Frequency Changes during Large Disturbances and their Impact on the Total System

The purpose of this document is to assist the Authority in its decision of whether to implement a proposed modification to the Distribution Code and Engineering Recommendation G59. The proposed modification was subject to consultation in August 2013. Revised proposals were then developed by Licensees with the assistance of Workgroup members. A second consultation was conducted in March 2014 on the implementation of the revised proposals. The modification proposed in the Report was developed by the network Licensees after consideration of responses to the second consultation.

Published on: **09 May 2014**

Recommendation

Rate of Change of Frequency (RoCoF) protection settings should be changed at new and existing distributed generators in stations of registered capacity of 5MW and above to $1Hzs^{-1}$, using a delay setting of 500ms, with the exception of synchronous generators commissioned before 1st July 2016, where a minimum setting of $0.5Hzs^{-1}$ with a delay setting of 500ms is permissible. The specific criteria to be applied should be stipulated in both the Distribution Code and Engineering Recommendation G59.

Who does it affect?

High Impact:	Owners of existing synchronous generators at stations of registered capacity of 5MW and above where, subject to a site specific risk assessment, mitigation measures may need to be implemented before protection setting changes can be applied in accordance with the Distribution Code and Engineering Recommendation change proposed.
Medium Impact:	Owners and developers of all other distributed generators at stations of registered capacity of 5MW and above where protection setting changes will need to be applied in accordance with the Distribution Code and Engineering Recommendation change proposed.
Low Impact:	None identified

Contents

About this document

This document is the Report to the Authority for Frequency Changes During Large System Disturbances which contains the responses to two Industry Consultations and the network Licensees recommendation. The purpose of this document is to assist the Authority in their decision whether to implement the proposed changes.

The revisions to the Distribution Code and Engineering Recommendation G59 proposed by Distribution network Licensees and sent to the Authority require approval by that body and will, if approved, come into force on such date (or dates) of which Authorised Electricity Operators will be notified by the ENA, in accordance with the Authority's approval.

Document Control

Version	Date	Change Reference
0.1	14 April 2014	Draft
1.0	09 May 2014	Report to the Authority

Any Questions

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1 Executive Summary

1.1 This Report to the Authority contains recommendations from the network Licensees for changes to the Distribution Code and Engineering Recommendation G59. The final recommendations have been developed by Licensees with the assistance of the "Frequency Changes During Large System Disturbances" Workgroup. The Report summarises the responses to two Industry Consultations and describes how the Licensees' recommendations have been developed.

1.2 The purpose of this document is to assist the Authority in their decision whether to implement the proposed changes. The main document is supported by a further 5 Volumes which are provided separately to limit the size of the main document. Two of the volumes are not publically available as they contain confidential responses to the consultations or confidential contact details. These two volumes have been provided to the Authority separately.

1.3 The joint Grid Code and Distribution Code Workgroup entitled "Frequency Changes during Large Disturbances and their Impact on the Total System" has been developing recommendations since October 2012. A copy of the Workgroup's Terms of Reference can be found in Annex 1.

1.4 Following a series of Workgroup meetings, stakeholder events and completion of a generic risk assessment, the Workgroup initially put forward proposals to change Rate of Change of Frequency (RoCoF) settings on the Loss of Mains Protection on distributed generators at stations of 5MW or larger to $1.0Hzs^{-1}$.

1.5 Having considered a range of options, the Workgroup's view was that it was necessary to change RoCoF settings because the costs of limiting the maximum system RoCoF were significantly higher than the cost of making a setting change. The Workgroup also identified that certain types of generators would be affected by the change more than others and highlighted risks that needed to be assessed, and if necessary, mitigated, prior to protection settings being changed.

1.6 The network Licensees' first consultation on the Workgroup's proposals ran from August to September 2013. The consultation recommended that RoCoF protection settings for all distributed generators at stations of 5MW or larger should be $1.0Hzs^{-1}$, and set out criteria that should be satisfied before new settings are applied. The proposals were to be implemented by changing the Distribution Code and Engineering Recommendation G59.

1.7 A total of 18 parties responded to the consultation. A majority of responses were in support of the proposals. A number of respondents expressed concern over certain aspects of the proposals which the Licensees sought to address in revised proposals with the help of Workgroup members. The revised proposals sought to address concerns raised in three key areas:

(a) The impact and cost for synchronous generators of making the recommended protection setting change to $1.0Hzs^{-1}$;

(b) The implementation of the change, including the time allowed to make protection changes; and

(c) The case for change based on the balance of the costs to implement the change and the potential savings.

1.8 Comments were also provided on the description of the required settings in the proposed legal text which were addressed.

1.9 The Workgroup helped Licensees develop a revised proposal based on the following criteria:

(a) The savings gained by implementing a higher RoCoF protection setting for generators at stations of 5MW capacity and greater, significantly outweigh the cost of changing the settings, with a payback achieved within 3 years;

(b) There is no material difference in the impact on owners of existing and new non-synchronous generators of a setting change of 0.5 Hzs^{-1} or 1.0 Hzs^{-1};

(c) There is little material difference in the impact on the developer of new synchronous generators of a setting change of 0.5 Hzs^{-1} or 1.0 Hzs^{-1}, and a setting of 1.0 Hzs^{-1} minimises the risk and cost of having to make another setting change in the near future;

(d) There is a perceived material difference in the impact on owners of existing synchronous generators of a setting change of 0.5 Hzs^{-1} or 1.0 Hzs^{-1}; and

(e) Affected parties need a reasonable amount of time to implement the proposed change and there is scope to extend the implementation period to two years from the date of a Distribution Code change.

1.10 The revised proposals had the effect of reducing the impact on owners of existing synchronous generators by allowing for a lower setting. All parties making a protection change would benefit from an extension of the implementation timescales. The additional guidance provided will also help existing generators perform the necessary risk assessment.

1.11 Licensees recognised however that these revisions meant that the proposed legal text for both the Distribution Code and Engineering Recommendation G59 was significantly different from that presented in the previous consultation document. Licensees therefore sought the views of affected parties on how well the proposed legal text captured the Workgroup's final set of recommendations concerning RoCoF settings on distributed generators at stations of registered capacity of 5MW and above. This was done through a second consultation which ran from March to April 2014.

1.12 Responses to this second consultation were received from 9 parties, some of which recommended changes to the draft legal text aimed at making it clearer. In a number of cases, Licensees agreed that recommendations improved the draft legal text and these suggestions have been incorporated in the legal text presented in this report. No new material was provided in responses which would impact on the Licensees assessment of the recommended approach.

1.13 The Licensees therefore recommend that the following requirements should be implemented by changing the Distribution Code and Engineering

Recommendation G59 such that for distributed generators at stations with a registered capacity of 5MW and above, the Rate of Change of Frequency settings specified for Loss of Mains protection will be:

(a) $1Hzs^{-1}$, with a delay setting of half a second, on all new distributed generation, with a commissioning date on or after 1 July 2016;

(b) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016;

(c) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned on or after 1 July 2014;

(d) $0.5Hzs^{-1}$, with a delay setting of half a second, on all synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016; and

(e) $0.5Hzs^{-1}$, with a delay setting of half a second, on all synchronous distributed generation commissioned on or after 1 July 2014 but before 1 July 2016.

1.14 The Workgroup's assessment indicates that the safety risk to network equipment and to personnel in proximity to network equipment (eg by electrocution) following implementation of the recommended change would lie within a range deemed acceptable by established practice.

1.15 The Workgroup's assessment indicates that the acceptability of the safety risk to synchronous generator equipment and to personnel in proximity to synchronous generator equipment following implementation of the recommended change is dependent on generator voltage control mode and local network conditions. Site specific risk assessments are therefore recommended by the Licensees prior to a protection setting change at synchronous generator sites. Assessment guidance is included in the proposed text for Engineering Recommendation G59.

1.16 The Workgroup has not developed proposals to address concerns raised over how protection setting changes are funded. The Workgroup highlighted previously that in the absence of any new arrangements, costs would fall upon the owners of the Loss of Mains protection equipment. The network Licensees recognise that these costs may be significant for some parties and that there is a notable body of opinion that would support a change in this area. However, the network Licensees believe that it is appropriate for these costs and risks to be picked up by Generators in the normal course of business. Furthermore the Workgroup is not able to address these concerns within its terms of reference, which fall within the scope of both the Distribution Code and Grid Code and therefore do no encompass changes to charging or funding arrangements. network Licensees and Workgroup members would be happy to support further discussions at an appropriate time if required.

1.17 The Workgroup has already initiated its second phase of work which is outlined alongside its Terms of Reference in Annex 1. The Workgroup has been charged with developing proposals for generators at power stations of less than 5MW, developing any necessary RoCoF withstand requirements and also reviewing Vector Shift requirements.

2 Why Change?

2.1 The electricity supply system in Great Britain is designed to operate as a single synchronised system. In the event of a network fault, it is possible for part of the network to be isolated from the rest of the system forming an islanded system. In these circumstances it is possible for a distributed generator, or a group of distributed generators, located within this island to supply the local distribution network and its customer demand.

2.2 Such an island would not be controlled to normal quality of supply standards and is potentially unsafe to people in the proximity of the energised equipment. Historically, smaller distributed generators have been required to have Loss of Mains protection which would, in the event of an island being formed, shut down the generator(s), and hence the island, safely.

2.3 One technique used to detect a Loss of Mains condition is to measure the Rate of Change of Frequency (RoCoF). This technique works because it is likely there will be an imbalance between electricity demand and supply within the island when an islanded system forms, meaning that frequency within the island changes at a rate higher than that experienced under normal system conditions. However, high RoCoF can occur over the whole of the electricity supply system in the event of a large infeed (generation or import) or off-take (demand or export) loss. If the RoCoF is high enough, RoCoF based Loss of Mains protection can operate which would cause distributed generation to stop generating leading to a further disturbance and a possible cascade effect. The current minimum recommended RoCoF setting is 0.125Hzs^{-1}.

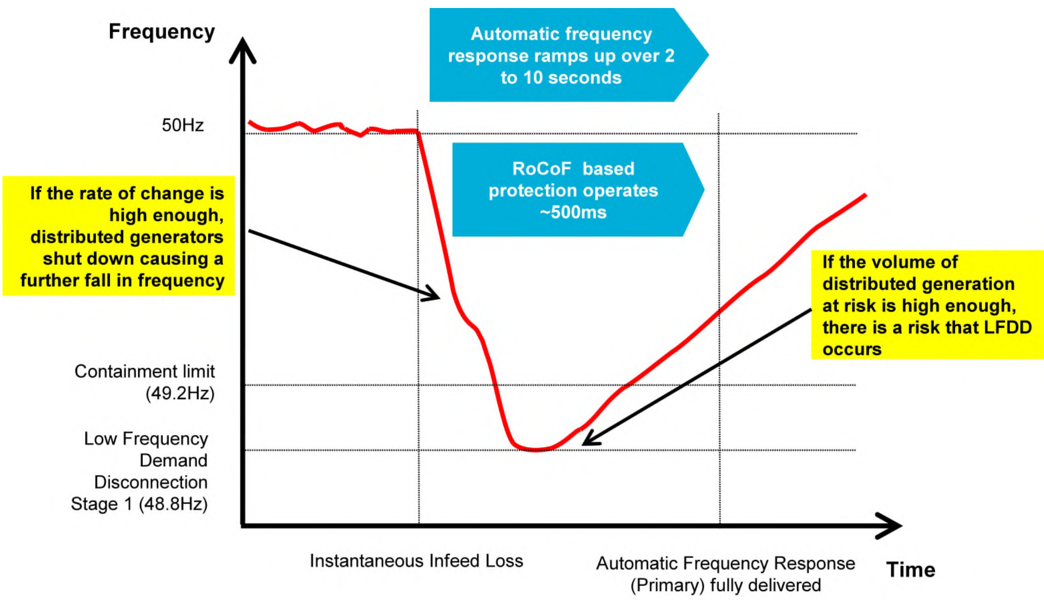

Figure 1: How LFDD would occur after an Infeed Loss and RoCoF trips

2.4 If enough distributed generation were to cease generating (there is currently over 10GW of installed capacity), the result of this cascade effect would be the operation of Low Frequency Demand Disconnection (LFDD). A large number of electricity consumers would suffer an involuntary loss of electricity supply. National Grid has a statutory obligation to ensure that unacceptable frequency conditions do not occur under situations specified in the National Electricity Transmission System Security and Quality of Supply Standard (the NETS SQSS[1]). Figure 1 illustrates how this might occur for an infeed loss.

2.5 LFDD has only operated once since privatisation in 1990. This occurred on the 27th May 2008 after the loss of two large transmission connected generators in rapid succession. There have been no occurrences of LFDD operation because of RoCoF to date.

2.6 National Grid has been working with the electricity supply industry to develop new frequency control services in response to the changing electricity generation and import mix. "Non-synchronous" technologies offer many benefits but do not provide the natural damping or "inertia" of the more conventional "synchronous" type of generation which is directly coupled to the network. This means that under high import, windy or sunny conditions, frequency will change at a faster rate than it does today, meaning more rapid frequency control capability is likely to be required. The Workgroup examining these requirements recommended that RoCoF protection settings should be reviewed for their future suitability.

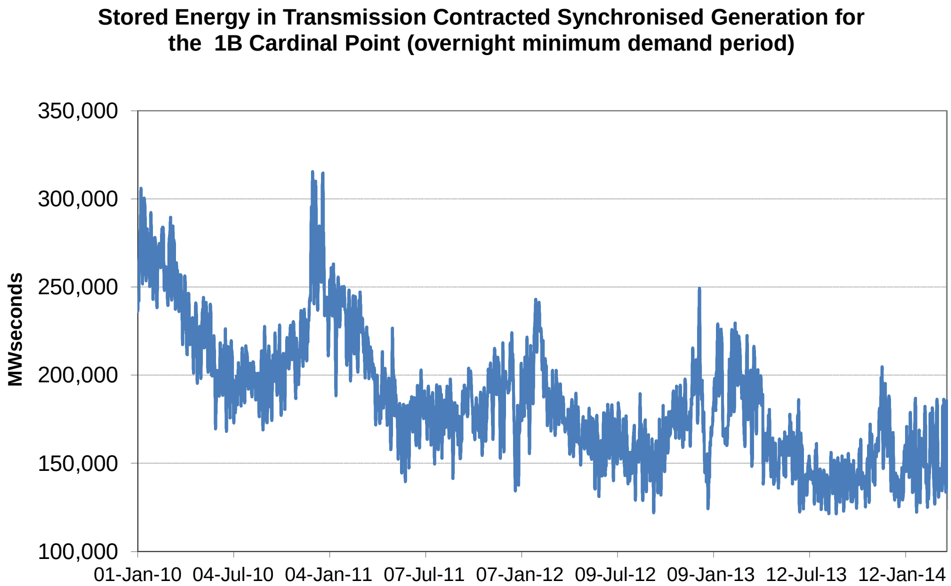

Figure 2: Trend in Inertia

2.7 Figure 2 is derived from the planned transmission connected generation operating conditions at the lowest overnight demand period every day over three years. The chart shows a clear trend in reducing inertia from large generation. The reduction has occurred as synchronous generation has been displaced by non-synchronous sources, such as wind and interconnectors, which has been necessary to meet emissions and renewable energy targets.

2.8 Good plant models and operating information is available for large generators and networks. It is therefore possible to simulate how these generators will behave in the event of a large frequency deviation.

[1]//http://www2.nationalgrid.com/uk/Industry-information/Electricity-codes/System-Security-and-Quality-of-Supply-Standards/

2.9 Less specific information is available on distributed generation and no specific information is available for industrial, commercial and domestic demand. The behaviour of these latter components can therefore only be deduced by looking at the behaviour of the system overall and removing the effect of the well understood components. For the purposes of looking at RoCoF risks, National Grid currently terms this the Residual Inertia. A value can be ascribed to Residual Inertia by looking at large frequency deviations and comparing an actual frequency trace with a simulated frequency trace which is based on known parameters (in this case, the known characteristics of transmission connected generation) as illustrated in Figure 3.

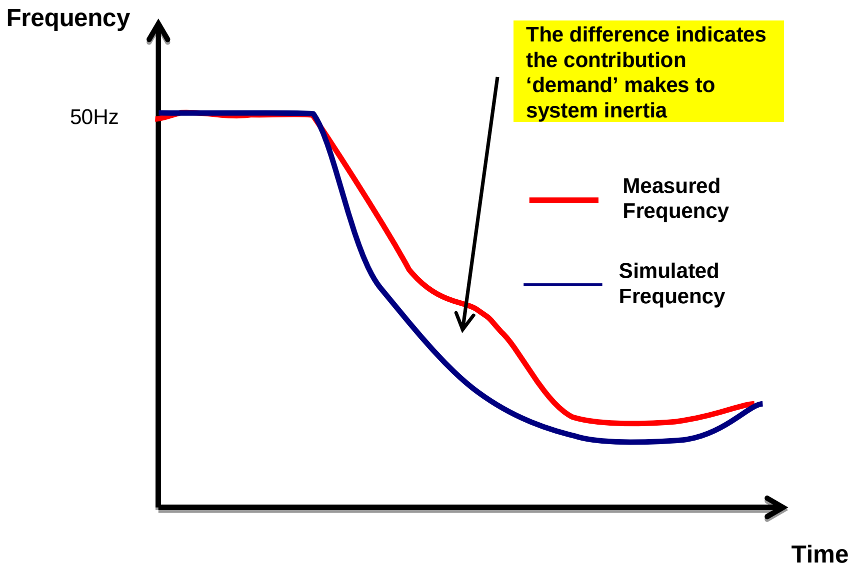

Figure 3: Evaluating Residual Inertia

2.10 It is conceivable that there is a downward trend in Residual Inertia. Electrical machines have become more efficient in recent years but in many cases the technology employed has the effect of supplying less inertia (the use of variable speed drives as opposed to induction machines for example). It should be noted that no clear trend or causal effect has been established at this time.

2.11 It is possible to predict a maximum rate of change using a combination of Residual Inertia, estimated by reviewing recent frequency deviations, and forecast generation operating patterns. Two tables are shown below which provide a view of RoCoF for different infeed loss risks.

2.12 The calculated figures are simulated system averages. Actual figures would vary depending on the location of measurement and transient effects meaning that a margin (in the order of 10%, but varying depending on the location of the event under consideration) needs to be applied to the figures illustrated.

2.13 The analysis referenced in Tables 1 and 2 is based on the Gone Green dataset used in the 2012 Electricity Ten Year Statement[2]. The load and availability factors, and scheduling assumptions previously adopted by the Frequency Response Technical Subgroup (FRTSG) were applied to the generation and demand schedule (eg 20GW demand scenarios reflect high wind conditions with 60% of installed wind capacity running).

[2] http://www.nationalgrid.com/uk/electricity/ten-year-statement/

2.14 Table 1 shows results from a “High Wind” condition. Table 2 is the same, but is intended to represent a “High Imports” condition, with an additional 2GW of non-synchronous sources accommodated. The lowest demand level considered was 20GW. The lowest demand experienced this year so far is 19GW (as viewed from the transmission system) and it is likely that this will reduce over time. Further information on the assumed generation background is provided in Annex 4.

2.15 It should be noted that the rate of change of frequency is sensitive to generation mix and that there is considerable scope for variation as wind output and interconnector positions vary and synchronous generation is displaced. A number of plausible sensitivities are not included in the analysis, including a growth in distributed generation from non-synchronous sources and a reduction in damping within demand, which would both cause an increase in the calculated figures (and a decrease for the opposite change).

2.16 Results are shown for the years up to 2020. It was not possible for the purposes of this analysis to derive feasible generation and demand balance solutions for scenarios beyond 2020 which satisfied frequency control requirements. Enhanced frequency control services, wider generator operating ranges and further demand side services are amongst the facilities that may be required to address this. Each of these options, if adopted, would have a different impact on the predicted maximum RoCoF value.

Year	**Demand**	**RoCoF Hzs^{-1}**			
		1320 MW loss		**1800 MW loss**	
		100ms	**500ms**	**100ms**	**500ms**
2014	20 GW	-0.24	-0.24	-0.34	-0.33
	35 GW	-0.13	-0.13	-0.18	-0.17
2016	20 GW	-0.25	-0.24	-0.35	-0.34
	35 GW	-0.13	-0.13	-0.19	-0.18
2018	20 GW	-0.30	-0.29	-0.43	-0.42
	35 GW	-0.16	-0.16	-0.23	-0.22
2020	20 GW	-0.36	-0.35	-0.50	-0.49
	35 GW	-0.19	-0.19	-0.27	-0.26

Table 1: Predicted Average System RoCoF in Hzs^{-1} (High Wind Conditions)

Year	**Demand**	**RoCoF Hzs^{-1}**			
		1320 MW loss		**1800 MW loss**	
		100ms	**500ms**	**100ms**	**500ms**
2014	20 GW	-0.26	-0.26	-0.36	-0.36
	35 GW	-0.14	-0.13	-0.19	-0.18
2016	20 GW	-0.27	-0.27	-0.38	-0.37
	35 GW	-0.14	-0.14	-0.20	-0.19
2018	20 GW	-0.33	-0.32	-0.47	-0.45
	35 GW	-0.17	-0.17	-0.24	-0.24
2020	20 GW	-0.42	-0.40	-0.57	-0.56
	35 GW	-0.21	-0.20	-0.29	-0.28

Table 2: Predicted Average System RoCoF in Hzs^{-1} (High Wind, High Imports)

2.17 The predicted RoCoF values shown are all above the current minimum setting of 0.125Hzs^{-1}. Values approach and exceed 0.5Hzs^{-1} for infeed losses of 1,800MW under low demand conditions. Connections which constitute an infeed loss risk of 1,800MW are currently expected from 2017 onwards.

2.18 National Grid monitors frequency on the electricity supply system continuously and analyses frequency deviations in detail when they occur. Large frequency deviations do not occur very often, but when they do they can provide new information on system behaviour. Recent frequency deviations have allowed National Grid to re-assess system characteristics (including "Residual Inertia") and take a view of future performance. The conclusion of this assessment is that there is at present a need to take action to ensure the minimum RoCoF protection setting of 0.125Hzs^{-1} will not be exceeded.

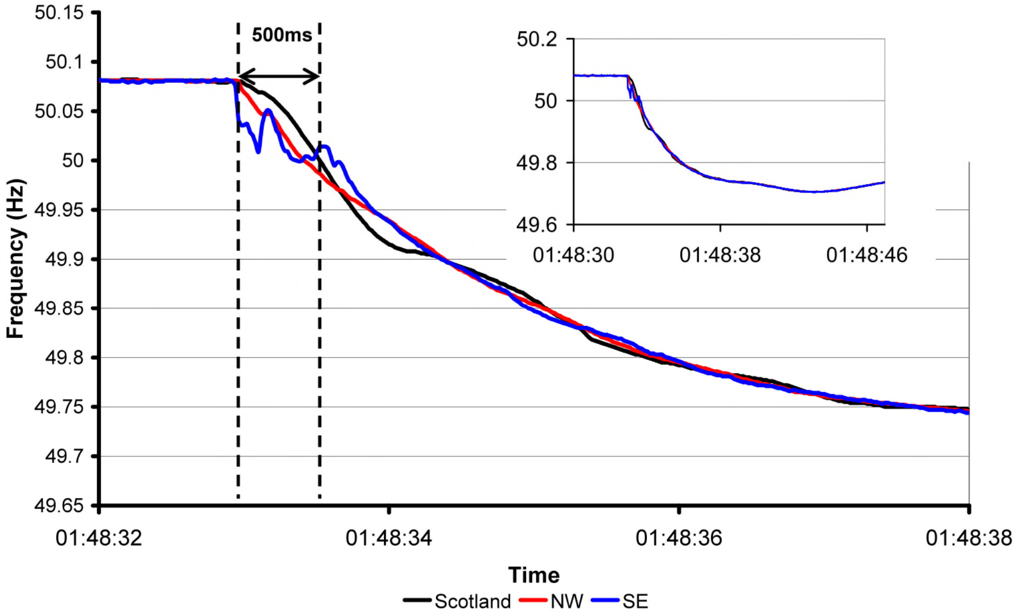

Figure 4: Frequency Measurements during a 1,000MW Instantaneous Infeed Loss on 28th September 2012

2.19 Figure 2 shows frequency measurements during an interconnector trip on the 28th September 2012. The total infeed loss was 1,000MW, and the maximum observed average rate of change of frequency over 500ms was 0.168Hzs^{-1}, with significant differences in the measurements taken at different locations as a result of differing phase angles (the minimum was 0.116Hzs^{-1}). There was also significant variation in rates of change of frequency during the first 500ms after the incident, particularly for the measurements taken closest to the source of the disturbance. These two features mean firstly, that there is some uncertainty over whether a RoCoF based protection relay will operate or not for a given average rate of change of frequency over the total system. Secondly, an automatic response mechanism intended to limit the rate of change of frequency (Synthetic Inertia for example) needs to be carefully designed to ensure it can respond appropriately.

2.20 National Grid currently takes actions to ensure that the present minimum RoCoF protection setting of 0.125Hzs^{-1} is not exceeded for secured infeed losses. The actions taken are either to pay for additional generators to run (these must be of a type which can limit the rate of change of frequency) or to limit the size of disturbance the system can be exposed to by reducing generator or interconnector output (or demand as the case may be).

2.21 Changes in generator or interconnector output are enacted by procuring Balancing Services. These are paid for by all parties who pay Balancing Services Use of System (BSUoS[3]) Charges and are ultimately part of an electricity consumer's bill. National Grid is incentivised to manage Balancing Services costs under the Balancing Services Incentive Scheme during an agreed term, typically up to 2 years. National Grid therefore receives a share of any benefit (or loss) in Balancing Services costs within a scheme period, but not over timescales beyond this.

2.22 Actions to limit RoCoF are currently required during light load periods for more than half the weekends and some weekdays in the year. The costs of these actions are estimated at £10m to £15m per annum in 2013/14 and 2014/15.

2.23 In the future, fast acting control systems such as those described as Synthetic Inertia, may provide an alternative solution but there is some uncertainty over whether this is feasible in the long term and little prospect of this offering a solution in the short term due to the speed of operation of Loss of Mains protection relays compared to the delivery of a controlled response like Synthetic Inertia.

2.24 Therefore, this report contains proposals to change RoCoF settings on Loss of Mains protection and set them at a sufficiently high value that they do not operate during a frequency deviation which is not the result of a power island being formed. Protection settings can only be changed if sufficient assurance can be provided over the safe operation of the distribution networks and user equipment. This means finding an appropriate generic RoCoF setting which when applied to a generator connection is high enough to prevent unwanted operation but still protects the DNO’s network and its users against the consequences of Loss of Mains.

[3] More information on BSUoS charges and who pays them can be found on the National Grid website here: http://www2.nationalgrid.com/bsuos/

3 Workgroup Discussion

3.1 This section of the Report describes how and why the Workgroup was established and is a record of discussions held between 26th October 2012 and 20th May 2013, and recommendations arising from these. These were first documented in Workgroup minutes and in the Workgroup Report[4].

3.2 In September 2010, National Grid presented paper pp10/21 to the Grid Code Review Panel (GCRP) entitled "Future Frequency Response Services"[5]. This paper summarised the issues associated with meeting the requirements for frequency response arising from significant changes to the generation background.

3.3 In October 2010, the Frequency Response Workgroup discussed the establishment of a Frequency Response Technical Subgroup (FRTSG) which would develop recommendations to address the issues discussed in pp10/21.

3.4 In November 2010, the FRTSG was established to complement and extend the technical work initiated by Frequency Response Workgroup. The FRTSG investigated the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background, and quantify future frequency response and synthetic inertial requirements.

3.5 The FRTSG published their conclusions in November 2011[6] which outlined proposals to develop frequency response which would act faster than the existing service definitions. The FRTSG recommended that further work was carried out to examine the effects of increasing rates of change of frequency and whether additional changes needed to be made to deal with these effectively. The simulations included in the FRTSG report, gave some indication to the potential change in the maximum rate of change of frequency settings which need to be considered in the context of the Loss of Mains protection deployed on distributed generation. As such, the FRTSG report was highlighted to the Distribution Code Review Panel for further consideration.

Terms of Reference

3.6 At the November 2011 GCRP, National Grid presented pp11/62[7] which took account of the FRTSG recommendations and proposed that a Workgroup was established to examine the expected behaviour of the Total System when subject to frequency changes during large disturbances, with particular focus on the rate of change of frequency. The purpose of the Workgroup was to assess whether the rates of change of frequency observed in the simulation work carried out in the FRTSG were plausible and would have an adverse impact on the resilience of the Total System.

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[4] Workgroup documents are available here: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0035/

[5] Future Frequency Response Services : http://www.nationalgrid.com/NR/rdonlyres/59119DD3-1A8D-4130-9FED-0A2E4B68C2D2/43089/pp_10_21FutureFrequencyResponseServices.pdf

[6] The Frequency Response Technical Sub-Group Report is available under the "Technical Sun-Group" tab at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0022/

[7] Draft Terms of Reference: http://www.nationalgrid.com/NR/rdonlyres/A948A721-F0A8-47E7-86E6-4406C62D3FA7/49869/pp11_62FCLDTSDraftToR.pdf

3.7 The Terms of Reference for the joint GCRP/DCRP *Frequency Changes during Large Disturbances and their Impact on the Total System* Workgroup were approved at the March 2012 GCRP and the March 2012 DCRP.

3.8 The Terms of Reference were updated in April 2013 and presented to the May 2013 GCRP. These revised Terms of Reference specified that the Workgroup would also investigate and quantify the risks to distribution networks and Users of desensitising Rate of Change of Frequency (RoCoF) protection on distributed generation. The Terms of Reference also proposed that the Workgroup would present proposals in two stages, with the first stage applicable to protection settings at generating stations with a registered capacity of 5MW or greater.

3.9 A copy of the amended Terms of Reference can be found in Annex 1 of this document.

Timescales

3.10 It was agreed that this Workgroup would report back to the GCRP and DCRP in July 2013. This report would present the findings from the first phase of work.

3.11 The Workgroup held a sequence of 7 meetings, the first on 26 October 2012 and the final one on 20 May 2013.

The Requirement for Loss of Mains Protection

3.12 The Workgroup reviewed the background to and the current need for Loss of Mains protection and concluded that Loss of Mains Protection was still required for the safety of people and protection of DNO and users' equipment.

3.13 The DNOs have statutory safety obligations stemming from the Energy Act 1983 and Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002.

3.14 Prior to the 1983 Energy Act, it was almost impossible to generate in parallel with the public supply. Engineering Recommendation G59 was first written to deal explicitly with the issues perceived at that time and was published in 1985.

3.15 Loss of Mains protection is designed to avoid problems for the following technical issues:

- Out of synchronism and phase re-closure;
- Inadvertent un earthed operation of an energised network;
- Effective protection; and
- Control of Voltage and Frequency.

Out of synchronism and phase re-closure

3.16 DNOs employ auto-reclose systems at all voltages. Typical dead times are between 3 seconds and 120 seconds but these can be as short as 1 second in some areas. After the dead time, the circuit will be automatically re-energized (though it may trip again if the fault is still present on the system). If the generator has continued to generate, then the system and the generator would be out of phase to an extent which cannot be predicted. This would impose a disturbance on both the system and the generator, with the impact dependent on the difference in phase angle and frequency between the system and the generator. For some generating plant this could cause severe damage and create a potentially dangerous situation. Generating plant which is not directly coupled to the system, such as inverter based plant, would not be subject to the same level of disturbance. For the purposes of this report, the term "out of phase re-closure" is used to describe this situation.

Earthing

3.17 DNO High Voltage systems are only earthed at one point, at the source transformer station. If a generator supports an electrical island within a DNO network, in most cases this would not include the source transformers for that network. The island would then be unearthed. This is potentially unsafe as an earth fault on the HV system would be undetected and could give rise to danger to persons. This is also not allowed under ESQCR 2002. It is this risk that makes Neutral Voltage Displacement protection appropriate in some cases.

Protection

3.18 DNO's protection against faults usually relies on high fault currents to operate. The source of the DNOs system has a low impedance. A generator supporting an island of the DNOs system will generally have a higher source impedance and may not provide sufficient current to operate the DNO's protection systems.

Control of Voltage and Frequency

3.19 A generator supplying an island within a DNO's network will be controlling (or not) the voltage and frequency of the island and, subsequently, the voltage and frequency provided to customers. If the generator has not been designed to maintain these within acceptable limits, customers' equipment might be damaged.

Summary of Requirement

3.20 For these reasons, power islands are not expected to be created unintentionally, and should not be allowed to form unintentionally. Under the current arrangements within Great Britain, having functioning Loss of Mains protection is the generator's responsibility.

3.21 Note that for system stability reasons, the over and under voltage, and the frequency protection settings in G59 and G83 are set well outside normal system operating ranges for voltage and frequency.

3.22 A variety of active and passive techniques can be applied to Loss of Mains protection. For example, reverse power detection is an effective Loss of Mains protection. However, if the generator wishes to export, this approach cannot be used.

3.23 The use of dedicated inter-tripping circuits is also very effective but incurs a relatively high capital and revenue cost and may not be cost effective for smaller distributed generation.

3.24 Traditionally within Great Britain, two methods for the detection of Loss of Mains, based on frequency measurements have been considered suitable, though they both suffer from nuisance tripping during faults on associated networks. For all its difficulties, Rate of Change of Frequency (RoCoF) protection has been believed to be the best compromise, though Vector Shift protection can be effective when used with non-synchronous generating units.

Types and Application of Loss of Mains Protection

3.25 Loss of Mains protection should not be necessary in sub-transmission networks (typically above 33kV in Great Britain) where there are not normally any embedded loads. Synchrocheck facilities would then ensure there is no risk of out of phase re-closure.

3.26 In lower voltage networks, where embedded loads are normally present, anti-islanding protection is necessary to prevent an islanded operation and broadly falls into two types:

- Voltage and/or frequency limit triggered or dedicated anti-islanding relays, such as RoCoF, or;
- Where the cost of communications links and additional relays can be justified, anti-islanding protection based on intertripping. Depending on the connection scheme, there are different solutions for the intertripping scheme:
  - Connection to a non-dedicated line: intertripping from the remote network licensee's circuit breaker;
  - Tapped connection: intertripping from the remote network licensee's circuit breakers;
  - Connection to a non-dedicated substation: intertripping from the local/remote line circuit breakers.

3.27 The operation of the anti-islanding protection must be faster than the auto-reclosing delay in order prevent a possible out of phase re-closure.

3.28 Some network Licensees take a view that anti-islanding protection requirements could potentially be subject to a carefully performed risk assessment exercise. In cases where the chance of forming a stable island is negligible (eg when minimum local load is significantly larger than the generator capacity) there could be scope for the exclusion from the requirement of dedicated anti-islanding protection.

3.29 There is a correlation between the requirement for the maximum time of islanding detection (0.5 seconds in most cases) and the settings of the auto-reclose schemes. The requirement could be less stringent in parts of the distribution system with much longer auto-reclose dead-time settings.

3.30 There are a variety of approaches regarding the detection of an islanding condition, with different techniques deployed in different countries. Even within the same country, different utilities approach the issue differently. Workgroup members suggested there may be a case for a higher degree of standardisation in anti-islanding protection requirements and laboratory tests.

3.31 Intertripping can be effective for some distributed generator connections where it is practicable and economic to monitor potential points of separation (generally larger generators with a higher capital cost).

International Experience

3.32 The Workgroup reviewed the International Council on Large Electric Systems (CIGRE) report on 'The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation' prepared by WG B5.34 issued in 2010. This report provides a useful review of the international practice on anti-islanding, below are some of the key points.

3.33 There are a variety of methods found in the technical literature but the results of the survey from the utility companies indicated in practice only a few are commonly used.

3.34 At sub-transmission level (110kV and above) there is currently no requirement for a dedicated anti-islanding protection apart from in Spain. At lower voltage levels (69kV and below) the requirement for anti-islanding protection is more common and the methods found in practice are be summarised below:

3.35 Voltage and/or frequency based protection is used in all countries. Where no other dedicated anti-islanding protection is installed, the voltage and frequency protection with fast operation fulfils this function.

3.36 RoCoF and Vector Shift are dedicated forms of passive anti-islanding protection for distribution system generator connections. Only six countries (UK, Australia, Austria, Belgium, Canada and Italy) were reported to use this form of protection.

3.37 Inter-tripping is also a common practice which although relatively expensive provides the best performance for anti-islanding generator protection where it is practicable to monitor all potential points of separation. This is used in Spain, France, Norway, Germany and also by some utilities in Great Britain.

3.38 Northern Ireland and the Republic of Ireland are in the process of reviewing the suitability of RoCoF protection for the purpose of Loss of Mains protection and they have proposed grid code amendments to respectively require or increase RoCoF withstand capabilities of generators.

3.39 It is worth noting that active methods are still not widely utilised due to power quality and reliability concerns, however, some methods are accepted in the US with inverter based generation.

Experience in Northern Ireland and the Republic of Ireland

3.40 The Workgroup examined the proposals under discussion in Ireland to change recommended rate of change settings for the purposes of Loss of Mains protection.

3.41 Recommendations had been developed as part of a package of changes. The Workgroup's understanding was that there was a reasonable consensus amongst the affected parties in Ireland that a change to Loss of Mains protection rate of change settings to $1Hzs^{-1}$ was acceptable. Some issues were unresolved where it was proposed that all generators should be able to withstand a rate of change of frequency up to the same level. The Workgroup understands that concerns focussed on existing generating plant as it was difficult and potentially costly to assess this type of plant's capability.[8]

Reported Events in Spain

3.42 The Workgroup also spent some time reviewing the information that was available concerning incidents observed within the electricity distribution network in Spain.

3.43 It was reported that on at least one occasion, an islanding event had occurred where an isolated section of network, fed solely by a large number of inverters driven by photovoltaics (PV), had remained energised and continued operating for some time.

3.44 This was contrary to the Workgroup's initial expectations, as it was presumed that given the lack of explicit control mechanisms, sustained operation in this configuration was extremely unlikely. However, the Workgroup concluded that it was credible for an island to be sustained in this manner, particularly if the island had an initial excess of generation and that generating equipment could shut down under protection operation until a balance of supply and demand was reached. The Workgroup agreed that it was important to consider such scenarios fully when developing recommendations for smaller generating plant.

Information Gathering

3.45 The Workgroup reviewed the information that was available concerning generation which had Loss of Mains protection fitted in accordance with ERG59 and ERG83.

3.46 For plant of capacity 5MW and larger, information had been gathered for under and over voltage, and under and over frequency protection settings changes initiated. A total of 4.3GW of generating capacity was captured by this list.

3.47 Data from the Feed in Tariff programme gave more information, particularly at the micro-generation scale. The dominant component here was PV at a capacity of 1.5GW and rising. The Workgroup noted that this type of generation was unlikely to make use of a separate Loss of Mains relay and would be protected using proprietary techniques built into the unit's control system. Where a rate of change was referenced, this would be $0.2Hzs^{-1}$ as a minimum. The Workgroup also noted that coincidence of periods of high solar output and times of low system inertia would be limited for the next 18 months at least.

3.48 Alternative information sources, including information gathered by the Energy Networks Association on distributed generation and DNO Long Term

[8] The Commission for Energy Regulation subsequently published its decision paper on 4 April 2014 approving a modification to change RoCoF settings to a $1.0Hzs^{-1}$ standard, subject to an industry implementation programme and further arrangements. The relevant documents can be found here:
http://www.cer.ie/document-detail/Rate-of-Change-of-Frequency-ROCOF-Modification-to-the-Grid-Code/260

Development Statements, suggested that a further 3 to 4GW of generation capacity of 5MW and smaller was connected to the networks.

3.49 The information available from the Digest of United Kingdom Energy Statistics (DUKES)[9] provided the most comprehensive view available to the Workgroup and the 2013 data is summarised in Table 3 below.

	Installed Capacity at the end of December (MW)	
Type	**2011**	**2012**
Coal	593	593
CCGT	2,481	2,520
Oil	448	409
Diesel Engines	134	134
OCGT	169	166
Conventional Thermal Gas	876	953
Hydro	643	654
Onshore Wind	2,680	3,633
Offshore Wind	598	598
Bioenergy	2,125	2,253
PV	991	1,700
Wave/Tidal	2	5
Other Fuels	554	556
Total	**12,295**	**14,174**

Table 3: Distributed Generation Capacity

3.50 The Workgroup facilitated further information gathering on the Loss of Mains protection settings currently applied to embedded generation by sending a structured questionnaire to embedded generators. Information had been requested by National Grid to aid its operational decision making process but that information was not readily available. The Workgroup therefore produced a template letter and questionnaire for DNOs to address to appropriate users to help ensure that a consistent dataset was produced. The results of this information gathering exercised are summarised in paragraph 5.13 of this document.

Stakeholder Engagement

3.51 The Workgroup concluded early in its discussions that a broad range of parties could potentially be impacted by changes that the Workgroup could ultimately recommend, and that there was a need to provide information to stakeholders on what changes could be made and how, prior to a formal consultation.

[9] The information presented is based on DUKES Table 5.13 and includes generation which is connected to the distribution network but captured by the Grid Code and would therefore not be expected to have Loss of Mains protection fitted. DUKES chapter 5 provides further explanation and can be found here:https://www.gov.uk/government/publications/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

3.52 An open letter highlighting the potential for change, and how to get involved in the decision making process, was published on the 24th January 2013[10]. The letter informed of a number of matters under discussion including likely ranges of RoCoF, how any decision to change requirements would be made and how protection setting changes would be implemented.

3.53 Workgroup members also hosted stakeholder workshops on the 25 April 2013 in Glasgow and the 8 May 2013 in London[11]. Further workshops were held as part of the consultation process discussed in Section 1 of this report.

Operational Actions

3.54 The Workgroup was briefed on the actions that National Grid was taking on a regular basis in order to prevent high rates of change of frequency impacting adversely on electricity consumers. These are intended to ensure that system frequency would remain stable following an instantaneous large infeed or off-take loss in line with National Grid's statutory obligations.

3.55 The actions described were a combination of re-configuring the generation pattern to increase system inertia (ie. keeping additional synchronous generation running at periods of low demand) and limiting the size of the maximum instantaneous loss. It was noted that not all 'instantaneous' losses occurred quickly enough to trigger RoCoF based protection.

3.56 National Grid can re-configure the generation pattern and limit the maximum secured instantaneous loss risk by procuring Balancing Services. These can either take the form of energy trades ahead of real-time, or services instructed within the Balancing Mechanism (from 90 minutes to real-time). Where there is a need to procure a significant volume of services, or to buy a particular type or combination of services, it can be efficient for National Grid to buy services, or options on services in advance. The latest forecast of the cost of these services is presented in Section 6 of this document.

3.57 The Workgroup was briefed on National Grid’s intentions to procure services to manage RoCoF risks through a tender process for Summer 2013. The DRIVe[12] tender (“Downward Regulation, Inertia and Volts”) would evaluate tenders to manage RoCoF, general frequency regulation and voltage control issues in an integrated tender and assessment process. The tender provided two potential benefits, the first being a more efficient way of buying the necessary services and the second being a means of establishing a value for inertia services to inform the development of new Balancing Services.

Work Phases

3.58 The Workgroup concluded that there was a strong case to review recommended RoCoF settings for Loss of Mains protection, and specify an associated withstand capability for generators and other affected equipment. In order to recommend a change, the Workgroup needed to establish how the

[10] A copy of the open letter is available here :
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=16945

[11] Slides from the London Workshop are available here:
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=16947

[12] For the commentary on DRIVe at the June 2013 Operational Forum (podcast at 28:00):
http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-system-operations/Operational-forum/Electricity-Ops-Forum-Archive-Slides-2013/

safety of the distribution networks and the equipment connected to it could be affected. An increase in setting would mean that it was less likely an island condition would be detected leading to a higher possibility of unsafe islanded operation which would have to be quantified and assessed.

3.59 In formulating its workplan, the Workgroup reviewed the work carried out to examine Neutral Voltage Displacement (NVD) requirements for connection to distribution networks as the risk assessment performed for the NVD work had similar features to the risk assessment that the Workgroup needed to perform (simulating network conditions and assessing how these impacted on individual risk for example). The Workgroup also considered the information that was available to it in terms of network design and behaviour, and generation type models.

3.60 The Workgroup further reviewed experience in modelling and assessing multiple generator infeeds, and in particular inverter dominated scenarios as could be expected in areas of high photovoltaic generation penetration. The Workgroup then debated how best to balance the need to make changes which would reduce the risk of a significant volume of unwanted distributed generation shutdowns occurring as quickly and efficiently as possible with the time taken to assess any risks thoroughly.

3.61 The Workgroup concluded that the work was best tackled in two phases. The first phase would use well-established modelling and assessment techniques which the group had confidence represented a reasonable worst case. This work would examine requirements for distributed generation plant which was 5MW or more in registered capacity (over 4GW of the generation capacity at risk). Smaller plant and lower voltage networks with many infeeds would be examined in a second phase of work which the Workgroup would scope out in its first phase deliverables. This re-phasing was presented to and agreed by the Grid Code Review Panel and the Distribution Code Review Panel in May and June 2013 respectively in the form of a revised Terms of Reference.

Impact of a Change to RoCoF Protection Setting Requirements

3.62 The revision to the Workgroup's Terms of Reference reduced the number of distributed generating stations impacted by any recommendation that the Workgroup makes relating to RoCoF settings in Loss of Mains protection.

3.63 The network users affected by the change fall into the 5MW and above registered capacity category. The Workgroup's estimate was that there were some 300 existing generating sites (of all generation technologies) in this category. The Workgroup estimated that less than 50% of these use RoCoF based protection. A change applied retrospectively would have to be implemented through a protection setting change, requiring competent engineering resource. The Workgroup estimated the cost of changing the relay setting alone (the act of planning the work and sending an engineer to site to change a relay setting) at up to £10k per site although members articulated a range of views over what the maximum cost could be.

3.64 Any change in settings will change the risk of an unsafe island condition being undetected which may need to be mitigated. Therefore, the Workgroup agreed that any change in settings needed to be assessed in terms of its impact to the safety of the distribution networks, its personnel and contractors, and to the safety of users' equipment. The group commissioned the University of Strathclyde to perform this assessment.

Probability and Risk Assessment

3.65 The University of Strathclyde performed a probability and risk assessment[13] under the supervision of the Workgroup and using input and scenario data provided by Workgroup members. The full report was provided as an Addendum to the Workgroup's consultation.

3.66 The assessment reviews and quantifies the probabilities and risks associated with proposed changes to RoCoF protection settings from the point of view of individuals' safety and equipment damage because of out of phase re-closure. This ascertains whether the risk of non-detection, under a range of possible proposed setting changes, is acceptable in light of the Health and Safety at Work act 1974 and other related utility policies and guidelines. To achieve this, experimental work was carried out to determine the potential islanding non-detection zone (NDZ) associated with different RoCoF settings.

3.67 The NDZ reflects the surplus or deficit power supplied by the Distributed Generator (DG) prior to islanding and is expressed as a ratio of this power to the DG rating. The experimental work used a hardware-in-the-loop testing approach which incorporates a DG interface relay commonly used in the UK. The NDZ data has been utilised by the developed risk assessment methodology to determine the probability of islanding non-detection and consequently the associated risks. In addition to the NDZ data, the methodology makes use of annual load profiles and statistics relating to incidences of loss of primary substation supplies.

3.68 Conclusions from the risk assessment are discussed below.

Probability and Risk Assessment Outcome

3.69 The group's probability and risk assessment examined the likelihood of an undetected island persisting for more than 3 seconds (as 3 seconds is the minimum auto-reclose time generally deployed currently). Eleven different settings options were applied and are listed in Table 4. Setting Options 9, 10 and 11 are representative of the current minimum settings.

3.70 The assessment derived a probability of an undetected islanding situation being feasible by combining historic data on the loss of grid supply to a primary substation and the number of synchronous generators in the range of 5MW to 50MW[14], with RoCoF based Loss of Mains protection, and capable of sustaining an island of equivalent size. For other generation technologies, it was assumed that they were not capable of sustaining an island using current control practice hence the probability of an island being sustained by wind generation alone, for example, was considered to be negligible.

3.71 This probability was then combined with an assessment of the load balance within any potential island based on measurements at sample sites and

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[13] The University of Strathclyde's report on the assessment is provided in Volume 4 of this report package

[14] The maximum size to which Loss of Mains protection can be applied under G59/2 by virtue of not being captured by the Grid Code

simulated generator behaviour in different voltage control modes (generators in this category would not operate in a frequency control mode although this may be considered desirable for future connections). The results were then fed into a G59 protection relay. If the relay did not operate within 3 seconds then an undetected island was deemed to exist.

Setting Option	RoCoF (Hzs^{-1})	Delay Setting[15]	Deadband Applied
1	0.5	0	No
2	0.5	0.5	No
3	1	0	No
4	1	0.5	No
5	0.5	0	Yes
6	0.5	0.5	Yes
7	1	0	Yes
8	1	0.5	Yes
9	0.12	0	No
10	0.13	0	No
11	0.2	0	No

Table 4: Setting Options

3.72 It was established that the sampling frequency of the historic measurements had a significant impact on results therefore the final results were based on data-streams with 1 data item per second. It was also established that the generator control mode had a significant impact. Where the generator could control the voltage in an island, there was greater dependency on the RoCoF element of the protection as the over or under voltage setting was less likely to be breached within 3 seconds.

3.73 Once the probability of an undetected island occurring had been established (termed P_{LOM}), this was be used to derive an estimate of the risks to network and user personnel and the public, by combining it with the risk of a person being exposed to network equipment in the undetected island (termed $P_{PER,E}$). The risk of harm to an individual from the distribution network was therefore estimated by combining the probability of an island being formed with the duration it would be sustained and the likelihood of a person being in a situation where they would come to harm (eg by electrocution). This was termed IR_e and captured the annual risk across the system of an island forming and a fatality occurring due to accidental contact with elements of the energised undetected island.[16]

[15] This column was labelled "Measurement Period" in the Workgroup's consultation
[16] A complete description of the calculation is provided in paragraph 3.1.3 of the risk assessment report provided as Volume 4 to this report

3.74 The highest calculated figure for IR_e was 2.37×10^{-9} for setting option 4 in P-V control mode which lies within the zone which is normally deemed acceptable (less than 10^{-6}). However, it should be noted that this is higher than the IR_e calculated for existing settings which was between 1.22×10^{-10} and 2.65×10^{-10} for the same conditions. The calculated values for IR_e are summarised in Table 5. Values of zero are shown where no undetected islands formed under the test conditions used in this assessment.

Setting Option	RoCoF (Hzs^{-1})	IR_e (P-V control mode)	IR_e (P-pf control mode)	
2	0.5	1.13×10^{-9}	1.43×10^{-13}	
4	1.0	2.37×10^{-9}	1.57×10^{-12}	
9	0.12	9.14×10^{-11}	0	Current G59 settings
10	0.13	1.22×10^{-10}	0	
11	0.2	2.65×10^{-10}	0	

Table 5: Summary of Individual Risk from energised elements

3.75 The annual rate of occurrence of out of phase of re-closure occurring after a desynchronised island formed amongst the population of generators under study was also estimated (N_{OA}). This was derived from the probability of an island being formed, under the assumption that auto-reclose schemes are in place in all locations and no facilities are in place to check for synchronism across the switches being closed (it was assumed that 20% of cases would be sufficiently in phase to have no impact).

3.76 The highest probability reported was 3.31×10^{-1} for the population of generators in power and voltage control mode under setting option 8 (a protection setting of $1.0Hzs^{-1}$, with a 0.5 second measuring period and a deadband applied). The probability was significantly lower for the generator population in power factor control mode at 4.56×10^{-4} (2.98×10^{-1} in voltage control mode) for the group's favoured setting of $1.0Hzs^{-1}$, with a 0.5 second measuring period and no deadband applied (setting option 4). The probability for a similar setting with $0.5Hzs^{-1}$ applied was 8.26×10^{-5} (setting option 2).

Setting Option	RoCoF (Hzs^{-1})	N_{OA} (P-V control mode)	N_{OA} (P-pf control mode)	
2	0.5	1.42×10^{-1}	8.26×10^{-5}	
4	1.0	2.98×10^{-1}	4.56×10^{-4}	
9	0.12	1.15×10^{-2}	0	Current G59 Settings
10	0.13	1.53×10^{-2}	0	
11	0.2	3.34×10^{-2}	0	

Table 6: Summary of Out-of-phase re-closure occurrence

3.77 An $IR_{OA,}$ figure, the annual risk of a single out-of-phase re-closure from the total population of generators, could be derived by combining the risk of the networks being sufficiently out of phase for harm to be caused, and the likelihood of personnel being put in danger. No figures were calculated for the individual and equipment risk from such an event as no information was available which would allow a generic value to be applied in the way that $P_{PER,E}$ was applied to the network associated risk calculation. However, interested parties can develop their own view based on the figures and methodology provided.

3.78 The risk assessment provides a view of risk for an average site. The risk at an individual site will vary depending on local conditions. The assessment allowed the group to identify the factors which would significantly increase the risk to a generator or person of an island being formed and sustained in an unsafe condition where RoCoF protection was deployed for Loss of Mains purposes:

(a) An increase in frequency control within the island;

(b) An increase in generator inertia;

(c) Generator operation in voltage control mode;

(d) Better matching of local demand to generation; and

(e) An increase in auto-reclose times.

3.79 The group also noted that an increase or decrease in the number of synchronous generators would increase or decrease the number of events expected to occur over the whole system.

3.80 The risk to an individual from the network (IR_e) would increase with the factors in paragraph 3.78 and with the time spent in proximity to the network and the likelihood of undertaking a dangerous activity.

3.81 The risk to generator equipment where RoCoF protection was deployed for loss of mains purposes would increase with the factors in paragraph 3.78 and decrease with:

(a) A decrease in time in LoM protection operation;

(b) Use of intertripping;

(c) Installation of synchrocheck facilities on auto-reclose schemes;

(d) Divergence in local load and generation capacity;

(e) Reduction in auto-reclose times where synchrocheck facilities or similar where installed; and

(f) An increase in auto-reclose times were no synchrocheck facilities or similar were installed.

3.82 The risk to personnel from an out of phase re-closure (IR_{OA}) is dependent on all the factors listed in paragraph 3.81 and increases with time spent near, and the proximity to equipment as well as the nature of the equipment and its protection mechanisms.

3.83 Estimated future rates of change of frequency are summarised in paragraph 2.11. The Workgroup concluded from these that a change of RoCoF settings to $1Hzs^{-1}$ was the preferred way forward as this was the only practicable way of ensuring substantial Balancing Services costs would not be incurred into the future. The group's proposals are therefore based on setting option 4.

3.84 The group noted that a setting of $0.5Hzs^{-1}$ achieved the same effect in the short term but that it was likely the setting would have to be revisited in a few years. If this option were preferred, the group would recommend setting option 2. This lower setting carried a risk that generators would incur a cost in making a further protection setting change at a later date as system conditions change.

3.85 The group's preference was therefore to develop proposals for a change to $1Hzs^{-1}$ (setting option 4) which would give it the opportunity to seek views on the validity of the assumptions deployed in its assessment through a formal consultation.

Workgroup View of Costs and Benefits

3.86 The Workgroup evaluated the costs and benefits of making a change to RoCoF protection settings to $1.0Hzs^{-1}$. The recommended changes apply to distributed generators within stations of registered capacity of 5MW and above.

3.87 The direct cost of not making a change to RoCoF settings on existing Loss of Mains protection is the cost of procuring Balancing Services to limit the rate of change of frequency for a secure infeed or offtake to the total system. A further effect is an increase in greenhouse gases due to the use of fossil-fuelled generation to provide inertia and the displacement of low carbon sources.

3.88 The annual incremental cost of procuring services to operate within the current criterion of $0.125Hzs^{-1}$ (which must be viewed in the context of other Balancing Services costs) was estimated at £10m per year with an upper value of £100m per year, rising into the future. It was also stated that costs will rise as larger infeed losses connect and as more wind and interconnector capacity connects to the system, the most significant increase being when losses of greater than 660MW (a large number of generators of this size are connected to the system) cannot be accommodated which is a risk from 2015 onwards. These estimates were revisited subsequently on the basis of consultation feedback as described in Section 1 of this Report.

3.89 The direct cost of implementing proposals for existing plant include the costs of making a protection setting change. These are estimated at less than £10k per distributed generator site with RoCoF based protection, with site numbers estimated at approximately half of the 300 generator sites. The Workgroup recognises that this work is as yet unplanned and will result in some unexpected inconvenience. For new connections, there is no incremental cost. The maximum cost of making a setting change is therefore estimated at £1.5m.

3.90 There are further costs in implementing the proposals to avoid the risk of damage to generator equipment. The Workgroup believes that these costs are negligible, provided appropriate assessment is undertaken and mitigation deployed. The Workgroup has assumed that there will be a cost in the assessment work in the order of £25k per site. Assuming 50% of synchronous generator sites have used RoCoF for Loss of Mains (estimated at approximately 90), the total cost would be £2.3m.

3.91 Mitigation measures for existing sites could cost up to £100k per site. In the absence of any cost recovery mechanism, this cost would be borne by owners of the affected generating plant. Assuming 20% of synchronous generator sites require action, mitigation measures would incur a cost of £3.7m.

3.92 The total implementation costs were therefore estimated at £7.5m.

3.93 The Workgroup concluded at this point that the benefits of the proposed change running at £10m per year and more outweighed the implementation costs of £7.5m by a significant margin. The Workgroup later took the opportunity to review its conclusions which are described in Section 5 of this Report.

Plan for Further Work

3.94 The Workgroup's Terms of Reference required the development of a plan to address further issues relating to RoCoF and Loss of Mains Protection. These require the Workgroup to develop proposals for consultation on any proposed changes drawing out the costs, benefits and risk of such a change to present to the GCRP and DCRP. An outline plan is provided below.

1. *Research the characteristics (numbers/types etc) of embedded generation of less than 5MW registered capacity including likely RoCoF withstand capabilities;*

    a. Review DNO information and survey additional sources as necessary;

2. *Investigating the characteristics of popular/likely inverter technology deployed, particularly in relation to RoCoF withstand capability and island stability;*

    a. Survey manufacturers and installers and survey additional sources as necessary;
    b. Assess the requirement to test equipment to verify its characteristics;

3. *Development of RoCoF withstand criteria for use in GB (as will be required by RfG 8.1(b));*

    a. Workgroup members to develop a view of generation technologies' inherent withstand capability;
    b. Review the final proposals (post consultation) from the July 2013 recommendations in respect of protection settings and the Total System requirement;
    c. Identify and asses any gaps in withstand capability;
    d. Assess the costs, benefits and risks of setting withstand capability requirements for future generators;
    e. Assess the costs, benefits and risks of setting withstand capability requirements for existing generators;

4. *Assessing or modelling the interaction of multiple generators in a DNO power island;*

    a. Review existing approaches to multi-machine dynamic simulation;
    b. Develop new approaches if required;

6. *Investigating and quantifying the risks to DNO networks and Users of desensitising RoCoF based protection on embedded generators of rated capacity of less than 5MW;*

a. Assess the costs, benefits and risks of requirements to de-sensitise RoCOF settings for future generators of registered capacity of less than 5MW;

7. *Analyse the merit of retrospective application of RoCoF criteria to existing embedded generation of less than 5MW (including comparison with similar programmes in Europe);*

   a. Review international experience of large retrospective change programmes;
   b. Assess the costs, benefits and risks of requirements to de-sensitise RoCoF settings for existing generators of registered capacity of less than 5MW;

8. *Consideration of issues relating to the continuing use of Vector Shift techniques;*

   a. Review the likely exposure of distributed generation to vector shifts in excess of recommended settings during system disturbances.

Workgroup Recommendations for Consultation

3.95 The Workgroup developed recommendations and asked that interested parties were consulted on:

(a) Proposals for a change to RoCoF settings on loss of mains protection for existing and distributed generators within stations of registered capacity of 5MW and above to 1Hzs^{-1} measured over half a second are taken forward to consultation with views sought on:

(i) the findings of the group's probability and risk assessment relating to the risk to individuals and the risk to equipment;

(ii) the acceptability of an increase in islanding risk in the context of existing network related risks; and

(iii) the assessment and mitigation measures that would be appropriate for synchronous generators to take to reduce the risk of out-of-synchronism re-closures that could otherwise present a hazard; and

(iv) The costs and benefits that the group have considered in determining the value of proceeding with a change.

(b) Completion of information gathering for distributed generation at stations of registered capacity of 5MW and larger;

(c) Implementation of protection setting changes within 18 months;

(d) Further, a site specific safety risk assessment in respect of distributed synchronous generators at stations of registered capacity of 5MW and larger prior to implementation of a protection setting change;

(e) To proceed with the workplan develop proposals for all distributed generation of less than 5MW in capacity and to develop proposals for a RoCoF withstand capability.

3.96 These recommendations formed the basis of the Industry Consultation described in the next section of this report and have subsequently been developed further in response to feedback received.

4 First Industry Consultation

4.1 Following the submission of the Frequency Changes due to Large System Disturbances Workgroup report to the July 2013 Grid Code Review Panel meeting and to an extraordinary Distribution Code Review Panel meeting also in July 2013, network Licensees consulted on the Workgroup's proposed solution to modify the Distribution Code and Engineering Recommendation G59 from 15 August to 27 September 2013. No changes were proposed to the Grid Code.

4.2 The proposed changes in the consultation, which applied to distributed generators at stations with a registered capacity of 5MW and above, were:

(a) that the minimum Rate of Change of Frequency settings specified for Loss of Mains protection on all new distributed generation, with a completion date on or after the date of implementation of these proposals, should be changed to $1Hzs^{-1}$ measured over half a second; and

(b) that the protection setting described in (a) should be applied to generation with RoCoF protection and a completion date prior to the implementation of these proposals.

4.3 The Workgroup's assessment indicated that the safety risk to network equipment and to personnel in proximity to network equipment (eg by electrocution) following implementation of the recommended change would lie within a range deemed acceptable by established practice.

4.4 The Workgroup's assessment indicated that the acceptability of the safety risk to synchronous generator equipment and to personnel in proximity to synchronous generator equipment following implementation of the recommended change was dependent on generator voltage control mode and local network conditions. The Workgroup recommended that site specific risk assessments should be undertaken prior to a protection setting change and notes that costs may be incurred in taking appropriate mitigating actions as a result of this assessment.

4.5 Both the Distribution Code Review Panel and the Grid Code Review Panel approved the Workgroup's programme for a second phase of work. The work programme was included in the consultation to give interested parties sight of how the Workgroup planned to tackle the remaining items in its terms of reference. The second phase aims to develop proposed minimum RoCoF values that equipment will need to withstand and protection settings for distributed generators with a registered capacity of less than 5MW.

4.6 A further two workshops were organised to help interested parties participate in the consultation. The first of these was in London on 9 September 2013 and the second in Glasgow on 16 September 2013[17]. The DNO's made contact with their respective customers to highlight the issues raised in the consultation and to publicise the workshops. A record of the contacts made is provided in Volume 5 of this report. Volume 5 contains confidential contact information and

[17] Workshop slides are available here: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=28641

has therefore not been published, but has been provided separately to the Authority.

4.7 Responses were invited to the following questions:

(a) Do you agree it is necessary to change RoCoF settings on Loss of Mains protection for new and existing distributed generators within stations of registered capacity of 5MW and above? If not, what alternative actions would you recommend and why?

(b) Do you agree that $1Hzs^{-1}$ measured over half a second is an appropriate RoCoF setting? If not, what alternative RoCoF setting would you recommend and why?

(c) Are you responsible for distributed generation which will be affected by these proposals? How much of your generating capacity is affected?

(d) Do you agree with the Workgroup's probability and risk assessment conclusions?

(e) Do you agree with the Workgroup's approach to the probability and risk assessment relating to the risk to individuals and the risk to equipment as a consequence of a change to RoCoF settings?

(f) What, if any, additional features should be added to the Workgroup's probability and risk assessment relating to the risk to individuals and the risk to equipment as a consequence of a change to RoCoF settings? How can these be quantified and by whom?

(g) Do you have specific information relating the risks to generators of out of phase re-closure which would improve upon the Workgroup's assessment?

(h) What assessment and mitigation measures would it be appropriate for synchronous generators to take to reduce the risk of out of phase re-closures that could otherwise present a hazard?

(i) What is your view of the costs that the Workgroup presented for implementing its proposals? Has the Workgroup over or under-estimated costs? Has the Workgroup missed some items or included costs that shouldn't be considered?

(j) What is your view of the potential Balancing Services costs that National Grid estimates can be saved by implementing the Workgroup's proposals? Has it over or under-estimated costs? Has National Grid missed some items or included costs that shouldn't be considered?

(k) Do you believe that 18 months is an appropriate period for protection setting changes to be implemented?

4.8 Table 7 below provides an overview of the 18 responses received. Each response was graded on whether it appeared to be supportive or not by the Licensees. Copies of the responses are included in a separate Volume.

Ref	Company	Supportive
GC0035 - CR-01	Energy UK	Yes
GC0035 - CR-02	Northern Powergrid	Yes
GC0035 - CR-03	SSE Generation Ltd & SSE Renewable UK Ltd	Mixed
GC0035 - CR-04	Deep Sea Electronics Plc	Yes
GC0035 - CR-05	Scottish Power Generation	Yes
GC0035 - CR-06	EDF Energy	Yes
GC0035 - CR-07	DNV KEMA	Yes
GC0035 - CR-08	London Underground	Yes
GC0035 - CR-09	Good Energy Ltd	Yes
GC0035 - CR-10	RES Ltd	Yes
GC0035 - CR-11	RenewableUK	Yes
GC0035 - CR-12	RWE	No
GC0035 - CR-13	E.ON UK	No
GC0035 -CR-14	UK Demand Response Association	Mixed
GC0035-CR-15	Enercon	Yes
GC0035 – CR-16	Trinity Mirror Printing	Yes
GC0035 - CR-17	Confidential	No
GC0035 - CR-18	Wykes Engineering Ltd	Withdrawn

Table 7: First Industry Consultation Responses

5 Post Consultation Review

5.1 The Workgroup reviewed consultation responses in two meetings, in September and October 2013. As a result of these discussions, the group developed its view of the material issues that needed to be addressed as a result of questions and concerns raised. These were:

(a) Feedback on the impact and costs of making a protection setting change;

(b) The implementation period for a change and resulting consideration of how the proposed requirements would be introduced for generators commissioning in the period prior to the expected setting change;

(c) Requests for further exploration of the potential Balancing Services costs savings the Workgroup believed were achievable;

(d) The case for change based on the balance of benefits in terms of Balancing Services costs savings and the costs to implement a change;

(e) Clarity over the legal drafting with respect to relay settings and the use of the expression "measurement period";

(f) Funding for the work required to make the change;

(g) Rate of Change of Frequency withstand requirements; and

(h) Concerns over future frequency quality.

5.2 The Workgroup reviewed its position on these aspects of its proposals. Its conclusions are summarised below.

The Impact and Costs of Making a Protection Setting Change

5.3 Many of the consultation respondents supported the Workgroup's proposal to change recommend RoCoF settings for Loss of Mains protection to $1Hzs^{-1}$ on distributed generators within stations of 5MW capacity or greater. However, a significant number of respondents raised some concerns over the application of this generic setting when applied to synchronous generators.

5.4 The Workgroup's original risk assessment had highlighted that the type of generation most affected by a protection setting change was a synchronous generator. The risk assessment indicated that the level of risk expressed in number of out-of-phase re-closure events per year for the overall population of synchronous generators in P-pf control mode, was $4.56x10^{-4}$ at a setting of $1.0Hzs^{-1}$ and $8.26x10^{-5}$ at a setting of $0.5Hzs^{-1}$. This difference in calculated general risk and the feedback from respondents suggests that the calculated out-of-phase re-closure risk to synchronous generators is materially different at a higher setting. Under the Workgroup's recommendations, the increased risk has to be managed to an acceptable level but a cost is incurred in assessing and managing that risk.

5.5 The Workgroup was mindful that existing generators were likely to suffer the highest costs and inconvenience in assessing the impact of a setting change. The required risk assessment could necessitate a revisit of the plant design and a new dialogue with the host network Licensees which had not previously been foreseen.

5.6 It was also recognised that some existing plant would have a limited lifetime, meaning that cost of a change had to be recovered over a shorter period. It was possible the plant would have ceased operating before system conditions meant that a $0.5Hzs^{-1}$ limit could be reached. In addition, existing generator's ability to withstand disturbances above $0.5Hzs^{-1}$ is likely to be difficult to establish.

5.7 The Workgroup acknowledged that new generators were likely to be able to deal with new guidance more easily. Also, under the presumption that new plant would operate for a number of years into the future it was significantly more likely that a $0.5Hzs^{-1}$ limit could be reached in their operating life.

5.8 The Workgroup therefore concluded that it was beneficial to specify a lower setting for existing synchronous generators as this reduced the cost burden to the affected parties and significantly reduced the risk of individual parties incurring high costs outside their control. In addition, the Workgroup could be assured that its estimate of implementation costs remained sufficiently representative for network Licensees to recommend that its proposals are implemented.

5.9 With respect to non-synchronous generators, both the consultation responses and the Workgroup's risk assessment suggested that the costs of implementing the proposed protection setting of $1.0Hzs^{-1}$ for non-synchronous generators were no different for a lower setting. The Workgroup therefore agreed that its recommended setting of $1.0Hzs^{-1}$ remained appropriate.

Implementation Period

5.10 A number of respondents suggested that more time should be allowed for generators to make protection setting changes. Workgroup members acknowledged this concern and expressed a preference to extend the period from its original proposal. However, the group also noted that delays in implementation had a proportionate and growing cost. The Workgroup agreed to fix an implementation date of 1 July 2016 (an extension on its original 18 month implementation period and assuming the Distribution Code change is introduced on 1 July 2014).

5.11 The Workgroup also responded to concerns about the criteria applicable to existing plant, and plant commissioning during the implementation period, by setting clear implementation dates in its redrafted legal text.

Cost Benefit Analysis

5.12 Some consultation responses questioned whether the benefits delivered by the proposed change outweighed the costs of making a change to a sufficient extent to justify a change. The Workgroup agreed that it was important that the case for change was robust and that any uncertainties in the costs and savings used in its assessment were dealt with appropriately. For the purposes of the proposals presented in this document, this meant that the estimated costs of implementation should be set at the Workgroup's view of the highest credible costs, whilst the benefits delivered by a change should be set at the Workgroup's view of the lowest credible savings.

Implementation Costs

5.13 The most recent results of the DNO information gathering exercise on Loss of Mains protection types and settings are summarised in Table 8. This information is required to quantify the potential costs of making a change by providing a view of the number of affected sites and has been updated since the second consultation was published.

5.14 For the purposes of evaluating the potential cost of changing RoCoF settings certain worst-case assumptions were applied where exact settings were not known. For example, sites where the protection technique and setting were not available at the time this report was written, it has been assumed that all of these use RoCoF techniques and have applied a setting that would need to be changed. In practice, only a proportion of these sites would need to apply a change. Information was not available for all distributed generators, but the information presented was considered sufficiently representative by the Workgroup with over 90% coverage achieved.

	No Action		Setting Change Only		Setting Change & Risk Assessment		Total	
LoM Type and Setting	**Capacity (MW)**	**Sites**	**Capacity (MW)**	**Sites**	**Capacity (MW)**	**Sites**	**Capacity (MW)**	**Sites**
Non-sync RoCoF <0.2Hzs^{-1}			232	16			232	16
Non-sync RoCoF >=0.2Hzs^{-1}			145	15			145	15
Non-sync >=1.0Hzs^{-1}	328	14					328	14
Sync RoCoF <0.2Hzs^{-1}					707	36	707	36
Sync RoCoF >=0.2Hzs^{-1}					317	21	317	21
Sync RoCoF >=0.5Hz s^{-1}	147	13					147	13
Unknown (Non-sync)			293	15			293	15
Unknown (Sync)					1350	75	1350	75
I/T	445	15					445	15
V/S (Sync)	204	11					204	11
V/S (Non-sync)	665	60					665	60
Other	334	13					334	13
Grand Total	**2124**	**{a} 126**	**670**	**{b} 46**	**2375**	**{c} 132**	**5168**	**{d} 304**

Table 8: Current status of Distributed Generators Loss of Mains Protection

5.15 The survey data covers 304 sites and indicates that a maximum of 178 sites (the sum of the quantities in {b} and {c} of Table 8) would require a protection setting change under the Workgroup's revised proposal. As described above, the 178 sites include those sites where the protection technique is "unknown" at the present time. Of the 178 sites where a protection setting change could be required, a maximum of 132 are synchronous generators and could therefore require a risk assessment. The Workgroup assumed that 40% of these sites could require mitigation measures, a total of 53 individual sites based on the survey data. At least 126 ({a}) sites of the total of 304 surveyed ({d}) are not impacted by the change.

5.16 The Workgroup reconsidered its initial view of average implementation costs per site in the light of consultation responses. Whilst the workgroup recognised that there would be a significant variation across sites, it concluded that its initial estimates were still valid for use in its assessment.

5.17 Estimating implementation costs using the Workgroup's view of costs per site and the latest view of affected sites based on the information presented in Table 8 gives a cost of £10.36m. The cost is made up of three categories of work which are explained below and shown in Table 9.

5.18 The first of these work categories is the act of making a protection setting change which necessitates a site visit by an appropriately authorised person and the associated work. For the purposes of this assessment, these costs were estimated at £10k per site and would be incurred at synchronous and non-synchronous generator sites where RoCoF protection techniques are used.

5.19 The second category of work is the site specific risk assessment carried out at all synchronous generator sites with RoCoF protection (up to 132 sites). The site specific risk assessment would need to be performed by an appropriately qualified engineer using information from the generator concerned and the host network company at an estimated cost of £25k per site.

5.20 The third category of works is mitigation. This would be necessary in circumstances where the site specific risk assessment indicated a higher than acceptable risk. Examples of mitigation are changes to auto-reclose schemes or use of alternative protection methods. The Workgroup estimates for the purposes of this assessment that mitigation could be required at 40% of sites, at an average cost of £100k per site. Note that the £100k would be incurred in addition to the cost of a protection setting change and the cost of a risk assessment.

	Protection Setting Change	Site Specific Risk Assessment	Mitigation	Total Cost
Max Number of Sites	178	132	53	
Cost Per Site	.010	.025	.100	
Sum (£m)	**1.78**	**3.30**	**5.28**	**10.36**

Table 9: Implementation Costs

5.21 The network Licensees recommend that a total cost of £11m should be referenced in the assessment of costs versus benefits to capture any residual uncertainty. This is spread over the recommended two year implementation period.

Balancing Services Cost Savings

5.22 A number of responses suggested that more information was needed concerning the Balancing Services Cost savings that the proposed change would facilitate. Some responses questioned the rate at which costs could grow and sought a clearer view of how these evolve over time. Respondents indicated that this explanation was necessary to confirm that action was required at this time.

5.23 The Workgroup agreed that it was necessary to clearly identify the costs that would be reduced if its recommendations were implemented and therefore sought to expand its forecast of cost savings. Consequently, National Grid extended its model to incorporate additional features and an extended period as is described below.

5.24 The Workgroup proceeded to re-evaluate its estimate of the savings that could be achieved (by making a RoCoF protection setting change) by examining the potential reduction in Balancing Services Costs using National Grid's extended model. The Workgroup agreed the model needed to be based on scenarios and assumption which provided a conservative view of forecast costs. The model had the following features:

(a) Balancing Services Costs for managing the total system within the existing RoCoF limits were forecast for the period 2013/14 to 2025/26 (noting that carbon costs were not modelled explicitly);

(b) Generation patterns were based on 2012 and 2013 metered generation;

(c) Non-synchronous generation capacity was scaled each year in accordance with National Grid's "Slow Progression" scenario;

(d) No demand growth or reduction was included;

(e) The effect of increased Solar PV capacity (an increase in non-synchronous generation) was not included.

5.25 The model was used to derive three views of future costs. The first of these, a "Best" view assumes:

(a) National Grid's access to energy trading solutions to manage interconnector flows is maintained,

(b) Synchronous plant becomes more flexible over time (operating at lower loads than currently) and

(c) a reduced output from wind.

5.26 The "Central" view assumes average trading ability and increasing synchronous plant flexibility.

5.27 The "Worst" view assumes average energy trading capability, no development in plant flexibility, windier conditions and earlier connection of new larger potential infeed losses.

5.28 The three views were ultimately combined using a 30/60/10 weighting ("Best" first) to derive a single cost per year.

5.29 The first step in producing each view was to estimate the Balancing Services cost of managing to the current limit of 0.125Hzs^{-1} in current and future years. This cost is made up of the costs of curtailing infeed losses where it is efficient to do so and the cost of synchronising additional generation on occasions where that is the optimal action to take. The total forecast cost was then estimated, taking into account the effect of planned new infeed loss risks.

5.30 These total costs were then scaled downwards to estimate the value of making a RoCoF protection setting change on distributed generators at stations of capacity 5MW and above. The costs are scaled down because the circumstances where RoCoF protection on generators at stations of capacity less than 5MW can be neglected arise from a subset of the infeed and offtake loss risks that need to be catered for in any given year. It is only when all RoCoF settings are raised (or shown not to present a risk) that the full potential savings are achievable. The results of the Balancing Services cost projection exercise are summarised in Annex 3 of this document.

Comparison of Costs and Savings

5.31 Having reviewed its view of the implementation costs, implementation period and Balancing Services costs savings associated with its revised proposal, the Workgroup compared the two assuming that implementation costs were spread evenly across two years. The analysis indicates break even occurs in the third year, with savings of £14.9m achieved at the end of the third year when compared to an implementation cost of £11m, the cost as recommended in paragraph 5.21. Note that the savings quoted for 2016/17 have been scaled in accordance with a July 2016 implementation date.

RoCoF Balancing Services Cost Projection vs Cost of Protection Change

All Costs £m (2013/14 prices)

		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Total Cost Of Managing RoCoF constraint	Best	9.0	10.4	29.3	31.1	149.8	146.1	182.3	328.4
	Central	9.6	11.4	56.1	59.5	184.2	294.6	364.9	390.2
	Worst	10.4	12.4	60.8	184.0	314.8	328.0	428.2	607.6
Total Cost if Settings are Raised for >=5MW plant	Best	8.1	9.3	26.1	27.7	146.0	142.9	176.8	322.3
	Central	8.6	10.2	50.3	53.4	177.4	289.1	355.5	379.8
	Worst	9.4	11.2	55.0	177.8	307.9	320.2	415.3	593.2
Scenario Weighting	Best	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Central	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Worst	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

All Costs £m (2013/14 prices)

Total Balancing Services Cost Summary

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Total Cost	9.5	11.2	48.5	63.5	187.0	253.4	316.5	393.4
Total Cost if Settings are Raised for >=5MW plant	8.5	10.1	43.5	58.1	181.0	248.4	307.9	383.9

Total Achievable Savings

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Cumulative Savings (>=5MW): 2016 Completion				4.0	9.9	14.9	23.5	33.0

Implementation Cost

		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Generators at Stations of >=5MW	Cost		5.5	5.5					
	Cumulative Cost		5.5	11.0	11.0	11.0	11.0	11.0	11.0

Table 10: Costs and Savings

5.32 The Workgroup also discussed the significant potential savings that could be achieved if a protection setting change could be implemented (or proven not to be necessary, because tests proved that the Loss of Mains protection techniques used would not activates for system RoCOF events of $1Hzs^{-1}$ of at least 500ms when tested for example) for all distributed generation. It was agreed that these savings needed to be discussed in the Workgroup's programme of further work and were not directly relevant to the proposal under consideration. The group also discussed the undesirable consequences of having to revisit settings at a later date which had been raised as a concern in the Workgroup's industry workshops.

Frequency Measurement Period

5.33 Consultation Respondents raised concerns about how the required protection setting had been expressed by the Workgroup. Concerns centred on the description of the measurement period.

5.34 The Workgroup sought the views of a wider range of protection relay experts and developed revised drafting. In accordance with expert advice, a new version of legal text has been drafted which specifies a 'time delay' as this is the terminology used in RoCoF relay setting parameters.

Funding

5.35 A number of Consultation respondents highlighted that the savings that could be achieved by implementing the Workgroup's proposals were in Balancing Services Costs, but the costs of implementation were incurred by parties that would get no direct benefit. Respondents asked that consideration should be given to the creation of specific funding arrangements to facilitate the required changes.

5.36 Workgroup members expressed a variety of views and noted that provision of funding to the parties who would incur a cost could accelerate a change and would make it easier to implement. The Workgroup concluded however that it could not resolve this question within its terms of reference but noted that generally accepted principle of code changes to date is that costs should lie where they fall and the purpose of cost benefit analysis is to determine if the new regime is reasonable and proportionate.

Withstand Capability

5.37 A significant number of consultation respondents highlighted that rates of change of frequency up to $1.0Hzs^{-1}$ could have a detrimental effect on synchronous generators in particular. Respondents raised the concern that the Workgroup's proposals would mean that synchronous generators could be put at risk.

5.38 The Workgroup noted the concerns raised and spent some time re-capping RoCoF withstand issues. In particular it reviewed developments in Northern Ireland and the Republic of Ireland where many of these concerns had been raised and evaluated but, at the time of the workgroup's considerations, no decisions had been made[18]. The Workgroup also noted that the specified RoCoF protection setting and the parameter used to specify the ability to continue to operate during a disturbance were not necessarily the same.

5.39 The Workgroup acknowledged the concerns raised and intends to account for these in its next phase of work. This includes developing a definition for withstand capability and an appropriate way of specifying the requirement.

[18] See footnote 8

Frequency Quality

5.40 A number of consultation responses contained concerns that the proposed change would be detrimental to frequency quality. The Workgroup acknowledges that there is a risk that frequency quality may deteriorate in the future and that it may be necessary to take appropriate action to manage this. However, the Workgroup did not agree that its proposals would lead directly to a deterioration in frequency quality and noted that implementation of its proposals would reduce the risk of severe frequency deviations occurring.

6 Second Industry Consultation

6.1 Network Licensees consulted a revised set of proposals to modify Distribution Code and Engineering Recommendation G59 including revised legal text. The consultation was published on 14 March 2015. Views were invited upon consultation to be received by 04 April 2014.

6.2 The consultation presented revised proposals that:

(a) The following requirements should be implemented by changing the Distribution Code and Engineering Recommendation G59 such that for distributed generators at stations with a registered capacity of 5MW and above, the Rate of Change of Frequency settings specified for Loss of Mains protection will be:

(i) $1Hzs^{-1}$, with a delay setting of half a second, on all new distributed generation, with a commissioning date on or after 1 July 2016;

(ii) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016;

(iii) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned on or after 1 July 2014;

(iv) $0.5Hzs^{-1}$ with a delay setting of half a second, on all synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016; and

(v) $0.5Hzs^{-1}$ with a delay setting of half a second, on all synchronous distributed generation commissioned on or after 1 July 2014 but before 1 July 2016.

(b) The Workgroup's assessment indicates that the safety risk to network equipment and to personnel in proximity to network equipment (eg by electrocution) following implementation of the recommended change would lie within a range deemed acceptable by established practice.

(c) The Workgroup's assessment indicates that the acceptability of the safety risk to synchronous generator equipment and to personnel in proximity to synchronous generator equipment following implementation of the recommended change is dependent on generator voltage control mode and local network conditions. Site specific risk assessments are therefore recommended prior to a protection setting change at synchronous generator sites. Assessment guidance is included in the proposed text for Engineering Recommendation G59.

Consultation Responses

6.3 Responses were invited to the following questions:

(a) Does the proposed Distribution Code and Engineering Recommendation G59 drafting implement the Workgroup's recommendations for Loss of Mains Protection settings effectively and unambiguously?

(b) Does the proposed Distribution Code and Engineering Recommendation G59 drafting set out implementation timescales for the different categories of distributed generation clearly and unambiguously?

(c) Does the proposed Engineering Recommendation G59 drafting capture the Workgroup's risk assessment guidance effectively and unambiguously?

(d) Does the informative text in Section 10 of the Engineering Recommendation G59 drafting provide useful guidance to affected parties?

(e) Do you believe the proposals better facilitate the Distribution Code objectives? Please include your reasoning.

6.4 Table 11 below provides an overview of the 11 responses received. Each response was graded on whether it appeared to be supportive or not by the Licensees. Copies of the responses are included in a separate Volume.

Ref	Company	Supportive
GC0035 (2) - CR-01	London Underground	Yes
GC0035 (2) - CR-02	Northern Powergrid	Yes
GC0035 (2) - CR-03	EDF Energy	Yes
GC0035 (2) - CR-04	RWE	No
GC0035 (2) - CR-05	Scottish Power Generation	Yes (subject to amendments)
GC0035 (2) - CR-06	E.ON UK	Yes
GC0035 (2) - CR-07	SSE Generation Ltd & SSE Renewable UK Ltd	Mixed
GC0035 (2) - CR-08	ESB	Mixed
GC0035 (2) - CR-09	Energy UK	Yes
GC0035 (2) - CR-10	Electricity North West	Yes
GC0035 (2) - CR-11	Western Power Distribution	Yes

Table 11: Second Industry Consultation Responses

6.5 Two responses highlighted the one of the dates in the RoCoF settings table in the legal text for both the Distribution Code and Engineering Recommendation G59 had been written as "01/04/14" but should have been written as "01/07/14" to match the recommended implementation timescales. This correction has been made in the final legal text for both the Distribution Code and Engineering Recommendation G59.

6.6 Two responses also suggested that the legal text could be improved by expressing the content of the "Ω" footnote directly in the table. Licensees disagree that this suggestion makes the text clearer. The suggested change has not been adopted in the final legal text for both the Distribution Code and Engineering Recommendation G59.

6.7 A number of suggestions were given to improve the draft text in Engineering Recommendation G59 which have been adopted. The suggested phrase "as reasonably requested by the generator" has been added to paragraph 10.3.18 as this clarifies the process to be followed. 13.11.2 has been changed to remove the reference to "failed" loss of mains protection". The phrase "and also any additional information required" has been added.

6.8 One response suggested that the proposals should be assessed as having a neutral effect on Distribution Code objectives and that they were better aligned with Grid Code objectives to promote the development of an efficient, co-ordinated and economical system. Licensees acknowledge that the proposals strongly align with Grid Code objectives but remain of the view that the proposals are positive with respect to Distribution Code objectives. An alternative approach would be to modify the Grid Code to put obligations on DNOs in regard of RoCoF protection, which the DNOs would have to reflect in the Distribution Code anyway, ie the same ultimate solution. The WG and the network Licensees do not see such an approach as an efficient response to the issue.

6.9 One respondent suggested that the requirements be amended to recommend a setting of $0.5Hzs^{-1}$ for all embedded synchronous generators between 5MW and 50MW, whilst noting the $1Hzs^{-1}$ is preferable but also that a risk assessment may indicate a more sensitive setting of $0.125Hzs^{-1}$. Licensees recognise that some parties have concerns of over the proposed settings and that costs will be incurred in implementing them. However, Licensees remain of the view that the benefits of making the change as proposed outweigh the costs and risks and that the take appropriate consideration of different plant characteristics and situations. One other respondent suggested that a simple and clear single setting of $1Hzs^{-1}$ should be applied to all generating plant.

6.10 One respondent expressed concern that the proposals had not dealt with RoCoF withstand requirements. The Workgroup’s proposals deal with the system risk presented by inappropriate LoM protections settings. The risk to the system and individual plant of a higher RoCoF is a separate though related issue. The Licensees intend for withstand requirements to be addressed in the Workgroup's programme of further work and are of the view that protection settings for Loss of Mains protection and generating plant's physical capability can be dealt with separately but recognise there is a relationship between the two.

6.11 Four responses suggested that it was unreasonable to ask parties to make a change from which other parties would benefits and asked that further consideration is given to funding the proposed changes. Licensees recognise that a number of parties share this view and have expressed it in responses to two consultations. However, changes to funding and charging arrangements are outside the scope of this Report.

6.12 The final proposals in Section 7 of this Report are therefore that same as those in the second consultation document, with the exception of changes to the legal text describe in paragraphs 6.6 and 6.7 above.

7 Solution

7.1 The following requirements should be implemented by changing the Distribution Code and Engineering Recommendation G59 such that for distributed generators at stations with a registered capacity of 5MW and above, the Rate of Change of Frequency settings specified for Loss of Mains protection will be:

(a) $1Hzs^{-1}$, with a delay setting of half a second, on all new distributed generation, with a commissioning date on or after 1 July 2016;

(b) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016;

(c) $1Hzs^{-1}$, with a delay setting of half a second, on all non-synchronous distributed generation commissioned on or after 1 July 2014;

(d) $0.5Hzs^{-1}$, with a delay setting of half a second, on all synchronous distributed generation commissioned before 1 July 2014, by 1 July 2016; and

(e) $0.5Hzs^{-1}$, with a delay setting of half a second, on all synchronous distributed generation commissioned on or after 1 July 2014 but before 1 July 2016.

7.2 The Workgroup's assessment indicates that the safety risk to network equipment and to personnel in proximity to network equipment (eg by electrocution) following implementation of the recommended change would lie within a range deemed acceptable by established practice.

7.3 The Workgroup's assessment indicates that the acceptability of the safety risk to synchronous generator equipment and to personnel in proximity to synchronous generator equipment following implementation of the recommended change is dependent on generator voltage control mode and local network conditions. Site specific risk assessments are therefore recommended prior to a protection setting change at synchronous generator sites. Assessment guidance is included in the proposed text for Engineering Recommendation G59.

8 Impact and Assessment

8.1 The proposals in this document amend the Distribution Planning and Connection Code section of the Distribution Code.

8.2 The proposals in this document also amend Section 10 of Engineering Recommendation G59 and add a new section 13.11 to the Appendices. Housekeeping changes are recommended to paragraph 9.8 and 10.3.2.

8.3 The text required to give effect to the proposals is contained in Annex 2 of this document.

8.4 There are no changes to the Grid Code proposed in this report.

Impact on Safety of the Distribution Networks

8.5 The generic risk assessment performed by the Workgroup indicates that the risk to individuals from contact with the energised elements of an undetected distribution network island, expressed as an annual risk of occurrence across the networks, remains within the range considered acceptable. The probability of a safety hazard was evaluated at significantly less than $1x10^{-6}$.

8.6 The Individual Risk values derived using the Workgroup's generic risk assessment are summarised in Table 12 below.

Setting Option	RoCoF (Hzs^{-1})	IR_e (P-V control mode)	IR_e (P-pf control mode)	
2	0.5	$1.13x10^{-9}$	$1.43x10^{-13}$	
4	1.0	$2.37x10^{-9}$	$1.57x10^{-12}$	
9	0.12	$9.14x10^{-11}$	0	Current G59 settings
10	0.13	$1.22x10^{-10}$	0	
11	0.2	$2.65x10^{-10}$	0	

Table 12: Summary of Individual Risk from energised elements[19]

Impact on Distribution Network Users

8.7 The proposed modification will require existing distributed generators at power stations with a registered capacity of 5MW or greater with RoCoF based Loss of Mains protection to apply new settings. New generators of this type will apply new settings as part of their planned construction and commissioning of their new plant.

8.8 The change in individual risk from contact with energised elements of an undetected distribution network island discussed in paragraph 8.5 also applies to user equipment connected to the islands, and remains within acceptable levels.

8.9 For synchronous generators at power stations with a registered capacity of 5MW or greater with RoCoF based Loss of Mains protection, the Workgroup's generic risk assessment indicates an increased probability of out-of-phase re-closure. There is no change in the out-of-phase re-closure risk at non-synchronous generator sites.

[19] Table 12 is identical to Table 5 and is repeated here for ease of reference

8.10 Table 13 summarises the results of the Workgroup's generic assessment of the annual probability of out-of-phase re-closure across the population of generators. The consequent risk to plant and personnel is a function of the arrangements applied at individual sites. However, the calculated probabilities are high enough to suggest that site specific assessments are required for synchronous generators and that mitigating actions may need to be taken by some existing generators to maintain acceptable levels of safety. The costs of these actions are included in the estimated implementation costs described below.

Setting Option	RoCoF (Hzs^{-1})	N_{OA} (P-V control mode)	N_{OA} (P-pf control mode)	
2	0.5	1.42×10^{-1}	8.26×10^{-5}	
4	1.0	2.98×10^{-1}	4.56×10^{-4}	
9	0.12	1.15×10^{-2}	0	Current G59 Settings
10	0.13	1.53×10^{-2}	0	
11	0.2	3.34×10^{-2}	0	

Table 13: Summary of Out-of-phase re-closure occurrence[20]

8.11 The maximum cost of implementing the proposals was estimated at £10.36m. The estimate is made up of £1.78m for making a protection setting change, £3.30m for site specific risk assessments and £5.28m for any mitigation measures. In order to cater for any residual uncertainty in the estimate, the network Licensees recommend that an implementation cost totalling £11m should be considered when evaluating the impact of the proposed change.

8.12 Under the proposed modification, there will be a reduced rate of occurrence of distributed generation shutting down and loosing output following either a frequency deviation or a local network disturbance due to Loss of Mains protection operating.

Impact on Balancing Services Costs

8.13 The proposed change will reduce Balancing Services costs and therefore reduce Balancing Services Use of System charges.

8.14 The reduction in costs made possible by the proposed change is estimated to exceed the costs of implementing the change in just over 2 years, with £14.9m saved by the end of the third financial year after implementation of the proposed change. Savings of £33m are achieved by the end of the fifth year. This reduction in costs is the most significant benefit of the proposed change.

8.15 The proposed change will also reduce the number and volume of balancing actions taken by National Grid in its role as system operator.

Overall Costs and Benefits

8.16 The costs of implementing the proposed change are estimated at £11m and are incurred in the two years following a change. The benefits of the proposed change start to be delivered at the end of the proposed two year implementation period. Break-even is achieved within the third financial year of implementation being completed.

[20] Table 13 is identical to Table 6 and is repeated here for ease of reference

Impact on Greenhouse Gas Emissions

8.17 The proposed change will reduce emissions by reducing the number and duration of the occasions where additional fossil fuelled plant has to be run to provide inertia to the total system.

Assessment against Distribution Code Objectives

8.18 The proposal will better facilitate the Code objective:

permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity

The proposal will reduce costs to electricity consumers by reducing the Balancing Services costs incurred in managing the risk of Loss of Mains protection operation due to a high RoCoF. The reduction in costs is greater than the costs required to implement the change. The proposal will reduce the time and number of occasions that the risk of Loss of Mains protection operation due to a high RoCoF is present.

facilitate competition in the generation and supply of electricity

The proposal better facilitates this objective by limiting the constraints that need to be applied to generator operation, and by facilitating access to the national electricity transmission system by reducing the volume of Balancing actions taken to managing the risk of Loss of Mains protection operation due to a high RoCoF.

efficiently discharge the obligations imposed upon distribution Licensees by the distribution licences and comply with the Regulation and any relevant legally binding decision of the European Commission and/or the Agency for the Co-operation of Energy Regulators.

The proposal has a neutral impact on this objective

Impact on Other Industry Documents

8.19 The proposed modification does not impact on any other industry document. For the avoidance of doubt, the proposed modification includes changes to Engineering Recommendation G59 as well as the Distribution Code.

Implementation

8.20 Licensees recommend that the proposed changes are implemented at the start of the calendar month following the Authority's decision.

ANNEX 1: Workgroup Terms of Reference and Future Workplan

Terms of Reference

pp13/32
May 2013 GCRP

nationalgrid

GC0035 Frequency Changes during Large Disturbances and their impact on the Total System.

TERMS OF REFERENCE

Governance

1. The Frequency Changes during Large Disturbances and their impact on the Total System Workgroup was established by Grid Code Review Panel (GCRP) at the May 2012 GCRP meeting.

2. The Workgroup shall formally report to the GCRP and the DCRP.

Membership

3. The Workgroup shall comprise a suitable and appropriate cross-section of experience and expertise from across the industry, which shall include:

Name	Role	Representing
Mike Kay	Chair	Electricity North West
Robyn Jenkins	Technical Secretary	National Grid
Graham Stein	Member	National Grid
William Hung	Member	National Grid
Geoff Ray	Member	National Grid
Campbell McDonald/Jane McArdle	Member	SSE (Generator)
Joe Duddy	Member	RES (Generator)
Paul Newton	Member	EON (Generator)
Joe Helm	Member	Northern Power Grid (DNO)
Martin Lee	Member	SSEPD (DNO)
John Knott	Member	SP Energy Networks (DNO)
Andrew Hood	Member	Western Power Distribution
Adam Dyśko	Technical Expert	University of Strathclyde
Julian Wayne	Authority Representative	Ofgem

Meeting Administration

4. The frequency of Workgroup meetings shall be defined as necessary by the Workgroup chair to meet the scope and objectives of the work being undertaken at that time.

5. National Grid will provide technical secretary resource to the Workgroup and handle administrative arrangements such as venue, agenda and minutes.

6. The Workgroup will have a dedicated section on the National Grid website to enable information such as minutes, papers and presentations to be available to a wider audience.

Scope

7. The Workgroup will:

- Review the expected behaviour of Total System when subject to frequency changes during large disturbances, with particular focus on the rate of change of frequency. Take into account the output of the Frequency Response Technical Sub-group and also recent experience of disturbances on the Total System.

- Take account of relevant international practice and the approach taken in European Code development.

- Research details of the RoCoF based protection settings applied to embedded generators of 5MW and greater rated capacity.

- Investigate and quantify the risks to DNO networks and Users of desensitising RoCoF protection on embedded generators above 5MW and greater rated capacity. Develop proposals for consultation on any proposed changes drawing out the costs, benefits and risks of such a change to present to the July GCRP and to DCRP members in July.

- Develop a work plan including timescales and resource requirements for the next stage of work, to include:

  - Development of RoCoF withstand criteria for use in GB (as will be required by the EU Network Code Requirements for all Generators (ref 8.1(b)));

  - Investigating and quantifying the risks to DNO networks and Users of desensitising RoCoF based protection on embedded generators of rated capacity of less than 5MW;

  - Investigating the characteristics of popular/likely inverter technology deployed, particularly in relation to RoCoF withstand capability and island stability;

  - Assessing or modelling the interaction of multiple generators in a DNO power island;

  - Researching the characteristics (numbers/types etc) of embedded generation of less than 5MW rated capacity including likely RoCoF withstand capabilities;

  - Analyse the merit of retrospective application of RoCoF criteria to existing embedded generation of less than 5MW (including comparison with similar programmes in Europe);

  - Consideration of issues relating to the continuing use of Vector Shift techniques; and

  - Develop proposals for consultation on any proposed changes drawing out the costs, benefits and risk of such a change to present to the January 2014 GCRP and DCRP.

Deliverables

8. The Workgroup will provide updates and a Workgroup Report to the Grid Code Review Panel and Distribution Code Review Panel which will:

- Detail the findings of the Workgroup;
- Draft, prioritise and recommend changes to the Grid Code, Distribution Code and associated documents in order to implement the findings of the Workgroup; and
- Highlight any consequential changes which are or may be required,

Timescales

9. Workgroup timescales are specified in the Scope section of this document.
10. If for any reason the Workgroup is in existence for more than one year, there is a responsibility for the Workgroup to produce a yearly update report, including but not limited to; current progress, reasons for any delays, next steps and likely conclusion dates.

Future Workplan

The workgroup's Terms of Reference require the development of a plan to address further issues relating to RoCoF and Loss of Mains Protection. These require the group to develop proposals for consultation on any proposed changes drawing out the costs, benefits and risk of such a change to present to the GCRP and DCRP. An outline plan is provided below.

1. *Research the characteristics (numbers/types etc) of embedded generation of less than 5MW registered capacity including likely RoCoF withstand capabilities;*

    a. Review DNO information and survey additional sources as necessary;

2. *Investigating the characteristics of popular/likely inverter technology deployed, particularly in relation to RoCoF withstand capability and island stability;*

    a. Survey manufacturers and installers and survey additional sources as necessary;
    b. Assess the requirement to test equipment to verify its characteristics;

3. *Development of RoCoF withstand criteria for use in GB (as will be required by RfG 8.1(b));*

    a. Workgroup members to develop a view of generation technologies' inherent withstand capability;
    b. Review the final proposals (post consultation) from the June 2014 recommendations in respect of protection settings and the Total System requirement;
    c. Identify and asses any gaps in withstand capability;
    d. Assess the costs, benefits and risks of setting withstand capability requirements for future generators;
    e. Assess the costs, benefits and risks of setting withstand capability requirements for existing generators;

4. *Assessing or modelling the interaction of multiple generators in a DNO power island;*

    a. Review existing approaches to multi-machine dynamic simulation;
    b. Develop new approaches if required;

5 *Investigating and quantifying the risks to DNO networks and Users of desensitising RoCoF based protection on embedded generators of rated capacity of less than 5MW;*

    a. Assess the costs, benefits and risks of requirements to de-sensitise RoCOF settings for future generators of registered capacity of less than 5MW;

5 *Analyse the merit of retrospective application of RoCoF criteria to existing embedded generation of less than 5MW (including comparison with similar programmes in Europe);*

a. Review international experience of large retrospective change programmes;
b. Assess the costs, benefits and risks of requirements to de-sensitise RoCoF settings for existing generators of registered capacity of less than 5MW;

6 *Consideration of issues relating to the continuing use of Vector Shift techniques;*

a. Review the likely exposure of distributed generation to vector shifts in excess of recommended settings during system disturbances.

ANNEX 2: Proposed Legal Text

Distribution Code

Drafting based on January 2014 Issue. New text is in red.

DPC7.4.3.4 The following summarizes the required **Protection** settings that will generally be applied:

Prot Function	Small Power Station				Medium Power Station	
	LV Protection$^{\$}$		HV Protection$^{\$}$			
	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n† - 13% = 200.1V	2.5s*	Vφ-φ‡ -13%	2.5s*	Vφ-φ‡- 20%	2.5s*
U/V st 2	Vφ-n† - 20% = 184.0V	0.5s	Vφ-φ‡ - 20%	0.5s		
O/V st 1	Vφ-n† + 14% =262.2V	1.0s	Vφ-φ‡ + 10%	1.0s	Vφ-φ‡ + 10%	1.0s
O/V st 2	Vφ-n†+ 19% = 273.7V	0.5s	Vφ-φ‡ + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees$^{\#}$		Intertripping expected	
LoM(RoCoF) <5MW§	K2 x 0.125 Hz/s		K2 x 0.125 Hz/s$^{\#}$		~~Intertripping expected~~	

<table>
<tr><th colspan="5">RoCoF§ settings for Power Stations ≥5MW</th></tr>
<tr><th colspan="2" rowspan="2">Date of Commissioning</th><th colspan="2">Small Power Stations</th><th rowspan="2">Medium Power Stations</th></tr>
<tr><th>Asynchronous</th><th>Synchronous</th></tr>
<tr><td rowspan="2">Generating Plant Commissioned before 01/07/14</td><td>Settings permitted until 01/07/16</td><td>Not to be less than K2 x 0.125 Hz/s$^{\#}$
and not to be greater than
1Hz/s$^{\P\#}$, time delay 0.5s</td><td>Not to be less than K2 x 0.125 Hz/s$^{\#}$
and not to be greater than
0.5Hz/s$^{\P\#\ \Omega}$, time delay 0.5s</td><td>Intertripping Expected</td></tr>
<tr><td>Settings permitted on or after 01/07/16</td><td>1Hz/s$^{\P\#}$, time delay 0.5s</td><td>0.5Hz/s$^{\P\#\ \Omega}$, time delay 0.5s</td><td>Intertripping expected</td></tr>
<tr><td colspan="2">Generating Plant commissioned between 01/07/14 and 30/06/16</td><td>1Hz/s$^{\P\#}$, time delay 0.5s</td><td>0.5Hz/s$^{\P\#\ \Omega}$, time delay 0.5s</td><td>Intertripping expected</td></tr>
<tr><td colspan="2">Generating Plant commissioned on or after 01/07/16</td><td>1Hz/s$^{\P\#}$, time delay 0.5s</td><td>1Hz/s$^{\P\#}$, time delay 0.5s</td><td>Intertripping expected</td></tr>
</table>

Notes:

φ-n; φ-φ denote RMS phase to neutral and phase-phase values respectively of the voltage at the **Connection Point**

$ HV and LV Protection settings are to be applied according to the voltage reference at which the protection is measuring, ie:

- If the G59 protection takes its voltage reference from an LV source then LV protection settings shall be applied.
- If the G59 protection takes its voltage reference from an HV source then HV protection settings shall be applied.

†A value of 230V shall be used for all DNO LV systems

‡A value to suit the voltage of the connexion point

* Might need to be reduced if auto-reclose dead times are <3s

Intertripping may be considered as an alternative to the use of a Loss of Mains relay

K1 = 1.0 (for low impedance networks) or 1.66 – 2.0 (for high impedance networks)

K2 = 1.0 (for low impedance networks) or 1.6 (for high impedance networks)

§ Rate of change of frequency

¶ The required protection requirement is expressed in Hertz per second (Hz/s). The time delay should begin when the measured rate exceeds the threshold expressed in Hz/s and be reset if it falls below that threshold. The relay must not trip unless the measured rate remains above the threshold expressed in Hz/s continuously for 500ms. Setting the number of cycles on the relay used to calculate the RoCoF is not an acceptable implementation of the time delay since the relay would trip in less than 500ms if the rate was significantly higher than the threshold.

Ω The minimum setting is 0.5Hz/s. For overall system security reasons, settings closer to 1.0Hz/s are desirable, subject to the capability of the generating plant to work to higher settings.

DPC7.4.3.5 Over and Under voltage **Protection** must operate independently for all phases in all cases.

DPC7.4.3.6 The settings in DPC7.4.3.4 apply to **Embedded Small Power Station**s and **Embedded Medium Power Station**s. In exceptional circumstances **Generator**s have the option to agree alternative settings with the **DNO** if there are valid justifications in that the **Generating Plant** may become unstable or suffer damage with the settings specified in DPC7.4.3.4. The agreed settings should be recorded in the **Connection Agreement**.

DPC7.4.3.7 The underfrequency and overfrequency **Protection** settings set out in DPC7.4.3.4 also apply to **Generation Sets** in **Embedded Small Power Stations** already existing on or before 1 August 2010 with a **Registered Capacity** at or above 5 MW**,** except where single stage **Frequency Protection** relays are used, in which case the following settings apply.

Engineering Recommendation G59

Drafting based on Issue 3 2013. New text is in red.

b. earthing arrangements;

c. short circuit currents and the adequacy of protection arrangements;

d. **System Stability**;

e. resynchronisation to the **Total System**;

f. safety of personnel.

9.8.3 Suitable equipment will need to be installed to detect that an island situation has occurred and an intertripping scheme is preferred to provide absolute discrimination at the time of the event. Confirmation that a section of **Distribution System** is operating in island mode, and has been disconnected from the **Total System**, will need to be transmitted to the **Generating Unit(s)** protection and control schemes.

9.8.4 The ESQCR requires that supplies to **Customers** are maintained within statutory limits at all times ie when they are supplied normally and when operating in island mode. Detailed system studies including the capability of the **Generating Plant** and its control / protections systems will be required to determine the capability of the **Generating Plant** to meet these requirements immediately as the island is created and for the duration of the island mode operation.

9.8.5 The ESQCR also require that **Distribution System**s are earthed at all times. **Generator**s, who are not permitted to operate their installations and plant with an earthed star-point when in parallel with the **Distribution System**, must provide an earthing transformer or switched star-point earth for the purpose of maintaining an earth on the system when islanding occurs. The design of the earthing system that will exist during island mode operation should be carefully considered to ensure statutory obligations are met and that safety of the **Distribution System** to all users is maintained. Further details are provided in Section 8.

9.8.6 Detailed consideration must be given to ensure that protection arrangements are adequate to satisfactorily clear the full range of potential faults within the islanded system taking into account the reduced fault currents and potential longer clearance times that are likely to be associated with an islanded system.

9.8.7 Switchgear shall be rated to withstand the voltages which may exist across open contacts under islanded conditions. The **DNO** may require interlocking and isolation of its circuit breaker(s) to prevent ~~out of phase~~out-of-phase voltages occurring across the open contacts of its switchgear. Intertripping or interlocking should be agreed between the **DNO** and the **Generator** where appropriate.

9.8.8 It will generally not be permissible to interrupt supplies to **DNO Customers** for the purposes of resynchronisation. The design of the islanded system must ensure that synchronising facilities are provided at the point of isolation between the islanded network and the **DNO** supply. Specific arrangements for this should be agreed and recorded in the **Connection Agreement** with the **DNO**.

10.3.13 Frequency variations are a constant feature of any AC electrical network. During normal operation of the system NGET maintains frequency within the statutory limits of 49.5Hz to 50.5Hz. However the loss of a large generation infeed, or a large block of load, may disturb the system such that it goes outside statutory limits for a short period. It is important that unnecessary Loss of Mains protection operation does not occur during these short lived excursions. The changing mix of generation and loads on the GB network has already resulted in a wider range of possible system rate of change of frequency (RoCoF) during these events. This wider range of RoCoF could exceed the expectations set out in previous versions of G59 and system RoCoF events above 0.125Hzs^{-1} have already been measured on the GB network. With the changes in generation mix expected over the next decade it is unlikely to be economic to contain all frequency excursions within 0.125Hzs^{-1}. Therefore the maximum system RoCoF which may be experienced for the maximum loss of generation infeed or block of load will rise over time. Studies indicate that by 2023 this may be as high as 0.5Hzs^{-1}, and that even higher levels may be experienced after 2023. The RoCoF settings for Power Stations of 5MW or more laid out in G59/3-1 are intended to strike an appropriate balance between the need to detect genuine island conditions and the risk of unnecessary operation for the system conditions anticipated.

~~Observations of frequency disturbances on the Great Britain **System** indicate that the rates of change of frequency that typically occur are within the range of 0.04 to 0.16 Hzs^{-1}. Experience to date suggests that settings which correspond to a rate of change of frequency of up to 0.1 Hzs^{-1} are suitable for the detection of an islanded situation but may result in some nuisance tripping. Use of a constant rate of change of frequency of 0.125 Hzs^{-1} reduces nuisance tripping. Section 10.5.7.1 includes setting factors to increase resilience against nuisance tripping when connected to weak networks. In order to provide a consistant value for application to **Type Tested Generating Units**, a value of 0.2 Hzs^{-1} has been adopted, and a no-trip test at 0.19 Hzs^{-1} has been introduced for **Type Tested Generating Units**. Further changes to the required no-trip test will be required in the future as the **Total System** has more embedded generation connected which does not have inbuilt inertia or the capacity to increase prime mover inputs and the use of RoCoF protection may not be viable in the future.~~

10.3.14 The LoM relay that operates on the principle of voltage vector shift can achieve fast disconnection for close up **Distribution System** faults and power surges, and under appropriate conditions can also detect islanding when normally a large step change in generation occurs. The relay measures the period for each half cycle in degrees and compares it with the previous one to determine if this exceeds its setting. A typical setting is 6 degrees, which is normally appropriate to avoid operation for most normal vector changes in low impedance **Distribution Systems**. This equates to a constant rate of change of frequency of about 1.67 Hzs^{-1} and hence the relay is insensitive to slow rates of change of frequency. When vector shift relays are used in higher impedance **Distribution Systems**, and especially on rural **Distribution Systems** where auto-reclosing systems are used, a higher setting may be required to prevent nuisance tripping. Typically this is between 10 and 12 degrees. In order to provide a consistant value for application to **Type Tested Generating Units**, a value of 12 degrees, and a no-trip test of 9 degrees have been introduced for **Type Tested Generating Units**.

10.3.15 RoCoF protection is generally only applicable for **Small Power Station**s. DPC7.4 in the **Distribution Code** details where RoCoF may be used, and what the differences are between Scotland and England and Wales.

10.3.16 Raising settings on any relay to avoid spurious operation may reduce a relay's capability to detect islanding and it is important to evaluate fully such changes. Appendix 13.6 provides some guidance for assessments, which assume that during a short period of islanding the trapped load is unchanged. In some circumstances it may be necessary to employ a different technique, or a combination of techniques to satisfy the conflicting requirements of safety and avoidance of nuisance tripping. In those cases where the **DNO** requires LoM protection this must be provided by a means not susceptible to spurious or nuisance tripping, eg intertripping. Protection settings for **Type Tested Generating Unit**s shall not be changed from the standard settings defined in this Engineering Recommednation.

10.3.17 For a radial or simple **Distribution System** controlled by circuit breakers that would clearly disconnect the entire circuit and associated **Generating Plant**, for a LoM event an intertripping scheme can be easy to design and install. For meshed or ring **Distribution System**s, it can be difficult to define which circuit breakers may need to be incorporated in an intertripping scheme to detect a LoM event and the inherent risks associated with a complex system should be considered alongside those associated with a using simple, but potentially less discriminatory LoM relay.

10.3.18 It is the responsibility of the **Generator** to incorporate the most appropriate technique or combination of techniques to detect a LoM event in his protection systems. This will be based on knowledge of the **Generating Unit,** site and network load conditions. The **DNO** will assist in the decision making process by providing information on the **Distribution System** and its loads as reasonably requested by the **Generator**. The technique and settings applied must be biased to ensure detection of islanding under all ~~practical~~ operating conditions as far as is reasonably practicable. More detailed guidance on how **Generators** can assess the risks and on the information that the **DNO** will provide is contained in Appendix 13.11.

10.4 Additional DNO Protection

Following the **DNO** connection study, the risk presented to the **Distribution System** by the connection of a **Generating Unit** may require additional protection to be installed and may include the detection of:

- Neutral Voltage Displacement (NVD);
- Over Current;
- Earth Fault;
- Reverse Power.

This protection will normally be installed on equipment owned by the **DNO** unless otherwise agreed between the **DNO** and **Generator**. This additional protection may be installed and arranged to operate the **DNO** interface circuit breaker or any other circuit breakers, subject to the agreement of the **DNO** and the **Generator**.

10.5.7.1 Settings for Long-Term Parallel Operation

Prot Function	**Small Power Station**				**Medium Power Station**	
	LV Protection(1)		**HV** Protection(1)			
	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n[†] -13% = 200.1V	2.5s*	Vφ-φ[‡] -13%	2.5s*	Vφ-φ[‡]- 20%	2.5s*
U/V st 2	Vφ-n[†] - 20% =184.0V	0.5s	Vφ-φ[‡] - 20%	0.5s		
O/V st 1	Vφ-n[†] + 14% =262.2V	1.0s	Vφ-φ[‡] + 10%	1.0s	Vφ-φ[‡] + 10%	1.0s
O/V st 2	Vφ-n[†]+ 19% =273.7V[$]	0.5s	Vφ-φ[‡] + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees[#]		Intertripping expected	
LoM(RoCoF) <5MW	K2 x 0.125 Hzs^{-1}		K2 x 0.125 Hzs^{-1}[#]		~~Intertripping expected~~	

RoCoF[§] settings for Power Stations ≥5MW				
Date of Commissioning		Small Power Stations		Medium Power Stations
		Asynchronous	Synchronous	
Generating Plant Commissioned before 01/07/14	Settings permitted until 01/07/16	Not to be less than K2 x 0.125 Hz/s[#] and not to be greater than 1Hz/s[¶#], time delay 0.5s	Not to be less than K2 x 0.125 Hz/s[#] and not to be greater than 0.5Hz/s[¶# Ω], time delay 0.5s	Intertripping Expected
	Settings permitted on or after 01/07/16	1Hz/s[¶#], time delay 0.5s	0.5Hz/s[¶# Ω], time delay 0.5s	Intertripping expected
Generating Plant commissioned between 01/07/14 and 30/06/16 inclusive		1Hz/s[¶#], time delay 0.5s	0.5Hz/s[¶# Ω], time delay 0.5s	Intertripping expected
Generating Plant commissioned on or after 01/07/16		1Hz/s[¶#], time delay 0.5s	1Hz/s[¶#], time delay 0.5s	Intertripping expected

(1) **HV** and **LV** Protection settings are to be applied according to the voltage at which the voltage related protection reference is measuring, eg:

- If the EREC G59 protection takes its voltage reference from an **LV** source then **LV** settings shall be applied. Except where a private none standard LV network exists, in this case the settings shall be calculated from **HV** settings values as indicated by section 10.5.16;
- If the EREC G59 protection takes its voltage reference from an **HV** source then **HV** settings shall be applied.

†A value of 230V shall be used in all cases for **Power Station**s connected to a **DNO LV Systems**

‡A value to suit the nominal voltage of the **HV System** connection point.

* Might need to be reduced if auto-reclose times are <3s. (see 10.5.13).

Intertripping may be considered as an alternative to the use of a LoM relay

$ For voltages greater than 230V +19% which are present for periods of<0.5s the **Generating Unit** is permitted to reduce/cease exporting in order to protect the **Generating Unit**.

¶ The required protection requirement is expressed in Hertz per second (Hz/s). The time delay should begin when the measured RoCof exceeds the threshold expressed in Hz/s. The time delay should be reset if measured RoCoF falls below that threshold. The relay must not trip unless the measured rate remains above the threshold expressed in Hz/s continuously for 500ms. Setting the number of cycles on the relay used to calculate the RoCoF is not an acceptable implementation of the time delay since the relay would trip in less than 500ms if the system RoCoF was significantly higher than the threshold.

Ω The minimum setting is 0.5Hz/s. For overall system security reasons, settings closer to 1.0Hz/s are desirable, subject to the capability of the Generating Plant to work to higher settings.

(2) LOM constants

K1 = 1.0 (for low impedance networks) or 1.66 – 2.0 (for high impedance networks)

K2 = 1.0 (for low impedance networks) or 1.6 (for high impedance networks)

A fault level of less than 10% of the system design maximum fault level should be classed as high impedance.

For **Type Tested Generating Unit**s K1=2.0 and K2=1.6. The LoM function shall be verified by confirming that the LoM tests specified in 13.8 have been completed successfully

(3)Note that the times in the table are the time delays to be set on the appropriate relays. Total protection operating time from condition initiation to circuit breaker opening will be of the order of 100ms longer than the time delay settings in the above table with most circuit breakers, slower operation is acceptable in some cases.

(4)For the purposes of 10.5.7.1 the commissioning date means the date by which the tests detailed in 12.3 and 12.4 of G59 have been completed to the DNO's satisfaction.

The **Manufacturer** must ensure that the **Interface Protection** in a **Type Tested Generating Unit** is capable of measuring voltage to an accuracy of ±1.5% of the nominal value and of measuring frequency to ± 0.2% of the nominal value across its operating range of voltage, frequency and temperature.

10.5.7.2 – Settings for Infrequent Short-Term Parallel Operation

Prot Function	Small Power Station			
	LV Protection		**HV** Protection	
	Setting	Time	Setting	Time
U/V	Vφ-n† -10% = 207V	0.5s	Vφ-φ‡ -6%	0.5s
O/V	Vφ-n† + 14% = 262.2V	0.5s	Vφ-φ‡ + 6%	0.5s
U/F	49.5Hz	0.5s	49.5Hz	0.5s
O/F	50.5Hz	0.5s	50.5Hz	0.5s

†A value of 230V shall be used in all cases for **Power Stations** connected to a **DNO LV System**s

‡A value to suit the voltage of the **HV System** connection point.

10.5.8 Over and Under voltage protection must operate independently for all three phases in all cases.

10.5.9 The settings in 10.5.7.1 should generally be applied to all **Generating Plant**. In exceptional circumstances **Generator**s have the option to agree alternative settings with the **DNO** if there are valid justifications in that the **Generating Plant** may become unstable or suffer damage with the settings specified in 10.5.7.1. The agreed settings should be recorded in the **Connection Agreement**.

10.5.10 Once the settings of relays have been agreed between the **Generator** and the **DNO** they must not be altered without the written agreement of the **DNO**. Any revised settings should be recorded again in the amended **Connection Agreement**.

10.5.11 The under/over voltage and frequency protection may be duplicated to protect the **Generating Plant** when operating in island mode although different settings may be required.

10.5.12 For **LV** connected **Generating Plant**, the voltage settings will be based on the 230V nominal **System** voltage. In some cases **Generating Plant** may be connected to **LV System**s with non-standard operating voltages. Section 10.5.16 details how suitable settings can be calculated based upon the **HV** connected settings in table 10.5.7.1. Note that **Generating Units** with non-standard **LV** protection settings cannot be **Type Tested** and these will need to be agreed by the **DNO** on a case by case basis.

10.5.13 Co-ordination with existing protection equipment and auto-reclose scheme is also required, as stated in DPC7.4.3 of the **Distribution Code**. In particular the **Generator**'s protection should detect a LoM situation and disconnect the **Generating Plant** in a time shorter than any ~~auto reclose~~auto-reclose dead time. This should include an allowance for circuit breaker operation and generally a minimum of 0.5s should be allowed for this. For auto-reclosers set with a dead time of 3s, this implies a LoM response time of 2.5s. A similar response time is expected from under and over voltage relays. Where auto-reclosers have a dead time of less than 3s, there may be a need to reduce the operating time of under and over voltage relays. For **Type Tested Generating Unit**s no changes are required to the operating times irrespective of the ~~auto reclose~~auto-reclose times.

10.5.14 If automatic resetting of the protective equipment is used, as part of an auto-restore scheme for the **Generating Plant**, there must be a time delay to ensure that healthy supply conditions exist for a continuous period of at least 20 s. The automatic reset must be inhibited for faults on the **Generator**'s installation. Staged timing may be required where more than one **Generating Plant** is connected to the same feeder. For **Type Tested Generating Unit**s the time delay is set at 20s.

10.5.15 Where an installation contains power factor correction equipment which has a variable susceptance controlled to meet the reactive power demands, the probability of sustained generation is increased. For **LV** installations, additional protective equipment provided by the **Generator**, is required as in the case of self-excited asynchronous machines.

10.5.16 Non-Standard private LV networks calculation of appropriate protection settings

The standard over and under voltage settings for **LV** connected **Generating Units** have been developed based on a nominal **LV** voltage of 230V. Typical **DNO** practice is to purchase transformers with a transformer winding ratio of 11000:433, with off load tap changers allowing the nominal winding ratio to be changed over a range of plus or minus 5% and with delta connected **HV** windings. Where a **DNO** provides a connection at **HV** and the **Customer** uses transformers of the same nominal winding ratio and with the same tap selection as the **DNO** then the standard **LV** settings in table 10.5.7.1 can be used for **Generating Units** connected to the **Customers LV** network. Where a **DNO** provides a connection at **HV** and the **Customers** transformers have different nominal winding ratios, and he chooses to take the protection reference measurements from the **LV** side of the transformer, then the **LV** settings stated in table 10.5.7.1 should not be used without the prior agreement of the **DNO**. Where the **DNO** does not consider the standard **LV** settings to be suitable, the following method shall be used to calculate the required **LV** settings based on the **HV** settings for **Small Power Station**s stated in table 10.5.7.1.

Identify the value of the transformers nominal winding ratio and if using other than the nominal tap, increase or decrease this value to establish a **LV System** nominal value based on the transformer winding ratio and tap position and the **DNO**s declared **HV system** nominal voltage.

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	for **Manufacturers**	
13.9	Main Statutory and other Obligations	
13.10	Guidance on acceptable unbalance between phases in a **Power Station**	
13.11	Guidance on Risk Assessment when using RoCoF LoM Protection for **Power Stations** in the 5MW to 50MW range	

Note that the table below applies to Power Stations less than 5 MW capacity.

The DNO will be able to provide, on request, corresponding figures for Power Stations of 5MW and above.

Loss-of-Mains (LOM) Protection Tests -– RoCoF for Power Stations <5MW

Calibration and Accuracy Tests

Ramp in range 49.5-50.5Hz	**Pickup** (+ / -0.005Hzs^{-1})				**Time Delay** RoCoF= ±**0.05Hz/s** above setting			
Setting = 0.125 / 0.20 Hzs^{-1}	Lower Limit	Measured Value	Upper Limit	Result	Test Condition	Measured Value	Upper Limit	Result
Increasing Frequency	*0.120* *0.195*		*0.130* *0.205*	Pass/Fail	0.175 Hzs^{-1} 0.25 Hzs^{-1}		*<0.5s*	Pass/Fail
Reducing Frequency	*0.120* *0.195*		*0.130* *0.205*	Pass/Fail	0.175 Hzs^{-1} 0.25 Hzs^{-1}		*<0.5s*	Pass/Fail

Stability Tests

Ramp in range 49.5-50.5Hz	Test Condition	Test frequency ramp	Test Duration	Confirm No Trip	Result
Inside Normal band	< RoCoF (increasing f)	Higher of 0.12 Hzs^{-1} or ROCOF - 0.01 Hzs^{-1}) = ___________	5.0s		Pass/Fail
Inside Normal band	< RoCoF (reducing f)		5.0s		Pass/Fail

Additional Comments / Observations:

13.11- Guidance on Risk Assessment when using RoCoF LoM Protection for Power Stations in the 5MW to 50MW range

This procedure aims to provide guidance on assessing the risks to a **Generator's** plant and equipment where a **Generator** with synchronous **Generating Units** is considering the effect of applying higher RoCoF settings than 0.2Hzs^{-1}. It is based on analysis undertaken for the network licensees by Strathclyde Universtity[11].

13.11.1 The guidance in this section 13.11 relates to a new activity. Early experience may suggest there are more efficient or effective ways of assessing the risk. **DNOs** and **Generators** will be free to adapt this procedure to achieve the **Generators'** ends.

13.11.2 First determine whether the **Power Station** includes a synchronous **Generating Unit**. This type of **Generating Unit** is at risk from an out-of-phase reclosure on a **DNO's** network where the **DNO** employs auto-reclose or automatic restoration schemes and the loss of mains protection has not operated to disconnect the **Generating Unit** before the supply is restored by the **DNO's** automatic equipment.

13.11.3 If all the synchronous **Generating Units** in a **Power Station** are operating with a fixed power factor then the chance of sustaining an island is low and the **Generator** may wish to consider that there is no need to take any further action though this does not eliminate the risk of an out-of-phase reclosure. If any synchronous **Generating Unit** is operating with voltage control then the risk of an out-of-phase reclosure is increased and the **Generator** is advised to continue with the risk assement process as described in sections 13.11.4 to 13.11.9 below.

13.11.4 When a **Generator** wishes to carry out a risk assessment the **DNO** will be able to provide an estimate of the potential trapped load. This can be in the form of a yearly profile, and possibly in the form of a load duration curve. It is possible that an island may form at more than one automatic switching point on the **DNO**'s network and the **DNO** will be able to provide a profile or estimate of a profile for each. This will enable a quick assessment to be made as to the whether the mismatch between load and generation is so gross as to obviate further study. It is for the **Generator** to determine what a gross mismatch is depending on the **Generating Unit's** response to a change in real or reactive power. The **Generator** should be aware that the trapped load on a network can change over time, due to the connection or disconnection of load and or **Generating Plant,** hence the trapped load assessment may need to be carried out periodically.

13.11.5 **DNO**s will also be able to provide indicative fault rates for their network that lead to the tripping of the automatic switching points in 13.11.4 above.

[11] A. Dyśko, I. Abdulhadi, X. Li, C. Booth "Assessment of Risks Resulting from the Adjustment of ROCOF Based Loss of Mains Protection Settings – Phase I", Institute for Energy and Environment, Department of Electronic and Electrical Engineering, University of Strathclyde, Glasgow, June 2013.

13.11.6 **DNO**s will provide any known or expected likely topology changes to the network and a view of the effects of this on the data provided in 13.11.4 and 13.11.5

13.11.7 **DNO**s will also be able to provide the automatic switching times employed by any auto-reclose switchgear employed at switching points identified in 13.11.4. This will include any potential changes to automatic switching times that it might be possible to deploy to reduce the risk of out-of-phase reclosure. The DNO will need to consider any potential effect from network faults on customer service and system performance before agreeing to modifying automatic switching times.

13.11.8 **DNO**s will provide the information above, and any other relevant information reasonably required, within a reasonable time when requested by the Generator.

13.11.9 A key influence on the stability of any power island will be the short term, ie second by second, variation of the trapped load. The **DNO** will be able to provide either a generic variability of the load with typically 1s resolution data points, or at the **Generator**'s expense will be able to measure actual load variability for the network in question for some representative operating conditions.

13.11.10 Armed with the above information the **Generator** will be able to commission appropriate modelling to simulate the stability of the **Generator**'s plant when subject to an islanding condition and hence assess the risks associated with an out-of-phase reclosure incident. Where the **Generator** considers these risks to be too high, sensitivity analysis should enable them to identify the effectiveness of various remedial actions.

ANNEX 3: Implementation Costs and Balancing Services Savings

RoCoF Balancing Services Cost Projection vs Cost of Protection Change

All Costs £m (2013/14 prices)

		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Total Cost Of Managing RoCoF constraint	Best	9.0	10.4	29.3	31.1	149.8	146.1	182.3	328.4	483.7	580.7	814.6	841.2	966.0
	Central	9.6	11.4	56.1	59.5	184.2	294.6	364.9	390.2	557.3	692.4	962.4	975.1	1,130.9
	Worst	10.4	12.4	60.8	184.0	314.8	328.0	428.2	607.6	662.1	1,152.0	1,409.5	1,661.5	2,130.3
Total Cost if Settings are Raised for >=5MW plant	Best	8.1	9.3	26.1	27.7	146.0	142.9	176.8	322.3	477.0	572.6	805.7	833.4	957.5
	Central	8.6	10.2	50.3	53.4	177.4	289.1	355.5	379.8	545.9	679.4	948.1	963.5	1,118.2
	Worst	9.4	11.2	55.0	177.8	307.9	320.2	415.3	593.2	646.3	1,130.3	1,385.7	1,636.2	2,102.7
Scenario Weighting	Best	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Central	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Worst	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

All Costs £m (2013/14 prices)

Total Balancing Services Cost Summary

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Total Cost	9.5	11.2	48.5	63.5	187.0	253.4	316.5	393.4	545.7	704.8	962.8	1,003.6	1,181.3
Total Cost if Settings are Raised for >=5MW plant	8.5	10.1	43.5	58.1	181.0	248.4	307.9	383.9	535.2	692.4	949.2	991.8	1,168.4

Total Achievable Savings

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Cumulative Savings (>=5MW): 2016 Completion				4.0	9.9	14.9	23.5	33.0	43.5	55.9	69.5	81.4	94.3

Implementation Cost

		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Generators at Stations of >=5MW	Cost		5.5	5.5										
	Cumulative Cost		5.5	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0