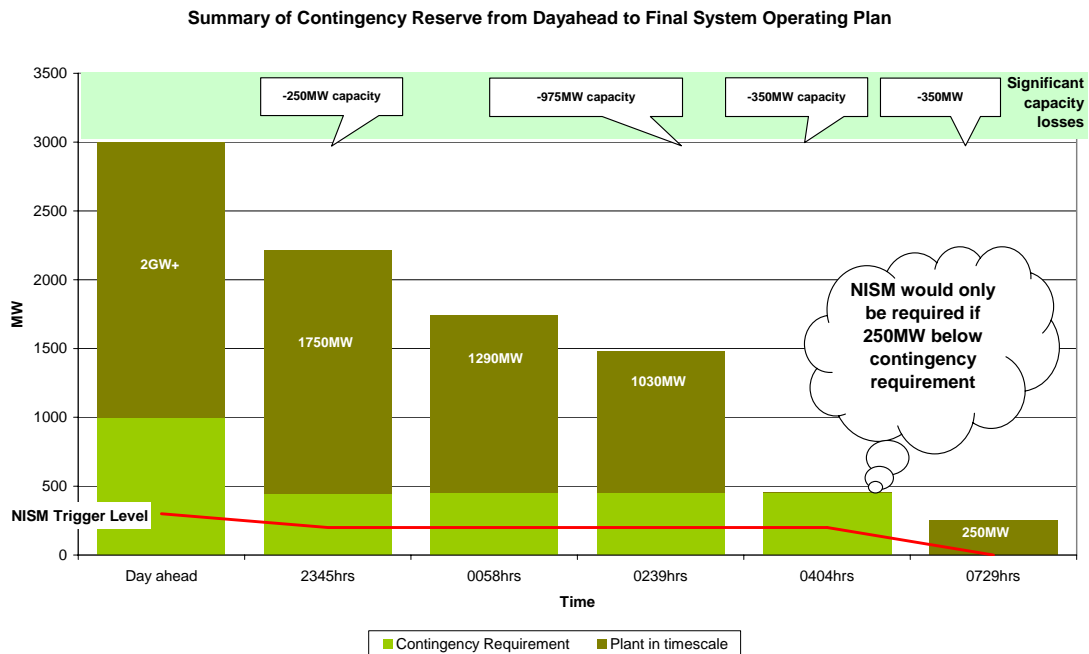


Figure 3 summarises the main changes in from day ahead to four hours ahead of real time to the Contingency Reserve Requirement for the morning demand peak System Operating Plan.

- The loss of capacity of 250MW was balanced by planning to arm the intertrip on a second Scottish unit, increasing the transfer from Scotland by 250MW to 1000MW
- The withdrawal of the Physical Notification’s (i.e.: notification of generation profile) of 975MW of capacity from two units at 01:35 resulted in two alternative units being planned to run in their place. The machines were still available and as such became contingency sets. As the contingency requirement could be met by another unit, these machines were removed from the contingency list when their Notice to Deviate from Zero (NDZ) precluded their ordering
- The loss of 350MW of capacity resulted in an additional unit being planned to run
- The failure of 350MW to synchronise necessitated an additional machine being planned to run.

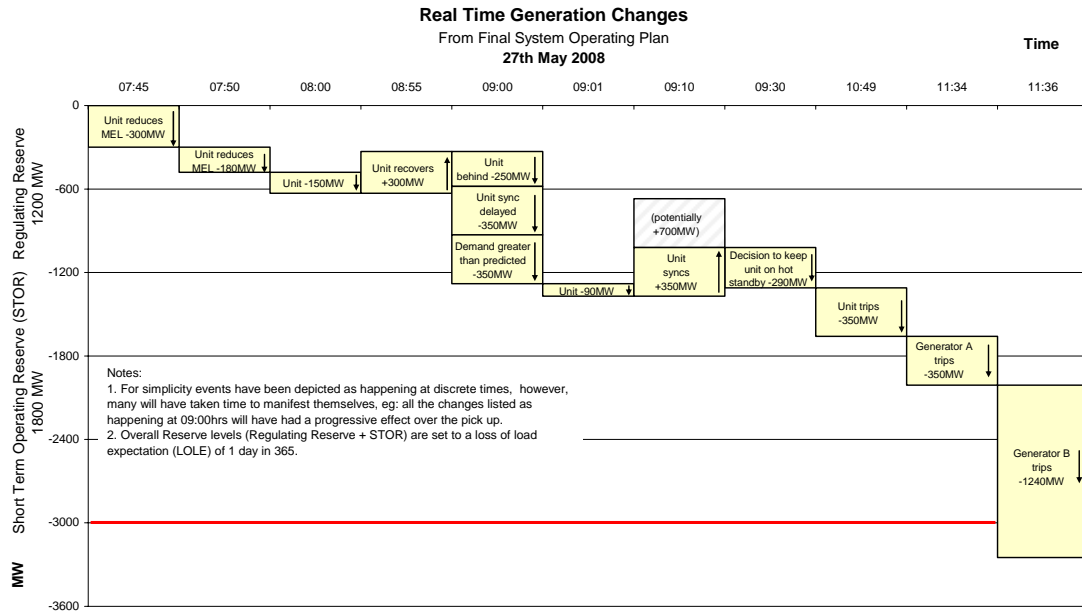
### 3.3 Regulating and Short Term Operating Reserve

Throughout the morning, ENCC had instructed the appropriate levels of Frequency response to ensure compliance with required standards and secure the system to the largest single loss, which on that day was 1260MW.

During the morning further generation losses eroded the Regulating Reserve and Short Term Operating Reserve was utilised to maintain Frequency Response capability. The levels of Regulating Reserve and Short Term Operating Reserve are set to allow no more than a 1 day in 365 Loss of Load Expectation as described in Appendix 1 Section 1.1.3. Figure 3 shows the use of reserve and that until the time of the Generator A trip sufficient reserve was available to replace the energy for the largest single loss on the day.



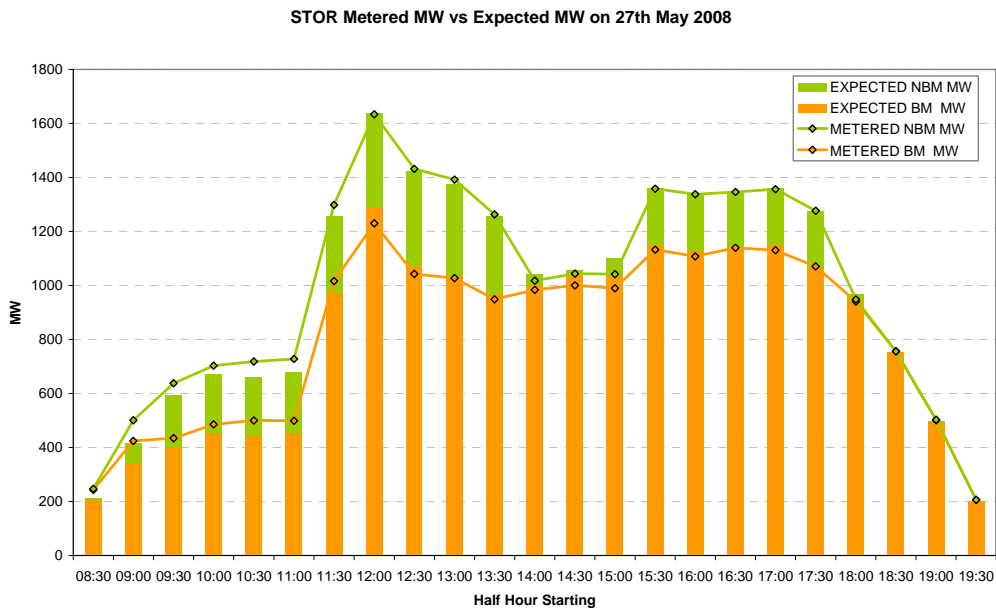
FIGURE 3



One machine was kept on standby as it would have only reached its Stable Export Limit in the time for the lunch time peak. Short Term Operating Reserve was utilised during the morning losses (and subsequently) ensuring that Frequency Response was maintained.

Figure 4 below shows the expected STOR delivery from Balancing Mechanism and non BM units (calculated from the unit's tendered capacity and appropriate instruction times on the day) as compared to the STOR delivery that was actually metered (taken from the half hourly settlement data for STOR). The graph is measured on total MW for each half hour settlement period to provide an overview. The performance of STOR is discussed in Section 4.1.2

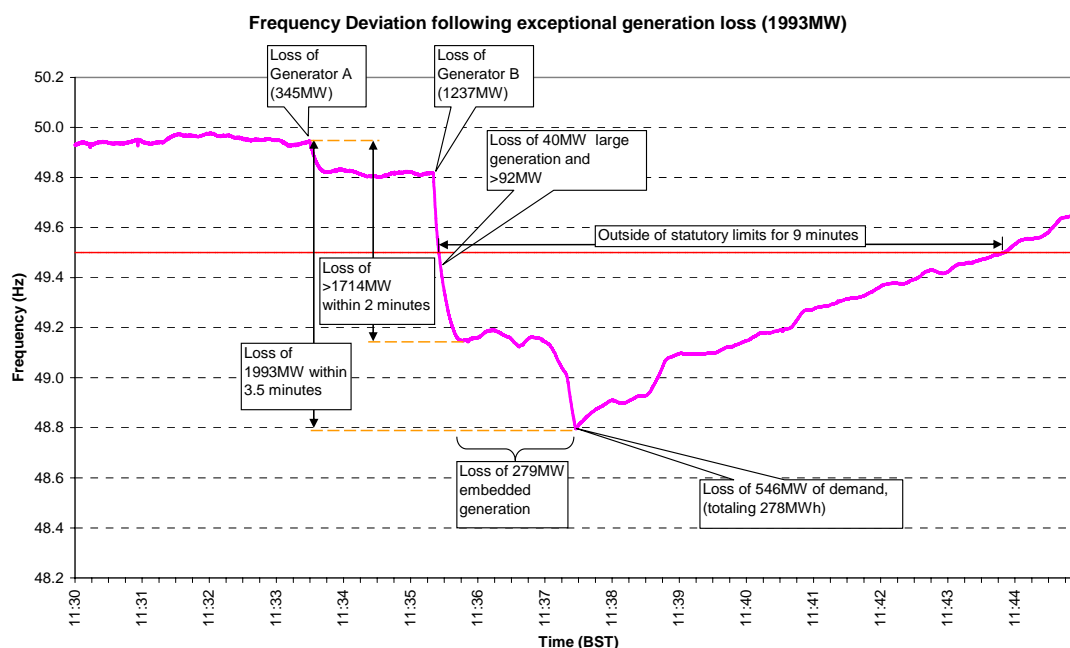
FIGURE 4



### 3.4 Generation Loss Incidents <sup>2</sup>

Figure 5 shows three system frequency deviations. The first was caused by the loss of Generator A (345MW). The initial and major part of the second deviation was caused by the loss of Generator B (1237MW) giving a combined loss of 1582MW. However, as the falling frequency reached 49.5Hz, two Large generators each with an output of 20MW and at least 92MW of embedded generation were unexpectedly lost giving a combined total loss of at least 1714MW within 2 minutes. The third frequency deviation down to 48.795Hz was contributed to by the unexpected loss of a further amount of embedded generation of around 279MW that occurred within 1.5 minutes of the loss of Generator B. The overall total generation loss was around 1993MW within 3.5 minutes.

**FIGURE 5**



The first loss (Generator A, 345MW generation at 11:34) resulted in the frequency falling by about 0.127Hz. National Grid's operational policy would require for a loss of this magnitude that the frequency deviation is <0.5Hz.

The second loss of at least 1369MW (Generator B, 1237MW and associated embedded generation losses of around 132MW at 11:36) resulted in the frequency initially transiently falling by a further 0.67Hz to 49.15Hz.

The above losses occurred in very close proximity such as to make them, in effect, a "single" event totalling at least 1714MW. This significantly exceeds the maximum secured loss which on this day was 1260MW. It should be noted that two minutes is not a sufficient time to recover frequency response capability on frequency sensitive generation plant.

Given the size of the actual loss of at least 1714MW compared to the maximum secured loss of 1260MW, the initial frequency fall would be expected to fall below 49.15Hz. However, additional unexpected short duration frequency support was provided by some generation units operating in Limited Frequency Sensitive Mode. This is discussed in detail in Section 4.2.2.

<sup>2</sup> The data available to the DNOs from embedded generation is considered incomplete and variable in quality. The assessment of embedded generation losses is discussed in Section 4.3.

For about 1.5 minutes after the frequency dropped to 49.15Hz, the frequency continued to oscillate around a downward trend then quickly fell to 49Hz when a further distinct sharper drop to 48.795Hz occurred. This last drop is contributed to by the loss of a further amount of embedded generation which was at least 115MW. This is discussed in detail in Section 4.3. The fall of frequency to 48.795Hz initiated the operation of the National Low Frequency Demand Disconnection Scheme.

### **3.5 Automatic Demand Disconnection and Frequency Recovery**

The collapse of frequency was successfully arrested by the operation of the first stage of automatic low frequency demand tripping relays. Operation of the relays, support from fast responding generation that had been instructed following the loss of Generator A and Generator B, support from automatically started Open Cycle Gas Turbine generation and some demand control relief resulted in the frequency recovering towards 50Hz. The frequency returned within Statutory limits within 9 minutes and operational limits within 11 minutes.

The Grid Code CC.A.5.5.1(a) stipulates that the first tranche of approximately 5% of demand at each DNO within England and Wales should trip automatically by low frequency relays set at 48.8Hz. With the national demand observed on the day, information from the DNOs confirmed that some 2266MW of demand, approximately 6.3%, should have been expected to trip when the frequency fell to 48.8Hz.

Information obtained from the DNOs confirms only some 546MW of demand as having been automatically disconnected. Whilst this is good in terms of minimising supply disruption, clearly some relays did not operate as expected. The effectiveness of the operation of low frequency relays is discussed in Section 4.5.

### **3.6 Recovery of Frequency and Demand Disconnection**

Within 2 minutes of the operation of the automatic low frequency relays, the ENCC control engineers had instructed a first stage ~5% of manual demand control across 9 DNOs areas. Demand control under Grid Code OC6.5.3(b) should typically be delivered within 5-10 minutes of instruction by National Grid. DNOs have indicated that generally the first ~10% of instructed demand reduction would normally be achieved by voltage reduction.

The DNOs instructed under the Grid Code to provide one stage (5%, ~1200MW) of demand reduction were:

- CE Electric (YEDL)
- Western Power Distribution (South Wales)
- Western Power Distribution (South West)
- Scottish & Southern (South)
- EDF Energy (East, London & South)
- EON - Central Networks (East)
- EON - Central Networks (West)

The demand reduction actually delivered appears to be significantly below the 1200MW expected. The effectiveness of demand reduction is discussed in Section 4.6.

The DNOs initially selected were in the southern part of the network and therefore their demand relief would assist with the balancing of the Transmission network following the loss of Generator B (which is located in the South) The Scottish DNOs were not instructed to provide demand relief as all available generation was committed in Scotland and there was no further capacity available on the circuits across the Scottish borders to carry the increased transfers that would result from a reduction in Scottish demand.

Following any major generation loss, the priority for the control engineers is to re-establish the capability of synchronised generation to provide frequency response capability to protect the wider GB system from the impact of any further demand or generation perturbations. On the 27<sup>th</sup> May, frequency response holding to re-secure to the next largest loss on the system was restored within 15 minutes of the exceptional generation loss.

Within 40 minutes of the operation of the automatic low frequency relays, instructions were given to all affected DNOs to restore automatically disconnected demand. Demand Control remained in place during the recovery to normal operating conditions.

### 3.7 Recovery to Normal Operating Conditions

FIGURE 6

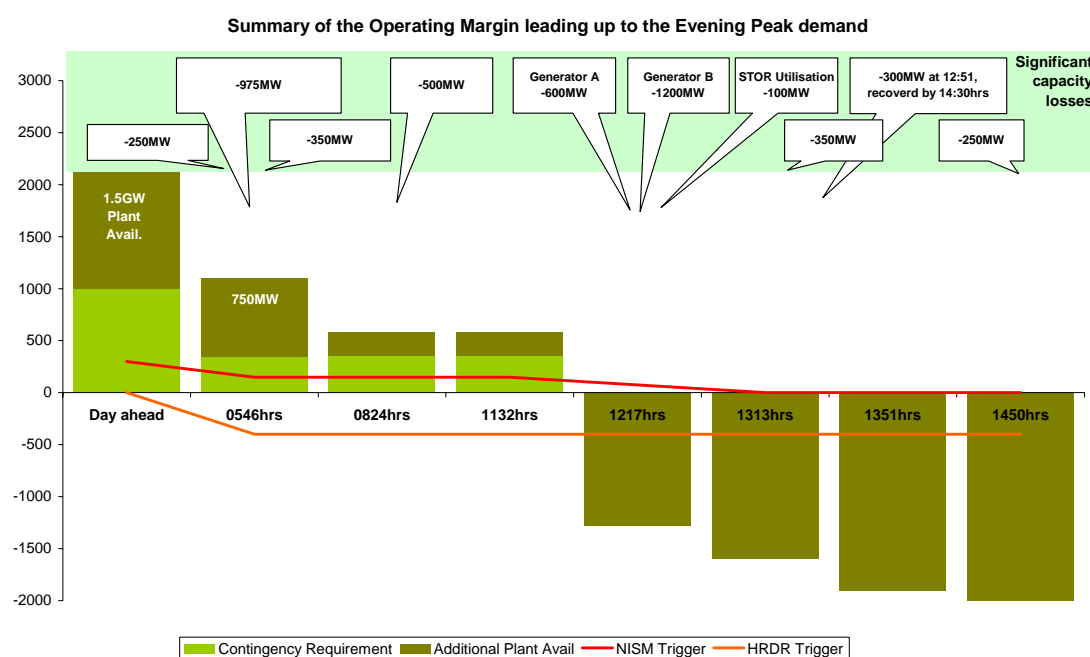


Figure 6 summarises the operating margins outlook for the evening demand peak up to and following the 1993MW generation loss shown in Figure 5. The resultant impact on operating margins triggered the requirement for a High Risk of Demand Reduction (HRDR) warning to be issued to the market, although demand control had already been instructed.

The HRDR was issued at 12:30, once the immediate restoration activities were complete and the short to medium term operational impact of the exceptional loss had been assessed.

In response to the substantial loss of generation, a number of actions were initiated by the ENCC to procure additional generation in order to quickly restore normal operating conditions for the remainder of the day.

All generators that would be able to assist with the recovery and the evening peak demand were instructed to generate.

Early in the afternoon, the ENCC requested the return of the Cellarhead-Drakelow 1 and the Feckenham-Hams Hall circuits which were out of service for routine maintenance. Neither circuit was actively constraining generation, however, given the uncertainty of the plant position for the rest of the day, the return of these circuits would maximise operational flexibility.

As the demand fell during the afternoon and more generation came on line, the level of demand control was reduced by instructing DNOs to restore demand. Demand control was distributed across the DNOs, and where possible DNOs were stood down. In addition ENCC sought to limit the time that demand control was applied to any one DNO. By the evening, changed generation patterns meant that location was no longer critical, hence demand control could be applied to NEDL and United Utilities. The timing of these instructions is summarised in Table 1 below.

**TABLE 1**

**Summary of Instructed Distribution Network Operator  
Demand Reduction**

| <b>Distribution Network Operator</b> | <b>Instructed Demand Reduction</b> | <b>Demand Reduction ceased</b> |
|--------------------------------------|------------------------------------|--------------------------------|
| YEDL                                 | 11:40                              | 13:49                          |
| Central Networks-E                   | 11:41                              | 15:26                          |
| WPD-Wales                            | 11:42                              | 17:54                          |
| WPD-Western                          | 11:42                              | 17:54                          |
| SSE (south)                          | 11:42                              | 14:45                          |
| Central Networks-W                   | 11:42                              | 15:26                          |
| EDF-E                                | 11:43                              | 15:37                          |
| EDF-L                                | 11:44                              | 15:08                          |
| EDF-S                                | 11:46                              | 14:43                          |
| United Utilities                     | 16:21                              | 18:06                          |
| NEDL                                 | 16:48                              | 18:07                          |

Demand Control was in force from 11:40 to 18:05 and High Risk of Demand Reduction Warning in force from 12:30 to 19:00.

Across the early evening peak (at 18:00) demand control was only in force across 4 DNOs. All demand control was lifted by 18:07.

## 4 SYSTEM PERFORMANCE ON 27<sup>TH</sup> MAY

### 4.1 Performance of Reserve and Frequency Response Holding

Figure 2 shows the minimum contingency reserve requirements were met at all times during the period leading up to the loss of Generator A, Generator B and other associated losses. The levels of generation available remained above that which would trigger National Grid to issue a Notification of Inadequate System Margin (NISM).

Figures 3 and 4 show that during the lead in to the loss of Generator A and Generator B, Regulating Reserve and STOR were utilised to maintain Frequency Response. The instantaneous losses of generation during the morning up to the Generator B loss were kept within the operating range of 49.8Hz and 50.2Hz demonstrating appropriate management of the Frequency Response holding. Section 4.2.1 explains the performance of the Frequency Response holding during the Generator A and Generator B trips.

### 4.2 Performance of Transmission Contracted Generation Plant

This section reports on the performance of Transmission connected and Large generation plant operating in both Frequency Sensitive Mode (FSM) and Limited Frequency Sensitive Mode (LFSM) during the incident as well as low frequency triggered Open Cycle Gas Turbine plant.

#### 4.2.1 Response Holding and Frequency Sensitive Mode Generation

The largest secured loss on the day was taken as 1260MW. To secure for this loss and return the Frequency above 49.5Hz within 60 seconds a response holding of 911MW was required (the balance of response to cover the 1260MW is provided by the natural reduction in demand that occurs when there is a drop in system frequency). This figure includes a 15% margin for items such as generator under-performance etc. The 911MW included a minimum dynamic requirement from generation of 450MW with the remaining being held on services initiated by frequency settings. Table 2 shows the breakdown of the response holding and performance delivery taken one minute after the Generator B trip.

**TABLE 2**

| Service                                | Held (MW) | Delivered (MW) |
|----------------------------------------|-----------|----------------|
| Demand Management                      | 274       | 274            |
| Frequency Control by Demand Management | 35        | 9              |
| Interconnector                         | 75        | 60             |
| Pumped Storage on LF Relay             | 90        | 90             |
| Dynamic – Pumped Storage               | 170       | 172            |
| Dynamic – Generation (FSM)             | 280       | 282            |
| Total                                  | 924       | 887            |

At the time of the Generator A and Generator B trips 924MW of response was being held against a requirement of 911MW. Various shortfalls occurred from certain providers however and 887MW was delivered. This is within the expected range and above the actual requirement of 792MW before the 15% margin was applied to take the required holding to 911MW.

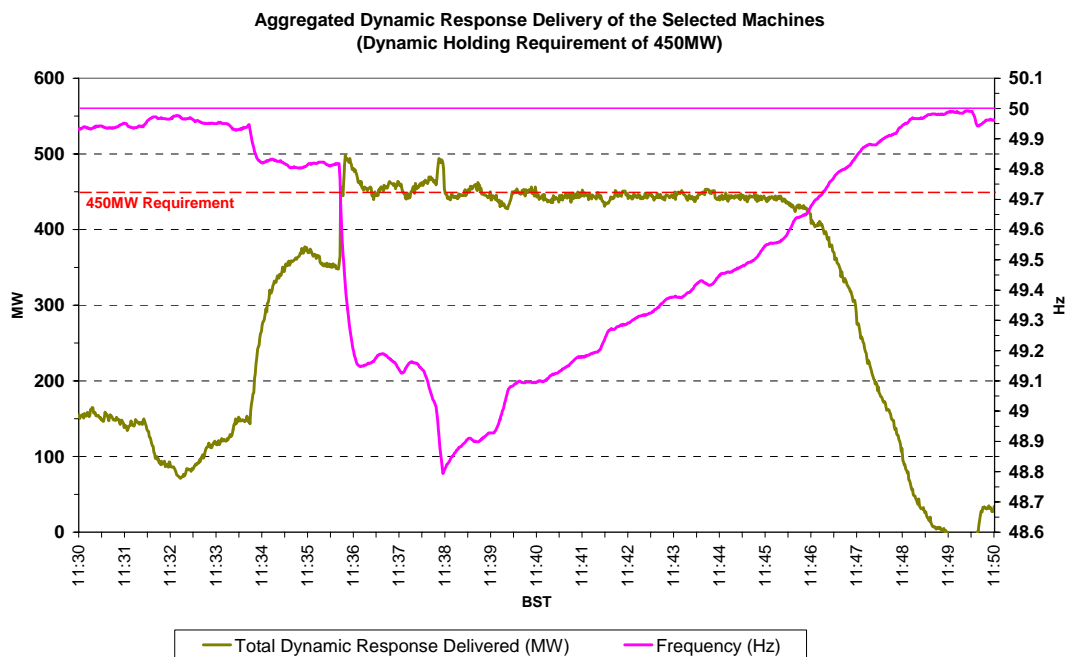
The dynamic holding of generation in Frequency Sensitive Mode was achieved by instructing 8 units, with one unit on Firm Frequency Response (a part loaded generator that responds very dynamically to changes in frequency). Although the

overall requirement was met there was a shortfall of 60MW from three units. This shortfall was due to one unit not being selected to respond at the Power Station, and minor shortfalls on two units which did not sustain the required output after the initial delivery.

Under the terms of the Ancillary Services Contracts corrective actions have been taken or are under way with the providers that did not meet the contracted requirements.

Overall, the delivery of dynamic response was in line with expectation as shown in Figure 7, which only includes those generators instructed to operate in FSM.

**FIGURE 7**



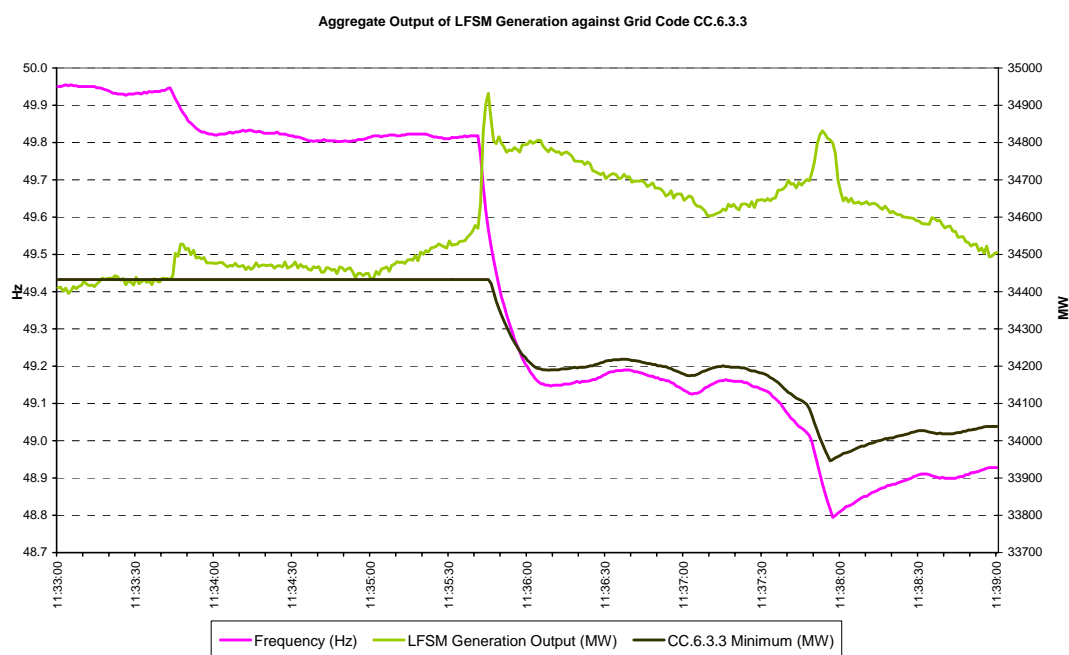
In addition to the above a unit provided 28MW of Frequency Sensitive Mode response although it had not been instructed to provide this service.

Figure 7 also shows that following the initial Generator A trip some 210MW of dynamic response had been used and had held the frequency above the lower operational limit of 49.8Hz without the use of services triggered by frequency relays. There was insufficient time to restore the dynamic response holding before the Generator B trip, although 320MW of replacement generation had been ordered to facilitate this.

#### 4.2.2 Generation in Limited Frequency Sensitive Mode

For the large number of generating units operating in LFSM, the assessment of their MW output performance against Grid Code Connection Condition 6.3.3 shows that some units operated in line with expectation and some units exceeded CC.6.3.3 requirement during the critical large frequency fall period. The plant that exceeded CC.6.3.3 requirement effectively delivered significant unexpected temporary response to the system that temporarily helped limit the extent of the initial frequency fall after Generator B's loss. The unexpected beneficial response delivered is shown in Figure 8.

FIGURE 8



During the frequency recovery period after automatic demand disconnection, certain plant, especially those with large thermal inertia such as fossil fuel and nuclear power stations, showed a temporary MW output reduction before settling to the pre-disturbance level. This behaviour is expected and is caused by the rapid release of stored energy from the plant during the frequency fall period that is inevitably followed by a temporary MW output back swing during the frequency recovery period. This phenomenon is considered as a reasonable tolerance of 'load following' during large frequency disturbances.

Three generators were dispatched immediately following the 345MW Generator A trip, totalling 320MW. However one unit (120MW), was unable to synchronise to the system until after the frequency had recovered to above 49Hz due to a governor setting. The setting has subsequently been corrected.

A number of Open Cycle Gas Turbines are contracted to start at specified frequencies (49.5Hz and 49.6Hz) and should have reached full MW output (567MW) in 5 minutes i.e. at approximately 11:41 or around 5 minutes after the loss of Generator B and after frequency was recovering. Analysis shows that there was a cumulative shortfall in output of 115MW. This is within the normally expected range for OCGTs starting automatically.

There was a further shortfall of 39MW, of STOR, bringing the total shortfall to 154MW, however other STOR units over performed by a total 150MW against the contracted levels off-setting the shortfall and providing a net shortfall of 4MW.

The OCGT units which underperformed have had performance tests carried out (National Grid's contractual right under the STOR service) where they were issued start instructions and had to generate within their tendered parameters. Two units failed their first performance test, but passed on subsequent tests and all units were tested to their tendered capacity and response times.

Two Large generators in Scotland tripped during the incident with a total loss of 40MW generation (20MW each). The tripping occurred when the frequency reached 49.5Hz i.e. almost immediately after the loss of Generator B. The owners of these sites have been informed. The low frequency setting at one has now been corrected to comply with the Grid Code while the owner of the other had applied for a derogation from the Grid Code due to the generator design and the date of installation.



There was also a loss of 15 MW from another generator. This occurred at 11:38 when the generator rapidly deloaded without disconnecting from the system. The generator restored its output immediately after frequency recovery. The owner has been informed and a solution is being sought to prevent a recurrence and ensure Grid Code compliance.

The frequency response provided by automatic demand management services and an interconnector delivered in line with expectation as described in Section 4.2.1.

### **4.3 Performance of Embedded Generation Plant**

Under the auspices of the GB Grid Code Review Panel, a reporting procedure was established in 1997 where the DNOs are required to provide National Grid with information on embedded generation that may have tripped in the event of a significant incident on the GB Transmission system including generation trips causing large frequency deviations.

Initial information provided by the DNOs at the time of the incident indicated that some 247MW of embedded generation plant tripped. The embedded generation loss is shown in column (1) of Table 3.

The questionnaire sent to the DNOs on the 10<sup>th</sup> of June 2008 sought information on the amount of MW tripped, time of trip and reason for trip. In addition, information on small scale embedded generation loss was sought. The MW loss data received is shown in column (2) of Table 3 and shows a new reduced figure of total loss of about 196MW. However, doubts on the quality of the data received as well as lack of sufficient information on the time and reasons of trip remained. National Grid believed that the available information was incomplete and did not provide sufficient information on the contribution of embedded generation loss to the events of 27<sup>th</sup> May leading to automatic demand disconnection.

National Grid raised this concern at the E3C Task Group meeting on 27<sup>th</sup> August 2008. Agreement was reached for National Grid to send a new request to DNOs to seek further assistance.

Table 3 Columns (3) to (6) has been compiled from data that DNOs have managed to collect from embedded generators. DNOs do not have telemetry fitted at most embedded generator installations, and so the data is incomplete (i.e. generation losses might be somewhat more than is reported here). The quality of the data is also variable in respect of exact tripping times and the cause of the tripping. This table is considered a reasonable assessment of the data made available to the DNOs and is adequate for the purposes of this report.

The new set of data received suggests that the total embedded generation loss was about 371 MW as shown in column (3) (this appropriately excludes trips that were reported to occur after the time of automatic demand disconnection). Therefore, this is the total reported amount of embedded generation tripped in the period between the loss of Generator B and the automatic low frequency demand disconnection.

TABLE 3

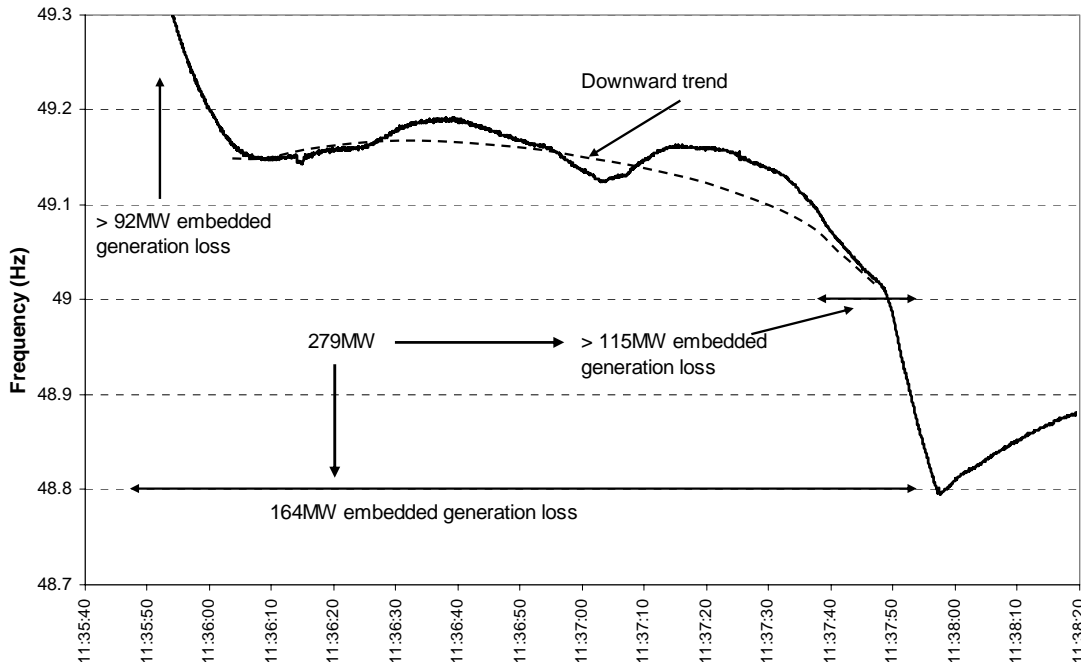
Summary of Embedded Generation Loss Data Received from Distribution Network Operators

|       | Returns from DNOs following E3C meeting                                |                                                                  |                                                                                            |                                                                                      |                                                                                           |                                                                             |
|-------|------------------------------------------------------------------------|------------------------------------------------------------------|--------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------|
|       | Notified loss under Grid Code ROCOF reporting at time of incident (MW) | Returns in response to incident investigation questionnaire (MW) | Reported loss from time of Generator B trip to time of automatic demand disconnection (MW) | Reported loss around the time of Generator B trip, at 49.5Hz or by ROCOF relays (MW) | Reported loss around the time of third frequency excursion or tripping around 49.0Hz (MW) | Reported loss based on 1/2 hourly energy data, no other data available (MW) |
|       | (1)                                                                    | (2)                                                              | (3)                                                                                        | (4)                                                                                  | (5)                                                                                       | (6)                                                                         |
| Total | 247.16                                                                 | 195.56                                                           | 371.2                                                                                      | 91.9                                                                                 | 115.3                                                                                     | 164                                                                         |

Column (4) data indicates that nearly 92MW tripped at 49.5Hz and column (5) data indicates that 115MW tripped at around 49Hz. Column (6) indicates that a further 164MW tripped but no data was available on time of or reason for these trips. This is low quality data obtained by the DNOs from half-hourly energy metered data. In the absence of specific information provided to DNOs from generators, and as per the data shown in columns (4) and (5), National Grid's judgement is that the 164MW loss is likely to have tripped at similar times and by similar mechanisms.

Given the overall data provided and that available to the DNOs, it is likely that at least 92MW tripped as the frequency was falling immediately after the loss of Generator B. It is likely that the remaining 279MW tripped just after the loss of Generator B and before the operation of automatic demand disconnection, of which at least 115MW tripped at around 49Hz. The loss of embedded generation at 49Hz would have increased the rate of fall of frequency as evidenced in Figure 9.

FIGURE 9



From the data provided by the DNOs it appears that there may be a significant amount of small embedded generation that have frequency settings that allow tripping at frequencies above 47Hz. If these small embedded generators do not remain connected to the system down to 47Hz at the time of a national generation shortfall they will contribute adversely to low frequency events and may increase the amount of automatic demand disconnection.

The DNOs data derived from half-hourly energy metered data may be erroneous and lower than it should be if, for example, some disconnected generation did re-establish its MW output within the half-hour period. More accurate data on the amount and timing of generation trips can only be obtained by the DNOs from the generation plant owners and the plant's protective relay logs. However, the DNOs advise this is not generally available.

#### **4.4 Additional Considerations**

Several further areas were considered that may have contributed to the third fall in frequency:

##### **4.4.1 Increase in Generation Auxiliary Unit Load**

From the metering available Station Load (Power Station Auxiliary demand taken from the transmission system) did not increase during the low frequency period and is not considered a contributory factor.

##### **4.4.2 Tap Changing on Super Grid Transformers**

During the critical period of the third fall in frequency a total of 26 taps were recorded on Super Grid Transformers across 16 sites, giving an increase in demand of approximately 24 MW at around 11:37. Tap-changers have a time delay of typically three minutes to avoid unnecessary operation during transient changes in voltage. This is not considered significant given the other changes in generation at the time and the size of the losses.

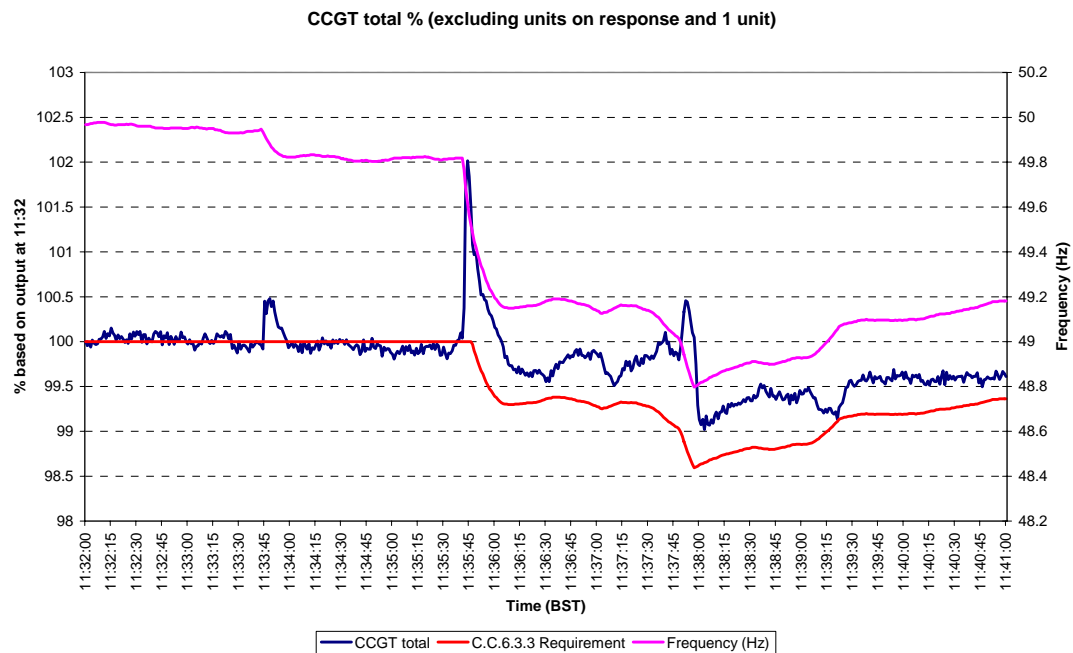
##### **4.4.3 Reduction in Wind Farm Output due to change in Wind Speed**

The wind speed data from generators that provide this information to National Grid was inspected to check if there was a significant contribution to fall in output due to wind speed. Over the critical 1.5 minute period there were small changes in output that are consistent with the normally expected variation.

##### **4.4.4 Generation Under Performance against Grid Code Connection Condition 6.3.3**

The following graph shows the performance of CCGT generators where second by second data is available. Generators in Limited Frequency Sensitive Mode did not contribute to the third fall in frequency. As can be seen in Figures 8 and 10 there was considerable over performance in LFSM which temporarily delayed the fall in frequency as described in Section 4.2.2.

FIGURE 10



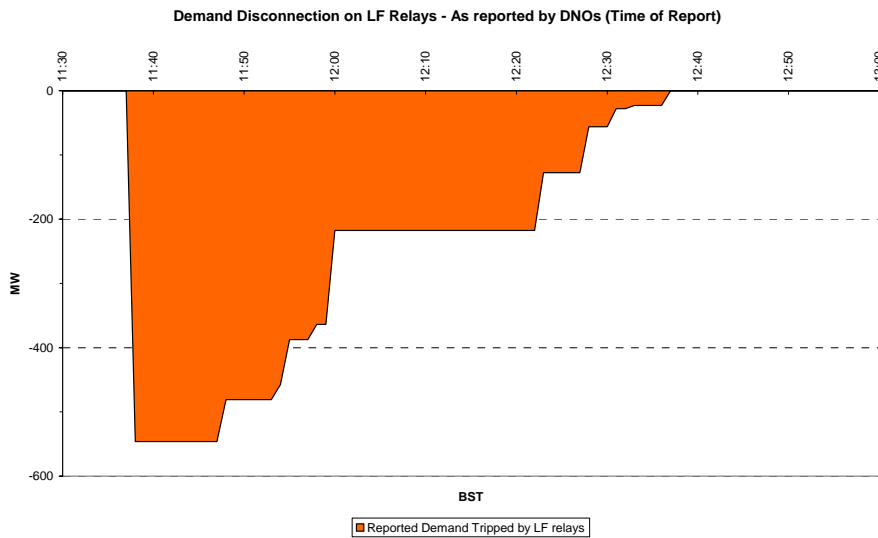
One Unit has been excluded from the above graph as it over generated by more than 70MW during the loss of Generator B and during the third fall in frequency.

Overall the CC 6.3.3 performance is considered good, with the majority of issues limited to the frequency recovery period, which is as to be expected as described in Section 4.2 and partly accounts for the rate of recovery of frequency.

#### 4.5 Performance of National Low Frequency Demand Disconnection Scheme and Associated Low Frequency Relays

The low frequency relays used by the National Low Frequency Demand Disconnection scheme are set to enable the automatic disconnection of demand uniformly in distribution networks generally in 9 blocks. The first demand block is set, on average, at 5% in each DNO area in England & Wales and the relays are set to trip at 48.8Hz. This is summarised in Appendix 2.

FIGURE 11



The minimum system frequency during the incident was 48.795Hz and was below 48.8Hz for 1.22 seconds. The actual amount of demand disconnected by low frequency relays, as initially reported by the DNOs at the time of the incident was 581MW. However, in their detailed reply to the questionnaire, the DNOs confirmed that the total demand disconnected was 546MW, as indicated in Figure 11 above.

The disconnection of around 546MW was just sufficient to arrest the fall in frequency and to cause a slight upward recovery as shown in Figure 9.

In their replies, the DNOs confirmed that some 2266MW of demand, approximately 6.3% of demand in England and Wales, should have tripped when the frequency fell to 48.8Hz. Clearly, some relays did not operate.

Based on DNOs returns, the number of relays in England and Wales set to trip at 48.8 Hz is approximately 91. However, the number of relays that did operate and disconnect demand was 26 relays.

The amount of demand disconnected of 546MW (about 1.5% of demand) was sufficient to arrest the frequency fall to 48.795 Hz. The relays that did not operate did not fail to operate as such because the frequency only fell 0.005 Hz below their setting and hence was within their measurement accuracy requirement of typically 0.010 Hz.

Three additional relays did operate but failed to disconnect any demand due to the design of the schemes, running arrangements on the day and the settings band of the low frequency relays. The amount of demand these three relays could have tripped would have been 68MW.

Reports were made that following the operation of the LF relays that demand was restored immediately by a combination of automatic and uninstructed manual actions on the DNO networks.

It is noted that whilst only around 546MW of demand was disconnected, this resulted in much less supply disruption to consumers nationwide. A larger amount of disconnection would have resulted in a greater supply disruption but a faster recovery of system frequency towards 50Hz.

Based on the success rate of automatic disconnection (excluding uninstructed manual restoration) had the frequency continued to fall to below the setting range of the LFDD Stage 1 Relays then the total amount of demand disconnection could have approached 2000MW. This is within the acceptable range as perfect operation is not assumed.

Following the recovery of system frequency, ENCC issued instructions to the DNOs to restore automatically disconnected demand within a range of 20 to 40 minutes. Given the actions needed by some DNOs, supplies to their customers were restored within 23 minutes of receipt of instructions.

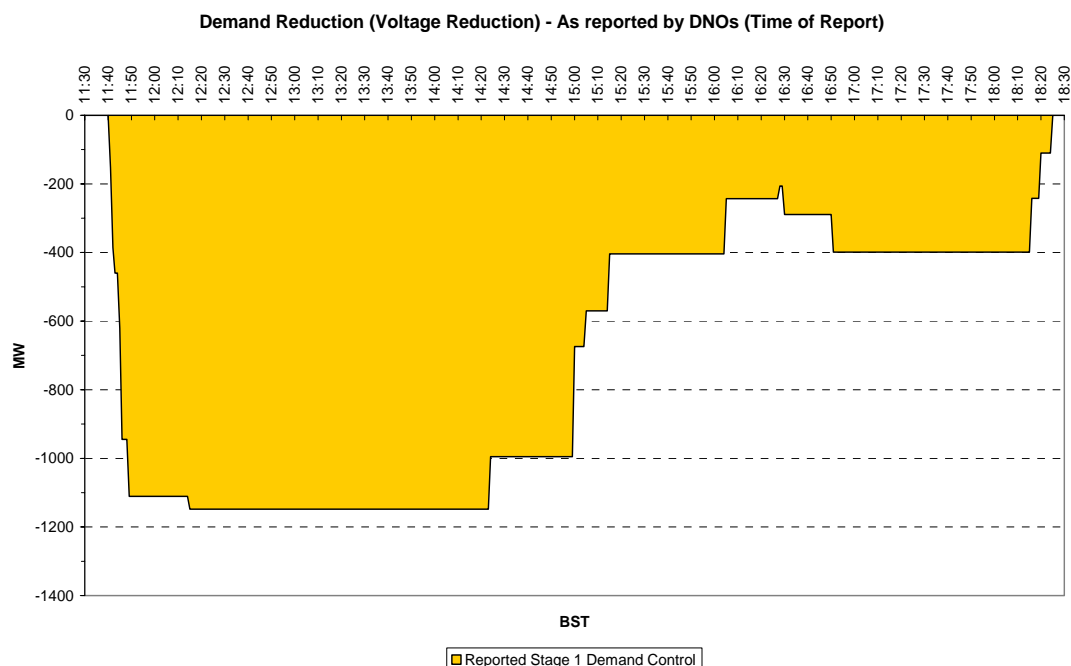
From the returns for the DNOs it has been calculated that overall some 278MWh of energy was lost due to the operation of LF Relays.

#### 4.6 Performance of Demand Control by Voltage Reduction

Historically DNOs have used voltage reductions of 3% and 6% for Demand Control Stage 1 and Stage 2 on the basis this provides demand relief of 5% and 10% respectively. Relatively recent changes in demand characteristics as such as greater use of power electronics, increasing level of air conditioning and ventilation systems as well as reduction in manufacturing means that it is likely that demand is now less sensitive to voltage reduction. This has been recognised by the electricity industry and under the auspices of the Energy Emergency Executive Committee Electricity Task Group in February 2008 a number of trials were planned to establish the effectiveness of voltage reduction. Once the trials have been completed and results analysed it is possible that trial outcome may provide an explanation for the difference between the level of demand reduction expected during this event and that which could be observed.

Within 2 minutes of the operation of low frequency relays, and in accordance with the Grid Code OC.6.5, Demand Control instructions were given to 9 DNOs estimated to provide around 1200MW of manual demand reduction by voltage reduction. Figure 12 summarises the demand reduction delivered as reported by the DNOs.

**FIGURE 12**



Together with other actions discussed in Section 3.7, the instructed Demand Control enabled:

- a) the re-establishment of the already exhausted frequency response holding on Frequency Sensitive mode generation plant in less than 15 minutes, and

- b) quicker restoration of the demand disconnected by low frequency relay operation. All instructions to affected DNOs to restore disconnected demand were completed by ENCC within 40 minutes of the automatic demand disconnection. (Initial returns from the DNOs indicate that all consumer supplies were restored within 23 minutes of receipt of this instruction).

Specific information on the various aspects of the Demand Control instructions implemented by the DNOs was sought from them to help with the complete analysis of this event. A copy of the questionnaire sent to DNOs is attached as Appendix 3.

The additional information provided identified that approximately 50MW of demand control had not been achieved due to equipment performance issues such as transformers being on fixed tap due to operational restrictions and communication failures.

Analysis of National Grid data has been able to identify an actual demand reduction of approximately 500MW from when it was instructed. It should be noted that the demand was expected to increase up until 12:15 as shown in Figure 1 and so some of the applied reduction would have been negated by the normal increase in demand.

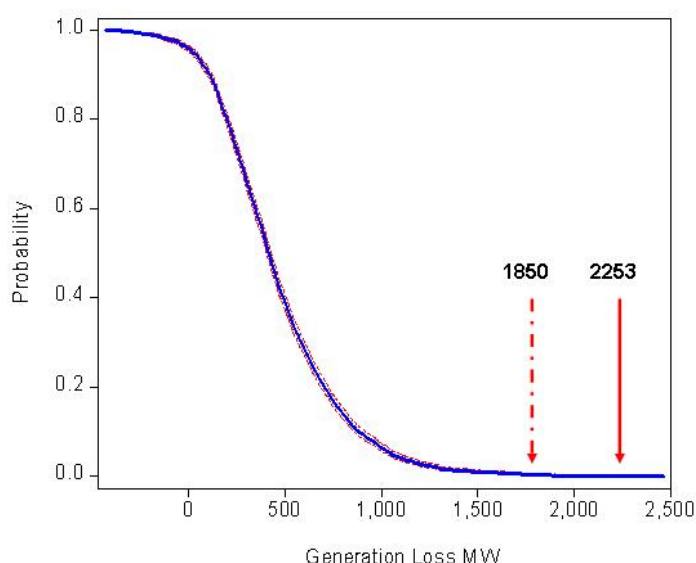
As noted above the existing E3C Electricity Task Group project has recently carried out controlled trials of demand reduction by voltage control. When fully analysed this may help inform if the current approach to using voltage reduction for Demand Control delivers the necessary levels. It is expected that any learning from these trials will be shared with both the GCRP and DCRP.

#### 4.7 System Operational Margins and Frequency Excursion

The application of the reserve policy as described in Appendix 1 Section 1.1.3 means for the period from around 1.5 hours ahead (Gate Closure) through to real time a cumulative plant loss of up to 1850MW would be covered (0.3% probability level). From gate closure to real time generation losses totalled 2253MW during this event (excluding the Large and embedded generation losses, but including other generator changes by way of physical notifications or maximum export limits). This is illustrated in Figure 13 below:

**FIGURE 13**

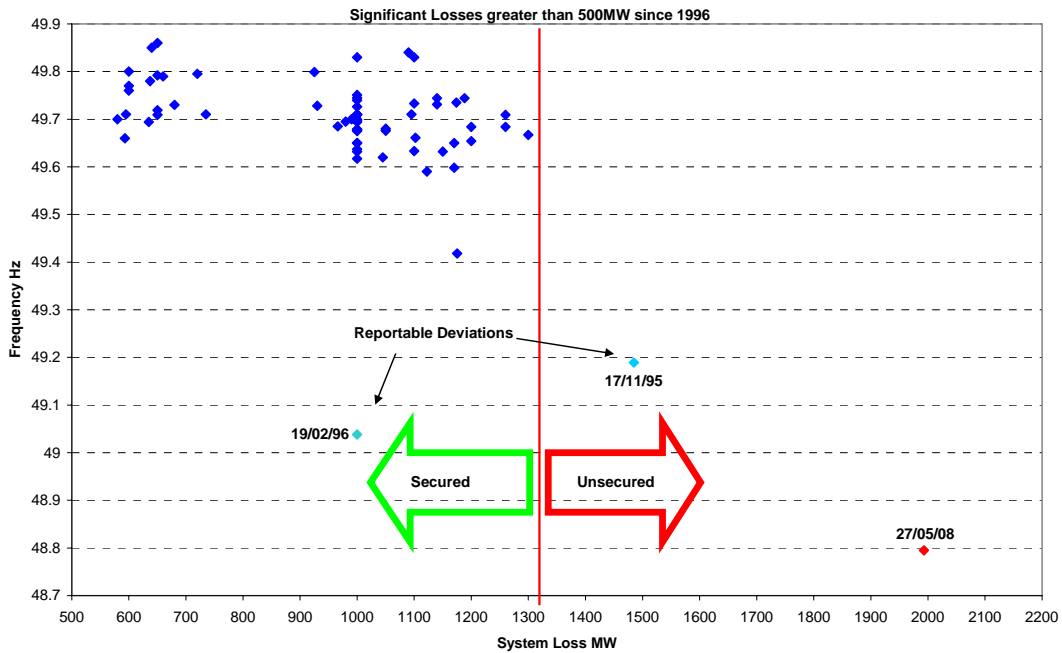
**Probability of Generation Loss between Gate Closure and Real Time**



The level of generation capacity loss experienced (2253MW) is a level that would only be experienced once in every 4 to 5 years. As a result of the exceptional generation loss, the use of demand control for the afternoon period is as would be anticipated by the operating standards.

There have only been two reportable frequency deviations since 1989/90. The first on 17<sup>th</sup> November 1995, when the frequency fell to 49.184Hz for 3 min 40 sec for a 1485MW generation loss and the second on 19<sup>th</sup> February 1996, when the frequency fell to 49.038Hz for 3 min 20 sec for a 1000MW generation loss.

FIGURE 14



The some 1993MW losses within 3.5 Minutes consisting of Generator A (345MW), Generator B (1237MW), two Large generators (40MW) and embedded generation of around 371MW are compared to simultaneous generation losses in Figure 15.

FIGURE 15

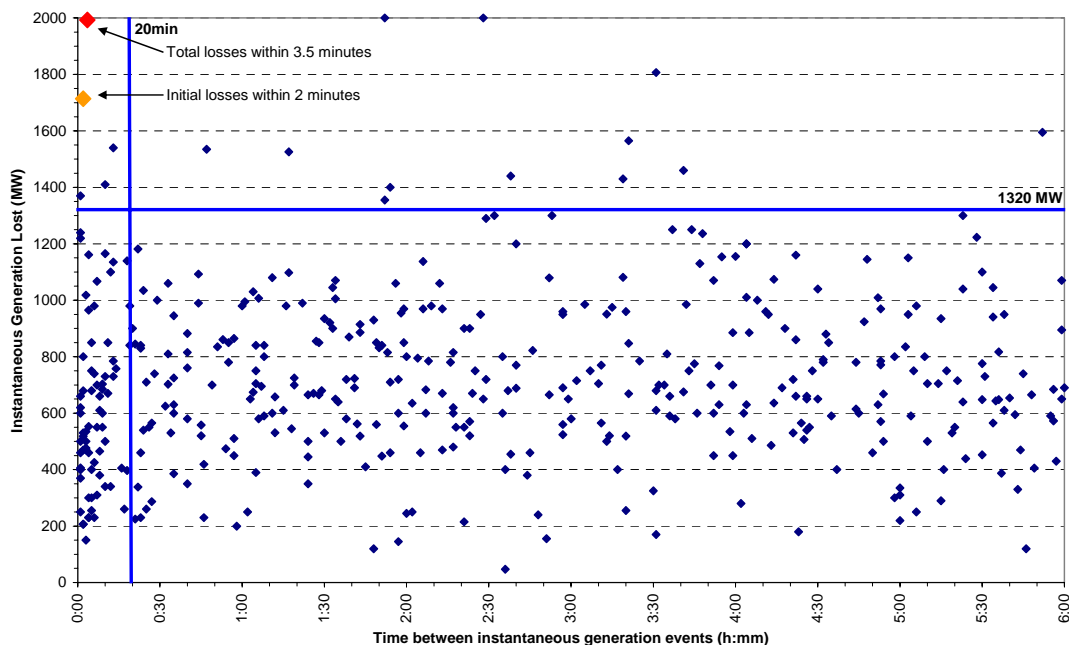
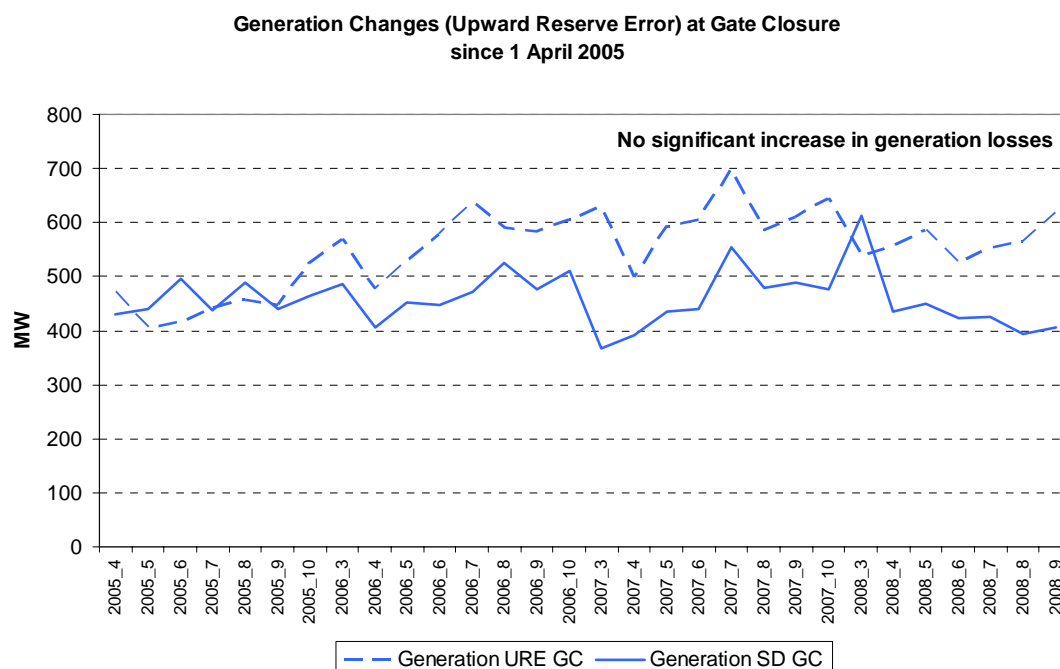




Figure 15 shows the total amount and timing between co-incident generation trips since the introduction of the New Electricity Trading Arrangements in 2001. The less time between the trips the less likely it is that frequency response will have been restored following the first trip. Frequency response can take up to twenty minutes to restore due to the type of generation available. Figure 15 shows that the initial and overall co-incident generation loss on the 27<sup>th</sup> May was exceptional and in the area furthest away from being secured. Figures 14 and 15 demonstrate that the effectively simultaneous generation loss on the 27<sup>th</sup> May is an exceptional, significant and low probability event.

Figure 16 shows the Generation changes (Upward Reserve Error) at Gate Closure, as well as the applicable Standard Deviation (SD). This data is used as a component in setting the Reserve Levels against the 1 day in 365 Loss of Load Expectation. This shows there has not been a recent significant increase in generation losses. There is no evidence to suggest that the probability of such a coincident loss of generation occurring has increased.

FIGURE 16



The subsequent plant shortages and demand control required throughout the afternoon are consistent with the impact of such a large loss in the context of the operating margins which statistically require demand control in such extreme conditions.

#### 4.8 Communications with Market, Generators and Distribution Network Operators

All warnings required by market rules were issued as required under the Grid Code. Messages were issued by fax and placed on the Balancing Mechanism Reporting System (BMRS) website.

## 5 SIMULATION OF GENERATION LOSSES AND AUTOMATIC LOW FREQUENCY DEMAND DISCONNECTION

A dynamic simulation study of system frequency performance was carried out. The aims were: (a) to recreate, as far as practically possible, the system frequency behaviour resulting from the various generation losses<sup>3</sup> and automatic demand disconnection by low frequency relays and (b) to explore if further light can be shed on the sequence of events as well as causes and effects.

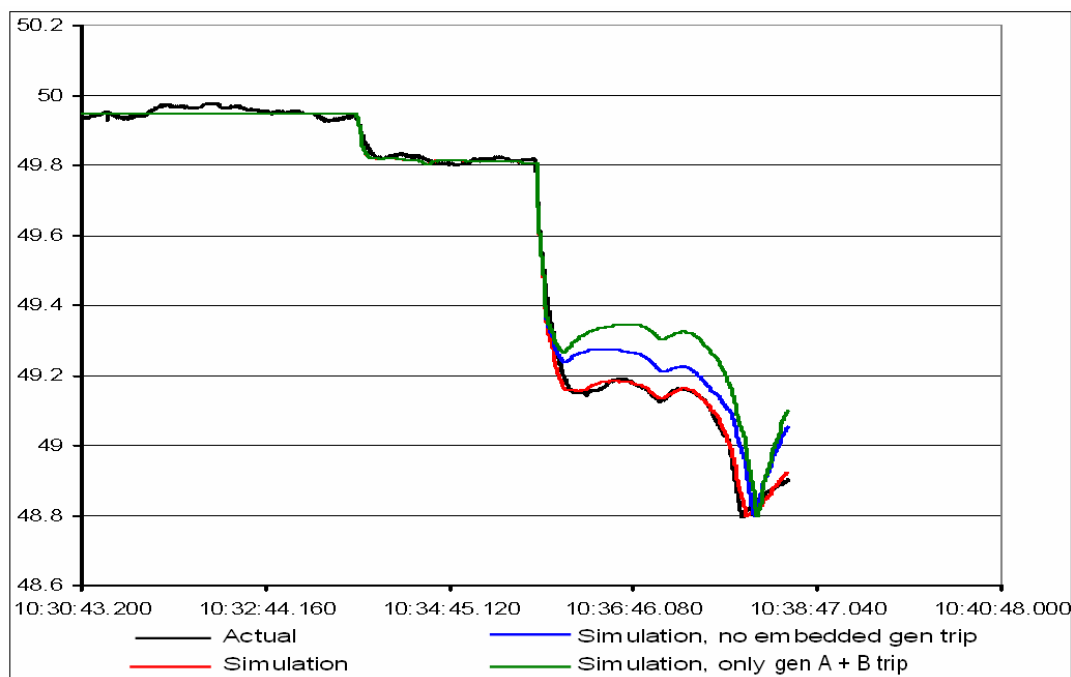
The study represented various types of generation plant including those operating in FSM and LFSM and allowed a 2% demand reduction per Hz for load/frequency sensitivity. The predicted system frequency behaviour from the simulation model is overlaid on the actual frequency and shown in Figure 17.

The modelling study confirmed the following observations:

The combined loss of at least 1714MW at 11:36 due to the loss of Generator A (345MW), Generator B (1237MW), two Large generators (40MW), and at least 92MW of embedded generation, led to an unstable system frequency. Although initially the frequency fall appears to be arrested at around 49.15Hz, the average frequency continued to slowly fall over the next 1.5 minutes.

**FIGURE 17**  
**Comparison of Actual and Simulation Model Frequencies**

The initial arrest of system frequency is caused by the significant unexpected additional response provided by LFSM generation plant. However, as this response was drawn from stored energy in the boilers it quickly started to decline, the frequency continued with its downward trend. This is not unexpected since the 1714MW loss significantly exceeds the 1260MW secured largest infeed loss on the day.



<sup>3</sup> The data available to the DNOs from embedded generation is considered incomplete and variable in quality. The assessment of embedded generation losses is discussed in Section 4.3.

Additional studies simulating a total loss of 1622MW i.e. excluding the 92MW of embedded generation, and a total loss of 1582MW (Generator B and Generator A only) confirmed that the system frequency would still be unstable. These losses are still some 29% and 26% respectively in excess of the on the day secured loss of 1260MW.

As the frequency gradually fell to 49Hz, a number of embedded generators totalling at least 115MW tripped. The effect was to increase the rate of fall of an already collapsing frequency.

The action of automatic low frequency relays disconnecting some 546MW of demand was sufficient to arrest the collapsing frequency and produce a small stable upward trend.

Overall, the low frequency demand disconnection scheme worked well and protected the GB power system from this extreme event as intended.

## **6 CONCLUSIONS**

### **6.1 Root Cause**

The root cause of the automatic demand disconnection was the exceptional amount of 1582MW loss of generation within two minutes for unrelated reasons, as well as the immediate loss of 40MW of large generation and some 92MW of embedded generation<sup>4</sup>, totalling 1714MW, resulted in a major system frequency disturbance. The some 1714MW of generation losses within two minutes exceeded the secured credible loss on the day of 1260MW by at least 36%.

### **6.2 Embedded Generation Losses**

There was further unexpected tripping of some small embedded generation at frequencies above 48.8Hz. This increased the size of the total generation loss to the GB system to some 1993MW, and hastened the frequency collapse. Although this embedded loss did not cause the frequency to fall to 48.8Hz, it only hastened it. In slightly different circumstances, it may do so and initiate the operation of the National Low Frequency Demand Disconnection Scheme.

### **6.3 Frequency of Exceptional Losses**

This level of simultaneous generation loss is an exceptional event that has not occurred since 1996. Including this event there as been three reportable frequency excursions since 1989/90 (i.e. the frequency below 49.5Hz for more than 60 seconds). The LFDD Scheme last operated in 1981 as a result of a system split leaving a disconnected part of the transmission system with insufficient generation (the LFDD relay operation successful created a stable disconnected system).

### **6.4 Securing against Exceptional Losses**

The National Low Frequency Demand Disconnection scheme is an efficient way of protecting the overall system from low probability events which are outside of normal operating conditions. This event has successfully demonstrated that the LFDD scheme prevented a system wide shutdown for an exceptional event.

### **6.5 Holding Frequency Response and Reserve to Secure this Loss**

An estimate for holding sufficient frequency response and reserve securing this type of event can be made based on the work of the GB SQSS Review Working Group GSR007 on increasing the "Infrequent Infeed Loss Risk".

Increasing the largest infrequent infeed loss from 1320MW to 1800MW is estimated at £160m per year at current prices. This would cover this event i.e. the 1714MW loss, but not all possible exceptional events.

Calculating the cost of energy lost due to the National Low Frequency Demand Disconnection scheme using the price applicable to the National Grid Transmission Network Reliability Incentive scheme of £45k per MWh, the energy lost on the 27<sup>th</sup> May of 278MWh equates to £12m. On this basis there is not an economic case to increase response and reserve levels to protect the system while these exceptional events remain infrequent.

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<sup>4</sup> The data available to the DNOs from embedded generation is considered incomplete and variable in quality. The assessment of embedded generation losses is discussed in Section 4.3.

## **6.6 Operation of the System**

The dual challenges of both the major system disturbance which led to demand disconnection and the extraordinary pattern of generation losses experienced on the 27<sup>th</sup> May provided significant system control challenges, which were successfully met by the staff at the Electricity National Control Centre.

National Grid believes that effective communications with the Generators and DNOs were maintained throughout the day and that the whole industry worked well together to support the restoration of consumers off supply and the orderly return to normal operating conditions.

## 7 RECOMMENDATIONS

1. The lack of a clear and explicit frequency range requirement on small embedded generation plant in the Distribution Code<sup>5</sup> should be addressed by the Grid Code Review Panel. The objective is to review and align the two codes on such a requirement as far as reasonably practicable.

Action: GCRP Chair by December 2009

2. Where reasonably practicable the frequency range settings on existing small embedded generation plant should be modified to improve their resilience to frequency excursions.

Action: GCRP Chair by June 2009

3. Under the GCRP auspices, National Grid and the DNOs review the arrangements under Grid Code OC6.6 to ensure effectiveness of all low frequency demand disconnection scheme stages and share best practice identified from this event. This is to include the obligations on restoration of demand.

Action: GCRP Chair by June 2009

4. With the continued assistance of the Association of Electricity Producers establish as far as possible the timing and cause of any embedded generation losses on the 27<sup>th</sup> May to further support action 1 and 2.

Action GCRP Chair by June 2009

5. Provide the Energy Emergency Executive Committee appropriate updates on the status and progress of actions 1 to 4.

Action GCRP Chair

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<sup>5</sup> The Distribution Code Review Panel is responsible for the governance of the Distribution Code and is represented at the Grid Code Review Panel.

**APPENDICES**

## 1 APPENDIX 1 - INDUSTRY FRAMEWORKS RELEVANT TO THE EVENTS OF 27<sup>TH</sup> MAY 2008

### 1.1 National Grid's Role as GB System Operator (GBSO): Frequency Control and System Operating Margin

#### 1.1.1 GB System Operator (GBSO)

National Grid is responsible for the management of transmission network security and real time balancing of generation with demand in our role of GB System Operator. Any imbalance between generation input and demand will result in perturbations around the nominal system frequency of 50Hz.

#### 1.1.2 Frequency Control Requirements

National Grid manages the system frequency to defined statutory steady state limits of  $\pm 0.5\text{Hz}$  (i.e. 49.5Hz to 50.5Hz) and our Operational limits of  $\pm 0.2\text{ Hz}$  (i.e. 49.8Hz to 50.2Hz).

The [GB Security and Quality of Supply Standard \(GB SQSS\)](#) specifies the limits of frequency deviations for secured faults, which include loss of output from a single generating unit, Combined Cycle Gas Turbine Module (CCGT), boiler, nuclear reactor or DC bi-pole lost as a result of an event. These limits are:

- Normal Infeed Loss Risk (1000MW): Maximum frequency deviation should not exceed 0.5Hz
- Infrequent Infeed Loss Risk (1320MW): Frequency should not deviate outside the range 49.5Hz to 50.5Hz for more than 60 seconds.

The largest Infrequent Infeed Loss Risk of 1320MW is derived from the largest possible generation infeed loss on the Transmission system that will result from a single secured event.

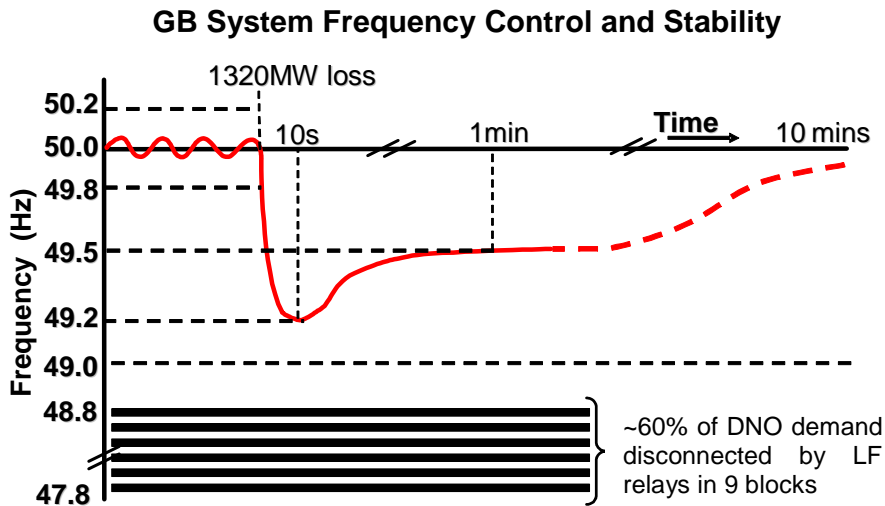
In the case of Infrequent Infeed Loss Risk, National Grid's practice is to ensure that the maximum frequency deviation is limited to 0.8Hz. In addition, National Grid aims to return the frequency to operational limits (49.8Hz to 50.2Hz) within 10 minutes.

For a larger generation loss than the Infrequent Infeed Loss Risk or a large generation deficit in an importing power island following a sudden system split, the National Low Frequency Demand Disconnection (LFDD) scheme (as described in Grid Code OC6.6) is designed to automatically disconnect demand using low frequency relays to contain the incident and prevent a total or partial shutdown of the GB power system.

Figure A illustrates the frequency control philosophy and frequency stability of the GB power system. In addition, where the initial frequency is close to the lower operational limit of 49.8Hz at the time of a 1320MW loss, the lowest planned frequency would be 49Hz. This would still restrict the maximum frequency deviation to 0.8Hz and provide a 0.2Hz margin above the level where the first stage of the LFDD scheme is designed to operate and disconnect demand.



FIGURE A



### 1.1.3 System Operating Margin

Looking ahead of real time, and in recognition of variability and uncertainty of demand for electricity and that statistically generating plant will break down, National Grid will, at all times, hold a “safety cushion” or “operating margin”. This will be generation capacity (or demand reduction) available to us, on instruction, in varying timescales (from minutes to hours ahead of real time) to ensure that for all credible, secured events, we can access sufficient generation output to meet the forecast demand and meet the 1 in 365 Loss of Load Expectation.

The safety cushion comprises 4 main components:

- Contingency Reserve – generation plant available at between 4 and, typically, 12 hours notice to generate
- Short Term Operating Reserve – generation (or demand) typically available to respond within 5 – 20 minutes
- Regulating Reserve – generation that is synchronised with capacity to enable us to instruct increases (or decreases) in output to assist with short term demand forecast errors or plant losses, available after two minutes
- Frequency Response Reserve – generation or demand instructed to automatically change output to help with correction of frequency deviations in real time

The actual size of the “contingency reserve” varies according to time of year and demand peaks, but for any particular point in the day our requirement decreases as real time approaches, typically ranging from some 1000MW at 12 hours ahead to zero by 4 hours ahead.

The Grid Code describes 3 System Warnings that are relevant to the 27<sup>th</sup> May. These are:

- **Notification of Inadequate System Margin (NISM)** – issued when there is inadequate System Margin (as referred to in Grid Code Balancing Code BC1.5.4) and it is uncertain if this would be recovered over the relevant timescales

- **High Risk of Demand Reduction (HRDR)** – issued when there is inadequate System Margin (as referred to in Grid Code Balancing Code BC1.5.4) and/or it is judged to be a high risk of demand reduction being instructed
- **Demand Control Imminent (DCI)** – issued to provide short term notice, where possible, when a demand reduction is expected in the following 30 minutes

National Grid's dispatch of reserve is described in detail in our [Balancing Principles statement](#). Our existing policy which has been in place since NETA aims to hold sufficient reserve such that the net impact of generation loss and demand forecast error would only exceed this level of reserve on average once per year, thus we would expect to utilise demand control as described in the Grid Code on one occasion per year (a Loss of Load Expectation of 1 in 365). This policy has been [described in detail](#) at a number of industry events.

## 1.2 Roles of Generators and Distribution Network Operators

### 1.2.1 Generators

As generation losses are normally by nature sudden and unexpected, National Grid contracts for automatic, commercial services ("frequency response") from generators and demand side participants which will deliver immediate changes to output to maintain the system frequency within the required limits.

The Grid Code Connection Condition (CC) 6.3 requires that Generators have a frequency response capability and Balancing Code 3 of the Grid Code sets out the procedure for National Grid to use in conjunction with Users of the Transmission system (including Generators) to undertake system frequency control provision.

All Generators are required to operate either in Frequency Sensitive Mode or Limited Frequency Sensitive Mode at all times. When operating in Frequency Sensitive Mode, Generators are required to comply with Grid Code CC6.3.7 and their ancillary service contracts in relation to how the MW output frequency response is delivered. When operating in Limited Frequency Sensitive Mode, Generators are required to comply with Grid Code CC6.3.3 that governs how their MW output changes in response to system frequency changes.

Furthermore, all generation subject to Grid Code CC6.1.3 is required to provide continuous stable operation in the range of 47.5Hz to 52Hz, and be able to operate for a period of at least 20 seconds in the range 47Hz to 47.5Hz. The Grid Code applies to all transmission connected generation, and all with registered capacity of generation in:

- England and Wales  $\geq 50\text{MW}$
- Scottish Power Transmission Ltd region  $\geq 30\text{MW}$
- Scottish Hydro-Electric Transmission Ltd region  $\geq 10\text{MW}$

Generally, all DNO connected embedded generation below these values will be required to comply with the Distribution Code and relevant Engineering Recommendations, G75 or G59, which will still typically require continuous stable operation in the range 47Hz or 48Hz to 52Hz, although G75 and G59 are not mandatory.

### 1.2.2 Distribution Network Operators

Grid Code Operating Code (OC) No 6, (Demand Control) is concerned, amongst other things, with the provisions to be made by DNOs to permit the reduction of demand in the event of insufficient active power generation being available to meet demand.

Grid Code OC6.5 describes the procedure for the implementation of manual Demand Control by the DNOs on the instruction of National Grid. The required demand reduction will be achieved at all times, with or without prior warning, within agreed timescales (as per Grid Code OC6.7.3) upon receipt of an instruction from National Grid.

Grid Code OC6.6 describes the automatic Low Frequency Demand Disconnection (LFDD) scheme and the arrangements that the DNOs are required to make in relation to this scheme. Following operation of this scheme, the DNOs are not permitted to restore automatically disconnected demand without instruction from National Grid.

## 2 APPENDIX 2 - GRID CODE LOW FREQUENCY DEMAND DISCONNECTION (LFDD) SCHEME

The table below is extracted from the Grid Code Connection Conditions showing the LFDD scheme settings in Great Britain.

| Frequency Hz          | %Demand disconnection for each <b>Network Operator</b> in <b>Transmission Area</b> |     |       |
|-----------------------|------------------------------------------------------------------------------------|-----|-------|
|                       | NGET                                                                               | SPT | SHETL |
| 48.8                  | 5                                                                                  |     |       |
| 48.75                 | 5                                                                                  |     |       |
| 48.7                  | 10                                                                                 |     |       |
| 48.6                  | 7.5                                                                                |     | 10    |
| 48.5                  | 7.5                                                                                | 10  |       |
| 48.4                  | 7.5                                                                                | 10  | 10    |
| 48.3                  |                                                                                    |     |       |
| 48.2                  | 7.5                                                                                | 10  | 10    |
| 48.0                  | 5                                                                                  | 10  | 10    |
| 47.8                  | 5                                                                                  |     |       |
| <b>Total % Demand</b> | 60                                                                                 | 40  | 40    |

Note – the percentages in table above are cumulative such that, for example, should the frequency fall to 48.6 Hz in the **NGET Transmission Area**, 27.5% of the total **Demand** connected in the **NGET Transmission Area** shall be disconnected by the action of **Low Frequency Relays**.

### 3 APPENDIX 3 - DNO QUESTIONNAIRE

#### 1. LF Demand Disconnection Performance

- 1.1. How much demand was set to trip at 48.8 Hz? (MW and as a % of DNO demand at time of trip, confirming your Grid Code submission.)
- 1.2. How much demand actually tripped?
  - 1.2.1. Gives details of what tripped:
    - time of trip (hh:mm:ss)
    - Demand at time of trip.
    - GSP
    - Feeder
    - Demand tripped (MW)
- 1.3. If some of the expected demand was not disconnected, why was this?
- 1.4. LF Relay Operation
  - a) How many LF relays set to 48.8 Hz
  - b) How many operated correctly
  - c) If any failed to operate, give the reason why.

#### 2. Embedded Generation Performance

- 2.1. Attachment shows the information you have provided to date. Please can you confirm the following details:
  - Time of trip (hh:mm:ss)
  - Embedded generator
  - Generation tripped (MW) for each generator.
  - Reason for trip
  - Was there any attempt at re-synchronisation?
- 2.2. Is there any evidence of more embedded generation tripping, particularly smaller units? If so how much and why did it trip?

#### 3. Demand Control

- 3.1. What level of demand control did you try to implement (MW)?
- 3.2. What specific actions were used to implement the demand control and at what time (hh:mm)?
- 3.3. What level of demand control was achieved (MW at what time)?
- 3.4. If the level of demand control achieved did not reach the level instructed, why was the expected level of demand control not achieved?

#### 4 APPENDIX 4 - HYPERLINK REFERENCES USED IN THIS REPORT

GB SQSS (Page 34)

[http://www.nationalgrid.com/NR/ronlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB\\_SQSS\\_V1.pdf](http://www.nationalgrid.com/NR/ronlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB_SQSS_V1.pdf)

Balancing Principles Statement (BPS) (Page 35)

<http://www.nationalgrid.com/NR/ronlyres/03A5FB8B-D6B9-450A-AB7D-11021233BB30/24545/BPSv80effectivefrom1apr08.pdf>

Reserve presentation (Page 35)

[http://www.nationalgrid.com/NR/ronlyres/012BE506-F6A1-4D16-BADD-C7A2FC49C52D/1913/NGTs\\_Role\\_in\\_Securing\\_Reserve.pdf](http://www.nationalgrid.com/NR/ronlyres/012BE506-F6A1-4D16-BADD-C7A2FC49C52D/1913/NGTs_Role_in_Securing_Reserve.pdf)