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

This consultation document presents further proposals to modify the Distribution Code and Engineering Recommendation G59. Views are sought on the implementation of Licensees' revised proposals. These were developed with the assistance of Workgroup members in response to feedback from the consultation exercise in August and September 2013. Any interested party is able to make a response in line with the guidance set out in Section 7 of this document.

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Length of Consultation: **15 Working Days**
Response by: **04 April 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 $0.5Hzs^{-1}$ is permissible. The specific criteria to be applied should be stipulated in both the Distribution Code and Engineering Recommendation G59.

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

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About this document

This Industry Consultation outlines the information required for interested parties to form an understanding of an issue within the Distribution Code and Engineering Recommendation G59 relating to the security of the total electricity supply system in Great Britain and seeks the views of interested parties in relation to the issues raised by this document.

Document Control

Version	Date	Change Reference
0.1	10 March 2014	Draft to Workgroup
1.0	14 March 2014	Consultation

Any Questions

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1 Executive Summary

1.1 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.

1.2 Following a series of Workgroup meetings, stakeholder events and completion of a generic risk assessment, the Workgroup 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 $1.0Hzs^{-1}$.

1.3 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.

1.4 The network Licensees consulted on the Workgroup's proposals in August and 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.

1.5 A total of 18 parties responded to the consultation. A majority of responses expressed support for the proposals. A number of respondents expressed concern over certain aspects of the proposals which the Licensees have sought to address with the help of Workgroup members. The revised proposals presented in this document seek 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.

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

1.7 The Workgroup has 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 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};

(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.

1.8 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.

1.9 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.

1.10 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.

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

1.12 Licensees recognise however that these revisions mean that the proposed legal text for both the Distribution Code and Engineering Recommendation G59 is now significantly different from that presented in the previous consultation document. Licensees therefore seek the views of affected parties on how well the proposed legal text captures the Workgroup's final set of recommendations concerning RoCoF settings on distributed generators at stations of registered capacity of 5MW and above.

1.13 The Workgroup has not developed proposals to addresses 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 Workgroup recognises 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 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. Workgroup members would be happy to support discussions at an appropriate time if required.

1.14 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 tasked 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 $0.125 Hzs^{-1}$.

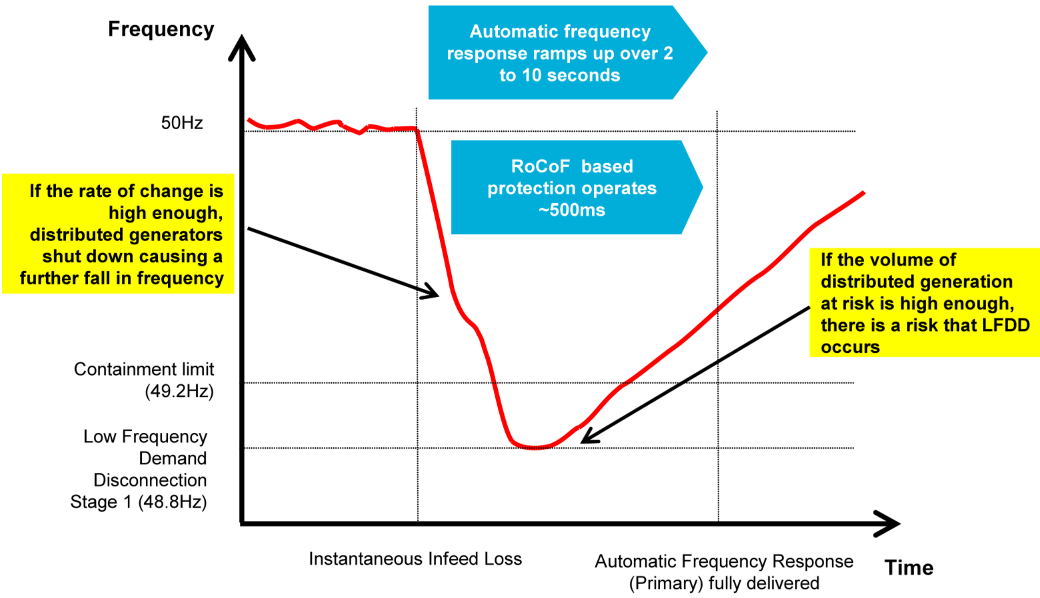

Figure 1: How LFDD would occur after an Infeed Loss and RoCoF trips

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.

2.7 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 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.

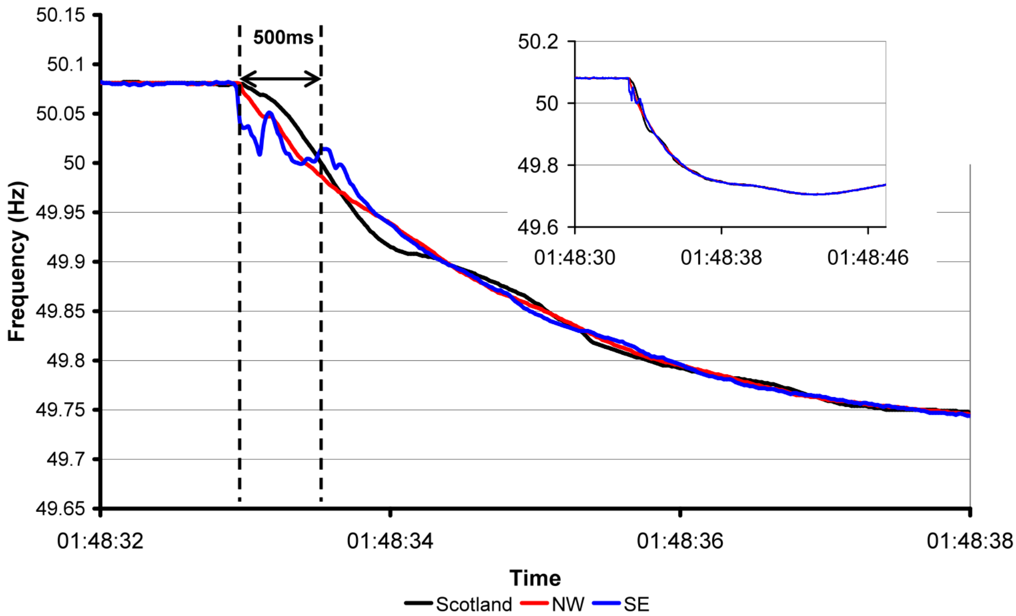

Figure 2: Frequency Measurements during a 1,000MW Instantaneous Infeed Loss on 28th September 2012

[1] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

2.8 Figure 2 shows frequency measurements during an interconnector trip on the 28^{th} 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 in 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.

2.9 National Grid currently takes actions by procuring Balancing Services 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). These actions 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 and 2014, rising to over £400m per annum over the period to 2020. 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.

3 First Industry Consultation

3.1 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. No changes were proposed to the Grid Code.

3.2 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.

3.3 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.

3.4 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.

3.5 Both the Distribution Code Review Panel and the Grid Code Review Panel approved the Workgroup's programme for a second phase of work. The 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.

3.6 Views were invited upon the proposals outlined in the consultation by the 27 September 2013.

3.7 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?

3.8 Table 1 below provides an overview of the 18 responses received. 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

Ref	Company	Supportive
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 1: Consultation Respondents

4 Post Consultation Review

4.1 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.

4.2 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

4.3 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.

4.4 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 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.

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

4.6 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.

4.7 The Workgroup acknowledged that new generators were likely to be able to deal with new guidance more efficiently. 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.

4.8 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.

4.9 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

4.10 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).

4.11 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

4.12 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

4.13 The DNO information gathering exercise (the results of which are summarised in **Table 2**) revealed that, of the sites surveyed, a maximum of 146 sites would require a protection setting change under the Workgroup's revised proposal. The 146 sites include those sites where the protection technique is “unknown” at the present time. Of the 146 sites, a maximum of 114 are synchronous generators and would require a risk assessment. The Workgroup assumed that 40% of these sites, 46 actual sites, would require mitigation measures.

4.14 The Workgroup reconsidered its initial view of average implementation costs per site. 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.

4.15 Estimating implementation costs using the latest view of the number of sites affected gives a cost of £8.87m. The cost is made up of three categories of work which are explained below and shown in Table 3.

4.16 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. The latest available information suggests up to 146 sites are affected.

4.17 The second category of work is the site specific risk assessment carried out at all synchronous generator sites with RoCoF protection (up to 114 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.

LoM Type and Setting	**Capacity (MW)**	**Sites**
Non Synchronous RoCoF <0.2Hz/s	216	12
Non SynchronousRoCoF >=0.2Hz/s	77	10
Non Synchronous RoCoF >= 1.0Hz/s	287	11
Synchronous RoCoF <0.2Hz/s	692	30
Synchronous RoCoF >=0.2Hz/s	256	15
Synchronous RoCoF >= 0.5Hz/s	141	12
Unknown (Non Synchronous)	271	10
Unknown (Synchronous)	1329	69
Intertrip	445	15
Vector Shift (Synchronous)	204	11
Vector Shift (Non Synchronous)	609	57
Other	334	13
Total	**4861**	**265**

Table 2: Current status of Distributed Generators Loss of Mains Protection

4.18 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 this 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	146	114	46	
Cost Per Site	.010	.025	.100	
Sum (£m)	**1.46**	**2.85**	**4.56**	**8.87**

Table 3: Implementation Costs

4.19 The Workgroup agreed that a total cost of £10m should be referenced in its assessment of costs versus benefits to capture any residual uncertainty. This was then spread over the recommended two year implementation period.

Balancing Services Cost Savings

4.20 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.

4.21 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.

4.22 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.

4.23 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.

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

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

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

4.27 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.

4.28 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

4.29 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 compared to a cost of £10m, as shown in Table 4. 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		5.0	5.0					
	Cumulative Cost		5.0	10.0	10.0	10.0	10.0	10.0	10.0

Table 4: Costs and Savings

4.30 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

4.31 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.

4.32 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

4.33 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.

4.34 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

4.35 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.

4.36 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 time of publication, no decisions have been made. 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.

4.37 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.

Frequency Quality

4.38 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.

5 Revised Proposals

5.1 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.

5.2 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.

5.3 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.

6 Impact and Assessment

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

6.2 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.

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

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

Impact on Distribution Code Users

6.5 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.

6.6 Owners of existing synchronous generators at power stations with a registered capacity of 5MW or greater with RoCoF based Loss of Mains protection may need to assess their exposure to out of phase re-closure under new protection settings. Mitigating actions may be required as a result of this.

6.7 There is a reduced risk of distributed generation shutting down following a frequency deviation due to Loss of Mains protection operating.

Impact on Other Parties

6.8 The proposed change will reduce Balancing Services costs and therefore reduce Balancing Services Use of System charges. The proposed change will also reduce the balancing actions taken by National Grid in its role as system operator.

Impact on Greenhouse Gas Emissions

6.9 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

6.10 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

6.11 The proposed modification does not impact on any other industry documents

Implementation

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

7 Responding to this Consultation

7.1 Views are invited upon the proposals outlined in thus consultation, which should be received by **04 April 2014**. Your formal response may be emailed to david.spillett@energynetworks.org.

7.2 Responses are 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.

7.3 If you wish to submit a confidential response please note the following:

(a) Information provided in response to this consultation will be published on the Distribution Code website and National Grid's website unless the response is clearly marked "Private and Confidential". You will be contacted to establish the extent of the confidentiality. A response marked "Private and Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Distribution Code Review Panel, Grid Code Review Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

(b) Please note an automatic confidentiality disclaimer generated by your IT System will not in itself mean that your response is treated as if it has been marked "Private and Confidential".

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.

System. These individual requirements must be ascertained in discussions with the **DNO**. To achieve the objectives above, the **Protection** must include the detection of:

a. Over Voltage (O/V)

b. Under Voltage (U/V)

c. Over **Frequency** (O/F)

d. Under **Frequency** (U/F)

e. Loss of Mains (LoM)

There are different **Protection** settings dependent upon the **System** voltage at which the **Generating Plant** is connected (LV or HV) and also its size (eg **Small Power Station**, **Medium Power Station** and **Large Power Station**).

Protection settings for a **Large Power Station** and any connexion at 132kV must be considered on an individual basis and be consistent with **Grid Code** requirements. Loss of Mains protection will only be permitted at these sites if sanctioned by **NGC** – see DPC7.4.3.8 below.

For the purposes of DPC 7.4.3 the date of commissioning of **Generating Plant** is the date on which the tests required by DPC 7.4.9 have been complete to the **DNO**'s satisfaction.

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~~	

RoCoF§ settings for Power Stations >5MW				
Date of Commissioning		Small Power Stations		Medium Power Stations
		Asynchronous	Synchronous	
Generating Plant Commissioned before 01/04/14	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

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 Stations** and **Embedded Medium Power Stations**. In exceptional circumstances **Generators** 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**.

10.3.2 LoM is mandatory for all **Small Power Stations**. For **Medium and Large Power Stations** the **DNO** will advise if LoM is required. The requirements of 10.5.2 apply to LoM protection for all ~~power~~ **Power** ~~s~~**Stations.**

10.3.3 A problem can arise for **Generator**s who operate **Generating Plant** in parallel with the **Distribution System** prior to a failure of the network supply because if their **Generating Plant** continues to operate in some manner, even for a relatively short period of time, there is a risk that when the network supply is restored the **Generating Plant** will be out of **Synchronism** with the **Total System** and suffer damage. LoM protection can be employed to disconnect the **Generating Plant** immediately after the supply is lost, thereby avoiding damage to the **Generating Plant**.

10.3.4 Many **Customers** are connected to parts of **Distribution System**s which will be automatically re-energised within a relatively short period following a fault; with dead times typically between 1s and 180s. The use of such schemes is likely to increase in future as **DNO**s seek to improve supply availability by installing automatic switching equipment on their **Distribution System**s.

10.3.5 Where the amount of **Distribution System** load that the **Generating Plant** will attempt to pick up following a fault on the **Distribution System** is significantly more than its capability the **Generating Plant** will rapidly disconnect, or stall. However depending on the exact conditions at the time of the **Distribution System** failure, there may or may not be a sufficient change of load on the **Generating Plant** to be able to reliably detect the failure. The **Distribution System** failure may result in one of the following load conditions being experienced by the **Generating Plant**:

a. The load may slightly increase or reduce, but remain within the capability of the **Generating Plant**. There may even be no change of load;

b. The load may increase above the capability of the prime mover, in which case the **Generating Plant** will slow down, even though the alternator may maintain voltage and current within its capacity. This condition of speed/frequency reduction can be easily detected; or

c. The load may increase to several times the capability of the **Generating Plant**, in which case the following easily detectable conditions will occur:

- Overload and accompanying speed/frequency reduction
- Over current and under voltage on the alternator

10.3.6 Conditions (b) and (c) are easily detected by the under and over voltage and frequency protection required in this document. However Condition (a) presents most difficulty, particularly if the load change is extremely small and therefore there is a possibility that part of the **Distribution System** supply being supplied by the **Generating Plant** will be out of **Synchronism** with the **Total System**. LoM protection is designed to detect these conditions. In some particularly critical circumstances it may be necessary to improve the dependability of LoM detection by using at least two LoM techniques operating with different principles or by employing a LoM relay using active methods.

10.3.7 LoM signals can also be provided by means of intertripping signals from circuit breakers that have operated in response to the **Distribution System** fault.

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 System**s. 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 System**s, and especially on rural **Distribution System**s 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 Unit**s, 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. 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 containedin 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**.

The requirement for additional protection will be determined by each **DNO** according to size of **Generating Unit**, point of connection, network design and planning policy. This is outside the scope of this document.

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 01/04/14	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 Systems**

‡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 **Generators** 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 Systems** 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.

For example a **Customer** is using a 11,000V to 230/400V transformer and it is proposed to operate it on tap 1 representing an increase in the high voltage winding of +5% and the nominal HV voltage is 11,000V.

13 APPENDICES

Appendix	Application	Form Title
13.1	Type Testing a **Generating Unit** (>16A per phase but ≤ 50kW 3 phase or 17kW 1 phase.	**Generating Unit** Type Test Sheet **Type Tested Generating Unit**(>16A per phase but ≤ 50 kW 3 phase or 17 kW 1 phase)
13.2	Comissioning a **Power Station** comprising only **Type Tested Generating Units**	**Generating Plant** Installation & Commissioning Confirmation
13.3	Commissioning a **Power Station** comprising one or more non-**Type Tested Generating Units** (Appendix applicable in addition to Appendix 13.2)	**Generating Plant** Installation & Commissioning Tests (Additional commissioning test requirements for non-type tested **Generating Units**)
13.4	Decommissioning of any **Generating Unit**	**Generating Plant** Decommissioning Confirmation
13.5	Connection application for a **Type Tested Generating Unit** in a new or existing installation where the aggregate installed capacity of the **Power Station** will be 50kW or 17kW per phase or less comprising only of **Type Tested Generating Units.** Note for all other **Power Stations** the **DNOs** common application form shall be used.	Application for connection of **Type Tested Generating Unit(**s) with Total Aggregate **Power Station** Capacity < 50kW 3-Phase, or <17kW Single Phase
13.6	Additional Information Relating to System Stability Studies	
13.7	Loss of Mains Protection Analysis	
13.8	Type Testing of **Generation Units** of 50kW three phase, or 17kW per phase or less. Guidance	

	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= $\pm$**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 failed 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 DNOs will provide the information above 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		5.0	5.0										
	Cumulative Cost		5.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0