SINCLAIR KNIGHT MERZ

NEW GENERATION TECHNOLOGIES AND GB GRID CODES

REPORT ON CHANGE PROPOSALS TO THE GRID CODES IN ENGLAND & WALES AND IN SCOTLAND

Final Report - December 2004

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Sinclair Knight Merz
10th Floor, Cale Cross House
156 Pilgrim Street
Newcastle upon Tyne, NE1 6SU
Tel: +44 (0) 191 211 2400
Fax: +44 (0) 191 211 2401
Web: www.skmconsulting.com

Executive Summary

Transmission companies have an obligation under Licence Condition 7 to have in place, and comply with, a Grid Code. This covers all material technical aspects of planning and operating a transmission system including the technical requirements of generators that connect to the system. Under Licence Conditions 7.1 (b) and 7.9, transmission licensees (TLs) have an obligation to develop a secure and efficient transmission network that will facilitate competition in the generation and supply of electricity that shall not unduly discriminate between any user or classes of users.

Scottish Power Transmission plc (SPT) and Scottish Hydro-Electric Transmission Ltd (SHET), the Scottish transmission licence holders, jointly maintain the Scottish Grid Code (SGC). The National Grid Company (NGC) is the licence holder for the England & Wales transmission system. NGC is responsible for maintaining a grid code for this system. Until 1 September this year, NGC met this responsibility by publishing the England & Wales Grid Code (E&WGC). On 1 September, as part of the introduction of BETTA, this was replaced by the Great Britain Grid Code (the "Grid Code"). It is intended that from 1 April 2005 the Grid Code will apply in England, Scotland and Wales, replacing the Scottish Grid Code. The TLs are seeking approval from Ofgem for a number of changes to both the Scottish Grid Code and the Grid Code relating to the technical performance parameters of generating plant connecting to their transmission systems. All grid code changes proposed by a TL require approval by the Office of Gas and Electricity Markets (Ofgem) before taking effect.

During the 18 month consultation process on the grid code changes to account for new generation technologies the TLs have made the case that, under a high penetration of new generation technologies scenario, system operation may be at risk under certain conditions and/or higher system operation and balancing costs may result, if changes to the grid codes are not implemented. The change proposals to the E&WGC (which are now to be incorporated in the Grid Code) and the SGC affect mainly the following areas:

1) fault ride through (FRT);
2) power/frequency characteristics;
3) frequency control;
4) ramp rates;
5) reactive range and voltage control; and
6) negative phase sequence.

SKM has reviewed the grid code changes proposed by the TLs as set out in the NGC "Report to the Authority" reference H/04 and the SPT/SHET "Report on Consultation" reference SA/2004 and finds that the changes are in accordance with Licence Condition 7 subject to further consideration of the following:

a) a complete revision of the fault ride through provisions to clearly differentiate between the requirements intended for existing plant and the requirements for plant installed after the completion date;
b) the need in Scotland for primary speech communications and manned control points for plant below 30MW;
c) the need in Scotland for more onerous ramp rate requirements prior to the introduction of BETTA;
d) a number of points of detail relating to DC Converters and Governor Systems;
e) different proposals for implementation dates of some of the same changes in Scotland and England and Wales; and
f) different proposals for generation capacity thresholds for relaxation of the same requirements in Scotland and England and Wales.

Some of the suggested revisions to the clauses are minor in nature and are considered as "non-essential", their purpose being mainly to improve clarity and facilitate understanding. However the revision of four particular clauses is considered as "essential" before the grid codes can be approved. Subject to the SKM comments receiving due consideration by the TLs we would recommend that the change proposals be accepted by Ofgem.

A review of international practice with regard to the requirements for new generation technologies has also been undertaken to confirm that the scope of the proposed changes by TLs are consistent with current practice in other relevant jurisdictions. We are satisfied that the TL's proposals on the key issues set out above are consistent with the requirements proposed in other relevant jurisdictions to cope with similar technical issues arising from increased penetration of new generation technologies.

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1. Introduction

The Office of Gas and Electricity Markets (Ofgem) is the regulator for the gas and electricity industries in England, Scotland and Wales. Ofgem was formed in 1999 by the merger of Ofgas (the former gas regulator) and Offer (the former electricity regulator).

1.1 The grid codes

Transmission companies have an obligation under Licence Condition 7 to have in place, and comply with, a grid code. This covers all material technical aspects of planning and operating a transmission system including the technical requirements of generators that connect to the system. Under Licence Conditions 7.1 (b) and 7.9, transmission licensees (TLs) have an obligation to develop a secure and efficient transmission network that will facilitate competition in the generation and supply of electricity that shall not unduly discriminate between any user or classes of users. Also under the British Electricity Trading and Transmission Arrangements (BETTA) which are planned to be introduced in April 2005, it is proposed that there will be a single grid code for Great Britain to apply to all users of the GB transmission system in place of the two separate grid codes that currently apply in England and Wales and in Scotland. All grid code changes proposed by a TL require approval by Ofgem before taking effect.

Scottish Power Transmission plc (SPT) and Scottish Hydro-Electric Transmission Ltd (SHET), the Scottish transmission licence holders, jointly maintain the Scottish Grid Code (SGC). NGC is responsible for maintaining a grid code for the England and Wales system. Until 1 September this year, NGC met this responsibility by publishing the England & Wales Grid Code (E&WGC). On 1 September, as part of the introduction of BETTA, this was replaced by the Great Britain Grid Code (the "Grid Code"). It is intended that from 1 April 2005 the Grid Code will apply in England, Scotland and Wales, replacing the Scottish Grid Code. The TLs are seeking approval from Ofgem for a number of changes to both grid codes relating to the technical performance parameters of generating plant connecting to their transmission systems.

1.2 The changes to the grid codes

The grid codes, as presently drafted, implicitly assume that generators connecting to the transmission system are synchronous generators that have a controllable prime mover. Generating technologies are now being connected to the transmission systems that do not fit this model. Wind turbine generators (WTGs) are the prime example of this. The grid codes therefore need to be updated so that they set out clearly the connection requirements for these new types of generator.

In December 2002 and October 2003 the Scottish licensees and NGC respectively submitted grid code change proposals to Ofgem for approval. Following the presentation made by Ofgem at the IEE Seminar on 16 October 2003, the TLs in England and Wales and in Scotland were asked to align the proposed grid code changes so that as far as possible the E&WGC and the SGC contain the same technical requirements. During January and February 2004, Ofgem and the TLs visited most of the manufacturers of wind generating units so that as far as possible the capabilities of the new types of generation being developed by manufacturers could be reflected in the grid codes.

The aligned E&WGC and SGC were submitted to Ofgem in March 2004. These versions of the grid codes provided the primary input to the further review and consultation proposed by Ofgem.

1.3 The Review Process

In March 2004 Ofgem engaged the services of Sinclair Knight Merz (SKM) to provide advice and guidance to assist it in reaching its decision on this important issue. Accordingly, this report reviews the proposed changes to the SGC and the E&WGC to the extent that the changes meet the licensees obligations as set out in Licence Condition 7. To facilitate this process SKM participated as an observer in the forum arranged by Ofgem on 24/25 March 2004 where the TLs and developers discussed the proposed changes to the grid codes. During the first day of the forum a number of manufacturers made presentations on the capabilities of their generating units with respect to meeting the grid code requirements.

Following the conclusion of the first forum the TLs produced revised proposals for changes to the Grid Codes. These revised proposals were discussed at a second forum on 30 April 2004 that was arranged between the key stakeholders. All parties had the opportunity to express views on the proposed changes with the "Fault Ride Through" requirements being the major outstanding issue. The notes of both forums have been published on the Ofgem website www.ofgem.gov.uk.

The TLs respectively discussed comments received on the proposed grid code changes at the England and Wales Grid Code Review Panel (EWGCRP) meeting on 20 May 2004 and at the Scottish Grid Code Review Panel (SGCRP) meeting on 13 May 2004. Following these reviews, consultation documents were issued on 23 June 2004 by both NGC (Document Reference H/04) and the Scottish TLs (Document Reference SA/2004) with responses to be submitted to the TLs by 21 July 2004. The responses were considered by the TLs and a "Report to the Authority" was issued by NGC on 27 August 2004 and a "Report on Consultation" was issued by the Scottish TLs on 2 September 2004. Both the TL reports summarised the proposed changes, the issues raised by consultees and the final TL proposals for the changes to the respective Grid Code.

1.4 Key topics

This report is concerned with the appropriateness of the grid code changes proposed by the TLs resulting from the H/04 and SA/2004 consultation processes. The focus of the report is on the grid code Connection Conditions (CC) and other sections of the grid codes where the functional and performance requirements of system users plant and equipment are set out. The report focuses on the following topics which have been identified as being major issues during the earlier stages of the consultation process:

a) **Fault ride through**: The requirement for generating units to revert to normal operation when a fault on the power network is cleared.
b) **Power/Frequency Characteristics**: The requirement for generating units to be able to deliver power and remain connected to the network when the system frequency deviates from 50 Hz.
c) **Frequency control**: The requirement for generating units to be able to increase or decrease power output with falling or rising frequency.
d) **Ramp rates**: The requirement for generating plant to be able to limit rates of rise/fall in power output.
e) **Reactive range and voltage control**: The requirement for generating plant to be able to supply lagging/leading reactive power and control the voltage at the grid connection point.
f) **Negative phase sequence**: The requirement for generating units to be able to withstand negative phase sequence currents caused by phase voltage unbalance and phase-to-phase faults.
g) **Thresholds**: The limits, stated either as dates or power levels, at which conditional grid code requirements come into effect.

In order for new types of generation to be able to comply with the above requirements, some manufacturers will need to develop their products and it will be beneficial to ensure that the requirements do not unduly advantage or disadvantage manufacturers.

1.5 SKM Approach

In this report, the approach adopted to deal with each of the above topics is to:

1) Describe the background to the requirements of the grid system and the connected plant and equipment.
2) Provide a reference to where the proposed changes to the Grid Code can be found in the TLs Reports to the Authority reference H/04 and SA/2004.
3) Review the issues raised by consultees identified by the TLs as set out in Tables B.1 of the reports on consultation and determine whether the issue list is complete and recommend, with justifications, whether the positions adopted by the TLs should be accepted, accepted in a modified form or rejected. The recommendations take full account of:
    a) the TLs justification for the change;
    b) the corresponding grid code requirements of other TSOs taking into account the differing characteristics of the other TSO networks;

c) the evidence from the manufacturing community; and

d) the output from the Ofgem forums.

4) Where no issues have been raised to changes by consultees but where we consider that the proposed changes do not reflect the needs of the grid system in an equitable manner by balancing the security and stability of supply with capital and operating costs, we provide a commentary and suggest modifications to the proposed changes.

5) Review the proposed changes, highlighting those areas where relevant differences occur between the E&WGC and the SGC.

This report should be read in conjunction with the NGC consultation document reference H/04 and the Scottish TLs' consultation document reference SA/2004 as reference is made in this report to clauses within those documents. Also, where appropriate, this report makes use of defined terms as set out in the glossary of the grid codes and the terms are denoted by the use of capitalisation.

It should be noted that the E&WGC is now superseded by the (GB) Grid Code and the proposed changes in H/04, subject to approval by Ofgem, will be incorporated in the Grid Code. The SA/2004 change proposals, subject to approval by Ofgem, will be included in the SGC, which remains active until "BETTA Go-Live" currently scheduled for 1/4/05. These change proposals have been drafted in the Grid Code but will be "switched off" until BETTA Go-Live. It is outside the scope of this report to consider the incorporation of the H/04 and SA/04 change proposals into the Grid Code.

The TLs were invited by Ofgem to comment on the first draft of this report and where considered relevant their comments have been taken into account.

2. Background to Grid Code Change Requirements

This section describes the background to the grid code change requirements in the following areas resulting from the introduction of new generation technologies:

1) fault ride through;
2) power/frequency characteristics;
3) frequency control;
4) ramp rates;
5) reactive range and voltage control; and
6) negative phase sequence.

An overview of each of the issues associated with the above topics is set out below and any significant difference between conventional and new generation technologies is highlighted.

2.1 Fault Ride Through

Power networks are subject to faults from time to time comprising a short circuit between one or more conductors (phases) to earth, or between two or more conductors. The severity of faults ranges from the most frequent and least onerous single phase to earth fault through to the least frequent and most onerous three-phase fault. Power system primary components are provided with automatic protection equipment to detect and disconnect faulted equipment by tripping associated circuit breakers. Grid systems are normally designed with resilience so that the system will recover and continue to operate without the disconnection of load when subject to a fault outage. Resilience is normally provided in the form of duplicate circuits and busbars to cover for network fault outages and by operating reserve to cover generation fault outages. The largest loss of power infeed that is planned for on the GB system is presently set at 1320 MW[1] and the system is operated to cover for this contingency. Any material loss of power infeed greater than 1320 MW will adversely affect the post-fault recovery of frequency and voltage to the extent that load may be disconnected.

Prior to the development of Power Park Modules (i.e. a collection of non-synchronous generating units with intermittent power sources such as wind turbine generators) with ratings in the order of hundreds of MW, clusters of Non-Synchronous Generating Units with ratings in the order of tens

[1] Infrequent Infeed Loss Risk as defined in Chapter 5 of "NGC Transmission System Security and Quality of Supply Standard".

of MW were normally connected to distribution networks. The loss of a few tens of MW of embedded generation in a pocket of a local distribution network due to a distribution network fault or nearby transmission system fault would not normally have a material effect on the transmission system. Accordingly, at the time there was no need for generation to be specified to have a fault ride through capability although, with large volumes of embedded generation, fault ride through could become an issue where a major transmission network fault causes a significant voltage depression in a number of distribution networks. However, as the penetration of non-synchronous generation is now increasing in distribution networks, and the connection of offshore Power Park Modules to the transmission network with ratings potentially of around 500 MW (with a combined capacity of between 5.4 and 7.2 GW) are being planned, the requirement for fault ride through is rapidly becoming a necessity to ensure the security and stability of supply. The loss of a power infeed of around 500 MW due the inability of the affected generation to ride through a fault that may have also caused the loss of 1,320 MW of conventional generation clearly has a material impact on the security and stability of the GB supply system.

2.2 Power/Frequency Characteristics

It is a fundamental requirement for all generating plant to be able to operate at frequencies above and below 50 Hz as it is not viable to maintain an exact balance between generation and demand at all times. For relatively large interconnected systems operating under normal conditions, the TSO should be able to maintain the frequency between relatively tight limits (say ±1%) with the use of despatch instructions and by the scheduling of "free governor action" on flexible plant providing operating reserve. Under abnormal system conditions (e.g. during generation forced outages, large load disconnections or network faults resulting in islanding) the frequency will exceed the normal operating limits by amounts determined by the initial generation/demand unbalance modified by automatic control and protection actions.

2.3 Frequency Control

As described above, NGC normally maintains an Operating Reserve to cover for the 1320 MW loss of the largest power infeed. The Operating Reserve is made up of "spinning reserve" carried on frequency sensitive generating units (flexible generation), interruptible load disconnection (e.g. pumped storage pumping load) and the characteristic reduction in the network gross demand with fall in frequency (typically 2% per Hz). Under the most the onerous circumstances, all of the operating reserve will need to be provided by flexible generation and during certain times of the year, in particular during minimum summer demand periods, it may be necessary to constrain down or constrain off inflexible plant to allow flexible plant to be brought into service to provide the required operating reserve.

From a technical point of view, thermal generating plant can provide frequency response through a variety of mechanisms such as deloading steam plant by throttling and deloading gas turbine plant by reduced-firing. The latest designs of wind turbine generators with pitch control can also provide frequency response at minimal extra cost. From a technical point of view there is no barrier to the latest design of wind turbine generators providing frequency response.

From a commercial point of view operating reserve is scheduled by the transmission system operator (TSO) through deloading plant by minimising the costs of "bids" and "offers" and/or by calling upon contracts for the provision of reserve that the TSO may have with market participants. From an electricity market point of view there is a mechanism in England and Wales and in Scotland (GB) for the provision of reserve that can be applied to wind turbine generation plant.

2.4 Ramp Rates

In the England and Wales system under normal system operation, the TSO has to balance generation with demand by means of accepting Bids and Offers as determined under the Balancing Code taking into consideration the Physical Notifications and Bids and Offers of market participants. Limits need to be set regarding maximum rates of change between changes in the physical positions of participants so that the operation of the system is not unduly subject to frequency deviations or frequency balancing costs by the TSO.

In the Scottish network rapid increases in the output of intermittent sources may be difficult to balance with the available generation in Scotland to maintain the agreed power interchange with the system in England and Wales and inadvertent power exchanges may occur. However under BETTA, which is due to come into effect in April 2005, the England-Scotland market driven power interchange limitation will cease to have effect.

2.5 Reactive Range and Voltage Control

Most loads on a power network consume reactive power (MVAr) and this has to be provided by sources of reactive power. The traditional sources of reactive power comprise synchronous generators where the ability to supply MVAr is inherent in the design of the alternator used to produce active power. To maintain a voltage profile between the statutory voltage limits at all busbars within the various geographical zones of a grid system to some extent requires a balance of generated and consumed reactive power within each zone. Reactive power cannot be transmitted (without transgressing voltage limits) over such long distances as active power (MW) and therefore has to be provided on a more local basis. Where reactive power production is not available as an inherent part of active power production then some form of reactive compensation (e.g. shunt capacitors) will be required to make up for any shortfall in reactive power required to maintain satisfactory voltage levels.

The consumption of reactive power varies during the day with the active power demand and the MVAr production needs to be variable in order to maintain satisfactory voltage levels. Traditionally voltage control has been achieved by the adjustment of the level of excitation on synchronous generating units and by the adjustment of tap changers on generating units and interbus transformers. Where reactive compensation is provided it may be necessary to switch in and out of service all or part of the compensation as the demand varies over a day. At some locations it may be necessary or provide continuously variable compensation devices such as Static VAr Compensators (SVCs) or STATCOMs.

The increasing use of non-synchronous generating units that are not able to produce the same amount of reactive power as Synchronous Generating Units (induction generators consume reactive power) is causing an increasing amount of reactive compensation devices to be required in the zones where the Non-Synchronous Generating Units are connected.

2.6 Negative Phase Sequence

Phase voltage unbalance is unavoidable on transmission and distribution networks due to the non-symmetrical disposition of overhead line phase conductors with respect to each other and earth and due to unbalanced loads such as ac traction. The connection of a balanced synchronous generating unit or a balanced induction generating unit to an unbalanced voltage source will cause a negative phase sequence current to flow in the rotor of the balanced machine. This can result in a continuous heating effect in the rotor that needs to be catered for in the machine design. The connection of a DC Converter to an unbalanced voltage source can produce non-characteristic harmonics on the DC side of the converter that may require filtering to avoid a resonance condition.

Phase to phase faults are unavoidable on power networks and a fault close up to a generator can result in relatively large amount of negative phase sequence current to flow in the rotor of the machine. This produces a short-term heating effect that needs to be taken into account in the machine design.

3. Grid codes change proposals and international comparisons

In this section we provide a guide to the sections within the grid codes that contain the revised clauses. We also provide a comparison of international practice with regard to the topics described in Section 2 above. It should be noted that throughout the consultation process, the TLs have harmonised as far as possible the requirements for both grid codes for the benefit of manufacturers and developers. As a result, most of the proposed changes are similar in the E&WGC and the SGC. The comparison of proposals with international practice is therefore only undertaken against the NGC proposals as most comments are also applicable to the SGC.

3.1 E&WGC and SGC grid codes changes

The topics described in Section 2 are covered mainly in the Connection Condition section of the grid codes. The following table sets out the main clauses involved in each of the versions of the grid codes contained in the respective TLs report on consultation.

Issue	E&WGC Main Clauses relating to the Issue	SGC Main Clauses relating to the Issue
Fault ride through	CC.6.3.15	CC.4.3.1 (f)
Frequency Range	CC.6.3.3	CC.4.3.1 (b)
Frequency control	CC.6.3.7	CC.4.3.2 (b)
Ramp rates	BC1.A.1.1	CC.4.3.1 (e)
Reactive range and voltage control	CC.6.3.2 and CC.6.3.4	CC.4.3.1 (a) and (c)
Negative phase sequence	CC.6.3.10 and CC.6.3.15 (c) (ii)	CC.4.3.3

3.2 International comparison

A comparison of the E&WGC and SGC change proposals (applicable to an interconnected system with an installed capacity of about 76 GW) with international practice has been undertaken using the relevant Grid Code sections of E.oN[2] (selected for its experience of large scale penetration of wind farms, although part of the much stronger UCTE interconnected system with an installed

[2] E.oN Netz, Grid Code High and extra high voltage, Bayreuth Germany, August 2003

capacity of about 550 GW) and Ireland[3] (an island system with similarities to the network in GB but less strong, i.e. with an installed capacity of about 7 GW). This comparison can be found in Appendix A of this document.

The objectives of this international comparison are to ensure that there are no relevant issues omitted and that the E&WGC and SGC proposals are consistent with requirements internationally. thus indicating the availability of equipment with the required functionality and performance from a wide range of manufacturers. A detailed analysis of the differences between the requirements of the grid codes for new generation technologies internationally has not been undertaken as there are other diverse historic and operational issues that would have to be considered.

[3] www.cer.ie/cerdocs/cer04136.pdf. Wind Farm Power Station Grid Code provisions

4. Review of issues raised and NGC response

4.1 Statement of completeness of NGC Table B.1

NGC has reviewed the responses submitted to their consultation document as summarised on Table B.1 of the Report to the Authority. Each of the respondents to the consultation document was separately sent a letter by NGC on 27 August 2004 explaining the proposed changes and the reasons for accepting or otherwise each of the comments made. NGC has also indicated in Table B.1 whether the issue raised by the respondent has been accepted or not.

We have reviewed the number of individual responses raised by the consultees and the subsequent responses by NGC and we are satisfied that NGC has covered all the relevant issues raised and that Table B.1 of the Report to the Authority is a proper reflection of the issues raised and the positions of the parties.

4.2 Review of issues raised by Consultees

We have reviewed the content of the issues raised by consultees as set out in Table B.1 of the Report to the Authority and summarise in Table 1 at the end of this section our comments on each of the issues and the positions adopted by NGC. We indicate in Table 1 whether we accept or reject the positions adopted by the consultees and/or NGC.

We discuss below those issues where we take exception to the position adopted by NGC and justify why the positions adopted by NGC should be rejected or accepted in a modified form.

CC.6.3.6 (a) - Frequency Control Implementation Date

The clause as drafted "…..on or after 1 January 2006 (irrespective of its Completion Date) must be capable of contributing to Frequency Control…." would seem to imply the need for retrofitting to existing units. However the requirement will not apply to current embedded medium schemes which are bound by a Licence Exempt Generator Agreement (LEGA). Consequently, this requirement will not apply retrospectively to any existing project. Nevertheless it is considered that to avoid any confusion it would be better to use "with a completion date on or after [January 2006 or as appropriate]". With this proposed change CC.6.3.6 (a) would then also be consistent with CC.6.3.6 (b).

CC.6.3.7 (a) - Governor System Standard

As there is not yet an agreed international standard the clause should clarify that the standard or specification from the manufacturer could be used as indicated by NGC in their responses.

CC.6.3.7 (e) (f) - Frequency Response Implementation Date

Same comment as CC.6.3.6 (a) applies on the wording of this clause. The Completion date of 1 January 2006 in this and other associated clauses is reasonable from the point of view of all the manufacturers having the technologies ready to comply with the Grid Code proposals. It should also not be an issue with "Round 2" wind farms which are expected to be completed not earlier than 2008. However, in the case of currently committed larger wind farms (>100 MW), which probably have already placed orders with manufacturers, the 1 January 2006 deadline could be tight. Consideration should be given to extending this limit further, to say 1 July 2006 for example, to allow for these committed projects to complete and not to be disadvantaged by the introduction of changes in the Grid Code. However we understand from NGC that the signed connection agreements for current wind generation projects include the requirement for the provision of frequency response therefore the 1 January 2006 completion date should not be an issue.

CC.6.3.15 - Fault Ride Through Implementation Date

Same comment as 6.3.6 (a) regarding the LEGA and the retrofitting of FRT capability to existing plant. However we understand from NGC that all but 2 out of 14 LEGAs have a FRT requirement included in the LEGA therefore the need to exclude explicitly all Power Park Modules before the implementation date will not be required.

CC.6.3.15 (a) and (b) - Fault Ride Through – Supergrid Faults

We note under Clause CC.6.3.15 (a) (ii) that Active Power output on voltage recovery shall be "immediately" restored to at least 90% of the level available immediately before the fault whereas under Clause CC.6.3.15 (b) (ii) Active Power output on voltage recovery shall be to at least 90% "within 1 second". We consider "immediate" power recovery to be unreasonable for some new generation technologies as there may be electrical and mechanical considerations that require a progressive recovery of electrical power.

We also consider clause CC.6.3.15 (b) (ii) to be inconsistent within itself as in the first sentence it requires all generating units to maintain power output at least in proportion to the retained Supergrid (i.e. the 275 kV and 400 kV system in GB) voltage (Figure 5) but the second sentence allows all units a one second recovery time to restore the power output to 90% when the voltage recovers to the minimum specified Supergrid voltage, i.e. 90%. Also it is questioned whether the requirement for the proportionality of power output/reduced Supergrid voltage should be applicable to all generators. The voltages in some parts of the network below Supergrid voltages will generally be further depressed when the Supergrid is subject to voltage dips. This requirement, based on the retained Supergrid voltage, could therefore be more onerous for embedded generators.

We also consider it confusing that Clause CC.6.3.15 (b) (ii) applies to all generating units regardless of completion date but refers to the voltage profile in clause CC.6.3.15 (b) (i) that applies only to generating plant after the completion date.

We consider that Clauses CC.6.3.15 (a) and (b) be reviewed to clearly define the requirements and differentiate between the requirements intended for existing plant and plant installed after the implementation date. The inconsistencies with respect to voltage/power recovery should also be resolved.

CC.6.3.15 (c) (i) - Fault Ride Through – Relaxation of Requirement

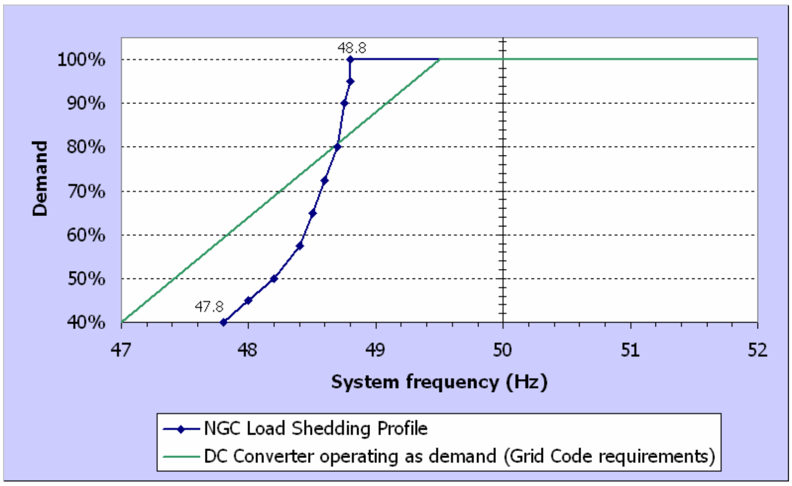
Clause (c) (i) relaxes the requirements of Clause (a) (i) and (b) (i) when a wind farm is operating at 5% or less than the registered capacity. Wind statistics in the UK indicate that for about half of the time the aggregate output of a wind farm will be below 20% and hence setting the relaxation limit to 5% would limit the maximum possible generation loss in the system in the most onerous credible case (1,320 MW + 5% of the wind farm output). For a typical wind farm, if the output is below 5% it can be expected that wind turbine generators will begin to shut down due to low wind. A reduction in the number of wind turbine generators in operation reduces the terminal voltage of the connected wind turbine generators in case of a fault and may not remain above 15% which is considered a technical limitation for fault ride through. We therefore agree with NGC about the lower relaxation limit for fault ride through.

For the above reason we consider it to be inconsistent on technical grounds that the relaxation should also be applicable when less than 50% of turbines are in service as the wind turbine generator terminals should remain above 15% terminal voltage with zero voltage at the connection point. The sudden coincidence of a shut down due to high wind speed and a low voltage at the connection point will not impose any additional performance requirement on the wind farm (equipment should not be modified) and under these circumstances it will be difficult to determine whether the WTG has shut down because of high wind speed or failing to ride through the low voltage condition. In any event the TSO should have allowed for the eventuality of the wind farm shutting down due to high wind speeds and made an allowance for this in the operating reserve. Accordingly the need for Clause (c) (i) should be reviewed.

4.3 Issues raised by SKM

CC.6.3.3 (d) - DC Converter Load/Frequency Characteristic

We question the frequency/power input characteristic indicated for DC converters. The following figure shows the proposed HVDC converter performance (when operating as a demand customer) and the NGC load-shedding scheme[4]. It is clear that the requirements for the DC converters are more onerous for frequency deviations below 49.5 Hz where they are required to reduce demand much earlier than indicated from the NGC load-shedding scheme. Also for frequencies below about 48.8Hz the requirements for DC converters demand are more relaxed than those indicated by the load-shedding scheme. We suggest that the DC converter requirements are approximated to a curve following the NGC load-shedding scheme.



Clause CC.6.3.3 (d) as written allows the DC converter operator to reduce demand, for whatever reason, below the linear relationship (green line) therefore a characteristic approximating to the NGC load-shedding scheme should not disadvantage the DC Converter operator.

CC.6.3.7 (c) (i) - Governor System during Islanded Operation

Unless control and communications facilities are provided to determine when generators have become islanded the generator governor system will not know when islanding in the system occurs. There should be no impact on governor operation irrespective of whether they control frequency in an island or in an interconnected system. Governors have the facility to respond to a frequency signal and in case of a system islanding would respond accordingly. The clause does not appear to serve any purpose.

CC.6.3.15 (a) (ii) - DC Converter Fault Ride Through

We consider that the reference to the DC Converter in Clause CC.6.3.15 (a) (ii) be included as a separate clause as the other requirements in the paragraph are not applicable to DC Converters.

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[4] Report to Grid Code Review Panel "Review of Grid Code Connection Condition Clause 6.3.3 Requirements for Frequencies below 49.5Hz", May 2003.

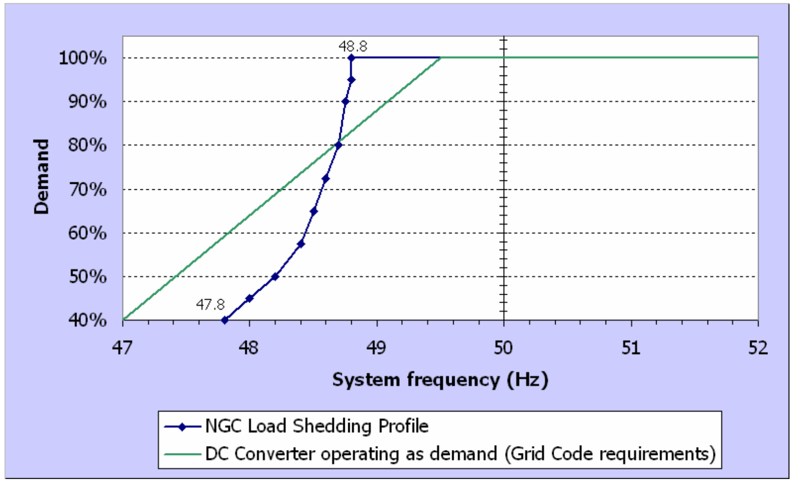
CC.A.4.2 – Supergrid Faults up to 140ms Duration

On the Figures (a) and (b) it is not clear what information is meant to be conveyed by the vertical and horizontal arrows - consider removing or possibly indicating the fault clearance time with an arrow. The busbar voltages should indicate 400 kV or 275 kV.

SKM

Table 1 Summary of issues with proposed Grid Code changes in E&W and SKM comments

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
CC.1.1				No issues raised
CC.3.1				No issues raised
CC.4.1				No issues raised
CC.5				No issues raised
CC.6.1				No issues raised
CC.6.2				No issues raised
CC.6.3.1			**EON and RWE** – frequency and voltage control should not be applied retrospectively to existing medium wind farms covered by Licence Exempt Generation Agreements (LEGA)	Agree with NGC that additional requirements should not be applied retrospectively to currently connected plant (or with a signed connection agreement).
CC.6.3.2	(a)			No issues raised
	(b)	**BWEA** – reactive power tolerance should be 5% of reactive power capability **EON** – there may be DNO restrictions on embedded generators	**EON** – suggest using defined term "Rated MW" **BNG/TML** - clarified to 5% of Rated MW, expressed in MVAr	Agree with NGC. NGC limits less onerous than proposed by commentators and considered reasonable. DNOs requirements should comply with Grid Code.
	(c)	**BWEA** – points C/D should be -/+5% of reactive power capability **RWE** – reactive power capability should apply down to 50% power **Nordex** –suggest dropping MW output when full Mvars are needed		Agree with NGC. NGC limits less onerous than proposed by consultees and considered reasonable. The 20% wind farm output limit is considered quite generous as it is expected that no wind turbines will have disconnected due to low wind speed and complying with the proposed characteristic should pose no technical challenge. The power factor requirement is also less onerous than equivalent requirements for conventional generators.
CC.6.3.3		**BWEA** – only (c) should apply as mechanical power is not constant		Relaxation for intermittent source generation is clearly stated. We question the frequency/power input characteristic indicated for DC converters. The following figure shows the proposed performance and the NGC load-shedding scheme. It is clear that the requirements for the DC converters are more onerous for frequency deviations below 49.5Hz where they are required to reduce demand much earlier than indicated from the NGC load-

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
				shedding scheme. Also for frequencies below about 48.8Hz the requirements for DC converters demand are more relaxed than those indicated by the load-shedding scheme. Suggest that the DC converter requirements are approximated to the NGC load-shedding scheme. 
CC.6.3.4	(a)	**BWEA** – relaxation should be extended to 132kV and 66kV as NGT cannot dispatch Mvar on embedded plant **RWE** – relaxation should be extended to all voltage levels		Agree with NGC. The different requirements for voltage levels assume use of tap changer on transformers above 33 kV and hence it is not discriminatory at higher voltages levels.
	(b)		**EON** – relaxation to include NGC system at 33kV and below as well as User system **EON** – Clause removed	Agree with NGC to remove this clause which incorrectly linked the Power factor/Voltage capability with the Active/Reactive capability. If removed then "(a)" should be removed from the clause above as it becomes the only subclause.
CC.6.3.5				No issues raised

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
CC.6.3.6	(a)	**RWE** – agree to build capability but suggest no obligation on delivery or compliance **RWE** – market for frequency response rather than grid code obligation to provide	**BWEA** – redraft to remove phrase "using NGC Transmission System"	Agree with NGC. The technology is considered to be available and hence the compliance requirement considered reasonable. As drafted it would seem to imply need for retrofitting to existing units, however the requirement will not apply to current embedded medium schemes which are bound by a Licence Exempt Generator Agreement (LEGA). Consequently, this requirement will not apply retrospectively to any existing project. Nevertheless it is considered that to avoid any confusion it would be better to use "with a completion date on or after [January 2006 or as appropriate]". It would also have a consistent draft to the b) clause. The consideration of a Market for frequency response is outside the scope of this review and Ofgem agreed to pursue the merits and convenience of a competitive market for frequency response services separately.
	(b)			No issues raised
CC.6.3.7	(a)	**BWEA** – wind generators should be exempted from designing governors to a given standard	**RWE** – clarified requirement for governor or frequency control device standards	As there is not yet an appropriate international standard the clause should clarify that the standard or specification from the manufacturer could be used (ii) as indicated by NGC in their responses.
	(b)			No issues raised
	(c)(i)	**BWEA** – wind farm governor should not be designed to control frequency as island operation not possible for wind farm	**EON** -redraft to make clear that generation could trip if islanded and system frequency above 52Hz	Facilities are not available for the generators to know when islanding in the system occurs. There should be no impact on the Governors if they are going to control frequency on an island or otherwise as they should have the facility to respond to a frequency signal and in case of a system islanding would respond accordingly. Suggest therefore removing clause (c)(i)
	(d)			No issues raised
	(e) (f)	**EON** – prefer requirement on projects with completion date of 1 January 2006 **RWE** – prefer requirement on projects with completion date not before 2007		Same comment as CC.6.3.6 (a) applies on the wording of the clause. Completion date 1 January 2006 in this and other clauses below seems reasonable from the point of view of all the manufacturers having the technologies ready to comply with the Grid Code proposals. It should also not be an issue with Round 2 wind farms which are expected to be completed not earlier than 2008. However, in the case of currently committed larger wind farms (>100 MW), which probably have placed already orders with manufacturers, the 01/01/06 deadline could be tight. Consideration should be given to extending this limit further, say 01/07/06 for example, to allow for these projects to complete and not being disadvantaged by

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
				the introduction of changes in the Grid Code. The clauses (e) and (f) are saying essentially the same. No need for separate clause. e.g. .clause (f)
CC.6.3.8	(a)	**RWE** – voltage control system performance specification should be in Grid Code not Bilateral Agreement		We agree with NGC to reject the RWE issue. Settings of voltage control devices are specific in nature (to the hardware used) and may be subject to changes as the network changes and therefore we consider it reasonable that form part of the Bilateral Agreement.
CC.6.3.9			**BWEA** – clarified allowance of variation of mechanical power output	We would prefer the wording to exclude explicitly generators with intermittent sources rather than using the term Power Park Modules.
CC.6.3.10				No issues raised
CC.6.3.11				No issues raised
CC.6.3.12				No issues raised
CC.6.3.13				No issues raised
CC.6.3.14				No issues raised
CC.6.3.15		**RWE** – agree to build capability but suggest no obligation on delivery or compliance **RWE** –should not be applied to existing synchronous generation		Same comment as 6.3.6. Agree with NGC Fault-ride through should be applicable to existing generators for faults lasting less than 140 ms but not be applicable retrospectively to existing synchronous generating plant for faults lasting more than 140 ms. However it should exclude explicitly all wind park modules before the implementation date.
	(a)	**BWEA and EON** – exact voltage recovery magnitude and time after fault clearance not specified	**EON** - Figure 5 considered as two distinct parts **EON** – Both fault clearance times and duration of zero voltage should be specified in Bilateral Agreement	Agree to split the voltage recovery profile from the fault duration. It is considered that the requirements with regard to post-fault clearance stated in clause a) ii) for existing generators are more onerous than those in clause b) as no voltage recovery magnitude/duration boundary is provided. We agree with BWEA and EON that under CC.6.3.15 (a) Active Power output on voltage recovery shall be “immediately” restored to at least 90% of the level available immediately before the fault whereas Clause CC.6.3.15 (b) (ii) requires Active Power output on voltage recovery shall be to at least 90% “within 1 second”. We consider it better that the reference to the DC converter be in a separate clause “Each DC Converter shall be designed to meet the Active Power recovery characteristics as specified in the Bilateral Agreement”

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
	(b)(i)	**RWE** – slowest voltage recovery time profile requirement should be specified in Grid Code not Bilateral Agreement **BWEA** – better if a wind farm disconnects for a long voltage recovery as this would avoid installing reactive compensation		See comments in clause (a) above.
	(b)(ii)	**BWEA** – relaxation should be for any reason below 20% or with less than 50% turbines in service **RWE** – relaxation should be for any reason with less than 50% turbines in service	**EON** – relaxation should be for Part 2 of Figure 5 as well as Part 1	The issue raised by the consultees has been reflected in a new clause (c) that only relaxes the requirement (i) when the wind farm is operating at 5% or less than the registered capacity. About half of the time aggregate wind farms output will be below 20% and hence setting the relaxation limit to 5% would limit the maximum possible generation loss in the system in the most onerous credible case(1,320 MW + 5% of the wind farm output). In a typical wind farm if the output is below 5% it can be expected than some wind turbines may shut down due to low wind and hence as the number of wind turbines connected reduce the terminal voltage of the remaining wind turbines in case of a fault may not remain above 15% which is considered a technical limitation. We therefore agree with NGC about the lower relaxation limit for fault-ride through. For the latter reason above we consider it not justifiable on technical grounds that the relaxation should also be applicable also when less than 50% of turbines are in service as the turbine generator terminals will remain above 15% terminal voltage with zero voltage at the connection point. The sudden coincidence of a shut down due to high wind speed and a low voltage at the connection point could be demonstrated by other means and this will not impose any additional performance requirement on the wind farm (equipment should not be modified) nor on the operator who should have allowed for the eventuality of the wind farm shutting down due to high winds in any case. The need for clause (c) (i) should be reviewed.
	(b)(iii)		**EON** - redrafted “maximum” to output available immediately before the fault	Agree
	(c)(i)		**BE, BNG and RWE** – will not be applied retrospectively to existing synchronous generation plant **Vestas** – concern on 80% voltage for 3 minutes requirement	Agree, see comment at the beginning of the clause Technical requirement is considered technically feasible and other manufactures have declared they can comply or they have not raised an issue.

Clause	Sub-clause	Issues Raised but not Accepted by NGC	Issues Raised and Accepted by NGC	SKM Comments
	(c)(ii)	**RWE** – clause should be removed **Nordex** – concern over restoration of power in less than 1 sec **Bonus** – power restoration in 5 seconds better for wind farms	**EON** – redrafted “maximum” to prevailing available output	Agree with NGC in rejecting the manufacturers wish to relax this clause provided it is applicable for projects with completion around 2006 to allow the manufacturers to meet this condition (see also comments for CC.6.3.7 (e)(f)
	(d)			No issues raised
	(e)		**EON** – clause removed	Agree
CC.6.3.16	(a)			No issues raised
	(b)			No issues raised
CC.6.5.4				No issues raised
CC.6.5.6				No issues raised
CC.6.5.9				No issues raised
CC.6.5.10				No issues raised
CC.6.5.11				No issues raised
CC.6.6.1				No issues raised
CC.7				No issues raised
CC.7.9				No issues raised
CC.8.1			**EON** - redrafted to make reference to CC6.3.2 clear	Agree
CC.A.1.1.1				
CC.A.3.1			**BWEA** – verbose wording replaced by tabular format	Agree
CC.A.3.2		**BWEA** – requested a worked example		
CC.A.3.3				No issues raised
CC.A.3.4				No issues raised
CC.A.3.5				No issues raised
CC.A.4.1				No issues raised
CC.A.4.2		**BWEA and EON** – exact voltage recovery magnitude and time after fault clearance not specified in Figures CC.A.4.2 (a) and (b)		Agree with NGC. Appearance of the graphs. In the (a) and (b) figures it is not clear the purpose of the vertical and horizontal arrows. Consider removing. The busbar voltages should say 400 kV or 275 kV Consider marking maybe the fault clearance time with an arrow.
CCA.4.3				No issues raised

5. Review of issues raised and SGCRP response

The review process for the SGC generally follows that for E&WGC as set out in Section 3. As such this report only covers those issues that are different to those for the E&WGC proposed changes and/or where the Scottish licensees response and/or position differs to that of NGC.

5.1 Statement of completeness of SPT/SHET Table B.1

SGCRP has reviewed the responses submitted to their consultation document as summarised on Table B.1 of the Report on Consultation SA/2004. Each of the respondents to the consultation document was separately sent a letter by the SGCRP on 2 September 2004 explaining the proposed changes and the reasons for accepting or otherwise each of the comments made. SGCRP has also indicated in Table B.1 whether the issue raised by the respondent has been accepted or not.

We have reviewed the number of responses raised by the consultees and the subsequent responses by SGCRP and we are satisfied that SGCRP has covered all the relevant issues raised and that Table B.1 of the Report on Consultation is a proper reflection of the issues raised and the positions of the parties.

5.2 Review of issues raised by Consultees

We have reviewed the content of the issues raised by consultees as set out in Table B.1 of the Report on Consultation and summarise in Table 2 at the end of this section our comments on each the issues and the positions adopted by the SGCRP. We indicate on Table 2 whether we accept or reject the positions adopted by the consultees and/or the SGCRP.

We discuss below those issues where we take exception to the position adopted by the SGCRP and justify why the positions adopted by SGCRP should be rejected or accepted in a modified form.

CC.4.3.1 (e) – Ramp Rates

We agree with the SGCRP that there is no need to clarify in the clause that it will not be applicable following the introduction of BETTA (April 2005) where the whole of the Scottish Grid Code will be superseded. As such it is arguable that this requirement should be enforced before then to assist the Scottish TSOs balance demand and generation for the first four months in 2005. We suggest that this sub clause is removed.

CC.4.3.2 (d) – Reactive Power Control

The relaxation (shaded area of Figure 2 in CC.4.3.1 (c)) arises from the lack of on-load tap changers. It is not clear what Clause CC.4.3.2.(d) adds to the requirements already indicated in CC.4.3.2 (c).

CC.4.5.1 – Manned Control Points

If most of the provisions of the Grid Code are not applicable for Generators and Power Park Modules below 30MW then there would seem to be little benefit from having a manned control point during office hours. SGCRP need to justify why the manned control point is required.

CC.4.5.2 – Primary Speech Facility

The reason for discriminating synchronous generation below 30 MW is unclear. We agree with E.oN comments and the clause should be modified. Note that the definition of Power Park Modules in both the E&WGC and SGC only allow for asynchronous machines.

Table 2 Summary of issues with proposed Grid Code changes in Scotland and SKM comments

Clause	Sub-clause	Issues Raised but not Accepted by Scottish TLs	Issues Raised and Accepted by Scottish TLs	SKM Comments
CC.4.1.2				No issues raised
CC.4.2.4				No issues raised
CC.4.2.5				No issues raised
CC.4.3.1	(a)	**BWEA** – reactive power should be 5% of reactive power capability. **RWE** – (a) Scottish proposals for pf range should be phased-in as per NGC proposal. (b) Scottish proposals should not apply embedded small power stations. (c) A reduced reactive capability should apply below 50% rated output. **Nordex** – suggest dropping MW output to meet MVAr requirement.	**BNG** – clarify wording to 5% of rated power expressed as MVAr. **BWEA & EON & RWE** – clause CC.4.3.1(a)(x) should be amended or removed.	Agree with Scottish TLs See comments to CC.6.3.2 of the E&W Grid Code. Regarding the introduction of the reactive capability requirement by January 2005 based on the significant volumes of wind farms above 30 MW it is considered that some committed wind farms may not have included this requirement in their specification. Unless it can be guaranteed that all committed generation would meet this requirement without additional expenditure then it is considered that the date indicated for the introduction of this requirement in E&W is more appropriate. See also comments on CC6.3.7 (e)(f) of the E&W Grid Code.
	(b)	**BWEA** – term pro-rata should be defined with chart.		Agree with Scottish TLs it is not considered that a chart should be included
	(c)	**RWE** – relaxation should be extended to non-embedded generating units.	**BWEA & RWE** – wording allowing Licensees to withdraw relaxation should be deleted.	Relaxation for Embedded generators as defined in the Glossary would cover 66 kV network and below whereas in E&W relaxation starts at 33 kV (see comments in E&W Grid Code CC.6.3.4)
	(e)	**BWEA** – add comment that ramp rates not applicable post-BETTA. **RWE** – remove requirement for ramp rates.	**BWEA** – Table should be changed to show 1 min and 10 min average ramp rates.	Ramp rates. Agree with Scottish TLs that there is no need to clarify in the clause that it will not be applicable following the introduction of BETTA (April 2005) where the whole of the Scottish Grid Code will cease to exist. As such it is arguable that this requirement should be enforced before then to assist the Scottish Operators balance demand and generation for the first four months in 2005. Suggest that this sub clause is removed

Clause	Sub-clause	Issues Raised but not Accepted by Scottish TLs	Issues Raised and Accepted by Scottish TLs	SKM Comments
	(f)	**BWEA & EON** - exact voltage recovery magnitude and time should be in Grid Code rather than in Connection Agreement. **BWEA** – (a) better to disconnect power park module for long voltage recovery as this would avoid installation of additional reactive compensation. (b) FRT should not apply below 20% output or when 50% of turbines shutdown whatever reason. (c) for voltage dips > 140ms, active power recovery should be changed from 1 second to immediately. **RWE** – (a) there should be no obligation on developer for delivery or compliance with requirement. (b) part 1 should not apply retrospectively to existing synchronous generation. (c) slowest voltage recovery time/profile should be specified in Grid Code not in Connection Agreement. (d) FRT should be required if 50% of generating units shutdown irrespective of reason. (e) requirement to restore power output to 90% following fault clearance should be deleted. Nordex – propose phasing-in of FRT active power recovery requirement over 6 to 12 months.	**EON** – (a) fault clearance time and duration of zero voltage should be specified in Connection Agreement. (b) Figure 3 considered as two distinct parts. (c) relaxation when output <5% or 50% shutdown during high wind speed shutdown under Part 1 should also apply to Part 2. (d) CC4.3.1(f)(vii) relevance of this clause not clear and should be deleted or qualified. **BE & BNG & RWE** – part 2 will not apply retrospectively to existing synchronous generation. **Vestas** – concern regarding requirement 80% for 3 minutes.	Essentially the same comments apply as those indicated in the E&W Grid Code in CC.6.3.15 and related sub-clauses as the issues raised and proposed draft for the Fault Ride Through is almost identical. However the main difference arises from the relaxations applicable in Scotland that vary from those applicable in England and Wales (through LEGA). The proposals in Scotland effectively require compliance for new plant above 30 MW connected from the date of implementation of the proposed changes. Plant below 30 MW connected before 1 July 2005 would have a relaxation of the requirement (above 15% voltage), with no requirements for those connected prior to 1 January 2004.
	(g)	**RWE** – Grid Code should include criteria for setting LOM protection.		The relaxations are already considered in other parts of the Grid Code (Voltage and frequency excursion limits) and hence it is considered that this clause is unnecessary. See also comments regarding islanded operation in E&W Grid code CC.6.3.7 (c)(i).

SKM

Clause	Sub-clause	Issues Raised but not Accepted by Scottish TLs	Issues Raised and Accepted by Scottish TLs	SKM Comments
CC.4.3.2	(b)	**BWEA** – 30MW is too low a capacity for provision of freq control. **RWE** – frequency control should only apply to Large Power Stations.	**BWEA** – requirement for active power reduction for high frequency should be consistent with National Grid's Code. **RWE** – all generation should control frequency below 52 Hz in line with the E&W GC.	Agree with the Scottish TLs. Technology is available to undertake frequency control with wind generators and most manufacturers confirm capability to comply with this requirement. Suggest that the text may benefit by introducing a clarification for generation using intermittent sources. See graph in CC.6.3.3 (c) of the E&W Grid Code.
	(c)	**RWE** – (a) voltage control should be limited to transmission connected generation only. (b) performance requirements should be in Grid Code not Connection Agreement.	**EON** – wording revised in line with comments.	Agree with proposed changes by the Scottish TLs. Voltage control should be applicable to all generation regardless of connection level
	(d)		**BWEA** – option of on load control of reactive power at Power Station level.	The relaxation (shaded area of Figure 2 in C.C.4.3.1(c) arises from the lack of on load tap changers. It is not clear what this clause adds to the requirements already indicated in CC.4.3.1(c). Consider removing.
CC.4.3.3	(a)		**BWEA** – clause should only apply to synchronous gen.	This clause is applicable to ALL generators in the E&W Grid Code.CC.6.3.15 (c)ii. IEC Standard is 60034/1
CC.4.3.5	(b)			No issues raised
CC.4.5.1		**BWEA** – no justification for control point for sub-30MW Power Stns. **EON** – relaxation should apply to Power Park Modules using any generator technology.		If most of the provisions of the Grid Code are not applicable for generators/Power Park Modules below 30 MW then there would seem to be little benefit from having a manned control point during office hours.
CC.4.5.2	(e)	**EON** – relaxation should apply to Power Park Modules using any generator technology		Unclear the reason for discriminating synchronous generation below 30 MW. Agree with EON comments and clause should be modified accordingly. Note definition of Power Park Modules in both Grid Codes only allow for asynchronous machines.
CC.A.1.1				No issues raised. See comments in E&W Grid Code CC.A.4.2 and CC.A.4.3.
CC.A.1.2				No issues raised
SDC 2				No issues raised
DRC 5.3 Schedule D			**Enercon** – Should include option to supply documented and validated model of converter and controls instead of individual data items.	Agree with proposed changes by TLs

6. Principal Differences Between E&WGC and SGC Proposals

The requirements of the E&WGC and SGC on the key contentious issues identified in earlier sections are practically identical with the exception on the implementation dates and relaxations and the requirements on the ramp rates. These issues are presented below and require further consideration by the TLs.

6.1 Implementation dates and thresholds

The following table summarises the proposed implementation dates for the requirements on the key issues identified above. The main differences between the scope of application of the requirements in Scotland and England and Wales are on the fault ride through, Reactive Control and frequency control.

Issue	E&WGC Proposals applicability	SGC Proposals applicability
Fault Ride Through	All new connected plant from Grid Code Implementation date (relaxation on part of the requirements apply to plant connected prior to that date) Existing generation does not have to comply with the requirements applicable to Power Park Modules after 140 ms although they should remain connected ("arguable" whether this is really a relaxation, see comments in previous section)	Relaxations vary with capacity and connection date as follows: *Power Park Modules <30 MW* - Before 1 January 2004: No requirement - Between 1 January 2004 and 1 July 2005: Requirement to comply for 15% or more retained Supergrid voltage - After 1 July 2005: Full compliance *Power Park Modules > 30 MW* - Before 1 January 2004: Requirement to comply for 15% or more retained Supergrid voltage. - After 1 January 2004: Full compliance
Frequency range and control	1 January 2006 (for Power Park Modules)	Implemented immediately for Power Park Modules >30 MW connected after 1st July 2004 and operational by 1 January 2006
Ramp rates	All from grid code Implementation date	All from grid code Implementation date
Reactive range and voltage control	1 January 2006 (Reactive range requirements for Power Park Modules)	Immediately for Power Park Modules (relaxation 0.95 lead-0.9 lag at the generator terminals accepted) 1 January 2006. Standard Reactive range requirements for power park modules
Negative phase sequence	All from grid code Implementation date	All from grid code Implementation date

Note: 'LEGA' connected generation are not bound by the grid code in E&W.

The differences between the above E&WGC and the SGC proposals arise because of the more advanced state of wind farm projects in Scotland and are not considered to disadvantage any grid system user in Scotland or in England and Wales.

6.2 Ramp Rates

The following table summarises the interim proposals for maximum ramp rates applicable in each of the jurisdictions.

E&WGC	SGC
- No limit for a change of up to 300 MW - 50 MW/min for a change between 300 MW and 1000 MW - 40 MW/min for a change over 1000 MW	- For Power Park Modules < 15 MW No limit - For Power Park Modules from 15 MW to 150 MW 20% of rated output /minute (1 minute average) 7% of rated output/minute (10 minute average) - For Power Park Modules above 150 MW 30 MW/minute (1 minute average) 10 MW/minute (10 minute average)

The difference between the ramp rate requirements arise from the requirements under NETA in the case of the E&W system and the need to maintain the agreed power exchanges through the Interconnector in the case of the system operators in Scotland. It can be expected that the limits in Scotland will be superseded by the introduction of BETTA.

7. Conclusions and recommendations

The main findings from our review of the latest drafts of the proposed changes to the grid codes in England & Wales and in Scotland are as follows:

1) The key issues are the changes to the requirements on fault ride through, power/frequency characteristics, frequency control, ramp rates, reactive range and voltage control and negative phase sequence.
2) The international comparison indicates that the change proposals are consistent with the requirements found in other jurisdictions as set out in the grid codes of E.oN in Germany and ESBNG in Ireland. In those cases where the requirements proposed are more onerous (or otherwise), we are satisfied that they reflect the different characteristics of the systems used in the comparison and/or reflect the advancements of new generation technologies. In all cases we are satisfied with the reasonableness of the proposals and the compatibility with modern generation equipment.
3) The TLs in their latest drafts of the grid codes have considered all the comments received as part of the consultation process.
4) The proposals for the technical requirements are, for the most part, consistent between the E&WGC and SGC.
5) Apart from the issues listed below we do not have any major concerns with the latest change proposals, other than minor formatting, points of clarification and presentation which have been detailed in the clause by clause review of each of the grid codes set out in this document.
6) The only significant differences between the E&WGC and the SGC on the key issues above relate to the scope of application (generating capacity from which compliance is required, including generation capacity threshold for license requirements[5]), the initial dates when the requirements are enforceable and relaxations applicable if any which are summarised in the following table:

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[5] Under BETTA all large power stations, including embedded, are required to comply with the requirements of the Grid Code. The definition of a "Large Power Station" in the Grid Code is: "A Power Station in NGC's Transmission Area with a Registered Capacity of 100 MW or more; or a Power Station in SPT's Transmission Area with a Registered Capacity of 30 MW or more; or a Power Station in SHETL's Transmission Area with a Registered Capacity of 5 MW or more". Source Treatment of Embedded Exemptable Large Power Stations under BETTA. "An Ofgem/DTI conclusions and further consultation document". November 2004. Ofgem website. Doc 253/04.

Issue	E&WGC Proposals	SGC Proposals
Fault Ride Through	All new connected plant from the grid code Implementation date (relaxation on part of the requirements apply to plant connected prior to that date) Existing generation does not have to comply with the requirements applicable to Power Park Modules after 140 ms although they should remain connected	Relaxations vary with capacity and connection date as follows: *Power Park Modules <30 MW* - Before 1 January 2004: No requirement - Between 1 January 2004 and 1 July 2005: Requirement to comply for 15% or more retained Supergrid voltage - After 1 July 2005: Full compliance *Power Park Modules > 30 MW* - Before 1 January 2004: Requirement to comply for 15% or more retained Supergrid voltage. - After 1 January 2004: Full compliance.
Frequency range and control	1 January 2006 (for Power Park Modules)	Implemented immediately for Power Park Modules >30 MW connected after 1 July 2004 and operational by 1 January 2006
Reactive range and voltage control	1 January 2006 (Reactive range requirements for Power Park Modules)	Immediately for Power Park Modules (relaxation 0.95 lead-0.9 lag at the generator terminals accepted) 1 January 2006. Standard Reactive range requirements for power park modules
Ramp Rates	- No limit for a change of up to 300 MW - 50 MW/min for a change between 300 MW and 1000 MW - 40 MW/min for a change over 1000 MW	- For Power Park Modules < 15 MW No limit - For Power Park Modules from 15 MW to 150 MW 20% of rated output /minute (1 minute average) 7% of rated output/minute (10 minute average) - For Power Park Modules above 150 MW 30 MW/minute (1 minute average) 10 MW/minute (10 minute average)

Recommendations

The list below sets out the clauses in the grid code change proposals that, in SKM's view, are essential to be modified before the grid codes can be approved. Additional revisions to the clauses are suggested in other parts of this report with the main purpose of improving clarity and facilitate understanding of the requirements. They are however considered "non-essential" and the grid codes could, in our view, be approved without making changes to those clauses.

The clauses where revisions of the proposals are considered essential are:

1. **Complete revision of the Fault Ride Through** to clearly define the requirements and differentiate between the requirements intended for existing plant and plant installed after

the implementation date. Also to resolve the indicated inconsistencies with respect to voltage/power recovery. The equivalent clauses are CC.6.3.15 (a) and (b) in the E&WGC and clause CC4.3.1(f) in the SGCRP.

2. **Primary Speech Facility/Communications**. The reason for discriminating synchronous generation below 30 MW is unclear in CC.4.5.2 of the SGC. This clause should be modified and the relaxation extended to all generating units below 30 MW.
3. **Revise CC.4.5.1 in the SGC. Manned Control Points for Generators and Power Park Modules below 30 MW.** If most of the provisions of the SGC are not applicable for Generators and Power Park Modules below 30MW then there would seem to be little benefit from having a manned control point during office hours.
4. **Remove the clause on ramp rates of the SGC CC.4.3.1. (e)** This clause will not be applicable following the introduction of BETTA. As such it is arguable that this requirement should be enforced before then to assist the Scottish TSOs balance demand and generation for the first few months in 2005.

Appendix A International Practice

A comparison of the E&WGC change proposals (for an interconnected GB system with an installed capacity of about 76 GW) with International Practice has been undertaken using the relevant grid code sections of E.oN (selected for its experience on large scale penetration of wind farms, although it is noted that it is part of the much stronger Union for the Coordination of Transmission of Electricity (UCTE) interconnected system on continental Europe with an installed capacity of about 550 GW) and Ireland (an island system with similarities to the network in GB but less strong with an installed capacity of about 7 GW).

A.1 Fault Ride Through

Fault ride through requirements are identified in both the "E.oN Grid Code"[6] and also the "Irish Wind Grid Code"[7] both of which are discussed below.

A.1.1 E.oN Grid Code requirements

The fault ride through requirements for wind and other "unconventional" generation connecting to the E.oN Netz GmbH (ENE) grid are outlined below:

Phase swinging or power oscillations must neither result in triggering of the generating unit protection nor in a controlled reduction of load. The turbine-generator unit control must not excite any phase swinging or power oscillations. Stability related characteristics of the turbine-generator unit control, i.e. the resulting effect of turbine and generator controls, must be co-ordinated between the operator of the generating unit and ENE. A disturbance is considered cleared when the generating unit has resumed normal operation, not immediately after fault clearing.

Figure 5b shows the voltage limit curve at the network connection above which non-conventional generating must not be disconnected from the network.

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[6] E.oN Netz, Grid Code High and extra high voltage, Bayreuth Germany, August 2003

[7] www.cer.ie/cerdocs/cer04136.pdf. Wind Farm Power Station Grid Code provisions

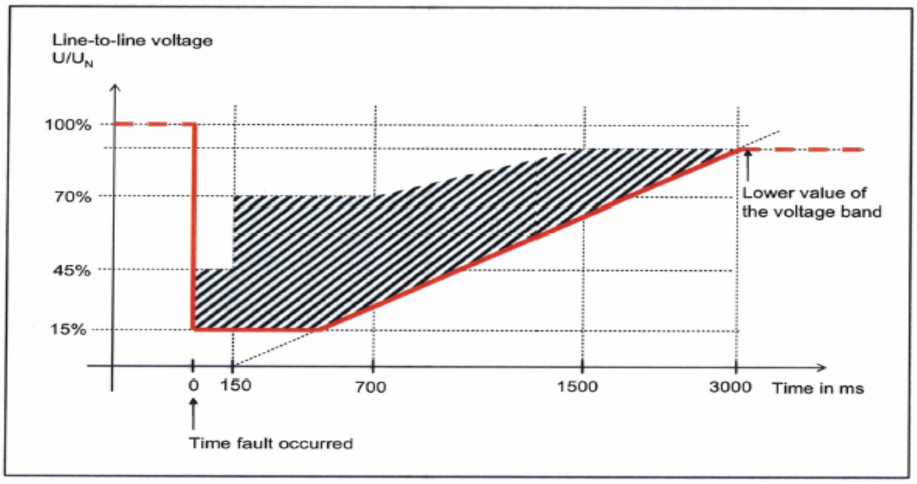


Fig. 5b Voltage limit curve of a network fault

Close up three-phase short-circuits above the red line in Figure 5b must not result in generating unit instability or in disconnection from the network. Active power output must resume immediately following fault clearing and be increased with a gradient of at least 20% of the rated power per second. Within the shaded area in Figure 5b the active power increase can take place at 5% of the rated power per second.

Although not explicit in the E.oN requirements, NGC indicates that discussions with E.oN confirm that the basis of the E.oN voltage depression requirements are similar to the NGC requirements, which are clarified in Appendix A of the Report to the Authority H/04. The NGC voltage-duration profiles are not voltage-time response curves but rather an overall envelope intended to encompass a number of differing voltage depression and associated durations, consistent with close up, severe faults being rapidly cleared and more distant, embedded or less severe faults cleared by distribution system or back-up protection systems persisting for somewhat longer durations.

E.oN also requires that during and immediately following a network fault, the generating units must act to support the system voltage. In the event of voltage drops in excess of 10%, the generation unit must be switched over to a voltage support mode to the extent indicated by Figure 6 below. The support of the network voltage must occur within 20 ms after fault identification and at a level of reactive power at the generator terminals equivalent to 2% of the rated current per percent of the voltage drop. This is equivalent to a conventional generator “quadrature droop” of 50 percent. Switching back from voltage control to normal operation is possible after 3 seconds.

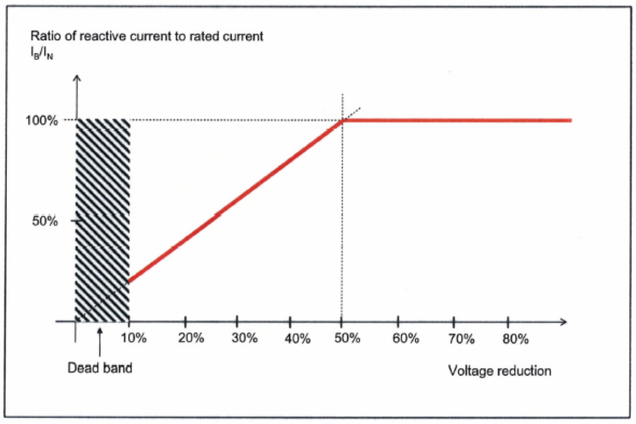


Fig. 6 Amount of reactive current feed for voltage support with a fault in the network

Any transient consumption of reactive power during and subsequent to the voltage disturbance, typical of fixed speed induction generators, must be completed within 400 ms, following which voltage support shall be provided as identified above.

A brief disconnection of the generating unit from the network of ENE can take place within the shaded area in Figure 5b, if resynchronisation of the generating unit following fault clearing does not take longer than 2 seconds and active power is increased with a gradient of at least 10% of the installed rated active power per second.

For less severe faults, disconnection of the generating unit from the network is not permitted even under delayed fault clearance, i.e. back-up protection operation. Also, the aforementioned conditions with regard to voltage support must still be provided.

A.1.2 Comparison of E.oN requirements and NGC proposals

The figure overleaf, which superimposes the NGC proposals (approximated for clarity) onto the E.oN voltage limit curve, shows two main differences namely the more onerous NGC requirement to ride through voltage depressions down to zero (against 15% in the case of E.oN) and the more onerous E.oN requirement with regard to the duration of voltage dips (red line below NGC line in figure overleaf). These issues are reviewed below.

NGC grid code change proposals require the generator to be able to "ride through" voltage depressions down to zero at the **Supergrid** connection point (400 kV and 275 kV), in contrast to the E.oN requirement of 15 percent voltage at the **network** connection point (60 kV and above).

Synchronous "conventional" generators have an inherent capability to ride through close zero-voltage faults. In contrast, many wind turbine generator technologies require a voltage at the individual **generator** connection point greater than about 15% to be able to satisfactorily ride through faults. However relatively simple calculations, based on typical interconnecting transformer impedance, generator "sub-transient" reactances, trapped flux levels and decay rates,

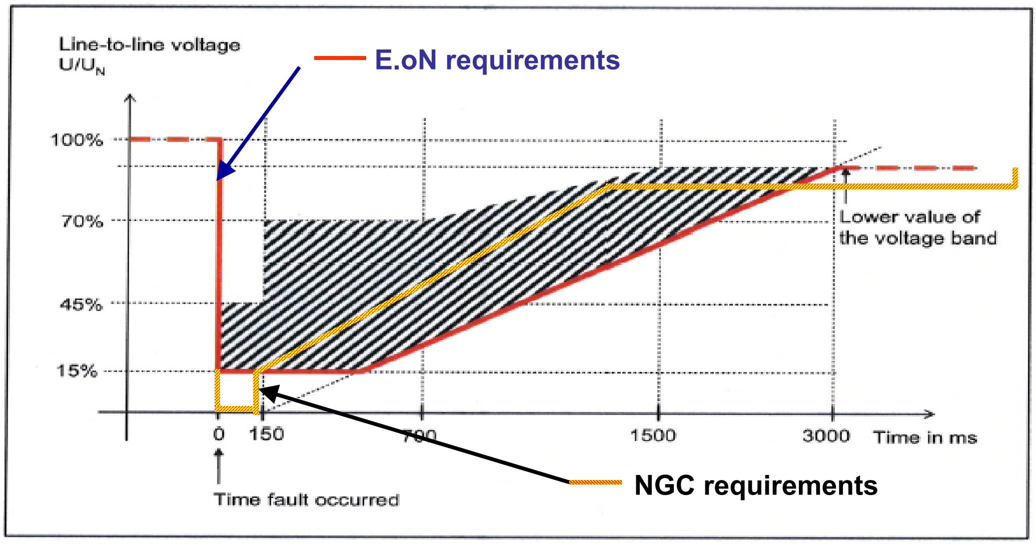


Fig. 5b Voltage limit curve of a network fault

indicate that the voltage depressions at the individual **wind generator** connection point are likely to be somewhat greater than 15% with zero volts at the Supergrid connection point. It can be concluded that the NGC requirement at Supergrid voltages, although more onerous than that of E.oN should be compatible with the fault ride through capabilities of modern 'unconventional' generation technology.

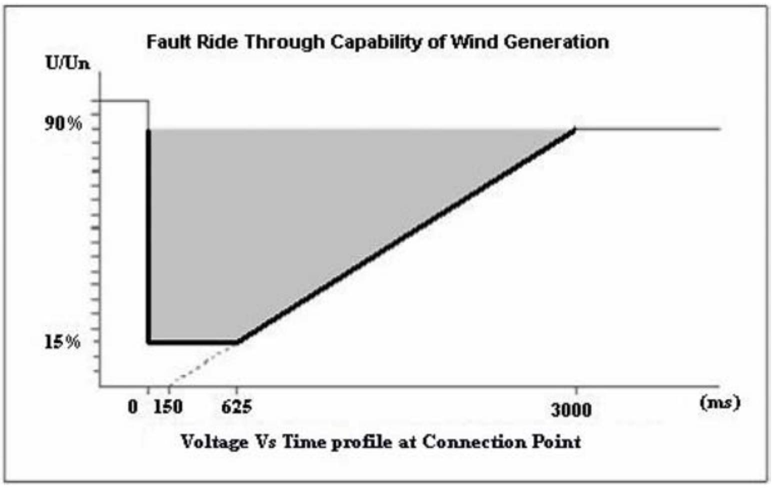
It should be noted that the E.oN Grid Code requirements apply at extra high voltage (220 kV and above) and high voltage (60 kV to 110 kV) network connections. In contrast the NGC requirements apply only at the Supergrid 400 kV and 275 kV connection points, with the implication that plant which is connected at 132 kV or a lower voltage is not required to demonstrate a capability to ride through "zero voltage" at its network connection point. Relatively simple calculations indicate that voltage depressions at 132 kV and lower voltage connection points for zero voltage faults at the Supergrid network are likely to be somewhat above the E.oN requirements.

A further difference between the E.oN Grid Code and the NGC proposals is the rate of rise of electrical power following fault clearance and system voltage recovery. NGC require immediate power recovery (within 1 second) whereas E.oN require recovery gradient of at least 20% of the rated output power per second (i.e. within 5 seconds). We consider that the E.oN power recovery gradient can be more relaxed than the NGC requirements since E.oN forms part of the UCTE system with an installed capacity of about 550 GW where the requirement to recover power output will not be so urgent as the NGC system requirements with an installed capacity of 76 GW. The one second allowance for the restoration of power to 90% of following restoration of voltage to normal operating range is within the capabilities of modern unconventional generation.

A.1.3 Irish Grid Code requirements for Wind Farms

The fault ride through requirements for wind generation connecting to the ESB grid are outlined below.

A Wind Farm Power Station shall remain connected to the network for voltage dips on any or all phases, where the voltage measured at the HV terminals of the Grid Connected Transformer remains above the heavy black line in the Figure below.



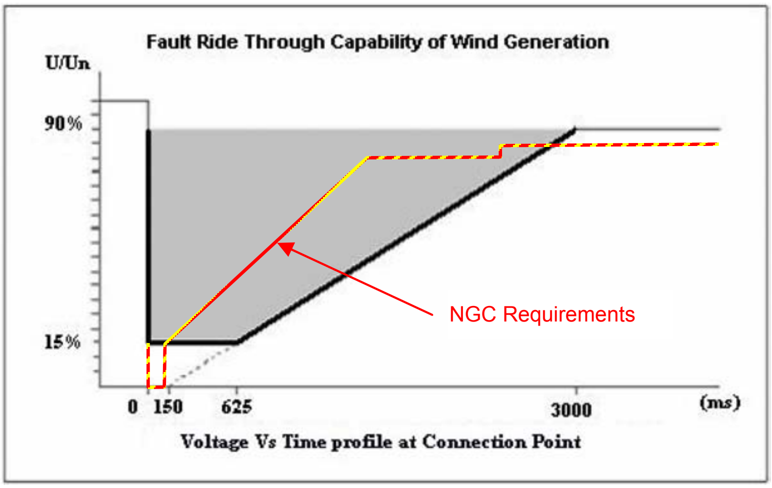
In addition to remaining connected to the network, the Wind Farm Power Station shall provide the following functions:

a) During the voltage dip the Wind Farm Power Station shall provide active power in proportion to retained voltage and maximise reactive current to the network without exceeding WTG limits. The maximization of reactive current shall continue for at least 600ms or until the voltage recovers to within the normal operational range of the transmission system, whichever is the sooner.
b) Within 1 second of the voltage recovering to the normal operating range, the Wind Farm Power Station shall provide at least 90% of its maximum available active power.

In addition to the requirements above, the TSO reserves the right to require a more enhanced Fault Ride-Through capability, or refuse connection to the network, for system security reasons.

A.1.4 Comparison of Irish requirements and NGC proposals

The following figure shows the NGC requirements superimposed over the requirements regarding fault ride through in Ireland. The two same issues observed in the E.oN case are observed in this case, namely the requirement to ride through a zero voltage fault at Supergrid voltage and the relaxation of the requirement (relative to the Irish wind code) for long voltage depressions. The same comments made in the comparison with the E.oN Grid Code requirements are therefore applicable here noting that the requirements in Ireland are applicable for Wind Farms connected to the 110 kV network. It is also apparent from inspection of the figure below that the requirements for voltage dip duration are more onerous in Ireland than those proposed by NGC which are based on the characteristics of the NGC system. Also the Irish Grid Code covers the 110 kV network and this extended requirement takes into account the performance in the relatively weak parts of this network.



The requirements in the Irish Wind Grid Code on power output during voltage dips are virtually identical to those in the NGC proposals namely the provision of active power in proportion to retained voltage and the restoration of 90% of the pre-fault power output within 1 second of the voltage recovering to the normal operating range.

A.1.5 Conclusions

The above paragraphs compare the requirements with regard to fault ride through grid code change proposals of NGC against the requirements in the E.oN and Ireland Grid Codes.

The main difference in both cases is the minimum voltage requirement for fault ride through which is zero in the NGC proposals against 15% in the case of the E.oN and Ireland Grid Codes. However the NGC only requires FRT for zero voltage faults applied at Supergrid voltages (i.e. 400 kV and 275 kV only), whereas the E.oN and Ireland requirements apply to lower voltage levels (110 kV in Ireland and 60kV and above in case of E.oN).

At voltages below Supergrid voltage the NGC requirements for a zero voltage fault at Supergrid voltage, a relatively simple calculation indicates that the corresponding voltage dip at lower voltage connection points are likely to be somewhat above the E.ON and Irish Grid Code FRT minimum voltage requirements (15%). It can be concluded that at voltage levels below Supergrid voltage the NGC requirements and those of E.oN and Ireland, although apparently different from a direct comparison of the FRT profiles, can be considered equivalent in practice.

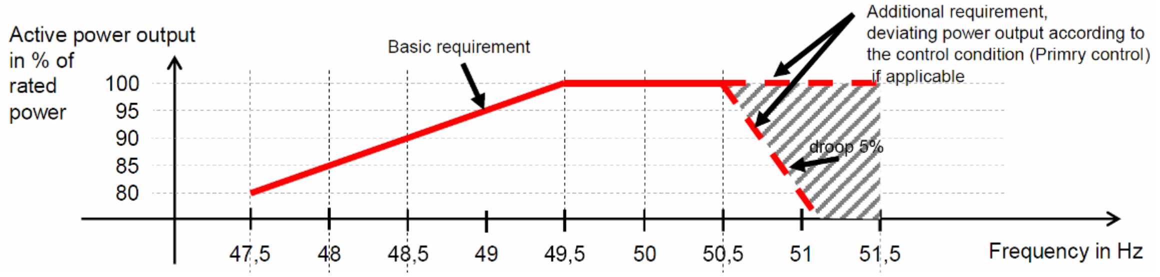
At Supergrid voltages the NGC requirement (i.e. zero voltage fault) is more onerous than those indicated in the E.oN and Ireland Grid Codes. However this more onerous requirement reflects the need to recognise that the planned Supergrid connection of clusters of large offshore wind farms (with combined capacities greater than the largest credible infeed loss of 1320W) can be influenced by the same Supergrid fault and therefore need to be able to ride through a credible zero voltage fault. This requirement is also compatible with the performance of modern "unconventional" generation equipment which can ride through a zero voltage Supergrid fault. We consider that this requirement can be accepted as it reflects the progress in the capability of unconventional generation technology and can be justified in the interest of system security following increased penetration of new generation technologies. In addition it should be noted that the Irish Grid Code allows the TSO discretion to impose a more severe requirement as would probably be applicable if clusters of large offshore wind farms were to be developed. The converse applies in the ENE network where the loss of a cluster of large wind farms will have an insignificant impact on the UCTE network.

A.2 Power/Frequency Characteristics

Frequency range requirements are identified in both the "E.oN Grid Code" and also the "Irish Wind Grid Code" both of which are discussed below.

A.2.1 E.oN Grid Code requirements

The main requirements for power frequency characteristics indicated in the E.oN Grid Code for renewable generation are no different from those applicable to 'conventional generation' and are summarised in the following figure:



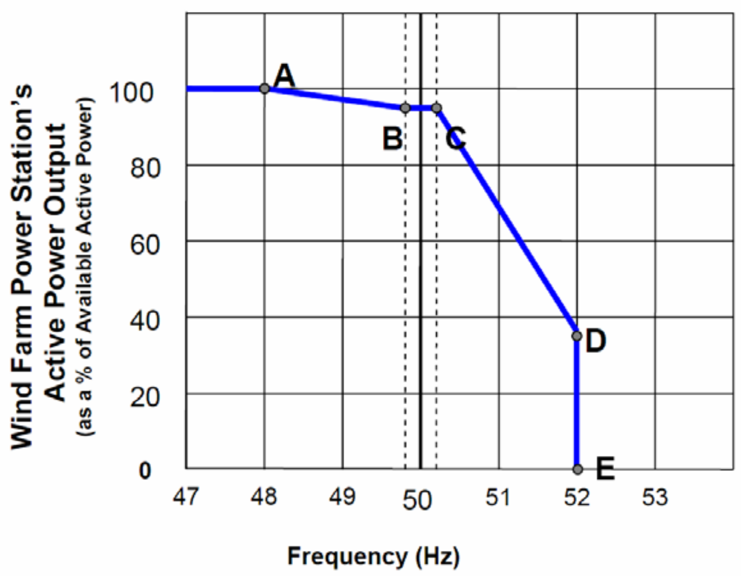
For frequencies below 49.5 Hz the generator output is allowed to reduce its output capability linearly reaching 80% of rated output when the frequency reaches 47.5 Hz. The unit must be automatically isolated from the network upon the system reaching 47.5 Hz or 51.5 Hz.

A.2.2 Irish Grid Code requirements for Wind Farms

The main requirements for power/frequency characteristics in Ireland for wind farms are as follows

Wind Farm Power Stations shall have the capability to operate continuously at normal rated output at frequencies in the range 49.5 Hz to 50.5 Hz. They should also remain connected to the network at frequencies within the range 47.5 Hz to 52.0 Hz for a duration of 60 minutes and remain connected to the network at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds each time the frequency is below 47.5 Hz. Additionally wind farm power stations should remain connected to the Network during rate of change of Frequency of values up to and including 0.5 Hz per second and no additional wind turbine generator shall be connected to the network while the frequency is above 50.2 Hz.

The frequency response system shall have the capabilities as per the following figure.



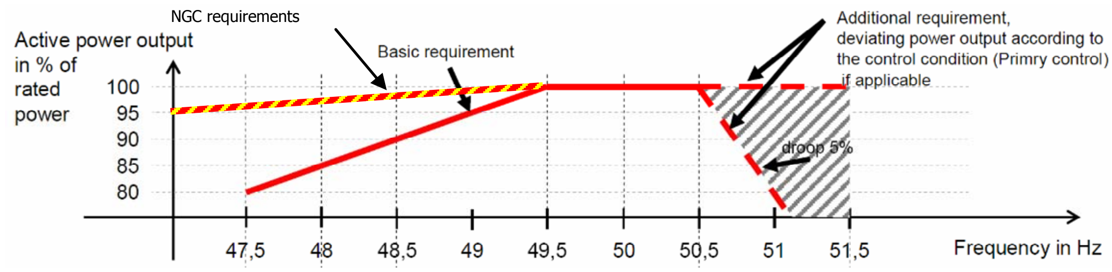
Points A to E, combination of power (P) and frequency (F) values, may be different for each wind farm power station and should be advised by the system operator prior to connection. The ranges of values applicable for these points are as indicated in the following table (MEC is the rated wind farm output)

	***Frequency** (Hz)*		***Available Active Power** (%)*	
			MEC >10MW	***MEC > 5MW***
F_A	*47.0-51.0*	P_A	*50-100*	*100*
F_B	*49.5-51.0*	P_B	*50-100*	*100*
F_C	*49.5-51.0*	P_C	*50-100*	*100*
F_D	*50.5-52.0*	P_D	*20-100*	*20-100*
F_E		P_E	*0*	*0*

If frequency goes above the D-E line in the figure above the wind turbine generators are allowed to disconnect. From inspection of the values in the table above there is a relaxation with regard to the provision of frequency response for generators below 10 MW for the low frequency part of the chart above. No requirement is evident for wind farms with a registered capacity below 5 MW.

A.2.3 Comparison of international practice with the proposals of NGC

The following figure superimposes the E.oN requirements with the NGC proposals. It shows that in both cases the capability of delivery of full output applies over the same frequency range namely from 49.5 to 50.5 Hz. However the power output requirements in NGC proposals are more onerous for frequencies below 49.5 , which require up to 95% output at 47 Hz (proportional to frequency), compared to the requirements of E.oN which allow a reduction in maximum output at 47.5 Hz to 80% of rating. This can be explained again by the relative size of the UCTE system compared to the systems in GB and the likelihood of disturbances that will affect system frequency in a relatively small system such as GB compared to the UCTE.



A similar comparison can be undertaken with the Irish Wind Grid Code. In this case a quantitative comparison cannot be made as the points in the power/frequency curve may vary for each wind farm . It is noted that the requirements in the Irish Wind Grid Code can be more onerous than those indicated in the NGC proposals and may be explained by the relatively small size of the system in Ireland the likelihood of larger generation / demand unbalances following system disturbances and the importance of generator performance under those conditions.

A.2.4 Conclusions

The Frequency Range proposals by NGC are in between the most onerous requirement found in the Irish Wind Grid Code and the least onerous found in the E.oN Grid Code. This can be explained by the likelihood of system frequency disturbances in each system and the importance of having adequate generation response under those circumstances. In this case, the NGC requirements are in between the most onerous in Ireland, the smallest system used in the comparison, and the most relaxed in E.oN the largest system (in terms of interconnected synchronised capacity via the UCTE network).

A.3 Frequency Control

Frequency control requirements are identified in both the "E.oN Grid Code" and also the "Irish Wind Grid Code" both of which are discussed below.

A.3.1 E.oN Grid Code requirements

Renewable generators should, following instruction from the system operator, be able to reduce its power output to a signalled value at a ramp rate of at least 10% of the connection capacity per minute without tripping. The latest E.oN Grid Code does exempt renewable units from providing primary frequency control even if the power output is greater than 100 MW.

A.3.2 Irish Grid Code requirements for Wind Farms

The frequency control requirements for wind turbine generators connecting to the ESB grid are outlined below. The Wind Farm Power Station is required to have a frequency response system capable of operating each wind turbine generator at reduced level if dictated by the system operator. The characteristics indicated in the frequency response and discussed above implicitly exclude wind farms below 10 MW from the provision of this facility.

A.3.3 Comparison of International requirements and change proposals

The E.oN Grid Code does not require that renewable generators provide frequency control. E.oN frequency control requirements for renewable generators can be more relaxed than the NGC requirements since E.oN forms part of the UCTE system with an installed capacity of about 550 GW where the requirement for frequency control will not be as important as in the GB or Irish systems with an total installed capacity of 76 GW and 7 GW respectively.

The comparison of the NGC proposals for frequency control with the requirements in Ireland are consistent in that the latter requires wind farms to be able to control its output under instruction of the system operator. In the Irish Grid Code there is a relaxation for the provision of frequency control for wind farms below 10 MW.

A.3.4 Conclusion

The NGC proposals for the provision of frequency control capability are compatible with the requirements in the Irish Grid Code. In the case of E.oN there is a relaxation for renewable technologies as E.oN forms part of a much larger interconnected UCTE system where frequency control should not be an issue. A relaxation for wind farms below 10 MW is indicated in the Irish Grid Code which compares well with the capacity thresholds in the definitions of Large Power Stations indicated the Grid Code (see footnote 5) where generators will not be required to comply with the Grid Code requirements.

A.4 Ramp rates

Ramp rates are identified in both the "E.oN Grid Code" and also the "Irish Wind Grid Code" both of which are discussed below.

A.4.1 E.oN Grid Code requirements

The E.oN Grid Code indicates that renewable generators should, following instruction from the system operator, be able to reduce its power output to a signalled value at a ramp rate of at least 10% of the connection capacity per minute without tripping. For frequencies above 50.5 Hz power output should be reduced at a rate of 5% per second. When the frequency deviation decreases, power output must be increased again accordingly. The maximum pick-up rate is 10% of the rated output per minute.

A.4.2 Irish Grid Code requirements for Wind Farms

The Irish Wind Grid Code requires that the Wind Farm Power Station shall be capable of controlling the ramp rate of its Active Power output with a maximum MW per minute ramp rate set by the system operator. There are two maximum ramp rate settings. The first ramp rate setting applies to the MW ramp rate average over one minute whereas the second ramp rate setting is applicable to the MW per minute ramp rate average over ten minutes. These ramp rate settings are applicable for all ranges of operation including start up, normal operation and shut down. A relaxation is provided for falling wind speed or frequency response.

It should be possible to vary each of these two maximum ramp rate settings independently over a range between 1 and 30 MW per minute. The Wind Farm Power Station shall have the capability to set the ramp rate in MW per minute averaged over both one and ten minutes.

A.4.3 Comparison of International requirements and proposals

The following table summarises the requirements regarding ramp rates in the various jurisdictions.

E.oN	Ireland	England & Wales	Scotland
10% of rated output/minute	- 1 to 30 MW/minute (1 minute average) - 1 to 30 MW/minute (10 minute average) (values specified by the TSO to each wind farm)	- No limit for a change of up to 300 MW - 50 MW/min for a change between 300 MW and 1000 MW - 40 MW/min for a change over 1000 MW	- For Power Park Modules < 15 MW No limit - For Power Park Modules from 15 MW to 150 MW 20% of rated output /minute (1 minute average) 7% of rated output/minute (10 minute average) - For Power Park Modules above 150 MW 30 MW/minute (1 minute average) 10 MW/minute (10 minute average)

The table above indicates that the limits stated by NGC are comparable with the requirements of E.oN. For example for a change between 300 MW and 1000 MW the limit is 50 MW/min which is equivalent to between 16% and 5% for a 300 MW and 1,000 MW plant respectively and compares well with the 10% of rated output/minute of E.oN. The Irish Wind Code imposes more onerous maximum requirements (30 MW/min) which could be expected as it is a much smaller system than NGC's. In Scotland, a system more similar to Ireland, the maximum ramp rate applicable for large wind farms are within the range ramp rates indicated in the Irish Wind Grid Code (at the discretion of the system operator).

A.4.4 Conclusions

The ramp rates proposed in the Grid Code for England & Wales and Scotland are consistent with the requirements in E.oN (better comparator with the NGC system) and Ireland (better comparator for the system in Scotland).

A.5 Reactive range and voltage control

Requirements for reactive range and voltage control are identified in both the “E.oN Grid Code” and also the “Irish Wind Grid Code” both of which are discussed below.

A.5.1 E.oN Grid Code requirements

The reactive range and voltage control requirements for wind turbine generators connecting to the E.oN Grid Code are outlined below.

For generating units with a rated power of less than 100 MW they must be able to be operated at full rated output between the power factors of 0.95 leading to 0.95 lagging (basic requirement). The system operator reserves the right to expand those requirements (additional requirement).

For generating units above 100 MW the basic operating range within the continuous line indicated in the following figure must be met.

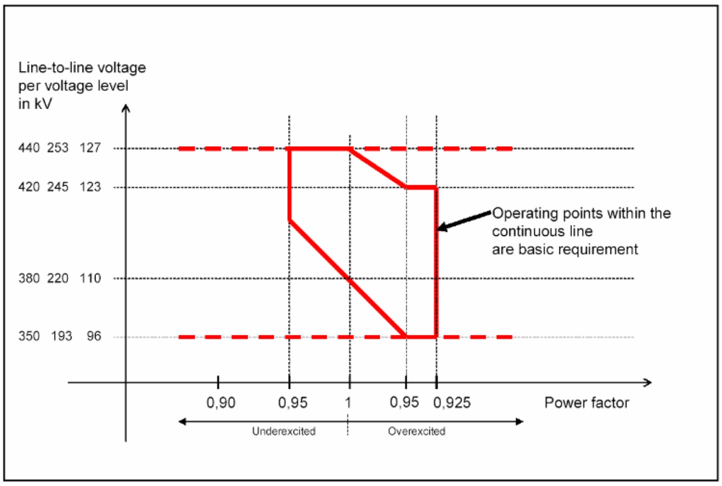


Fig. 4 Requirements on the reactive power provision of a generating unit at frequencies between 49.5 and 50.5 Hz without restriction of the active power output

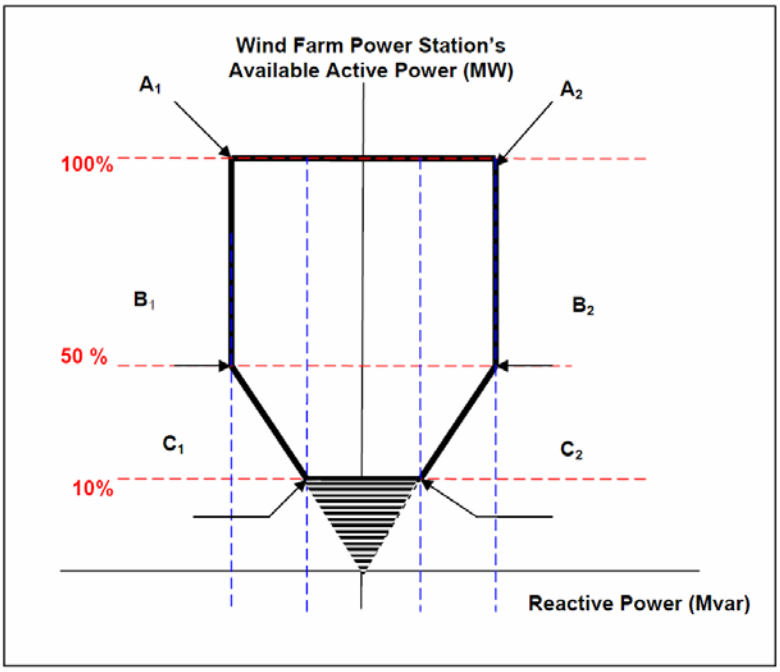
It should be noted that the normal voltage operating range for the various E.oN networks are between 350 kV and 420 kV on the 380 kV network, between 193 kV and 245 kV on the 220 kV network and between 96 kV and 123 kV on the 110 kV network. The upper value may be exceeded for up to 30 minutes.

A.5.2 Irish Grid Code requirements for Wind Farms

The requirements for wind generation connecting to the ESB grid with respect to reactive range and voltage control are outlined below.

Wind farms connected at 400 kV, 220 kV and 110 kV should remain connected at any output for the voltage variations of -12.5% to 5% at 400 kV, -9.1% to 11% at 220 kV and -10% to 11.8% at 110 kV and also for a step change in voltage of up to 10%.

Wind Farm Power Stations shall be capable of operating at any point within the power factor ranges illustrated in the figure below, as measured at the LV side of the Grid Connected Transformer, for any voltage at the connection point within the ranges above. Points A, B and C are equivalent to 0.95, 0.835 and 0.835 power factors respectively (leading or lagging as appropriate).



For operation below 10% of the Wind Farm Power Station maximum rated output, the Wind Farm Power Station shall operate within the shaded triangle in the Figure above. However, the total reactive power charging current requirements of the Wind Farm Power Station network during no load operation shall be examined during the TSO Connection Offer process, following which, the above requirement for operation below 10% may need to be altered.

A.5.3 Comparison with the proposals of NGC

For wind farms below 100 MW the requirements of E.oN and NGC are identical within the range of normal operating ranges in each jurisdiction. However a relaxation of requirements for wind farms connected at 33 kV and below is indicated in NGC's proposals that assume the lack of tap changing transformers which is considered reasonable. For wind farms above 100 MW, the following figure shows the E.oN requirements for reactive power control and superimposed the proposed NGC requirements. The figure shows the NGC requirements for generators connected above 33 kV (square hashed line below) and also the requirements for generators connected below 33 kV (lines indicated in the figure below). For comparison purposes only the requirements above 33 kV are valid as the E.oN requirements shown in the figure (red line) only apply for wind farms above 33 kV .

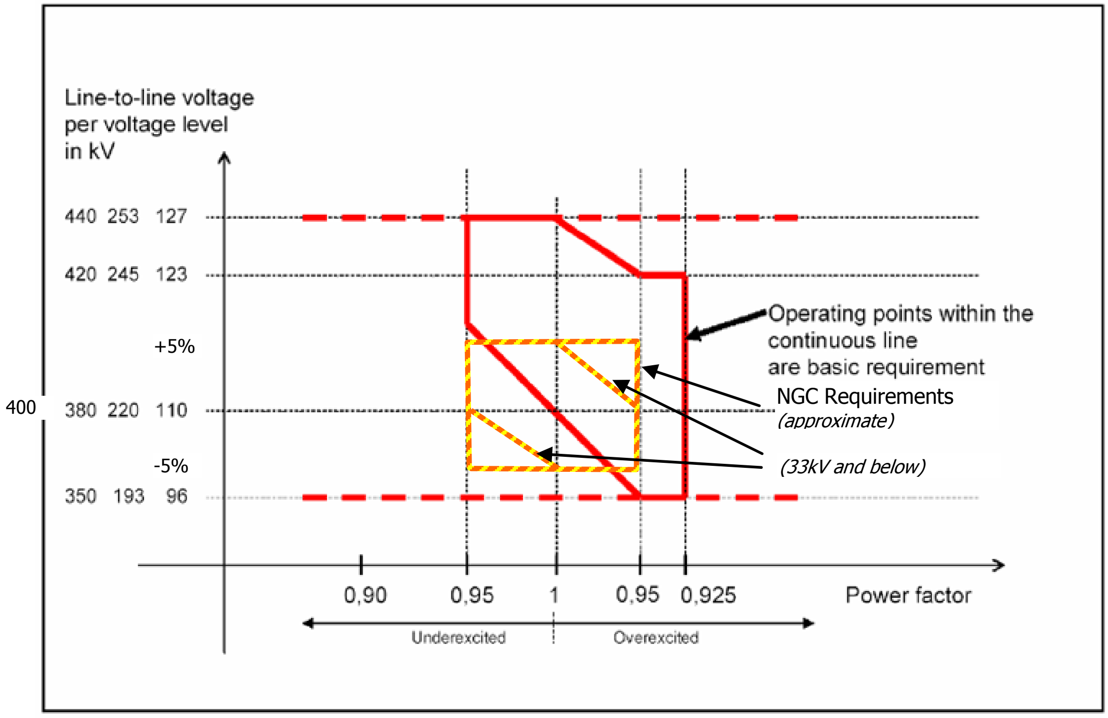
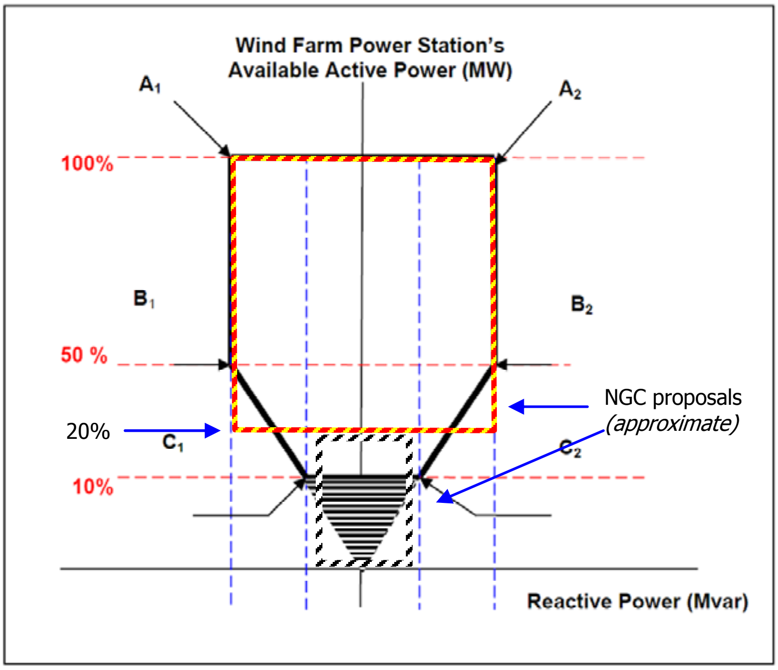


Fig. 4 Requirements on the reactive power provision of a generating unit at frequencies between 49.5 and 50.5 Hz without restriction of the active power output

The comparison of the outline curves in the figure indicates that the E.oN "basic requirement" is more onerous than NGC's in terms of maximum operating voltage and power factor (overexcited) and indeed the possible maximum requirement (dashed red line). It should be noted that the E.oN requirement includes normal operating conditions and transient overvoltages (up to 30 min, in the graph the area above the 420/245/123 kV dotted line) NGC proposals are more onerous in the case of E.oN when voltages are below nominal and the machines are required to be able to operate under-excited. However it should be noted that there are different requirement philosophies in the

E.oN grid code and NGC proposals. The E.oN basic requirement is a "minimum" requirement that can be further expanded (within the dashed red lines shown in the figure above). The NGC requirement is a "maximum requirement" that could be reduced in the connection agreement. As such it can be concluded that the NGC requirements for large wind farms (>100 MW) are completely within E.oN possible range of requirements.

The following figure shows the NGC proposals superimposed against the requirements in the Irish Wind Grid Code . The main difference between both requirements is that the relaxation of the reactive power requirements in Ireland starts to drop for wind farm outputs below 50% compared to 20% in the NGC proposals. However it is not considered that this difference is relevant as with a 20% wind farm output it can be expected that all wind turbines will be connected to the network and hence its reactive capability would remain intact. Typically it can be expected that individual wind turbine generators will start to trip when the wind farm output gets around 5%.



A.5.4 Conclusion

The comparison of the requirements for reactive range and voltage control in the NGC proposals and the E.oN grid code indicates identical requirements (within each jurisdictions normal operating voltages) for wind farms below 100 MW. For wind farms with capacities above 100 MW the NGC proposals are within the range of possible requirements by E.oN. The comparison of the requirements for reactive range and voltage control in the NGC proposals and the Irish wind code

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indicate identical requirements for wind farm outputs between 100% and 50% and a more onerous requirement in the NGC case for power outputs between 50% and 20% where NGC proposals require to maintain the full reactive range. However it is considered that this should not pose any difference in practice as for wind farm power outputs of 20% it can be expected that all individual wind generators would be connected (typically tripping due to low wind speed when the wind farm output is about 5%). It can be concluded that the NGC proposals with respect to reactive range and voltage control are consistent with other requirements found internationally.

A.6 Negative phase sequence

Requirements for negative phase sequence for renewable generation are not specifically identified in the "E.oN Grid Code" nor in the "Irish Wind Grid Codes". It can be assumed that no specific requirements or relaxations are applicable for renewable generators from those applicable to conventional power plants.

A.6.1 Comparison with the proposals of NGC

The additional requirements for renewable generators are only applicable to synchronous generators, essentially to withstand a close phase-to-phase fault cleared by the backup protection at any voltage level. There are no additional requirements for Power Park Modules over and above those applicable to conventional plants and it can be concluded that the proposed lack of requirements for negative phase sequence for "unconventional" generation in the NGC proposals are consistent with requirements found in other jurisdictions.