Accommodating Demand Side Response in Engineering Recommendation P2/6 – Change Proposal

Capacity to Customers (C_2C) Project

CONTENTS

VERSION HISTORY

Version	Date	Author	Status (draft, etc)	Comments
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APPROVAL

Name	Role	Signature & date
Paul Turner	C_2C Technical Manager	Paul turner 29th August 2013

GLOSSARY OF TERMS

Abbreviation	Term
C_2C	Capacity to Customers
DCUSA	Distribution Connection and Use of System Agreement
DG	Distributed Generation
DNO	Distribution Network Operator
DSR	Demand Side Response
ER	Engineering Recommendation
ESQCR	Electricity Safety, Quality and Continuity Regulations
ETR	Engineering Technical Report
LCN Fund	Low Carbon Network Fund
LMA	Load Managed Area
MIC	Maximum Import Capability
MPAN	Meter Point Administration Number
NETS SQSS	National Electricity Transmission Security and Quality of Supply Standard
NOP	Normal Open Point
Ofgem	Office of the Gas and Electricity Markets
RIGs	Regulatory Instructions and Guidance Documents
RTS	Radio Teleswitch
SDRC	Successful Delivery Reward Criteria milestone
SLC	Standard Licence Condition

All other definitions shown starting with a Capital letter are as per LCN Fund Governance Document v6.

1 EXECUTIVE SUMMARY

Compliance with Engineering Recommendation P2/6 is a distribution licence condition (Standard Licence Condition 24, "Distribution System planning standard and quality of performance reporting") and is included as a reference document at Appendix 1 of The Distribution Code.

ER P2/6 does not explicitly allow or disallow responsive demand to be included within the security of supply assessment for any given Group Demand, consequently, there is uncertainty whether the benefit of customers who contractually agree to an interruption or reduction of demand for network contingencies can be realised and remain strictly within the requirements of ER P2/6.

This report presents the results of a review of ER P2/6[1], its supporting document ETR 130[2] and a set of proposed changes to how they might accommodate responsive demand. The definition and treatment of demand side response (DSR) with P2/6 security assessments is an important factor in the adoption of DSR as a business as usual technique. Unrestricted or inappropriate use of DSR may adversely affect security of supply to customers; conversely unnecessarily restrictive treatment of DSR would tend to preclude some or all of the potential economic and technical benefits.

This review has been conducted as part of the Electricity North West's Capacity to Customers (C_2C) project which is supported by Ofgem's Low Carbon Networks (LCN) Fund. The C_2C project aims to use new technology and innovative commercial contracts to increase the amount of energy that can be transmitted through the infrastructure that is already in place throughout the region. C_2C is based upon the use of automated switching to provide post fault demand response to manage power flows when operating with abnormal network configurations after a fault.

In parallel with the C_2C work, a more structural review of ER P2 has been commissioned by the Distribution Code Review Panel which is intended to reassess the underlying basis of network security assessments. This more fundamental review is envisaged, to recommend more extensive changes but is unlikely to finalise its recommendations in less than 2 years. The work presented in this report provides a valuable bridge between current assessment methodologies and a future P2/7. The recommendations are sufficient to enable the early adoption of DSR by network operators in a consistent and prudent manner.

The recommendations detailed in this report have been obtained following an industry wide consultation exercise and recognise in the short term the need for a number of modifications to ETR 130. These modifications are designed to provide timely guidance on how DSR should be accounted for within network security of supply assessments. These recommended modifications lead the DNO to make an appropriate allowance for DSR when determining group demand; a detailed methodology for the allowance was thought to be unnecessary at this point.

The changes recommended by this report shall be referred to the Distribution Code Review Panel which presides over the formal governance of ER P2/6, and ultimately to Ofgem for the approval of any changes

2 INTRODUCTION

2.1 ER P2/6 (2006): Security of Supply

Compliance with Engineering Recommendation P2/6 is a distribution licence condition (Standard Licence Condition 24, "Distribution System planning standard and quality of performance reporting") and is included as a reference document at Appendix 1 of The Distribution Code.

ER P2/6[1] defines the required levels of security of supply in terms of the time to restore supplies to customers affected by any interruption; there is less allowed time for larger groups of load (Group Demand). Engineering Technical Reports ETR130[2] and ETR131[3] provide additional information which supports ER P2/6.

A system's ability to satisfy the requirements of ER P2/6 is judged by comparing the Group Demand with the capability of the network. Group Demand is presently defined as the sum of the Measured and Latent demands, where Latent demand is the increase in demand which would be observed if all distributed generation (DG) in the group were not producing any output. The capability of the network is presently calculated as the sum of the capability of the network equipment following an outage of the most critical circuit, and includes allowances for the transfer capacity to adjacent circuits and for any appropriately contracted DG.

2.2 Requirement for Change

The evaluation of the effects on demand levels due to the operation of responsive loads is not explicitly permitted in ER P2/6. However, DNOs are able to make allowances for individual customers when undertaking customer connections and network reinforcement assessments. Guidance Note 1 of The Distribution Code permits that a customer can elect to receive security at a level lower than a ER P2/6 connection, provided that it does not affect the quality of supply to any other customer in that network.

DSR may be initiated via a variety of methods including and not limited to:

- energy price signals to consumers.
- incentive payments coupled to response requirements initiated by signals derived from asset events or demand levels.

The latter method is particularly useful to network operators for network balancing; potentially enabling deferment of system reinforcement and better use of existing assets. The potential economic benefits of DSR in meeting the challenge of energy decarbonisation have driven recent work in this area including C_2C.

2.3 Objective of this Review and the timetable for Change

The remit of this report is to present a recommendation for how DSR can be accommodated within ER P2/6 and its supporting documents in order to ensure benefits of the growing

[1] Energy Networks Association, Engineering Recommendation P2/6 – Security

[2] Energy Networks Association, ETR 130 Application Guide for Assessing the Capacity of Networks Containing Distributed Generation, July 2006.

[3] Energy Networks Association, ETR 131 Analysis Package for Assessing Generation Security Capability – Users' Guide, July 2006.

number of novel operational techniques can be realised. In addition to this it aims to provide a consistent and practical approach for the industry to follow when assessing the contribution of DSR to security of supply assessments.

It has already been recognised that a wider review of P2/6 is required as discussed in an open letter[4] from the Chairman of the Distribution Code Review Panel, dated 11 December 2012. However, resolution of wider security issues is likely to result in a significant update which is likely to take several years to complete. Hence the need for an update just related to recognising DSR within ER P2/6 in the interim period. This is based upon an anticipated increase in the use of DSR throughout this distribution price control period (to March 2015), and the next, referred to as RIIO ED1, beginning April 2015.

The changes recommended by this report shall be referred to the Distribution Code Review Panel which presides over the formal governance of ER P2/6 and its associated ETR 130, and ultimately to Ofgem for the approval of any changes.

2.4 P2/6 Changes in the context of the Capacity to Customers Project

An example of the current trialling of DSR is Electricity North West's Capacity to Customers (C_2C) project[5]. In November 2011 the C_2C project was awarded £9.1 million funding from the Low Carbon Networks Fund[6]. The C_2C project aims to show how, through the use of new technology and innovative commercial contracts, the amount of energy that can be distributed through the existing infrastructure can be increased. Within the trials the project proposes to take advantage of the capacity that presently exists within the network[7] to allow new Low Carbon Technologies to connect to the existing distribution network, without reinforcement. It is proposed that new and/ or existing customers are allowed to connect new demands resulting in a system loaded beyond the level which could be supplied historically in strict compliance with ER P2/6. This is based on the understanding that they will reduce their demand when the system is operating abnormally ie in an outage/fault condition. Widespread rollout of C_2C contracts could lead to reduced costs for new connections, incentive payments for participating businesses and a reduction in the amount of new infrastructure that would normally be needed to meet the growing demand for electricity.

Ofgem granted Electricity North West a derogation from ER P2/6 in order to trial the proposed C_2C operating regime. However, a small number of respondents to the Ofgem consultation on the derogation commented that such a derogation was not required because ER P2/6 did not specifically exclude an allowance for responsive demand. This highlights some of the lack of clarity regarding the interpretation of ER P2/6.

[4] http://www.energynetworks.info/storage/P2 Security of Supplies Open Letter.pdf.pdf

[5] http://www.enwl.co.uk/c2c

[6] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=163&refer=Networks/ElecDist/lcnf/stlcnp/year2

[7] An obligation enshrined in the ER P2/6 Security of Supply document

3 REVIEW PROCESS

3.1 Overall Process

A broad approach was adopted for the review to ensure that views of the industry were reflected in the conclusions. The review process flow chart is shown in Figure 1 along with the timeline. Each process step is discussed in the following subsections of this report.

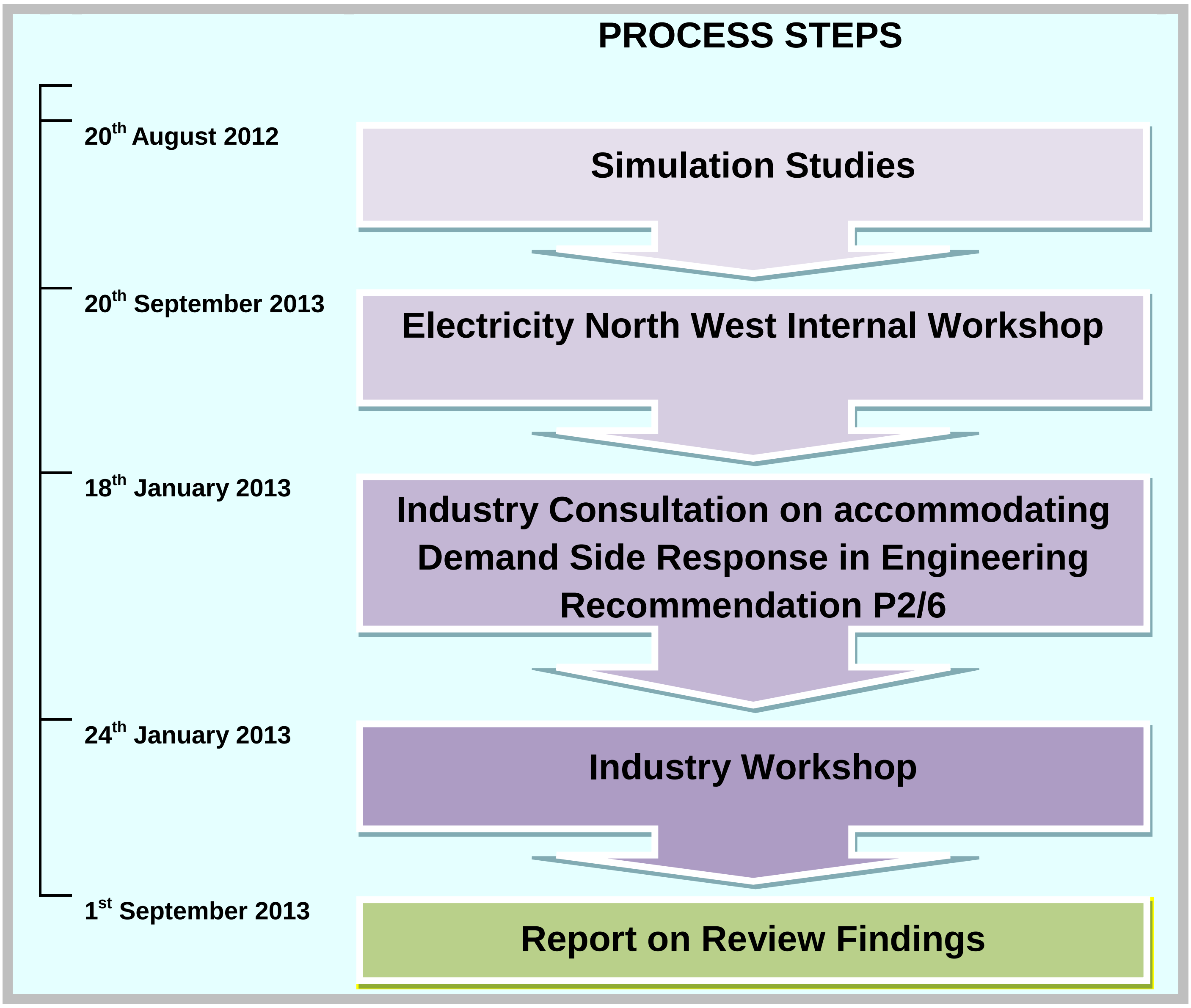

Figure 1 : Review Process

3.2 Simulation Studies

The discussions on the incorporation of DSR within ER P2/6 were placed in the framework of the C_2C Project where widespread application of demand response is projected. A desktop based simulation study[8] was undertaken to evaluate the additional capacity, above that associated with traditional network operation, made available when the C_2C operating regime is applied to a HV distribution system. The potential additional capacity available through the application of C_2C techniques to an actual primary substation system was established to inform potential limits to be applied to system intact operation

3.3 Electricity North West Internal Workshop

An internal Electricity North West workshop[9] provided an opportunity to explore the issue of ER P2/6 and DSR with engineers experienced in applying the security of supply standards to practical situations.

Alternative methods of making the changes necessary to accommodate the widespread application of demand side response were debated and preferred options supported by substantive reasons were identified.

3.4 Industry Consultation

Electricity North West also consulted with the industry on the need for modification of ER P2/6 to accommodate DSR in the short term.

This consultation[9] was considered necessary even though the complete review of all aspects of ER P2/6 has been suggested by the DNOs (and explained in the open letter from the Chairman of the Distribution Code Review Panel[4]). The resulting overall review should include consideration of DSR, but the timing of any consequential changes is unlikely to align with the more imminent expected application of DSR. There is an expectation from key stakeholders that clarification of DSR and P2/6 would be achieved before the start of RIIO ED1 in April 2015.

3.5 Industry Workshop

An industry workshop[10] was held to gather views and judge the consensus of opinion of stakeholders, in particular distribution and transmission network operators, with regard to accommodating DSR within ER P2/6. The results of both the internal and industry wide consultations were used to inform the review results in section 4.

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[8] https://www.enwl.co.uk/docs/default-source/c2c-key-documents/c2c_simulation-report.pdf

[9] https://www.enwl.co.uk/docs/default-source/c2c-er-p26-consultation-letter.pdf

[10] https://www.enwl.co.uk/docs/default-source/c2c-key-documents/p2-6-review---external-workshop-summary.pdf

4 REVIEW RESULTS

4.1 Accommodating DSR within the existing ER P2/6

ER P2/6 does not specifically allow or disallow responsive demand to be excluded from Measured and therefore Group Demand. Consequently, there is uncertainty whether the benefit to customers who contractually agree to interruption or reduction of demand for network contingencies can be realised in practice.

Responsive demands within Group Demand are not explicitly allowed for in either ER P2/6 or ETR130. However DNOs are able to make allowances for individual large customers when undertaking customer connections and network reinforcement assessments as indicated in Guidance Note 1 of The Distribution Code. It allows individual customers to receive security at a level lower than defined in ER P2/6, provided that it does not affect the quality of supply to other customers in that network.

For this reason some companies within the industry infer that ER P2/6 does accommodate individual responsive demands, as commented in SP Energy's letter [10] to Ofgem when responding to Ofgem's consultation on Electricity North West's requirement for a derogation for the C_2C trial. The Western Power Distribution[11] response makes a similar comment that it has been industry practice, but they note that the C_2C operating regime would require applying the principle to multiple responsive demands.

Uncertainty in the ER P2/6 definitions of Group Demand and network capability has been acknowledged within the industry as documented in the 2007 KEMA/Imperial College Report[12].

The debatable nature of compliance meant that during the LCN Fund bidding phase for the C_2C project, Electricity North West discussed with Ofgem the need for a derogation to operate the planned trials of supply interruptions allowed by a suitable contract. Ofgem commented at the time they would be minded to grant the derogation [13]. Later, Electricity North West submitted a formal application [14] for the derogation and it was subsequently approved by Ofgem.

Findings from the industry workshop undertaken as part of Electricity North West's C_2C project, showed that none of the attendees considered ER P2/6 to preclude the application of DSR. However, when asked the question "From your company's point of view could responsive demand be employed without breaching ER P2/6?" approximately half of the respondents indicated that they were uncertain if ER P2/6 would not be breached. This clearly supports the requirement for clarification with regard to DSR within ER P2/6.

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[10] SP Energy Networks, Letter in response to the "Consultation on a proposed request for P2/6 derogation under Standard Licence Condition 24 of the Electricity Distribution Licence", 29th September 2011. http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=46&refer=Networks/Techn/TechStandds

[11] Western Power Distribution, Letter in response to the "Consultation on a proposed request for derogation under Standard Licence Condition 24 of the Electricity Distribution Licence", 9th September 2011.

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=46&refer=Networks/Techn/TechStandds

[12] KEMA with Imperial College London, "Final Report: Review of Distribution Network Design and Performance Criteria" G06-1646 Rev 003, 19th July 2007.

[13] 13

http://www.ofgem.gov.uk/Networks/Techn/TechStandds/Documents1/Decision%20Letter%20on%20a%20proposed%20request%20for%20derogation%20under%20Standard%20Licence%20Condition%2024.pdf

[14] http://www.enwl.co.uk/docs/c2c-key-documents/application-for-definite-derogation-from-er-p2-6.pdf

The responses to Electricity North West's written consultation with the industry on the need for modification of ER P2/6 to accommodate DSR in the short term, recognised the benefits of clarifications in ER P2/6 with regard to DSR, despite commenting that the existing document was flexible enough to allow DSR.

Following consultation Electricity North West has concluded that clarification of ER P2/6 would be required to facilitate the widespread application of post fault demand response and other generic DSR schemes to ensure no doubt in the compliance and therefore legal operation of the system. Making changes to P2/6 itself is not preferred because of the planned overall review of P2/6 and the more extensive changes that are envisaged. Instead it seems that clarifying the interpretation of Group Demand in ETR130 would be a pragmatic solution.

4.2 Incorporating Responsive Demand in Security of Supply Assessments

There is no reason to provide a detailed methodology for including responsive demand in security assessments in ER P2/6 or the associated ETRs. A simple statement allowing for responsive demand within system security assessments, leaving the methodology to the DNO, should be sufficient to ensure compliance whilst realising the benefits of DSR.

The response to the industry consultation[11] commented that, due to the longer term wider review of ER P2/6 underway, it was appropriate to limit the short term change to ER P2/6 to "a generic requirement to either make an appropriate adjustment to the demand that needs to be secured or to ascribe a security allowance for DSR."

The question of how to accommodate DSR within security assessments can be split into two questions that are addressed in the following sections;

i) What allowance should be made for responsive demands?
ii) How should this allowance be included within the system security assessment?

4.3 Development of a Responsive Demand Allowance

The actual demand taken by customers with DSR contracts is likely to fluctuate over a number of time periods, including daily, weekly and seasonal variations, and in the absence of measurements it will be necessary to estimate an allowance for responsive demand. The minimum change approach to accommodating DSR within ER P2/6 and/or ETR 130 is to instruct the DNOs to make an appropriate allowance.

The summation of the maximum import capacities of DSR customers with contracts permitting post fault demand response would reflect the theoretical maximum benefit that could be achieved when disconnecting all responsive demand for a circuit outage. However, this total benefit is unlikely to be delivered in practice.

Development of an appropriate allowance for responsive demands will be a compromise. Over estimation might result in a level which cannot be achieved in practice. However, under estimation might result in a more onerous assessment of security of supply, ie requirement to restore greater demands, necessitating greater network capability and not realising the full benefits of DSR.

The allowance for the benefit due to interruptible responsive demands, such as C_2C customers, could include consideration of the following factors:-

i. Sum of managed customer maximum import capacities
ii. Reliability of switching
iii. Allowable duration of interruption defined in a customer's contract
iv. Number of interruptions allowed per year defined in a customer's contract
v. Number of interruptible responsive demands
vi. Actual demand taken by responsive loads including any periodicity in responsive demands
vii. Accuracy of any network connectivity model used for responsive demand aggregation

Evaluation of a responsive demand allowance at primary voltage levels and above could potentially require the impractical summation of multiple DSR customers and the procedure would need to accommodate this and make the necessary approximations. However, the view that making allowances for DSR customers connected at lower voltages was undesirable has been expressed in the consultations.

It is suggested that the allowance for responsive demand could be calculated using a scaling factor, similar to the 'F' factor used in the determination of the contribution from DGs within ER P2/6. However, the development of such a detailed methodology is likely to be time consuming and outside the scope of Electricity North West's C_2C project.

ER P2/6 'F' factors were developed using empirical data. There is unlikely to be sufficient data available from DSR trials for the determination of similar factors for interruptible responsive demands, therefore conservative approximations may be necessary or further data collection required.

A de minimis level could be defined below which there would be no need to consider the contribution of responsive demands, again similar to the handling of DG in ETR130.

The response to the consultation agreed that detailed factors could be appropriate in the longer term development of security standards, but commented that it would be appropriate in the short term to implement "minimum changes based on guiding principles rather than a prescriptive detailed approach", recognizing that DNOs are best placed to understand the risks and benefits to their network and customers from the early adoption of DSR.

4.4 Incorporating Responsive Demand in First and Second Circuit Outage Assessments

When considering how ER P2/6 and/or ETR130 could be changed to accommodate DSR operation, it is apparent that an allowance for DSR could be incorporated by adjusting either Group Demand or Network Capacity to allow for the expected functionality of responsive demands within ER P2/6 assessments. Alternatively an additional demand level or network capability could be defined.

The response to the consultation supported implementation of "the simplest arrangements which achieve the short term objective" was suggested as a reasonable approach in the short term.

4.4.1 Making allowance for DSR within Group Demand

Group Demand would be decreased by an allowance for responsive demands and this would be intuitively correct because Group Demand is presently considered as the basis of the load that is to be restored. Group Demand would be discounted for responsive demand since there would be no need to restore this demand relating to customers with interruptible contracts after an outage. Another advantage of decreasing Group Demand to allow for responsive demand is historic Group Demand values are used as the basis for load forecasts. Therefore, it is preferable that Group Demand does not include interruptible demand in the long term to avoid complicating the forecasting task.

4.4.2 Making allowance for DSR within Network Capability

The alternative is to increase the network capability by an allowance for responsive demand in the way that Transfer Capacity and Distributed Generation contribution are presently added to the capacity of network equipment when evaluating the total Network Capability. This approach would mean that Group Demand would remain unchanged and consequently the Class of Supply associated with a demand might increase due to DSR customers. The increase in Class of Supply might then result in the requirement to provide improved system security which could be considered counter intuitive based on the objective of DSR operating regimes. However, it was commented at the industry workshop that the Class of a demand should reflect responsive demand. Others held the view that if the allowance for DSR was included in network capability, then the definition of the Classes of Supply could be changed to make allowances for responsive demands and avoid any increase in security of supply due to DSR customer connections.

Definition of an additional demand level inclusive of interruptible responsive demand might be appropriate, but this would be less in line with the present ER P2/6 methodology, and in any event would not be a simple accommodation. It is appropriate that the wholesale review of P2 initiated by the Distribution Code Review Panel consider if this is a better solution for the longer term.

Although the industry workshop had a preference for the Network Capability approach as outlined in 4.4.2, considerations of simplicity and applicability in the short term strongly suggest that the best short term approach is to allocate a DSR discount in Group Demand

4.5 Assessing system intact or short-term loading after first circuit outage in a system incorporating Responsive Demands

ER P2/6 presently allows for network transfers for Supply Classes B to E. For closed ring arrangements transfer of load happens automatically or manually after the first unplanned circuit outage. Consequently, the remaining network assets will carry the whole demand until the first transfer is made or load is tripped. This would normally be assessed by DNOs, and is an implicit requirement of ER P2/6. Generally it is not an issue because most network equipment has a short term overload capability.

Responsive demand could also be switched a short time after the circuit outage, meaning that the remaining network assets would carry the associated power flow after an outage until the responsive demand was switched out. This is illustrated in Figure 2(a) and is the approach used byC_2C

The remaining network would trip if the system subsequent to a circuit outage was not capable of supplying the expected total demand including responsive demands for the short period of time before they are switched or loads transferred, as illustrated in Figure 2(b).

System studies indicated that between 78% and 107% of additional capacity can be made available due to the application of C_2C on a HV circuit running in ring configuration. These demand levels coupled with running HV circuits in rings will lead to tripping of both circuits. Similarly the studies showed 76% additional capacity available at Primary substation level and this would again lead to tripping of the remaining Primary transformer.

A more controlled system operation to avoid tripping subsequent to overload post fault clearance would be achieved by anticipating the potential overload and clearing faults in systems with responsive demands by cross-tripping or by co-ordinated protection. All customers would then experience a short duration interruption during which customers with interruptible contracts would be disconnected. The system could then be re-established without the faulted circuit and without customers with post fault demand response contracts, as illustrated in Figure 2(c). As many HV circuits have identical protection settings when operating a ring configuration this tripping is effectively achieved for any fault on that ring.

On non ring systems such as dual primary transformers with adequate discrimination then cross tripping would not be required if the penetration of DSR was limited so that the short duration capability of the system subsequent to a circuit outage was adequate for the supply of the expected total demand including responsive demands for the short period of time before they are switched or loads transferred.

The acceptability of the need to cross trip infeeds in the period between loss of the first circuit (N-1) and disconnection of the DSR is therefore a key consideration. In other words at what point does it become necessary to limit the pre fault demand to a level below the intact system capability.

Figure 2(a) total loading (including DSR) is within the N-1 rating of the system

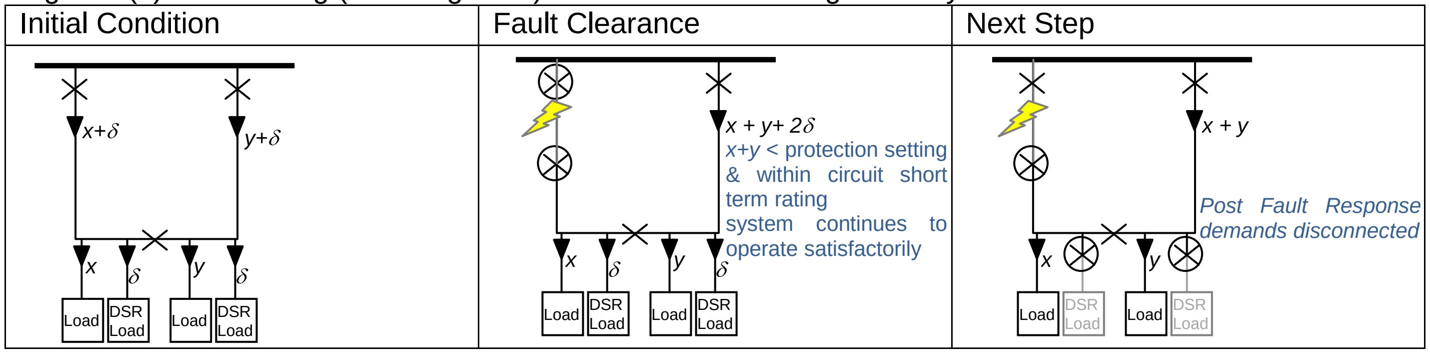

Figure 2(b) total loading (including DSR) exceeds the N-1 rating of the system

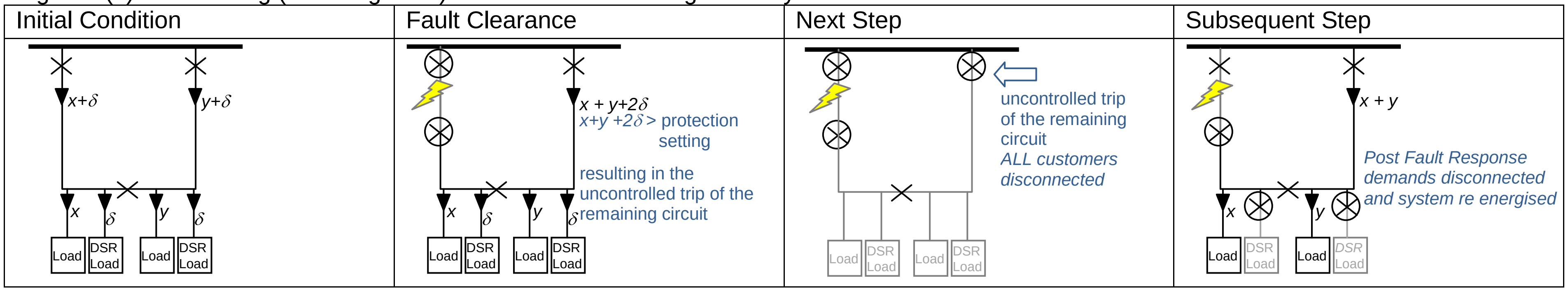

Figure 2(c) total loading (including DSR) exceeds the N-1 rating of the system but with controlled intertrip

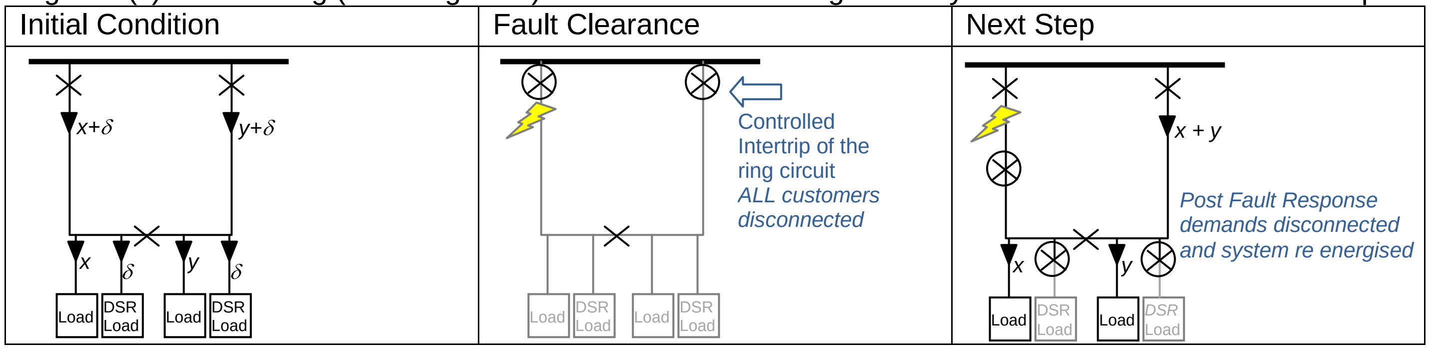

Figure 2 : Consequences of the connection of different amounts of post fault demand response loads.

4.5.1 Acceptability of cross-tripping to accommodate post fault demand response

Short duration interruptions lasting less than three minutes are presently reported by DNOs but are not included in Ofgem's quality of service assessment under the interruptions incentive scheme. Consequently, there is no commercial reason why a DNO would not consider cross-tripping as part of fault clearance, disconnecting customers with interruptible contracts and restoring the system within the three minutes.

The concept of interrupting the supplies to customers without DSR contracts was raised at the industry workshop. The acceptability of degrading a traditional customer's supply as a consequence of providing supplies to a DSR customer was discussed. The principle of effectively lowering the service to traditional customers in order to make savings for DSR customers was questioned. However, it was acknowledged that DSR could significantly reduce reinforcement costs, effectively providing savings for all customers. Concern was expressed that customer complaints could become an issue if the frequency of short duration interruptions increased to an intrusive level

The attendees of the external workshop judged that cross-tripping resulting in a short duration interruption for traditional customers was only acceptable when applied to 11/6.6kV ring circuits. Half of the audience considered it acceptable and the other half considered it probably acceptable. This opinion was based upon the number of customers (under 5 000) affected by the short duration interruption and reliability of automatic switching at a small number of locations.

When considering the next step up the system; the majority of attendees considered it inappropriate to trip both Primary substation supplies, even for a short duration, based upon the number of customers affected (generally over 7 000) .

The attendees of the external workshop judged that it was acceptable to consider the benefits of DSR at higher voltages, if the DSR penetration did not necessitate cross-tripping. The perceived level of attendee's acceptability was noted to increase as the pre-fault loading decreased, but decrease with increasing numbers of remote control sites upon which successful disconnection of the DSR was dependent. This concern is therefore linked to the reliability of the remote control technology.

4.5.2 Requirement for system intact assessments

It is apparent that application of post fault demand response may introduce an additional limiting factor to be considered when planning a system.

Where systems are not designed to cross trip, (ie primary substation groups and above) then potentially there is a requirement to check the short term loading of a network operating abnormally (N-1 system) to confirm that after fault clearance the supply of the maximum overall demand does not cause the remaining network to cascade trip with subsequent loss of supplies to an unacceptably high number of customers.

Alternatively, the system loading, including responsive demands, must be checked for an intact system if the system is to be operated with inter-tripping as discussed in section 4.5.1. ER P2/6 already defines the requirement for consideration of system intact through inclusion of the statement in Section 4 – Capability of a Network to Meet Demand point c) "Note that the assessed capacity may need to be reduced to ensure that, under normal running conditions, equipment is not loaded to a point where it would suffer loss of life".

Clarification of the assessment of short term loading, which is already inherent in ER P2/6, is likely to be required for consistent planning of systems with post fault demand response.

The difficulties of defining limits for system intact were recognised by the audience at the external workshop. It was also recognised that the application of a pre-fault load limit has the effect of limiting the penetration of DSR to typically 50% of the EHV group capacity. However, there was clearly a preference for definitions in industry documents to define limits of operation. The response to the consultation for short term change commented that "there isn't a need for explicit limits to be developed in relation to system intact conditions".

5 SUMMARY OF CHANGE PROPOSAL AND NEXT STEPS

The need for guidance on how DSR should be accounted for within security of supply assessments has been recognised. However, due to the planned overall review of ER P2 and the associated onerous change process, it is judged that it is not appropriate to change ER P2 to accommodate DSR in the short term; rather the associated application guide ETR 130 can be modified to provide appropriate clarity.

The results of this review, the consultation and industry workshop were all taken into consideration when developing proposals for changes to ETR 130 in order to accommodate DSR in the short term. The proposed amendments to ETR 130 can be found detailed in Appendix A.

It is proposed that:

1) In the short term an appropriate allowance for DSR should be taken in to account when calculating Group Demand rather than adjusting Network Capability.
2) It is up to each individual DNO to decide on the percentage of DSR that it will take into account when calculating Group Demand and this value should be recorded.
3) At this current time it is the view of the industry that for EHV networks the gross level of demand (Group Demand plus the responsive demand) should be curtailed so as to ensure that the system is able to maintain supplies to customers whilst responsive demand is disconnected.

As part of the C_2C Project, participating customers will be consulted by a series of surveys on their acceptance of increased short duration interruptions. The results of which, combined with other customer focused industry initiatives should be used to inform future proposals to change to the security of supply standards.

6 APPENDIX A

Distribution Code Review Panel

Amendment to ETR130 to Account for Demand Side Response

Paper by Chairman

1. Background

The move to a low carbon economy is expected to significantly increase electricity demand thus requiring additional network capacity, which will have a significant cost implication when using traditional methods of reinforcement. Demand Side Response (DSR) is seen as one of the solutions in reducing this cost and the requirement for intrusive traditional reinforcements.

The use of DSR is set to increase with Distribution Network Operators (DNOs) already looking to offset spending in the next price review period RIIO ED1 by using DSR. There is currently uncertainty between DNOs regarding the use of DSR in ER P2/6 because it does not specifically include or exclude any allowance for responsive demand.

DNOs are able to make allowances for individual large customers when undertaking customer connections and network reinforcement assessments as indicated in Guidance Note 1 of The Distribution Code. This allows customers to receive security at a level lower than defined in ER P2/6, provided that it does not affect the quality of supply to any other customer in that network. For this reason some companies within the industry believe that ER P2/6 does accommodate individual responsive demands.

Future DSR techniques will allow customers to choose a form of demand side response which is only called upon in the event that the network experiences a fault outage (N-1). The additional demand could be interpreted as increasing the Group Demand possibly into the next class of supply – which would need reinforcement to remain compliant. Hence, if DSR is to be effective in reducing the need for reinforcement, this additional responsive demand should be excluded from the estimation of Group Demand.

2. Demand Side Response (DSR)

2.1 Types of DSR

2.1.1 Traditional

Traditional approach of utilizing DSR at system peaks. This approach can be seen in the measured demand readings and has the effect of moving demand from peaks times to times of low load. This flattens the demand curve and reduces the need for reinforcement which may have been required due to the peak demand.

2.1.2 Post Fault

In the event that the network experiences a fault outage (N-1), DSR is used to reduce the demand on the remaining network still in service. DSR only has an effect on measured demand readings during a fault outage; the effect will not be visible under system normal conditions. This DSR reduces the need for reinforcement which may have otherwise been required for an N-1 situation.

2.2 Effects on Customers

2.2.1 For individual customers

Customers that sign up for DSR contracts may have the benefit of cheaper connection charge and DUoS charges. Customers who are involved in peak lopping will have to reduce demand at peak periods but this may also decrease their electricity supply bill as they are using more demand during off peak periods. Individual customers who have signed up to DSR in terms of the N-1 method may have a delayed restoration in event of a fault as a counter to their reduced charges.

2.2.2 For customers in general

Customers in general will benefit from lower bills due to less network reinforcement. They should also benefit from increased levels of remote control on the network necessary to implement N-1 DSR, which may decrease restoration times in general for faults.

2.3 Capacity to Customers

As part of one of its Low Carbon Network Fund projects (Capacity to Customers or C_2C) Electricity North West has just undertaken a consultation to see if ER P2/6 allows the use of DSR as an alternative to network reinforcement, specifically for DSR required for N-1 situations. The consultation was split into the following sections:-

- Simulations - Examples of DSR at different voltage levels developed to promote discussions in the workshops.
- Workshops - Used to gather views internally and externally regarding what changes may be required for DSR to be used in the short term.
- Consultation questions – To enable a formal view to be established on what if any changes are required to P2/6 order for it to recognise DSR.

The published report with its recommendations can be found at the following web address

http://www.enwl.co.uk/c2c/about-c2c/key-documents

3. Amendments to Industry Documents

The requirement for guidance on how DSR should be accounted for within security of supply assessments has been recognised. However, due to the planned overall review of ER P2 and the more onerous change process, it is judged that it is not appropriate to change ER P2 to accommodate DSR in the short term; rather the associated application guide ETR 130 should be modified.

The suggested amendments to ETR130 are kept to a minimum to enable DSR to develop and prevent ER P2/6 from being seen as a barrier to future developments. It is proposed that in the short term DSR should be taken into account when calculating group demand.

The changes clarify that allowable DSR can be deducted from group demand if it is not already included in the measured demand but the level of DSR should be formally recorded. The changes do not provide guidance on the level of DSR that can be taken into account when calculating group demand; it is the responsibility of each DNO to justify this level individually.

3.1 Proposed Consultation on ETR 130

The consultation paper will be a revision of this paper and in addition to the background information, will also ask respondents the following questions:

- Do you believe it is appropriate to recognise the use of DSR formally in ETR 130?
- Do you have any comments on proposed drafting to ETR130?
- Any other comments relevant to the use of DSR by DNOs?

As ETR 130 is a D Code Appendix 2 document, subject to the Panel having a unanimous view of any proposed changes to ETR130, following consultation, the changes will be made and published at the first convenient date after the Panel has formed its unanimous view.

4. Recommendation

The Panel is asked to discuss the proposed changes to ETR130 and agree to a public consultation on the proposals.

ENGINEERING TECHNICAL REPORT 130

JULY 2006

APPLICATION GUIDE FOR ASSESSING THE CAPACITY OF NETWORKS CONTAINING DISTRIBUTED GENERATION

Energy Networks Association
Engineering Directorate

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Energy Networks Association
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TABLES

FIGURES

APPLICATION GUIDE FOR ASSESSING THE CAPACITY OF NETWORKS CONTAINING DISTRIBUTED GENERATION

1 PURPOSE

The purpose of this Engineering Technical Report is to support Engineering Recommendation P2/6 [Ref 1] by providing guidance on how to assess the ER P2/6 compliance of a network containing DG.

2 SCOPE

This Engineering Technical Report provides guidance on how to assess whether a system comprising both network assets and DG meets the security requirements specified in Engineering Recommendation P2/6. In order to achieve this, there is a need to establish the Group Demand, and to assess the security contribution provided from both network assets and DG. This ETR provides technical guidance on both these issues. The procedures described in this report are based on the same principles that underpinned the previous standard, Engineering Recommendation P2/5.

The contribution to System Security from DG plant specified in ER P2/6 and this ETR have been derived from the best data available at the time. In the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and this ETR.

This report also provides general guidance on the likely contractual considerations that a DNO might need to consider when looking to include the contribution from a DG plant(s) and DSR to satisfy the requirements of ER P2/6. However the detailed form that any contractual and commercial considerations might take is outside the scope of this technical document.

The definitions and numbering of Table 2 (including sub-tables 2-1 to 2-4) used in this report align with those used in ER P2/6.

3 DEFINITIONS

For the purposes of this Engineering Technical Report the following definitions apply.

NOTE: Defined terms are capitalised where they are used in the main text of this report.

Capped

The term applied where the contribution to System Security from a DG plant(s) has been limited during the assessment stage to ensure that the DG plant does not exceed the materiality criteria for the network under consideration.

Circuit

A Circuit is the part of an electricity supply system between two or more Circuit breakers, switches and/or fuses inclusive. It may include transformers, reactors, cables and overhead lines. Busbars are not considered as Circuits and are to be considered on their merits.

Circuit Capacity

The appropriate cyclic ratings or, where they can be satisfactorily determined, the appropriate emergency ratings should be used for all Circuit equipment.

For First Circuit Outages, the Circuit Capacity will normally be based on the cold weather ratings, but if the Group Demand is likely to occur outside the cold weather period the ratings for the appropriate ambient conditions are to be used. Where the Group Demand does not decrease at the same rate as the Circuit Capacity (eg with rising temperature) special consideration is needed.

For Second Circuit Outages, in view of the proportions of Group Demand to be met in Table 1 (in ER P2/6 [Ref 1]), the ratings appropriate to the appropriate ambient conditions of the period under consideration should be used, which may be other than winter conditions.

“Classes of Supply” are defined in MW, but Circuit requirements should be assessed in MVA with due regard for generating plant MW sent out and MVAr capability where appropriate.

Declared Net Capability (DNC)

The declared gross capability of a DG plant, measured in MW, less the normal total parasitic power consumption attributable to that plant.

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NOTE 1: Declared Net Capability (DNC) as used in this Engineering Technical Report should not be confused with declared net capacity (DNC) as used in the Electricity Act and Statutory Instrument 2001 3270.

NOTE 2: For the purpose of this definition the term “parasitic power consumption” refers to the electrical demand of the auxiliary equipment, which is an integral part of the DG, essential to the DG’s operation. For the avoidance of doubt “parasitic power consumption” does not include demand supplied by the DG to an on-site customer.

NOTE 3: The DNC of Intermittent Generation is taken as the aggregate nameplate capacity of all the units within the DG plant, less any parasitic load.

Demand Side Response (DSR

Demand to be intelligently controlled in response to events on the power system. Such events may include lack of network capability or insufficient generation.

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Distributed Generation (DG)

A generating plant connected to the distribution network, where a generating plant is an installation comprising one or more generating units.

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Distribution Network Operator (DNO)

The organisation that owns and/or operates a distribution network and is responsible for agreeing the connection of Distributed Generation to that network. A DNO might also be referred to as a Distributor.

First Circuit Outage (FCO)

Signifies a fault or an arranged Circuit outage.

NOTE: For classes of supply C to F in ER P2/6 [Ref 1] supplies to consumers should not be interrupted by arranged outages.

Generator

A person who generates electricity under licence or exemption from Section 4.1(a) of the Electricity Act 1989 or the Electricity (Northern Ireland) Order 1992.

Group Demand

The DNO's estimate of the maximum demand of the group being assessed for ER P2/6 compliance with appropriate allowance for diversity and DSR. The Group Demand at grid supply points must be consistent with the demand data submitted to a transmission company under the terms of the GB Grid Code.

Intermittent Generation

Generation plant where the energy source of the prime mover can not be made available on demand.

Latent Demand

The demand that would appear as an increase in Measured Demand if the DG within the network (for which the Group Demand is being assessed) were not producing any output.

NOTE: Group Demand is the sum of Latent Demand and Measured Demand

Measured Demand

The summated demand measured at the normal (network) infeed points to the network for which Group Demand is being assessed.

Non-intermittent Generation

Generation where the energy source for the prime mover can be made available on demand.

Persistence (T_m)

T_m represents the minimum time for which an Intermittent Generation source is expected to be capable of continuously generating for it to be considered to contribute to securing the Group Demand.

Second Circuit Outage (SCO)

Signifies a fault following an arranged Circuit outage.

NOTE: The recommended levels of security are not intended at all times to cater for a first fault outage followed by a second fault outage or for a simultaneous double fault outage. Nevertheless, in many instances, depending upon switching and/or loading/generating arrangements, they will do so.

System Security

The capability of a system to maintain supply to a defined level of demand under defined outage conditions.

Transfer Capacity

The capacity of an adjacent network which can be made available within the times stated for the First and Second Circuit Outages in Table 1. Transfer Capacity will be limited by Circuit Capacity or other practical limitations on power flow associated with the outage(s) in question.

4 INTRODUCTION

The provisions contained in Engineering Recommendation P2/5 (ER P2/5) for assessing the contribution to System Security as provided by DG were limited to large steam and OCGT sets that were prevalent at the time ER P2/5 was published in 1978. With the growth of DG in the UK all stakeholders agreed that it was necessary to carry out a limited revision of ER P2/5 to ensure that the possible security contribution from modern types of DG plant could, where appropriate, be properly recognised.

The task of revising ER P2/5 was given to a joint working group of DNOs, Generators, the Regulator, academics and consultants. A major part of the work of this group was the production of three reports for Future Energy Solutions (FES) [Refs 2, 3 and 4], (FES being the agency responsible for managing technical projects on behalf of the DTI). These three reports formed the basis of the revised text in Engineering Recommendation P2/6 (ER P2/6) [Ref 1].

This Engineering Technical Report uses the information contained in the three FES reports to provide background information on the requirements contained in ER P2/6. The intention is that this information will guide users of ER P2/6 to make a consistent interpretation of the requirements therein.

5 ASSESSMENT PROCESS

5.1 General

When it is recognised that a system could become non-compliant with ER P2/6 [Ref 1], it may be possible to rely on the contribution from DG to help maintain compliance. Where compliance cannot be achieved, even with the contribution from existing DG plant, further security contribution would be required by the DNO either in the form of network reinforcement or by an increased contribution from existing or new DG plant connected to the network.

In considering the simple diagrammatic representations that follow throughout Section 5, it should be noted that for simplicity of presentation Circuit ratings and security contribution from DG are simply summated where appropriate to assess aggregate capacities etc. However, in reality it will always be necessary to perform appropriately complex assessments, probably via modelling software, to ascertain that equipment is not unacceptably overloaded. Note also Section 4.c. of ER P2/6 where there is a specific requirement that equipment should not be overloaded to a point where it suffers loss of life.

When seeking to assess whether a particular section of network is compliant with the security requirements contained in ER P2/6 it is necessary to follow a procedure similar to that shown diagrammatically in Figure 5.1. This figure includes a number of stages and makes reference to further figures and sections providing detailed guidance on each of these stages.

For DNOs this exercise is a periodic one across the full network, supplemented by specific assessments at points on the network where changes to security levels arise from changes in network design, demand or DG plant. In assessing the security contribution from DG plant, the DNO will want to balance the effort required to obtain accurate availability data with the risks to loss of supplies from using inaccurate or uncertain data.

NOTE: An overview of the technical issues that will need to be considered are shown in the Technical Check List provided at Appendix 1 to this report.

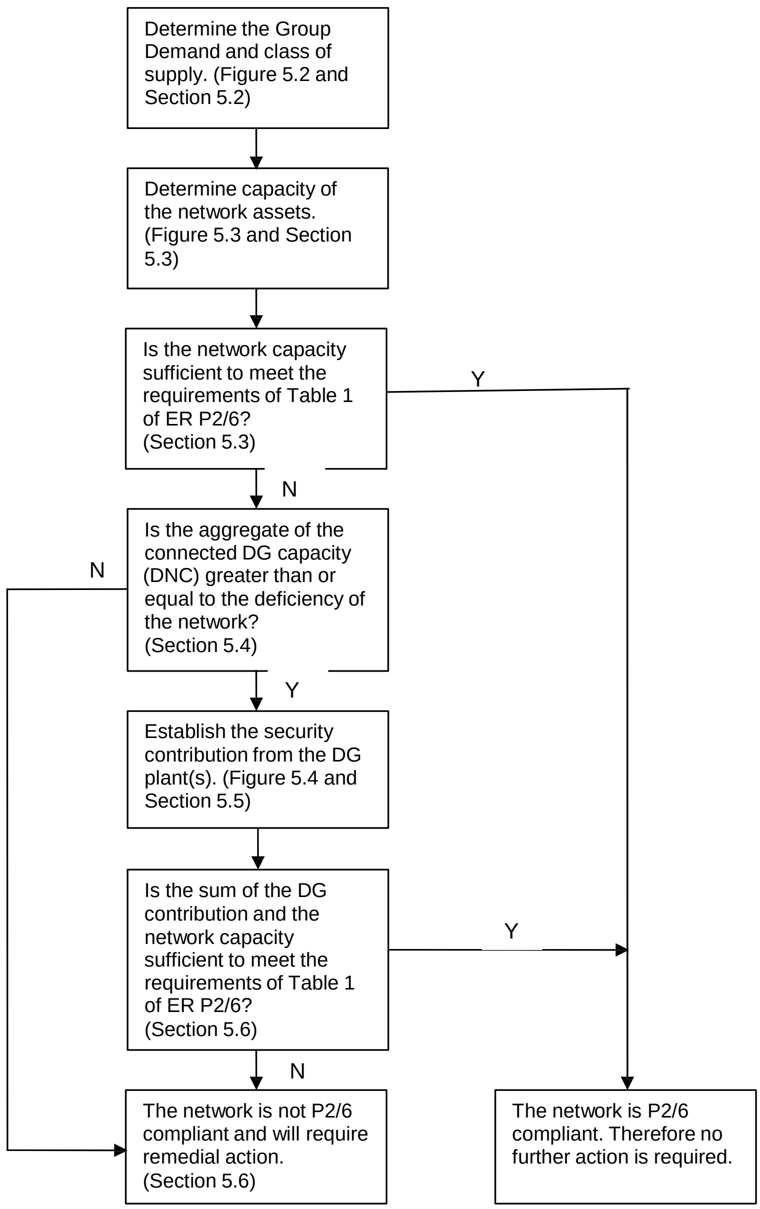

Figure 5.1 The assessment process

NOTE: Detailed guidance on each stage of the process is given in the following sections and figures; the relevant numbers are shown in brackets.

5.2 Determine the Group Demand and Class of Supply

In order to identify the class of supply (see Table 1 in ER P2/6 [Ref 1]) the section of network under consideration falls into, the Group Demand needs to be established. – See Figure 5.2 below. If there is DG on the network it will be necessary for the DNO to determine whether there is any Latent Demand (see 7.6.1) and if so it should be added to the Measured Demand to establish the Group Demand. Similarly where DSR is employed, an appropriate allowance for DSR should be made (see 7.6.10)

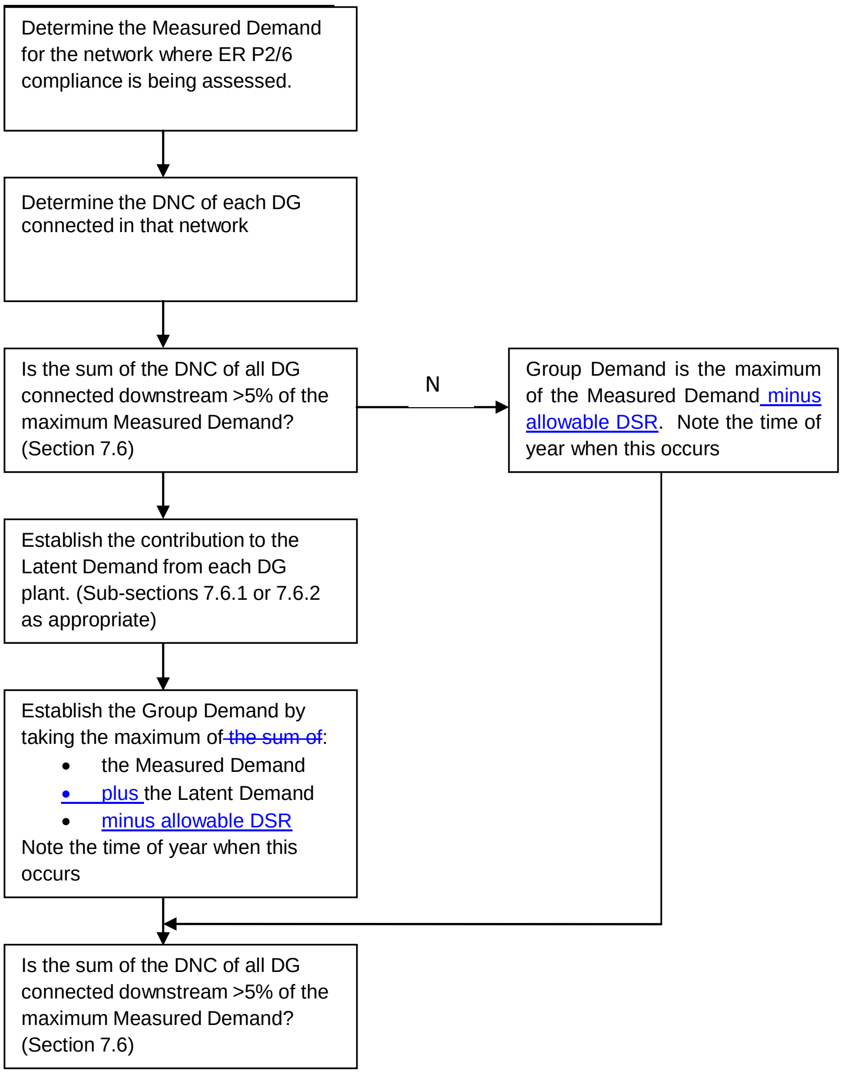

Figure 5.2 Determine class of supply and Group Demand

5.3 Determine Capacity of Network Assets and Assess Compliance

The next step is to identify the capacity of the existing network assets – see Figure 5.3 below. Once the capacity has been deduced it will be necessary to assess whether the existing network capacity is capable of securing the Group Demand identified in 5.2, in accordance with the criteria specified in ER P2/6 Table 1. If this can be achieved, without the need for a contribution from DG, then the network under consideration can be deemed compliant with ER P2/6 and there is no need for further analysis.

NOTE: Voltage criteria and differing Circuit capacities and impedances may be limiting factors in determining the network capacity under FCO and SCO conditions. In such situations the use of network analysis software becomes essential to determine the network capacity

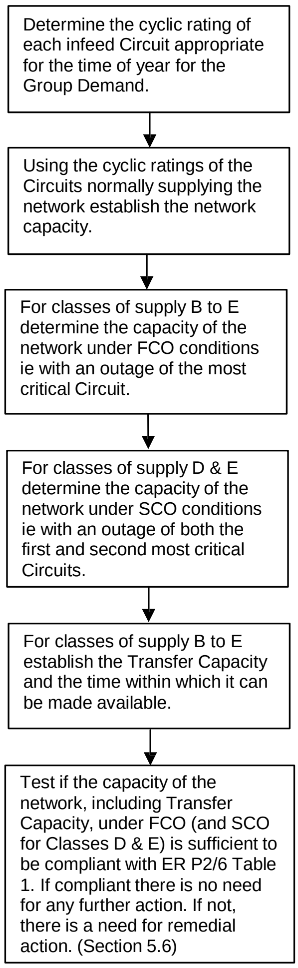

Figure 5.3 Determine capacity of network assets and assess ER P2/6 compliance

5.4 Assess the Maximum Potential Security Contribution

In the event that network assets alone are insufficient to meet the requirements of ER P2/6 it will be necessary for the DNO to identify the most efficient mechanism available to enhance System Security, this may mean assessing the contribution from DG. An assessment can be made to establish whether the aggregate DNC of all the DG connected to the network has the potential to meet any deficiency in System Security available from the network assets. If the aggregate DNC would be insufficient to meet any deficiency, the actual DG security contribution will definitely be inadequate to meet the requirements of ER P2/6 and it will be necessary for the DNO to consider alternative options such as network reinforcement. However the contribution of the DG might still be of value, in limiting the extent of that reinforcement.

If the aggregate DNC is greater than any deficiency it will be necessary to carry out further analysis to confirm the actual security contribution from the DG. The process for assessing the security contribution afforded by a DG plant connected to a network is described in section 5.5.

5.5 Determine the Contribution from DG

The process for assessing the contribution to System Security that can be provided by DG is described in the following sub-sections and shown diagrammatically in Figure 5.4.

NOTE: An overview of the technical issues that will need to be considered is shown in the Technical Check List presented Appendix 1 to this report.

5.5.1 Assessing the sufficiency of the DG plant

This step in the assessment process is to check whether the DNC of each DG plant is equal to or above the de-minimis level. A full explanation of de-minimis is provided under section 7.5. If the DNC of the DG is above the de-minimis level, it can be taken forward for assessment of its contribution.

5.5.2 Assessing the ride through capability of the DG plant

In the context of utilising the contribution from a DG plant to ensure compliance with the requirements of Table 1 of ER P2/6, it will be necessary for the DNO to be satisfied with how the DG plant will respond to both normal and credible abnormal events on the network. For example:

- during a network fault that results in a FCO event, the DG will need to be either stable enough to remain connected during the fault and then continue to support the requisite level of demand during the period of the FCO, or until the demand can be transferred to an alternative network; or
- if the DG disconnects as a result of the fault it will be necessary for the DG to be capable of being re-connected to support the requisite level of demand within the times allowable in Table 1 of ER P2/6.

5.5.3 Establishing the contribution to System Security

In order to assess the contribution to System Security from a DG plant or a group of DG plants it is necessary to use one of the three approaches described in section 6. These approaches take account of the following influencing factors:

- Availability (see section 7.2)
- Operating regime (see section 7.7)
- Remote generation (see section 7.8)
- Intermittency (see section (see section 7.9)

By using either generic DG information or bespoke operational data for a particular DG, it is possible to establish security contribution or F factors for each individual DG plant(s).

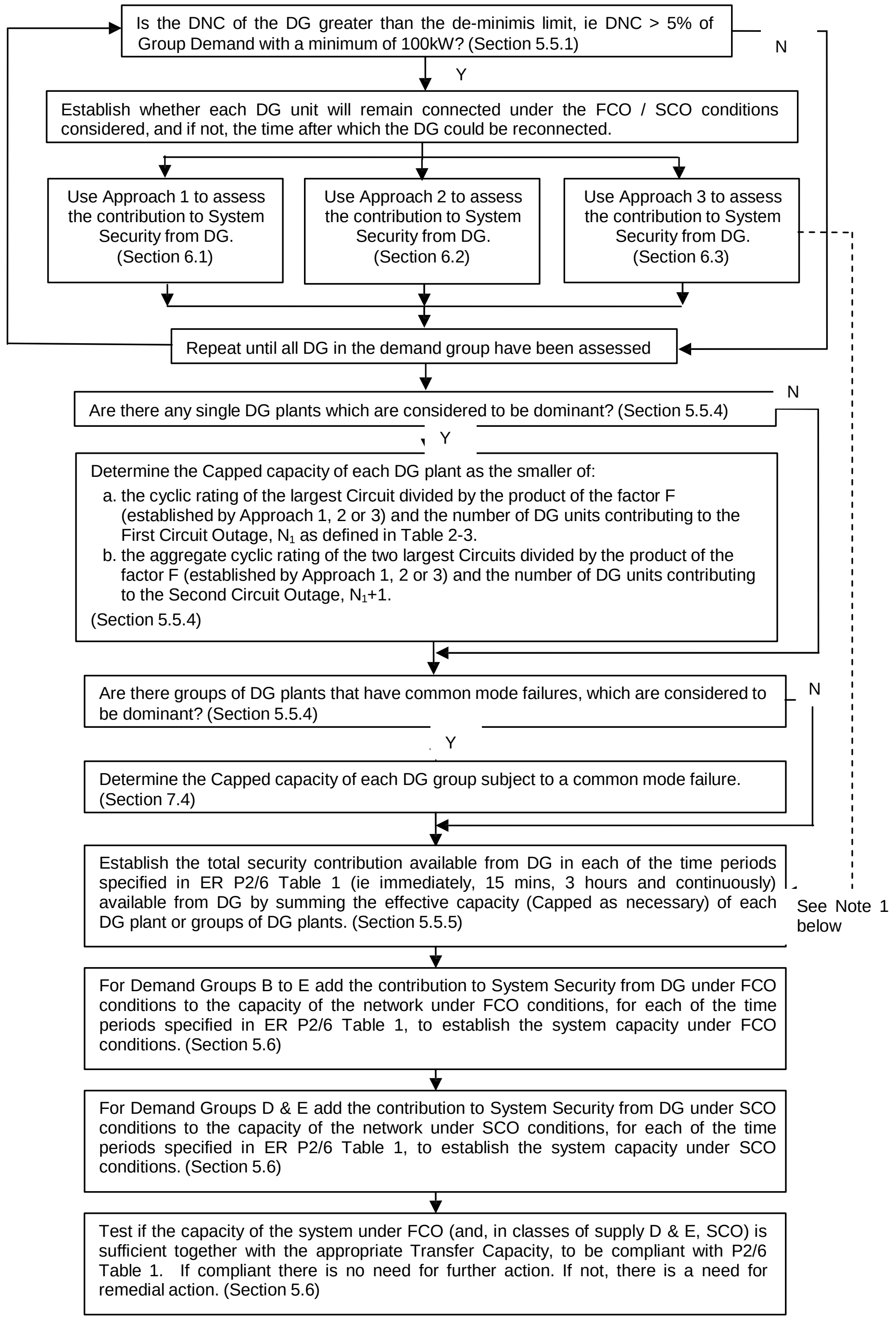

Figure 5.4 Assessing the security contribution from DG

NOTE 1: Where Approach 3 is used to asses the DG security contribution from a collection of Generators, and there is no requirement to cap either an individual DG plant of groups of DG it possible to go direct to establishing the total security contribution .

5.5.4 Avoiding DG dominance

In order to avoid customer supplies from being put at excessive risk from the loss of a DG plant, the maximum allowable contribution to System Security from generation plant under ER P2/5 was limited so that the most material outages, ie FCO and SCO were defined as being outages of network Circuits rather than outages of generating plant. The effect of this was to ensure that the security contribution from a generating plant did not dominate the security contribution from network assets.

In order to continue this principle so as not to put customer supplies at any more risk under ER P2/6 than they were under ER P2/5, it is necessary to limit the contribution from DG ie to cap the contribution from DG plants. (See section 7.3)

5.5.5 Evaluating the overall contribution from DG

Application of the assessment process described under sub-sections 5.5.1 – 5.5.4 should establish a value of the security contribution from a particular DG plant to a particular network. Where there is more than one DG type or multiple DG plants in a network, a similar process is followed to establish the security contribution from each DG subgroup. The overall security contribution from DG within the network is taken to be the arithmetic sum of the contribution from each DG plant within that network.

NOTE: When using Approach 3 the contribution from individual DG is automatically summated.

5.6 Determine the Sufficiency of the Network and DG Assets

Once the potential contribution to System Security from DG plant(s) has been determined it is a simple matter of adding this value to the level of security contribution provided by the network assets. The network under consideration can be deemed compliant with the requirements of Table 1 of ER P2/6 if the aggregate of the DG contribution(s) and network contribution is sufficient to meet the level of security required in Table 1.

It is critically important to note that this capability assessment needs to be done for each of the time periods specified in Table 1 of ER P2/6. For instance, in the case of Class C, the two time periods of concern are the demand that must be recovered in 15 minutes and the demand that must be recovered in 3 hours. Both periods must be assessed separately since the required demand, the number of Circuits and the amount of DG could be different in each case. Compliance with ER P2/6, as in ER P2/5, is required for each time period.

If the demand to be met exceeds the system capacity (ie the capacity provided by the network assets plus the contribution from DG) under First Circuit Outage (FCO) conditions in any one time period, the system is declared as not complying with ER P2/6. If the network under consideration is compliant under FCO conditions, then the process moves to checking for compliance under conditions of a Second Circuit Outage (SCO), noting that under ER P2/6 the requirement to remain secure after a SCO only applies to Group Demands in excess of 100MW.

In the event that the system capacity is not sufficient to meet the System Security requirements, as detailed in Table 1 of ER P2/6, it will be necessary for the DNO to consider remedial action. Remedial action could mean seeking additional DG contributions or network reinforcement.

6 APPROACHES FOR ASSESSING THE CONTRIBUTION FROM DISTRIBUTED GENERATION TO SYSTEM SECURITY

This section describes three approaches for assessing the potential contribution from DG to System Security. Use of these approaches will form an integral part of the assessment process described in sub-section 5.5.3.

Approach 1 provides the simplest method to assess the contribution. Approach 2 provides an assessment method for DG that falls outside of the criteria for Approach 1; and Approach 3 is used where it is necessary to carry out bespoke analysis using site specific data.

6.1 Approach 1 – Look-Up Table(s) Approach

Approach 1 is a simple method based on the use of look up tables. The look up tables (Tables 2, 2-1, 2-2, 2-3 and 2-4) are based on typical or average availability data relating to specific DG types. These tables have been derived from analysing data from operational DG plants; see [Refs 2 – 4].

It is valid to use Approach 1 in the following situations:

- Where the DG type is one of those cited in Tables 2-1 or 2-2; and
- Where the average availability of the Non-intermittent Generation under consideration is not significantly different from that used to produce Table 2-1 (using the availability values cited in Table 5); or
- Where the average availability of the Intermittent Generation under consideration is not significantly different from that used to produce Table 2-2 (using the approach cited in Table 6); or
- Where a 'first pass' assessment is required to determine if a particular DG plant is likely to have sufficient capacity to satisfy a particular requirement.

Approach 1 is based on assessing the contribution from identical DG units on the same site. However, the approach may be expanded to cover non-identical units and DG on different sites within the same network. Each DG unit may be assessed individually and the aggregate DG capability is the arithmetic sum of all the individual contributions DG plus any additional contribution from DG having an operational period less than 24hr, see Table 2. This summation gives a conservative assessment of the DG contribution.

Table 2

Type of Distributed Generation	**Contribution** (see Note 1 below)
Generation as listed in Tables 2-1A and 2-1B	F % of DNC
Generation as listed in Tables 2-2A and 2-2B	F % of DNC (see Note 2 below)
Plant operating for 8 hours (see Note 3 below)	Smaller of value derived from relevant row above; or 11 % of Group Demand
Plant operating for 12 hours (see Note 3 below)	Smaller of value derived from relevant row above; or 12 % of Group Demand

NOTE 1: The contributions derived from this table apply from the point of time when the DG is connected or reconnected to the demand group following the commencement of an outage. This may be immediately if the DG does not trip, otherwise it will be from the point of time when the DG is reconnected.

NOTE 2: The value derived applies to the complete DG plant irrespective of the number of units.

NOTE 3: The values in these two rows assume that the operating period is such that operation spans the peak demand, and the demand at start-up is the same as the demand at shut-down, ie operation is symmetrically placed on the daily load curve. If these conditions do not apply, the contribution could be optimistic (eg at one extreme, the contribution would be zero if the operating period did not span the peak demand at all), in which case the generation ought to be treated as a special case and therefore subject to detailed studies to assess the expected level of contribution – See ETR 130 [Ref 1].

Table 2-1 F factors in % for Non-intermittent Generation

The F factors for non-intermittent generation are related directly to the number of units in the generating station. It is assumed that the energy source for the prime mover is available on demand so that Persistence does not need to be considered.

Table 2-1A High confidence data

Type of generation	**Number of units**									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10+**
Landfill gas	63	69	73	75	77	78	79	79	80	80
CHP sewage treatment using a spark ignition engine	40	48	51	52	53	54	55	55	56	56

Table 2-1B Sparse data

Type of generation	Number of units									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10+**
Waste to energy	58	64	69	71	73	74	75	75	76	77
CCGT	63	69	73	75	77	78	79	79	80	80
CHP sewage treatment using a Gas Turbine	53	61	65	67	69	70	71	71	72	73

NOTE: This table is provided for guidance, however the data sets used to create this table have limited statistical robustness and the DNO should take care when using these F factors for these types of generation. It is preferable to seek site specific data when looking to assess the contribution to System Security from the types of DG listed in this table.

Table 2-2 F factors in % for Intermittent Generation

The F factors for Intermittent Generation are related directly to the period of continuous generation (ie Persistence) and are not affected by the number of units at an individual site.

NOTE: Recommended values of T_m are shown in Table 2-4.

Table 2-2A High confidence data

Type of generation	Persistence, T_m (hours)							
	½	**2**	**3**	**18**	**24**	**120**	**360**	**>360**
Wind farm	28	25	24	14	11	0	0	0

Table 2-2B Sparse data

Type of generation	Persistence, T_m (hours)							
	½	**2**	**3**	**18**	**24**	**120**	**360**	**>360**
Small hydro	37	36	36	34	34	25	13	0

NOTE 1: The “small hydro” DG plants used to produce Table 2-2B were all rated below 1MW with water storage.

NOTE 2: This table is provided for guidance, however the data sets used to create this it have limited statistical robustness and the DNO should take care in establishing appropriate F factors for this type of generation. It is preferable to seek site specific data when looking to assess the contribution to System Security from a small hydro DG plant.

Table 2-3 Number of DG units (N) equivalent to FCO

Type of generation	Number of units									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10+**
Landfill gas	1	2	2	2	2	2	3	3	3	3
CCGT	1	2	2	2	2	2	3	3	3	3
CHP sewage treatment, spark ignition	1	2	3	4	4	5	5	6	6	7
CHP sewage treatment, GT	1	2	2	3	3	3	4	4	4	4
Waste to energy	1	2	2	2	3	3	3	3	4	4
Wind farm	1 (see Note below)									
Small hydro	1 (see Note below)									

NOTE: For Intermittent Generation N is assumed to be 1 in all cases because the DNC used to determine the contribution to System Security is the DNC of the complete plant.

Table 2-4 Recommended values for T_m

This table provides recommended values for T_m for three system conditions that may apply at the time that an infeed is lost. For example, “Switching” values apply where the DG contribution is only required for the time necessary to reconfigure the system by switching operations.

P2/6 demand class	**Switching** (see Note 1 below)	**Maintenance**	**Other outage** (see Note 2 below)
A (FCO)	N/A	N/A	N/A
B (FCO)	3 hours	2 hours	24 hours
C (FCO)	3 hours	18 hours	15 days
D (FCO and SCO) (see Note 3 below)	3 hours (see Note 4 below)	24 hours	90 days
E (FCO and SCO) (see Note 3 below)	N/A	24 hours	90 days

NOTE 1: Switching values for T_m are only appropriate where sufficient Transfer Capacity exists within the times specified in ER P2/6 Table 1.

NOTE 2: Examples of “other outage” are an unplanned outage or an outage as part of a major project.

NOTE 3: SCO only applies for demands greater than 100MW.

NOTE 4: FCO only applies where compliance is achieved by automatic demand disconnection of 20MW or less.

6.2 Approach 2 – Generic Approach

This approach is an extension of Approach 1 based on the application of a series of tables and charts rather than the simple tables used in Approach 1. This approach means that the security contribution associated with a greater range of generation and fuel types can be assessed. Specifically Approach 2 can be used in the following situations:

- For all types of DG for which data is available, not just those types listed in Tables 2-1 or 2-2; or
- Where the average availability of the Non-intermittent Generation under consideration is considered to be significantly different to that used to produce Table 2-1 (using the availability values cited in Table 5); or
- Where consideration of a value of persistence other than that shown in Table 2-2 is required for Intermittent Generation and there is no reason to doubt that the average availability of the Intermittent Generation under consideration will be significantly different to that used to produce Table 2-2 (using the approach cited in Table 6).

For Non-intermittent Generation, Approach 2 takes the appropriate DG contribution from Table 2, using values of F selected from Table 3.

For Intermittent Generation, Approach 2 takes the appropriate DG contribution from Table 2, using values of F from Figure 6.1 for wind farms and from Figure 6.2 for small hydro generation.

For Non Intermittent Generation where it is necessary for the DG to be Capped the appropriate value of N_1 is taken from Table 4 and applied to the formulae in section 7.3. For Intermittent Generation the figure to use for N_1 is 1 (ie the whole plant) in all cases.

The treatment of non identical units on the same DG site and other DG units within the network is the same as Approach 1.

Table 3 F factors in % as function of availability and number of DG units

Availability (%)	Number of units									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
5	3	5	5	5	5	5	5	5	5	5
10	7	10	10	10	10	10	10	10	10	10
15	10	14	15	15	15	15	15	15	15	15
20	13	19	19	20	20	20	20	20	20	20
25	16	23	24	24	25	25	25	25	25	25
30	20	27	28	29	29	29	30	30	30	30
35	23	31	32	33	34	34	34	34	35	35
40	26	34	36	37	38	38	39	39	39	39
45	30	38	40	41	42	43	43	43	43	44
50	33	41	44	45	46	47	47	47	48	48
55	36	45	47	49	50	50	51	51	52	52
60	40	48	51	52	53	54	55	55	56	56
65	43	51	54	56	57	58	59	59	60	60
70	46	54	58	60	61	62	63	63	64	64
75	50	57	61	63	65	66	67	68	68	69
80	53	61	65	67	69	70	71	71	72	73
85	58	64	69	71	73	74	75	75	76	77
90	63	69	73	75	77	78	79	79	80	80
95	69	74	78	80	82	83	84	85	87	88
98	75	79	82	85	89	92	92	93	94	94

Table 4 Number of DG units (N_1) equivalent to a FCO

Availability (%)	Number of units									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
30										
35										9
40								7	8	9
45							6	7	8	8
50			all units			5	6	7	7	8
55						5	6	6	7	7
60					4	5	5	6	6	7
65					4	4	5	5	6	6
70				3	4	4	4	5	5	6
75				3	3	4	4	4	5	5
80			2	3	3	3	4	4	4	4
85			2	2	3	3	3	3	4	4
90			2	2	2	2	3	3	3	3
95		1	2	2	2	2	2	2	2	2
98		1	1	1	1	2	2	2	2	2

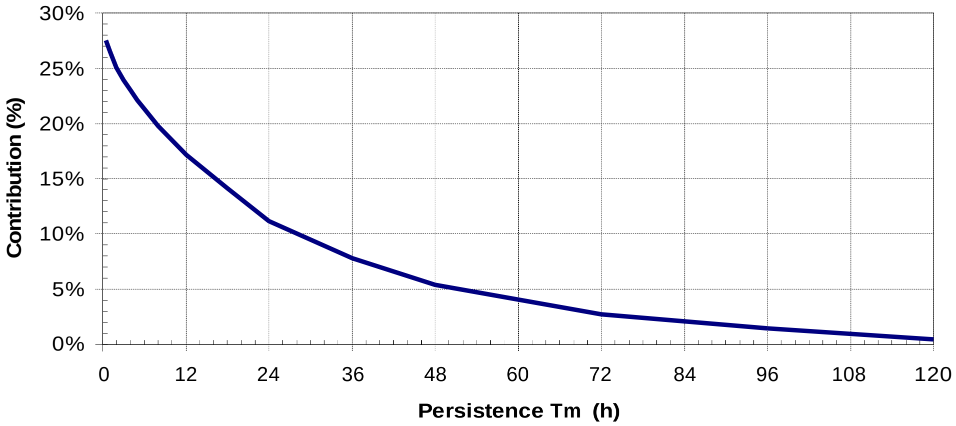

Figure 6.1 F Factors (%) as a function of Persistence T_m for wind farms

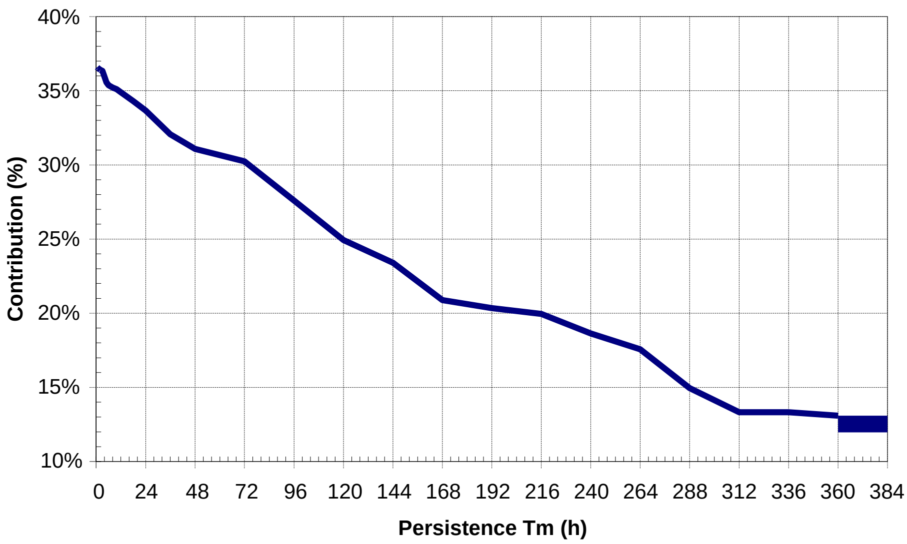

Figure 6.2 F Factors (%) as a function of Persistence T_m for small hydro

NOTE 1: The “small hydro” DG plants used to produce Figure 6.2 were all rated below 1MW with water storage.

6.3 Approach 3 – Computer Package Approach

This approach uses a computerised model of the methodology which was used to create the tables used in Approaches 1 and 2. It offers the ability to accommodate a wide range of data and assumptions, and permits the underpinning conditions of the other approaches to be relaxed and modified. It is therefore appropriate for special studies and bespoke analyses.

Approach 3 relies on the DNO obtaining a set of input data. This data could be provided by the Generator or from other sources, such as the DNOs own records. The exact details of the data required and how to use the analysis package are described in ETR 131 [Ref 6]. The package is implemented in Microsoft Excel ® using the VBA environment and is available from the Energy Networks Association (ENA). The package calculates the security contributions from DG only and can be used for assessing for compliance with ER P2/6 in the same way as performed with either of the two previous approaches.

7 INFLUENCING FACTORS

7.1 General

Whichever of the three approaches is used to determine the security contribution from DG, the generation characteristics need to be assessed to determine whether they are sufficiently normal to allow the application of either the look-up table Approach 1 or Approach 2. If any of the conditions or constraints used to produce the tables in Approach 1 or 2 are considered to be relevant then, as in ER P2/5, special studies will need to be performed. This will entail using the computer program, Approach 3.

The remainder of this section provides an explanation of the key factors which will influence the System Security contribution provided by DG in a network.

7.2 Generation Availabilities

The values cited in ER P2/6 for the effective contribution to System Security, as afforded by different types of modern DG plant, were derived from analysis [Ref 3] based on the historic performance of a small number of sampled plants. The analysis showed that the availability can vary significantly across the different types of plant and in some cases for different plants of the same type. In some cases a wide range of availabilities was observed. In other cases, although the range was narrow, the sample size was very small. The observed ranges of availabilities for Non-intermittent Generation (as used in [Ref 3]) are shown in Table 5 below. The approach taken to determining average availabilities for Intermittent Generation is shown in Table 6.

Other aspects need to be considered, such as history of the availability, and whether this provides an accurate forecast of future availability, or indeed, the treatment of new plant where no history exists. Although it is preferable to use data specific to a particular plant, or similar plant operated in a similar manner, this may not be possible in practical terms because of paucity of data. In such cases use of generic data becomes necessary.

It may be acceptable to use the average availability from DG of a similar type to that which has been determined in the recent research referred to above and used in the preparation of the Tables 2 in ER P2/6. Table 2-1 shows the type of generation split into ‘high confidence’ and ‘sparse data’ sub-groups. Landfill gas and sewage gas fuelled reciprocating engine CHP availabilities are based on good quality data, and these figures can be used with confidence. For the other generation types, the available data was sparse, and so the confidence in the average availability figures is lower.

It is recommended that the DNO should use the F factors in Table 2-1 and the availability values in Table 5 as the first indicator of the security contribution from DG plant connected to a specific network. For the high-confidence generation types (landfill gas and sewage gas CHP), where compliance is marginal, a closer examination of the specific availability would be required. For the ‘sparse data’ group, the average availabilities should be used as an initial check of contribution, and if possible better quality site-specific data should be sought.

Where measured data is available from a specific DG plant and is used to assess the observed availability, this should be checked against the technical, commercial and fuel availability considerations to ensure that the measured availability is sustainable for the timeframe being considered.

The case of new DG plant connecting to the system raises different issues as no history of overall availability will be available for the specific plant. The DNO will need to consider whether the plant is likely to fall into a range of performance that allows an average availability figure to be used. If the plant type is well understood, technical availability may be judged. Fuel sources and commercial operation may be predictable. If these elements of overall availability cannot be assessed with some confidence, the DNO may choose a more conservative overall availability figure until some history can be developed, and/or seek to secure a desired availability through contract with the Generator.

Operation over the first year or two could then be used to confirm the appropriateness of using the initial availability values.

Table 5 Average availabilities for Non-Intermittent Generation

Non-intermittent Generation	Number of sampled sites	Range of availability %	Average availability, %
Landfill gas	32	60-99	90
CCGT	1	90	90
CHP sewerage: spark ignition	16	35-85	60
Sewerage: GT	4	60-99	80
Waste to Energy	5	Wide (see Note below)	85

NOTE: From the Data Collection Report [Ref 3]: The performance of these plants shows a wide variation. The best plants may offer relatively high % of DNC when operating (planned down time (5%) and forced outages (usually related to municipal and industrial waste (MIW) handling) causes a further 15% downtime). At the other extreme, outages of several months can occur.

On the basis of the evidence gathered to date, it is difficult to suggest that any general guide output performance can be relied upon for planning purposes unless evidence of performance is available. It may be that evidence of site specific performance could be used to establish actual contributions. As an example it may then be reasonable to operate with the expectation that such plant could make 80% DNC delivery with a planned outage rate of two weeks per year and a forced outage rate of 1 week per year.

Table 6 Approach to average availabilities for Intermittent Generation

Intermittent Generation	**Output profile** (see Note 2 below)
Wind	Average 6-month winter profile for three sites ½ hr and 1 min resolutions
Small Hydro	Average 6-month winter profile for three sites ½ hr resolution

NOTE 1: Values of T_m used in the approaches shown in Table 6: ½, 2, 3, 18 and 24 hr, 5 days, and more than 5 days.

NOTE 2: Output profile – this describes the criteria used in [Ref 3] to determine the average availability of Intermittent Generation plants to determine the F factors in Table(s) 2-2 and the graphs shown in Figures 6.1 and 6.2.

The overall average availability can be considered as the product of three specific elements: technical availability, fuel source availability and commercial availability. Each can be considered as 100% if fully available, providing a 100% overall availability. However, it will generally be difficult to separate out the three elements for a given plant, as was found in the data collection exercise (see [Ref 3]), and an assessment will need to be made as to the level of the overall availability based on the observed output from the DG plant.

7.2.1 Technical availability

Technical availability is constrained by planned or unplanned outages of the DG plant. It can be separately observed where the Generator allows the DG plant to run continuously with full fuel being available, a good example being landfill gas. Modern DG plant demonstrates generally very high technical availability, often greater than the 86% figure that was used in the derivation of ER P2/5.

7.2.2 Fuel source availability

Fuel source availability can be constrained by any restrictions in the primary energy source preventing the DG plant from achieving expected output over any time period. The impact of fuel source constraints is greatest where the DG plant has high technical and commercial availability but where fuel is limited or variable. Wind farms are an obvious example of this.

Landfill Gas is also a good example, where there may be high technical availability and continuous running to burn off the gas. However the output may be limited by the absolute fuel availability with, say, a 1.5MW unit having a continuous output constrained at 1MW.

Some plant, such as CCGT installations, will have interruptible gas supplies, and where invoked, would reduce the fuel availability element of the overall availability.

7.2.3 Commercial availability

Commercial availability can be considered as being the result of the Generator choosing, for financial reasons, to run his plant below full output or to take the plant off line for any time period.

For example, the primary factor normally influencing the running of a CHP plant, and hence its commercial availability, will be the need to provide heat for a process on the same site. This may result in export to the system only being available when process demand falls, and in the plant being taken off-line for periods within a 24-hour cycle. In this case the implications associated with estimation of Group Demand must be taken into account.

Similarly, CCGT plant is observed to have high technical availability, typically above 90%, together with good fuel availability. However, when operated as a merchant DG plant with its main objective being to meet energy contracts, or provide energy balancing services, the availability of its full output is under the control of the Generator and will be varied for purely commercial reasons.

7.3 Materiality and Capping

A principle of ER P2/5 is that both FCO and SCO conditions relate to Circuit rather than generation outages ie no individual generating unit should be dominant, and P2/5 contained explicit criteria to achieve this. Under ER P2/6 these materiality criteria have been revised from the equivalent provisions from ER P2/5. These revised criteria are:

a. The cyclic rating of the largest Circuit is greater than F% of the DNC of the N_1 largest DG units.

b. The cyclic rating of the two largest Circuits is greater than F% of the DNC of the (N_1+1) largest DG units.

If these conditions are not satisfied, then the capacity of the DG units (C_g) used to assess the security contribution should be Capped at the maximum value that satisfies the above assumptions, ie for identical units:

From the first condition $C_g \le \frac{C_{c1}}{F \cdot N_1}$

From the second condition $C_g \le \cdot \frac{C_{c1} + C_{c2}}{F \cdot (N_1 + 1)}$

Where: C_{c1} is the capacity of the largest Circuit (C_{c2} the next largest) and N_1 is the number of DG units equivalent to a FCO, as specified in Table 2-3 or Table 4. As part of the assessment procedure outlined under sub-section 5.5.4 it will be necessary for the DNO to assess the materiality of each DG contribution. If the conditions set out above are met for each DG, then the FCO is the outage of the largest Circuit and the process continues with the calculation of the system capacity under this outage condition. Note that the above relationships are general for several identical units of the same size. If all units are different sizes then the relationship will need to be tested for all DG plants individually, and N_1 will be equal to unity in each case.

If the first condition is not met (ie the generation would otherwise dominate), then the generation capacity used to assess the security contribution must be Capped (to C_g) so that the DG does not dominate and hence an outage of the largest Circuit can be taken to be the FCO. The process then continues with the calculation of the system capacity under this outage condition which is:

- The cyclic capacity of the remaining Circuit(s); plus
- Any Transfer Capacity; plus
- The appropriate DG contribution determined from Approach 1, 2 or 3.

A similar capping process is used to ensure that the SCO relates to the outage of the second largest Circuit.

Where the determination of System Security includes the contributions of numbers of DG plants of several types, the materiality conditions become:

$\left[C_{gi}\right]_1^n \le C_{c1} \cdot \left[\frac{1}{F_i \cdot N_{1i}}\right]_1^n$ and $\left[C_{gi}\right]_1^n \le \left(C_{c1} + C_{c2}\right) \cdot \left[\frac{1}{F_i\left(N_{1i} + 1\right)}\right]_1^n$ for FCO and SCO respectively.

where there are *n* different types and sizes of DG plants, ie types as listed in Tables 2-2 and 2-3.

7.4 Common Mode Failures

Implicit in ER P2/5 is the assumption that generation will not be subject to common mode failures. Given the growth of DG and its inherently different character to CEGB plant, it is necessary to deal with the risk of common mode failure explicitly.

Common mode failure of DG can occur for a variety of reasons. The following is illustrative but not exhaustive:

- Fuel Source — Failure of common fuel supply such as the gas supply to several landfill generating units on the same site; mains gas supply to CCGTs etc should there be a gas network security problem; etc.
- Connection — It is possible that significant DG contribution to Group Demand is connected via a single Circuit. It is necessary to check that loss of this Circuit would not trigger materiality considerations, although this is unlikely to happen in practice.
- Stability — Inability of certain types of DG or types of protection to remain stable and/or ride through a system disturbance.

To avoid common mode failures of DG degrading System Security beyond that expected in ER P2/5 it is appropriate to cap DG that is subject to common mode failure under the same arrangements as provided in 7.3 above. Each type of DG that could be subject to common mode failure should be aggregated and this aggregate capacity tested for dominance and capped accordingly.

This can be expressed as:

$$\left[\sum_{j=1}^{m} C_{gij} \cdot F_{ij} \cdot N_{1ij}\right]_{i=1}^{n} \leq C_{c1} \text{ and } \left[\sum_{j=1}^{m} C_{gij} \cdot F_{ij} \cdot N_{1ij}\right]_{i=1}^{n} \leq \left(C_{c1} + C_{c2}\right)$$

for FCO and SCO respectively, and where there are *n* types of common mode failures, and within each type there are *m* DG of different types and sizes to be aggregated.

If these inequalities are not satisfied, it will be necessary to cap each DG plant pro-rata to its contribution such that the Capping criteria are met.

7.5 De-minimis tests

To avoid excessive and unproductive computation in assessing security compliance where DG exists, it is important to have lower thresholds below which the effects of DG will not be considered. There are two de-mimimis tests that should be applied:

1) There is a de-mimimis test to establish whether there is a need to assess the Latent Demand in order to determine the Group Demand. This test based on the aggregate DNC of all the DG connected to the network under consideration compared to the Measured Demand, is described in 7.6 below. Note that if the aggregate DNC of all the DG connected to the network under consideration is less than the de-minimis value specified in 7.6, then Group Demand should be taken to be the same as Measured Demand.

2) There is another de-minimis test to establish whether DG plant is sufficiently small that it is considered inappropriate to assess its security contribution. It seems reasonable to base this de-minimis test on the Group Demand of the network to which the DG plant is connected. It is recognised that establishing an appropriate de-minimis threshold is subjective, therefore a pragmatic approach needs to be taken. This report recommends that the de-minimis threshold should be set at 5% of Group Demand with a minimum value of 100kW, ie assessments of security contribution are not necessary for DG rated below this value. When testing if a DG plant meets this criterion, the DNC of the plant should be used.

7.6 Identification of Group Demand

In order to ensure that there are sufficient network assets, ~~and~~ DG and DSR to secure the customer demand, it is necessary to identify the Group Demand to be secured. This requires that, as far as reasonably practical, Latent Demand within the network is identified and added to the recorded or Measured Demand, taking appropriate account of diversity and co-incidence of demand and DG output profiles, to establish the Group Demand.

The most rigorous assessment would require the impact of DG at each network node to be assessed for each half hour period, where the half hour timescale relates to the information typically available from DNO SCADA systems. This analysis is potentially extensive, and in the case of demand sites with on-site generation, obtaining the relevant data could be difficult.

The key issue associated with establishing the Group Demand is striking a balance between the need to undertake significant analysis, with data that may not be readily available, and the risks associated with there being insufficient network assets and DG to support the Group Demand. The risk arises because if the export from some DG is considered to be negative demand, it is effectively being ascribed a 100% security contribution. The magnitude of the risk relates to the aggregate DG capacity in the network under consideration rather than the size of any individual DG. It is recognised that establishing an appropriate approach is subjective, and that a pragmatic approach, as described below, needs to be taken.

Where the aggregate DNC of the DG in any given network exceeds 5% of the maximum value of the Measured Demand of the network, the DNO should make an assessment of the Latent Demand so that it can be added, making appropriate allowances for diversity and coincidence, to the Measured Demand to establish the Group Demand. The 5% figure is a practical limit and relates to the accuracy of typical DNO SCADA information.

The extent of the analysis is dependent upon a number of factors including:

- Whether the generation is directly connected to the DNO network, as would typically be the case for landfill generation or a wind farm, or is embedded in a customer's installation with a significant amount of on-site demand, as would typically be the case for an industrial site with CHP generation plant;
- The coincidence of the maximum value of the Measured Demand and the maximum output from DG in the network for which Group Demand is being established.

Where the aggregate generation exceeds 5% of the Group Demand, but comprises large numbers of very small DG units (eg domestic CHP), the export from these units need not be added to the Measured Demand, as there will probably be sufficient diversity for the overall network risk to be small. However, if the DNO considers the effect of such generation to be material, the use of generic profiles for small-scale generation (such as domestic CHP) would facilitate further assessment of the Latent Demand.

7.6.1 Establishing the Latent Demand from generation only sites, ie merchant DG

For DG where there is no on-site demand, the contribution to Latent Demand is the export from the DG to the network. As indicated above, the most rigorous method is to summate the recorded half hourly output from all the DG (greater than 100kW) for the network. These half hourly contributions are then added to the half hourly network demands measured at network entry points to establish the profile of demand from which the maximum demand, ie the Group Demand, can be found. However, where it is believed that there is good co-incidence between the time of the maximum value of the Measured Demand and the maximum value of the contribution to Latent Demand from each DG plant, it will often be sufficiently accurate to estimate the Latent Demand by summating the export from the DG, at the time of the maximum Measured Demand.

7.6.2 Establishing the Latent Demand from customer's demand sites with on-site generation

Where a demand site comprises DG with a capacity greater than 100kW, wherever possible the actual site demand (ie the demand measured for the site plus the contribution to the Latent Demand associated with the on-site DG) should be established and the contribution to System Security from the DG should be assessed in accordance with ER P2/6.

There are a number of options outlined below for treating demand sites with generation, which have differing requirements for the availability and quality of network and generation data. The purpose of describing these options is primarily to expand on some of the issues that need to be considered when assessing the contribution to Group Demand from such sites. Implementation of some of these methods may require an enhancement of existing data systems.

- Option 1. Obtain separate demand and generation data from the site operator in order to separately assess both the overall site demand and the security contribution from the on-site generation.

- Option 2. As Option 1, but where data from the site operator is not available and the DNO uses data from other sources - eg its own SCADA data and export information from the BSC Settlements system. The DNO would need to be comfortable that it had sufficiently accurate data to undertake the analysis before applying this option. The security contribution from the generation would be considered separately.

- Option 3. Estimate the contribution to Group Demand by ignoring any contribution to Latent Demand by the on-site generation and assume that only the authorised supply capacity (ASC) demand has to be met. It is important to recognise that the maximum site demand may be different from the ASC and any difference should be treated in the same way as for any other demand site that has a possible maximum demand different from its ASC. The security contribution from the generation would be considered separately. It is worth noting that where the customer has an ASC lower than the site maximum demand, he is effectively managing internally the risk of his generation not operating and in this case it may not be appropriate for the security contribution of the generation to be separately assessed.

- Net Option 1. The DNO could develop a model of the on-site generation in net terms based on the import/export data at the ownership boundary. Information may be obtained from DNO SCADA system and/or the BSC Settlements system. In this case there would be no requirement to separately assess the security contribution from the generation.

- Net Option 2. The most general option is to explicitly allow the DNO to use its engineering judgement to determine the appropriate contribution to Latent Demand of the site to be used in an assessment of Group Demand. In this case there would be no requirement to separately assess the security contribution from the generation.

An approach based on Option 1 is the most robust and is the preferred approach where sufficient data is available and a high degree of accuracy is required. However as described above the application of a pragmatic option for disaggregating the demand and generation will often be sufficient.

A pragmatic approach for assessing the contribution to Latent Demand by on-site generation plant has been identified. This method is not completely rigorous but is generally thought to be appropriate where it is obvious by inspection that there is good co-incidence between the maximum values of the Latent Demand and Measured Demand. This technique does cater for the following risks:

- basing the on-site demand on the import/export data at the ownership boundary – which could lead to an under engineered network; and
- ignoring the on-site generation and assuming that that the ASC demand has to be met – which could lead to an over engineered network

The technique for establishing Group Demand is therefore to take the lesser of the following two conditions:

- The expected generation output (G) at the time of the maximum Measured Demand; or
- The site ASC (A) minus the site import[1] (D) at the time of maximum Measured Demand. (ie A-D)

and add it to the maximum value of the Measured Demand.

[1] Note that for a site that is exporting to the DNO's network, the import is simply a negative quantity.

ie *Group Demand = maximum Measured Demand + min [G, (A – D)]*

The contribution to System Security of the DG should then be treated independently in accordance with Table 2 of ER P2/6.

7.7 Generation Operating Regime at Maximum Demand

The operating régime of DG plant(s) at the time of Group Demand must be ascertained, eg whether it operates for 8 hr or 12 hr or whether it is continuously operated. Where the DG operates for at least 8 (or 12 hours) the appropriate values for F in Table 2 can be applied. In the case of restricted operating times, it is assumed that the increasing demand at the start-up time is the same as the decreasing demand at shut-down time. If this is not so, then the contribution may be less than the approach suggests. In the extreme, if the operating period does not span the peak demand at all, the contribution from such generation is zero.

If the operating times are restricted, special studies will be required. Refer to ETR 131 for guidance [Ref 6].

7.8 Remote Generation

When assessing the security contribution from DG that is electrically remote from the point on the network where the contribution is traditionally assessed (eg the infeed substation busbars), the key issue relates to the reliability of the network assets between the DG and the network point where a security contribution is required; this will affect the actual contribution from the DG. However, this effect has been taken account of in the probability analysis within the agreed methodology [Ref 2] and need not be considered further unless there is particular reason to believe that the availability of the network assets is significantly less that that for a typical network.

Hence, if a DG plant is considered to be above the de-minimis level, then it should not be considered as being 'too remote' to provide a security contribution to a particular network and the security contribution should be assessed in accordance with the assessment procedures described in this report.

7.9 Intermittent Generation and selection of T_m

ER P2/6 requires that some or all demand (depending on class of supply) should be restored within 15 min or 3 hr, or after the time to repair. Therefore when looking to include a security contribution from DG a necessary part of the assessment process will be to ensure that the DG can contribute in the required restoration time and continue to contribute for the repair time or until demand transfers are effected. For example, following a forced First Circuit Outage for a Group Demand in Class C, any contribution must be initially available in 15 minutes (as required in Table 1 of ER P2/6), and fully available by 3 hours. Once available, it is assumed that the DG needs to remain available for the duration of the forced outage, which for Class C is assumed to be 15 days, based on an emergency repair time for a 132kV transformer, or until sufficient Transfer Capacity can be made available.

Different values of T_m might be appropriate depending on network configuration and worst case repair time. Indicative values for T_m are shown in Table 2-4 in section 6 above.

7.10 DSR

An appropriate allowance should be made for DSR. The effects of DSR might already be included in the Measured Demand. To the extent that this is a reasonable interpretation of

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future effects of DSR, no further action need be taken. Where DSR is to be deployed on a contingency basis across future system loading peaks, an assessment needs to be made of the MW of DSR that will actually be delivered at that time. This assessment, in MW, will need to be deducted from the Measured Demand. This assessment should be formally recorded as part of the overall compliance assessment.

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8 CONTRACTUAL CONSIDERATIONS

8.1 Commercial Considerations

This section provides general guidance on the possible need for contractual and commercial arrangements to be put in place. However, as expressed in the Scope, the detailed form that these arrangements might take is outside the scope of this technical document.

The process for determining compliance with Engineering Recommendation P2/6 begins with assessing whether the existing DNO network provides sufficient System Security. Only where the existing network provides insufficient System Security is the contribution from DG considered.

The DNO can assess the output profiles from established DG plant, and may conclude that certain plant exhibits predictable and steady output profiles, such as those typically associated with landfill gas schemes. Even though the output may vary over short periods, as can be the case with wind farms, the overall output profile may be considered to be sufficiently predictable and well understood. In these cases, the DNO can determine a security contribution (probably using Approaches 1 or 2) without further recourse to the Generator. In the event of the DNO needing to rely on the DG output, during Circuit outages, the Generator is unlikely to be asked to alter the operation of his DG plant to meet the DNO's requirements. Under these conditions, no service is being requested of the DG, and no contract for services is required. The DNO takes the risk of the plant being unavailable at the time of a depleted system. This is analogous to the uncontracted DNO risk of aggregated load being subject to variation above normal maximum demands.

There will be DG for which the DNO:

- cannot assess the output profiles, either from established or newly connecting DG plant; or
- considers that the DG plant does not exhibit predictable and steady output profiles; or
- requires enhanced output from the DG plant above the normal observed output profile, either to extend to 24hour operation, or to provide temporarily greater MW output.

In these cases, and where the DNO elects to rely on a security contribution from the DG plant, the DNO will need to contract with the Generator to ensure that security services can be reliably provided when requested by the DNO. A security contribution will be based on the service that the Generator is able to offer and guarantee, and will probably be determined using Approach 3. The contract is likely to be such that the Generator takes the risk of the plant being unable to provide an agreed service upon request.

The DNO will wish to assess whether the costs, risks and benefits of procuring additional System Security contribution from DG, through such a contract, is a more efficient and cost-effective option overall compared to the additional System Security that would be provided by reinforcing the network.

8.2 Technical Considerations

The Technical Check List in Appendix 1 has been written to provide guidance on the technical issues that may need to be considered by a DNO when looking to enter into a

contract with a Generator for the provision of a contribution to System Security from a DG plant.

It is expected that the relevant sections of this check list will be included as a schedule to any security contract drawn up between a Generator and a DNO.

9 EXAMPLES

9.1 Introduction

These three examples of the application of ER P2/6 have been designed to demonstrate the processes described in this ETR. The concepts captured in these examples include:

a. Establishing the system capacity
b. Establishing the contribution to System Security from Intermittent and Non-intermittent Generation
c. Application of Approach 1 and 2
d. Establishment of Group Demand where there are various types of DG, eg merchant DG plant and/or CHP plant
e. De-minimis issues
f. Aggregation DG contributions to System Security
g. DG response under outage conditions
h. System capacity under FCO and SCO conditions

The system used in the first two examples is illustrated in Figure 9.1 and described below:

a. A network is supplied by two 100 MW transformers
b. The existing Measured Demand is 70 MW
c. The existing transfer capability available in 30 minutes is 10MW
d. New load is to be connected in the group which will increase the Measured Demand by 10MW
e. The network power factor is assumed to be unity and all ratings are expressed in MW
f. The DNO knows that the network contains:
   1) A wind farm having a DNC of 35MW
   2) A landfill gas installation comprising 2 x 0.5MW identical units
   3) A landfill gas installation comprising 4 x 2MW identical units
   4) Fifty 1kW microgeneration units at various locations
   5) An industrial site that has a CHP plant comprising a 7MW gas turbine and a 3MW steam turbine powered unit which operates 24 hrs per day. The site details are as follows:
      - The actual site demand is 15MW
      - The generation output at the time of the recorded maximum Measured Demand is 10MW
      - The site import at the time of maximum Measured Demand is 5MW
      - The Authorised Supply Capacity (ie the import limit of the site) is 7MW

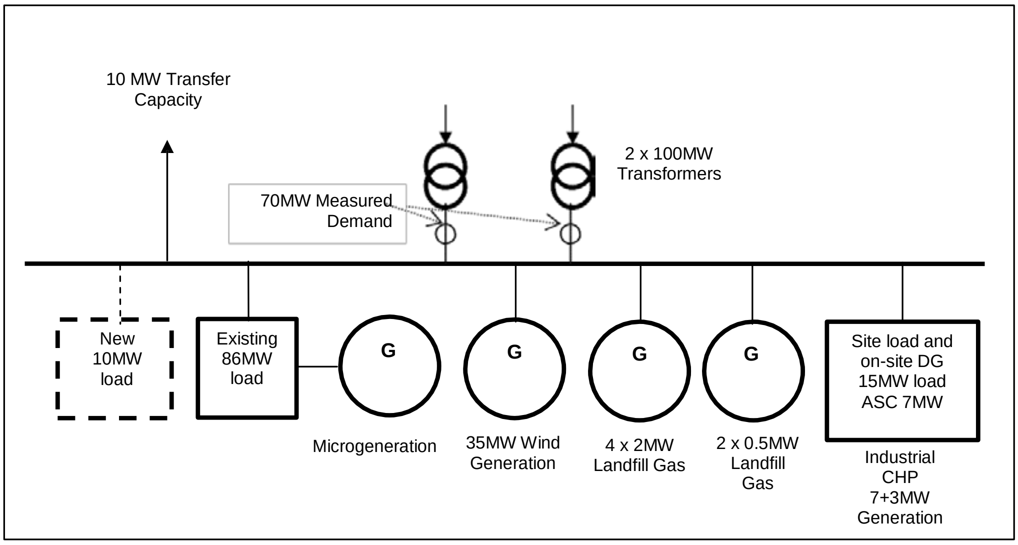

Figure 9.1 Example system

The DNO has to assess whether the network is ER P2/6 compliant once the new load is connected. Example 1 is used to assess the network compliance with the existing demand, Example 2 develops this example to analyse the ER P2/6 compliance in the scenario that the demand increases by 10MW.

It illustrates how the generation that is connected in the group can, under ER P2/6, contribute to compliance.

The example is structured to follow the process set out in Section 5 of this ETR. Each step of the process is cross-referenced to the appropriate sub-section of the ETR. For simplicity it uses Approach 1 of Section 6 to determine the contributions from the sources of generation where possible.

9.2 Example 1

9.2.1 Step 1 – Determine the Group Demand and class of supply

NOTE 1: This first step is exactly the same in ER P2/6 as it was in ER P2/5.

NOTE 2: See also sub-section 5.2

a. Measured Demand: 70MW
b. Capacity of downstream generation: (35 + (2 x 0.5) + (4 x 2) + 10) = 54MW
c. The sum of the downstream generation is > 5% of the Measured Demand, hence it is necessary to analyze the generation to establish the Latent Demand contribution to Group Demand
d. Using the approach in section 7.6:
    - The output from the wind farm at time of maximum Measured Demand = 15MW

contract with a Generator for the provision of a contribution to System Security from a DG Measured Demand = 0MW

- The output from the larger landfill gas installation at time of maximum Measured Demand = 6MW

e. In this example there is sufficient information about the load and generation on the CHP site to apply the simple analysis in section 7.6.2. ie the smaller of the expected generation output at a time of maximum Measured Demand (10MW), and the ASC (7MW) minus the import at the time of the maximum Measured Demand(5MW), should be added to the Measured Demand, ie 2MW, the smaller of (10) and (7 – 5)
f. There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected
g. Therefore the Group Demand = 70 + 15 + 0 + 6 + 2 = 93MW
h. The network falls into class of supply D in ER P2/6 Table 1

NOTE: The Group Demand is subtly different from the actual connected demand of 86MW of existing load plus the 5MW of net demand from the industrial CHP site. This is because the Group Demand includes an allowance of 5MW to cater for the latent effect of the CHP generation plus the additional 2MW that might need to be supplied at this site should it take up to its authorized capacity.

9.2.2 Step 2 – Establish the capacity of network assets

NOTE: See also sub-section 5.3

a. The relevant network assets are the two transformers supplying the network ie the capacity of each network Circuit = 100MW
b. FCO capacity = 100MW, available immediately
c. SCO capacity = 0MW immediately available & 10MW available within 30 minutes
d. From Table 1 of ER P2/6 under a FCO, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection)[2]. The FCO capacity of 100MW is sufficient to meet the 93MW of demand
e. From Table 1 of ER P2/6 under a SCO, there is a requirement to secure all the demand within the time to restore the arranged outage ie capacity under SCO conditions is not required
f. In conclusion, the network assets are sufficient to ensure that the network is compliant with ER P2/6, and no further analysis is required

9.3 Example 2 (Additional Network Demand)

In order to continue to demonstrate the application of ER P2/6, this example develops Example 1 but with additional demand connected such that the Measured Demand increases by 10MW.

9.3.1 Step 1 – Determine the Group Demand and class of supply

NOTE: See also sub-section 5.2

a. Measured Demand: (70 + 10) = 80MW
b. Capacity of downstream generation: (35 + (2 x 0.5) + (4 x 2) + 10) = 54MW

[2] Strictly ER P2/6 permits of the automatic disconnection of up to 20MW of demand in this scenario. However, many DNO networks are not currently designed to automatically disconnect demand, and this example is based on the assumption that all demand should be supplied immediately.

c. The sum of the downstream generation is > 5% of the Measured Demand, hence it is necessary to analyze the generation to establish the Latent Demand contribution to Group Demand
d. Using the approach in section 7.6:
    - The output from the wind farm at time of maximum Measured Demand = 15MW
    - The output from the smaller landfill gas installation at time of maximum Measured Demand = 0MW
    - The output from the larger landfill gas installation at time of maximum Measured Demand = 6MW

e. In this example there is sufficient information about the load and generation on the CHP site to apply the simple analysis in section 7.6.2. ie the smaller of the expected generation output at a time of maximum Measured Demand, and the ASC minus the import at the time of maximum Measured Demand, should be added to the maximum Measured Demand. In this case the smaller of (10) and (7 – 5) ie 2MW
f. There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected
g. The gross network MD (Group Demand): (80 + 15 + 0 + 6 + 2) = 103MW
h. The network falls into class of supply D in ER P2/6 Table 1

9.3.2 Step 2 – Establish the capacity of network assets

NOTE: See also sub-section 5.3

a. The relevant network assets are the two transformers supplying the network ie the capacity of each network Circuit = 100MW
b. FCO capacity = 100MW, available immediately
c. SCO capacity = 0MW, immediately available & 10MW available within 30 minutes (ie Transfer Capacity)
d. From Table 1 of ER P2/6 under a FCO, there is a requirement to secure all the demand immediately (assuming as before that there is no automatic disconnection). Considering the security provided by network assets, there is a FCO deficiency of (103-100) = 3MW
e. From Table 1 of ER P2/6 under a SCO, as the Group Demand exceeds 100MW, there is a requirement to secure the smaller of (Group Demand minus 100MW and 1/3 of Group Demand), ie 3MW within 3 hours. As 10MW Transfer Capacity is available within 30 minutes, there are sufficient network assets to meet the SCO requirements, there being an excess of 7MW. There is a further requirement to secure all the demand within the time to restore the arranged outage
f. In summary, considering the network assets alone, there is a FCO deficiency of 3MW (required immediately) and a SCO surplus of 7MW and hence the network is non compliant with ER P2/6

9.3.3 Step 3 – Assessing the potential security contribution from DG

NOTE: See also sub-section 5.4

Step 2 indicates that the network assets alone are insufficient to ensure compliance with ER P2/6 and hence further assessment is required. This next step assesses whether there is the potential for the connected DG to meet the security deficiency.

The aggregate of the DNCs of the DG in the network can be calculated. If this aggregate is less than the capacity deficit revealed in Step 2 then there is no possibility that the DG capacity will make the network compliant. If the aggregate exceeds the deficit then further analysis is required.

In this example, the aggregate of all the DG connected in the network = 35 + (2 x 0.5) + (4 x 2) + 10 = 54MW.

Hence there is the potential for the connected DG to meet the System Security deficiency, and the analysis therefore continues to Step 4.

9.3.4 Step 4 – Assessing the contribution from DG

NOTE: See also sub-Section 5.5

The following steps establish the security contribution from the DG in the network.

9.3.4.1 Step 4a – Check each DG source against the de-minimis criterion

NOTE: See also sub-sections 5.5.1 & 7.4

The microgeneration units are excluded from the compliance assessment as they are, even in aggregate, less than 100kW.

The first landfill gas installation (2 x 0.5MW) is less than 5% of the Group Demand (103MW), ie below the de-minimis criterion, and is therefore not considered further.

The second landfill gas installation (4 x 2MW) is approx 7% of the Group Demand ie above the de-minimis criterion, and therefore the security contribution should be assessed.

The wind farm (35MW) is approx 33% of the Group Demand ie above the de-minimis criterion, and therefore the security contribution should be assessed.

9.3.4.2 Step 4b – Fault ride-through capability

NOTE: See also sub-section 5.5.2

The behaviour of each DG unit rated above the de-minimis limit, under the relevant outage conditions should be assessed. In this example, it is assumed that both the wind farm and CHP generation will remain connected under a fault forming the FCO condition and that the larger landfill installation will disconnect under fault conditions (eg owing to the sensitivity of its protection systems), but has the capability to be reconnected to the system within 30 minutes. DG contribution under SCO conditions can only be provided in practice in the event that the DG has been designed to run in island mode, or alternatively that there is sufficient interconnection to the rest of the total system to allow the DG to resynchronize.

9.3.4.3 Step 4c – Taking account of availability

NOTE: See also sub-sections 5.5.3 and section 6

At this point in the process the contribution from each DG unit can be established. In this example, Table 2 of ER P2/6 (ie Approach 1) is used to establish the contributions from the wind farm and landfill gas installation. The CHP installation is a gas powered unit, with a steam turbine, and establishing the F factor is outside the scope of Approach 1, hence Approach 2 has been used.

Larger Landfill gas installation

- From ER P2/6 Table 2-1A, the F factor for the larger landfill gas installation = 75%
- From ER P2/6 Table 2, the security contribution from the landfill gas installation = ((75/100)x8) = 6MW

Wind farm

- The security contribution from the wind farm is dependent upon the required value of T_m. In this example, the most onerous FCO relates to an outage of one of the two 100MW network Circuits for a major reconstruction project
- From ER P2/6 Table 2-4, the required value of T_m = 90 days
- From ER P2/6 Table 2-2A, the F factor the for wind farm =0
- From ER P2/6 Table 2, the security contribution from the wind farm = (0/100x35) = 0MW

However, in this example the wind farm has the capability to provide continuity of supply under FCO conditions in the time period between the inception of the FCO and the time when the Transfer Capacity of the network can be utilised, in this case 30 minutes. A T_m value of 30mins is used to assess this capability.

- From ER P2/6 Table 2-4, the required value of T_m = 30mins.
- From ER P2/6 Table 2-2A, the F factor the for wind farm = 28
- From ER P2/6 Table 2, the security contribution from the wind farm = ((28/100)x35) = 9.8MW

CHP units

- The availability of the CHP units, based on examination of several years operating data provided by the CHP operator, shows that the availability to be 95%

Gas Turbine Generation

- From ETR 130 Table 3, the F factor the for CHP gas turbine generation = 69%
- From ER P2/6 Table 2, the security contribution from the CHP generation = ((69/100)x7) = 4.8MW

Steam Turbine Generation

- From ETR 130 Table 3, the F factor the for CHP steam turbine generation = 69%
- From ER P2/6 Table 2, the security contribution from the CHP generation = ((69/100)x3) = 2.1MW

- The aggregate contribution from the gas turbine and stream turbine can be determined by summating these individual contributions, so that the contribution from the CHP installation is 6.9MW

9.3.4.4 Step 4d – Checking for dominance

NOTE: See also sub-section 5.5.4

By inspection, it can be seen that the contribution to System Security from each of the DG plants is less than the capacity of one of the incoming Circuits, and hence the DG is not dominant and capping is not required.

Table 7 summarises the security contribution from each DG plant and the time after the FCO when the contribution is available. The contribution to System Security after the SCO will depend upon the ability of the DG to synchronise under the depleted network conditions.

9.3.4.5 Step 4e – Time durations

NOTE: See also sub-section 5.5.5

Table 7 summarises the security contribution from each DG plant and the time after the outage when the contribution is available. The security contribution after the SCO will depend upon the ability of the DG to synchronise with the depleted network conditions.

Table 7 Example 2 – DG contribution after a FCO

Distributed Generation	Security contribution (MW)	Time in which the DG is available post a FCO
Wind farm (50MW)	9.8	Immediately (but only for 30mins)
Landfill gas installation (2 x 0.5MW)	0	N/A
Landfill gas installation (4 x 2MW)	6.0	After 30mins
CHP generation	6.9	Immediately

9.3.5 Step 5 – Checking for ER P2/6 compliance with DG

NOTE: See also sub-sections 5.5.6 and 5.6

The relevant network assets are the two transformers supplying the network ie the capacity of each network infeed Circuit = 100MW. The contribution to System Security from the generation established in Step 4 is combined with the contribution from the network assets for both the FCO and SCO condition in each of the relevant time periods ie immediately, within 3 hours and within the time to restore the arranged outage.

FCO capacity (Time period: inception of FCO to 30 mins)

From Table 1 of ER P2/6 under FCO, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and generation, there is a FCO capacity of (100 + 9.8 + 6.9) = 116.7 MW ie a surplus of (116.7 - 103) = 13.7MW.

FCO capacity (Time period: 30 mins from inception of FCO to 3 hours)

From Table 1 of ER P2/6 under FCO, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and generation, there is a FCO capacity of (100 + 10 + 6 + 6.9) = 122.9MW ie a surplus of (122.9 - 103) = 19.9MW. The change in capacity arises due to the fact that the wind farm contribution has been replaced by the transfer capability that is switched within 30 minutes of the inception of the fault and the resynchronisation of the larger landfill gas installation. The 10MW Transfer Capacity can be sustained indefinitely, whilst the contribution provided from the wind farm will reduce with time.

The FCO capacity is the lower of these two figures ie116.7 MW

SCO capacity (Time period: from inception of SCO to 30 mins)

SCO capacity immediately available= 6.9MW (of CHP) plus 9.8MW (wind farm), although unless island mode operation is viable, this contribution can only be utilised if the transfer capability provides a Circuit to which the generation can be synchronised. Hence this capacity is zero in the event that no facility for island operation exists.

SCO capacity (Time period: 30 mins from inception of SCO to 3 hours)

SCO capacity available within 30min = 10 (network Transfer Capacity) + 6 (Resynchronised landfill gas installation) + 6.9 (CHP installation) = 22.9MW. This condition could persist for extended periods and hence it would inappropriate to consider any contribution from the wind farm as T_m could be in excess of 120hours. It is worth noting that the contribution to System Security from DG could only be realised if the generation could be synchronized to the assets providing the network Transfer Capacity. If this were not the case, the SCO capacity would be limited to the Transfer Capacity (10MW).

In summary, by considering the contribution to System Security from the network alone, there is a FCO deficiency of 3MW and a SCO surplus of 7MW. Hence the network is non compliant with ER P2/6. Taking the contribution to System Security from generation into account produces a FCO surplus of 10.7 MW. The increase in FCO capability arises due to the output from the wind farm covering the period between the inception of the outage and the Transfer Capacity becoming available.

The SCO surplus may increase to 19.9MW due to the contribution from the reconnected landfill gas installation, the CHP output and the Transfer Capacity, but may be limited to 7MW provided by the Transfer Capacity. In either case, the system can be considered to be P2/6 compliant.

The DNO would need to consider whether a contract was required with the CHP generation, based on the guidance in Section 8.

9.4 Example 3 Capping and Common Mode Failure

9.4.1 Checking for Capping

Consider a section of network supplied by two 10MW Circuits and containing two landfill gas sites with the following mix of generation types:

	Site A	Site B
	2 x 1 MW	2 x 1MW
	2 x 1.5MW	3 x 1.5MW
	1 x 2 MW	
	1 x 5 MW	
Total	**12MW**	**6.5MW**

For site A

Applying the capping criterion, $C_g \le \frac{C_{c1}}{F \cdot N_1}$,

then provided the inequality is true, it is not necessary to cap.

C_{ga} = 1MW ≤10/(69% x 2)
= 1MW ≤ 7.25MW
ie for the two 1MW DG units at Site A the inequality is true hence there is no need to cap

C_{gb}....
C_{gc}....
C_{gd} = 5MW ≤ 10/(63% x 1)
= 5MW ≤15.9MW
ie the inequality is true hence there is no need to cap

For Site A no Capping is required because the DG is not dominant.

For site B

C_{ga} = 1MW ≤10/(69% x 2)
= 1MW ≤ 7.25MW
ie for the two 1MW DG units at Site A the inequality is true hence there is no need to cap

C_{gb} = 1.5MW ≤ 10/(73% x 2)
= 1.5MW ≤ 6.8MW
ie the inequality is true hence there is no need to cap

Again, for Site B no Capping is required because the DG is not dominant.

9.4.2 Common mode failure

Now consider that for common mode failure at site A, the following contributions must be less than the largest Circuit, ie 10MW.

a) 1 x 69% x 2
+ b) 1.5 x 69% x 2
+ c) 2 x 63% x 1
+ d) 5 x 63% x 1

= 7.86 MW ≤ 10 MW

ie the inequality is true hence there is no need to cap

Hence no Capping is required for common mode failure. Had Capping been required it would be appropriate to cap each DG plant in groups a) to d) in the example pro-rata the contribution in the summation to the extent that the inequality becomes satisfied.

REFERENCES

1. Engineering Recommendation P2/6: Security of Supply 2006

2. Security Contribution from Distributed Generation, November 2002. Final report by UMIST for FES. Project K/EL/00287.

3. Data Collection for Revision of Engineering Recommendation P2/5, January 2004. Final report by Power Planning Associates (PPAL) for FES. Project K/EL/00303/05.

4. Developing the P2/6 Methodology, April 2004. Final report by UMIST for FES. Project DG/CG/00023/00/00

5. ACE Report No. 51 (1979): Report on the Application of Engineering Recommendation P2/5 Security of Supply.

6. Engineering Technical Report 131: Analysis Package for Assessing Generation Security Capability – Users' Guide.

APPENDIX 1 TECHNICAL CHECK LIST

1 Introduction

This appendix contains checklists for the various phases of the assessment process, as outlined in the main document. These checklists are intended as an aide memoir for the network designer rather than being a definitive activity list.

2 Establishing Group Demand

	Complete
Recorded maximum demand	
Connected DG capacity	
1/2 hourly demand profile	
1/2 hourly DG export profile	
Data re sites with on-site generation	

3 Establish Network Capability

	Complete
Capacity of individual Circuits	
Time of year of recorded maximum Group Demand	
Cyclic rating factor appropriate to time of year	
Network Transfer Capacity	
Time within which Transfer Capacity is available	

4 DG Information

	Complete
For each DG installation:	
4.1 General	
Number of DG installations	
Capacity of each DG unit	
Type of DG – Prime mover	
Type of DG – Fuel source	
Type of DG - Intermittent / Non-intermittent	
Operating period if less than 24 hrs	
½ hourly output profile	
Merchant or process linked?	
4.2 Technical	
Compliant with ER G75/1 and/or G59/1	
Interface protection • operating parameters and settings • ride through capability	
DG stability	
Status of the technology (proven / experimental)	
Evidence of good management procedures	
Proven performance track record	
What are cold start/warm start / reconnection times for generation?	

4.3 Fuel	
Contracted fuel supply	
Uninterruptible fuel supply (gas)	
Fuel stocks available	
4.4 Commercial	
Ability for DNO to request operation	
Contracted repair and maintenance	
Coordination of network and DG planned outages	
Expected lifespan of the DG plant	
4.5 Contract	
Contracts in place	
Ability to operate on demand	
Appropriate communications with Generator / DG plant to be in place	

5 Network & DG Related Issues

	Complete
Will generation under outage overload any remaining plant	
Does the generation need to run to a different loading pattern immediately - can the governor cope	
Can the AVR cope with the required PF under outage conditions etc	
Will protection for remaining network still work/discriminate with generation	
Will an island result (if so - longer checklist required)	
Is the DG exposed to any common mode failure (eg gas supplies; drought)	
Will the DG cause voltage violations during outages	

6 Other

	Complete
Identify which sections of ER G59/1 apply	
Communication arrangements between DNO and Generator	