NIE Networks' Generator Interface Protection Amendment Project

Consultation Report and Next Steps

22/09/17

1. EXECUTIVE SUMMARY

On 18 July 2017 NIE Networks issued a Distribution Code (D-Code) consultation on Generator Interface Protection Amendments. This consultation proposed that the current Generator interface protection settings associated with Large Scale Generation (LSG[1]) connected to the NIE Networks' distribution system should be amended to allow for higher levels of SNSP on the electricity system. The consultation also proposed that the settings associated with Small Scale Generation (SSG[2]) should not be amended due to the higher risk of fatality and out of phase reclosure associated with islanding of SSG. The consultation period ran from 18 July 2017 to 15 August 2017. NIE Networks made direct contact with 165 individual stakeholders and a total of 13 responses were received.

Taking into consideration the responses to this consultation, and subsequent engagement with stakeholders including the SEM Committee (SEMC), NIE Networks has requested (in September 2017) that Strathclyde University undertake additional research to assess the impact on risk of mitigation measures which includes the impact of generator interface protection being set at 1Hz/s measured over 500ms.

In summary, NIE Networks recommends that the UR approves:

1. Amendments to LSG interface protection settings to 1Hz/s with a 500ms time delay as outlined within Appendix 2 of this document.

2. The proposed D-Code modifications outlined in Appendix 2 where references to SSG interface protection have been removed.

Responses to this consultation also referred to the wider RoCoF programme and as a result NIE Networks has included a number of points within this document that it will aim to discuss further with SONI.

After the completion of the additional Strathclyde University research, and NIE Networks' decision on SSG interface protection settings, then the proposed SSG settings will be consulted upon, after which further changes may be proposed for inclusion within the D-Code.

NIE Networks would like to reiterate its commitment to working constructively with all stakeholders to ensure the successful delivery of DS3.

[1] Generation ≥5MW. Predominantly connected at 33kV.
[2] Generation <5MW. Predominantly connected at voltages below 33kV.

Northern Ireland Electricity Networks

2. CONSULTATION OVERVIEW

2.1 Background

Following a consultation period, on 7 May 2014 a decision paper was published in relation to the "Rate of Change of Frequency Modification to the Northern Ireland Grid Code"[3]. This decision paper sets out the role of the Transmission System Operator (TSO) as well as the necessary interaction with the Distribution System Operator (DSO). In particular, Section 3.5 of this decision paper states:

"The generation that will be within the scope of this decision paper will be limited to transmission connected generation and to >5MW power stations connected to the 33kV distribution network"

This section also states that the implementation of the new RoCoF standard will:

"…require support and cooperation from the DSO in respect of consideration of the impact to the 33kV distribution network. This interaction will also be required to ensure coordination with proposed Distribution Code RoCoF requirements."

NIE Networks had previously informed SONI, on 19 September 2013 that "…the new settings will apply to 33kV generators only, and not 11kV connected generators"[4]. With reference to Low Voltage (LV) connected generation, NIE Networks also stated on 20 March 2014 that "NIE Networks do not intend to adjust these settings even if a new 1.0Hz/s standard is approved given the potential islanding risks". NIE Networks believe that their 2013 commitment to amend settings to be compliant with the new RoCoF standard at all 33kV connected generation, which includes all generation >5MW, is consistent with the scope of the May 2014 RoCoF decision paper. Delivery of these changes, as proposed in the recent D-Code modification consultation, would fulfil the requirements placed on NIE Networks by the decision paper.

During the period March to May 2014 when NIE Networks confirmed their position regarding settings amendments at LV connected generation, c207MW of this LV connected generation was already connected to the NIE Networks' distribution system.

Mindful of its statutory and licence obligations to have regard to the safety of the network, in September 2014 NIE Networks' determined that it would be prudent to commission research to quantify and determine if the impact of the proposed change to 33kV connected generation would be acceptable with regards to risk of fatality and out of-phase reclosure of generation. This followed the approach used in GB. It was also requested by SONI that NIE Networks perform the same analysis on generation connected to the LV network to determine if it would be possible to amend their settings also. SONI confirmed that this analysis should be carried out against a RoCoF standard of 2Hz/s. NIE Networks' agreed to proceed on this basis.

In order to perform this analysis NIE Networks' commissioned Strathclyde University, who were regarded as the industry experts in this field, as they had completed similar research for the GB DNOs, to quantify the associated impact of amending the interface protection settings associated with LSG and SSG. To ensure consistency of approach with other GB DNOs NIE Networks agreed to sit on the ENA working group, GC0079 who were engaged in analogous work.

[3] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf
[4] Minutes – Joint NIE/Eirgrid/SONI meeting 19th September 2013

2.2 Research Outcome (Large Scale Generation, LSG)

The outcome of the work by Strathclyde University is that the risk of fatality associated with amending generator interface protection settings, for LSG, resides on the boundary[5] between the Health and Safety Executive's (HSE's)[6] "broadly acceptable" region and "tolerability" region: shown in Figure 1 – LSG Risk of Fatality. The HSE declare that any risks within the tolerability region are acceptable only if all necessary measures have been taken to achieve a level as low as reasonably practicable (ALARP). It is NIE Networks' view that with the prudent approach used in the derivation of the risk figures, measures have been taken to achieve a risk level as low as reasonably practicable. Consequently, the positive outcome of the work done by NIE Networks and Strathclyde University is that amendments to interface protection settings can be progressed for LSG[7], addressing c70% of the generation connected to the distribution system. These proposed amendments to the Distribution Code necessitate that all LSG are compliant with the proposed settings by 31st December 2017. The proposed interface protection settings are shown in Table 2.

Protection Function	Existing Settings	Proposed Settings			
		Power Stations ≥16A/phase and <5MW		Power Stations ≥5MW	
	Setting	Setting	Time Delay	Setting	Time Delay
U/V stage 1	0.9pu	0.9pu	0.5s	0.85pu	3.0s
U/V stage 2	N/A	N/A	N/A	0.6pu	2.0s
O/V	1.1pu	1.1pu	0.5s	1.1pu	0.5s
U/F	48Hz	48Hz	0.5s	48Hz	0.5s
O/F	50.5Hz	50.5Hz	0.5s	52Hz[8]	1.0s
LoM (RoCoF)	0.125 – 0 .4Hz/s	0.125 – 0 .4Hz/s	0s	1.5Hz/s	0.3s
LoM (Vector Shift)	6 – 12deg	N/A		N/A	

TABLE 1

It should however be noted that an additional risk of out-of-phase reclosure[9] exists which will have an associated risk of fatality if the generator suffers catastrophic failure. This risk cannot be quantified as it is dependent on generator technology and geographic location. However, NIE Networks has requested that these LSG perform their own risk assessment to determine if the risk of out-of-phase reclosure is acceptable. This is an important issue that is the responsibility of the generators to complete.

[5] Boundary between the "tolerability" region and "broadly acceptable" region is 1E-06
[6] http://www.hse.gov.uk/comah/assessexplosives/step5.htm
[7] c930MW
[8] Staged up to 52Hz as per Over Frequency Shedding Schedule. Specific setting for generator will be stated in letter to generator.
[9] Out-of-Phase reclosure for LSG = 2.16E-3

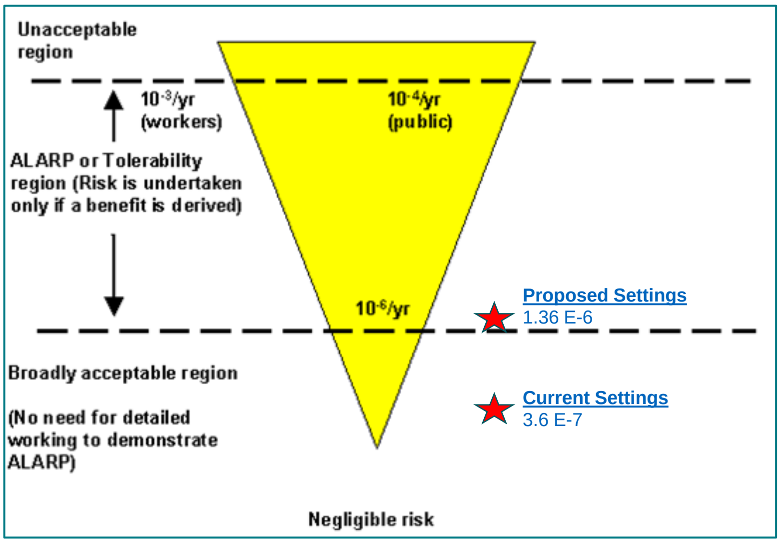

FIGURE 1 – LSG RISK OF FATALITY

2.3 Research Outcome (Small Scale Generation, SSG)

The risk of fatality associated with existing generator interface protection settings, for SSG, resides well within the Health and Safety Executive's (HSE's) "tolerability" region: shown in Figure 2 – SSG Risk of Fatality. Moreover, this risk of fatality figure is not inclusive of the unquantifiable risk of fatality associated with out-of-phase reclosure[10] and therefore, the overall risk of fatality will be higher than that presented. Consequently, NIE Networks has taken the view that introducing additional risk, when the existing risk resides well within the "tolerability" region, cannot be justified and therefore changes to the interface protection settings for SSG will not be allowed. This conclusion reaffirms NIE Networks' position outlined in 2013.

Notwithstanding this and respecting SONI's view that Vector Shift (VS) is not a stable form of interface protection, NIE Networks has decided that the use of VS protection for new SSG connectees should no longer be allowed and RoCoF must be used. The interface protection settings consulted upon are shown in Table 2.

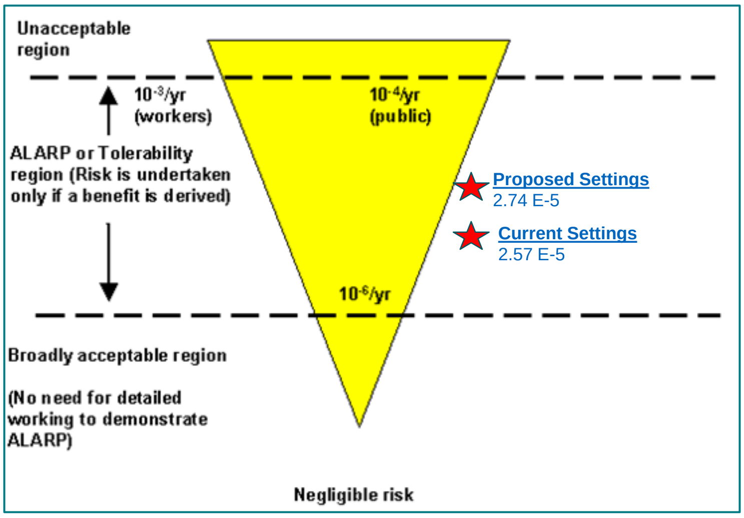

FIGURE 2 - SSG RISK OF FATALITY

[10] Out-of-phase reclosure for SSG = 4.36E-2

3. OVERVIEW OF RESPONSES

3.1 The consultation can be found at the following location: http://www.nienetworks.co.uk/About-us/Distribution-code/DC-review-panel.

3.2 The 13 respondents (from various industry sectors) are listed below:

Company Name
SSE
Northern Ireland Renewables Industry Group + Irish Wind Energy Association
Bord na Móna
ESBI
Tynagh Energy Limited
SONI
Electricity Exchange
Brookfield Renewables
AES
Nordex
Ionic Consulting
RES Group
Respondent who wished to remain Anonymous

3.3 Due to the large number and detailed content of the responses received, an overview of the more significant comments is considered below in Table 2. Detailed commentary around all the responses is provided in Appendix 1.

Response	NIE Networks' Comments
Supportive of LSG settings moving	Many of the respondents stated that they were supportive of NIE Networks' proposal to amend the interface protection settings associated with LSG and requested that this is progressed urgently. NIE Networks would comment that they are committed to ensure that all LSG have amended their interface protection settings by the end of 2017, subject to regulatory approval and LSG making the necessary arrangements to perform the amendment.
Concern around the withstand capability of older plant	Some respondents raised concerns around the withstand capability of generators. This concern was also highlighted by a respondent to a previous NIE Networks consultation on proposed changes to the Rate of Change of Frequency[11]. NIE Networks would comment that the purpose of interface protection is to prevent electrical islanding from occurring, it is not to safeguard the generator against a high RoCoF. The Northern Ireland Distribution Code currently requires all independent generating plant > 100kW to remain connected to the Distribution Network for a Rate of Change of Frequency up to 1Hz/s measured over 500ms. The Utility Regulator in 2014 approved in principle Grid Code modifications to include a RoCoF standard of 1Hz/s measured over 500ms. Consequently, generation will be obligated to remain connected to the system for a RoCoF up to the D-Code and Grid Code standards. If a generator is not prepared to remain connected to the system for RoCoFs less than the D-Code and Grid Code standards then they should seek a derogation from the Utility Regulator. The generator may wish to employ protection to disconnect from the system for RoCoFs outside of these standards. Moreover, NIE Networks has become aware of concerns among demand customers with regards to adopting a new RoCoF standard of 1Hz/s and the associated impact on their systems and processes. NIE Networks point out that the responsibility of

[11] http://www.nienetworks.co.uk/documents/D-code/RATE-OF-CHANGE-OF-FREQUENCY-DISTRIBUTION-CODE-MODI.aspx

	managing system frequency is a function of SONI; consequently, it is SONI's responsibility to assess the impact on demand customers and quality of supply as outlined in the Utility Regulator's decision paper[12] in 2014. To fulfil this requirement SONI commissioned research to perform a high level assessment of short frequency deviations with regards to any possible effects on demand customers[13]. Whilst this high level report identified that the risks for infrequent or inadvertent tripping up to a RoCoF level of 1 Hz/s are expected to be low it does acknowledge that "…controlled power electronics are initially more prone to tripping due to RoCoF events as opposed to uncontrolled power electronics. However the controlled power electronic settings can be adjusted to mitigate tripping risks that a higher RoCoF level might cause. Initially this means that controlled power electronics might need attention following a change of Grid Code (e.g. RoCoF)." Moreover, the report identified that the likely specific areas that could be impacted due to the new RoCoF standard are: Response of the demand site to the RoCoF event; impacts on power quality provided to the site, operational impacts on the demand site and impacts on embedded generation within the site. Industries where controllable power electronics are prevalent include Pharmaceutical, Semiconductor, Alumina, Data centres, Chemical and the Food & Drink industry. On the basis of this report NIE Networks would request visibility of the work carried out by SONI to determine if controlled power electronics need attention following a change of Grid Code (RoCoF). NIE Networks would also request that this report is consulted on by industry to establish if industry agrees with the findings in the report. Finally NIE Networks would request SONI consider more detailed quantitative analysis to ensure that more robust statements can be made around the RoCoF withstand capability of demand and generation.

[12] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf

[13] DNV GL. (2016) "Assessment of higher RoCoF events on demand customers: research to perform a high level assessment of short frequency deviations with regards to any possible effects on demand customers".

Concern that SSG settings are not being moved and the potential impact of this	Many respondents raised concerns regarding NIE Networks proposal to not amend the interface protection settings associated with SSG and the impact of this decision. They also pointed to the fact that the impact of this decision has not been assessed within the consultation reports. With regards to this NIE Networks would make the following comments: • The decision paper issued by the Utility Regulator in 2014 states that "The generation that will be within the scope of this decision paper will be limited to transmission connected generation and to >5MW power stations connected to the 33kV distribution network". The section also states that the implementation of the new RoCoF standard will: "…require support and cooperation from the DSO in respect of consideration of the impact to the 33kV distribution network. This interaction will also be required to ensure coordination with proposed Distribution Code RoCoF requirements." As such NIE Networks believe that the proposal within the consultation document fulfils the obligations outlined in the Utility Regulator's 2014 decision paper. • NIE Networks informed SONI in 2013 that LoM settings would not be moved at Generation <5MW, however at the request of the SONI, NIE Networks agreed to extend the scope of the studies to also look at the possibility of moving LoM settings on generators <5MW. NIE Networks were made fully aware of the system operation issues that would arise should LoM settings not be moved on generation >5MW. At no stage did SONI convey similar concerns should LoM settings not be moved on generation <5MW, indications from SONI at the time were that other balancing options were available to solve any system operation issues that would arise due to settings not being moved on generation <5MW. It is also worth noting SONI did not include the risk associated with not moving settings at generation <5MW in the risk report presented to the DS3 advisory group in September 2014 and again September 2015. Based on the above points NIE Networks believe that their position to not amend the interface protection settings associated with SSG as outlined within the consultation document is justified. SONI, in response to this consultation have now stated that following actions will result if the interface protection settings associated with SSG are not amended: • Operational SNSP limit cannot increase above 65% • Operational ROCOF limit cannot increase from current 0.5Hz/s limit • Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8. • Minimum inertia levels on the system cannot be reduced. Notwithstanding the points outlined above, through engagement with the SEM Committee, TSO and after reviewing the responses to this consultation, NIE Networks has committed to further consider mitigation measures for SSG to determine if there is a quantum of SSG interface protection settings that can be amended. This is outlined within section 4 of this document.

Concern that LSG deadline of December 2017 may not be met if new relays have to be procured	NIE Networks appreciate that the proposed timescales are challenging, especially if new relays need to be procured, installed and commissioned. However, NIE Networks anticipate that the majority of relays will be capable of accepting the new settings and therefore only require a settings change and NIE Networks witness testing. NIE Networks has ensured that suitable resources have been made available for witness testing purposes. NIE Networks therefore believe that the risk of delaying the implementation plan is more significant than the risk that a small number of generators may not be able to meet the proposed deadlines. Consequently, NIE Networks do not propose amendments to the implementation timescales associated with LSG.

TABLE 2

4. RECOMMENDATIONS

Having reviewed the responses to the consultation, NIE Networks recommends that the UR approves:

1. Amendments to Large Scale Generator (LSG) interface protection settings to 1Hz/s with a 500ms time delay as outlined within Appendix 2 of this document.

2. The proposed D-Code modifications outlined in Appendix 2 which have removed any reference to SSG interface protection.

After the completion of the additional Strathclyde University research, and NIE Networks' decision on SSG interface protection settings, the proposed settings for SSG will be consulted upon and included within the D-Code

4.1.1 Supporting Information for Recommendations - Large Scale Generation

SONI had previously informed NIE Networks that the interface protection settings to be studied in the Strathclyde University analysis should remain stable for a 2Hz/s trace which they provided. This was to cover the loss of the Louth-Tandragee 275 kV double circuit, resulting in the commutation blocking of the Moyle Interconnector. Studies have shown that in this rare situation, if not managed correctly, there may be a RoCoF experienced up to 2Hz/s. The decision to ensure stability of interface protection for 2Hz/s as opposed to the 1Hz/s Grid Code standard as documented by the Utility Regulator in their 2014 decision paper[14] has been raised by stakeholders. This 2Hz/s 'standard' is different from GB and ROI which are both 1Hz/s.

If interface protection settings are required to remain stable for 1Hz/s as opposed to 2Hz/s, as previously stated by SONI, this will allow NIE Networks to adopt lower interface protection settings, therefore reducing the risk of fatality and out-of-phase reclosure. This measure would help to reduce the risk associated with SSG and when combined with other risk mitigation measures may present a risk value low enough to allow NIE Networks to accept amendments to the interface protection of SSG. To ensure consistency across all voltage levels as well as consistency with GB and ROI NIE Networks recommends that a 1Hz/s setting is approved for LSG. Additional justification for this is provided below:

- The Strathclyde University studies determined that a 1Hz/s relay setting with a time delay of 500ms will remain stable for RoCoF events well in excess of 1Hz/s measured over 500ms (see Figure 3).

[14] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf

- SONI has previously stipulated a relay setting of 1Hz/s with a time delay of 500ms on a transmission connected windfarm which will be exposed to the same RoCoF as distribution connected generation.

- The NIE Networks Distribution Code has a RoCoF withstand requirement of 1Hz/s measured over 500ms in line with the RoCoF standard proposed in the UR RoCoF decision paper. Whilst NIE Networks can enforce a RoCoF relay setting at the interface in excess of the 1Hz/s standard, they cannot force the generator to increase their internal RoCoF setting in excess of the 1Hz/s standard. Consequently, generators could disconnect from the system at 1Hz/s measured over 500ms irrespective of the interface protection settings.

- Whenever the second North-South Interconnector is built the risk of a 2Hz/s RoCoF event will be mitigated.

4.1.2 Supporting Information for Recommendations - Small Scale Generation

Taking into consideration the responses to this consultation and engagement with stakeholders including the SEMC, NIE Networks has requested that Strathclyde University assess the impact on risk of mitigation measures which will include the impact of interface protection set at 1Hz/s as opposed to 1.5Hz/s. Following the assessment NIE Networks will determine if there is a quantum of SSG interface protection settings that can be amended. After the completion of the additional Strathclyde University research in October 2017, the proposed SSG settings will be consulted upon and if approved by UR then included within the D-code.

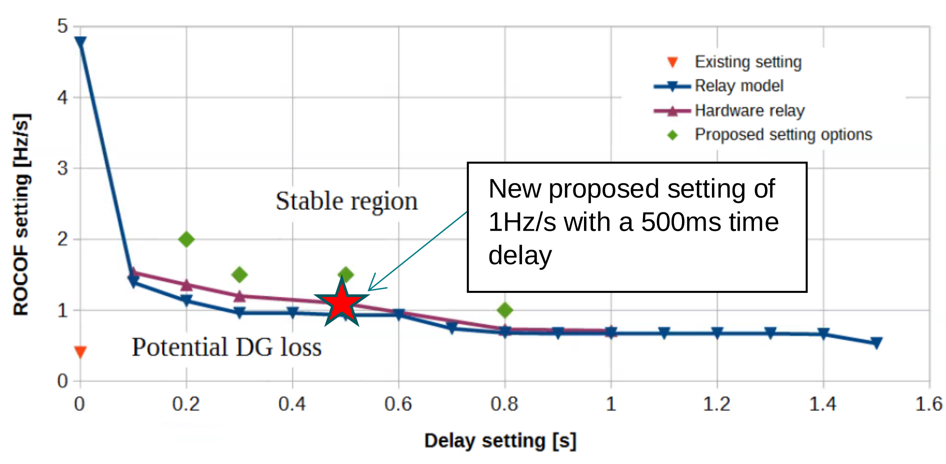

Figure 12. Proposed ROCOF setting options mapped against established stability settings (simulated events)

FIGURE 3

4.2 Points for further discussion with SONI

Responses to the consultation also referred to the wider RoCoF programme and NIE Networks has therefore included a number of points that NIE Networks will aim to discuss further with SONI.

4.2.1 Withstand Capability

Some respondents raised concerns regarding the withstand capability of older generation. Moreover, NIE Networks has become aware of concerns among demand customers with regards to adopting a new RoCoF standard of 1Hz/s and the associated impact on their systems and processes. On the basis of the report commissioned by SONI[15] NIE Networks would suggest that:

- **Visibility is provided of the work carried out by SONI to determine if controlled power electronics need attention following a change of Grid Code (RoCoF).**
- **The high level report on assessment of higher RoCoF events on demand customers is consulted on by industry to establish if industry agree with the findings and are aware of the potential implications of a higher RoCoF standard.**
- **SONI consider more detailed quantitative analysis to ensure that more robust statements can be made around the withstand capability of demand and generation.**

4.2.2 Short Term Frequency Response

In 2014 SONI commissioned research titled: An investigation into the Short-term Frequency Response of the Ireland and Northern Ireland Power System[16]. This analysis concluded that even at low levels of secondary tripping (40MW) the impact of the trip subsequent to the initial imbalance could lead to a frequency nadir which would trigger under frequency load shedding. The analysis went on to examine the relationship between frequency nadir and SNSP and concluded the following:

"The trend of the lowest nadirs occurring with SNSP levels 55-65% are illustrated, assuming 2% of wind generation trips due to anti-islanding relays. As the SNSP increases beyond 65% the frequency deviation is lessened, as conventional generators are dispatched down and the size of the largest infeed reduces (note that other system issues develop at higher SNSP levels but are not considered in this report)"

Following further analysis on this relationship the report concludes:

"In the 500 high SNSP test cases, the system nadir is better in cases in which higher levels of wind generation are tripped – this is due to the lower size of infeed at times of high wind . As wind penetration increases on the system, more and more generation is backed off, resulting in a double effect of reduced trip size and increased headroom on generators. As a result the system appears to better handle larger wind trips. Similarly to Figure 6, from a frequency nadir performance perspective, the system is better able to cope with secondary trips at times of small infeed trips, which tend to coincide with very high SNSP cases"

Whilst the analysis in the report concludes that secondary tripping of generation due to anti-islanding relays will occur when high RoCoFs are experienced, it is clear also that the impact of the secondary tripping is less as SNSP increases beyond 65%. This analysis was however carried out based on 2% secondary tripping (representing a relatively small amount of between 20MW & 80MW of wind in each case). NIE Networks understand that SONI now believe that the volume of generation <5MW, which is well in excess of the 2% figure considered in this study, could exacerbate the secondary tripping issue but to date SONI has been unable to quantify the volume of generation subject to secondary tripping that the system can sustain.

[15] DNV GL. (2016) "Assessment of higher RoCoF events on demand customers: research to perform a high level assessment of short frequency deviations with regards to any possible effects on demand customers".
[16] An Investigation into the Short-term Frequency Response of the Ireland and Northern Ireland Power System

NIE Networks, in line with the future work recommendations contained in the report, would ask that SONI carry out further analysis to quantify the extent of the secondary tripping issue using a more detailed network model to confirm the key findings.

4.2.3 Alternative Solutions

NIE Networks' believes that other solutions may be available in order to manage the system if the interface protection settings associated with SSG are not amended. These solutions were considered within SONI and Eirgrid's Alternative RoCoF project. NIE Networks would like to draw SONI and the Utility Regulator's attention to the findings of the Phase 2 report[17] with specific attention to the following sections:

The Executive Summary on page 4 states "Synchronous inertia is a solution to maintaining RoCoF within ± 0.5 Hz/s" and "Synthetic inertia could be a solution to maintaining RoCoF within ± 0.5 Hz/s". Further on the report states that "Our analysis presented within this report illustrates that there are credible alternative solutions to the RoCoF issue" and in the conclusion it states "We believe that the project has demonstrated that alternative solutions are available to resolve the RoCoF issue. At this stage, we believe that further analysis on alternative solutions to the RoCoF issue should only be performed if results from the primary RoCoF projects indicate that alternatives are required".

In light of the fact that NIE Networks communicated to SONI in 2013 that the interface protection settings of SSG will not be amended and that SONI have now suggested that this decision will have the following impact , NIE Networks would like to understand what further analysis SONI has performed on alternatives to RoCoF:

- Operational SNSP limit cannot increase above 65%
- Operational ROCOF limit cannot increase from current 0.5Hz/s limit
- Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8.
- Minimum inertia levels on the system cannot be reduced.

5. CONCLUSIONS & NEXT STEPS

On 18 July 2017 NIE Networks issued a D-Code consultation on Generator Interface Protection Amendments. This consultation proposed that the current settings associated with LSG connected to the NIE Networks distribution system should be amended to allow higher levels of SNSP on the system. The consultation also proposed that the settings associated with SSG should not be amended due to the higher risk of fatality and out of phase reclosure associated with islanding of SSG.

In total 13 responses to this consultation were received. Some of the more significant views are summarised below:

- Concerns around the withstand capability of older plant
- Supportive of LSG settings moving

[17] http://www.eirgridgroup.com/site-files/library/EirGrid/RoCoF-Alternative-Solutions-Project-Phase-2-Report-Final.pdf

- Concerns that SSG settings are not being moved and the potential impact of this

- Concerns that the LSG deadline of December 2017 may not be met if new relays have to be procured

Having reviewed the responses to the consultation NIE Networks has proposed recommendations to the Utility Regulator to allow the progress of the amendment of generator interface protections settings. These recommendations are outlined below:

1. Amendments to Large Scale Generator (LSG) interface protection settings to 1Hz/s with a 500ms time delay as outlined within Appendix 2 of this document.

2. The proposed D-Code modifications outlined in Appendix 2 which have removed any reference to SSG interface protection.

After the completion of the additional Strathclyde University research, and NIE Networks' decision on SSG interface protection settings, then the proposed SSG settings will be consulted upon, after which further changes may be proposed for inclusion within the D-Code.

Responses to this consultation also referred to the wider RoCoF programme and as a result NIE Networks has included a number of points within this document that it will aim to discuss further with SONI i.e.

- Visibility is provided of the work carried out by SONI to determine if controlled power electronics need attention following a change of Grid Code (RoCoF).

- The high level report on assessment of higher RoCoF events on demand customers is consulted on by industry to establish if industry agree with the findings and are aware of the potential implications of a higher RoCoF standard.

- SONI consider more detailed quantitative analysis to ensure that more robust statements can be made around the withstand capability of demand and generation.

- NIE Networks, in line with the future work recommendations contained in the report[18], would ask that SONI carry out further analysis to quantify the extent of the secondary tripping issue using a more detailed network model to confirm the key findings.

- In light of the fact that NIE Networks communicated to SONI in 2013 that the interface protection settings of SSG will not be amended and that SONI have now suggested that this decision will have significant impacts on the DS3 work program, NIE Networks would like to understand, in line with the recommendations contained within the RoCoF Alternatives Phase 2 Report[19], what further analysis SONI has performed on alternatives to RoCoF.

NIE Networks will review the findings of the Strathclyde University research into SSG in October 2017 and will share this with UR, SEMC and other interested stakeholders as requested.

NIE Networks would like to reiterate that it is committed to working constructively with all stakeholders to ensure the successful delivery of the DS3 program.

[18] An Investigation into the Short-term Frequency Response of the Ireland and Northern Ireland Power System

[19] http://www.eirgridgroup.com/site-files/library/EirGrid/RoCoF-Alternative-Solutions-Project-Phase-2-Report-Final.pdf

APPENDIX 1

The table below gives an overview of the respondent's feedback to the consultation and the corresponding NIE Networks' comments.

<table>
<tr><th>Consultee</th><th></th></tr>
<tr><td rowspan="2">SSE</td><td><u>Consultee Comment:</u>
We welcome the consultation proposals to change the ROCOF settings for generators >5MW. We request that the changes to NIE distribution code and changes in generator protection systems are completed as soon as possible and by the end of 2017 at the latest. However, we are very concerned that the ROCOF settings for generators <5MW will not be changed. A key concern is that this substantial impact has not been defined within the consultation.

<u>NIE Networks' Response:</u>
The respondent correctly identifies that the impact of not amending the settings associated with generators <5MW has not been defined within the consultation. This is due to a number of reasons:
A working understanding had been established between SONI and NIE Networks that if the settings associated with generators <5MW could not be amended then SONI could operate the system in a manner to accommodate this without jeopardising the DS3 programme. After this consultation went live SONI has subsequently stated that if the settings associated with generators <5MW cannot be amended then the ramifications are significant, which include:
Operational SNSP limit cannot increase above 65%
Operational ROCOF limit cannot increase from current 0.5Hz/s limit
Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8.
Minimum inertia levels on the system cannot be reduced.
The decision paper issued by the Utility Regulator in 2014[20] states that "The generation that will be within the scope of this decision paper will be limited to transmission connected generation and to >5MW power stations connected to the 33kV distribution network". The section also states that the implementation of the new RoCoF standard will: "…require support and cooperation from the DSO in respect of consideration of the impact to the 33kV distribution network. This interaction will also be required to ensure coordination with proposed Distribution Code RoCoF requirements."
As such NIE Networks believe that the proposal within the consultation document fulfils the obligations outlined in the Utility Regulator's 2014 decision paper. Notwithstanding the points outlined above NIE Networks has committed to consider mitigation measures for SSG as outlined within section 4.</td></tr>
<tr><td><u>Consultee Comment:</u>
We have a specific query in regards to generators who are currently rated to 1Hz/s RoCoF; where current Connection Condition 7.12.2b (Now updated to CC7.14.2b) allows this generating plant to trip off for RoCoF in excess of 1Hz/s. The supplementary proposed new RoCoF protection settings require generators to stay online for RoCoF of up to 1.5Hz/s. In this case, given the age and technology type of the generator, increased RoCoF withstand capability is not possible. It would be our contention that site specific protection settings should be implemented which help NIE in their operation of the Distribution Network but which also take account of the specific generators technical and physical limitations. CC7.11 would seem to provide this possibility: "Suitable Protection arrangements and settings will depend upon the particular Generator's installation and the requirements of the Distribution System. These individual requirements must be ascertained in discussions with the DNO." Can NIE confirm that in instances like this that NIE and the individual generator will work out a solution which is agreeable to both parties?</td></tr>
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[20] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf

	NIE Networks' Response: The purpose of interface protection is to prevent electrical islanding from occurring, it is not to safeguard the generator against a high RoCoF. The Northern Ireland Distribution Code currently requires all independent generating plant > 100kW to remain connected to the Distribution Network for a Rate of Change of Frequency up to 1Hz/s measured over 500ms unless disconnected by the correct operation of the G59 protection. Consequently, a generator may wish to disconnect from the distribution system for RoCoFs in excess of 1Hz/s measured over 500ms using their internal protection. If a generator is not prepared to remain connected to the system for RoCoFs less than 1Hz/s measured over 500ms then they should seek derogation from the Utility Regulator.
	Consultee Comment: We have a specific query in regards to the time delays outlined in the table in section CC7.11. Can NIE confirm that these delays relate only to the specific protection function to timeout in the relay, or do these time delays relate to the entire clearance time which would include time for the relay to operate, the Circuit Breaker to operate as well as clearing time for arcing? **NIE Networks' Response:** The time delay of 300ms included within the consultation document is specifically referring to the inherent time delay that must be inputted into the protection relay. It does not take into consideration the circuit breaker operation time or other associated timings. For the avoidance of doubt, once the interface protection has instigated a trip there should no inherent time delay associated with the CB operation.
	Consultee Comment: NIE has stipulated that any alterations to G59 protection for >5MW installations needed to be witnessed by NIE staff. Can NIE confirm it has the resources to facilitate all witness testing by the end of 2017? **NIE Networks' Response:** NIE Networks has made provisions to ensure that all witness testing can be facilitated before the end of 2017. Notwithstanding this if, due to unforeseen circumstances, witness testing cannot be facilitated prior to the end of 2017 due to an NIE Networks delay then generators will not be unduly penalised by NIE Networks.
Northern Ireland Renewables Industry + Irish Wind Energy Association	**Consultee Comment:** We welcome the consultation proposals to change the ROCOF settings for generators >5MW. We request that the changes to NIE distribution code and changes in generators protection systems are completed as soon as possible and by the end of 2017 at the latest as proposed in the NIE documents. We are very concerned that the ROCOF settings for generators <5MW will not be changed. This could have a substantial impact on the Northern Ireland renewable industry, and a key concern is that this substantial impact has not been defined within the consultation. It is noted that the incremental risk between the different settings appears to be relatively small and that the risk remains within the 'tolerable' band. In the Costs and Benefit section it is shown that there is a substantial benefit to the consumer in lower SEM costs from increasing the ROCOF settings and therefore the SNSP limits. What is very concerning is that the impact on SNSP limits of this decision is not detailed in the NIE consultation documents. It is not clear if this decision will result in the SNSP limit not being increased further. We would request that there is further dialogue and analysis between NIE and the Transmission System Operators on the impact of not changing the SNSP limits. We would also request that further analysis is completed by NIE and their consultants on potential mitigation measures. In summary, NIRIG and IWEA request the decision to increase ROCOF settings for >5MW is approved and implemented as soon as possible. We would request that the complexity of the SSG decision should not delay the approval of the LSG decision. We have major concerns on the proposals to not increase the ROCOF settings for <5MW generation. We request that NIE, the System Operators, the Regulators and the SEM committee have further dialogue on the SSG issue. **NIE Networks' Response:** NIE Networks are fully committed to ensure that all LSG have amended their interface protection

	settings by the end of 2017. However, we do recognise that this is dependent on the Utility Regulator making a timely decision on the proposed amendments to the Distribution Code and individual generators ensuring that they make the necessary arrangements, including NIE Networks' witness testing, to align with the new settings. The respondent correctly identifies that the increase in risk for generators <5MW is relatively small, especially when compared to the very large increase in risk for generators >5MW. This comment however needs to viewed in the context of the HSE ALARP diagram where even though there is a significant increase in the risks associated with generators >5MW the actual risk still resides on the boundary of the broadly acceptable region. This is in contrast to the risks associated with generators <5MW, where although the increase in risk is much smaller the actual risk resides well into the tolerability region. NIE Networks concluded that the actual risk for generators >5MW was in an area of ALARP that was acceptable, however the risk associated with generators <5MW was in area of ALARP where increased risk could not be justified. This must also be viewed in the context that a working understanding had been established between SONI and NIE Networks that if the settings associated with generators <5MW could not be amended then SONI could operate the system in a manner to accommodate this without jeopardising the DS3 programme. After this consultation went live SONI has subsequently stated that if the settings associated with generators <5MW cannot be amended then the ramifications are significant, which include: o Operational SNSP limit cannot increase above 65% o Operational ROCOF limit cannot increase from current 0.5Hz/s limit o Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8. o Minimum inertia levels on the system cannot be reduced. Notwithstanding the points outlined above NIE Networks has committed to consider mitigation measures for SSG as outlined within section 4. NIE Networks has also proposed to progress the amendment of interface protection settings associated with LSG, subject to Utility Regulator approval, which aims to be complete by the end of 2017.
Bord na Móna	**<u>Consultee Comment:</u>** As such amendments to facilitate renewables should be grounded in progressing with proven improvements. BnM commend the proposed changes that have been made with regards to RoCoF setting for generators >5M, further supporting increased SNSP on the system. However, contrary to the progression with larger plant, BnM do not agree with the treatment of <5MW generators and the proposed RoCoF treatment. They will have a threshold of 0.125Hz/s with a maximum allowable tolerance of 0.4 Hz/s for cases where a high likelihood of nuisance tripping is demonstrated. This is divergent with the goals of the Facilitation of Renewables study, 2010 and BnM believe that it will have the effect of diluting the progression seen in the larger units. From an operational perspective, the very concept of disconnecting any unit below 5MW would impact on SONI's ability to operate the system at higher SNSP and cause larger plants to trip in an already turbulent environment. BnM acknowledge that there is a safety issue here that requires consideration, however we would like to query if higher RoCoF thresholds would be feasible if supplementary mechanisms were imposed to improve the reliability of Loss of Mains detection. **<u>NIE Networks' Response:</u>** NIE Networks acknowledge the concerns raised by BnM with respect to the impact on operating the system at higher levels of SNSP with not amending the interface protection settings associated with SSG. However, as outlined above the decision paper published by the UR in 2014 did not obligate NIE Networks to consider the impact of the proposed RoCoF standard on SSG. Moreover, a working understanding had been established between NIE Networks and SONI that if SSG could not be moved then SONI could operate the system to accommodate this without jeopardising the DS3 programme. Notwithstanding the points outlined above and in relation to BnM's specific question "higher RoCoF thresholds would be feasible if supplementary mechanisms were imposed to improve the reliability of Loss of Mains detection", NIE Networks has committed to consider mitigation measures, to reduce the risks associated with SSG and potentially enable SSG amendments to proceed. This process is outlined in more detail in section 4.

ESBI	**<u>Consultee Comment:</u>** As outlined in the consultation the NIE Networks' Generator Interface Protection Amendment Project is a component of a wider industry level project to adapt to increases in the potential RoCoF levels resulting for changes in the system operations driven by increasing the system non synchronous generations (SNSP). With these high SNSP level beginning required to allow the 2020 RES-E targets to be achieved. Given the proposed generator protection setting will result in a significant volume of distribution connected generation in Northern Ireland remaining sensitive to lower levels of RoCoF the impact of the consultation proposals on the wider RoCoF project must be reviewed. This is particularly salient given the scale of the investment that has been made by the industry in the implementation of the RoCoF. This is clearly a question that NIE Networks cannot be expected to answer alone however GWM would welcome, given their expertise in the area, if NIE Networks considers if there are any innovative generation interface protection topologies that would support the implementation of the RoCoF project while ensuring the safe continued operation of the system. **<u>NIE Networks' Response:</u>** The respondent raises a specific point if NIE Networks considers if there are any innovative generation interface protection topologies that would support the implementation of the RoCoF project while ensuring the safe continued operation of the system. While there have been developments in academia with regards to alternative Loss of Mains technologies, NIE Networks are unaware of any fully operational innovative Loss of Mains technologies implemented in other jurisdictions. NIE Networks will however keep abreast of developing technologies through their engagement with the ENA and other industry forums.
Ionic Consulting	**<u>Consultee Comment:</u>** We fully support the NIRIG and IWEA position in response to this consultation and reiterate their concerns on the proposals to not increase the ROCOF settings for <5MW generation. We welcome the consultation proposals to change the ROCOF settings for generators >5MW. We request that the changes to NIE distribution code and changes in generator protection systems are completed as soon as possible and by the end of 2017 at the latest. However, we are very concerned that the ROCOF settings for generators <5MWwill not be changed. A key concern is that this substantial impact has not been defined within the consultation. We request that NIE, the System Operators, the Regulators and the SEM committee have further dialogue on the SSG issue. **<u>NIE Networks' Response:</u>** NIE Networks are fully committed to ensure that all LSG have amended their interface protection settings by the end of 2017. However, we do recognise that this is dependent on the Utility Regulator making a timely decision on the proposed amendments to the Distribution Code and individual generators ensuring that they make the necessary arrangements, including NIE Networks' witness testing, to align with the new settings. The respondent raises a concern that the substantial impact of not amending settings associated with generation <5MW has not been defined within the consultation. This is due to a number of reasons: 1. A working understanding had been established between SONI and NIE Networks that if the settings associated with generators <5MW could not be amended then SONI could operate the system in a manner to accommodate this without jeopardising the DS3 programme. After this consultation went live SONI has subsequently stated that if the settings associated with generators <5MW cannot be amended then the ramifications are significant, which include: ○ Operational SNSP limit cannot increase above 65% ○ Operational ROCOF limit cannot increase from current 0.5Hz/s limit ○ Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8. ○ Minimum inertia levels on the system cannot be reduced.

	2. The decision paper issued by the Utility Regulator in 2014[21] states that "The generation that will be within the scope of this decision paper will be limited to transmission connected generation and to >5MW power stations connected to the 33kV distribution network". The section also states that the implementation of the new RoCoF standard will: "…require support and cooperation from the DSO in respect of consideration of the impact to the 33kV distribution network. This interaction will also be required to ensure coordination with proposed Distribution Code RoCoF requirements." As such NIE Networks believe that the proposal within the consultation document fulfils the obligations outlined in the Utility Regulator's 2014 decision paper. Notwithstanding the points outlined above NIE Networks has committed to consider mitigation measures for SSG as outlined within section 4.
Renewable Energy Systems	**<u>Consultee Comment:</u>** We welcome the review of generator interface protection arrangements to enable the Northern Ireland grid to support a greater penetration of renewable non-synchronous generation. In particular, we support the modifications and protection settings relating to all Power Stations ≥5MW and support their implementation as soon as possible. We, however, do not agree with the proposals for the Power Stations ≥16Amps/phase and <5MW (small scale generation) connected prior to 1st October 2017 to maintain their contracted protection settings and do not support the proposed RoCoF settings for new small scale generation (SSG). Given the significant amount of SSG already on the system and which will only increase over time, our concern is how the significant amount of SSG MW that would disconnect in the event of a ROCOF event would be managed. The consultation paper and supporting document do not mention how many MW of SSG could be disconnected if RoCoF is >0.4Hz/s which is an important consideration for TSOs. TSOs would need to hold sufficient frequency response reserves to manage this contingency and assess if the costs are affordable. If TSOs cannot procure sufficient reserves at acceptable prices then SNSP limits would have to be maintained at lower levels, grid curtailment would remain elevated, leading to lower levels of renewable energy investment and renewable electricity targets being missed. We therefore request that the proposal RoCof settings for the SSG be reviewed in consultation with TSOs. Whilst we would support the earliest implementation of the proposed changes for Power Stations ≥5MW, we are slightly concerned over the specification of a hard date of 31st December 2017 for the completion of the protection changes. This is because from the date the Distribution Codes changes are approved, there may be not enough time for the procurement, installation and commissioning of the required equipment. We would propose setting a relative period from approval of Distribution Code modifications, for example within 6 months or some other period considered adequate for the completion of the required works. We do not make this suggestion in an attempt to delay the changes, but in the interest of having an orderly process with realistic timelines. **<u>NIE Networks' Response:</u>** The respondent correctly states that the consultation paper or supporting document do not mention how many MW of SSG could be disconnected if RoCoF is >0.4Hz/s which is an important consideration for SONIs. However, NIE Networks provide monthly to SONI figures on the volumes of SSG connected to the distribution system. NIE Networks also present to SONI the interface protection technology and settings employed by each generator. Consequently, NIE Networks provide to SONI the necessary information to enable them to determine the volume of generation that would disconnect from the system if RoCoF is >0.4Hz/s. The respondent also pointed out that additional reserve could be carried if the settings associated with SSG are not amended. NIE Networks believe that other solutions may be available in order to manage the system if the interface protection settings associated with SSG are not amended. These solutions were considered within SONI and Eirgrid's Alternative RoCoF project. NIE Networks would like to draw SONI and the Utility Regulator's attention to the findings of the Phase 2 report with specific attention to the following sections: The Executive Summary on page 4 states "Synchronous inertia is a solution to maintaining RoCoF within ± 0.5 Hz/s" and "Synthetic inertia could be a solution to maintaining RoCoF within ±

[21] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf

	0.5 Hz/s". Further on the report states that "Our analysis presented within this report illustrates that there are credible alternative solutions to the RoCoF issue" and in the conclusion it states "We believe that the project has demonstrated that alternative solutions are available to resolve the RoCoF issue. At this stage, we believe that further analysis on alternative solutions to the RoCoF issue should only be performed if results from the primary RoCoF projects indicate that alternatives are required". In light of the fact that NIE Networks communicated to SONI in 2013 that the interface protection settings of SSG will not be amended and that SONI have now suggested that this decision will have the following impact , NIE Networks would like to understand what further analysis SONI has performed on alternatives to RoCoF: • Operational SNSP limit cannot increase above 65% • Operational ROCOF limit cannot increase from current 0.5Hz/s limit • Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8. • Minimum inertia levels on the system cannot be reduced. NIE Networks appreciate that the proposed timescales are challenging, especially if new relays need to be procured, installed and commissioned. However, NIE Networks anticipate that the majority of relays will be capable of accepting the new settings and therefore only require a settings change and NIE Networks witness testing. NIE Networks therefore believe that the risk of delaying the implementation plan is more significant than the risk that a small number of generators may not be able to meet the proposed deadlines. Consequently, NIE Networks do not propose amendments to the implementation timescales associated with LSG.
Tynagh Energy Limited	**<u>Consultee Comment:</u>** TEL are wholly supportive of the DS3 programme and have invested significant time, effort and expenditure to comply with the new 1Hz/s RoCoF standard required in Ireland. This consultation clearly outlines the importance of the revised protection settings in the context of RoCoF, but the impact due to the exclusion of Small Scale Generation from the protection settings revision has not been documented in the paper. If this decision on the small-scale generation interface protection settings has implications for the implementation of the new RoCoF standard, then TEL would urge NIE Networks and SONIs to determine the subsequent steps required to solve the issue and ensure the timely facilitation of the DS3 objectives. **<u>NIE Networks' Response:</u>** The respondent states that the impact of not amending SSG interface protection settings has not been documented within the paper. This is due to a number of different reasons: • As previously outlined the decision paper published by the UR in 2014 did not obligate NIE Networks to consider the impact of the proposed RoCoF standard on SSG. • A working understanding had been established between NIE Networks and SONI that if SSG could not be moved then SONI could operate the system to accommodate this without jeopardising the DS3 programme. Notwithstanding the points outlined above, NIE Networks has committed to consider mitigation measures, to reduce the risks associated with SSG and potentially enable SSG amendments to proceed. This process is outlined in more detail in section 4.
SONI	**<u>Consultee Comment:</u>** The analysis conducted does not demonstrate the appropriate balance of context, risk, additional mitigation and costs that are required to justify the findings. **<u>NIE Networks' Response:</u>** NIE Networks, as part of SONI-DSO implementation project established by the Utility Regulator (UR) decision paper on a 1Hz/s NI RoCoF standard, engaged in studies to determine the possibility of moving Loss of Mains (LoM) settings on generators >5MW and connected to the 33kV distribution network. This approach is in line with Section 3.5 of the UR decision paper on RoCoF: *"The generation that will be within the scope of this decision paper will be limited to transmission connected generation and to >5MW power stations connected to the 33kV distribution network"* NIE Networks informed SONI in 2013 that LoM settings would not be moved at Generation <5MW, however at the request of the SONI, NIE Networks agreed to extend the scope of the

SONI	studies to also look at the possibility of moving LoM settings on generators <5MW. NIE Networks were made fully aware of the system operation issues that would arise should LoM settings not be moved on generation >5MW. At no stage did SONI convey similar concerns should LoM settings not be moved on generation <5MW, indications from SONI at the time were that other balancing options were available to solve any system operation issues that would arise due to settings not being moved on generation <5MW. It is also worth noting SONI did not include the risk associated with not moving settings at generation <5MW in the risk report presented to the DS3 advisory group in September 2014 and again September 2015. This is the context under which NIE Networks has been working as part of SONI-DSO Implementation project. The risks associated with moving LoM settings were established as part of the studies and given that early indications from the studies were that there was a high possibility that LoM settings could be moved at >5MW generation then additional mitigation measures were not considered necessary. The studies associated with moving LoM settings at generation <5MW did not give early indication of a positive outcome, this information was communicated to SONI and given that no concerns were raised then NIE Networks did not consider additional mitigation measures were appropriate. Given the context under which NIE Networks were engaged in SONI-DSO implementation project, and given that no additional mitigation measures were requested by SONI in respect of LoM settings not being moved at generation <5MW, then NIE Networks did not consider that costs should be included in the analysis. The studies that NIE Networks carried out were to determine if the risks associated with electrical islanding were acceptable in line with HSE(NI) guidelines. NIE Networks do not therefore agree with the concern raised by SONI that the analysis conducted does not demonstrate the appropriate balance of context, risk, additional mitigation and costs as these were not the context under which the NIE Networks carried out the analysis.
	Consultee Comment: Insufficient consideration is given to alternatives or costs in implementing alternate protection settings that are consistent with the stated ALARP principle used in the analysis and public policy objectives with respect to renewable energy **NIE Networks' Response:** As stated in the previous response above, NIE Networks agreed to extend the scope of the LoM studies at the request of SONI even though this generation was excluded in the UR decision paper on RoCoF. Prior to the start of the LoM studies, SONI reviewed the project scope and provided feedback, no request was made by SONI at that time, or during the period when the studies were being carried out, that NIE Networks give consideration to alternatives or the costs associated with implementing alternate protection settings. NIE Networks does not therefore agree with the concern raised by SONI that insufficient consideration was given to alternatives or costs associated with implementing alternate protection settings as this was not included in the LoM studies project scope as reviewed and agreed by SONI.
	Consultee Comment: The findings do not consider evidence from other jurisdictions that Distribution Operators are today operating with higher ROCOF settings without comprising public safety, including progress made in immediately neighbouring jurisdictions in the adjustment of relay settings. **NIE Networks' Response:** Prior to the commencement of LoM studies, NIE Networks reviewed similar research already completed in GB & ROI. Following a review of the methodologies used in these studies, NIE Networks concluded that previous GB research carried out in association with Strathclyde University used methodology that was directly applicable to the NIE Networks system. This conclusion was reached after considering factors such as planning standards, design standards, protection design, engineering recommendations documents and voltage levels. This approach has already been subject to an industry consultation in GB and the results of the research accepted by TSO's, DNO's and the Regulator. NIE Networks also agreed to sit on the GB working group GC0079 which is considering this work in GB. NIE Networks has also liaised with ESBN Networks to understand the differences in the research conducted and approach taken to the amendment of generator interface protection. NIE Networks does not therefore agree with the concern raised by SONI that evidence from other

	jurisdictions was not considered as the LoM studies that NIE Networks carried out used methodology previously used in a neighbouring jurisdiction.
	Consultee Comment: Notes that in the time NIE Networks have been engaged in this analysis with Strathclyde University since 2014 SSG connected to the NIE network has grown from approximately 150MW to over 400 MW. **NIE Networks' Response:** Since 2012 NIE Networks has been providing a monthly report to SONI which gives a detailed breakdown on the volumes of generation <5MW connected to the NI distribution system. This report lists the total generation for each generating technology and total generation at each Bulk Supply Point substation. In addition, since 2014 due to the large volumes of connection applications being received, NIE Networks has provided SONI with regular updates and been in regular contact regarding the volumes of committed to connect generation. It is not clear whether this comment is a concern or a statement of fact, NIE Networks would however comment that during the period 2014 to present, whilst SONI were made fully aware of the rapid growth in generation <5MW they did not raise this as a concern or a major risk to the delivery of the DS3 Project objectives.
SONI	**Consultee Comment:** It could be read that whilst the overall risk rating is low and therefore considered to be in the generally acceptable ALARP region the new settings slightly increase the risk. This does not in itself make the risk unacceptable, and indeed our expectation would be that all of the various options available to mitigate this risk further would be assessed under the general principle of ALARP. **NIE Networks' Response:** The determination of whether the level of risk is acceptable or not lies solely with NIE Networks as the duty-holder. SONI correctly state that the new settings slightly increase the risk, however the risk already resides in an area where the ALARP principle requires the duty-holder to implement risk reduction measures, any increase in risk therefore, however small, must be viewed in this context. SONI's expectation that all various options available to mitigate risk further is only valid if SONI had made NIE Networks fully aware of the implications of not moving settings at generation <5MW. Now that NIE Networks are aware of the implications, we are currently considering various options available to mitigate the risk to an acceptable level as determined by NIE Networks.
	Consultee Comment: Understanding to what extent this has been done in preparation of the report is not straight-forward given the lack of information provided in relation to the model and methodology used, as well as the assumptions made. Lack of clarity with regard to the impact of changing the ROCOF settings is further exacerbated by the decision taken to evaluate the impact of implementing all of the proposed settings together, rather than evaluating each criterion individually. It is not possible from the information provided to understand the impact of the increased ROCOF setting alone. **NIE Networks' Response:** The report on the LoM studies carried out by Strathclyde University extends across 3 documents, 2 annexes and over 350 pages. The information provided in these reports in relation to model and methodology is similar to that provided to stake holders in GB following a similar exercise. NIE Networks are not aware of any such concerns being raised in this area as a result of the GB studies. In addition to carrying out studies on the impact on risk associated with changing LoM settings, SONI also requested NIE Networks to include settings changes to over frequency protection and under voltage protection in the project scope. SONI, when explaining the rationale on why these additional changes were required, highlighted that these were also critical to future system operation. Consequently NIE Networks did not consider it necessary to evaluate the impact of implementing the proposed settings on an individual basis. As stated previously, SONI when reviewing the project scope, did not highlight this as an issue, had they done so then the studies could have taken account of it. NIE Networks strongly disagree with SONI's comment and are surprised that they have taken issue with the decision to evaluate the impact of moving settings collectively given that they had input to that decision.
	Consultee Comment:

SONI	We do not see evidence that the general principle of ALARP has been followed with any degree of transparency. **NIE Networks' Response:** NIE Networks do not agree that the general principle of ALARP has not been followed with any degree of transparency and would point to the various reports and consultation documents for the required transparency.
	Consultee Comment: In relation to the evaluation of potential mitigating measures as per the ALARP principle, it is not apparent that any such measures have been considered other than the use of NVD protection, for which little information is provided. **NIE Networks' Response:** NIE Networks requested additional studies to consider the impact of NVD protection as a risk mitigation measure; the reports on these studies are included in 2 Annexes to the main reports. NIE Networks therefore strongly disagree with SONI's comment that little information is provided, the detail included in the 2 Annexes is extensive leaving NIE Networks to conclude that SONI have not considered these Annexes when making this comment.
	Consultee Comment: It is also worth noting that the WP4, assessing the impact on SSG, states repeatedly that the introduction of the new ROCOF standard on risk is "minor" and that "it should be noted that in this case [small scale generators], the relative impact of the change on the overall risk resulting from the settings change is much lower (maximum 16.5% increase) than it was estimated for large generators in Phase 1 (approximately two orders of magnitude)." This is in contradiction to the interpretation NIE Networks has taken and the ultimate recommendations they have put forward. **NIE Networks' Response:** SONI correctly state in this comment that the increase in risk for generators <5MW is much smaller than the increase in risk for generators >5MW. This comment however needs to viewed in the context of the HSE ALARP diagram where even though there is a significant increase in the risks associated with generators >5MW the actual risk still resides on the boundary of the broadly acceptable region. This is in contrast to the risks associated with generators <5MW, where although the increase in risk is much smaller the actual risk resides well into the tolerability region. NIE Networks concluded that the actual risk for generators >5MW was in an area of ALARP that was acceptable, however the risk associated with generators <5MW was in area of ALARP where increased risk could not be tolerated. NIE Networks therefore do not agree that there is a contradiction either in our interpretation or recommendations.
	Consultee Comment: SONI would expect any risk assessment in relation to the new ROCOF setting to demonstrate a thorough and robust approach in line with the ALARP principle. At a minimum, we would expect to see consideration (including costs) associated with implementing alternative protection settings that are consistent with the public policy objectives in Northern Ireland and renewable energy philosophy outlined in this response. Without this information, substantive statements with regard to what is or is not "reasonable" in these circumstances cannot be made with any confidence. **NIE Networks' Response:** Once again SONI make reference to consideration (including costs) associated with implementing alternative protection settings. NIE Networks would reiterate that at no stage during the period that the studies were being conducted, did SONI make known the material risk to the objectives of the DS3 program should the studies into the changing of protection settings at generators <5MW conclude that is was not possible to move them. This was exacerbated by SONI's failure to include this significant risk in their DS3 project risk report. Consequently NIE Networks were unaware of the implications of not moving settings and therefore did not consider it necessary to consider alternative protection settings.
	Consultee Comment: Given these policy objectives and the relative maturity of the DS3 ROCOF project, SONI are surprised that during this period NIE Networks has not performed (or do not mention) any benchmarking or best practice sharing with similar organisations on this topic, both in

SONI	neighbouring jurisdictions and further afield. **NIE Networks' Response:** As stated in a previous response, NIE Networks has considered similar research on this topic in neighbouring jurisdictions and have engaged in best practice sharing with the other 14 DNO's in the UK through the Energy Networks Association. NIE Networks therefore strongly disagree with this comment and would go further to point out that the approach adopted by NIE Networks followed best practice in the UK and as such the comment is materially inaccurate.
	Consultee Comment: This figure of approximately 420MW has risen from approximately 150MW in October 2013. SONI note that some generation is rarely run so the risk of tripping is lower; however, NIE Networks has not quantified the risk. **NIE Networks' Response:** NIE Networks has since 2012, provided SONI with a detailed breakdown of the volumes of generation <5MW. More recently, following a request from SONI, NIE Networks provided a further analysis of this generation including actual load profiles form the different generation types. NIE Networks agree that some of this generation is rarely run but due to the highly intermittent nature of renewable generation it was not possible to incorporate this into the studies. A significant portion of this generation is of a standby conventional type under dispatch by SONI however SONI did not request this be taken into account when they reviewed the project scope.
	Consultee Comment: Given this growth however, SONI would note that if NIE Networks had taken a similar approach to the one which ESB Networks have taken in Ireland and implemented the increased ROCOF settings for new generation, a less significant amount of SSG would now be in need of retrospective alteration. **NIE Networks' Response:** It is NIE networks understanding that ESB Networks implemented increased RoCoF settings for new generation following the completion of their own research which concluded that it was safe to move to the new settings. Had NIE Networks adopted a similar approach and applied increased settings for new generation ahead of the conclusion of the studies, then it would have been doing so with no knowledge as to the risk it was exposing the general public to. NIE Networks would view such a move as both reckless and outside the terms of their license and are very surprised that SONI, given the seriousness that it takes health and safety, would suggest that NIE Networks take such an approach.
	Consultee Comment: As things stand, with over 400MW of SSG set at the lower ROCOF level the following impacts are expected as a direct result of NIE Networks not changing the SSG protection settings in NI: • Operational SNSP limit cannot increase above 65% • Operational ROCOF limit cannot increase from current 0.5Hz/s limit • Minimum number of large sets (conventional generators on the system at any given time) required to operate the system cannot be reduced from its current level of 8. • Minimum inertia levels on the system cannot be reduced. **NIE Networks' Response:** NIE Networks, as part of SONI-DSO DS3 implementation project, provide quarterly updates to SONI on the protection settings at all generation <5MW. Should SONI wish to review this information they would see that c75% of this generation use vector shift as their LoM protection and it is therefore incorrect to state that 400MW of SSG is set at the lower RoCoF setting. In order to better understand the impacts that SONI stated in this comment NIE Networks requested the analysis on which these conclusions were based. SONI provided NIE Networks their analysis, completed in 2014 and referred to earlier in their consultation response. This analysis concluded that even at low levels of secondary tripping (40MW) the impact of the trip subsequent to the initial imbalance could lead to a frequency nadir which would trigger under frequency load shedding. The analysis went on to examine the relationship between frequency nadir and SNSP and concluded the following: *"The trend of the lowest nadirs occurring with SNSP levels 55-65% are illustrated, assuming 2% of wind generation trips due to anti-islanding relays. As the SNSP increases beyond 65% the frequency deviation is lessened, as conventional generators are dispatched down and the size of the largest infeed reduces (note that other system*

	issues develop at higher SNSP levels but are not considered in this report)" Following further analysis on this relationship the report concludes: *"In the 500 high SNSP test cases, the system nadir is better in cases in which higher levels of wind generation are tripped – this is due to the lower size of infeed at times of high. As wind penetration increases on the system, more and more generation is backed off, resulting in a double effect of reduced trip size and increased headroom on generators. As a result the system appears to better handle larger wind trips. Similarly to Figure 6, from a frequency nadir performance perspective, the system is better able to cope with secondary trips at times of small infeed trips, which tend to coincide with very high SNSP cases"* Whilst the analysis in the report concludes that secondary tripping of generation due anti-islanding relays will occur when high RoCoF's are experienced, it is clear also that the impact of the secondary tripping is less as SNSP increases beyond 65%. This analysis was however carried out based on 2%secondary tripping (representing a relatively small amount of between 20MW & 80MW of wind in each case). NIE Networks understand that SONI now believe that the volume of generation <5MW, which is well in excess of the 2% figure considered in this study, could exacerbate the secondary tripping issue but to date SONI have been unable to quantify the volume of generation subject to secondary tripping that the system can sustain. NIE Networks, in line with the future work recommendations contained in the report, would ask that SONI carry out further analysis to quantify the extent of the secondary tripping issue using a more detailed network model to confirm the key findings.
Electricity Exchange	**<u>Consultee Comment:</u>** Our primary concern relates to the proposed RoCoF threshold of 0.125 Hz/s for power generation of <5MW capacity. Based on the facts presented in the consultation document and its supporting documents, it is apparent that the DNO appreciates that this is contrary to the goals of the Facilitation of Renewables study, 2010. While we do not disagree with the motives for the DNO's position, we believe that considering the RoCoF threshold alone is ineffective and that the consideration of other factors may allow for broader tolerance bands while achieving the protection required by the DNO. The effective use of RoCoF measurements to identify a loss of mains is predicated on a sufficient energy differential at the point of connection to force a step loading on the generator at the time of uncoupling that results in a rapid change in frequency. While it is good industry practice to maintain a reasonable differential, it is not mandated. Furthermore, owners of low-cost embedded generation on non-exporting sites are commercially motivated to maintain their import of power to as close to 0 MW as possible provided the export of power is avoided. With a residual remand of 0 MW, RoCoF will not be effective in detecting loss of mains, regardless of the threshold, in the event that the feeder to that site is opened. As such, we believe that it would be prudent to stipulate a minimum net import/export level, defined as a function of the step loading capability of the connected generation. The parameters of such a function should be considered in light of any proposed RoCoF threshold, with higher RoCoF thresholds requiring a higher differential load. The DNO should consider situations in which allowing partial export by traditionally non-exporting sites would serve to improve the reliability of RoCoF as a means of loss of mains detection. **<u>NIE Networks' Response:</u>** The respondent provides a proposed solution to enable the interface protection settings associated with generation < 5MW to be amended. Whilst NIE Networks welcome engagement on proposed solutions to reduce the risk associated with electrical islanding we do not believe that this proposed solution will materially reduce the risk on the NIE Networks' distribution system. The respondent states that the effective use of RoCoF measurements to identify a loss of mains is predicted on a sufficient energy differential at the point of connection. However, the primary function of interface protection is to prevent electrical islanding of the distribution system not electrical islanding of the customers premise after the protection device at the customer's point of connection has operated. Electrical islanding of the distribution system may occur after the upstream circuit breaker has operated or supplies to the upstream substation have been lost. The probability of electrical islanding occurring in these cases will be dependent on a number of factors, including the energy differential on these potential islands, not at the customer's site. Consequently, Strathclyde University inputted actual, high resolution, loadings of NIE Networks'

	circuits and substations and outputted the probability of electrical islanding for the current interface protection settings and for the proposed settings. The respondent proposes that NIE Networks stipulate a minimum net import/export level. Not considering major concerns regarding the financial, technical and legal aspects of the implementation of this policy, NIE Networks do not believe that it would offer a material risk reduction. This policy may increase the energy differential at a customer's point of connection but does not necessarily offer an increase in energy differential on the islanding groups as identified by Strathclyde University and may, in instances, offer a decrease in the energy differential at the islanding groups and therefore increase risk. However, as outlined previously NIE Networks has identified various mitigation measures and has committed to assess the impact of the measures on risk to determine if there is a quantum of SSG interface protection settings that can be amended.
Brookfield Renewables	**<u>Consultee Comment:</u>** Brookfield Renewable fully support the roll out of generator interface protection amendments to implement the new RoCoF standards in Northern Ireland. We do however question the proposal in the consultation paper that of the units connected to the Distribution Network prior to 1st October 2017, only Large Scale Generation (LSG) will be required to adopt the proposed settings and that Small Scale Generation (SSG) will be exempt. Brookfield Renewable are of the opinion that the new settings should apply to both LSG and SSG connected to the network prior to 1st October 2017. Given the significant volume of SSG generation currently connected to the Distribution Network in Northern Ireland, we believe the generator interface protection amendments should also apply to SSG connected to the network prior to 1st October 2017. We note that the new settings will apply for SSG connected on or after 1st October 2017. Brookfield Renewable are of the opinion that the new settings should apply to all SSG, regardless of the connection date. **<u>NIE Networks' Response:</u>** The respondent raises concerns regarding NIE Networks' decision in the consultation paper to not apply the new RoCoF setting for SSG after 1st October 2017. They also believe that the new settings should apply to all SSG, regardless of the connection date. NIE Networks would point out that their decision to not amend the settings associated with SSG is based on the risk of fatality. The respondent does not provide a view on these risks or provide proposed measures to reduce them. It is therefore unclear whether the respondent views the risk of fatality as determined by Strathclyde University is acceptable. Nevertheless, NIE Networks' has committed to assess the impact of mitigation measures on risk to determine if there is a quantum of SSG interface protection settings that can be amended.
AES	**<u>Consultee Comment:</u>** AES welcome the NIE Networks' recommendation of applying new protection settings, in line with RoCoF, to Large Scale Generation (LSG) connected to the Distribution System and to make such requirement retrospective. AES also welcomes the NIE Networks' recommendation of applying new protection settings, in line with RoCOF, to **new** Small Scale Generation (SSG). We would however support a similar approach to that taken by SONI and Eirgrid (TSOs) in that all generation should be compliant. We acknowledge that the consultation document highlights that there may be an increased risk regarding changes to protection settings. These appear to remain well within the HSE region of Tolerability. The new protection settings approach still offers as low a risk as possible, whilst being cognisant of the benefit that they bring. AES believes that there is however a strongly identified Social Benefit to the ability of SONIs and DSOs being able to support the operation of the System to a level of over 60% SNSP, up to a level of 75%. Such benefits bring better prices of electricity, better environmental practices, potential economic benefits to both jurisdictions and an overall more stable System. To that end AES would suggest that similar protection settings be applied retrospectively to SSG connected to the Distribution System and that changes to the Distribution Code support the

	overall approach to RoCoF and SNSP provision. **<u>NIE Networks' Response:</u>** NIE Networks agree with the respondent that there is a strongly identified Social Benefit to the ability of SONIs and DSOs being able to support the operation of the System to a level of over 60% SNSP, up to a level of 75%. NIE Networks would however point out that in 2013 they informed SONI that they would not be amending the interface protection settings associated with generation <5MW. From then until this consultation went live indications from SONI were that other balancing options were available to solve any system operation issues that would arise due to settings not being moved on generation <5MW. It is also worth noting that SONI did not include the risks associated with not moving settings at generation <5MW in the risk report presented to the DS3 advisory group in September 2014 and again September 2015. Consequently, the interface protection settings outlined in the consultation document and the acceptance, or otherwise of their associated risks was on the basis that the proposed settings would not prevent SNSP from reaching 75%. However, notwithstanding the above NIE Networks has identified various mitigation measures and has committed to assess the impact of the measures on risk to determine if there is a quantum of SSG interface protection settings that can be amended.
Nordex	**<u>Consultee Comment:</u>** The protection settings are indicating that a power station >5MW might be required to stay connected to the grid while the frequency is above 53 Hz for a short period. Starting at 51.9 Hz where still no protection will kick in, we might have a fast frequency movement with 1.499 Hz/s so RoCoF will also not trigger. When crossing the 52 Hz we have to stay connected for a further second, so it is possible to reach 53.499 Hz or higher values before given protection settings will disconnect the power station. Our default settings for protecting the turbines is 53 Hz with a delay of 0.2 s. Does that mean we would not be compliant? I know, I'm mentioning a very unlikely event, but it makes me uncertain how to implement the protection setting in a compliant way without having upper frequency values up to 54 Hz. Also it is not described that the 1.5 Hz/s RoCoF is a minimum requirement. So I suppose we wouldn't be allowed to implement higher gradients for df/dt protection than 1.5 Hz/s? But for grid stability I guess it would be in the favour of a network operator to have the generating units withstand higher gradients as these gradient are also relevant for a falling frequency. Suggestion would be: - to define a upper limit for frequency were a unit is allowed/required to disconnect immediately like e.g. 53 Hz. - to define 1.5 Hz/s as a <u>minimum</u> requirement **<u>NIE Networks' Response:</u>** 1) Define an upper limit for frequency were a unit is allowed/required to disconnect immediately like e.g. 53 Hz. Clause 7.13.5 of the NIE Networks' Distribution Code states: Each **Generator** shall be responsible for protecting the **Generating Unit** owned or operated by it against the risk of damage which might result from any **Frequency** excursion outside the range 52 Hz to 47 Hz and for deciding whether or not to interrupt the connection between its **Plant** and/or **Apparatus** and the **Distribution System** in the event of such a **Frequency** excursion. Therefore, a generator may wish to disconnect from the distribution system, by interrupting the connection between its plant and/or apparatus, if frequency increases beyond 52Hz. 2) Define 1.5 Hz/s as a <u>minimum</u> requirement. NIE Networks do not allow generators to implement an interface protection RoCoF setting which is higher than that stated in connection agreements or in the appropriate network code. Higher RoCoF settings will increase the risk of electrical islands being maintained and therefore increases the risk of electrocution and out-of-phase reclosure of generation. Consequently, NIE Networks will not define 1.5Hz/s as a minimum requirement. For the avoidance of doubt NIE Networks has removed paragraph 7.11.7 from the proposed D-Code modifications.

Respondent who wished to remain anonymous	**<u>Consultee Comment:</u>** The respondent has serious concerns over NIE's proposal to change RoCoF settings for power stations >5MW particularly with respect to the assessment carried out and also with settings in the table in section 7.11: 1. The RoCoF withstand capability of generators does not appear to have been assessed (in particular that of wind turbines). NIE appears only to have assessed generator interface protection settings. We believe there will be an issue with implementing these RoCof settings without assessing the withstand capability of the generating plant due to the predicted potential of catastrophic failure of generating plant. 2. We do not believe that new settings should be applied retrospectively as older generating plant will not be able to withstand a RoCoF rate of 1.5 Hz/s in particular wind turbines. We would therefore request that paragraph 7.11.4 of the proposal should be removed. In addition to the above, the respondent would like to understand why a 1Hz/s over 500ms was not considered as an option as this is already implemented in mainland UK **<u>NIE Networks' Response:</u>** NIE Networks acknowledge the concerns that the respondent has raised regarding the RoCoF withstand capability of generators. This concern was also highlighted by a respondent to a previous NIE Networks consultation on proposed changes to the Rate of Change of Frequency[22]. NIE Networks would comment that the purpose of interface protection is to prevent electrical islanding from occurring, it is not to safeguard the generator against a high RoCoF. The Northern Ireland Distribution Code currently requires all independent generating plant > 100kW to remain connected to the Distribution Network for a Rate of Change of Frequency up to 1Hz/s measured over 500ms. The Utility Regulator in 2014 approved in principle Grid Code modifications to include a RoCoF standard of 1Hz/s measured over 500ms. Consequently, generation will be obligated to remain connected to the system for a RoCoF up to the D-Code and Grid Code standards. If a generator is not prepared to remain connected to the system for RoCoFs less than the D-Code and Grid Code standards then they should seek derogation from the Utility Regulator. The generator may wish to employ protection to disconnect from the system outside of these standards. Moreover, NIE Networks has become aware of concerns among demand customers with regards to adopting a new RoCoF standard of 1Hz/s and the associated impact on their systems and processes. NIE Networks point out that the responsibility of managing system frequency is a function of SONI; consequently, it is SONI's responsibility to assess the impact on demand customers and quality of supply as outlined in the Utility Regulator's decision paper[23] in 2014. To fulfil this requirement SONI commissioned research to perform a high level assessment of short frequency deviations with regards to any possible effects on demand customers[24]. Whilst this high level report identified that the risks for infrequent or inadvertent tripping up to a RoCoF level of 1 Hz/s are expected to be low it does acknowledge that "…controlled power electronics are initially more prone to tripping due to RoCoF events as opposed to uncontrolled power electronics. However the controlled power electronic settings can be adjusted to mitigate tripping risks that a higher RoCoF level might cause. Initially this means that controlled power electronics might need attention following a change of Grid Code (e.g. RoCoF)." Moreover, the report identified that the likely specific areas that could be impacted due to new RoCoF standard are: Response of the demand site to the RoCoF event; impacts on power quality provided to the site, operational impacts on the demand site and impacts on embedded generation within the site. Industries where controllable power electronics are prevalent include Pharmaceutical, Semiconductor, Alumina, Data centres, Chemical and the Food & Drink industry. On the basis of this report NIE Networks would request visibility of the work carried out by SONI to determine if controlled power electronics need attention following a change of Grid Code (RoCoF). NIE Networks would also request that this report is consulted on by industry to establish if industry agree with the findings of it. Finally NIE Networks would request SONI consider more detailed quantitative analysis to ensure that more robust statements can be made around the withstand capability of demand and generation. 1Hz/s measured over 500ms was not considered as an option as clear direction was given to NIE

[22] http://www.nienetworks.co.uk/documents/D-code/RATE-OF-CHANGE-OF-FREQUENCY-DISTRIBUTION-CODE-MODI.aspx

[23] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf

[24] DNV GL. (2016) "Assessment of higher RoCoF events on demand customers: research to perform a high level assessment of short frequency deviations with regards to any possible effects on demand customers".

	Networks from SONI that interface protection must remain connected to the system for a RoCoF up to 2Hz/s measured over 500ms. Strathclyde University identified that an interface protection setting of 1.5Hz/s with a 300ms time delay would remain stable for a RoCoF up to 2Hz/s measured over 500ms hence why it was selected. Due to the high risks associated with SSG, NIE Networks has committed to access mitigation measures to attempt to reduce the risk of fatality. One of these mitigation measures will include the assessment of risks at the lower 1Hz/s setting.

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APPENDIX 2 - PROPOSED DISTRIBUTION CODE MODIFICATIONS (REDLINE)

Connection Conditions

7 **Additional Technical Criteria for Generating Units**

7.1 All **Power Stations** shall, in addition to the requirements of paragraph CC6, meet the technical design and operational criteria in this paragraph CC7, and the **Setting Schedules** insofar as each requirement is applicable to them, which contains more detailed requirements for **Power Stations** than those set out in paragraph CC6 and are intended to be complementary to paragraph CC6. However, in the event of any conflict between the requirements of paragraph CC6 and the requirements of this paragraph CC7 and the **Setting Schedules**, the provisions of the **Setting Schedules** shall prevail. Detailed information relating to a particular connection will, where indicated below, be made available by the **DNO** on request by the **Generator**.

7.2 Each connection between a **Power Station** and the **Distribution System**, unless specified otherwise in the **Connection Agreement**, must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the **Connection Point**. The short circuit current design values at a **Connection Point** will be set out in the **Connection Agreement**.

7.3 All **Power Stations** must comply with the requirements of NIE Engineering Recommendation G59/1/NI, Recommendations for the connection of embedded generating plant to Public distribution systems above 20kV G75/1 or with outputs over 5MW, and Engineering Recommendation G83/1, each as applicable and as amended, supplemented, varied or replaced from time to time and with all other relevant Engineering Recommendations and relevant regulations and the particular requirements of the **DNO** which will take account of the conditions prevailing on the **Distribution System** at the **Connection Point** at the relevant time. The **DNO** will notify its particular requirements to the **Generator** during the course of the **Generator's** application for connection to the **Distribution System**.

7.4 **Reactive Power** capability

7.4.1 Each **Power Station** must be capable of operating at its **Registered Capacity** in a stable manner as a minimum within the following power factor ranges:

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	Range
Type A Generating Units	0.95 absorbing - 0.98 absorbing
Type B Generating Units	0.95 absorbing – 0.98 generating
Type C Power Stations	0.95 absorbing – 0.95 producing

7.4.2 In this paragraph CC7 **Type A Power Stations** means **Induction Generating Units**.

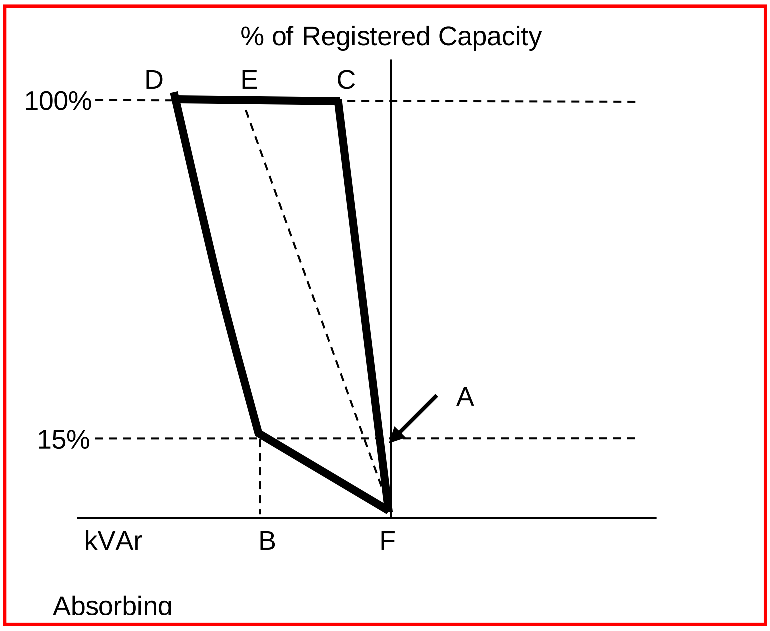
7.4.3 In this paragraph CC7 **Type B Power Stations** means:

(a) **Synchronous Generating Units**; with a **Registered Capacity** from 100 kW to under 5MW;

(b) **Generating Units** of all types connected in part or in total through convertor technology with a **Registered Capacity** from 100kW; to under 5MW

7.4.4 In this paragraph CC7 **Type C Power Stations** means **Power Stations** with a **Registered Capacity** of 5MW and above

7.4.5 Each **Power Station with a Registered Capacity** of 100kW or more shall have a **Reactive Power** capab**ility at its Registered Capacity** as described in the following reactive power performance charts:-



Type A Reactive Power Performance

a) Point A is the minimum absorbing **Reactive Power** capability at 15% **Registered Capacity** (voltage and power factor control modes);

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b) Point B defines the maximum absorbing **Reactive Power** capability at 15% **Registered Capacity** (voltage control mode);

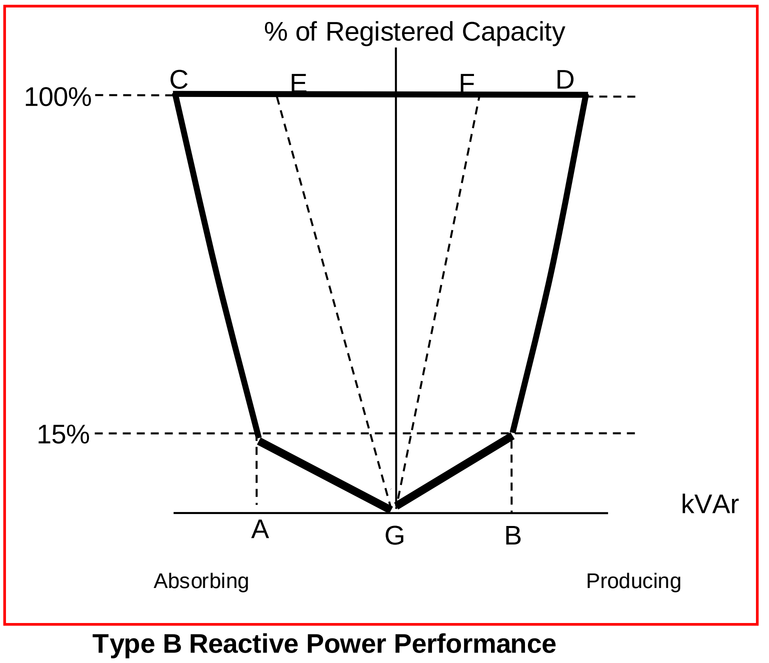
c) Point C is the minimum absorbing **Reactive Power** capability at 100% **Registered Capacity** and power factor limit of 0.98 absorbing either in power factor or voltage control modes;

d) Point D is the maximum absorbing capability at 100% **Registered Capacity** (voltage control mode);

e) Point E is the power factor limit of 0.95 absorbing at 100% **Registered Capacity** (power factor control mode);

f) Points A,B & D i.e. reactive capabilities are defined by the capability declared by the **Generator** during the application process; and

g) Point 'F' is the kVAr capability below 15% of **Registered Capacity** which may not be zero.



Type B Reactive Power Performance

a) Point A is the maximum absorbing **Reactive Power** capability at 15% **Registered Capacity** (voltage control);

b) Point B is the maximum producing **Reactive Power** capability at 15% **Registered Capacity** (voltage control);

c) Point C is the maximum absorbing **Reactive Power** capability at 100% **Registered Capacity** (voltage control);

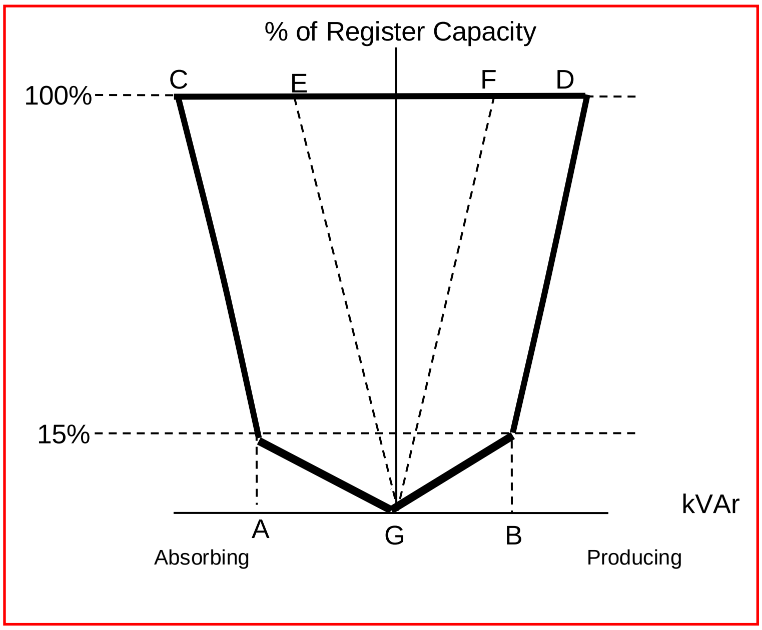
d) Point D is the maximum producing **Reactive Power** capability at 100% **Registered Capacity** (voltage control);

e) Point E is the power factor limit of 0.95 absorbing at 100% **Registered Capacity**;

f) Point F is the power factor limit of 0.98 producing at 100% **Registered Capacity**;

g) Point G is the kVAr capability, which may not be zero, at zero kW output; and

h) Points A,B,C & D i.e. reactive capabilities are defined by the capability declared by the **Generator** during the application process.



Type C Reactive Power Performance

a) Point A is the maximum absorbing **Reactive Power** capability at 15% **Registered Capacity** (voltage control);

b) Point B is the maximum producing **Reactive Power** capability at 15% **Registered Capacity** (voltage control);

c) Point C is the maximum absorbing **Reactive Power** capability at 100% **Registered Capacity** (voltage control);

d) Point D is the maximum producing **Reactive Power** capability at 100% **Registered Capacity** (voltage control);

e) Point E is the power factor limit of 0.95 absorbing at 100% **Registered Capacity**;

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f) Point F is the power factor limit of 0.95 producing at 100% **Registered Capacity**;

g) Point G is the kVAr capability, which may not be zero, at zero kW output; and

h) Points A,B,C & D i.e. reactive capability are defined by the capability declared by the **Generator** during the application process.

7.5 A **Power Station** shall maintain the voltage at the **Connection Point** within its reactive capability power limits as outlined in paragraph CC7.4, the appropriate **Setting Schedules** and the statutory voltage limits as described in paragraph CC5.3.

7.6 All **Power Stations** connecting to the **Distribution System** shall be capable of providing the following **Reactive Power** control modes. All **Power Stations** shall operate in the control mode instructed by the **DNO**.

7.6.1 **Power Stations** with a **Register Capacity** of 5MW and above shall be capable of providing three control modes**,** Power Factor Control, Voltage Control and VAr Control.

7.6.1.1. Whilst the **Power Station** is operating in Power Factor control mode its reactive capability is described by the envelope EFG within the Type C reactive power performance chart of paragraph CC7.4.5.

7.6.1.2. Whilst the **Power Station** is operating in Voltage Control Mode, the minimum reactive capability is described by the envelope ACDBG within the Type C reactive power performance chart of paragraph CC7.4.5.

7.6.1.3. Whilst the **Power Station** is operating in VAr Control Mode the **Power Station** must be capable of importing or exporting VArs within the envelope described by ACDBG within the Type C reactive power performance chart of paragraph CC7.4.5.

7.6.2 **Power Stations** with a **Registered Capacity** of less than 5MW shall be capable of providing two control modes, Power Factor Control and Voltage Control.

7.6.2.1. Whilst the **Power Station** is operating in Power Factor control mode its reactive capability is described by the envelope ACE within the Type A and EGF for Type B within their associated reactive power performance charts of paragraph CC7.4.5.

7.6.2.2. Whilst the **Power Station** is operating in Voltage Control mode its reactive capability is described by the envelope ACDB for Type A and ACDBG for Type B within their associated reactive power performance chart of paragraph CC7.4.5.

7.7 The short circuit ratio for each **Power Station** shall not be less than 0.5.

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7.8 For the avoidance of doubt, all **Power Stations** must be capable of delivering **Reactive Power** performance at the **Connection Point**. However, where complex **User Systems** involve **Generating Units** and **Load**, the **User** may submit calculations to support compliance.

7.9 Co-ordination with existing **Protection**

7.9.1 Each **Generator** must meet, in relation to each of its **Power Stations**, the target clearance times for fault current interchange with the **Distribution System** in order to reduce to a minimum the impact on the **Distribution System** of faults on circuits owned by a **Generator**. The target clearance times are measured from fault current inception to arc extinction and will be specified by the **DNO** to meet the requirements of the relevant part of the **Distribution System**. A **Generator** may obtain relevant details specific to its **Power Stations** pursuant to paragraph CC6.4. The **DNO** shall ensure that (subject to any necessary discrimination) the same target fault clearance times can be achieved by its own **Apparatus** at each **Connection Point**.

7.9.2 Unless otherwise agreed, the fault clearance times required by the **Connection Agreement** shall not be faster than 120ms but, if otherwise agreed, nothing in this paragraph CC7.9.2 shall prevent a **Power Station** or the **DNO's Apparatus** at the **Connection Point** from having faster clearance times (subject to necessary discrimination being maintained). The times specified in the **Connection Agreement** will reflect the **DNO's** view of the requirements of the **Distribution System**, and the **User's System**, for the expected life time of the **Protection** (for example, 15 years). The probability that the fault clearance times stated in the **Connection Agreement** will be exceeded by any given fault must be less than 2%.

7.9.3 To cover for failure of the above **Protection** systems to meet the above fault clearance times, the **Generator** may be required to provide back up **Protection**. The back up **Protection** shall be required to discriminate with other **Protections** fitted on the **Distribution System**. Relevant details will be made available to a **Generator** upon request pursuant to paragraph CC7.1.

7.9.4 The setting of any **Protection** controlling a circuit breaker or the operating values of any automatic switching device at any **Connection Point** shall have been agreed between the **DNO** and the **User** during the course of the application for a **Connection Agreement**. The settings and operating values will only be changed if both the **DNO** and the **User** agree provided that neither the **DNO** nor the **User** shall unreasonably withhold their consent.

7.9.5 If in the opinion of the **DNO** following an overall review of **Distribution System Protection** requirements improvements to any **Power Station Protection** scheme are necessary, the relevant provisions of the **Connection Agreement** shall be followed.

7.9.6 The Power Station Protection must co-ordinate with any auto reclose policy specified by the DNO.

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7.10 Specific **Protection** Required for **Power Stations**

In addition to any **Protection** installed by the **Generator** to meet its own requirements and statutory obligations, the **Generator** must install **Protection** to achieve the following objectives:

i. For all **Power Stations**:

  a. To disconnect the **Power Station** from the **System** when a **System** abnormality occurs that results in an unacceptable deviation of the **Frequency** or voltage at the **Connection Point**;

  b. To ensure the automatic disconnection of the **Power Station**, or where there is constant supervision of an installation, the operation of an alarm with an audio and visual indication, in the event of any failure of supplies to the protective equipment that would inhibit its correct operation.

ii. For polyphase **Power Stations:**

  a. To inhibit connection of **Power Station** to the **System** unless all phases of the **DNO's Distribution System** are present and within the agreed ranges of **Protection** settings;

  b. To disconnect the **Power Station** from the **System** in the event of the loss of one or more phases of the **DNO's Distribution System**;

iii. For single phase **Power Stations:**

  a. To inhibit connection of **Power Station** to the **System** unless that phase of the **DNO's Distribution System** is present and within the agreed ranges of **Protection** settings;

  b. To disconnect the **Power Station** from the **System** in the event of the loss of that phase of the **DNO's Distribution System**;

7.11 Suitable **Protection** arrangements and settings will depend upon the particular **Generator**'s installation and the requirements of the **Distribution 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 size of the Power Station.~~

	~~Power Stations >16A/phase and <5MW~~	Power Stations ≥5MW

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Blue Text = Changes following consultation

Protection Function	~~Setting~~	~~Time Delay~~	Setting	Time Delay
U/V stage 1	~~0.9pu$~~	~~0.5s~~	0.85pu$	3.0s
U/V stage 2	~~N/A~~	~~N/A~~	0.6pu$	2.0s
O/V	~~1.1pu$~~	~~0.5s~~	1.1pu$	0.5s
U/F	~~48Hz~~	~~0.5s~~	48Hz	0.5s
O/F	~~50.5Hz~~	~~0.5s~~	52Hz#	1.0s
LoM(RoCoF)¥	~~0.125 – 0 .4Hz/s€~~	~~0s~~	~~1.5~~1.0Hz/s	~~0.3~~0.5s∝

Notes: ∝ 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 ~~300~~ 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 ~~300~~ 500ms if the rate was significantly higher than the threshold.

~~€ 0.125Hz/s is the preferred setting, 0.4Hz/s can be accepted where the Generator's studies indicate that nuisance tripping could occur at the lower setting. All Protection settings will be agreed between NIE Networks and the Generator during the connection process.~~

¥ RoCoF – Rate of Change of Frequency.

$ Base unit is defined as the nominal voltage at the **Connection Point.** This applies to phase-phase and phase-neutral voltages.

A default setting of 52Hz will apply unless a lower setting is requested by the **DNO**.

7.11.1 For each of the **Protection** functions, the CB opening should occur with no inherent time delay following a protection trip operation from the relay.

7.11.2 All **Power Stations** with an output >~~16A/phase~~≥5MW and connected to the **System** on or after 1st October 2017 must apply protection settings as per paragraph CC7.11. For the avoidance of doubt, **Power Stations** with an output ~~>16Amps/phase~~≥5MW and connected on or after 1st October 2017 shall not employ vector shift as a LoM technique.

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7.11.3 All **Power Stations** >16Amps/phase and <5MW connected to the **System** ~~prior to 1st October 2017~~ shall maintain the protection settings as outlined in their **Connection Agreement.**

7.11.4 **All Power Stations** ≥5MW connected to the system prior to 1st October 2017 shall ensure that the **Protection** settings as per paragraph CC7.11 are applied by 31st December 2017. For the avoidance of doubt, Power Stations with an output ≥5MW and connected to the **System** prior to 1st October 2017 shall not employ vector shift as a LoM technique.

7.11.5 For the avoidance of doubt, the requirements of paragraph CC7.11 shall take precedence in any conflict arising between this **Distribution Code** and Engineering Recommendation G59/1/NI

7.11.6 In line with HSENI recommendations, all **Generators** should review and update relevant risk assessments to take account of the risks associated with islanding, with particular emphasis on out of phase re-closure, when adhering to the requirements of paragraph CC7.11. Further information on this is included in Appendix 4.

~~7.11.7 Each **Generator** must ensure that, in relation to each of its **Power Stations,** any **Protection** installed to meet its own requirements does not interfere with the correct operation of the **Protection** requirements detailed in paragraph CC7.11. For the avoidance of doubt, any **Protection** employed by the **Generator** should not operate to disconnect the **Power Station** from the **System** ahead of the operation of the **Protection** as required in paragraph CC7.11~~

7.12 Fault Ride Through Requirements

7.12.1 **Power Stations** Types A and B shall be capable of remaining connected to the **Distribution System** for voltage dips on any or all phases, where the **Distribution System** phase voltage measured at the **Connection Point** remains above the heavy black line in the diagram titled “ Fault ride through capability of Power Stations < 5MW “ (below).

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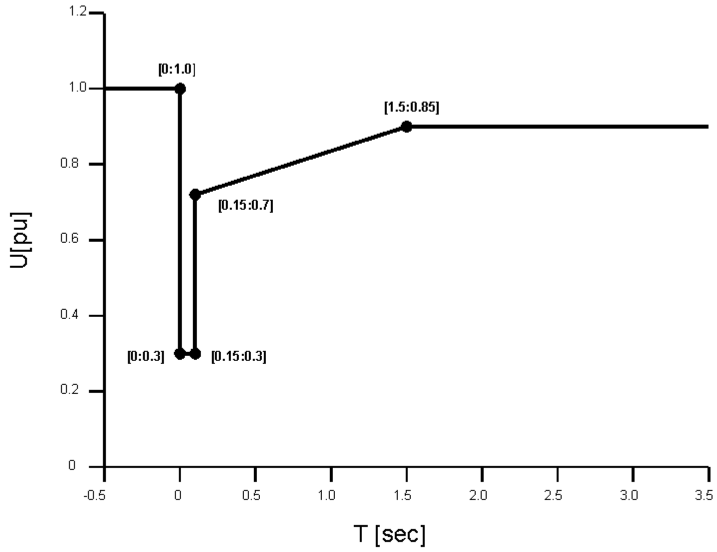
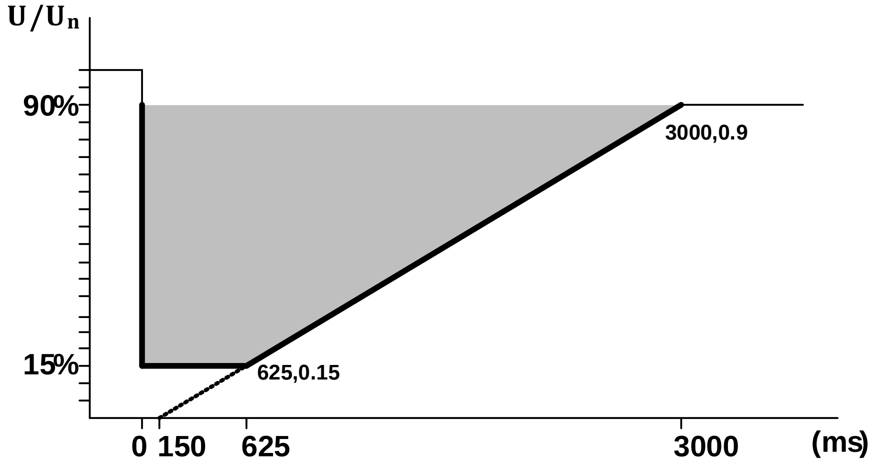


Fault Ride Through capability for Power Stations < 5MW

7.12.1.1. After fault clearance the **Power Station** shall have the technical capability to provide at least 90% of its maximum available **Active Power** as quickly as the technology allows and in any event within 5 seconds of the voltage at the **Connection Point** recovering to within the normal operational range, as specified within the **Connection Agreement** for the particular site.

7.12.2 A **Power Station** with a **Registered Capacity** >5MW shall have the technical capability to remain connected to the **Distribution System** for voltage dips on any or all phases, and remain stable, where the **Distribution System** phase to phase voltage measured at the **Connection Point** remains above the heavy black line in the diagram below titled “Fault Ride-Through Capability for Generation units ≥ 5MW connected to the Distribution System”.

7.12.2.1. After Fault Clearance the **Power Station** shall have the technical capability to provide at least 90% of its maximum available **Active Power** as quickly as the technology allows and in any event within 5 seconds of the voltage at the **Connection Point** recovering to within the normal operational range as specified within the **Connection Agreement** for the particular site.



Fault Ride Through Capability for Power Stations ≥ 5MW connected to the Distribution System

7.12.3 In addition to remaining connected to the **Distribution System**, the **Centrally Dispatched Generation Units** shall have the technical capability to provide the following functions:

7.12.3.1. During voltage dips, the **Power Station** shall provide **Active Power** in proportion to retained voltage and provide **Reactive Power** to the **Distribution System.** The provision of **Reactive Power** shall continue until the distribution voltage recovers to within the normal operational range, as specified within the **Connection Agreement** for the particular site, and in any case within the statutory limits as specified under paragraph CC5.3, of the voltage level at which the **Power Station** is connected, or for at least 500ms, whichever is the sooner. The **Power Station** may use all or any available **Reactive Power** sources, including installed statcoms or SVCs, when providing reactive support during voltage dips.

7.12.3.2. For voltage dips cleared within 140ms, the **Power Station** shall provide at least 90% of its maximum available **Active Power** as quickly as the technology allows and in any event within 500ms of the voltage at the **Connection Point** recovering to the normal operating range, as specified within the **Connection Agreement** for the particular site, and in any case within the statutory limits as specified under paragraph CC5.3 of the voltage level at which the **Power Station** is connected**,**. For longer duration voltage dips, the **Power Station** shall provide at least 90% of its maximum available **Active Power** within 1 second of the voltage at the **Connection Point** recovering to the normal operating range for the voltage at which it is connected.

7.12.3.3. During and after faults, priority shall always be given to the **Active Power** response as defined in paragraphs CC7.12.3.1 and CC7.12.3.2. The reactive current response of the **Power Station** shall attempt to control the voltage back towards the voltage at which the **Power Station** is connected and should be at least proportional to the voltage dip. The reactive current response shall be supplied within the rating of the **Power Station** with a rise time no greater than 100ms and a settling time no greater than 300ms. For the avoidance of doubt, the **Power Station** may provide this reactive current response directly from a **Generating Unit**, or other additionally installed dynamic reactive devices on the site, or a combination of both.

7.12.3.4. The **Power Station** shall be capable of providing its transient reactive response irrespective of the reactive control mode in which it was operating at the time of the voltage dip. The **Power Station** shall revert to its pre-fault reactive control mode and set point within 500ms of the voltage at which the **Power Station** is connected, recovering to its normal operating range

7.12.3.5. The DNO may seek to reduce the magnitude of the dynamic reactive response of the **Power Station** if it is found to cause over-voltages on the **Distribution System**. In such a case, the **DNO** will make a formal request to the **Generator.** The **Generator** and the **DNO** shall seek to agree on the required changes, and the **Generator** shall formally confirm that any requested changes have been implemented within 120 days of receiving the formal request from the **DNO**.

7.13 Minimum connected impedance

7.13.1 For **Generating Units** which do not form part of a **WFPS** the minimum connected impedance applicable to the generator and **Generator Transformer** will be specified in the **Connection Agreement**. The **DNO's** requirements for the impedances will reflect the needs of the **Distribution System** from the fault level and stability points of view.

7.13.2 For **WFPSs** the minimum connected impedance applicable to the whole **WFPS** as a single unit will be specified in the **Connection Agreement**. The **DNO's** requirements for the impedance will reflect the needs of the **Distribution System** from the fault level and stability points of view.

7.14 Variations in **System Frequency**

7.14.1 In order to comply with its **Grid Code** obligations, the **DNO** requires that, apart from those circumstances set out in paragraph CC7.14.2, all **Independent Generating Plant** with an **Output** of 100kW or more shall stay connected and operate:

(a) <u>continuously</u> where the **Distribution System Frequency** varies within the range 49.5 to 52.0 Hz;

(b) for a period of up to one hour where the **Distribution System Frequency** varies within the range 48.0 to 49.5 Hz; and

(c) for a period of up to 5 minutes where the **Distribution System Frequency** varies within the range 47.0 to 48.0 Hz.

7.14.2 The requirements of paragraph CC7.14.1 do not apply where:

(a) The G59 relay has operated correctly, consistent with the settings agreed pursuant to paragraph CC7.11; or

(b) The **Distribution System Frequency** has changed at a rate greater than 1.0 Hz/s measured over a rolling 500ms

(c) There is manual intervention by the **Generator**.

7.15 Agreement of rate-of-change-of-frequency settings

7.15.1 Where **Power Stations** are equipped with rate-of-change-of-frequency relays or other devices which measure and operate in relation to a rate-of-change-of frequency the procedure in paragraphs CC7.15.2 to CC7.15.5 below will be followed to ensure satisfactory operation of the **Power Station**.

7.15.2 At a reasonable time prior to a **Power Station** being connected to the **Distribution System**, and prior to any relevant modification to a **Power Station** or any relevant **Power Station Equipment**, the **Generator** shall contact the **DNO** with details of the proposed rate-of-change-of-frequency setting.

7.15.3 The **DNO** shall, within a reasonable period and in any case no more than 28 days after being contacted pursuant to paragraph CC7.15.2, discuss with the **Generator** whether the proposed settings are satisfactory. The agreed settings shall be specified in the **Connection Agreement**.

7.15.4 In relation to any **Generator** which has agreed the settings with the **DNO** under these provisions, the **DNO** shall notify that **Generator** of any change of which it is aware in the expected rate-of-change-of-frequency on the **Distribution System** which may require new settings to be agreed.

7.15.5 Each **Generator** shall be responsible for protecting the **Generating Unit** owned or operated by it against the risk of damage which might result from any **Frequency** excursion outside the range 52Hz to 47Hz and for deciding whether or not to interrupt the connection between its **Plant** and/or **Apparatus** and the **Distribution System** in the event of such a **Frequency** excursion.

7.16 **Power Station** control arrangements

7.16.1 All **Power Stations** in use after 1 January 2010 must be fitted with a device capable of setting the **power factor** of the **Power Station** within the relevant range, as set out in paragraph CC7.4.

7.16.2 All **Power Stations** first connected on or after 1 January 2010 with an **Output** of 100kW or more, all **WFPSs** with an **Output** of 5MW or more first connected on or after 1 November 2007 and all **Power Stations** with an **Output** of 10MW or more (other than **WFPSs**) connected to the **Distribution System** since 31 March 1992, must be fitted with a Fast Acting control system capable of being switched between **Voltage Control** mode and power factor control mode within a voltage band as specified within the **Connection Agreement** for the particular site , and in any case within statutory limits as specified under paragraph CC5.3. If the voltage is outside the specified limit the power factor control must revert to Emergency **Voltage Control** as described within the appropriate **Setting Schedules.** The control of voltage and power factor must ensure stable operation over the entire operating range of the **Power Station**. In the event that action by the **Power Station Active** and **Reactive Power** control functions is unable to achieve a sustained voltage within the statutory limits, the **Power Station** must detect and remain connected to the distribution system unless disconnected directly by a protection operation.

7.16.3 All **Power Stations** first connected on or after 1 January 2010 with an **Output** of 5MW or more, must be fitted with a **Fast Acting** control system capable of being switched between **Voltage Control** mode, VAr control mode and power factor control mode within a voltage band as specified within the **Connection Agreement** for the particular site, and in any case within statutory limits as specified in paragraph CC5.3.

All **Power Stations** connected after 1 January 2012 must be fitted with voltage, power and frequency control and droop capabilities as described within the appropriate **Setting Schedules.**

7.14.4 Other **Voltage Control** schemes may be possible, but agreement between the **Generator** and the **DNO** must be reached at the application stage for connection about their suitability. If **Voltage Control** is implemented for the **Controllable WFPS** or **Dispatchable WFPS**, rather than on individual wind turbines, then the range of **Reactive Power** available should not be less than that which would have been available if **Voltage Control** had been on individual wind turbines. **Voltage Control** schemes based upon equipment located on the **DNO's** side of the connection may be possible, but such schemes are considered special, and the details, responsibilities and cost schedule must be agreed between the **Generator** and the **DNO** in the **Connection Agreement.**

7.17 **Power Station** SCADA and control

7.17.1 **Generators** shall in respect of their **Power Stations** in any of the following three categories comply with the SCADA signal requirements set out in this paragraph CC7.17 and, in addition, such other SCADA signal requirements as the **DNO** may require because of network reasons, which will be specified prior to entry into the **Connection Agreement**:

(a) **Power Stations** with an **Output** of 1MW or more which are first connected after 1 January 2010;

(b) **Power Stations** with an **Output** of 100kW or more up to 1MW which are first connected after 1 January 2010 where the **DNO** decides that SCADA is required because of local network reasons; and

(c) **Power Stations** with an **Output** of 5MW or more which were connected prior to 1 January 2010.

7.17.2 The **DNO** shall issue control instructions by means of the SCADA signals set out in the appropriate **Setting Schedules** or, in the event of a SCADA malfunction, such other means as are determined by the **DNO** in consultation with the **User**.

7.17.3 The **User** shall acknowledge, where relevant, receipt of a control instruction issued under this paragraph CC7.17 and shall comply promptly with the control instruction.

7.17.4 The following signal formats shall be used where required by the particular connection:

(a) Analogue signals: 4 to 20 mA

(b) Digital pulse from the **DNO**: 24V dc

(c) Digital input from the **User**: 0 and 24V dc

7.17.5 Analogue signals:

7.17.5.1. The analogue signal requirements for connecting Generators are set out in the appropriate **Setting Schedules.**

7.17.6 Digital signals:

7.17.6.1. The digital signal requirements for connecting Generators are set out in the appropriate **Setting Schedules**

7.18 Neutral **Earthing**

7.18.1 The winding configuration and method of **Earthing** of **Generating Units** and associated **Generator Transformers** shall be agreed with the **DNO** or, if agreement cannot be reached, determined by the **DNO**.

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APPENDIX 4

GUIDANCE ON RISK ASSESSMENT WHEN USING ROCOF LOM PROTECTION

1 This procedure aims to provide guidance on assessing the risks to a **Generator's Plant** and equipment where a **Power Station** is considering the effect of applying higher interface **Protection** settings. Information provided by the **DNO** in relation to this appendix 4 may be at the expense of the **Generator.**

1.1 The guidance in this appendix 4 relates to a new activity. Early experience may suggest there are more efficient or effective ways of assessing the risk. The **DNO** and **Generators** will be free to adapt this procedure to achieve the **Generators'** ends.

1.2 When a **Generator** wishes to carry out a risk assessment the **DNO** will be able to provide an estimate of the net (ie taking into account as appropriate other Generation on that part of the network) 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 Generation and network topology changes; hence the trapped load assessment may need to be carried out periodically.

1.3 **DNOs** will also be able to provide indicative fault rates for their network that lead to the tripping of the automatic switching points in paragraph 1.2 above.

1.4 **DNOs** will also be able to provide the automatic switching times employed by any auto-reclose switchgear employed at switching points identified in paragraph 1.2.

1.5 **DNOs** will provide the information above and any other relevant information reasonably required within a reasonable time when requested by the **Generator**.

1.6 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.

1.7 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 re-closure incident. Where the Generator considers these risks to be too high, sensitivity analysis should enable them to identify the effectiveness of various remedial actions.

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