**National Electricity Transmission System**

**Security and Quality of Supply Standard**

# Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation – NETS SQSS text

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| **Responses Required By:** | **29th October 2010** |
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| Prepared By: | SQSS Review Group |
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SP TRANSMISSION Scottish and Southern Energy nationalgrid

# 1. Introduction

In March 2010 the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) Review Group established a working group to develop proposals to amend the NETS SQSS so that it includes criteria relating to the integration of intermittent generation in system design and operation. In June 2010 the Review Group undertook a consultation (GSR009)[1] on the findings and recommendations of the working group.

The consultation report described the analysis undertaken by the working group, the results obtained, the advantages and disadvantages of a number of options considered, and indicated the working group's preferred approach. It sought industry views, both on the principle of the proposals and on several specified questions in respect of the detail. The consultation report did not include proposed wording to be included in the NETS SQSS in order to implement any of the methods described.

Following the consultation and discussion of the comments received, the Review Group has agreed the method that it will recommend to the Authority, and the detail of that method.

This consultation describes the method to be recommended. In accordance with the NETS SQSS governance process[2], the Review Group is now seeking industry views on whether the proposed NETS SQSS wording of Appendix 1 clearly and accurately reflects that method. The SQSS Review Group would welcome feedback. Responses are required by 29th October 2010, as described in Section 4. For the avoidance of doubt, the Review Group is not looking for further comment on the method itself.

Following this period of consultation, the Review Group will submit its report to Ofgem. The report will describe the recommended method and include the proposed NETS SQSS text.

# 2. Proposed method

The GSR009 consultation report proposed a dual criteria approach in which the transmission system is developed to meet both a demand security criterion and an economy criterion. This approach will be recommended to Ofgem.

The detail of the two criteria is described below.

### *2.1 Security criterion*

[1] The GSR009 report can be found at: http://www.nationalgrid.com/NR/rdonlyres/E22B1547-D4CC-4F88-AEEF-C76305718C25/41720/GSR009SQSSConsultation.pdf

[2] The governance documentation can be found at: http://www.nationalgrid.com/NR/rdonlyres/00679067-2077-42A0-B975-FA214D179FF4/17781/governance.pdf

The intention of this criterion is to ensure that peak demand can be met by conventional generation, with no reliance on either intermittent generation or imports from external systems.

The method, based on that currently used, is:

- Intermittent generation is excluded from the background (ie availability of all intermittent sources is set to zero)
- Connections to external systems are set to neither import nor export ie. they are at float
- A ranking order is used to establish the contributory plant from the remaining generation. Where the remaining generation capacity exceeds 120% of ACS peak demand the contributory plant will be limited to 120% demand. Where the remaining generation is less than 120% demand, all of it will be contributory
- A planned transfer condition is determined by uniformly scaling the contributory plant to meet the demand
- A required transfer is established for each system boundary by applying an interconnection allowance in addition to the planned transfer, as now – the level of interconnection allowance depends on whether single or two circuit outages are being considered

Reinforcements required to ensure the system meets the required transfer capability for specified events are identified.

### *2.2 Economy criterion*

This criterion determines a level of capability beyond that needed for demand security, based on overall economic efficiency, taking account of transmission and generation costs. It was described in the GSR009 consultation as the Pseudo-CBA method.

- Plant that is expected to be uneconomic to run in the scenario considered is excluded from the background (for example OCGTs)
- All other plant is deemed contributory
- The output of contributory power stations in certain generation categories are scaled by a fixed factor
    - o Intermittent generation is scaled by 70%
    - o Nuclear generation and plant with carbon capture technology is scaled by 85%
    - o Pumped storage plant is scaled by 50%
    - o Connections to external systems, which are considered likely to import, are fixed to import 100% of their capacity
- All other plant is scaled by a factor that ensures the total generation meets the ACS peak demand – this is the planned transfer condition
- A required transfer is establish by applying a boundary allowance in addition to the planned transfer – the level of boundary allowance depends on whether single or two circuit outages are being considered.

Reinforcements required to ensure the system meets the required transfer capability for specified events are identified.

## 3. NETS SQSS wording

The proposed NETS SQSS changes to implement these criteria are as follows:

- The requirement to meet the dual criteria is included in chapter 4, specifically clause 4.4
- New definitions have been added (demand security planned transfer condition, economy planned transfer condition, and boundary allowance) and an existing definition modified (interconnection allowance)
- The existing Appendix C, which describes the planned transfer condition, has been modified to describe the security planned transfer condition
- Minor changes have been made to Appendix D (interconnection allowance) to reflect the renumbering in chapter 4
- A new Appendix E has been introduced that describes the economy planned transfer condition
- A new Appendix F, detailing the boundary allowance for use in the economy criterion, has been added
- The existing Appendix E has become Appendix G and references have been updated throughout the document.

## 4. Consultation responses

The NETS SQSS Review Group will welcome comments on whether the proposed NETS SQSS text clearly implements the method described in section 2. Further comment on the fundamental strengths and weaknesses of the proposed approach is not being sought. Please provide comments to Mark Perry at either:

Mark Perry
Electricity Network Investment
National Grid House
Warwick Technology Park
Gallows Hill
Warwick CV34 6DA

or

eni.sqss@uk.ngrid.com

Please provide any comments by 29th October 2010

# Appendix 1 – proposed NETS SQSS text

Existing text (NETS SQSS version 2.0, 24th June 2009) is in black font
Changes are shown in red font – deletions have a strikethrough
Exceptions to this are where equations and charts are added or modified. In Appendix E and F, all of the equations and the chart are new but are in black font. In clause C6, the existing equation, marked with a strikethrough but black font, is to be replaced by the equation highlighted with a red background.
Two comments are included with yellow highlighting – these do not form part of the NETS SQSS text.

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2.4 It is permissible to design to standards higher than those set out in paragraphs 2.5 to 2.13 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

2.13 Where necessary to satisfy the criteria set out in paragraph 2.12, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraph 2.12 provided that maintenance access for each *transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

2.18 The additional operational costs referred to in paragraph 2.16.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

3.4 It is permissible to design to standards higher than those set out in paragraphs 3.5 to 3.10 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

3.15 The additional operational costs referred to in paragraph 3.12.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

## 4. Design of the *Main Interconnected Transmission System*

4.1 This section presents the planning criteria for the Main Interconnected Transmission System (MITS).

4.2 In those parts of the *onshore transmission system* where the criteria of Section 2 and/or Section 3 also apply, those criteria must also be met. In those parts of the *offshore transmission system* where the criteria of Section 7 and/or Section 8 also apply, those criteria must also be met.

4.3 In planning the *MITS*, this Standard is met if the design satisfies the minimum deterministic criteria detailed in paragraphs 4.4 to 4.12. It is permissible to design to standards higher than those set out in paragraphs 4.4 to 4.12 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

### Minimum *Transmission capacity* Requirements

At *ACS peak demand* with an *intact system*

4.4 The *MITS* shall meet the criteria set out in paragraphs 4.5 to 4.6 under both the Security and Economy ~~the following~~ background conditions below:

Security Background

4.4.1 *generating units*' outputs shall be set to those ~~which ought reasonably to be foreseen for that demand~~ arising from the *Security planned transfer condition* described in Appendix C;

4.4.2 power flows shall be set to those arising from the ~~*planned transfer condition*~~ *Security planned transfer condition* (using the appropriate method described in Appendix C) prior to any fault, and such power flows modified by an appropriate application of the *interconnection allowance* (using the methods described in Appendix D) under *secured events*;

Economy Background

4.4.3 *generating units*' outputs shall be set to those arising from the *Economy planned transfer condition* described in Appendix E;

4.4.4 power flows shall be set to those arising from the *Economy planned transfer condition* (using the appropriate method described in Appendix E) prior to any fault, and such power flows modified by an appropriate application of the *boundary allowance* (using the methods described in Appendix F) under *secured events*;

Security and Economy Backgrounds

4.4.5 sensitivity cases on the conditions described in 4.4.2 and 4.4.4 shall comprise *generating units* with output equal to their *registered capacities* such that the required power transfers described in 4.4.2 and 4.4.4 above are approximated by selection of individual units; and

4.4.6 the expected availability of generation reactive capability shall be set to that which ought reasonably to be expected to arise. This shall take into account the variation of reactive capability with the active power output (for example, as defined in the machine performance chart). In the absence of better data the expected available capability shall not exceed 90% of the Grid Code specified capability, (unless modified by a direction of the *Authority*) or 90% of the contracted capability for the active power output level, whichever is relevant.

4.5 The minimum *transmission capacity* of the *MITS* shall be planned such that, for the background conditions described in paragraph 4.4, prior to any fault there shall not be:

4.5.1 equipment loadings exceeding the *pre-fault rating*;

4.5.2 voltages outside the pre-fault planning voltage limits or insufficient voltage performance margins; or

4.5.3 system instability.

4.6 The minimum *transmission capacity* of the *MITS* shall also be planned such that for the conditions described in paragraph 4.4 and for the *secured event* of a *fault outage* of any of the following:

4.6.1 a single *transmission circuit*, a reactive compensator or other reactive power provider;

4.6.2 a double circuit overhead line on the supergrid;

4.6.3 a *double circuit overhead line* where any part of either circuit is in the England and Wales area or the SHETL area;

4.6.4 a section of *busbar* or mesh corner; or

4.6.5 provided both the *fault outage* and prior outage involve plant in the England and Wales area, any single *transmission circuit* with the prior outage of another *transmission circuit*, or a *generating unit*, reactive compensator or other reactive power provider,

there shall not be any of the following:

4.6.6 *loss of supply capacity* (except as permitted by the demand connection criteria detailed in Section 3 and Section 8);

4.6.7 unacceptable overloading of any primary transmission equipment;

4.6.8 unacceptable voltage conditions or insufficient voltage performance margins; or

4.6.9 system instability.

Under conditions in the course of a year of operation

4.7 The *MITS* shall meet the criteria set out in paragraphs 4.8 to 4.10 under the following background conditions:

4.7.1 conditions on the *national electricity transmission system* shall be set to those which ought reasonably to be foreseen to arise in the course of a year of operation. Such conditions shall include forecast demand cycles, typical *power station* operating regimes and typical *planned outage* patterns; and

4.7.2 the expected availability of generation reactive capability shall be set to that which ought reasonably to be expected to arise. This shall take into account the variation of reactive capability with the active power output (for example, as defined in the machine performance chart). In the absence of better data the expected available capability shall not exceed 90% of the Grid Code specified capability, (unless modified by a direction of the *Authority*) or 90% of the contracted capability for the active power output level, whichever is relevant.

4.8 The minimum *transmission capacity* of the *MITS* shall be planned such that, for the background conditions described in paragraph 4.7, prior to any fault there shall not be:

4.8.1 equipment loadings exceeding the *pre-fault rating*;

4.8.2 voltages outside the pre-fault planning voltage limits or insufficient voltage performance margins; or

4.8.3 system instability.

4.9 The minimum *transmission capacity* of the *MITS* shall also be planned such that, for the background conditions described in paragraph 4.7, the operational security criteria set out in Section 5 can be met.

4.10 Where necessary to satisfy the criteria set out in paragraphs 4.8 and 4.9, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraphs 4.8 and 4.9 provided that maintenance access for each *transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

**General criteria**

4.11 In addition to the requirements set out in paragraphs 4.4 to 4.10, the system shall also be planned such that operational switching does not cause *unacceptable voltage conditions*.

4.12 *Transmission circuits* comprising the *supergrid* part of the *MITS* shall not exceed the circuit complexity limit defined in paragraphs B.3 to B.7 of Appendix B.

4.13 Guidance on complexity of *transmission circuits* on the *MITS* operated at a nominal voltage of 132kV is given in paragraphs B.8 to B.13 of Appendix B. Relaxation of the restrictions cited in paragraphs B.8 to B.13 may be justified in certain circumstances following appropriate liaison between the relevant transmission licensees responsible for the design of the circuits and their operation.

**Switching Arrangements**

4.14 Guidance on substation configurations and switching arrangements are described in Appendix A. These guidelines provide an acceptable way towards meeting the criteria of this section. However, other configurations and switching arrangements which meet the criteria are also acceptable.

7.6 It is permissible to design to standards higher than those set out in paragraphs 7.7 to 7.19 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

7.19 Where necessary to satisfy the criteria set out in paragraph 7.18, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraph 7.18 provided that maintenance access for each *offshore transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

7.24 The additional operational costs referred to in paragraph 7.22.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

8.4 It is permissible to design to standards higher than those set out in paragraphs 8.5 to 8.10 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

8.15 The additional operational costs referred to in paragraph 8.13.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

## 11. Terms and Definitions

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| Boundary Allowance | An allowance in MW to be added in whole or in part to transfers arising out of the *Economy planned transfer condition* to take some account of year round variations in levels of generation and demand. This allowance is calculated by an empirical method described in Appendix F of this Standard. |
| Interconnection Allowance | An allowance in MW to be added in whole or in part to transfers arising out of the *Security planned transfer condition* to take some account of non-average conditions (e.g. *power station* availability, weather and demand). This allowance is calculated by an empirical method described in Appendix D of this Standard. |
| Security Planned Transfer Conditions | The condition arising from scaling the *registered capacity* of each directly connected *power station* and embedded *large power station* that is considered able to reliably contribute to peak demand security such that the total of the scaled capacities is equal to the *ACS peak demand*. Generation powered by intermittent sources (eg. wind, wave, solar) and imports from *external systems* are not included in this condition. This scaling shall follow the techniques described in Appendix C. |
| Economy Planned Transfer Conditions | The condition arising from scaling the *registered capacity* of each directly connected *power station* and embedded *large power station* according to the type of generation such that the total of the scaled capacities is equal to the *ACS peak demand*. This scaling shall follow the techniques described in Appendix E. |
| Planned Transfer Conditions<br><br>(not changed but included for comparison with new terms above) | The condition arising from scaling the *registered capacities* of each directly connected *power station* and embedded *large power station* such that the total of the scaled capacities is equal to the *ACS peak demand* minus imports from *external systems*. This scaling shall follow the techniques described in Appendix C . |

## Appendix C Modelling of *Security* *Planned Transfer*

C.1 There are two techniques relevant to the determination of *Security planned transfer conditions*. For circumstances in which apparent future *plant margins* exceed 20%, the 'Ranking Order technique' should be applied. Where the apparent future *plant margin* is 20% or less, the 'Straight Scaling Technique' should be applied. These techniques are described below.

C.2 ~~Imports from *external systems* (e.g. in France or Ireland) shall not be scaled under either of these two scaling techniques because they result from tranches of generation rather than single *power stations*.~~

### Availability Factors

C.2 In derivation of *Security planned transfer conditions*, the registered capacities of power stations are scaled by availability factors, known as $A_T$, for classes T of power station. For the *Security planned transfer condition*, these factors are set as follows:

C.2.1 For stations powered by wind, wave, or tides, $A_T = 0$. This zero factor is set for the *Security planned transfer condition* so that there is confidence that there is sufficient transmission capacity to meet demand securely in the absence of this class of generation.

C.2.2 For imports or exports from / to *external systems*, $A_T = 0$.

C.2.3 For all other *power stations*, $A_T = 1.0$

### Ranking Order Technique

C.3 In some circumstances apparent future *plant margins* may exceed 20%. This may arise where *NGC* has been notified of increases in future generation capacity but has not yet been formally notified of future reductions in generation capacity due to plant closures. The ranking order technique maintains the output of directly connected *power stations* and embedded *large power stations* considered more likely to operate at times of *ACS peak demand* at more realistic levels and treats those less likely to operate as non-contributory.

C.4 This is achieved by ranking all directly connected *power stations* and embedded *large power stations* in order of likelihood of operation at times of *ACS peak demand*. Those *power stations* considered least likely to operate at peak are progressively removed and treated as non-contributory until a *plant margin* of 20% or just below is achieved. The output of the remainder is then calculated using the same scaling method as used in the straight scaling technique described in paragraphs C.5 and C.6 below.

### Straight Scaling Technique

C.5 In this technique, all directly connected *power stations* and embedded *large power stations* on the system at the time of the *ACS peak demand* are considered contributory and their output is calculated by applying a scaling factor to their *registered capacity* proportional to an availability representative of the generating plant type at the time of *ACS peak demand* such that their aggregate output is equal to the forecast *ACS peak demand* minus total imports from *external systems*.

C.6 Thus,

$$P_{T_i} = S \cdot A_T \cdot R_{T_i}$$

Where

$$\sout{S = \frac{P_{\text{loss}} + \sum_j P_{l_j} - \sum_k P_{I_k}}{\sum_T \left( A_T \cdot \sum_i R_{T_i} \right)}}$$

$$S = \frac{P_{\text{loss}} + \sum_j L_j}{\sum_T \left( A_T \cdot \sum_i R_{T_i} \right)}$$

The first equation above, with the red strikethrough, is replaced by the second equation, highlighted by a red background

and

$P_{T_i}$ = the output of the *i*th directly connected or *embedded large power station* of *generating plant type T*

$A_T$ = an availability representative of *generating plant type T* at the time of *ACS peak demand*

$R_{T_i}$ = the *registered capacity* of the *i*th directly connected or *embedded large power station* of generating plant type *T*

$P_{\text{loss}}$ = total *national electricity transmission system* active power losses at time of *ACS peak demand*

~~$P_{l_j}$ = the active power demand at the *j*th *national electricity transmission system* demand site at the time of *ACS peak demand*~~

$L_j$ = the active power demand at the *j*th *national electricity transmission system* demand site at the time of *ACS peak demand*

~~$P_{I_k}$ = the import from the *k*th *external system*~~

## Appendix D Application of the *Interconnection Allowance*

D.1 This appendix outlines the techniques underlying the use of the *interconnection allowance* under paragraphs 4.4.2 and ~~4.4.3.~~ 4.4.5.

D.2 The modification of the *MITS* *Security* *planned transfer condition* power flow pattern to reflect an *interconnection allowance* shall apply to the *national electricity transmission system* divided into any two contiguous parts provided that

D.2.1 the smaller part contains more than 1500MW of demand at the time of the *ACS peak demand*; and

D.2.2 the boundary between the two parts lies on the boundary between the SHETL and SPT areas, or between the SPT area and the England and Wales area, or entirely within the England and Wales area.

D.3 The *interconnection allowance* is then applied by:-

D.3.1 summing the demand and the total active power generation output (including imports from *external systems*) under the *Security* *planned transfer condition* within the smaller of the two parts and expressing this sum as a percentage of twice the *ACS peak demand*;

D.3.2 using Figure D.1, traditionally known as the 'Circle Diagram', to determine the *interconnection allowance* (in MW) by taking the appropriate percentage of the *ACS peak demand*;

D.3.3 finding the total active power generation output and total demand in each part of the system when applying the *interconnection allowance* or half *interconnection allowance* (as appropriate) as described in paragraphs D.4 and D.5;

D.3.4 for the conditions described under paragraph 4.4.2, proportionally scaling all the generation and demand in both parts of the system, as described in paragraphs D.4 and D.5 below, such that the transfer between the two parts increases by: first, the full *interconnection allowance* when considering the single *fault outages* in 4.6.1; and second, half the *interconnection allowance* for all other *secured events* in paragraph 4.6;

D.3.5 for the conditions described under paragraph 4.4.5 ~~4.4.3~~, proportionally scaling demand in both parts of the system and setting *generating units* with their outputs such that their totals are as described in paragraphs D.4 and D.5 below such that the transfer between the two parts increases by: first, the full *interconnection allowance* when considering the single *fault outages* in item 4.6.1; and second, half the *interconnection allowance* for all other *secured events* in paragraph 4.6.

D.4 Suppose that the two contiguous parts of the system in question are areas 1 and 2 and that area 1 exports to area 2. Let $G_1$ and $G_2$ be the total generation in areas 1 and 2 respectively and $D_1$ and $D_2$ be the total demand in areas 1 and 2 under the *Security* *planned transfer condition*. Let $I$ be the transfer required in addition to that under the *Security* *planned transfer condition* (i.e.

the value of $I$ is equal to the *interconnection allowance* or half the *interconnection allowance* as specified in paragraphs D.3.4 and D.3.5).

D.5 The additional transfer is proportionally divided between the generation and demand in the two areas as follows:

the total demands after application of the *interconnection allowance* or half *interconnection allowance* in areas 1 and 2 are

$$D_1' = k_{d1} D_1$$
$$D_2' = k_{d2} D_2$$

and the total amounts of generation in areas 1 and 2 are

$$G_1' = k_{g1} G_1$$
$$G_2' = k_{g2} G_2$$

where

$$k_{d1} = 1 - \frac{I}{D_1 + G_1}$$
$$k_{g1} = 1 + \frac{I}{D_1 + G_1}$$

and

$$k_{d2} = 1 + \frac{I}{D_2 + G_2}$$
$$k_{g2} = 1 - \frac{I}{D_2 + G_2}$$

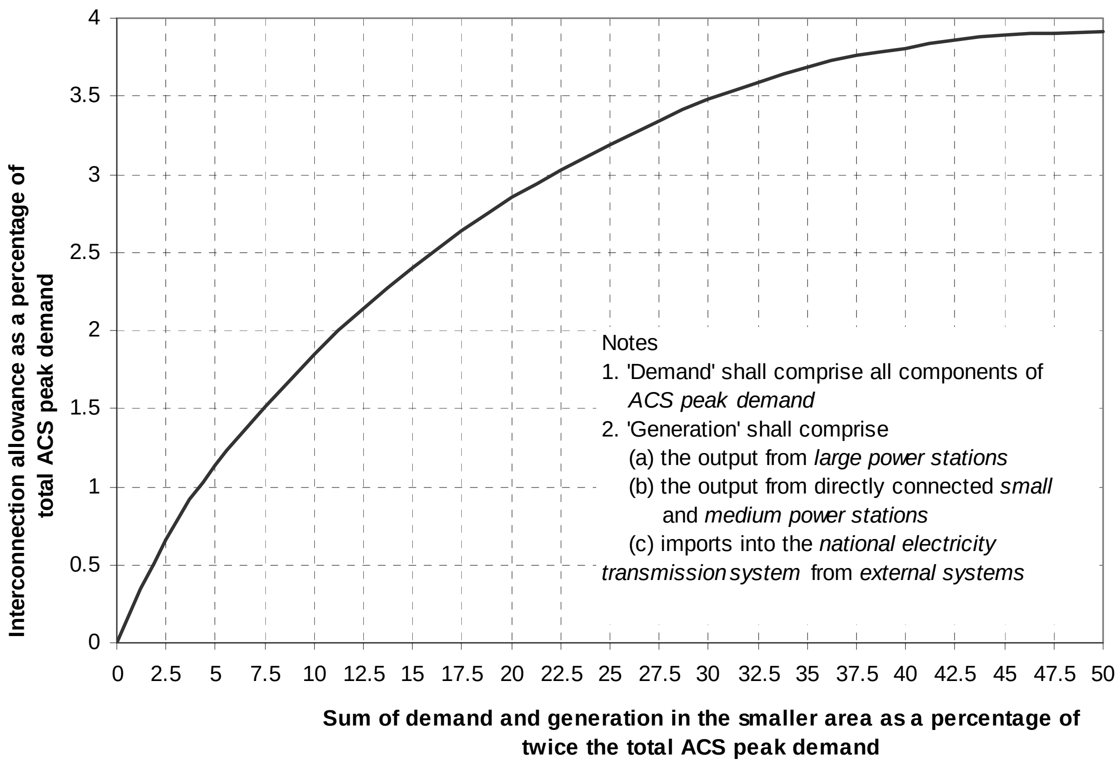


Figure D.1 *Interconnection allowance* as a function of area size (the 'circle diagram')

## Appendix E Modelling of *Economy Planned Transfer*

E.1 For the determination of Economy *planned transfer conditions* plant is categorised in three groups:

E.1.1 non-contributory generation. This plant, such as OCGTs, does not form part of the generation background

E.1.2 directly scaled plant. The ouput of plant in this category is determined by a fixed scaling factor, described in E.3

E.1.3 variably scaled plant. The output of plant in this category is uniformly scaled by a variable factor that is calculated to ensure that generation and demand balance. This is described in E.5.

E.2 The NETS SO will from time-to-time review, consult on, and publish the categorisation of plant.

### Directly Scaled Plant

E.3 In the *Economy planned transfer condition* the *registered capacities* of certain classes of *power station* are scaled by fixed factors, known as $D_T$, for classes T of *power station*. These factors are set as follows:

E.3.1 For nuclear stations, and for coal-fired and gas-fired stations fitted with Carbon Capture and Storage, $D_T = 0.85$

E.3.2 For stations powered by wind, wave, or tides, $D_T = 0.70$.

E.3.3 For pumped storage based stations, $D_T = 0.5$

E.3.4 For interconnectors to external systems regarded as importing into GB at the time of peak demand, $D_T = 1.0$

E.4 The NETS SO will from time-to-time review the appropriateness of these factors and revise them where necessary, based on alignment with cost benefit analysis.

### Variably Scaled Plant

E.5 All remaining directly connected *power stations* and embedded *large power stations* on the system at the time of the *ACS peak demand* are considered contributory and their output is calculated by applying a scaling factor to their *registered capacity* such that their aggregate output is equal to the forecast *ACS peak demand* minus the total output of directly scaled plant.

E.6 Thus,

$$P_{T_i} = \begin{cases} 0 & \text{for non-contributory plant} \\ D_T \times R_{DT_i} & \text{for directly scaled plant} \\ S \times R_{VT_i} & \text{for variably scaled plant} \end{cases}$$

where

$$S = \frac{P_{\text{loss}} + \sum_j L_j - \sum_{DT}\left(\sum_k \left(D_T \times R_{DT_k}\right)\right)}{\sum_{VT}\left(\sum_n R_{VTn}\right)}$$

and

$P_{T_i}$ = the output of the $i^{th}$ directly connected or *embedded large power station* of generation plant type *T*

$D_T$ = the direct scaling factor for directly scaled generation of plant type *T*

$R_{DT_k}$ = the *registered capacity* of the $k^{th}$ directly connected or *embedded large power station* of generation plant type *DT* in the directly scaled category

$R_{VTn}$ = the *registered capacity* of the $n^{th}$ directly connected or *embedded large power station* of generation plant type *VT* in the variably scaled category

$P_{\text{loss}}$ = total *national electricity transmission system* active power losses at time of *ACS peak demand*

$L_j$ = the active power demand at the $j^{th}$ *national electricity transmission system* demand site at the time of *ACS peak demand*

## Appendix F Application of the *Boundary Allowance*

F.1 This appendix outlines the techniques underlying the use of the *boundary allowance* under paragraphs 4.4.4 and 4.4.5.

F.2 The modification of the *MITS Economy planned transfer condition* power flow pattern to reflect a *boundary allowance* shall apply to the *national electricity transmission system* divided into any two contiguous parts, irrespective of the size of location of the parts.

F.3 The *boundary allowance* is applied by:-

F.3.1 summing the demand and the total active power generation output (including imports from *external systems*) under the *Economy planned transfer condition* within the smaller of the two parts;

F.3.2 using Figure F.1 to determine the *boundary allowance* (in MW)

F.3.3 finding the total active power generation output and total demand in each part of the system when applying the *boundary allowance* or half *boundary allowance* (as appropriate) as described in paragraphs F.4 and F.5;

F.3.4 for the conditions described under paragraph 4.4.4, proportionally scaling all the generation and demand in both parts of the system, as described in paragraphs F.4 and F.5 below, such that the transfer between the two parts increases by: first, the full *boundary allowance* when considering the single *fault outages* in 4.6.1; and second, half the *boundary allowance* for all other *secured events* in paragraph 4.6;

F.3.5 for the conditions described under paragraph 4.4.5, proportionally scaling demand in both parts of the system and setting *generating units* with their outputs such that their totals are as described in paragraphs F.4 and F.5 below such that the transfer between the two parts increases by: first, the full *boundary allowance* when considering the single *fault outages* in item 4.6.1; and second, half the *boundary allowance* for all other *secured events* in paragraph 4.6.

F.4 Suppose that the two contiguous parts of the system in question are areas 1 and 2 and that area 1 exports to area 2. Let $G_1$ and $G_2$ be the total generation in areas 1 and 2 respectively and $D_1$ and $D_2$ be the total demand in areas 1 and 2 under the *planned transfer condition*. Let $B$ be the transfer required in addition to that under the *planned transfer condition* (i.e. the value of $B$ is equal to the *boundary allowance* or half the *boundary allowance* as specified in paragraphs F.3.4 and F.3.5).

F.5 The additional transfer is proportionally divided between the generation and demand in the two areas as follows:

the total demands after application of the *boundary allowance* or half *boundary allowance* in areas 1 and 2 are

$$D_1' = k_{d1} D_1$$
$$D_2' = k_{d2} D_2$$

and the total amounts of generation in areas 1 and 2 are

$$G_1' = k_{g1}G_1$$
$$G_2' = k_{g2}G_2$$

where

$$k_{d1} = 1 - \frac{B}{D_1 + G_1}$$
$$k_{g1} = 1 + \frac{B}{D_1 + G_1}$$

and

$$k_{d2} = 1 + \frac{B}{D_2 + G_2}$$
$$k_{g2} = 1 - \frac{B}{D_2 + G_2}$$

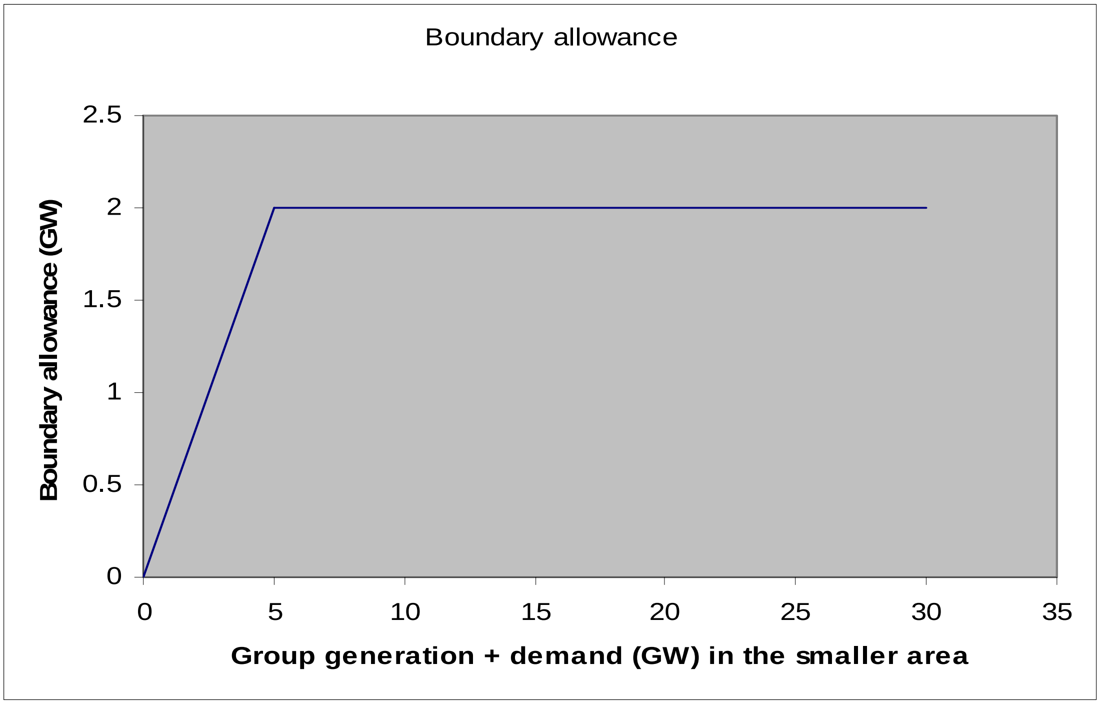


**Figure F1 Boundary allowance**

## Appendix ~~E~~G Guidance on Economic Justification

~~E~~G.1 These guidelines may be used to assist in the:

~~E~~G.1.1 economic justification of investment in transmission equipment and/or purchase of services such as reactive power in addition to that required to meet the planning criteria of Sections 2, 3, 4, 7 or 8.

~~E~~G.1.2 economic justification of the rearrangement of typical *planned outage* patterns and appropriate re-selection of *generating units*, for example through *balancing services*, from those expected to be available under the provisions of paragraph 2.13 in Section 2, paragraph 4.10 in Section 4 and 7.19 in Section 7; and

~~E~~G.1.3 evaluation of any expected additional operational costs or investments resulting from a proposed variation in connection design under the provisions of paragraphs 2.15 to 2.18 and/or paragraphs 3.12 to 3.15 and/or paragraphs 7.21 to 7.24.

~~E~~G.2 Guidelines:

~~E~~G.2.1 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 are less than the net present value of the expected operational or unreliability cost that would otherwise arise.

~~E~~G2.2 the assessment of expected operational costs and the potential reliability implications shall normally require simulation of the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9 of the Standard.

~~E~~G.2.3 due regard should be given to the expected duration of an appropriate range of prevailing conditions and the relevant *secured events* under those conditions as defined in section 5 and Section 9.

~~E~~G.2.4 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.

~~E~~G.2.5 all costs should take account of future uncertainties

~~E~~G.2.6 the evaluation of unreliability costs expected from operation of the *national electricity transmission system* 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.