SQSS Fundamental Review

Working Group 1

International Benchmarking

Report

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1 Introduction

The Fundamental Review of the Great Britain Security and Quality of Supply Standards (SQSS) was initiated in September 2008. The aim of the review is to fundamentally reassess the criteria and methodologies of the SQSS.

As part of the Fundamental Review, a benchmarking exercise has been undertaken to review the methodologies of the SQSS against comparable international standards.

Specifically the aim of the international benchmarking exercise was to address the two following questions:

Are the GB SQSS criteria and methodologies consistent with those in use internationally?

What kind of new developments are taking place internationally to accommodate the move to sustainable energy sources?

This report highlights the differences between international practice and current SQSS used for planning and operating the GB transmission system.

The working group would like to extend their gratitude to all of the respondents to the questionnaire.

2 Methodology

The bechmarking exercise was based on a questionnaire issued to 14 transmission utilities around the world which addressed the fundamental principles of the planning and operational standards employed. The questionnaires were analysed and the results presented at a workshop in London on 10th March 2009. This report reflects the analysis of the questionnaires and the discussions that took place at the workshop.

2.1 Questionnaire

2.1.1 Contents

The questionnaire consisted of nine principal sections.

The first three sections were designed to set the context of the questionnaire responses and to understand overall market and strategic environment of the respondents.

System – This section of the questionnaire establishes an overview of the size of the respondents system and the level of renewables that are expected to connect in the future.
Market – This section provides an overview of the energy market and also the process for gaining access to the transmission system.
Strategic – This section address the existing regulatory regime and potential developments to allow for transmission enhancements to precede the connection of new generation projects.

The following six sections dealt with specific chapters of the GBSQSS. The aim here was to provide a direct comparison between the GBSQSS criteria and methodologies and those of the responding organisations.

Transmission Entry (generation connections)
MITS – This section considers the methodologies used in assessing the required capacity of the MITS and the process for bringing forward system reinforcements
Transmission Exit (Load connections)
Voltage limits
Operations
Offshore – Have specific criteria been developed for the design of offshore transmission systems

A copy of the questionnaire is attached in Appendix 1.

2.1.2 Comparison Countries

The working group selected a group of countries based on one or more of the following criteria:

- they operated island systems
- they were experiencing significant levels of renewables connection
- they were implementing new transmission planning methodologies

2.2 Benchmarking Workshop

Once the completed questionnaires were received then the results were analysed. A workshop was held on 9th March 2009 with a number of the respondents in order to clarify and validate the interpretation of the questionnaire responses.

3 Results from the Benchmarking

This section provides a summary of the results from the benchmarking exercise.

3.1 Response

In total there were eight responses to the questionnaire. These included

RTE France
REE Spain
Eirgrid Ireland
National Grid USA
Transpower New Zealand
Transelec Chile
Elia Belgium
Tohoku EpCo Japan

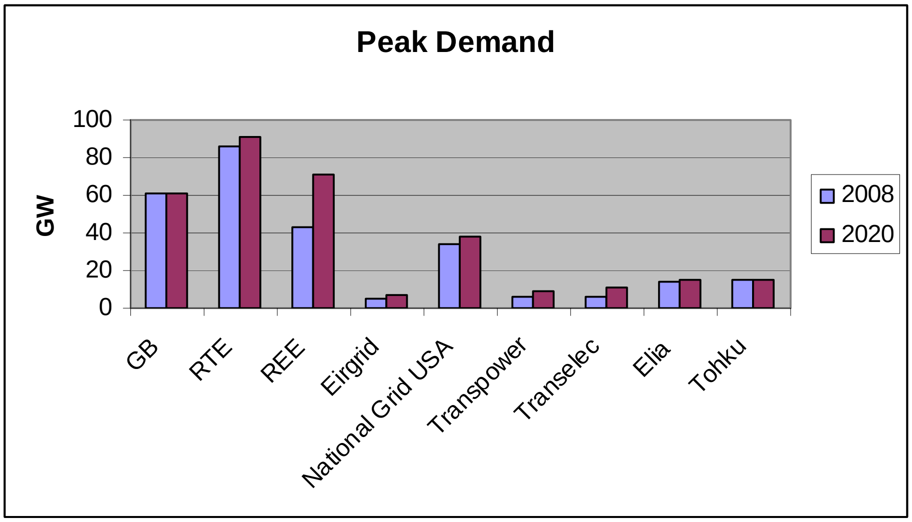
3.2 Systems

3.2.1 Demand

The predictions for demand changes into the future are very variable. In part this is due to the nature and maturity of the existing demand and the predicted increase in demand due to the increased transport electrification etc

The following table shows the expected demand in GW of each of the respondents.

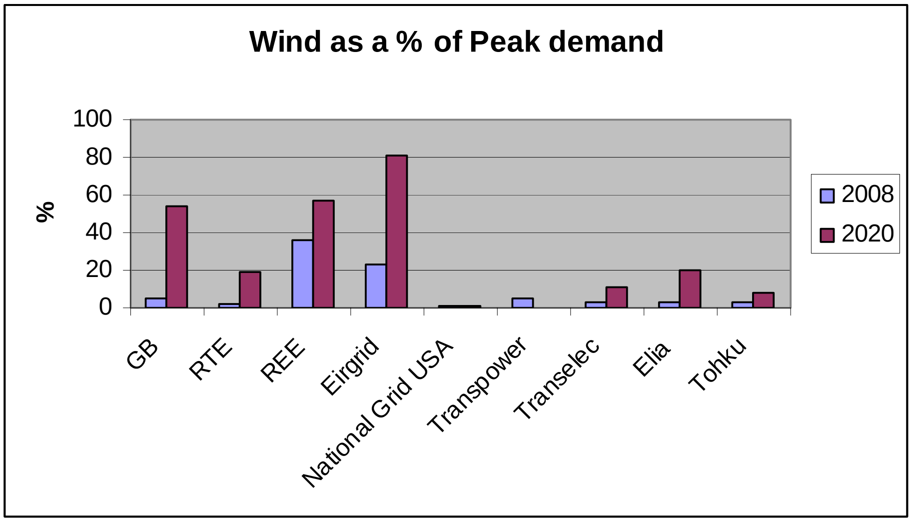
	2008	2020
GB	61.4	60.8
RTE	86	91
REE	42.9	70.6
Eirgrid	5.3	6.7
National Grid USA	33.8	37.9
Transpower	6.5	8.6
Transelec	6.2	11.5
Elia	14	15
Tohku	15	15.4



3.2.2 Generation Mix

Most respondents predict an increase in the level of renewables connected to their system, wind in particular.

The following table shows the level of Installed and Predicted Wind Power (Onshore and Offshore) as a percentage system peak demand.



All of the respondents to the questionnaire are experiencing large volumes of windpower wishing to connect. Most of the respondents are in a similar position to the UK, ie low levels connected to date but levels equivalent to circa 20% of peak to be connected by 2020.

By volume Spain has the highest installed capacity today (16GW on a system with peak demand of 45GW) and is also predicting the highest volume of installed capacity (40 GW) by 2020.

Although most of the respondents are predicting the installation of some offshore wind farms the GB system is predicting by far the largest amount (20GW). Most of the respondents expect predominantly onshore windfarms.

3.3 Markets

3.3.1 Energy Markets

Of the respondents there were two main types of market described for the real time trading of energy. These were the bilateral market based around balanced generation/supply declared positions and a centrally dispatched pool type market (Ireland, Chile and New Zealand).

Most of the markets have in place or are putting into place special arrangements for the treatment of renewable energy. These may be in the form of special “feed in tariffs” or a requirement on supply companies to provide certificates to demonstrate their utilisation of renewable energy. The latter is broadly equivalent to the Renewables Obligations in the UK.

Some of the markets provide capacity payments to generators (Ireland and Chile). In Spain capacity payments are limited to “qualified” generators that are required to provide a minimumvolume of MWhrs over the course of a year.

3.3.2 System Access and Charging

In most countries, a shallow connection charge regime is operated: cconnectees pay local connection charges to reflect the cost of providing connection equipment specifically related to that conectee; and the cost of deep system reinforcements are recovered through a transmission network use of system charge.

In addition to covering capital costs these charges include a rate of return element and a maintenance charge paid to the transmission company.

There is not always a charge for making an assessment of a new grid connection, however in most cases it is required to make a financial commitment, eg France 10% of reinforcement costs in order to reserve any capacity identified.

In Spain the transmission company can guide generators to connect in a particular location. However the connectee may insist on connection at a particular location. In any case the generator is exposed to the cost of not being able to generate due to system constraints ie the generator does not receive constraint payments. More recently the transmission company is able to set a maximum connection capacity for particular zones in order to optimise the use of the existing network and reduce the need for system reinforcement

In general there is no difference in the processing of generation applications from renewable energy and conventional generators. However, in Ireland a Gate Processing Approach is utilised. Under this process all new generation connections are processed in batches and the new connections are for a period of 20 years

3.3.3 Regulation

In general transmission companies submit plans to their regulators for the development of the transmission system over a period of time. These plans are then used to set transmission revenue and hence user charges over the next regulatory period. The duration of the regulatory periods are different across the respondents e.g. In France the regulatory period is three years, in Belgium 4 years, in Ireland and the United Kingdom it is 5 years.

In Chile a 4 year plan is agreed by the regulator and reviewed on an annual basis. Reinforcements are assessed using a Value of Investment test which takes into account cost of construction, cost of maintenance and cost of operation. In Chile it is also possible for different transmission owners to own different parts of the integrated transmission system.

3.3.4 Strategic Investments

Most of the respondents indicate that transmission investments are associated with the development of generation projects

In France and New Zealand (also GB) system regulatory regimes are being developed to facilitate the development of transmission systems in advance of the connection of new generation.

In the US FERC provides a mechanism for investing in non routine investments where the transmission owner demonstrates: (i) the facilities ensure reliability or reduce the cost of delivered power by reducing congestion; (ii) the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project; and (iii) the resulting rates are just and reasonable.

3.4 Entry (Generation connections)

3.4.1 Large infeed loss limits

Most the respondents cite generation infeed loss limits. The European UCTE network (350GW MD) has a largest infeed loss limit of 3000MW. Chile and Japan have no prescriptive limits but do have mitigating cost messages for generation loss of infeed events. On the GB system the largest infeed loss is set at 1320MW. This is currently being reviewed in light of the future requirement to connect larger nuclear generating units.

EirGrid have a limit, such that the generator must not have a fault level contribution of more than 5% of the total for the connection point.

3.4.2 Maximum length of a generator circuit

Unlike GB, no respondents declared a limit on the length of generator circuits, although stability and voltage limits may limit the length of a connection.

3.4.3 Background assumptions for assessing generation connections

Most respondents assess entry capacity based on generation and demand profiles that may reasonably be foreseen at strategic points of the annual demand profile.

In UCTE countries entry capacity is also assessed using “reference transit flows” through member states networks, used in conjunction with a probabilistic approach to analyse a large number of “year round” scenarios to assimilate the network constraint volumes and provide message to invest.

3.4.4 Basic planning criteria for entry assets

All respondents assume peak demand for assessing entry capacity requirements. However the security criteria differs by country: Belgium, NZ, Chile and EirGrid apply (N-1), (Note Belgium (N-1-G)). Spain applies (N-2) in operational time-scales. France and Japan apply (N-D) and USA applies (N-1-1) Assuming 30 minutes between contingencies.

3.4.5 Customer choice in connection security

All respondents offer elements of customer choice for connection security but the incentives to change are driven by differing shallow/deep and firm/non firm access arrangements

3.4.6 Economic justification of investment for entry assets

All respondents may justify investment in entry assets based on an economic test apart from Belgium. who only use their deterministic standard.

3.4.7 Special treatment for the processing of renewable connection applications and market access

Six of the eight respondents indicated that there was no special treatment for the processing of renewable connection applications.

However, EirGrid may be directed by their regulator to process renewable generation connections ahead of conventional generation connections. Eirgrid also operate a “gate” process for batch processing renewable generation applications.

Belgium does provide special treatment for renewable connection applications, but this process is not clearly defined.

3.5 MITS

Most of the respondents stated that investments on the main transmission system are based on deterministic criteria. In most cases there is also a cost benefit assessment to justify the reinforcement.

In New Zealand parts of the transmission system are categorized as either core or non core and different criteria applied to each. Across the full system, reinforcements must be justified on the basis of a cost benefit assessment but on the core system there is also an n-1 "safety net" criteria.

In France MITS investments are justified based on a cost benefit/probabilistic analysis in which multiple scenarios are screened in order to detect system constraints.

3.5.1 Planning backgrounds

Planning backgrounds used to assess the performance of the system are typically undertaken for a range of system load levels. These will typically include an assessment at peak demand levels and a range of off peak demand levels.

Renewable generation is modelled at a range of outputs. For wind a range of output levels considered. On the Spanish system wind is assessed at both a 10% and a 60% output level.

On the National Grid USA system wind and Hydro are considered at a range of different output levels based on the system load level, season and type of facility (eg onshore/offshore for wind; pumped hydro, ponding or river run for hydro).

In New Zealand long term studies are undertaken against a set of generation “scenarios” provided by the regulator. Conventional generation is typically modelled at its nominal output and units selected to be on or off based on a ranking order. Consideration of forced outage rates on conventional generation is also considered.

RTE utilise a system of probabilistic scenario generation based on historic utilisation.

3.5.2 Planning criteria

All of the respondents stated that they consider N-1 criteria. The contingencies are used to assess post fault conditions on the systems. Typically there are prescribed limits for voltage, frequency, thermal overloads and system stability that must be met.

In France where much of the transmission construction is single circuit, assessment is against n-1 contingency, although N-D contingencies are also considered on double circuit lines.

On the National Grid USA system and in Ireland N-1 contingencies are considered with the maintenance outage of another system element. i.e. N-1-1.

On the GB, Belgian and Spanish networks N-2 criteria are considered. This is the sequential outage of two network elements at peak demand.

The New Zealand transmission system is subdivided into “core system” and “economic limb”. On the core system there is an N-1 safety net. Reinforcement of the system to cope with contingencies more onerous than this and for any contingencies on “economic limbs” are considered on a cost benefit basis.

On the Chilean network N-1 will be used to justify system reinforcement if there are significant congestion costs.

3.5.3 Role of cost benefit analysis

The respondents reported a range of uses for cost benefit analysis.

In Belgium cost benefit analysis is utilised in the selection of specific reinforcements identified via the deterministic process.

On the National Grid USA system cost benefit analysis is utilised in selecting between deterministically identified reinforcements and also in considering High Impact Low Probability events on the transmission system.

In France a combined probabilistic cost benefit tool is utilised in assessing reinforcements to the transmission system. The tool assigns probabilities to the range of flow levels expected across a boundary. In this way the planner develops confidence for the right level of transmission capacity justified.

In Spain, New Zealand and Chile all reinforcements are determined on a cost benefit basis. These cost benefit studies include an assessment of outage rates, congestion costs and the cost of unsupplied energy.

3.6 Exit (Demand)

3.6.1 Background Assumptions

All respondents assume maximum demand for assessing exit capacity. In Spain it is reported that summer rating of plant often provides investment signals and in the USA light load provides significant voltage control issues.

Most respondents take a prudent view on the security afforded from embedded generation to secure demand, i.e. no wind generation and dry season hydro conditions etc, to ensure that there is adequate transmission system capacity to supply demand.

3.6.2 Basic Planning Criteria

A number of respondents apply a cost benefit to justify investment in exit assets using a wide range of Value of Lost Loads (VOLL) £/MWh i.e. New Zealand (£8k), Chile (£1.4k), France (23k), Australia (£23k) (reported by NZ) and UK (£30k).

Most respondents secure demand to N-1, however Chile may have demand disconnection for N-1 (i.e. VOLL 1.4k/MWh to justify investment).

In Spain the DNO system has to support 60% of the demand through interconnection for the loss of Transmission infeed. New demand/generation capacity must be greater than 50MW or 125MW before connection to the 220 and 400kV transmission system respectively.

3.6.3 Demand size and security

No respondents provide security based on the ER P2/6 approach of banding demand groups favouring a cost benefit or straight forward N-1 for all demand group sizes.

In France there is an authorised loss of supply of up to 1500MW for an N-D event. This is similar to the operational criteria on the GB system.

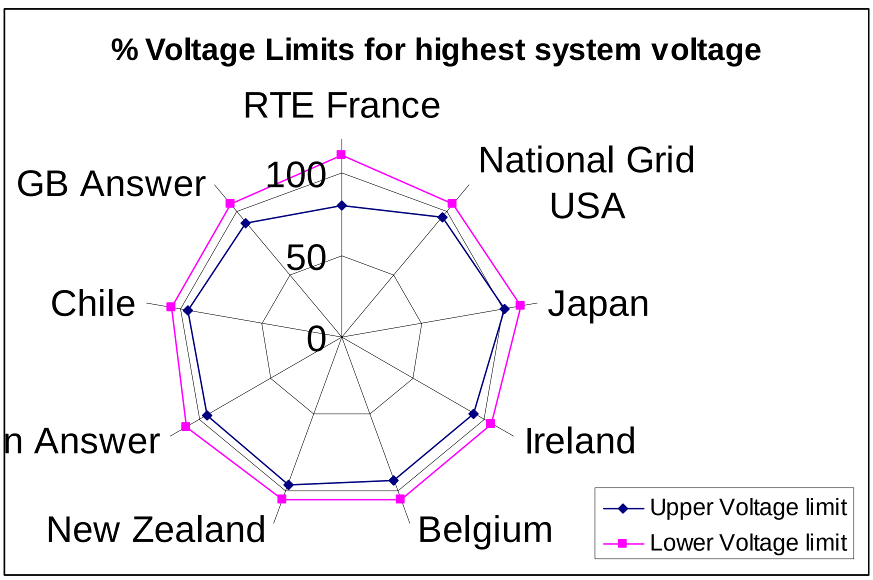
3.6.4 Sites of strategic importance

In Belgium "double back-up" supplies are afforded to Nuclear sites and sites with a chemical hazard. In Japan the Nuclear Regulator Commission may determine the security of supply. No other respondents reported special treatment for sites of strategic importance or sensitivity.

3.7 Voltage

A chart showing the 400kV max and min voltage against the highest system voltage limits from the respondents is shown below. Typically the respondents indicated a range of between 10~15% of nominal voltage for the upper and lower voltage limits. The voltage range on the GB system is 15%.

Of significant note however is the minimum allowed voltage on the RTE 400kV system of -30%.



3.8 Operations

3.8.1 Operational Criteria

All of the respondents stated that they assessed the performance of their system against a minimum n-1 criteria. More onerous criteria are also assessed on most of the networks. The allowable consequences of the different criteria being assessed are typically graded according to the size of the demand within the affected area, or the amount of generation infeed affected by the contingency.

On the Spanish network double circuit routes are considered where circuits share the same route for more than 30km. On the RTE network it is within the accepted criteria for up to

1500MW of demand to be disconnected in response to a double circuit fault. This is equivalent to the requirement within the GBSQSS.

The impact of the 1500MW allowable disconnection means that on some systems the n-1 criteria being considered are equivalent ie no demand is disconnected for an n-1 contingency but up to 1500MW may be disconnected for an n-d contingency.

3.8.2 Normal and Adverse system conditions

Most of the respondents distinguished between normal and emergency conditions.

During emergency conditions the transmission operators may operate to wider limits (thermal, voltage) in place on the transmission system or they may operate to a more onerous contingency level.

On the GB system during fair weather conditions it is acceptable to relax contingency criteria from n-d (double) to n-1, provided should the n-d contingency occur there would be no unacceptable voltage or system instability. This is to minimise the potential for cascading system events.

In France the contingency criteria is increased from n-1 to n-d on double circuit routes during adverse weather.

3.8.3 Special Protection Systems

A range of Special Protection schemes are utilised by the respondents.

These include automatic measures to vary the flow on circuits through the tapping of quad booster\phase shifting transformers.

Respondent also report the use of generator intertripping schemes to reduce post fault flows across boundaries.

Schemes are also used to sectionalise systems following specific outages.

Schemes which implement demand tripping, irrespective of demand type, in response to under frequency and wide spread under voltage are typically installed on most systems. The role of these schemes is to minimise the extent of wide spread disturbance on systems operating beyond acceptable operating limits as a defence against full system collapse.

In Chile direct tripping of industrial demand is being considered as a means of increasing transmission flows over certain boundaries.

3.9 Offshore

A set of criteria defining the planning and operation of the offshore transmission system have been developed and are now included in the Security and Quality of Supply Standard.

Of the respondents only Belgium has criteria specifically for the connection of offshore generation:

“The offshore connections to the onshore grid are the responsibility of the offshore park developer. The onshore grid must be able to transport 100% $P_{installed}$ during N, but only 60-50-40% (seasonal limits for Winter-Spring/Autumn-Summer) during N-1. There is priority access: the TSO first has to reduce traditional power plants (using standard incremental/decremental bids) to accommodate the renewable energy. If this is not sufficient, the wind farms have to reduce (without shutdown, and at > 10% $P_{installed}$ per minute) to the seasonal limits, without compensation. If a reduction below the seasonal limits is needed, the wind farms are compensated.”

4 Conclusions

The process and criteria defined within the SQSS are detailed and complex. They work as an integrated package. The level of security delivered by the SQSS is a function of the criteria specified within the SQSS and the way the criteria are assessed and utilised in practice. As an example the GB system is built almost exclusively using double circuit overhead lines whereas there are examples internationally of systems built almost exclusively using single circuit towers, and consequently there is no mechanism to loose two circuits via a single event. As such not considering double circuit faults in operational time phases may or may not deliver a different level of reliability to end users.

On many systems where double circuit towers are widely utilised then consideration of double circuit faults for contingency planning is normal. In France circuits which are more at risk to double circuit faults are assessed against N-D while the majority of the network is assessed against N-1 criteria.

Similarly several of the respondents indicated that they utilised an N-1-1 approach to planning where there is a specified time interval between the first and the second outage. This is analogous to the N-2 criteria adopted in the SQSS planning criteria.

The type of special protection schemes implemented on the National Grid System (ie generation intertripping, post fault tapping of transformers and quad boosters, low frequency demand shedding) are similar to those currently in use by the respondents to the questionnaire.

With the exception of Spain, the respondents are at a similar level of wind penetration. In addition all expect that the level of wind will increase significantly over time. To cope with the volume of wind connections in Ireland the transmission organisations have adopted a gated approach to the issue of connections for renewable energy as a way to manage the complexity associated with assessing large numbers of independent new connection.

A general theme of the response is that the connection of wind will lead to the requirement for more analysis to consider the impact of different levels of wind and at different levels of system load. In Belgium the firm capacity provided for renewable energy varies by season. This is in line with operational experience which demonstrates the seasonality of windfarm output levels.

In Summary, the criteria utilised within the existing GBSQSS are broadly consistent with those in use internationally. However there are some alternative practices in use internationally which will be considered in developing proposals for the revised GBSQSS

Appendix 1

Thank you for taking the time to complete this questionaire.

The following sections are to let us know who you are.

Name of sender:	
Your position/ function within the organization:	
Email address:	

Web address of your organization:		

Respondent's Information

This is the person who has filled in the questionnaire so that we can contact the individual in the event that clarification is needed.

Name of Respondent:	
Your position/ function within the organization:	
Email address:	

Please return this completed spreadsheet to: colin.bayfield@scottishpower.com

System Overview **GB Security Standard Benchmark Questionnaire**

This section of the questionaire is aiming to establish an overview of your utility and the size of your system.

	Question	Benchmark Partner Answer	GB Answer
1.1	Country		Great Britain (GB)
1.2	Utility Name(s)		National Grid (NG) ScottishPower (SPT) Scottish & Southern Energy (SHETL)
1.3	Utility Structure		NG are the GB System Operator and the England & Wales Transmission Owner SPT & SHETL are Scottish Transmission Owners

		2008	2020 Prediction / Target	2008	(Central Scenario)
1.4	Peak Demand (GW)			61.4	60.8
	Annual Demand (TWH)			373	365
					Gone green 2020
1.5	Generation (GW)				
	Nuclear			11	7
	Coal			28	20
	Gas			30	34
	Oil			4	1
	Hydro			2	2
	Onshore Wind			2	13
	Offshore Wind			1	20
	Other Renewables (Please describe)			-	-
	Pump Storage			3	3
	Other - Please list				
1.6	External Interconnections				
	France			2000	2000
	Northern Ireland			500	500
	Netherlands				1320
	- all of the above are via DC links				
1.8	Renewable Targets % of annual			None	35%
	Renewable Target Units (TWH)			None	128

Market and Access **GB Security Standard Benchmark Questionnaire**

This section of the questionaire is an overview of the Market operation and the transmission access arrangements.

There is a high volume of renewable generation seeking to connect to the British transmission system. The connection arrangements described here are resulting in long lead times for the connection of new generation eg a new transmission connection application received today, will be unlikely to make a connection before 2016. The Access arrangements are currently under review and the options being considered include:-
1) Change from "Invest and Connect" described to a "Connect and Manage" arrangement where the cost of constraints are socialised,
2) Provide a range of short and long term access products,
3) Facilitate the connection of intermittent generation via capacity sharing either by trading between existing connectees or by auction.
The GB answers provided below describe the existing arrangements. A policy statement with additional information is linked below.

Connecting low carbon generation

	Question	Benchmark Partner Answer	GB Answer
2.1	**Energy Market** Describe high level market arrangements		1) Wholesale market is self despatch, Generators having agreements with suppliers. Full cost recovery is through generator Bid prices. There is no payment for capacity or availability. 2) SO operates a balancing market and ancillary services for Frequency Response, Reserve Response, Reactive Power and System Security with a 1 hour lead time. 3) Renwables market is delivered by obligations on suppliers to source % of energy from renewable sources. Renewable Obligation Certificates (ROC's) provide framework for demonstrating compliance Defaulting suppliers have to purchase ROC's at the "buy out" rate of £34 / ROC (2007/08)
2.2	**System Access Charging Arrangements** **Describe high level access for enduring and new connections**		Enduring Connections:- 1) Users pay a Use of System Charge based on their Transmission Entry Capacity (TEC) and location within the GB transmision 2) Users pay a charge for the sole use Entry (Connection) assets i.e. for the provision and maintenance of assets 3) Generator has an enduring right to use the transmission capacity until they cease paying Use Of System Charges New Connections:- 1) GBSO administers system access arrangements 2) New connections are delivered by TO construction agreements 3) Application Fee secures connection offer within 3 months 4) Users pay for shallow connection assets only 5) Connection offer provides "firm" access to market and compensation is paid to generators for constrained access (on and off) The Access arrangements are under review in GB as a result of the long queue for renewable generation connections 1) Connection Agreements are "open ended"
2.3	**System Access Charging Arrangements (Continued)** **Please highlight any difference between conventional and renewable generation for the processing of connection applications.**		The processing of a generation connection application is the same for all types of generation. However the amount of deep infrastructure reinforcement required is factored to take account of intermittency and diversity. (see MITS)

Strategic Investments **GB Security Standard Benchmark Questionnaire**

This section descibes in overview the GB regulatory arrangements, the consideration of strategic investments and provides a hyperlink to the GB Security and Quality of Supply standar

	Question	Benchmark Partner Answer	GB Answer
3.1	**Regulation** Describe the main elements of the regulatory framework		A 5 Year Regulatory Price Review determines the Licensee's revenue stream recovered through Use of System Charges which are paid by all transmission system users During Price Review, the transmission companies complete historic and future business plan questionnaires used by regulator to assess business capital needs, operating costs and business efficiency targets. Other regulatory incentive schemes in place for TO system
3.2	**Strategic Investments** Are there any incentive schemes for the Licensee to facilitate strategic investment to accommodate future markets, a) for main infrastructure b) for interconnectors		There is currently significant regulatory discussion ongoing on the requirement to make strategic investments to accommodate 2020 renewables targets. This could lead to the allowance to make additional investments in addition to those included within the regulatory review. Reinforcements being considered include the construction of offshore DC links to facilitate increased north south flows.
3.3	**Criteria for planning/reliability** Do you utilise a deterministic, pobabalistic or cost benefit based criteria. Can you provide a link to your standards.		There are a prescribed set of standards. To acess a copy of the Great Britain Security and Quality of Supply Standards paste the attached address into your internet explorer. http://www.nationalgrid.com/NR/rdonlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB_SQSS_V1.pdf
			Great Britain Security and Quality of Supply Standards

ENTRY (Connection of generation) **GB Security Standard Benchmark Questionnaire**

This section relates to planning criteria which specifically address the connection of generation onto the transmission system

	Question	Benchmark Partner Answer	GB Answer
4.1	Are the size of generatiors restricted and/or system connectivity designed to limit the amount of generation that may be lost in a credible event?		To protect against system frequency drops outside of +/-0.5Hz two levels of infeed loss are defined. 1) Normal infeed loss limit 1000MW {2.6.3} 2) Infrequent loss limit 1320MW to curtail frequency deviation {2.6.4} Losses greater than the normal infeed loss should not occur more than twice per year. The infrequent loss limit is currently under review to accommodate replacement nuclear generators and other new technologies
4.2	Is there a limit to the maximum length of single circuit used to connect generation		1) 5km for high load factor generation (output>2000GWh) {2.7.1} 2) 20km for low load factor generation (eg windfarms) {2.7.2}
4.3	What are the background assumptions for generation and demand when assessing entry capacity requirments.		Generation and demand conditions are set to those that may reasonably be forseen during a year {2.8} eg maximum/minimum generation and maximum/minimum demand <u>In assessing local works:</u> All generation is set to 100% of output Load is modelled at various percentages of peak demand
4.4	What are the basic planning criteria for Entry assets ?		Starting from an intact network and assuming the above conditions, then for the following faults:- a) N-1, eg the loss of a single circuit on a double circuit route b) N-D (the loss of a double circuit route) or busbar coupler/section switch There shall not be:- A loss of supply greater than that permitted under the Exit criteria, unnaceptable overloading of plant, unacceptable voltage condition or operating margin or system instability
4.5	Is it possible to accommodate customer choice in security requirements ?		Customer has choice of a non firm (single circuit) connection {2.15} (To avoid delays in planning consent Users may seek a single circuit cable connections and forfeit "firm" entry benefits)
4.6	Can investment be justified based on an economic justification ?		Investments over and above the deterministic standards described above may be made providing they are justified economically {2.4} ie through the avoidance of system constraint costs during maintenance conditions.
4.7	Is renewable generation given special treatment in terms of connection application processing and market access		No special treatment for renewable generation

Main Interconnected Transmission System (MITS) **GB Security Standard Benchmark Questionnaire**

This section of the questionaire relates to the planning of the Main Transmission System linking the large generation areas with large demand areas.

	Question	Benchmark Partner Answer	GB Answer
5.1	What background assumptions are made regarding generation and demand levels for planning?		1) Where in future years there is a large predicted plant margin then the total generation is reduced to 120% of demand using a Ranking Order Technique {4.4}. 2) All conventional generation is scaled back uniformly to meet demand. 3) Wind generation contribution is scaled back to 60% (Presently a draft proposal for the planning standards) 4) To enhance the level of demand security planned transfers across boundaries are increased by an "Interconnection Allowance" taken from "Circle Diagram" {4.4.2} Generation scaled to meet the new "Required" transfer
5.2	What is the basic Design criteria for the Main Inter- connected Transmission System ?		For the purposes of planning the capacity of the transmission system, the system is divided into areas of demand greater than 1500MW. The capacity of the boundaries between the areas is assessed to see that it is capable of securely transporting the required inter area flows. The network connecting these demand areas is called the Main Interconnected Transmision System. Analysis of system compliance is undertaken at Peak Demand and at Off Peak conditions. At Peak demand {4.4} For the contingency criteria:- a) N-1, b) N-2), c) N-D or d) busbar fault There shall not be:- A loss of supply greater than that permitted (Exit criteria), unnaceptable overloading of plant, unacceptable voltage condition or margin or system instability For off peak, year round conditions {4.7} For the following fault conditions:- a) N-1, b) N-D There shall not be:- A loss of supply greater than that permitted (Exit criteria), unnaceptable frequency, overloading of plant, unacceptable voltage condition or system instability Use economic criteria (Note - N-2 is a fault outage followed by another fault outage, not sim
5.3	Are cost benefit analysis techniques used to justify infrastructure investment ?		Investments over and above the minimum reinforcements to satisfy the deterministic standards described above, may be made providing they are justified economically {4.3}
5.4	Are probabilistic techniques used in planning infrastructure investment ?		The standards currently in use are deterministic in nature. Probablistic assessment of boundary flows is not a core part of the existing GBSQSS.

Exit (Demand connections) **GB Security Standard Benchmark Questionnaire**

This section relates to planning criteria which specifically address the connection of load onto the transmission system

	Question	Benchmark Partner Answer	GB Answer
6.1	What background assumptions are made in establishing the transmission system supply capability to the distribution networks ?		1) Assumes peak demand 2) For planned outages, the demand shall be set to that expected during a maintenance period {3.5.2} 3) The contribution of an embedded generator within the distribution system shall be taken into account {3.5.3} 4) The demand transfer capability between demand poinnts
6.2	What are the basic planning criteria applied when planning for demand capability ?		Assuming the above background conditions:- For the following fault conditions:- a) N'-1, b) busbar or mesh corner outage There shall be no:- unnaceptable overloading of plant, unacceptable voltage condition or margin or system instability
6.3	How does the level of demand security vary with group size ?		{Table 3.1} Group Size Group Demand Criteria Demand to be suppied >1500MW N-1 All N-2 All N-D All 300 to 1500MW N-1 All N-2 All of maintenance period demand 60 to 300MW N-1 All N-2 Smaller of (Group demand -100MW or 1/3 of Group demand)
6.4	Is special consideration given to sites of strategic importance or sensitivity eg. Oil Refineries Nuclear sites, Business Districts etc		

Voltage Criteria

GB Security Standard Benchmark Questionnaire

The voltage criteria referred to here are for use in operational or planning planning timescales.

	Question	Benchmark Partner Answer	GB Answer
7.1	Nominal transmission voltage levels and planning limits? Planning limits are used in planning the design of the transmission system.		Nominal Min Max 1) 400kV 390kV (97.5%) 410kV (102.5%) 2) 275kV 261kV (95.0%) 289kV (105.0%) 3) 132kV 119kV (90.0%) 139kV (105.0%) (132kV Scotland only)
7.2	Permissible voltage step changes used for planning studies ?		Event Fall (%) Rise (%) Secured OHL/Cable fault -6.0 6.0 Transformer/double circuit or mesh corner/busbar fault -12.0 6.0 Planned Switching Operation -3.0 3.0
7.3	Steady state voltage limits in operational time-scales? These are the limits used in the real time operation of the system.		Voltage Min Max 400kV 360kV 420kV 275kV 248kV 303kV 132kV 119kV 145kV <132kV 94% 106% Note for short durations (max 15minutes) the maximum voltage may increase to 440kV, 316kV or 158kV respectively
7.4	Voltage planning limits for offshore transmission systems Do they differ from onshore?		Nominal Min Max 400kV -10% +5% <400kV ?132kV -10% +10% <132kV -6% +6%

Operational Criteria **GB Security Standard Benchmark Questionnaire**

The criteria described here are to meet the operational standards

	Question	Benchmark Partner Answer	GB Answer
8.1	Basic Operational Security of the Main Interconnected Transmission System ?		During Off-peak, year round, prevailing conditions {4.7} then for any of the following conditions a) N-1, b) N-D, c) Section of busbar / mesh corner d) the most onerous loss of power infeed There shall not be:- A loss of supply greater than that permitted by the Exit criteria, unnaceptable frequency, overloading of plant, unacceptable voltage condition or system instability
8.2	Are there different operational criteria under normal and adverse system conditions.		If there is an increased likelyhood of a double circuit fault (eg due to bad weather) the transmission system may be secured against enhanced criteria such that under prevailing conditions there shall not be:- if there is no economic penelty, any loss of supply greater than 300MW. {5.5.4} In periods of major system risk, SO may implement risk mitigation measure including:- provision of additional reserve, reducing generator to system intertripping and reducing system transfers, for example through balancing services. {5.6}
8.3	Does you system utilise special protection systems to increase demand security and transmission capability		Use of system to generator intertrip schemes to maintain boundary capabilities during outage conditions. The use of automatic switching schemes to re-configure substations following fault outages. Options are being developed to enable to automatic tapping of quadrature booster transformers following contingencies. Low frequency demand shedding and under voltage demand shedding schemes are installed on the system to minimise the impact of large disturbances on the transmission system.

Offshore **GB Security Standard Benchmark Questionnaire**

This section relates to draft proposals in place covering the design of offshore connections to offshore windfarms.

	Question	Benchmark Partner Answer	GB Answer
9.1	What are the basic approach in determining the security standard for offshore connections		A deterministic approach has been developed based on the cost of onshore and offshore plant taking into account the loss of revenue for fault and maintenance outages. The detail below are a current draft and subject to review taking into account the latest offshore development proposals
9.2	What restrictions are applied to the planning criteria		The criteria are based on radial connections that are: < 100km from onshore interface < 1500MW wind farm capacity < 50km of onshore overhead line < 200MW gas turbine Additional criteria are beinmg developed to accommodate larger winfarms further offshore.
9.3	What is the planning criteria for each element of the connection - for wind farm		**Onshore connection substation** Min 2 transformers - 50% redundancy **Cable to offshore platform** No redundancy up to infrequent infeed loss (1320MW) **Onshore Overhead line** Based on capacity and length calculation **Offshore Platform AC** Min 2 transformers - 50% redundancy **Offshore Platform DC - Converter** No redundancy up to normal infeed loss (1000MW)
9.4	What is the planning criteria for each element of the connection - for gas turbine		**Onshore connection substation** Min 1 transformer - no redundancy **Cable to offshore platform** No redundancy up to infrequent infeed loss (1320MW) **Onshore Overhead line** Based on capacity vs length calculation **Offshore Platform AC** Min 2 transformers - 100% redundancy