Mr. John Scott
Technical Director
Ofgem
9 Millbank
LondonSW1P 3GE

20 September 2007

Dear John,

Electricity Distribution Network Planning – Engineering Recommendation P2/6

Thank you for your open letter dated 1 August 2007 regarding the above.

Attached to this letter are EDF Energy's comments, both on the options outlined in your letter and our more general observations as to how we believe this review should now be taken forward. We also provide comments on some of the key findings and recommendations from the KEMA/IC report which we believe has been generally well researched and provides a sound basis for further meaningful debate.

We believe that this is an important consultation which has the potential to address a matter of significant and increasing importance. ER P2/6 has an important role in providing guidance on the levels of security to be applied in the design of electricity distribution networks. It is doubtful whether the monitoring of 'output' measures alone would provide the necessary assurance that adequate design principles are being adopted. However, issues have emerged, the impacts of which are not wholly addressed by the provisions currently within ER P2/6; these include:

- Summer loading which can undermine the assumptions within ER P2/6 regarding maintenance windows;
- Extended periods associated with construction (as opposed to maintenance) outages;
- High impact low probability events (including common mode failure events), especially in respect of networks serving critical national infrastructure or central business districts.

We believe that these issues should be addressed as a matter of priority and covered by either a future revision of ER P2 or other provisions.

EDF Energy Networks
Barton Road
Bury St Edmunds IP32 7BG

Tel +44 (0) 8701 965370
Fax +44 (0) 8701 962255
Mob +44 (0) 7875 115093

dave.openshaw@edfenergy.com

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Although not strictly related to ER P2 we also believe there is merit in the proposal within the KEMA/IC report to develop incentives surrounding maximum expected interruption frequencies. Such incentives might beneficially redress the current imbalance between the quality of supply typically experienced by best (or 'average') and worst served customers by refocusing quality of supply improvement priorities towards discrete groups of customers who suffer more frequent interruptions.

A further matter which might be addressed through a new revision to ER P2 (or by other means) is the extent to which generation curtailment might become an increasing issue as distribution networks become more 'active'. If distribution networks do not provide overall levels of security equivalent to the GB transmission network SQSS (for a given overall quantum of connected generation) then potential constraints on generation export due to arranged or fault outages might become an increasing concern, especially under a scenario wherein upwards of 20% of electricity generation is derived from renewable energy sources by 2020 (as may be required to support EU binding targets).

In terms of clarity of the licence obligation, we believe that any concerns can be addressed relatively easily through a minor modification to the drafting of SLC 5 (1) in conjunction with a new revision to ER P2 addressing the issues outlined above. In drafting any new revision to ER P2, it would be helpful to clarify the terms 'Group Demand' and 'Transfer Capacity' in order to remove any possible ambiguity.

We note and acknowledge the issue that changes to ER P2/6 might have implications for DNOs' costs in meeting any requirements for a higher level of design security in certain circumstances. We would also cite the joint DBERR / Ofgem discussion paper prepared for the Energy Emergencies Executive - Electricity Task Group meeting on 23 August 2007 which has given rise to the formation of a 'High Impact Low Probability Events Working Group'. The conclusions arising from this working group might also have implications for higher levels of design security; i.e. for central business districts.

However, whilst we also note Ofgem's comment that fundamental changes to ER P2/6 are unlikely to be progressed in time for the forthcoming distribution price control review, we would strongly advocate that the changes required are now too significant to be artificially constrained by the 'periodicity' of such reviews. In the event that a review of ER P2 and/or the output from the High Impact Low Probability Events Working Group leads to the conclusion that significantly higher levels of design security would be appropriate in certain circumstances, it should be for Ofgem and each DNO to then jointly agree the scope, timing and funding of any necessary reinforcement measures, irrespective of the position within the 5-yearly review cycle.

We are happy for our response to be published on your website and we trust that you will find our comments informative and useful. You may be assured that EDF Energy will fully support the work necessary to bring the issues raised by the KEMA/IC report and this open consultation to a satisfactory conclusion.

Yours sincerely,

Dave Openshaw
Head of Engineering Regulatory Strategy
EDF Energy Networks

Overview

Ofgem are right to cite the benefits that ER P2/6 and its predecessors have brought to the development of intrinsically secure transmission and distribution systems in the UK. Embedding within both the Distribution Code and the Distribution Licences, a requirement upon GB DNOs to plan and develop their distribution systems in accordance with the guidance provided by ER P2/6 (and previously P2/5) has been an important provision for ensuring that such systems continue to be developed against commonly agreed security of supply planning principles.

In terms of quality of service impact, whilst ER P2/6 and its predecessors have undoubtedly influenced quality of supply indices, in particular the provisions concerning target times for restoration of demand groups following a fault outage, it is of course the case that the guidance is silent on numbers of interruptions that a given demand group should reasonably expect to experience over any given timescale. ER P2/6 (Table 1) is also silent as to what might be considered acceptable by customers in terms of 'repair time' or 'time to restore an arranged outage'[1]. It is our view that the IIP mechanism should now be developed to also include an incentive based on performance targets in respect of numbers of interruptions experienced by discrete groups of customers. Such a requirement might promote a welcome balance between investment aimed at further 'global' improvements in quality of supply indices (which in incremental cost-benefit terms will generally favour improvements which benefit relatively large groups of customers who may already be experiencing 'average' numbers and durations of interruptions) and investment aimed at improving service for 'worst served' customers.

We note the KEMA/IC report's recommendations regarding frequency of supply interruptions to customers, based on section 4.5 of their report. Whilst these may not be directly relevant to the purposes of the study, we believe they merit further consideration from an IIP perspective, albeit we believe that a more practical approach would be to aim the incentive towards discrete groups of customers rather than individual customers[2].

It is our view that the generally satisfactory quality of supply performance indices now reported by GB DNOs has been due to a combination of the guidance provided by ER

[1] ACE Report 51 Appendix F Table F1 refers to predicted long run average maximum frequencies of supply interruptions for each class of supply.

[2] Whilst we agree in principle with the recommendation in the KEMA/IC report, for this to be workable, the performance metrics must be based on practicably measurable outputs. One approach could be to create incentives on DNOs in respect of numbers of customers experiencing more than a given target number of sustained interruptions in any one year due to faults occurring at HV and above. Setting targets in respect of 'individual customers' as advocated by the KEMA/IC report would require complex mapping of incidents occurring at all voltage levels and the measure would not necessarily reflect the underlying design security or reliability of the network.

P2/6 and effective regulatory incentives. We would agree that for Demand Groups A, B (and to a lesser extent C) in ER P2/6, regulatory incentives (in the form of Guaranteed Standards of Performance and particularly IIP) have been a strong investment driver in recent years[3]. However, we do not agree that it is appropriate to represent these two drivers simply as (respectively) 'input' (design level of security) and 'output' (IIP) measures. These are discrete drivers, each having a specific purpose and each having different (albeit sometimes overlapping) inputs and outputs.

For example, improvements in quality of supply performance over the last decade or so, as now measured by the IIP indices, have been brought about primarily through DNOs implementing new technologies (such as more discriminatory protection, and remote control and automation) and through improved systems of response, including intelligent customer information systems and dedicated trouble call teams. A consequence of this is that many distribution networks have now acquired the capability to perform beyond the ER P2/6 Table 1 '3 hours' (for Group Demand minus 1 MW) restoration performance guidance for Demand Group B. However, for Demand Groups C and above, whilst there have been benefits from new technology (e.g. the application of network automation to effect rapid load transfer capability) the overall impact on demand restoration capability has been relatively small.

It might be argued that since IIP performance has driven network design standards and equipment functional specifications beyond the requirements of ER P2/6 for the Class A, B and (to some extent) C Demand Groups, ER P2/6 has become superfluous up to this level. However, we would not support this view. IIP provides a measure of a DNO's overall quality of supply performance; it does not provide a standard or target level of security for individual elements of the network. Eliminating the Class A, B and C Demand Groups from Table 1 would mean that a DNO would be entitled to connect up to 60MW of demand without any switched alternative, such that the restoration for the whole of that Group Demand would be subject to repair time. Perhaps more typically, for groups of customers falling within Demand Groups A and B, the temptation might be to reverse the recent trend and provide more teed connections in lieu of ringed connections, and to provide manually rather than remotely controlled or automated switchgear [4]. The immediate impact on IIP indices would be likely to be small, if not negligible, even if such a policy were to be maintained for many years. However, customers affected by an 'in-section' fault would experience considerable disruption.

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[3] For Class C, although there are exceptions, networks have generally been designed to a higher level of security than that proposed by ER P2/5 (P2/6) due to the impracticality in most cases of meeting the FCO criteria other than by providing N-1 redundancy (i.e. a primary substation served by two system transformers) which effectively provides for group demand to be met immediately.

[4] The principal driver for providing more ringed connections to new groups of customers falling in Demand Group A (i.e. up to 1MW) was the now discontinued Overall Standard OS1a.

Even assuming that a DNO would not ‘take advantage’ of such a relaxation, there is no guarantee that an ICP or IDNO would not. Indeed, since ICPs have no ongoing responsibility in terms of the security of the installed network or its availability performance, and since IDNOs are not subject to IIP measures, there is every possibility that competitive pressure would lead to precisely such a scenario. Given the scale of major redevelopment in our region which requires the creation of significant new electricity infrastructure, we anticipate that ICP and IDNO activity will continue to be particularly strong. The potential for such a scenario therefore causes us considerable concern.

We note and broadly agree with the arguments put forward in section 3.8.5 of the KEMA/IC report regarding market liberalisation considerations. In the absence of a licence obligation to comply with any security guidance for Class A, B and C Demand Groups, DNOs would have difficulty in influencing the design policy of an ICP and may have no option but to adopt a network design providing a level of security less than that which the DNO would normally apply and way below that currently recommended by Table 1 of ER P2/6.

As a consequence of the above, we believe that both ER P2 (albeit a new revision) and IIP should each continue to have a role for the range of demand covered by Groups A, B and C, i.e. in providing guidance on security of supply resilience and incentives for quality of supply performance respectively. Whilst Ofgem may not believe that the KEMA/IC report has made a compelling case that it is in customers’ interests to retain an obligation to comply with the guidance provided by ER P2/6 (or perhaps a further revision of P2), our view is that the report at least provides some strong arguments that it is. We would agree with those arguments.

Questions raised by Ofgem’s open letter

The following are our brief comments on the four questions raised at the beginning of Ofgem’s letter. In each case you will find that we have expanded on these comments under either ‘issues for the short term’ or ‘issues for the longer term’.

Clarity as to what is required of licensees – requirement to comply

We believe that the licence and Distribution Code requirements are sufficiently clear in that they require DNOs to comply with the ‘guidance’ provided by ER P/6. Requiring specific compliance with Table 1 (or any revision thereto) would in our view be unnecessarily restrictive, noting that the underpinning principle should be to use Table 1 as a general guide but to take account of economics and risk, and optimise design levels of security (and the scale and timing of any reinforcement made necessary by demand growth) accordingly.

It could therefore be argued that Table 1 could be deleted and that the provided level of security in any given case should instead be based on a probabilistic evaluation of risk and an evaluation of the economic trade-off between cost of infrastructure and value of 'Expected Energy Not Supplied'. However, such a regime might well prove impracticable to manage (and would in any case depend on the availability of reliable data which may not always be readily available). The preferred approach is therefore to limit the application of such studies to that of supporting departures from the guidance where appropriate. We note and broadly agree with arguments put forward by section 3.7 of the KEMA/IC report in this respect.

Clarity of drafting and fitness for purpose

In the context of a guidance document, the technical drafting of the document is appropriately pitched. Moreover, subject to the need to now address emerging issues which we address under 'issues for the longer term' below, we believe that ER P2/6 and its underlying philosophy remain broadly fit for purpose. We would caution against any proposal to tighten the drafting of ER P2 purely to address concerns over possible loopholes. The consequence of such an exercise might be to produce an unwieldy document that would prove less useful to practitioners than the current document in terms of setting out the principles for network design security. We do however believe that a review is now required of the underpinning assumptions regarding switching time and repair time indices, and the financial valuation of 'kWh saved' or its corollary, 'Expected Energy Not Supplied' (EENS). In the particular case of major cities, we would question the reliance on a valuation of EENS, when something more related to GDP/GVA not delivered might be more appropriate.

Changes in demand characteristics and network access for asset replacement

Emerging trends in demand characteristics, particularly the growth in air cooling, have major implications in terms of the validity of the underpinning assumption within ER P2/6 regarding the availability of maintenance outages. For major substations serving dense commercially oriented urban networks, the peak demand (or the most onerous period in terms of firm capacity margin) might well be during the summer period. Indeed, for Class E Group Demands, in order not to undermine the principle underpinning the second circuit outage (SCO) assumptions in Table 1 for substations operating close to firm capacity, arranged outages might need to be restricted to weekends; these being the only period during which daily average demand falls below 67% of the Group Demand[5]. Whilst such arranged outage constraints may be manageable for normal maintenance purposes, the erosion of the traditional summer outage window clearly has more serious

[5] For the Class E Demand Group, the assumption underpinning the SCO demand restoration criteria are that normal maintenance can be undertaken when demand is below 67% of the Group (maximum) Demand.

implications for construction (i.e. major renewal / reinforcement) outages, which can extend over many months.

Impact of increases levels of distributed generation and customer interaction

As distribution networks become more actively managed with higher levels of distributed generation, and with the possibility of load profiles being actively managed as a consequence of demand side participation incentives on customers, it will be important to recognise the impact that network constraints (i.e. due to unplanned or arranged outages) might have on the operation of the market. At the higher voltage levels, distribution network constraints might have a significant impact on the ability of power stations (e.g. offshore wind farms) to achieve their export potential. At the lower voltage levels, network constraints could impact on the efficient operation of the Virtual Power Plant (VPP) model wherein Aggregators assemble bids and offers based on the aggregated contribution from small scale generation and demand side energy management.

Issues for the short term

Adequacy of clarity in the licence drafting

We believe that concerns over the fact that ER P2/6 is a guidance document (or literally a 'recommendation') rather than a standard are largely misplaced. However, we would agree that the current licence drafting is loose and for consistency would ideally be amended to more accurately reflect the role of ER P2/6 as an 'Engineering Recommendation'. In particular, the drafting would ideally reflect the existing provision within ER P2/6 to depart from the recommended 'normal' level of security defined in the document subject to detailed risk and economic studies (which might support a higher or lower level of security in particular cases) [6].

Moreover, whilst we understand the desire for consistency of approach towards design levels of security (however measured, including via inputs or outputs) we believe that a more prescriptive drafting of the licence condition might have the unfortunate effect of removing the flexibility that DNOs are able to apply towards the management of firm capacity margins which can benefit customers in terms of optimisation of investment. In this context we would cite Ofgem's welcome letter dated 5 March 2007 granting Licensees derogation from the Licence Condition 5 obligation to comply with 'normal' levels of security as set out in Table 1 of ER P2/6 for demand Groups up to 60MW under specific circumstances.

In conclusion, whilst we would accept that compliance with a guidance document might be less easy to demonstrate deterministically, that should be a secondary consideration to the benefits (including benefits to customers) of retaining what

[6] ER P2/6 section 2 – Recommended Levels of Security.

has demonstrably provided a sound, and broadly consistent, basis for economic network development across the UK, providing generally favourable quality of supply indices compared with most European countries and a sensible (but not excessive) level of redundancy to cater for arranged and fault outages in most circumstances. This is not to say that ER P2/6 as currently drafted adequately caters for all circumstances (we refer to our comments in our covering letter which we expand on later in this paper) but our view is that a revision of ER P2 rather than a more rigid drafting of the licence condition would more effectively address our concerns in this respect.

In conclusion, EDF Energy do not favour any of the four specific options for SLC 5 (1) as presented in Ofgem's letter. However, our alternative proposal is as follows:

I. Further studies should be undertaken with a view to a new revision of ER P2 which would address those areas of ER P2/6 which we believe no longer reflect the requirements for security of supply in certain circumstances (in particular central business districts); and

II. The licence condition should be redrafted to reflect the nature of ER P2 as a guidance document; in particular the provision to depart from normal levels of security (which might be redefined, e.g. for central business districts) subject to detailed risk and economic studies.

EDF Energy would be very pleased to lead, or participate in, a workstream to consider in light of the KEMA/IC report the need for a new revision to ER P2. We would be equally pleased to assist Ofgem with the required redrafting of SLC 5 (1).

Issues Raised by KEMA/IC to be addressed in the short term

Transfer Capacity

The concept of transfer capacity is clearly understood. However we have noted some anomalous interpretations of the first and second circuit outage (FCO and SCO) requirements under ER P2/6 Table 1 in circumstances where transfer capacity is used, and also different possible interpretations of 'Group Demand' where transfer capacity (or interconnection) exists.

Transfer-out capacity might legitimately be used in the form of post-fault (possibly automatic) switching in order for a Demand Group to meet the FCO or SCO requirements for that Group. Alternatively (or additionally) transfer capacity might legitimately be used in the form of pre-switching prior to an arranged outage in order to reduce customer impact in the event of an SCO (whether or not such pre-switching is actually necessary to meet the SCO capability specified in Table 1). However, this has given rise to two questions:

- Should the Group into which load has been transferred then be required still to meet the FCO and SCO outage capability specified in Table 1 even though the Group may now be loaded beyond its design level of security (noting that in some cases the transferred-in demand may even result in a Group with a (temporary) peak demand above the threshold for its Demand Group classification)?
- In the event of an SCO affecting the Demand Group that is subject to an arranged outage and from which demand has been transferred, should any further outage affecting the (extended) Group into which demand has been transferred then be regarded as an FCO for that Group, or a SCO for the combined Group?

A further ambiguity arises in terms of defining Group Demand where there is transfer capacity between Groups and, in particular, where such Groups operate as an interconnected network. One example of an anomaly that can arise due to this ambiguity is in the case where a DNO has two adjacent networks each supplying (say) a Class D Group Demand and where the aggregate simultaneous maximum demand of the two Groups is above 300MW.

If the DNO were to take advantage of the opportunity to interconnect those two Groups (which, in the case of interconnection between GSPs, might also benefit the TO in terms of GB SQSS compliance) then it could be argued that the two Class D Demand Groups would effectively become a single Class E Demand Group giving rise to a more onerous requirement in terms of SCO capability[7]. Hence there is a perverse incentive on DNOs not to provide transfer capacity (or interconnection) beyond that necessary to satisfy the SCO requirements for Class D Groups, even where such capacity is readily available and would clearly benefit customers[8].

In our view Demand Groups should be classified according to the demand normally (or naturally in the case of a permanent interconnection) supplied by that Group irrespective of any temporarily transferred-in demand or permanent interconnection. Moreover, in the event that transfer capacity is used either to transfer-out demand following a (fault) FCO, or in order to reduce the potential impact of an SCO following an arranged outage, the Demand Group to which demand is transferred-in should not necessarily be expected to be capable of more

[7] This step-change requirement in SCO capability is illustrated graphically by Figure 3 in the KEMA/IC report.
[8] Interconnection between GSPs also increases the size of the 'Access Group' and thus imposes additional requirements for data submissions in respect of maintenance periods under the proposed new Week 28 requirements.

than the FCO and SCO capability specified in Table 1 based on the demand supplied by that Group under normal running arrangements[9].

Imposing a more onerous requirement could lead to DNOs either investing to meet a level of design security unintended by ER P2/6 (or its predecessor P2/5) and/or to DNOs not taking advantage of beneficial interconnection opportunities. Neither scenario would be in the interests of customers. Our view therefore is that there would indeed be some merit in clarifying the terms 'Group Demand' and 'Transfer Capacity' in this particular context.

Average Cold Spell

ACS correction has been the traditional approach to normalising winter maximum demands recorded at different temperatures, hence enabling more meaningful demand growth trends over successive years to be established. That said, it is generally accepted that the traditional Gwilym Jenkins approach to ACS correction is valid only for a very limited range of variances from the generally accepted 'average' cold spell temperature of +1 deg C. EDF Energy no longer uses this approach; our studies have shown that the mean cold spell average daily ambient temperature for our region, measured over recent years, is -1.4 deg C. Moreover, for summer peaking substations, the ACS corrected demand serves no purpose. For the central London area, EDF Energy has ascertained from a 5-year archive of ambient temperature data that a hot spell (AHS) daily average ambient temperature of 25.3 deg C is appropriate.

More importantly, we now ascertain, on an individual basis, thermal capacity margins for system and grid transformers (which initial analyses indicate might be at risk) and their associated transformer feeders, plotting weekday maximum demand against daily average ambient temperature for either the complete year or the period specifically at risk. Transformer emergency cyclic rating, determined from a suitable algorithm, is also plotted against daily average ambient temperature and demand. From these plots, it is possible to ascertain capacity margin at the AHS temperature or indeed, by extrapolation, at any given daily average ambient temperature within a credible range of possible values. A typical set of plots illustrating this approach is included as Fig.2 in the annexe attached to this paper. It will be clear from these plots that this approach provides for a more robust assessment of available capacity margin (taking account of forecast demand growth) and hence compliance with ER P2/6 guidance.

In conclusion, we believe there is a continued role for ACS (and now AHS) in terms of normalising annual variations in seasonal demand but we would agree with the recommendation in the KEMA/IC report that, for critically loaded substations and

[9] This is not to say that where the impact of an interruption outage is particularly high, e.g. in the case of a central business district, an enhanced SCO capability would not be appropriate.

networks, DNOs should develop more detailed assessments of firm capacity margin, taking account of short-term emergency ratings and any beneficial thermal capacity (especially in respect of transformers). In the event that such margin might be negative for limited periods (which might be legitimate from an economic perspective), DNOs should assess the level of risk (whether in CI/CML or EENS terms) that such negative margin represents. This in turn would inform decisions regarding the need for, and timing of, any system reinforcement. Referring again to Ofgem's concern that ER P2/6 is not a 'standard' we would cite this proposed approach as an argument for ER P2 retaining its purpose as a guidance document, providing a basis for departures from Table 1 criteria where there is a sound technical and economic (risk assessed) basis for so doing.

Co-ordination of planning at GSPs

EDF Energy has actively supported the Grid Code Review Panel Working Group and has made constructive suggestions as to the changes that might be incorporated within a new revision to the Grid Code in order to promote a more efficient, meaningful and timely exchange of information between companies. Whilst we are disappointed with the rate of progress, we do feel that the eventual revisions will be beneficial. It is EDF Energy's wish to improve the transparency of information from, and to, each party concerned so that any risk of future non-compliance with GB SQSS requirements or a potential departure from ER P2/6 guidance regarding design levels of security can be established at an early stage, thereby enabling any required GSP reinforcement planning to be better co-ordinated.

Traditionally problematic areas have been those where EDF Energy's 'interconnected' 132kV networks operate in parallel with NGET's system. In such circumstances, network modelling can be complex and critically dependent on exchange of good quality information. We believe that the proposals of the Working Group will go a long way towards meeting the objective of information transparency, and we look forward to the final proposals from the Grid Code Review Panel in respect of changes to the Code. To further that objective, EDF Energy are now developing a model of the higher voltage levels of our network using similar software to that which NGET are proposing to use to develop their new outage planning model. This will greatly facilitate the exchange of our respective analyses of future SQSS / ER P2/6 compliance in respect of load growth forecasts, and provide for better outage co-ordination.

In the meantime (and indeed thereafter) EDF Energy will continue to actively support joint liaison meetings with NGET in order to ensure optimisation of investment at the Transmission / Distribution interface and the most effective co-ordination of transmission / distribution network development.

Early experiences with ER P2/6

Perhaps disappointingly, and despite our efforts to support the growth of DG though our Long Term Development Statements, our application of the DG incentive where appropriate, and our R&D investment focus on enablers to wider DG penetration, we have not yet seen a significant level of DG connection proposals sited in locations that would provide a potential network security benefit offsetting the need for planned (demand driven) network reinforcement.

What we have experienced is the need for more detailed analysis in order to now specifically account for 'latent' demand (i.e. demand masked by existing DG) when assessing firm capacity margin. The netting off of such generation (above a deminimus limit) can in some cases lead to tighter network capacity margins than might traditionally have been assessed under ER P2/5, particularly where the DG is well established and is directly associated with local demand; for example co-generation. We note the comment in section 5.7.1 of the KEMA/IC report reflecting this point.

Issues for the longer term

Active networks and DG – implications for security standards

One of the issues to consider for the longer term is the emergence of more 'active network' drivers such as higher penetrations of DG, a wider role for Demand Side Participation, and the Virtual Power Plant (VPP) model which might in future allow Aggregators to draw on both of these distributed energy sources in forming bids and offers under BETTA. Under such a scenario the 'cost' of generation curtailment due to network constraints would be a further consideration alongside the valuation of (demand) kWh saved.

A similar issue arises where distribution networks provide a point of connection and an export path for large scale DG (such as offshore windfarms). Under such a scenario the risk (cost) of generation curtailment due to a network constraint arising from a circuit outage is a further factor that should be considered even where the network is compliant with the guidance provided by Table 1 of ER P2/6. The issue arises because whilst ER P2/6 takes account of potential DG contribution to demand security, there is currently no guidance as to the level of DG connection security that should be provided, for example under FCO / minimum demand conditions. We note that this issue is addressed briefly in section 5.7.3 of the KEMA/IC report.

It might be argued that this is a matter for each DG operator to determine, or it might be considered that a minimum security standard should be incorporated within a new revision to ER P2. Our view is that a minimum distribution network security standard for distribution-connected offshore generation (which will be subject to both an offshore and a (GB) land-based transmission SQSS) should be given serious consideration. We note that section 5.7 of the KEMA/IC report makes specific reference to this 'DNO sandwich' issue and we agree that an SQSS for onshore distribution networks (providing DG export transportation) would be a logical and worthwhile development.

Apart from the DNO sandwich issue (which might in any case be addressed other than through a revision to P2) we do not envisage any further DG or active network related changes to P2, save for possible natural evolutions of Table 2 in light of future experience of integrating DG. Where we believe active networks will have an impact is in terms of more refined monitoring and control of power flows (including possibly demand side management) which in turn will lead to the possibility of more refined assessments of firm capacity margin based on dynamic plant and equipment ratings.

By the same token, we believe that active network technologies will also have an increasing role in real-time monitoring of asset condition. Whilst we would not anticipate asset age or condition being a factor embedded in ER P2 we do believe that condition assessment (and in particular the impact of increased duty on aged assets arising from an arranged or fault outage) will be an increasing factor in outage risk assessment. This will go some way to addressing the issue raised in section 3.8.6 of the KEMA/IC report.

Climate change and summer loading

We believe that there is an issue (albeit it is a current rather than a longer term issue, and not necessarily one related to climate change) of higher summer loadings and the effect of higher summer 'daily average' ambient temperatures (and extended daily load cycles) on plant ratings. One consequence of high summer-loaded networks is that the implicit assumption within ER P2/6 Table 1 for the Class E Demand Group - i.e. that maintenance can be scheduled when the demand is less than 67% of Group Demand - might no longer be valid.

Section 5.4 of the KEMA/IC report points to the need to give consideration to the more protracted arranged outages necessary to permit major reinforcement or renewal projects, the length of which will generally far exceed that required for maintenance works. Again, for EDF Energy, this is a current rather than longer term issue due to the present sustained level of new development activity across the region supplied by our licensed networks. A consequence is that, at least unless interim reinforcement is feasible and economically justified, arranged outages to effect major works at GSP substations, where the annual demand cycle precludes such work being completed during a period when the demand will be less than 67% of Group Demand, will involve a risk of some customers remaining disconnected following an SCO. Where a DNO such as EDF Energy is managing an ongoing major reconstruction / reinforcement programme sometimes with overlapping outages affecting electrically adjacent networks, the risk of an unplanned SCO is significantly raised. Indeed the level of risk is such that our construction solutions frequently require interim reinforcement and/or 'off-line' build to mitigate the risk.

Taken together, the above two issues give rise to a further concern. The scenarios surrounding high summer loading, extended (weekday) daily load cycles, and high ambient temperatures are particularly characteristic of high density urban networks such as those serving central London. Indeed, in central London, the well known 'heat island' effect can result in summer night-time ambient temperatures being uplifted by typically 6 deg C and by up to 9 deg C during very hot spells. As well as reducing plant ratings, this in turn creates additional demand on air cooling systems and hence electrical demand[10].

In terms of updating ER P2/6 to take account of climate change, again we do not envisage changes to ER P2 per se. Climate change in any case is not necessarily what is driving demand patterns in the shorter term so much as growing expectations of employees and customers in terms of ambient comfort levels and the growing need to provide air cooling to combat IT equipment related heat dissipation.

In terms of plant and equipment ratings, again it is not necessarily climate change that is driving the trend towards higher ambient temperatures in the shorter term so much as the above mentioned heat island effect from increasing numbers of high-rise buildings (and the fact that air cooling is also having a heating effect on ambient temperature) leading not only to higher ambient day temperatures but also a heat-storage effect that extends higher ambient temperatures into the evening period, to some extent undermining plant and equipment cyclic rating assumptions. This does not compel changes to ER P2/6 but it does mean that capacity margin assessments need to take account of changes to daily and annual demand patterns and their impact on cyclic (particularly emergency cyclic) ratings.

Environmental and sustainability issues

In terms of 'environmental and sustainability' issues, any consideration of 'sustainability' must take account of environmental, social and economic factors. In particular, measures to address climate change might have a direct impact on the economic and sustainable development of distribution networks. Again taking central London as an example, it is becoming very clear that significant investment (in terms either of conventional reinforcement or active network management technologies) will be necessary to accommodate the fault level contribution from

[10] London's Urban Heat Island: A Summary for Decision Makers http://www.london.gov.uk/mayor/environment/climate-change/docs/UHI_summary_report.pdf

decentralised generation (for example in the form of CHP) that will be a feature of much new major development required to demonstrate a low carbon footprint. It follows that reinforcement might be triggered even though the network is ER P2/6 compliant.

There is a clear analogy here between firm capacity headroom (the basis of ER P2/6) and fault level headroom; indeed the analogy extends to the consideration of outages. Indeed, for the networks serving central London, under FCO conditions, the fault level headroom may actually become more constrained. This is due to the fact that the busbars at central London's main substations operate in split formation under normal running arrangements due to the background fault level. In the event of a (fault) FCO of a transformer feeder, demand (and any DG) is transferred through automatic coupling of the busbars, thereby increasing the overall fault level contribution from DG onto the now coupled busbars as well as increasing the 'G74' motor infeed contribution[11].

EDF Energy are sponsoring research into zero fault-level generation and fault current limiting technologies which might provide a solution to fault-level constraints in the longer term. In the meantime, there have been a number of cases where the connection of synchronous generators (in the form of CHP) has made it necessary to either provide active constraint (e.g. in the form of intertripping), undertake reinforcement, or provide sole use assets in the form of long cable connections to parts of the network with sufficient fault level headroom.

Aspects of ER P2/6 which should be reviewed

Ofgem's letter poses the question as to whether the reliability calculations which underpin ER P2/6 should be reviewed. Due to the improvements that DNOs have achieved through targeted investment and condition based maintenance, it may be that the reliability (particularly overhead line reliability) assumptions underpinning ER P2/6 might now be pessimistic in some respects. On the other hand, there is evidence of a negative reliability trend for some ageing underground paper insulated cables. Moreover, based on experience, an increase in newbuild activity (for example as a consequence of the Governments targets for new housing) might precipitate an increase in 3rd party cable damage.

Apart from 'reliability calculations' there are other factors that might now call into question the 'currency' of ER P2/6 Table 1 and the underpinning analyses within ACE Report No. 51 (1979); in particular switching time and repair time indices, and

[11] Following a (fault) FCO of a transformer feeder, the transformer infeed capacity onto the coupled busbar either increases (4 transformer sites) or remains the same (3 transformer sites), as distinct from the case of a 'conventional' two-transformer primary with a normally coupled bus-section where the transformer infeed capacity would decrease.

the financial valuation of 'kWh saved' as applied to cost-benefit calculations. Partly because of the incentives on DNOs to improve the quality of supply performance of their networks, and partly because of the higher valuations that some customers might now place on a secure electricity supply (for which purposes 'kWh saved' may or may not be the appropriate measure), it would be inappropriate without further investigation to assume that the underlying assumptions within ACE Report No. 51 continue to be valid.

What does, in our view, compel a review of ER P2/6 is consideration of two important (and related) issues:

- Where annual demand patterns would preclude outages being constrained to periods where the demand is less than 67% of Group Demand (as per the assumption in ER P2/6 regarding 'maintenance' outages for Class E Demand Group) and, more to the point, where the demand on the Group is such that restoration of the complete Group Demand under SCO conditions would be dependent on restoring the outage;
- The issue concerning 'construction' outages which will generally require much longer outage restoration periods, noting that such construction outages are often taken to effect major reinforcement which means that firm capacity (including transfer capacity) margins will generally be very thin.

Central Business Districts and Critical National Infrastructure

For major commercial centres, the criticality of reliable infrastructure to economic sustainability should not be underestimated; current concerns over the potential impact on business of inadequate airport capacity serving London being a case in point. Our belief is that for central London to retain its status as a major international centre of finance and culture, and a pathway for inward investment, it is now essential to plan for a future more secure and resilient infrastructure with adequate capacity to sustain continued growth. Within that context, electricity infrastructure must be a key priority.

Whilst Ofgem's letter cites generally favourable comparisons between European and GB quality of supply indices, it is nevertheless the case that many comparable financial, commercial and cultural centres across the world enjoy the benefits of a considerably more secure electricity network infrastructure; those of Hong Kong, Tokyo, New York and Paris being prime examples.

Prolonged power outages in such centres can be particularly traumatic for large groups of people. Whilst we applaud the recommendations in the KEMA/IC report for a far more robust assessment of the value of EENS (as outlined in section 5.1. of the report) taking account of differential 'sector customer damage functions', we do not believe that even this approach is capable of fully reflecting the impact on society of prolonged power outages in major city centres and particularly areas such as central London.

For example, consideration needs to be given to the potential impact of extensive and prolonged power outages on businesses, cultural centres, education establishments, transportation and telecommunication systems, emergency services, and the urban infrastructure generally. It will be evident from such consideration that the numbers of people impacted by a power outage will be of a higher order of magnitude than numbers of (connected) customers; it will include employees, tourists, theatre-goers, students, school parties, shoppers and people simply passing through London as a consequence of it being a natural transport hub (e.g. for the national rail network).

It follows that using numbers of (connected) customer interruptions and customer minutes lost as a measure of the seriousness of a power outage could seriously understate the impact on people (or society) of supply interruptions in such areas, as could any financial evaluation of impact using 'kWh saved' as a basis. This is particularly pertinent in the context of an SCO for a Class D or E Demand Group following an arranged construction (as opposed to maintenance) outage.

Whilst applying the principles adopted in CIGRE Technical Brochure 191 and other methods to evaluate the impacts of electricity supply interruptions (as referred to in sections 4.5 and 5.1.2.1 of the KEMA/IC report) might close the gap, even this approach might not fully reflect the whole of the societal impact of prolonged power outages in central business districts. Indeed the relative rarity of such events is not conducive to deterministic evaluation. Nevertheless, the potentially severe consequences of such events are such that the risk must now be addressed.

We therefore believe there is a need to now give serious consideration to the wider societal impacts of major power outages in our increasingly digital and electricity-dependent major cities, accurately reflecting the impact on people and the national economy; not simply connected customers. Such consideration would naturally take account of the potential impact of feasible common mode failure events (i.e. multiple unplanned outages) and of the potential impact of (unplanned) second circuit outages during construction (arranged) outages where critical items of plant will generally be out of commission for prolonged periods.

It may be that consideration of 'high impact low probability' events would be more effectively addressed outside the remit of any proposed revision to ER P2 (the newly formed 'HILP' working group will deliver its conclusions in this respect in due course) but it will be important to ensure that any recommendations are based on the underlying principle that design levels of network security should at all times be commensurate with the level of risk to society, and not simply based on numbers of connected customers impacted, or EENS.

Annexe - EDF Energy's approach to evaluation of capacity margin

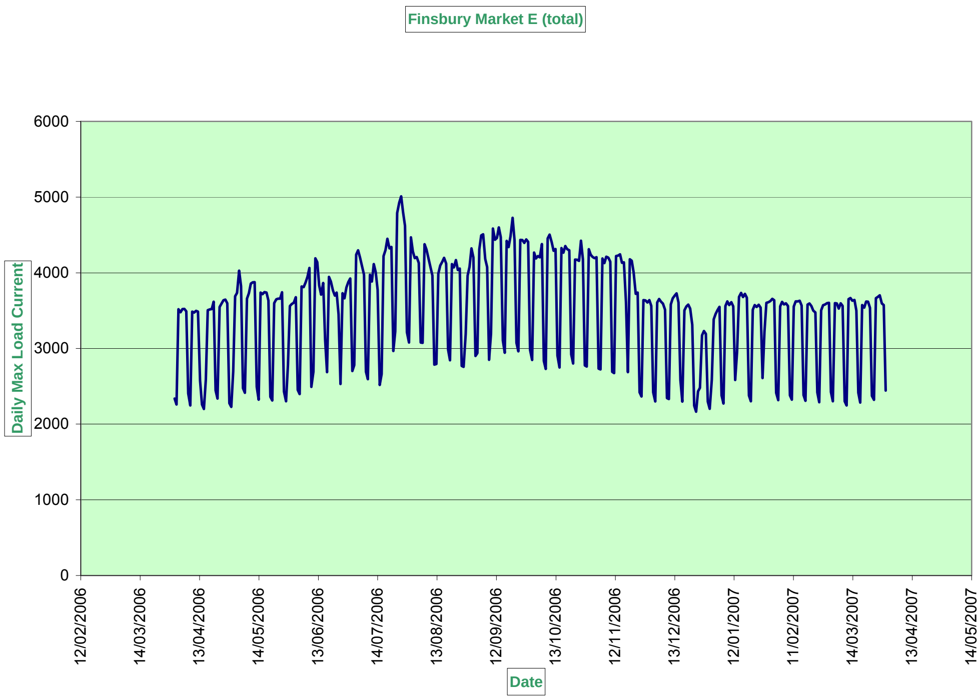

Fig 1 – plot of daily maximum loadings for Finsbury Market E - a summer peaking substation

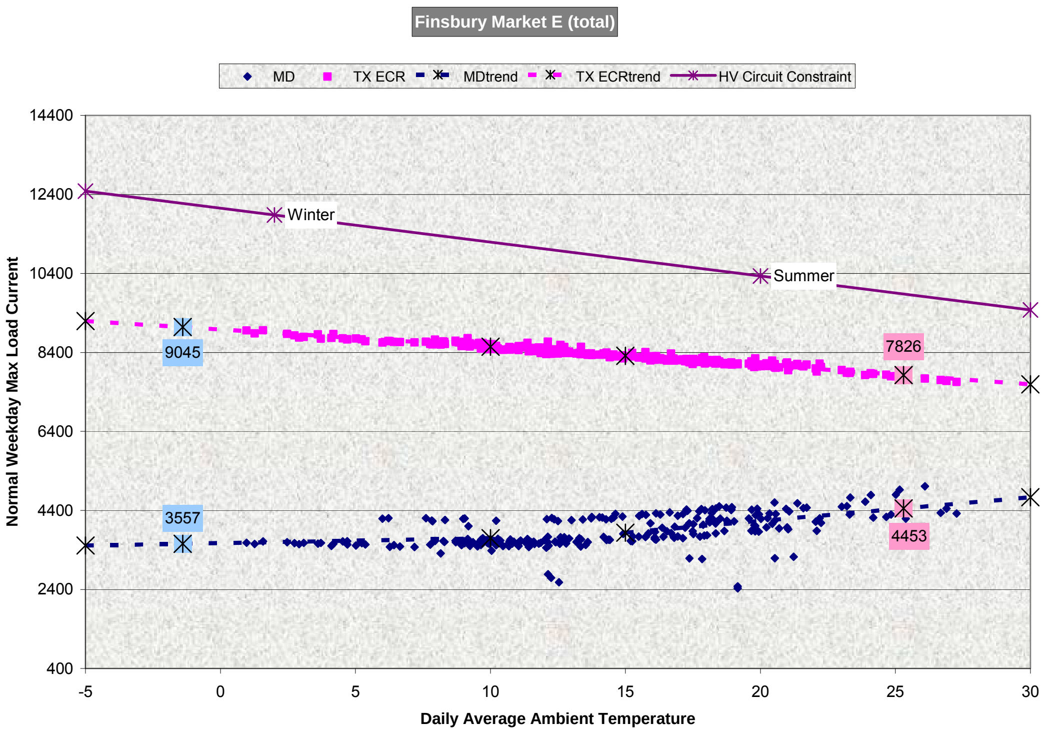

Fig 2 – evaluation of firm capacity headroom for Finsbury Market E substation