Transmission Entry Working Group

Final Report

15th June 2012

1 SCOPE

This document sets out the draft report (Issue 1) of the Entry Working Group working under the auspices of the NETS SQSS Review Panel. The Working Group was formed following consultation on the Fundamental Review and specifically the proposals and further work recommended by the Transmission Entry and Exit (TEE) Working Group.

The NETS SQSS provides a co-ordinated set of criteria and methodologies for use in planning, operating and maintaining the GB onshore and offshore transmission systems. The review of the Standard reflects a need to update or revise the Standard arising from background changes to equipment / operating regimes or to ensure alignment with other Standards or Codes.

This Working Group considered, as part of the review into Transmission Entry criteria, the onshore generation connection criteria set out in Section 2 of the NETS SQSS together with associated sections such as Definitions, Appendices and Introductory sections.

Section 2 of the Standard covers the connections which extend from the generation points of connection into the main interconnected transmission system (MITS).

Specifically excluded from the review were offshore connections.

1.1 Membership

The Working Group membership, established at project initiation in February 2011, was:

David Carson (Chair)	SPT
Chris Humphries	NGET
David Gregory (until Oct 2011)	NGET
John Morris	EdF
Sarah Owen	Centrica
Paul Plumptre	NGET
Frank Prashad	RWE npower
Brian Punton	SHETL
Louise Schmitz (EdF Alternate)	EdF
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1.2 Working Group Terms of Reference

The formal Terms of Reference are provided as Appendix A of this report.

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3 EXECUTIVE SUMMARY

The Working Group considered the issues associated with Generation Connection Criteria Applicable to the Onshore Transmission System which forms Section 2 of the NETS SQSS together with associated components of the wider document.

At present, the generation connection criteria for connection to the transmission system does not differentiate, in respect of connection security, between base load power stations and those with intermittent fuel sources or indeed power stations of differing capacities (other than consideration for power stations larger than the infrequent infeed loss risk). The commercial arrangements for connection to and use of high voltage transmission system are set out in the Connection and Use of System Code (CUSC). Specifically, system access, charging and compensation arrangements are based upon the standard of service provided through the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) and any ‘User Choice’.

Currently generation customers are able to choose to have a connection to the system that is below the deterministic minimum. This will result in reduced access charges and an associated reduction in compensation, which has implications on some commercial aspects of their development.

The current NETS SQSS principle is to provide secure access for all generation and individual generators. This contrasts with the sliding scale of security for the connection of demand whereby smaller demand blocks generically have lower connection security than larger blocks.

The Working Group proposals consider that it is possible to alter the focus of the methodology to revise the level of security provided as the deterministic minimum with the ability for the customer to choose a greater level of connection security. The deterministic minimum criteria would be amended to reflect the differing size and intermittency of new generation technology, effectively reducing the transmission system capacity provided for smaller and intermittent generation. This approach is aimed at fulfilling the SQSS objectives and does not seek to define commercial arrangements within the context of the CUSC. Any clarification to the commercial regime to improve transparency as a result of this proposal would be considered separately through the CUSC governance process. This is not considered a prerequisite for this NETS SQSS proposal as the current commercial regime already covers charges for single circuit connections (introduced in 2009) and the associated compensation arrangements (through individual bilateral agreements).

This proposal would establish more targeted connection arrangements for each Generator, and allows the Generator to more easily determine the exact security of their connection to the transmission system.

In high level terms, the key differences between the current philosophy and that proposed are:

- For the current 'As Is' philosophy, many smaller transmission connecting customers exercise customer choice to choose a non-SQSS compliant connection. They do this principally to lower their connection charge (for sole use assets) and also to potentially facilitate an earlier connection to the grid. These instances require the TO to design and document a bespoke connection arrangement for each customer with consequential impact on timescales. This also adds complexity for the customer to enable them to understand the options available to them. There is no explicit Cost Benefit Analysis (CBA) justification as to what may be considered appropriate connection asset(s) as this is solely down to the customer. In opting for a non-compliant connection the customer agreement contains conditions (Clause 10) removing their right to compensation for loss of grid connection.
- If the SQSS modification is supported as drafted, the 'To Be' situation hasn't changed for the customer who has the same rights and options as today. However they can be better informed as to what an appropriate connection would be and the process and charging options can be standardised in advance. With regard to their commercial rights there are 2 potential options CUSC members could take:
  1) To redefine when compensation should be paid with potentially an increase in TNUoS charges to reflect the increased frequency compensation would be required, or
  2) To maintain the existing arrangements.

4 INTRODUCTION

As part of the ‘Fundamental Review’ of the SQSS, a number of Working Groups were established. Working Group 2 was commissioned to consider the Entry and Exit Criteria of SQSS Chapters 2 and 3 respectively. Working Group 2 made some recommendations for initial changes to both Entry and Exit criteria together with aspects worthy of further development. The recommendations of WG2 were consolidated into the overall Fundamental Review (GSR008) report and consultation. As at the date of this report, GSR008 is currently with the Authority for approval.

With respect to WG2 recommendations for further work, the Exit criteria aspects were proposed as a joint review by the SQSS Review Group and the Distribution Code Review Panel, while the Entry criteria follow-on work was considered by this Working Group.

The Working Group therefore considered, as part of the review into Transmission Entry criteria, the onshore generation connection criteria set out in Section 2 of the NETS SQSS. The group reviewed the work previously considered and reported by Working Group 2 and identified appropriate change proposals with respect to section 2 as well as consequential changes to other sections of the document.

The structure of this report provides in Section 5 a background of the existing criteria, and follows in Section 6 with change proposals and discussion.

The final sections of the document provide proposed draft coding of the affected sections to facilitate both the scope and the spirit of the Working Group developments to be consolidated by the Drafting Group. These sections are indicative only and represent how the relevant sections may look. It is acknowledged that final drafting may significantly modify the content.

5 EXISTING GENERATION CONNECTION PRINCIPLES

5.1 Introduction

The basic structures and principles of the Security and Quality of Supply Standards (SQSS) were reflective of the legacy systems, where generation was predominantly derived from large dedicated installations producing bulk energy which was then transmitted across country to load centres.

The subsequent updating and harmonisation with the corresponding security standards of the Scottish TOs to create a GB SQSS on the run up to BETTA go-live in April 2005 retained the same basic principles. The GB SQSS was updated to accommodate the Offshore Transmission regime in June 2009 and renamed the NETS SQSS. More recently, in 2011, changes to Section 4 (MITS) of the NETS SQSS were proposed, and subsequently approved by Ofgem, to address the impact of increasing volumes of renewable / intermittent generation on the transmission system.

The current SQSS Section 2 criteria apply to the connection of any ‘power station’ to the onshore transmission system without making any distinction in terms of size or intermittency. Therefore, the SQSS requirements which require the connection to be able to withstand planned or unplanned outages with ‘no loss of power infeed’ drives the provision of similar connectivity and resilience for very large high load-factor generation sites (such as CCGT or nuclear installations), and much smaller directly connected generators with intermittent fuel sources (such as wind farms). This renewable generation could drive differing connection methodologies because it is both low load factor, and requires premium access to the system when available. The Commercial and Charging arrangements are cost reflective and so intrinsically linked to the connection security provided under the SQSS and any User choice variations. If a User chooses a lower level of connection than currently standard under the NETS SQSS this is already reflected under the commercial arrangements in lower charges and reduced compensation.

Given the increasing growth in renewable generation developments in a wide range of site capacities, the Licensees’ overarching obligations to develop an economic, efficient and coordinated system may be prejudiced by the provision of significant transmission infrastructure for intermittent or small generation developments.

5.2 Existing Criteria

Section 2 of the current version of the Standard (which is not materially impacted by the changes proposed under GSR008) establishes the Generation Connection philosophy and deterministic criteria (with additional cost benefit assessment) for application to the security of connections for ‘power stations’ under system intact, planned outage and post-fault conditions. Although the Standard represents the minimum requirements, it is permissible to design to higher security standards than those set out in Section 2 provided that the higher standard can be economically justified.

Applicable criteria ensure that the transmission system shall be planned such that:

- For the background condition of an intact system:
  - equipment loads shall not exceed the relevant pre-fault rating
  - system voltages and voltage margins are acceptable
  - the system shall be stable

- With a pre-existing intact system for a secured fault outage of
  - a single transmission circuit, generation unit or reactive power source
  - a double circuit supergrid fault
  - a double circuit overhead line fault (SHETL & NGET only)
    - there shall be no loss of supply capacity other than as specified in section 3
    - system loads shall not result in unacceptable overloading of transmission equipment
    - system voltages and margins shall be within acceptable ranges
    - the system shall be stable

- With a pre-existing outage of a single transmission circuit and for a secured fault outage of a single transmission circuit; a pre-existing outage of a generation unit or reactive power source for a secured fault outage of a single transmission circuit; or a fault outage of a section of busbar or mesh corner
    - there shall be no loss of supply capacity other than as specified in section 3
    - system loads shall not result in unacceptable overloading of transmission equipment
    - system voltages and margins shall be within acceptable ranges
    - the system shall be stable

5.3 Appropriate Access

As discussed in the introduction to this section, the current SQSS criteria applicable for the connection of a ‘power station’ to the onshore transmission system are not conditional on plant size or intermittency but purely on the capacity declaration made by the generator for access to the electricity market.

As a result, the recent rapid growth of renewable generation developments, with a wide variety of generation capacities, requires the connection to be able to withstand planned or unplanned outages with ‘no loss of power infeed’, unless the generator has opted for a customer variation to reduce the security of their connection. This results in the provision of similar connectivity and resilience of connection to all parties. Therefore, the default connection connectivity provided for smaller developments, and those with intermittent fuel sources, will be broadly similar to that for very large, high load factor generation sites such as CCGT or nuclear installations.

From a technical perspective, the previous Working Group 2 endeavoured to develop a methodology which facilitated appropriate levels of connection arrangements which are determined by the size and type of generation. The approach of this workstream has been to adopt a philosophy which is consistent with the underlying methodology applicable to demand group connections.

This Entry Working Group has adopted this background philosophy, and aims to further develop the methodology and robustness of the scenarios and generation access criteria.

5.4 Review of Background Conditions

In setting the background conditions for designing generation connections, Section 2 states that the output of a power station shall be set to its declared Connection Entry Capacity (CEC). This is the maximum amount of active power deliverable by a power station at the grid entry point as declared by the generator. The generator declares their CEC within their Standard Planning Data submissions forming part of their application for connection to the transmission system. This is separate from the rated MW of any generating unit or group of generating units, and does not relate to the transmission capacity that the Generator wishes to have for their power station, known as Transmission Entry Capacity, (TEC) nor the charging arrangements.

5.4.1 Basis of Capacity

Consideration within the preceding group discussion and report highlighted, at that time, some options for determining the most appropriate 'capacity' terminology when addressing access and equipment capability in the design of transmission entry connections. The options were perceived to be:

- The registered capacity or CEC of the development which is effectively the maximum site output net of station or site demand
- (TEC which allows the developer to take a view on the operating regime of their plant as well as considering any cost message for the establishment of the connection. TEC may change from being a constant value arising from applications by the developer
- Local Capacity Nomination (LCN) which was a term (developed as part of CUSC amendment proposals arising from the Transmission Access Review (TAR)) to describe the maximum access capacity that a generator will require in a given transmission-charging year.

Notwithstanding the fact that some of the capacity terms were not progressed under the TAR proposals, the Working Group concluded that, as Chapter 2 considers the Entry assets, tradable or other parameters subject to contractual adjustment are not appropriate for the sizing of Entry assets.

It was therefore concluded that Connection Entry Capacity (CEC - defined as "the figure specified as such for the Connection Site and each Generating Units as set out in Appendix C of the relevant Bilateral Connection Agreement") being the connection capacity required and requested by the User, is the most appropriate parameter. This may simply be the aggregate of the plant capacities of the development less station or site demand but some sites with intermittent energy sources may declare a CEC of lower than the aggregate of capacities to take account of intermittency, plant outage and efforts to improve the load factor. However it forms an absolute cap on the normal output of a power station and / or generating unit.

As the CEC will form the basis of the connection design, this parameter will require to be visible in planning application timescales and processes. For 'conventional' plant this is perceived to be the Registered Capacity. For renewable sourced developments such as wind farms the <u>declared</u> Registered Capacity remains valid. (The relevant part of the SQSS definition is: c) *In the case of a power station, the maximum amount of active power deliverable by the power station at the GEP (or in the case of a power station embedded in a user system, at the user system entry point), as declared by the generator, expressed in whole MW. The maximum active power deliverable is the maximum amount deliverable simultaneously by the generating units and/or CCGT Modules and/or offshore gas turbines and/or power park modules less the MW consumed by the generating units and/or CCGT Modules and/or offshore gas turbines and/or power park modules in producing that active power.*

Some sites with multiple generating units (e.g. a wind farms) may opt to establish equipment which aggregates to a higher value than the declared CEC; the objective being to take account of source fuel intermittency and unit unavailability. The operator will operate to constrain the actual output i.e. "*the maximum amount of active power deliverable by the power station at the GEP"* within the declared CEC value. The declared CEC is therefore used in this Report as the parameter for defining generation capacity, although it could be considered synonymous with Registered Capacity.

5.5 Definitions

A comparison of existing Definitions relevant to Entry Working Group considerations was carried out and are summarised in the following sections: (note that there are differing definitions of the same terms between sources, and these will be considered in Section 6.8)

5.5.1 Seven Year Statement

5.5.1.1 Transmission Circuit

Part of the National Electricity Transmission System between two or more circuit-breakers which includes, for example, transformers, reactors, cables and overhead lines but excludes Busbars and Generation Circuits.

5.5.1.2 Grid Entry Point (GEP)

A point at which a Generating Unit or a CCGT Module or a CCGT Unit, as the case may be, which is directly connected to the National Electricity Transmission System, connects to the National Electricity Transmission System.

5.5.2 NETS SQSS

5.5.2.1 Generation Circuit

The sole electrical connection between one or more onshore generating units and the Main Interconnected Transmission System i.e. a radial circuit which if removed would disconnect the onshore generating units.

5.5.2.2 Generation Point of Connection

For the purpose of defining the boundaries between the MITS and generation circuits, the generation point of connection is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, or other equivalent point as may be determined by the relevant transmission licensees for new types of substation

5.5.2.3 Grid Entry Point (GEP)

A point at which a generating unit or a CCGT module or an offshore power park module, as the case may be, which is directly connected to the National Electricity Transmission System, connects to the national electricity transmission system. The default point of connection is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, or equivalent point as may be determined by the relevant transmission licensees for new types of substation.

5.5.2.4 Transmission Circuit

This is either an onshore transmission circuit or an offshore transmission circuit.

5.5.2.5 Offshore Transmission Circuit

Part of an offshore transmission system between two or more circuit-breakers which includes, for example, transformers, reactors, cables, overhead lines and DC converters but excludes busbars and onshore transmission circuits.

5.5.2.6 Onshore Transmission Circuit

Part of the onshore transmission system between two or more circuit-breakers which includes, for example, transformers, reactors, cables and overhead lines but excludes busbars, generation circuits and offshore transmission circuits.

5.5.2.7 National Electricity Transmission System

The National Electricity Transmission System comprises the onshore transmission system and the offshore transmission systems.

5.5.2.8 Offshore Transmission System

A system consisting (wholly or mainly) of high voltage lines of 132kV or greater owned and/or operated by an offshore transmission licensee and used for the transmission of electricity to or from an offshore power station to or from an interface point, or user system interface point if embedded, or to or from another offshore power station and includes equipment, plant and apparatus and meters owned or operated by an offshore transmission licensee in connection with the transmission of electricity. An offshore transmission system extends from the interface point or user system interface point, as the case may be, to the offshore grid entry point/s and may include plant and apparatus located onshore and offshore. For the avoidance of doubt, the offshore transmission systems, together with the onshore transmission system, form the National Electricity Transmission System.

5.5.2.9 Onshore Transmission System

The system consisting (wholly or mainly) of high voltage electric lines owned or operated by onshore transmission licensees and used for the transmission of electricity from one power station to a substation or to another power station or between substations or to or from offshore transmission systems or to or from any external interconnections and includes any plant and apparatus and meters owned or operated by onshore transmission licensees within Great Britain in connection with the transmission of electricity. The onshore transmission system does not include any remote transmission assets. For the avoidance of doubt, the onshore transmission system, together with the offshore transmission systems form the National Electricity Transmission System.

5.5.2.10 Main Interconnected Transmission System (MITS)

This comprises all the 400kV and 275kV elements of the onshore transmission system and, in Scotland, the 132kV elements of the onshore transmission system operated in parallel with the supergrid, and any elements of an offshore transmission system operated in parallel with the supergrid, but excludes generation circuits, transformer connections to lower voltage systems, external interconnections between the onshore transmission system and external systems, and any offshore transmission systems radially connected to the onshore transmission system via single interface points.

5.5.2.11 Interface Point (IP)

A point at which an offshore transmission system, which is directly connected to an onshore transmission system, connects to the onshore transmission system. The Interface Point is located at the first onshore substation which the offshore transmission circuits reach onshore. The default point of connection, within the first onshore substation, is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, on either the lower voltage (LV) busbars or the higher voltage (HV) busbars as may be determined by the relevant transmission licensees. Normally, and unless otherwise agreed, if the offshore transmission owner owns the first onshore substation, the interface point would be on the HV busbars and, if the first onshore substation is owned by the onshore transmission owner, the interface point would be on the LV busbars.

5.5.3 CUSC

5.5.3.1 Transmission Interface Point

In the context of a Construction Agreement means the electrical point of connection between the Offshore Transmission System and an Onshore Transmission System as set out in the Offshore Works Assumptions.

5.5.3.2 Transmission Circuits

As defined in the NETS SQSS;

5.6 Previous 'Standard' Designs (TDM 13/6)

Transmission Design Memorandum TDM 13/6 was first issued in 1968 and summarised the recommendations of the Committee on Supergrid Switching Facilities. The document provided general (but high level functional) guidance for switching stations for a variety of circumstances across the transmission system.

TDM 13/6 also provided a useful collection of 'standard' substation layouts for generation connection sites and marshalling sites.

While this document may still provide a form of guidance, the current status of this legacy document is not known.

5.7 Customer Choice

When a customer requests connection to the transmission system, the default is for the connection design to be compliant with the NETS SQSS in terms of connection security. Under these circumstances, the User contribution to connection capital cost, subsequent TNUoS charges and access to the system will be in accordance with the Commercial Codes.

However, for a variety of reasons, the customer may opt for a less secure connection or one which will have some level of constraint associated with it. The reasons may be many and nested but some of the major reasons are:

- **Planning Consents & Land-owner Agreements or Easements** – the option to achieve a connection (say) via a single circuit rather than a double circuit will potentially reduce land-owner resistance and planning consent timelines
- **Underground cable options** – to mitigate against the uncertain timelines and outcomes associated with planning consents for overhead line, some developers may opt to fund the incremental costs of fully undergrounded circuits
- **Cost** – potentially arising from the decision to progress fully undergrounded options, the 'one-off' incremental costs incurred by the User would potentially promote the selection of lower security connection options.
- **Time –** constrained or lower connection security schemes may have shorter delivery timescales than substantive and compliant connection options, and therefore it may prove beneficial to Users to gain access to the system early with some level of constraint, rather than wait for associated works to provide full access.

Clearly any reduced level of security or system access resultant from the Customer Choice, will give rise to a lower level (or zero) of Constrained-Off compensatory payments when compared to connections with a higher security. The scenarios and equipment/circuit outages which would give rise to constrained output or disconnection from the system, without compensatory payments, would be catalogued as a Clause 10 annex to the Bilateral Connection Agreement (BCA).

The effect of 'Customer Choice' reduction in connection security for the developer could be some of the following (or a combination of some or all):

- **Possible reduction in capital contribution** - but specifically excluding the costs associated with any 'one-off' discretionary works at the request of the customer. However, due to the shallow charging mechanism, it is unlikely that this reduction is likely to be significant or material.
- **Lower TNUoS Charges** – this will reflect the reduction in the local assets (local TNUoS[1]). The rights to the wider network, beyond the MITS and the associated wider TNUoS charges are not affected (Customer choice cannot be applied on the wider system).
- **Lower Constrained-Off compensatory payments** – the BCA will specify local equipment and outages for which compensation will not be applicable - these are limited to those assets affected by the Customer choice.
- **Periods of constrained output** - for maintenance and constructional outage periods of the connection assets - these are limited to those assets affected by the Customer choice which may coincide with periods of high renewable resource energies.

[1] Introduced in 2009 under GB ECM11

6 PROPOSED METHODOLOGY

6.1 Philosophy

Subject to the review of the commercial implications of any proposals, the working group endeavoured to further develop the deterministic methodology proposed by the previous Working Group 2. The objective was to enable the establishment of appropriate levels of connection security based on the aggregate of generation capacity and an equivalent generation load factor. It was considered that a deterministic based approach supported by cost benefit analysis to determine transition points was prudent and appropriate.

The overall objective was to reduce the complexity of the current philosophy and provide a set of deterministic rules (supported by cost benefit analysis, as mentioned above) to ensure a consistent and appropriate application of the standard. In order to be consistent in approach and 'feel' with the demand criteria, the mechanism for presentation of the deterministic rules was agreed to be by means of a look-up table.

This reference, proposed to be included as a new Table 2.1 of the SQSS, will facilitate consideration of the impact on generator output of outages such as:

- Planned outage of a single transmission circuit
- Planned outage of a single section of busbar or mesh corner
- Fault of a single transmission circuit
- Fault of a single generator circuit
- Fault of a single section of busbar or mesh corner
- Fault of any two transmission OR generator circuits on the same double circuit overhead line
- Fault of a bus-section circuit breaker, bus-coupler circuit breaker or mesh corner circuit breaker
- Planned outage of any single transmission circuit, single section of busbar or mesh corner followed by a fault of any single transmission circuit, single section of busbar or mesh corner
- Planned outage of any single section of busbar or mesh corner followed by a fault of a bus-section circuit breaker, bus-coupler circuit breaker or mesh corner circuit breaker

It is considered that the 'look-up' table approach would provide a more consistent and transparent approach, and it is anticipated that the table and philosophy will be supported by 'typical' or 'suggested' connection schemes for the range of generation capacities under consideration. This is likely to be best supported by a significant expansion of the existing SQSS Appendix A (Recommended Substation Configuration and Switching Arrangements) with the intention to provide schematic layouts which are indicative of compliant generation connections.

6.2 Working Group Approach

In order to convert the existing complex rules to a set of transparent criteria which, while applied in a deterministic manner, would be based on cost benefit analysis techniques, the Working Group methodology broke the process down to the following components:

- **Aggregate Generation Capacity Bands** - the full potential range of generation capacities, while based on the work of the preceding working group, further considered the likely mix and plant capacities based on experience and knowledge of the industry.
- **Develop connection types** - these were originally anticipated to be a range of eight options but this was subsequently revised to nine by the inclusion of an additional option in the lower mid-range. While the matching of aggregate generation capacity to connection types was to be influenced and informed by the cost benefit analysis, a ‘first cut’ was developed as a skeleton to firstly form a starting point for incremental comparison by the CBA and secondly to ensure that the capacity bands could pragmatically be served by existing equipment types and ratings.
- **Assess resilience of connection types** - in order to determine and document the resilience of the connection types to the scenarios detailed in section 6.1, all scenarios were identified and the impact on the connection type identified. This facilitated an assessment of the level of generation which remains connected following a given outage or combination of outages.
- **Assess appropriateness of assumptions** - this was achieved by applying incremental cost benefit analysis between group sizes and intermittency values as detailed in section 6.5. The objective was to identify any crossover points and inform the capacity band values and intermittency level split points.
- **Finalise capacity bands** - following the CBA, bolt down the upper and lower band values for the aggregate generation capacities.
- **Finalise intermittency bands** - similarly, conclude the most appropriate crossover values for intermittency
- **Finalise table 2.1** - final completion of the form, content and structure of table 2.1 is achieved from the results of the preceding sections.

These components are described more fully in the following sections.

6.3 Clarification of Definitions

As previously mentioned, when analysis was initiated on outline connection designs which would form the basis of the criteria and cost benefit analysis, the existing suite of definitions did not provide sufficient clarity to enable clear and transparent application of the revised methodology. Comparison to other codes proved unhelpful.

While the Standard acknowledges an overlap between criteria, the group particularly identified a lack of clarity in the differentiation of generation and transmission circuits and where the connection asset ends and the MITS begins.

In order to resolve some of the clarity issues, it is proposed to modify the NETS SQSS definitions for Generation Circuit and MITS as indicated in the following sections. It is considered that there will be no unintended consequential impact on this or other Codes arising from the change to the definitions but it is anticipated that assessments during the consultation process would highlight any issues.

It is perhaps worthy of comment that, the Working Group discussed the asset ownership boundary as a means if identification and distinction of generator circuits (i.e. the Generator owns, operates and maintains a Generation Circuit) but considered the potential for legacy connections where this distinction is not valid. It is anticipated that, going forward, this differentiation would be appropriate and that, by definition, all Generation Circuits would be owned, operated and maintained by the Generator. This view aligns with and supports the conclusions with respect of generation circuit length as described in section 6.7.

6.3.1 Generation Circuit

It is proposed that the revised definition of Generation Circuit will be:

The sole electrical connection between one or more onshore generating units and the National Electricity Transmission System (NETS), i.e. a radial circuit which if removed would disconnect the onshore generating units. This specifically excludes radial transmission circuits which are used to connect one or more generators to the transmission system which, if removed, would have a similar effect.

6.3.2 Main Interconnected Transmission System (MITS)

Proposed revisions to the definition for the MITS are as follows (text additions indicated in red):

This comprises all the 400kV and 275kV elements of the onshore transmission system and, in Scotland, the 132kV elements of the onshore transmission system operated in parallel with the supergrid, and any elements of an offshore transmission system operated in parallel with the supergrid, but excludes generation circuits, transformer and transformer feeder connections to lower voltage systems, radial circuits which do not necessarily terminate on transformer connections to lower voltage systems (irrespective of system entry or exit purposes), external interconnections between the onshore transmission system and external systems, and any offshore transmission systems radially connected to the onshore transmission system via single interface points.

6.4 Development of Connection Designs

Following clarification of the differences between generation and transmission circuits and the boundary with the MITS, nine methods for the connection of generation developments were identified which were then classified in a manner comparable with demand group categories and assigned identification reference numbers between 1 and 9. In order to ensure that these scenarios remain valid when considering the range of connection voltages and equipment types, verification of the scenarios was carried against current plant and equipment types and ratings.

Representative indications of the connection types are shown diagrammatically in the following figures. Other connection variations which provide the same functionality and resilience are possible. Although these have not been assessed here, they are not specifically excluded.

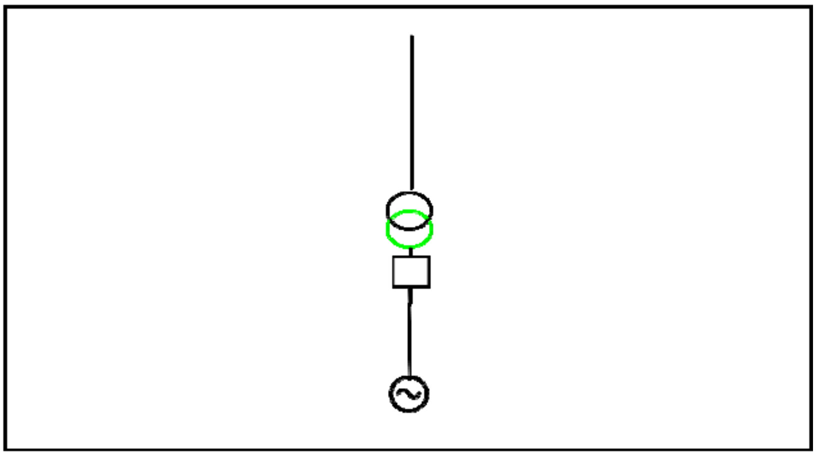


Figure 1: Method 1 - Single Circuit Radial, Sub-Transmission. Connection Voltage

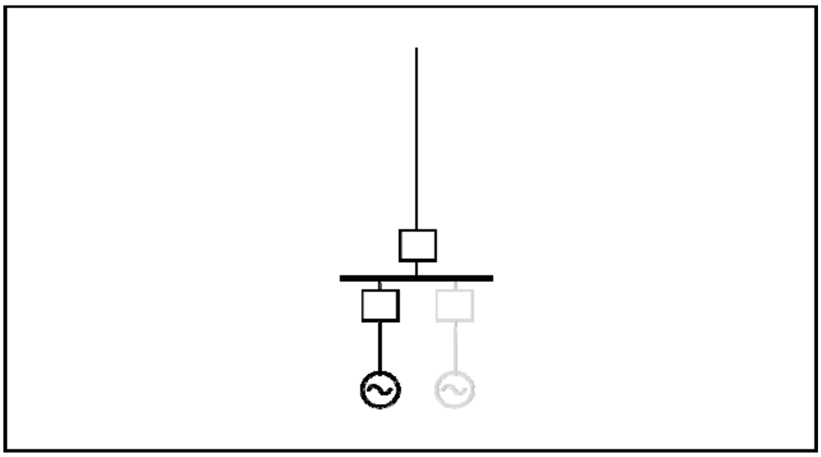


Figure 2: Method 2 - Single Circuit Radial, Transmission Connection Voltage

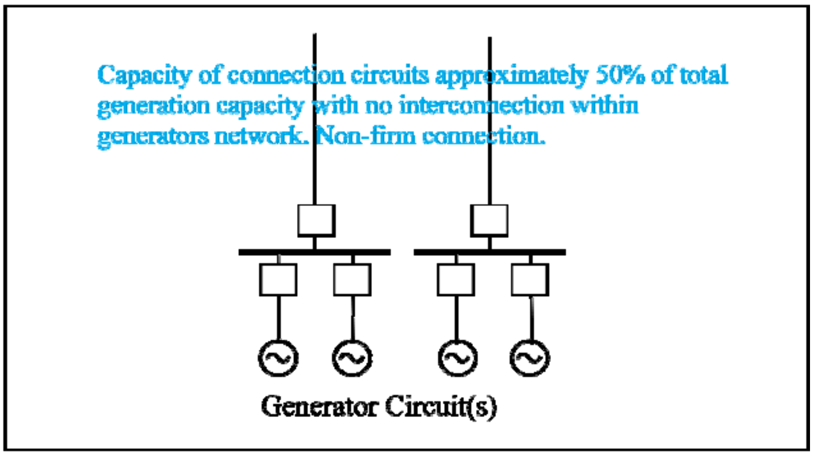


Figure 3: Method 3 – Non-firm, two single circuits, no interconnection

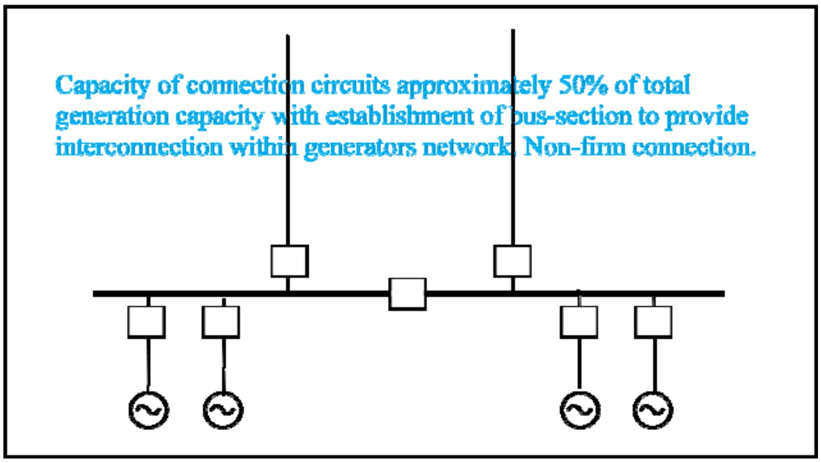


Figure 4: Method 4 - Non-firm, two circuits of reduced capacity

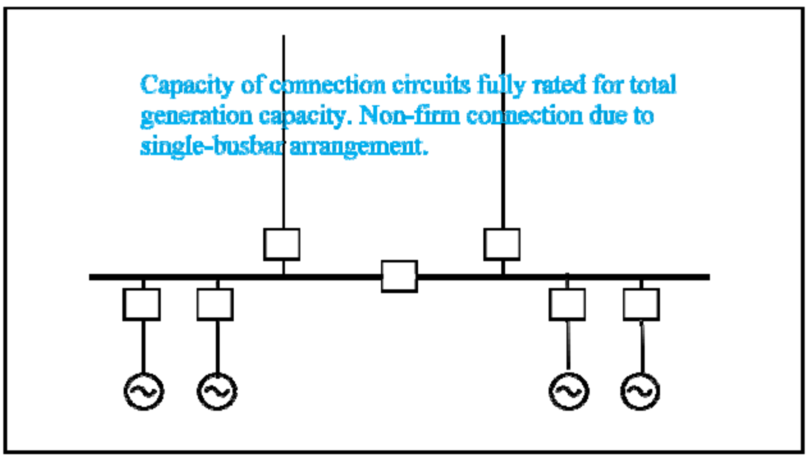


Figure 5: Method 5, Non-firm, two fully rated circuits

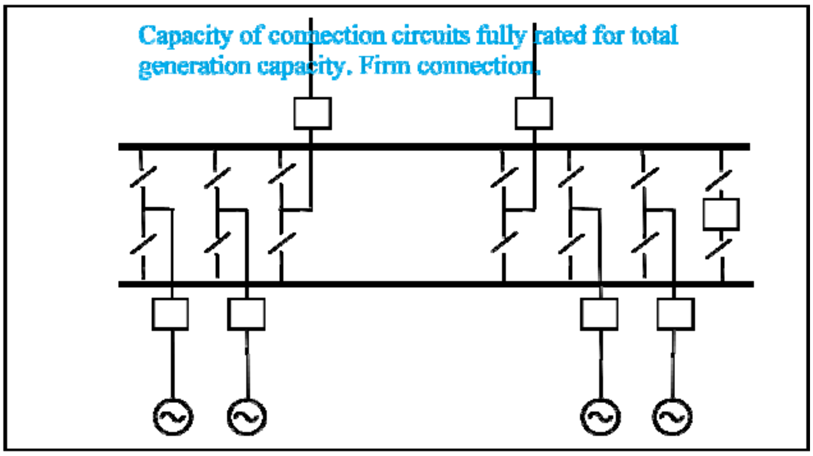


Figure 6: Method 6 - Firm connection, 2 circuits, two section double busbar

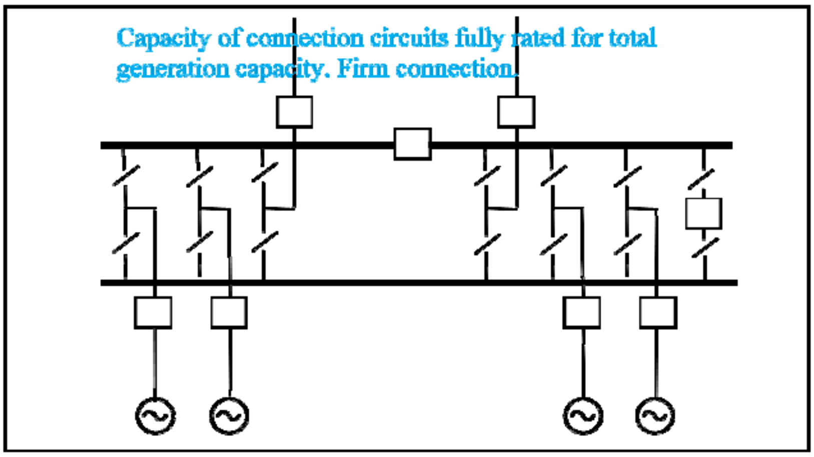
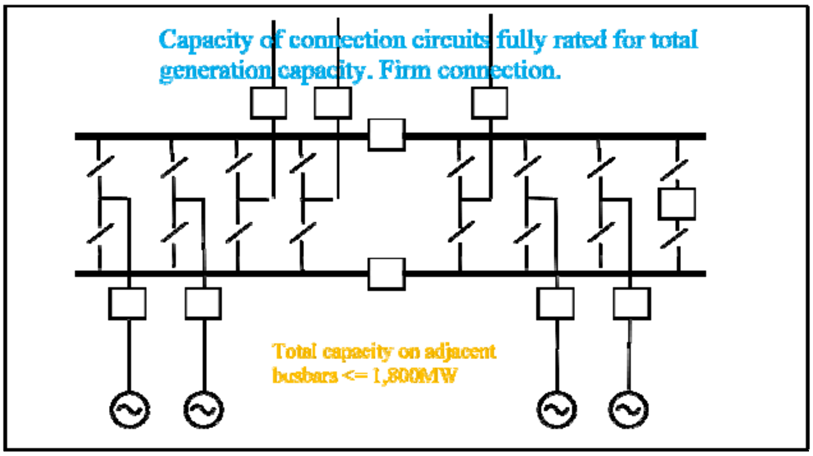


Figure 7: Method 7 - Firm connection, 2 circuits, three section double busbar



Other alternative configurations are possible such as an additional bus-coupler on the left hand side with the replacement of the bus-section circuit breaker on the reserve busbar by disconnectors. This provides similar functionality but improved operational flexibility.

Figure 8: Method 8 - Firm connection, 3 circuits, four section double busbar

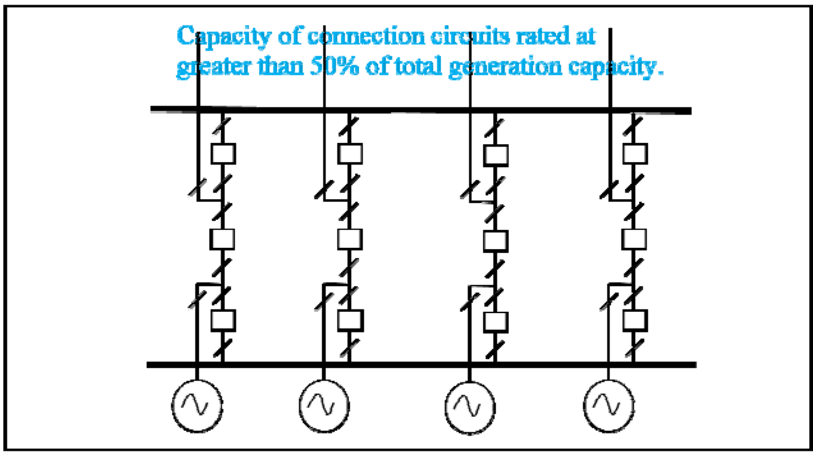


Figure 9: Method 9 – Firm connection, 4 circuits, 1½ switch layout

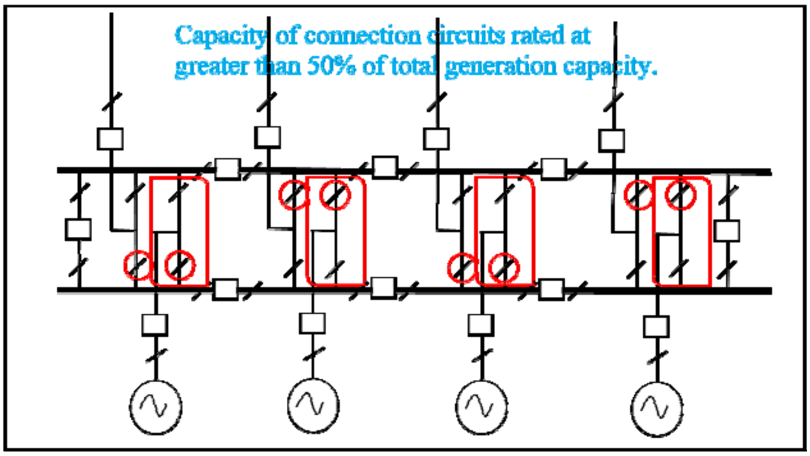


Figure 10: Alternative Method 9 - Firm Connection, 4 circuits, mult-mesh arrangement

As previously stated, other connection options are available which provide the same functionality. These arrangements, provided they comply with the required resilience to the appropriate scenarios, are permissible.

6.5 Cost Benefit Analysis

The background philosophy of the Entry/Exit Working Group (WG2) was to endeavour to develop a deterministic methodology which would enable the establishment of appropriate levels of connection security, based on the aggregate of generation capacity connected and generation load factor.

It was concluded that the deterministic rules would be supported by cost benefit analysis and would ensure consistent and appropriate application of the guidance and it was considered that presentation of the rules would be by means of a reference table similar to (but by definition more complex than) the corresponding reference table for demand groups.

WG2 identified eight scenarios for the connection of generation developments which were then classified in a manner comparable with demand group categories and assigned identification letters A to H. The connection scenarios reflected available equipment types, voltages and ratings which enabled the generation groups to be assigned with bands of generation capacity which could be associated with the generation group classification.

The generation group classifications were further broken down to three levels of load factor. In reflection of the relative contribution by a high capacity/low load factor development and a lower capacity/higher load factor site, high-level assessments indicated that high load factor sites should be advanced to the higher classification.

The initial proposals for the recommended Connection Methods by generation capacity and load factor, as inherited from the previous Working Group 2, are shown in Figure 11 following.

Increasing Generation Capacity ↑		Increasing Load Factor → <40% Wind	40-70% eg. Biomass / CHP	>70% eg. CCGT
	H >= 3,600MW	9	9	9
	G 1800 - 3,600MW ***	8	8	8
	F 1,320 - 1,800MW **	7	7	8
	E 700 - 1,320MW *	6	6	7
	D 300 - 700MW	5 ↑Q3b	5 →Q2b	6
	C 100 - 300MW	(3) → 4 ↑Q3a	(3) → 4 →Q2a	5
	B 50 - 100MW	2 ↑Q1a	2 ↑Q1b	2
	A 0 - 50MW	1	1	1

* normal infeed loss
** infrequent infeed loss risk
*** double infrequent infeed loss risk

Figure 11: Proposed Connection by Generation Capacity and Load Factor

Note: Working group 2 did not identify our connection method 4. Hence the original WG2 proposals identified connection method 3 for the cells C 100-300MW and 0-40% and 40-70% load factor. Now that we have identified connection method 4, we have retrospectively changed the WG2 proposal from connection method 3 to method 4 for these two cells.

The Working Group then performed a number of Cost Benefit analyses, which were articulated in the form of Questions. For example, question 1a marked on Figure 2 is: "is 100MW the correct generation size, for a generic windfarm of <40% load factor, at which to transition from connection method 2 to connection method 4?".

These cost benefit analyses had to use a number of generic data assumptions. These are detailed in the full cost benefit report (Appendix C), but the more important assumptions include:

- Indicative costs of typical 132kV transmission assets, as provided by Scottish TOs;
- A generic overhead line route length of 50km for connection circuit(s);
- Transmission outage rates of 2 weeks per circuit per summer of planned (maintenance) outage, and a further ½ week per circuit per year of unplanned (fault) outage;
- For assessments of constraints on Wind generation, generic onshore wind output distributions are used, of load factor 22% summer and 37% winter, thus 28% annual;
- A constraint price of 60 £/MWh for any restriction to conventional (ie all non-Wind) generation; and a constraint price of 140 £/MWh for any restriction to Wind generation (in fact any Renewable generation in receipt of ROC subsidies);
- Note that the cost-benefit is on total costs incurred –ie it is from the point of view of UK plc; no consideration is given to individual entities' cash-flows, for example who pays and receives individual parts of the costs and benefits.

The recommendations from these cost benefit analyses are shown in Figure 12.

		Increasing Load Factor →		
		<40% Wind	40-70% eg. Biomass / CHP	>70% eg. CCGT
Increasing Generation Capacity ↑	F - H 1,320MW - 3,600MW ***	7 / 8 / 9	7 / 8 / 9	7 / 8 / 9
	E 700MW - 1,320MW *	6 *[section 13.2]*	6	7
	D 300 - 700MW	5 *[section 12.2]*	6 (from 5) *[section 11.3]*	6
	C 100 - 300MW	4 *[section 12.1]*	5 (from 4)	5
	B 50 - 100MW	4 (from 2) *[section 8.1]*	2	2 (from 4)
	A 0 - 50MW	1 / 2	1 / 2	1 / 2

* normal infeed loss
*** double infrequent infeed loss risk

new recommendation

Figure 12: Revised Proposed Connection Matrix

The broad proposals from WG2 are supported by the CBA, namely that one progresses from connection methods 1/2 at 0-100MW up to connection methods 6/7 above 700MW. However, in the central area of 50-700MW, where these CBA methods are most insightful, there are a few changes recommended:

1. For gen capacity class B of 50-100MW, we draw the paradoxical conclusion that a windfarm of <40% load factor justifies connection method 4, namely a second circuit (but only of half rating); whereas a CCGT of load factor 50-90% only justifies connection method 2. This is because of both the greater constraint price incurred in constraining off a windfarm, and because the output profile of a generic onshore windfarm means that a 50%-rated circuit enables almost all the potential wind generation to be exported during the second circuit outage.

2. For gen capacity classes C and D of 100-700MW, the CBA does not support a break-point at 70% load factor. This is because the generic assumptions within the CBA methodology are too broad, to support a different recommendation between (say) 60% and 80% load factor – this is only a 33% difference in input data. However, it should be noted that if one was assessing a particular case, of known generation size and route length and proposed transmission technology, then a more specific recommendation could be reached.

This revised Connection Matrix is applied for the rest of this report, and forms the central recommendation of this Working Group. .Of course, cases outside the assumptions of this generic CBA are not covered, for example a CCGT of 25% planned load factor. Such cases will have to be considered on a case-by-case basis.

The full Cost Benefit Analysis report is provided as Appendix C.

6.6 Calculation of Group Capacity and Load Factor

In order to apply the connection methodology criteria, in planning timescales, two connection parameters are required: Group Generation Capacity and Group Generation Load Factor. The anticipated derivation of these parameters for a variety of scenarios is considered in the following sections

6.6.1 Calculation of Group Generation Capacity

Where a single site is connected, the Group Capacity to be accommodated is readily identifiable from applicant data and effectively is the declared entry capacity (CEC).

For scenarios where there is more than one generator associated with the connection, the Group Generation Capacity is effectively the aggregate of all generation capacities associated with the connection assets.

6.6.2 Calculation of Group Generation Load Factor

Similarly, where a single site is connected, the Group Generation Load Factor to be applied is also readily identifiable from applicant data. This value can also be applicable to a group of generator developments of identical technologies or load factors.

However, where, in planning timescales, the generator load factor for application in table 2.1 is unknown or remains undefined, a generic load factor for the source energy from the following table can be utilised:

Source Energy	Generic Load Factor
Biomass	0.85
CCGT	0.75
CHP (Continuous Process)	0.75
CHP (Landfill)	0.80
Coal / Clean Coal	0.75
Hydro	0.40
Nuclear	0.75
Tidal	0.45
Wave	0.25
Wind	0.30

As detailed above, for scenarios where there is more than one generator of identical technology (and hence load factor) contributing to the Group Aggregate Generation Capacity associated with the connection, then the applicable Group Generation Load Factor will be the load factor common to the sites.

However, where there are multiple generators of differing technologies or load factors, an assessment of the equivalent load factor requires to be derived. Derivation of the equivalent load factor (LF_E) while taking due cognisance of differing site capacities (CEC_N) and load factors (LF_N) contribution to the aggregate values is achieved by application of the following methodology and formula:

$$LF_E = \sum_1^N \left(\frac{(CEC)_N}{\sum_1^N (CEC)} \times (LF)_N \right)$$

6.7 Location of Grid Entry Point

The issue relating to the length of any overhead route connection of generating Units to the onshore transmission system is referenced in the section of the Current Issue of the NETS SQSS version 2.1 (March 2011) and titled “Limits to Loss of Power Infeed Risks”.

Paragraph 2.7 in the SQSS states:

2.7 The maximum length of overhead line connections in a generation circuit for generating units which are directly connected to the onshore transmission system shall not exceed:

- 2.7.1 5km for generating units of expected annual energy output greater than or equal to 2000 GWh; otherwise
- 2.7.2 20km.

The motivation for this clause is considered to be two fold:
(a) to ensure that the grid entry point is, as far as reasonably practicable, close to the generator to limit the exposure of the lesser reliability a single overhead route, and
(b) to maintain the responsibility of the Transmission System Owner to consent and build a transmission infrastructure to connect a prospective generator who, for whatever reason, would like to construct a large power station in an area where there is not an existing transmission system.

This second requirement is thought to be valid since the TO can be expected to produce a more cost effective design than any other party which integrates the Generator connection within the existing Grid and possible DNO systems. Furthermore, this option facilitates subsequent connections by other Users to the public Transmission System rather than necessitate negotiation for access to a private system of generation circuits.

Since the origin of these clauses relates more to the underlying coverage of transmission than reliability, the Working Group recommends that these clauses and parameters remain unchanged.

6.8 System Resilience

In order to respond to the impact of losing generation plant from the system, the GBSO carries two blocks of reserve:

- Frequency Response – generation which is immediately available in order to support system frequency in the event of loss of the largest credible generating unit (deemed as the Infrequent Infeed Loss Limit). The current Infrequent Infeed Loss Limit is 1,800MW and the GBSO will consider, in operational timescales, the loss risks and retain adequate generation to maintain the system frequency within statutory limits.
- Generation Reserve – a tranche of generation which can be made available within 4 hours to replace a number of generators which have become unavailable due to unrelated or system events. The level of Reserve is determined by the GBSO in reflection of prevailing system conditions and portfolio of contributory generation.

  The Reserve level of plant able to respond within 4 hours is currently of the order of 4,000MW. It is anticipated that this level of Reserve will migrate upwards as account is taken of the greater penetration of wind generation with an estimate of 8,000MW Reserve required by 2020, against a background of a system with 20GW of wind connected.

In the event that, through adoption of these proposals or by other means such as customer choice, there is a significant move towards connecting individual or groups of generation on single transmission circuits, then in aggregate terms across the system, there could be an excessive volume of generation exposed to single circuit or double circuit overhead line risk. There is a perception that, if the condition perpetuates, there is the possibility that a single weather related event such as high wind, snow or lightning storms could result in the loss of an aggregate generation capacity exceeding the infrequent infeed loss risk. Depending on the event, this could be a near simultaneous loss of generation or at least within the Reserve timescale of 0-4 hours which would result in the GBSO having insufficient Reserve plant to maintain the generation/demand balance with consequential impact on system frequency and demand block security.

The background assumption to this scenario is that, if the generation is secured on multiple circuits and the weather event causes widespread circuit outages, at least some of the circuits will remain energised or returned to service within DAR timescales and therefore some generation capacity will ride-through the event.

Storm events can result in the rate of faults of transmission circuits being increased over the annual average fault rate. Historical fault statistical data indicates that the rate of transmission faults during a storm event can exceed 1,000 times the annual average.

The Group considered event types such as high wind, lightning, snow etc which would give rise to disruption of the connections to generators. In addition, the weather can have a direct impact on the electrical output of some generators, for example, wind turbines have a maximum operating windspeed of around 25m/s (56mph) beyond which the turbine mechanism is protected from mechanical damage and electrical output ceases. Consideration was therefore given to the holistic consequences of weather related events – i.e. generation cessation either from source fuel issues or transmission system depletion.

It is also considered unlikely that, given topography and connectivity, it is unlikely that any ‘storm’ would have an impact on the wider network which would be equivalent to an instantaneous loss of a single 1,800MW set i.e. there would be sequential tripping of sites which would move the support requirement into the 0-4hour range for Reserve as opposed to the instantaneous Frequency Response requirements.

The conclusions of the discussions were that the proposals should not contribute to an increase in the GBSO Reserve requirement but a means of assessing the incremental risk should be identified. Weather-related events, such as gales, snow or lightning storms, were considered unlikely to be GB-wide and therefore unlikely that the entire GB system would simultaneously be exposed to the same event. This therefore indicated that the assessment of risk requires to be on a smaller zone basis, i.e. the aggregate generation capacity within a ‘zone’ exposed to single or double circuit (comprising overhead lines) risk shall not exceed the anticipated Reserve capacity.

The high level risk and likelihood assessment considered the population of generation connections (in particular wind generation) and the Working Group concluded that the exposure to generation drop-off arising from weather-related events is fundamentally geographically based. Given that the proposals should not increase the requirements for Reserve and the anticipated level of Reserve by 2020 is expected to be of the order of 8,000MW, the question of geographic area which would give rise to this level of risk was considered. Again, considering the current and projected portfolio and geographic disposition of wind generation, it is therefore proposed that the zone size should be set at 200km in diameter at this time. This therefore requires that, for any 200km zone throughout the GB system, there shall be no more than 8,000MW of total generation capacity exposed to single or double circuit overhead lines risk.

This aspect of the standard should be subject to periodic review to ensure that the risk and probabilities are balanced and that the system reserve capacity applicable at that time remains adequate to secure the system balancing and frequency.

6.9 System Reliability

The Working Group does not envisage material impact on the reliability of the overall system or the systems connecting individual generators from adoption of these proposals. The issue for the main aspects of the proposals is briefly addressed in the following sections:

6.9.1 System Connections for Generation

There is a subtle distinction between reliability and security although there are interactions between the two:

- Security considers the connectivity which remains (and consequently blocks of demand or generation which continues to be energised) following credible combinations of planned and unplanned outages.
- Reliability considers the statistical probability of a point on the network (connected by a circuit or circuit combination) losing connection and hence the disconnection of demand or generation.

Clearly the reliability of a circuit is a function of the equipment and components of the circuit and in general terms and intuitively, the more equipment employed, the less reliable the circuit is likely to be, e.g. a circuit comprising of 40km will be exposed to higher outage rates than one of 20km. Therefore the reliability of individual circuits is a function of location and source and therefore the proposals for modification of system connection do not materially impact the reliability of those individual circuits as effectively the circuits will be broadly similar.

Equally clearly, the reliability of a connection point on the system, as it is a function of alternative circuits, may be reduced when considering reduced numbers of circuits to a development.

6.9.2 System Resilience

As previously discussed in section 6.8, the condition has been considered from an overall system perspective with any impact on reliability addressed.

6.9.3 Location of Grid Entry Points

The proposals maintain the current parameters for location of grid entry points and therefore there is no incremental impact.

6.9.4 Definitions

It is not considered that the proposals to carry out minor modifications to the SQSS definitions will materially affect the reliability of either the overall system or generator connections.

6.10 Proposed Drafting Changes

The conclusions and recommendations of the workstream, have been translated into indicative code changes for the following sections:
Section 1 – Introduction
Section 2 – Generation Connection Criteria Applicable to the Onshore Transmission System
Section 11 – Terms and Definitions
Appendix A – Recommended Substation Configuration and Switching Arrangements

The detailed recommended code changes are provided in full in the following Appendices of this Report:

Appendix D NETS SQSS Section 1 (Introduction)
Appendix E NETS SQSS Section 2 (Entry)
Appendix F NETS SQSS Section 11 (Definitions)
Appendix G NETS SQSS Appendix A (Recommended Substation Configuration)

6.11 Assessment Against SQSS Principles

The proposals have been assessed to consider their contribution towards the SQSS Principles. Given the changes proposed under the GSR008 (SQSS Governance Review), the proposals have also been assessed against the SQSS Objectives as proposed under the Governance submission. Assessment against the existing principles has been considered as an overall consideration of the proposals while assessment against the revised Objectives has been reviewed at component level.

6.11.1 Overall Assessment Against Current SQSS Principles

The recommendations of this report would support the following NETS GBSQSS principles:

- *The development, maintenance and operation of an efficient, economical and coordinated system of electrical transmission*

The Working Group acknowledges that, by various means, the current SQSS and associated arrangements generally end up with the majority of new Generators connecting by efficient connection methodologies, as explored in the Report. Hence the recommendations of this Report are not expected to significantly alter the final connection designs of much new generation but provide a more pragmatic starting point. Accordingly, this Report further progresses the objective: the development, maintenance and operation of the electricity transmission system will be more efficient, economical and coordinated than at present.

- *Ensure an appropriate level of security and quality of supply and safe operation of the GB Transmission System*

The recommendations of this Report reflect considerations of generator connections, which are more to do with economy than security. Hence this report is neutral with regard to this SQSS principle.

- *Facilitating effective competition in the generation and supply of electricity*

By clarifying the options for connection, particularly of small to medium volumes of generation in the 50-700MW classes, and by simplifying the SQSS process to effect such connections, the recommendations of this Report will make it easier for such generation to connect, and hence will facilitate competition in the generation of electricity.

6.11.2 Assessment Against GSR008 SQSS Objectives

The SQSS Objectives as proposed under GSR008 are:

The Review Panel shall endeavour at all times to perform its functions to ensure efficient discharge by each of the Transmission Licensees of the obligations imposed upon it under the Electricity Act and its associated licences, specifically focusing on the following objectives:

(i) facilitate the planning, development and maintenance of an efficient. Coordinated and economical system of electricity transmission, and the operation of that system in an efficient, economic and coordinated manner;

(ii) ensure an appropriate level of security and quality of supply and safe operation of the National Electricity Transmission System;

(iii) facilitate effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the distribution of electricity; and

(iv) facilitate electricity transmission licensees to comply with their obligations under EU law.

The following sections therefore consider each proposal and assess their contribution towards the SQSS Objectives:

6.11.2.1 System Connections for Generation

- *Facilitate the planning, development and maintenance of an efficient. Coordinated and economical system of electricity transmission, and the operation of that system in an efficient, economic and coordinated manner;*

  As stated earlier, the Working Group acknowledges that, by various means, the current SQSS and associated arrangements generally end up with the majority of new Generators connecting by efficient connection methodologies, as explored in the Report. Hence the recommendations of this Report are not expected to significantly alter the final connection designs of much new generation but provide a more pragmatic starting point. Accordingly, this Report further progresses the objective: the development, maintenance and operation of the electricity transmission system will be certainly more efficient, economical and coordinated than at present.

- *Ensure an appropriate level of security and quality of supply and safe operation of the National Electricity Transmission System;*

  Clearly, the proposals will provide guidance on the level of security which is appropriate to the development and therefore supports the SQSS Objectives.

- *Facilitate effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the distribution of electricity;*

  As previously stated, by clarifying the options for connection, particularly of small to medium volumes of generation in the 50-700MW classes, and by simplifying the SQSS process to effect such connections, the recommendations of this Report will make it easier for such generation to connect, and hence will facilitate competition in the generation of electricity.

6.11.2.2 System Resilience

- *Ensure an appropriate level of security and quality of supply and safe operation of the National Electricity Transmission System;*

  The proposals will support and interact with the existing arrangements for system Reserve.

6.11.2.3 Location of Grid Entry Points

- *Facilitate the planning, development and maintenance of an efficient. Coordinated and economical system of electricity transmission, and the operation of that system in an efficient, economic and coordinated manner;*

  While the existing parameters have been reassessed, the recommendations propose continuation and therefore this Report is broadly neutral with regard to this SQSS objective:

6.11.2.4 Definitions

- *Facilitate the planning, development and maintenance of an efficient. Coordinated and economical system of electricity transmission, and the operation of that system in an efficient, economic and coordinated manner;*

  By clarifying the definitions as proposed, it is considered that the recommendations of this Report will improve clarity and understanding for users of the Standard and facilitate consistent interpretation and application.

6.12 Impact on Other Codes

6.12.1 Commercial Codes

In capital terms, the cost of generation connection assets are funded in accordance with the Connection Charging Methodology. Due to the shallow-charging nature of the methodology, the generator only directly funds the sole use assets and any one-off costs (for incremental discretionary costs) with the infrastructure or shareable asset costs being funded by the transmission licensee. In general, the 'infrastructure' assets and consequential costs form the major proportion of the connection works and the transmission licensee is permitted to recover these costs through Price Control provisions. The NETSO recovers all transmission licensee costs from Users through TNUoS charges, these include a generic signals to ensure Users make efficient choices in the best interests of end consumers.

TNUoS charges are split into two components:

- Wider TNUoS associated with the system infrastructure This covers all the transmission assets including and beyond the nearest MITS substation.
- Local TNUoS charges associated with the connection substation and circuits to the nearest MITS substation.

Those assets generally covered by NETS SQSS section 2 and currently possibly User Choice are covered by Local TNUoS.

Currently when a connection is provided with some form of redundancy (e.g. a double circuit), the CUSC provides for compensation, in the particular event of certain unplanned outages or combinations of planned and unplanned outages. The local TNUoS charges will reflect this level of redundancy.

A developer may accept a less secure connection, through Customer choice, or a transmission licensee may impose a lower level of connection (subject to derogation, but consistent with its wider duties to be efficient). In these cases the User pay lower local TNUoS, but will also have reduced access under defined planned or unplanned outages directly associated with this lower level of connection. This will not affect wider TNUoS charges or compensation associated with the MITS and beyond.

Therefore, with respect to the CUSC, at present, there are effectively two classes of Generation Connectee (although it should be noted that these 'classes' are not defined in the CUSC):

- Class 1: this is fully compliant with existing NETS SQSS and consequently no generic restriction clauses in their Bilateral Connection Agreement (BCA).
- Class 2: Users sign up for a 'Customer Variation' clause and opt for fewer assets than full SQSS compliance and in return pay lower local TNUoS charges. In return, the Users' agreement will include a 'Clause 10', which may oblige them to constrain or cease generation, such as:
  - declare zero output under certain nominated transmission outage events; or
  - have some generation output management system in place; or
  - install and arm an intertrip scheme

This latter class also covers those instances where the only connection offered to connectees were single circuit connections.

The core of the SQSS Entry Group proposal is to vary the SQSS connection options in proportion with the aggregate CEC with the objective of facilitating compliance with SQSS objectives from technical, economic and coordination perspectives.

While the rationale is to initially consult solely from an SQSS perspective and not to pre-empt or influence the commercial arrangements under the CUSC, the CUSC could potentially be clarified and aligned with the SQSS. This would not change the existing principles of compensation for loss of access set out in the CUSC: A suggested approach could be

Reflect changes in the CUSC

For the developments towards the smaller end of the scale, these would be connected by 'non-firm' connections comprising of single switch, half-rated circuits or single circuits. This shift could be more transparently reflected in the CUSC, possibly as:

- **Class 1** - as an existing category, Class 1 is fully compliant, and consequently does not have generic Clause 10s in their BCA.
- **Class 2**: will still be described as 'compliant', but has a 'non-firm' standard of connection. The direct implications of the non-firm arrangement would be included as generic Clause 10s in their BCA.
- **Class 3**: as existing. The 'Customer Variation' option will be retained in order to provide user choice to cover the eventuality where Users may wish to vary (either up or down) the connection security or market access from the deterministic option variation will be reflected in Clause 10s in the BCA and the charging arrangements.

The Use of System Charging methodology in the CUSC already covers these scenarios as it is asset based and not related to SQSS compliance.

The conclusions and recommendation of the Entry Working Group is that, in common with the philosophy for demand connections, the Standard should indicate compliant connection methodologies appropriate for the generation capacity and that these changes could potentially require to be reflected in CUSC modifications.

6.12.2 Changes to the Grid Code

It is not considered that there will be any consequential changes to the Grid Code as a result of these proposals.

6.13 Impact on Planning, Operation and Generators

The following impacts of this SQSS change are identified:

6.13.1 Connection Process

The process under which new generation applicants are planned for and made Connection Offers will be somewhat simplified. The aspiration is that the majority of 50-700MW applicants will fall clearly into one of the given connection methodologies, and such a connection can be planned and accepted readily.

Note that the Working Group is not expecting that the end Connection of such generators will be often different than under the current process. But the current process is more tortuous, in that the planner and applicant both start out at a firm connection methodology (e.g. connection method 6), and then work back to a more appropriate methodology and work through a 'Customer Choice' process from afresh in each such case.

6.13.2 Impact on Planning

This SQSS change is not often expected to lead to changes in the end connection design of any potential generators.

6.13.3 Impact on Operation

The presence of a large number of 'Customer Choice' connections is already a significant overhead for the industry. Whereas all compliantly connected generation can be treated commonly in operational timescales (namely any restriction is accomplished by the default instrument of a Bid/Offer acceptance), the 'Customer Choice' connections have to be individually considered for each transmission outage configuration:

This complexity remains following this SQSS change, since the same 'Clause 10s' in BCAs are expected to result from the same connection methodologies. Hence this SQSS change has little material impact on the System Operator.

6.13.4 Impact on Generators

Applicants for new Connection Offers are expected to see a somewhat simplified process. The SQSS will indicate or even define an appropriate connection methodology, and the commercial consequences are already largely included in the CUSC. Bring clause 10s out of BCAs into the CUSC a standard clauses may improve transparency, but will be complex to codify and so lose simplicity Hence, for the majority of cases where the recommended connection methodology is acceptable, the generic implications of the connection should be transparent at the outset and therefore bespoke individual 'Customer Variation' clauses in the Connection Offer may be reduced or require lesser contractual assessment.

We have noted elsewhere in this report, that care needs to be taken in the drafting the SQSS, that no unintended consequences fall on existing Generators.

6.14 ENDORSEMENT BY GB SQSS PARTIES

The Terms of Reference and Working Group proposals are focused on the onshore transmission system and this section sets out the analysis and impact assessment (“Assessment”) provided by NETS SQSS Parties.

Parties who have provided endorsement of the proposals are:
National Grid Electricity Transmission in its roles as Transmission Owner (TO) for England and Wales and GB System Operator (GBSO)
Scottish Hydro-Electric Transmission Limited in its role as Transmission Owner (TO) for northern Scotland, and
SP Transmission Limited in its role as Transmission Owner (TO) for southern Scotland.

6.14.1 National Grid Electricity Transmission (NGET) Assessment

NGET, in both of its roles, believes that the proposed NETS SQSS change proposals will better facilitate the NETS SQSS Principles, laid out in Section 6.11 of this report.

NGET, as GBSO, operates the GB transmission system and therefore has the responsibility to assess frequency response and Reserve. Work has recently been carried out to consider the economic and practical impact of revised loss of infeed limits.

National Grid believes that the extra required response can be procured at economic cost, such that there is no impact on the quality of system frequency. The consequent changes to the planning of transmission will lead to modest capital savings in certain cases, at no degradation to standards of service.

6.14.2 Scottish Hydro-Electric Transmission Limited (SHETL) Assessment

The SHETL system, as with the transmission systems of all GB Transmission Owners, is planned such that the requirements of the NETS SQSS and STC codes are met.

SHETL has identified no adverse technical, economic or environmental planning impact on its transmission network resulting from the proposed changes.

6.14.3 SP Transmission (SPT) Assessment

Similarly, the SPT system is planned in accordance with the requirements of the NETS SQSS and STC. From a technical perspective, SPT consider the proposals appropriate and economic.

SPT anticipate positive economic and environmental benefits arising from the proposed changes.

7 CONCLUSIONS AND RECOMMENDATIONS

The Working Group has benefitted from the experience, knowledge and contributions from the members of the group. Their input, candid discussions and time commitment in already busy schedules is appreciated and worthy of special comment. It is considered that the Working Group constitution and wide range of skills has enabled a positive and productive outcome.

The work, based on the founding principles established by the preceding group, is considered a viable and credible methodology in establishing a revised philosophy for establishing the appropriate level of security for generation developments as the industry moves forward with new generation technologies and connection locations.

The work builds on the enduring philosophy of the NETS SQSS in having a deterministic standard which enables transparent and consistent application by system planners with the principles supported by Cost Benefit Analysis.

It is believed that we have discharged all their obligations contained within our Terms of Reference (reproduced in Appendix A) and that the recommended code contained within the relevant appendices, together with the supporting analysis contained within this report, is positive and worthy of progression to codification.

The Working Group therefore recommends adoption of these proposals, namely:

- System Connections for Generation
- System Resilience
- Location of Grid Entry Points
- Definitions

and seeks endorsement of our recommendations and conclusions by the SQSS Review Panel. The Group further recommend that the Review Panel progress the work to industry consultation.

Appendix A **Working Group Terms of Reference**

NETS SQSS Review – Transmission Entry
Terms of Reference

Objective To review and determine the most appropriate and economic treatment of Transmission Entry connection conditions taking due cognisance of individual generator and overall system security.

Detailed Objectives:

1. Minimum System Connections for Generation connections **-** develop the appropriate level of connection security for the full range of generation developments and technologies. The methodology will be supported by Cost Benefit Analysis, which will also inform and determine aspects and variables of the methodology such as group generation capacity bands and generation intermittency.
   The cost benefit analysis will also inform and clarify the appropriate security which takes account of the components in the generator circuit.

2. System Resilience for generation at single circuit risk – in the event of significant penetration of non-firm generation connections for renewable generation, the potential exists for the aggregate generation capacity at risk to exceed the Normal Infeed Loss Risk or the Infrequent Infeed Loss Risk. The issue will be considered and inform the Minimum System Connection methodology parameters.

3. Impact on Commercial Codes – engagement with the SO Commercial Charging Group will be required to consider the commercial impact of the proposals and any consequential change proposals and implementation timescales.

4. Standard Connection Schemes – in order to establish transparency and consistency for compliant system connections, it is proposed to develop indicative connection configurations which will be provided as an appendix to the main document.

Constitution The team comprises membership from National Grid, Scottish Power Transmission, Scottish Hydro Electric Transmission, Ofgem, and Industry representatives. The team will be chaired by Dave Carson (SPT).

Reporting The team reports to the NETS SQSS Review Group under SQSS Governance. It is intended to report by the end of 2011.

Scope The working group scope is anticipated to be:

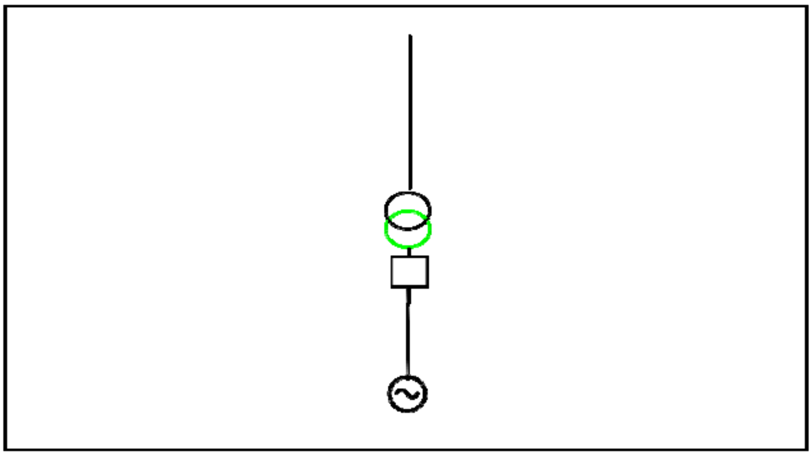
- The onshore SQSS Chapter 2 with any impact on Chapter 1, Appendix A and Definitions all considered within scope.
- Remaining onshore Chapters (3 to 6) and offshore Chapters (7 to 10) are considered out of scope.
- Cost benefit assessment to consider overall industry costs irrespective of cost apportionment or funding mechanisms

Meetings The team will meet approximately bi-monthly.

Methods The team will be required to adopt a cost-benefit framework to support a number of its recommendations. The cost-benefit tools may be developed in-house by National Grid, or by SEDG.

Appendix B **Standard Connection Arrangements**

Connection Method 1 - Single Circuit Radial, Sub-Transmission. Connection Voltage

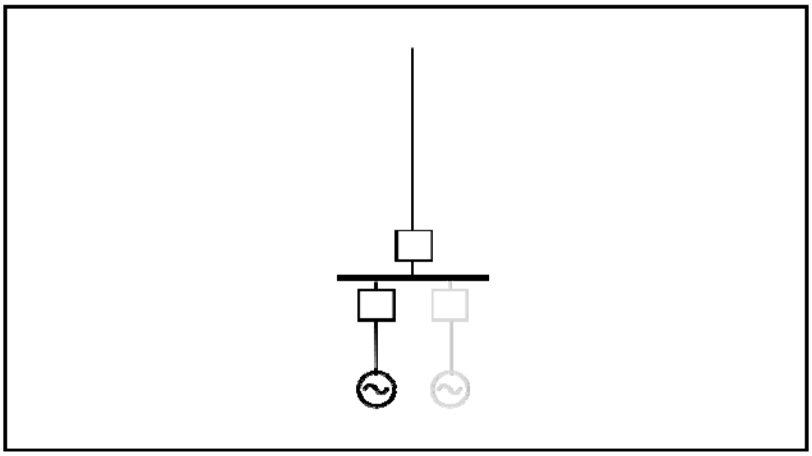


The simplest connection method is considered appropriate for smaller developments and enables a direct transmission connection while retaining a sub-transmission connection voltage.

Connection is achieved via a single circuit terminating on a dedicated transformer. The generator will be connected to the lower voltage side of the transformer via a single circuit breaker.

In the event that other developers wish to connect, these can be accommodated, within the thermal limits of the transformer, by additional circuit breakers connected to the LV side of the transformer, either by conventional switchgear arrangements or by free-standing single switch arrangements.

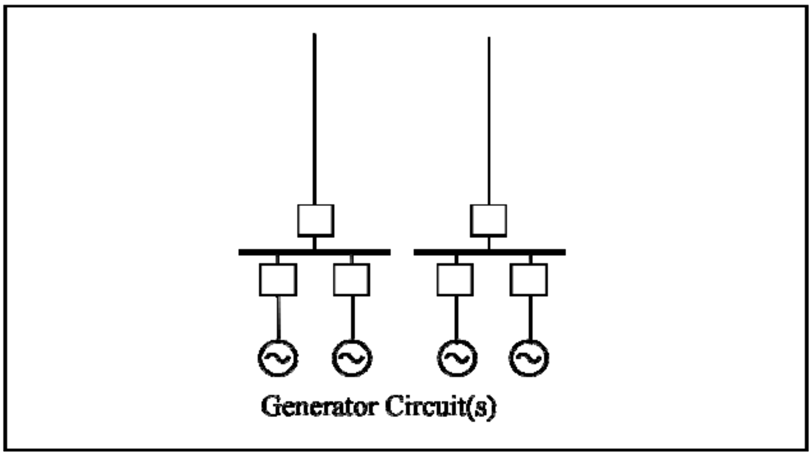
Connection Method 2 - Single Circuit Radial, Transmission Connection Voltage



This connection method is considered appropriate for larger developments or groups of developments and enables a direct transmission connection at a transmission voltage.

Connection is achieved via a single circuit terminating with a simple switchgear arrangement appropriate to the number of developments being connected.

Connection Method 3 – Non-firm, two single circuits, no interconnection



More significant developments could be connected by means of this connection method.

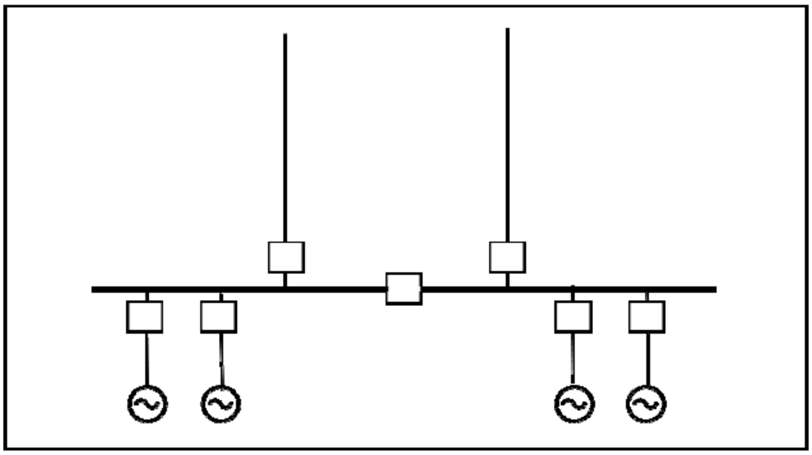
The connecting circuits could typically be two single circuits or conceivably arranged on a double circuit overhead line.

The developments could be either a single development (say a windfarm) or multiple developments by different operators. These would connect into the substation associated with a circuit and there would be no connectivity with the other circuit, either via the substation arrangement or the developer's network.

As the generation capacity will be met by two circuits and no interconnection, by definition each circuit will be rated to accommodate approximately 50% of the total generation capacity. Therefore, an outage of either circuit will result in generation disconnection until the circuit or associated plant is restored to service.

It was identified that the deterministic rules for scenario resilience must endeavour to take account of a lack of symmetry in terms of generation capacity associated with each circuit i.e. the circuit capacities and associated outage scenario resilience are likely to prohibit (say) a group generation capacity split of 90% and 10% across the two circuits.

Connection Method 4 - Non-firm, two circuits of reduced capacity

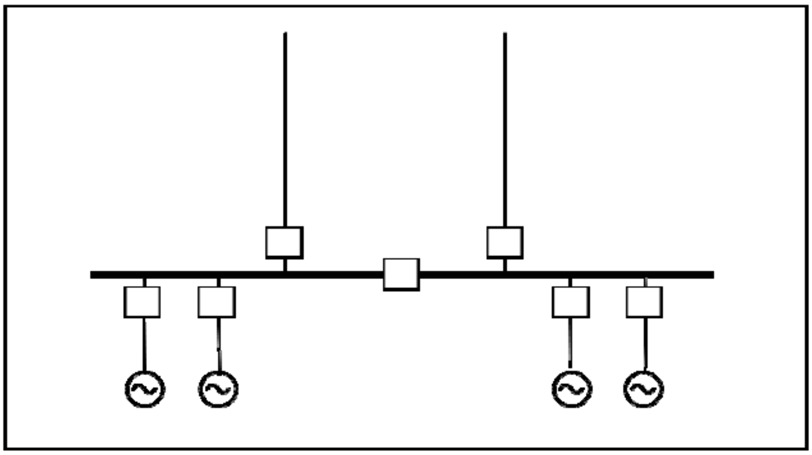


Connection method 4 is a more robust development of method 3. Effectively the arrangements are very similar:

- Connecting circuits typically either two single circuits or arranged on a double circuit overhead line.
- Each circuit rated at greater than 50%, but less than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 50% of group generation capacity)
- A bus-section circuit breaker established to enable system access during single circuit outage conditions
- Non-firm arrangement due to single busbar arrangement and overhead line capacity

The establishment of the bus-section circuit breaker resolves any issues around the symmetry of the generation capacity apportionment across the two sides of the switchboard.

Connection Method 5, Non-firm, two fully rated circuits

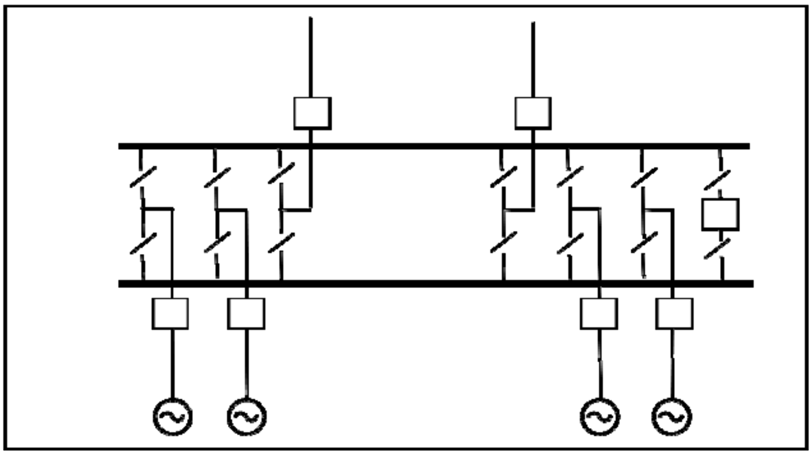


Connection method 5 is an incremental development of method 4 which provides system access to the entire group generation capacity during single circuit outages. The arrangements can be summarised:

- Connecting circuits typically either two single circuits or arranged on a double circuit overhead line.
- Each circuit rated at greater than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 100% of group generation capacity)
- A bus-section circuit breaker established to enable system access during single circuit outage conditions
- Non-firm arrangement due to single busbar arrangement

As in method 4, the establishment of the bus-section circuit breaker resolves any issues around the symmetry of the generation capacity apportionment across the two sides of the switchboard.

Connection Method 6 - Firm connection, 2 circuits, two section double busbar



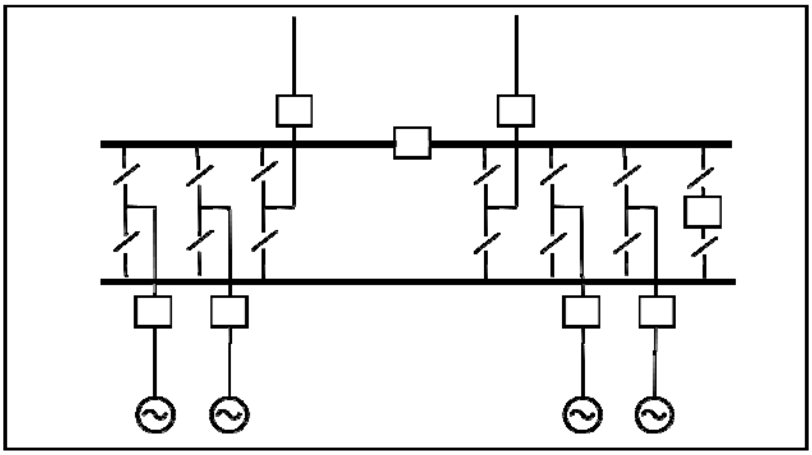
Connection method 6 is the simplest application of a double busbar switchgear layout providing a ‘firm’ connection for the associated generation. The arrangements can be summarised:

- Connecting circuits typically either two single circuits or arranged on a double circuit overhead line.
- Each circuit rated at greater than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 100% of group generation capacity)
- A two section double busbar switchgear arrangement with a main and reserve busbar and a single bus-coupler circuit breaker.
- Firm connection arrangement enables system access during single circuit or single busbar outage conditions

In general terms and in operational timescales, with one circuit out of service then one busbar will have a generation and a circuit selected to it and the other busbar will only have generation selected to it. Therefore loss of the relevant busbar will trip the other circuit and disconnect all generation capability. Clearly, loss of the other busbar will only disconnect a proportion of the generation.

It should be noted that the configuration, depending on system requirements, may vary to facilitate the connection of other system components such as Inter-bus transformers or Grid Supply Point connections.

Connection Method 7 - Firm connection, 2 circuits, three section double busbar



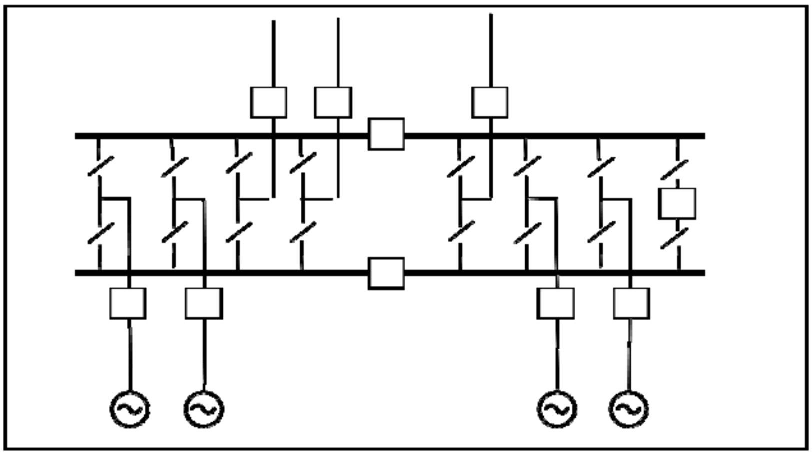
Connection method 7 is an incremental development of method 6 with the addition of a single bus section circuit breaker. This method also provides a ‘firm’ connection for the associated generation with additional resilience. The arrangements can be summarised:

- Connecting circuits typically either two single circuits or arranged on a double circuit overhead line.
- Each circuit rated at greater than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 100% of group generation capacity)
- A three section double busbar switchgear arrangement with a main and reserve busbar, a single bus-section circuit breaker and a single bus-coupler circuit breaker.
- Firm connection arrangement enables system access during single circuit or single busbar outage conditions

Operational assignment of circuits during busbar outages would be reflective of the actual outage but the actual arrangement may leave the remaining configuration and hence generation exposed to subsequent busbar, bus section circuit breaker or bus coupler circuit breaker faults.

As previously stated, it should be noted that the configuration, depending on system requirements, may vary to facilitate the connection of other system components such as Inter-bus transformers or Grid Supply Point connections.

Connection Method 8 - Firm connection, 3 circuits, four section double busbar



Connection method 8 is a further incremental development of the double busbar arrangement and the figure above indicates one of a number of similar configurations. An alternative arrangement with similar functionality, but improved operational flexibility, would have a bus-coupling circuit breaker established on the left hand side and the replacement of the bus-section circuit breaker on the reserve busbar by disconnectors. As well as the addition of a third fully rated circuit, this variation has a bus-section circuit breaker added to the reserve busbar. This method provides a ‘firm’ connection for the associated generation with additional resilience. The arrangements can be summarised:

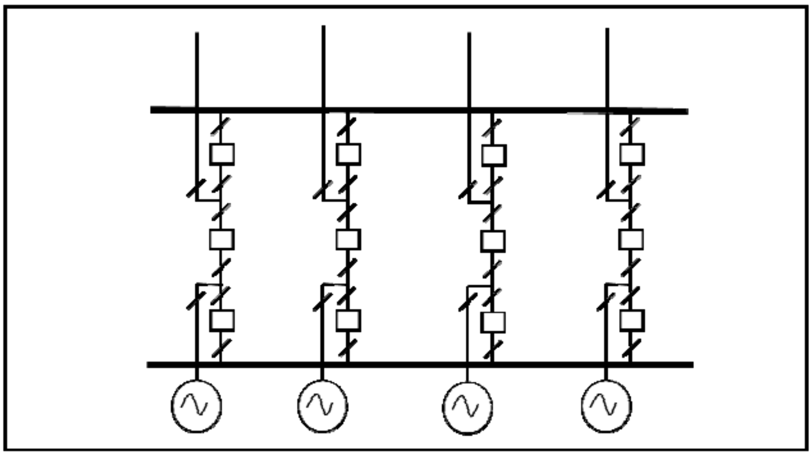
- Three connecting circuits either arranged as three mutually exclusive circuits or a single circuit with a further two circuits arranged on a double circuit overhead line.
- Each circuit rated at greater than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 100% of group generation capacity)
- A four section double busbar switchgear arrangement with a main and reserve busbar, two bus-section circuit breakers and a single bus-coupler circuit breaker.
- Firm connection arrangement enables system access during single circuit, double circuit or single busbar outage conditions with resilience for bus section and bus coupler circuit breakers.

Operational flexibility enables generators to be connected two switches apart to enable resilience against bus-section or bus-coupler circuit breakers.

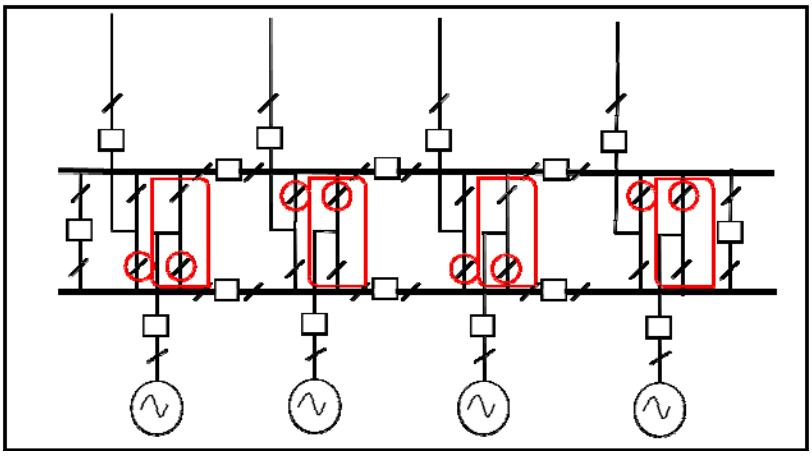
As previously stated, it should be noted that the configuration, depending on system requirements, may vary to facilitate the connection of other system components such as Inter-bus transformers or Grid Supply Point connections.

Connection Method 9 – Firm connection, 4 circuits,

1½ switch layout



Multi-mesh arrangement



Connection method 9 is the most secure of the connection arrangements together with the addition of a fourth circuit.

Two arrangements are shown – a ‘switch and a half’ and an extensible multi-mesh double busbar arrangement. The arrangements can be summarised:

- Four connecting circuits either arranged as mutually exclusive circuits or two double circuit overhead lines.
- Each circuit rated at greater than 100% of group generation capacity (i.e. the appropriate equipment rating which is greater than 100% of group generation capacity)
- A switchgear arrangement which renders the generation connections immune to mesh corner, busbar, bus-section circuit breaker and bus-coupler circuit breaker outages

As previously stated, it should be noted that the configuration, depending on system requirements, may vary to facilitate the connection of other system components such as Inter-bus transformers or Grid Supply Point connections.

Appendix C **Cost Benefit Analysis**

SQSS Entry Review:

Cost-Benefit Study

Authors: Paul H. Plumptre and Christopher Humphries
Future Strategy (Economics)

Electricity Network Investment

National Grid

Date: 12th December 2011

Summary
A generic cost-benefit study, which supports the proposals of the 'SQSS Entry Review Group', convened under the auspices of the SQSS Review Panel.
We assess up to 9 connection methodologies for differently-sized generation groups with low, medium and high load factors.

1 Introduction

This note introduces a generic cost-benefit study, which supports the proposals of the 'Entry Review Group'. This group has been convened under the auspices of the SQSS Fundamental Review.

We assume familiarity with the proposals of the Entry Review Group; in particular, the matrix of proposed security of Generation Connections, and the corresponding connection diagrams.

This matrix suggests connection methodology categories for combinations of generation capacity size (MW) and load factor. Load factor bands were chosen to reflect the operation of the fuel types we expect to connect: they are *<40%* (Wind); *>70%* (eg. CCGT), and *40-70%* (eg. Biomass or CHP).

The matrix is validated or modified here such that we establish deterministic rules founded on cost benefit principles.

The CBA takes into consideration several factors:

- the cost to the wider industry;
- wind curtailment pricing;
- a distance dimension, in order to consider connection reliability.

2 Connection Methodologies

We have identified nine possible connection methodologies: the details of a sub-set of these, methodologies 2–7, are shown in Figure 13. These are used in the CBA. Note that some preliminary discussions concerning steered us away from method 3 towards method 4, which is the same configuration apart from the bus section circuit breaker.

Figure 13: Connection Methodologies

Connection methodology	Circuits	Circuit Capability	firm / non-firm	Bus	Circuit Breakers			
					Bus Coupler	Bus Section	Line Ends	Total
7	2	Full	firm	double	1	1	2	4
6	2	Full	firm	double	1	-	2	3
5	2	Full	non-firm	single	-	1	2	3
4	2	Half	non-firm	single	-	1	2	3
3	2	Half	non-firm	2 x single	-	-	2	2
2	1	Full	non-firm	single	-	-	1	1

3 Proposed Connection Matrix

Figure 14 summarises the proposed connection matrix. For each combination of generator load factor and group capacity, we show the proposed connection methodology *prior* to CBA assessment[1]. This matrix reflects connection methodologies 1-9 (introduced in June 2011) rather than the original set 1-8.

As mentioned above, our preliminary recommendation to use connection methodology 3 was revised to the new method 4, and the table and subsequent CBA reflects this.

Of the eight generation group capacity bands, this cost-benefit rationale considered the four most significant step-change areas which provided the ability to analyse the incremental benefits and costs across the wider range of 50MW to 1320MW.

The identified groups were:

B (50-100MW);

C (100-300MW);

D (300-700MW); and

E (700MW – normal infeed loss).

Figure 14: Proposed Connection by Generation Capacity and Load Factor

		Increasing Load Factor →		
		<40% Wind	**40-70% eg. Biomass / CHP**	**>70% eg. CCGT**
Increasing Generation Capacity ↑	**H >= 3,600MW**	9	9	9
	G 1800 - 3,600MW ***	8	8	8
	F 1,320 - 1,800MW **	7	7	8
	E 700 - 1,320MW *	6 ↑ Q3b	6	7
	D 300 - 700MW	5 ↑ Q3a	5 → Q2b	6
	C 100 - 300MW	(3) → 4 ↑ Q1a	(3) → 4 ↑ Q1b → Q2a	5
	B 50 - 100MW	2	2	2
	A 0 - 50MW	1	1	1

* normal infeed loss
** infrequent infeed loss risk
*** double infrequent infeed loss risk

[1] In other words, the connection methodologies suggested by the previous 'Working Group 2'.

4 Some Cost-Benefit Questions

There are several cost-benefit questions that arise immediately (illustrated in the matrix as arrows and described below):

- As we propose moving from one connection methodology to another (eg. from 3 to 5) on the basis of increasing *load factor*, have we chosen the right 'load factor cut-off point'? **(Horizontal arrows)**
- As we move from one connection methodology to another on the basis of increasing generation group *capacity*, have we chosen the right 'capacity size cut-off point'? **(Vertical arrows)**

4.1 Question 1

Here we consider moving between generation groups B (50-100MW) and C (100-300MW).

Q1a: *Is 100MW the 'correct' level to move from connection method 2 to 3 for Wind capacity?*

Q1b: *Is 100MW the 'correct' level to move from connection method 2 to 3 for CCGT capacity?*

4.2 Question 2

Assuming connection of CCGT capacity:

Q2a: *In generation group C (100-300MW), is 70% the 'correct' load factor to move from connection method 3 to method 5?*

Q2b: *In group D (300-700MW) is 70% the 'correct' load factor to move from method 5 to 6?*

4.3 Question 3

Connecting Wind at 30% load factor:

Q3a: *Is 300MW the 'correct' level to move from connection method 3 to 5 – ie. between generation groups C (100-300MW) and D (300-700MW)?*

Q3b: *Is 700MW the 'correct' level to move from connection method 5 to 6? – ie. between groups D (300-700MW) and E (700MW–normal infeed loss)?*

5 Generic CBA Assumptions

We make several generic assumptions in this cost benefit that relate to costs of transmission assets, circuit outage rates, generation/demand in the entry group, and the treatment of wind intermittency.

5.1 Transmission Capital Costs (132kV)

SHETL have provided the following, which we will use to calculate transmission costs for connection methodologies.

Item	Comment	Cost / Price	Transmission Price
Circuit breaker bay	All types: includes civil works, protection, disconnectors, earth switches, etc.	£ 500k	n/a
Wood Pole 'Trident' Line	Single circuit; up to 150MVA	£ 300k / km	£2,000 / MW.km
Steel Tower Overhead Line	Double Circuit; up to max of 400MVA per circuit	£ 600k / km	£1,500 / MW.km

In the absence of further information, we make some assumptions concerning the prices of 'intermediate-rating' lines, eg. that 200MW rating steel tower overhead line is 75% the price of the 400MW shown above.

The cost of isolators is considered immaterial in the CBA and is ignored.

The transmission prices were added by National Grid: the Trident option is somewhat more expensive per MW.km than the steel tower option.

5.2 Circuit Outages

5.2.1 Planned Outage

Each circuit is on planned outage for 2 weeks pa (4%). Scheduled in summer only, planned outages are independent of circuit length.

5.2.2 Unplanned Outage

Each circuit suffers a further ½ week pa (1%) unplanned outage, which occur at any time of the year. We ignore the modest correlation between unplanned outage rate and circuit length.

5.3 Entry Group Generation and Demand

There is no other generation in the entry group than that specified, and there is zero group demand.

5.4 Route Length

The route length is assumed to be 50km in all cases.

5.5 Assessments of Constraints

Constraint costs are calculated as the product of the estimated constraint volume and the assumed replacement price.

The constraint volume (GWh) is derived from the duration of the circuit outages, the assumed running profile of the group generation, and the volume of restriction.[1]

The Constraint price (£/MWh) is the Offer price (taken on marginal plant outside the entry group) *less* the Bid price submitted by the entry group generation capacity. We assume

- an Offer price of 90/MWh on marginal gas / coal plant and
- Bid prices for (i) CCGT £30/MWh, and (ii) an onshore windfarm of -£50/MWh
- This yields Constraint prices of £60/MWh for constraining off CCGT capacity and £140/MWh for onshore wind.

For simplicity, we assume constant constraint prices, ie. we make no allowance for changes in Bids/Offers through inflation or fluctuations in fuel prices.

[1] This is a raw cost of the curtailment. No pre-suppositions are made on whether CUSC access rules would require or permit such payments.

6 Cost Benefit Methodology

Our approach to answering these questions is to

- assess the difference in capital costs ('T') of two possible connection methods;
- derive the difference in annual constraint costs ('O') under each connection method for the plant type;
- determine from the length of the payback period (ie. how many years it takes for the constraints saving to match the extra cost of transmission reinforcement[1]) which connection method is indicated.
- Given that the costings are crude, no attempt is made to discount or 'present value' costs. Broadly, we assume that an extra T cost is justified only if the payback period is less than 10 years.

[1] (T – t) / (O – o) = payback period of n years

7 Wind Modelling

7.1 Data and Assumptions

In order to assess the constraints arising from the curtailment of intermittent output from Wind, we have relied upon the assumptions and data from our Constraints forecast tool, and many of the following charts are direct outputs from Monte Carlo simulation software.
The wind speed profile – back-derived from Pöyry data – is that seen by a typical well-sited Scottish onshore windfarm. A generic power curve is applied to derive the windfarm output profile, and Winter and Summer load factors are 37% and 22% respectively.
Once we have assessed the CBA for a 150MW windfarm, we believe simply ‘scaling up’ for larger (eg. 400MW and 800MW) windfarms introduces no significant error[1].

7.2 Wind Speed Distribution

Figure 15: Seasonal Wind Speed Distribution

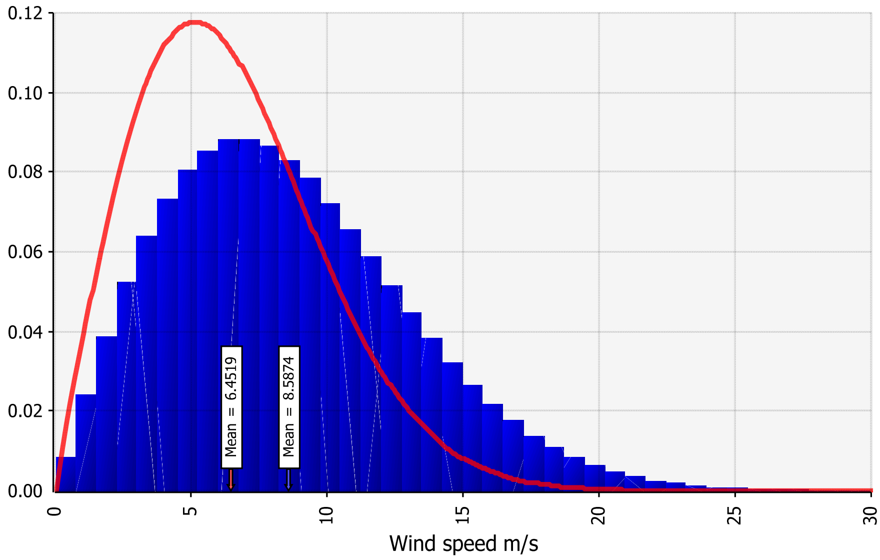


Figure 15 shows the seasonal wind speed distributions[2]: summer is shown as a line trace and winter as an area.

[1] One could argue against this treatment, as different-sized windfarms may well employ differently-sized turbines with rather different characteristics.
[2] Weibull distributions (with shape parameter 2) are used to simulate wind speeds.

7.3 Wind Turbine Power Curve

Figure 16: Power Curve (2,376MW windfarm)

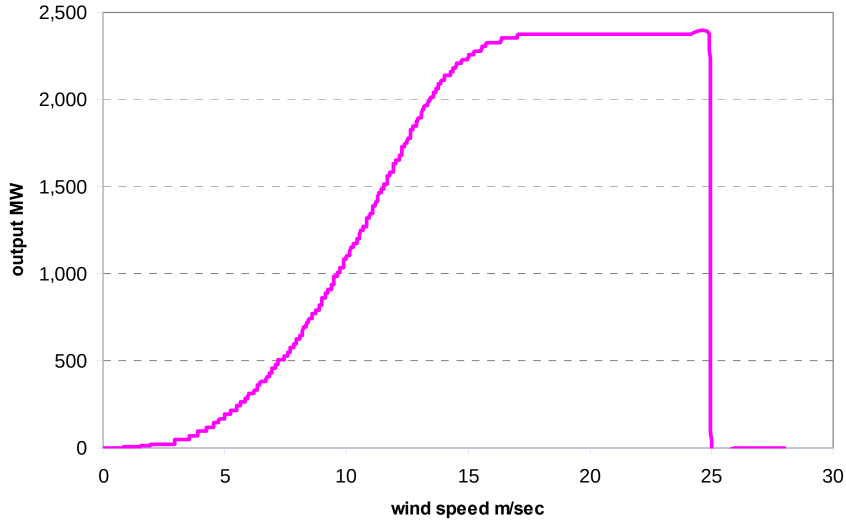


Figure 16 shows the generic windfarm power curve that we have used in this assessment. It is in fact a trace for a 2.4GW windfarm, but we scale this down appropriately.

7.4 Wind Output

- Figure 17 and Figure 18 show the (150MW) windfarm output probability distributions for summer and winter. The output distributions are replicated in cumulative ascending format.
- There is the usual local peak for winter at maximum output – corresponding to the plateau in the power curve for wind speeds greater than some 17m/s – and, as always for onshore wind, this feature is barely noticeable in summer;
- Up to half of the potential output of the 150MW windfarm could be constrained off. The probability of output greater than 75MW – ie. a constraint arises – is 12.8% in summer and 31.3% in winter.
- The windfarm output – and so the possible level of constrained off generation – is markedly different in summer and winter; therefore in our CBA we must we deal with each season separately.

Figure 17: Windfarm Output – Summer

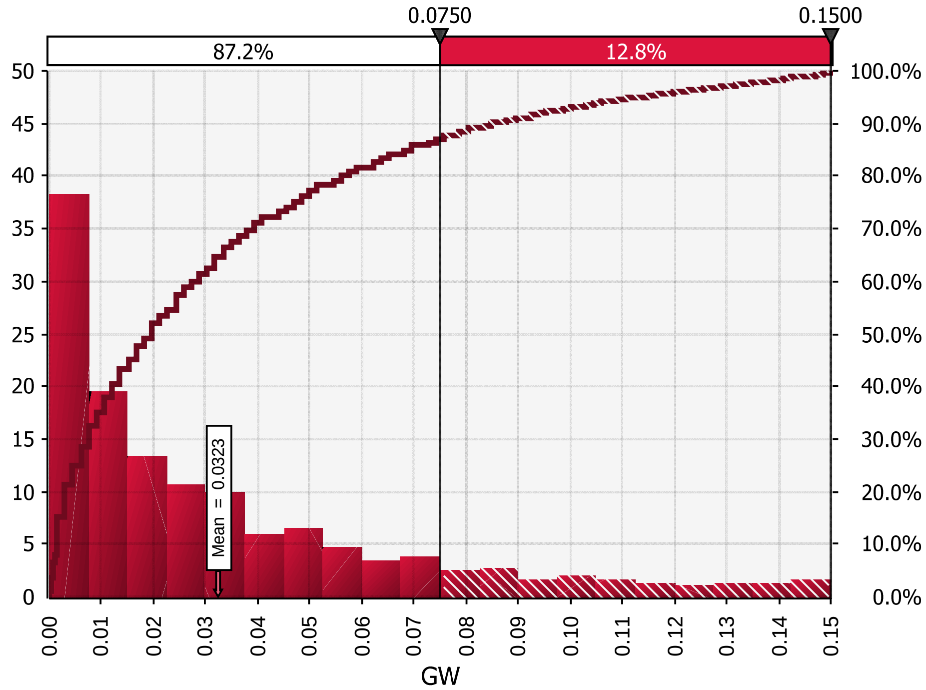
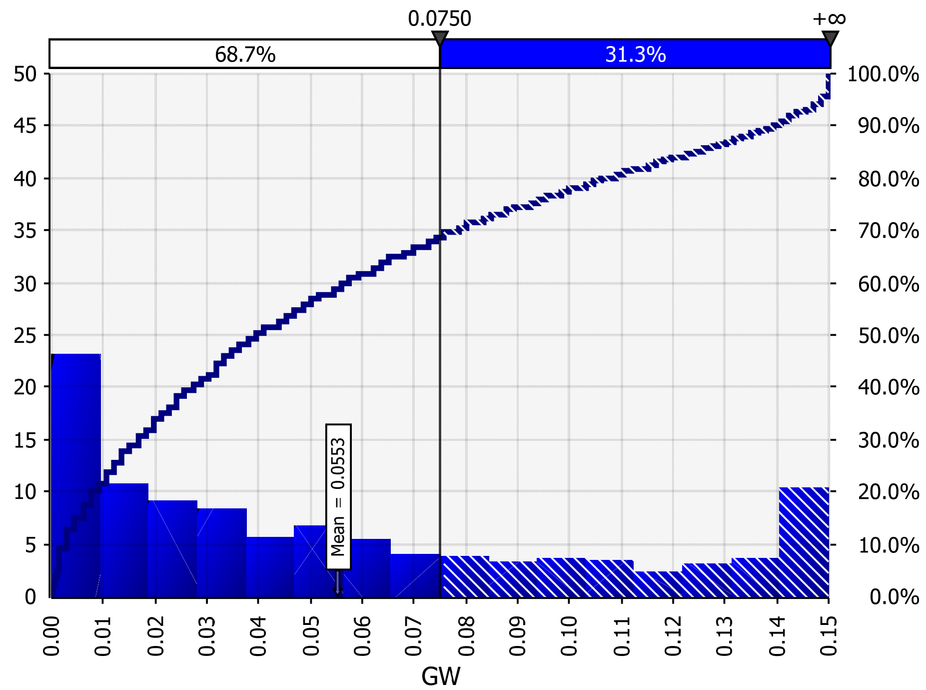


Figure 18: Windfarm Output – Winter



For interest, Figure 19 shows the *approximate* probability distribution for the output of this onshore Scottish windfarm for 150MW, 400MW and 800MW capacities. To derive a mean constrained off volume, we *could* 'sumproduct' the appropriate windfarm outputs and their associated probabilities from this table. Instead, we elect to use @Risk to do this for us with greater accuracy.

Figure 19: Seasonal Wind Output for Scottish Onshore Windfarm (Location 'JG16')

Bins	Avg Output (MW) for Size			Probability	
Range	150MW	400MW	800MW	winter	summer
0% - 10%	7	20	40	27.4%	43.3%
10% - 20%	22	60	120	14.0%	17.9%
20% - 30%	37	100	200	11.1%	12.0%
30% - 40%	52	140	280	9.2%	8.5%
40% - 50%	67	180	360	6.9%	5.4%
50% - 60%	82	220	440	5.8%	3.9%
60% - 70%	97	260	520	5.0%	2.8%
70% - 80%	112	300	600	4.6%	2.2%
80% - 90%	127	340	680	4.6%	1.8%
90% - 99%	142	379	758	6.9%	1.7%
100%	150	400	800	4.3%	0.4%
				100%	100%

8 Cost-Benefit – Question 1a

Is 100MW the 'correct' level to move from connection method 2 to 4 – ie. between generation groups B (50-100MW) and C (100-300MW) for Wind capacity?

We will answer this question in two parts: firstly, we will attempt to justify the connection methodology 2 (over 4) for a 60MW windfarm; next, we try to justify connection methodology 4 (over 2) for a 120MW windfarm. Then we can say that for some MW capacity between 60–120MW, we should move from connection 2 to 4.

8.1 60MW windfarm

8.1.1 T Cost – Method 2

Asset	Number	Comment	Price	Cost
single-circuit 'Trident' wooden pole line;	1 (50km)	Circuit rating 60MW; circuit is 75% of the cost of the fully rated 150MW circuit.	0.75 * £300k/km = £ 225k / km	£11.25m
circuit breaker	1	Line end	£500k	£0.5m
Total				**£11.75m**

8.1.2 T Cost – Method 4

Asset	Number	Comment	Price	Cost
single-circuit 'Trident' wooden pole line;	2 (50km)	Circuit rating 30MW; circuit is 50% of the cost of the fully rated 150MW circuit.	0.50 * £300k/km = £ 150k / km	£15m
circuit breakers	3	Bus section plus two line ends	£500k	£1.5m
Total				**£16.5m**

8.1.3 Constraints Costs O – Method 2

The constraints under method 2 caused by the circuit outage is the full windfarm output (should it be generating). We must consider the summer and winter costs separately.

For the probability of generation we can use the seasonal load factors (summer 22%; winter 37%), however we note in passing that the probability of the windfarm not generating, and therefore there being no constraint, is rather higher in summer (15%) than in winter (9%).

Summer

- Volume of Constraint =
  - duration of outage (2¼ weeks) x
  - probability of generation x
  - volume of restriction under circuit outage
  - = 378hr x 22% x 60MW = 4.99GWh
- Cost of Constraint = 4.99GWh x 140 £/MWh replacement price = **£0.70m pa**

Winter

- Volume of Constraint =
  - duration of outage (¼ weeks) x
  - probability of generation x
  - volume of restriction under circuit outage
  - = 42hr x 37% x 60MW = 0.93GWh
- Cost of Constraint = 0.93GWh x 140 £/MWh replacement price = **£0.13m pa**

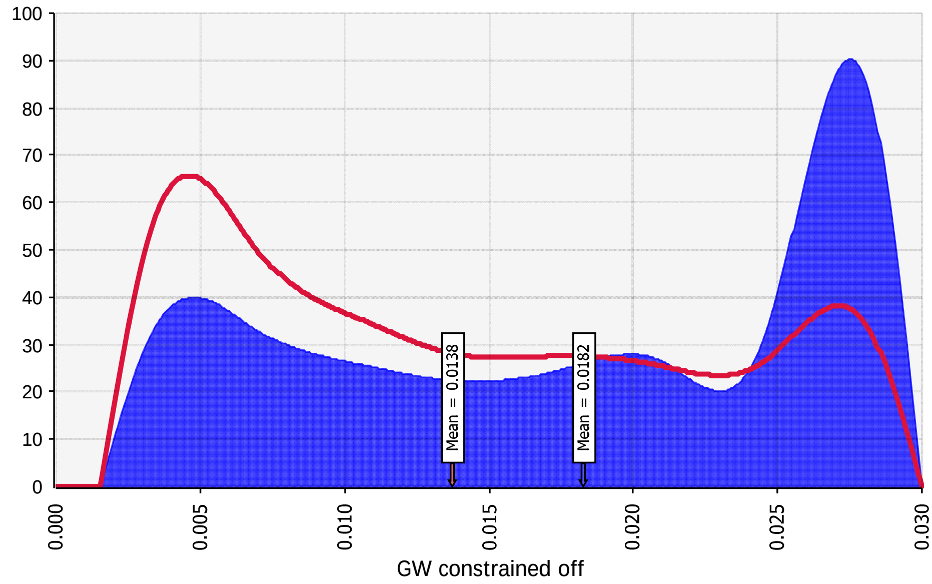
Hence the total cost of constraints under method 2 is **£0.83m pa**.

8.1.4 Constraints Costs O – Method 4

The constraints under method 4 arise during either circuit outage, and the constrained volume is any output above 30MW, with a maximum restriction of 30MW (ie. the windfarm would have been at full 60MW output). There will, of course, be no constraint should the output of the windfarm be below 30MW.

Figure 20 shows the probability distribution of windfarm output above 30MW for winter. Naturally the mean constraint in winter (18MW) is greater than in summer (14MW) as constraints occur more commonly in winter – when high wind speeds are more prevalent – than in summer (31.3% of the time for winter and 12.8% for summer).

Figure 20: Distribution of Output > 30MW by Season



Summer

- Volume of Constraint =
  - duration of outage (2 x 2¼ weeks) x
  - probability of generation >30MW x
  - mean volume of restriction under single circuit outage
  - = 756hr x 12.8% x 14MW = 1.36GWh
- Cost of Constraint = 1.36GWh x 140 £/MWh replacement price = **£0.19m pa**

Winter

- Volume of Constraint =
  - duration of outage (¼ weeks) x
  - probability of generation >30W x
  - mean volume of restriction under single circuit outage
  - = 84hr x 31.3% x 18MW = 0.47GWh
- Cost of Constraint = 0.47GWh x 140 £/MWh replacement price = **£0.07m pa**

Hence the total cost of constraints under method 4 is **£0.26m pa**.

8.1.5 Cost-Benefit

The cost-benefit for method 4 vs method 2 is simply +£4.75m of Transmission capital vs £0.57m of Constraints pa. The extra transmission of connection method 4 pays back in around 8 years, and this justifies the investment.

8.2 Answer 1a

Since for the 60MW windfarm case method 4 is preferable to method 2, we have *not* identified a transition between methodology 2 and 4. The original premise that method 2 was appropriate for this size of windfarm was in fact false and we recommend moving to method 4.

9 Cost-Benefit – Question 1b

Is 100MW the 'correct' level to move from connection method 2 to 4 – ie. between generation groups B (50-100MW) and C (100-300MW) – for CCGT capacity (70% load factor)?

If we justify connection methodology 2 (over 4) for a 60MW CCGT and then methodology 4 (over 2) for a 120MW CCGT, we can say for some MW capacity between 60–120MW, we should move from connection 2 to 4.

9.1 60MW CCGT

9.1.1 T Cost – Methods 2 and 4

The T costs for methods 2 and 4 (respectively, £11.75m and £16.5m; difference £4.75m) are derived *exactly* as illustrated in 0 and 0 above. The fact that we are connecting a CCGT rather than a windfarm is irrelevant.

9.1.2 Constraints Costs O – method 2

The constraints under **method 2** arise under a single circuit outage:

- Volume of Constraint =
  - 2½ weeks (duration of outage) x
  - 70% (probability of generation) x
  - MW (volume of restriction)
  - = 420hr x 70% x 60MW = **17.64GWh**
- Cost of Constraint = 17.64GWh x 60 £/MWh = **£1.06m pa**

9.1.3 Constraints Costs O – method 4

The constraints under **method 4** arise under a single circuit outage:

- Volume of Constraint =
  - 2*2½ weeks (duration of outage) x
  - 70% (probability of generation) x
  - MW (volume of restriction)
  - = 840hr x 70% x 30MW = **17.64GWh**
- Cost of Constraint = 17.64GWh x 60 £/MWh = **£1.06m pa**

9.1.4 Cost-Benefit

Thus this cost-benefit for connection method 4 vs method 2 is simply: £12.75m of Transmission capital vs. zero reduction in Constraints costs. Therefore connection method 2 is justified and there is no case for additional transmission investment to method 4.

9.2 Answer 1b

The 120MW CCGT case will also give no constraint benefit under method 4 and therefore we cannot justify the investment; indeed, we have *not* identified a capacity-size transition point between methods 2 and 4.

10 Cost-Benefit – Question 2a

In generation group C (100-300MW), is 70% the 'correct' load factor to move from connection method 4 to connection method 5?

Firstly we assess the case of a 50% load factor 150MW CCGT. We will then tackle 70% and 90% load factor CCGTs should this prove necessary.

10.1 T Costs – Method 4

Asset	Number	Comment	Price	Cost
single-circuit 'Trident' wooden pole line;	2 (50km)	Circuit rating 75MW; each circuit is 80% of the cost of the fully rated 150MW circuit.	0.80 * £ 300k/km = £ 240k / km	£24.0m
circuit breakers	3	Two line ends; one bus section	£500k	£1.5m
Total				**£25.5m**

10.2 T Costs – Method 5

Asset	Number	Comment	Price	Cost
single-circuit 'Trident' wooden pole line;	2 (50km)	Circuit rating 150MW	£ 300k / km	£30.0m
circuit breakers	3	Two line ends; one bus section	£500k	£1.5m
Total				**£31.5m**

Thus the T cost for method 5 is £6.0 m higher than for method 4.

10.3 Constraints Costs O

The constraints under **method 4** arise during an outage of either circuit.

- Volume of Constraint =
  - 2 x 2½ weeks (duration of outage) x
  - 50%[1] (probability of generation) x
  - 75MW (volume of restriction)
  - = 840hr x 50% x 75MW = **31.5GWh**
- Cost of Constraint = 31.5GWh x 60 £/MWh = **£1.89m pa**

The constraints under method 5 arise only under conditions of both circuits out ('N-2'), and under busbar outages at the connection site. Since these conditions also arise for the method 4 connection, and we are assessing deltas, there is no need to estimate them here.

10.4 Cost-Benefit

Thus this cost-benefit for connection method 5 vs method 4 is simply: +£6.0m of Transmission capital vs £1.89m of Constraints costs pa. The extra transmission cost of method 5 is paid back in under 4 years, which easily justifies the additional transmission investment.

[1] the load factor of 50% is represented as ½ chance generating at maximum output and ½ chance not generating.

As this cost-benefit favours connection method 5 for a 50% CCGT load factor, there is in fact no need to repeat for 70% and 90% load factor plant.

10.5 Answer 2a

Our recommendation is to adjust the matrix so that for the combination of group C and 40-70% load factor, we propose connection methodology 5.

11 Cost Benefit – Question 2b

In group D (300-700MW) is 70% the 'correct' load factor to move from method 5 to 6?

11.1 T Costs

Connection methods 5 and 6 differ in moving from a single to a double busbar design. The 132kV indicative costs shown in 0 do not cover such costs. However, 275kV indicative costs (source: D. Gregory, National Grid) show that the *cost difference* between methods 5 and 6 is two reserve busbar sections, at a capital cost (275kV AIS equipment) of £0.94m.

11.2 O Costs

For the case of a 400MW CCGT, the O costs incurred under method 5 arise during one week (assumed) of busbar outage pa. Assuming an 80% chance that this outage can be aligned with the generator outage, then against the 20% chance of a non-aligned outage:

- Volume of Constraint =
    - 1 week (duration of outage) x
    - 20% (non-aligned outage probability) x
    - 50% load factor (probability of restriction) x
    - Half output (MW volume of restriction)
    - = 168hr x 20% x 50% * 200MW = **3.36GWh**
- Cost of Constraint = 3.36GWh x 60 £/MWh = **£0.2m pa**

11.3 CBA

The additional T cost of £0.94m is paid back within 5 years, given an O saving of £0.2m pa. Hence connection method 6 is recommended for a 50% load factor 400MW CCGT.

12 Cost-Benefit – Question 3a

Is 300MW the 'correct' level to move from connection method 4 to 5 – ie. between Wind capacity groups C (100-300MW) and D (300-700MW)?

Firstly we will attempt to justify the connection methodology 4 (over 5) for a 150MW windfarm; next, we try to justify connection methodology 5 (over 4) for a 400MW windfarm. Then we can say that for some MW capacity between 150–400MW, we should move from connection 4 to 5.

12.1 150MW windfarm

12.1.1 T Costs – Methods 4 and 5

The T costs for methods 4 and 5 (respectively, £25.5m and £31.5m; difference £6.0m) are derived *exactly* as illustrated in 0 and 0 above. The fact that we are connecting a windfarm rather than a CCGT is irrelevant.

12.1.2 Constraints Costs O – Method 4

The constraints under method 4 arise during either circuit outage. The constrained volume caused by a circuit outage is any output above 75MW, with a maximum restriction of 75MW (ie. the windfarm would have been at full 150MW output). There will, of course, be no constraint should the output of the windfarm be below 75MW. We can scale the results from Figure 20 and 0 to derive the constraint cost:

Summer: (£0.19m * 150/60 =) £0.48m pa

Winter: (£0.07m * 150/60 =) £0.17m pa

Hence the total cost of constraints under method 4 is **£0.63m pa**.

Constraints under method 5 arise only under conditions of both circuits out ('N-2'), and under busbar outages at the connection site. Since these conditions also arise for the method 3, there is no need to estimate them.

12.1.3 Cost-Benefit

The cost-benefit for method 5 vs method 4 is simply +£6.0m of Transmission capital vs £0.63m of Constraints pa. The extra transmission investment of connection method 5 pays back in around 10 years, and it is doubtful that this return justifies the additional transmission investment of method 5. Hence for the 150MW windfarm case, method 4 *is* preferable to method 5.

12.2 400MW windfarm

12.2.1 T Costs – Method 4

Asset	Number	Comment	Price	Cost
steel tower overhead line	2 (50km)	Circuit rating 200MW; each circuit is 80% of the cost of the fully rated 400MW circuit.	0.80 * £ 600k/km = £ 480k / km	£48m
circuit breakers	3	Two line ends; one bus section	£500k	£1.5m
Total				**£49.5m**

12.2.2 T Costs – Method 5

Asset	Number	Comment	Price	Cost
steel tower overhead line	2 (50km)	Circuit rating 400MW	£ 600k / km	£60.0m
circuit breakers	3	Two line ends; one bus section	£500k	£1.5m
Total				**£61.5m**

12.2.3 O Costs – Methods 4 and 5

We can scale up the constraints costs from the 150MW windfarm results in 0: £0.63m * 400/150 = £1.68m for method 4. Again, constraints under method 5 arise under conditions for which that also arise for method 4, and there is no need to estimate them.

12.2.4 Cost-Benefit

The cost-benefit for method 5 vs method 4 is:

- +£12.0m of Transmission capital vs £1.68m of Constraints pa. The extra transmission of connection method 5 pays back in around 7 years, and this return justifies the additional transmission investment of method 5.
- Hence for the 400MW windfarm case, method 5 *is* preferable to method 4.

12.3 Answer 3a

Since connection methodology 4 is indicated for a 150MW windfarm and 5 for a 400MW windfarm, then for some windfarm capacity between 150–400MW, we *should* move from connection 4 to 5. The value of 300MW would appear to be a reasonable value to effect this transition.

13 Cost Benefit – Question 3b

Is 700MW the 'correct' level to move from connection method 5 to 6? – ie. between Wind capacity groups D (300-700MW) and E (700MW–normal infeed loss)?

Once again we answer this question by attempting to justify methodology 5 (over 6) for a 600MW windfarm; and then methodology 6 (over 5) for an 800MW windfarm. Then we can say that for some MW capacity between 600–800MW, we should move from connection 5 to 6.

13.1 600MW windfarm

13.1.1 T Costs

Connection methods 5 and 6 differ in T cost by £0.94m, as derived in 0.

13.1.2 O Costs – Method 5

The O costs incurred under method 5 arise during one summer week (assumed) of busbar outage pa. Assuming an 80% chance that this outage can be aligned with the generator outage, and scaling up the mean volume of restriction from the 60MW windfarm case, then against the 20% chance of a non-aligned outage:

- Volume of Constraint =
  - 1 week (duration of outage) x
  - 20% (non-aligned outage probability) x
  - probability of generation >300MW x
  - mean volume of restriction under bus outage
  - = 168hr x 20% x 12.8% * [14MW * 600/60] = **0.60GWh**
- Cost of Constraint = 0.6GWh x 140 £/MWh = **£0.08m pa**

13.1.3 CBA

The additional T cost of £0.94m is paid back after 11 years, given an O saving of £0.08m pa. Hence connection method 5 is recommended for a 600MW windfarm.

13.2 800MW windfarm

By simply scaling up the 600MW windfarm results, we identify an O saving of (£0.08m *800/600 =) £0.11m pa. Against a T cost of £0.94m the payback some 8 years and hence connection method 6 is recommended for an 800MW windfarm.

13.3 Answer 3b

Since for the 600MW windfarm case connection methodology 5 is preferable to method 6, and for the 800MW case 6 is preferable to 5, then we have established that for some capacity within the range 600-800MW there is a transition. A transition point at 700MW seems reasonable

14 Recommendations and Conclusions

The revised connection methodology matrix suggests four changes from the original matrix, in the light of this CBA (Figure 21).
Perhaps counter-intuitive is our conclusion that half-sized connections for small CCGTs (method 2) are justified, but for similar-sized windfarms we propose stronger full-size connections (method 4). This is principally a Wind bid pricing effect.

Figure 21: Revised Proposed Connection Matrix

Increasing Generation Capacity ↑		Increasing Load Factor →		
		<40% Wind	40-70% eg. Biomass / CHP	>70% eg. CCGT
	F - H 1,320MW - 3,600MW ***	7 / 8 / 9	7 / 8 / 9	7 / 8 / 9
	E 700MW - 1,320MW *	6 [section 13.2]	6	7
	D 300 - 700MW	5 [section 12.2]	6 (from 5) [section 11.3]	6
	C 100 - 300MW	4 [section 12.1]	5 (from 4)	5
	B 50 - 100MW	4 (from 2) [section 8.1]	2	2 (from 4)
	A 0 - 50MW	1 / 2	1 / 2	1 / 2

* normal infeed loss
*** double infrequent infeed loss risk

new recommendation

15 Other Recommendations

15.1 Capacity Group A (0-50MW) and Connection Methodologies 1 and 2

Connection methods 1 and 2 only differ in the voltage of the single circuit, and a transformer at the Generation Entry Point. From the cost-benefit perspective of this paper these two designs are indistinguishable. Hence for generation class A, namely 0-50MW, no recommendation is made between connection methods 1 and 2.

15.2 Connections Above Infrequent Infeed Risk

For connection of stations or a generation group above the Infrequent Infeed Risk (1,800MW from 01-Apr-2014) connection methods 8 or 9 are recommended. These involve a full double busbar design, and 3 or 4 connecting circuits. It is not worthwhile to set out here recommendations between 8 and 9 – the decision can be made on a case-by-case basis. (In many instances, the TOs' natural inclination to build in units of a double circuit overhead line will lead to connection method 9).

Appendix D Code Recommendations NETS SQSS Section 1 (Introduction)

Overlap of Criteria

1.25 When determining the applicable connection security for Generation or Demand connection arrangements where that Generation or Demand is connected to the onshore transmission system, the following criteria philosophy should be applied:

Demand Connections – for sites which are exclusively or predominately demand connections, the applicable connection security is covered in section 3 “Demand Connection Criteria Applicable to the Onshore Transmission System”

Generation Connections - for sites which are exclusively for the purposes of generating electricity the appropriate connection security is detailed in section 2 “Generation Connection Criteria Applicable to the Onshore Transmission System”.

Exporting GSPs – where sites are composite and have a mixture of demand connections and generation connections, the security afforded to the block of demand customers shall be not less than that provided for a standard demand connection of an identical size. The applicable security standard should therefore be the more secure of the corresponding criteria of section 2 or section 3.

Specifically excluded from this category is a generation site with on-site station demand. Such sites shall be treated as a Generation site connected to the onshore transmission system with appropriate security levels.

Appendix E **Code Recommendations NETS SQSS Section 2 (Entry)**

*The following Code Recommendations are provided to a base of Version 2.2 of the NETS SQSS **plus** the changes recommended under GSR008. The proposed code recommendation therefore assumes that GSR008 receives Authority approval.*

Conventionally, text deletions are indicated as strike-through text, but in this section, in the interests of clarity, as the complete section is being redrafted, the deleted text has not been shown. It should therefore be assumed that the entire existing Section 2 will be replaced by the following:

2. Generation Connection Criteria Applicable to the Onshore Transmission System

2.1 This section presents the planning criteria applicable to the connection of one or more power stations to the onshore transmission system. The criteria in this section will also apply to the connections from a GSP to the onshore transmission system by which power stations embedded within a customer's network (e.g. distribution network) are connected to the onshore transmission system.

2.2 In those parts of the onshore transmission system where the criteria of Section 3 and/or Section 4 also apply, those criteria must also be met.

2.3 In planning generation connections, this Standard is met if the connection design either:

2.3.1 satisfies the deterministic criteria detailed in paragraphs 2.5 to 2.13; or

2.3.2 varies from the design necessary to meet paragraph 2.3.1 above in a manner which satisfies the conditions detailed in paragraphs 2.15 to 2.18.

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 G.

Limits to Loss of Power Infeed Risks

2.5 For the purpose of applying the criteria of paragraph 2.6, the loss of power infeed resulting from a secured event on the onshore transmission system shall be calculated as follows:

2.5.1 the sum of the registered capacities of the generating units disconnected from the system by a secured event, plus

2.5.2 the planned import from any external systems disconnected from the system by the same event, less

2.5.3 the forecast minimum demand disconnected from the system by the same event but excluding (from the deduction) any demand forming part of the forecast minimum demand which may be automatically tripped for system frequency control purposes and excluding (from the deduction) the demand of the largest single end customer.

2.6 Generation connections shall be planned such that, starting with an intact system, the consequences of secured events on the onshore transmission system shall ensure that the aggregate generation capacities remaining shall be not less than the levels specified in Table 2.1.

2.7 The maximum length of overhead line connections in a generation circuit for generating units which are directly connected to the onshore transmission system shall not exceed:

2.7.1 5km for generating units of expected annual energy output greater than or equal to 2000 GWh; otherwise

2.7.2 20km.

Generation Connection Capacity Requirements

Background conditions

2.8 The connection of a particular power station shall meet the criteria set out in paragraphs 2.9 to 2.13 under the following background conditions:

2.8.1 the active power output of the power station shall be set equal to its registered capacity;

2.8.2 the reactive power output of the power station shall be set to the full leading or lagging output that corresponds to an active power output equal to registered capacity

2.8.3 for connections to an offshore transmission system, the reactive power output of the offshore power station/s shall normally, and unless otherwise agreed, be set to deliver zero reactive power at the offshore grid entry point with active power output equal to registered capacity; and the reactive power delivered at the interface point shall be set in accordance with the reactive requirements placed on the offshore transmission licensee set out in Section K of the STC (System Operator – Transmission Owner Code); and

2.8.4 conditions on the onshore transmission system shall be set to those which ought reasonably to be expected 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 modified where appropriate by the provisions of paragraph 2.11.

Pre-fault criteria

2.9 The transmission capacity for the connection of a power station shall be planned such that, for the background conditions described in paragraph 2.8, prior to any fault there shall not be any of the following:

2.9.3 equipment loadings exceeding the pre-fault rating;

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

2.9.5 system instability.

Post-fault criteria – background condition of no local system outage

2.10 The transmission capacity for the connection of a power station shall also be planned such that for the background conditions described in paragraph 2.8 with no local system outage and for the secured event of a fault outage on the onshore transmission system of any of the following:

2.10.1 a single transmission circuit, a single generation circuit, a single generating unit (or several generating units sharing a common circuit breaker), a single Power Park Module, or a single DC converter, a reactive compensator or other reactive power provider;

2.10.2 a double circuit overhead line;

2.10.3 a single transmission circuit with the prior outage of another transmission circuit;

2.10.4 a section of busbar or mesh corner; or

2.10.5 a single transmission circuit with the prior outage of a generation circuit, a generating unit (or several generating units, sharing a common circuit breaker, that cannot be separately isolated), a Power Park Module, a DC converter, a reactive compensator or other reactive power provider, or;

2.10.6 a single generation circuit, a single generating unit (or several generating units sharing a common circuit breaker), a single Power Park Module, a single DC converter, a reactive compensator or other reactive power provider with the prior outage of a single transmission circuit,

there shall not be any of the following:

2.10.7 a loss of supply capacity except as permitted by the demand connection criteria detailed in Section 3 or loss of generation capability comprising of the aggregate of the Connection Entry Capacities for that secured event shall not exceed the corresponding levels set out in Table 2.1;

2.10.8 unacceptable overloading of any primary transmission equipment;

2.10.9 unacceptable voltage conditions or insufficient voltage performance margins; or

2.10.10 system instability.

2.11 Under intact system or planned outage conditions with background conditions as described in paragraph 2.8, a fault on any circuit breaker shall not cause unacceptably high voltage.

2.12 Under planned outage conditions it shall be assumed that the prior circuit outage specified in paragraphs 2.10.3, 2.10.5 and 2.10.6 reasonably forms part of the typical outage pattern referred to in paragraph 2.8.4 rather than in addition to that typical outage pattern.

Post-fault criteria – background condition with a local system outage

2.13 The transmission capacity for the connection of a power station shall also be planned such that for the background conditions described in paragraph 2.8 with a local system outage on the onshore transmission system, the operational security criteria set out in Section 5 and Section 9 can be met.

2.14 Where necessary to satisfy the criteria set out in paragraph 2.13, investment should be made in transmission capacity except where operational measures suffice to meet the criteria in paragraph 2.13 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 G.

2.15 The load factor applicable for the Group Aggregate Generation Capacity reflects either a single generator development or a group of generator developments of identical technologies or load factors. Where neither scenario applies, then the applicable load factor can be derived by either:

2.15.1 Where more than one generator contributes to the Group Aggregate Generation Capacity and when those generators are of mixed technologies or with load factors in differing bands, then the equivalent load factor for the aggregate of N generators in the group can be determined by:

$$LF_E = \sum_1^N \left(\frac{(CEC)_N}{\sum_1^N (CEC)} \times (LF)_N \right)$$ Or;

2.15.2 Where, in planning timescales, the generator load factor for application in table 2.1 is unknown or remains undefined, a generic load factor for the source energy from table 2.2 can be utilised:

Table 2.2 Generic Generator Load Factor

Source Energy	Generic Load Factor
Biomass	0.80
CCGT	0.75
CHP (Continuous Process)	0.75
CHP (Landfill)	0.80
Coal / Clean Coal	0.75
Hydro	0.37
Nuclear	0.90
Tidal	0.45
Wave	0.30
Wind	0.30

Switching Arrangements

2.15 Guidance on substation configurations and switching arrangements are described in Appendix A. These guidelines provide an acceptable way towards meeting the criteria of paragraph 2.6. However, other configurations and switching arrangements which meet those criteria are also acceptable.

Variations to Connection Designs

2.16 Variations, arising from a generation customer's request, to the generation connection design necessary to meet the requirements of paragraphs 2.5 to 2.14 shall also satisfy the requirements of this Standard provided that the varied design satisfies the conditions set out in paragraphs 2.17.1 to 2.17.3. For example, such a generation connection design variation may be used to take account of the particular characteristics of a power station.

2.17 Any generation connection design variation must not, other than in respect of the generation customer requesting the variation, either immediately or in the foreseeable future:

2.17.1 reduce the security of the MITS to below the minimum planning criteria specified in Section 4; or

2.17.2 result in additional investment or operational costs to any particular customer or overall, or a reduction in the security and quality of supply of the affected customers' connections to below the planning criteria in this section or Section 3, unless specific agreements are reached with affected customers; or

2.17.3 compromise any transmission licensee's ability to meet other statutory obligations or licence obligations.

2.18 Should system conditions subsequently change, for example due to the proposed connection of a new customer, such that either immediately or in the foreseeable future, the conditions set out in paragraphs 2.17.1 to 2.17.3 are no longer satisfied, then alternative arrangements and/or agreements must be put in place such that this Standard continues to be satisfied.

2.19 The additional operational costs referred to in paragraph 2.17.2 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 G.

Table 2.1 Connection Security for Group Generation Capacities
Minimum Generation Capacity To Be Met Following Outage Scenarios

Generation Group	Group Aggregate Generation Capacity (CEC)		Source Fuel Load Factor	Connecting Substation Configuration (with reference to Appendix A)	Timescale	Initial and Subsequent System Conditions								
						Intact							Planned outage of any single transmission circuit, single section of busbar or mesh corner	Planned outage of any single section of busbar or mesh corner
	Minimum	Maximum				Planned outage of a single transmission circuit	Planned outage of a single section of busbar or mesh corner	Fault of a single transmission circuit	Fault outage of a single generator circuit	Fault of a single section of busbar or mesh corner	Fault of any two transmission OR fault on two generator circuits on same double circuit overhead line	Fault of a bus-section circuit breaker, bus-coupler circuit breaker or mesh corner circuit breaker	Fault of any single transmission circuit, single section of busbar or mesh corner	Fault of a bus-section circuit breaker, bus-coupler circuit breaker or mesh corner circuit breaker
A	0	< 50	<= 40%	1 - Figure A.4.3.1 (or similar)	Immediately	Nil		Nil	Nil					
					In time to restore either outage or fault	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity					
			40 – 70%	1 - Figure A.4.3.1 (or similar)	Immediately	Nil		Nil	Nil					
					In time to restore either outage or fault	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity					
			70 – 100%	1 - Figure A.4.3.1 (or similar)	Immediately	Nil		Nil	Nil					
					In time to restore either outage or fault	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity					
B	>=50	< 100	<= 40%	4 - Figure A.4.3.4 (or similar)	Immediately	1/2 of Group Generation Capacity	Lesser of (1/5 of GGC) and (GGC less 150MW)	1/2 of Group Generation Capacity	Lesser of (1/5 of GGC) and (GGC less 150MW)	Lesser of (1/5 of GGC) and (GGC less 150MW)	Nil	Nil	Nil	Nil
					In time to restore either outage OR fault	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	Group Generation Capacity
			40 – 70%	2 - Figure A.4.3.2 (or similar)	Immediately	Nil	Nil	Nil	Nil	Nil			Nil	
					In time to restore either outage OR fault	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity				
					In time to restore both outage AND fault								Group Generation Capacity	
			70 – 100%	2 - Figure A.4.3.2 (or similar)	Immediately	Nil	Nil	Nil	Nil	Nil			Nil	
					In time to restore either outage OR fault	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity				
					In time to restore both outage AND fault								Group Generation Capacity	
C	>=100	<300	<= 40%	4 - Figure A.4.3.4 (or similar)	Immediately	1/2 of Group Generation Capacity	Lesser of (1/5 of GGC) and (GGC less 150MW)	1/2 of Group Generation Capacity	Lesser of (1/5 of GGC) and (GGC less 150MW)	Lesser of (1/5 of GGC) and (GGC less 150MW)	Nil	Nil	Nil	Nil
					In time to restore either outage OR fault	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	Group Generation Capacity
			40 – 70%	5 - Figure A.4.3.5 (or similar)	Immediately	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Nil	Nil	Nil	Nil
					In time to restore either outage OR fault		Group Generation Capacity		Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	Group Generation Capacity
			70 – 100%	5 - Figure A.4.3.5 (or similar)	Immediately	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Nil	Nil	Nil	Nil
					In time to restore either outage OR fault		Group Generation Capacity		Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	Group Generation Capacity
D	>=300	<700	<= 40%	5 - Figure A.4.3.5 (or similar)	Immediately	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Group Generation Capacity	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Lesser of:(1/3 of GGC) & (GGC less 100MW)	Nil	Nil	Nil	Nil
					In time to restore either outage OR fault		Group Generation Capacity		Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	Group Generation Capacity
			40 – 70%	6 - Figure A.6.7.1 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
			70 – 100%	6 - Figure A.6.7.1 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
E	>=700	Normal Infeed Loss (1,320)	<= 40%	6 - Figure A.6.7.1 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
			40 – 70%	6 - Figure A.6.7.1 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
			70 – 100%	7 - Figure A.6.7.4 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
F	>=Normal Infeed Loss (1,320)	<Infrequent Infeed Loss Risk (1,800)	<= 40%	7 - Figure A.6.7.4 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
			40 – 70%	7 - Figure A.6.7.4 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
			70 – 100%	7 - Figure A.6.7.4 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	Nil	Nil	Nil	Nil	Nil	Nil
					In switching time					Group Generation Capacity				Group Generation Capacity
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault								Group Generation Capacity	
G	> =Infrequent Infeed Loss Risk (1800)	<2 x Infrequent Infeed Loss Risk (3,600)	<= 40%	8 - Figure A.6.7.9 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time					Group Generation Capacity			Group Generation Capacity	
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault									Group Generation Capacity
			40 – 70%	8 - Figure A.6.7.9 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time					Group Generation Capacity			Group Generation Capacity	
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault									Group Generation Capacity
			70 – 100%	8 - Figure A.6.7.9 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time					Group Generation Capacity			Group Generation Capacity	
					In time to restore either outage OR fault				Group Generation Capacity		Group Generation Capacity	Group Generation Capacity		
					In time to restore both outage AND fault									Group Generation Capacity
H	> =2 x Infrequent Infeed Loss Risk (3,600)	-	<= 40%	9 - Figure A.6.7.10 or A.6.7.11 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time							Group Generation Capacity		
					In time to restore either outage OR fault				Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity
					In time to restore both outage AND fault									
			40 – 70%	9 - Figure A.6.7.10 or A.6.7.11 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time							Group Generation Capacity		
					In time to restore either outage OR fault				Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity
					In time to restore both outage AND fault									
			70 – 100%	9 - Figure A.6.7.10 or A.6.7.11 (or similar)	Immediately	Group Generation Capacity	Group Generation Capacity	Group Generation Capacity	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk	GGC Less Infrequent Infeed Loss Risk
					In switching time							Group Generation Capacity		
					In time to restore either outage OR fault				Group Generation Capacity	Group Generation Capacity	Group Generation Capacity		Group Generation Capacity	Group Generation Capacity
					In time to restore both outage AND fault									

2.15 The load factor applicable for the Group Aggregate Generation Capacity reflects either a single generator development or a group of generator developments of identical technologies or load factors. Where neither scenario applies, then the applicable load factor can be derived by either:

2.15.1 Where more than one generator contributes to the Group Aggregate Generation Capacity and when those generators are of mixed technologies or with load factors in differing bands, then the equivalent load factor for the aggregate of N generators in the group can be determined by:

$$LF_E = \sum_1^N \left(\frac{(CEC)_N}{\sum_1^N (CEC)} \times (LF)_N \right) \qquad \text{Or;}$$

2.15.2 Where, in planning timescales, the generator load factor for application in table 2.1 is unknown or remains undefined, a generic load factor for the source energy from table 2.2 can be utilised:

Table 2.2 Generic Generator Load Factor

Source Energy	Generic Load Factor
Biomass	0.80
CCGT	0.75
CHP (Continuous Process)	0.75
CHP (Landfill)	0.80
Coal / Clean Coal	0.75
Hydro	0.37
Nuclear	0.90
Tidal	0.45
Wave	0.30
Wind	0.30

Switching Arrangements

2.16 Guidance on substation configurations and switching arrangements are described in Appendix A. These guidelines provide an acceptable way towards meeting the criteria of paragraph 2.6. However, other configurations and switching arrangements which meet those criteria are also acceptable.

Variations to Connection Designs

2.17 Variations, arising from a generation customer's request, to the generation connection design necessary to meet the requirements of paragraphs 2.5 to 2.14 shall also satisfy the requirements of this Standard provided that the varied design satisfies the conditions set out in paragraphs 2.18.1 to 2.18.3. For example, such a generation connection design variation may be used to take account of the particular characteristics of a power station.

2.18 Any generation connection design variation must not, other than in respect of the generation customer requesting the variation, either immediately or in the foreseeable future:

2.18.1 reduce the security of the MITS to below the minimum planning criteria specified in Section 4; or

2.18.2 result in additional investment or operational costs to any particular customer or overall, or a reduction in the security and quality of supply of the affected customers' connections to below the planning criteria in this section or Section 3, unless specific agreements are reached with affected customers; or

2.18.3 compromise any transmission licensee's ability to meet other statutory obligations or licence obligations.

2.19 Should system conditions subsequently change, for example due to the proposed connection of a new customer, such that either immediately or in the foreseeable future, the conditions set out in paragraphs 2.18.1 to 2.18.3 are no longer satisfied, then alternative arrangements and/or agreements must be put in place such that this Standard continues to be satisfied.

2.20 The additional operational costs referred to in paragraph 2.18.2 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 G.

System Resilience

2.21 In order to reflect the greater risk of an impact on the operating frequency of the GB system arising from a single event which could result in the disconnection of generation capacity at single circuit risk, the total generation within any zone of 200km radius of the GB network at single circuit risk shall not exceed the system Reserve capacity.

Appendix F Code Recommendations NETS SQSS Section 11 (Definitions)

Recommendations for additional Terms and Definitions arising from proposed modifications to sections 2 and 3 of the NETS SQSS which will require to be included within Section 11 of the Standard:

Group Aggregate Generation Capacity	The arithmetical summation of the Connection Entry Capacity (expressed in MW) for each generation site connected to a single transmission connection point. No allowance is made for diversity or non-simultaneous peaks.
Generation Circuit	~~The sole electrical connection between one or more onshore generating units and the Main Interconnected Transmission System i.e. a radial circuit which if removed would disconnect the onshore generating units.~~ The sole electrical connection between one or more onshore generating units and the National Electricity Transmission System (NETS), i.e. a radial circuit which if removed would disconnect the onshore generating units. This specifically excludes radial transmission circuits which are used to connect one or more generators to the transmission system which, if removed, would have a similar effect.
Main Interconnected Transmission System (MITS)	This comprises all the 400kV and 275kV elements of the onshore transmission system and, in Scotland, the 132kV elements of the onshore transmission system operated in parallel with the supergrid, and any elements of an offshore transmission system operated in parallel with the supergrid, but excludes generation circuits, transformer and transformer feeder connections to lower voltage systems, radial circuits which do not necessarily terminate on transformer connections to lower voltage systems (irrespective of system entry or exit purposes), external interconnections between the onshore transmission system and external systems, and any offshore transmission systems radially connected to the onshore transmission system via single interface points.

Appendix G Code Recommendations NETS SQSS Appendix A (S/S Configurations)

Part 1 – *Onshore Transmission System*

~~A.1 The recommendations set out in paragraphs A.2 to A.6 apply to the *onshore transmission system*~~

~~A.2 The key factors which must be considered when planning the *onshore transmission system* substation include:~~

~~A.2.1 Security and Quality of Supply - Relevant criteria are presented in Sections 2, 3 and 4.~~

~~A.2.2 Extendibility - The design should allow for the forecast need for future extensions.~~

~~A.2.3 Maintainability - The design must take account of the practicalities of maintaining the substation and associated circuits.~~

~~A.2.4 Operational Flexibility - The physical layout of individual circuits and groups of circuits must permit the required power flow control.~~

~~A.2.5 Protection Arrangements - The design must allow for adequate protection of each system element.~~

~~A.2.6 Short Circuit Limitations - In order to contain short circuit currents to acceptable levels, *busbar* arrangements with sectioning facilities may be required to allow the system to be split or re-connected through a fault current limiting reactor.~~

~~A.2.7 Land Area - The low availability and/or high cost of land particularly in densely populated areas may place a restriction on the size and consequent layout of the substation.~~

~~A.2.8 Cost~~

~~A.3 Accordingly the design of a substation is a function of prevailing circumstances and future requirements as perceived in the planning time phase. This appendix is intended as a functional guidance for substation layout design and switchgear arrangements. Variations away from this guidance are permissible provided that such variations comply with the requirements of the criteria set out in the main text of this Standard.~~

~~*Generation Point of Connection* Substations~~

~~A.4 In accordance with the planning criteria for generation connection set out in Section 2, *generation point of connection* substations should:~~

~~A.4.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *generation circuits* and *onshore transmission circuits* may be selected to either);~~

~~A.4.2 have sufficient *busbar* sections to permit the requirements of paragraph 2.6 to be met without splitting the substation during maintenance of *busbar* sections;~~

~~A.4.3 have sufficient *busbar* coupler and/or *busbar* section circuit breakers so that each section of the main and reserve *busbar* may be energised using either a *busbar* coupler or *busbar* section circuit breaker;~~

~~A.4.4 have *generation circuits* and *onshore transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and~~

~~A.4.5 have sufficient facilities to permit the transfer of *generation circuits* and *onshore transmission circuits* from one section of the main *busbar* to another.~~

~~*Marshalling Substations*~~

~~A.5 The recommended arrangements for *Marshalling substations* are shown in Figures xxxx.~~
~~Where reasonably practicable, *Marshalling substations* should:-~~

~~A.5.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *onshore transmission circuits* may be selected to either);~~

~~A.5.2 have sufficient *busbar* sections to permit the requirements of paragraphs 2.6, 4.6 and 4.9 to be met;~~

~~A.5.3 have *onshore transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and~~

~~A.5.4 have sufficient facilities to permit the transfer of *onshore transmission circuits* from one section of *busbar* to another.~~

~~***Grid Supply Point* Substations**~~

~~A.6 In accordance with the planning criteria for demand connection set out in Section 3., *GSP* substations configurations range from a single transformer teed into an *onshore transmission circuit* to a four switched mesh substation or a double *busbar* substation. The choice and need for the extendibility will depend on the circumstances as perceived in the planning time phase.~~

SQSS Appendix A Recommended Substation Configuration and Switching Arrangements

Part 1 – *Onshore Transmission System*

A.1 The recommendations set out in paragraphs A.2 to A.6 apply to the *onshore transmission system*

A.2 The key factors which must be considered when planning the *onshore transmission system* substation include:

A.2.1 Security and Quality of Supply - Relevant criteria are presented in Sections 2, 3 and 4.

A.2.2 Extendibility - The design should allow for the forecast need for future extensions.

A.2.3 Maintainability - The design must take account of the practicalities of maintaining the substation and associated circuits.

A.2.4 Operational Flexibility - The physical layout of individual circuits and groups of circuits must permit the required power flow control.

A.2.5 Protection Arrangements - The design must allow for adequate protection of each system element.

A.2.6 Short Circuit Limitations - In order to contain short circuit currents to acceptable levels, *busbar* arrangements with sectioning facilities may be required to allow the system to be split or re-connected through a fault current limiting reactor.

A.2.7 Land Area - The low availability and/or high cost of land particularly in densely populated areas may place a restriction on the size and consequent layout of the substation.

A.2.8 Cost

A.3 Accordingly the design of a substation is a function of prevailing circumstances and future requirements as perceived in the planning time phase. This appendix is intended as a functional guidance for substation layout design and switchgear arrangements. Variations away from this guidance are permissible provided that such variations comply with the requirements of the criteria set out in the main text of this Standard. Figures shown consider functionality and therefore are not exhaustive in presenting all associated equipment. For example, in many of the figures disconnectors (e.g. on either side of a circuit breaker) have not been shown in the interests of clarity. Their existence is inferred as, on a practical level, they will be required to enable equipment maintenance and operation.

***Generation Point of Connection* Substations**
Non-Firm Connections

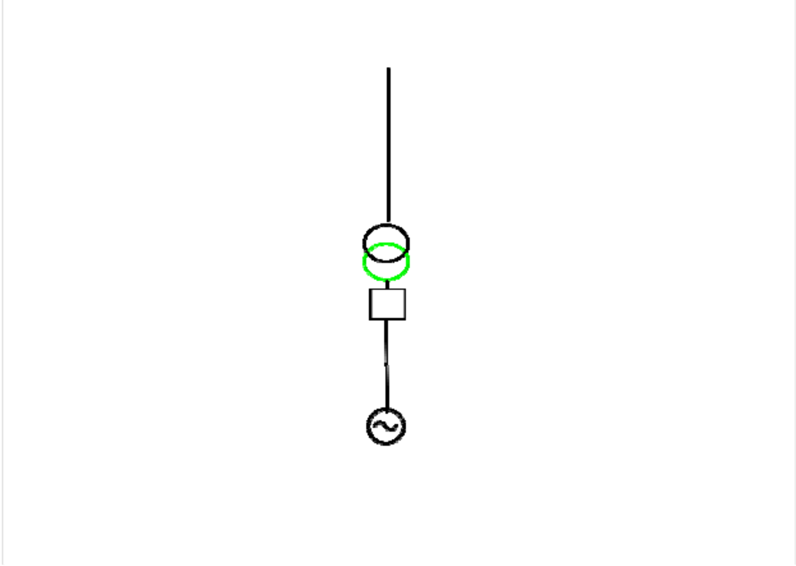
A.4 The principles adopted in recommending switching standards at substations connecting moderate generating stations with operating regimes or source fuels which result in low load factor operation or intermittent / unpredictable power output, are:

A.4.1 the connection arrangement and consequential security is reflective of generation capacity and intermittency factor.

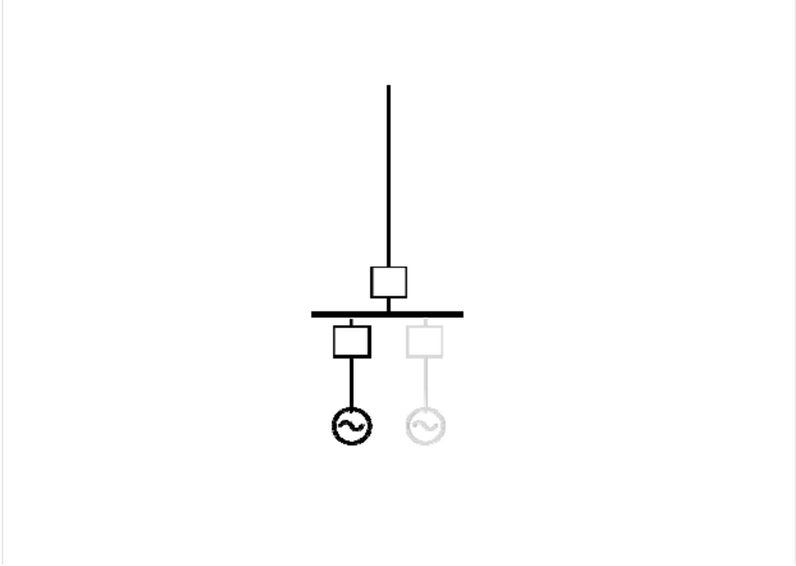
A.4.2 circuit switching or unplanned outages may result in loss or all of the associated generation capacity. By application of the criteria, no single fault should disconnect more than twice the infrequent infeed loss risk

A.4.3 The recommended switching arrangements resulting from these principles are shown in Figures A.4.3.1 to A.4.3.5. These switching arrangements are provided for guidance but are not considered exhaustive – many other permutations and configurations will be available provided they comply with the relevant section of this Standard.

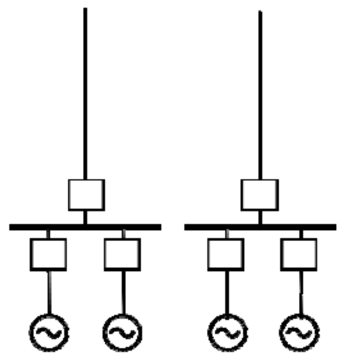
A.4.3.1 Single Circuit Radial, Sub-Transmission Connection Voltage



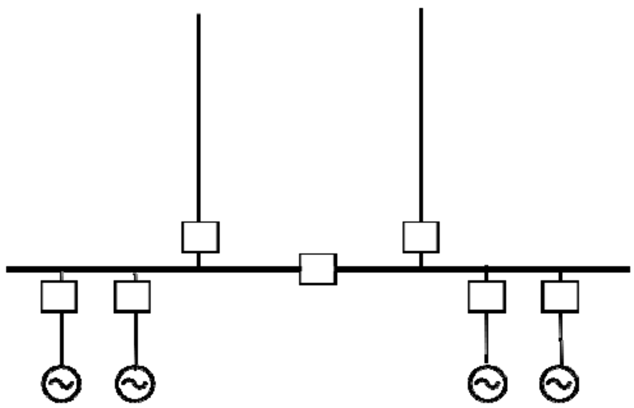
A.4.3.2 Single Circuit Radial, Transmission Connection Voltage



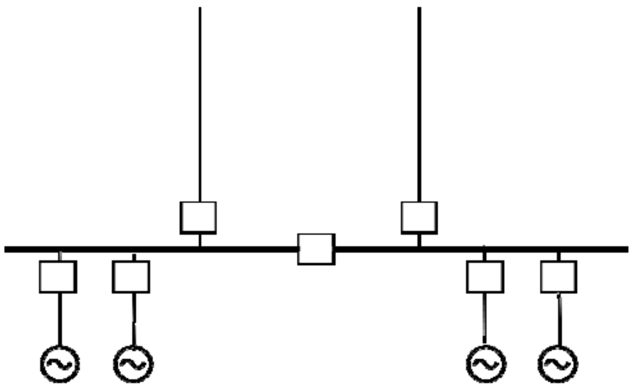
A.4.3.3 Non-firm, two single circuits, no interconnection



A.4.3.4 Non-firm, two circuits of reduced capacity



A.4.3.5 Non-firm, two fully rated circuits



Firm Connections

A.5 Where, in accordance with the planning criteria for generation connection set out in Section 2, the Generation should be secured on a firm connection (or the generator has opted under customer choice to have a firm connection) the recommended switching standards at substations are:

A.5.1 the main *busbar* to be sectionalized so that the loss of generating capacity on the disconnection of any one section of *busbars* is limited to the infrequent infeed loss risk

A.5.2 the circuit assignment should be arranged so that no single fault should disconnect more than twice the infrequent infeed loss risk

A.5.3 the reserve *busbar* should be normally uncommitted at the planning stage, but arranged to be available at the operating stage for either:

A.5.3.1 temporary replacement of one of the sections of main *busbar*, or,

A.5.3.2 transfer of circuits from one side to the other of any opening in the main *busbar.*

A.6 In application of these criteria, the *generation point of connection* substations should:

A.6.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *generation circuits* and *onshore transmission circuits* may be selected to either);

A.6.2 have sufficient *busbar* sections to permit the requirements of paragraph 2.6 to be met without splitting the substation during maintenance of *busbar* sections;

A.6.3 have sufficient *busbar* coupler and/or *busbar* section circuit breakers so that each section of the main and reserve *busbar* may be energised using either a *busbar* coupler or *busbar* section circuit breaker;

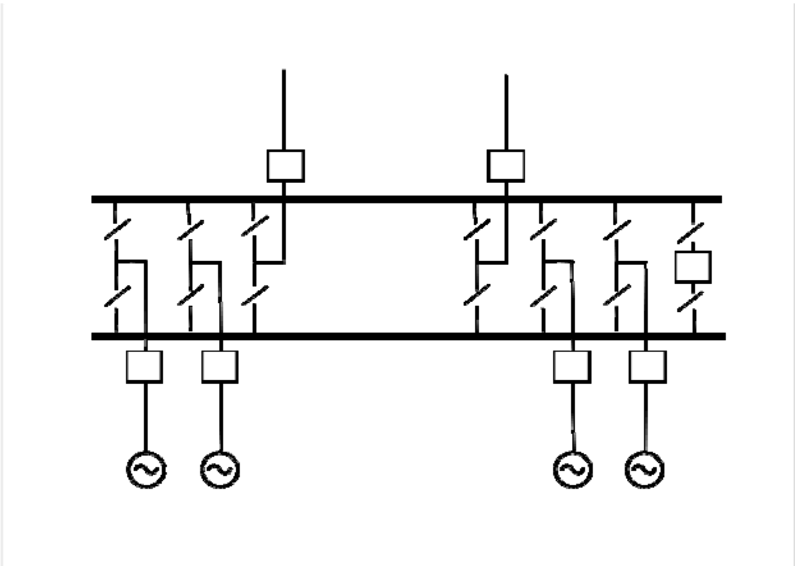
A.6.4 have *generation circuits* and *onshore transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and

A.6.5 have sufficient facilities to permit the transfer of *generation circuits* and *onshore transmission circuits* from one section of the main *busbar* to another.

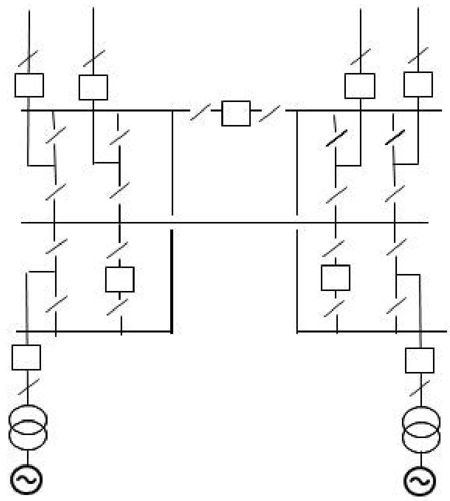
A.6.6 It is recommended that only one reserve bar section isolator should be provided at double busbar substations, as this will usually be operationally adequate. The provision of second isolators should be confined to the special cases where there is a specific operational need for maintenance of the bus-section isolator with an adjoining part of the reserve bar alive.

A.6.7 The recommended switching arrangements resulting from these principles are shown in the following figures for the use of wrap-round *busbars* with both central and outside 'main' bar; also for a straight *busbar* arrangement. Short-circuit equipment limitations should be assessed when considering larger sites with multiple circuits and generating units which may require that these sites need to be operated in two sections. Therefore, the more comprehensive developments are essentially two simpler designs with coupling facilities via an additional section breaker. These switching arrangements are provided for guidance but are not considered exhaustive – many other permutations and configurations will be available provided they comply with the relevant section of this Standard.

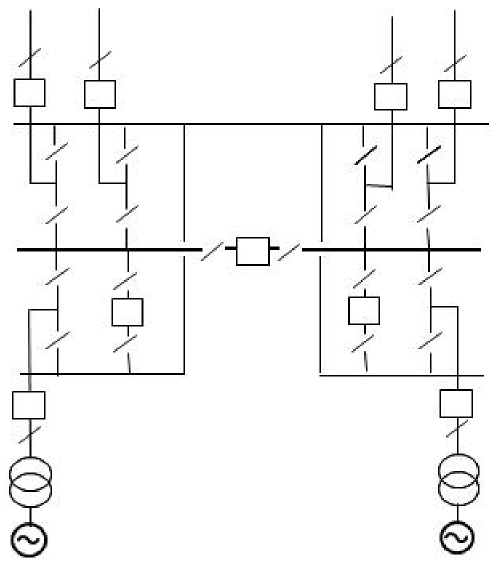
A.6.7.1 Firm connection, 2 circuits, two section double busbar



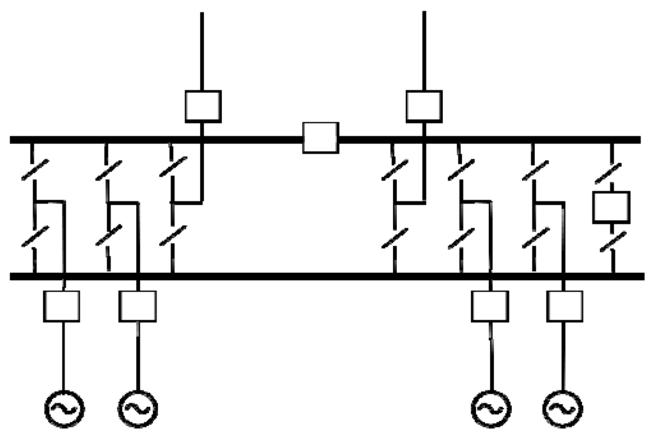
A.6.7.2 Firm connection, Two section wrap-around busbar, main b'bar outside



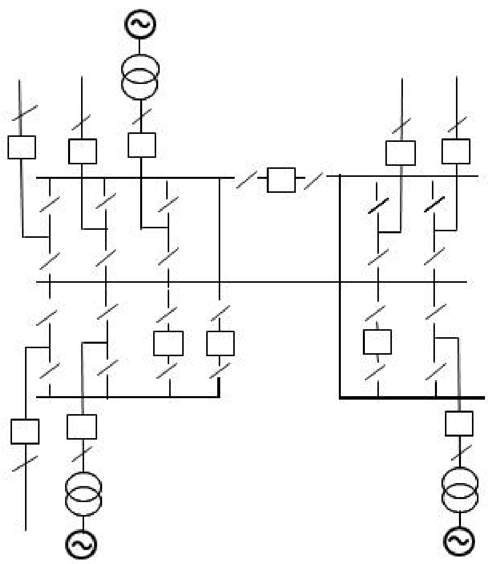
A.6.7.3 Firm connection, Two section wrap-around busbar, main b'bar central



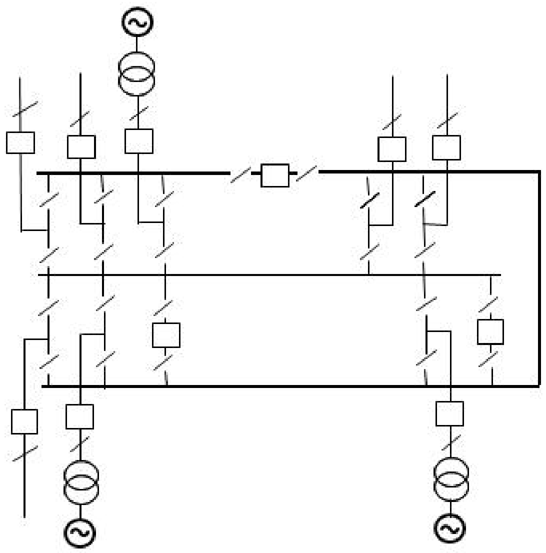
A.6.7.4 Firm connection, 2 circuits, three section double busbar



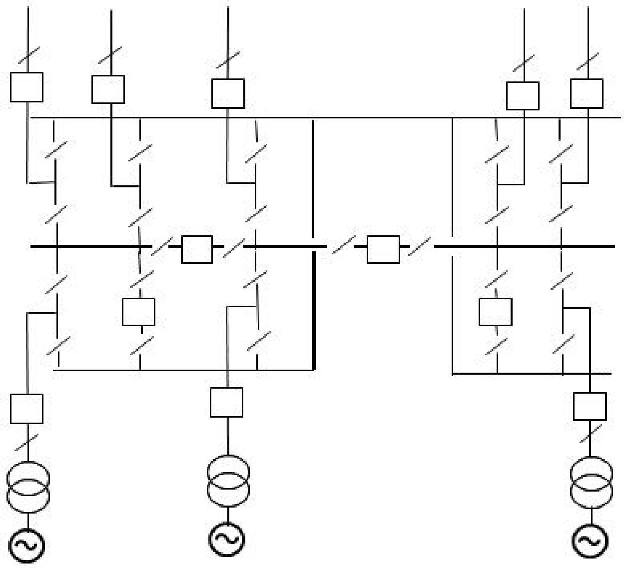
A.6.7.5 Firm connection, three section wrap-around busbar, main b'bar outside



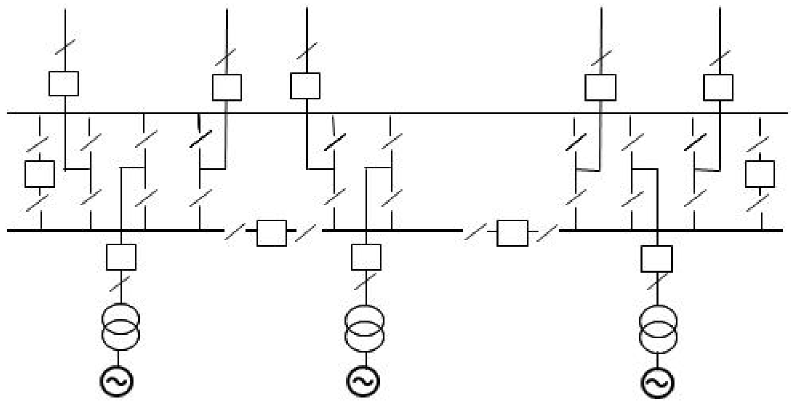
A.6.7.6 Firm connection, three section wrap-around busbar, (B/B end-wrap)



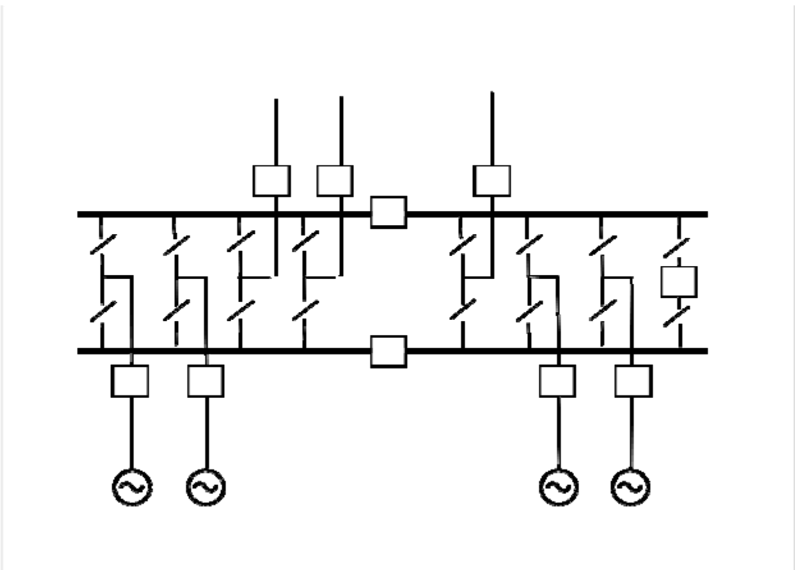
A.6.7.7 Firm connection, three section wrap-around busbar, main b'bar central



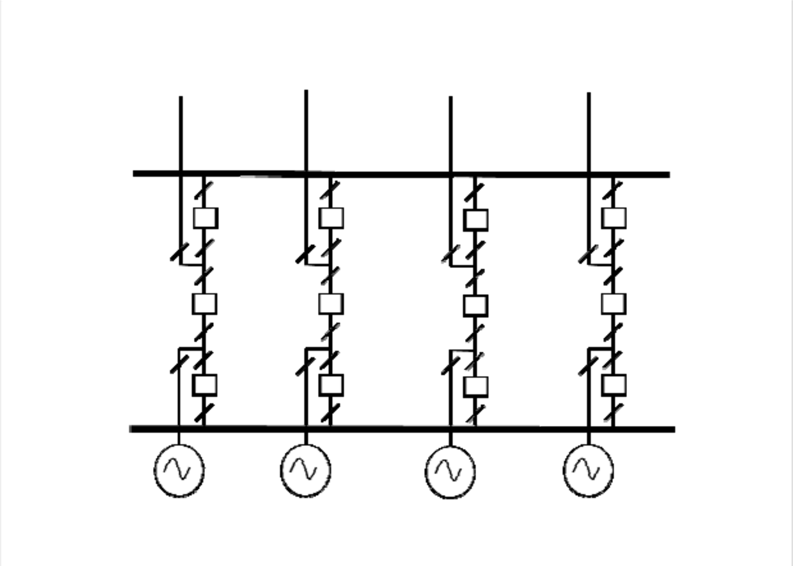
A.6.7.8 Firm connection, three section wrap-around busbar, main b'bar central



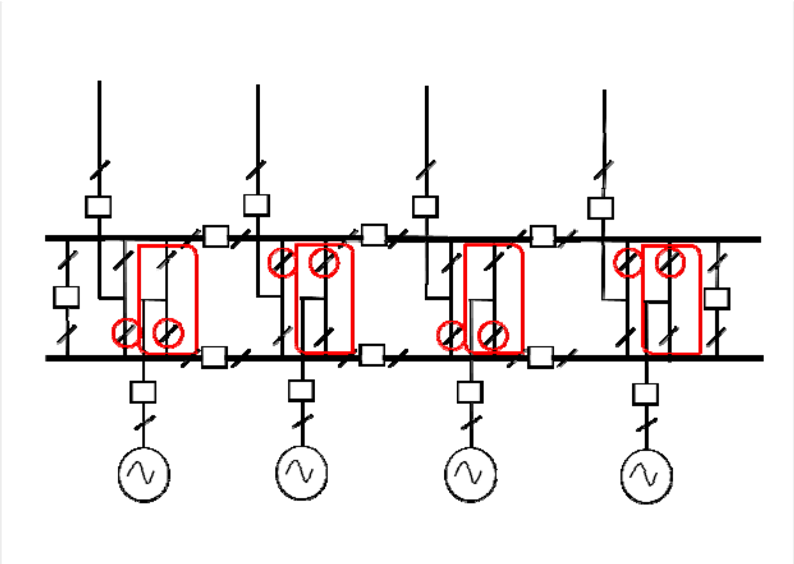
A.6.7.9 Firm connection, 3 circuits, four section double busbar



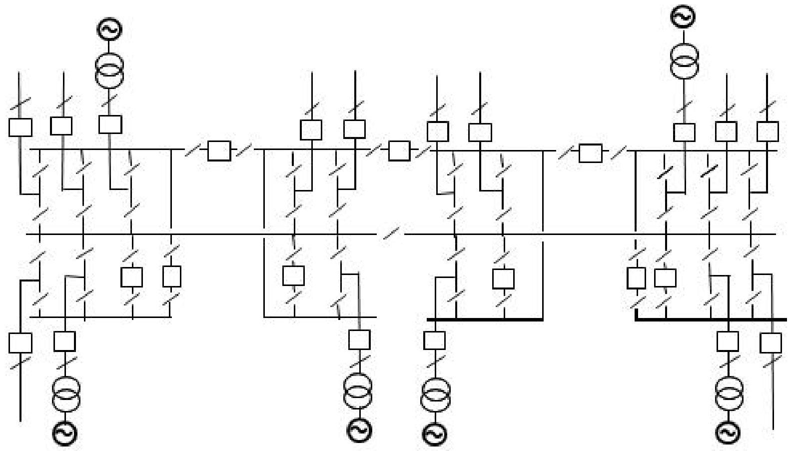
A.6.7.10 Firm connection, 4 circuits, 1½ switch layout busbar



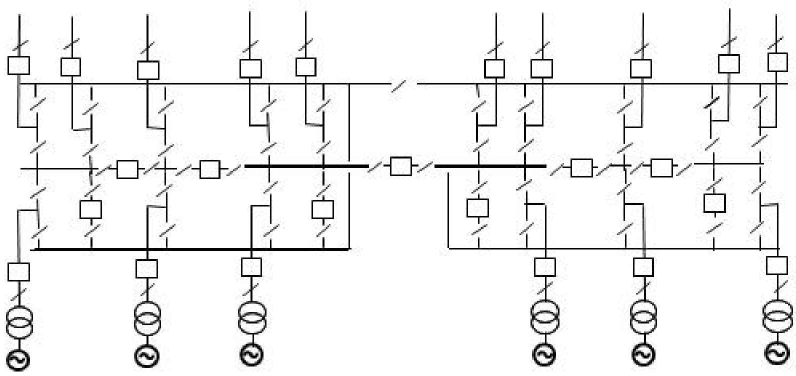
A.6.7.11 Firm connection, 4 circuits, Multi-mesh arrangement



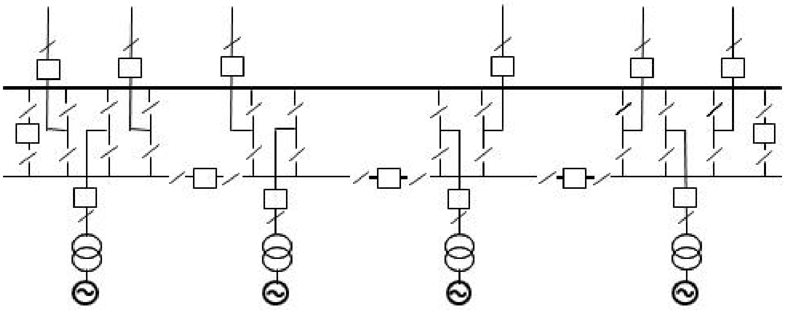
A.6.7.12 Firm connection, four section Wrap-Round Busbar, Outside Main



A.6.7.13 Firm connection, four section Wrap-Round Busbar, Central Main



A.6.7.14 Firm connection, four section Double Busbar

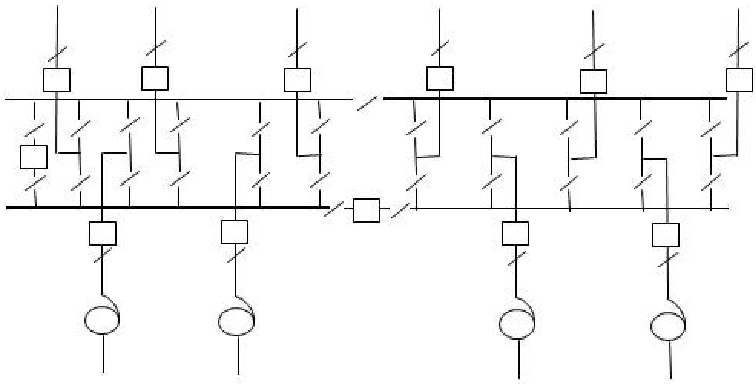


Marshalling Substations

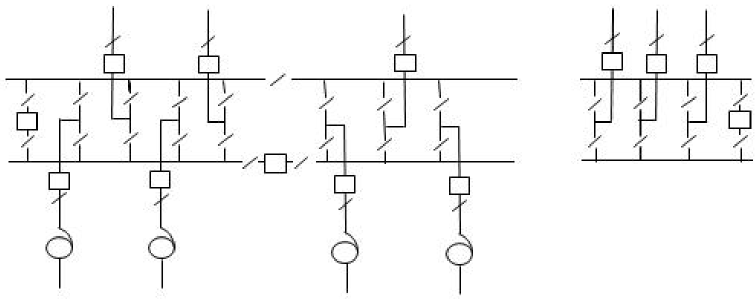
A.7 The recommended arrangements for *Marshalling substations* are shown in Figures xxxx. Where reasonably practicable, *Marshalling substations* should:-

- A.7.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *onshore transmission circuits* may be selected to either);
- A.7.2 the reserve busbar should be normally uncommitted at the planning stage, but arranged to be available at the operating stage for either:
  - A.7.2.1 temporary replacement of one of the sections of main busbar, or,
  - A.7.2.2 transfer of circuits from one side to the other of any opening in the main busbar.
- A.7.3 One bus-coupler is considered sufficient for up to, and including, six circuits;
- A.7.4 have sufficient *busbar* sections to permit the requirements of paragraphs 2.6, 4.6 and 4.9 to be met;
- A.7.5 have *onshore transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and
- A.7.6 have sufficient facilities to permit the transfer of *onshore transmission circuits* from one section of *busbar* to another.
- A.7.7 The recommended switching arrangements resulting from these principles are shown in Figures A.7.7.1 to A.7.7.5. These switching arrangements are provided for guidance but are not considered exhaustive – many other permutations and configurations will be available provided they comply with the relevant section of this Standard.

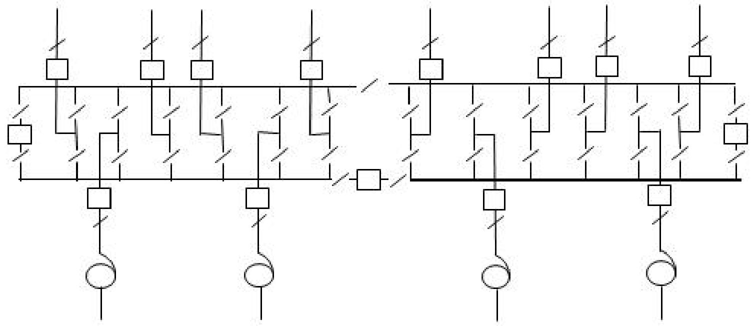
A.7.7.1 Six circuit marshalling Substation, double busbar arrangement



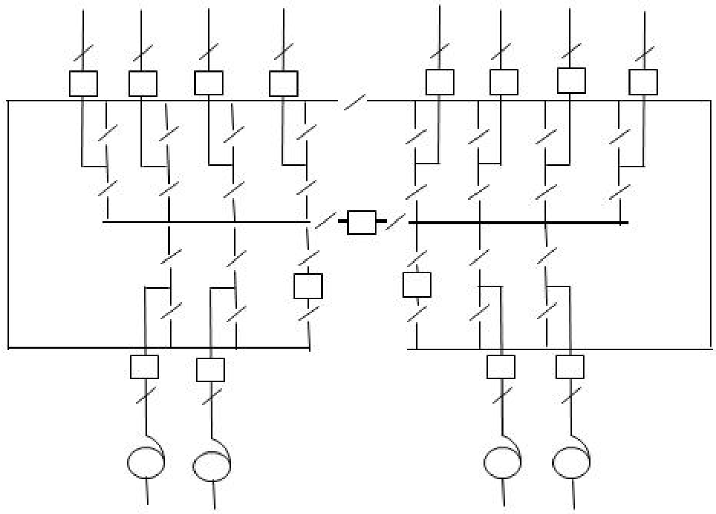
A.7.7.2 Six circuit marshalling Substation, double B'bar with physical split



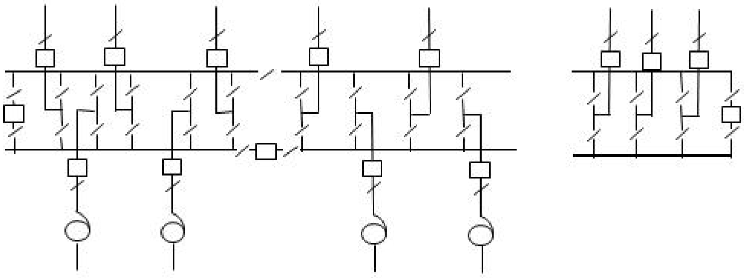
A.7.7.3 Eight circuit marshalling Substation, Double busbar arrangement



A.7.7.4 Eight circuit marshalling Substation, Wrap-Around busbar



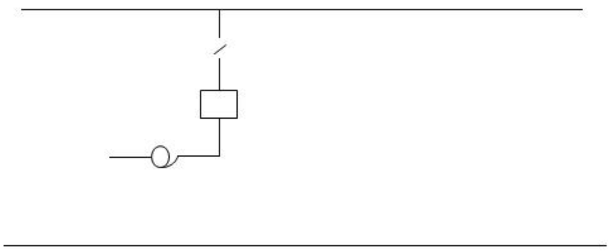
A.7.7.5 Eight circuit marshalling Substation, double b'bar & physical split



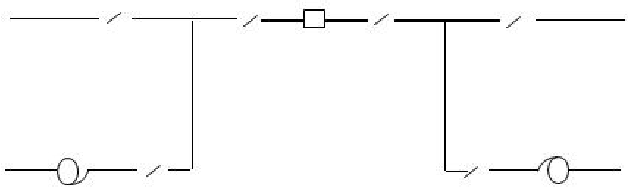
***Grid Supply Point* Substations**

A.8 In accordance with the planning criteria for demand connection set out in Section 3, *GSP* substations configurations range from a single transformer teed into an *onshore transmission circuit* to a four switched mesh substation or a double *busbar* substation. The choice and need for the extendibility will depend on the circumstances as perceived in the planning time phase.

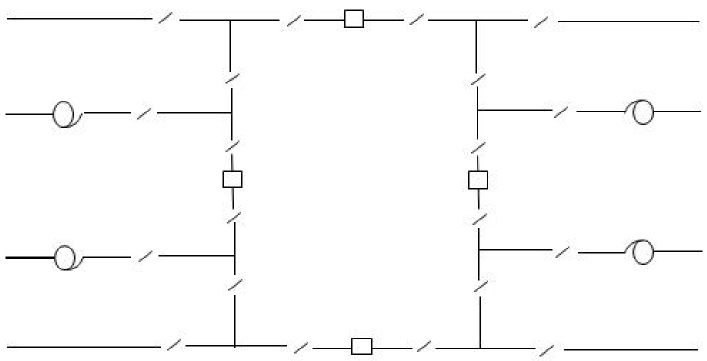
A.8.1 Single Transformer Tee



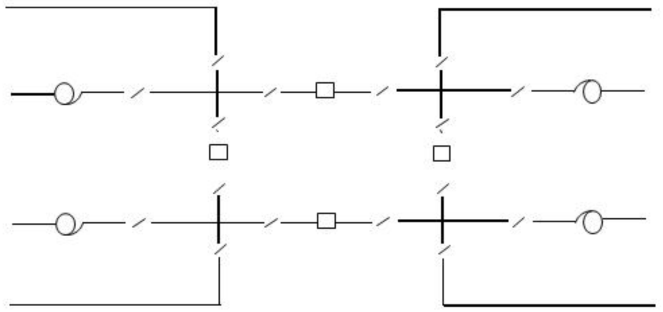
A.8.2 Single Switch



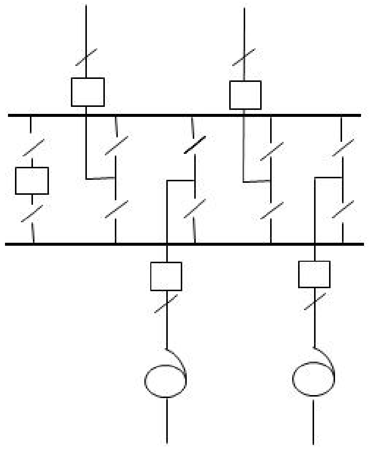
A.8.3 Mesh Substation, Semi-Independent Banked



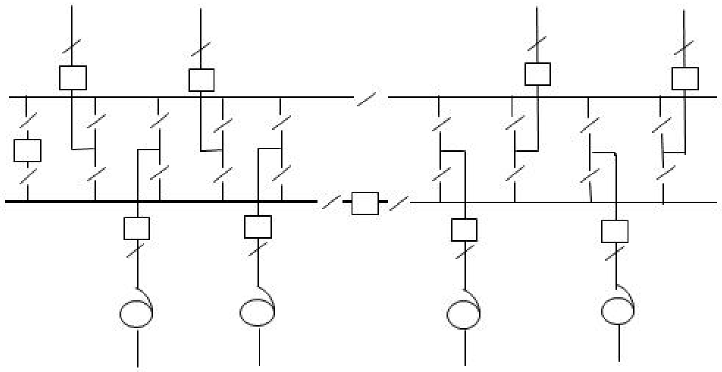
A.8.4 Mesh Substation, Independent Banked



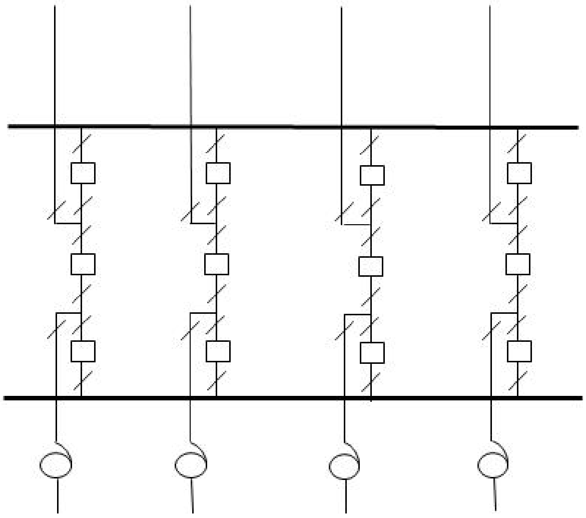
A.8.5 Two section double busbar arrangement



A.8.7 Three section double busbar arrangement



A.8.8 'One-and-a-Half-Switch' Arrangement



Part 2 – *Offshore Transmission Systems*

A.~~7~~9 The recommendations set out in paragraphs A.7 to A.15 apply to *offshore transmission systems*

A.~~8~~10 The key factors which must be considered when planning an *offshore transmission system* substation include:

A.~~8~~10.1 Security and Quality of Supply - Relevant criteria are presented in Sections 7 and 8.

A.~~8~~10.2 Maintainability - The design must take account of the practicalities of maintaining the substation and associated circuits.

A.~~8~~10.3 Operational Flexibility - The physical layout of individual circuits and groups of circuits must permit the required power flow control.

A.~~8~~10.4 Protection Arrangements - The design must allow for adequate protection of each system element.

A.~~8~~10.5 Short Circuit Limitations - In order to contain short circuit currents to acceptable levels, *busbar* arrangements with sectioning facilities may be required to allow the system to be split or re-connected through a fault current limiting reactor.

A.~~8~~10.6 Available Area – The high cost of the *offshore platform* may place a restriction on the size and consequent layout of the substation.

A.~~8~~10.7 Cost

A.~~9~~11 Accordingly the design of a substation is a function of prevailing circumstances and future requirements as perceived in the planning time phase. This appendix is intended as a functional guidance for substation layout design and switchgear arrangements. Variations away from this guidance are permissible provided that such variations comply with the requirements of the criteria set out in the main text of this Standard.

***Offshore Transmission System* Substations**

GEP, IP and *USIP* Substations

A.~~10~~12 The following recommendations apply equally to substations at the:

A.~~10~~12.1 Offshore *Grid Entry Point* (on the *Offshore Platform*);

A.~~10~~12.1 Onshore *Interface Point* (at the *First Onshore Substation*); and

A.~~10~~12.1 Onshore *User System Interface Point* (at the *First Onshore Substation*)

A.~~11~~13 In accordance with the planning criteria for offshore generation connection set out in Section 7, the substation should in the case of an offshore power park module and multiple gas turbine connections:

A.~~11~~13.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that offshore generation circuits owned by the generator and *offshore transmission circuits* may be selected to either);

A.~~11~~13.2 have sufficient *busbar* sections to permit the requirements of paragraph 7.8 to be met without splitting the substation during maintenance of *busbar* sections;

A.~~11~~13.3 have sufficient *busbar* coupler and/or *busbar* section circuit breakers so that each section of the main and reserve *busbar* may be energised using either a *busbar* coupler or *busbar* section circuit breaker; and

A.~~11~~13.4 have sufficient facilities to permit the transfer of offshore generation circuits owned by the generator and *offshore transmission circuits* from one section of the main *busbar* to another.

A.~~12~~14 In the case of a single gas turbine connection and in accordance with the planning criteria for offshore generation connection set out in Section 7, the substation should have a single *busbar* design;

Marshalling Substations

A.~~13~~15 The following recommendations apply to offshore *marshalling substations*, which interconnect *offshore transmission circuits* from two or more *offshore platforms*, where offshore *grid entry points* are located, and the *first onshore substation,* where the *interface point* or *user system interface point* is located.

A.~~14~~16 *Marshalling Substations* should:

A.~~14~~16.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *offshore transmission circuits* may be selected to either);

A.~~14~~16.2 have sufficient *busbar* sections to permit the requirements of Section 7 to be met;

A.~~14~~16.3 have *transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and

A.~~14~~16.4 have sufficient facilities to permit the transfer of *offshore transmission circuits* from one section of busbar to another.

***Offshore Supply Point* Substations**

A.~~15~~17 *Offshore supply point substations* should be designed to meet the requirements of Section 8. The actual design will depend on the circumstances as perceived in the planning time phase.

Part 2 – *Offshore Transmission Systems*

A.7 The recommendations set out in paragraphs A.7 to A.15 apply to *offshore transmission systems*

A.8 The key factors which must be considered when planning an *offshore transmission system* substation include:

A.8.1 Security and Quality of Supply - Relevant criteria are presented in Sections 7 and 8.

A.8.2 Maintainability - The design must take account of the practicalities of maintaining the substation and associated circuits.

A.8.3 Operational Flexibility - The physical layout of individual circuits and groups of circuits must permit the required power flow control.

A.8.4 Protection Arrangements - The design must allow for adequate protection of each system element.

A.8.5 Short Circuit Limitations - In order to contain short circuit currents to acceptable levels, *busbar* arrangements with sectioning facilities may be required to allow the system to be split or re-connected through a fault current limiting reactor.

A.8.6 Available Area – The high cost of the *offshore platform* may place a restriction on the size and consequent layout of the substation.

A.8.7 Cost

A.9 Accordingly the design of a substation is a function of prevailing circumstances and future requirements as perceived in the planning time phase. This appendix is intended as a functional guidance for substation layout design and switchgear arrangements. Variations away from this guidance are permissible provided that such variations comply with the requirements of the criteria set out in the main text of this Standard.

***Offshore Transmission System* Substations**

GEP, IP and *USIP* Substations

A.10 The following recommendations apply equally to substations at the:

A10.1 Offshore *Grid Entry Point* (on the *Offshore Platform*);

A10.1 Onshore *Interface Point* (at the *First Onshore Substation*); and

A10.1 Onshore *User System Interface Point* (at the *First Onshore Substation*)

A.11 In accordance with the planning criteria for offshore generation connection set out in Section 7, the substation should in the case of an offshore power park module and multiple gas turbine connections:

A.11.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that offshore generation circuits owned by the generator and *offshore transmission circuits* may be selected to either);

A.11.2 have sufficient *busbar* sections to permit the requirements of paragraph 7.8 to be met without splitting the substation during maintenance of *busbar* sections;

A.11.3 have sufficient *busbar* coupler and/or *busbar* section circuit breakers so that each section of the main and reserve *busbar* may be energised using either a *busbar* coupler or *busbar* section circuit breaker; and

A.11.4 have sufficient facilities to permit the transfer of offshore generation circuits owned by the generator and *offshore transmission circuits* from one section of the main *busbar* to another.

A.12 In the case of a single gas turbine connection and in accordance with the planning criteria for offshore generation connection set out in Section 7, the substation should have a single *busbar* design;

Marshalling Substations

A.13 The following recommendations apply to offshore *marshalling substations*, which interconnect *offshore transmission circuits* from two or more *offshore platforms*, where offshore *grid entry points* are located, and the *first onshore substation,* where the *interface point* or *user system interface point* is located.

A.14 *Marshalling Substations* should:

A.14.1 have a double *busbar* design (i.e. with main and reserve *busbars* such that *offshore transmission circuits* may be selected to either);

A.14.2 have sufficient *busbar* sections to permit the requirements of Section 7 to be met;

A.14.3 have *transmission circuits* disposed between *busbar* sections such that the main *busbar* may be operated split for fault level control purposes; and

A.14.4 have sufficient facilities to permit the transfer of *offshore transmission circuits* from one section of busbar to another.

***Offshore Supply Point* Substations**

A.15 *Offshore supply point substations* should be designed to meet the requirements of Section 8. The actual design will depend on the circumstances as perceived in the planning time phase.