System Operator for Northern Ireland

Review of Transmission System Security and Planning Standards

Consultation Paper

September 2014

1 Introduction

1.1 Under Condition 20 of its Licence to Participate in the Transmission of Electricity (the License), SONI is responsible for the planning of the transmission system in accordance with The Transmission System Security and Planning Standards, the Distribution System Security and Planning Standards, the Grid Code and the Transmission Interface Arrangements as appropriate.

1.2 Under Condition 20 SONI is also required to periodically review the Transmission System Security and Planning Standards in consultation with the Transmission Owner and other parties likely to be materially affected.

1.3 SONI has identified and reviewed those the elements that are specific to its transmission license and propose to make changes as documented in this report.

1.4 The purpose of this paper is to set out the proposed changes and seek feedback from stakeholders.

2 Scope

2.1 The License which under which SONI operates was modified recently to reflect the transfer of the investment planning function.

2.2 The transmission system in Northern Ireland is considered to include the overhead lines, underground cables and substation assets operating at 275 kV and 110 kV. The interface with the distribution system is considered to be at the secondary terminals of the 110/33 kV transformers at bulk supply points.

2.3 The full set of Transmission and Distribution System Security and Planning Standards is set out in Table 1. The documents were designated as NIE license standards (with several associated amendment sheets) in 1992 and also SONI standards in 2007. The subset of these which it is proposed to designate as the Transmission System Security and Planning Standards (TSSPS) and review in this paper is set out in Table 2. The documents are available to download from the SONI website[1].

[1] Documents are stored at http://www.soni.ltd.uk/InformationCentre/Publications/.

Table 1 T&D System Security and Planning Standards

Reference	Title
ER P2/5	Security of Supply
PLM-SP-1	Planning Standards of Security for the Connection of Generating Stations to the System Issue 1
PLM-ST-4	CEGB Criteria for System Transient Stability Studies Issue 1
PLM-ST-9	Voltage Criteria for the Design of the 400kV and 275kV Supergrid System Issue 1
ER P28	Planning Limits for Voltage Fluctuations
ER P16	EHV or HV Supplies to Induction Furnaces
ER P29	Planning Limits for Voltage Unbalance
ER G5/3	Limits for Harmonics
ER G12/2	Application of Protective Multiple Earthing to Low Voltage Networks
EPM-1	Operational Standards of Security of Supply Issue 2

Table 2 Sub set relevant to transmission

Reference	Title
ER P2/5	Security of Supply
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PLM-ST-9	Voltage Criteria for the Design of the 400kV and 275kV Supergrid System Issue 1
ER P28	Planning Limits for Voltage Fluctuations
ER P16	EHV or HV Supplies to Induction Furnaces
ER P29	Planning Limits for Voltage Unbalance
ER G5/3	Limits for Harmonics

2.4 G12/2 is excluded from the Transmission Standards because it applied to low voltage networks only. EPM-1 is also excluded from this review because it relates to the operation of the transmission system, rather than its planning.

2.5 In addition to the License changes referred to above there have been a number of other contributory factors to the need to review the standards:

- **All island transmission planning:** The transmission system in Northern Ireland is interconnected to that of the Republic of Ireland (RoI) and is a functional part of the Single Electricity Market. There is therefore a need to ensure that transmission planning is considered on an all island basis. It is recognised that both systems were designed to standards which differ in some areas, which over time will have become reflected in the specification and design of physical assets. It is therefore accepted that some differences shall remain. However it is planned that major items should as far as reasonably practicable be consistent. The standard applied by EirGrid is known as the Transmission Planning Criteria (TPC) and is available on the EirGrid website.

- **The penetration of intermittent renewable generation:** The original standards were drafted to cater for base load steam turbine and nuclear powered generators[2]. A large part of the generation portfolio, unlike that envisaged when the standards where first adopted, is intermittent. Currently there is over 550 MW of wind generation connected in Northern Ireland with more connections planned.

- **Offshore transmission systems:** Given the planned connections of offshore wind and tidal generation in Northern Ireland there is a need to establish relevant standards.

- **Cost benefit analysis:** The general use of cost benefit analysis (CBA) which requires the use of probabilistic techniques is now being used by some utilities and regulators to support some investment decisions.

[2] The present NI standards are based on GB documents.

3 GRID CODE AND OTHER LEGISLATION

Grid Code

3.1 The SONI Grid Code places an obligation on the TSO to apply the relevant Licence Standards in the planning and development of the Transmission System. It also requires Users to take these standards into account in the planning and development of their own plant and systems.

Electricity Safety, Quality and Continuity Regulations (Northern Ireland) 2012

3.2 The Electricity Safety, Quality and Continuity Regulations (Northern Ireland) 2012, replacing the Electricity Supply Regulations, came into operation on 31 December 2012 and set out the obligations regarding the safe operation of equipment and design requirements to be met. These regulations also include requirements that are to be supported by and complement the security standards. In brief these requirements are:

- The network to be designed such as to restrict, so far as is reasonably practicable, the number of consumers affected by any fault in the network. (Part 1).
- A distributor shall declare to a consumer the frequency and voltage to be provided as follows (unless otherwise agreed). (Paragraph 28).
- Frequency 50 Hz, with a variation not exceeding 1% above or below.
- Voltage of 230 volts with variations of +10/-6 % for low voltage, $\pm$6 % for high voltages below 110 kV, $\pm$10 % for voltage of 110 kV.

4 FAULT RATES OF TRANSMISSION SYSTEMS

4.1 In revising the planning standards for Northern Ireland it is useful to examine the planned and unplanned availability rates for the transmission system in Northern Ireland in comparison with similar data for GB and RoI. Consistency between the availability of the various systems is important in any consideration of the adoption of similar standards of planning and security.

4.2 A comparison of the total availability[3] in NI, GB and RoI transmission systems is given in Figure 1. A comparison in unplanned unavailability between NI and GB data is given in Figure 2. The unplanned availability for the transmission system in RoI[4] by voltage is given in Figure 3. These figures indicate reasonable consistency between the availability of the three transmission systems.

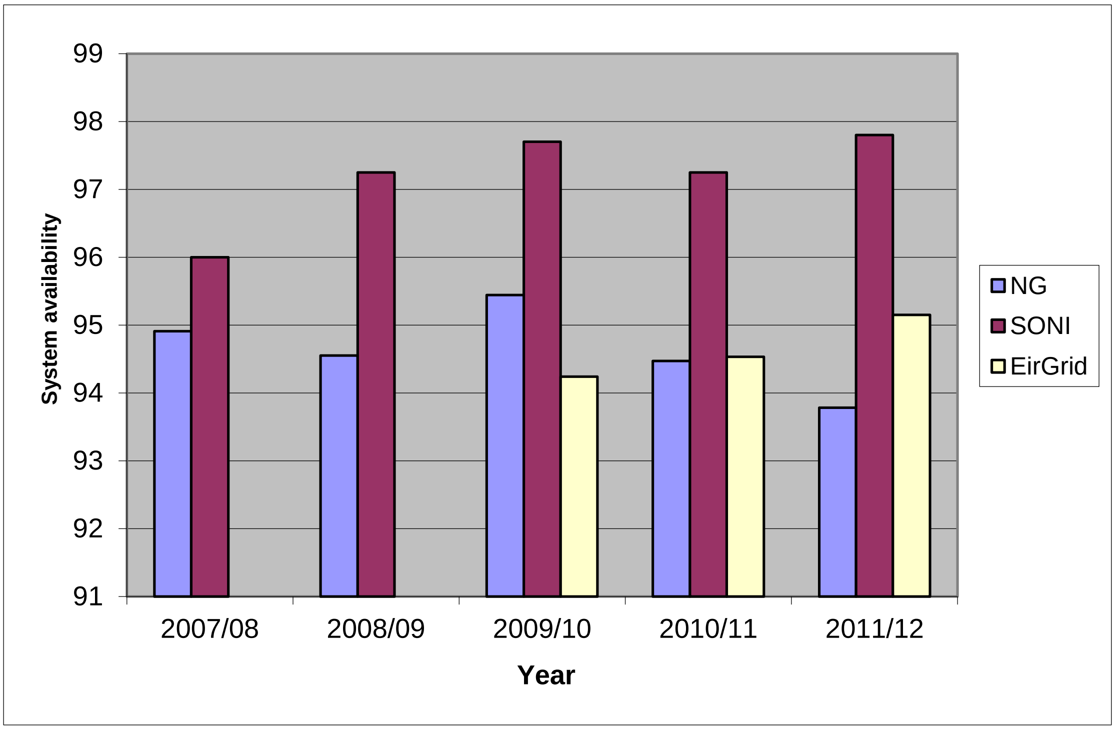

Figure 1 – Total availability of transmission systems controlled by SONI and National Grid

[3] SONI and NG have used financial years, EirGrid use calendar years.

[4] Sourced from EirGrid Transmission System Performance Report 2009, 2010 and 2011

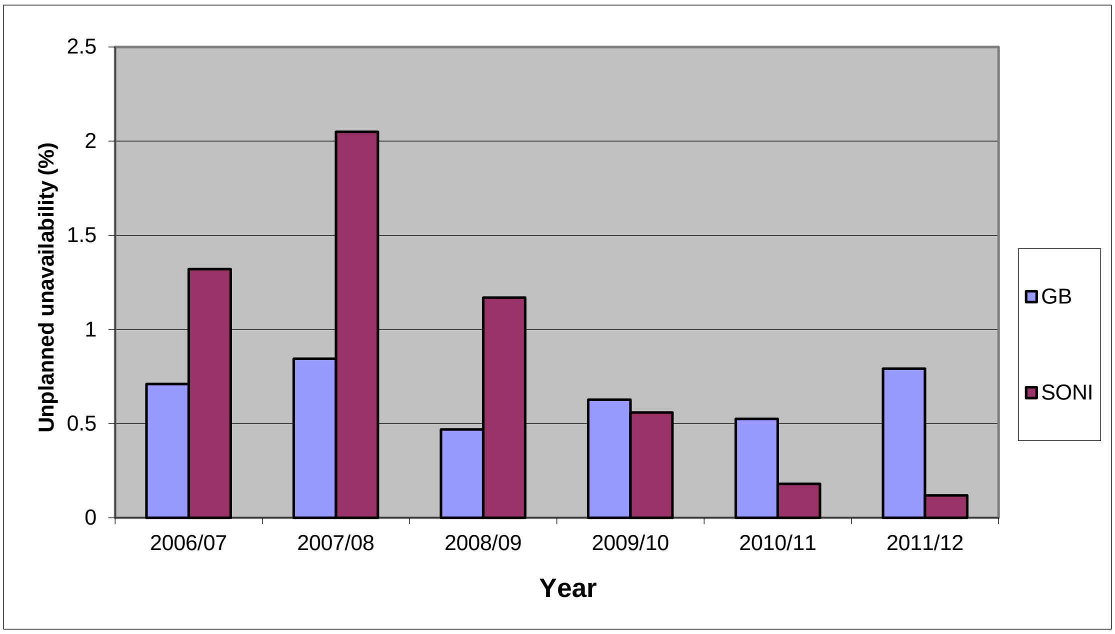

Figure 2 – Unplanned unavailability of transmission systems controlled by SONI and National Grid

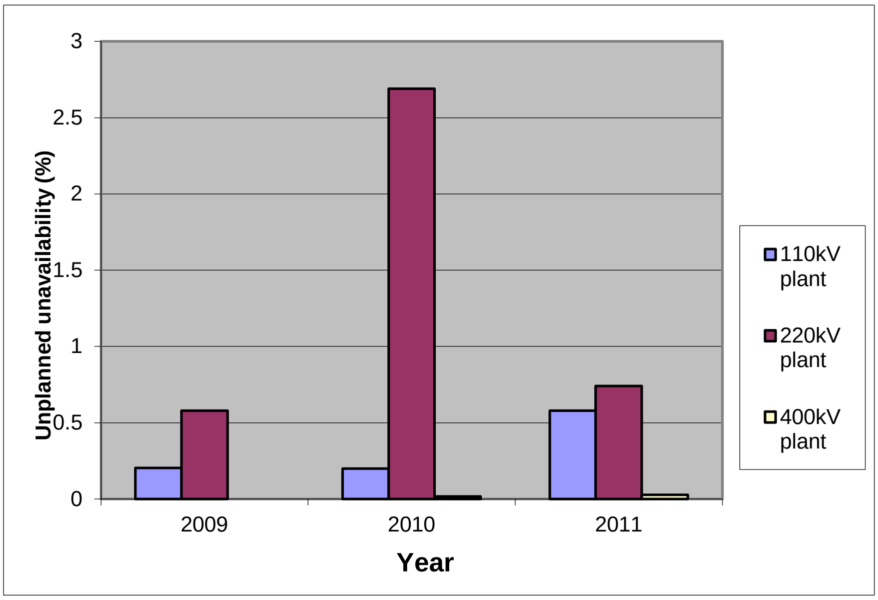

Figure 3 – EirGrid unplanned availability by voltage

5 REVIEW AND COMPARISON OF STANDARDS

(i) Security of supply ER P2/5 with NIE Amendment Sheet

5.1 This standard was prepared by the Electricity Council and published in 1978.

5.2 This standard was originally based on reliability studies using fault statistics, the value of lost load (VOLL) and the contribution from any embedded generation, to establish the risk/cost of supply failure and compared this with the cost of investment in the network.

5.3 The standard has a supporting document known as 'ACE 51' "Report on the application of Engineering Recommendation P2/5 Security of Supply" briefly outlining the philosophy and application. It states that the intention of security standards is to "provide sufficient plant and other resources to provide and maintain an economic level of reliability of supply to the consumer" and that "simple tables formulated from experience of working conditions and system studies should aim at setting out proposals which, if applied, would in general give reasonable reliability of supplies at a reasonable cost".

5.4 The intention in writing P2/5 was to present rules which would give a reasonably deterministic approximation of the network capacity required but did not preclude economic assessments being carried out if required.

5.5 The standard considers demand group levels from 1 MW through to 1500 MW against six categories (Category A, B, C1, C2, D, E and F). For each of these categories the standard provides requirements for demand to be restored following first (N-1)[5] and second (N-2 and N-M-T) circuit outages. The NIE amendment sheet introduced a change to higher level of demand in Category B (lowered from 12 MW to 8 MW) and a split in Category C (at 24 MW).

5.6 The categories relevant to the transmission system are C (8 MW to 60 MW), D (60 MW to 300 MW) and E (300 MW to 1500 MW). In the original P2/5 Category F was included for demand groups in excess of 1500 MW, directing the user to the CEGB Planning Memorandum PLM-SP-2 and Scottish Board standard NSP 366, however this was removed in the NIE amendment sheet. The category was considered not of practical application in Northern Ireland as maximum demand in 1992 did not exceed 1500 MW.

Treatment of embedded generation in P2/5

5.7 Whilst P2/5 primarily specifies the levels of redundancy required for various demand groups, it allows the designer to give consideration to the security of supply provided by various types of embedded generation as set out in Table 2.

[5] N-1 refers to normal configuration followed by a single circuit outage either planned or forced; N-2 refers to normal configuration followed by two circuit outages; N-M-T reflects the more credible N-2 situation of an unplanned circuit outage whilst a planned outage is on going

5.8 The original analysis for P2/5 Table 2 was captured in ACE 51. This was a reliability assessment aimed at deriving what rating an additional circuit into a demand group should have such that its contribution to meeting demand is equivalent to the average contribution of generation in the group in terms of 'expected energy not supplied' (EENS). The rating of the equivalent circuit, i.e. the 'contribution' of the embedded generation, was expressed as a percentage of the installed generation capacity.

Application of P2/5 in Northern Ireland

5.9 It should be noted that transmission network in NI includes the 110 kV radial circuits and the 110/33 kV transformers, which interface with the distribution system. Therefore the standard must include for the aggregated demand impact of these interface nodes. In respect of application at transmission level it is mainly used to assess the level of security available to 275/110 kV and 110/33 kV substations. The standard can also be applied to any instance where a group of 110/33 kV substations are connected to a section of network.

5.10 The standard can be applied also to circuits that supply groups of demand and establishes the basis for studying N-1 and N-2 (or N-M-T) contingencies on the transmission network. Currently N-1 is studied in all seasons, with N-2 only studied in summer and autumn cases[6] (the maintenance seasons).

5.11 For the main interconnected network connecting power stations and interconnectors or tie lines, the standard applies in respect of the risk of losing supply to groups of demand.

Comparison with GB and ROI standards

5.12 At the time of its formal designation as an NIE license standard in 1992 the P2/5 standard was the applied throughout the UK. The three transmission licensees in Great Britain, however, have since developed a composite standard known as System Quality and Security Standard (SQSS) with guidelines similar to the original P2/5 included. The GB DNOs, however, have since developed a new standard, known as P2/6, which has been designated for the connection of demand blocks in Great Britain. NIE as the distribution network owner in Northern Ireland has recently carried out a consultation with a recommendation that P2/6 is designated thus replacing the P2/5 standard.

5.13 The standard includes an updated method for considering the contribution to security of supply provided by various modern types of embedded generation. It is also noted that the SQSS does not as yet reflect the changes that have

[6] The simultaneous loss of two circuits (N-2) on the backbone network is not considered to be a credible scenario under the Standards. The loss of a circuit whilst a maintenance outage is on-going (N-M-T) is however considered credible even though investment decisions are normally subject to cost benefit analysis, i.e. the cost of re-dispatch during the maintenance period is often much lower than network investment.

been adopted by the distribution network owners in Great Britain within P2/6. Given the relatively small size of the Northern Ireland transmission system and the fact that the interface is at the 110/33 kV transformers there may be a case for greater alignment.

5.14 The current P2/5 standard, for Class E (>300 MW), refers to compliance with N-2 (for example maintenance followed by trip) at 2/3 of the group demand. In the 1970s when P2/5 was written the ratio of summer to winter demand was more reflective. However this ratio now in practice often exceeds 4/5, due mainly to the impact of air conditioning demand which increases in summer. It is noted that the SQSS standard recognises this change in demand characteristics and now refers to the maintenance period demand rather than any specific percentage. Any new Northern Ireland standard should also consider this change.

5.15 In RoI, the Transmission Planning Criteria (TPC) doesn't have an equivalent table, however there is a recommendation that multiple 110/38 kV stations supplying demand in excess of 80 MVA, or up to four 110/38 kV substations, should not be isolated for an N-2 event. This requirement would be implicit within Category D (60 MW to 300 MW) of P2/5 which requires a re-supply to 1/3 of group demand within 3 hours for an N-2 event. If two adjacent 110/33 kV substations were disconnected for an N-2 then it is unlikely that the 1/3 re-supply requirement could be met. The practice in Northern Ireland has been to connect 110/33 kV substations as individual transformer feeder arrangements unless introduced as a node on the main interconnected transmission system.

Latest Practice by ENTSO-E

5.16 ENTSO-E has published approaches to transmission planning in the 2012 Ten Year Network Development Plan (TYNDP). Appendix 3 of the 2012 TYNDP includes a separately published document "Guidelines for Grid Development". The document does not specify redundancy requirements for varying levels of group demand such as are included in P2/5. The document does, however, refer that the maximum loss of load should not exceed the active power frequency response.

Cost Benefit Considerations

5.17 The Council of European Energy Regulators (CEER) gives European guidelines[7] on estimating the costs of electricity interruptions and voltage disturbances, recommending that "*National Regulatory Authorities should perform nationwide cost-estimation studies regarding electricity interruptions and voltage disturbances".*

5.18 It is understood that most countries design demand connections to an N-1 criteria with a cost benefit analysis used to justify investment to an N-2 level.

Proposal

5.19 The review by NIE of the distribution planning standards has resulted in a proposal by NIE for the designation of ER P2/6 replacing P2/5 in the set of Distribution System Security and Planning Standards. It is therefore proposed, for a consistent approach across the system, that the new transmission standard should take account of the techniques within P2/6. Assessment of capacity to supply demand should use demand values that have been modified to allow for embedded generation with the appropriate factors already applied. A reference to the Distribution System Security and Planning Standards would be used to capture this approach. For larger, perhaps 33 kV connected generation, it is considered that this should be modelled separately within the transmission studies but that the same techniques in terms of contribution to security of the supply to the demand group should be assumed.

(ii) Connection of generation PLM-SP-1

5.20 The CEGB Planning Memorandum PLM-SP-1 was published in September 1975 to set out the requirements for connection of generation. The document sets out the requirements for the capacity and number of circuits required to connect generation in terms of multiples of the largest single generating unit, which at the time was 660 MW in Great Britain.

5.21 In summary the document recommended that generating units up to 660 MW could be connected with a single circuit, with groups of generating units between 660 MW and 1320 MW being connected by at least two circuits. Above that at least three circuits were required. The document also prescribed limits to the length of 400 kV and 275 kV circuits to connect generating power stations.

5.22 When designated as a license standard in Northern Ireland an amendment sheet was included which reduces the level for at least three circuits from 1320 MW to 550 MW (due to the predominant use of double circuits it was actually described as four circuits). At the time the transmission system in Northern

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[7] Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010. Other reports have also established such guidelines, such as CIGRE (2001) and EPRI (

Ireland was an isolated system (North South interconnector was restored to service in 1995) and the largest generating unit was approximately 260 MW.

Maximum distance of a generation connection circuit

5.23 The PLM-SP-1 set limits on the maximum distance of 400 kV and 275 kV generation connection circuits for high and low load factor power stations to 5 km and 20 km respectively. It is understood that these limits were primarily applicable to generator owned circuits in Great Britain. In Northern Ireland this situation does not arises apart from relatively short connecting cables within the power station complex.

5.24 PLM-S-1 is silent regarding the length of 110 kV connections. A limit for 110 kV connections is likely to become a barrier to the economic and timely connection of key renewable generators in the future, possibly risking renewable generation targets. It is suggested, since NI is relatively small in geographic terms that the number of instances that generators would connect using 110 kV circuits in excess of the distances specified above will be relatively few. Also with 110 kV applications other factors such as fault level and voltage regulation will lead to a natural limit on the length of 110 kV connection circuits, depending on the capacity required. It is therefore not proposed to extend these limits to the connection of 110 kV connected generators or clusters. The issue should be kept under review.

5.25 For 275 kV and 400 kV connections the scale of generation that could be connected would be up to the largest single infeed. Again however the application of the limit could be a barrier to the connection of offshore generation in particular. It is proposed however to retain the 5 km limit for large base load onshore generation.

Intact system and under credible contingencies

5.26 PLM-SP-1 specifies that a new generation connection shall not cause voltage violations (Clause 2.1.4) or system instability (Clause 2.1.5). Clause 2.1.4 also states that frequency and voltage will be maintained within equipment ratings (assumed to indicate thermal current ratings). The SQSS has also included these elements (Clauses 2.9.1, 2.9.2 and 2.9.3).

5.27 PLM-SP-1 also refers that the above will apply during credible contingencies. The SQSS specifies that for these conditions there are no equipment overloads (2.10.8), voltage violations (2.10.9) and that there is no loss of demand apart from that specified in P2/5 (2.10.7).

5.28 It is considered imperative to retain the above provisions in any updated set of standards.

Largest Single Infeed

5.29 The Largest Single Infeed[8] (LSI) can be defined as a block of generation consisting of a single large unit, a group of units, or an interconnector importing, connected to the all-island power system via a single transmission circuit, the loss of which would result in the loss of the entire block of generation. The LSI is used in RoI in the TPC to define the requirements for the connection of generation, however the actual level is not stated.

5.30 PLM-SP-1 specified that the largest single generation connection in GB was to be 660 MW (Clause 3.1). The NIE amendment sheet however does not align with this value, instead setting the requirement for at least three circuits to 550 MW reflective of the smaller system. As a consequence the largest set in NI was never envisaged as 660 MW. It can be inferred from the NIE Amendment Sheet, since the limit requiring N-2 security (reserved for a group of generation of twice the largest single infeed) was set for 550 MW that the LSI in NI at the time of privatisation was considered to be 275 MW. The actual LSI in 1992 was Kilroot G1 and G2 which each had a capacity of 260 MW (on oil).

5.31 When the North – South interconnector was restored in 1995 generating reserve was shared. Since then, larger power infeeds have been commissioned in NI, including the Moyle Interconnector[9] (connection of 450 MW) in 2002 and Coolkeeragh CCGT (414 MW) in 2005. On the all island basis the East West Interconnector (EWIC) was connected in 2012 raising the LSI to on the island to 500 MW. To be consistent on an all island basis it is proposed that the LSI for the NI standard should be clearly defined as 500 MW.

Generators or groups up to the capacity of the largest single infeed

5.32 In terms of the number of circuits required Clause 2.1.2 of PLM-SP-1 states that no single fault shall cause the instantaneous loss of generation greater than the single largest infeed. From a minimum standard it therefore follows that a single connection circuit is acceptable for the connection of generators up to the LSI.

5.33 The 2004 version of the SQSS specified the same, however, this was amended in the most recent version in 2012, recommending that up to 1320 MW can be connected via a single generation connection circuit. This change came from a review carried out by the transmission owners (TO) in GB.

5.34 In RoI, the TPC states that any group of generators with a combined capacity in excess of the LSI shall have two generation connection circuits (section 4.2

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[8] The Largest Single Infeed is an important concept in that it dictates the level of generation reserve and automatic under frequency load shedding that the TSO requires to provide for.

[9] Whilst the Moyle Interconnector has two poles it is connected to a single 275kV circuit in Scotland, thus could be lost for a single contingency.

iv). Therefore, it follows that for a generator smaller than the LSI, a connection with a single circuit is acceptable. Thus this is consistent with the SQSS.

5.35 It is proposed that the new standard shall recommend a single circuit is acceptable for generators or groups thereof with total capacity up to the LSI, set at 500 MW.

Generator groups in excess of once but less than twice the largest single infeed

5.36 PLM-SP-1 (clause 3.2.1) specifies that two circuits are required for generation connections up to twice the single largest infeed (Clause 3.2.1).

5.37 In RoI the TPC also states that two circuits are required for a group of generators with a capacity in excess of the LSI. On that basis it would appear permissible for a capacity of twice the largest single infeed to be lost for the loss of two circuits.

5.38 It is proposed that for a group of generating units above the LSI that two circuits will be required. However considering the relatively small size of the Northern Ireland transmission system, the widespread use of double circuit tower lines and its limited interconnections this is capped at 1.3 times the LSI is proposed, i.e. 650 MW. This can be reviewed as appropriate when further interconnection is established.

5.39 The standard should also allow for the use of operational intertripping to reduce the generation output provided that does not introduce excessive complexity (assessed by risk assessment), frequency or instability problems and can be economically justified on a case by case basis.

5.40 The PLM-SP-1 standard (with NIE amendment sheet) suggested that it would be normal for power stations over 550 MW (NIE Amendment sheet Revision 2) would be connected via four circuits (i.e. secure after an N-2). The definition of four circuits of course was reflective of the practice in Northern Ireland to use double circuit tower lines. The main objective however was that the connection would be secure for an N-2 event. The equivalent in the SQSS is the *infrequent infeed loss risk* (2.6.1 and 2.6.3) which is currently 1320 MW. The SQSS states that following the loss of a double circuit tower line the maximum that can be lost is the *infrequent infeed loss risk* (Clause 2.6.4). Above this level (1320 MW) it is assumed that if a DCT is used in the connection it must be supplemented by at least one additional circuit.

Generators above 1.3 times the largest single infeed

5.41 The TPC specifies that for generation in excess of twice the largest generation, it shall be possible to transmit the full output less one generating set in a trip maintenance (or N-M-T) condition (see Clause 4.2.iv). Thus this standard envisages that the output of the station could be constrained during the initial maintenance outage.

5.42 As stated in 5.39 it is proposed to limit the application of two circuits up to 1.3 times the LSI. Above this it is proposed that at least three circuits are required. If provided by double circuit tower lines then four circuits would be required.

Busbar arrangements

5.43 PLM-SP-1 sets standards for the busbar arrangements to connect various levels of generation. For certain outages on the transmission system it is accepted that there is a risk of losing connected generation. A comparison between PLM-SP-1, relevant sections of the SQSS and TPC relating in this regard are shown in Table 1.

Table 3 – Comparison of busbar requirements

Contingency	Loss of power		
	PLM SP 1	SQSS	TPC
Fault outage of any single generation connection circuit	Largest authorised generator (2.1.2)	Infrequent infeed risk, 1320MW (2.6.3)	Largest set (4.2 ii)
Planned outage of any busbar section	Not directly specified, however historically in practice no loss of infeed for transmission connected.	No loss of power infeed (2.6.2)	Not specified
A fault outage of any single busbar section	No greater than the largest set (2.1.3).		No greater than the largest set (4.2 ii)
A fault outage of bus section or bus coupler circuit breaker	No greater than twice the largest set (2.1.3).		No greater than twice the largest set (4.2 ii)
A fault outage of transmission circuit or busbar section, during the planned outage of a transmission circuit or busbar section	The current NI standard specifies that there is no loss of power greater than twice the single largest infeed (NIE Amendment Sheet Revision 2).	No loss of power greater than twice the single largest infeed.	Not specified but by implication of 4.2 ii considered same.
A fault outage of bus section or bus coupler circuit breaker, during the planned outage of any busbar section	Twice the single largest infeed (NIE Amendment Sheet Revision 2).	Infrequent infeed loss risk (1320MW)	Not specified

Definition of generation connection circuit

5.44 Consideration should also be given, if one combined standard is developed, that two classes of circuit are defined, i.e. a) a generation connection circuit, and b) a main interconnected transmission circuit, as defined in the GB SQSS. Some circuits can of course be classed as providing both functions as there is often an overlap. This would help to clarify how each circuit is to be considered in the standards, i.e. must comply with N-1 or in the case of a generation circuit would allow a limited loss of generation infeed.

5.45 The existing standards clearly define the need for double busbar arrangement for the connection of conventional generation.

Levels of embedded generation connected to 110/33kV substations

5.46 PLM-SP-1 being a transmission standard doesn't offer any specific guidelines on the levels of embedded generation that can be connected at cluster type and mixed demand type 110/33kV substations.

5.47 In such scenarios the level of generation will always be lower than the LSI and therefore N-1 security is not required. Therefore at cluster substations a single 110/33kV transformer, rated accordingly, is acceptable. If two transformers are required then it would be the combined capacity that would be assessed against the peak generation with no redundancy. For the loss of one transformer the remaining generation would have to be constrained.

5.48 However, in substations that also have significant demand connected the P2/5 security of supply standard, or replacement provisions, should be respected. Therefore generation cannot be connected such that it would overload the remaining in service transformer under n-1 and as a result cause the loss of demand potentially above that specified in P2/5. There are other factors such as operability issues, transformer life, losses, voltage step changes, reactive power requirements, flicker and harmonic headroom with the associated risks assessed on a case by case basis.

5.49 It is proposed that the new standard should cater for instances where the flows from generation embedded within the distribution system interface with the transmission system at a bulk supply point. It does not seem prudent to specify an arbitrary limit on this but state that operational intertripping can be used to reduce the level of embedded generation to protect a second transformer from overload risking the loss of demand customers.

(iii) PLM-ST-9; Voltage Criteria

5.50 CEGB Planning Memorandum PLM-ST-9 published in December 1985. The document sets out the voltage requirements in terms of upper, lower and step limits. In GB the voltage regulation requirements are as set out in Section 6 of the SQSS. In RoI similar requirements are set out throughout the TPC.

5.51 A Comparison of NI, ROI and GB voltage lower and upper limits is given in Table 4 and 5. The NI and GB SQSS (England and Wales) standards are identical. The RoI standard permits a higher voltage rise on the 220kV and 110kV networks, both during system normal and fault conditions. The limits above have been designed over time into the transmission systems in Northern Ireland and RoI.

Table 4 – Comparison of lower voltage limits (pu)

Case	Nominal Voltage	Lower limit (pu)			
		NI	RoI (TPC)	GB (SQSS)	
				England and Wales	SPT and SHETL areas
System Normal	400kV		0.925 (Section 2.2.6)		
	275/220kV	0.95	0.954	0.95	0.95
	110/132kV	0.95	0.954	Note 2	Note 1
Contingency	400kV		0.875		
	275/220kV[10]	0.9	0.91	0.9	0.9
	110/132kV	0.9	0.9	Note 3	Note 3

Note 1 – There is no minimum planning voltage provided that Note 3 can be observed for a lower voltage derived from the 132 kV transmission system.

Note 2 – There is no minimum planning voltage for a lower voltage supply provided that it is possible (e.g. by tap changing) to achieve up to 105% of nominal voltage at the busbar on the LV side of a transformer stepping down from the onshore transmission network at a GSP

Note 3 – it shall be possible to operate the busbar of a GSP up to 100% of nominal voltage unless the fault includes a supergrid transformer.

The standards are identical across NI, RoI and GB, with the exception of the 132kV voltage in the GB standard both for system normal and during a fault.

[10] 275kV used in GB and NI, 220kV used in RoI

Table 5 - Comparison of Upper voltage limits (pu)

	Voltage	NI	RoI (TPC)	GB (SQSS)
System Normal	400kV			
	275/220kV	1.05	1.09	1.05
	110/132kV	1.05	1.09	1.05
Contingency	400kV			
	275/220kV	1.05	1.09	1.05
	110/132kV	1.05	1.09	1.05

5.52 The voltage step change limits are given in Table 6. The voltage step change for switching events on the network is identical across NI, RoI and England and Wales. The voltage standard for N-1 events is the same in NI and GB (±6%), however, ROI permits a voltage step change of ±10% for N-1 events. For N-DCT events, the NI standard permits a voltage step change of ±10%. In Scotland the lower voltage limit for an N-DCT can be -12% (with an upper voltage limit of +6%). It is proposed to retain the existing step change limits.

Table 6 Voltage step change limits in NI, GB and ROI

		NI	TPC	GB (SQSS)		
				England and Wales	SPT	SHETL
System Normal	Switching	±3%	±3%	±3%	Doesn't specify	Doesn't specify
	N-1	±6%	±10%	±6% Note 4	±6% Note 5	±6% Note 6
	N-DC	±10 %	Note 7	±6%	+6%, -12%	+6%, -12%

Note 4: Can be -12% if fault includes section of busbar, mesh corner or supergrid transformer.

Note 5: Can be -12% for loss of a double circuit.

Note 6: Can be -12% for loss of a double circuit, section of busbar, mesh corner or supergrid transformer

Note 7: The ROI system is mainly constructed with single circuits thus a figure for the loss of a DCT is not specified in the TPC.

(iv) PLM-ST-4; Transient Stability

5.53 The CEGB Planning Memorandum PLM-ST-4 published in September 1975 was adopted with an NIE amendment sheet in 1992. The standard outlines the transient stability criteria. The NIE amendment sheet 2 states that the system shall remain stable following a three phase fault to any circuit, at all levels of system demand, and with a reasonable number of other circuits out for maintenance.

Comparison with SQSS

5.54 The SQSS splits instability into the areas of generation connection, the connection of demand blocks and the main interconnected network. However the SQSS requires that there must not be instability for the full range of secured events on the transmission system. The definition of system instability within the SQSS is regarding loss of synchronism of generators and poor damping of oscillations. It expands to require that the worst single failure of protection musts also be considered and is consistent with the PLM-ST-4.

Transmission Planning Criteria

5.55 The TPC, in Section 2.2.2 makes the following requirements with regards to transient stability in reference to generator rotor angles and pole slipping: "The strength of the system shall be such as to maintain stability following a three-phase zero impedance line-end fault. It shall be assumed that the fault is cleared by primary protection and that line re-closing is in operation where appropriate."

Proposal

5.56 The SQSS includes for the loss of a single item of protection as was also required in the PLM-ST-4. The Northern Ireland transmission system at 275kV includes double main protection as required by PLM-ST-4 and also with the SQSS requirements. The 110kV system has high speed primary protection but lower speed backup. It is proposed that the standard should allow for the loss of primary protection at 275kV and above.

6 MAIN INTERCONNECTED TRANSMISSION SYSTEM STANDARD

Need for backbone standard in NI

6.1 Whilst the NI standards include for generation entry to (PLM-SP-1) and demand exit from (P2/5) the transmission system the set designated in 1992 did not include a standard for the main interconnected transmission system. The NI network being relatively small with a large degree of overlap between generation connection circuits and demand exit such a standard may not have been considered necessary.

6.2 In practice the main interconnected transmission system has been assessed according to an N-1 standard with N-DCT and N-2 risks either being managed with intertripping schemes or justified through cost benefit analysis. It is important however to confirm the practice into a standard.

6.3 It is also important to confirm the applicable generation dispatches that should be considered, for example merit order only or stressed case and also include information on the assumptions regarding the operation of the all island transmission network including interconnectors.

Generation Dispatch Assumptions

6.4 A key consideration in transmission system assessment is the assumed location, size and availability of present and future generating units. Planners should model future generation, for example based those that have connection offers or have received planning permission. Also generation that is planned to retire perhaps must also be considered. The risk that generating units can be rendered not available for prolonged periods due to mechanical or electrical failure is also an important consideration.

6.5 The three common types of generation dispatch used in transmission planning:

- economic dispatch (also referred to as merit order)
- stressed dispatch and
- flat dispatch.

Each will result in a different pattern of generation and subsequent transmission loadings and voltage performance. These different transmission performance outputs can affect what transmission investments are required.

6.6 The economic dispatch assumes that all generation is available and is dispatched according to its merit order also making an allowance for operating margin. A range of wind generation assumptions should also be included. This type of dispatch leads to the development of a transmission system which favours the least cost generation however it can also restrict the versatility of the transmission network to generation outages.

6.7 It is also necessary to include 'stressed' system conditions. For example, the long term outage of generator perhaps at a load centre or an interconnector infeed. Such long term outages, perhaps due to equipment failures, may take some years to repair owing to financing uncertainty and long procurement lead times for specialist plant, during which time other network contingencies will also occur. Transmission investment planners should consider if during stressed conditions such as long term generation or interconnector outage that the transmission system will perform adequately for a range of the more common contingencies, such as N-1 and possibly N-DCT.

6.8 The flat dispatch results in the same level of scaling across each generator regardless of merit order. The flat dispatch is not based however on economic dispatch or a predictable stressed case.

6.9 It is proposed that the standards will include an economic dispatch and a number of stress tests.

National Grid Generation Dispatch Assumptions

6.10 It is useful to review the approach taken by National Grid in terms of generation dispatch assumptions. The SQSS has a section 4 entitled "Design of the *Main Interconnected Transmission System".* This section refers to two main studies. One at the winter peak Average Cold Spell (ACS) and others over the course of a year. The ACS study refers to two alternative generation assumptions:

- Security planned transfer condition
- Economy planned transfer condition

6.11 The outputs of generators can also be set up to allow flows from one area to another, known as the Interconnection Allowance. In terms of generation assumptions the standard recommends that typical planned outage patterns should be considered[11]. The standard recommends that there should be no overloads, or voltages outside standard, for single circuit loss and for the loss of both circuits of a double circuit tower line. Whilst the standard covers SHETL, SP and NGET systems the latter network area must also cover a maintenance followed by trip condition (N-M-T).

[11] In terms of reactive power, the standard recommends that either a reactive capability chart is used, or that the maximum output set to 90% of that specified by the Grid Code.

6.12 The requirement to cover N-M-T in NI, however, would allow re-dispatch after the maintenance condition. Post fault re-dispatch in Northern Ireland is more difficult because there is no policy on emergency ratings.

6.13 The use of the Security planned transfer condition is to ensure that the network in GB has sufficient capacity to allow indigenous conventional plant to supply the demand. Interconnector flows and intermittent generation outputs are therefore set to zero.

Transmission Planning Criteria

6.14 The TPC states that the base case must be set up with a credible generation dispatch, although this may be out of merit, to allow for abnormal generation conditions. The pre-fault case should be set up to include any operational measures that would be available to aid in mitigation in the event of a contingency.

6.15 The TPC also sets out "more probable" and "less probable" contingencies. More probable contingencies include N-1 and N-1-1 (or N-M-T), and must not lead to breach of normal limits (after enacting allowable remedial actions[12]) or emergency limits before remedial actions (typically 10% above normal). The less probably contingencies include busbar faults and N-DC and must not result in voltage collapse or cascade tripping.

6.16 The normal N-1 contingency is covered but also the requirements for N-M-T. During the first maintenance re-dispatch is allowable. Also following the fault it is acceptable to change power flow controller setting and also re-dispatch online plant and fast response offline units.

6.17 In NI circuit ratings are based on ER P27 multi-circuit ratings. The use of emergency ratings cannot be used at this time because these have not been defined for NI.

6.18 The NI 275kV transmission system is almost entirely constructed with double circuit tower lines, and the loss of both circuits is more probable than an N-M-T condition, mainly due to weather phenomena such as ice accretion. The 220kV system in RoI is mostly constructed with single circuit tower lines.

ENTSO-E

6.19 The ENTSO-E TYNDP 2012 includes "Guidelines for Grid Development" in Appendix 3. In particular Section 12.2.3 sets out the standard recommendations for analysis and investment. The section states that currently deterministic criteria are used for planning.

6.20 The section differentiates between normal, rare and out of range contingencies.

[12] Such as tap changing, phase angle regulators, generation redispatch, switched shunts and network switching

6.21 A normal contingency is the (not unusual) loss of one of the following elements:

- generator;
- transmission circuit (overhead, underground or mixed);
- a single transmission transformer or two transformers connected to the same bay;
- shunt device (i.e. capacitors, reactors);
- single DC circuit;
- network equipment for load flow control (phase shifter, FACTS …) or
- a line with two or more circuits on the same towers if a TSO considers this appropriate and includes this contingency in its normal system planning.

6.22 A rare contingency is the (unusual) loss of one of the following elements:

- a line with two or more circuits on the same towers if a TSO considers this appropriate and does not include this contingency in its normal system planning,
- a single busbar,
- a common mode failure with the loss of more than one generating unit or plant or
- a common mode failure with the loss of more than one DC link.

6.23 An out-of-range contingency includes the (very unusual) loss of one of the following:

- Two lines independently and simultaneously;
- a total substation with more than one busbar or
- loss of more than one generation unit independently.

6.24 The document suggests that normal (N-1) and rare contingencies (N-DCT) could result in investment backed if necessary by cost benefit analysis. The out of range contingencies would not normally result in investment provided the risk can be managed by other means, for example, re-dispatch during the maintenance period. In considering the recommendations from ENTSO-E as set out in this document the practices currently carried out would be consistent with current EirGrid and NI practice.

Assumptions regarding wind generation

6.25 Analysis carried out by SONI has shown that wind generation has a low load factor and also across a wider geographical area has an increased level of diversity. Figure 1, 2 and 3 show the wind output distribution for the three seasons within 2010, 2011 and 2012. There are variations between the three years studied and between the three seasons. The minimum demand and lowest circuit rating would occur in summer. It is seen that for the summer season, the wind only exceeds 70% of installed capacity for no more than 3% of the time, with wind in excess of 85% being almost non-existent. This suggests that setting the level of wind generation to the installed capacity across the system is not credible.

6.26 It is also noted that similar observations would appear to have been made in GB, as included in the SQSS for Economy planned transfer condition. Appendix E of the SQSS sets out the dispatch conditions assumed for an economic dispatch and it is noted that wind, wave and tidal generation should be scaled to 0.7 times the installed capacity.

6.27 It is considered that a certain wind generation dispatch should only be highlighted for further examination if they are in existence for greater than 3% of the time. Based on historical data it is recommended that for screening studies wind generation is dispatched at no more than 70% in summer min, 80% in summer max and 90% in winter peak. Before investment is sanctioned a cost benefit analysis is also likely to be carried out using data across the year.

6.28 It should be noted that this analysis relates to the operation of all wind generation in Northern Ireland. The actual shallow connection circuits to an individual wind farm or cluster substation will have much less diversity due to the smaller geographic area. For a single wind farm the developer could oversize the wind turbines and cap there output thus ensuring that it makes full use of its maximum export capacity. It is therefore proposed that the shallow connection circuits should always be rated to at least 100% of the agreed maximum export capacity.

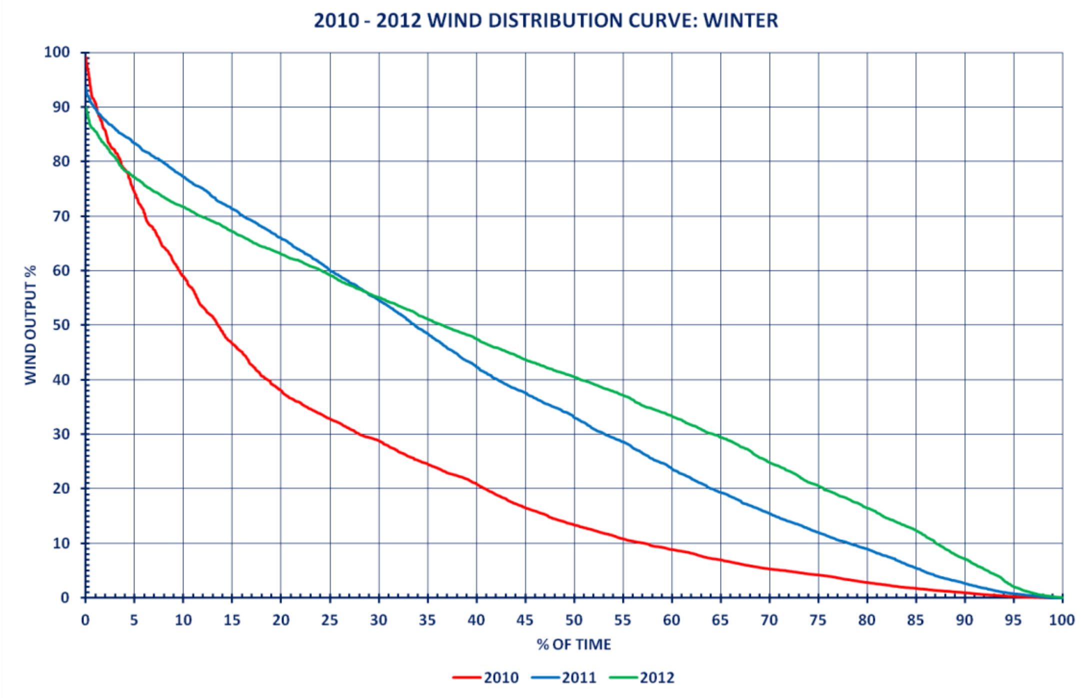

Figure 1 – Wind winter distribution

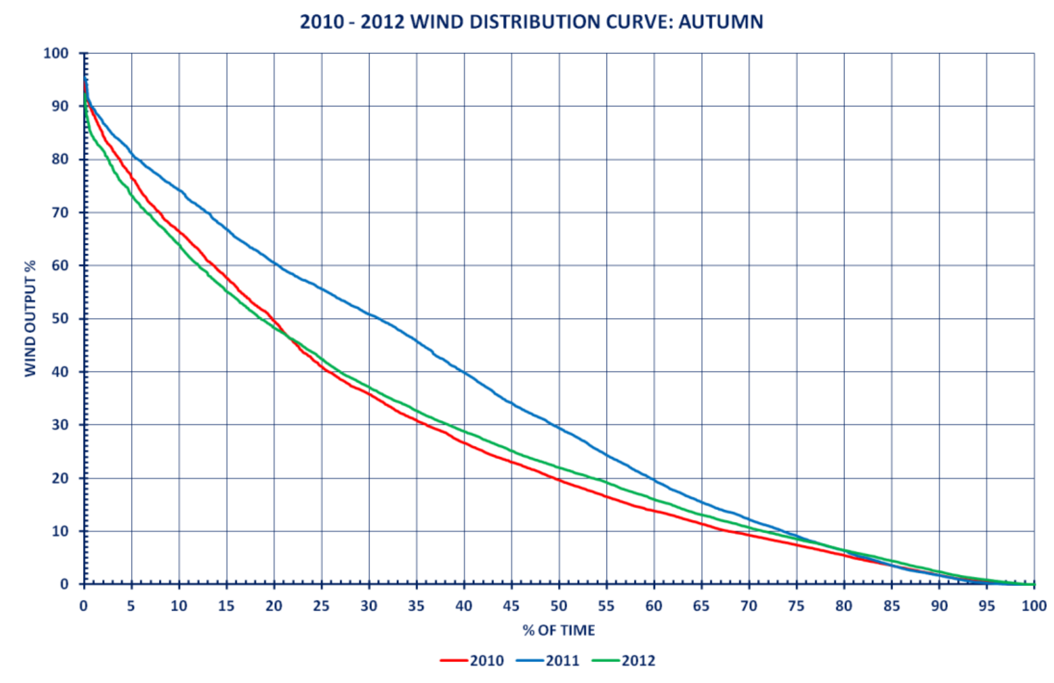

Figure 2 – Wind autumn distribution

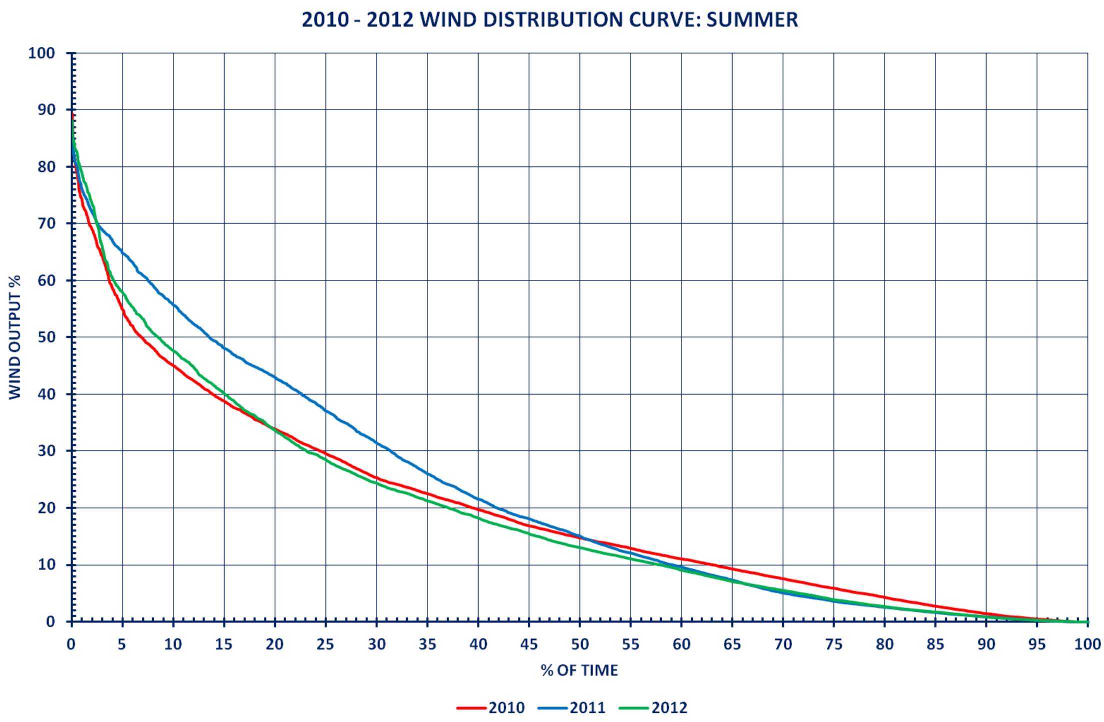

Figure 3 – Wind summer distribution

Pre and post fault ratings

6.29 The P27 document provides a set of ratings for single circuit and multiple circuit systems. The single circuit ratings imply that there is no risk of overload for a constant loading across the typical weather patterns in the UK. The multiple circuit ratings, however, are higher, and for a constant loading, and based on typical weather conditions, would allow the design operating temperature (DOT) to be exceeded for 3% of the year. Due to this rating only being used for multiple circuit systems the risk of exceeding the DOT only occurs during outage conditions and is therefore much lower than the 3% figure.

6.30 Therefore, the above ratings are considered to be similar to the concept of pre and post fault ratings as used by the transmission licensees in GB and RoI. Nevertheless, consideration should be given to reviewing the determination of ratings in line with the GB and RoI transmission licensees.

Use of special protection schemes to control intermittent generation

6.31 There are several SPS schemes in place in Northern Ireland. The experience of the schemes however is that:

- The schemes can be complex and require significant contribution from a limited technical expertise to design, install and maintain;
- Some of the equipment, for example temperature probes, have had reliability issues;
- In order to be sufficiently trusted the schemes require redundancy in terms of hardware and communication links adding additional cost;
- The cost of constraining pre fault can often be more economic than investing in complex and expensive hard wired special protection schemes;
- Network upgrade can renders certain schemes redundant adding cost to recover or amend the schemes;
- The operation of overlapping schemes on the main interconnected transmission system can be difficult to predict and model;
- The tripping of a large numbers of wind generation sites has to be limited by the level of spinning reserve otherwise risking under frequency load shedding.

6.32 In general schemes that involve overload risks on the main interconnected transmission system with tripping multiple wind farms over long distances using rented pilots should be avoided or subject to detailed risk assessment. SPS with a simple design purely to cover a local constraint, for example transformer capacity at a 110/33kV substation, will still be considered however the implications for power quality should be assessed.

Proposals

6.33 In terms of dispatch assumptions it is proposed that there should be two main types of study, i.e. one with economic all island dispatch and a further set of stressed case scenarios. The stressed case scenarios may include long term interconnector outages, long term generator outages and operation of in merit generators at full output.

7 REVIEW OF STANDARD FOR LIMITS FOR HARMONICS (ER G5/3)

Description of ER G5/3

7.1 ER G5/3, published in 1976, provides limits of harmonic currents to be fed into the electricity network thus limiting the overall voltage distortion at planning levels which are set to achieve compatibility with user's equipment.

7.2 Since the publication of ER G5/3 the structure of the electricity supply industry has changed significantly. Moreover European Legislation, in particular the 'EMC Directive', has been implemented, adding mandatory product specific requirements in terms of compatibility and emissions.

7.3 There has been considerable activity in the formulation of a series of International Electromagnetic Compatibility Standards and Technical Reports concerned with low frequency phenomena. The driving force within Europe has been the 'EMC Directive' of the European Union. The Directive has been enacted within the UK by the EMC regulations, which came into force in January 1996. This Directive seeks to ensure the removal of technical barriers to trade by:

- Enabling equipment to operate satisfactorily in its specified environment and
- Protecting the public electricity distribution system from electromagnetic disturbances emitted by equipment by limiting emissions so that other connected equipment does not malfunction.

Adoption of ER G5/4

7.4 A review of ER G5/3 in light of the EMC standards, in particular the IEC 61000 series has highlighted a considerable number of aspects that needed revision. This has resulted in the publication of an updated standard ER G5/4 which has compatibility and planning levels based on IEC and CENELEC standards are now given in ER G5/4. ER G5/4 now:

- covers all voltage levels from 400V to 400kV (ER G5/3 covered up to 132kV);
- covers harmonics up to and including the 50^{th} harmonic;
- introduces guidance including sub-harmonics, inter-harmonics, and voltage notching.

7.5 G5/4 was further updated to G5/4-1 allowing for the application of a 'Partial Weighted' methodology for higher frequency harmonics and 'Conditional Connections'.

7.6 EirGrid has adopted the requirements set out in IEC/TR 61000-3-6 recommended methodology for transmission in Appendix D. The main difference between IEC/TR 6100-3-6 and ER G5/4 is that the latter offers headroom on a “first come first served” or “straw that breaks the camel’s back” basis, whereas then the IEC allocates headroom based on proportion of demand or generation.

Proposal

7.7 It is considered necessary that the standard used to assess transmission connections should be harmonised to that proposed to be applied to the distribution system. It is therefore proposed to designate G5/4-1 to replace G5/3 as a transmission standard.

8 OFFSHORE WIND GENERATION CONNECTION STANDARD

Background

8.1 The arrangement in GB involves the installation of an Offshore Transmission System generally installed by the developer under contestability and then transferred to, and owned by, a licensed Offshore Transmission Owner (OFTO).

8.2 In NI there is as yet no provision for an OFTO approach to ownership of offshore assets.

8.3 For the purposes of defining a standard, however, it is considered that an offshore transmission system should be defined similar to the reference in the System Security and Quality of Supply. The transmission standards as defined shall apply to the assets regardless if the final owner/operator.

Cost benefit analysis conducted in GB

8.4 The current SQSS was developed using a set of studies detailed in a report "Cost Benefit Methodology for Optimal Design of Offshore Transmission Systems" published by the Centre for Sustainable Electricity and Distributed Generation. This document was used in the development of the section of the SQSS. The report main findings were:

- The number of offshore cables should be minimised with no planned redundancy;
- Total capacity of the cables may be lower than the maximum export capacity (MEC) of the wind farm, due to diversity;
- Maximum rating of a single transformer connecting a wind farm should be 90MVA (due to the cost of the expected energy constrained and the MTTR of a single transformer);
- Cost benefit analysis showed that a 132kV double circuit overhead line could be used depending on distance. At greater distance the additional cost however became more difficult to justify.

8.5 Upon review of the above the recommendations, it is accepted that there should be no redundancy, except for that available if two circuits are required for capacity. The under-sizing of the connecting circuits lower than the MEC on the forecast that there will be diversity is not supported. Cables would be installed according to standard sizes and given the installation cost under sizing on the rating of the cable is not supported.

Reactive support connection

8.6 For offshore connected wind generation it is accepted in Great Britain that the reactive support requirement is provided at the onshore grid entry point (GEP) with the power factor at the offshore platform GEP kept at unity. This was on the basis that offshore wind farm connections would be radial only. It is noted however that the ENTSO-E Network Code Requirements for Generators (RfG) has set the required level of reactive support at the Connection Point (OffGEP) to 0.66 MVAr/MW (equating to a power factor of 0.95 leading to 0.95 lagging). This requirement makes provision for offshore connections in the future to become meshed rather than pure radial connections. It is expected that this will in the future be adopted into the Grid Code.

8.7 It is accepted that in the case of a radial connected wind farm the cable will provide reactive power. It is proposed therefore that the standard will allow a proportion of reactive power to be provided by the wind turbines connected to the offshore platform and the cable charging. However if the Grid Code is changed then the standard shall will require to comply.

Proposed limit of a single offshore power station

8.8 The studies in GB were based upon the connection of single offshore power stations up to 1500MVA in size. At the time the normal infeed loss risk[13] was based upon a capacity of 1000MW, although this is due to rise to 1320MW in 2014. In NI, and the all-island system, the largest single infeeds are 450MW (Moyle) and 500MW (EWIC) respectively. Therefore for the purposes of a new NI standard, the recommended largest single infeed from a single wind farm should be established at 500MW.

[13] Loss of generation that would cause a 0.5Hz deviation.

9 COST BENEFIT ANALYSIS

Current Practice in Northern Ireland

9.1 It is useful to refer to HM Treasury guidance as set out in “THE GREEN BOOK - Appraisal and Evaluation in Central Government” and also the Northern Ireland Department of Finance and Personnel website guidelines entitled “Northern Ireland Guide to Expenditure Appraisal and Evaluation (NIGEAE)”. These documents acknowledge that performing a cost benefit analysis is a time consuming effort. The extent of effort should therefore be proportional to the level of investment being proposed.

9.2 Cost benefit analysis was carried out in support of the upgrades for the Medium Term Plan. This included a comparison between the cost of constraining wind generation and the cost of the reinforcement projects.

Current Practice in RoI

9.3 The Transmission Planning Criteria also states in section 1.3 that any transmission plan proposed for adoption under the criteria must ultimately be justifiable taking account of economic, financial, strategic and environmental considerations.

ENTSO-E Guidelines

9.4 ENTSO-E has produced the “Guidelines for Cost Benefit Analysis of Grid Development Projects (Draft)”. This draft document is an update to “Guidelines for Grid Development” (as included as Annex 3 of the TYNDP 2012) and is intended for use in considering projects of common interest (PCI) status. The document is mainly to be used when assessing interconnection between TSO’s or bidding areas. The document defines benefits into categories as follows:

B1 Security of supply (SoS)

B2 Socio-economic welfare (SEW)

B3 RES Integration (minimising constraints)

B4 Variation in losses

B5 Variation in CO_2 emissions (linked to B3)

B6 Technical resilience/system safety.

9.5 The document recommends the study of various scenarios across the time horizon to deal with uncertainty. There should be studies based on mid-term (5-10 years), long term (10-20 years) and very long term (30-40 years). The cost of storage instead of network should also be taken into account.

9.6 Cost of generation and balancing services can be monetised however Expected Energy Not Supplied (EENS) and Great variation in Value of Lost Load (VOLL) across the EU. VOLL is not monetised on a Union wide project.

GB Transmission Licensee guidlines

9.7 The SQSS includes guidelines on economic justification of investment in transmission equipment, purchase of services, outage patterns, balancing services and changes to standard connection designs.

9.8 Additional investment in transmission equipment and/or the purchase of services would normally be justified if the net present value of the additional investment and/or service cost is less than the net present value of the expected operational or unreliability cost that would otherwise arise.

9.9 The assessment of expected operational costs and the potential reliability implications shall normally require simulation of the expected operation of the network.

9.10 Due regard should be given to the expected duration of an appropriate range of prevailing conditions and the relevant *secured events* under those conditions.The operational costs to be considered shall normally include those arising from:

- transmission power losses;
- frequency response;
- reserve;
- reactive power requirements; and
- system constraints,

and may also include costs arising from:

- rearrangement of transmission maintenance times; or
- modified or additional contracts for other services.

9.11 The document also states that all costs should take account of future uncertainties, and that the evaluation of unreliability costs shall normally take account of the number and type of customers affected by supply interruptions and use appropriate information available to facilitate a reasonable assessment of the economic consequences of such interruptions.

10 CONCLUSIONS

General

10.1 The NI Transmission Planning standards are over 30 years old. National Grid has replaced all the old CEGB standards with a new composite standard known as the SQSS. This document encompasses all of the requirements (Security, Voltage and Transient Stability).

10.2 The present P2/5 document applied by NIE is not used for the planning of either Transmission or Distribution in Great Britain. National Grid has combined the requirements for generation and demand connection to the Transmission system into its SQSS document. For Distribution, the DNOs in GB have adopted an updated standard, P2/6, which provides recommendations on the level of contribution provided by various levels of embedded generation.

10.3 The NI standards for generation connection were based on the CEGB standards at the time of privatisation. The NIE amendment sheet, however, appears obsolete given the increases in the capacity of the LSI that has occurred in recent years. It also appears inconsistent with the TPC used in RoI.

Transmission Performance

10.4 The performance of the transmission system in NI is comparable to that of GB and RoI. The standards, in terms of redundancy, should therefore be compatible.

Largest Single Infeed

10.5 The current standards do not define the largest single infeed in NI. It can be inferred from the NIE Amendment Sheet the fact that the limit requiring N-2 security (usually reserved for a group of generation of twice the largest single infeed) was set for 550MW. Therefore the LSI at the time of privatisation was considered to be around 275MW. The actual LSI in 1992 was Kilroot G1 and G2 which each had a capacity of 260MW (generating on oil).

10.6 The North – South interconnector was however restored in 1995 allowing generating reserve to be shared. Since then, larger power infeeds have been commissioned in NI, including the Moyle Interconnector (450MW) in 2002 and Coolkeeragh CCGT (414MW) in 2005. The East West Interconnector (EWIC) was connected to the all island transmission system in 2012 raising the all island LSI to 500MW. It is concluded that the LSI for NI should therefore be defined as 500MW. Future changes to this figure would be subject to all island economic studies by the TSO's.

Offshore transmission systems

10.7 There are proposals for the connection of offshore power stations to the Northern Ireland transmission system. Extensive economic studies have been carried out by the Centre for Sustainable Electricity and Distributed Generation. This work was funded by the GB Government Department for Business Enterprise & Regulatory Reform (BERR). Many of the proposals made were adopted by BERR and incorporated into the GB SQSS. It is proposed to adopt these proposals with some amendments to take account of the smaller size of the Northern Ireland transmission system and also allowing that Grid Code changes following from legislation will take precedence.

Updated Transmission Standards

10.8 SONI has developed a single standard, based on the style of the GB SQSS (the successor to the original CEGB documents). There are no fundamental changes to those standards that were included in the original GEGB documents. The document includes requirements for generation connection, the main interconnected transmission system, the design of demand groups and a minimum standard for the connection of offshore wind farms. The document is harmonised where possible with the RoI TPC and the recently revised NIE Distribution standards.

10.9 A draft of the proposed Northern Ireland version of the SQSS is included in Appendix 1. This will facilitate replacement of the current set of Electricity Council and ex CEGB standards with NIE amendment sheets, specifically ER P2/5, PLM-SP-1, PLM-ST-4 and PLM- ST-9.

10.10 To provide for the standards necessary to cover power quality issues it is proposed to replace ER G5/3 with ER G5/4-1 and retain ER P16, ER P28 and ER P29.

10.11 The proposed Transmission Standards are therefore as set out in Table 8.

Table 8 - Proposed Transmission Standards

Reference	Title
SQSS (NI)	System Quality and Security Standard (NI)
ER P28	Planning Limits for Voltage Fluctuations
ER P16	EHV or HV Supplies to Induction Furnaces
ER P29	Planning Limits for Voltage Unbalance
ER G5/4-1	Limits for Harmonics
EPM-1	

11 NEXT STEPS

11.1 Stakeholders are invited to express a view on the proposed changes in Transmission System Security and Planning Standards and any other aspect of this paper. Responses should be received by SONI by 1700 on Friday 31st October 2014 and should be addressed to:

Raymond Smyth

SONI

12 Manse Road

Belfast

BT6 9RT

Tel: 02890 707834

E-mail: Raymond.smyth@soni.ltd.uk

11.2 During the consultation period, should any stakeholder have any specific queries on any aspect of this document, or on the proposed changes in standards, or require a meeting with SONI, they should contact Raymond Smyth as set out above.

11.3 SONI intends to collate all responses received to this consultation as part of its report to the Utility Regulator (the Authority).

11.4 Following the end of the consultation period and receipt of responses from stakeholders, SONI will, in accordance with its Transmission Licence send to the Authority:

- A report on the outcome of its review;
- The proposed revisions to the Transmission System Security and Planning Standards which SONI (having regard to the outcome of such review) proposes to make and
- Any written representations or objections from any electricity undertakings (including any proposals for revisions to the documents that were not accepted in the course of the review) arising during the consultation process and subsequently maintained.

11.5 Following the end of the consultation period and the discussions to be held with the Authority, revisions to the Transmission System Security and Planning Standards will be finalised and published on the SONI website once approval has been received from the Authority.