NETS SQSS

Offshore Working Group (GSR011)

Working Group Report

July 2012

Executive Summary

The SQSS was initially developed for application to the onshore transmission system. In response to the first proposals to develop offshore generation, additional criteria relating to the connection of offshore generation and demand to the MITS were introduced to the standard in June 2009. At the time that the standard was reviewed, offshore generation development was limited to relatively small wind farms in close proximity to the shore. Although the review focussed on radial connections to the MITS, amendments were introduced relating to the design and operation of an offshore network in parallel with the onshore system.

The existing NETS SQSS criteria pertaining to offshore generation connections were not developed for the generation connections envisaged for the Round 3 developments. Whilst they specify some requirements for offshore networks in providing transmission capability, those were intended to be subject to future review, and they do not address all of the issues that arise, such as the use of HVDC cables with a rating above 1800MW. Consequently, the NETS SQSS Review Group (now the SQSS Review Panel) instigated a review of the offshore criteria, to ensure that they continue to facilitate the development of an overall economic, efficient, and secure system.

The SQSS modification working group has addressed the following five questions:

1. MITS design criteria - The circuit loss criteria that should be applied in Main Interconnected Transmission System (MITS) design when offshore networks provide capacity (ie N-1, N-2)
2. Capacity Provided - The appropriate capacity of connections for round 3 zone wind farms to the transmission system
3. Interconnection of windfarms - The benefits in constraint reduction of interconnecting wind farms
4. The treatment of wind generation in wider infrastructure analysis – Are the current criteria appropriate for a system with high volumes of offshore wind generation?
5. The capacity of offshore HVDC links - The use of HVDC cables of greater capacity than the infeed loss limits in the context of offshore networks

and has made the following recommendations:

- In designing the transmission system the following should be considered as secured events: an N-1 outage of an offshore circuit; an N-1-1 outage involving an offshore circuit on prior outage followed by either an offshore circuit or an onshore circuit fault outage, and an N-1-1 condition with an onshore circuit containing a cable section on prior outage, followed by an offshore circuit fault outage. (All these terms are described in the main report.)

- In designing local connections, it is appropriate to provide a connection capacity of 100% TEC (Transmission Entry Capacity).

- For infrastructure capacity analysis, it is appropriate to consider offshore wind at 70% output, as per the criteria of the current standard.

- Short duration losses of a DC link carrying more than the Infrequent Infeed Loss can be tolerated where parallel routes can increase their flows.

The majority of the conclusions and recommendations are that the existing NETS SQSS criteria are appropriate. Consequently, the modifications to the standard that are proposed are not extensive. Draft text changes in line with the recommendations are included in this report.

Contents

1 Introduction

The National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) specifies criteria for the design and operation of the GB electricity transmission system. The criteria apply to both generation and demand connections, and to the Main Interconnected Transmission System (MITS).

The SQSS was initially developed for application to the onshore system. In response to the first proposals to develop offshore generation, additional criteria relating to the connection of offshore generation and demand to the MITS were introduced to the standard in June 2009. At the time that the standard was reviewed, offshore generation development was limited to relatively small wind farms in close proximity to the shore. Consequently the scope of the review, and the resulting criteria, were based on generation capacities of less than 1500 MW, with radial connections to shore of less than 100km. Although the review focussed on radial connections to the MITS, amendments were introduced relating to the design and operation of an offshore network in parallel with the onshore system. The standard states that the criteria that were introduced should apply until reviewed.

Subsequent reviews of the maximum infeed loss criteria relating to the whole GB system (GSR007/7a) resulted in changes to the offshore criteria such that generation with a capacity up to 1800MW can be radially connected via a single cable. The amendment reports are available at:

http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/LiveAmendments

In June 2008, The Crown Estate made available further significant tranches of seabed around GB for the development of renewable generation. These tranches are referred to as Round 3 sites. The Round 3 sites are much further from shore (some sites go up to 300km) than those previously considered, and have far greater potential generation capacities (up to 13 GW in one area). The economic connection of generation in these zones is likely to involve the use of HVDC circuits, and may require the use of higher capacity cables than those currently used. The use of interconnection within a Round 3 zone, and between zones, offers significant benefit in developing through routes in parallel with parts of the onshore transmission system, effectively providing reinforcement of the onshore system and forming a single interconnected network.

The existing NETS SQSS criteria pertaining to offshore generation connections were not developed for the generation connections envisaged for the Round 3 developments. Whilst they specify some requirements for offshore networks in providing transmission capability, those were intended to be subject to future review, and they do not address all of the issues, such as the use of HVDC cables with a rating above 1800MW. Consequently, the NETS SQSS Review Group instigated a review of the offshore criteria, to ensure that they continue to facilitate the development of an overall economic, efficient, and secure system. The terms of reference of the review are included in Appendix A.

The SQSS modification working group has addressed the following five questions:

1. MITS design criteria - The circuit loss criteria that should be applied in Main Interconnected Transmission System (MITS) design when offshore networks provide capacity (ie N-1, N-2)

2. Capacity Provided - The appropriate capacity of connections for round 3 zone wind farms to the transmission system
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This report describes each of the issues considered, and makes recommendations on NETS SQSS amendments to accommodate the development of offshore networks that both connect high capacity generation developments and provide transmission capability. Proposed NETS SQSS text is included in Appendix B.

2 Related SQSS Modifications

Several reviews of the NETS SQSS have recently been undertaken, leading to a number of modifications to the standard. Of these, three are particularly relevant for for this working group. They considered the largest permitted infeed loss; the modelling of all generation in planning a system with large volumes of intermittent generation, and the types of faults that should be considered in system design. A separate working group is currently examining issues around the classification of infeed loss events, and the potential need for mitigation against multiple infeed loss events.

Infeed Loss Review (GSR007/7a)

In view of the potential future onshore connection of larger generating units than those currently connected in GB, a review of the NETS SQSS was initiated in 2007 to ensure that its criteria in relation to infeed losses were appropriate. This review proposed amendments to the SQSS to accommodate single generating units up to 1800 MW, with an implementation date to be determined by the first such connection. Subsequently the proposals were modified to fix the implementation date to 1st April 2014, and to allow the radial connection of 1800MW of offshore generation. The standard was amended to reflect these proposals in March 2011. The reports are available at:

http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/LiveAmendments

Accommodating Large Volumes of Intermittent Generation (GSR009)

The envisaged large scale development of intermittent generation in the coming years led to a review in 2010 of the SQSS criteria for MITS planning. This review proposed that infrastructure developments driven by intermittent generation should be based on their economic benefit, and put forward specifications for the treatment of all types of generation in peak demand planning analysis such that the results would emulate those from year round cost benefit analysis. In these proposals, intermittent generation is scaled to 70% of its capacity. The proposals were implemented in March 2012. The reports are available at:

http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/LiveAmendments

Regional Variations and Wider System Issues (GSR008)

The Regional Variations and Wider System Issues review covered a range of issues and has made a number of proposals. One issue was whether it is reasonable to plan the system for an N-2 fault (ie the loss of two circuits that are not on the same towers) at peak demand levels. The review has recommended that this should only be the case when one circuit contains a cable, which could be on long term outage (ie an N-1-1 fault). The link to the reports of this review can be found at:

http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/LiveAmendments

The proposals of this review are currently being considered by the Authority.

Offshore connections – loss of infeed risks (GSR011)

A parallel working group is currently considering the impacts of multiple loss events, and whether measures to reduce their likelihood or impact are necessary. This includes questions such as the likelihood of an anchor damaging several cables in a short time, and whether this leads to requirements for cable separation. It is also considering the configuration requirements for HVDC converters such that the normal infeed loss criteria[1] are met for faults in converters of higher rating than the normal infeed loss limit.

We expect this working group to conclude its work later this year.

[1] The current SQSS requirements consider the loss of a converter to be sufficiently frequent that it must meet the criteria for a normal infeed loss. This means that the frequency must not fall below 49.5 Hz. From 2014, the normal infeed loss limit will be 1320 MW.

3 Summary of Existing SQSS Criteria for Offshore Connections

The existing standard for offshore generation connections is based on analysis that only considered radial connections up to specified capacities and distances from shore. Beyond these limits, no criteria are specified. The criteria, and their limits, in Chapter 7 of SQSS can be summarised as follows;

- The capacity of offshore power park modules is limited to 1500MW. Following the review of infrequent infeed loss risk, it will be 1800MW from April 1st 2014.
- The distance of an offshore grid entry point on an offshore platform to the onshore interface point is limited to 100km.
- For a planned/fault outage of a single cable transmission circuit, the power infeed loss must be less than the infrequent infeed loss risk (1800 MW from 2014).
- For a planned/fault outage of a single AC transformer circuit or a single DC converter the power infeed loss must be less than 50% of grid entry point capacity or infrequent infeed loss risk (1320MW from 2014) – whichever is the smaller.

Chapter 4 of the NETS SQSS relates to MITS planning. The MITS includes both the onshore transmission system and parts of the offshore system in parallel with it. Under these criteria the MITS is designed to be secure for the loss of a single offshore cable (N-1), and for the loss of either an onshore or offshore transmission circuit with a prior outage of an offshore circuit (N-1-1). Chapter 7 includes a note that the criteria of chapter 4 should apply until reviewed. Section 4.1 of this report further describes the MITS planning criteria.

The operation of offshore transmission is covered in chapter 9. This specifies that, under all prevailing conditions (demand and generation level, circuit outages), the loss of an offshore transmission circuit shall not lead to unacceptable operating conditions on the MITS.

The voltage limits applicable to an offshore system are specified in chapter 10. These are based on the assumptions that there is little demand offshore, and that the main factor is the rating of the plant.

4 Issues Considered by the Working Group

The review has addressed issues relating to:

1. MITS design criteria - The circuit loss criteria that should be applied in Main Interconnected Transmission System (MITS) design when offshore networks provide capacity (ie N-1, N-2)
2. Capacity Provided - The appropriate capacity of connections for round 3 zone wind farms to the transmission system
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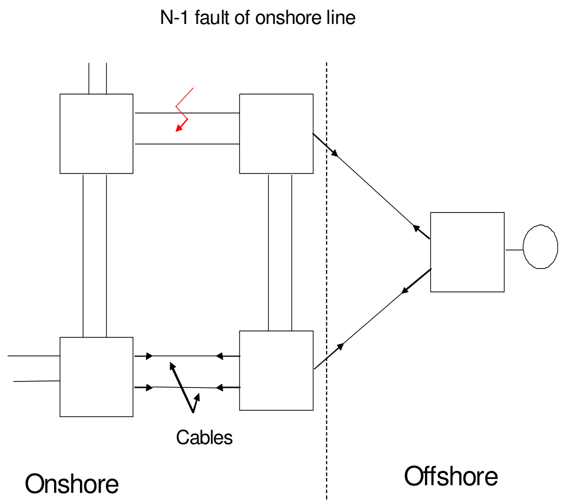
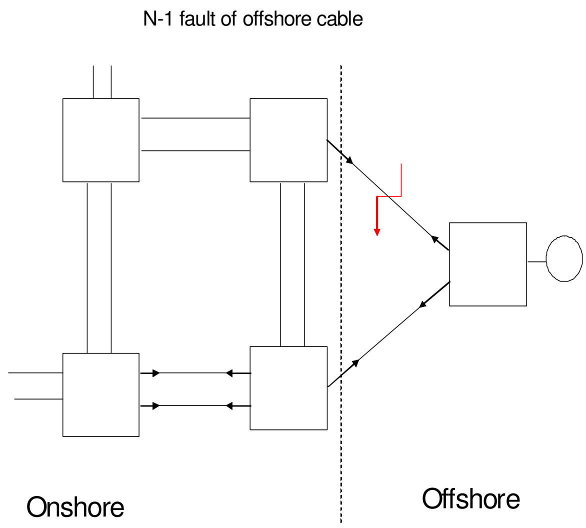
The review has not considered the existing criteria relating to whether particular events leading to an infeed loss, such as a cable loss or a converter loss, should be considered as infrequent or normal, and whether the infeed loss limits are appropriate. A separate working group, Offshore connections – loss of infeed risks (GSR013), is currently considering the impacts of multiple infeed losses, and the need for mitigation measures.

4.1 Offshore Contingencies

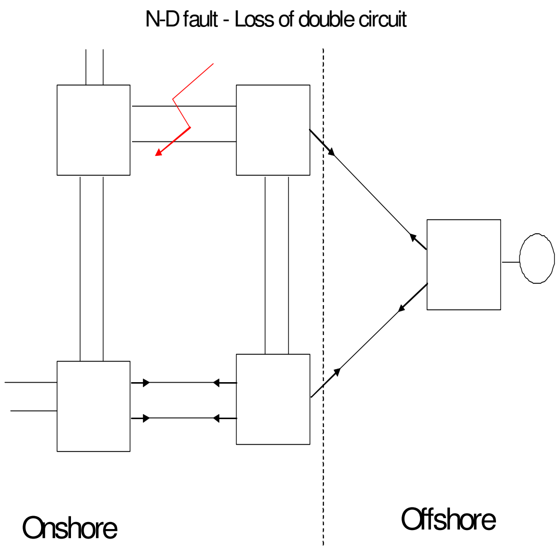
As the 'NETS' evolves towards an integrated onshore/ offshore network, system boundaries will traverse a more complex mixture of onshore and offshore circuits. The capability requirements of such boundaries fall within the scope of SQSS Chapter 4 which sets out the criteria for designing the Main Interconnected Transmission System (MITS). Under these criteria, the system is planned to be robust against:

The loss of a single transmission circuit (onshore or offshore)



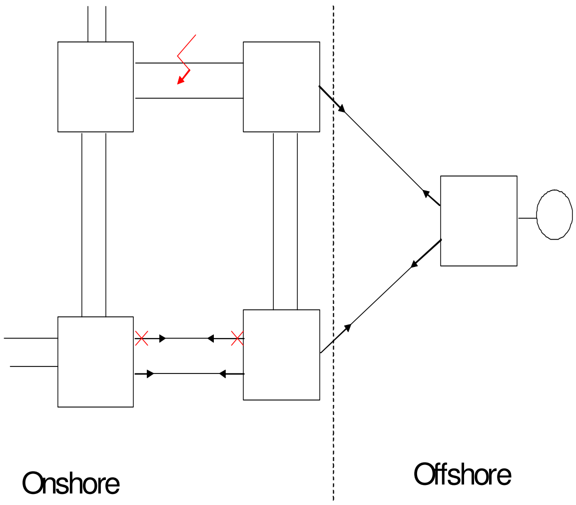


The simultaneous loss of two circuits on common towers (N-D)

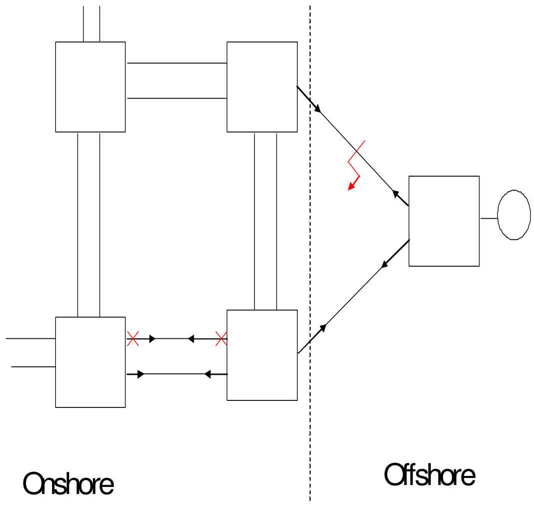


The loss of a single circuit with a prior outage of another circuit (N-1-1). The proposals of GSR008 will modify this to the loss of a single circuit with a prior outage of another circuit only when the prior outage is a cable circuit (because at peak demand levels circuit outages will be due to faults rather than maintenance, and cable fault outages are generally significantly longer than for overhead lines, increasing the probability of concurrence with a fault).

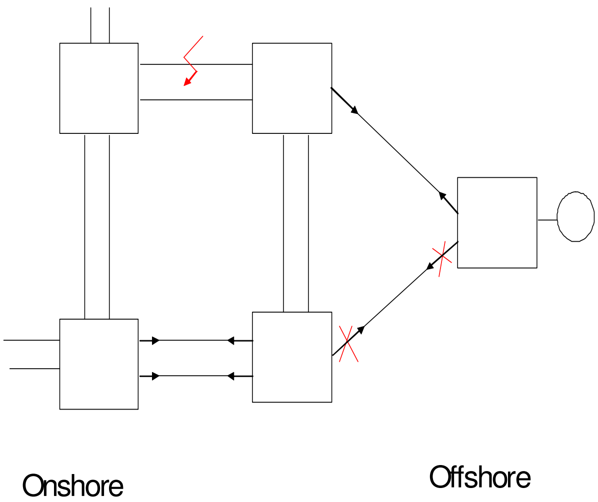
N-1-1 fault : Single circuit loss with prior outage of onshore cable



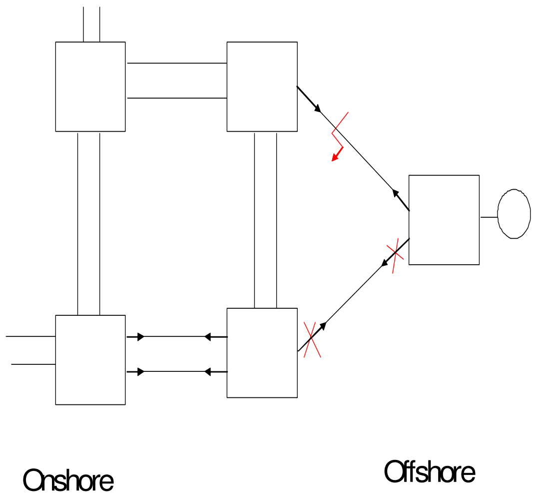
N-1-1 fault : Single circuit loss with prior outage of onshore cable



N-1-1 fault : Single circuit loss with prior outage of offshore cable

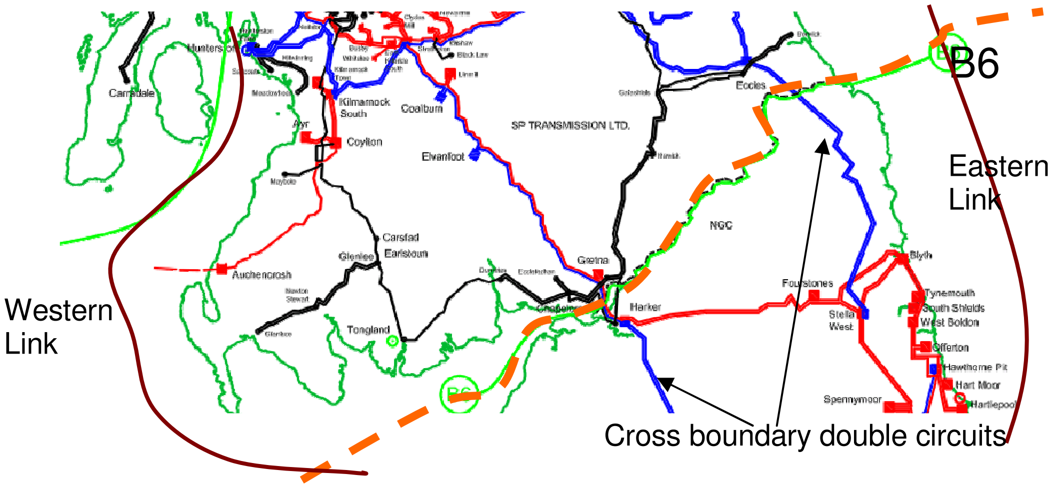


N-1-1 fault : Single circuit loss with prior outage of offshore cable



This review has considered whether the fault rates and down-times of offshore HVDC transmission circuits are sufficiently different from those of onshore AC circuits, such that a different contingency criterion is warranted, from the current N–1-1 / N–D criterion of Chapter 4.

The analysis has considered the Anglo-Scottish (B6) boundary as an example boundary, but if the proposals are supported the new standard would apply to all boundaries. This example boundary contains four onshore AC circuits of 100km OHL, configured as two double circuits, and for this analysis is deemed to contain two offshore circuits of 400km cable – Western Link and potential Eastern Link.



Based on the basic fault rate and downtime assumptions of onshore and offshore circuits (Appendix C), the following criteria are formed

N–1 Criterion

Each of the four onshore AC circuits shown above will experience 0.5 transient (restored in less than a minute), plus 0.12 sustained faults per year (as demonstrated in Appendix C).

Each of the offshore HVDC cables may experience 1.0 bipole faults per year. The nature of offshore cable faults means that virtually all of these will be sustained. Note – based on the fault rated of existing HVDC converters, HVDC link faults will be more frequent if converter faults are included. However, it is expected that the HVDC links used to provide transmission capacity will be configured as bipoles, and so converter faults will only result in a loss of half of the link capacity, and they have not been included in this analysis.

Despite this, it is evident that the N–1 faults offshore are likely to have higher incident rates than onshore faults, **and so N-1 criterion must apply equally to offshore as onshore circuits.**

N–D Criterion

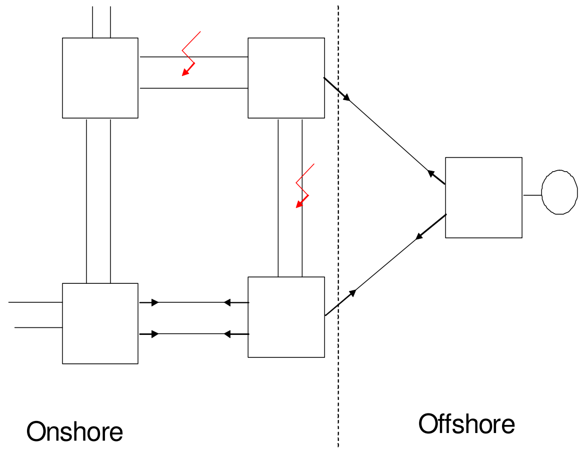
Each of the two onshore AC double circuit routes, on the data in Appendix C, will experience 0.05 transient plus 0.05 sustained faults per year. (This equates to one fault per double circuit per decade.)

This observation sets the benchmark of 0.1 (0.05 + 0.05) double circuit faults per year, for the frequency rate appropriate to secure, to be compatible with the N–D security level of the SQSS.

N–2 Instantaneous Fault

The most likely mechanism for an onshore instantaneous N–2 simultaneous fault (ie: two independent N-1 faults happening at the same time) is a fault on one circuit, accompanied by a protection mal-operation on another circuit (which is not the double-circuit pair of the first).

N-2 fault : Simultaneous loss of 2 circuits on different towers



On average, we experience two such protection mal-operations per year – i.e. across the 100 single-circuit faults National Grid experience each year, there is a 2% chance that any of them is accompanied by a protection mal-operation.

For the four onshore B6 circuits in our example, they will see

4x 0.62 (0.5 transient + 0.12 sustained) = 2.5 faults per year on this boundary

and hence 2% x 2.5 = 0.05 faults with coincident protection mal-operations.

Since more than half of these mal-operations will trip some local but non-B6 circuit (e.g. a Strathaven-Inverkip or a Blyth-Harker), the rate of instantaneous N–2 faults on B6 circuits will be less than 0.02 per year, or less than once in fifty years. It is for this reason that the existing NETS SQSS criteria do not require an N–2 instantaneous fault to be secured in Planning.

The same argument applies to the combination of instantaneous onshore and offshore N–2 instantaneous faults. The chances of protection mal-operation across the different AC and DC technologies will be lower than the onshore probabilities across AC alone; and so **the instantaneous onshore and offshore N–2 event does not need to be considered**. Similarly, **the instantaneous loss of the two offshore circuits is considered to be of very low probability and does not need to be considered**, because they are independent circuits, the probability of a fault on either cable is lower than the probability of a fault on one of the AC circuits, and the probability of protection mal-operation is not expected to be higher than for the AC circuits.

N–1–1 Fault

The planning criteria require that, at the time of peak demand, the system is robust for an N-1-1 condition. The peak demand occurs in winter. For the onshore system, let's assume the worst case whereby the N–1–1 fault will happen in winter when one circuit is on prior fault outage (we would not plan a major boundary circuit outage in winter) and a second circuit faults.

For each of the four B6 AC circuits in our example, and assuming a winter unplanned outage rate of 0.2% $=7$ hours per winter (based on the historic outage rate considered in GSR008, but increased to take account of switchgear and protection outages in addition to those on overhead lines), the probability of an N-1-1 event on the AC circuits can be found as follows.

- Given that the single circuit fault rate is 0.62 faults per year, the chance of a particular N–1–1 fault will be $7\times0.62/8760$ per hour = 5×10^{-4} per winter = one every 2000 winters.

- For the chance of any N–1–1 fault across B6, this needs to be multiplied by 4 (for any circuit on prior outage), and by 3 (for any remaining circuit to fault); so we get to a B6 N–1–1 fault rate of $12\times5\times10^{-4}=0.006$ = one every 167 winters.

Under the proposal of GSR008, these faults will no longer be considered in design. However, the N-1-1 fault involving an onshore cable on prior outage is still considered by GSR008. This is because of the typical duration of cable repairs, making the probability of a cable being on prior outage significantly higher than that for a line.

If DC circuits offshore are considered along with the onshore circuits, the fault rates become:

- For the prior outage of one onshore AC circuit, and the fault outage of a DC circuit, the system peak (winter) N–1–1 fault chance is

- 4x7hour (duration one of four AC circuits out) x 2/8760 (either of two bi-pole fault rate, per hour)

- = 0.006 = one every 167 years.

For the prior outage of one offshore DC circuit, and the fault outage of an onshore AC circuit, the system peak (winter) N–1–1 fault chance is

- 2x105hour (duration one of two DC circuits out, at target 97% availability over a 3500hour winter) x $4\times0.62/8760$ (any of four AC fault rate, per hour)

- = 0.06 = one every 17 years.

For the prior outage of one offshore DC circuit, and the fault outage of the other DC circuit, the system peak (winter) N–1–1 fault chance is

- 2x105hour (duration one of two DC circuits out, at target 97% availability over a 3500hour winter) x 1/8760 (remaining DC fault rate, per hour)

- = 0.024 = one every 42 years.

There are some obvious conclusions from the above analysis. If the N–1–1 condition of onshore cable prior outage plus onshore AC fault should be covered (as per the recommendations of GSR008), **then the latter two N–1–1 faults are at least as common, and should be considered as a secured event.**

Another conclusion is that the **resulting N–1–1 criterion should be specified as a prior DC cable outage, followed by an onshore or an offshore fault**. The counter case of a prior AC outage, followed by a DC fault, need not be considered.

N–1–D Fault

The remaining winter contingency that may be considered is a prior single circuit outage, followed by an AC double-circuit fault.

For the prior outage of one onshore AC circuit, and the double-circuit fault, the winter N–1–D fault chance is

- 28hour (duration one of four AC circuits out) x 0.1/8760 (remaining double-circuit fault rate, per hour)
- = 0.0003 = one every 3000 years.

For the prior outage of one offshore DC circuit, and the double-circuit fault, the winter N–1–D fault chance is

- 2x105hour (duration for one of two DC circuits out, at target 97% availability over a 3500hour winter) x $2 \times 0.1/8760$ (either of two double-circuit fault rate, per hour)
- = 0.005 = one every 200 years.

It is clear why the former contingency is not secured in planning. The latter has a fault rate greater than once per millennium, but the fault rate is comparable to the onshore N–1–1 fault rate GSR008 proposes to remove. Hence **there is no case to consider this N–1–D contingency**.

Conclusions

- The N–1 fault of an offshore DC circuit is at least a likely as that of an onshore circuit, and should be considered alongside the onshore N–1 fault.
- The N–1–1 contingency of an offshore DC circuit on prior outage, followed by either an onshore or an offshore single circuit fault, has a chance of greater than one in 100 winters, and should be treated as a credible contingency in Chapter 4 of the SQSS.
- The N–1–1 contingency of two onshore circuits, and the N–1–D contingency of a prior offshore outage followed by the onshore double-circuit fault, both have a comparable fault rate of less than one in 100 winters, and neither need be considered as a credible contingency for SQSS Chapter 4.

These conclusions are consistent with the existing SQSS criteria and the proposals of GSR008.

4.2 Treatment of Wind in Local Connections and Wider Infrastructure Developments

Under the existing standard, wind generation connections are based on 100% of the generation capacity, and, under the economy criterion, wind powered generation is scaled to 70% of its capacity when assessing the need for MITS reinforcement. These criteria are based on a previous cost benefit analysis that, at that time, assumed relatively low levels of wind generation development, at locations close to shore (less than 100km). The proposals for Round 3 generation development have prompted a further review of these criteria in this modification.

Local Connections

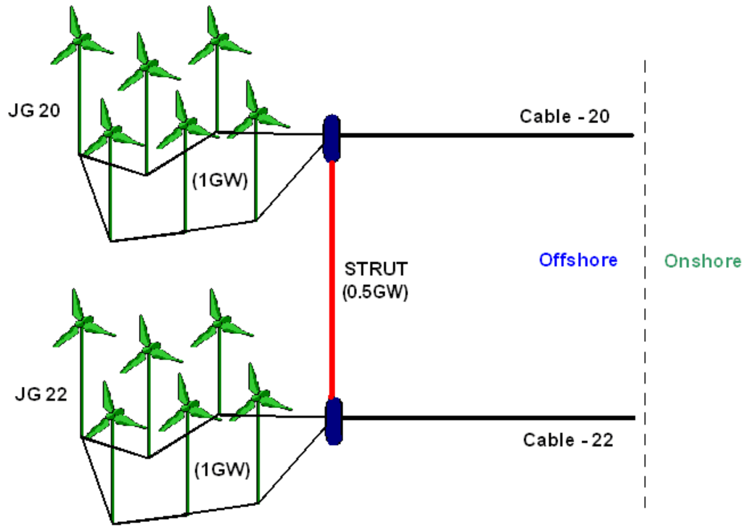
The optimal connection design is determined by balancing the following two categories of costs

- Cost of offshore transmission system investment 'T'
- Capitalised cost of expected constrained energy 'O'

Appendix D considers the plant and constraints costs for a range of cable sizes in connecting 1 GW offshore windfarms with different wind profiles at distances of 100 and 200km from shore. The analysis compares the savings on 'T' costs by opting for lower capability cables with the increase in 'O' costs due to energy curtailment. The optimal cable size for a minimum value of 'T+O' cost is dependent on both the distance from shore and the site wind profile. The results for representative Round 3 and Round 2 sites are similar, indicating that a 95% rating is optimum. However, there **is very little regret to providing capacity at any level between 90% and 100%** and there is significant uncertainty in the data used within the cost benefit analysis – future energy prices and HVDC system costs are very difficult to forecast. The cost benefit analysis undertaken in 2006 to derive the existing criteria supported the use of 100% rated connections for Round 1 and 2 windfarms. The analysis in this review indicated that the optimum for Round 3 windfarms is similar to that for Round 2. It is the view of the working group that the results, together with the uncertainty in the data and the low regret for building a link at a higher rating than the optimum, are **supportive of the existing criteria that require connections rated at 100% of the windfarm capacity**.

Against a base case of a 1GW wind farm and a 900MW cable, the 6 hour overload rating of a standard cable does not contribute significantly to rescue the constrained energy (Appendix D shows that it saves only 13% of the constrained off energy cost per year).

Appendix D also considers the benefits of interconnecting wind farms that are geographically close to each other. Two 1GW wind farms, each connected radially with a 1GW cable as shown below, were considered.



Loss of one of those cables will result in some degree of energy curtailment. The analysis shows that, if the wind farms are interconnected by a relatively short strut, the cost of the strut could be warranted by the extra energy delivered to the system. Sensitivity studies that vary the cable failure rates and costs of constraints are included.

The analysis indicates that the economic benefits of a strut in allowing greater levels of generation export to the system during cable outages is highest when the distance for interconnection is short. This implies that the benefits are likely to be seen for interconnection within a Round 3 zone when more than one cable for connection to shore is used. Development of such a strut would be a consideration for the zone developer, and it is not the basis for a requirement in the NETS SQSS.

Connections between windfarm zones, where the distances are often greater than 100 km, will require justification beyond the level of energy that may be rescued between the zones. Where there is justification on the basis that the interconnection provides capacity to the transmission system, the SQSS criteria pertaining to MITS development should apply.

Further analysis has considered the issue of offshore cable redundancy – should an additional connection cable, giving connection capacity greater than the generation capacity, be used to cover outages of one or more of the cables. A simple case of a 5GW wind farm was developed, which is assumed to connect with the onshore system through five 1GW cables. The analysis showed that a sixth cable would pay back over 18 years. This is likely to be too long to be justified for an offshore wind generation development. This is described in appendix D. **Whilst the analysis does not support an SQSS requirement to develop connection capacity beyond 100% of generation capacity, it does suggest that in some cases there may be economic justification for additional capacity** – this would need to be considered separately for each generation development by the relevant windfarm developer.

Conclusions

- The SQSS criteria for connection circuit capacity should be to match the generation capacity. Any additional capacity requires economic justification, based on the cost of the capacity and the constraints saved.

- The use of short term ratings does not provide significant benefit in reducing constraints.

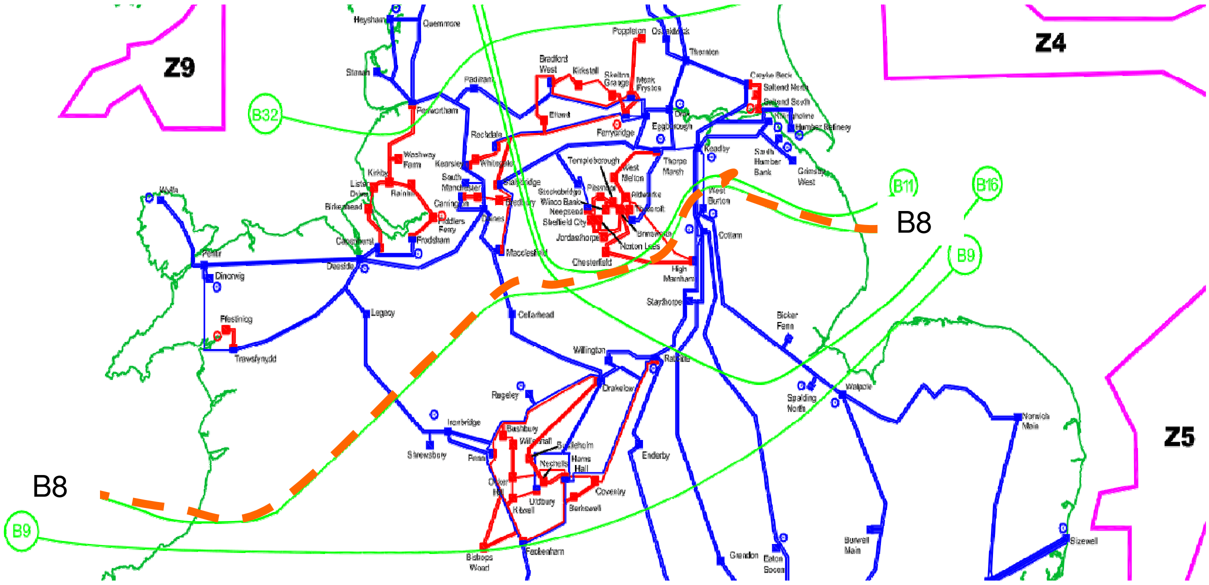
- There are benefits in interconnecting two offshore wind farms over a short distance (within a round 3 zone) in the reduced constraints during a cable outage. This should not be an SQSS requirement – it is a decision for the developer.

- The caveats in the existing NETS SQSS wording that the analysis has only considered capacities up to 1800MW at distances up to 100km can be removed – the working group's analysis indicate that the requirements are applicable to all currently envisaged developments.

Wider Infrastructure Development

The criteria for the design of the MITS were reviewed and amended under review GSR009, and are appropriate for generation backgrounds that include high volumes of intermittent generation. The criteria were developed from year round cost benefit analysis (cba) that included the likely output of wind powered generation across a whole year. The cba included an assumption on the mix of onshore and offshore wind generation, for which different annual load profiles were used. The working group has updated some of the GSR009 analysis against a background with a significantly higher proportion of offshore generation, to test whether the NETS SQSS criteria are robust against such scenarios.

Boundary B8 has been chosen for analysis as it extends through any potential East Cost offshore transmission network, and is affected by significant Round 3 offshore developments – Dogger Bank, Hornsea, and Irish Sea. Accelerated Growth generation background in years 2020 and 2025 is considered, which has 42 GW of wind generation (32 GW offshore) in 2020, and 55 GW in 2025 (43.5 GW offshore).



The requirements of the standard that were implemented as a result of GSR009, plus the informal planning criteria used prior to GSR009, have been evaluated:

- The pre-GSR009 approach (method 1a – wind scaled to 60%),
- The economy criterion of the existing standard (method 1e – wind scaled to 70%),
- The demand security criterion of the existing standard (method 1s – no wind).

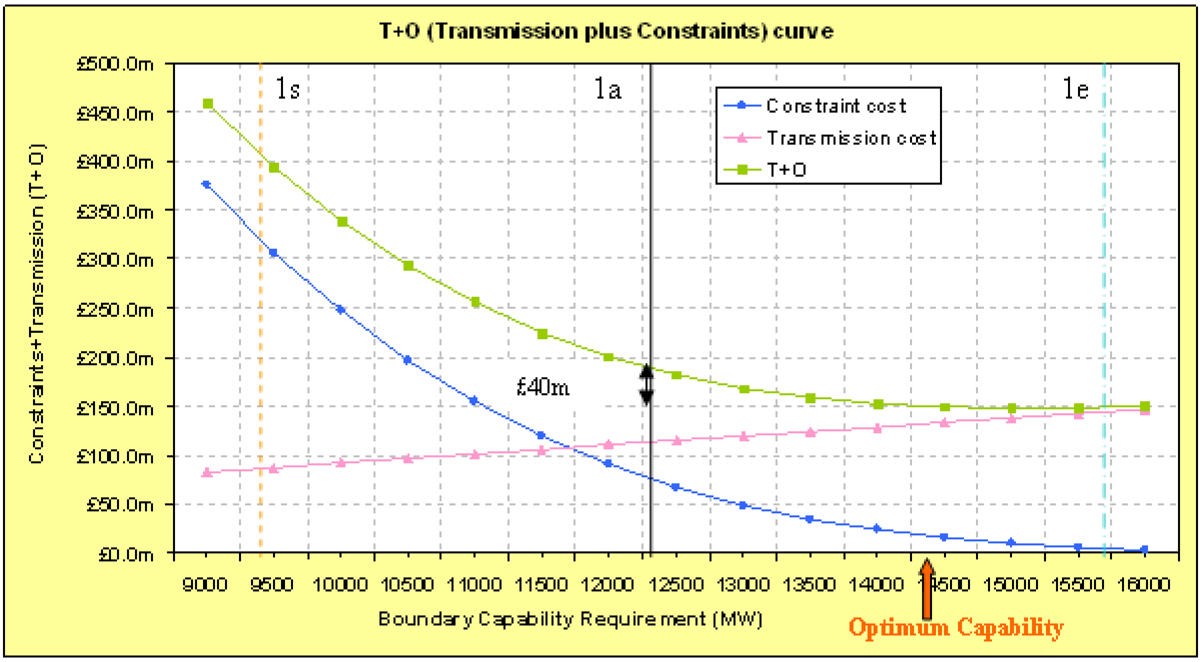
The demand security criterion does not show a need to reinforce B8 above its current capability. It is included as a reference to show the impact of the wind generation on the requirement.

The analysis methodology is described in appendix E, and is summarised as:

- The transmission cost of reinforcing B8 is plotted, assuming that the cost increases linearly with capacity from the current level
- A constraint cost versus boundary capability curve is plotted across a range of capabilities
- The two cost curves are summed to give a total cost of reinforcement (T) and operating (O) costs – the T+O cost
- The capability requirement identified by each of the three methods above is compared with the minimum of the T+O curve to assess their relative merits.

The results for B8 are summarised below.

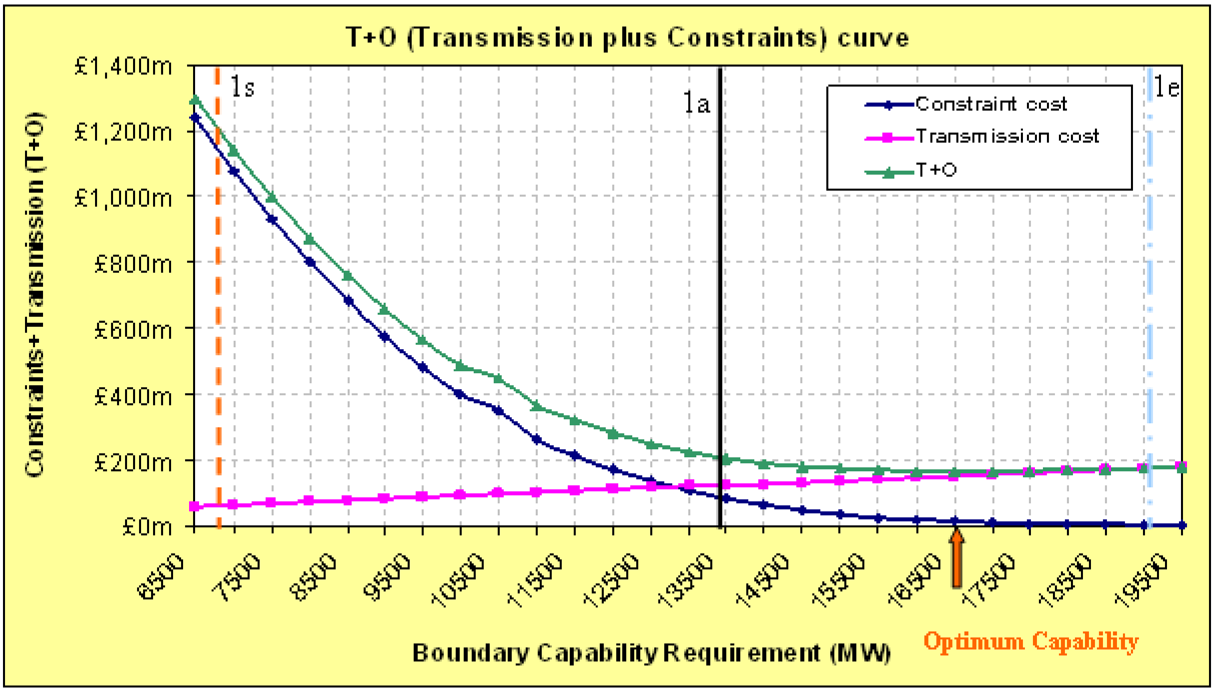
The curves show that around the minimum cost, significant variations in boundary capacity only result in small cost variations. The slope of the T+O curve is such that the costs of providing capacity above the optimum are generally lower than providing capacity below the optimum.



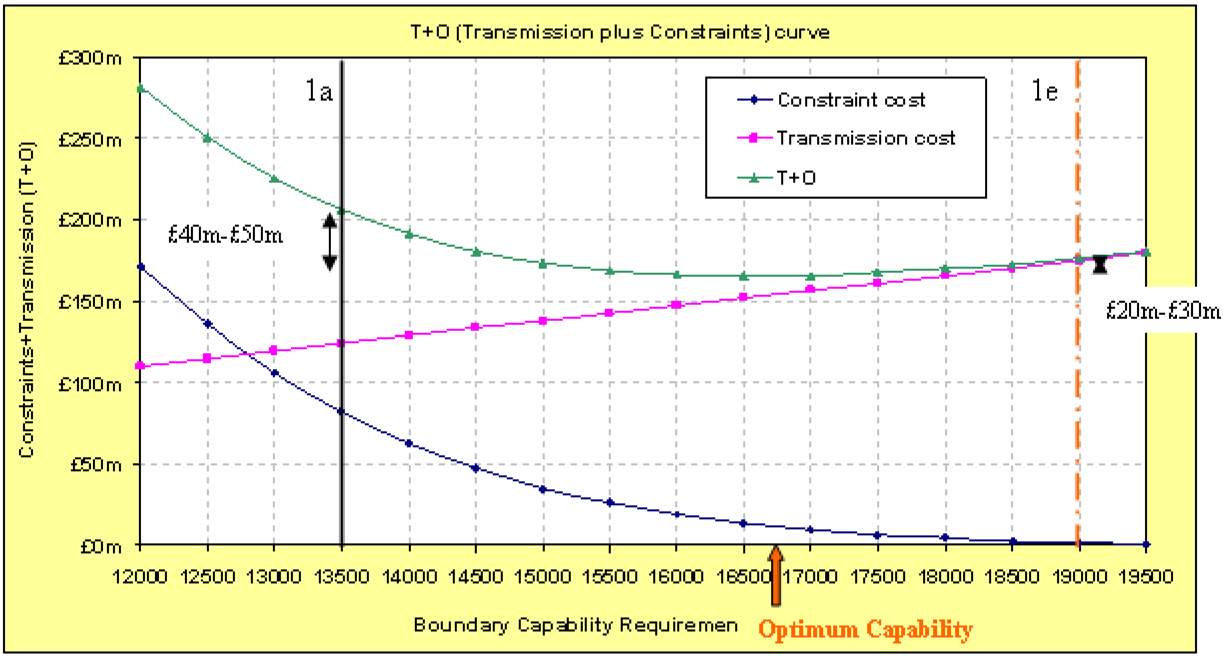
B8 2020/21 'T+O' Results

Examining above, we observe that:

- The optimum capability is that which delivers the minimum T+O cost (green line), and is at 14400 MW of B8 boundary capability.
- 1a requires a capability approximately 2.5 GW below the optimum, at a cost in excess of £40m per year above minimum cost
- 1e requires a capability approximately 1 GW above the optimum, but the cost of this is very low
- The required capability from both 1a and 1e is in excess of the current capability of B8, and is driven by the high levels of wind assumed in and off the shores of Scotland and Northern England.



B8 2025/26 'T+O' Results



B8 2025/26 'T+O' Results (Zoom in for 1a and 1e approaches)

Examining the charts for 2025/26, we observe that:

- The optimum capability is that which delivers the minimum T+O cost (green line), and is at 16700 MW of B8 boundary capability
- 1a requires a lower level of reinforcement than 1e
- the difference between the capacity requirements of 1a and 1e is 5.5 GW
- the capacity differences from the optimum are similar for 1a and 1e
- the cost difference from the optimum is higher for 1a (£40-£50m) than for 1e (£20-£30m)

Conclusions

- As discussed in the GSR009 report, the risk-reward balance is asymmetrical: the regret of incurring greater constraints costs for under-investment is far greater than the regret of extra transmission costs if reinforcements take the capacity above the optimum.
- For this boundary and scenario-year 2020, the requirements of approaches 1a and 1e are around 3GW apart. The ‘T+O’ optimum is relatively close to 1e (~1 GW away). The cost curve around the optimum is extremely flat, and although 1e requires additional capacity, it only incurs a cost of £1m per year by doing so.
- For scenario-year 2025, the requirements of approaches 1a and 1e are 5½GW apart. The ‘T+O’ optimum falls approximately half-way between them. Method 1e incurs lower overall costs, ~£25m per year, than method 1a, ~£45m per year.
- Whereas approach 1e calibrates well against the cost-benefit optimum for scenario-year AG 2020, it is further from the optimum in 2025. However, the 2025 result is still within the region of uncertainty arising from the assumptions on future generation developments and costs. As the difference from the optimum occurs in the Accelerated Growth scenario rather than the current best view Gone Green scenario, **the working group has concluded that re-calculation of the generation scaling factors is not warranted to take account of the larger Round 3 generation** at this time. However, as per the recommendations of GSR009, the scaling factors should be kept under periodic review, and should be re-calculated if a scenario closer to Accelerated Growth develops.
- For now, it is reasonable to say that the GSR009 scaling factor for wind of 70% should be applied to both onshore and offshore wind generation in MITS design analysis.

4.3 Infeed Losses for Large Cables

A loss of power infeed to the transmission system results in a drop in system frequency. The size of the drop is dependent on a number of factors including the level of infeed lost, the demand at the time of loss, the generation mix connected at the time, and the response provision of the connected generation. In normal system operation, response and reserve is held to contain frequency falls following the largest credible loss at any specific time, in line with NGET’s system operator licence[2]. The design criteria of the NETS SQSS determine the maximum potential generation infeed loss that could occur, and hence significantly impact on the levels and costs of response and reserve that are needed operationally. This maximum permitted infeed loss allowed for in design is derived from an economic assessment of the costs of response holding to cover the loss, the costs of developing transmission capacity to limit the size of the loss, and the generation market benefits that arise from the use of larger generating sets.

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[2] NGET’s licence as system operator includes requirements on frequency management. These state that under normal operation the frequency should remain above 49.5Hz. If the frequency goes below 49.5Hz following a significant event, it must return above 49.5 Hz within 1 minute. Any fall must be limited to 0.8Hz, which means that, from a starting frequency of 50Hz, it must not fall below 49.2Hz.

Onshore generation can be connected radially or in a meshed manner. For radial connections, the capacity is limited to the SQSS infeed loss limit. For meshed connections, sufficient connection circuits are provided so that, for the credible loss of a double circuit, the generation will remain connected to the system. Where these connections are by ac circuits, those remaining following a fault will automatically pick up the power that was being transmitted on the faulted circuits, and so there will be no loss of infeed to the system. If the redistribution of power results in circuit overloads, system to generator intertrips up to the infeed loss limit can be used.

For offshore generation, the scope of the existing SQSS criteria is limited to radial connections, specifying the capacity of generation that can be connected via a single cable. From 1st April 2014 onwards, the SQSS infeed loss limit will be 1800MW. This will facilitate the radial connection of larger Round 3 offshore wind farms with a single cable rating of up to 1800MW. This review has not considered the option of raising the infeed loss limit to permit the use of higher capacity cables in radial connections. However, **the analysis included in appendix F indicates that it would be necessary to connect significant volumes of offshore wind generation (beyond that envisaged) to justify any change** to the infeed loss limit.

The proposals for the integrated connection of offshore generation will be similar to meshed onshore connections. For the loss of a connection cable, the generation will remain connected through other cables. However, the distance of the Round 3 windfarms from shore means that they will generally be connected by dc links. These dc links will not automatically take up power from the faulted link post fault; a controlled action will be required, and this will take time to implement. Consequently, there will be an instantaneous infeed loss to the system equal to the pre-fault loading of the faulted cable for the time it takes for the control action. This loss will be reduced by subsequent control actions on remaining links, with the extent of the restored infeed limited by their ratings. The most onerous condition will be when the offshore generation is at full output, when there will be very little spare capacity available on the connection circuits, and it may be necessary to use overload ratings for any power re-distribution.

Analysis work (detailed in Appendix F) has considered the level of power redistribution needed, and the time required to achieve this, in order to ensure that the system frequency will remain within statutory limits without the need to hold response beyond that required for an instantaneous 1800 MW loss.

Figures 4 and 5 below show the requirements for the loss of a 2GW link and a 2.2 GW link. The shaded regions indicate time / capacity combinations that would meet the system requirements.

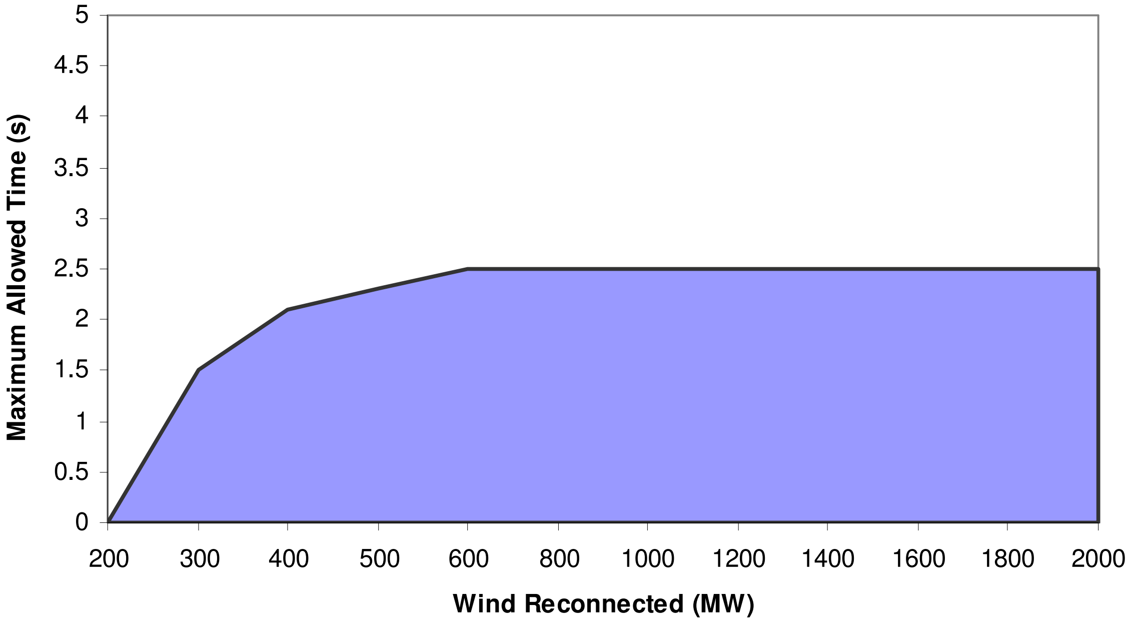


Figure 1: 2GW loss allowed time

The study was repeated for the loss of 2.2GW of wind as shown in Figure 2.

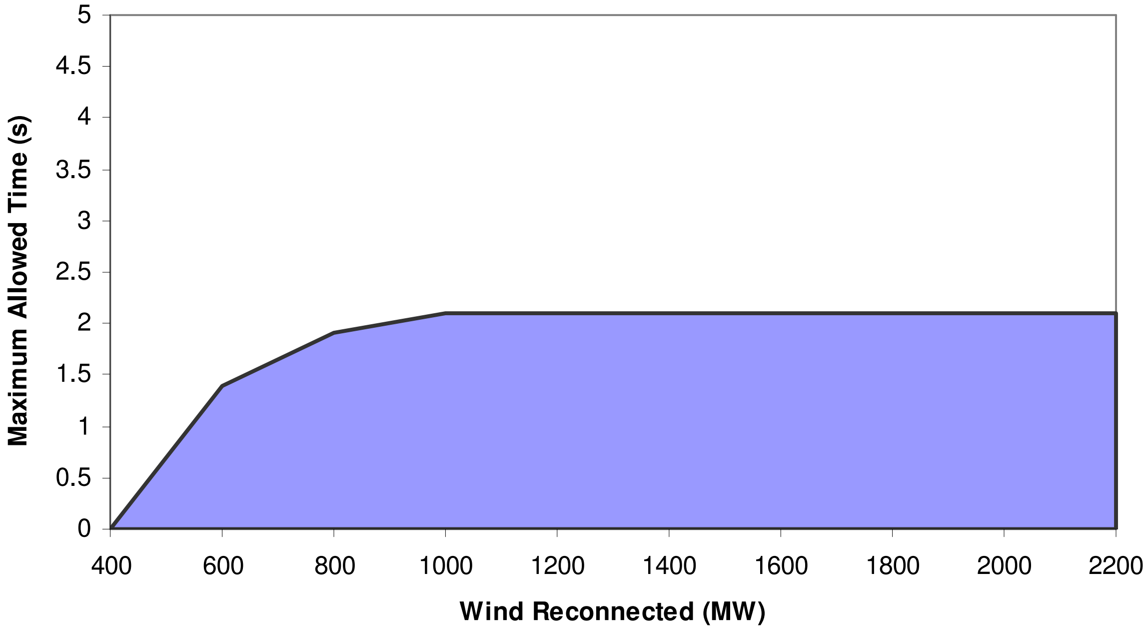


Figure 2: 2.2GW loss allowed time

The results show that the level of redistribution needed increases with increasing control action time. Beyond a certain time (2.5s for the 2GW loss, 2s for the 2.2GW loss) the frequency limits cannot be maintained – at this time they have reached the minimum allowed value.

It should be noted that the loss of a generation connection cable will have impacts wider than the system frequency – for example the offshore generation will speed up and may trip if the generation / demand balance is not restored quickly enough. In assessing the loss of a cable and subsequent redistribution of power, it will be necessary to ensure that all the criteria of the NETS SQSS are met.

Conclusions

The study suggests that for the loss of a cable that provides a system infeed greater than 1800MW, it is possible to contain the frequency within its statutory limits if a proportion of the infeed is redistributed within a short time. This is possible in an integrated offshore network using VSC based links, providing there is sufficient capacity available on links parallel to that lost. The longer the control action takes to redistribute the flow takes, the greater the level of redistribution that is needed. This means that there is no requirement to specify a limit on connection cable size, and hence the potential instantaneous infeed loss – the requirement is to ensure sufficient capability exists in remaining circuits and control systems to ensure the frequency fall is contained without the need for additional response holding.

5 Recommendations

On the basis of the analysis described in section 4, the working group recommendations are:

In designing local connections, it is appropriate to provide a connection capacity of 100% TEC. This recommendation is based on economic analysis of the potential constraint costs versus the transmission plant costs of a range of connection capacities. Whilst the analysis indicated that the optimum rating is around 95%, there is significant uncertainty in the background data underpinning the analysis, whereas the regret associated with building a fully rated link is low. The analysis showed that the optimum rating for Round 3 windfarms is similar to that for those of Round 2, for which connections of 100% rating are required under the existing standard. In the view of the working group, the analysis does not provide a justification for amending the requirements to cater for Round 3 windfarms.

For infrastructure analysis, it is appropriate to consider offshore wind at 70% output, as per the recommendations of GSR009. This is based on extension of the cost benefit analysis undertaken for GSR009, considering the impact of high volumes of offshore wind generation on the alignment of the GSR009 proposals with the CBA results.

In designing the transmission system the following should be considered as secured events: an N-1 outage of an offshore circuit; an N-1-1 outage involving an offshore circuit on prior outage followed by either an offshore circuit or an onshore circuit fault outage, and an N-1-1 condition with an onshore circuit containing a cable section on prior outage, followed by an offshore circuit fault outage. This recommendation comes from analysis of cable fault rates, together with the duration of loss events. At present, data on this is limited, but that available indicates that overlapping cable loss events will have a similar rate to double circuit losses onshore. This is consistent with the GSR008 proposals for considering N-1-1 events in planning.

Short duration losses of a DC link carrying more than the Infrequent Infeed Loss can be tolerated where parallel routes can increase their flows. Analysis of system frequency performance following a loss of more than 1800MW shows that the frequency fall can be maintained within existing limits provided the loss can be quickly reduced to a level less than 1800 MW – the amount of power restoration required will depend on the delay in restoring it. Whilst the frequency analysis suggests restoration times up to 2 or 3 seconds would be acceptable, it is likely that much faster restorations will be required to prevent generation instability and tripping.

Appendix A - Terms of Reference

NETS SQSS Review – Offshore and HVDC
Terms of Reference

Objective To review and determine the most appropriate treatment of Offshore Transmission within the NETS SQSS. Also to determine appropriate treatments of transmission HVDC circuits.

Detailed Objectives:

1. The 2008–2009 offshore review determined treatment of offshore transmission, for limits of up to 1500MW of offshore park modules, and up to 100km of connection distance. This review should extend these limits, to accommodate the sizes of offshore Round 3, namely up to 13GW of generation and up to 250km connection distance.

2. Determine the case, if any, for any redundancy in an offshore transmission network, both in subsea cables and within offshore platforms, which connects to the onshore transmission network at a single site.

3. Determine the case, if any, for any redundancy in an offshore transmission network, which connects two asynchronous systems within the NETS, or which connects to the synchronous onshore transmission system at two sites, and thus provides additional transmission capacity for an onshore boundary. In particular under this condition, determine the case, if any, for the application of the Chapter 2 requirements for redundancy of generation connections.

4. Consider the status of an HVDC circuit connecting two nodes of the synchronous AC onshore system, either onshore or offshore. Determine if any special treatment is recommended for such a circuit.

5. Deliver results which have been open to consultation and industry workshops, and a report with recommendations and proposed drafting changes.

Constitution The team comprises membership from National Grid, Scottish Power (Transmission), Scottish Hydro Electric Transmission, Ofgem, and Industry representatives. The team is chaired by Andrew Hiorns, and deputed by Paul Plumptre, National Grid. Secretariat will be supplied by National Grid.

Reporting The team reports to the NETS SQSS Review Group, under SQSS governance. The intended timescale is to report by end 2011, but if this appears unachievable, the group should report thus to the SQSS Review group by mid 2011.

Scope The following issues are out of scope:

- The onshore SQSS Chapters 1 to 6 are within scope, to the extent warranted by consideration of offshore or HVDC circuits only.
- All the offshore Chapters 7 to 10 are within scope.

Meetings The team will meet approximately bi-monthly.

Methods The team will need 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. An early decision needs to be reached on the sourcing of appropriate tools.

(reviewed by SQSS Review Group 5/12/2010)

Glossary The following definitions do not supplant more formal definitions within various Codes.

HVDC: High Voltage Direct Current. Nowadays used to refer to circuits carrying Direct Current (rather than Alternative Current – AC) at voltages of some 250kV and above.

NETS SQSS: the SQSS ('Security and Quality of Supply Standard') has been in place for National Grid within England and Wales since 1990. It was conformed with companion Scottish Standards into the GB SQSS at BETTA Go-Live in April 2005. With the introduction of the Offshore TO regime, the GB SQSS was replaced by the NETS SQSS ('National Electricity Transmission System') in June 2009.

SEDG: the Centre for Sustainable Energy and Distributed Generation, which is led by Prof. Goran Strbac. In the 2008-2009 review of Offshore Standards, much cost-benefit work was performed by SEDG; hence they are natural candidates to continue this work.

Appendix B - SQSS Proposed Text

The proposed text to implement each of the recommendations of section 5 is discussed below. The proposals are based on version 2.2 of the NETS SQSS. Some of the proposals interact with the recommendations of GSR008 (Regional variations and wider issues) review, which is currently the subject of an industry consultation. Where this is the case, it is noted below.

Local connection capacity

The recommendation is to provide connection capacity for offshore generation at 100% of TEC. This is consistent with the current requirements of chapter 7. The current requirements are based on analysis of Round 1 and 2 windfarms, and clause 7.2 describes the limits to the scope of the analysis. It is proposed to remove clause 7.2 as the recommendations of this review are intended to apply to all offshore generation developments.

The proposed change is:

7. Generation Connection Criteria Applicable to an *Offshore Transmission System*

7.1 This section presents the planning criteria applicable to the connection of one or more offshore power stations to an offshore transmission system. The criteria in this section apply from the offshore grid entry point/s (GEP) at which each offshore power station connects to an offshore transmission system, through the remainder of the offshore transmission system to the point of connection at the first onshore substation, which is the interface point (IP) in the case of a direct connection to the onshore transmission system or the user system interface point (USIP) in the case of a connection to an onshore user system.

~~7.2 The generation connection criteria, applicable to an *offshore transmission system*, presented in this section, are based on a series of cost benefit analyses. The scope of those analyses was bounded by certain pragmatic assumptions, which recognised the technology available at the time the analyses were carried out. Accordingly, the generation connection criteria presented in this section should only be applied up to those limits. The criteria have been updated since the initial analysis to account for developments in cable and HVDC technology. The limits are:~~

~~7.2.1 the capacity for *offshore power park modules* was limited to a maximum of 1500MW. Following review of the values of *normal infeed loss risk* and *infrequent infeed loss risk,* this capacity limit will equal the *infrequent infeed loss risk* from April 1st 2014.~~

~~7.2.2 the type of intermittent power source powering the offshore power park module was limited to wind.~~

~~7.2.3 the capacity of offshore gas turbines was limited to a maximum of 200MW per platform;~~

~~7.2.4 the distance from an offshore *grid entry point* on an *offshore platform* to the *interface point* or *user system interface point* (as the case may~~

~~be) at the *first onshore substation* was limited to a maximum of 100km;~~

~~7.2.5 the length of any overhead line section of an *offshore transmission system* was limited to a maximum of 50km; and~~

~~7.2.6 Radial offshore network configurations only have been considered. Until reviewed, section 4 shall apply in respect of interconnected offshore networks.~~

~~The above limits will be subject to periodic review in the light of technological developments and experience. The limits should not be exceeded without justification provided by further review.~~

~~7.3~~7.2 Planning criteria are defined for all elements of an *offshore transmission system* including: the *offshore transmission circuits* and equipment on the *offshore platform* (whether AC or DC); the *offshore transmission circuits* from the *offshore platform* to the *interface point* or *user system interface point (*as the case may be) including undersea cables and any overhead lines (whether AC or DC); and any onshore AC voltage transformation facilities or *DC converter* facilities.

The remaining clauses of chapter 7 will need renumbering.

Treatment of wind generation in MITS analysis

The recommendation is to maintain the current requirements (wind generation scaled to 70% in MITS analysis), and so no amendments are required.

Consideration of Offshore contingencies

The recommendations of the working group are that the following should be considered as secured events:

- Loss of a single offshore transmission circuit
- Loss of a single offshore circuit with a different circuit on prior outage
- Loss of a single onshore circuit with an offshore circuit on prior outage

These requirements are consistent with the current version of the standard. GSR008 proposes to limit consideration of circuits on prior outage to those containing cable sections. As all offshore connections will use cables, there will be no impact from the GSR008 proposals, and so no changes are required to the NETS SQSS, irrespective of whether GSR008 is approved.

Loss of cables carrying more than the infrequent infeed loss limit

The current SQSS requirements for the loss of infeed from offshore generation specify that the loss is calculated at the point of connection to the onshore system (definition of Loss of Power Infeed). There is no specification of the timing of this disconnection in the definition or in any of the criteria relating to the loss of infeed. The proposal of this review allows for the automatic re-distribution of power infeeds through HVDC links to the onshore system following the loss of an offshore connection cable. In principle this may be covered by the current definition. However, the working group propose to clarify the definition such that it refers to this re-distribution, as follows:

Loss of Power Infeed	The output of a *generating unit* or a group of *generating units* or the import from *external systems* disconnected from the system by a *secured event*, less the demand disconnected from the system by the same *secured event*. For the avoidance of doubt if, following such a *secured event*, demand associated with the normal operation of the affected *generating unit* or *generating units* is automatically transferred to a supply point which is not disconnected from the system, e.g. the station board, then this shall not be deducted from the total *loss of power infeed* to the system. For the purpose of the operational criteria, the *loss of power infeed*, includes the output of a single *generating unit*, CCGT Module, boiler, nuclear reactor or DC Link bi-pole lost as a result of an event. In the case of an *offshore generating unit* or group of *offshore generating units*, the *loss of power infeed* is measured at the *interface point,* or *user system interface point,* as appropriate. In the case of an *offshore generating unit* or group of *offshore generating units* for which infeed will be automatically re-distributed to one or more *interface points* or *user system interface points* through one or more HVDC links, the re-distribution should be taken into account in determining the total generation capacity that is disconnected.

Appendix C - Offshore Contingencies

Type	Fault rate (faults per item per year)	Mean down-time = repair time	Unplanned Unavailability	Source
Onshore AC overhead line, single cct per 100km – transient	0.50	1min	negligible	WG4 Report, National Grid 8year data
AC OHL, single cct per 100km – sustained	0.12	56hour	7hour per year = 0.1%	Mean downtime from TRIP data
Onshore AC overhead line, double cct per 100km – transient	0.05	1min	negligible	WG4 Report, National Grid 8year data
AC OHL, double cct per 100km – sustained	0.05	28hour	1.4hour per year = 0.02%	Mean downtime from TRIP data
Offshore HVDC 400km circuit	1	260hour	260hour = 3%	National Grid Tender Spec

Table 1: Reliability data for onshore and offshore circuits

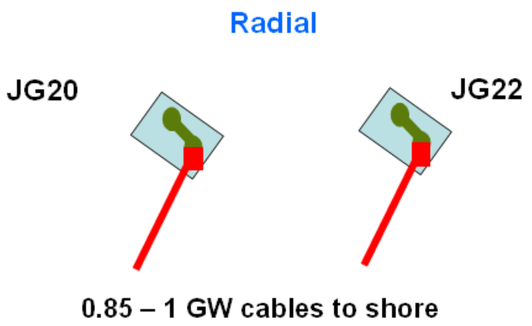
Notes:

It is taken into account that GSR008 is proposing that the existing onshore criterion moves from a full N–2 criterion, to an N–D criterion for AC overhead line pairs, and N–2 only when one circuit contains "cable outside the substation" (which more exactly was intended to include cables of length >1.5km).
8year dataset for NGET from the WG4 report (years 2000–2007) is used as being the most comprehensive. WG4 also reports SPT and particularly sparse SHETL data for 275kV and 400kV circuits, and that data is consistent for both single and double circuit fault rates.
Equivalent reliability history for HVDC circuits is hard to obtain and interpret. (There is historic CIGRE data, but this covers a wide variety of HVDC systems.) It is suspected that the faults rates for 400km offshore circuits will arise approximately half on the cables - at a low fault rate of ~ 0.1 per year times and a very long repair time, and half on the converters - at a greater fault rate and a shorter repair time.
Estimating HVDC reliability from history of cables and converters is not useful. We are able to use tender for the Western HVDC link, which sets targets of 1 bi-pole failure per year and 97% planned availability (Back-deriving a downtime of 260hours per failure from 97%). Of course, there is no guarantee whether our suppliers will under-perform or exceed these targets; however, we can consider that they will plan to bury the undersea cables deep enough to achieve < 0.1 cable faults per year, and that they will design converter components towards a bipole fault rate of < 1 per year.

Appendix D - Offshore Design

Optimal Size of a Radial Connection in Offshore Transmission

Consider two separate 1GW offshore wind farms, called JG20 and JG22. These wind farms have different annual wind profiles and can both be located either 100km or 200km from shore. Each is connected by a single radial cable. For a connection cable rating of 850-1000MW what is the curtailed energy, and what is the most economic overall connection, for each location? Is the existing criterion that requires connection ratings to be 100% of the generation capacity supported?



Wind speed and consequent generation output data has been extracted from the Poyry data for the years 2004 – 2008 for two suitable offshore sites. The data gives the number of hours for which generation at each site would be above 85% of their capacity factors (this is the level at which there will be constraint with the lowest rated cable considered), split into discrete ranges of generation output of 1%. Assuming that the generation is in the mid-point of the range for the time it is within each range, the constrained off energy can be calculated. The level of constrained energy is dependent only on generation output and cable rating – cable length is not considered to be a factor.

For example, JG20 is between 88 and 89% output for 48 hours. For 1000 MW of generation capacity this would be 880-890 MW. Assuming that the output averages 885 MW for the time when it is in this range, and that the cable is rated at 850MW, there will be (885-850)*48 = 1680 MWh of constrained energy.

The total constrained energy for the connection can then be found by summing the constrained energy for each output range above its rating. Table 2 shows the total constrained energy for JG20 and JG22 with 850 MW connection cables.

Hours to Curtail Wind																
Output Range	*850-860*	*860-870*	*870-880*	*880-890*	*890-900*	*900-910*	*910-920*	*920-930*	*930-940*	*940-950*	*950-960*	*960-970*	*970-980*	*980-990*	*990-999*	*1000*
Average MW Curtailed	**5**	**15**	**25**	**35**	**45**	**55**	**65**	**75**	**85**	**95**	**105**	**115**	**125**	**135**	**145**	**150**
JG20	41	50	43	48	86	40	40	82	73	74	70	64	105	152	408	151
JG22	41	47	38	44	74	36	44	76	75	65	59	56	107	141	307	97
Energy Curtailed (MWh)																
JG20	205	750	1075	1680	3870	2200	2600	6150	6205	7030	7350	7360	13125	20520	59160	22650
JG22	205	705	950	1540	3330	1980	2860	5700	6375	6175	6195	6440	13375	19035	44515	14550
												Total		**JG20 =**	**161.9 GWh**	
														JG22 =	**133.9 GWh**	

Table 2: Curtailed wind energy

Average energy curtailed by each wind farm site with an 850MW radial connection is:

JG20 wind farm curtailment = 162 GWh per year
JG22 wind farm curtailment = 134 GWh per year

These constrained energy values are then translated to annual operational costs, **'O'**, on the basis of a wind curtailment price of £75/MWh. For example, for JG20 the O cost is 162 GWh * £75/MWh = £12.14m.

Similar calculations have been made for the energy curtailment across the range of cable ratings up to 1000MW. The annual 'O' costs are shown in table 3.

O costs (£m pa)																
When capability is	850	860	870	880	890	900	910	920	930	940	950	960	970	980	990	1000
JG20	12.14	11.07	9.98	8.91	7.89	6.91	5.98	5.08	4.23	3.43	2.69	2.01	1.37	0.8	0.32	0
JG22	10.04	9.12	8.18	7.28	6.42	5.59	4.81	4.05	3.34	2.69	2.09	1.54	1.03	0.58	0.22	0

Table 3: 'O' cost

The transmission costs, 'T', are dependent on both rating and length and are independent of the level of wind resource (ie they are the same for the JG20 and JG22 datasets). They are calculated from the following assumptions (based on ODIS costs):

1 GW cable cost = £1.1m / km
1 GW offshore converter = £190m
1 GW onshore converter = £115m
1 GW ac offshore platform = 2 * £85m = £170m

Calculations have been made for cables of 100 km and 200 km lengths, reflecting the range of potential Round 3 connections. Assuming that 'T' cost varies linearly with capability (ie an 850 MW link costs 85% of a 1GW link), the costs for the links are:

T cost (£m)																
When capability is	850	860	870	880	890	900	910	920	930	940	950	960	970	980	990	1000
Cable length = 100km	497.25	503.1	508.95	514.8	520.65	526.5	532.35	538.2	544.05	549.9	555.75	561.6	567.45	573.3	579.15	585
Cable length = 200km	590.75	597.7	604.65	611.6	618.55	625.5	632.45	639.4	646.35	653.3	660.25	667.2	674.15	681.1	688.05	695

Table 4: 'T' cost

and on an annual basis, with annuitizing at 10% per year, they are:

T cost (£m pa)																
When capability is	850	860	870	880	890	900	910	920	930	940	950	960	970	980	990	1000
Cable length = 100km	49.73	50.31	50.90	51.48	52.07	52.65	53.24	53.82	54.41	54.99	55.58	56.16	56.75	57.33	57.92	58.50
Cable length = 200km	59.08	59.77	60.47	61.16	61.86	62.55	63.25	63.94	64.64	65.33	66.03	66.72	67.42	68.11	68.81	69.50

Table 5: Annuitised 'T' cost

Summing the T and O costs for each option gives

T+O costs for JG20 (£m pa)																
When capability is	850	860	870	880	890	900	910	920	930	940	950	960	970	980	990	1000
Cable length = 100km	61.87	61.38	60.88	60.39	59.96	59.56	59.22	58.90	58.64	58.42	58.27	58.17	58.12	58.13	58.24	58.50
Cable length = 200km	71.22	70.84	70.45	70.07	69.74	69.46	69.23	69.02	68.87	68.76	68.72	68.73	68.79	68.91	69.13	69.50

T+O costs for JG22 (£m pa)																
When capability is	850	860	870	880	890	900	910	920	930	940	950	960	970	980	990	1000
Cable length = 100km	59.77	59.43	59.08	58.76	58.49	58.24	58.05	57.87	57.75	57.68	57.67	57.70	57.78	57.91	58.14	58.50
Cable length = 200km	69.12	68.89	68.65	68.44	68.27	68.14	68.06	67.99	67.98	68.02	68.12	68.26	68.45	68.69	69.03	69.50

Table 6: 'T + O' costs

with the lowest overall costs shown in red.

The results show that the variations in annual T cost (which increase) and O cost (which decrease) are very similar for an increase in cable rating from 850 MW to 1000 MW: the T costs increase by ~ £9m and £10.5m (100km and 200km), and the O costs decrease by ~ £12m and £10m (JG20 and JG22). This means that the variation in total cost (T+O) across the range of cable sizes is small in each of the four cases. It should be noted that whilst the T costs vary linearly, the decrease in O costs reduces for each increase in rating.

None of the cases indicates that the optimum is to build a 1000MW connection (ie 100% rating). The regret at building a fully rated connection is lower at shorter distances and for the higher level of wind JG20. For Round 3 developments, that are likely to be far from shore and in areas of high wind, the case of JG20 at 200km is the most relevant. This indicates an optimum rating of 95%, with approximately symmetrical regret at either building a higher or lower rated connection (the overall costs for 100% and 90% are very close). This result is comparable to that for the case of JG22 at 100km from shore (potential Round 2 site), for which the existing NETS SQSS criteria would require a 100% rated connection.

There are a number of assumptions underlying the analysis above, and the results will be very sensitive to these as the differences in total cost are small for variations in ratings. These assumptions include:

The wind profile data is translated into generation output on the basis of assumed turbine efficiency and availability. Turbine efficiency is likely to improve in the future as is availability (due to both technology developments and potential overplanting of wind farms to account for unavailability). Both of these factors are likely to increase the level of constraints, favouring higher cable ratings.

The costs of transmission plant have been estimated and could prove to be significantly different. They are dependent on a number of factors that could either increase or decrease the costs. For example, a requirement for a large number of identical cables will tend to decrease the costs as development and tooling costs will be spread, but the costs are likely to increase if demand is high relative to supply capacity. The future cost of materials is another factor that will be impacted by the level of demand. The analysis has assumed a linear reduction in cost with rating – this assumption is not accurate and will slightly underestimate the costs of lower rated cables.

The price of constrained energy in the future is unknown. Small variations in this cost from the £75/MWh assumed will affect the analysis results.

Of these factors, the costs of transmission plant and price of constrained energy could affect the results in either direction: variations may support either larger or smaller capacity connections. Improvements in turbine efficiency and availability will support the use of higher rated cables.

Table 7 below shows the percentage overall cost regret, compared to the optimum, in building a 1000MW connection in each case. It also shows the increase in O costs that would be needed to make the 1000MW capacity cable more economic than the optimum in table 6. This O cost is directly related to the volume of constrained energy, and consequently the turbine efficiency and availability. The percentage decrease in T costs required to make the 1000MW connection economic is the same as the regret value.

Connection	Percentage cost regret with 1000MW cable	Percentage increase in O cost to make 1000MW cable optimum
JG20 100 km	0.6	28
JG20 200km	1.1	29
JG22 100km	1.4	40
JG22 200km	2.2	46

Table 7: Regret with sub-optimal cable size

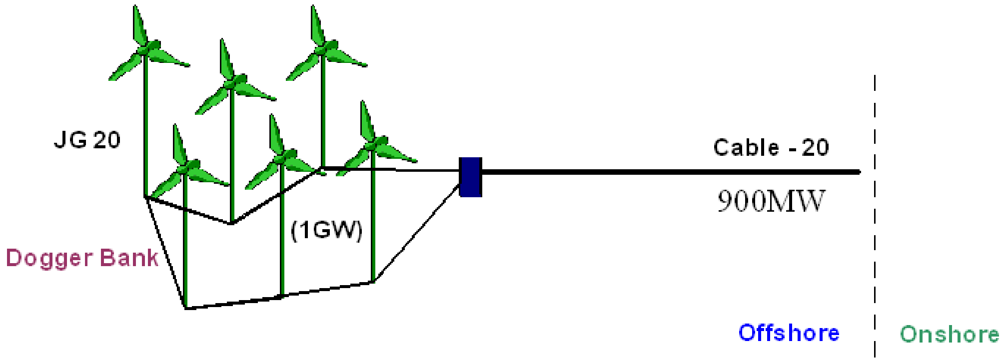
The table shows that the cost regrets associated with a 100% rated connection are low and small compared to the uncertainties around the assumptions underpinning the analysis. Whilst significant changes in O costs will be needed to support higher ratings than the optimum, only small decreases in T costs are needed.

Conclusions

The results do not give any clear indication for a generic percentage rating that can be applied to connection circuits. However, they do indicate that there are only small regrets associated with rating connections at 100% of the generation capacity. The results for the less windy site, located 100km from shore can be compared with the basis of the existing standard. This shows that the connection cables could currently be rated above the optimum, with a small additional cost. The results for the other generation profile and locations are very similar to this case, and do not indicate a strong need to introduce criteria requiring anything below 100% connection capacity.

Value of overload ratings

Against a base case of a 900MW cable for a 1GW wind farm how much of the curtailed energy is recovered by the 6 hour rating of the cable?



For a previous load of <= 60% (average of previous 24 hours), the cable can carry 110% of its MW rating for 6 hours (i.e. power produced more than 0.9GW). The price of wind energy curtailment is taken as 75 £/MWh.

In this analysis, the energy produced above 90% capacity factor (CF) of a 1GW JG20 wind farm is Constrained off Energy (CoE) due to the limitation of the cable rating. The number of hours in each year (2004-2008) when the energy was constrained off is counted. The amount of CoE for each year is noted (for example in 2004, 79.1GWh energy was constrained off for 1,098 hours). Applying 6 hour short term rating for 2004, 13.2GWh energy (17% of CoE) is rescued based upon the assumption that the previous 24 hours loading on the cable was <= 60%.

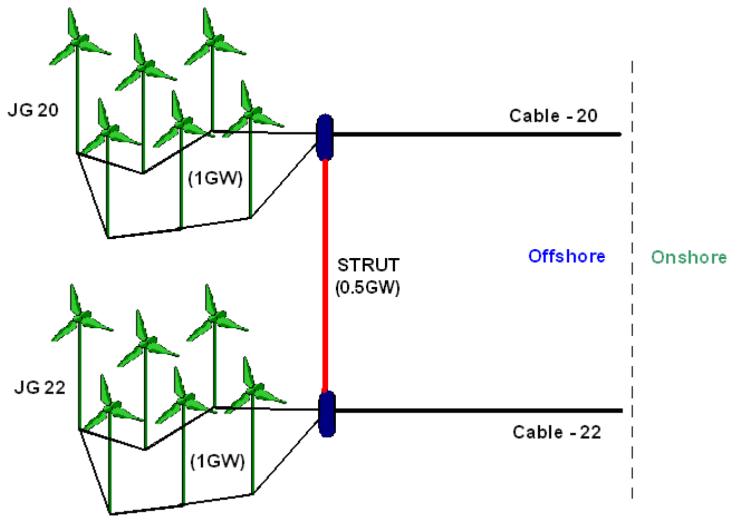
Table 8: Rescued wind energy

	Energy Rescued by using 6hr rating					
	2004	**2005**	**2006**	**2007**	**2008**	**Average 2004-2008**
JG20 Average Load Factor	38.9%	43.0%	39.7%	42.4%	44.5%	**41.7%**
Unconstrained Energy (TWh)	3.41	3.77	3.48	3.71	3.90	**3.65**
Number of Hours when the energy was Constrained off	1,098	1,164	1,074	1,487	1,449	**1,254**
Constrained off Energy (GWh)	79.1	85.2	79.5	111.1	105.2	**92.0**
Number of Hours when a 6hr rating was used	*201*	*157*	*161*	*201*	*189*	***182***
Constrained off Energy Rescued using 6 hr rating (GWh)	*13.2*	*9.7*	*10.1*	*12.4*	*11.9*	***11.5***
% of Constrained off Energy Rescued using 6hr rating	***17%***	***11%***	***13%***	***11%***	***11%***	***12%***
£m Cost of Constraining off energy @ 75 £/MWh	5.9	6.4	6.0	8.3	7.9	**6.9**
£m Saving using 6hr rating @ 75 £/MWh	1.0	0.7	0.8	0.9	0.9	**0.9**

Table 8 shows the energy rescued by using 6 hours rating. It is seen that for a 1GW wind farm, 6 hours rating can be used to rescue approximately 11.5GWh of energy per year (12.5% of the total CoE) for approximately 182 hours per year (14.5% of the CoE hours), and saves approximately £0.9m per year (13% of the total CoE cost).

Economic Value of a Strut in Offshore Transmission

Consider two separate 1GW offshore wind farms, called JG20 and JG22. In the base case, each is connected by a single radial 1000MW cable. For a 500MW offshore strut, how much curtailed energy is rescued by the strut, under either of the two cable outage conditions?



In the base case, energy produced by each wind farm is transmitted to the onshore grid point by a separate 1GW 100km HVDC radial cable. The two offshore wind farms are connected together by a 500MW strut. This offshore bidirectional strut has the ability to rescue constrained-off energy from either of the two wind farm sites, under the cable outage condition. Using Pöyry hourly dataset 2004 – 2008 for these two offshore sites, the amount of CoE that can be rescued by a 500MW strut during a radial cable outage condition, has been calculated for each year.

CBA for this offshore strut has been carried out but its detailed design is outside the scope of this discussion. Cable availability factor is taken to be 95% and further sensitivities for 98% and 93% cable availability per year are provided. These numbers have been chosen based on an Ofgem's availability incentive document for OFTOs[3].

The analysis is categorised into the following two cases. The output of both is then added to get the total energy rescued assuming that the outages do not overlap (when they do, both the wind farms are disconnected):

JG20-Cable Outage: Energy rescued from JG20 site by a 500 MW strut when JG20-Cable is out for 5% of the time in a year

JG22-Cable Outage: Energy rescued from JG22 site by a 500 MW strut when JG 22-Cable is out for 5% of the time in a year

Energy (GWh) is rescued when any one of the four conditions in the table below are satisfied. The conditions are designed in order to utilize the maximum capacity available on a 1GW JG22-Cable during JG20-Cable outage (i.e. Case a):

Table 9: Outage conditions

Condition	JG20 Output (GWh)	JG22 Output (GWh)	Rescued Energy (GWh)
1	X >= 0.5	Y >= 0.5	(1 - Y)
2	X >= 0.5	Y < 0.5	0.5
3	X < 0.5	Y >= 0.5	If (1 - Y) < X then rescue (1 -Y); but if (1 - Y) > X then rescue all X
4	X < 0.5	Y < 0.5	X

X *JG20 Output (GWh)*
Y *JG22 Output (GWh)*

Example illustration for Case a

The four conditions in Table above are illustrated by an example below. For any given hour of the year:

If JG22 = 0.8GWh and JG20 = 0.9GWh:
the rescued energy is (1.0 – 0.8) = 0.2GWh from JG20
If JG22 = 0.3GWh and JG20 = 0.7GWh:
the rescued energy is 0.5GWh
If JG22 = 0.7GWh and JG20 = 0.2GWh:
since (1 – 0.7) > 0.2GWh, the rescued energy is 0.2GWh
If JG22 = 0.3GWh and JG20 = 0.1GWh:
the rescued energy is 0.1GWh

[3] Changes to the Offshore Transmission Owner (OFTO) availability incentive – published by Ofgem on 28/03/2011. We understand that the target availability for current offshore radial connections is 95%.

The individual output for Case a and Case b with the total savings are shown in Table 10.

Table 10: Savings made by strut at 5% cable outage condition

Hours per annum @5% cable outage	*438*
Price of wind energy curtailment	*75 £/MWh*

Total energy rescued by 500MW Strut if JG20-Cable is out	2004	2005	2006	2007	2008	Average 2004-2008
GWh Rescued @100% cable outage	1,744	2,025	1,800	1,778	1,899	1,849
GWh Rescued @5% cable outage	87	101	90	89	95	92
Saving using 500MW strut in £m	£6.5m	£7.6m	£6.8m	£6.7m	£7.1m	£6.9m
Total energy rescued by 500MW Strut if JG22-Cable is out	**2004**	**2005**	**2006**	**2007**	**2008**	**Average 2004-2008**
GWh Rescued @100% cable outage	1,578	1,639	1,587	1,558	1,574	1,587
GWh Rescued @5% cable outage	79	82	79	78	79	79
Saving using 500MW strut	£5.9m	£6.1m	£6.0m	£5.8m	£5.9m	£6.0m
Total Savings made by strut	*£12.5m*	*£13.7m*	*£12.7m*	*£12.5m*	*£13.0m*	*£12.9m*

On average, a total saving of around (£6.9m + £6.0m) = £12.9m per year can be made by using a 500MW strut between JG20 and JG22 to rescue energy.

The strut under discussion is built up by using HVAC technology. The cost of HVAC offshore platform (including equipment) and the HVAC cable for a 500MW strut is approximated as below.
HVAC offshore Platform for 500MW = £80m per end[4]
HVAC 600MVA offshore Cable = £1.2m per km

A 30km long 500MW strut will cost = Platform (2 x £80m) + Cable Length (1.2 x 30km) = £196m
£12.9m per year savings made by a strut over 15 years = £193.5m

The capital cost of building a 500MW HVAC offshore strut is almost justified over approximately 15 years (Note: no discounting is taken into account).

The cable annual availability (%) sensitivity has been performed as shown below.

98% Cable Availability

With 98% availability of the subsea cable, strut justification almost disappears. The strut savings made with 98% cable availability is shown in

Table 11.

[4] Source: ODIS 2010 costs

Table 11: Savings made by strut at 2 % cable outage condition

Cable availability	***98%***					
Outage Hours per annum	*175*					
Price of wind energy curtailment	*75 £/MWh*					
Total energy rescued by 500MW Strut if JG22-Cable is out						**Average**
	2004	**2005**	**2006**	**2007**	**2008**	**2004-2008**
GWh Rescued	35	40	36	36	38	**37**
Saving using 500MW strut in £m	**£2.6m**	**£3.0m**	**£2.7m**	**£2.7m**	**£2.8m**	**£2.8m**
Total energy rescued by 500MW Strut if JG22-Cable is out						**Average**
	2004	**2005**	**2006**	**2007**	**2008**	**2004-2008**
GWh Rescued	32	33	32	31	31	**32**
Saving using 500MW strut in £m	**£2.4m**	**£2.5m**	**£2.4m**	**£2.3m**	**£2.4m**	**£2.4m**
Total Savings made by strut in £m	***£5.0m***	***£5.5m***	***£5.1m***	***£5.0m***	***£5.2m***	***£5.2m***

Average total savings reduce from £12.9m to £5.2m per year. The capital cost of building up a 500MW strut is now justified over 38 years.

93% Cable Availability

With 93% offshore cable availability, strut justification ratchets up. The results are shown in Table 12.

Table 12: Savings made by strut at 7 % cable outage condition

Cable availability	***93%***					
Outage Hours per annum	*613*					
Price of wind energy curtailment	*75 £/MWh*					
Total energy rescued by 500MW Strut if JG22-Cable is out						**Average**
	2004	**2005**	**2006**	**2007**	**2008**	**2004-2008**
GWh Rescued	122	142	126	124	133	**129**
Saving using 500MW strut in £m	**£9.2m**	**£10.6m**	**£9.5m**	**£9.3m**	**£10.0m**	**£9.7m**
Total energy rescued by 500MW Strut if JG22-Cable is out						**Average**
	2004	**2005**	**2006**	**2007**	**2008**	**2004-2008**
GWh Rescued	110	115	111	109	110	**111**
Saving using 500MW strut in £m	**£8.3m**	**£8.6m**	**£8.3m**	**£8.2m**	**£8.3m**	**£8.3m**
Total Savings made by strut in £m	***£17.4m***	***£19.2m***	***£17.8m***	***£17.5m***	***£18.2m***	***£18.0m***

Average total savings made by using 500MW strut increases from £12.9m up to £18.0m per year. Now the capital cost of building a 500MW offshore strut is justified over 10 years.

Based on 95% offshore cable availability assumption, there appears to be a cost-benefit justification for the strut in this offshore design.

Modifications

The economic value of strut cost benefit analysis for a central value of wind energy curtailment of 100 £/MWh for wind availability factor of 97% and revised cost of strut.

<u>JG20-Cable Outage:</u> Energy rescued from JG20 site by a 500MW strut when JG20-Cable is out for 3% of the time in a year

<u>JG22-Cable Outage:</u> Energy rescued from JG22 site by a 500MW strut when JG 22-Cable is out for 3% of the time in a year

Example of JG20-Cable outage

If JG22 >= 500MW and JG20 >= 500MW:
then rescue (1000 – JG22) MW from JG20
to utilize the maximum capacity available on a 1GW JG22-Cable during a JG20-Cable outage.

If JG22 >= 500MW and JG20 < 500MW:
and if (1000 – JG22) < JG20 then rescue (1000 – JG22) MW
but if (1000 – JG22) > JG20 then rescue all JG20 MW
to utilize the maximum capacity available on a 1GW JG22-Cable during a JG20-Cable outage.

If JG22 < 500MW and JG20 >= 500MW:
then rescue 500MW
to utilize the maximum capacity available on a 1GW JG22-Cable during a JG20-Cable outage.

If JG22 < 500MW and JG20 < 500MW:
then rescue all JG20 MW
to utilize the maximum capacity available on a 1GW JG22-Cable during a JG20-Cable outage.

The individual output for each Case c and Case d with total savings are shown in Table below.

Table 13: Savings made by strut at 3 % cable outage condition

Total energy rescued by 500MW Strut if JG22-Cable is out						Average
	2004	2005	2006	2007	2008	2004-2008
GWh Rescued	52	61	54	53	57	55
Saving using 500MW strut in £m	£5.2m	£6.1m	£5.4m	£5.3m	£5.7m	£5.5m

Total energy rescued by 500MW Strut if JG20-Cable is out						Average
	2004	2005	2006	2007	2008	2004-2008
GWh Rescued	47	49	48	47	47	48
Saving using 500MW strut in £m	£4.7m	£4.9m	£4.8m	£4.7m	£4.7m	£4.8m

Total Savings made by strut in £m	*£10.0m*	*£11.0m*	*£10.2m*	*£10.0m*	*£10.4m*	*£10.3m*

On average, total savings of about £10.3m per year can be made by using a 500MW strut between JG20 & JG22 to rescue energy.
The strut cost in this part is the cost of HVAC cable for building up a 500MW strut as shown below.

HVAC 2 x 220 kV 307 MVA offshore cable = £1.2m per km

A 30 km long 500 MW strut will cost = (2x1.5 x30) = £90m
£10.3m per year savings made by a strut over 15 years = £90m

The capital cost of building a 500 MW HVAC offshore strut in this paper is almost justified over 9 years.

The curtailment cost of energy is taken to a base value of 100 £/MWh.

98% Cable Availability

With the 98% of offshore cable availability, strut justification almost disappears. The strut savings made with 98% cable availability is shown in Table 14.

Table 14: Savings made by strut at 2 % cable outage condition

Total energy rescued by 500MW Strut if JG22-Cable is out						Average
	2004	2005	2006	2007	2008	2004-2008
GWh Rescued	35	40	36	36	38	37
Saving using 500MW strut in £m	£3.5m	£4.0m	£3.6m	£3.6m	£3.8m	£3.7m

Total energy rescued by 500MW Strut if JG20'-Cable is out						Average
	2004	2005	2006	2007	2008	2004-2008
GWh Rescued	32	33	32	31	31	32
Saving using 500MW strut in £m	£3.2m	£3.3m	£3.2m	£3.1m	£3.1m	£3.2m

Total Savings made by strut in £m	*£6.6m*	*£7.3m*	*£6.8m*	*£6.7m*	*£6.9m*	*£6.9m*

Average total savings reduce from £10.3m down to £6.9m per year. The capital cost of building up a 500MW strut is now justified over 13 years.

93% Cable Availability

With the 93% of offshore cable availability, strut justification ratchets up. The results are shown in Table 15.

Table 15: Savings made by strut at 7 % cable outage condition

Total energy rescued by 500MW Strut if JG22-Cable is out	2004	2005	2006	2007	2008	Average 2004-2008
GWh Rescued	122	142	126	124	133	129
Saving using 500MW strut in £m	£12.2m	£14.2m	£12.6m	£12.4m	£13.3m	£12.9m
Total energy rescued by 500MW Strut if JG20-Cable is out	2004	2005	2006	2007	2008	Average 2004-2008
GWh Rescued	110	115	111	109	110	111
Saving using 500MW strut in £m	£11.0m	£11.5m	£11.1m	£10.9m	£11.0m	£11.1m
Total Savings made by strut in £m	*£23.3m*	*£25.6m*	*£23.7m*	*£23.4m*	*£24.3m*	*£24.1m*

Average total savings made by using 500MW strut increases from £10.3m up to £24.1m per year. Now the capital cost of building a 500MW offshore strut is justified over 4 years.

Redundancy of Offshore Cables

To analyse case of offshore cable redundancy, a 5GW offshore wind farm with the following assumptions is considered:

Connection Unit is five 1GW DC cables, each 100km
Wind farm is all collected at a common hub (this assumption is artificial as there will be a number of 'hub' collection points).
Offshore cables each 95% available
Poyry 'JG20' wind output duration curve (used in CBA in 10.2)
Price of wind curtailment = 75 £/MWh

The base case is 5 connecting cables. The test case is redundancy, with an 6th connecting cable. Capital cost = £275m for the 6th cable.

5 cables of availability 95% each have combined availability:

0 cables out = 0.95^5 = 0.77378

1 cable out = …. = 0.4072
2 cables out = …. = 0.0214
3 cables out = …. = 0.001128

Energy lost from 5GW wind farm, base case:
0 cables out = 0.77378 x 0 = 0
1 cable out = 0.4072 x 460GWh = 187GWh x 75 £/MWh = £14m
2 cables out = 0.0214 x 1200GWh = 26GWh x 75 £/MWh = £2m

Energy lost from 5GW wind farm, test case with 6th cable:
0 / 1 cables out = 0= 0
2 cables out = 0.032 x 460GWh = 15GWh x 75 £/MWh = £1.1m

Therefore, energy rescued by the 6th cable = 16 –1.1= £14.9m and the 6th cable appears to pay back over 18 years.

Appendix E - Review of Intermittent Generation (GSR009 Update)

The assessment is carried out in three parts, a 'Winter Peak' model study, a constraints model study, and a cost-benefit process. The Peak and Constraint models determine the constraint cost ('O'), and the annuitized transmission cost ('T') is calculated in the cost-benefit process. The minimum of 'T+O' plotted against boundary capability gives the optimum balance – from a cost benefit viewpoint – between transmission investment and constraints costs.

Winter Peak Model

This model calculates the required capability for a selected boundary. The inputs are: a given forecast demand; a generation background, a ranking order, and an SQSS approach. For example, for B8 under approach 1a (described below) for 2020/21, the model may indicate a required capability of 10GW under Gone Green or 12GW under Accelerated Growth. The model handles details such as

- whether a ranking order is used (to allocate as 'Contributory' the most economic plant ahead of expensive plant) or whether the capacity of the plant types are 'scaled' in some manner;
- how wind is treated – which may be different on the import and export sides of the boundary (though not for the three approaches considered here);
- how a global scaling factor is applied to qualifying generation to meet forecast demand;
- and the nature of the allowance that is added to the Planned Transfer to give the Required DC Thermal Capability for the selected boundary.

Constraints Model

We have progressed from the 'two zones / one boundary' version of our original 'seven zones / six boundaries' annual Constraints forecasting model[5]. We now use a very similar optimising constraints model, as this addresses some of the weaknesses in the original[6]. Some of the main features are:

- use of a fuel-type merit order to determine the unconstrained generation schedule
- representation of the year by three seasons and eight demand blocks of varying duration
- in each iteration in the Monte Carlo simulation, the model
  - samples the probabilistic fuel-type availability
  - determines the marginal fuel for each demand block
  - resolves constraints, should the unconstrained transfer be higher than the boundary capability by (i) accepting the most attractive available Bid(s) to reduce plant running in the export zone, and (ii) accepting the cheapest available offer(s) from the import zone

Model output is the constraint cost, volume, and price for the boundary whose required capability was derived earlier from the Peak model.

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[5] Used in the GSR001 review (2008) and in the ENSG Report assessment of transmission system reinforcement options for 2020.

[6] Rather than develop a two-zone variant, we have elected to set all boundary capabilities to 99,999MW apart from the boundary under consideration.

Cost-benefit process

The cost-benefit process seeks to determine the optimum balance between transmission investment cost ’T’ and residual constraints cost ‘O’. ‘O’ has already been determined (0 above); ‘T’ is the product of transmission price, boundary thickness, and GW required capability.

Plotting the combined cost ‘T+O’ for several boundary capabilities produces the shape of the function, from which the optimum balance of ‘T’ and ‘O’ – the minimum of the function – can be determined.

SQSS Approaches

We have considered three deterministic approaches, two of which – 1s and 1e – are set under GSR009:

1a (the high-level deterministic approach of the pre-GSR009 SQSS for MITS)
1s (‘Demand Security’ - existing)
1e (‘Economy- existing’)

The details of each SQSS approach are discussed below, i.e. the percentages applied to Wind/ Wave[7] generation, and the contributory/ non-contributory derivation.

Approach 1a (pre-GSR009)

All plant is uniquely ranked to determine the contributory / non-contributory volumes. Wind capacity is scaled at 40% for the contributory calculation, and then scaled using an A_T factor of 72% (for both import and export sides of the boundary) to determine the global scaling factor to apply to meet demand. (Thus wind is effectively scaled by almost 60%, as the global scaling factor is usually around 83%).

The planned transfer is added to an Interconnection Allowance (½IA) to determine the required capability for the boundary in question.

Approach 1e (Economy–GSR009)

This approach uses a Boundary Allowance rather than the standard Interconnection Allowance, and uses ‘direct scaling’ rather than a ranking order. The premise is to represent the most economically efficient way of running the power system; i.e. what one might expect to run under conditions of high wind and normal conventional plant availability.

To meet demand; the most economically efficient generation is directly scaled on at high values.
‘Uneconomic’ peaking plant is scaled at zero and the sum of direct scaled generation is subtracted from demand, to leave a residual demand.

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[7] Since mid-2008, we have agreed that, since Wave and Tidal generation sources look to have an annual load factor of some 25-40%, it is sensible to treat Wave/Tidal identically to Wind, for the purposes of SQSS scaling. This decision appears robust for penetrations of Wind/Tidal of up to 5GW. Accordingly, ‘Wind’ and ‘Wind/Wave’ are used interchangeably for the rest of this document.

The residual demand is met by all ‘variable’ generation (eg. hydro, pumped storage; existing non-CCS coal and gas) in the ranking order. The variable generation capacity is scaled down to meet demand (this factor may be low – perhaps 20%).

Table 16 illustrates the classes of plant and their allocated scaling factors.

The Boundary Allowance is defined below. It increases linearly from 0MW to 1000MW (for ½ BA) as the total of group generation plus demand rises to 5GW. For higher levels of generation and demand it is capped at 1GW, and all but the small boundaries end up with ½ BA of 1GW.

Boundary Allowance = minimum [2000, 0.4 * (zone generation + zone demand)]

Table 16: Approach 1e Generation Direct Scaling Factors

Approach 1e				
Direct scaled				
CCGT - new CCS	Thermal	Other - conv	direct_N_CCS	85%
Coal - new CCS	Thermal	Other - conv	direct_N_CCS	85%
Nuclear (New)	Nuclear	Other - conv	direct_N_CCS	85%
Nuclear (A)	Nuclear	Other - conv	direct_N_CCS	85%
Nuclear (M)	Nuclear	Other - conv	direct_N_CCS	85%
Nuclear (P)	Nuclear	Other - conv	direct_N_CCS	85%
Pumped Storage	Pumped Storage	Other - conv	direct_PS	50%
Tidal/Wave	Wave & Tidal	Wave & Tidal	direct_WT	70%
Wind (offshore)	Wind	Wind	direct_Wind	70%
Wind (onshore)	Wind	Wind	direct_Wind	70%
Wind (onshore - embedded)	Wind	Wind	direct_Wind	70%
Interconnector	Interconnector	Other - Intcon	direct_Int_Gen	100%
Variable scaled				
Biofuel / Biomass	Biomass	Other - conv	variable	n/a
CCGT	Thermal	Other - conv	variable	n/a
CCGT - new	Thermal	Other - conv	variable	n/a
CHP	Thermal	Other - conv	variable	n/a
Coal - LCPD in	Thermal	Other - conv	variable	n/a
Coal - LCPD out	Thermal	Other - conv	variable	n/a
Coal - new	Thermal	Other - conv	variable	n/a
Hydro	Hydro	Other - conv	variable	n/a
Uneconomic				
AGT/OCGT	Thermal	Other - conv	none_Unecon	0%
Oil	Thermal	Other - conv	none_Unecon	0%

Approach 1s (Security- GSR009)

This new approach is also known as the *Demand Security* approach, and represents the case where there is no wind and GB cannot import – its purpose is to ensure GB has security of supply.

All interconnectors are fixed at float, i.e. GB cannot import, but also (and not unreasonably if there is no wind) that GB would not export. All plant are ‘contributory’ if the plant margin < 20%, else the ranking order technique is used (as in 1a) to identify non-contributory plant. Interconnection Allowance is calculated using the Circle Diagram as in approach 1a.

Background Scenarios

We have appraised possible SQSS methodologies against the April-2011 *Accelerated Growth* background scenario for 2020/21 and 2025/26 (boundary B8 only).

The background is illustrated in Table 16, broken down by NGET/Scotland. Table 17 shows the installed capacity and demand by Import and Export zone, for boundary B8.

Table 17: Demand and Installed Capacity by Background Scenario

Accelerated Growth (2020/2021)		SHETL	SPT	NGET	Total
Sum of MW_Cap					
		AG			AG Total
vlup_fuel	Type	SHETL	SPT	NGET	
Nuclear	Nuclear (AGR)		1,215	1,203	2,418
	Nuclear (New)			2,870	2,870
	Nuclear (PWR)			1,200	1,200
	Nuclear (Mag)				
Nuclear Total			**1,215**	**5,273**	**6,488**
Marine		533	100	800	1,433
Wind_Off	Wind (offshore)	1,620	3,568		5,188
	Wind (offshore) R1&2			6,764	6,764
	Wind (offshore) R3	1,809	1,547	16,931	20,287
Wind_Off Total		**3,429**	**5,115**	**23,695**	**32,239**
Wind_On		5,632	3,860	483	9,975
Base_Gas	CCGT	590		4,312	4,902
	CCGT - new			10,270	10,270
	CHP			1,218	1,218
Base_Gas Total		**590**		**15,800**	**16,390**
France				1,988	1,988
Biomass			347	1,329	1,676
Hydro		1,099	33		1,132
Marg_Gas	CCGT	590		13,856	14,446
	CHP	22	120	596	738
Marg_Gas Total		**612**	**120**	**14,452**	**15,184**
PumpStor		300	440	2,004	2,744
Britned / Imera				1,268	1,268
Oil					
Aux GT / Main GT				717	717
Base_Coal	Coal - LCPD in		1,142	6,473	7,615
	Coal - new			3,200	3,200
Base_Coal Total			**1,142**	**9,673**	**10,815**
Marg_Coal	Coal - LCPD in		1,142	5,559	6,701
	Coal - LCPD out			230	230
Marg_Coal Total			**1,142**	**5,789**	**6,931**
Grand Total		**12,195**	**13,513**	**83,270**	**108,978**

Accelerated Growth (2025/26)		SHETL	SPT	NGET	Total
Nuclear	Nuclear (AGR)		1,215	1,203	2,418
	Nuclear (New)			10,280	10,280
	Nuclear (PWR)			1,207	1,207
	Nuclear (Mag)				
Nuclear Total			**1,215**	**12,690**	**13,905**
Marine		1,620		211	1,831
Wind_Off	Wind (offshore) STW	1,000	3,150		4,150
	Wind (offshore) R1			584	584
	Wind (offshore) R2			6,807	6,807
	Wind (offshore) R2.5			1,631	1,631
	Wind (offshore) R3	2,575	2,500	25,410	30,485
Wind_Off Total		**3,575**	**5,650**	**34,432**	**43,657**
Wind_On	Wind (onshore)	4,773	4,226	659	9,657
	Wind (onshore Embed)	199	550		749
Wind_On Total		**4,972**	**4,775**	**659**	**10,406**
Base_Gas	CCGT	1,180		2,400	3,580
	CCGT - new			20,361	20,361
	CHP			499	499
Base_Gas Total		**1,180**		**23,260**	**24,440**
France				1,988	1,988
Biomass			347	1,693	2,040
Hydro		1,099	33		1,132
Marg_Gas	CCGT			11,293	11,293
	CHP	22	120	428	570
Marg_Gas Total		**22**	**120**	**11,721**	**11,863**
PumpStor		300	440	2,004	2,744
Britned / Imera			80	5,100	5,180
Oil					
Aux GT / Main GT				604	604
Base_Coal	Coal - LCPD in			1,277	1,277
	Coal - new		2,284	2,986	5,270
Base_Coal Total			**2,284**	**4,263**	**6,547**
Marg_Coal	Coal - LCPD in			3,795	3,795
	Coal - LCPD out			230	230
Marg_Coal Total				**4,025**	**4,025**
Grand Total		**12,767**	**14,944**	**102,650**	**130,361**

DEMAND B8 (EC2)

	2020/21 AG
exp	20.2
imp	36.9
Grand Total	**57.1**

GENERATION CAPACITY

imp/exp	Fuel Type	Type2	Sum of 2020/213 (2020/21 AG)
Export	Biomass		1.5
	Hydro		1.1
	Interconnector		-0.6
	Nuclear	Existing	2.4
		New	1.2
	Pumped Storage		2.7
	Thermal	AGT/OCGT	0.2
		CCGT - existing	8.9
		CCGT - new	2.4
		CCGT - new CCS	
		CHP	1.6
		Coal - existing	10.6
		Coal - new CCS	0.6
	Wave & Tidal		1.2
	Wind	Wind (offshore)	20.4
		Wind (onshore)	8.5
		Wind (onshore - embedded)	0.7
Export Total			**63.4**
Import	Biomass		0.4
	Interconnector		
	Nuclear	Existing	1.2
		New	1.7
	Thermal	AGT/OCGT	0.5
		CCGT - existing	14.5
		CCGT - new	11.4
		CCGT - new CCS	
		CHP	0.4
		Coal - existing	3.3
		Coal - new CCS	
		Oil	
	Wave & Tidal		0.1
	Wind	Wind (offshore)	12.5
		Wind (onshore)	0.7
Import Total			**46.6**

DEMAND B8 (EC2)

	2025/26 AG
exp	20.7
imp	37.7
Grand Total	**58.4**

GENERATION CAPACITY

imp/exp	Fuel Type	Type2	Sum of 2025/263 (2025/26 AG)
Export	Biomass		1.5
	Hydro		1.1
	Interconnector		-0.5
	Nuclear	Existing	2.4
		New	3.6
	Pumped Storage		2.7
	Thermal	AGT/OCGT	0.1
		CCGT - existing	4.6
		CCGT - new	2.4
		CCGT - new CCS	2.0
		CHP	1.6
		Coal - existing	4.1
		Coal - new CCS	4.2
	Wave & Tidal		1.6
	Wind	Wind (offshore)	29.4
		Wind (onshore)	9.0
		Wind (onshore - embedded)	0.7
Export Total			**70.7**
Import	Biomass		0.5
	Interconnector		
	Nuclear	Existing	1.2
		New	6.7
	Thermal	AGT/OCGT	0.5
		CCGT - existing	12.5
		CCGT - new	10.4
		CCGT - new CCS	2.8
		CHP	0.4
		Coal - existing	
		Coal - new CCS	2.0
		Oil	
	Wave & Tidal		0.2
	Wind	Wind (offshore)	14.3
		Wind (onshore)	0.7
Import Total			**52.0**

Cost-Benefit Data

Cost of Transmission Reinforcements (‘T’)

Since we are performing a generic appraisal, we use a generic reinforcement price of 1000 £/MW.km capital. Annuitized over ten years, this is a price of 100 £/MW.km. per year.

Actual reinforcement prices currently being considered for real within the TII projects to appraise the *Accelerated Growth* scenarios exceed even these prices. This is broadly because we do not believe that long overhead line routes would be feasible within *Accelerated Growth* timescales, and hence we are exploring offshore DC cables options, which have greater unit prices.

The Transmission Reinforcement cost is the product of reinforcement price, boundary thickness and required capability. Thus 1GW capability on B8 equates to a transmission cost of £9.3m per year (1GW x 93km x £100/MW.km).

We should note that we are assessing an *absolute* capability, rather than an *increase from a baseline* capability. In fact this does not matter, since our method only affects the absolute value of ‘T’ quoted in ‘T+O’: it does not alter the relative comparison of approaches at all.

Cost of Constraints (O)

Table 18 shows the Generation prices for each fuel type[8] – naturally these are a very important assumption in the calculation of constraint costs.

Table 18: Merit Order

Technology	Bid price	Offer price	Rank	*Operation*
Nuclear	-200	**99,991**	1	*NGC Inflexible*
Marine	-160	**99,993**	2	*NGC Inflexible*
Wind_Off	-150	**99,995**	3	*NGC Inflexible*
Wind_On	-75	**99,997**	4	*NGC Inflexible*
Base_Gas	25	60	5	*BaseLoad*
Base_Coal	30	75	6	*BaseLoad*
France	32	80	7	*Mid_Merit*
Biomass	33	83	8	*Mid_Merit*
Hydro	34	85	9	*Mid_Merit*
Marg_Gas	35	90	10	*Mid_Merit*
Marg_Coal	40	105	11	*Mid_Merit*
PumpStor	60	150	12	*Peaker*
Britned / Imera	80	200	13	*Peaker*
Oil	100	300	14	*Peaker*
Aux GT / Main GT	150	400	15	*Peaker*

A fairly typical Constraint action in these studies is to constrain off the 'Base_Gas' plant in Scotland (Peterhead), at a Bid price of 25£/MWh; and to replace with 'Marg_Gas' plant in England, at an Offer price of 90£/MWh. Thus for most of the studies reported below, the average Constraint price is 65£/MWh, which follows directly from these Bid and Offer pricing assumptions.

Since the GSR009 analysis of June 2010 we have adopted two moderate changes to bid and offer prices:
The Bid-Offer spread between Base and Marg gas is now slightly reduced; and,
Wind Bid prices are now more negative (onshore from -25£/MWh to -75£/MWh; offshore from -50 £/MWh to -150 £/MWh).

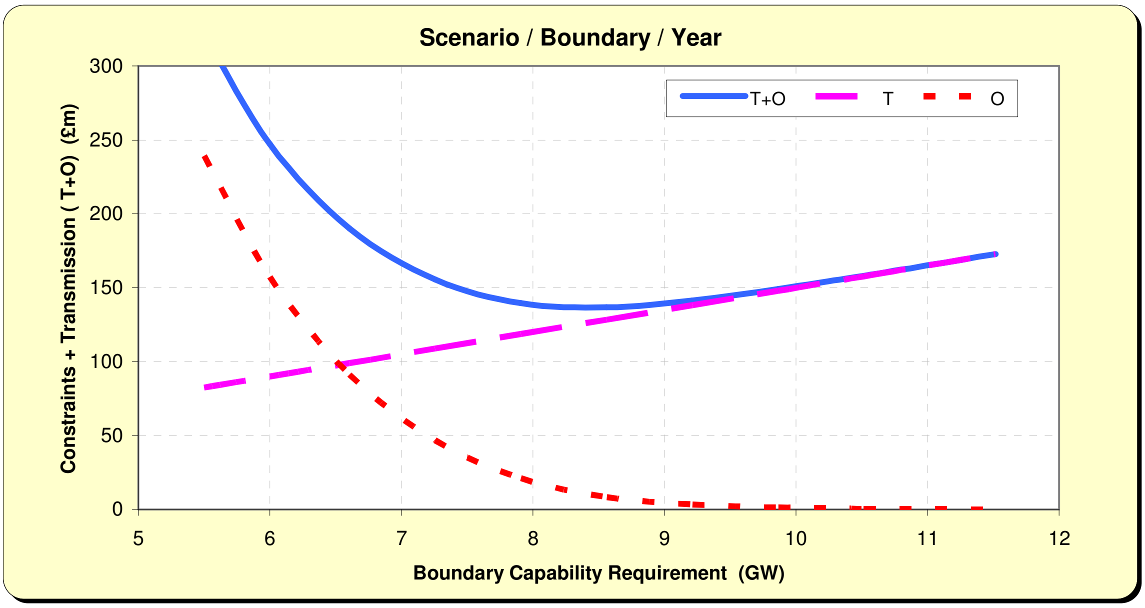
Transmission plus Constraints ('T+O') Costs

Since we are ignoring losses and construction outage costs, our cost-benefit curve is defined as the sum of the (linear) transmission costs and the (approximately quadratic) constraints costs, as shown in

Figure 3.

[8] £99,999 prices mean not available, in effect.

Figure 3: Transmission plus Constraint Curve



The optimal MW capability point is the *minimum* of the 'T+O' curve, and here this is some 8.5GW. We can see that inadequate capability incurs too great a constraints cost penalty despite low transmission costs, whereas too high a capability – whilst eliminating nearly all constraints costs – incurs too great a transmission cost.

Required Boundary Capabilities, by Approach

Applying the three SQSS approaches yields the required AG boundary capabilities for year 2020 and 2025 shown in Figure 4 & Figure 5. These are in fact the winter capabilities: the Constraints model studies three seasons (Winter, Summer_Intact and Summer_Outage) and the capabilities for the summer seasons are calculated as a fraction of the Winter capability (Summer_Intact 85% and Summer_Outage 70%).

Figure 4: Required AG Boundary Capabilities (GW) for 2020 for B8

SQSS Approaces (include embeded wind)	1s	1a	1e
Planned transfer	8,304	11,216	14,718
Interconnection Allowance	1,102	1,123	1,000
Required Capability (DC)	**9,406**	**12,339**	**15,718**
Existing Capability	10,000	10,000	10,000
DC compliant/(non-compliant)	-600	2,300	5,700
Scaling Factor	85.6%	69.2%	34.7%

Figure 5: Required AG Boundary Capabilities (GW) for 2025 for B8

SQSS Approaces (include embeded wind)	**1s**	**1a**	**1e**
Planned transfer	5,701	12,293	18,020
Interconnection Allowance	1,114	1,147	1,000
Required Capability (DC)	**6,815**	**13,440**	**19,020**
Existing Capability	10,000	10,000	10,000
DC compliant/(non-compliant)	-3,200	3,400	9,000
Scaling Factor	86.7%	66.0%	-7.2%

The approach 1a required capability is rather lower than the 1e capability for B8, and the main reason is that 1a scales wind by <60% whereas 1e scales Wind by 70%.

Constraint Results for B8 2020

Detailing an individual Constraint study against the boundary capability required for each approach may not show the cost curve to its best advantage. Therefore we interpolate between the minimum and maximum required capability, and perform several constraint runs for each row in Figure 4, including runs below the minimum and above the maximum. The constraint cost profile for boundary B8 is discussed below.

Constraint Costs for B8 2020

From B8 2020/21 'T+O' Results, it can be seen that as always, the constraint cost curve is approximately quadratic. Constraints rise rapidly for capability values below 14GW and breaches £280m around 10GW. When the capability approaches 16GW, constraint costs on this boundary are under £5m per year.

'T+O' Results for B8 2020

For each boundary we plot 'T+O' against GW boundary capability and flag the capability required by each of the three approaches. It appears 1s is severely under-reinforced as predicted, and therefore the main focus in this report is to compare 1a and 1e. We can identify the optimum boundary capability (i.e. the minimum of the 'T+O' curve) and identify the corresponding 'T+O' cost.

Figure 9: Optimum points on the 'T+O' Curve

Boundary	Thickness		SQSS Approach 1a	SQSS Approach 1e	SQSS Approach 1s	Optimum GW T+O
B8	93 km	GW	12.3GW	15.7GW	9.4GW	**14.5GW**
		T	£115.0m	£150.0m	£85.0m	**£15.6m**
		O	£78.0m	£5.0m	£330.0m	**£133.4m**
		T+O	£193.0m	£155.0m	£415.0m	**£149.0m**
		Δ GW from Optimum	2.2GW	1.2GW	5.1GW	
		Δ T+O from Optimum	£41.0m	£1.0m	£261.0m	

0-£10m
£10m-£100m
>£100m

Constraint Costs for B8 2025

From B8 2025/26 'T+O' Results, it can be seen that as always, the constraint cost curve is approximately quadratic. Constraints rise rapidly for capability values below 13GW and breaches £400m around 10GW. When the capability approaches 16GW, constraint costs on this boundary are under £20m per year.

'T+O' Results for B8 2025

For each boundary we plot 'T+O' against GW boundary capability and flag the capability required by each approach. It appears the approach 1s is severely under-reinforced as predicted, and therefore the main focus in this report is to compare 1a and 1e approaches. We can identify the optimum boundary capability (i.e. the minimum of the 'T+O' curve) and identify the corresponding 'T+O' cost.

Figure 10: Optimum points on the 'T+O' Curve

Boundary	Thickness		SQSS Approach 1a	SQSS Approach 1e	SQSS Approach 1s	Optimum GW T+O
B8	93 km	GW	13.5GW	19GW	6.8GW	**16GW**
		T	£125.0m	£189.0m	£70.0m	**£147.0m**
		O	£80.0m	£1.0m	£1,130.0m	**£19.0m**
		T+O	£210.0m	£190.0m	£1,200.0m	**£166.0m**
		Δ GW from Optimum	2.5GW	3GW	9.2GW	
		Δ T+O from Optimum	£44.0m	£24.0m	£1,034.0m	

0-£30m
£30m-£100m
>£100m

Appendix F Offshore Infeed Loss Criteria

Re-distribution of power through HVDC links

The study was carried out in power factory with a single bus model (equivalent shown in 11). The size of generation-demand system under study is 27 GW. A low demand system is considered as this presents the most onerous condition for frequency control. The model has a higher wind proportion as compared to the other generating sources. Frequency response is provided such that for a loss of 1800MW the minimum system frequency will be 49.2Hz, ie the system is on the limit of compliance with the SO's licence requirements. The model also takes into account a contractual load shedding of 200 MW. This same model has been previously used by National Grid in the study of 1800 MW loss for Frequency Response Technical Sub group within Grid Code CUSC working group.

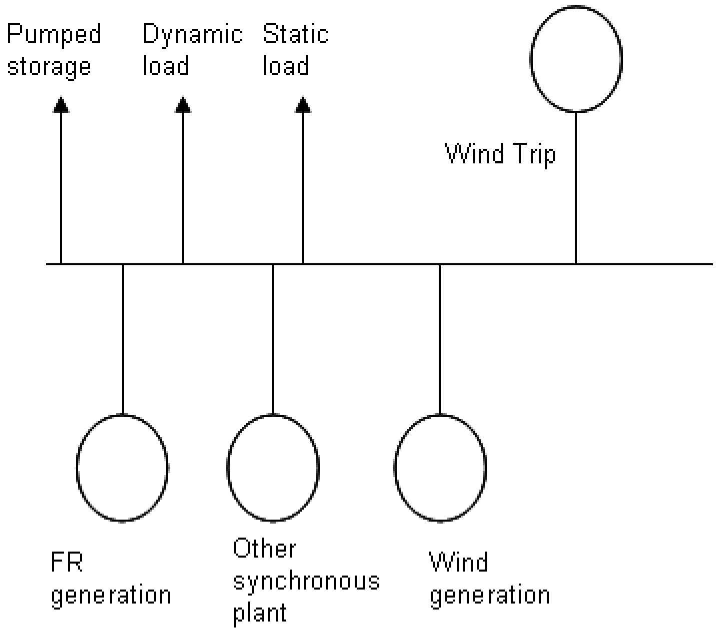


Figure 11: Study model

The figures below show the system frequency following varying sizes of generation loss and the post fault restoration of some of the generation infeed. The time by which the restoration is required to ensure compliance has been calculated, and the graphs show the cases in which the maximum restoration delay is used – in each case the frequency drops to 49.2 Hz. The wind trip occurs at t = 1s in the following frequency response plots.

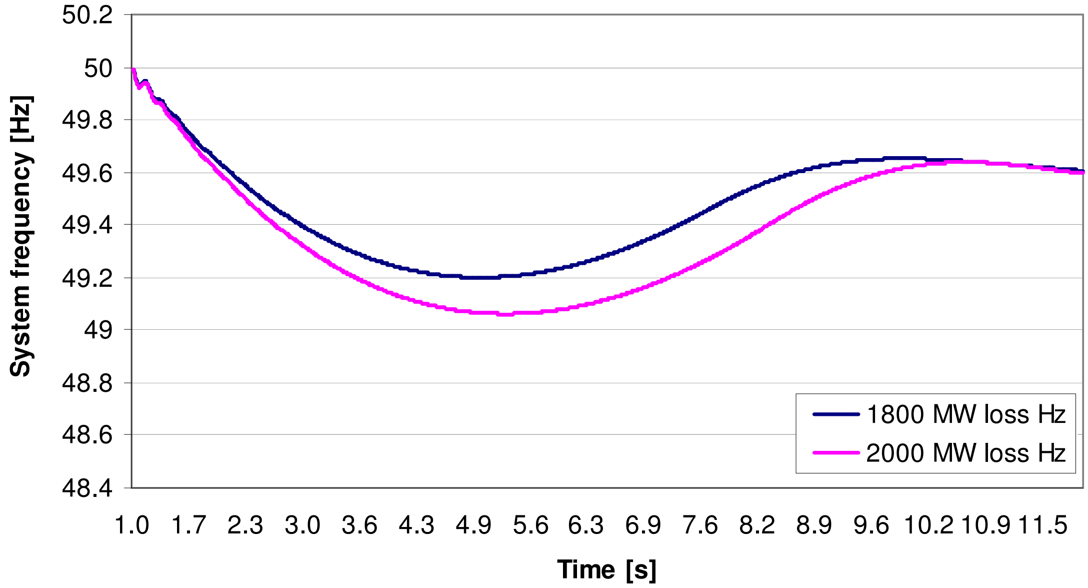


Figure 12: Frequency response

Figure above shows the frequency change for loss of 1800 MW from system at t= 1s, resulting in a frequency drop to 49.2 Hz and for a loss of 2000 MW, when the frequency drops below 49.2 Hz.

For a 2000MW loss, in order to bring the frequency back within acceptable limits, various proportions of the lost generation are connected back to the system at the latest time possible to keep the frequency above 49.2Hz. The graph below shows the results for re-connections between 200 and 2000MW. For reference, the loss with no reconnection is included.

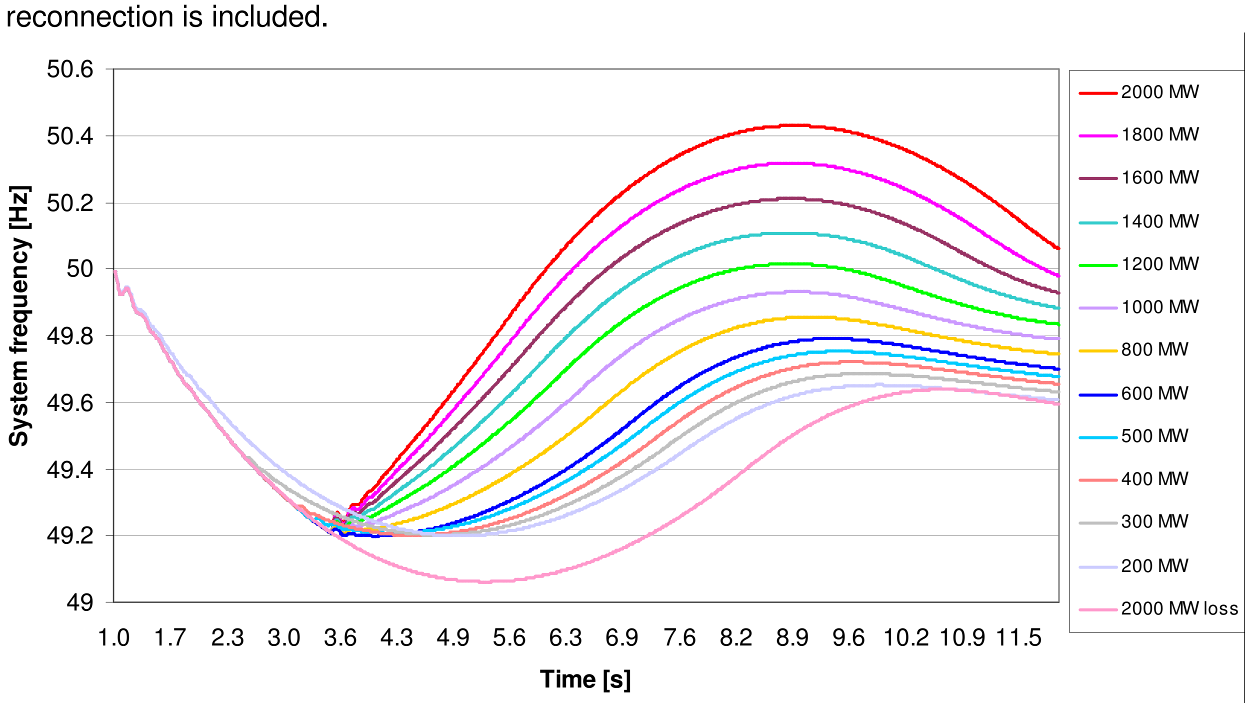


Figure 13: System frequency for MWs reconnected

It can be seen from the curves in figure 13 that smaller reconnections require earlier action. For example the curve for the 200MW reconnection diverges from the no-reconnection very soon after the generation loss – the reconnection of 200MW must occur immediately to effectively make the loss an 1800MW loss, for which just sufficient response is held. For a 2000MW reconnection, the control action can be delayed until the time that the frequency reaches 49.2Hz.

Figures 14 and 15 below show the time / capacity combinations for reconnection that would meet the system requirements for the loss of a 2GW link and a 2.2 GW link.

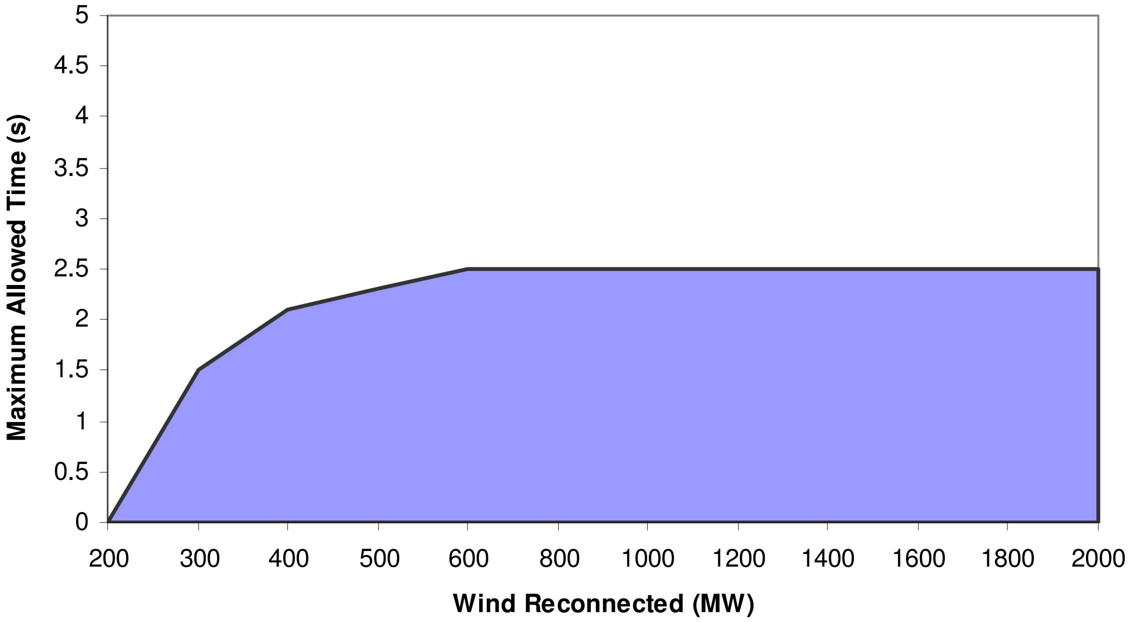


Figure 14: 2GW loss allowed time

The study was repeated for the loss of 2.2GW of wind as shown in Figure 15.

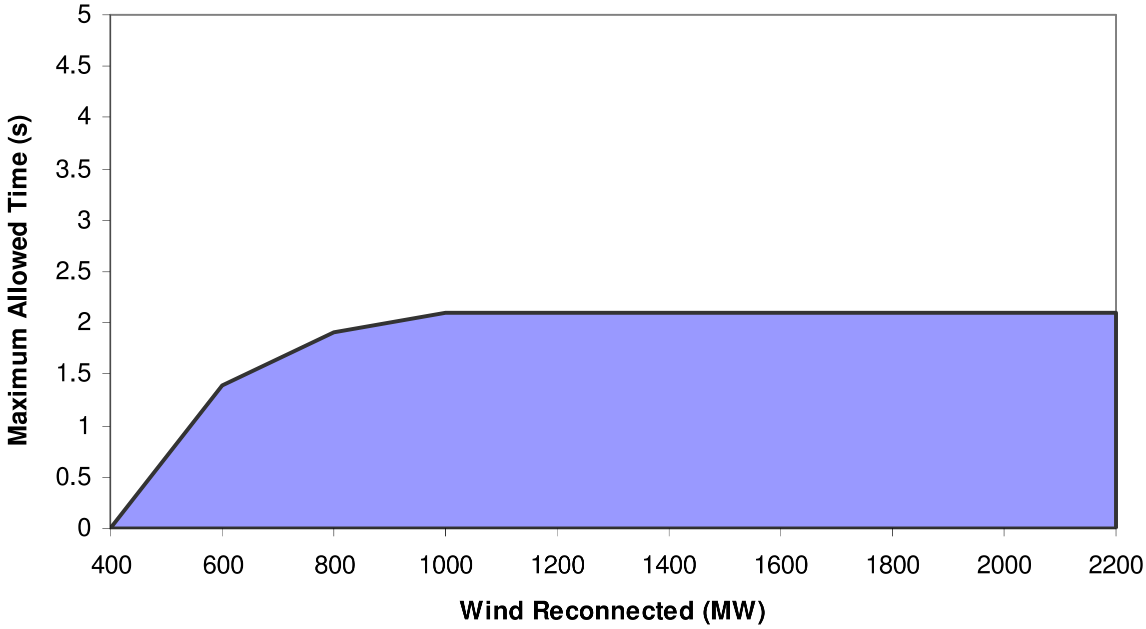


Figure 15: 2.2GW loss allowed time

Raising the infeed loss limit

GSR007 justified raising the infrequent infeed loss limit from 1320 MW to 1800 MW by demonstrating that the reduction in energy prices resulting from the introduction of the proposed 1800 MW nuclear generating units was greater than the additional costs of response holding.

A simple analysis of the benefits in total cable cost savings if larger cables are used for radial offshore generation connections (the savings result from fewer cables being required) versus the additional response costs is:

The additional cost of holding 1800 MW response compared to 1320 MW response was found to be ~ £160m per year in GSR007

If 2GW cables are used instead of 1.8 GW cables, additional response holding of 200 MW will be required. Based on the above, this will cost ~ £60m per year

Assuming a 1.8 GW cable costs ~ £300m (200km at £1.5m / km; converter costs can be ignored, as the total converter capacity will remain constant for all cable sizes) – this is £30m per year

This implies it will be necessary to save 2 cables to justify the extra response holding

The two cables saved will have a capacity of 3.6 GW that will need to be taken up by other cables. This will require that eighteen cables of 2GW capacity are used in place twenty 1.8 GW cables.

The generation capacity needed to require this number of cables is 36 GW.

The connection of offshore generation at this level is not anticipated for the foreseeable future. Even if it does develop at this level, it will be staged over a number of years. The extra response will be required from the date of the first connection – any benefit would not be seen for many years.

Appendix G - Status of Generator Intertrip in Offshore Design

It is self-evident that radial designs within offshore transmission systems lose generation for transmission faults. This is an accepted feature of radial designs: the costs of offshore transmission redundancy exceed the costs of the wind curtailment. The question is:

To what extent this principle of losing wind output for transmission faults should be extended into integrated offshore designs?

Integrated offshore designs suffer by comparison with radial offshore designs, if intertrips are not permitted. The simplest illustration is a case of two 1.8GW offshore wind farms. Under a radial design, two 1.8GW OFTO cables suffice; on any cable fault, one wind-farm output (up to 1.8GW) is lost. Under an Integrated design, the two wind farms are coupled, but two connecting 1.8GW cables do not suffice. The N–1 criterion of SQSS Chapters 7 is clearly violated for any cable fault with >1.8GW combined output pre-fault; hence a third 1.8GW cable is required. This illustration makes no sense, of the simple integrated concept to couple the two wind farms.

Proposed Adoption of Offshore Intertrips

The proposal is to permit adoption of an offshore intertrip for the planning of SQSS Chapter 7- connections of offshore generation. The proposal also permits adoption, for the SQSS Chapter 4 considerations of both onshore and offshore boundaries. The proposal requires the following:

Particularly for the latter case, the proposal only permits adoption of an intertrip signal from an offshore AC or DC circuit (including the parts of that circuit onshore into an onshore converter or connecting substation) to offshore generation.
It is assumed that such intertrips can be engineered and installed, to the equivalent standards and reliability as onshore intertrip systems.
It is desirable, but not strictly necessary, that the intertrip is negotiated commercially as a 'quid-pro-quo' under an integrated design. In return for the reliability benefits of an integrated design, the offshore developer accepts the intertrip at a reasonable price. The intertrip would come under CAP076 category 4 terms in the Chapter 7; but in the Chapter 4, the intertrip may not come under CAP076 terms, in which case it would be necessary to reach a commercial agreement with the developer. In designing the system, designer has to perform the CBA of the intertrip arming costs against the additional offshore transmission costs, or else the wind curtailment costs.

Comparison with Onshore Intertrips

It is a reasonable question, why we believe that adoption of offshore-intertrips is acceptable, whereas onshore intertrips are not regarded as acceptable to meet the main onshore peak security criterion.

Extract from Working Group 4 Report: 'Use of Intertrips'

This section repeats the extensive discussion *in italics* of onshore intertrips, from the 2010 'Working Group 4; report on SQSS Contingency Criteria. For each consideration, discussion is made of the differences (if any) between the onshore and offshore cases. This discussion is insightful, and mainly concludes that the onshore and offshore intertrip cases are sufficiently different to merit separate treatment.

Benefits of using intertrips

The benefits of using system-to-generator intertripping include;

Intertripping and communications equipment provide a low cost solution compared with transmission reinforcement.

This is even more true for offshore intertrips than for onshore intertrips. The costs of intertrip equipment are little greater offshore than onshore, whereas the unit costs of offshore HVDC transmission, per km, are almost 3-5 times the unit cost of onshore overhead lines (depending on the distances, hence proportion of DC converter costs).

Early connection of renewable generation to meet Government targets for CO_2 reductions, if the alternative transmission reinforcements are lengthy to consent and construct.

It can be argued that Radial connections permit rapid connection, by virtue of it being implicit that 1.8GW of offshore generation will be lost for each radial cable fault. Hence this is only an issue for offshore intertrips, to the extent that refusing to use offshore intertrips would force one into Radial rather than Integrated designs, as the only way to achieve earlier connections.

Reduction in constraints that would arise if no other action were taken. This benefit would be notable under a 'Connect then Manage' framework for transmission access. However, under the previous framework of 'Invest then Connect', the GB SO would refuse to connect new generation before required transmission reinforcements are completed.

All offshore works are 'Enabling', in the language of 'Connect and Manage'; so this issue does not apply to offshore intertrips.

Disadvantages of using intertrips in planning timescales instead of reinforcement

If intertripping was used as a means of increasing transmission capacity as an alternative to system reinforcement in the form of new circuits for example, the transmission network would carry the same load but over fewer or lower capacity circuits. This would increase the loading on existing circuits and lead to the following;
Increased losses (I^2R and I^2X), which will increase the costs of operating the system and could lead to voltage performance issues.

Increased pre-fault loading on the network, which will result in circuits operating closer to their rating and could lead to a reduction in operational flexibility – for example, the GB SO will have less ability to use short-term or post-fault ratings.
Increased complexity and risk in operating the system with potentially severe consequences if there is a mal-operation or failure of the intertrip scheme or an interaction with other intertrip schemes.

Radial offshore connections suffer all these disadvantages, albeit to a much smaller extent than onshore. Permitting an Integrated offshore design to have the same cable capacity offshore to onshore as a Radial design, by permitting offshore intertrips, only leaves these disadvantages at a comparable level to the Radial design.

Multiple schemes - overlapping intertrip schemes: where dozens of generators can be selected for one circuit trip, there is an increased risk of Operator or Scheme error, arming too many intertrips for the one fault. Broadly, the Working Group accepted that this risk ('one-to-many') should be acceptable, with careful intertrip specification and operation. More significantly, where multiple boundaries are being protected by separate intertrips, there is an increased risk during a typical system disturbance – e.g. the multiple tripping often experienced during severe storms – that cascade generator tripping follows from multiple circuit trips and intertrip firings. The Working Group considered that, in general this risk ('many-to-many') was unacceptable; during storm events, many circuits trip, and we could see no way of ensuring confidence that signals from multiple circuits to the same generators would activate correctly, and achieve simultaneous security for multiple circuits.

The 'one-to-many' risk will be present for offshore intertrip designs, since a single offshore circuit fault may need to be armed to intertrip up to 1800MW of offshore generation, maybe being collected at more than one offshore hub. This 'one-to-many' risk is certainly no greater than for onshore systems, and so is acceptable. The 'many-to-many' risk should not be present, since one is envisaging intertrips from at most a few distinct offshore circuits, running broadly in parallel across one system boundary. In this sense, these 'many-to-many' risks offshore are no greater than the 'one-to-many' risks discussed onshore.

Economics - use of intertrips in planning timescales could reduce effectiveness in operational timescales. This re-iterates point a) (iii).above – extensive adoption of intertrips will lead to lower short-term ratings being available to the Operator. Also, outage placement will be impeded, because whereas now the outage planner can use the extra flexibility of an operational intertrip to place a transmission outage, this flexibility will already have been used if intertrips have been adopted in the planning timescale.

These concerns do not apply offshore. There are limited short-term ratings available for offshore circuits, and low redundancy anyway, so adoption of intertrips will not erode much flexibility. And outages are not planned for in offshore transmission design, so adoption of intertrips does not erode outage flexibility.

There is a maximum of 1320MW of generation that can be permitted armed on any one intertrip, which matches the maximum operational response holding; otherwise there would be an unacceptable frequency excursion on the firing of the intertrip[9].
This limit, now to be 1800MW, is fully reflected in all considerations of offshore intertrips.

Reduced stability margins. The increased pre-fault flows arising from use of intertripping will increase generator rotor angles and this reduces the positive effect

[9] The Working Group noted that, if the current GB SQSS modification GSR007 is endorsed and when a 1600-1800MW risk connects to the GB system, then this 1320MW limit is effectively raised to an 1800MW limit. This increase would enlarge this limit by 36%, but would not remove the limitation. In passing, it is not conceivable that the benefit of an intertrip would suffice to justify holding extra Response; the additional cost of moving from a 1320MW to an 1800MW risk is estimated at +£150m per year in GSR007.

that intertripping can have on stability margins. For example, it is frequently the case that selecting 1320MW of generation in Scotland for intertrip only increases the pre-fault flows that can be secured on the circuits between Scotland and England by around 600MW; i.e. the intertrip is only 50% effective. Hence one often needs to intertrip more post-fault than one would need to constrain off pre-fault to achieve same stability limit.

HVDC links are intended to improve, not worsen, concerns of onshore AC stability.
Network changes in future will require ongoing updating of intertrip schemes. This can be achieved – for example, probably twenty such circuit re-configurations were accommodated during the lifetime of the Teesside intertrip over 1992–2004; but the possibility of installation error and mal-operation is increased.

Offshore systems, because of the substantial investment in cables, will be subject to fewer evolutionary changes than onshore systems.

While the first intertrip or group of intertrips from one boundary to a group of stations up to 1320MW, installed as an alternative to planned reinforcements may gain direct benefit for just one boundary, subsequent intertrips will clash. On the same boundary, the second intertrip will run into the 1320MW limit, and hence be unacceptable. For a more Northern boundary, one will remain non-compliant on the original boundary, and thus not be secure; hence accepting new generation for a more Northern boundary under intertrip is insufficient – one now has to reinforce the original boundary. For a more Southern boundary, one might as well merely extend the first intertrip to more Southern circuits, encountering the complexity issue of (b). Thus the benefit of relaxing the Planning standard to permit intertrips only helps the first such application, or group of applications up to 1320MW. Subsequent applications rapidly become valueless.

This consideration remains applicable, in the case of multiple nested onshore and offshore boundaries. However, the gains in the main case of single offshore boundaries are large and worth adopting.

Reliability of existing operational intertrip schemes in remote locations is not good. SHETL have already experienced sufficient difficulties, mainly relating to reliability of communications, to switch out intertrips installed to new generation in Kintyre and the Western Isles. This illustrates the point that, where intertrip monitoring is very remote from the generation site to be tripped, this can increase the risk of failure to operate correctly.

Reliability of remote operational signals already has to be mastered for offshore wind farms. Mastering intertrip reliability cannot be a larger challenge, than mastering remote operation in the first place. In many cases, one end of the faulting offshore circuit will be at the same offshore hub as the generation connects.

There are a number of issues relating to commercial intertrips to be sorted.
Such issues remain present for offshore intertrips. The commercial issues will need to be addressed early in offshore design.

Appendix H – System Boundary Map