Fundamental SQSS Review

Review of Planning and Operational Contingency Criteria

Working Group 4 Report

April 9th 2010

Contents

0 Executive Summary

0.1 Overview

The Planning and Operation Contingency Criteria Working Group was tasked with reviewing the Planning and Operational Contingency Criteria by the Fundamental GB SQSS Steering Group in October 2008. The purpose of the review was to revisit the fundamentals of the standard to ensure that it is delivers the appropriate level of access, demand security and quality of supply against a system background with significant volumes of new generation technologies such as wind farms. Within the terms of reference, the Working Group endeavoured to carry out as much work as was practicable and significant work has been carried out in most of the areas. However, due to limited resource, the Working Group could not bring this work to full completion and there remain areas where the review could benefit from further work. Where such further work was identified, it has been noted as appropriate within the text.

This report covers the work done, findings and conclusions on the areas that were investigated by the Working Group. The attention of the Steering Group is brought to the fact that not all of the contents of this report have been fully agreed by all parties. Where this is the case, the text clearly indicates so.

The working Group has made a number of recommendations and conclusions. Most notably, the Working Group proposed draft revised Voltage Criteria presented in Appendix D of this report.

0.2 Review of Fault Statistics

The frequency of a potential ‘secured event’ and its potential impact are important factors to be considered when setting the policy of the security standard. Fault statistics are an important tool in the investigation of the probability of events occurring and subsequently in determining appropriate rules of the security standard. This review of fault data, for the first time, collected the fault data across the three TOs and made comparisons on the derived fault statistics where it was possible, thus making it possible to consider the occurrence of faults and their relevance to the current standard.

The purpose of this exercise was to determine faults statistics of the three TO systems and make comparisons among them to inform the review of the planning and operational contingency criteria of the SQSS.

The Working Group found no evidence to suggest that there is need to make significant changes to the SQSS rules on account of changes in transmission fault rates if we are to maintain the same level of customer security.

The limited analysis of geographic differences suggests that the frequency of faults increases the further north the geographical area lies. With single circuit fault rate (per 100km circuit per year) increasing from 0.485 in the south of England and Wales to 0.88 in the north of England to 1.23 in the south of Scotland.

There is a noticeable occurrence of double circuit faults, with 76 noted in England and Wales in the 10 year period analysed with only half of these due to the weather. These included an airplane crash and several fires under overhead lines.

The observed fault rate of 132KV double circuits in the SPT area is broadly equivalent to the general double circuit fault rate. Currently unlike in the NGET and SHETL areas, these are not defined as a secured event. Notwithstanding the recommendations of the MITS Working Group, it was concluded that SPT would need to carry out extensive studies to determine the consequent derogations and system investments before removing this regional variation in the SPT area.

0.3 Review of Treatment of Switch Faults

Review Request (ref. GSR004), submitted in October 2007, seeking to ensure the security standard is consistent and unambiguous with regard investment driven by switch fault outages. Statistics relating to the fault outage of transmission switches indicate the probability of a fault outage of any such switch to be considerably lower than other types of faults that occur on high voltage transmission systems. The consequences of a fault outage of any switch can be extremely serious however, significantly more severe than fault types with greater frequency of occurrence, potentially involving the widespread loss of demand and generation. The purpose of this exercise was to investigate the rationale for the treatment of a single fault outage as a secured event in the SQSS.

The Working Group found that it is appropriate that busbar coupler, busbar section or mesh circuit breaker fault outages continue to be secured events in SQSS Section 2.6. and Busbar coupler, busbar section or mesh circuit breaker fault outages need not be introduced to the set of secured events in SQSS Section 4.

A detailed impact assessment would need to be undertaken to assess the implications of including the requirement for acceptable post-fault thermal, voltage and stability performance under intact system conditions pre-fault.

Consideration ought to be given to the introduction of a requirement to consider the impact of Major System Faults at the planning stage, including busbar coupler, busbar section, mesh circuit breaker fault outages and stuck breaker events and the economic case for securing the event or mitigating the risk of the event.

Circuit breaker faults causing unacceptable voltage rise should be reinstated in the set of secured events at the planning stage. Alternatively, they could be considered under the category of Major System Faults as described above.

0.4 Review of Voltage Criteria

In reviewing the voltage criteria within the standard, the Working Group included the SQSS Review Group Request GSR005, submitted in November 2007, which asked for investigation of the extent to which network transmission capacity might be increased by widening the voltage limits in the SQSS. The Working Group has considered this request in the course of its work and have also taken the opportunity to address other issues such as inconsistencies and regional differences.

The current SQSS specifies steady-state voltage criteria as well as voltage step-change criteria for each of the three regional transmission owners in both planning and operational timescales. The standard also includes voltage step-change criteria for operational switching in England and Wales, but not in Scotland. In its review of the voltage criteria, the Working Group considered the significant factors taken into account when determining transmission voltage criteria for both steady-state voltage and voltage step-changes in planning and operational timescales

Investigations by the Working Group found that relaxing the HV voltage limits as suggested in GSR005 would provide little extra bulk transmission capacity, at the expense of increased security risk.

The existing voltage criteria in the SQSS contain a number of inconsistencies. A draft revision of the Voltage Criteria which deals with the inconsistencies as well as the regional variations is given in Appendix D. The following points are addressed in the draft revised Voltage Criteria:

- It is recommended that in operations, the pre-fault steady-state voltage limits can be flexed but the post-fault limits must always be enforced.
- It is recommended that the secured events for planning the system should include circuit breaker faults, where these could cause voltage rise beyond the upper planning limits.

– It is recommended that the secured events for planning and operating the system should include the loss of any generating unit.

– Regional variations in the voltage step-change criteria can be eliminated by varying the criteria according to the voltage at which customers or distribution networks are supplied.

– It is recommended to introduce a new category of ‘Infrequent Operational Switching’ with more relaxed voltage step-change limits than normal ‘Operational Switching’.

Further work was suggested in the areas of regional difference in the voltage step-change allowed after a *double circuit* fault on the supergrid as well as the definition of insufficient *voltage performance margins*.

0.5 Review of Stability Criteria

In reviewing the stability criteria within the standard, the Working Group included the SQSS Review Group Request GSR006 – ‘Review of stability criteria in the GB SQSS’). In summary, GSR006 requested a review of the SQSS in respect of the following two aspects: (i) the stability criteria for use in stability studies (to cover credible stability related events); and (ii) whether the stability criteria should form part of the standard and to what detail it should be.

The stability criteria within the SQSS define the conditions for which individual or groups of generators remain in synchronism with the remainder of the system. It also defines criteria for power frequency oscillatory damping on the system resulting from small perturbations such as switching events.

The possibility of releasing additional transmission capacity by relaxing stability criteria as detailed in review request GSR006, was also investigated and the Working Group found that no material additional transmission capacity would be released by relaxing the stability criteria in the current SQSS. Based on the work carried out the following points were noted:

– When considering the impact of different fault types, it was found that the post-fault transmission system strength was the dominant factor in determining the maximum stability constrained power transfer capability across a boundary.

– Relaxing fault clearance times does not release significant additional transmission capacity.

The Working Group has no evidence to suggest that there is sufficient justification or benefit to change from the most onerous 3-phase to earth fault criteria to a single phase to earth or 2-phase to earth fault, the Working Group therefore recommends the retention of a 3-phase fault as the basis for the stability criteria. Similarly the Working Group have insufficient evidence to justify changing the stability criteria with respect to fault clearance times.

0.6 Review of Use of Dynamic Ratings

The Working Group investigated the extent to which additional transmission capacity could be realised by using dynamic ratings. The GB SQSS does not currently present a barrier to the use of dynamic ratings as it allows the use of time dependant ratings. The most significant enhancements are achieved when the weather is windy as the air flow across the conductor has the most impact on removing the heat from the conductor. However, ‘wind shadow’ can reduce this cooling effect for example if the circuit is in a valley or runs through a forest.

0.7 Review of Use of Intertrips

One of the areas intensely debated by the Working Group was the use of Intertrips in creating transmission capacity. Intertrips are currently used on the system in operational timescales but are not considered an alternative to reinforcement at time of winter peak except in very limited circumstances. The Working Group considered the merits and demerits of using intertrips in planning to provide transmission capacity.

Working Group members were divided on the principle of the applicability of intertrips in planning timescales, and in particular drew differing conclusions from the O+X work of the

MITS Working Group The following conclusions reflect the views of the majority of Planning and Operational Criteria Working Group.

- If an intertrip is commercial, not operational, it is extremely unlikely to be economic against the alternative of transmission reinforcement.
- If a sole boundary is under consideration, installation of an operational intertrip is cheaper than the transmission reinforcement. It could presumably be accommodated securely on a one-off basis.
- But only 1320MW of such intertrip of this form is ever valuable on one boundary. Beyond 1320MW, further intertrips are of zero value.
- Furthermore, commitment to intertrips in planning timescales is asymmetric. Non-commitment of an intertrip on a boundary allows for temporary accommodation of further generation behind the boundary subject to intertrip. Conversely, if the intertrip has already committed, then no further generation can be accommodated without risk of non-maintenance of transmission on that boundary, or ultimately insecurity leading to risk of blackouts.

Hence the Working Group recommend that the current practice be retained, that intertrips do not provide an alternative to reinforcement at time of winter peak, except in limited circumstances, but should be considered as an option in ensuring year round operating criteria can be met.

1 Introduction

1.1 Background

The Planning and Operation Contingency Criteria Working Group was tasked with reviewing the Planning and Operational Contingency Criteria by the Fundamental GB SQSS Steering Group in October 2008. The purpose of the review was to revisit the fundamentals of the standard with the view to remove barriers to the connection of generation onto the GB transmission system.

The Working Group considered this objective in its dealings and also took the opportunity to iron out irregularities that exist within the standard due to regional variations and other planning and operational differences within the different parts of the standard wherever possible.

1.2 Scope

The remit of the Working Group covered the areas of work listed below. A more succinct scope definition together with the general background of the Fundamental GB SQSS Review Project and the constitution of the Working Group are given in the Terms of Reference in Appendix F.

1.2.1 Fault statistics

The frequency of a potential 'secured event' and its potential impact are important factors to be considered when setting the policy of the security standard. Fault statistics are an important tool in the investigation of the probability of events occurring and subsequently in determining appropriate rules of the security standard. The purpose of this exercise was to determine faults statistics from the three TO systems and make comparisons among them to inform the review of the planning and operational contingency criteria of the SQSS.

1.2.2 Treatment of switch faults

A GB SQSS Review Request (ref. GSR004[1]), was submitted in October 2007, seeking to ensure the security standard is consistent and unambiguous with regard investment driven by switch fault outages. This review request was assigned to this Working Group.

Statistics relating to the fault outage of transmission switches indicate the probability of a fault outage of any such switch to be considerably lower than other types of faults that occur on high voltage transmission systems. The consequence of a fault outage of any switch can be extremely serious however, significantly more severe than fault types with greater frequency of occurrence, potentially involving the widespread loss of demand and generation. The purpose of this exercise was to investigate the rationale for the treatment of a single fault outage as a secured event in the SQSS.

1.2.3 Voltage criteria

A GB SQSS Review Group Request (GSR005[2]), submitted in November 2007, asked for investigation of the extent to which network transmission capacity might be increased by widening the voltage limits in the SQSS. The Working Group has considered this request in the course of its work

The current GB SQSS specifies steady-state voltage criteria as well as voltage step-change criteria for each of the three regional transmission owners in both planning and operational timescales. The standard also includes voltage step-change criteria for operational switching

[1] GSR006 can be viewed online at: http://www.nationalgrid.com/NR/rdonlyres/0FFD62F4-08D0-4ED0-AB3B-61D297DB4F08/21637/Buscouplerreviewrequest_GSR004_.pdf

[2] GSR006 can be viewed online at: http://www.nationalgrid.com/NR/rdonlyres/CC8E6021-9A40-4F2F-B518-A487BC09ED03/24787/VoltageCriteria_v1.pdf

in England and Wales, but not in Scotland. In addition to GSR005, the Working Group also looked at the regional differences as well as other inconsistencies within the Voltage Criteria of the SQSS.

1.2.4 Stability criteria

This Working Group encompassed the review request GSR006[3] – 'Review of stability criteria in the GB SQSS'. In summary, GSR006 requested a review of the SQSS in respect of the following two aspects: (i) the stability criteria for use in stability studies (to cover credible stability related events); and (ii) whether the stability criteria should form part of the standard and to what detail it should be. The main driver for this review request was to determine the possibility of releasing additional transmission capacity by relaxing the Stability Criteria of the SQSS.

1.2.5 Use of dynamic ratings

The Working Group investigated the extent to which additional transmission capacity could be realised by using dynamic ratings.

1.2.6 Use of Intertrips

One of the areas intensely debated by the Working Group was the use of Intertrips in creating transmission capacity. Intertrips are currently used on the system in planning timescales but are not considered to provide transmission capacity in planning timescales except in very limited circumstances. The group considered the merits and demerits of using intertrips in planning to provide transmission capacity.

1.3 Working Group Approach

Where there was scope, the Working Group endeavoured to carry out as much work as was practicable. Significant work went into most of the areas. However, due to limited resource, the Working Group could not bring this work to full completion at this moment. There remain areas where the review could benefit from further work. Where such further work was identified, it was noted as appropriate within the text.

This report covers the work done, findings and conclusions on the areas that were investigated by the Working Group. Not all the contents of this report have been fully agreed by all parties. Where full agreement was not reached by all the Working Group members, this is indicated as appropriate. In particular, the attention of the Steering Group is drawn to the fact that the conclusions on the section on Use of Intertrips reflect the views of not all, but the majority of Working Group members.

Although not explicitly mentioned under 'Scope' above, the Working Group also made considerable effort to address regional differences where there is scope for harmonisation across the GB transmission system. The GB SQSS has a number of regional differences, where the standard differs by region of GB. In the main, these regional differences reflect relatively minor differences in the pre-BETTA security standards for England and Wales and the predecessor companies for Scotland, which could not be easily resolved in the run-up to BETTA in 2005. The Working Group considered these differences on a number of occasions.

In Chapter 2, 'Fault Statistics' the fault rates are broken down by region, namely Southern England and Northern England for NGET, South Scotland for SPT, and North Scotland for SHETL. The differences in fault rates do not appear to justify any regional differences in security standards. In particular, the current exclusion of SPT 132kV double circuit faults appears anomalous.

Chapter 4, 'Voltage Criteria' extensively re-considered and reworked a number of regional differences within the voltage criteria of the SQSS.

[3] GSR006 can be viewed online at: http://www.nationalgrid.com/NR/rdonlyres/B8F735E7-B564-4AA0-A931-51970E171321/23487/StabilityCriteria_v1.pdf

With regards to system operation, the GB SQSS is often interpreted as having a regional variation in the operational security requirement along the lines that it says:

"In England & Wales, the transmission system is secured to double circuit faults at all times, whereas in Scotland, the transmission system is secured to single circuit faults and only secured to double circuit faults under adverse weather." In actual fact the GB SQSS operational requirement says more than this.

The SQSS truly reads:

"For all TOs, double circuit faults must be secured for demand groups greater than 1500MW"; Section 5.3 for all TOs does not require thermal compliance, whereas Section 5.4 for England Wales does
unless there is adverse weather, it is not required to secure double circuit faults, for thermal overloads into demand groups less than 1500MW. (in adverse weather, demand groups less than1500MW should be secured by all TOs).There are practically zero instances of demand groups <1500MW for MITS circuits in England and Wales, whereas there are plenty of such instances in Scotland, including almost all Scottish 132kV transmission routes.

The Working Group are therefore satisfied that in general terms the operational standard is consistent across the GB and that it is the characteristics of the network rather than the location of the network that drives the security requirement.

1.4 Report Structure

The report is structured as follows:

Chapter 2 presents the work done on Fault Statistics in which various fault statistics are determined. Chapter 3 follows on with work done and findings on the treatment of Switch Faults in the SQSS. Chapter 4 gives the details of the review of the SQSS Voltage Criteria. Chapter 5 deals with Stability Criteria while Chapter 6 looks at the Use of Dynamic Ratings. Chapter 7 gives the Group's findings on the Use of Intertrips and finally, Chapter 8 presents the conclusions arrived at by the Working Group on the areas reviewed.

On the fundamental issue of releasing transmission capacity, the Working Group's findings show that there is no material gain in transmission capacity as a result of flexing voltage or stability criteria or harmonising the planning and operational contingency criteria to remove inconsistencies and regional variations as far as is practicable.

2 Fault Statistics

2.1 Introduction

When setting the policy of the security standard it is necessary to consider the frequency of the potential 'secured event' and therefore the potential impact. It is assumed that a more frequent event should have a lesser impact on the consumers. It is also worth considering the impact of a secured event that is more frequent but it only affects a small demand group.

Fault statistics are an important tool when investigating the probability of an event occurring and support the rules required under a security standard. This review of fault data will for the first time attempt to compare the data that has been collected by the three TOs. Thus consider their occurrence and relevance to the current standard.

For any fault the impact can just be on the system, e.g. thermal overloading of transmission equipment or it can impact the customer e.g. voltages outside the prescribed limit or stability problems which can damage generation equipment. From a system stability perspective it may also be necessary to consider the types of faults (Phase to phase, phase to earth etc) and their relevance.

This section provides a summary of the recent fault data and where possible also compares this with the available historical data. Due to the way the transmission companies have recorded data direct comparison of all data is very difficult where possible. Different tables are shown for each company. Where possible the data has been summarised to allow comparisons. The comparisons also consider the geographical differences of the GB transmission system.

2.2 Definitions

N denotes the configuration of the system at the time. In Planning timescales this is an intact system with the normal circuit configuration. In operational timescales the configuration will include circuits out of service and these are not included in N or D.

N-1 denotes the system and one fault

N-2 denotes the system and two simultaneous faults (within 1min of each other i.e. before DAR has had a chance to return the first circuit).

N-3 and greater (SP Data), there have been two previous faults which have not returned to service and further faults occur.

N-D denotes the system and simultaneously a trip of both sides of a Double circuit overhead line

Ref: SQSS - Version 2 issued 24th June 2009

2.2.1 Considered Faults in the GB SQSS

2.2.2 Higher Probability Events

Single circuits – currently operationally a fault on the following single items is considered as a higher probability secured event:

- Circuit – connecting two or more parts of the transmission system i.e. a Transformer, cable or overhead line;
- A single item of compensation; and

A busbar for thermal reasons, but only if it is designed to be secure. (See note below on busbar faults).

2.2.3 Lower Probability Events

- Double circuit (DC) overhead line
- Busbar faults

2.2.4 Busbar Faults

Busbar faults are generally currently considered a low probability event. If the design of substation allows, the current SQSS states we will secure this to the demand loss table. This means that for a local outage there should be no loss of supply if the demand affected is over 300MW.

2.2.5 Transient versus Permanent Faults

Transient faults are relevant when securing the system for generation stability and voltage limits as the impact is immediately apparent on the system. For thermal issues unless the overloading is severe we can wait for DAR to operate and also time dependant ratings on circuits can be used which means a short period of time is available to adjust generation or carry out switching to remove overloads.

2.3 Fault Data

There are two main reasons for collecting fault data and the data required for each case is slightly different:

- *Monitoring the operation of the system from a System Operator's perspective:* What are the faults that the SO should worry about including permanent and transient faults? Was the weather was a contributory factor? Was the circuit(s) switched out at short notice? Double circuit permanent faults are rare but emergency DC switch outs do occur.
- *Monitoring asset performance from an Asset Manager's perspective:* Did the protection operate correctly, what was the type of fault and are there trends to consider?

The data is considered on the following basis and would be considered a secured event:

<u>Transient:</u>

- Circuit trips and is correctly returned by DAR.

<u>Permanent:</u>

- Circuit trips and stays out or a DAR attempt is made and circuit trips on re-closure
- Circuit trips and should have re-closed but DAR is not available
- Circuit switched out under urgent instruction from site usually within 30 minutes of receipt of the instruction. Reasons could be equipment in distress or safety issue (debris on line, fire under line etc). Re-securing the system commences in parallel with switch out or immediately after the switch out.

The data mainly focuses on OHL data with some work on substation type faults.

Note: currently the definition of a Double Circuit differs depending on the TO. In England and Wales it is the sharing of the towers for at least one span by each circuit and in SPT it is sharing for at least two miles. This is something that should be considered in any follow-up review.

2.4 England & Wales Data

2.4.1 Overview

Table 2-1 gives an overview of recent data – 2006 and 2007 average per year for the Supergrid Transmission system in England and Wales. This period does not cover any extreme weather related events. This data suggests a downward trend when compared to historical data. Analysis of earlier data is covered later.

Table 2-1. Table of recent England and Wales fault data

Fault	All	Weather Related	Generation affected	Fault Rate per 100km/year	Fault rate per total no
OHL SC permanent	9	2	1	0.0616	
OHL DC permanent*1	2	0	0	0.0300	
OHL SC transient	63	58	0	0.4565	
OHL DC transient*1	6	6	0	0.0870	
Busbar (app 800 in E&W)	5	1	1		0.0060
Switchgear*2	10	1	1		0.0068

*1 Fault rate is per route 100Km/year,
*2 All switchgear faults not necessarily a Bus Coupler or Section Switch

Data based on approximately:
- 10,600Km 400KV OHL circuit km
- 3,200Km 275KV OHL circuit km
- 1470 Circuit Breakers

This means that a 100km overhead line is likely to have one transient single circuit fault every two years. And if this was part of a double circuit it would have one DC fault every ten years.

2.4.2 Lower Probability, High Impact Faults – Background

Table 2-2 shows more detailed information on England and Wales Double Circuit faults. This data does include analysis of emergency manual switch out of circuits. This is where the Control room switch out the circuit for safety reasons and to limit equipment damage should the fault develop and the equipment fail if the circuit were left in service. (This type of incidence is not examined in the SHETL and SPT data).

Table 2-2. England and Wales Double Circuit Faults over a 10 year period

Year	Trans	DC Perm	DC MSO	Total	Comments on some faults
2007	4	0	2	6	MSO to investigate pilot cable problems
2006	8	0	3	11	MSO's due to: severe fire (causing conductors to fall to ground, note one circuit tripped); one further fire; man up tower
2005	6	0	5	11	MSO's due to: severe fire under overhead lines; string on bottom conductors. Transient - assumed data
2004	3	2	0	5	One permanent fault due to double mesh corner fault tripping the related overhead lines.
2003	4	0	0	4	One transient due to fire under line.
2002	4	3	1	8	MSO due to man up a tower
2001	2	3	2	7	One DC permanent due to airplane crash. MSO's to fight fires.
2000	4	1	0	5	DC permanent includes an occurrence where circuits tripped within 5 mins of each other during severe storm
1999	8	0	0	8	
1998	8	3	0	11	April and Dec08 permanent faults caused by storms
Total	**51**	**12**	**13**	**76**	

Table Key
- Trans = Transient faults where at least one of the circuits automatically reclosed by DAR. In most cases these are due to weather problems.

- DC Perm = Faults where both circuits trip and remain out service, usually after one attempt by DAR to re-energise the circuits.
- DC MSO = Double circuit Manual switch outs. These are where the control room are requested by site staff to switch circuits out on an urgent basis. This will be within 30 minutes, giving little chance to make significant generation adjustments. Any emergency generation rescheduling would be those were pre-planned in the eventuality that the circuits had automatically tripped.

From an operations perspective there is an equal split for DC faults between those detected by protection and those requiring an urgent switch out by site staff. These have to be managed in an almost similar way to a trip by protection although there may be a bit of time to start adjusting generation before switching out the circuit.

It is worth noting that 6 of the MSOs were due to fires under an overhead line. Almost all DC transient faults were due to weather conditions although one was due to a fire under the line. MSOs do have an impact when considering the thermal overloading of the system as safety usually dictates that the circuit must be switched as soon as the control room are aware of problem. The data above equates to a DC fault rate of 0.11 faults per route 100km per year which is very similar to the recent 2 year average in table 2.1.

2.4.3 England and Wales Further Data

Table 2-3 shows the summarised analysis of all England and Wales fault data recorded between 2000 and 2007. This data should give a better statistical view compared to the data in table 2.1 and this extended period does include some severe weather related events with a corresponding increase in the single circuit faults. There is little change in the DC fault rate where the impact of weather is marginal.

Table 2-3. England and Wales eight-year period data

Fault (eight-year data)	All	Weather Related	Fault Rate per 100km/year	Fault Rate per total no
OHL SC permanent	18	12	0.1263	
OHL DC permanent*1	3	1	0.0435	
OHL SC transient	71	62	0.5061	
OHL DC transient*1	4	3	0.0526	
Busbar (app 800 in E&W)	4	1		0.0048
Switchgear*2	34	1		0.0149
Transformer circuits	21			0.0091

*1 Fault rate is per route 100Km/year,
*2 All switchgear faults not necessarily a Bus Coupler or Section Switch

2.5 SHETL Data

2.5.1 Overview

For SHETL data from March 2005 to February 2009 was analysed. The results of the analysis are shown in Table 2-4. Due to the relatively short space of time and relatively small plant population size of the data, its statistical significance may be somewhat limited. This is particularly true for the Double Circuit fault statistics. Manual circuit switch out data was not included.

Table 2-4 shows transmission overhead line fault rates calculated from the fault data gathered. It can be seen that the fault rates are higher at 132kV than at 275kV. This is expected given the less robust construction of the 132kV system and its geographically diverse nature compared to the 275kV network.

Table 2-4. SHETL Overhead line fault rates

		Fault Rate [Faults/100km/yr]			Ratio of fault rates: Bad/Good weather
		Good weather	Bad weather	Combined	
132kV	SC	0.382	0.740	1.12	1.9
	DC	0.0208	0.458	0.479	22.0
275kV	SC	0.0999	0.199	0.299	2.0
	DC	0	0.0725	0.0725	----
275kV and 132kV	SC	0.289	0.562	0.851	1.9
	DC	0.0132	0.317	0.331	24.0

For other fault types, the available data sample size was considered not large enough but the following were noted:

– Busbar faults: 3 at 132kV and 1 at 275kV, Total 37 bus bars (9 at 275kV, 28 at 132kV)

– Cable faults: 1 at 132kV, Total length 52km (3km at 275kV, 49km at 132kV)

Switch faults: 1 breaker at 132kV (frozen in very bad weather), Total breakers = 458

2.5.2 SHETL Fault Data

Table 2-5 shows the fault incidence by voltage level and by month of year. Fault incidence is high in summer due to lightning and in January due to poor weather conditions during the middle of winter. The 132kV single-circuit fault rate is approximately four times the 275kV single circuit fault rate. The corresponding ratio for the double-circuit fault rate is approximately seven.

Table 2-4 also shows that the impact of bad weather is more significant on double circuit faults than on single circuit faults. Although 132kV is treated as a transmission voltage in Scotland, 132kV fault characteristics are significantly different from those of 275kV systems and undoubtedly 400kV.

Table 2-5. SHETL Overhead line fault data by voltage by month

			Number of faults						
			Bad Weather			Good Weather			Grand Total
			Permanent	Transient	Total	Permanent	Transient	Total	
132kV	DC	Jan		3	3				3
		Feb							
		Mar		2	2				2
		Apr		1	1				1
		May		1	1				1
		Jun	1	10	11				11
		Jul		3	3	1		1	4
		Aug							
		Sep							
		Oct							
		Nov							
		Dec		1	1				1
	DC Total		*1*	*21*	*22*	*1*		*1*	*23*
	SC	Jan	12	17	29	4	2	6	35
		Feb	2	3	5		3	3	8
		Mar	2	8	10	1	2	3	13
		Apr	1	5	6		3	3	9
		May	3	4	7	3	7	10	17
		Jun	2	12	14		1	1	15
		Jul	1	4	5	2	5	7	12
		Aug		2	2		4	4	6
		Sep		2	2		3	3	5
		Oct	1	4	5	1	1	2	7

			Number of faults						
			Bad Weather			Good Weather			Grand Total
			Permanent	Transient	Total	Permanent	Transient	Total	
		Nov	2	1	3	2	2	4	7
		Dec		3	3		1	1	4
	SC Total		*26*	*65*	*91*	*13*	*34*	*47*	*138*
132kV Total			27	86	113	14	34	48	161
275kV	DC	Jan							
		Feb							
		Mar							
		Apr							
		May							
		Jun		1	1				1
		Jul							
		Aug							
		Sep		1	1				1
		Oct							
		Nov							
		Dec							
	DC Total			*2*	*2*				*2*
	SC	Jan		3	3				3
		Feb							
		Mar					4	4	4
		Apr							
		May				1		1	1
		Jun		1	1				1
		Jul	1	1	2		1	1	3
		Aug							
		Sep							
		Oct	1	1	2				2
		Nov		1	1				1
		Dec	2	1	3				3
	SC Total		*4*	*8*	*12*	*1*	*5*	*6*	*18*
275 Total			4	10	14	1	5	6	20
Grand Total			**31**	**96**	**127**	**15**	**39**	**54**	**181**

Notes, bad weather would include snow heavy rain wind, and lightening.

2.6 SP Transmission Data

SP Transmission have a more comprehensive set of data to analyse and have looked at the sixteen year period 1992 to 2007. It does include severe weather events in Jan 93, Feb 01 and Dec 98. Faults analysed are those that were caused by the in service failure of equipment and were removed from the system by automatic operation of protection. N is based on the system configuration at the time and therefore a number of circuits could already have been out of service.

Data includes faults that are not considered ‘secured events’ in the current SQSS

N-2 only secured in planning time scales for an intact system and only N-D in Operational timescales

N-3 and greater are not currently considered

400KV fault events are high, certainly compared to England and Wales; however there are several severe weather events in the data

Table 2-6, Table 2-7, Table 2-8 summarise the SP fault data split by type, single circuit OHL faults/fault rate data and double circuit OHL faults/fault rate data respectively.

Table 2-6. SP fault data split by fault type

Year	N-1	N-D (All)	N-D (132kV)	N-2	N-3	N-4 OR >	BUS/ MESH	Circ. Brkr.	CB FAIL
	Number of Secured Events / Major System Faults								
1992	106	9	2	18	0	2	2	0	1
1993	83	3	2	1	0	0	2	1	1
1994	45	3	0	2	0	0	0	1	0
1995	46	4	3	1	0	0	4	1	1
1996	93	1	1	1	0	0	2	1	0
1997	28	1	1	1	1	0	0	0	0
1998	150	2	2	8	2	2	1	0	1
1999	39	2	1	0	0	1	3	3	0
2000	147	3	3	16	0	0	2	1	0
2001	142	7	6	5	2	1	1	0	1
2002	33	3	0	0	1	0	1	1	0
2003	40	2	1	0	1	0	0	0	0
2004	34	1	1	2	0	0	2	0	0
2005	26	2	2	1	0	0	1	0	0
2006	43	1	0	5	2	0	0	0	0
2007	48	2	2	6	0	0	2	0	0
Average*	**69**	**3**	**1.7**	**4**	**0.6**	**0.4**	**1.4**	**0.6**	**0.3**

* Average for 1992-2007

Table 2-7. SP single circuit OHL faults and fault rate data

Year	132kV Transient	275/400KV Transient	132KV Permanent	275/400KV Permanent
1992	6	59	3	13
1993	36	18	3	3
1994	7	8	1	0
1995	13	8	3	5
1996	17	45	9	6
1997	10	4	1	1
1998	42	83	6	13
1999	12	9	1	2
2000	40	102	8	10
2001	41	82	3	11
2002	13	14	0	2
2003	8	13	4	0
2004	16	16	0	0
2005	14	8	0	0
2006	13	31	1	3
2007	26	13	1	0
1992 – 2007 Total	314	513	44	69
Circuit km (in 2006)	1543	2192	1543	2192
Faults / yr / 100km	1.27	1.46	0.18	0.2

Table 2-8. SP DC overhead line faults and fault rates

	132kV	275kV	400kV
Double Circuit Events 1992-2007	27	19	19
Double Circuit Route Length (km)	596.2	612.7	450.5
Double Circuit Faults / yr / 100km	0.28	0.11	0.11

2.7 Comparison of recent data to historical trends

A general inspection of data suggests a downward trend. There has not however been a recent severe storm event. The SP transmission data does include some severe storm events with the total of 112 events (275 and 400KV single circuit faults) for the year 2000. This is over 3 times the long term average of 36 per year.

2.8 Combined data for the GB transmission System

The following circuit fault rate data was extracted to enable a comparison of fault statistics between the three transmission companies. For England and Wales further analysis was undertaken to split this area in to two regions, north and south. This data is for the 275kv and 400KV transmission system only. Table 2-9 shows the combined 275kV and 400kV fault rate data for the three transmission areas. Note that the original data covered different periods of time and to ensure the data has not been distorted by a severe weather event, the data was compared over the same period in time. SHETL data was not included due to the more limited time period of the data that was available.

Table 2-9. Combined Fault rate data, 275KV and 400KV system

	All	South England	North England	South Scotland
App. OHL Km	16336	8208	4432	2191
OHL SC permanent		0.0911	0.1655	0.16
OHL DC permanent		0.0438	0.0796	0.11
OHL SC transient		0.3934	0.7148	1.07
OHL DC transient		0.0469	0.0851	
OHL SC Total		0.485	0.880	1.23

NB: North of Scotland statistics are for 275kV only and there were no permanent 275kV faults during the period in which the data was analysed.

2.9 Other Data

The data focuses on overhead line data and further work would be needed to analyse bus bar faults. Note that during 2009 there were two ‘switch faults’ on the England and Wales system and one in the SP system. In the GB SQSS planning standard switch faults are mentioned from a generation security point of view but operationally they are not secured events.

2.10 Summary

This is the first time there has been a collation of GB-wide fault statistics and these need to be viewed with little caution as there is no common standard for collecting fault data and there are different definitions of a double circuit fault.

Care needs to be taken when there are severe weather events with multiple trips in an area in one day as they can distort the figures if looking at a short period of time. There have not been any recent occurrences, with the last major storms being in 2000 in Scotland and 1990 in England and Wales. It is therefore difficult to determine trends but there is a view that there has been a mild downward trend. There is no evidence to suggest that there is a need to make significant changes to the SQSS rules if we are to maintain the same level of customer security.

The fault data helps us to derive transmission fault statistics which form the basis for consideration on whether we are either exposing the transmission system to undue risk or whether we are too cautious and ‘over-securing’ the transmission system.

The following were noted:

- The observed fault rate of 132KV double circuits in the SPT area is broadly equivalent to the general double circuit fault rate. Currently unlike in the NGET and SHETL areas, these are not a secured event.

- The limited analysis of geographic differences suggests that the frequency of faults increases the further north the geographical area lies. With single circuit fault rate increasing from an occurrence rate of 0.485 per 100km circuit per year in the south of England and Wales to 0.88 per 100km circuit per year in the north of England to 1.23 per 100km circuit per year in the south of Scotland.
- There is a noticeable occurrence of double circuit faults, with 76 noted in England and Wales in the 10 year period analysed with only half of these due to the weather. These included an airplane crash and several fires under overhead lines.
- We also note that there is no consistent definition of fair weather or adverse weather. This has two consequences:
    - When recording faults this will be a personal interpretation at the time and therefore there are likely to be inconsistencies.
    - It is very difficult to make recommendations on different operating standards dependant on the weather.
- It is also worth noting that there have not been any recent coastal pollution events where there is a long dry spell with offshore winds depositing salt on the substation and overhead line insulation. This is not an issue until this period ends with damp drizzle type precipitation which can cause multiple flashovers.
- A fault outage of a 132kV double circuit overhead line (where the line is entirely within the SPT area), is not currently a secured event in Section 4.6.3 of the SQSS. Retention of paragraph 4.6.3 has been assumed by Working Group, notwithstanding the conclusions and recommendations of the MITS Working Group (WG3). This could be followed in future with a consultation with the SPT to identify issues, solutions and opportunities which would enable the removal of the regional difference.
- If this regional difference were removed right now, there would need to be extensive studies by SPT to establish the consequent derogations and system investments. These studies have not yet been performed within this review.

3 Switch Faults

3.1 Introduction

Section 2 of the GB SQSS, ‘Design of Generation Connections’ identifies the fault outage of any single busbar coupler circuit breaker, busbar section circuit breaker or mesh circuit breaker, referred to herein as ‘switch faults’ as a secured event i.e. a contingency which must not result in the remaining system being in breach of specified security criteria. The fault outage of any single switch is not identified as a secured event in Section 4 of the GB SQSS, ‘Design of the Main Interconnected Transmission System’ or Section 5, ‘Operation of the GB Transmission System’.

Statistics relating to the fault outage of transmission switches indicate the probability of a fault outage of any such switch to be considerably lower than other types of faults that occur on high voltage transmission systems, faults on overhead line circuits for example. The consequences of a fault outage of any switch can be extremely serious however, significantly more severe than fault types with greater frequency of occurrence, potentially involving the widespread loss of demand and generation.

The purpose of this exercise was to set out high level proposals regarding the identification of a single fault outage of a switch as a secured event in the GB SQSS. These high level proposals were informed by:

- A review of the inclusion of switch fault outages as secured events within Section 2 of the GB SQSS, together with the associated security criteria; and
- GB SQSS Review Request (ref. GSR004), submitted in October 2007, seeking to ensure the security standard is consistent and unambiguous with regard investment driven by switch fault outages. This request was subsequently incorporated into the Fundamental GB SQSS Review under the Planning and Operational Contingency Criteria (POCC) review.

3.2 Working Group Approach to Switch Faults

A two-stage review process was adopted, firstly considering the continued appropriateness of provisions in the GB SQSS Section 2 followed by a second stage, informed by the first, considering provisions in the GB SQSS Section 4.

3.2.1 Stage 1 – Key Elements

Establish statistics regarding transmission switch ‘fault outage’ and switch ‘failure to open’ rates;

Review the economic case for continuing to secure switch outages to the infrequent infeed loss risk, as per GB SQSS Section 2; and

Consider the continued appropriateness of securing post-fault frequency within GB SQSS Section 2, and absence of reference to thermal, voltage or stability performance.

3.2.2 Stage 2 – Key Elements

Consider the appropriateness of explicitly including switch fault outages as secured events in GB SQSS Section 4, recognising:

- GBSQSS Section 1.8 refers to the ‘reach’ of generation connection criteria into the MITS;
- Section 1.11 refers to parts of the system where more than one set of criteria apply; and
- Section 4 allows a higher standard to be applied if economically justified

3.3 Relevant Provisions in Previous Security Standards

3.3.1 Planning Standards

3.3.1.1 Security of Connection of Generating Stations (PLM-SP-1)

PLM-SP-1 Clause 2.1.3 stated, 'No bus section or bus coupler circuit-breaker fault, double circuit fault on an overhead line or two simultaneous circuit faults shall cause the instantaneous loss of generation greater than the sent out capacity of the two largest authorised generators, boilers or nuclear reactors on the system'.

PLM-SP-1 Clause 2.1.4 stated, 'System frequency and voltage shall be maintained within statutory and equipment design limits under normal and credible outage conditions'. The definition of credible transmission outage does not encompass bus section or bus coupler circuit-breaker faults however, consequently Clause 2.1.3 had the effect of securing system frequency.

3.3.1.2 Security for the Supergrid Transmission Network (PLM-SP-2)

PLM-SP-2 did not make reference to busbar coupler, busbar section or mesh circuit breaker fault outages, or indeed busbar fault outages. It was permissible to provide more or less than the normal standard subject to technical and economic appraisal.

3.3.1.3 CEGB Voltage Criteria for the Design of the 400 kV and 275 kV Supergrid System (PLM-ST-9)

Paragraph 4.2 of PLM-ST-9 stated that the criteria were applicable to the secured outages designated under PLM-SP-2 and Engineering Recommendation P2/5, with the following additions:

a) With regard to voltage rise conditions only, Criterion C refers, the outage(s) due to a fault on any circuit breaker, including a bus coupler or bus section switch, should also be considered.

b) In the application of all criteria, consideration of single circuit outages (but not double or two circuit cases) should be extended to include single busbar sections."

3.3.1.4 CEGB Criteria for System Transient-Stability Studies (Supergrid System) (PLM-ST-4)

PLM-ST-4 Clause 3.1 stated that the 400kV and 275kV Supergrid system will normally be designed to remain stable for credible transmission plant fault outages, including 'Any single section of busbar'.

The same clause goes on to specify that maintenance of stability of generating plant and system will not be designed for in the case of 'Faults on bus-section or bus-coupler switches which result in the tripping of two busbars' and in the case of 'Delayed fault clearance due either to failure, mal-operation or slow operation of any protection or circuit-breakers.'

The standard stated that the occurrence of faults on bus-section or bus-coupler switches is considered sufficiently rare to justify acceptance of the risks involved. However, the system is to be studied at the planning stage to quantify the severity of the disturbance caused by faults of abnormal severity and establish the requirement for safeguards.

3.3.1.5 Security of the 400kV and 275kV Systems in Scotland (NSP 366)

Similar to PLM-SP-2, which was adopted by CEGB and applied in England and Wales, the standard applied in Scotland, NSP 366 has not make reference to busbar coupler, busbar section or mesh circuit breaker fault outages.

NSP 366 Section 4 with regard transient stability criteria states, 'The system should preferably remain stable on the occurrence of any three phase fault but if this cannot be guaranteed, stability should be achieved for two phase to earth faults'.

While the stability criteria refers to any fault, it is the authors' understanding that the intention was not that this criterion include faults within the overlapping protection zones associated with busbar couplers and busbar section circuit breakers.

The requirement of PLM-ST-4 to quantify the severity of the disturbance caused by faults of abnormal severity and establish appropriate safeguards is consistent with the policy of the South of Scotland Electricity Board on Supergrid Switching Facilities, which recommended studies be carried out to establish the extent of system disturbance occasioned by a fault on a circuit breaker or a failure to trip of a circuit breaker. If these disturbances were serious and widespread then additional sectioning or other remedial measures were to be provided where economically justified.

3.3.2 Operational Standards

3.3.2.1 Operational Standards of Security of Supply (OM3)

The OM3 standard did not require the transmission system to be secured for bus-coupler, bus-section or mesh circuit breaker fault outages in operational timescales. OM3 Appendix B states that the probability of faults causing outages should be assumed to be in the following order:

a) Fault causing the loss of a circuit or single generator;

b) Faults causing the loss of two circuits strung on the same towers;

c) Faults causing the loss of a section of busbar;

d) Faults causing the loss of two sections of busbar e.g. faults on bus coupler or bus section circuit breakers; and

e) Coincident faults on independent circuits.

3.3.2.2 ScottishPower Operational Standards of Security of Supply (GCI B1)

The set of single fault outages to be considered included any generation or transmission plant, specifically with the exception of 'bus section and coupler switches'

3.4 Relevant Provisions in the Existing Security Standard

GB SQSS Section 1.8 refers to the 'reach' of generation connection criteria into the MITS. Section 1.11 refers to parts of the transmission system where more than one set of criteria applies.

3.4.1 Design of Generation Connections

Section 2 of the GB SQSS details the planning criteria for connection of one or more power stations to the transmission system. Section 2.6 describes the secured events that should not lead to a loss of power infeed in excess of the infrequent infeed loss risk, presently 1320MW. These include the fault outage of any single busbar coupler circuit breaker, busbar section circuit breaker or mesh circuit breaker.

Similar to provisions in PLM-SP-1, this requirement ensures post-fault frequency is above the threshold at which operation of automatic under-frequency load shedding relays will commence. The terms 'fault outage' and 'busbar' are defined terms in the GB SQSS.

Again similar to PLM-SP-1, there is no requirement to ensure acceptable post-fault thermal, voltage performance or stability performance.

3.4.2 Design of the Main Interconnected Transmission System

Section 4 of the GB SQSS sets out the minimum planning criteria for the Main Interconnected Transmission System (MITS). It is permissible to design to higher standards than those set out in Section 4 provided the higher standards can be economically justified.

In the event of a fault on a section of busbar there shall not be any system instability. The set of secured events against which the MITS is planned does not include bus-coupler or bus-section fault outages and in this respect is similar to PLM-SP-2, PLM-ST-4 and NSP366. The GB SQSS therefore defines this type of event as a Major System Fault.

3.4.3 Operation of the GB Transmission System

Section 5 of the GB SQSS does not require the system to be secured against bus-coupler, bus-section and mesh circuit breaker fault outages, similar to OM3 and GCI B1.

3.5 Relevant Transmission Failure Statistics

3.5.1 Plant within Overlapping Protection Zones

A fault outage which results in the tripping of two adjacent busbar sections can arise from a fault on any item of primary plant within the overlapping busbar protection zone. Primary plant within the overlapping busbar protection zone generally comprises:

- 1 x circuit breaker;
- 2 x current transformers; and
- Primary connections, which are generally designed to be as short as possible.

3.5.2 Fault Outage

The GB SQSS defines a fault outage as ‘an outage of one or more items of primary transmission apparatus and/or generation plant initiated by automatic action unplanned at that time, which may or may not involve the passage of fault current.’

3.5.3 Circuit Breaker Failure Statistics

The main source of electrical breakdown within the overlapping busbar protection zone covering busbar coupler, busbar section or mesh circuit breakers is attributable to the high voltage circuit breaker.

There appears to have been only one incident involving the electrical breakdown failure of a current transformer on the SP Transmission system in the period from 1992. In this incident the 275kV current transformer that failed did form part of a busbar coupler protection zone.

Historical data relating to circuit breaker electrical breakdown failures, fires in the SP Transmission area for the sixteen year period from 1992 – 2007 is set out in Table 3-1. This data identifies nine electrical breakdowns/fire events in approximately 6500 circuit breaker years.

Table 3-1. SP Transmission circuit breaker failure statistics

Year	No. of Circuit Breaker Electrical Breakdown Failures/Fire				No. of Failures to Open on Fault
	132kV	275kV	400kV	Total	
1992	-	-	-	-	1 (Bulk Oil CB)
1993	1	-	-	1	1 (Air Blast CB)
1994	-	1	-	1	-
1995	-	1	-	-	1 (Air Blast CB)
1996	-	-	1	1	-
1997	-	-	-	-	-
1998	-	-	-	-	-
1999	3	-	-	3	-

Year	No. of Circuit Breaker Electrical Breakdown Failures/Fire				No. of Failures to Open on Fault
	132kV	275kV	400kV	Total	
2000	-	1	-	1	-
2001	-	-	-	-	-
2002	-	1	-	1	-
2003	-	-	-	-	-
2004	-	-	-	-	-
2005	-	-	-	-	-
2006	-	-	-	-	-
2007	-	-	-	-	-
16Yr Total	4	4	1	9	3
Indicative Faults pa	0.25	0.25	0.06	0.56	0.19
Indicative No. of Units	203	161	40	404	201 (Supergrid only)
Failure per CB year	0.0012	0.0016	0.0015	0.0014	0.0009

All of the circuit breaker electrical breakdown failures/fires above occurred on air-blast type circuit breakers, with the exception of one 132kV fault on a modern SF6 type unit.

All events involving circuit breaker failure to open on fault resulting in fault clearance via Circuit Breaker Fail (CBF) protection involved 275kV units.

Considering only the Supergrid system operating at 275kV and 400kV, the number of circuit breaker electrical breakdown failures, fires (5 events) is comparable to the number of circuit breaker failures to open on fault (3 events).

The failure rates above indicate the electrical failure of a Supergrid circuit breaker may be a 1 in approximately 625 year event. This compares to the 1 in approximately 10 year risk of a Supergrid double circuit fault on a 100km overhead line route.

3.5.4 Circuit Breaker Failure Statistics – Cigre

International statistics relating to circuit breaker failure have been published by Cigre, reference ‘Final Report of the Second International Enquiry on High Voltage Circuit-Breaker Failures and Defects in Service’, published June 1994. This survey was limited to single pressure SF6 type circuit breakers as almost all new circuit breakers purchased by utilities since 1982 have been of this type.

The reported breakdown failure rate for metal enclosed equipment is comparable to that of non-metal enclosed. The total reported failure rates at the relevant voltage levels are as follows:

Table 3-2. Electrical Breakdown failure rates (as per Cigre Table 2.9.8.2)

Voltage (kV)	Total Population	
	Sample size (CB years)	Failures per CB year
100 < kV < 200	23520	0.00021
200 < kV < 300	10933	0.00082
300 < kV < 500	9917	0.00141

The electrical breakdown failure rates above, particularly at 275kV and 400kV, are similar to the electrical breakdown failure rate witnessed on the population of SP Transmission circuit breakers, which includes air-blast, bulk oil and SF6 type units.

3.6 Assessment of GB SQSS Section 2 Criteria

Statistics of the probability of a fault outage of a transmission circuit breaker indicate this fault type has low likelihood. The consequences of such a fault can be extremely serious however.

3.6.1 Initial Cost Benefit Assessment

An initial cost-benefit assessment of the case for continuing to secure bus-coupler, bus-section and mesh circuit breaker fault outages, as per GB SQSS Section 2, is provided below:

Table 3-3. Initial cost-benefit assessment of the case for continuing to secure bus-coupler, bus-section and mesh circuit breaker fault outages

Input Parameters:			
% of Year Exposed	72.25	%	Two units on adjacent busbars, with 0.85 availability.
Fault Rate	0.0016	pa	Average of SPT 400kV and 275kV fault outage rate.
Demand Loss	2000	MW	1x5% block of load reduction, on average 40GW demand.
Restoration Time	1	hour(s)	
VoLL	33000	£/MWh	As per NGET Network Reliability Incentive.
Discount Rate:	6.25	%	As per Transmission Price Control Review.
Calculations:			
Cost of Fault	66.0	£m	
Probability of Event	0.0011	pa	
Annual Cost of Event	0.0741	£m pa	
Investment Justified	1.08	£m	

The capital cost of providing an additional busbar section to ensure the loss of power infeed following a busbar coupler, busbar section or mesh circuit breaker fault outage does not exceed the infrequent infeed loss risk is similar to the capitalised value of lost load associated with the fault.

An exhaustive series of sensitivity studies has not been completed, however it is proposed at this stage that busbar coupler, busbar section or mesh circuit breaker fault outages continue to be secured events in GB SQSS Section 2.6.

3.6.2 Security Criteria: Frequency, Thermal, Voltage and Stability Performance

Section 2.6 of the GB SQSS effectively secures system frequency above the threshold at which under-frequency load shedding will be initiated following the fault outage of a busbar coupler, busbar section or mesh circuit breaker.

This requirement is without reference to acceptable post-fault thermal, voltage and stability performance. Without ensuring acceptable post-fault thermal, voltage and stability performance however, albeit at potentially increased capital cost, there may be a risk of consequential generation disconnection and the intended frequency performance may not be achieved.

A detailed impact assessment could be undertaken to assess the implications of including the requirement for acceptable post-fault thermal, voltage and stability performance under pre-fault intact conditions.

3.7 Considerations Relating to GB SQSS Section 4

The high-level cost-benefit analysis in Section 3.6.1 indicates that it continues to be economic to secure busbar coupler, busbar section and mesh circuit breaker faults in relation to generation disconnection and where the cost of mitigation only relates to the capital cost of additional busbar sectioning facilities.

The same is likely to be true of new MITS substations. At existing MITS substation sites however, the capital and operational costs associated with modifying an existing busbar system to deliver additional sectioning facilities may not be out-weighed by the benefits.

To introduce busbar coupler, busbar section or mesh circuit breaker faults in the set of secured events in GB SQSS Section 4 may not therefore be consistent with the statutory obligation to develop and maintain an economical system of electricity transmission.

The inclusion of this fault type in the set of secured events would require the provision of additional busbar sectioning facilities at a number of existing sites. The risk of the fault outage may be mitigated in a more economic manner by other means however, via installation of modern / high reliability equipment in the busbar coupler protection zone for example.

Referring to the incidence of Supergrid Circuit Breaker Electrical Breakdown Failures/ Fires and the number of fault clearances via Circuit Breaker Fail Protection (CBF) detailed in Table 3-1, and recognising the relatively small sample size, the probability of a ‘stuck breaker’ event on the 275kV and 400kV system may be around half the probability of circuit breaker electrical breakdown.

In the case of a double busbar substation with single busbar coupler, the probability of slow fault clearance via CBF protection may therefore be in excess of the probability of a fault within the overlapping protection zone associated with the busbar coupler. Similar to a fault outage of a busbar coupler, busbar section or mesh circuit breaker, GB SQSS Section 4 presently categorises a ‘stuck breaker’ event as a Major System Fault.

GB SQSS Section 4.3 states that it is permissible to design to standards higher than those set out in paragraphs 4.4 to 4.12 provided the higher standards can be economically justified. It is proposed that consideration is given to including a requirement to consider the impact of Major System Faults at the planning stage and the economic case for securing the event or mitigating the risk of the event.

This may formalise the current practice of assessing the extent of system disturbance occasioned by a fault on a circuit breaker, or a failure to trip of a circuit breaker for example. If the disturbance is shown to be serious and widespread, involving system instability and considerable loss of generation, the economic case for provision of additional busbar sections, or other remedial measures, would be considered.

In this context, the Working Group have noted that the current SQSS does not mention circuit breaker faults in the context of voltage criteria, although the earlier standard PLM-ST-9 did require them to be considered. Circuit breaker faults that cause voltage rise can, in some circumstances, result in extensive insulation damage with the possibility of multiple circuit losses and long repair times. It is therefore proposed that the planning standard should include a requirement to assess circuit breaker faults for their potential to cause unacceptable voltage rise. The costs of securing this extra requirement are not particularly material.

3.8 Working Group Conclusions on Switch Faults

In summary, the working Group concluded that:

It is appropriate that busbar coupler, busbar section or mesh circuit breaker fault outages continue to be secured events in SQSS Section 2.6.

A detailed impact assessment would need to be undertaken to assess the implications of including the requirement for acceptable post-fault thermal, voltage and stability performance under intact system conditions pre-fault.

Busbar coupler, busbar section or mesh circuit breaker fault outages need not be introduced to the set of secured events in SQSS Section 4.

Consideration ought to be given to the introduction of a requirement to consider the impact of Major System Faults at the planning stage, including busbar coupler, busbar section, mesh circuit breaker fault outages and stuck breaker events and the economic case for securing the event or mitigating the risk of the event.

Circuit breaker faults causing unacceptable voltage rise should be reinstated in the set of secured events at the planning stage. Alternatively, they could be considered under the category of Major System Faults as described above.

4 Voltage Criteria

4.1 Introduction

The current GB SQSS specifies steady-state voltage criteria as well as voltage step-change criteria for each of the three regional transmission owners in both planning and operational timescales. The standard also includes voltage step-change criteria for operational switching in England and Wales, but not in Scotland.

A GB SQSS Review Group Request (GSR005), submitted in November 2007, asked for investigation of the extent to which network transmission capacity might be increased by widening the voltage limits in the SQSS. The Working Group has considered this request in the course of its work.

In its review of the voltage criteria, the Working Group considered the significant factors taken into account when determining transmission voltage criteria for both steady-state voltage and voltage step-changes in planning and operational timescales. The Group took as its scope:

– The options for modifying the criteria, and the effects of such modifications on secure power transfer capability;

– The possibilities for harmonising the voltage criteria across the three regional transmission areas;

– The relationships between planning and operational voltage criteria and possibilities for aligning them.

The Working Group noted that the following factors are relevant to the development of consistent voltage criteria for the GB NETS:

– The network operates at three voltage levels: 400 kV, 275 kV, and, in Scotland, also at 132 kV. There is considerable diversity in load density, ranging from hundreds of MW/km2 in south-east England to hundreds of square km per MW in northern Scotland. A fault in one section of the system might have much greater consequences in terms of security and quality of supply than a fault at a different voltage level in a different area.

– The development of large quantities of renewable generation in Scotland will change the role of the Scottish transmission systems. From having had a primary function of transmitting power comparatively short distances from Scottish generation to Scottish demand, with limited export to England, they will develop as essential parts of the overall GB infrastructure transmitting bulk power to the South. The power-at-risk for faults on some parts of the Scottish network will consequently increase considerably.

The voltage section of the SQSS does not specify the contingencies for which the voltage criteria apply; the relevant contingencies are defined throughout the other sections of the SQSS document. In this section of the Working Group report we comment on the contingencies appropriate to the voltage standards, and recommend changes to the contingency definitions where necessary.

4.2 Planning and Operational Steady State Voltage Limits

The SQSS specifies voltage limits and targets for the steady state performance of the system, for both planning and operational timescales. The intention of these has been to:

– meet statutory requirements for supply to connected customers[4],

– prevent damage to plant,

– enable stable power transmission and

– provide a defined level of voltage performance at interfaces to distribution networks.

[4] ESQCR 2002

This section reviews the current SQSS and considers the scope for modifying the standards in future.

4.2.1 Steady-State Voltage Limits in the Current GB SQSS

4.2.1.1 Steady-State Voltage Limits in Planning Timescales

Figure 4-1 shows the pre-fault planning voltage limits as given in Table 6.1 in the current GB SQSS.

Nominal voltage	Minimum	Maximum
400kV	390kV (97.5%)	410kV (102.5%) ***Note 1***
275kV	261kV (95%)	289kV (105%)
132kV in SPT and SHETL areas	***Note 2***	139kV (105%)
< 275kV in the England and Wales area and < 132kV in SPT and SHETL areas	***Note 3***	105%

Notes

1. 420kV (+5%) is permissible for no longer than 15 minutes.
2. There is no minimum planning voltage provided that Note 3 can be observed for a lower voltage derived from the 132kV transmission system.
3. There is no minimum planning voltage for a lower voltage supply provided that it is possible (for example by tap changing) to achieve up to 105% of nominal voltage at the busbar on the LV side of a transformer stepping down from the *GB transmission system* at a *GSP*.

Figure 4-1. Pre-fault planning voltage limits in the current GB SQSS (re: GB SQSS V1.0 Table 6.1)

Following a secured event or operational switching, an affected site that remains directly connected to the GB transmission system in the steady state (i.e. after manual or automatic operation of available facilities including switching in and out of relevant equipment) should satisfy the steady state planning voltage limits specified in the GB SQSS Table 6.3 at GB transmission substations or grid supply points. This table and associated notes is given here as Figure 4-2.

Nominal voltage	Minimum	Maximum
400kV	380kV (95%) ***Note 1***	410kV (102.5%) ***Note 2***
275kV	248kV (90%)	289kV (105%)
132kV	***Note 3***	139kV (105%)
<132kV	***Note 3***	105%

Notes

1. It is permissible to relax this to 360kV (-10%) if:
   - the affected substations are on the same radially fed spur post-fault;
   - there is no lower voltage interconnection from these substations to other *supergrid* substations; and
   - no auxiliaries of *large power stations* are derived from them.
2. It is permissible to relax this to 420kV (+5%) if lasting for no longer than 15 minutes.
3. It shall be possible to operate the lower voltage *busbar* of a *GSP* up to 100% of nominal voltage unless the *secured event* includes the simultaneous loss of a *supergrid* transformer.

Figure 4-2. Steady state planning voltage limits in the current GB SQSS (re: GB SQSS V1.0Table 6.3)

Section 6.3 of the current GB SQSS also states that, “The steady state voltages are to be achieved without widespread post-fault generation transformer re-tapping or post-fault adjustment of SVC set points to increase reactive power output or to avoid exceeding the available reactive capability of generation or SVCs.”

4.2.1.2 Steady-State Voltage Limits in Operational Timescales

Following a secured event or operational switching in England and Wales the affected site that remains connected to the GB transmission system in the steady state (i.e. after manual or automatic operation of available facilities including switching in and out of relevant equipment) should satisfy the steady state operational voltage limits specified in the GB SQSS Table 6.5 at GB transmission substations or grid supply points. This table and associated notes is given here as Figure 4-3.

Section 6.6 of the current GB SQSS also states that, "Where possible, the steady state pre-fault voltage on the GB transmission system will be no lower than 95% of nominal. The target operational voltages at grid supply points should be as agreed with the relevant network operators."

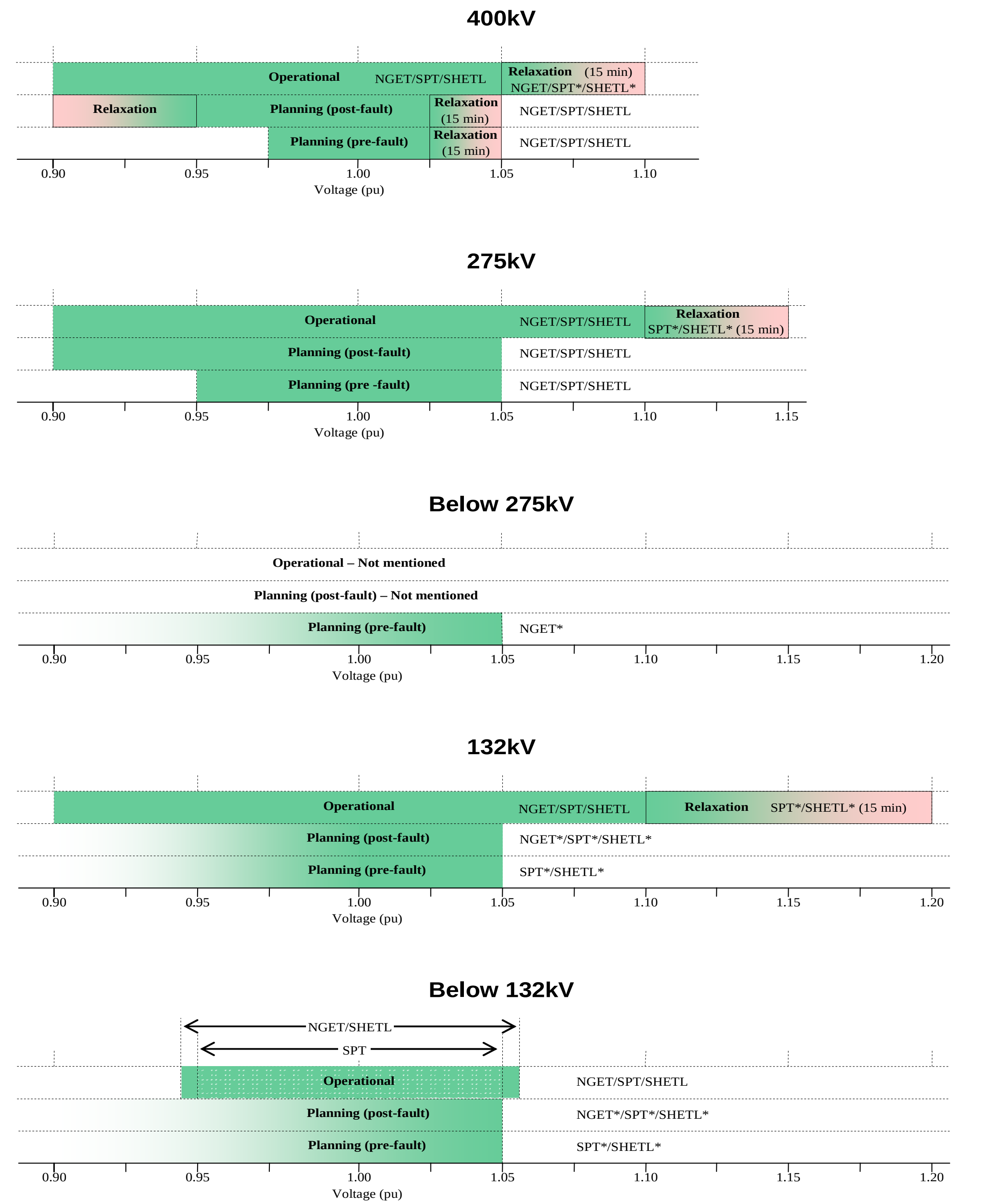
Nominal Voltage		Area		
		England and Wales	SPT	SHETL
400kV	Minimum	360kV (90%)	360kV (90%)	360kV (90%)
	Maximum	420kV (105%) ***Note 1***	420kV (105%) ***Note 2***	420kV (105%) ***Note 2***
275kV	Minimum	248kV (90%)	248kV (90%)	248kV (90%)
	Maximum	303kV (110%)	303kV (110%) ***Note 3***	303kV (110%) ***Note 3***
132kV	Minimum	119kV (90%)	119kV (90%)	119kV (90%)
	Maximum	145kV (110%)	145kV (110%) ***Note 4***	145kV (110%) ***Note 4***
Less Than 132kV	Minimum	94%	95%	94%
	Maximum	106%	105%	106%

Notes
1. May be relaxed to 440kV (110%) for no longer than 15 minutes.
2. May be relaxed to 440kV (110%) for no longer than 15 minutes following a *major system fault*.
3. May be relaxed to 316kV (115%) for no longer than 15 minutes following a *major system fault*.
4. May be relaxed to 158kV (120%) for no longer than 15 minutes following a *major system fault*.

Figure 4-3. Steady state operational voltage limits in the current GB SQSS (re: GB SQSS V1.0 Table 6.5)

4.2.1.3 Commentary on Steady State Voltage Limits in the Current GB SQSS

The Working Group noted that there are differences within the voltage criteria broadly according to timescales (planning and operational) and regional (by transmission owner area). Figure 4-4 shows a pictorial summary of the voltage criteria within the current GB SQSS showing both regional differences and differences between operation and planning timescales.



* indicates additional qualifications, see relevant figures with pre-fault, post fault and operational limits tables and associated notes.

Figure 4-4. A 'pictorial' summary of the steady state voltage criteria in the current GB SQSS

4.2.1.4 Differences between Planning and Operational Timeframes

The voltage range allowed at the planning stage is generally narrower than the range allowed operationally:

400kV

The planning upper voltage limit at 400 kV is 102.5%, but can be relaxed to 105% for no more than 15 minutes. This applies pre-fault and following any secured event. The equivalent operational limits are 105% and 110%.

The planning lower voltage limit at 400 kV is 97.5% pre-fault, and 95% following a secured event. However, the lower limit following a secured event can be relaxed to 90% in certain specific circumstances[5] - see Figure 4-2. Operationally, the lower limit is 90% unqualified.

275kV

The planning upper voltage limit at 275 kV is 105% pre-fault and following a secured event. Operationally, the upper limit is 303kV (110%), but can be relaxed to 316kV (115%) for no longer than 15 minutes in Scotland following a major system fault.

The planning lower voltage limit at 275kV in planning timescales is 95% pre-fault and 90% following a secured event. Operationally, the 275kV lower voltage limit is also 90% with no qualifications.

Below 275kV

For voltages below 275kV only the upper voltage limit is specified as 105% for the England and Wales area, only for the planning timescale pre-fault. There is no mention of this category neither in post-fault planning, operational timescale nor in Scotland.

The corresponding lower voltage limit for voltages below 275kV in England and Wales pre-fault in planning timescales is not specified. However, it should be possible to achieve up to 105% of the nominal voltage at the LV busbar of a step down grid transformer at a GSP.

132kV in Scotland

Where 132kV is a transmission voltage, the planning upper voltage limit is 139kV (105%) both pre-fault and following a secured event. The operational upper voltage limit at 132kV is 145kV (10%), but can be relaxed to 158kV (120%) in Scotland following a major system fault.

There is no defined planning lower voltage limit for the 132kV transmission network. The network and Grid Supply Points are designed to achieve target voltages on the LV sides of the transformers at GSPs. Pre-fault, it should be possible to achieve up to 105% of nominal voltage; following a secured event, it should be possible to achieve up to 100% of nominal voltage, unless the secured event includes the simultaneous loss of a supergrid transformer. A lower voltage limit is however defined at 132kV in operational timescales. This is to 119kV (90%) with no qualifications.

132kV in England and Wales

The upper voltage limit in planning is 139 kV (105%), and in operations it is 145 kV (110%).

There is no lower limit as such in planning, but the network is planned to achieve certain target voltages at busbars on the LV (132 kV) side of the step-down transformers at GSPs. Pre-fault, it should be possible to achieve up to 105% of nominal voltage; following a secured event, it should be possible to achieve up to 100% of nominal voltage, unless the secured event includes the simultaneous loss of a supergrid transformer. Operationally, the lower limit is 119 kV (90%)

Below 132kV

The pre-fault upper voltage limit below 132kV (only in Scotland) is 105%.The corresponding post-fault upper voltage limit is also 105%.

[5] Note 1 to Table 6.3 in the GB SQSS:- “It is possible to relax this to 360kV (-10%) if: the affected substations are on the same radially fed spur post-fault, there is no lower voltage interconnection from these substations to other supergrid substations and no auxiliaries of large power stations are derived from them.”

There are no pre-fault lower voltage limits in planning timescales for voltages below 132kV although the criteria specified for the 132kV pre-fault applies.

No lower voltage limit is specified for voltages below 132kV, but the same criteria as 132kV post-fault are applicable. This applies to the entire GB transmission system.

In operational timescales, the limits are ± 6% in the NGET and SHETL areas while the limits in the SPT area are ± 5%.

In operational timescales, the overall voltage limits are as shown in Table 6.5 of the GB SQSS, but paragraph 6.6 requires pre-fault voltages to be kept to 95% or higher, wherever possible.

It is noted that the voltage limits in planning timescales are more restricted than the operational limits, which align with the statutory limits (and insulation capability at 400 kV). Historically, the reason given for using narrower voltage limits in planning was to provide some margin to cover uncertainties, for example, in demand distribution. The validity of this might now be questioned and is discussed further in Section 4.2.5. It is notable that the "halving" of the operational range in planning is not universal: the GB SQSS allows the 400kV system to be planned to the operational limit of 90% voltage post-fault in some circumstances, and the 275kV system to be planned to the operational limit of 90% post-fault in all circumstances.

The planning standard allows 400kV voltages to fall to 90% post-fault in certain circumstances, but retains a limit of 95% at sites supplying the auxiliaries of large power stations. This is not the case at 275kV where voltages are allowed to fall to 90% post-fault irrespective of whether the sites supply large power station auxiliaries or not. It is noted that the earlier CEGB planning standard PLM-ST-9 specified a minimum voltage of 95% at both 400kV and 275kV sites supplying power station auxiliaries.

The terms "up to 105%", "up to "100%" in the requirements for LV voltage targets appear to cause some confusion. The wording suggests that they do not require the targets of 105% or 100% to be achieved in all circumstances. However "up to 105% could be construed as meaning any value between 0% and 105%, which is presumably not what is intended.

4.2.1.5 Regional Differences

The main regional differences concern the circumstances under which the upper voltage limit can be relaxed:

- In England and Wales, the upper limit for the 400kV system is relaxed from 420kV to 440kV for no more than 15 minutes following any secured event. This is because the 400kV plant originally had a nominal rated voltage of 380kV ± 10%; operation above 420kV increases the risk of insulation failure.
- In Scotland, the relaxation of the 400kV upper limit to 440kV is also allowed, but only following a major system fault. This is defined in the GB SQSS as "an event, or sequence of events so fast that it is not possible to re-secure the system between each one, more onerous than those included in the normal set of secured events." It is reasonable to assume that major system faults are rarer than normal secured events but the standard is approximately equivalent in application to the standard in England and Wales.
- In Scotland, the relaxation of upper voltage limits following major system faults is extended to the 275kV (110% to 115%) and 132kV (110% to 120%) networks.

In Scotland, the criteria for operation of the GB transmission system allow unacceptable voltage conditions (i.e. outside the criteria of GB SQSS Section 6.5) for one or more grid supply points whose group demand is less than 1500MW following a double circuit line fault or busbar or mesh-corner fault[6]

[6] See Section 5.3 and 5.4 of the current GB SQSS

4.2.2 Relevant Provisions in Previous Security Standards

4.2.2.1 CEGB Planning Memorandum 099/32 (TDM13/9)

This standard was used in the CEGB until 1985, applying to planning time scales only. Its main features were:

- Specification of upper voltage limits of 102.5 % at 400 kV and 105% at 275 kV. These were lower than the physical limits of 105% and 110%. The 400 kV limit could be relaxed from 102.5% to 105% for up to 15 minutes, mirroring the relaxation allowed from 105% to 110% in operational timescales.
- Voltage step-changes of ± 6% following single circuit faults, +6%, -12% for double circuit faults.

Voltage targets for points of connection to distribution networks.

4.2.2.2 CEGB Planning Memorandum PLM-ST-9

In force from 1985 to 2000, this planning standard expanded on the requirements of TDM 13/9. Key differences were:

- Introduction of lower steady state voltage limits at 400kV and 275kV.
- Change of the contingencies for which -12% voltage step is accepted, from double circuit trip to secured outage which includes the loss of supergrid transformers (see Section 4.3.1 of this report)
- Introduction of a voltage stability margin (defined under insufficient voltage performance margin in the current SQSS)

PLM-ST-9 applied to all the secured events defined in the relevant CEGB and Electricity Council planning standards at the time, i.e. PLM-SP-2 and ER P2/5. It also applied to circuit breaker faults if these might cause an unacceptable voltage rise. The reasoning was that although switch faults are rare, the consequences of an unacceptable voltage rise, in terms of damage to plant and consequent insecurity, could be significant. For example, if a bus-section switch fault left lengths of supergrid cable back-charged from LV networks and uncoupled from reactive compensation, the resulting voltage rise could cause insulation failure and lengthy outages.

4.2.2.3 CEGB Operational Memorandum OM3

This was the CEGB operating standard used until 2000. It defines unacceptable voltage performance as

- Step change of greater than ± 6%, except for double circuit faults or faults on designated single circuit pairs, for which 12% fall was permitted (see also section YZY of this report)
- Inability to restore voltages at Bulk Supply Points (supplies to DNOs) to nominal values following a step-change.

OM3 included no specific voltage limits or targets.

4.2.2.4 SPT/SHETL Standard

Up to 2005, in planning timescales SPT and SHETL used the TDM 13/9 standard as outlined above. In operational timescales SPT and SHETL used their own operational standard, both referred to as ‘Voltage and Reactive Power Control’ but with different document references, ‘GCI B4’ for SPT and ‘OM4’ for SHETL.

4.2.3 Factors Determining HV System Voltage Limits

As mentioned in the introduction to this section, the factors determining steady state voltage limits can be put into various categories, such as physical constraints, statutory requirements, or contractual arrangements.

SQSS Review Request GSR005 has asked if significant extra power transmission capability can be released by relaxing the voltage standard. The Working Group has considered this request in the course of the overall review of standards.

4.2.3.1 Physical Factors

4.2.3.1 (a) Factors Affecting the Upper Voltage Limit

The upper voltage limit is set by the need to avoid overstressing insulation. As mentioned in 4.2.1.5, plant on the 400 kV system has a rated voltage of 420 kV, so that if its nominal voltage range were defined in the same way as for the 275 kV and 132 kV systems, the nominal operating voltage would be 380 kV ± 10%. The nominal working voltage of 400 kV was decided to maximise transmission capability, and the reduction in operating headroom was accepted as a consequence of this. Plant specialists offered the concession of occasional operation between 420 kV and 440 kV, for up to 15 minutes at a time, balancing operational flexibility against the risk of plant damage.

The current advice of plant specialists to the Working Group is that this relaxation can still stand, but there have been no technology changes or new information that would allow it to be extended. It is noted that the current SQSS mentions operation above 420 kV for up to 15 minutes, without defining how often this can occur. Taken literally, the standard could allow repeated 15 minute excursions above 420 kV separated by short spells at lower voltage. The Working Group therefore consider it prudent to amend the standard to make it clear that operation above 420 kV is only acceptable in abnormal circumstances, e.g. following a *secured event*.

The Working Group has noted that the existing SQSS specifies 303 kV (110%) as the upper operational limit for the 275 kV network, whereas in plant specifications the rated voltage is 300 kV[7]. Since the latter is an IEC standard rated voltage, it would be prudent to align the SQSS with the actual plant rated voltage. This is expected to have negligible effect on investment or operating costs, or on plant performance.

4.2.3.1 (b) Factors Affecting the Lower Voltage Limit

There is no actual physical lower voltage limit on the transmission network itself. In the absence of contractual or legal constraints, any voltage less than the upper limit would be possible, provided that stable power transmission was achieved and satisfactory voltage was delivered at the LV side of Grid Supply Points.

The early voltage security standard TDM-13/09, used by the CEGB up until 1985, did not include lower voltage limits for the supergrid system, although it specified target voltages for supplies to distribution networks. The CEGB standard PLM-ST-9 introduced lower limits for the supergrid voltage in planning timescales. The reasons were not stated but they may have included:

- Defining a voltage range for the interface with supergrid-connected customers and power station auxiliaries (although the standard did not restrict the requirement to points of connection);
- Allowing investment-forecasting studies to proceed without detailed representations of Grid Supply Points or LV networks, to obtain approximate indications of future HV reactive compensation requirements.

There may have been pressure to introduce a lower voltage limit to appear symmetrical with the upper voltage limit, i.e. -5% to go with +5%.

4.2.3.2 Statutory and Contractual Factors

4.2.3.2 (a) Statutory Limits

[7] The earlier CEGB standard PLM-ST-9 recorded 300 kV as the maximum working voltage at 275 kV

There are statutory voltage limits for high voltage supplies to customers[8]. These are:

- For 132kV and above, ±10%
- Below 132kV, ±6%

The operational voltage limits align with these, except that the SQSS only allows 400kV +10% for up to 15 minutes, for the reasons discussed above, and SPT operate to ±5% rather than ±6% for supplies at less than 132 kV.

4.2.3.2 (b) Contractual and Customer Interface Factors

These also apply at any interface between a TO and a User, such as:

- There is a need to maintain an acceptable voltage range at an interface with a DNO. Appendix C highlights voltage targets and limits issues at interface points to distribution networks. Having defined parameters at the interface allows both parties to design their networks more or less independently.
- There is a also a need for a defined and acceptable voltage range at the interface with directly-connected customers whose point of connection is at transmission voltage. Customers will need to know the voltage range in order to define their plant specifications to ensure satisfactory performance of their equipment. Examples are:
  - Generating station main generator transformers
  - Generating station auxiliaries: these may be supplied by station transformers connected at transmission voltage
  - Direct loads, such as Culham JET
  - Traction supplies, if the commercial boundary is at HV.

Generation owners specify their own station transformers against a range of HV system voltage. It can be assumed that they do this with reference to the statutory limits, the Grid Code (CC6.1.4 – 'Grid Voltage Variations[9]') and the GB SQSS.

At 275 kV and below, the operational criteria in the GB SQSS, and the Grid Code voltage range, align with the statutory limits.

At 400 kV, although the statutory limit is +10%, the Grid Code makes it clear that voltage beyond +5% will not persist for more than 15 minutes. This is in line with the physical performance of 400 kV insulation.

However the Grid Code definition of the minimum voltage is less clear: although the normal range is stated to be above -5%, unless abnormal conditions prevail, the minimum voltage is stated to be -10% unless abnormal conditions prevail. Clearly, the latter set of abnormal conditions is considered more abnormal than the first, but there is no indication of the circumstances or duration of a voltage falling between -5% and -10%.

Examination of a small sample of four existing large 400 kV-connected power stations (Appendix A) suggests that it may be difficult to deliver 100% voltage to station auxiliary plant when the 400 kV voltage falls below 95%. Since three of the power stations pre-date the Grid Code, their design may reflect the PLM-ST-9 requirement to design to a minimum supergrid voltage of 95% where power station auxiliary supplies are connected.

These customer interface factors, whilst not being physical limits like insulation performance or voltage stability, are nevertheless significant in setting the planning and operational voltage criteria.

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[8] Electricity Safety, Quality and Continuity Regulations 2002

[9] The Grid Code CC 6.1.4 generally defines contractual voltage limits at User points of connection

4.2.3.3 SO/TO Internal and Commercial Frameworks

The HV voltage limits in the SQSS in planning timescales may also fulfil a range of functions:

4.2.3.3 (a) Investment Forecasting

A detailed system design will encompass the Main Interconnected System, generation connections and grid supply points. Provided that all ‘external’ (e.g. Statutory) voltage constraints are met and stable transmission is achieved without overloads or risk to Users’ supplies or substation auxiliaries, there would be no value in investment to meet minimum voltage targets at system nodes that have no User connections. In these circumstances, any lower voltage limit that lies within the statutory limits and physical constraints can be regarded as a “soft” limit. The current GB SQSS post-fault planning limit of 95% at 400 kV falls into this category. However, experience suggests that a highly-interconnected 400 kV network that meets all statutory and voltage stability constraints is likely to achieve 95% voltage at most locations following secured events.

Longer-term network planning and investment forecasting frequently involves less detailed analysis and design. In these cases it may be convenient to plan investments to achieve a specified minimum HV voltage, knowing that this will allow the design to be optimised through more detailed work in future. In these circumstances the minimum HV voltage criterion in the SQSS can be used to identify likely future investment requirements, before all the detailed design is complete

4.2.3.3 (b) Grid Supply Point Design

The HV system voltage is a factor in the design of GSPs. The TO designs these to meet distribution network active and reactive demands, using standard-specification transformers wherever possible. LV target voltages are as specified in the SQSS or as agreed with the Network Operator, so the reactive power suppliable becomes a function of the HV system voltage. If the reactive demand is high, a low HV voltage might need the GSP to be reinforced with more transformers, transformers with wider tap ranges, or power factor correction compensation. There may be an advantage in fixing an HV lower voltage limit to:

- Allow GSP design to proceed part-independently of MITS design and
- Establish a commercial datum for determining the connection assets at a GSP. For example, if the GSP were designed to an HV voltage of (say) 95%, any LV reactive compensation or other reinforcement needed to meet LV voltage targets would be charged as a connection asset.

Appendix B details the analysis of the relationship between HV and LV target voltages and the reactive demand that can be supplied at Grid Supply Points. The results of the analysis show that GSP LV voltage targets and limits in the current GB SQSS are appropriate and that there is reasonable consistency between planning and operational criteria.

The general conclusion of Appendix B is that the LV voltage targets and limits in the current GB SQSS are justified. However, it is noted that low HV voltages restrict the reactive demand that can be supplied by substations if the LV voltage targets, used in planning, are observed. The restriction would become more severe if HV voltage limits were relaxed downwards.

Conversely, it is possible to supply more reactive demand at substations by raising the HV system voltage. In such cases there is a risk that the capability of the network as a whole could be reduced by having to restrict the system voltage range to support a single heavily-loaded substation with a poor power factor. This should be avoided by careful design.

4.2.4 Effects of Increasing the 400kV Limits Range

In order to consider the options for widening the voltage range at 400 kV it is necessary to consider the technical performance of the 400 kV network.

4.2.4.1 System Reactive Requirements

The reactive gains and losses in the network are sensitive to system voltage. For a given line construction, changing the voltage by, say, 1% produces a much bigger change in net Mvar requirement on a 400 kV circuit than it would at 275 kV at 132 kV. That is, the 400 kV system is more sensitive to voltage changes than the lower voltage networks. The effect is discussed further in Appendix A. Reducing the 400 kV system voltage depletes lagging reactive reserves at a faster rate than reducing the 275 kV system voltage; conversely, increasing the voltage depletes leading reserves.

The GB supergrid system is typically employs high-rating bundled conductors, with thermal ratings that are several multiples of the lines' natural loadings. The longer circuits require large amounts of reactive compensation in order to utilise this thermal capacity, so that stable power transmission relies on the receiving end voltage remaining high.

This sensitivity was noted in PLM-ST-9 where it was cited as a reason for the 95% minimum voltage limit on the interconnected 400 kV system. Circuit thermal ratings have increased substantially since PLM-ST-9 was written, and utilising this capability relies on increasing quantities of reactive compensation. The need to maintain high voltages, particularly on the 400 kV system, is thus reinforced.

4.2.4.2 Voltage Stability

With environmental pressure to minimise the use of new wayleaves, there has been a trend in the UK to increase the thermal capacity of lines on existing routes when additional capacity is needed. Lines may thus be operated at several times their natural loading post-fault, so reactive compensation is installed to provide the line reactive losses and regulate voltage. Appendix A includes an analysis of a hypothetical case (single circuit) and also of a major system boundary under a particular set of conditions.

For short transmission circuits operating at unity or lagging power factor, the receiving end voltage falls smoothly as the power transfer increases, until a point of voltage instability is reached. This point of instability – at which power transfer is at its maximum – is typically at a voltage well below the lower operating limit in the SQSS. There is thus a margin of power transfer capacity between the lower voltage limit in the SQSS and the stability limit.

However, for longer circuits for which a large amount of reactive support must be provided, the stable operating limit may occur at a voltage within the normal operating limits in the SQSS. Voltage regulation at the receiving end depends on the control characteristics of the reactive provider. Regulating reactive reserve is depleted as power transfer is increased, until the reserve is exhausted. This may be at a voltage within the SQSS limits, but little or no additional power transfer may be possible before the stability limit is reached. (Fig A 3, Appendix A).

This effect is seen in the real network (Figure A 4, Appendix A). The implication is that lowering the voltage limits in the SQSS may not increase power transmission capability of the system; in fact, increasing power transfers tends to reduce the voltage range over within which the network can operate.

Another consequence of this "brittle" behaviour is that the voltage level is not the only descriptor of system "voltage performance". It is necessary to plan and operate so that there are adequate margins between any operating point and the voltage stability limit. For this reason, the SQSS defines the term "insufficient voltage performance margins".

Different effects are observed on tie lines carrying high power transfers between large generation/demand groups which have adequate reactive resources and voltage control internally. Voltages at intermediate points on the tie lines fall as transfer increases. In the examples considered South-West import, Figure A5, and Scottish Export, Figure A7), stable transfer is possible at voltages of 90% and lower. However these low HV voltages are associated with high reclosing angles and grid supply transformers reaching tapping limits and failing to regulate distribution network voltage.

4.2.4.3 Voltage Profile and Reactive Reserves

The reactive requirements of an area of the system may be met by reactive sources within the area, such as generators or reactive compensation, or by reactive transfers from elsewhere. Transfers of real (and particularly) reactive power create voltage differences between parts of the system and these voltage differences are known as the voltage profile.

The overall reactive requirement of an area consists of the requirement pre-fault plus the reserve needed to meet increased requirements after a secured event such as a circuit trip. When the capability of the reactive sources in an area exceeds the area's overall reactive requirement, the surplus can be exported to deficit areas by despatching the voltage in the exporting area to a higher level than that in the deficit area. The extent to which this can be done is restricted by the pre-fault voltage limits of the system and in practice it is found that reactive compensation must be installed in deficit areas even though there is spare reactive capacity elsewhere.

Widening the pre-fault planning voltage limits would allow greater use of existing reactive reserves and potentially reduce investment in reactive compensation. In planning timescales, the pre-fault voltage range is restricted to half the operating range so there may be benefits in relaxing this restriction.

The extent to which pre-fault voltage can be raised is restricted by the physical insulation limit, as previously stated. Also, the Grid Code in CC 6.3.4 does not require generators to deliver their maximum reactive capability at voltages above 105% so the scope for despatching the HV voltage above this level to make better use of reactive reserves may be limited. Some pre-Vesting generating units have generator transformer tapping ranges that impose reactive restrictions at voltages below 105%.

The scope for lowering pre-fault voltage limits is likely to be restricted by the GSP performance and supplies to power station auxiliaries and other direct supplies, as well as by voltage stability performance. However, some GSPs with low power factors may require the HV voltage to be held well above the HV system lower limit. It is possible that power factor correction at such sites may release additional supergrid capacity.

4.2.5 Planning Voltage Limits and Uncertainties

The GB SQSS prescribes pre-fault and post-fault voltage ranges in planning timescales that are half of those used operationally (see SQSS tables 6.1, 6.3 and 6.5). The reason given for this, historically, was to cover uncertainties in planning data such as the distribution of demand.

It is not clear how effective this halving of the voltage range is in handling uncertainties; it is possible that it leads to additional investment as described in the previous section, for little actual benefit.

The policy of planning to half the operational voltage limits dates back to the 1960s, when computing facilities were rudimentary and ac analysis was extremely time-consuming. At that time the range of voltage studies that could be undertaken in planning was very limited and would generally be restricted to one or two planned-transfer peak load studies and one or two off-peak studies per year. Halving the voltage range was therefore a prudent precaution. At the time, the standards only specified an upper voltage limit for planning the supergrid, as discussed in Section 4.2.1.5. It should be noted that at that time, the CEGB planning and operating procedures also included a requirement to hold a reactive absorption reserve, of 2000Mvar in planning timescales and 1000Mvar in operational timescales, at times of minimum demand. This requirement was also to cover for uncertainties but has been dropped from the current security standards as the problem of voltage control under light-load conditions has receded.

It is now possible to conduct many more studies of voltage conditions in planning and operational timescales so data variations that were previously covered by uncertainty margins in the voltage limits can now be examined explicitly. Examples include the inclusion of interconnection allowances, ‘whole-set’ generation modelling, and the additional variations in demand and equipment availability used in checks for insufficient voltage performance margins. The requirement to study these system conditions has been included in the standards from the mid-1980s onwards and postdates the use of restricted voltage limits in planning. It is therefore possible that there is now some double-counting in the treatment of uncertainties.

The GB SQSS Fundamental Review Working Group on MITS principles is reviewing the range of variations in background conditions for which the system must be secure; if this review encompasses all the conditions for which operational voltage criteria must be met, it would no longer be necessary to plan to a reduced voltage range to cover uncertainties. It may then be possible to make better use of reactive reserves, as discussed in Section 4.2.4.3.

One option would be to allow partial relaxation of the 400 kV upper voltage limit in planning from 102.5% to something higher in areas of the system where it is possible to demonstrate that there is minimal risk of operational voltage limits being exceeded, i.e. where actual system conditions are highly predictable at the planning stage. This would allow otherwise-unusable lagging reactive capability to be utilised. However, it is noted that design engineers have sometimes made such relaxations where they have been confident that all operational limits can be met and the reactive capability will be available. It is therefore unlikely that any practical savings in investment would result from a formal relaxation of the 102.5% limit in the standard.

The existing SQSS refers to “insufficient voltage performance margins” as a criterion in system planning. That is, irrespective of the absolute value of the voltage pre- or post-fault, the network must be planned to have adequate margins to voltage collapse. In situations such as those described in the section on voltage stability, above) and illustrated in Figure A 3and Figure A 4, voltage instability could occur within the normal operational voltage limits. Investment may be required to provide sufficient margin, even though voltage levels are satisfactory. The current SQSS defines voltage performance margins in terms of an increase in demand “credible demand sensitivities”. This definition is relevant in certain importing areas with limited generation but is more difficult to interpret for system boundaries between major areas that include significant amounts of demand and generation.

It would be possible to review the requirement and develop some more-or-less arbitrary rules for setting voltage performance margins (For example, the Western Electricity Coordinating Council requires that interface transfers should not come within 5% of the voltage stability limit). However, the introduction of large quantities of renewable and embedded generation means that traditional views of demand and generation uncertainties will be invalid in future so that the definition of suitable voltage stability margins needs to be rethought. Analysis of uncertainties in power transfers falls within the remit of Working Group 3 of the SQSS Review so their work may contribute to new ways of determining appropriate margins.

4.3 Planning and operational voltage step change limits

The current SQSS defines limits for voltage step-changes following secured events, and following operational switching. The requirements vary between the three TOs, and there are some apparent inconsistencies between the requirements in planning and operational timescales. Requirements have also varied historically as published security standards have been revised. These historic variations may contribute to the present regional differences, as the TOs design and operating criteria have evolved from the earlier standards.

These differences mainly concern the circumstances under which the “normal” limit of -6% for the voltage fall after a *secured event* would be relaxed to 12%, and the application of step-change limits for operational switching.

The Working Group has taken a fresh view of these criteria, looking at the magnitudes of voltage steps that might be expected after particular contingencies at different types of substations, to see if there is a sound basis for eliminating the regional variations. More details of this analysis are given in Appendix C.

The review has not addressed the following:

- Which secured events are appropriate for the voltage step-change criteria (apart from the generating unit trips which are discussed in the text), since these form part of the wider Fundamental Review;
- The ±6% and -12% values allowed for the "normal" and "relaxed" voltage step criteria. These limits have been in use for many years, so are presumed to remain satisfactory for end-customers. It would be possible to embark on an exercise to determine if other values (±5%? ±7%? -10%) would be more appropriate but this would be a lengthy and probably inconclusive task.

The voltage step-change standard applies at interfaces between the onshore transmission network and customers. Voltage steps on the supergrid network will affect HV-connected customers (power station auxiliaries, railway supplies etc) and can be assumed to propagate down to lower voltage levels. Contingencies at lower voltages, or involving supergrid or Grid Supply Transformers, may cause significant voltage steps at the directly-affected LV busbars but the step changes at HV and at more remote Grid Supply Points are assumed to be attenuated. These assumptions have been made throughout this review.

4.3.1 Voltage Step Change Criteria in the Current Standard

The current standard stipulates voltage step criteria in planning and operational timescales following secured events on the GB transmission system. Voltage steps of ±6% are generally allowed following secured events, but this requirement is relaxed to -12% under certain circumstances. The three transmission areas differ in the circumstances for which this relaxation is allowed, such that similar secured events might be subject to different criteria in each region.

Within England and Wales, the criteria vary between planning and operational timescales. The current standard also includes voltage step criteria for operational switching in England and Wales, but not in Scotland.

4.3.1.1 Voltage Step Limits in Planning Timescales

Table 4-1 shows the voltage step limits in planning timescales from Table 6.2 in the GB SQSS. These have been presented in a different format for clarity.

Table 4-1. Voltage step change limits in planning timescales

	EVENT			FAULT INVOLVES LOSS OF:			VOLTAGE STEP LIMIT	
	Secured event	Operational Switching less frequent than ER P28	Operational Switching covered by ER P28	Double circuit	Section of busbar or mesh corner.	Supergrid transformer	Fall (%)	Rise (%)
NGET area	✓						-6	6
	✓				✓		-12	6
	✓					✓	-12	6
		✓					-3	3
			✓				ER P28	ER P28
SPT area	✓						-6	6
	✓			✓			-12	6
SHETL area	✓						-6	6
	✓			✓			-12	6
	✓				✓		-12	6
	✓					✓	-12	6

4.3.1.2 Voltage Step Limits in Operational Timescales

Table 4-2 shows the voltage step limits in operational timescales from Table 6.4 in the GB SQSS. As above, these have been presented in a different format for clarity. The red/circle marks indicate differences between the planning and operational voltage step limits.

Table 4-2. Voltage step change limits in operational timescales

	EVENT			FAULT INVOLVES LOSS OF:			VOLTAGE STEP LIMIT	
	Secured event	Operational switching less frequent than ER P28	Operational switching covered by ER P28	Double circuit	Section of busbar or mesh corner.	Supergrid transformer	Fall (%)	Rise (%)
NGET area	✓						-6	6
	✓			✓			-12	6
	✓				✓		-12	6
		✓					-3	3
			✓				ER P28	ER P28
SPT area	✓						-6	6
	✓			✓			-12	6
SHETL area	✓						-6	6
	✓			✓			-12	6
	✓				✓		-12	6
	✓					✓	-12	6

4.3.1.3 Differences between Planning and Operational Timeframes

The only difference between the planning and operational limits is in the relaxations allowed for the lower voltage step in England and Wales. While in planning timescales the relaxation is applied for a fault involving a section of a busbar, mesh corner or loss of a supergrid transformer (i.e. no relaxation for a fault involving a double circuit loss), in operational timescales a fault involving a double circuit loss qualifies for relaxation. The fault also qualifies for relaxation if a section of busbar or mesh corner is involved but does not qualify if a supergrid transformer is involved.

It can be argued that in its current form, the standard prescribes a tighter operating voltage lower step limit compared to the planning lower step limit with respect to faults involving the loss of a supergrid transformer in England and Wales. This appears to be contrary to the trend seen elsewhere within the GB SQSS.

The operational standard (GB SQSS para. 5.1.2) includes “the most onerous loss of power infeed” as a secured event for which unacceptable voltage conditions are to be avoided. There is no equivalent reference to loss of power infeed in the planning criteria (Sections 2 and 4 of the GB SQSS). These sections discuss loss of power infeed only as a consequence of transmission plant failure, and in terms of the effect on system frequency.

4.3.1.4 Regional Differences

The three TOs apply different criteria for allowing a 12% voltage fall:

- In SPT it is permitted only for the loss of a double circuit overhead line
- In England and Wales it is permitted at the planning stage for loss of a busbar, mesh corner or supergrid transformer. However, in operations, it is not permitted for the loss of a supergrid transformer alone but permitted for the loss of a double circuit.

– In SHETL it is permitted for the loss of a double circuit overhead line, busbar or mesh corner, or supergrid transformer.

There are also regional differences in the application of the standard to secured events. Sections 5.3 and 5.4 of the GB SQSS refer to avoidance of unacceptable voltage conditions for double circuit overhead line outages or outages of a busbar section or mesh corner. However, section 5.3 excludes demand groups of less than 1500 MW from the voltage criteria in Scotland, but section 5.4 refers to England and Wales and applies no such exclusion.

Standards for operational switching in Scotland differ from those in England and Wales. In England and Wales, the general step-change limit is ± 3%, with E.R. P28 applying if the frequency of switching is such as to require it. The standard makes no reference to operational switching limits in Scotland.

4.3.2 Comparison of Networks

From comparisons of network and substation layouts, it does not appear that these alone can justify the regional differences. However, in Scotland 132 kV is a transmission voltage and much demand is fed from 132/33 kV or 275/33 kV Grid Supply Points. This contrasts with England and Wales where the majority of supplies to DNOs are at 132 kV. Typical 132/33 kV and 275/33 kV transformers have higher impedances than 400/132 kV or 275/132 kV units, so an outage involving loss of say, a 132/33 kV grid supply transformer is likely to yield a larger voltage fall than and outage of a 400/132 kV transformer. To compensate this, typical 132/33 kV and 275/33 kV transformers have a greater boost tap range than 400/132 kV and 275/132 kV transformers, and are thus better able to restore the LV voltage to nominal following a larger drop. The Working Group believes this difference in characteristics could form the basis of a standard where the requirements are differentiated by voltage level rather than by region. This possibility is examined in detail in Appendix C.

4.3.3 Treatment of Different Types of Contingencies under the Current SQSS

In the current SQSS, different criteria are applied for contingencies carrying similar levels of risk, while very rare contingencies may be subject to the same criteria as more frequent ones. For example, relaxation of the step change limit to -12% is allowed for faults involving sections of busbar (rare) and for faults involving loss of a mesh corner (much less rare, since it can be caused by a line fault) Further examples are discussed in more detail in Appendix C and tabulated in Table C1.

The only events that are treated consistently in all areas and both timescales are the loss of a single circuit without loss of other equipment (for example a circuit switched on a busbar with a dedicated circuit breaker) and the loss of a double circuit together with the loss of one or more transformers.

It is the view of the Working Group that secured events of similar probability should receive similar treatment in the SQSS.

4.3.4 Factors Affecting Voltage Step Change

4.3.4.1 <u>Categories of Events</u>

Customers will experience negative voltage steps as a consequence of any of the following events individually or combined:

a) Increase the impedance between the customer and voltage sources;

b) Reduce the shunt reactive gain/increase the shunt reactive loss of the network;

c) Reduce the real and/or reactive power injection into the network

Typical significant events within each of the above categories would be:

a) Loss of a Grid Supply Transformer: the voltage step-change will be greatest on the LV busbar and in the distribution network downstream.

b) Loss of one or more high susceptance circuits, perhaps including cable sections

c) Trip of a generator.

In general, the factors that determine the voltage-step performance of the system are fixed at the design stage. In many – perhaps the majority – of cases it will be difficult or impossible to influence step-change performance by operational measures. Where it is possible, high constraint costs may be incurred. There is little if anything to be gained by designing to tighter criteria than the system is operated to, or by trying to operate to tighter criteria than it is designed for.

Even when voltage falls of more than 6% are acceptable to customers, they can be indicative of a highly stressed system. The standard should emphasise that where a large voltage step-change is predicted, the system should be checked to ensure that voltages can be restored to target values post-fault and that there are adequate margins for voltage stability.

The voltage step-change that would occur in reality depends on the response of the demand to voltage variations. In the absence of recent demand response measurements at the sites in question, which will very seldom be available, system analysis in planning and operation would use standard characteristics based on historic measurements which date back to the 1970s. There is thus great uncertainty in knowing which demand response to apply at any given site. If there is no evidence of steady-state voltage problems, careful sensitivity analysis should be undertaken before expenditure is committed to eliminating minor apparent non-compliance with the step-change criteria.

4.3.4.2 Voltage Falls at Grid Supply Points

The most common events that would cause voltage falls in excess of 6% are those involving losses of grid supply transformers. The effects of such events are generally confined to the LV side of the substation where the transformers are tripped.

The step-change experienced at a GSP LV busbar is sensitive to the demand power factor. A given network and substation design can produce acceptable voltage step-changes for a given load at a high power factor, but much larger voltage steps if the power factor is lower. The effects of power factor variations are shown in Appendix B.

4.3.4.3 Voltage Steps due to Loss of Generator or Other Infeeds

Tripping a generator will almost always produce a voltage step-change on the system. Generator trips were included as secured events in earlier standards such as PLM-ST-9. They are comparatively frequent events so the reason for their exclusion from the current standard is not clear. Section 2 of the SQSS refers to the loss of power infeed due to transmission faults not exceeding the normal or infrequent loss; Section 5 refers to the most onerous loss of power infeed. In Section 2 the reference is solely in terms of the consequences for system frequency. In Section 5 the same inference is likely to be made, though it is not explicitly stated. By contrast, the old OM3 standard defined the most onerous single system infeed as the largest single generator synchronised to the system as a whole or to a defined group.

Generator trips could cause voltage step-changes of significant magnitude:

- Generator unit sizes are likely to increase in future from the present 776 MVA maximum on the GB system, up to perhaps 2000 MVA.
- Renewable and CHP plants are being connected in 132 kV and distribution networks. Tripping a generator may cause a large voltage step within the local network.

4.3.4.4 Operational Switching

The standard in England and Wales limits voltage steps due to operational switching to ± 3% generally, and to Engineering Recommendation P28 limits for more frequent events. This requirement has been in place for over twenty years and is related to the large numbers of switched shunt reactors and shunt capacitors used in England and Wales.

The characteristics of the network have been different in Scotland, so this standard has not been applied there. There is much less reactive compensation to switch and networks are sparser than in England and Wales. Typical operational switching events are the infrequent isolation of circuits for maintenance and subsequent restoration. On occasion, such events may cause voltage steps between 3% and 6%.

4.4 Proposed Revisions to the Voltage Step-Change Criteria

The Working Group proposes revisions to the Voltage step-change criteria, with the intention that they should:

Be clear and unambiguous in application;

a) Be consistent between planning and operational timescales, and between Transmission Owners. Where differences are essential and justified, the reasons for them should be recorded, preferably within the standard;

b) Apply the same voltage step criteria to secured events of equivalent probability and severity, with the relaxed limit restricted to rarer events;

c) By extension of (b), provide consistent voltage quality to all customers wherever possible, irrespective of the type of transmission substation they are supplied from (since this is at the discretion of the TO and individual customers have no influence);

d) Limit severe voltage step changes to as few customers as possible; hence if a secured event results in voltage steps over a wide area (e.g. several GSPs) the voltage steps should be within 6%;

e) Require the minimum of capital and operational expenditure in a TOs area as a consequence of the revised standard;

f) Involve the minimum reduction in actual voltage quality to customers as a consequence of the revised standard.

The proposed criteria are included in the Draft Revised Voltage Criteria set out in Appendix D. Criteria are varied according to the voltage at which customers are connected. This is consistent with the physical characteristics of the network and plant in various parts of the network.

4.5 Proposed Revised Voltage Criteria in the GB SQSS

4.5.1 Scope

a) The existing separate requirements for the three Transmission Owners are combined into a common GB transmission standard;

b) The format of the standard is changed from that of the existing SQSS. The aim is to achieve consistency between the layouts of planning and operational criteria, and to aid the interpretation of the standards.

c) This draft of the standard does not propose radical change to the restricted voltage limits in planning timescales, which were the subject of GB SQSS Review Request GSR005 of 11/11/07. The planning uncertainties that these restrictions were intended to cover are being addressed by another SQSS Working Group. However, the proposed standard does allow for the relaxation of these limits where there is judged to be sufficient certainty of meeting operational criteria in operational timescales. This is consistent with the way these planning limits have been applied historically.

d) This draft of the standard consolidates the criteria for accepting voltage falls of either 6% or 12% after secured events. It does not review the validity of the 6% or 12% values in themselves. Establishing the “right” amount of voltage step-change from fundamental principles would be a considerable task, and the current step-change limits have been used in the industry for over 40 years and so are assumed to be acceptable to users.

e) The concepts of Insufficient Voltage Performance Margins have been removed from the SQSS definitions and incorporated into the requirements for voltage limits in planning timescales within the proposed voltage criteria. This is in response to irritation expressed by users of previous versions of the SQSS in that the overall voltage performance requirements were scattered through the SQSS document; in this proposal, they are brought together in one chapter.

4.5.2 Principles

4.5.2.1 Consistency Across GB (Without Regional Variations)

Where variations in the standard do occur, they should be determined by factors such as the technical characteristics of the system or numbers of end-customers affected, rather than by transmission ownership

4.5.2.2 Consistency between Planning and Operational Standards

The aim is to meet operational standards on the day, and the planning standards should provide just enough investment to do that, with sufficient allowance for the planning uncertainties between the planning and operational timeframes. In particular, there should be no question of trying to operate to more stringent criteria than the system was planned for. Conversely, the planning standard should not drive investment that is not ultimately required operationally.

4.5.2.3 "Leave Well Enough Alone"

The revised standard should not cause increased capital or operational expenditure where the experience of stakeholders under the previous standard has been satisfactory. Neither should it lead to deterioration in security or quality of supply.

4.5.2.4 Clarity

The standard should be straightforward and unambiguous to apply. Preferably, there should be no need of internal guidance documents to interpret the standard for engineers in the TOs or SO. Historically, such documents have attempted to clarify the standard, particularly where it has been ambiguous, but have tended to depart from the standard in the process. It is accepted that parts of the standard, notably the definition of "credible demand sensitivities" state a principle, and a further procedure will be needed to turn this into numerical values that can be applied in design studies. However, any such procedure should not duplicate or amend the proposed standard.

4.5.2.5 Factors Driving Criteria

- Insulation, which determines the upper voltage limits operationally;
- The need to provide a defined steady-state voltage range for customers. Customers can connect at any voltage, for example power station auxiliary supplies at 400 kV or 275 kV, as well as supplies to DNOs at Grid supply Points. Voltage ranges are defined by statute in the Electricity Safety, Quality and Continuity Regulations 2002 [Ref. 1]. Para 27 (3) specifies variations up to ±10% at supply terminals at 132kV and above and ±6% for high voltage supplies at less than 132 kV. Voltage ranges are also referenced in the Grid Code C.C. 6.1.4.
- The need to provide acceptable voltage step-changes to customers, caused by operational switching and by secured events.
- The need to ensure stable power transmission.

The proposed Revised Voltage Criteria are set out in Appendix D, along with a commentary on detailed aspects of it.

4.5.3 Key proposals:

a) Acceptance of the steady state upper voltage limit in planning timescales as a “soft” constraint, with some flexibility provided that designers can demonstrate a high degree of confidence that operational limits can be met on the day.

b) Inclusion of circuit-breaker faults as secured contingencies for which upper voltage limits must not be exceeded.

c) Inclusion of generator trips as secured contingencies

d) Revised voltage step-change criteria, with common requirements across GB. Criteria so far as possible are varied, where necessary, according to the voltage at which customers are connected

e) Inclusion of a GB-wide step-change requirement for operational switching that is consistent with ER P28.

f) Inclusion of a new category of Infrequent Operational Switching with more relaxed voltage step-change limits than normal operational switching.

4.6 Working Group Conclusions on Voltage Criteria

The conclusions of the Working Group on Voltage Criteria are:

The existing voltage criteria in the SQSS contain a number of inconsistencies and the standards should be revised to eliminate these and produce a common GB standard without regional variations. A draft revision of the Voltage Criteria is appended as Appendix D.

Voltage Criteria can be categorised as “Hard Limits” and “Soft Limits”

Hard Limits include:

- The steady-state upper voltage limits in operational timescales. These are determined by insulation performance and are not negotiable
- Statutory limits: the post-fault steady state operational limits align with these (except at 400 kV, where the long-term insulation limit over-rides the statutory limit). These also are regarded as non-negotiable.
- The minimum voltage at which voltage stability can be maintained. This depends on circumstances, but may be higher than the statutory lower voltage limit

Soft Limits include:

- The steady-state upper voltage limits in planning timescales;
- The steady-state pre-fault lower voltage limits in planning timescales
- The steady-state pre-fault upper and lower voltage limits in planning timescales
- The steady-state post-fault lower limit in planning timescales for parts of the 400 kV system remaining interconnected
- The target voltages at the LV side of Grid Supply transformers
- The voltage step-change limits (Noting the uncertainty in load response characteristics).

In planning timescales, it is recommended that all limits are observed in investment forecasting (e.g. Business Plan) studies, but that at the detailed scheme design stage the “soft” limits should be applied with discretion in consultation with interested parties.

In operations, the pre-fault steady-state voltage limits can be flexed but the post-fault limits must always be enforced.

As revised, the criteria are reasonably self-consistent and consistent with the physical characteristics of the network. For example, it will frequently be found that if the system is loaded to the point where one voltage limit is breached, other voltage criteria may be close to being infringed also.

With regard to the request to the Review Group GSR005, some flexibility in the steady state upper voltage limits in planning timescales may allow more power to be transferred. However, design engineers have frequently flexed this limit in the past, and continue to do so where they are confident that conditions are sufficiently predictable to ensure that operational limits can always be met. It is likely that all transmission capacity that can be obtained by raising the voltage above the steady-state planning limit is already being assumed. The lowest voltage on the supergrid, particularly at 400 kV, is frequently set by voltage stability considerations and may exceed the lower limit in the standard. In these cases, relaxing the lower voltage limit will not increase power transfer capability on heavily loaded 400kV circuits. Where stable 400 kV voltages below 95% can be found on the interconnected system post fault, they may be associated with high power transfers over tie lines across critical boundaries. Transmission angles, voltages and reactive requirements become increasingly sensitive to transfer, while voltage instability could result in system break-up with consequent frequency disturbances and possible load-shedding in deficit areas. Any increased transfer obtained by planning to lower voltage limits would be offset by this increased risk. The conclusion is that relaxing the HV voltage limits as suggested in GSR 005 would provide little extra bulk transmission capacity, at the expense of increased security risk.

It is recommended that the secured events for planning and operating the system should include the loss of any generating unit (this would include any module or combination of units connected through the same circuit breaker or with a common prime mover or steam supply).

It is also recommended that the secured events for planning the system should include circuit breaker faults, where these could cause voltage rise beyond the upper planning limits.

Regional variations in the voltage step-change criteria can be largely eliminated by varying the criteria according to the voltage at which customers or distribution networks are supplied. This is consistent with the characteristics of the networks and substation plant, and ensures that larger voltage falls (between 6% and 12%) affect the fewest end-customers.

An exception is the voltage fall acceptable following a *double circuit* supergrid fault in planning timescales. In England and Wales the current standard is -6%; in Scotland it is -12%. The working group was advised that applying the -6% standard in Scotland would incur additional investment for little practical benefit in terms of quality of supply. Conversely, relaxing the standard in England and Wales to -12% was perceived as potentially reducing quality of supply and general system robustness, for no identified saving in investment. The working group reluctantly concluded that the best option at present is to continue with a regional variation in the standard until better evidence is found in favour of a change either way. The issue is discussed in the “Commentary” section of Appendix D, paras 30 -33.

GB-wide step-change limits for operational switching can be specified in a way that matches the varying characteristics of the system by separating operational switching into “frequent” and “infrequent” events. The former would include routine daily switching for voltage control for example, while the latter would include switching out circuits for maintenance. The requirements for frequent operational switching may also be simplified by including a chart, of permissible voltage changes as a function of switching intervals, in the body of the SQSS. This would be consistent with ER P28 for the types of events covered by the SQSS, but would remove the need to refer to that document in every case.

More work is needed on the definition of “insufficient voltage performance margins”. As HV circuits become more heavily loaded and more reliant on regulating reactive sources, voltage instability becomes an increasing risk. Investment has been, and will be, driven by the need to maintain voltage stability. Intermittent and fluctuating generation means that traditional ways of defining voltage performance margins become invalid, whilst it is ever more important to define these margins adequately. It is proposed that further work will be done by this Working Group to develop joint TO planning procedures to provide sufficient voltage performance margins. It is hoped that the work of SQSS Working Group 3 will inform this activity.

5 Stability Criteria

5.1 Introduction

The stability criteria within the SQSS define the conditions for which individual or groups of generators remain in synchronism with the remainder of the system. It also defines criteria for power frequency oscillatory damping on the system resulting from small perturbations such as switching events.

In the past, parts of the system were limited by oscillatory or small signal dynamic stability, rather than transient stability. However the introduction of Power System Stabilisers (PSS) on large generators, particularly in Scotland, has meant that small signal stability is no longer limiting and transient stability is the main limiting condition for specific parts of the system. This does not mean that small signal stability should be ignored; merely that it is not currently driving any requirement for investment in the transmission system.

The focus of this chapter is to;

(i) Examine the definition of stability within the SQSS.

(ii) Examine the rational for using a transient stability criteria based on a 3-phase fault criteria coupled with the failure of the fastest main protection.

(iii) Examine the potential transfer capacity that could be released by reducing fault clearance times or by use of less onerous fault types for stability assessment.

In addition to considering the ongoing requirement to prevent system instability, this review has encompassed the GB SQSS Review Request ref. GSR006 – 'Review of stability criteria in the GB SQSS'. In summary, GSR006 requested a review of the SQSS in respect of the following two aspects:

(i) the stability criteria for use in stability studies (to cover credible stability related events); and

(ii) whether the stability criteria should form part of the standard and to what detail it should be.

During the course of the Working Group investigations it has only been possible to undertake a limited number of stability studies. Consequently the work presented herein gives the Working Group's initial findings and recommendations and further work may be required to substantiate findings.

In reviewing the requirement to prevent instability, the Working Group adopted the following approach:

(i) Identification of the requirements of previous security standards with regard to stability;

(ii) Identification of the requirements of the prevailing security standard with regard to stability;

(iii) A review of previous stability study results.

5.2 Stability Analysis

The two key issues focused on by the Working Group were:

(i) the impact of different clearance times on transfer capacity;

(ii) the impact of changing the fault type (from 3ph to 2ph-E or 1ph-E) on transfer capacity;

5.3 Relevant Provisions in the Prevailing GB SQSS

Provisions to prevent instability are set out in a number of sections in the current SQSS (National Electricity Transmission System Security and Quality of Supply Standard Version 2.0 June 24, 2009). Key sections are:

Section 2 - Generation Connection Criteria Applicable to the Onshore Transmission System

Section 3 - Demand Connection Criteria Applicable to the Onshore Transmission System

Section 4 - Design of the Main Interconnected Transmission System

The current SQSS definition of system instability is as follows:

(i) poor damping - where electromechanical oscillations of generating units are such that the resultant peak deviations in machine rotor angle and/or speed at the end of a 20 second period remain in excess of 15% of the peak deviations at the outset (i.e. the time constant of the slowest mode of oscillation exceeds 12 seconds); or

(ii) pole slipping - where one or more transmission connected synchronous generating units lose synchronism with the remainder of the system to which it is connected

For the purpose of assessing the existence of system instability, a fault outage is taken to include a solid three phase to earth fault (or faults) anywhere on the national electricity transmission system with an appropriate clearance time.

The appropriate clearance time is identified as follows:

(i) in the England and Wales area and on other circuits identified by agreement between the relevant transmission licensees, clearance times consistent with the fault location together with the worst single failure in the main protection system should be used;

(ii) elsewhere, clearance times should be consistent with the fault location and appropriate to the actual protection, signalling equipment, trip and interposing relays, and circuit breakers involved in clearing the fault.

5.4 Proposed Changes to Background Conditions

Proposals to change the “Background Conditions” required for the assessment of system stability as set out in Section 2 (Clause 2.8.3) of the SQSS have been proposed by Working Group 2 to remove the regional differences that are currently implied in the section. The proposed Clause 2.8.3 will read as follows;

> ‘For all connections, the reactive power output of the power station shall be set to the full leading or lagging output that corresponds to an active power output equal to Registered Capacity, for the assessment of pre and post-fault ratings. For the purpose of assessment of voltage and system stability output should be set to conditions which ought reasonably to be expected to arise in the course of a year of operation.’

These proposed modifications are discussed further in the Working Group 2 report.

5.5 Stability Analysis

Stability analysis was carried out to investigate the impact of different fault clearance times and different fault types on transfer capacity.

5.5.1 Impact of Clearance Times

The stability studies carried out to investigate the impact of fault clearance times were conducted for boundary B6 (between Scotland and England) on an intact 2009 GB transmission network.

The fault clearance times used in planning timescales for stability studies currently assume the failure of one item of equipment in the protection system, effectively removing the fastest protection channel such that the other channel clears the fault. This is justified by operating experience that indicates there is a significant risk of protection unavailability or a protection failure during a fault

Removing the requirement to consider the failure of the fastest protection system and instead assuming that the fastest protection operates correctly could provide a small reduction in fault clearance times (typically 10ms, but up to 30ms on some slower systems).The impact of changing fault clearance times was therefore assessed by making the following simple changes: either a reduction of 10 or 20ms at the near end only, or a reduction of 20ms for all clearance times. Table 5-1 shows a summary of the key results.

Table 5-1. Summary of the key results is shown below

Scenario	Fault	Clearance times (ms)	Maximum transfer (MW)	Maximum transfer (%)
Intact	Western Interconnector (SthaHarkLinm-HarkSGT3B)	80/95/135	2370	100%
Intact	Western Interconnector (SthaHarkLinm-HarkSGT3B)	70/95/135	2420	102%
Intact	Western Interconnector (SthaHarkLinm-HarkSGT3B)	60/75/115	2460	104%
Intact	Western Interconnector (SthaHarkLinm-HarkSGT3B)	60/95/135	2450	103%
Intact	Eastern Interconnector (Eccl/Stew DC)	80/125/135	2330	100%
Intact	Eastern Interconnector (Eccl/Stew DC)	60/105/115	2360	101%
Intact	Eastern Interconnector (Eccl/Stew DC)	60/125/135	2360	101%

In the cases studied, the greatest increase obtained in transfer levels was 4% (90MW) for a 20ms reduction in fault clearance times when applying the Strathaven – Harker (Western Interconnector) fault. For the Eastern Interconnector fault, a similar reduction in fault clearance times resulted in only a 1% (30MW) increase in transfer capability.

Both the studies carried out for this review and previous studies showed that small changes made to the fault clearance times did not have any significant effect on either rotor angles or the transfer capability of the Scotland-England border.

5.5.2 Impact of Fault Type

Stability studies to examine the impact of fault type (3 phase, 2 phase to ground or single phase to ground) were undertaken on a full representation of the GB system for the year 2012/13. The studies were carried out using PSSE for the critical stability limited boundary between Scotland and England, in particular for the double circuit fault on the Strathaven 400kV circuits (clearing lines Strathaven – Coalburn and Strathaven – Elvanfoot in 80 msecs) including a Longannet set on post-fault intertrip.

From a starting point of 4GW transfer across the boundary, the fault type was changed from 3 phase to a 2 phase to earth, then to a single phase to earth and the stability limit was determined for all three fault types. Finally, an additional study was carried out with no fault applied but the two lines switched out. The results of these studies are presented in Appendix E.

The results of Appendix E give the stability limit for a 3-phase-to-earth fault as 4.3GW, whereas the limit for all other fault types, including the no-fault case, is 4.4GW. It can be concluded from this work that for the fault location studied, the different fault types have little impact on the stability limit, indeed it would appear that the effect of merely switching out the double circuit has just as much impact as changing of the fault type.

In the example described above, a double circuit fault on the B6 boundary results in a significant change in impedance between the Scottish generation and that elsewhere in GB. Similar situations may be found throughout the GB system, where double circuit trips leave generators connected through high-impedance transmission routes. The increase in kinetic energy of the machine rotors as they move from their pre-fault to their post-fault steady states may be comparable to, or greater than, the energy increase due to the short circuit. With high post-fault impedances and short fault-clearance times the effect of the impedance change tends to dominate over the effect of fault type.

The acceleration of generator rotors during a fault depends on the voltage depression at the generator terminals when the fault occurs. In the case of the B6 boundary the critical fault location (Strathaven) for the boundary as a whole is not directly adjacent to any particular generating station. The voltage depressions at the generators due to the fault are thus attenuated, so that the effects of different fault types are further reduced in significance compared with the effects of tripping the double circuit.

It is noted that when using fast fault clearance times on an integrated transmission system (as is now standard practice on the GB system), there is a minimum post-fault system strength below which instability will result regardless of the type of fault. As this limiting condition is approached, fault type becomes less and less relevant in determining transmission capability.

5.6 Conclusions

On the GB MITS, the ability of a generator to remain stable following a fault depends on a number of variables including the strength of the transmission system pre and post fault, fault clearance times, unit inertia, operating power factor, governor and excitation systems etc. With the short fault clearance times currently in operation on the GB MITS, transmission system strength is the dominant factor in determining the maximum power transfer capability across a boundary.

With respect to fault clearance times, the analysis conducted for this exercise and the review of previous analysis suggests that any increase in maximum transfers attributable to changes in fault clearance times is small. The small increases suggest that there would be little benefit in relaxing the security standards and therefore the working group recommends retention of the current wording with regard to fault clearance times for stability analysis.

With respect to fault types, no new evidence has been produced to suggest that there is sufficient justification or benefit to change from the most onerous 3-phase to earth fault to a single phase to earth or 2-phase to earth fault. In favour of retaining the existing 3 phase criteria it was felt that, although 3-phase faults occur infrequently, there could potentially be a significant increase in risk of a widespread system disturbance if a fault occurs on the transmission system that has not been studied. The working group therefore recommends the retention of a 3-phase fault as the basis for the stability criteria.

The working group also recommends that further work be carried out to further substantiate the conclusions from this study, in particular to consider the impact of the fault location on the results and also to assess stability results from a different simulation package such as DigSilent PowerFactory.

6 Use of Dynamic Ratings

The use of Dynamic Ratings was reviewed and the following noted.

Currently, the GB SQSS does not present a barrier to the use of dynamic ratings. The current standard allows for the use of time dependant ratings, allowing higher short term ratings depending on weather and type of equipment. Using dynamic ratings means that a new rating can be calculated for example at the day ahead planning stage based on the predicted weather. This is currently carried out on selected circuits by National Grid using its MORE system (Met Office rating Enhancements).

The most significant enhancements are achieved when the weather is windy as the air flow across the conductor has the most impact on removing the heat generated by the higher loading. But note, 'wind shadow' can reduce this cooling effect for example if the circuit is in a valley or runs through a forest.

7 Use of Intertrips

7.1 What is Intertripping?

Intertripping is a means by which a generator or demand can be removed from the system following the fault and trip of one or more circuits at a given point on the network. Communication equipment is required to send a signal from the critical circuit(s) to the generator or demand that is to be intertripped. This could be local or remote from the circuits being monitored. Generally, intertrip schemes require high reliability achieved by redundancy and diverse communication routes.

The Working Group mainly considered the more common case of system-to-generator intertrips. System-to-demand intertrips are only employed in the rare case, where there is no other alternative to securing the system, and there is a particular demand customer or demand group of useful volume who accept the risk of demand loss.

7.2 Working Group Approach to Intertripping

The Working Group considered the treatment of Intertrips in planning timescales via the following steps:

- Identify the requirements of the prevailing security standard with regard to intertripping
- Qualitatively discuss the Pro's and Con's of relaxing the rules for treatment of intertrips
- Consider an outline cost-benefit, for various cases of a single MITS boundary and multiple MITS boundaries

The treatment of Intertrips in the Operational standards is covered within the modelling performed by the MITS group on T+O+X. At the highest level, if a system-to-generator intertrip is present and can be armed securely, then it is of course permitted and recommended to use that intertrip, if the alternative is constraining on and off generation. The only exception is the rare case, where the arming (or other) fee for the commercial intertrip is at a greater price than the constraint action.

7.3 Relevant Provisions in the GB SQSS

In the GB SQSS, intertripping is mentioned in three places as outlined below.

- In Section 5.6, during periods of major system risk, the GB SO is permitted to mitigate these risks by implementing various operational measures including reducing system-to-generator intertrip risks.
- In Section 7, the definition of Operational Intertripping is given as “the automatic tripping of circuit breakers to remove generating units and/or demand. It does not provide additional transmission capacity and must not lead to unacceptable frequency conditions for any secured event."
- In Section 7, the definition of Transmission Capacity states “The ability of a network to transmit electricity. It does not include the use of operational intertripping except in respect of paragraph 2.13 in Section 2 and paragraph 4.10 in Section 4. Reference to 2.13 in the generation connection criteria, is in relation to the system with a prevailing local system outage. In this case, to secure the system to operational standards, the balance between investment in transmission capacity should be tested economically against operational measures, one of which could include intertripping. Reference to 4.10 in the MITS criteria again refer to the need to test the economic balance between investment in the system capacity or operational procedures to deal with conditions that could occur in the course of a year of operation (this is in addition to meeting the deterministic criteria at peak demand).

7.4 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.

– Early connection of renewable generation to meet Government targets for CO2 reductions, if the alternative transmission reinforcements are lengthy to consent and construct.

– 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.

7.5 Disadvantages of using intertrips in planning timescales instead of reinforcement

a) 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;

   i) Increased losses (I2R and I2X losses), which will increase the costs of operating the system and could lead to voltage performance issues.

   ii) 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.

   iii) 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.

b) 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 inter-trips, 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.

c) 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.

d) 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[10].

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

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[10] 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 inter-trip would suffice to justify holding extra Response; the additional cost of moving from a 1320MW to an 1800MW risk is estimated at +£150m pa in GSR007.

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.=

f) 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.

g) 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.

h) 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 inter-trip monitoring is very remote from the generation site to be tripped, this can increase the risk of failure to operate correctly.

i) There are a number of issues relating to commercial inter-trips to be sorted.

7.6 Economics of Intertrips

The Working Group considered a number of generic cases of the economics of intertrips. The first case considered, was an example where intertrips are both permitted and are effectively used under the current GB SQSS, namely a local group of 2–5GW of generating capacity connected to the main system by two double circuits. In this case, intertrips are not used for the winter N–2 compliance, but are often employed effectively against the summer N–3 operating condition. For comparison with the cases below, the Working Group noted the features of this arrangement that make it 'work':

a) Because the intertrip is visibly 100% effective on the overload in the N–3 case, the intertrip is clearly labelled as Operational – category 2 under the current CAP076 rules.

b) The intertrip is designed at the Planning stage, and is properly incorporated into the Connection Agreements.

c) There is no interaction with wider MITS boundaries; the intertrip does not apply to them, or relieve them at all.

The more general case considered, involves extending the GB SQSS to accept a system-to-generator intertrip as delivering transmission capability for GB SQSS compliance. It was noted that in almost all cases, it would not suffice to install the intertrip only against the 4 or 6 circuits of a narrow MITS boundary, but one would install the intertrip against additional circuits North and South of the formal boundary. For example in the case of B6 Cheviot, one would probably need capability to arm for North-of-Eccles as well as South-of-Eccles circuits; and for Harker-Hutton circuits as well as Strathaven-Harker circuits. Moreover, there is a severe issue, whether the intertrip has to be extended to multiple MITS boundaries. Again in the case of B6 Cheviot, if one has achieved 1200MW of extra B6 capability by installing an intertrip, has one merely shifted the problem further North to B4 and B5, or further South to B7 and B8?

Some generic economics of such cases can be summarised:

a) The capital cost of installing such an intertrip, from 12 circuits to one station, is estimated at £1m set-up plus 12 x £0.2m per end = £3.4m total.

b) The alternative cost of transmission would be 500MW (say) x 1 boundary x 100 km thickness x 500 £/MW.km (ideal price of transmission) = £25m transmission capital.

c) If one had to pay a commercial arming fee, the annual cost would be 500MW x 1000hrs (say) x 10 £/MWh (average commercial intertrip price) = £5m pa. This would be more expensive than the transmission, at any credible discount rate.

d) If the only alternative were constraints – i.e. one could not reinforce or install an intertrip, then the constraint might cost 500MW x 50 £/kW (a typical non-compliant constraint price, here set at 50 £/MWh x 1000hr active) = £25m pa.

e) For illustration, generic calculations for a 100km 4-circuit boundary estimate an increase in cost of Transmission Losses (priced at 50 £/MWh) of £3m pa, in the unreinforced case where greater boundary flows are being facilitated by an intertrip. This is of the same order as the annualised cost of the transmission reinforcement.

7.7 Impact of 'Connect and Manage'

DECC have flagged (see Decision Document, March 2010) that the enduring regime for Transmission Access will be changed to a regime of 'Connect and Manage'. Exactly how this regime will be enacted, and what is then meant by compliance with the SQSS, is still (as of April 2010) being debated. In this context, the Working Group make the following observations:

Adoption of operational Inter-trips is perforce likely to form a strong part of the TOs' tools to 'Manage' under 'Connect and Manage'.

However, the new regime is likely to need to retain a notion of a 'compliant' system. Albeit, we doubtless will not use a term as strong as 'non-compliant' to describe a system, to which new generation has been connected in advance of desirable infrastructure reinforcements. Hence we think it sensible, not to erode the current concept of a 'compliant' system by extensive use of inter-trips for Planning compliance.

7.8 Working Group Conclusions on Intertrips

Considering the above advantages and disadvantages of intertrips, together with the economics, the POCC Working Group conclude:

a) Operational intertrips are frequently used on the GB system, and are useful to reduce the volume and cost of constraints.

Working Group members were divided on the principle of the applicability of intertrips in planning timescales, and in particular drew differing conclusions from the O+X work of Working Group 3. The following conclusions reflect the views of the majority of Working Group 4.

b) If an intertrip is commercial, not operational, it is extremely unlikely to be economic against the alternative of transmission reinforcement.

c) Yes if a sole boundary is under consideration, installation of an operational intertrip is cheaper than the transmission reinforcement. It could presumably be accommodated securely on a one-off basis.

d) But only 1320MW of such intertrip of this form is ever valuable on one boundary. Beyond 1320MW, further intertrips are of zero value.

e) Furthermore, commitment to intertrips in planning timescales is asymmetric. If one has not committed to an intertrip on a boundary, one can temporarily accommodate further generation behind the boundary subject to intertrip. If one has already committed to an intertrip, then one cannot accommodate further generation without risk of non-maintenance of transmission on that boundary, or ultimately insecurity leading to risk of blackouts.

Hence the Working Group recommend that the current practice be retained, that intertrips do not provide an alternative to reinforcement at time of winter peak, except in limited circumstances, but should be considered as an option in ensuring year round operating criteria can be met. There will often be instances of derogation, for example 2YL over 1992-2003 and Cheviot over 2005-2012, where one non-compliant boundary needs to use up the system capability to accommodate one such inter-trip, to manage a period of under-reinforcement.

8 Conclusions

The Working Group observations, recommendations and conclusions on the work undertaken on the Review of the Planning and Contingency Criteria are as follows:

8.1 Fault Statistics

The Working Group found no evidence to suggest that there is need to make significant changes to the SQSS rules on account of changes in transmission fault rates if we are to maintain the same level of customer security. In particular, the Working Group noted the following:

a) The limited analysis of geographic differences suggests that the frequency of faults increases the further north the geographical area lies. With single circuit fault rate (per 100km circuit per year) increasing from 0.485 in the south of England and Wales to 0.88 in the north of England to 1.23 in the south of Scotland.

b) There is a noticeable occurrence of double circuit faults, with 76 noted in England and Wales in the 10 year period analysed with only half of these due to the weather. These included an airplane crash and several fires under overhead lines.

c) There is no consistent definition of fair weather or adverse weather. This has two consequences; (i) possible inconsistencies due to differing personal interpretations at the time of recording the faults and (ii) it makes it difficult to make recommendations on different operating standards based on weather.

d) It is also worth noting that there have not been any recent coastal pollution events where there is a long dry spell with offshore winds depositing salt on the substation and overhead line insulation.

e) The observed fault rate of 132KV double circuits in the SPT area is broadly equivalent to the general double circuit fault rate. Currently unlike in the NGET and SHETL areas, these are not a secured event.

f) Notwithstanding the recommendations of the MITS Working Group, it was concluded that SPT would need to carry out extensive studies to determine the consequent derogations and system investments before removing this regional variation in the SPT area.

8.2 Switch Faults

The Working Group carried out analysis regarding the treatment of a single fault outage of a switch as a secured event in the SQSS and arrived at the following concludes:

a) It is appropriate that busbar coupler, busbar section or mesh circuit breaker fault outages continue to be secured events in SQSS Section 2.6.

b) Busbar coupler, busbar section or mesh circuit breaker fault outages need not be introduced to the set of secured events in SQSS Section 4.

c) A detailed impact assessment would need to be undertaken to assess the implications of including the requirement for acceptable post-fault thermal, voltage and stability performance under intact system conditions pre-fault.

d) Consideration ought to be given to the introduction of a requirement to consider the impact of Major System Faults at the planning stage, including busbar coupler, busbar section, mesh circuit breaker fault outages and stuck breaker events and the economic case for securing the event or mitigating the risk of the event.

e) Circuit breaker faults causing unacceptable voltage rise should be reinstated in the set of secured events at the planning stage. Alternatively, they could be considered under the category of Major System Faults as described above.

8.3 Voltage Criteria

The Working Group conclusions and recommendations on the Review of the SQSS Voltage Criteria are as follows:

a) Relaxing the HV voltage limits as suggested in GSR 005 would provide little extra bulk transmission capacity, at the expense of increased security risk.

b) The existing voltage criteria in the SQSS contain a number of inconsistencies. A draft revision of the Voltage Criteria which deals with the inconsistencies as well as the regional variations is given in Appendix D. The following points are addressed in the draft revised Voltage Criteria:

c) Voltage Criteria can be categorised as "Hard Limits" and "Soft Limits". In planning timescales, it is recommended that all limits are observed in investment forecasting studies, but that at the detailed scheme design stage the "soft" limits should be applied with discretion in consultation with interested parties.

d) It is recommended that in operations, the pre-fault steady-state voltage limits can be flexed but the post-fault limits must always be enforced.

e) It is recommended that the secured events for planning the system should include circuit breaker faults, where these could cause voltage rise beyond the upper planning limits.

f) It is also recommended that the secured events for planning and operating the system should include the loss of any generating unit.

g) Regional variations in the voltage step-change criteria can be eliminated where possible by varying the criteria according to the voltage at which customers or distribution networks are supplied.

h) GB-wide step-change limits for operational switching can be specified in a way that matches the varying characteristics of the system by separating operational switching into "frequent" and "infrequent" events. The former would include routine daily switching for voltage control for example, while the latter would include switching out circuits for maintenance.

i) It is recommended to introduce a new category of 'Infrequent Operational Switching' with more relaxed voltage step-change limits than normal 'Operational Switching'.

<u>Further work</u>
A regional difference remains in the voltage step-change allowed after a *double circuit* fault on the supergrid. The Working Group noted that aligning the requirement in Scotland with the current England and Wales standard could incur additional investment costs, while modifying the England and Wales requirement to align with the current Scottish standard may incur risks in terms of quality of supply and general system performance, for no investment saving that can currently be identified. The Working Group recommended that further work is undertaken in this area with the aim of justifying a common standard.

The existing definition of insufficient *voltage performance margins* need to be reviewed in the light of the introduction of large amounts of intermittent and variable generation. The information needed to conduct such a review is not yet available and the Working Group suggested that work should continue in this area.

8.4 Stability Criteria

The main conclusion of the Working Group on the review of Stability Criteria is that no material increase in transmission capacity would be achieved by relaxing the stability criteria. The following were noted:

a) <u>Transmission System Strength:</u>
Given the short fault clearance times currently in operation on the GB MITS, post-fault transmission system strength is the dominant factor in determining the maximum stability constrained power transfer capability across a boundary.

b) <u>Fault Clearance Times:</u>

The analysis conducted for this exercise and the review of previous analyses suggest that any increase in maximum transfers attributable to changes in fault clearance times is small suggesting that there would be little benefit in relaxing the clearance times specified in the security standard. On that basis, the Working Group concludes that the current wording with regard to fault clearance times for stability analysis should be retained.

c) Fault Types:
No new evidence has been produced to suggest that there is sufficient justification or benefit to change from the most onerous 3-phase to earth fault to a single phase to earth or 2-phase to earth fault. Although 3-phase faults occur infrequently, there could potentially be a significant increase in risk of a widespread system disturbance if a fault occurs on the transmission system that has not been studied. The Working Group therefore recommends the retention of a 3-phase fault as the basis for the stability criteria.

d) Further Work
The working group recommends that further work be carried out to further substantiate the conclusions from this study, in particular to consider the impact of the fault location on the results and also to assess stability results from a different simulation package such as DigSilent PowerFactory.

8.5 Use of Dynamic Ratings

The use of Dynamic Ratings was reviewed and the following conclusions were reached:

a) The GB SQSS does not currently present a barrier to the use of dynamic ratings as it allows the use of time dependant ratings. National Grid already uses revised ratings on selected circuits based on day ahead predicted weather using the Met Office Rating Enhancements system.

b) The most significant enhancements are achieved when the weather is windy as the air flow across the conductor has the most impact on removing the heat from the conductor. But ‘wind shadow’ can reduce this cooling effect for example if the circuit is in a valley or runs through a forest.

8.6 Use of Intertrips

The conclusions of the Working Group are as follows:

a) Operational intertrips are frequently used on the GB system, and are useful to reduce the volume and cost of constraints.

Working Group members were divided on the principle of the applicability of intertrips in planning timescales, and in particular drew differing conclusions from the O+X work of the MITS Working Group The following conclusions reflect the views of the majority of the Working Group.

b) If an intertrip is commercial, not operational, it is extremely unlikely to be economic against the alternative of transmission reinforcement.

c) If a sole boundary is under consideration, installation of an operational intertrip is cheaper than the transmission reinforcement. It could presumably be accommodated securely on a one-off basis.

d) But only 1320MW of such intertrip of this form is ever valuable on one boundary. Beyond 1320MW, further intertrips are of zero value.

e) Furthermore, commitment to intertrips in planning timescales is asymmetric. Non-commitment of an intertrip on a boundary allows for temporary accommodation of further generation behind the boundary subject to intertrip. Conversely, if the intertrip has already committed, then no further generation can be accommodated without risk of non-maintenance of transmission on that boundary, or ultimately insecurity leading to risk of blackouts.

Hence the Working Group recommend that the current practice be retained, that intertrips do not provide an alternative to reinforcement at time of winter peak, except in limited circumstances, but should be considered as an option in ensuring year round operating criteria can be met.

Appendix A

Factors Affecting HV System Voltage Range

This appendix provides further detailed information and analysis of some of the factors that determine the HV system voltage range.

A1. Generating Station Auxiliaries

A power station operator will wish to have stable supplies to auxiliaries during power station start-up operation and shut down. Most sites have station supply transformers, though some draw all auxiliary supplies through generator transformers, and use LV generator circuit breakers for synchronising. At sites with station transformers it is normal practice to use these to supply unit auxiliaries during start up and shut down. It is therefore necessary to be able to control the station board voltage to allow paralleling with the unit board when necessary. The plant designer needs to know the HV system voltage range in order to specify station transformers and their tap-changers.

For 275 kV or 132 kV-connected stations, the expected voltage range is clearly stated in the GB SQSS and the Grid Code as ±10% in line with the statutory limits. The range at 400 kV is less clear; the Grid Code states ±5% as normal with -10% as the minimum, while the SQSS quotes 90% as the operational minimum, in line with the statutory limit, with pre-fault voltages maintained above 95% where possible.

A station owner connecting at 275 kV or 132 kV would be assumed to design his station supplies to operate over the ± 10% HV voltage range quoted in the SQSS and Grid Code[11]. If connecting at 400 kV, some cost might be saved by assuming a ‘normal’ minimum voltage of 95%, and accepting a risk of poor plant performance on the occasions when voltage falls to 90% post-outage. However, these savings may not be very significant in the context of the overall power station project.

A case could therefore be made for quoting a lower voltage limit of 90%, in line with the statutory limit, for the 400 kV system in external documents such as the Grid Code. The pre-fault planning and operating limits would be considerations of prudent design and operation, internal to the TO and SO. However, any relaxation of planning and operating limits would have to be compatible with existing Users’ plant connected to the system.

Performance of Existing Power Station Supplies

A small sample of power station transformer data and auxiliary demands has been extracted from Week 24 data submissions for 400 kV-connected stations[12]. The stations were chosen to give an indicative sample of the types of auxiliary demands and connection arrangements that are found. Stations A and C have relatively high maximum demands; station C supplies through a 400/11 kV transformer while the other is supplied via a 275 kV busbar on the same site. Station B is typical of the 1960s/70s generation of large coal plants, while station D is a CCGT station with no separate station supply transformers. The generating units have LV circuit breakers so that site supplies are taken from the LV side of the main generator transformers. Table A 1 indicates the ability to maintain 1.0 per unit voltage to the auxiliaries for HV voltages of either 0.95 p.u. or 0.9 p.u.

[11] There may be 275kV-connected pre-vesting power stations where the design of station supplies reflects the 95% lower voltage limit in the earlier CEGB PLM-ST-9 standard.

[12] This data is confidential to the plant owners and the GB System Operator, so the names of the stations have been withheld.

Table A 1. Performance of existing power station auxiliaries for different HV System Voltages

Station	Station load connection	no of transformers	Tap range	Transformer Reactance (% on 100 MVA)	Max/Typical Stn demand			Supplibable at HV Voltage of:		See Note
						MW	Mvar	0.95 p.u.	0.9 p.u.	
A	275/11.8 kV stn Tx, 61 MVA	2	+/-10%	35	Max	90	80	n/a	**No**	1, 4
					Typical	24	20	n/a	Yes	
B	400/11.3 kV stn Tx, 50 MVA	2	+/-10%	34	Max	40	34	**No**	**No**	1
					Typical	17	8	Yes	**No**	
C	400/11.3 kV stn Tx, 61 MVA	2	+/-10%	27	Max	90	80	**No**	**No**	1, 2
					Typical	4	3	Yes	Yes	
D	405/16 kV Gen Tx, 190 MVA	1	+7.5%, -10%	7	Max	2.9	1.8	Yes	**No**	1,3
					Typical					

Notes
1 Average pos.seq. reactance on max. tap, on 100 MVA base
2 Maximum demand not stated in DRC, so estimated from transformer rating
3 Auxiliaries supplied from LV side of gas turbine generator transformers, both GT units identical
4 Although a 400kV-connected station, station "A" takes supplies from a 275 kV busbar at the site, therefore the applicable minimum voltage is 0.9 p.u.

All the stations can achieve 100% LV voltage when supplying typical station demand, at the appropriate intact-system HV voltage (95% stations B, C and D; 90% for station A, which takes its supplies from the 275 kV busbar). Of the 400 kV-connected stations, only station C can achieve 100% LV voltage with typical demands at 90% HV voltage.

Although this is a small sample, it suggests that there may be potential difficulties in supplying station loads at existing generation sites if the "normal" lower voltage at 400 kV is reduced below 95%. [Is this sample not too small to make this statement?]

A2. System Reactive Requirements

The reactive gains and losses in the network are sensitive to system voltage. Figure 1 shows the effect of varying system voltage on a section of L6 double circuit line, operating at 400 kV and at 275 kV. In each case the line is operated at its natural loading so that at 100% loading its reactive loss balances its reactive gain.

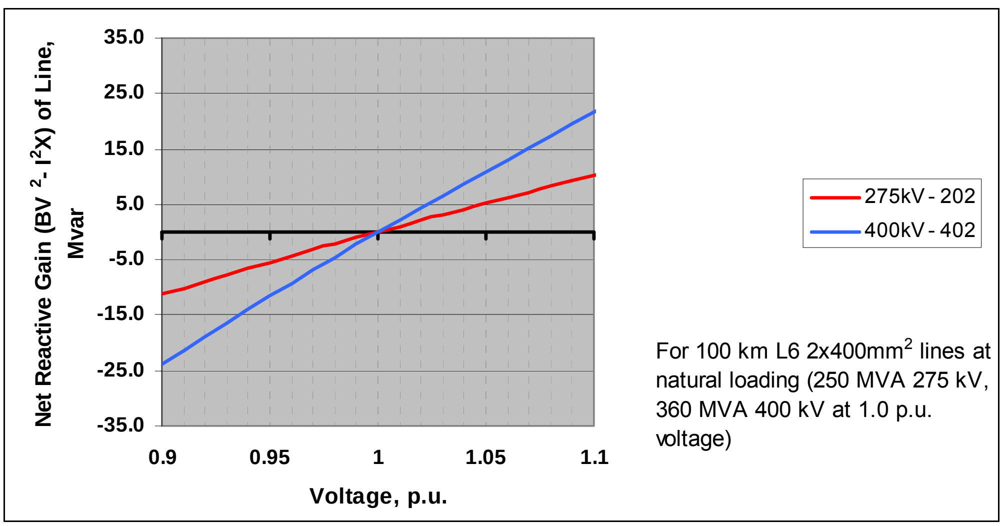


Figure A 1. Variation in line reactive requirement with voltage

For a constant power transfer, it is assumed that line current is inversely proportional to voltage and shunt gain is proportional to voltage squared. The shunt susceptance, in % on

100 MVA, is higher at 400 kV than at 275kV so the net reactive gain/loss (in Mvar) of a 400 kV circuit is more sensitive to voltage change than it is for a 275 kV circuit carrying the same power.

The effect is illustrated at the GB system level in Figure 2. Here system BV^2 and I^2X losses calculated at 1.0 p.u. voltage have been adjusted for uniform variation in voltage[13].

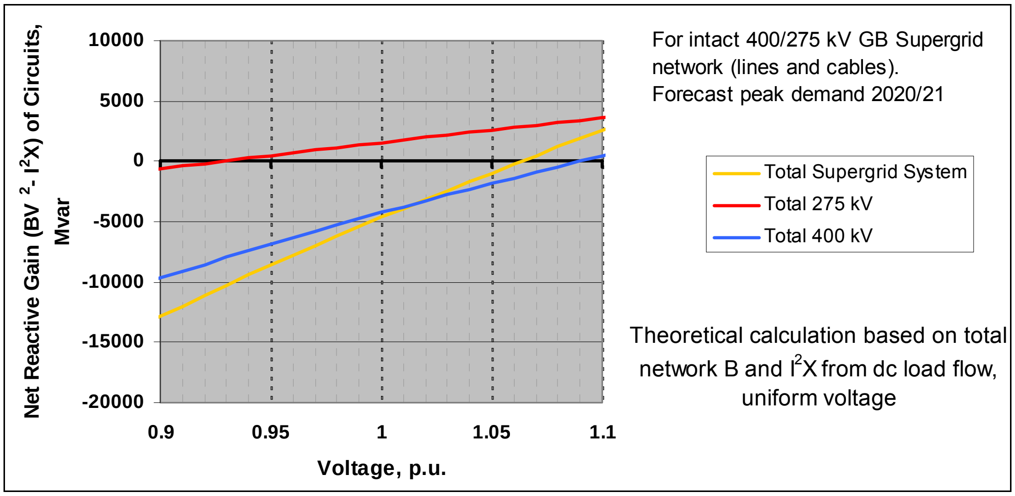


Figure A 2. Variation in supergrid reactive requirement with voltage

As with the single-line example, the 400 kV network is most sensitive to voltage change. The total system reactive requirements vary with voltage; each 1% reduction in voltage increases the net reactive requirement by about 750 Mvar, or about 5% of the total network susceptance. The 400 kV network would contribute some 500 Mvar of this change. In comparison, the reactive power produced by a shunt capacitor falls by about 2% for each 1% reduction in voltage.

Allowing the voltage of part of the system to fall beyond current limits may well require more reactive support in that area. If this cannot be obtained by var imports from other areas (see the discussion on voltage profile, below) it must be provided locally, by investment in additional reactive compensation.

A3. Stability of Power Transmission

The power that can be transmitted along a transmission line depends on the voltages at the line ends, as illustrated by the equation:

$$P = \frac{V_1 \times V_2}{X} \times \sin\delta$$

where V_1, V_2 are the voltages at each end of the line, X is the reactance and δ is the phase angle across the line.

More power can be transmitted if the voltages are as high as possible, and a limit is reached when $\delta = 90°$. This relationship between power transmission capability with voltage, and the increase in system reactive requirements as voltage falls, produces a situation where high power transfers require voltages that are well above the lower limits allowed by the current

[13] The BV^2 is the nominal shunt susceptance of all 400 kV and 275 kV circuits. The I^2X is obtained from a peak load DC load flow that assumes a uniform 1.0 p.u. voltage. The effect of voltage variation assumes I α 1/V, with a uniform voltage across the system.

SQSS. In these circumstances, reducing these lower limits would not provide any increased transmission capacity.
This is illustrated in the following examples:

A4. Case 1: Theoretical Analysis of a 400 kV Transmission Line

Figure A3 shows the voltage regulation of a 100 km 400 kV circuit employing 3x700 mm^2 bundled conductors. Such a line has a winter thermal rating of up to 3800 MVA per circuit, but substantial receiving-end reactive support is needed to sustain this level of transfer if the line has significant length. The reactive support (compensation, or receiving-end generation) must have a regulating capability (for example, SVCs with Q-V droop controls) in order to control the receiving end voltage. When the voltage falls to a level where the regulating Mvar response is exhausted, the system may be close to or beyond the "nose" of the Voltage-Power (P-V) curve and voltage collapse may ensue.

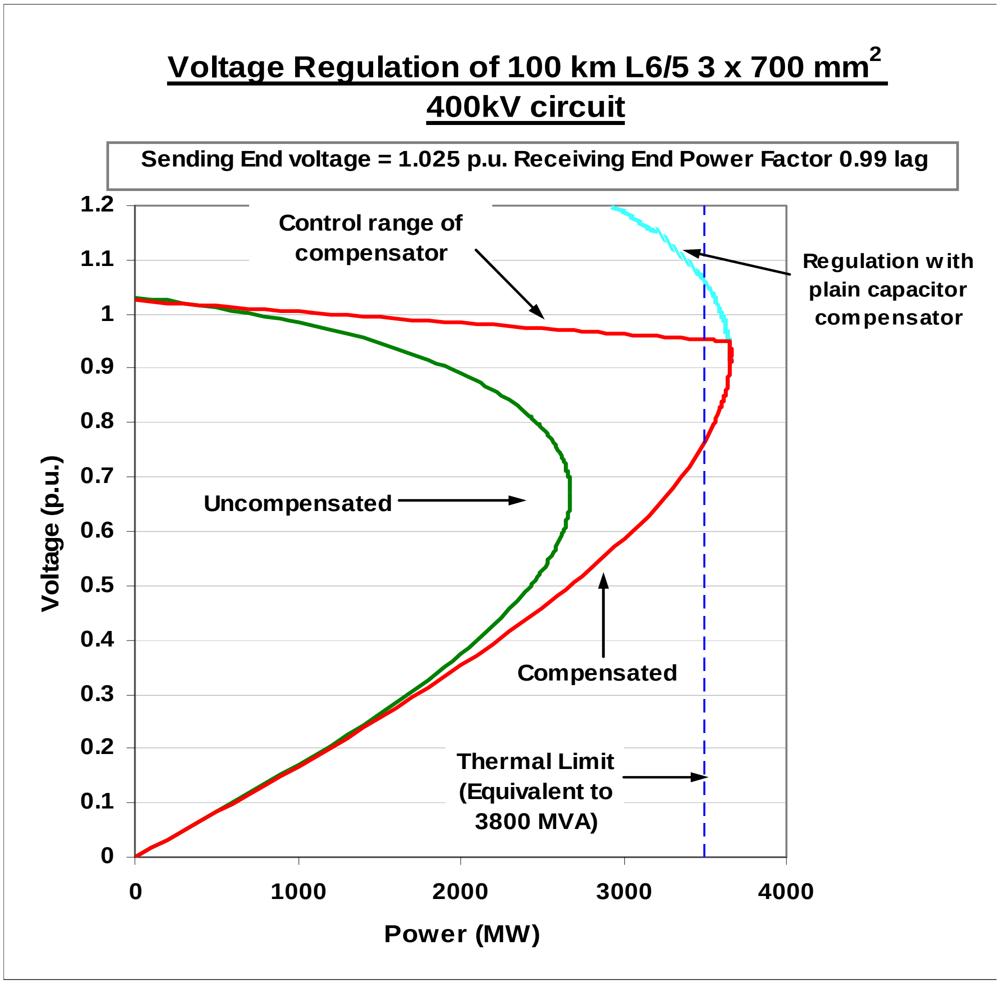


Figure A 3. Voltage Regulation of a 100 km 400 kV 3x 700mm^2 Overhead Circuit

Without compensation, the voltage regulation curve is as shown in green. As the load is increased from zero to 1900 MW, the receiving end voltage falls from 103% (0.5% higher than the sending voltage) to 90%. The voltage falls further to reach a "nose point" at 67% voltage and a maximum transfer of 2675 MW.

In order to reach the thermal rating of the circuit, reactive compensation must be added (red curve). The effect of the compensation is to raise the nose-point of the P-V curve so that it now lies above 90% voltage. The compensation is controlled to regulate voltage in the range

95% to 102.5%. When the limit of the compensation regulating range is reached, at 95% voltage, the compensation reverts to plain shunt capacitance. There is now little or no power transfer margin between the point at which the reactive regulating capacity runs out and the nose point of the regulation curve.

The example illustrates that although the power transmission capability of a line can be increased by raising the sending end voltage, a lightly loaded line has a receiving end voltage higher than the sending end. For the 100 km circuit considered, without compensation, this voltage rise is about 0.5%. Thus, when operating at high voltages at peak load pre-fault to maximise transmission capability sufficient "headroom" must be left for trips that cause voltages to increase.
It is thus clear that power transmission may not be constrained by SQSS voltage limits; rather, increasing the loading of circuits tends to raise the minimum voltage at which the system can operate.

A5. Case 2: Midlands-South (B9) Boundary Capability Study

A realistic example is shown in Figure A4. this plots a P-V curve for the Midlands to South boundary (B9 in the Seven Year Statement) following a *double circuit* fault. In this example, the critical trip for voltage stability is the loss of the *double circuit* south of Feckenham, while the critical condition for thermal capability is the loss of both Cottam-Eaton Socon circuits.

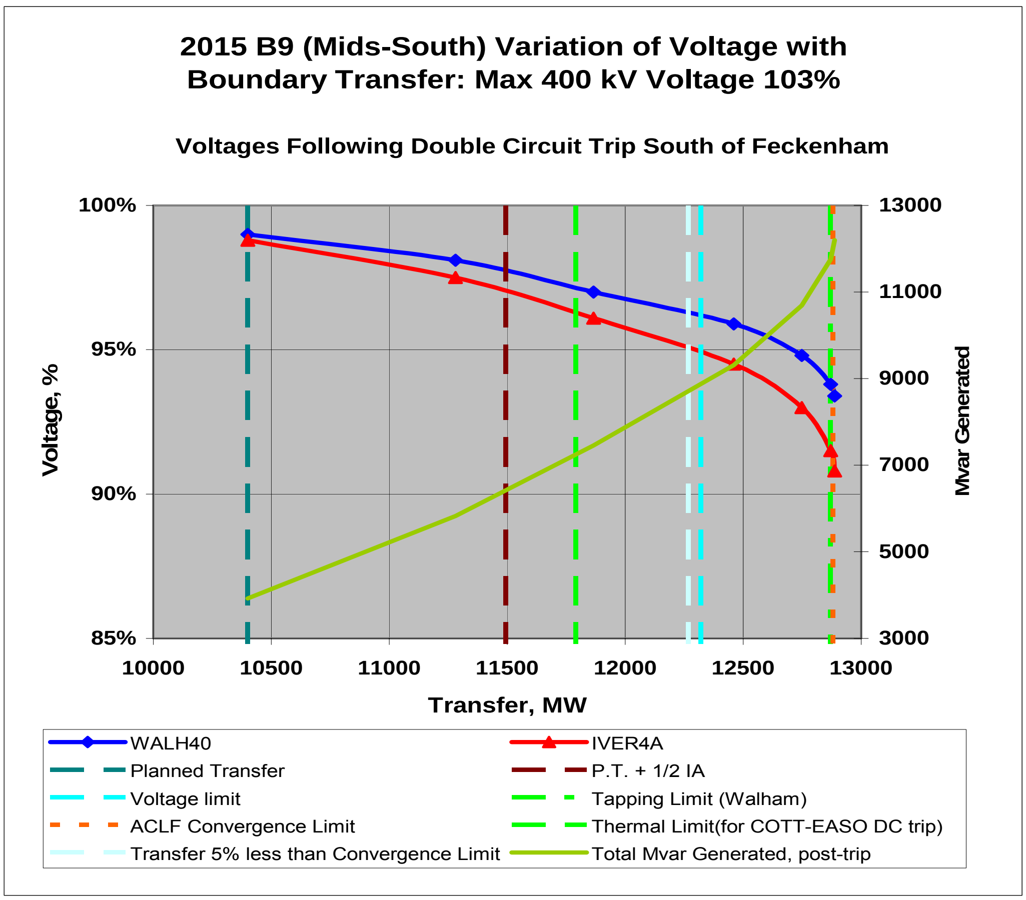


Figure A 4. Variation of Post-Fault Voltage with Transfer (P-V Curve) for SYS Boundary 9 (Midlands – South)

The weakest 400 kV node in the network following the outage is Iver. The nose of the P-V curve occurs at a voltage of about 92%. It can be observed that beyond the transfer at which 400 kV voltages fall below 95% the total system reactive generation begins to increase ever more steeply, as regulating reactive reserves in London and the south become exhausted. At the limit of stable power transmission, other constraints are also becoming apparent. Supergrid transformers at Walham reach their tap limits whilst restoring LV voltage to 100%, even though the 400 kV voltage is about 93%. Reclosing angles across the outaged circuits are approaching 45°.

It should be noted that in this example the voltage constraints are rather academic: the boundary thermal limit is reached for the Cottam – Eaton Socon double circuit trip before the voltage at any substation falls below 95%.

The thermal capability of a line can be maximised and losses minimised by operating it at the highest feasible voltage; operating, say, a 400 kV circuit with a nominal capacity of 3000 MVA at 90% voltage would reduce the capability to 2700 MVA.

Raising the upper voltage limits could thus provide more power transfer capability, but the scope for doing this is limited by the insulation. However, if the planning voltage limit (102.5% pre-fault, 105% post fault)) were relaxed upwards, it may be possible to plan to transmit more power than the current GB SQSS allows.

A different kind of performance characteristic is exhibited where two parts of the system, each having adequate internal reactive resources, are connected by a tie line. Power transfer capability is then limited by voltage stability on the tie line, and the reactive resources at points on the tie line, rather than by the resources within the importing region. Two examples have been identified and analysed

A6. Case 3: South West (B13) Boundary Capability Study

The first example is South West England, following the commissioning of the Langage power station. The combination of the long, lightly-loaded lines in the south-west and the reactive capability of the Langage generators means that voltages west of Exeter can be easily held within normal planning limits. However, following a double-circuit trip south of Hinkley Point, any power import must come along the long south coast route from Fawley and Nursling via Mannington to Exeter. Transfer capability then relies on reactive support at the substations along this route, notably Mannington. The performance of the system is illustrated in Figures A5 and A6:

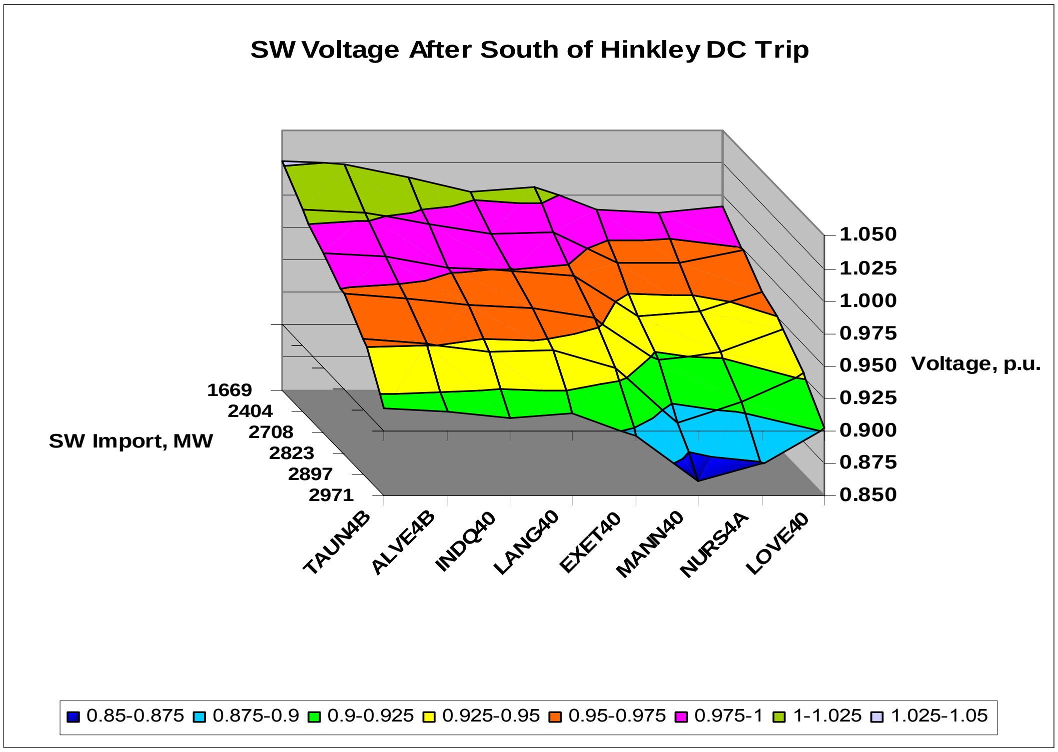


Figure A5. Variation of Post-Fault Voltage Profile with Transfer for SYS Boundary 13 (South West Import)

As the transfer increases the reactive reserve on the Mannington SVCs is used up very rapidly but the voltage at Mannington continues to decline until a limit for stable transmission is reached[14]. This occurs with a voltage of 86% at Mannington and a transfer of 2970 MW. It should be noted that this is well beyond any forecast transfer for this area with this generation background, but the study serves to illustrate the principles involved.

Further west in the peninsula the available reactive reserves mean that the voltages decline more slowly with transfer, so the effect of the transfer increase is to create an ever-deepening “hole” in the voltage profile centred on Mannington and Nursling.

Figure A6 illustrates the how the voltages at significant busbars vary with transfer, and showing the increasing rate of decline below 95% voltage

[14] This is actually the limit at which an ac load flow study just converged. It is believed to be a reasonable approximation to the actual physical limit of the system.

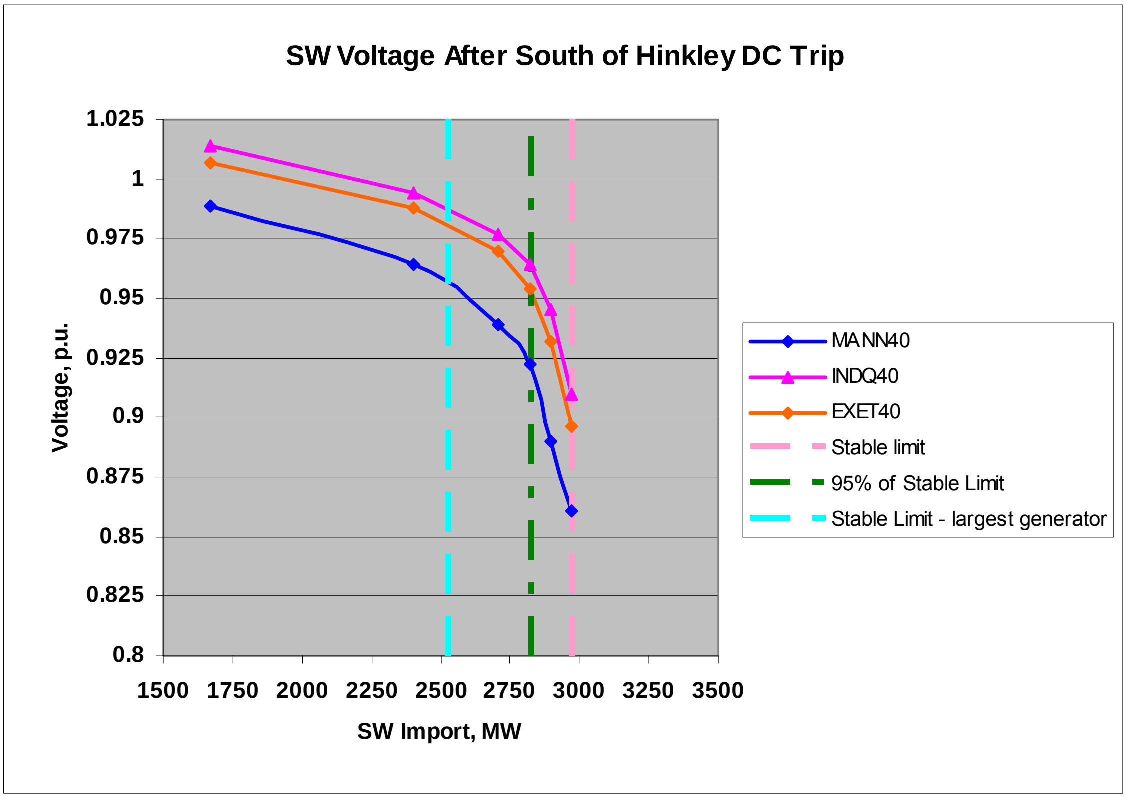


Figure A6. Variation of Post-Fault Voltages with Transfer for SYS Boundary 13 (South West Import)

Reclosing angles also increase with transfer, from 35° in the starting condition and exceeding 50° as the Mannington voltage falls below 95%.

If the Mannington voltage were allowed to fall to 90% rather than 95% post-fault, the power transferable would increase by some 250 MW. However, this would allow a margin of just 80 MW to the point of voltage instability.

It would be prudent to plan for a maximum power transfer that left some margin to the point of voltage instability. More work is needed to establish the appropriate margins to apply between demand/generation groups in GB, particularly with the advent of intermittent and variable generation ("credible demand sensitivities" as defined in the current SQSS are really only appropriate in areas where the variations in transfer are dominated by demand forecasting error). However, for the purpose of this exercise a 5% margin has been considered, in line with the WECC reliability standards in North America. On this basis the maximum transfer would be about 2800 MW – approximately 200 MW more than the transfer at which the Mannington voltage falls to 95%.

A7. Case 4: Scotland-England (B6) Boundary Capability Study, Incorporating Strategic Reinforcements

The Scotland-England boundary (B6) provides a larger-scale example of two regions connected by tie lines. Both Scotland and the majority of the English system have sufficient reactive resource to be able to regulate their voltages as transfer increases, but low voltages can occur at Harker and other substations along the Western Interconnector following a double-circuit trip south of Eccles.

For this exercise a study case for 2020 was used, incorporating 35% series compensation in the Strathaven-Harker and Harker-Hutton routes, with MSC Damping Networks switched in post-fault. Additonal capacitors (total 180 Mvar) were added at Harker 132 kV to correct the demand power factor there and prevent the Harker SGTS reaching tap-limits at high (> 95%) values of HV voltage.

The voltage profile along the Western Interconnector (Figure A7) exhibits a similar pattern to that of the South Coast in the previous example. As transfers increase, the reactive reserves of the Harker SVCs are used up and voltage dips develop at Harker, Elvanfoot and Moffat. The voltages to the north and to the south do not fall to the same extent.

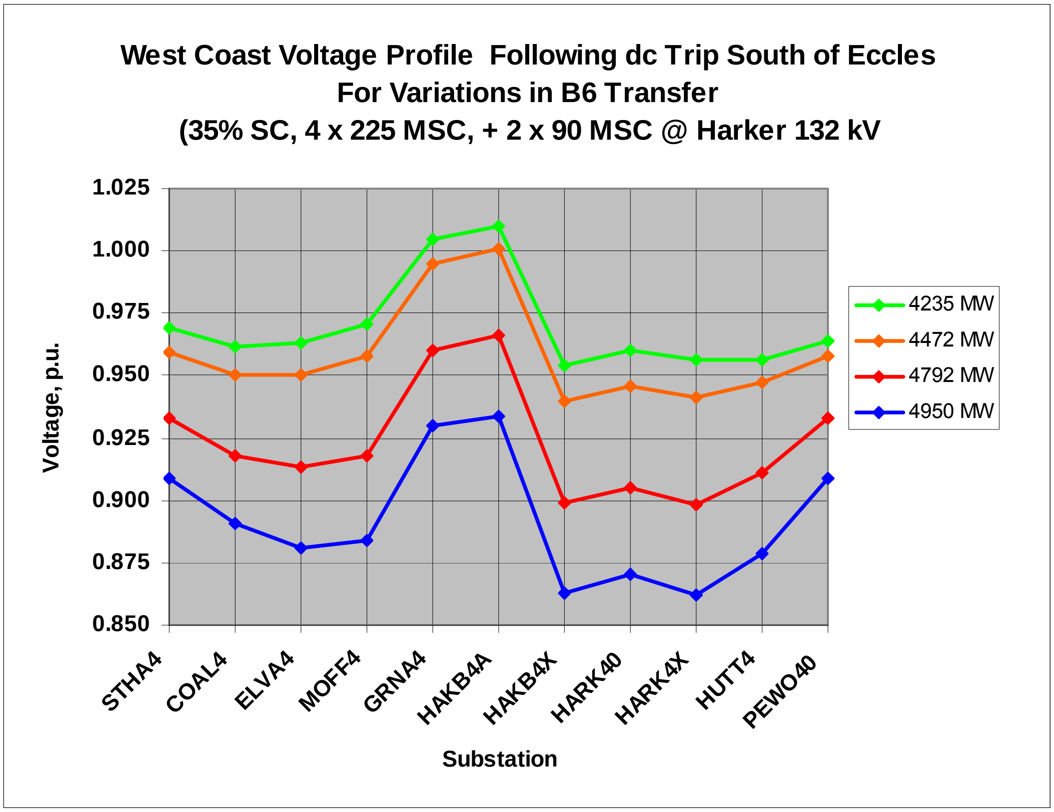


Figure A7. Variation of Post-Fault Voltage Profile with Transfer for SYS Boundary 6 (Scotland-England)

Figure A7 also shows the voltage rise across the series capacitors north of Harker (HAKB4A and HAKB4X), and the smaller rise between HARK4X and HARK40 due to the series compensation south of Harker in this study.

The fall in voltage with transfer is steady and progressive, with no sudden increase in rate of fall or identifiable “nose point”. The Harker 400 kV voltage is 95% at 4400 MW transfer, and falls to 90% at 4800 MW. (Figure A8)

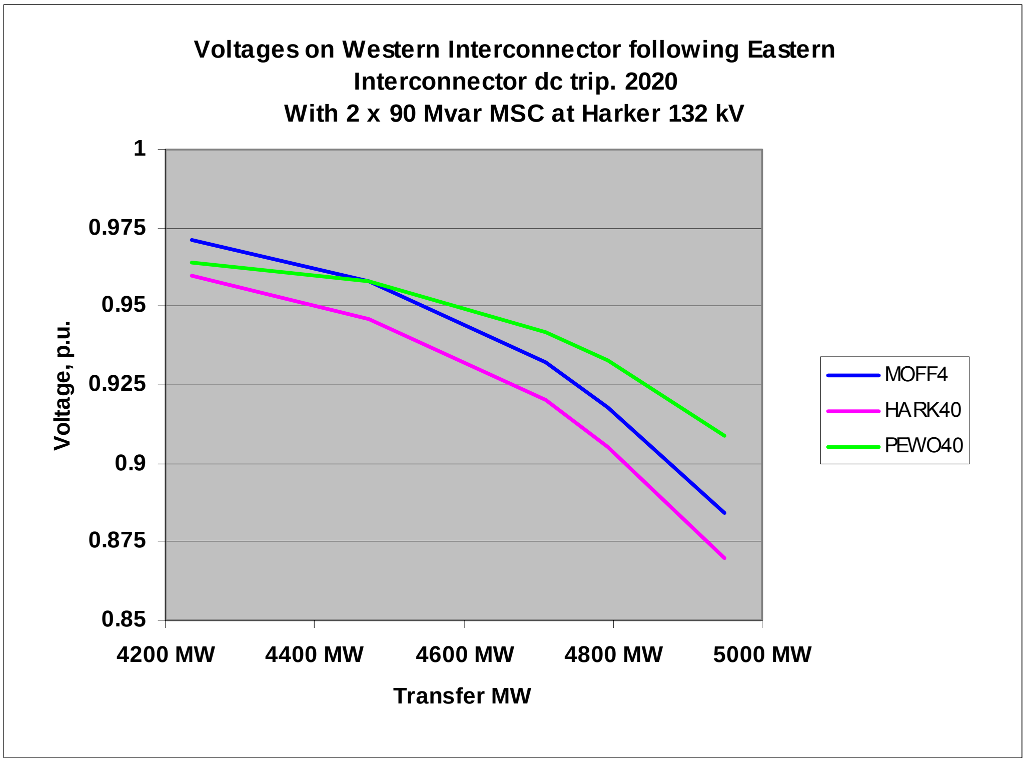


Figure A8. Variation of Post-Fault Voltages with Transfer for SYS Boundary 6 (Scotland-England)

The implication is that it might be possible to operate down to a voltage of 90% at Harker and Elvanfoot at a transfer of 4800 MW. The limit of stable transmission is found at 4950 MW (a margin of 150 MW from the transfer at the 90% voltage level).

However, in the 4800 MW transfer case supergrid transformer tap limits are reached at Hutton, Elvanfoot and Wishaw (so that GSP LV voltage targets could not be maintained), and voltage step-changes exceed 6% at several Grid supply Points.

Reclosing angles increase from just under 50° at 4400 MW transfer to over 56° at 4800 MW. The extra 400 MW of transfer requires some 2000 Mvar of additional reactive support (in addition to the 900 Mvar of switched capacitors) to sustain it. If the transfer is restricted to 95% of the limiting transfer for voltage stability, as in the previous case study, the maximum transfer would be 4700 MW, i.e. an increase of 300 MW on the original transfer. At this value of transfer the post-fault voltage at Harker would fall to about 92%.

These last two case studies demonstrate specific circumstances on some 400 kV tie-lines where stable transmission is possible at voltages of less than 90%, and suggest that it may be safe to plan to voltages between 90% and 95% post-fault, subject to meeting all other requirements for voltage step-change, Grid Supply Point LV voltage targets, and circuit-breaker reclosing angles, and subject to maintaining sufficient voltage performance margins. In the two cases studied, these criteria were not met at the 90% voltage level.
Voltage performance margins are particularly important since the risk in these circumstances is that voltage collapse on the tie line could result in separation of the two demand/generation groups, with consequent major frequency disturbances.

As an additional measure of system performance, the post-fault voltage angles of the northern system were plotted as a function of power transfer (Figures A9 and A10)

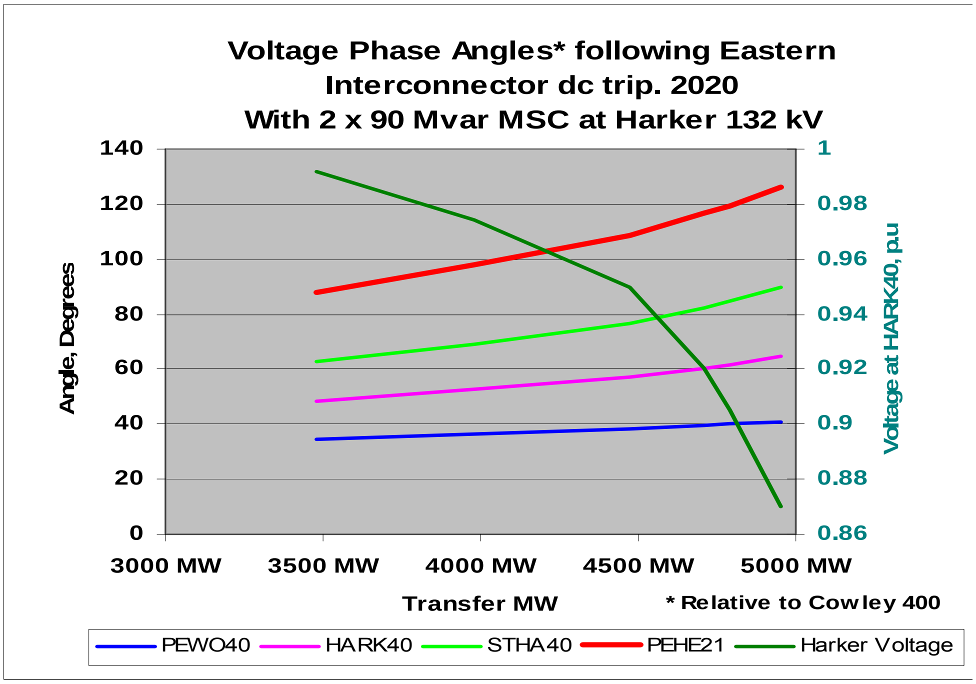


Figure A9. Post-Fault Voltage Phase Angles, Scotland and Northern England

Figure A9 shows busbar phase angles, relative to the reference node at Cowley, together with the post-fault voltage at Harker 400 kV. Of specific interest is the angle difference across the Western Interconnector circuits, and this is illustrated in Figure A10:

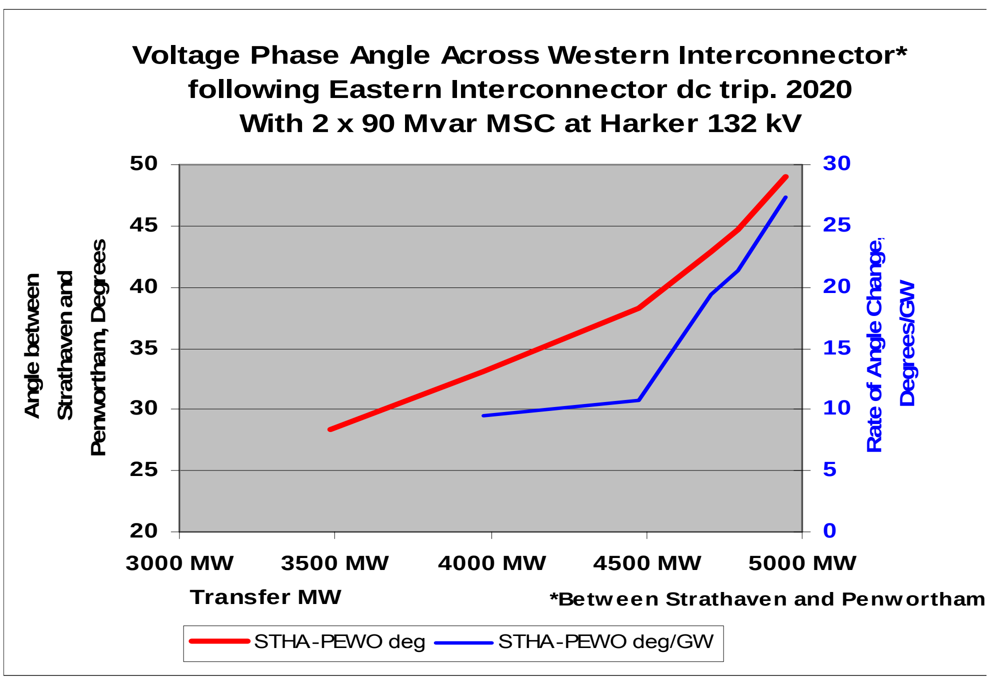


Figure A10. Post-Fault Phase Angle Difference, Strathaven – Penwortham, and Rate of Change of Angle Difference with Transfer

Figure A10 also shows the rate of change of the phase angle difference (in degrees per Gigawatt) at different levels of transfer. As the transfer increases and the voltage along the lines sinks, the phase angle difference across the lines increases, but the rate of change of this angle difference also increases. This indicates that the stability of the system is becoming more sensitive to transfer changes at higher transfers and lower tie-line voltages.

Relaxation of the 95% lower voltage limit is currently allowed in the planning criteria for 400 kV substations left radially-connected following an outage. Were a voltage collapse to occur at such a site or sites, the likely result would be a localised brown-out with some loss of load due to under-voltage tripping of motors. The main interconnected system may not be severely affected. For substations on tie lines however, the consequence of voltage collapse could be break-up of the system with frequency disturbances and possible under-frequency load shedding in importing areas (e.g. England and Wales would have a deficit of ~ 4.5 GW, in this particular case-study). Even though stable power transmission appears possible at voltages of 90% and below in some instances, planning to a 90% limit would involve reduced operating margins and greater risks than planning to a 95% limit.

A8. Voltage Profile and Reactive Reserves

The reactive requirements of an area of the system may be met by reactive sources within the area, such as generators or reactive compensation, or by reactive transfers from elsewhere. Reactive transfers create voltage differences between parts of the system and these voltage differences are known as the voltage profile.

The overall reactive requirement of an area consists of the requirement pre-fault plus the reserve needed to meet increased requirements after a secured event such as a circuit trip. When the capability of the reactive sources in an area exceeds the area's overall reactive requirement, the surplus can be exported to deficit areas by despatching the voltage in the exporting area to a higher level than that in the deficit area. The extent to which this can be done is restricted by the pre-fault voltage limits and the voltage stability of the system, and in practice it is found that reactive compensation must often be installed in deficit areas even though there is spare reactive capacity elsewhere.

Raising the pre-fault planning upper voltage limit from the present level of 102.5% at 400 kV and 105% at 275 kV may allow greater use of existing reactive reserves and potentially reduce investment in reactive compensation. However, Connection Condition CC6.3.4 of the Grid Code requires the full reactive range of generators to be available in an HV voltage range between 95% and 105% of nominal, and accepts reactive restrictions outside this range. Therefore increasing the planning voltage limit at 275 kV above 105% may provide no benefit. Any benefit obtainable by raising the planning limit at 400 kV above 102.5% is likely to be limited by the tapping ranges available on generating transformers.

A9. Conclusion

It is concluded that the physical constraints of insulation rating, stable power transmission and the characteristics of existing Grid Supply Transformers and Users' plant restrict the scope for relaxing the present HV voltage limits. In many cases the physical limits will be found to lie well within the statutory limits, particularly at 400 kV.

Appendix B

Voltage Targets and Limits at Interfaces to Distribution Networks

B1. Introduction

B1.1. The voltage standards in the SQSS specify voltage targets and upper and lower voltage limits at interfaces to distribution networks. *(Refer to tables 6.1, 6.3, 6.5 in current SQSS; tables 6.1 - 6.4 in proposed draft)*

B1.2. The definition of these targets and limits in the current SQSS[15] is rather vague. In the criteria for planning they are referenced in footnotes to the tables of transmission system steady-state voltage limits and step-change limits. In particular, the steady state criteria refer to LV targets of to "up to 105%", and "up to 100%". This vague wording has been queried as a design standard since it does not define what is actually acceptable.

B1.3. Working Group 4 have therefore considered the option of replacing this wording with definite targets to be achieved pre- and post- fault. If there is an option of relaxing the requirement under any conditions, these conditions should be defined along with back-stop voltage limits.

B1.4. The effects of fixing LV voltage targets were investigated by examining the performance of different types of substation design for different types of contingency.

B1.5. The metric used for quantifying the substation performance is the reactive demand that can be supplied at any given active power demand, up to the thermal cyclic ratings of the transformers left in service.

B1.6. This "reactive demand suppliable" is significant in determining the need for LV reactive compensation or substation reinforcement and for apportioning reactive compensation and reinforcement requirements between the substation (Connection) and the main interconnected system (Infrastructure).

B1.7. The LV voltage targets used are the same as those carried forward from earlier standards into the current SQSS. That is, in planning timescales, an LV voltage of 105% should be achievable pre-fault and 100% following a *secured event*. The current SQSS allows for relaxation from the 100% target following a loss of a supergrid transformer.

B1.8. The Working Group are making no proposal to change the absolute values of these targets, as they are assumed to have formed the basis of DNO network design for many years. However, the option of relaxing a target at a particular site, in consultation with the DNO, is not ruled out if it is cost effective to do so in that specific instance.

B1.9. The following analysis set out to establish:

[15] National Electricity Transmission System Security and Quality of Supply Standard Version 2.0 of 24/06/2009

B1.9.1 the effects of enforcing LV target voltages of 105% and 100% pre-and post-fault in planning timescales, and

B1.9.2 the desirability of relaxing the LV target voltage in planning timescales following a contingency involving loss of a transformer.

B1.10. For a given Grid Supply Point, the most critical *secured event* in terms of local voltage conditions is likely to be the tripping of a Grid supply Transformer.

B1.11. Accordingly, some sample calculations have been carried out for generic 400/132kV, 275/132kV and 275/33kV substation designs with two transformers at each. For each example, we calculated the maximum lagging reactive power that could be supplied to the LV busbar, for a range of active power transfers, whilst respecting the voltage limits and targets in either the planning or operational timescale.

B1.12. No attempt has been made as yet to assess the materiality of these criteria in terms of the numbers of substations having particular configurations, their demands and power factors and any consequent difficulties in meeting the standards.

B2. 400/132kV Substation:

Planning Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	8.333
Maximum Tap Ratio:	1.15	Minimum Tap Ratio:	0.95
Minimum HV Voltage, Pre-fault:	0.975	Minimum HV Voltage, Post-fault:	0.95
LV Target voltage, Pre-Fault:	1.05	LV Target Voltage, Post-Fault:	1.0[+]

[+] May be relaxed following loss of a transformer: see text.

Operating Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	8.333
Maximum Tap Ratio	1.15	Minimum Tap Ratio	0.95
Minimum HV Voltage, Pre-fault	0.95	Minimum HV Voltage, Post-fault	0.90
LV Target voltage, Pre-Fault	1.00*	Minimum LV Voltage, Post-Fault	0.90

* 1.0 assumed for this exercise: would actually be agreed with DNO.

B2.1. The first case considered is that of a transformer trip (e.g. due to loss of a mesh corner), with pre-fault HV voltage held at 97.5%, falling to 95% following the outage. The proposed GB SQSS allows the LV voltage target of 100% to be relaxed following a transformer trip, provided operational standards are met. Figure B 1 shows the reactive power that can be supplied in these circumstances, for different active power levels and LV voltages of 90%, 95%, and 100%:

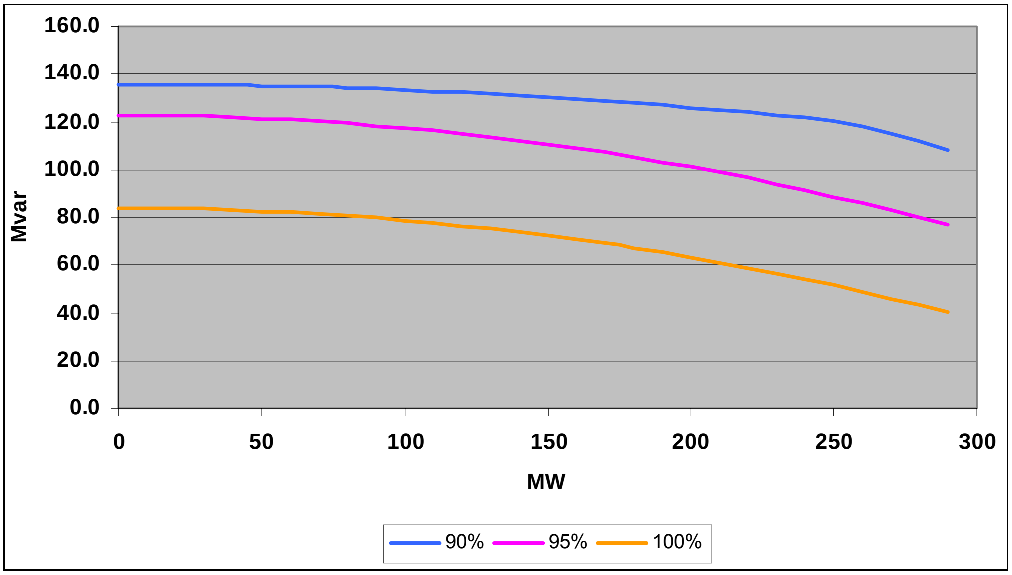


Figure B 1. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 97.5% pre-fault, 95% post-fault, LV 105% pre-fault; varying LV post-fault target voltages. (Relaxed planning criteria post-trip) 1 SGT out.

B2.2. With the post-fault LV target voltage relaxed to 90%, the reactive power is limited by the need to achieve 105% voltage pre-fault. At the higher post-fault target voltages, the limit on reactive transfer is set by the post-fault conditions.

B2.3. If the pre-fault target voltage were relaxed to 100%, the constraint on reactive transfer would depend only on post-fault conditions (Figure B 2)

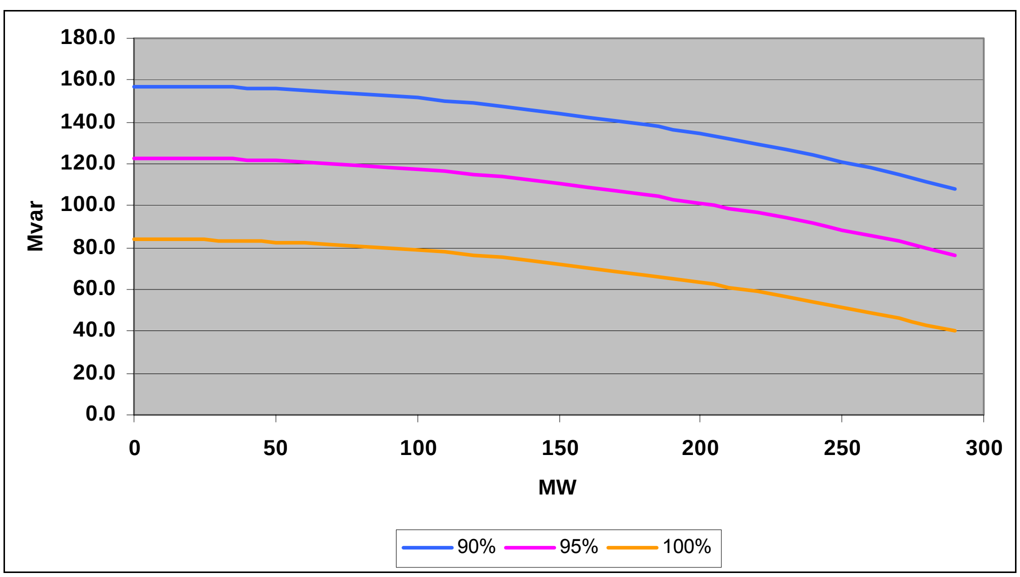


Figure B 2. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 97.5% pre-fault, 95% post-fault, LV 100% pre-fault; varying LV post-fault target voltages. (Relaxed planning criteria pre- and post-trip)

B2.4. If a 400kV substation is left on a radial spur following a *secured event*, the current and the proposed standards allow the HV voltage to fall to 90%. If there is no loss of an SGT, the LV target voltage would not be relaxed from 100%. In these circumstances the reactive demand suppliable by a 2-transformer substation varies as shown in Figure B 3.

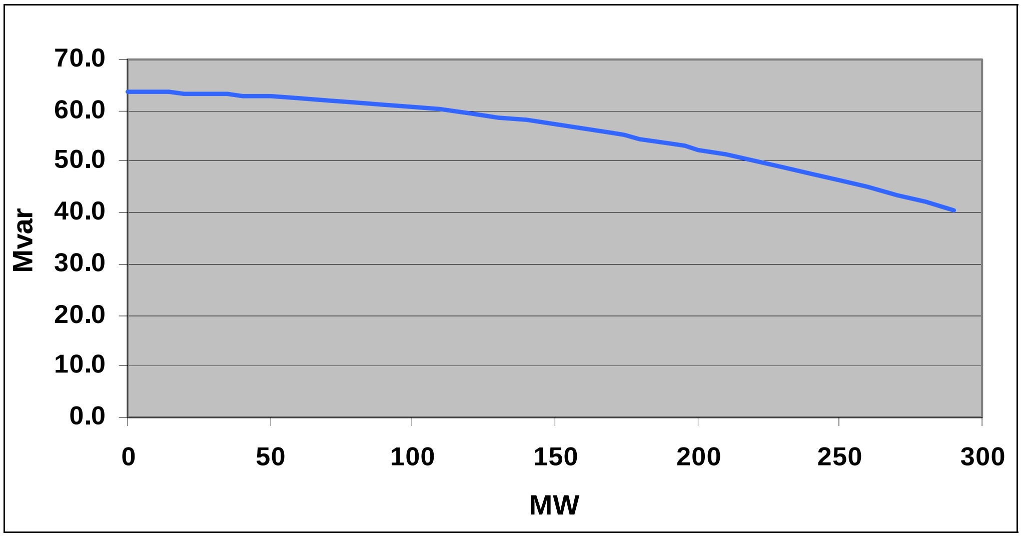


Figure B 3. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 97.5% pre-fault, 90% post-fault, LV 105% pre-fault, 100% after secured event. No SGT trip.

B2.5. If the *secured event* includes a transformer outage, the SQSS allows the LV target voltage in planning timescales to be relaxed, within the operational limits. Lowering the target voltage from 100% allows more reactive demand to be supplied than in the previous case, despite the transformer outage (Figure B 4). The pre-fault target voltage of 105% is not relevant here; the reactive limit is determined by the post-fault condition in all cases.

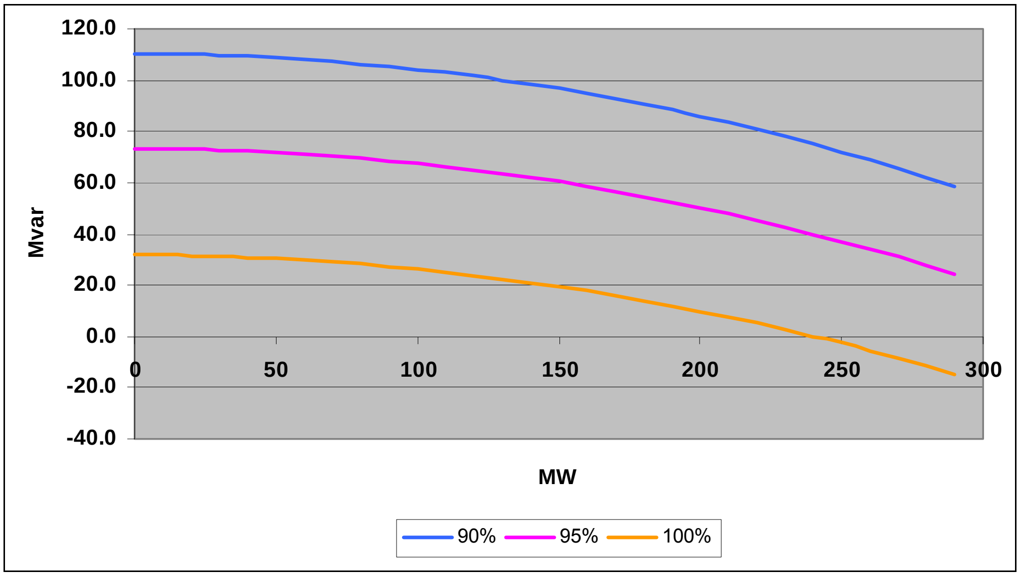


Figure B 4. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 97.5% pre-fault, 90% post-fault, LV 105% pre-fault; varying LV post-fault target voltages. (Relaxed planning criteria post-trip) 1 SGT out.

B2.6. Comparing Figure B 3 and Figure B 4, it can be seen that for the case of a 400kV substation left radially-connected post-event, a fault that does not involve a transformer outage is more restrictive than one that does, under the current and proposed planning standards.

B2.7. A substation with four transformers would be similarly limited following a fault without a transformer outage (Figure B 5):

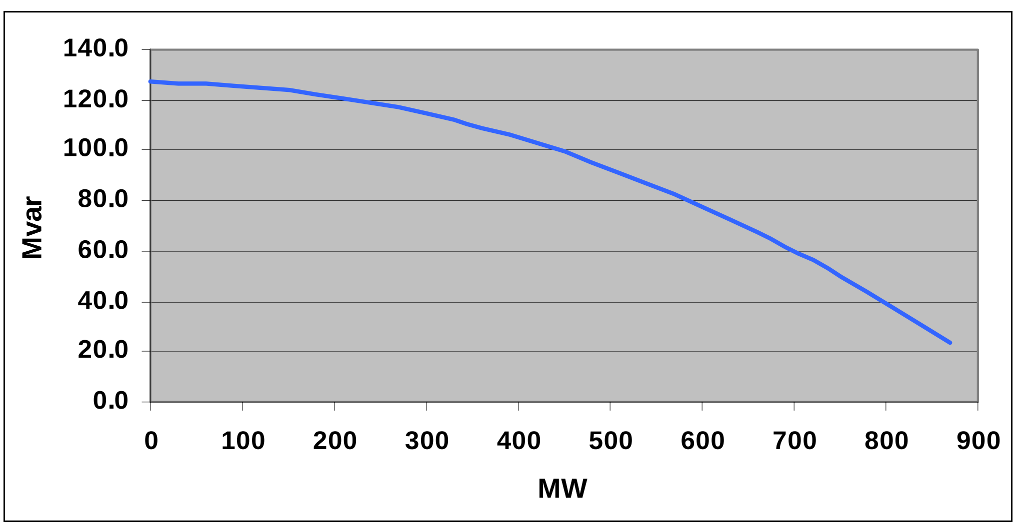


Figure B 5. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS/ HV 97.5% pre-fault, 90% post-fault, LV 105% pre-fault, 100% after secured event. No SGT trip.

B2.8. In operational timescales, the pre-fault and post-fault voltage LV targets are relaxed, the HV voltage limit pre-fault is now 95% but the post-fault HV limit is 90%, as it is in the planning standard. The reactive demand is limited by the post-fault conditions, which are the same as they are in planning timescales with the LV target voltage relaxed to 90%. (Compare Figure B 6, below, with the curve for LV voltage = 90% in Figure B 4).

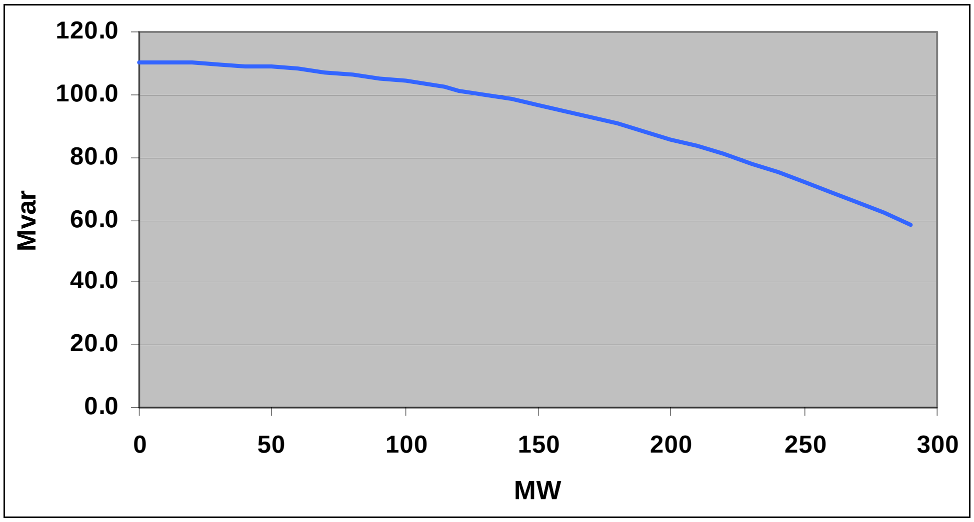


Figure B 6. Limits of lagging reactive load on 400/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 95% pre-fault, 90% post-fault, LV 100% pre-fault, 90% after SGT trip (Operational standard)

B2.9. From the above charts, it appears that:

B2.9.1 The pre-fault LV voltage target for planning (105%) can constrain the reactive demand in the case where the substation is not left on a radial spur by the fault (hence minimum HV voltage is 95%) and the fault trips a transformer so that the LV target voltage post-fault is relaxed to 90%. In all other cases, the demand is constrained by post-fault conditions.

B2.9.2 The most onerous conditions occur when a substation is left on a radial spur following a contingency. The minimum HV voltage in both planning and operational timescales is 90%; following a transformer trip, the LV target voltage in planning timescales can relax to the 90% minimum allowed operationally. The maximum reactive demand that can be supplied is the same in both cases.

B2.9.3 However, for a contingency in planning timescales that does not involve a transformer outage, the LV target voltage is not relaxed, so the reactive demand is constrained to about 60% of that which can be supplied following a transformer trip (Figure B 3. Figure B 4 and Figure B 6).

B2.10. Hence, for a 400/132kV substation:

B2.10.1 in planning timescales, for a contingency that leaves the substation on a radial 400kV spur, the maximum reactive transfer is constrained by the case of a *secured event* that does not involve the loss of a transformer (Figure B 3);

B2.10.2 in planning timescales, for a contingency that leaves the substation within the 400kV interconnected network, the maximum reactive transfer is the same whether a transformer is tripped or not; it is constrained by the pre-fault LV target voltage of 105%.

B2.10.3 in operational timescales, it is constrained by a *secured event* that does involve the loss of a transformer (Figure B 6)

B2.10.4 The maximum reactive transfer possible under the planning criteria is about 60% of that possible under the operational criteria (assuming targets relaxed to the maximum extent possible under the operational criteria).

B2.11. The interactions between pre- and post –fault HV voltage limits, pre- and post-fault LV voltage targets, number of transformers at the site, and the real power transfer are quite complex. In certain circumstances the maximum reactive power transfer is constrained by the pre-fault target voltage, in others it is constrained by the post-fault target. The cases studied here are examples to provide some insight into the different consequences of applying the planning or operational voltage criteria.

B2.12. The planning criteria allow the LV voltage target to be relaxed from 100% for events involving loss of a transformer. The effect of this relaxation is very significant, particularly for contingencies where the HV voltage is allowed to fall to 90% post-contingency. Without the relaxation (i.e. with the LV target voltage held at 100%), the maximum reactive transfer falls to zero as the active power increases towards the transformer rating (Figure B 4)

B3. 275/132kV Substation

Planning Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	8.333
Maximum Tap Ratio	1.15	Minimum Tap Ratio	0.95
Minimum HV Voltage, Pre-fault	0.95	Minimum HV Voltage, Post-fault	0.90
LV Target voltage, Pre-Fault	1.05	LV Target Voltage, Post-Fault	1.0*

* May be relaxed following loss of a transformer: see text.

Operating Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	8.333
Maximum Tap Ratio	1.15	Minimum Tap Ratio	0.95
Minimum HV Voltage, Pre-fault	0.95	Minimum HV Voltage, Post-fault	0.90
LV Target voltage, Pre-Fault	1.00*	Minimum LV Voltage, Post-Fault	0.90

* 1.0 assumed for this exercise: would actually be agreed with DNO.

B3.1. The requirements for a 275/132kV substation are similar to those for a 400/132kV site that is left on a radial spur post-contingency, so similar constraints will apply. Reactive demand constraints are illustrated in Figure B 7, for a contingency involving a transformer trip.

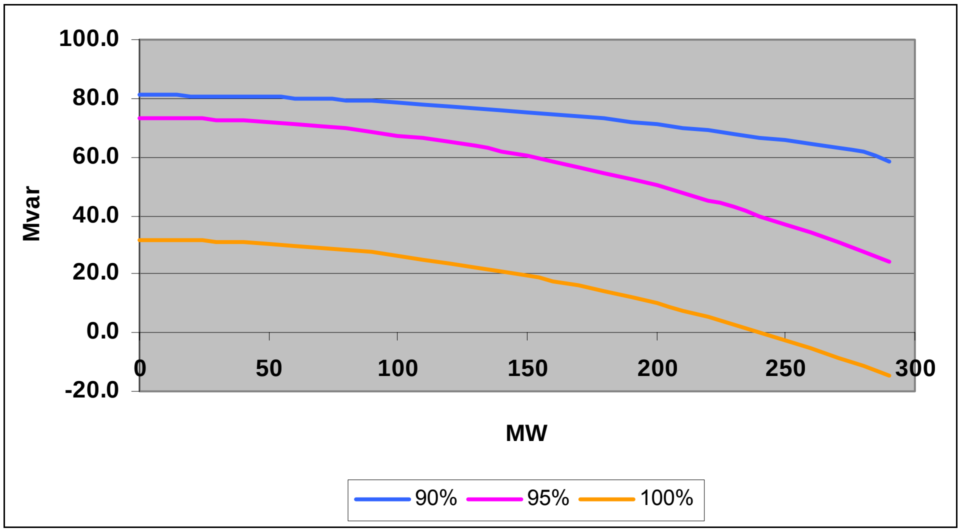


Figure B 7. Limits of lagging reactive load on 275/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 95% pre-fault, 90% post-fault, LV 105% pre-fault; varying LV post-fault target voltages. (Relaxed planning criteria post-trip) 1 SGT out.

B3.2. When the LV target voltage is relaxed to 90% following a transformer trip, the capability in planning timescales is constrained by the need to achieve 105% LV voltage pre-fault, with an HV voltage as low as 95%. If the pre-fault target voltage is lowered to 100%, as it might be operationally, the maximum reactive transfer increases to match that in Figure B 6.

B3.3. As in the case of the 400/132kV substation, the reactive demand is substantially constrained in planning timescales by the need to achieve 100% voltage at LV following a contingency that does not include the loss of a transformer. (Figure B 8)

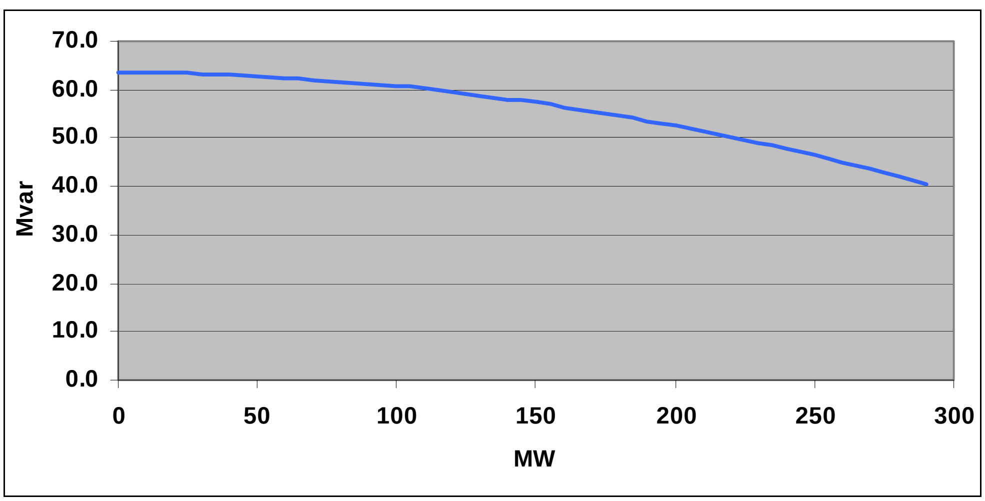


Figure B 8. Limits of lagging reactive load on 275/132kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 95% pre-fault, 90% post-fault, LV 100% pre-fault No SGT outage (Planning criteria).

B3.4. For a 275/132kV site, the reactive constraints due to the pre-fault and post-fault voltage targets in planning are very similar, so relaxing one of these targets on its own would not substantially increase the reactive suppliable. This contrasts with the 400/132kV example, where the higher HV pre-fault voltage limit means that the reactive transfer is limited by the post-fault conditions.

B3.5. Operationally, a lower pre-fault LV target voltage and lower post-fault voltage limit will allow more reactive to be supplied. At a post fault voltage of 90%, the reactive demand supplied could be up to three times higher than it is under the planning criteria.

B3.6. For an event in operational timescales that does involve a transformer trip, the performance will be as per Figure B 6 (the conditions are the same as for the 400/132kV example).

B3.7. Hence, for a 275/132kV substation:

B3.7.1 in planning timescales, the maximum reactive transfer is constrained by the case of a *secured event* that does not involve the loss of a transformer (Figure B 8);

B3.7.2 in operational timescales, it is constrained by a *secured event* that does involve the loss of a transformer (Figure B 6)

B3.7.3 The maximum reactive transfer possible under the planning criteria is about 60% of that possible under the operational criteria (assuming targets relaxed to the maximum extent possible under the operational criteria).

B4. 275/33 kV Substation

Planning Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	27.0
Maximum Tap Ratio	1.10	Minimum Tap Ratio§	0.80
Minimum HV Voltage, Pre-fault	0.95	Minimum HV Voltage, Post-fault	0.90
LV Target voltage, Pre-Fault	1.05	LV Target Voltage, Post-Fault	1.0*

* May be relaxed following loss of a transformer: see text.

Operating Criteria:			
No. of Transformers:	2	Transformer Reactance (% on 100 MVA):	27.0
Maximum Tap Ratio	1.10	Minimum Tap Ratio§	0.80
Minimum HV Voltage, Pre-fault	0.95	Minimum HV Voltage, Post-fault	0.90
LV Target voltage, Pre-Fault	1.00*	Minimum LV Voltage, Post-Fault	0.94

* 1.0 assumed for this exercise: would actually be agreed with DNO.

§ Line end taps: Minimum ratio determines maximum LV voltage boost

B4.1. The 275/33 kV substation differs from the 275/132kV example in that:

B4.1.1 the transformer impedances, in % on 100MVA base, are generally higher;

B4.1.2 the transformers have more boost tap range;

B4.1.3 the operational LV voltage range is ±6% rather than ±10% (statutory limits)

B4.2. For a fault involving a transformer loss, the planning and operational criteria are essentially the same, since the LV target voltage can be relaxed from 100% in planning timescales towards the operational limits.

B4.3. Consequently, the limits on reactive power that can be supplied following a transformer loss are as per Figure B 9. Limits are imposed by post-fault conditions and the pre-fault voltage target of 105% is not a constraint.

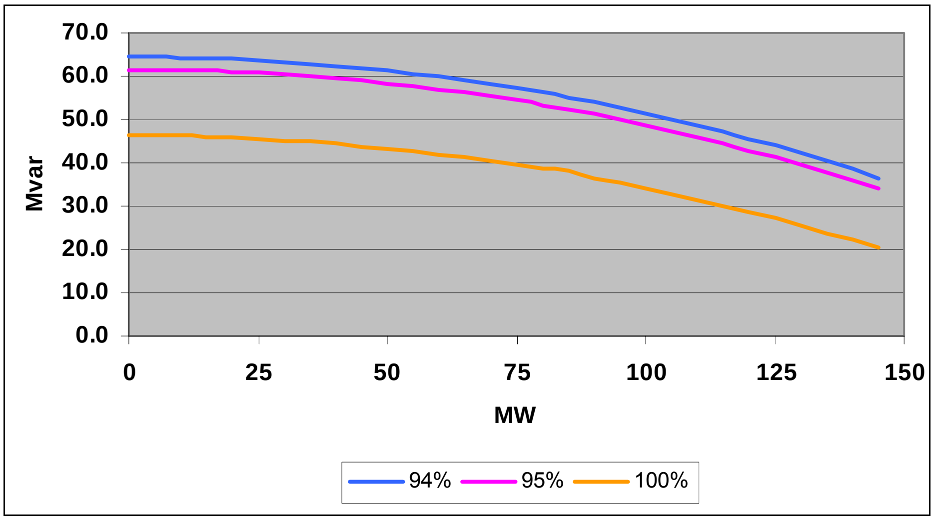


Figure B 9. Limits of lagging reactive load on 275/33kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 95% pre-fault, 90% post-fault, LV 105% pre-fault; varying LV post-fault target voltages. (Relaxed planning criteria post-trip) 1 SGT out.

B4.4. The case of a *secured event* without a transformer trip in planning timescales is comparatively less onerous than it is for a 275/132kV substation. The limit on reactive transfer is set by outages involving transformers. The reason for the difference is that the 275/132kV transformers, despite their higher impedances, have more boost tap range than typical 275/132kV examples, and the LV voltage following a transformer trip must only fall to 94% at 33 kV, compared with the 90% allowed at 132kV. (Figure B 10)

B4.5. Following an event without a transformer trip, the reactive suppliable under operational criteria is greater than that under planning criteria; however, this is irrelevant since the maximum reactive transfer at the site is limited by the planning and operating criteria following a transformer trip.

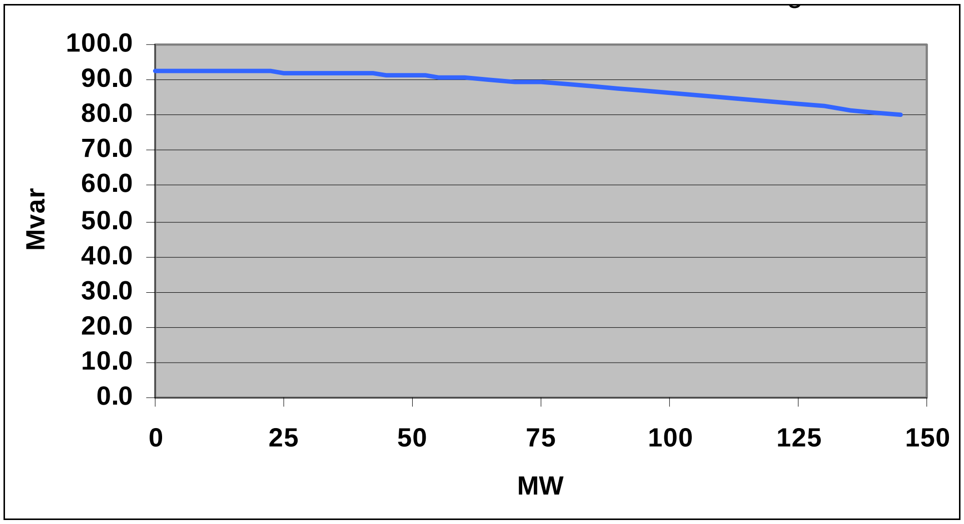


Figure B 10. Limits of lagging reactive load on 275/33kV 2-SGT GSP to meet voltage requirements of the GB SQSS. HV 95% pre-fault, 90% post-fault, LV 105% pre-fault 100% post-fault (Planning criteria)m No SGT outage.

B4.6. Hence, for a 275/33 kV substation:

B4.6.1 in both planning and operational timescales, the maximum reactive transfer is constrained by the case of a *secured event* that involves the loss of a transformer (Figure B 9);

B4.6.2 The limit is set by post-fault voltage limits, and the pre-fault LV target voltage is not a constraint.

B5. Assessment of Results

B5.1. The interactions between pre- and post –fault HV voltage limits, pre- and post-fault LV voltage targets, number of transformers at the site, and the real power transfer are complex. The following conclusions are drawn from some sample calculations.

B5.2. In certain circumstances the maximum reactive power transfer is constrained by the pre-fault target voltage, in others it is constrained by the post-fault target.

B5.3. The planning criteria of the current SQSS[2] and of the proposed revision allow relaxation of the GSP LV target voltage from 100% down to the operational limit for contingencies involving the loss of a Grid Supply Transformer. It is demonstrated above that this relaxation relieves a severe restriction on the reactive demand that could be supplied following a transformer trip, and it is concluded that it is sensible to retain this relaxation within the SQSS. There is logic in assuming that the DNO will design the distribution network to withstand a distribution contingency with 100% (or some other agreed target) voltage at the GSP. A simultaneous outage of a Grid Supply Transformer and a distribution circuit would be regarded as non-credible.

B5.4. In planning timescales, the maximum reactive demand can be constrained by contingencies that do not involve outages of supergrid transformers. This is because the planning standard specifies LV target voltages of 105% pre-fault and 100% post-fault. In the case of 275/132kV substations, and 400/132kV substations that are left on radial spurs post-fault, the standard also allows the HV voltage to fall to 90% post-fault. The combination of low HV voltage and 105% or 100% LV voltage allows very little voltage drop across the transformer reactance, so this condition imposes the limit on reactive transfer in planning timescales.

B5.5. At 275/132kV sites, and at 400/132kV sites left on radial spurs post-fault, the maximum reactive demand that can be supplied under planning criteria is about 60% of that which could be supplied under operational criteria, assuming the LV busbar voltage could fall to the operational limit of 90% post-fault. This difference is caused by the need to meet voltage targets in planning timescales for faults that do not involve the loss of a transformer.

B5.6. One option would be to relax the LV target voltages in the planning criteria for non-transformer faults. However, this would mean that the achievable LV voltage at the substation would vary according to an indeterminate number of possible transmission contingencies, so the DNO would not have a firm supply point voltage on which to base the design of the distribution network.

B5.7. Another alternative to enforcing the LV target voltages as investment drivers would be to apply them initially in design studies and then conduct a cost benefit analysis, in consultation with the DNO, if their enforcement would lead to significant costs. Otherwise, the constraints could be retained as providing a worthwhile margin for operators.

B5.8. In planning timescales for 275/33 kV sites and for 400/132kV substations that remain interconnected post-contingency (i.e. not left on radial spurs), the maximum reactive demand is constrained by contingencies involving the loss of a transformer.

B5.9. For 275/33 kV sites, the reactive transfer limit is imposed by contingencies involving transformer trips, and is the same under the planning and operational criteria.

B5.10. In operational timescales, the limit on reactive transfer is always set by contingencies involving the loss of a transformer.

B5.11. A substation designed to the planning criteria can be operated in accordance with the operating criteria, for the same active and reactive power demand.

B6. Conclusions

B6.1. From the above, it is judged that the GSP LV voltage targets and limits in the SQSS are appropriate, and that there is reasonable consistency between the planning and operational criteria.

B6.2. The greatest constraints occur at 275/132kV substations, or 400/132kV substations that are left radially-connected following a contingency. This is because the SQSS permits the HV system voltage to fall as low as 90% in these cases.

B6.3. At such sites, the proposed planning criteria require an LV target voltage of 105% to be achievable pre-fault, and 100% post-fault. The post-fault requirement is relaxed if the contingency involves the loss of a Grid Supply Transformer, but not otherwise.

B6.4. The logic of this is assumed to be that the DNO will normally expect to design the distribution network to secure customers' supplies against distribution contingencies, assuming a firm target voltage at the Grid Supply Point. However, coincident outages of DNO circuits and a Grid Supply transformer would be regarded as non-credible, so the GSP voltage target is relaxed following a transformer fault.

B6.5. Relaxation of the LV target voltage in planning timescales for contingencies involving loss of transformer(s) is considered to be justifiable. Without this relaxation, there would be a very limited ability to supply reactive power if the HV system voltage falls towards its lower limits. Reactive compensation or other reinforcement would be needed to meet the planning standard, that would not be needed in operational timescales when the LV voltage is allowed to vary within the operational and statutory limits.

B6.6. The most significant effect of the difference between planning and operating criteria is the constraint on reactive demand imposed by the LV target voltages in planning, for faults that do not involve transformer trips. For some sites, these would restrict the reactive demand to about 60% of that which could be supplied operationally, assuming the LV voltage was then allowed to fall to the minimum operational limit.

B6.7. This constraint (amounting to a few tens of Mvar per site, at most) could be regarded as providing some margin for operational uncertainties. Alternatively, critical cases could be subjected to cost benefit analysis at the design stage to justify any reinforcement required to meet those specific design criteria.

No attempt has been made as yet to assess the materiality of these criteria in terms of the numbers of substations having particular configurations, their demands and power factors and any consequent difficulties in meeting the standards.

Appendix C

Voltage Step-Change Criteria

C1 Scope of Review

Working Group 4 noted that the existing SQSS tables of permissible step-change limits included significant regional differences and inconsistencies between the requirements in planning and operational timescales. These differences apply to the circumstances in which the "normal" voltage fall limit following a *secured event* is relaxed to a 12% limit, and to the step-change limits associated with operational switching. It was decided to review the factors determining the step change criteria with a view to removing the inconsistencies and regional differences.

The Group did not consider the validity of the absolute values of the step changes; for example, whether a 5% or 7% limit would be more appropriate than the current assumed value of 6%. This would be a long, and probably fruitless, exercise. The existing limits have been in use for many years and so are assumed to be satisfactory in terms of customer expectations.

Voltage step changes are calculated in predictive studies to ensure adequate quality of supply to end-customers. It is noted that predicted step-changes are used by design and operational engineers as a quick indicator of system health following secured events. It is often found that when step-changes approach or exceed the current limits that the system is at risk of failing to meet other security requirements, such as the ability to meet DNO voltage targets, or is approaching the limits of voltage stability.

The review has concentrated on defining those contingencies for which the normal 6% voltage fall limit can be relaxed to 12%. It also considered the issue of the limits to apply for operational switching events.

C2 The Current GB-SQSS Standard

C2.1 The Current Standards:

Area	Voltage fall	Voltage rise
England and Wales, following *secured events*	-6% ***Note 2,3***	+6%
England and Wales, following operational switching less frequent than specified in ER P28	-3%	+3%
England and Wales, following operational switching of frequencies covered by ER P28	In accordance with ER P28	
SPT	-6% ***Note 1***	+6%
SHETL	-6% ***Note 1,2,3***	+6%

Notes

1. This is relaxed to –12% if the fault involves the loss of a *double circuit* overhead line.
2. This is relaxed to –12% if the fault involves the loss of a section of *busbar* or a mesh corner.
3. This is relaxed to –12% if the fault includes the loss of a *supergrid* transformer.

Figure C 1. Voltage step change limits in planning timescales (Adopted from the current GB SQSS standard - Table 6.2)

Area	Voltage fall	Voltage rise
England and Wales, following *secured events*	-6% ***Notes 1, 2***	+6%
England and Wales, following operational switching less frequent than specified in ER P28	-3%	+3%
England and Wales, following operational switching of frequencies covered by ER P28	In accordance with ER P28	
SPT	-6% ***Note 1***	+6%
SHETL	-6% ***Notes 1, 2, 3***	+6%

Notes

1. This is relaxed to –12% if the fault involves the loss of a *double circuit* overhead line.
2. This is relaxed to –12% if the fault involves the loss of a section of *busbar* or a mesh corner.
3. This is relaxed to –12% if the fault includes the loss of a *supergrid* transformer.

Figure C 2. Voltage step change limits in operational timescales (Adopted from the current GB SQSS standard - Table 6.4)

C2.2 Inter-Regional Differences

The three TOs apply different criteria for allowing a 12% voltage fall:

- In SPT it is permitted only for the loss of a double circuit overhead line
- In England and Wales it is permitted at the planning stage for loss of a busbar, mesh corner or supergrid transformer. However, in operations, it is not permitted for the loss of a SGT alone.
- In SHETL it is permitted for the loss of a double circuit overhead line, busbar or mesh corner, or supergrid transformer.

There are differences between the planning and operational standards in terms of the secured events for which the criteria apply. Also, there are regional differences in the application of the standard to secured events:

- The operational standard, GB SQSS para 5.1.2, includes "the most onerous loss of power infeed" as a *secured event* for which unacceptable voltage conditions are to be avoided. There is no equivalent reference to loss of power infeed in the planning criteria (Sections 2 and 4 of the GB SQSS). These sections discuss loss of power infeed only as a consequence of transmission plant failure, and in terms of the effect on system frequency.
- Sections 5.3 and 5.4 of the GB SQSS refer to avoidance of unacceptable voltage conditions for *double circuit* overhead line outages or outages of a busbar section or mesh corner. However, section 5.3 excludes demand groups of less than 1500 MW from the voltage criteria in Scotland, but section 5.4 refers to England and Wales and applies no such exclusion.

Standards for operational switching in Scotland differ from those in England and Wales:

- In England and Wales, the general step-change limit is ± 3%, with E.R. P28 applying if the frequency of switching is such as to require it.
  - The standard makes no reference to operational switching limits in Scotland.

C2.3 Comparison of Networks

In England and Wales, NGET own the 400kV and 275kV network which is extensive and strongly interconnected. Supplies to distribution companies are predominantly taken at 132kV although there are supplies at 66 kV, 33 kV and lower voltages in some areas. Most, but not all, of these are supplied from the 275kV networks. The majority of Grid Supply points are mesh, single-switch or tee-connected on the HV side, but some supplies are taken from generation connection sites or marshalling substations which are usually double-busbar, with transformers switched independently from lines.

The Scottish system differs from that in England and Wales in that the supergrid network is less extensive and 132kV is also classed as a transmission voltage. Consequently, all connections to the distribution network are at voltages lower than 132kV. Mesh, single-switch and tee-connections are most commonly used for the HV arrangements at Grid supply Points.

All three regions have similarities in that mesh, single-switch, and teed connections are extensively used for Grid Supply Points, with some HV busbars at marshalling substations. Switching arrangements alone would not appear to justify different criteria within the three regions. However, in Scotland, the majority of supplies to customers are at voltages below 132kV and it is noted that the impedances of typical 132/33 kV, 275/33 kV and similar transformers are much higher, in % on 100 MVA, than the impedances of 400/132kV and 275/132kV transformers. Outages involving the lower voltage transformers are likely to cause larger voltage steps than those involving the larger transformers and this may justify different criteria. This matter is discussed further in section 8 of this note.

C2.4 Analysis of Current Criteria for Different Types of Contingencies

Table C1 shows how the current criteria of Tables 6.1 and 6.4 of the GB-SQSS would be applied to different types of secured events in the different areas.
The only events that are treated consistently in all areas and both timescales are the loss of a single circuit without loss of other equipment (for example a circuit switched on a busbar with a dedicated circuit breaker) and the loss of a double circuit together with the loss of one or more transformers. In some cases the differences in criteria appear illogical:

- Different criteria are applied to events that carry similar levels of risk, and result in outage of similar types and amounts of equipment. For example, in England and Wales, a -6% criterion is applied for the loss of a single circuit switched independently on a busbar, whereas the criterion would be -12% if the circuit terminates on a mesh corner, even if there is no outage of a supergrid transformer.
- As a consequence, the voltage quality experienced by customers depends on the switching arrangements at their Grid Supply Point rather than the risks of secured events. For example, customers supplied from a mesh substation can experience 12% voltage falls for a trip of any supergrid transformer or any circuit connected to the mesh. If the substation has a single- or double-busbar layout, customers would be exposed to 12% falls only for supergrid transformer faults *or* simultaneous double-circuit faults, both of which are much rarer events than faults on single circuits.

In England and Wales and in SHETL, a voltage fall of 12% is allowed for single-circuit outages that do not involve the loss of supergrid transformers. On the supergrid it is unlikely that such outages would voltage falls in excess of 6%, except in circumstances where the system is extremely stressed and other criteria of the SQSS are unlikely to be satisfied.

Table C 1. Comparison of voltage fall standards by contingency type and area (Application of the current standard to various contingencies - Voltage step-changes in planning and operational timescales).

Planning

Case	Contingency	E&W	SPT	SHETL
1	single cct - switched on busbar	-6%	-6%	-6%
2	single cct - with Tee'd SGT	**-12%**	-6%	-12%
3a	single cct - on mesh corner - no SGT loss	-12%	-6%	-12%
3b	single cct - on mesh corner - with SGT loss	-12%	-6%	-12%
3c	single cct - on mesh corner - with SGT loss, prior outage on another cct	-12%	-6%	-12%
4a	single cct - to 1-switch s/stn. - no SGT loss	-12%	-6%	-12%
4b	single cct - to 1-switch s/stn. - with SGT loss	-12%	-6%	-12%
5	double cct trip - switched on busbar	**-6%**	-12%	-12%
6	double cct trip - on mesh (with SGT loss)	-12%	-12%	-12%
7a	mesh corner - no SGT loss	-12%	-6%	-12%
7b	mesh corner - with SGT loss	-12%	-6%	-12%
8a	busbar section - no SGT loss	-12%	-6%	-12%
8b	busbar section - with SGT loss	-12%	-6%	-12%
9	SGT trip only	**-12%**	-6%	-12%
10	bus-coupler or bus-section fault	n/a	n/a	n/a

Operational

Case	Contingency	E&W	SPT	SHETL
1	single cct - switched on busbar	-6%	-6%	-6%
2	single cct - with Tee'd SGT	**-6%**	-6%	-12%
3a	single cct - on mesh corner - no SGT loss	-12%	-6%	-12%
3b	single cct - on mesh corner - with SGT loss	-12%	-6%	-12%
3c	single cct - on mesh corner - with SGT loss, prior outage on another cct	-12%	-6%	-12%
4a	single cct - to 1-switch s/stn. - no SGT loss	-12%	-6%	-12%
4b	single cct - to 1-switch s/stn. - with SGT loss	-12%	-6%	-12%
5	double cct trip - switched on busbar	**-12%**	-12%*	-12%*
6	double cct trip - on mesh (with SGT loss)	-12%	-12%*	-12%*
7a	mesh corner - no SGT loss	-12%	-6%*	-12%*
7b	mesh corner - with SGT loss	-12%	-6%*	-12%*
8a	busbar section - no SGT loss	-12%	-6%*	-12%*
8b	busbar section - with SGT loss	-12%	-6%*	-12%*
9	SGT trip only	**-6%**	-6%	-12%
10	bus-coupler or bus-section fault	n/a	n/a	n/a

Notes:

-6% Text in **Red** indicates difference between Planning and Operational standards

Highlighting indicates that this Area applies a different standard from the other two

* No voltage standard is applied if the group demand is less than 1500 MW

29/01/09/DJC

C3 Factors Affecting Voltage Fall

C3.1 Categories of events

Customers will experience negative voltage steps as a consequence of events that:

a) Increase the impedance between the customer and voltage sources;

b) Reduce the shunt reactive gain of the network;

c) Increase the series reactive loss of the network;

d) Increase the shunt reactive loss of the network;

e) Reduce the real and/or reactive power injection to the network; or

f) Combinations of the above.

Within (a) the most significant events are:

- Loss of one or more supergrid transformers; or
- Loss of a double-circuit line leaving a GSP supplied through a more circuitous, higher impedance route.

For any contingency of type (a), the voltage step-change at the LV busbar of a Grid Supply Point will depend partly on the net active power demand but predominantly on the net reactive demand. GSPs with low power factors are therefore most prone to experience large voltage falls.

The most significant event in (b) would generally be the simultaneous loss of one or more high-susceptance circuits, often including sections of cable. Such an event would rarely cause voltage falls of more than 6% unless it also greatly increased the impedance of the system as in (a).

Secured events of type (d), that would cause voltage falls of 6% or more, are highly improbable.

C3.2 Voltage Falls at Grid Supply Points

The commonest events that would cause voltage falls in excess of 6% are those involving losses of grid supply transformers. The effects of such events are generally confined to the LV side of the substation where the transformers are tripped.

In general, the factors that determine the voltage-step performance of the system are fixed at the design stage. In many – perhaps the majority – of cases it will be difficult or impossible to influence step-change performance by operational measures. Where it is possible, high constraint costs may be incurred. There is little if anything to be gained by designing to tighter criteria than the system is operated to, or by trying to operate to tighter criteria than it is designed for.

Even when voltage falls of more than 6% are acceptable to customers, they can be indicative of a highly stressed system. The standard should emphasise that where a large voltage step-change is predicted, the system should be checked to ensure that voltages can be restored to target values post-fault and that there are adequate margins for voltage stability.

The step-change experienced at a GSP LV busbar is sensitive to the demand power factor. A given network and substation design can produce acceptable voltage step-changes for a given load at a high power factor, but much larger voltage steps if the power factor is lower. The effects of power factor variations are explored in section 6.

C3.3 Voltage Falls due to Loss of Generator or Other Infeeds

Voltage falls can be caused by loss of reactive or active power infeeds to the system (category (e) in the list above), such as loss of a shunt capacitor or tripping of a generator or HVDC bipole. Loss of a reactive compensator is included as a *secured event* in sections 4.6 and 5.1, but tripping of a generating unit is not[16].

Loss of a generator affects voltage step-change as follows:

For generators connected to the supergrid, the dominant effects are:

- By loss of the reactive output of the generator, and the consequent change in I_QX voltage regulation of the system and
- By the change in I^2X losses due to the change in system power flows following the generator trip.

At lower voltages, circuit R/X ratios are higher so changes in real power flows also affect voltage drop. Hence I_PR voltage regulation and I^2R losses are significant, in addition to the I_QX and I^2X terms mentioned above.

Generators up to 660MW are unlikely to generate more than about 250 Mvar so loss of their reactive injection alone will not cause voltage changes much greater than those due to switching of a large (225 Mvar) capacitor, which must meet the 3% operational switching criterion. However, generating units with ratings up to 2000 MVA are now becoming available worldwide and may eventually be connected in the GB system.

Units in this size range could, if they are designed in line with the current GB Grid Code, produce of the order of 500 – 700 Mvar at their HV terminals. Loss of the reactive output alone would not cause a voltage change in excess of 6% unless the system is quite weak (fault level ~ 8 - 12 GVA). The worst case would occur if the loss of the generator causes a change in system power flow and consequent increase in I^2X loss, as well as the loss of reactive injection. Clearly, the change in power flows due to a generator trip is site specific, depending on network topology and the generation and demand pattern. In most cases excessive voltage step-changes due to generator tripping are unlikely, but the possibility should be examined at the design stage and if necessary design modifications or additional investment (for instance in SVCs) should be made to contain the voltage step. Such large generators will always be connected at supergrid voltage and the voltage step-change due to a unit trip may be experienced over a wide area.

Another potential circumstance where excessive voltage steps may result from a generator trip would be when generation is connected within a 132kV network. In 132kV and lower-voltage networks, circuit R/X ratios are substantially higher than they are for the supergrid. The flow of MW through the circuit resistance can thus have as much or more influence on the network voltage profile as reactive power flows. Tripping a generating unit in such a network can cause a reversal of power flow, which, associated with a loss of var injection, may result in a significant voltage step. The problem may be particularly severe where new generation is added in a network that was initially designed for demand distribution only. In some cases it may be possible to despatch the generator reactive output so as to minimise the voltage disturbance if the unit trips. However, there may be a conflict between the reactive despatch desirable for voltage step control and that which is optimal for the steady-state voltage profile and for security following circuit or transformer trips. As with the very large supergrid-connected generators, these issues should be considered at the planning stage and addressed by design modifications and additional investment if justified.

In terms of numbers of consumers affected, tripping a 132kV generating unit is roughly equivalent to a *secured event* involving the loss of a supergrid transformer. Generating unit trips are at least as frequent as transformer and circuit trips.

[16] The earlier CEGB design standard PLM-ST-9, used within NGET until 2000, treated a generating unit outage on the same terms as a circuit outage.

Generating units embedded within distribution networks may also trip, causing voltage disturbances at Grid Supply Points. The network would be designed and operated by the DNO in accordance with distribution security standards so the GSP LV voltage conditions would not be determined solely by the GB SQSS. For centrally-despatched embedded generating units, the GBSO would despatch reactive output but system-wide reactive management objectives may be subservient to DNO local requirements.

C4 Desirable Attributes for Harmonised Step-Change Criteria

A revised set of criteria would ideally be clear and unambiguous in application;

a) Be consistent between planning and operational timescales, and between Transmission Owners. Where differences are essential and justified, the reasons for them should be recorded, preferably within the standard.

b) Apply the same voltage step criteria to secured events of equivalent probability and severity

c) By extension of (c), provide consistent voltage quality to all customers wherever possible, irrespective of the type of supergrid substation they are supplied from (since this is at the discretion of the TO and individual customers have no influence)

d) Limit severe voltage step changes to as few customers as possible; hence if a secured event results in voltage steps over a wide area (e.g. several GSPs) the voltage steps should be within 6%.

e) Require the minimum of capital and operational expenditure in a TO's area as a consequence of the revised standard, if the revised standard includes tighter criteria than those it supersedes.

f) Involve the minimum reduction in actual voltage quality to customers as a consequence of the revised standard, where the revised standard implies a relaxation of criteria in a TO's area.

C5 Step Changes for Particular Secured Events and System Conditions

To assist in the assessment of the current standard and suitable alternatives, voltage step changes have been calculated for a range of secured events and pre-and post-fault system conditions, using a simple model network illustrated in Figure C 4.

Secured events were modelled as outages of combinations of lines Zs1 and transformer(s). Impedances Zs1, Zs2 adjusted to achieve required pre- and post-contingency fault levels at the HV Bus. Transformer impedances were adjusted to match the type of transformers being studied.

Demand on the LV Bus has "Heavy Industrial" load response, with no additional LV susceptance. A "Heavy Industrial" (P1/Q2) load response characteristic was used throughout in the absence of any better information. Voltage step-changes are sensitive to the load response and the appropriate choice of characteristics is a matter of great uncertainty.

The results are illustrated in Figure C 5– Figure C 16, which chart voltage step-changes against substation load for a range of substation types and contingencies at demand power factors of 0.95 and 0.85. From information in the 2008 GB Seven Year Statement, roughly 56% of GSPs have power factors of 0.95 or better, and 92% have power factors of 0.85 or better. Figure C 3 shows the demand power factors at GB GSPs without LV susceptance or LV compensation for all regions and all voltages based on data derived from the Seven Year Statement of 2008. Since the real system will exhibit a wide range of pre- and post-fault system configurations, demand power factors and numbers and types of transformers at sites, the calculations must be considered as indicative only. The results of these analyses are summarised in Table C 2.

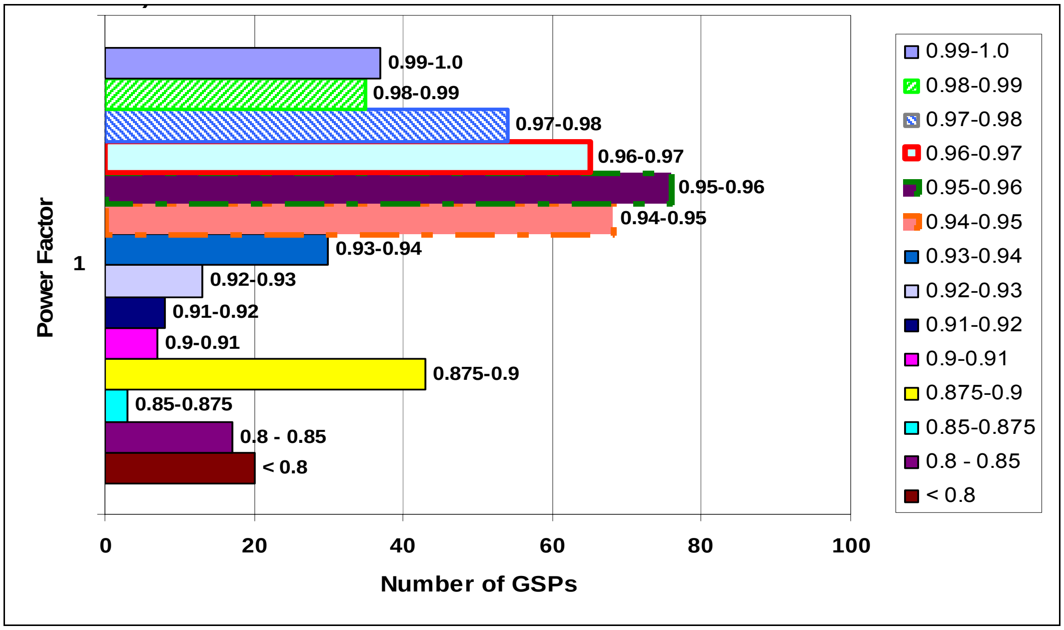


Figure C 3. Demand power factors at GB GSPs without LV susceptance or LV compensation (All regions, all voltages) ***[Derived from Table E.1.7 of GB SYS, 2008]***

Table C 2. Calculated Worst-Case Voltage Steps for Some Typical Contingencies

No. of Transformers and Contingency Considered	Figure	Voltage Step Changes and Demands at Which They Occur	
		0.95 Power Factor	0.85 Power Factor
2 x 400/132kV SGT; Single Circuit outage only. Weak system post fault.	Figure C 5	< 4% fall, up to normal rating of transformers	<6% fall, up to normal rating of transformers. Potentially difficult to retap to 1.0 p.u. voltage for > 350 MW[1]
2 x 400/132kV SGT; Single SGT outage.	Figure C 6	< 6% fall, up to cyclic loading of SGT	~ 8% fall possible at cyclic loading of transformer; > 6% possible for > 200 MW. Potentially difficult to retap to 1.0 p.u. voltage for > 250 MW[1]
2 x 400/132kV SGT; SGT + Circuit outage. Weak system post fault.	Figure C 7	> 6% fall possible for > 240 MW	>12% fall possible for > 270 MW. Retapping to 1.0 p.u. voltage may be difficult for > 230 MW
4 x 400/132kV SGT; double circuit outage only. Weak system post fault	Figure C 8	< 12% fall, up to normal rating of transformers. 6% fall at 700 MW. Retapping to 1.0 p.u. voltage may be difficult for > 790 MW[1]	12% fall at ~ 790 MW Retapping to 1.0 p.u. voltage may be difficult for > 550 MW. Voltage fall at this demand is ~ 6%[1]
4 x 400/132kV SGT; double circuit outage only. Moderately weak system post fault	Figure C 9	< 6% fall, up to normal rating of transformers.	< 6% fall up to 900 MW. Retapping to 1.0 p.u. voltage may be difficult for > 670 MW.
4 x 400/132kV SGT; 2 SGT + double circuit outage. Weak system post fault	Figure C 10	< 12% fall, up to cyclic rating of remaining transformers. < 6% fall up to 370 MW. Retapping to 1.0 p.u. voltage may be difficult for > 470 MW[1]	> 12% fall possible at > 430 MW. Retapping to 1.0 p.u. voltage may be difficult for > 370 MW[1]
4 x 400/132kV SGT; single circuit + SGT outage following outage of another circuit. Moderately weak HV system post-fault (10 GVA)	Figure C 11	6% fall at ~ 800 MW. ~6.5% fall at cyclic loading of remaining transformers. Retapping to 1.0 p.u. voltage may be difficult for > 830 MW[1]	12% fall at ~850 MW, 6% fall at ~600 MW, Retapping to 1.0 p.u. voltage may be difficult for > 570 MW[1]

No. of Transformers and Contingency Considered	Figure	Voltage Step Changes and Demands at Which They Occur	
		0.95 Power Factor	0.85 Power Factor
4 x 400/132kV SGT; single circuit + SGT outage following outage of another circuit. weak HV system post-fault (5 GVA)	Figure C 12	6% fall at ~ 580 MW. ~12% fall at 800 MW. Retapping to 1.0 p.u. voltage may be difficult for > 690 MW[1] Even at 1.0 pf, voltage step is 6% at 800 MW	12% fall at ~640 MW, 6% fall at ~400 MW, Retapping to 1.0 p.u. voltage may be difficult for > 470 MW[1]
2 x 120 MVA 275/33 kV SGT; single circuit outage only. Moderately weak system post fault (3GVA)	Figure C 13	< 3% fall within ratings of transformers. Retapping to 1.0 p.u. voltage may be difficult for > 140 MW[1]	< 4% fall within ratings of transformers
2 x 120 MVA 275/33 kV SGT; single circuit + SGT outage. Moderately weak system post fault (3GVA)	Figure C 14	~ 12% fall at cyclic rating of remaining transformer. Retapping to 1.0 p.u. may be difficult at this demand	~ 12% fall at 110 MW. Retapping to 1.0 p.u. may be difficult beyond 100 MW
2 x 60 MVA 132/33 kV transformers. single circuit outage only. Moderately weak (1 GVA) system post fault	Figure C 15	< 6% fall within normal rating of two transformers.	~6% fall at 95 MW (ie beyond cyclic rating of one transformer)
2 x 60 MVA 132/33 kV transformers. Transformer + single circuit outage. Moderately weak (1 GVA) system post fault	Figure C 16	~6% fall at 60 MW.	12% fall at 70 MW. (Cyclic rating of transformer at this power factor is 61 MW) Retapping to 1.0 p.u. voltage may be difficult at 70 MW[1]

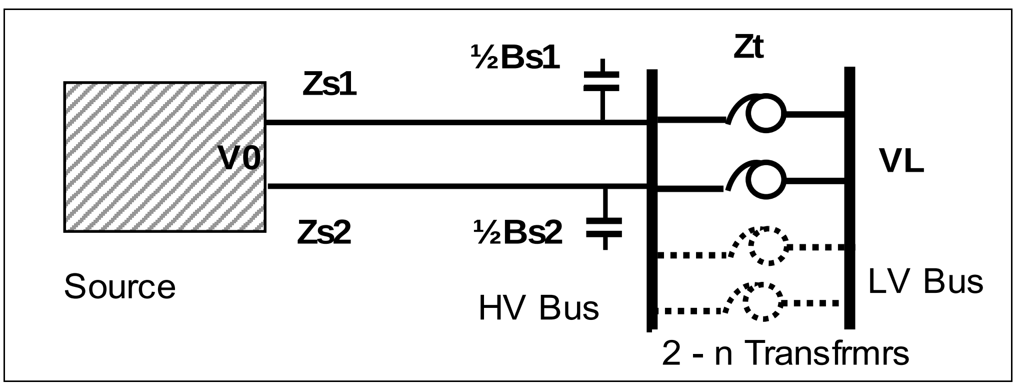


Figure C 4. Model system for calculating voltage step changes

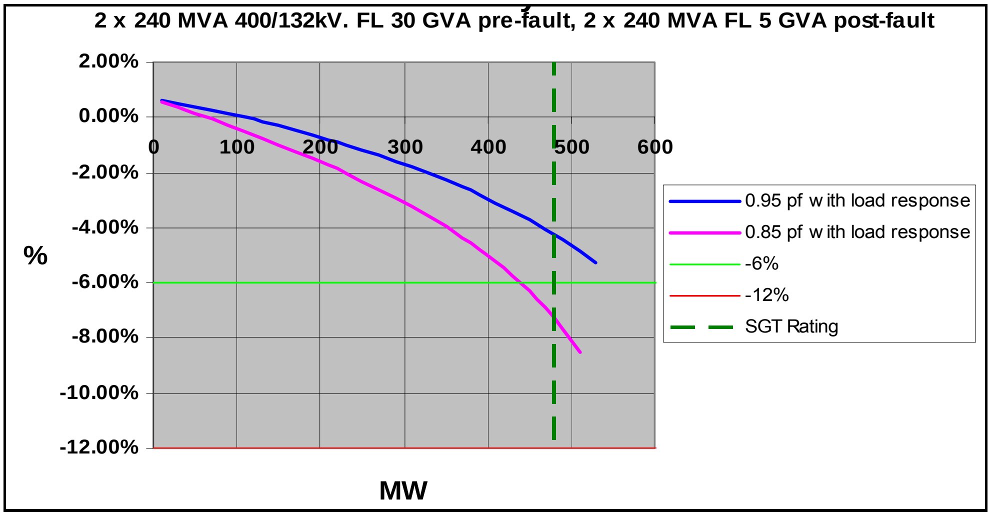


Figure C 5. Voltage step change for an outage of a single circuit only on a two-transformer 400/132kV substation resulting in a weak system post-fault.

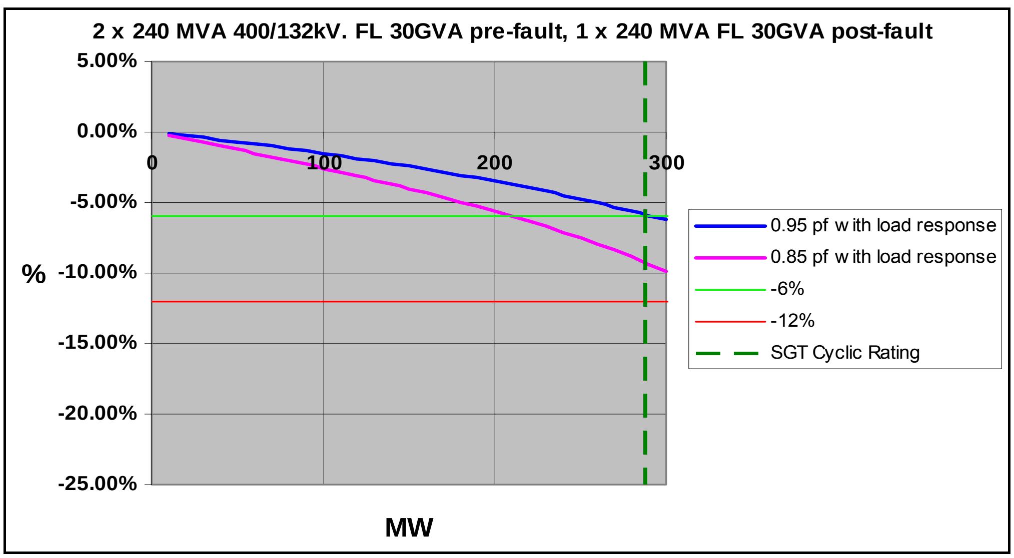


Figure C 6. Voltage step change for an outage of 1 x SGT only on a two-transformer 400/132kV substation.

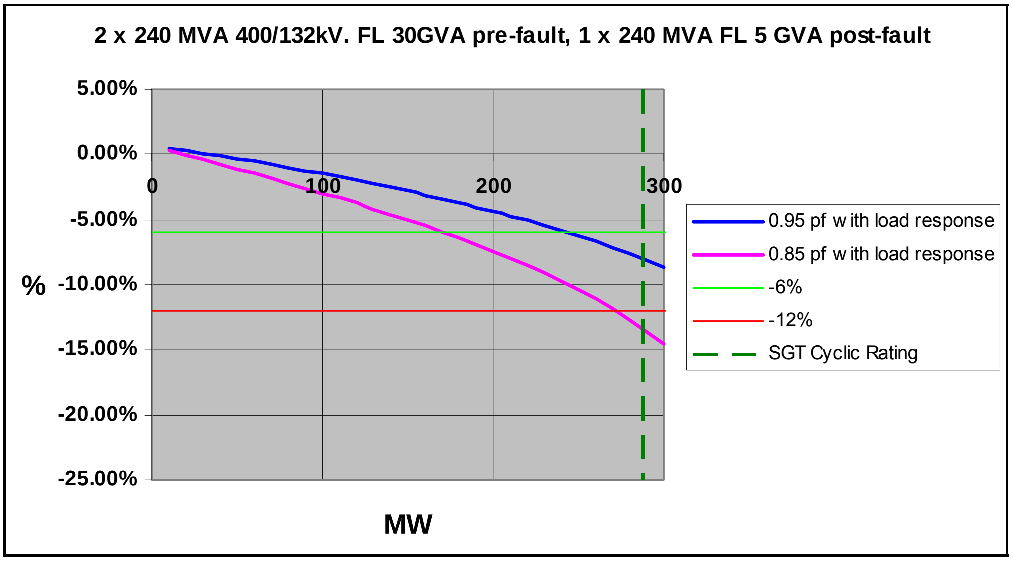


Figure C 7. Voltage step change for 1 x SGT and single circuit outage on a two-transformer 400/132kV substation resulting in weak system post fault

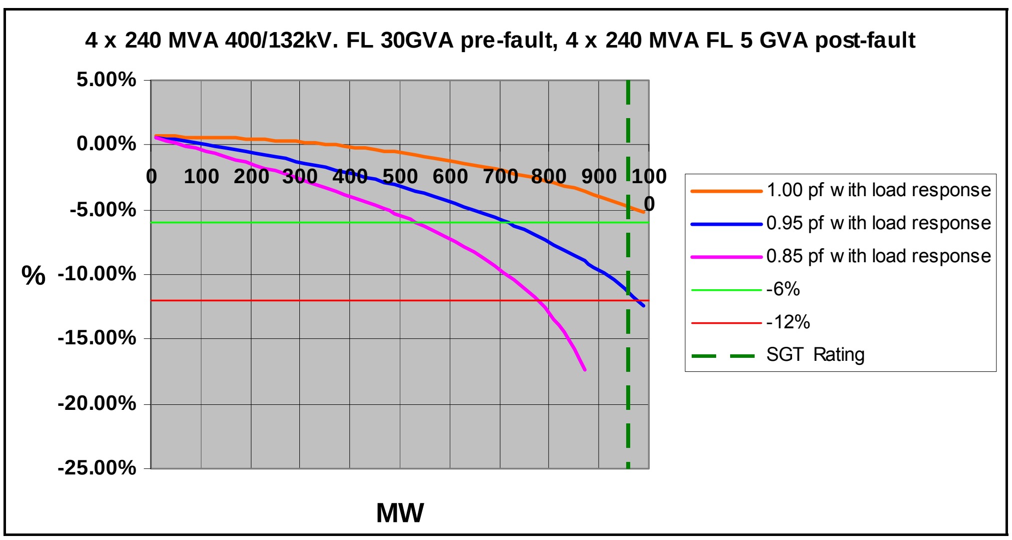


Figure C 8. Voltage step change for an outage of a double circuit only on a four-transformer 400/132kV substation resulting in a weak system post-fault.

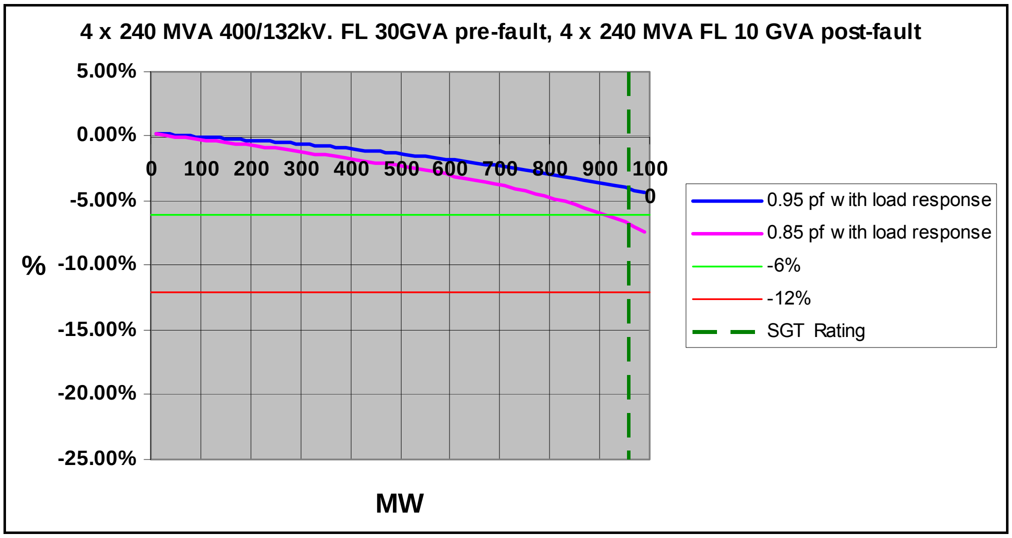


Figure C 9. Voltage step change for an outage of a double circuit only on a four transformer 400/132kV substation resulting in a moderately weak system fault level post-fault

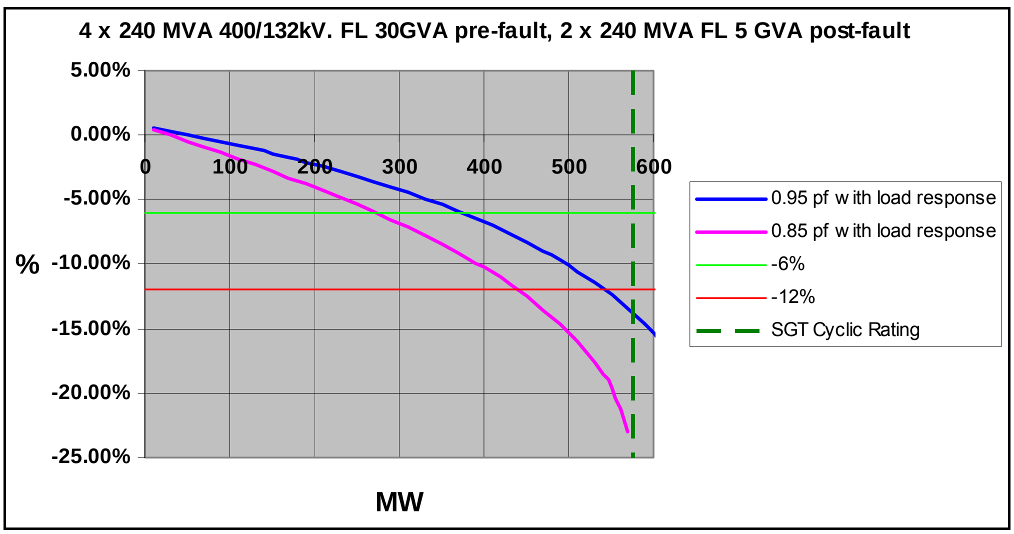


Figure C 10. Voltage step change for 2 x SGT + double circuit line outage on a four-transformer mesh 400/132kV substation resulting in a weak system post-fault

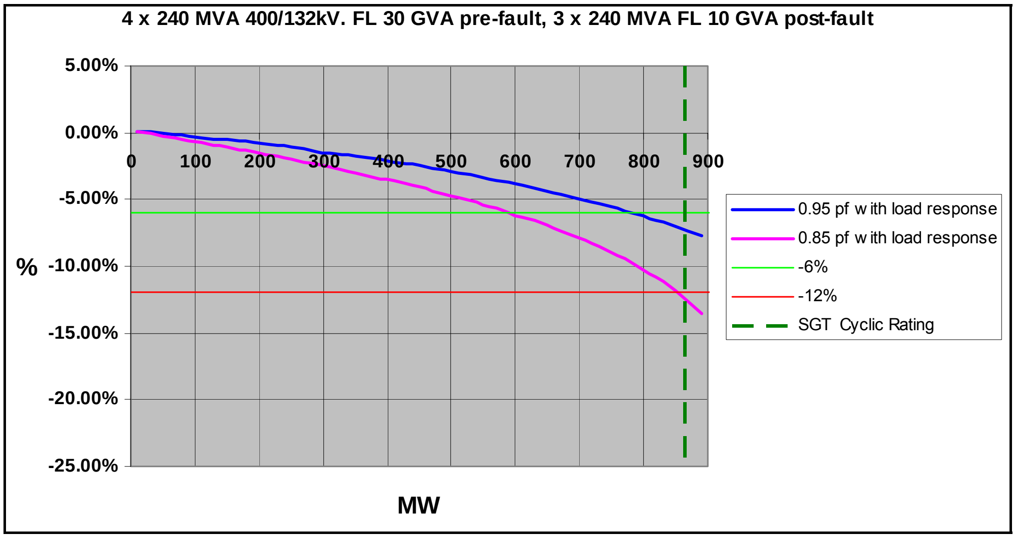


Figure C 11. Voltage step change for 1 x transformer + single circuit outage following a prior single circuit outage on a four-transformer mesh 400/132kV substation resulting in a moderately weak system post-fault

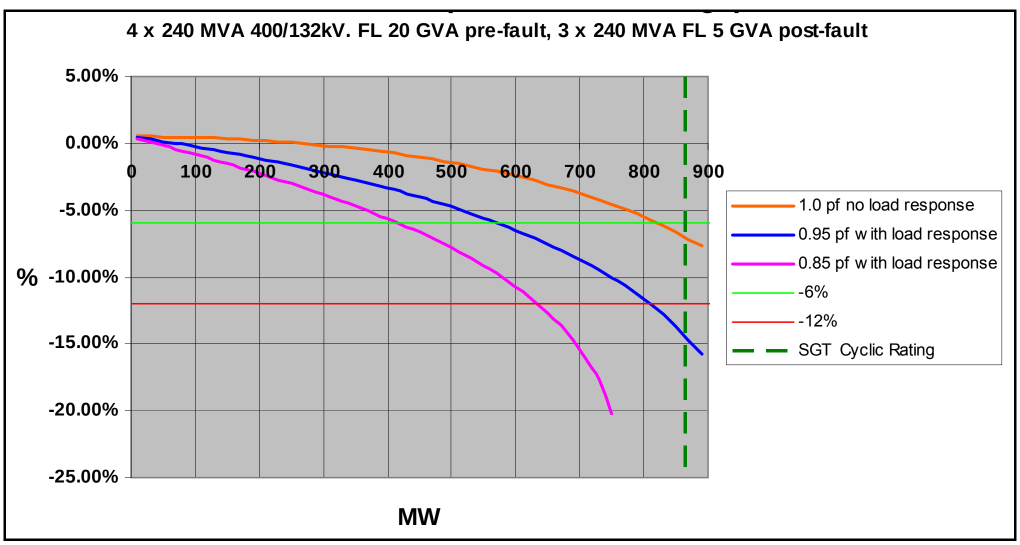


Figure C 12. Voltage step change for 1 x transformer + single circuit outage following a prior single circuit outage on a four-transformer mesh 400/132kV substation resulting in a weak system post-fault.

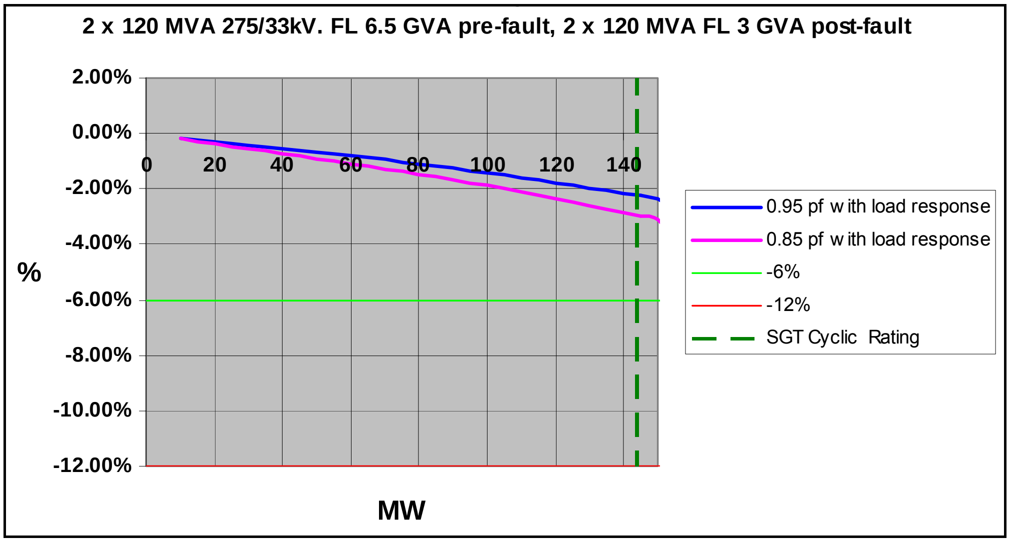


Figure C 13. Voltage step change criteria for an outage of a single circuit only on a two-transformer 275/33kV substation resulting in a moderately weak system post-fault.

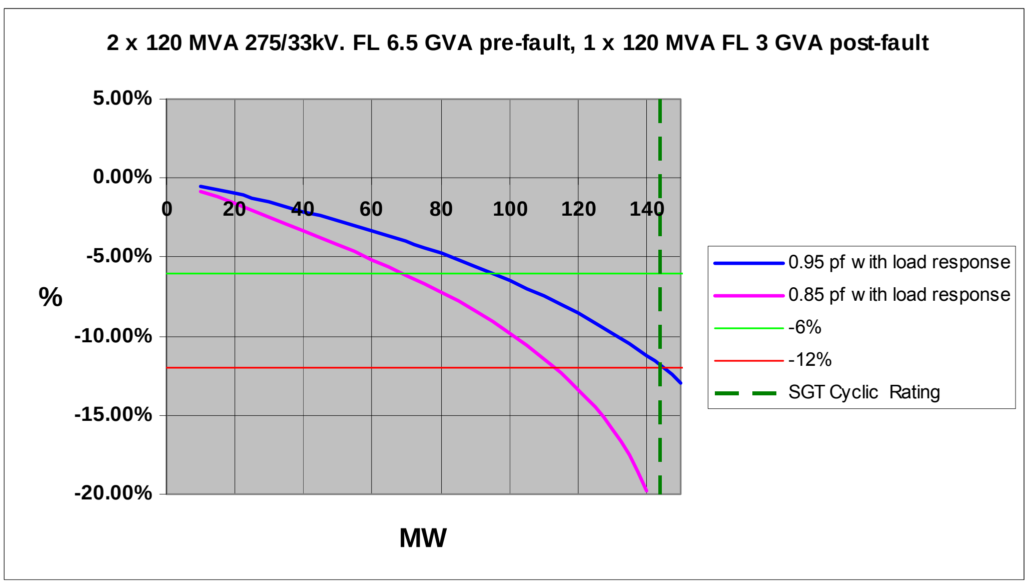


Figure C 14. Voltage step change for 1 x SGT + single circuit outage on a two-transformer 275/33kV mesh substation resulting in a moderately weak system post-fault.

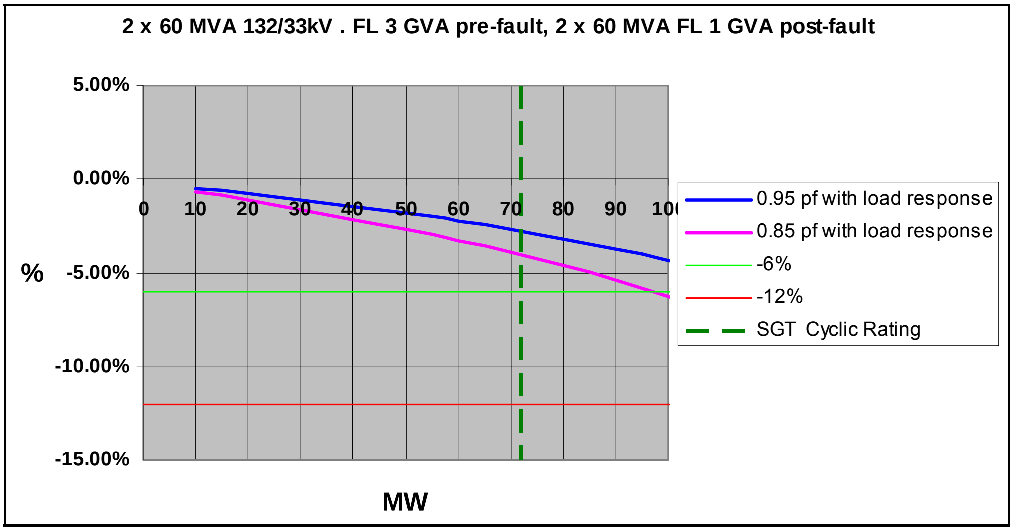


Figure C 15. Voltage step change for an outage of a single circuit only on a two-transformer 132/33kV substation resulting in a weak system post-fault.

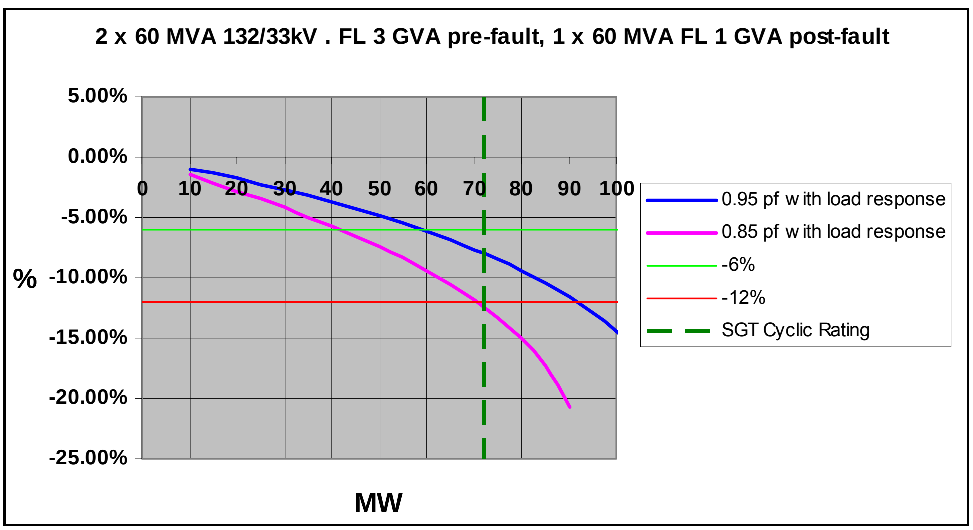


Figure C 16. Voltage step change for 1 x transformer + single circuit outage on a two-transformer 132/33kV substation resulting in a moderately week system post fault.

C6 Operational Switching

The standard in England and Wales limits voltage steps due to operational switching to ± 3% generally, and to P28 limits for more frequent events. This standard has not been applied in Scotland. The nature of the system in England in Wales, with long supergrid circuits, significant supergrid cabling, and very variable generation pattern and circuit loadings, has meant that a considerable quantity of reactive compensation plant has been installed on the system. Since the supergrid was built in the late 1960s regular, widespread, daily switching of shunt reactors, capacitors and circuits has taken place to manage the system voltage. The low impedance of the system means that a switching event results in voltage changes over a wide area, admittedly of diminishing magnitude as distance from the switching location increases. This means that customers have been exposed to frequent voltage steps, of varying magnitudes, due to operational switching of reactive compensation. The voltage step criteria for operational switching put operational voltage fluctuations on the same footing as voltage flicker due to the operation of large demands such as steel works. The provisions of P28 are adhered to in order to manage the nuisance to customers at acceptable levels.

In Scotland, there are considerably fewer items of reactive compensation plant than in England and Wales (Table B5.1 of the 2008 SYS shows the reactive compensation for the three TOs). It may be, therefore, that Scottish customers experience fewer voltage steps than those in England and Wales; operational switching events in Scotland are likely to be related to maintenance outages or busbar rearrangements for fault level control in most cases. Such events typically occur no more than a few times per year at a given location. The need to have an operational voltage step criterion explicitly linked to P28 is less evidently necessary than in England and Wales.

The Grid Code (CC 6.1.7) imposes different requirements on customers in England and Wales from those it imposes in Scotland; however, it requires customers throughout GB to comply with P28:

Voltage Fluctuations

CC.6.1.7 Voltage fluctuations at a **Point of Common Coupling** with a fluctuating **Load** directly connected to the **GB Transmission System** shall not exceed:

(a) In England and Wales, 1% of the voltage level for step changes which may occur repetitively. Any large voltage excursions other than step changes may be allowed up to a level of 3% provided that this does not constitute a risk to the **GB Transmission System** or, in **NGET's** view, to the **System** of any **User**. In Scotland, the limits for voltage level step changes are as set out in **Engineering Recommendation** P28.

(b) For voltages above 132kV, **Flicker Severity (Short Term)** of 0.8 Unit and a **Flicker Severity (Long Term)** of 0.6 Unit, for voltages 132kV and below, **Flicker Severity (Short Term)** of 1.0 Unit and a **Flicker Severity (Long Term**) of 0.8 Unit, as set out in **Engineering Recommendation** P28 as current at the **Transfer Date**.

The STC governs relationships between the GBSO and the TOs. Section D para 2.2.6 requires TOs to comply with certain sections of the Grid Code, including CC 6.1.7:

2.2.6 Without limitation to Section C, Part One, paragraph 2.2, in planning and developing its Transmission System, each Transmission Owner shall ensure that its Transmission System complies with:

2.2.6.1 the minimum technical, design and operational criteria and performance requirements set out or referred to in Connection Conditions 6.1, 6.2, 6.3 and 6.4 and in Planning Code 6.2 and/or 6.3 as applicable; or

2.2.6.2 such other technical criteria or requirements as apply to any relevant part of its Transmission System by virtue of a current Transmission Derogation; and

(From STC Part D Version 3 – 24 June 2009)

The extent to which the requirements of ER P28 apply to operational switching events throughout GB may depend on interpretation of the above clauses of the Grid Code and STC, particularly the word “Loads” in CC6.1.7, and the term “as applicable” which is a new inclusion in the 2009 revision of the STC.

From the above, it appears that operational switching criteria throughout GB should be consistent with ER P28 unless the TO obtains a derogation from CC 6.1.7 of the Grid Code. Logically then, the GB-SQSS should either:

a) refer to the operational switching requirements as applying across the GB system; or

b) it should refrain from mentioning them at all and leave the TOs to ensure that their networks comply with the Grid Code provisions.

The latter option could be seen as retrograde in England and Wales, where the operational switching criteria have been consistent with ER P28 for many years and frequent switching of reactive compensation can cause voltage disturbances within the timescales of ER P28.

A third option would be to distinguish between frequent operational switching – such as routine compensation switching – and less frequent events such as the isolation of circuits for maintenance. The operational switching requirements of the current SQSS would apply to the frequent events but a ±6% step change limit would be applied to the others.

It is noted that ER P28 applies to voltage fluctuations of all types, including voltage ramps and random variations caused by, for example, arc furnaces. It defines requirements in terms of the output of a flicker meter, and is not straightforward for a non-expert (e.g. a typical transmission designer or system operator) to interpret. However, operational switching events as covered by the GB SQSS cause simple voltage steps and it is possible to derive a simple chart of allowable voltage step as a function of switching frequency that is consistent with ER P28. This could be included in the SQSS document as guidance for designers and operators.

C7 Possible Harmonised Criteria

The Working Group considered several options for unified criteria without regional variations. The most obvious, and apparently simplest, would be to allow 12% voltage fall after any *secured event*.

The logic for adopting this option would be that "*if 12% fall is acceptable for some secured events, it must be acceptable for all*". This option would represent a significant relaxation from current standards in England and Wales and a considerable relaxation in SPT.

A number of issues would arise if this standard were adopted:

– It would apply the same criteria to all events, irrespective of their rarity or the number of consumers affected. Different events of similar probability are no longer subject to different criteria, but only at the expense of allowing the worst system performance for all events.

– A large number of consumers in England and Wales and Southern Scotland would potentially experience a reduction in their quality of supply.

– Supplies taken at 275kV and 400kV, such as power station site supplies and railways, would now be subject to 12% voltage falls. Such Users may resist the change to this standard.

– Despite the apparent relaxation in the standard, it is unlikely that significant expenditure will be saved. This is because many contingencies, if they can be secured at all, will still result in a voltage fall of 6% or less. Voltage falls greater than this are frequently associated with other problems, such as an inability to restore voltage to the required steady-state value, or insufficient voltage collapse margin, so that expenditure would be required in any case.

– Voltage steps following contingencies are frequently used as a rapid method of screening for general voltage problems in planning and operational planning studies. Planning and operating to a relaxed criterion may result in fewer such problems being picked up at the appropriate time.

- Overall, then, relaxing to a -12% step-change for every *secured event* may not be the simple cost-free solution it appears to be at first, and it would tend to degrade the overall voltage performance and security of the system.

Other options, such as designing and operating to 6% voltage fall in all cases except for *double circuit* trips, or for faults involving supergrid transformers, were also considered and rejected. They resulted in different standards being applied to faults of similar probability, or did not take account of the technical differences between different parts of the system, or take account of the differing numbers of customers that would be affected by different contingencies.

A more fundamental approach was then adopted, with the intention of producing criteria that meets the following objectives:

- Apply the same criteria to trips of similar levels of risk
- Apply the same criteria in planning and operational timescales
- Apply the same criteria throughout the GB Transmission System
- Apply relaxed criteria only for rarer events or events affecting a small number of consumers.
- Include tripping of generator units or other active/reactive power infeeds in the secured events for which the criteria apply.
- Recognise differences in characteristics between 275/132kV and 400/132kV substations, and substations supplying customers at lower voltages (eg 33kV). Also recognise differences in characteristics between the supergrid network and the 132kV transmission network as used in Scotland.

  For example, 275/33kV and 132/33kV transformers typically have higher impedances than 400/132kV or 275/132kV supergrid transformers so outages involving a transformer feeding a 33kV connection point will tend to cause larger step-changes than, say, a 400/132kV transformer outage. However, typical transformers supplying the 33kV system have more boost tap-range than 400/132kV transformers (20% rather than 15%) and so are better able to re-tap to an acceptable steady-state voltage.

- Recognise that substations supplying customers at 132kV typically supply many more consumers than those supplying customers at lower voltages. It is desirable to confine large voltage step-changes to as few consumers as possible, hence it could be appropriate to accept -12% voltage step for a supply at less than 132kV for a contingency involving a single transformer outage, but to accept only -6% for a similar contingency affecting a 132kV supply point. Fortunately this relaxation for lower voltage supply points is consistent with the differences in system characteristics, discussed above.
- Minimal additional expenditure in working to this standard compared with the current standard. Where expenditure is needed to meet the -6% step change criterion as opposed to -12%, it is quite possible that this expenditure would be incurred anyway to meet the requirement to restore supply point voltage to its nominal value post-event, or to provide adequate margin to voltage collapse.
- Incorporate operational switching standards in all three regions, recognising the apparent STC requirement (via the Grid Code) to observe the requirements of ER P28, and the differences between the three transmission networks.
- Be clear and unambiguous to apply.

C8 Conclusion

The Working Group is proposing revised step change criteria for inclusion in the SQSS. The revised criteria will have the following characteristics:

- The previous regional variations are replaced by variations based on the voltage at which customers (or distribution networks) are supplied;

- Relaxation to -12% is permitted for fewer types of secured events at substations supplying customers at higher voltages, and for more types of events affecting supplies at lower voltages. Consequently, the larger step changes are experienced most at sites serving fewer customers.
- Voltage step-change limits for operational switching will be applied across GB. Varying local conditions will be handled by defining two classes of operational switching – frequent and infrequent – for which different limits will apply. The criteria will no longer refer the reader to ER P28 for the limits for frequent switching events; a chart of permissible voltage step magnitudes, consistent with P28, will be included in the SQSS to make that document self-contained.
- The format of the table of step-change limits will be changed, with the aim of making it easier to interpret than the current version.

It is intended that generating unit trips (including trips of modules with common prime movers or steam supplies) should be included in the lists of secured events for which the voltage standards will apply.

Appendix D

Draft Revised Voltage Criteria

6. Voltage Criteria in Planning and Operating the *Onshore Transmission System*

Voltage and Voltage Performance Margins in Planning Timescales

6.1. A voltage condition is unacceptable in planning timescales if:

6.1.1. There is any inability to achieve pre-fault steady-state voltages as specified in Table 6.1 at *onshore transmission system* substations or *GSP*s,

<u>or</u>

6.1.2. if, after either

6.1.2.1. a *secured event*,

or

6.1.2.2. *operational switching*,

and the affected site remains directly connected to the *onshore transmission system* in the *steady state* after the relevant event above, any of the following conditions applies:

6.1.2.3. the *voltage step change* at an interface between the *onshore transmission system* and a *User System* exceeds that specified in Table 6.5

or

6.1.2.4. there is any inability following such an event to achieve a *steady state* voltage as specified in Table 6.2 at *onshore transmission system* substations or *GSP*s using manual and/or automatic facilities available, including the switching in or out of relevant equipment.

<u>or</u>

6.1.3. if, pre-fault, or after either:

6.1.3.1. a *secured event*,

or

6.1.3.2. *operational switching*

there are *insufficient voltage performance margins*, as evidenced by:

i) *voltage collapse*;

ii) over-sensitivity of system voltage; or

iii) unavoidably exceeding the continuous reactive capability expected to be available from generating units or other reactive sources, so that accessible reactive reserves are exhausted;

under any of the following conditions:

i) credible demand sensitivities;

ii) the unavailability of any single reactive compensator or other reactive power provider; or

iii) the loss of any one automatic switching system or any automatic voltage control system for on-load tap changing.

6.2. The *steady state* voltages are to be achieved without widespread post-fault re-despatch of generating unit reactive output or changes to set-points of SVCs or automatic reactive switching schemes and without exceeding the available reactive capability of generation or SVCs. In particular, following a *secured event*, the target voltages at Grid Supply Points should be achieved after the operation of local reactive switching and auto-switching schemes, and after the operation of Grid Supply Transformer tap-changers.

6.3. The *pre-fault planning voltage limits* and targets on the *onshore transmission system* are as shown in Table 6.1.

Table 6.1 Pre-Fault Steady State Voltage Limits and Requirements in Planning Timescales

(a) Voltage Limits on Transmission Networks		
Nominal voltage	Minimum (***Note 1***)	Maximum
400kV	390 kV (97.5%)	410 kV (102.5%) ***Note 2***
275kV	261 kV (95%)	289 kV (105%)
132kV	125 kV (95%)	139 kV (105%)
(b) Voltages to be Achievable at Interfaces to Distribution Networks		
Nominal voltage		
Any	105% at forecast *Group Demand*; 100% at *forecast Minimum Demand,* or as otherwise agreed with the relevant Network Operator	

Notes

1. It is permissible to relax these to the limits specified in Table 6.2 if:
   - following a *secured event*, the voltage limits specified in Table 6.2 can be achieved,

   <u>and</u>
   - there is judged to be sufficient certainty of meeting Security and Quality of Supply Standards in operational timescales.
2. It is permissible to relax this to 420 kV (105%) if there is judged to be sufficient certainty that the limit of 420 kV (105%) can be met in operational timescales.

6.4. The voltage limits in Table 6.2 are to be observed following any *secured event*.

Table 6.2 Steady State Voltage Limits and Requirements in Planning Timescales

(a) Voltage Limits on Transmission Networks		
Nominal voltage	Minimum	Maximum
400kV	380 kV (95%) ***Note 3***	410 kV (102.5%) ***Note 4***
275kV	248 kV (90%)	289 kV (105%)
132kV	119 kV (90%)	139 kV (105%)
(b) Voltage Limits at Interfaces to Distribution Networks		
Nominal Voltage		
Any	See below for the minimum voltage that must be achievable. Must always exceed lower limits of Table 6.4(b)	105%
(c) Voltages to be Achievable at Interfaces to Distribution Networks		
Nominal voltage		
Any	100% at any demand level ***Note 5*** or as otherwise agreed with the relevant Network Operator	

Notes

3. It is permissible to relax this to 360kV (-10%) if the affected substations are on the same radially fed spur post-fault, and:

- there is no lower voltage interconnection from these substations to other *supergrid* substations; and
- no auxiliaries of *large power stations* are derived from them.

4. It is permissible to relax this to 420kV (+5%) if there is judged to be sufficient certainty of meeting Security and Quality of Supply Standards in operational timescales, and operational measures to achieve these are identified at the planning stage.
5. May be relaxed downwards following a *secured event* involving the outage of a Grid Supply Transformer, provided that there is judged to be sufficient certainty that the limits of Table 6.4(b) can be met in operational timescales.

6.5. For a site or a group of sites with a combined *Group Demand* of less than 1500MW, operational measures shall be identified at the planning stage to ensure that the requirements of Table 6.3 and 6.4 can be met in operational timescales for all sites remaining connected following any *secured event* for which it is not required to secure the full *Group Demand*.

Voltage Limits in Operational Timescales

6.6. A voltage condition is unacceptable in operational timescales if:

6.6.1. There is any inability to achieve pre-fault *steady-state* voltages as specified in Table 6.3 at *onshore transmission system* substations or *GSP*s

or

6.6.2. if, after either

6.6.2.1. a *secured event*,

or

6.6.2.2. *operational switching*,

and the affected site remains directly connected to the *onshore transmission system* in the *steady state* after the relevant event above, either of the following conditions applies:

6.6.2.3. the *voltage step change* at an interface between the *onshore transmission system* and a *User System* exceeds that specified in Table 6.5,

or

6.6.2.4. there is any inability following such an event to achieve a *steady state* voltage as specified in Table 6.4 at *onshore transmission system* substations or *GSP*s using manual and/or automatic facilities available, including the switching in or out of relevant equipment.

Table 6.3 Pre-Fault Steady State Voltage Limits and Targets in Operational Timescales

(a) Voltage Limits on Transmission Networks		
Nominal voltage	Minimum	Maximum
400kV	380 kV (95%) ***Note 6***	420 kV (105%)
275kV	261 kV (95%) ***Note 6***	300 kV (109%)
132kV	125 kV (95%) ***Note 6***	145 kV (110%)
(b) Voltages to be Achievable at Interfaces to Distribution Networks		
Nominal voltage		
Any	Target voltages and voltage ranges as agreed with the relevant Distribution Network Operators, within the limits of Table 6.4	

Notes

6. It is permissible to relax this to 90% at substations if no auxiliaries of *large power stations* are

derived from them.

Table 6.4 Steady State Voltage Limits and Targets in Operational Timescales

(a) Voltage Limits on Transmission Networks		
Nominal voltage	Minimum	Maximum
400kV	360 kV (90%)	420 kV (105%) ***Note 7***
275kV	248 kV (90%)	300 kV (109%)
132kV	119 kV (90%)	145 kV (110%)
(b) Voltage Limits at Interfaces to Distribution Networks		
Nominal voltage		
132 kV	119 kV (90%)	145 kV (110%)
At less than 132kV	94%	106%

Notes

7. May be relaxed to 440kV (110%) for no longer than 15 minutes following a *secured event*

Voltage Step Change Limits in All Timescales

6.7. *Voltage step change* limits must be observed at every interface point between the National Electricity Transmission System and Users' plant. The *voltage step change* limits do not apply where no User is connected.

6.8. The *voltage step change* limits must be applied with load response taken into account.

Table 6.5 Voltage Step Change Limits in Planning and Operational Timescales

Type of Event	**Voltage Fall**	**Voltage Rise**
(a) At substations supplying *User Systems* at any voltage		
1. Following *operational switching* at intervals of less than 10 minutes	In accordance with Fig. 6.1	
2. Following *operational switching* at intervals of more than 10 minutes, 3. except for *infrequent operational switching* events as described below	-3%	+3%
4. Following *infrequent operational switching* ***(Notes 8, 9)***	-6%	+6%
5. In planning timescales, following a *fault outage of* a *double circuit* supergrid overhead line ***(Note 10)***	-6%	+6%
6. Following any other *secured event*, **(*Note 11)*** <u>except as detailed below:</u>	-6%	+6%
(b) At substations supplying *User Systems* at voltages above 132 kV		
7. Following a *secured event* involving a *fault outage* of a section of *busbar*	-12%	+6%
8. In operational timescales, following a *secured event* involving a *fault outage* of a *double circuit* overhead line	-12%	+6%

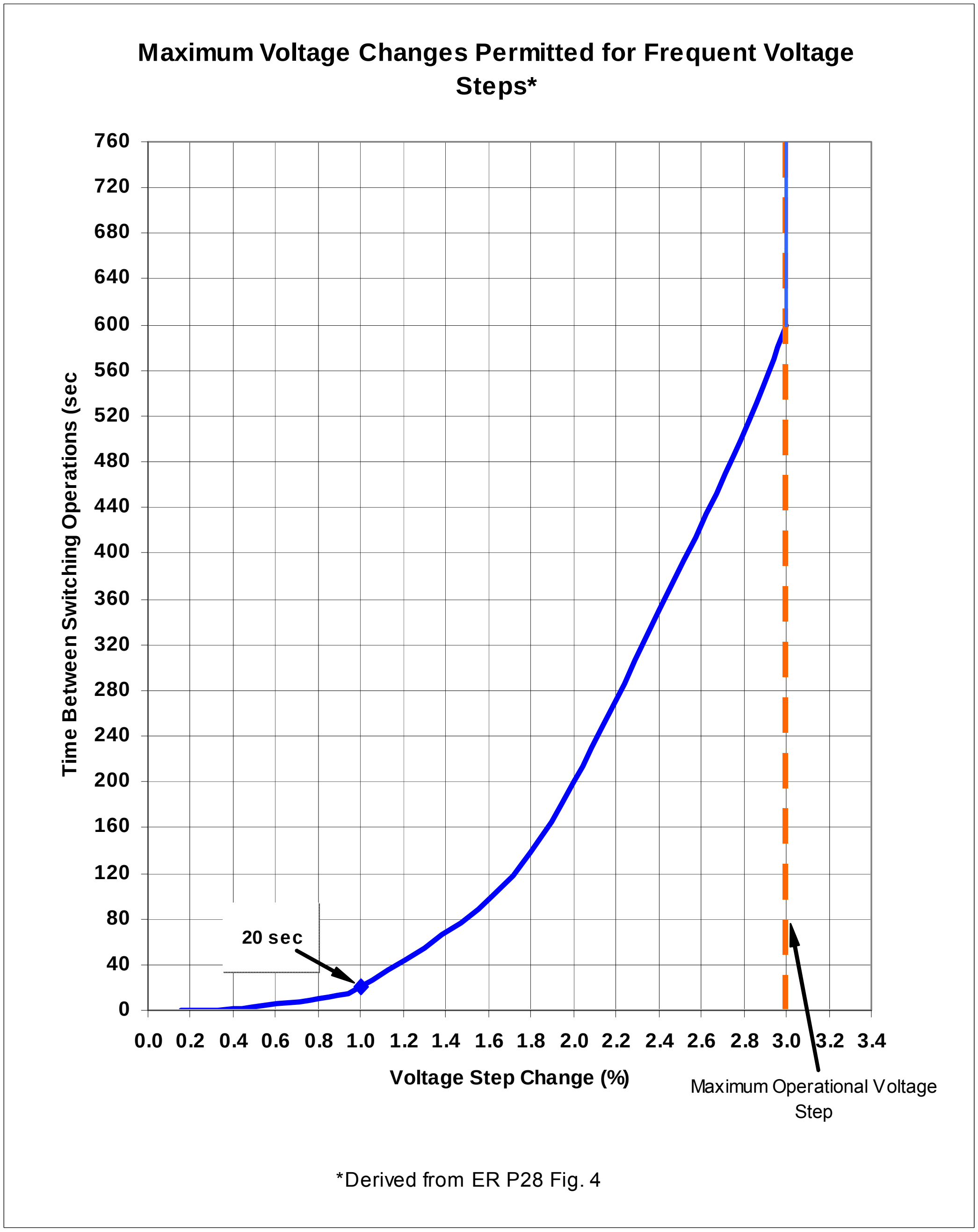
(c) At substations supplying *User Systems* at 132 kV ***As (a) and (b) plus:***		
9. Following a secured event involving loss of a double circuit transmission overhead line, and one or more Supergrid Transformers stepping down to 132 kV	-12%	+6%
10. Following a *secured event* involving loss of a single *transmission* circuit <u>*and*</u> one or more *Supergrid Transformers stepping down to 132 kV*, with a prior outage of another circuit connected to the substation or of another mesh corner at the substation	-12%	+6%
1. Following a *secured event* involving loss of a *double circuit* transmission overhead line operating at 132 kV **(*Note 12)***	-12%	+6%
(d) At substations supplying *User Systems* at voltages below 132 kV ***As (a), (b) and (c) plus:***		
11. Following a *secured event* involving the loss of one or more Grid Supply Transformers	-12%	+6%

Notes

8. An individual User must not experience voltage steps exceeding ± 3% due to infrequent operational switching
   - On a regular basis, and/or
   - at intervals of less than two hours,
   - unless abnormal conditions prevail.

   Infrequent operational switching would typically include disconnection of circuits for routine maintenance, but would not include switching out of circuits for voltage control, or switching out of circuits to allow safe access to other plant, where it is foreseen that such switching may be a regular practice, such events would be classed as *operational switching*.
9. Voltage steps exceeding ± 3% due to infrequent operational switching may be accepted only on busbars or circuits fed directly by the transmission circuits involved in the infrequent operational switching.
10. It is permissible to relax this to -12%, +6% in Scotland if the aggregate demand of sites experiencing voltage falls between 6% and 12% does not exceed 1500 MW
11. Operationally, the -6% requirement may be relaxed to -12% at a site or sites with a combined Group Demand of less than 1500 MW, provided all other SQSS requirements are met, if the -6% requirement may only be met by shedding load.
12. For demand groups with aggregate demand less than 1500 MW, this criterion applies to any demand left connected post-fault

Figure 6.1 Maximum Voltage Step Changes Permitted for *Operational Switching*



Definitions and Commentary (these are not part of the draft Section 6)

Proposed Definitions:

Operational Switching	Operation of plant and/or apparatus within the *onshore transmission system* or *offshore transmission system* to the instruction of the relevant control engineer. For the avoidance of doubt, *operational switching* includes manual actions and automatic actions including tap-changing, auto-switching schemes and automatic reactive switching schemes.
Infrequent Operational Switching	*Operational switching* associated with rare or infrequent events rather than routine management of the system. *Infrequent operational switching* includes, for example, isolation of circuits for maintenance and subsequent re-energisation, and operation of intertrip schemes consequent upon secured events. *Operational switching* associated with rare or infrequent events rather than routine management of the system. *Infrequent operational switching* includes, for example, isolation of circuits for maintenance and subsequent re-energisation, and operation of intertrip schemes consequent upon secured events. It would not include switching out of circuits for voltage control, or switching out of circuits to allow safe access to other plant, where it is foreseen that such switching may be a regular practice; such events would be classed as *operational switching*.
Supergrid Transformer stepping down to 132 kV	A 400/132 kV transformer or 275/132 kV transformer. In England and Wales, these are Grid Supply Transformers; in Scotland, they are not.
Credible Demand Sensitivities	*Interim:* retain existing definition. *Desirable:* redefine, consistent with demand uncertainties and intermittent/variable generation.

Commentary on the Draft Proposed Standard

Steady-state Voltage Limits on Transmission Networks

1. The operational upper voltage limits are determined by insulation performance. At 400 kV the upper limit is 420 kV (+105%). This is the actual equipment limit; as a concession it is relaxed to 440 kV for no longer than 15 minutes. Advice from an NG plant expert is that this limit is still appropriate as it is determined, in the first instance, by the performance of oiled paper insulation.

2. In the format of the draft proposed standard, it is made clear that the relaxation to 440 kV is only permitted for 15 minutes following a secured event.

3. The previous standard (version 2, 24/6/2009) allowed the 275 kV voltage in Scotland to rise to 316 kV (115%) following a major system fault, and the 132 kV voltage in Scotland to rise to 158 kV (120%) following a major system fault. No such relaxations are permitted in England and Wales. The TOs' plant specialists do not support these relaxations so the references to them are removed. This proposal will align maximum steady state voltage limits across the GB transmission system.

4. The previous SQSS states that the upper voltage limit at 275kV is 303 kV (110%, after rounding). In fact, 275 kV plant is specified in National Grid and IEC specifications for a maximum working voltage of 300 kV so that operating at 303 kV would, technically, overstress it. It is therefore proposed to change the upper voltage

limit in the SQSS to 300 kV (109%) in line with the plant rating. A similar change would be needed in C.C. 6.1.4 of the Grid Code. (Note that the statutory limits remain at ±10% at 275 kV, but this does not preclude utilities offering Users tighter voltage regulation.)

5. The restrictions on steady-state voltage ranges in planning timescales (Tables 6.1 and 6.2) are retained in line with the previous standard, in the absence of better proposals for dealing with uncertainties in the distribution of demand and generation. There is still scope for work to assess whether these restrictions are a necessary or sufficient means of handling uncertainties.

6. These restrictions were originally imposed at a time when the ability to conduct detailed AC analysis at the planning stage was very limited: typically, only an average ACS or summer minimum condition would be studied for each year. The risk of uncontrollable voltage runaway at the minimum demand condition was of particular concern, due to the limited amount of generation running and its unpredictable distribution. Reducing the voltage range helped to ensure that keeping the voltage in one part of the system within insulation limits would not depend excessively on reactive absorption by generators in another part.

7. Nowadays a wider range of analysis is possible, and it is noted in particular that planning studies are carried out for average ACS planned transfer conditions and for planned transfer + interconnection allowance (or half-interconnection allowance) on boundaries of concern. Thus, some of the range of planning uncertainties is now subject to explicit analysis.

8. The upper voltage limit in planning is 410 kV (102.5%) and allowance is made for relaxing this upwards, as before, to 420 kV, but now only after a secured event. However, this voltage is still within the insulation limit so explicit reference to a 15 minute time limit seems inappropriate.

9. In network planning, the pre-fault planning voltage limits have often been applied flexibly where it has been cost-effective to do so. For example, engineers have sometimes assumed pre-fault voltages of 103% – 103.5% in parts of the system to make use of reactive reserve that would otherwise be inaccessible, but have done so with a high degree of certainty that the voltages in those areas will be manageable in the operational timescale.

10. It is concluded that there is a case for allowing some flexibility in the application of the planning voltage limits in the SQSS.

11. The conditions for relaxing the planning voltage limits are that there is sufficient assurance of meeting operational limits on the day. For example, planning to allow a 400 kV system voltage above 410 kV would require the identification of operational measures that would bring the voltage down to 420 kV within 15 minutes, should it rise above that level after a secured event occurring in operational timescales.

12. It is recommended that, where the planning voltage limits are flexed in this way, the justifications for doing so, and any capital cost avoided, are recorded.

13. In planning, the post-fault lower limit at 400 kV is 95% on the parts of the system that remain interconnected, with a relaxation to 90% at substations left on radial spurs. The operational standard is simpler, with a general lower limit of 90%. The two standards are considered consistent: a system designed to the planning limits but operated to the operational limits should only see voltages down to 90% in a few locations following an outage in operational timescales. On the remaining interconnected system the voltage should remain high enough to ensure stable power transmission.

14. Consideration has been given to the possibility of allowing relaxation of the 95% lower limit in planning, at 400 kV nodes other than those left radially-connected following a *secured event*. The conclusion was that it is preferable to retain this limit for general planning. In some cases the system has a “brittle” performance characteristic and voltage instability is possible at voltages above 90%. In these circumstances, little or no savings would be made by planning to a voltage limit below

95%. In other cases, operation below 95% appears possible but the low voltages are associated with difficulties in maintaining LV target voltages at GSPs and potential increased risk of instability and system break-up.

15. Paras 6.3 and 6.13 of the proposed standard state that the voltage criteria apply at any sites that remain connected to the system following a secured event. This has been carried forward from previous versions, and the intention is that any demand remaining connected should be supplied with acceptable voltage [Ref 3, paras 149-151].

16. In the proposed standard we extend this principle to include demand groups < 1500 MW, which are not required to be secure for a double circuit transmission fault. The intention is that potential operational measures, such as demand shedding, should be identified at the planning stage so that any demand still connected should have acceptable voltage without the risk of local voltage collapse or voltage runaway. Para 6.9 is worded generally, in terms of secured events for which it is not necessary to secure the whole group demand, but the main application will be for double-circuit faults involving sub-1500 MW demand groups.

17. The operational voltage limits are now divided between two tables (6.3 and 6.4) in the manner of the planning voltage limits. Table 6.3 now includes the pre-fault operational limits which are currently discussed in the text of para 6.5.5 in the current SQSS.

18. Consideration was given to combining Tables 6.1 and 6.2 into one table and Tables 6.3 and 6.4 into another. This would give a single table for steady state voltages and targets, pre- and post-fault, in planning timescales, and the equivalent for operational timescales. The resulting layout was compact, but on consideration, the tables appeared congested and it was felt to be more difficult to explain, and understand, the differences between pre- and post-fault LV voltage targets and limits at GSPs. On balance, it was felt better to accept a longer document if it would be easier to understand.

<u>Voltage Targets and Limits at Interfaces to Distribution Networks</u>

19. These are now included in the tables rather than being referred to in footnotes. This is to acknowledge the significance of these constraints, which were given prominence in the earlier design standard PLM-ST-9 [Ref. 2]. In addition, the table sets out more specific target voltages in planning timescales than the current standard [Ref. 4], which refers rather confusingly to “up to 105%” and “up to 100%”.

20. It is normal practice to design Grid Supply Points to achieve a desired steady-state target voltage at the interfaces to the distribution network. The default values carried forward from earlier standards are 105% pre-fault and 100% post fault at peak demand, and 100% pre-fault and post-fault at minimum demand. The voltage target may be varied by agreement with the distribution operator. At the detailed design stage the transmission owners and operators way coordinate with the distribution network operator to optimise the overall design of the substation and distribution network.

21. The default pre-fault voltage to be achievable at GSPs is set at 105%, in continuation with previous practice. However, it is noted that achieving the required LV voltages with the minimum allowable HV voltages (e.g.105% LV voltage with an HV voltage of 95%) may restrict the reactive demand suppliable. This is an area of the SQSS that may require further investigation and clarification.

22. The proposed standard continues the current practice of relaxing the target voltage in planning timescales following loss of a Grid Supply Transformer. However, the proposed standard now requires that there should be sufficient certainty of remaining within operational limits on the day (the present standard has no specific requirement). The rationale for this is that:

    – It is assumed that the DNO designs a network such that with target voltage at the GSP and a secured distribution outage, customer voltage remains within limits.

- An intact DNO network should be able to provide satisfactory customer voltage provided that the GSP voltage remains within operational limits following a GST loss, but:
- a coincident GST loss and DNO circuit loss are regarded as non-credible.

23. Note that relaxing the planning voltage target in this way following the loss of a GST was a departure from the requirement of PLM-ST-9 and earlier standards.

24. It is expected that the interpretation of the GSP voltage target requirements may vary between TOs: the relationship between NGET and DNOs in England and Wales is likely to be more formal than relationships in Scotland, where transmission and distribution networks have the same owners.

Voltage Step Changes

25. The proposed standard has a set of common criteria applying to all TOs and, with slight variations, in both operational and planning timescales.

26. The main point at issue is the circumstances in which a 12% voltage fall is allowed, rather than the more general 6% change following a secured event.

27. In the current standard [Ref. 4] there are regional variations and differences between planning and operational requirements, including some anomalies. In one case (loss of a SGT) the current standard [Ref. 4] requires the system to be operated to tighter limits than it is designed for.

28. The principles applied in reviewing these criteria are:

    - Apply the same voltage step criteria to secured events of equivalent probability and severity (for example, the current standard [Ref. 4] applies different criteria for a single circuit outage, depending on whether the circuit terminates on a busbar or a mesh-corner);
    - Hence, provide consistent voltage quality to all customers wherever possible, irrespective of the type of supergrid substation they are supplied from (since this is at the discretion of the TO and individual customers have no influence);
    - Limit severe voltage step changes to as few customers as possible; hence if a secured event results in voltage steps over a wide area (e.g. several GSPs) the voltage steps should be within 6%;
    - Limit severe voltage steps to rarer secured events;
    - Cause no deterioration in customers' quality of supply, and no increase in TOs costs where quality of supply is already satisfactory;
    - Achieve a clear, simple format without over-reliance on footnotes to define the conditions for which 12% voltage falls are accepted.

29. It is considered appropriate to have one standard for planning and operations, in general, since the voltage step experienced by customers is largely driven by the design of the network. The secured events that cause the largest voltage steps are usually those involving the loss of supergrid transformers and Grid Supply Transformers.

30. It has been possible to determine common GB standards for planning and operation for all types of secured events except the outage of a supergrid *double circuit*.

31. In planning, with England and Wales the supergrid is currently planned to a previously-intact system, only 6% voltage fall for a *double circuit* trip but a 12% fall is

allowed. However, this is relaxed operationally, . The reason for this is taken to be that the tighter planning standard caters for uncertainty in demand and generation distribution and results in a system that can then be operated successfully to the -12% limit when a *double circuit* outage trip may occur on a depleted network. The working group saw no evidence to change these assumptions so it is proposed to continue with this existing standard

32. In Scotland, a 12% voltage fall is allowed for a *double circuit* transmission outage in planning timescales, under the current SQSS [4]. The working group has considered the arguments for and against applying a common planning standard in Scotland, England and Wales:

    – has been noted that the role of the supergrid in Scotland is developing from one where, largely, it transmits power from Scottish generation to local demand, to one where it will transmit considerable bulk power to demand in the south. On the basis that planning to a 6% voltage fall would result in a generally more robust system than one planned to a 12% fall, a case may be made for applying a 6% voltage fall criterion to the interconnected supergrid system across GB.

    – Where voltage steps on the supergrid exceed -6% it is frequently found that the steady state voltages are falling below their planning limits, and/or supergrid transformers tap limits prevent desired GSP LV voltages being achieved. That is, it is uncommon for investment to be required solely to meet the -6% voltage step change criterion.

    – However, there are arguments for retaining the status quo in Scotland:

        i. Achieving 6% step-changes in planning timescales will require additional capital expenditre beyond that already forecast to meet future power transfer requirements, and provide a higher quality of supply than that currently found acceptable.

        ii. Notwithstanding future generation developments, much of the Scottish network will not have a significant role in “strategic” power transfers.

        iii. The distribution of generation, and the structure of the network, are such that the patterns of power flows, and hence voltages, are expected to remain more predictable than those on the interconnected England and Wales network. There is therefore less justification than there is in England and Wales for planning to a tighter standard than the operating standard.

    – There are also arguments for retaining the status quo in England and Wales:

        i. As previously stated, planning to – 6% provides a cushion against uncertain generation and demand distribution, so that the system can be operated to a -12% standard without undue constraint cost.

        ii. As also previously stated, it is hard to find evidence that planning to a -12% limit on the interconnected system in England and Wales would produce significant saving in investment. Voltage steps in excess of 6% tend to be associated with other infringements of the SQSS such as steady state voltage limits on the supergrid or at GSPs, or insufficient voltage performance margins.

        iii. Although *double circuit* faults are comparatively rare, at about 1 per 100km per 10 years, the voltage step-change due to supergrid faults can propagate over a wide area. In densely-populated parts of England and Wales the MW demand per 100km of *double circuit* is about three or four times greater than in Scotland. Voltage steps in these densely-loaded areas can therefore affect more end-customers than voltage steps in Scotland, so an argument can be made for retaining the current England and Wales standard on the grounds of maintaining the existing quality of supply.

33. In view of the above, the working group can neither recommend applying the -6% planning limit in Scotland (which would increase investment requirements for limited quality of supply benefit) nor recommend relaxing the current England and Wales planning standard to -12% (which may reduce quality of supply for no obvious saving in investment). It is therefore proposed to retain a regional variation in the standard, pending further investigations of the options for a common standard.

34. The table of criteria (Table 6.5) is divided into four sections, depending on the voltage at which Users are connected to the transmission system. This structure attempts to address the current regional differences:

    - More relaxed criteria are applied to supergrid sites supplying distribution at voltages lower than 132 kV, because the transformer impedances are higher than those for 275/132 kV or 400/132 kV SGTs so voltage falls will more frequently exceed 6%. For example, a mesh corner fault is allowed 12% voltage fall at a 33 kV site but only 6% at a 132 kV site.

    - The same criteria are applied at sites connecting 132 kV transmission to distribution networks in Scotland as are applied at 400/132 kV and 275/132 kV Grid Supply Points in E & W.

    - For larger substations (400/132 kV and 275/132 kV) supplying large numbers of end-customers the criteria are more stringent than those supplying networks at lower voltages, with fewer customers.

35. The table is formatted to present the secured events for which voltage steps must be restricted to 3% or 6%, followed by, for each voltage level, the secured events for which 12% voltage fall is acceptable.

36. The criteria apply to secured events involving losses of supergrid transformers supplying the 132 kV network in Scotland as well as supergrid transformers supplying distribution networks in England and Wales. It is necessary to distinguish between 400/275 kV supergrid transformers, supergrid transformers stepping down from the supergrid to 132 kV, grid supply transformers stepping down from the supergrid to 66 kV and below in England and Wales and grid supply transformers stepping down from 132 kV to lower voltages in Scotland. Hence the choice of wording “Supergrid Transformers stepping down to 132 kV”.

37. It is assumed that a secured event on a lower voltage system should not cause a voltage change beyond ±6% at a higher voltage. This seems unlikely, in any case.

38. Loss of a generating unit (or several generating units with a common prime mover, or common steam supply) is now recommended for inclusion in the secured events for which the maximum step change is ±6%. It will be necessary to amend Section 4 of the revised SQSS to include such generator trips in the list of secured events. Section 5 of the current SQSS refers to the most onerous loss of power infeed as a secured event. It must be made clear, either in the revised SQSS or in TO procedures, that this refers to the most onerous local loss, as well as to the most onerous national loss affecting system frequency; otherwise Section 5 must make separate reference to generator trips in the same way as Section 4.

Operational Switching

39. The previous standard included requirements to observe ±3% voltage step limits, and the provisions of Engineering Recommendation P28, in England and Wales but not in Scotland.

40. It is believed that the decision to include the requirement in the England and Wales criteria may have been triggered originally by the large numbers of shunt reactors and capacitors subject to regular switching in the National Grid network.

41. The Grid Code (CC6.1.7) requires that the voltage fluctuation limits of P28 apply throughout GB; Section D of the SO TO Code requires that TOs comply with the Grid Code as applicable.

42. P28 requirements may therefore be judged to apply, whether or not they are included in the SQSS. It has been normal practice in NGET to adhere to P28 limits in the design and operation of reactive compensation schemes in England and Wales. It is proposed to retain the reference to operational switching limits in the SQSS, applying across GB, since they are a significant constraint in planning and operating the system. Including them reduces the number of documents to be referenced in planning and operations.

43. "Operational switching" is not defined in the current SQSS but is taken to have the same meaning as it does in the definition in the Grid Code, but including automatic switching of capacitors and reactors, and tap-changing on transformers. It is suggested that the revised SQSS should include a definition, or else refer to a common SQSS/Grid Code/STC definition.

44. The definition of a voltage step-change in ER G75/1 may be appropriate:

> *"Following system switching, a fault or a planned outage, the change from the initial voltage level to the resulting voltage level after all the Generating Unit automatic voltage regulator (AVR) and static var compensator (SVC) actions, and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced."*

45. By this definition, voltage depressions caused by transformer inrush would not be classed as step changes for the purposes of operational switching in the SQSS. However they would of course be subject to the provisions of ER P28 to which the TOs may be bound by the Grid Code and STC.

46. Operational switching has a different meaning from the "Routine Switching" referred to in ER P28. Routine switching in P28 means any switching done to control fault level, or for steady-state voltage control, i.e. it defines the network on which the voltage fluctuation-causing event occurs.

47. In parts of the GB system activities such as isolation of circuits for maintenance may cause voltage steps in excess of 3%. Although these are operational switching events, they are infrequent and do not appear to fall within the categories of disturbance that ER P28 is intended to regulate. It is therefore proposed to divide "operational switching" events into two classes: regular, frequent, events such as frequent switching of reactive compensators, and rarer events such as maintenance switching. The ER P28 limits would apply to the first category but not to the second.

48. It is, of course, understood that TOs and the GBSO plan operational switching to minimise disturbances to customers as far as is reasonably possible.

49. ER P28 describes a method for assessing the likely subjective effects of a range of different types of voltage disturbance arising from the operation of a variety of equipment. The voltage step-changes caused by operational switching form a simple sub-set of such disturbances. It seems inappropriate then for transmission design and operations engineers to need to keep referring to, and interpreting, the complete ER P28 document. The draft SQSS therefore includes a chart of permissible voltage steps for events that occur at intervals of less than two hours. This is consistent with ER P28 limits.

Secured events

50. The following changes are proposed to definitions of secured events in other sections of the SQSS for which the voltage criteria are to be applied:

- Loss of a generating unit, power park module or DC link bipole, or more than one generating unit where they share a common prime mover or steam supply (common-mode failure)
- A circuit-breaker fault, if this leads to a voltage rise.

References for the "Proposed Revised Voltage Criteria":

1. Electricity Safety, Quality and Continuity Regulations 2002
2. Planning Memorandum PLM-ST-9 Issue 1 CEGB December 1985
3. "Guidance in Support of the GB Security and Quality of Supply Standard" Version 0.5, 9 August 2005
4. National Electricity Transmission System Security and Quality of Supply Standard version 2.0 24 June 2009
5. Engineering Recommendation P28: "Planning Limits for Voltage Fluctuations Caused by Industrial Commercial and Domestic Equipment in the United Kingdom".

Appendix E

Analysis of Unbalanced Fault Types for Strathaven 400kV DC Fault (Year 2012/13)

Previously, using the Investment Planning Year 2012/13 100% SMD system with Schedule B it was found that the system remains stable for a solidly earthed 3-phase fault with a 4.0 GW export and double circuit Strathaven fault (clearing lines Strathaven – Coalburn and Strathaven – Elvanfoot in 80 msecs) with a Longannet set on trip. This study was pursued to find the stability limit. The fault type was changed to a 2 phase to earth, then to a single phase to earth and the stability limit was determined for both fault types. Finally, no fault was applied but the two lines were switched out and the stability limit was found.

The studies are tabulated below:

Generation :	1xTorness; 2xHunterston; 4xLongannet; 2xCockenzie; 1xCruachan; (1+3)xPeterhead; 1xFoyers
Load :	100% SMD
Fault :	DC STHA4-; Clear STHA4-/COAL4- & STHA4- /ELVA4- 80ms; Loan01 trip

Export (GW)	Fault Type	Generation amendments from previous study	Stability Output File (.out)	Stable /Unstable
4.2	3 phase to earth	Peterhead increased (243)	ip07_2012_B42_1a	Stable
4.3	3 phase to earth	Peterhead increased (37); Cruachan set added (100)	ip07_2012_B43_1a	Stable
4.36	3 phase to earth	Sloy gen added (60)	ip07_2012_B436_1a	Unstable
4.4	3 phase to earth	Cruachan set added(100); Sloy gen removed (60)	ip07_2012_B44_1a	Unstable
4.45	3 phase to earth	Sloy gen added (60)	ip07_2012_B445_1a	Unstable
4.4	2-phase to earth	as for 4.4 above	ip07_2012_B44_LLG_1a	Stable
4.45	2-phase to earth	Sloy gen added (60)	ip07_2012_B445_LLG_1a	Unstable
4.4	1-phase to earth	as for 4.4 above	ip07_2012_B44_LG_1a	Stable
4.45	1-phase to earth	Sloy gen added (60)	ip07_2012_B445_LG_1a	Unstable
4.4	No fault	as for 4.4 above	ip07_2012_B44_NF_1a	Stable
4.45	No fault	Sloy gen added (60)	ip07_2012_B445_NF_1a	Unstable

Results

The above table shows that, excluding the 3-phase-to-earth fault,with a stability limit of 4.3GW, the limit for all others, including the no-fault case, is 4.4GW. It appears that the effect of switching out the double circuit is much greater than the changing of the fault type. Further work is required to properly assess the effect on the system of changing the fault type.

Appendix F

Great Britain Security and Quality of Supply Standard
Fundamental Review

Planning and Operational Criteria Working Group Terms of Reference

Working Group: 4	**Chairperson:** Brian Punton **Secretary:** Bless Kuri

Title of Working Group: Planning and Operational Contingency Criteria (POCC)

Background:
This Working Group has been formed by the GB SQSS Project Steering Group and forms part of the project for the Fundamental Review of the GB SQSS as detailed in the GBSQSS Fundamental Review Project Definition Document.

The **draft GB SQSS dated 29 April 2008**[17] contains a co-ordinated set of criteria and methodologies that the relevant transmission licensees will be required to use in the planning, operation and maintenance of the GB transmission system (i.e. both the onshore transmission system and the offshore transmission systems).

To ensure that unacceptable conditions on the GB transmission system do not occur under any circumstances would, of course, be cost prohibitive; both in planning and operational timescales. The GB SQSS, as the previous standards, recognises that some conditions are more likely than others and these are identified as 'secured events'. That is, events against which the GB transmission system is planned and operated such that, should those events occur, unacceptable conditions shall not arise as a result. Unacceptable conditions include: loss of power infeed in excess of stipulated limits; loss of supply capacity in excess of specified limits; unacceptable overloading; unacceptable voltage conditions; and system instability.

There are a number of developments within the industry (e.g. anticipated large volumes of renewable generation expected to connect and the emergence of offshore networks connecting offshore power stations to the mainland) and reviews (e.g. the Transmission Access Review) which have the potential to impact on the GB SQSS. Given such developments, it is appropriate that a review of the GB SQSS is now conducted to ensure that secured events and unacceptable conditions used in planning and operating the onshore transmission system remain appropriate to current and forecast circumstances.

Scope:
The Working Group will review the planning and operational contingency criteria (Secured events and unacceptable conditions) of the GB SQSS in the light of current and forecast developments and make change proposals as necessary. All change proposals should be relative to the draft GB SQSS dated 29 April 2008 rather than relative to the existing GB SQSS dated 2004. Offshore planning and operational contingency criteria fall within the scope of the Offshore Transmission Systems work area (Working Group 5).

In developing change proposals, the Working Group shall include consideration of:

- N-1, N-2, N-D, N-3 etc. Any change proposals identified should be demonstrated as being appropriate and would include: the results of a survey of fault statistics; an assessment of the consequences of different types of event; identification of areas of the GB SQSS where there are currently regional differences; and consideration as to whether such differences are appropriate;
- The impact of changing the contingency criteria on demand security, constraint costs and

[17] A PDF copy of the 29 April 2008 draft GB SQSS can be accessed from the Ofgem website at the following link: **draft GB SQSS, dated 29 April 2008**

infrastructure requirements from a MITS planning perspective;

- The impact of changing the contingency criteria on demand security and constraint costs from a MITS operational perspective;
- Take due account of the WG3 (MITS) views on the appropriate methodology for setting the generation and demand background conditions (recognising the contribution of different generation technologies) against which the need for additional transmission capacity is judged in planning timescales;
- Use of intertrip schemes (the current GB SQSS does not permit the use of generator and/or demand intertripping to create system capacity in planning timescales). The use of intertrip schemes to disconnect exports across interconnections with external systems is being considered by WG3 (MITS);
- The treatment of bus coupler and bus section switch faults under intact and outage conditions;
- Use of dynamic ratings;
- Voltage limits including: the differences (in percentage terms) between 400kV and 275kV voltage limits; the background and purpose of the 15min relaxation; the differences between planning and operational voltage limits; 90% reactive availability on generators; the 6% and 12% voltage step change limits; review notes 2 and 3 of Table 6.1 ie up to 105%, or, at least 105%; a review of current methodology used for voltage analyses; and the use of manual and/or automatic facilities;
- Stability assessment criteria including; examine the rational for using the 3 phase close up fault criterion and failure of the fastest main protection; the increase in effective capacity available from the use of less onerous criteria;
- Criteria for assessing the consequences of any change proposal.

In addition, the Working Group shall take due account of:

- Interactions with the work of other Fundamental Review Working Groups;
- The potential impact of the findings of other relevant reviews (e.g. Transmission Access Review); and
- In the context of any change proposals to the GB SQSS arising, compatibility with other industry Codes (e.g. GB Grid Code).

Deliverables:
The Working Group deliverables include:

- <u>Outline Principles Document (15 October 2008)</u>
  Written report to the Programme Manager on issues being addressed, new issues arising, approach adopted for addressing issues, progress to date and likely outcome (where reasonably known).
  The Programme Manager will then consolidate the individual 'Outline Principles Documents' from each Working Group into a single document and submit for consideration by the Project Steering Group
- <u>High Level Proposals (December 2008)</u>
  Written report to the Programme Manager on progress in the form of high level proposals to address issues.
  The Programme Manager will then consolidate 'High Level Proposals' reports from all Working Groups into a single document and submit for consideration by the Project Steering Group (January 2009).
- <u>Draft Change Proposals (May 2009)</u>
  Issue detailed proposals and assist the GB SQSS Drafting Working Group, as necessary, in developing draft change proposals to the GB SQSS in the form of additional and/or modified change proposals to the NGET change proposals dated 29 April 2008.
  The Programme Manager, with the assistance of the GB SQSS Drafting Working Group, will consolidate the draft change proposals from all Working Groups into a single set of change proposals and submit for consideration by the Project Steering Group.
- Final Change Proposals (August 2009)
  Issue final detailed proposals taking account of comments received on draft change

proposals.

The Programme Manager, with the assistance of the GB SQSS Drafting Working Group, will prepare the consolidated set of change proposals to the GB SQSS (i.e. in the form of draft amendments to the draft GB SQSS dated 29 April 2008) and submit for consideration by the Project Steering Group.

- Final Change Proposals Consultation (First Consultation), (Sept to Oct 2009)
  Assist the Project Steering Group, as required, to conduct a targeted consultation on the consolidated final change proposals with participants of the Industry Peer Review Group.
  Following the First Consultation the GB SQSS Drafting Working Group will (with assistance of other Working Groups as necessary) amend the final change proposals to take due account of comments received. The revised final change proposals will be submitted to the Project Steering Group for onward submission to the GB SQSS Review Group for sign-off.
  The Project Steering Group (on behalf of the GB SQSS Review Group) will then submit the final Change proposals to Ofgem.

In addition to the above, the Working Group shall:

- Prepare and maintain Working Group Risk and Assumptions Registers in accordance with the requirements set out in the Project Definition Document;
- Prepare and maintain a detailed plan covering the scope and deliverables contained within these Terms of Reference, again in accordance with the requirements set out in the Project Definition Document; and
- Liaise with other Working Groups; particularly on areas of interaction; and take due account of other reviews which are currently in progress (e.g. Transmission Access Review).

Programme:
The Working Group detailed program should align with the overall Project Plan.

Members:
Working Group membership:

- Brian Punton SHETL Chairperson
- Bless Kuri SHETL
- Noel McGoldrick NGET (Replaced by Mark Perry, NGET)
- Ian Gilbert NGET
- (Dave Coates NGET)
- (Paul Plumptre NGET)
- Dave Adam SPT
- Danny Pudjianto SEDG
- Rodrigo Moreno SEDG
- John Morris British Energy

Members in parenthesis ( ) will provide input to specific areas.

Meetings:
The meetings for the Working Group will alternate between Scotland and England and consideration will be given to using technology to minimise travel requirements.

Approved by:

Project Manager: Andrew Hiorns

Working Group Chairman: Brian Punton

Date: 14th October 2008